Using Biomarker Geochemistry as a Reservoir Surveillance Tool; Supported by 4D Seismic and Observation Well Results

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Introduction

In the McMurray Formation within the Athabasca Oilsands in Alberta, Canada, Steam Assisted Gravity Drainage (SAGD) developments are monitored for steam chamber growth to aid in reservoir characterization and ultimately production optimization. The most common industry accepted methods to monitor the spatial distribution of steam chamber growth are: 1) using observation wells to monitor the pressure and temperature changes throughout the reservoir, 2) using 4D seismic inversion results to produce a 3D image of the steam chamber. This case study focuses on using oil geochemistry as a reservoir surveillance tool. The case study will go through the benefits and limitations of using oil geochemistry as a surveillance tool.

Theory and/or Method

In the case study area of Long Lake, the in-situ viscosity of the bitumen in the McMurray Formation ranges from 300,000 to 10 million centipoise. The large viscosity range is due to different rates of biodegradation, which is primarily dependent on the proximity to water sources (bottom water, flank water, high water saturation intervals and top water) where microbial concentrations are higher (Larter, 2003, 2008; Fustic, et al., 2011, 2013; Adams, et al., 2013). These biomarker concentration changes throughout the bitumen column are used to identify diffusivity baffles, obstacles and barriers and identify the stratigraphic location of produced oil (Devere-Bennett, et al., 2018).

The case study focuses on a development area of 11 horizontal producers with 11 vertical core wells in close proximity (Figure 1, top right image). Multiple bitumen samples were extracted from each core at strategic reservoir intervals through Solid Phase Extraction (SPE) and individually analyzed using gas chromatography – mass spectrometry (GC-MS). Produced emulsion samples were taken from the field at the well head, dewatered with sodium anhydrite and followed up by SPE and GC-MS analysis.

The core and emulsion sample's GC-MS data were analyzed to determine stratigraphically where the oil was being produced. The core sample's GCMS data allowed for baffles, obstacles and barriers to be identified from the concentration data (Figure 1). This also led to the petrophysical pay top for Well 3 to be adjusted, as the two metre mudplug facies at 262m ASL, was interpreted to be an obstacle; a short lateral diversion for the steam chamber to grow around.

The produced emulsion sample's concentration and chromatogram data were analyzed and compared to the core sample's GC-MS data using multiple methods including: correlating the summation of specific biomarker classes and compound groups, comparing compound ratio results and fingerprinting the peaks of compounds within distinct mass to charge ratios.

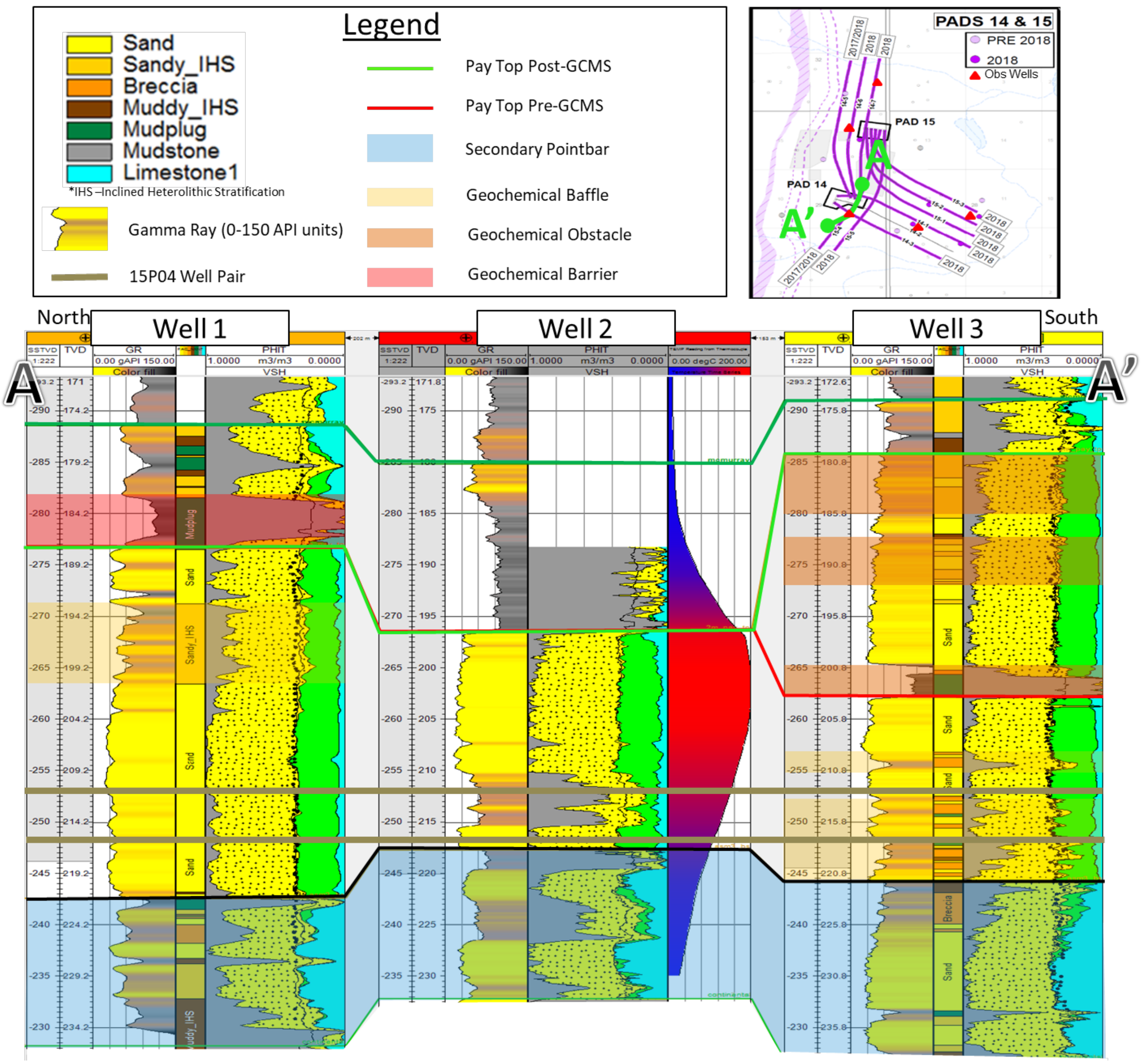

Figure 1: A structural cross-section from north to south (A to A'). The cross-section is parallel to 15P04 well pair and the wells are <30m projected from the well pair.

Examples

The GC-MS data analysis of the produced emulsion samples of 15P04 resulted in identifying produced oil derived from above the mudplug obstacle at 262m ASL (seen in Figure 1, Well 3). All analytical methods pointed to evidence in which some portion of the oil has been drained from above the mudplug. Based on the dip of the mudplug and inclined heterolithic strata (IHS), it was suspected the oil was draining towards the toe of 15P04.

The 4D seismic inversion image along 15P04 (Figure 2), illustrates strong P-impedance anomalies above the mudplug in Well 3 (Figure 1), indicating the steam chamber has grown around the mudplug from the south. This supports the interpretation of the GC-MS analysis.

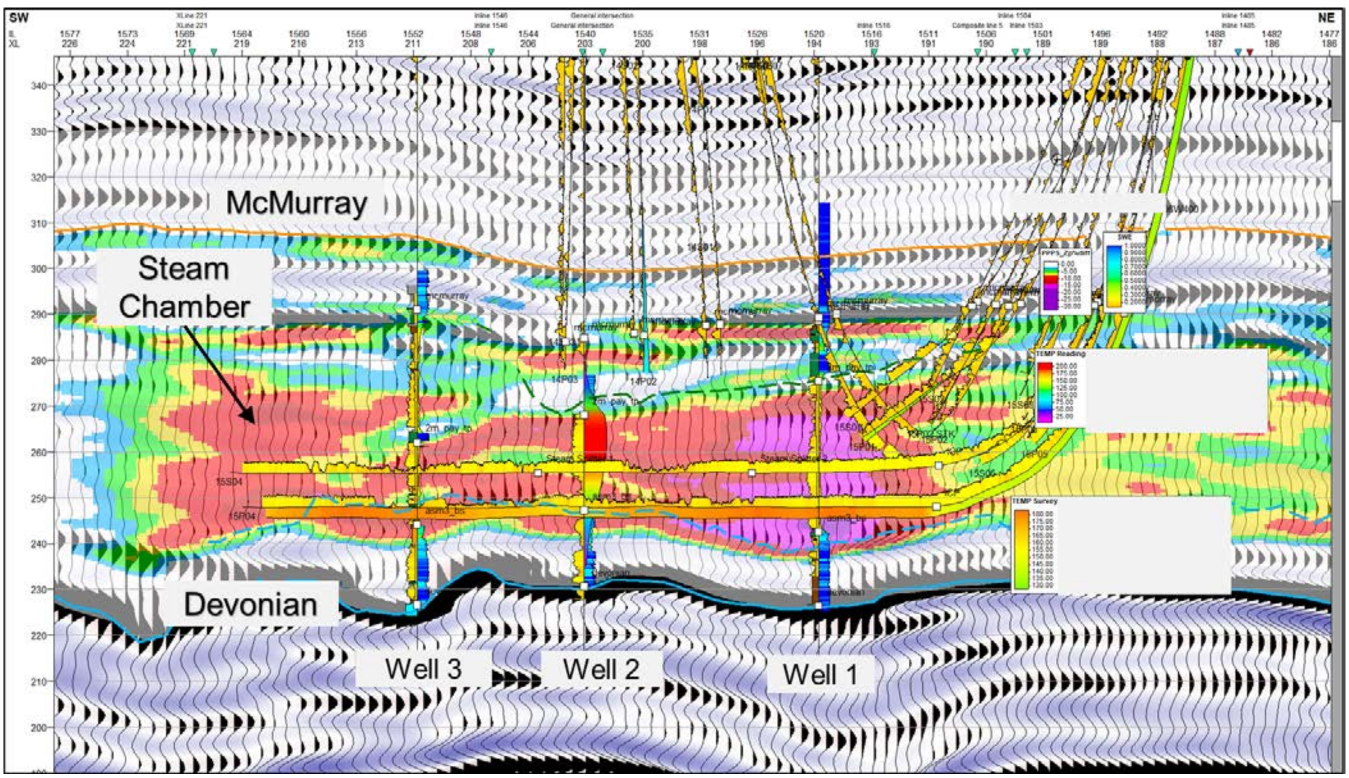

Figure 2: A 4D seismic image along 15P04, illustrating the P-impedance difference between the 3D monitor and baseline seismic surveys.

Conclusion

As a product of GC-MS, the concentration and chromatogram data have been used to align the produced oil samples stratigraphically to the core samples from the vertical wells. Produced oil samples have geochemically demonstrated there is growth in the steam chamber height over time. The geochemically interpreted stratigraphic elevations in which oil production is derived, has been supported using 4D seismic inversion results, along with observation well data results. The 4D seismic inversion work seen in Figure 2, came after the geochemical data was interpreted and supports multiple hypotheses from the GCMS analysis.

The accuracy of the interpretation is dependent on the number of core holes in relation to the number of horizontal producers and the frequency in which produced oil samples are collected and analyzed.

Overall, GC-MS analysis of produced emulsion samples can be a valuable reservoir surveillance tool, which can be monitored at any frequency.

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