Oil Petroleum System of the Cenomanian-Turonian Blackstone Formation, Ferrier – Willesden Green – Gilby Area, West-Central Alberta*

Kevin Greff[1] and Burns Cheadle[1]

Search and Discovery Article #80371 (2014)
Posted March 31, 2014

*Adapted from extended abstract prepared in conjunction with presentation at CSPG/CSEG/CWLS GeoConvention 2012, (Vision) Calgary TELUS Convention Centre & ERCB Core Research Centre, Calgary, AB, Canada, 14-18 May 2012, AAPG/CSPG©2014

[1]Western University, London, Ontario, Canada (kgreff@uwo.ca)

Summary

The Cretaceous (Cenomanian - Turonian) Blackstone Formation of the Colorado Group in west-central Alberta represents a self-sourced petroleum system with proved light oil production. Although a high-resolution allostratigraphic framework for the Upper and Lower Colorado Group of the foredeep of the Western Canada Sedimentary Basin is documented (Tyagi et al, 2007), the understanding of the Blackstone carbonaceous mudstones in the context of a self-sourced petroleum system remains rudimentary.

The Second White Specks light oil play is hosted within heterolithic carbonaceous mudstone reservoirs of the Blackstone Formation in the central region of a 110 township project area (Twp. 35-45, Rge. 1-10 W5) of west-central Alberta . Historically, exploration results in this play have been inconsistent. The research goal is to characterize the burial history and reservoir properties of this organic-rich mudstone reservoir in order to develop a process-based petroleum system model. The resulting model is intended to provide guidance for exploration and development of a large conventional oil resource play hosted in "hybrid" carbonaceous silty mudstone reservoirs.

The Second White Specks petroleum system model is constrained by a high-frequency allostratigraphic framework constructed using a subsurface dataset of over 2200 wells. Available cores in the Blackstone Formation have been sampled at closely-spaced regular intervals for Rock-Eval pyrolysis analyses, supplementing a regional dataset of legacy Rock-Eval data. Petromod petroleum system analysis will be integral to modeling the timing and extents of the system. The resulting data is integrated into a reservoir characterization workflow (Cheadle, 2011) which aids in prospect identification.

Introduction

The Second White Specks light oil play of west-central Alberta has been a secondary target for operators since the 1960's, but inconsistent production performance has discouraged development. Frequently dismissed as an unpredictable, fracture-controlled play, the alternative possibility is that extreme heterogeneity in primary intrinsic porosity distribution (Schieber, 2010) may be responsible for much of the inflow performance variability. Multistage hydraulic fracture treatments coupled with horizontal completions have opened new opportunities to develop this heterogeneous, unconventional reservoir. The successful application of these technologies, however, depends on providing drilling and completion guidance through a properly constrained reservoir characterization model.

While producibility of many carbonaceous mudstone reservoirs is at least partially dependent on natural fracture systems (Gale et al., 2007), the Blackstone Formation performance may reflect a different, and much earlier, set of processes. The intrinsic porosity of mudstone is determined by fabrics imposed during deposition and compaction of the mudstone (Schieber, 2010). Two of the most common forms of intrinsic (fabric-related) microporosity developed in carbonaceous mudstones, such as the Blackstone Formation, are phyllosilicate framework pores and micropores developed within disseminated organic matter particles as a result of kerogen degradation. Both of these pore types have been observed in Blackstone Formation samples as part of a related research project at Western. Mudstones with these forms of intrinsic porosity are finely interbedded with very fine-grained sandstones and siltstones that exhibit conventional interparticle porosity. The interbedded nature of the Blackstone means it should be considered as a “hybrid’ system, rather than a pure end-member “shale” reservoir. Reactive carbon, with its associated organic-matter porosity, is preferentially preserved in the mudstone laminae and thin beds, and is the putative source of oil and gas reservoired locally within the Blackstone strata. The composition and distribution of reactive organic matter varies laterally and vertically within mudstones due to the influence of allogenic controls on depositional environment (Passey et al, 2010). Consequently, integration of organic-matter characterization within a high-frequency allostratigraphic framework is necessary for prediction of the spatial and temporal distribution of both source and reservoir properties (Aplin and MacQuaker, 2011).

When characterizing a heterogeneous hybrid reservoir, such as the Blackstone Formation, conventional variables used to simulate production, such as physical, chemical and structural data, must be adapted to effectively predict production behaviour. This adaption is accomplished through a reservoir characterization workflow that explicitly embeds the dynamic interplay of geological processes in the depositional and burial domains. The resulting petroleum system model provides a fully coupled spatial and temporal framework that describes and predicts not only hydrocarbon distribution, but also fabric-controlled storage capacity and flow capacity.

Method

The project, located in the Willesden Green – Ferrier – Gilby area, lies within the central region of the Second White Specks oil play corridor of west-central Alberta. Rock-Eval pyrolysis analyses have been performed on 88 samples from three full-diameter cores within the study area in order to evaluate the timing and extent of the petroleum system. A 75-metre core (100/07-19-045-06W5) with a total of 73 samples, presents the most complete cored interval (Figure 1) of the lower Vimy Member and upper Sunkay Member of the Blackstone Formation (Varban and Plint, 2008), whereas two shorter cores intersect the oil-productive, siltier-to-sandier-upward interval of the lowermost Vimy Member overlying the "red (Bighorn River) bentonite" (Tyagi et al., 2007).

A dense grid of cross-sections, incorporating the cored wells, has been constructed using digital well log data for approximately 2200 wells in the project area. The cross-sections tie into published Colorado Group allostratigraphic cross-sections (e.g., Varban and Plint, 2008; Tyagi et al., 2007) in order to maintain regional consistency. The goal of creating a high-frequency allostratigraphic framework is to constrain subsequent petrophysical and burial history analyses. Most bentonite markers and allomember tops are laterally continuous in the study area. The dense grid aids in detection of subtle changes in petrophysical responses in the heterolithic mudstone succession.

Rock-Eval analyses of core samples (e.g., Figure 2) have been integrated with detailed graphic core logs and well log responses in order to visualize high-frequency allostratigraphic controls on lithological and geochemical properties. Future petrophysical work will involve mineralogical modeling and porosity and organic-content estimations. These will be ground-truthed, using sample analyses, including imaging of intrinsic microporosity in the disseminated organic matter and clay fabrics from focused ion beam and secondary electron microscopy (FIB-SEM) imaging.

Results

The allostratigraphic framework is complemented by the core samples of well 100/07-19-045-06W5 (Figure 1), as well-log responses correlate to the siltier-upwards sequences seen in core. The Red Bentonite, which is normally indicated by high gamma-ray values, is apparently not present in this well, although it is evident in most wells in the project area. The siltier-upwards cycles culminate in flooding surfaces. Elevated TOC levels are associated with the siltier, heterolithic allomembers, whereas the mud-dominated Red Bentonite to K1 interval (i.e., 1820-1845 mKB, Figure 2) exhibits significantly lower TOC.

Plotting the S2 versus TOC (Figure 3) confirms preservation of Type II organic matter and suggests that the thermal maturation phase of burial immediately began catagenesis of oil with sufficient time and temperature (Passey et al., 2010). All of the samples for well 100/07-19-045-06W5 have Tmax values between 443 – 450°C, indicating the rocks have undergone heating necessary to peak oil production.

Conclusions

The Upper Cretaceous Colorado Group of the Western Canadian Sedimentary Basin offers a unique perspective into “hybrid” carbonaceous, silty mudstone reservoirs. Rock-Eval pyrolysis analyses of samples from well 100/07-19-045-06W5 provide evidence of carbonaceous source rock having undergone burial conditions ideal for peak oil generation. TOC values show that the Blackstone mudstone is a viable source rock, with variations in source-rock properties reflecting stacking of stratal packages. The Blackstone is considered self-sourcing due to it hosting the original organics within a tight mudstone reservoir. The resulting data when integrated into a reservoir characterization workflow aids in prospect identification.

Acknowledgements

We thank Mr. Bill Bell for his generous support of the petroleum geosciences program at Western.

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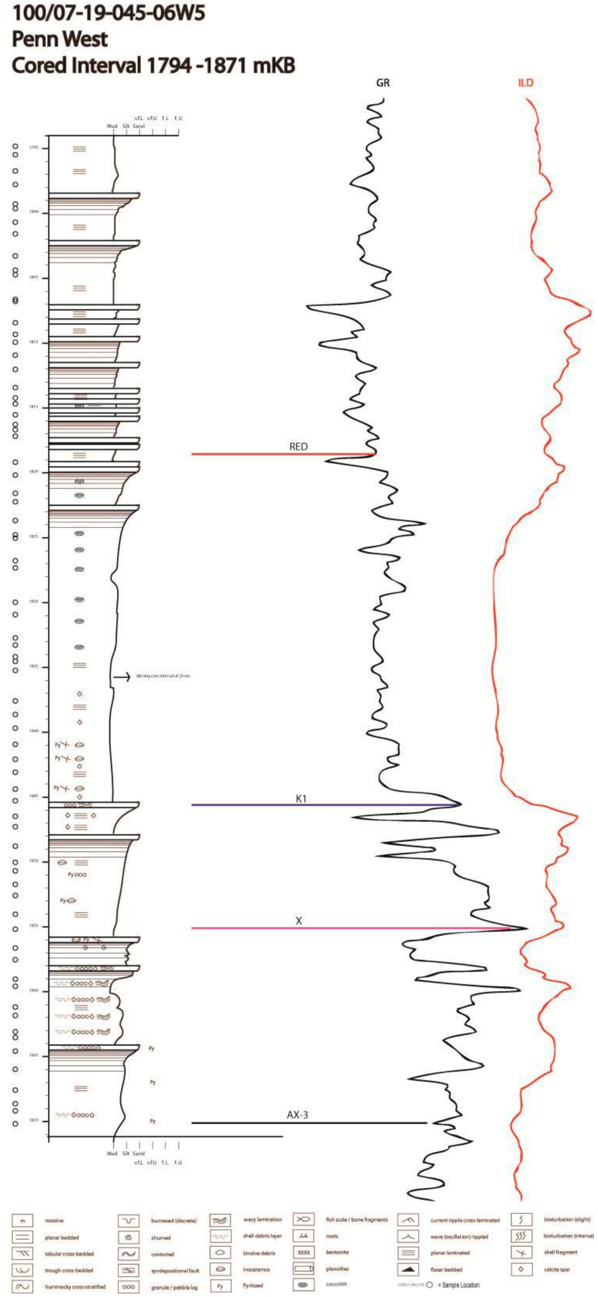

Figure 1. Graphic core description correlated to gamma ray (GR) and deep resistivity (ILD) responses, 100/07-19-045-06W5.

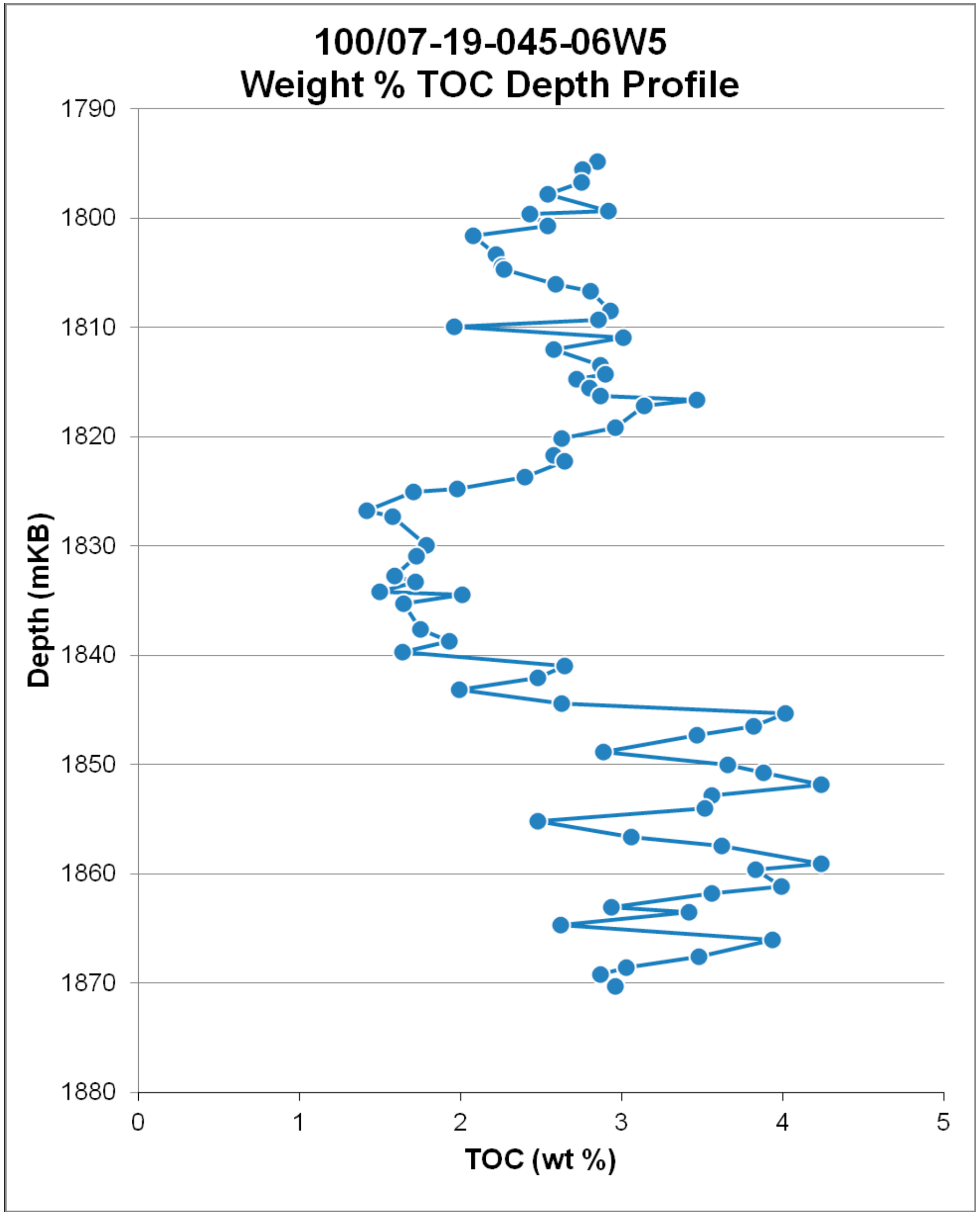

Figure 2. Measured TOC profile of well 100/07-19-045-06W5 using Rock-Eval pyrolysis data.

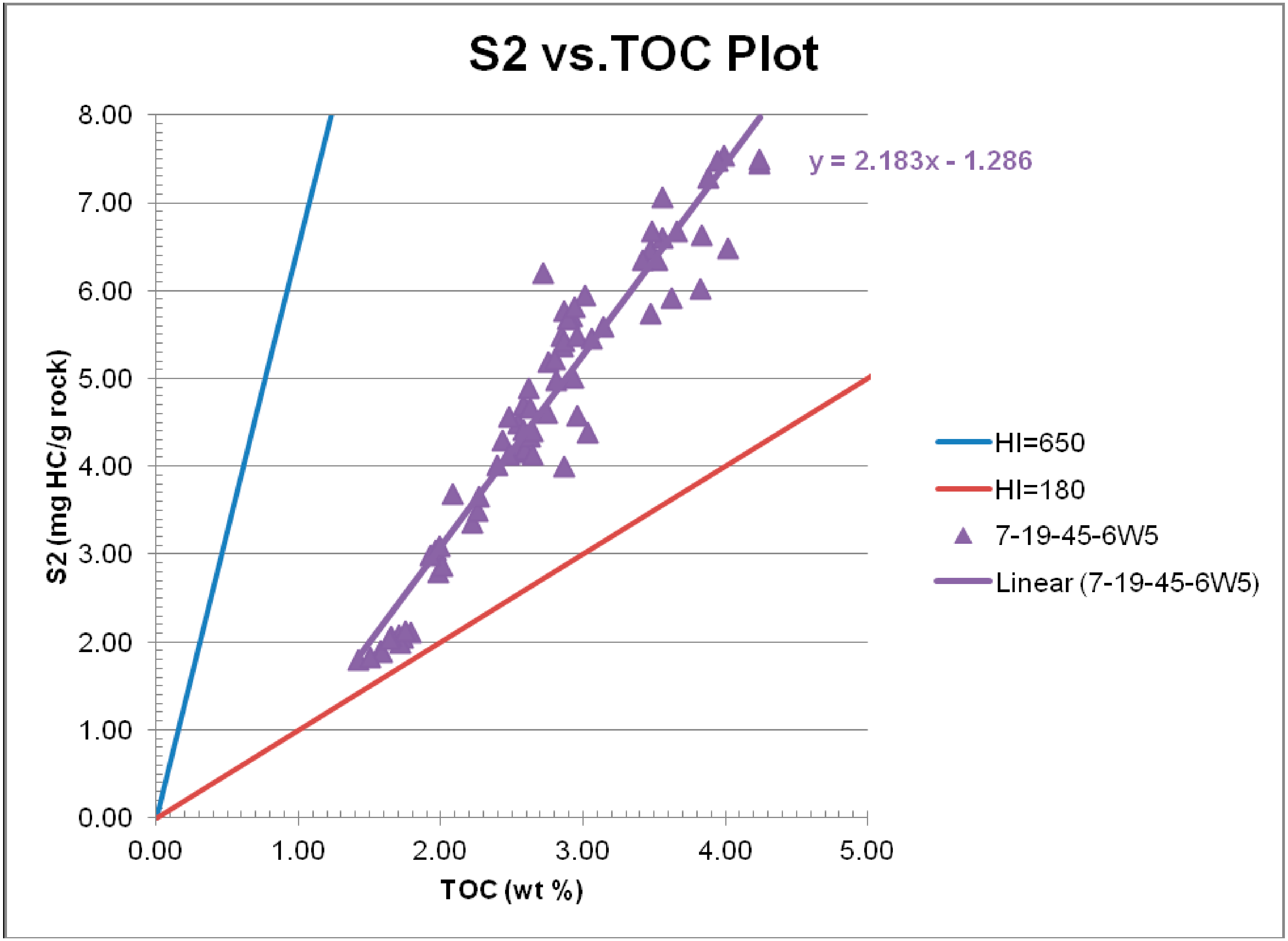

Figure 3. Plot showing Type II kerogen classification of well 100/07-19-045-06W5. The slope of the plotted points gives the average hydrogen index (HI) of the samples. An HI greater than 180 but less than 650 indicates a Type II kerogen. HI>650 indicates Type I, and HI< 180 indicates Type III.