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Geochemical Solutions to Heavy Oil Production Problems

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Summary

The ability to provide geochemical solutions to petroleum production issues requires high resolution sampling and that high quality; accurate quantitative geochemical data may be obtained consistently from a range of matrices (cores, cuttings or oils) over time. High resolution samples of core, or even cuttings, can be used to assess vertical fluid communication (barriers or baffles) of petroleum reservoirs where shale interbeds are present. Quantitative and qualitative molecular data may be represented in spatially defined molecular oil definitions which may be used to allocate production along horizontal wells that are designed for cold production or in 3D steam chambers produced in thermal recovery operations. Here we show how heavy oil geochemistry may be employed to define whether interbedded reservoir shales act as baffles or barriers to fluid flow and how to production allocate during oil production

Introduction

Reservoir and reservoir fluid heterogeneities are ubiquitous in heavy oil and bitumen reservoirs and adversely impact fluid mobility and therefore recovery, especially in cold production operations. At the reservoir scale, steep gradients in oil composition and associated fluid properties are understood to be the product of preferential biodegradation of different hydrocarbons, which gives oils a distinct molecular signature or “fingerprint” related to level of degradation. This natural variability in oil composition can be used to indicate the level of fluid communication or compartmentalisation in reservoirs and may also be exploited to allocate oil production along a long horizontal well or to assess the contribution of different production streams in a commingled well by mapping the original oil composition distribution (Larter et al., 2008). This is a well established geochemical procedure applied in many heavy oil fields worldwide as part of standard production monitoring procedures (McCaffrey et al., 1996).

The quantification of saturated and aromatic hydrocarbons recovered from heavy oil and bitumen presented a number of challenges. Heavy oil and bitumen are notoriously difficult to handle in the laboratory due to their high resin and asphaltene content. In our experience, we have found that methods developed previously for the recovery of hydrocarbons from conventional crude oils are not readily amenable for the accurate quantitative recovery of hydrocarbons from heavy oils and bitumen. In addition, varying sample matrices may be collected for analyses such as conventional core, side wall cores, cuttings or produced oils which may require different sample preparation procedures. The analytical protocols from sample collection, through preparation, LC and GCMS have been standardized with extensive use of conventional and recursive analytical standards and highly reproducible qualitative and quantitative data may now be obtained paving the way towards a number of geochemical solutions.

Methodology

To determine the molecular fingerprint for each solid reservoir sample, 0.5 g of core or drilling cuttings is solvent extracted. An aliquot of the extract from core or cuttings is selected to provide 50mgs (or 50mgs of produced oil) of substrate, which with added quantification and protocol standards is separated by solid phase extraction (e.g., Bennett et al., 2006) to recover a hydrocarbon fraction, which is analysed by gas chromatography – mass spectrometry (GC-MS). The data may be collected as chemical fingerprints (e.g. Fig. 1) and processed into concentrations ($\mu\text{g/g}$ oil or extract) assessed using internal standards.

Table 1 shows the qualitative and quantitative results from selected classical hydrocarbon compounds following replicate (6x) analyses of a standard heavy oil. The parameter based on C_{23} tricyclic terpane relative to C_{30} $\alpha\beta$ hopane namely, 23TT / 30H is employed to monitor possible deterioration in response of low boiling point versus high boiling point compounds. Ratios based on internal standards i.e., phenanthrenes-*d*10 versus cholestane-*d*4 serves to indicate separation issues, such as the potential for differential recoveries and responses between saturated and aromatic hydrocarbon compounds. The ratio also serves to indicate that instrument response is consistent between saturated and aromatic hydrocarbon compounds.

Table 1. Replicate data for molecular ratios based on saturated and aromatic hydrocarbons isolated from a standard heavy oil.

Sample	<u>P-d10</u> C-d4	<u>TT23</u> 30H	<u>Ts</u> (Ts+Tm)	<u>C20</u> (C20+C28)	<u>TAS</u> (MAS+TAS)	<u>DBT</u> P	MPI	<u>2MA</u> (1MA+2MA)	<u>2MN</u> 1MN
4660-1	1.12	0.46	0.31	0.14	0.45	0.63	0.73	0.36	1.44
4660-2	1.14	0.46	0.31	0.14	0.44	0.63	0.73	0.37	1.42
4660-3	1.15	0.46	0.30	0.14	0.43	0.63	0.73	0.37	1.43
4660-4	1.16	0.46	0.31	0.14	0.43	0.64	0.74	0.37	1.43
4660-5	1.13	0.45	0.29	0.13	0.45	0.65	0.74	0.37	1.42
4660-6	1.14	0.46	0.32	0.13	0.45	0.63	0.74	0.37	1.43
Std Dev	0.02	0.00	0.01	0.00	0.01	0.01	0.01	0.00	0.01
Mean	1.14	0.46	0.31	0.14	0.44	0.64	0.74	0.37	1.43
Coeff Var%	1.35	0.65	2.63	3.28	1.77	0.87	0.73	0.57	0.59

The reproducibility of the quantitative data is shown for a selection of saturated hydrocarbons and aromatic hydrocarbons (Table 2). The acquisition of high quality accurate and reproducible data, within <5% error, is considered to be the ultimate requirement to ensure that the data can be interpreted spatially such as in a 4D production allocation application where spatial oil production is monitored through time.

Table 2. Replicate concentration data ($\mu\text{g/g}$ oil) for selected saturated and aromatic hydrocarbons in a standard heavy oil.

Sample	N	2MN	26,27DMN	DBT	P	3MP	23TT	Ts	Tm	30H
4660-1	19.95	136.79	223.73	52.79	83.71	54.77	179.21	48.19	108.33	389.12
4660-2	20.16	137.78	225.14	53.86	85.14	55.52	189.34	50.29	112.61	411.71
4660-3	19.84	137.10	223.66	53.06	83.61	55.00	184.70	49.77	115.45	404.40
4660-4	19.92	136.10	222.38	52.96	82.73	54.84	186.57	50.11	112.45	405.76
4660-5	20.36	139.84	229.49	54.49	84.38	56.66	187.17	46.53	112.73	413.30
4660-6	19.94	136.93	222.51	53.01	83.52	55.12	182.78	50.49	109.45	397.29
Std Dev	0.19	1.30	2.65	0.67	0.82	0.71	3.59	1.56	2.56	9.10
Average	20.03	137.42	224.49	53.36	83.85	55.32	184.96	49.23	111.84	403.60
Coeff Var%	0.97	0.95	1.18	1.25	0.98	1.28	1.94	3.17	2.29	2.26

Geochemical solutions

1) Barrier versus baffles

A preliminary assessment of the well log data from two related vertical heavy oil wells indicated the presence of an interbedded shale located approximately towards the middle of the 50m thick oil leg (Fig. 1). In order to arrive at a suitable recovery strategy, the nature of the shale, whether barrier or baffle and its potential impact on vertical fluid flow behaviour must be established. In well A the geochemical profile based on the methylphenanthrenes (MPs) shows a classical gradual and progressive decrease in component concentration towards the bottom of the oil column as a function of biodegradation. The smooth gradient in composition indicates the shale is most likely short and is at most a baffle to vertical fluid communication and may have little impact on vertical oil flow. However, inspection of the geochemical profile based on MPs in well B shows a clear offset in the trend coinciding with the shale interbed. The shale basically separates the reservoir into two compartments which have been exposed to different petroleum charge and degradation systematics. The shale represents a barrier to vertical fluid communication and is therefore likely to impact low pressure thermal recovery strategies that depend on a high K_v/K_h value for the reservoir. For example locating a SAGD well pair below the shale would be detrimental to establishing steam chamber expansion. In summary, the shale is acting as a barrier to vertical mixing on geological timescales and is likely to drastically impact production strategies.

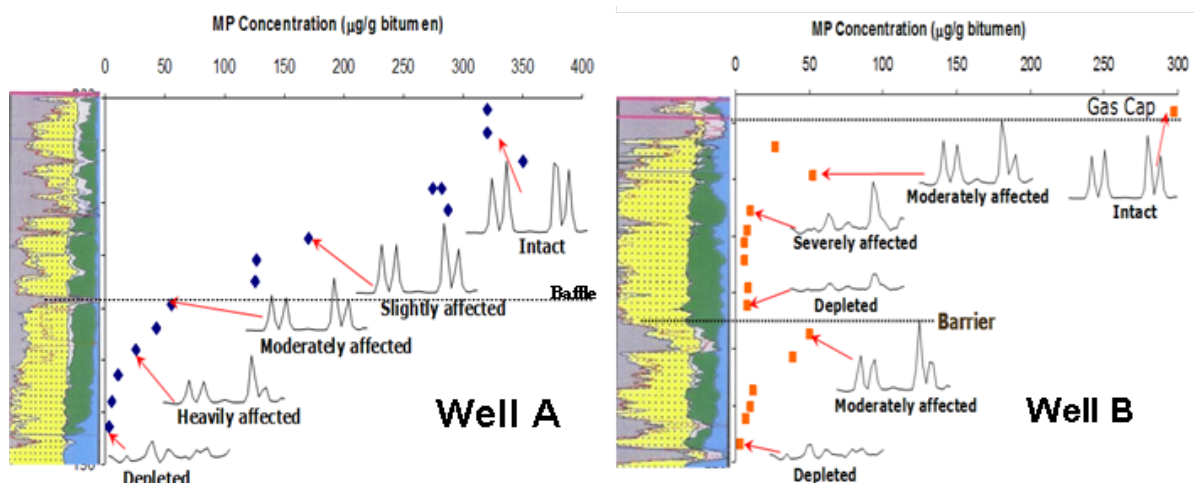


Figure 1: High resolution supporting geochemical logs based on methylphenanthrenes ($\mu\text{g/g}$ oil) in oil sands core from well A, B.

2) Production allocation

Allocation of oil production to a well location from analysis of produced fluids is achieved using multivariate statistical or supervised learning method comparison of absolute concentrations of produced oil components or chromatogram fingerprints to those from oil from core or cuttings samples from the reservoir section of a production well or nearby delineation wells (Kaufman et al., 1990; McCaffrey et al., 1996). This approach identifies the distinguishing components or patterns in the reservoir sample set which in heavy oilfields are usually related to the molecular components that are most susceptible to biodegradation but are not susceptible to fractionation, preferential production in cold production recovery, or evaporation from the samples post recovery.

The combination of mass chromatograms as molecular fingerprint data and direct measurement of specific component abundances in oil/bitumen samples are combined numerically. The data are analysed by principal component analysis, regression based chemometrics or small sample

set neural network analysis to derive a compositional model based on the geochemical reservoir sample data. Then the production oil composition is compared to the model to identify the dominant zones of production and proportions of contribution from each part of the reservoir. We generally do not prefer to use molecular ratio approaches as during oil biodegradation, some peak ratios change, while others appear intact even though the component concentrations are actually changing synchronously such that there is apparently no response in the relative abundance. Employing accurate compound concentrations also offers the ability to simply barcode the oils by assigning multi-level fingerprinting associated with up to 500 components.

In a case study from the Peace River oil sands, a compartmentalized reservoir is being produced in a comingled manner from two pay zones separated by a shale barrier. Production from the well declined suddenly. Six core samples were collected from a vertical well (Well A; Fig. 2) that intersected two pay zones (upper and lower) very close to the horizontal production wells (Well B; Fig. 2). The contribution of two horizontal wells producing from two stacked reservoirs separated by a barrier (Fig. 2) was assessed based on analysis of the produced oil from the comingled production stream. In this example, we have focused on groups of compounds that appear to respond to biodegradation by showing variations in non-hydrocarbon composition, i.e. the aromatic sulphur compounds. The aromatic sulphur compound fingerprint shown in Fig. 2 shows subtle changes in distributions, which also translates into changes in abundances supported by the quantitative data. In essence, the ratio of 1-methyldibenzothiophene versus 4-methyldibenzothiophene (abbreviated to 1MDBT / 4MDBT) increases with increasing biodegradation due to the faster removal of 4MDBT. The 1MDBT / 4MDBT ratios are recorded highest in oils recovered from the lower zone indicating that the oil is more biodegraded than the upper zone. The oil residing in the upper zone is better preserved, probably due to the oil column filling down to the shale barrier which acts as an underseal and slows biodegradation in the vertical direction. The oil in the lower zone is more biodegraded since the oil column is in direct contact with the water leg which provides the condition required to support microbial activity. In general, based on the molecular data, we observe two oil populations which may be exploited for the production allocation. Multivariate curve resolution on a large multivariate data set indicated that 70% of the production was from the upper pay zone, however, since the oil mobility of the lower zone was initially higher, indications were that production should in fact be greater from the lower zone. Further investigation of the lower zone revealed a collapsed casing in the lower producer and re-completion of the well resulted in improved production. We also describe a 4D production allocation study of an active SAGD wellpair.

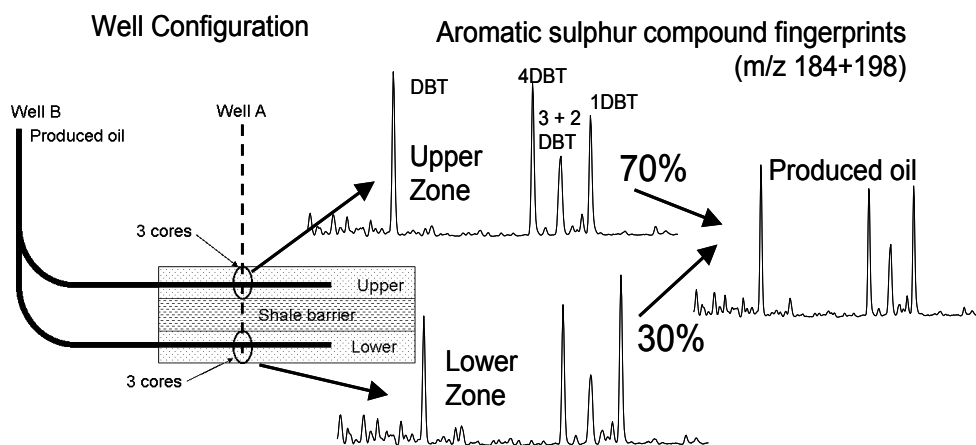


Figure 2: Production allocation based on aromatic sulphur compounds, case study. Aromatic sulphur compound fingerprints (GCMS chromatograms, m/z 184+198) show peaks indicating the relative abundance of each molecular marker.

Conclusions

Heavy oilfields show systematically varying oil composition related to biodegradation, oil mixing and charging over geological timescales which provides tools to detect barriers and allocate oil production to well locations. To permit this, very accurate and reproducible data is needed. In heavy oil and bitumen reservoirs low oil quality means that cuttings samples are often usable for geochemical applications and routine analysis of vertical and horizontal well core or cuttings permits compositional baselines to be defined that permit many production problems to be resolved including 4D production allocation.

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