Reservoir and Bitumen Heterogeneity in Athabasca Oil Sands

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Abstract
The Athabasca Oil Sands (AOS) deposit, the largest petroleum accumulation in the world, is extremely heterogeneous with respect to physical reservoir characteristics such as geometry, component distribution, porosity, permeability; mineralogy and mineral chemistry; aqueous fluid distribution and chemistry; and the distribution and chemistry of bitumen. Variations in these properties appear to be interrelated, and reflect the dynamic and complex depositional history as well as post-depositional oil alteration processes.

Detailed characterization of all of the above aspects is required to better understand the interrelationship of components within the reservoir and the overall reservoir behaviour and reactivity at production conditions, for optimization of exploitation methods and the development of new technologies.

Our geochemical studies focus on the heterogeneous distribution and composition of minerals and hydrocarbons. These are placed in a stratigraphic and sedimentologic context, and integrated to address the problem of reservoir heterogeneity. Variability of the bitumen maybe a function of several parameters, including presence or absence of a water leg, the continuity of the reservoir column, sedimentary facies, water chemistry (salinity), and mineralogy. Bitumen composition is correlated with viscosity measurements and the geology of the host rocks. The results obtained indicate that the bitumen is heterogeneous on a reservoir thickness scale and that a close relationship exists between bitumen composition and viscosity, implying bitumen properties are predictable. Generally the quality of bitumen decreases down the hole, but also along certain depositional breaks.

The above provides a multi-faceted approach to obtain information suitable for optimising either in situ or surface mining operational recovery of bitumen and advancing development of new technologies.

Introduction

The AOS deposit (Fig. 1), the largest petroleum accumulation in the world, contains immobilized bitumen as a result of microbial degradation of conventional crude oils. Within the deposit, petroleum gravity ranges from 6 to 11 API. This unfavourable characteristic of the petroleum requires a thorough economic assessment of the resource that starts with a search for thick, continuous and highly permeable sand intervals with high bitumen grade, and lack of fines (clay and silt). Open pit mining and Steam Assisted Gravity Drainage (SAGD), two currently employed technologies for exploitation of this vast bitumen resource requires enormous amount of energy for extraction and upgrading bitumen to crude oil. Economics suggests that an average energy equivalent of 1.2 barrels of oil is used to produce 2 barrels of oil in mine operations. In the case of SAGD, this ratio is even worse, and in some on going operations has not been proved economical.

Alberta Ingenuity Centre for In Situ Energy (AICISE) is multidisciplinary research group formed as an initiative of the Alberta government that investigates application of innovative technologies. The current focus is on *in situ* upgrading to enhance recovery and product value. Such a project requires a detailed characterization of the reservoir and the petroleum within it. Reservoir heterogeneity is investigated on several scales with a focus on a scale suitable to guide *in situ* production.

Here, we present and compare preliminary results from two study areas. One is from a surface mineable area located about 60 km north of Fort McMurray. The other is from an *in situ* designated area located about 45 km south of Fort McMurray (Fig. 1). Details from two representative cores (11-27-095-9 W4M and 1 AD / 13-26-084-11 W4M) are presented.

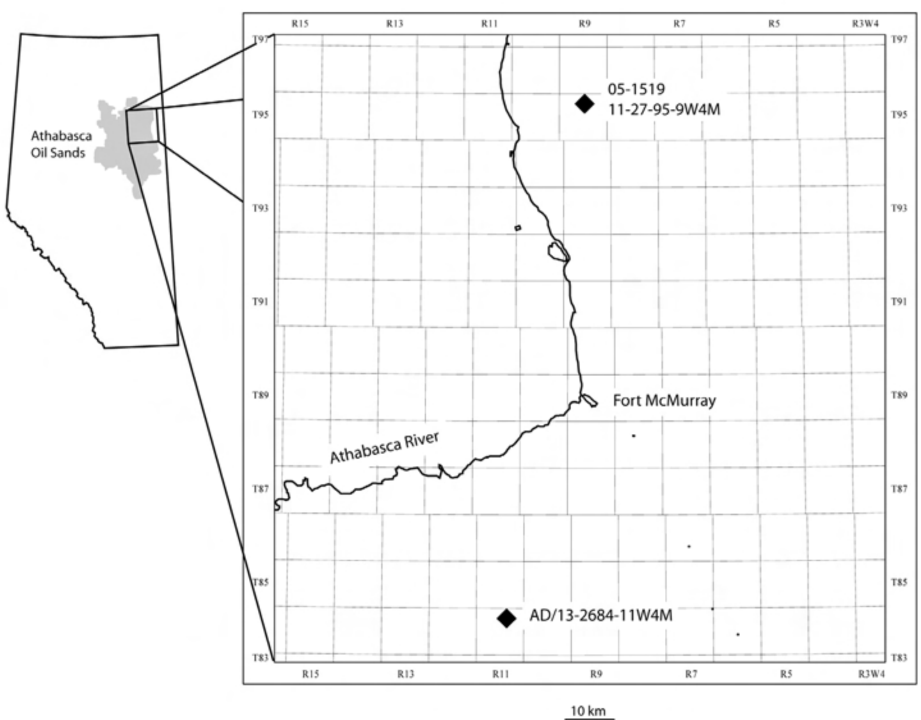

Figure 1. Location Map

Stratigraphy, sedimentology and oil biodegradation

The complex reservoir stratigraphy and architecture are inherited from dynamic depositional processes that range from fluvial to shallow marine (Fig. 2). The main bitumen hosting zones are thought to have been deposited in estuarine settings of the Middle McMurray Formation. It has been suggested that the sequence consists of multiple estuaries overlapping in space and time (Wightman and Pemberton, 1997), and that each estuary comprises several hierarchical levels of heterogeneity. Fluvial, estuarine and shallow marine lithofacies assemblages (lower, middle and upper McMurray Formation, respectively) are mappable between exploration wells. However, due to significant heterogeneity, correlating individual estuarine facies is difficult, even with closely spaced wells (100-150 meters apart). Heterogeneity is due to a complex interfingering of estuarine architectural elements being point bars, abandoned channels and tidal flats (see Fig. 2 furthest right). Dipmeter logs have been proven as a valuable tool for prediction of channel-fill type (Muwais and Smith, 1988) and for assessment of vertical continuity of channel deposits (Brekke and Evoy, 2004).

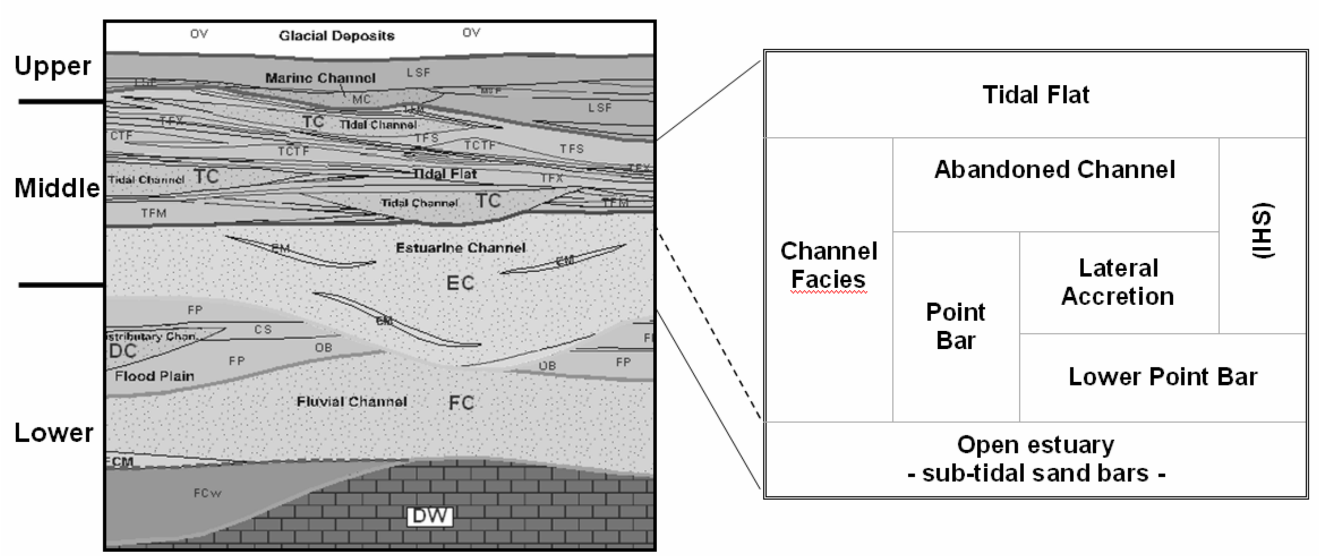

Figure 2. Schematic 2D depositional diagram of McMurray Formation broken into its constitutional units: continental (lower McMurray Formation), estuarine (middle McMurray Formation) and marine (upper McMurray Formation). The right side of diagram shows major architectural elements that comprise the most heterogeneous sediments deposited in estuarine setting. Modified chart courtesy of Albian Sands Energy Inc.

In some respects post-depositional processes, diagenesis, within these reservoirs are thought to be minimal and the quality of the reservoir is considered to reflect the depositional history of sediments (Wightman and Pemberton, 1997). This appears to be true for physical properties of the reservoir, such as porosity and permeability. However, the quality of petroleum within the deposit, commonly assessed by API gravity, appears to be very strongly influenced by post-depositional processes. Microbial degradation is identified as a major alteration factor (Deroo *et al*., 1974, Brooks *et al*., 1988) that destroyed more than two thirds of initially emplaced oil. Potential controls on biodegradation processes are reservoir temperature, charging, in reservoir mixing, presence and size of oil-water contact, water chemistry (salinity) and availability of nutrients (Larter *et al*, 2003; Head *et al*, 2003).

The Shallow burial history suggests very low reservoir temperature ranges (up to 30 degrees C), which are favourable for rapid growth of micro-organism populations (Wilhelms *et al* 2001). Very little is known about timing and mechanisms of oil emplacement, but considering the size and complexity of the reservoir, mixing of fresh oil into actively degrading oil contained in reservoirs is anticipated, particularly during later stages of the charging history. Regional geological studies suggest the presence of an extensive basal water leg (Ranger and Rottenfusser, 2005). In addition to carbon and hydrogen from petroleum, bacteria may utilize nutrients supplied through groundwater, including local mineral dissolution.

Overall, conditions appear to have been very favourable for intensive biodegradation in the Athabasca region. In addition, reservoir heterogeneity implies complex charging and alteration histories that provide for diverse intensity of biodegradation within reservoirs, and possibly for different alteration pathways.

The result of biodegradation is heavier and more acidic petroleum with methane as a common by-product. Reported bitumen viscosities from different SAGD operations suggest that it ranges from as low as 200 000 cP, parts of Encana's Foster Creek project, to more than 6 000 000 cP, Suncor's Firebag project (data from EUB applications). Petroleum degradation can be measured according to the 10 point scale of Peters and Moldowan (1993). Peters and Moldowan level 1 (abbreviated as PM 1) represents fresh, or very slightly biodegraded, oil; Peters and Moldowan level 10 (abbreviated as PM 10) is severely degraded oil (hopanes and diasteranes absent, C_{26}-C_{29} aromatic steroids attacked). The presence of 25-norhopanes in biodegraded oils is usually an indication that an accumulation has been heavily biodegraded (PM 6 or greater). Samples analysed from the Athabasca tar sands show Peters and Moldowan scales of degradation of about PM 5 (moderate) in the main oil columns. However, levels of biodegradation may vary significantly within wells. There is a trend towards higher levels of biodegradation associated with oil-water contact zones, to level PM 9 (very heavy).

<u>Methodology</u>

Core description and detailed geochemical analysis are conducted on wells from both study areas. Additional mineralogical, palynological and advanced petrophysical investigations were conducted only on wells from the southern Athabasca.

Lithofacies were described based on assemblages of sedimentary structures and ichnology observed in slabbed oil sands cores. Dipmeter logs (when available) were used to identify the vertical continuity of units and orientation of IHS beds. This information was then used to interpret depositional environments.

Bitumen grade (mass %) was measured by the Dean Stark Method or determined by the IATROSCAN method.

Bulk petroleum composition was analysed using IATROSCAN. This provides compositional information on the Saturated and Aromatic hydrocarbons, Resins and Asphaltenes (SARA). Individual compounds were identified by Gas-Chromatography – Mass-Spectrometry. Comparison of molecular markers was used to interpret intensity of degradation in each sample.

Viscosity and density measurements were performed on homogenized sample intervals. Bitumen was extracted by centrifuge in order to avoid possible contamination by solvents. Viscosity measurements were performed using a “Brookfield viscometer” at temperatures of 50, 60, 70 and 80 degrees C, and later back extrapolated to estimate viscosity at the average reservoir temperature of 4 degrees C.

Bulk and clay mineralogy were determined using X-Ray Diffraction (XDR) with a Rigaku Multiflex X-Ray Diffractometer (40kV, 40mA, Cu radiation). These data were analysed semi-quantitatively, and are reported as relative proportions of the major peak heights for bulk mineralogy. Relative proportions of clay minerals were estimated from peak heights using glycolated mounts of the <2 micron size fraction. Data are useful in comparing relative abundance of minerals down the core, but not for absolute abundance.

Petrographic descriptions were carried out using standard thin section and point counting techniques. Bitumen was removed from unconsolidated samples in a soxhlet apparatus with a chloroform / methanol mixture and the clean sand grains were mounted in epoxy prior to thin sectioning.

Palynological analyses were performed on samples that were initially put in 10% HCl to remove carbonates. Silica was then removed with hydrofluoric acid. Unwanted organic matter was oxidized with fresh Schulz’s solution for approximately 2.5 minutes. Samples were further treated with a zinc bromide solution to separate the organic and mineral fractions. The residue was sieved using a 10 micron cloth, mounted on a clean cover slip, which was then mounted on a glass slide using bio-plastic as the mounting medium.

A trained Artificial Neural Network computer based programme (SHALEQUANT) with a wireline log suite as basic input was used to model mudstone physical properties such as grain density and percentage clay content (grains <2µm).

<u>Results</u>

Well 05-1519 – Northern Athabasca Oil Sands Deposit

At this location, the reservoir extends virtually from the surface to the depth of 64 m. (see log on Fig. 3).

The base of the reservoir is a three metre thick cross-bedded sand that displays good sorting and porosity. The sand is interpreted as the deposit of sub-tidal sand bars in an open estuarine environment. Bitumen content is about 16 % by mass.

The cross-bedded sand is overlain by a succession with massive sand at the base that passes upward into thin-bedded heterolithic strata (from 60 to 40 metres on Fig. 3). This unit is interpreted as a 20 meter thick point bar sequence, deposited in a tidally influenced estuarine setting. The inclination of the heterolithic strata and the vertical continuity of this channel fill sequence are inferred from dipmeter logs. Reservoir heterogeneity controls the bitumen content, with a range from 0 % by mass in mud dominated beds and laminae, to as much as 16 % in clean sand.

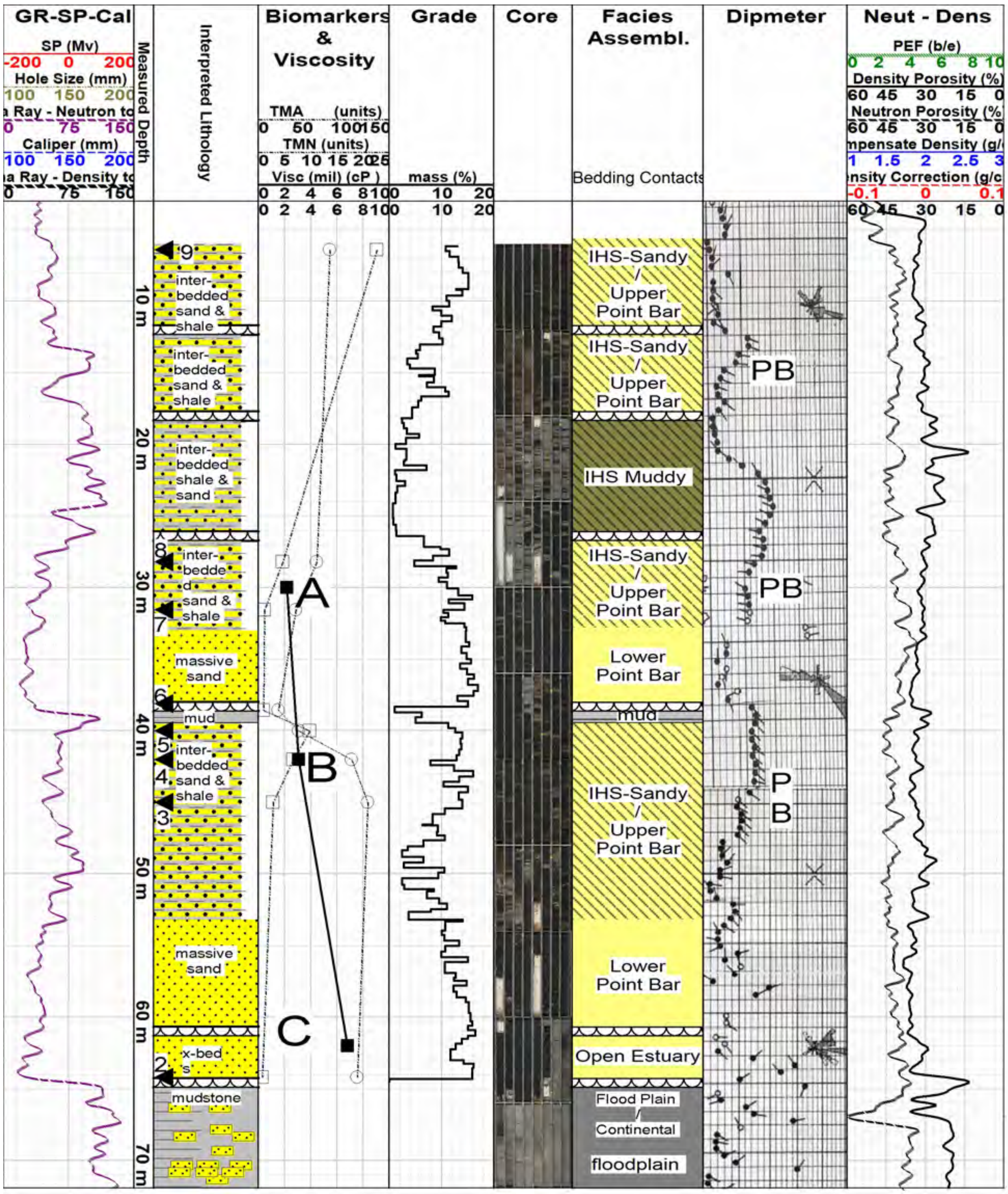

Figure 3. Composite Log 05-1519. Reservoir heterogeneity controls not only the bitumen grade but also quality of the bitumen. Viscosity increases down the hole (points A, B and C) and appears to be the intensified in the best reservoir facies. Biomarker analysis suggests the presence of 3 compartments. From bottom to top the first compartment comprises geochemical samples 2-5, the second 6-8, and the third sample 9. Biodegradation intensifies down the each compartment.

The heterolithic stata of this point bar sequence are overlain by a second massive sand unit that passes upward into sandy, thin bedded heterolithic strata (from 40 to 26 metres on Fig 3), overlain by muddy thin bedded heterolithic strata that are in turn overlain by sandy, thin bedded heterolithic strata. Dipmeter data indicate three separate channel systems in this interval from the surface to 40 metres depth. Despite recognition of several channels with varying properties, no significant vertical permeability barrier is identified, and a continuous petroleum column was initially inferred.

Bulk geochemical profiles obtained by the Iatroscan method (SARA) reveal subtle and gradual changes in composition down the hole (Fig. 4). Interestingly, the bitumen viscosities for temperature of 4°C were from 2,167,618 cP, 3,092,085 cP, and 6,818,609 cP at depths of 30, 40 and 60 meters respectively (Fig. 3). The physical properties data indicate a significant vertical composition gradient. More detailed investigation of the bitumen composition by GC-MS reveals that a number of components appear to respond to the decrease in oil quality indicated by the physical property data. The formation of C_{28} and C_{29} 17α 25-norhopanes increases down to the oil water contact, while over a similar depth the C_{29} and C_{30} 17α hopanes decrease (Fig. 5). These data indicate an increase in the extent of biodegradation down the oil column. Depth profiles of two other compounds, trimethyladamantane and tetramethylnaphtalene (see Fig. 3) also suggest that the bitumen column is discontinuous and may be compartmentalized, with one compartment below 40 meters depth, and the other above. The third compartment may be present above 19 meters depth.

A nearby well (05-1520), shows an overall similar characteristics to this well, but in addition contain a water leg. High-resolution sampling was conducted from the transition zone at the base of the bitumen column. Results confirm the most severe biodegradation at the base and suggest that microbiological alteration is still taking place within this zone.

The reservoir thickness extends from about 270 m. to 316 m (see log on Fig. 6). Eight bitumen samples taken along the column were analysed and placed in context of the sedimentary facies. In addition 24 XRD analyses of selected mudstones and 6 palynological analyses were conducted. Dipmeter data were not available from this well.

Depositional setting is based on sedimentary structures and ichnofacies assemblages. Paleozoic carbonate beds are overlain by a 4 m thick interbedded sand and mud unit which is bioturbated. *Cruziana* to *Skolithos* ichnofacies are dominant. The unit is interpreted as a tidal plain deposit (316 to 312 metres on Fig. 6).

Above this is a 10 metre thick sand dominated unit. Sand beds are punctuated intermittently with thin mudstone beds and laminae. Adjacent wells contain a succession in which this sand passes upward into heterolithic strata. This succession is interpreted as the lower portion of an estuariane channel system.

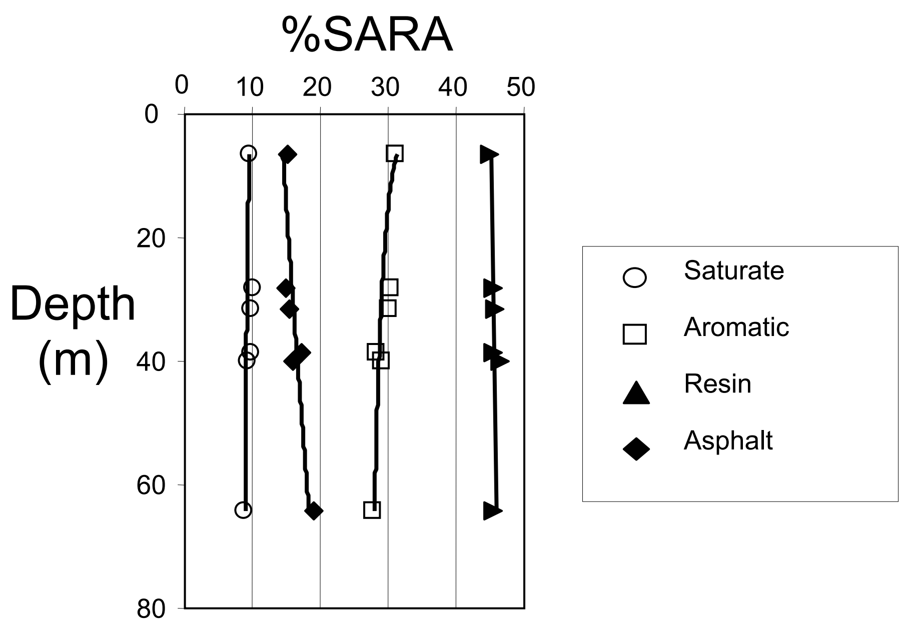

Figure 4. Well 05-1519. Iatroscan (SARA) bulk composition for bitumen versus depth

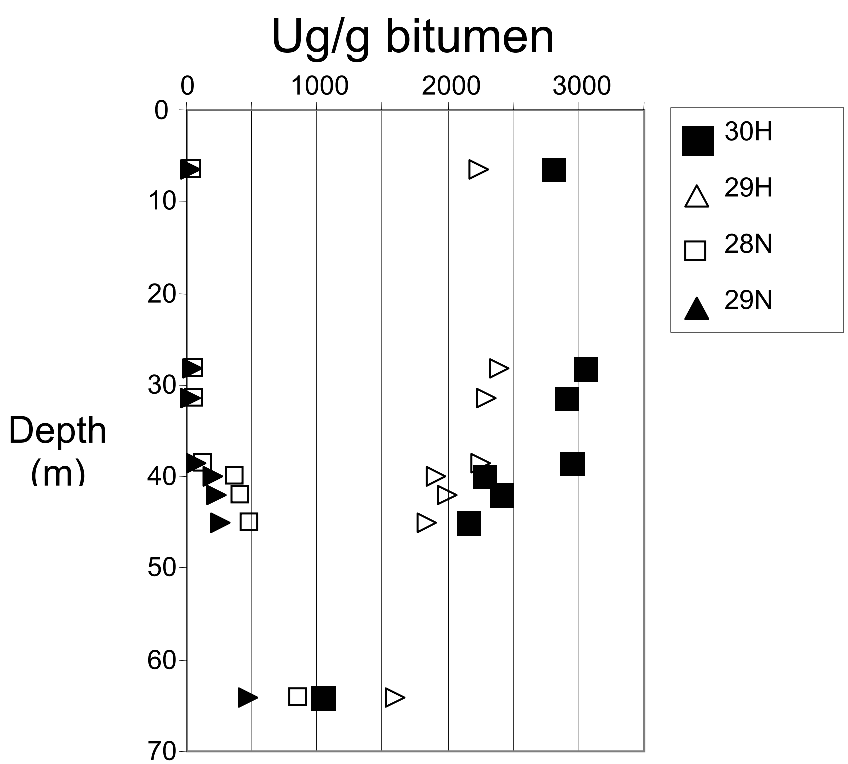

Figure 5. Concentrations (μg/g bitumen) of C_{29} (29H) 17α-hopane, C_{30} (30H) 17α-hopane, C_{28} (28N) 17α-25norhopane and C_{29} (29N) 17α-25-norhopane versus depth in well 05-1519.

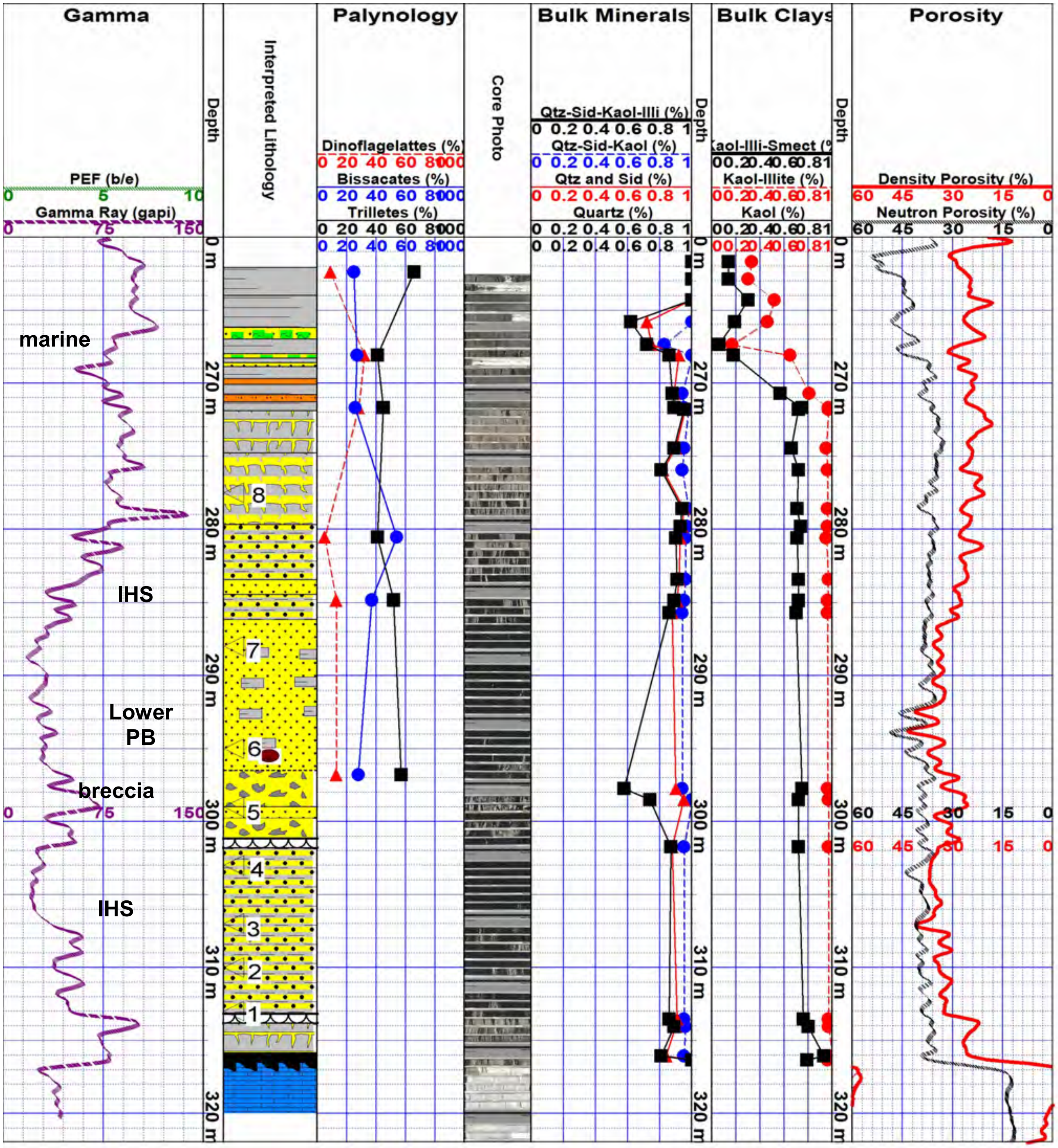

Figure 6. 1 AD 13-26-084-11 W4M. Reservoir heterogeneity inherited from depositional processes is reflected by distinct sedimentary structures and ichnofacies, and confirmed by mineralogical, palynological and petrophysical data. Numbers 1-8 are sample points used to create a geochemical compositional profile presented in Figure7.
Palynology: triangles – dinoflagelattes; circles – bissacates; and squares – trilletes.
Bulk Mineralogy is a cumulative plot for quartz (squares), quartz and siderite (triangles); quartz, siderite and kaolinite (circle); with smectite and glauconite being the rest to 100 %. Bulk Clay is a cumulative plot for kaolinite (squares), kaolinite and illite (circles), and the rest to 100% are smectite and glauconite.

Well 1 AD / 13 – 26 – 084 – 11 W4M – Southern Athabasca Oil Sands Deposit

A four metre thick interval containing angular mudstone clasts is present from 298 to 302 metres in the core and is overlain by an 8 metre thick sand unit which in turn is overlain by sand dominated and then mud dominated heterolithic strata. This succession is interpreted as an estuariane channel unit with an interclast channel breccia at the base, overlain by channel bar sands and heterolithic strata of a point bar.

The mud dominated heterolithic strata above contain light grey mudstone. This unit is overlain by dark grey to black mudstone. These dark mudstones appear to mark the change from a brackish water to a marine environment. Although there are significant changes in the clay mineralogy associated with this change, from a kaolinite-illite to a smectite dominated assemblage, microfossils do not indicate a truly open marine environment.

The composition of the bitumen was determined by GC-MS and indicates heavy levels of degradation throughout the oil column. Fig. 7 shows the behaviour of four geochemical parameters suggesting two petroleum compartments separated by the interclast breccia zone. As in the case of the 05-1519 well, the vertical compositional gradient suggests an overall decrease of petroleum quality down the hole, and comparison with reservoir facies suggests the most intense biodegradation in the best reservoir facies.

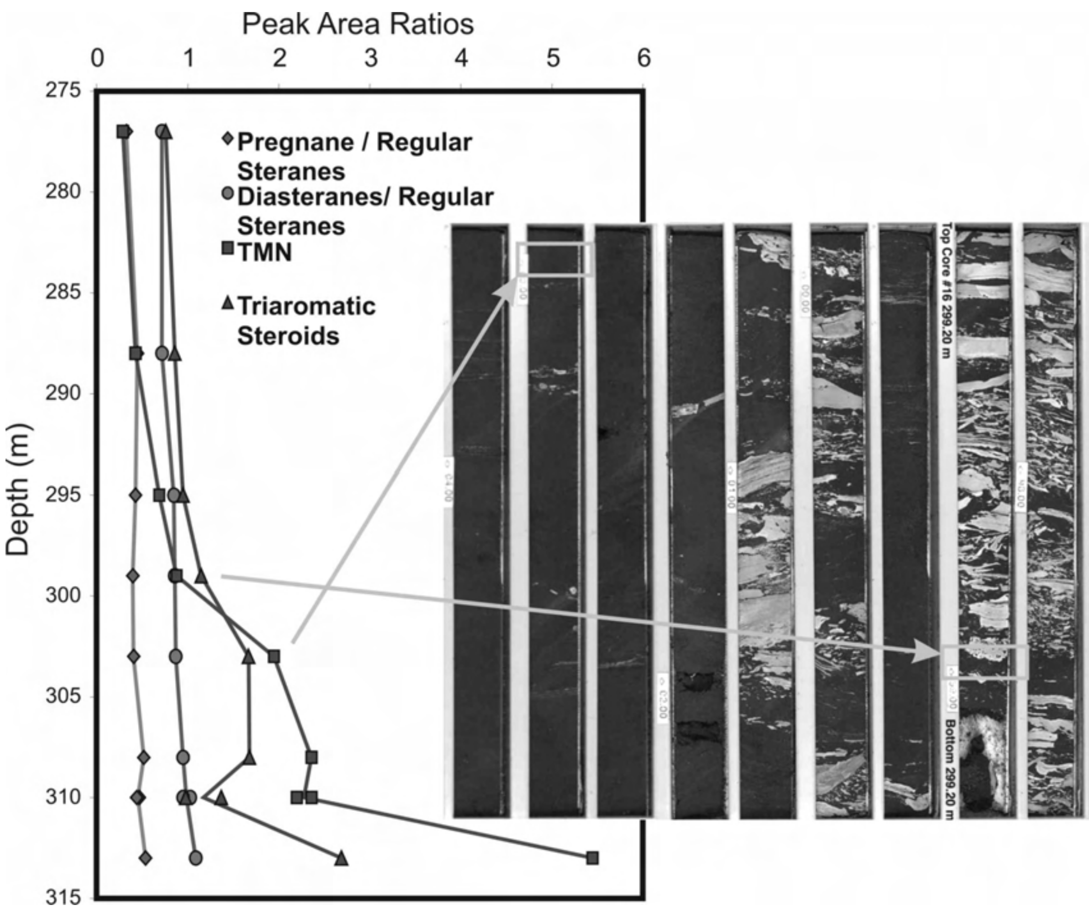

Figure 7. geochemical profile through 1 AD 13-26-084-11 W4M well. Ratios and abundance of certain biomarkers indicates increased biodegradation down the hole.

XRD analyses indicate the bulk mineralogy of mudstone layers, lamina and particles is dominated by Quartz (see Fig. 6). Other minerals (clays, feldspars) constitute a relatively small percentage of the whole rock mineralogy. However, there are notable occurrences of Siderite, within clasts of the channel interclast channel breccia facies. Clay minerals are identified in three groups. The relative abundance of these vary little throughout most of the core; kaolinite and illite are dominant through much of the sequence, with minor amounts of smectite which appears to be inter-layered with illite. Above ~271 m the clay mineralogy is dominated by smectite with two distinct intervals of glauconite.

The palynology indicates a near shore brackish water environment with a relatively strong marine influence toward the top of the core (between 268 m and 272 m). Below this dinoflagellates are not abundant, are very thin walled and poorly preserved. The poor preservation could be due to a number of environmental factors including (but not restricted to) salinity.

Results from the Artificial Neural Network mudstone predictive model reveal some heterogeneity in the mudstones. Generally, clay content decreases down hole with values in the marine mudstones toward the top of the core ranging from 30 to 40% while the more estuarine interbedded mudstones have lower clay content (<20%). Grain density of 2.75 g/cm^3 is observed in the marine mudstones while lower values of 2.5 g/cm^3 are observed in the interbedded estuarine mudstone. Results from our previous work on predicting mudstones physical properties suggest that these properties are important in understanding fluid flow through mudstone barriers. Physical properties such as clay content are known to correlate with pore size distribution, porosity (compaction), permeability and capillary pressure properties of mudstones (Jokanola *et al*. 2006). Increased clay content in mudstones ultimately increases the capillary pressure and reduces permeability hence enhancing the capillary sealing potential of the mudstones. This becomes important in explaining the geochemical heterogeneity observed in the petroleum bearing sandstones, which carries several mudstone interbeds. The ability to predict these physical properties coupled with detailed mudstone mineralogy would help in understanding the response of the interbedded mudstones to changing stress conditions during SAGD and other in-situ upgrading processes.

Discussion and conclusion

Analyses and comparison of results between two wells suggests that bitumen composition in the Athabasca Oil Sands deposit is heterogeneous. In addition to the large scale regional changes in bitumen quality recognized in the past we have observed variations in bitumen quality vertically within individual wells. Generally the quality of bitumen decreases down the hole, but also along the certain depositional breaks. Biomarker analyses suggest that in general the level of degradation according to the Peters and Moldowan scales of degradation is PM 5 (moderate) in the main oil column increasing down hole to level PM 9 (severe degradation) at the bottom. Biomarkers define vertical compositional gradients in the continuous petroleum columns. This is a result of the degradation process being driven from the oil water contact.

The preliminary results, presented here, suggest that variation in bitumen composition and properties are geologically controlled. In addition to distance from oil-water interface where biodegradation is the most intense, results suggest influence of other reservoir properties such as compartmentalization and reservoir quality, porosity and permeability of bitumen-saturated zones. The reservoir is commonly characterized by upwards fining sequences that result in decreasing reservoir quality upwards. However, with bitumen quality the trend is the reverse with viscosity increasing downwards. This is confirmed by chemical composition measurements. In addition, it is noticeable that biodegradation intensifies in the best reservoirs zones.

The study above provides a conceptual model to explain bitumen heterogeneity. This approach and the techniques allow bitumen properties to be mapped at high resolution.

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