Heavy Oil Biodegradation – Important?

Most of the world's oil is biodegraded as exemplified by the super-giant viscous heavy oil and bitumen deposits in Venezuela, here in Western Canada and elsewhere. Understanding in–reservoir oil biodegradation is of significance for petroleum exploration (e.g. pre-drill prediction of the likelihood a prospect is biodegraded) and production (e.g. selection of reservoirs, well locations and operating strategies in biodegraded oil fields where fluid properties will be most favourable for production). The technology we use today came from basic and applied research done in universities and industry over many years and that research sought to understand the processes that are involved in the formation of such heavy oil deposits, the rates of oil degradation over geological timescales, the importance of microbial activity in the deep biosphere for heavy oil formation and factors that control the occurrence of heavy oil and its viscosity variations.

The outcome of this research has been a new model of in-reservoir oil biodegradation where anaerobic processes, primarily oil degradation linked to methanogenesis, drive oil biodegradation and that site of biodegradation is the oil water transition zone in the reservoir leading to variations in oil composition and extreme fluid property gradients in the reservoirs. Understanding the nature and magnitude of these fluids property gradients has already had commercial benefit in the sighting of wells and in oil recovery process operations. In addition to practical applications, these gradients have allowed biodegradation rates to be estimated and deep biosphere processes to be elucidated. We have shown that reservoir geometry, formation water salinity and most significantly reservoir temperature are key controls on whether in reservoir oil biodegradation will occur. Even if a reservoir is currently at a low temperature, if it has experienced temperatures much in excess of 80°C, then the oil is unlikely to be biodegraded and we have developed a model known as the palaeopasteurization hypothesis to explain this phenomenon. This not only has significance for our understanding of petroleum systems but provides fundamental insights on the deep biosphere, indicating that once palaeopasteurized, reservoirs are not readily recolonized by hydrocarbon degrading microorganisms from the surface. It also suggests that in harsh deep subsurface sediment environments, that the upper temperature limit for life is considerably lower than in high energy systems such as hydrothermal vents where the thermal limit for life may be in excess of 120°C. A good summary of the basic research in this area is in Head, I.M. et al (2003). Biological activity in the deep subsurface and the origin of heavy oil. Nature 426 344-352.

How does this affect your bottom line? The biodegradation process produced ubiquitous vertical and lateral oil composition variations and oil viscosity gradients in your reservoirs; it produced immense amounts of gas which sometimes formed small local gas zones which then filled with water as the gas leaked away to form top and middle water zones as oil was too viscous and too dense to flow to replace gas; the biodegradation process also increases the thickness of low water saturation zones at the base of pay. Biodegradation also produces consistent chemical changes in oil composition spatially in 3D in a reservoir, this provides a unique tool with which to understand which oil is flowing in a reservoir by analysis of produced oils and relating the oil composition to a prior baseline study.

Value proposition-why is viscosity and variable oil composition so important??

The flow of a fluid such as oil(or water)through a porous and permeable medium such as a rock is controlled by Darcy's law and both the properties of the rock medium(relative permeability) and the oil viscosity are factors in controlling oil flow rate under any fluid potential gradient driving flow to a production well. Higher oil viscosity means lower flow rates and vice versa. It is often tempting to think that when one heats bitumen in a thermal recovery process, that when the oil reduces in viscosity from the sometimes millions of cP under native reservoir conditions to the around 5-20cP target viscosity in SAGD processes, that it doesn't matter if it is 5 or 20cP at oil flow temperature (commonly lower than steam temperature). In reality of course a fourfold change in viscosity can have a substantial, economically important impact on actual SAGD well flow rate. In reality bitumen reservoirs do not have uniform permeability and neither do they have uniform oil viscosity at either native conditions or at oil flow temperature(or even steam temperature). This further impacts well flow rates unless operations are designed to allow for these inherent heterogeneities. While it is the(up to X 50), vertical variations in native reservoir bitumen viscosity that grab headlines, the lateral oil viscosity gradients also seen in oil sands are probably a bigger impactor of well economics as they impact the uniformity of steam chamber development during SAGD startup. Fluid viscosity variation between the injector and producer is a major control on SAGD performance during startup and in SAGD mode and cold spots at startup are notoriously persistent. Variations in viscosity at oil flow temperature are real and need to be understood as they do impact production flow rates. This is best done through high resolution vertical and lateral oil viscosity studies from core or from cutting samples performed soon after sampling.

Understanding the processes by which heavy oil and bitumen deposits form, coupled with field observations of bitumen column variations in well over 1000 wells shows that in continuous pay sections, gradual consistent and ubiquitous compositional gradients are seen in all bitumen reservoirs. Where baseline compositional studies have been performed, comparison of the composition of produced oils with the baseline background compositional variations using neural networks, partial least squares or other multivariate data analysis methods allows us to assign the produced oil spatially within the reservoir-an oil production allocation. This is very useful in assessing how productive the whole well length is in cold or thermal recovery and can also be used to assess casing and cement failures when production profiles change suddenly or when leakage occurs. The key to such production allocation studies is having a reference baseline study available and this is always most cost effective before problems arise rather than after. Perhaps our largest growing area of study is on barrier and baffle assessment pre steaming or pre cold flow. The processes that produce heavy oil and bitumen result in gradual, consistent and ubiquitous compositional gradients in continuous pay sections. Where continuous shales or other features compartmentalise a reservoir, the reservoir filling and biodegradation process always produces a discontinuity or step in oil composition at the barrier. This sometime is also seen in a viscosity profile which may show a step but geochemical oil composition is a much more reliable preproduction indicator of barriers. Where a reservoir zone contains partial flow barriers (baffles), changes in the slope of compositional gradients and smaller discontinuities are seen. Geochemical reservoir profiling is probably the best preproduction technology for barrier and baffle detection in a heavy oil or oil sands reservoir. The key step is making a baseline study before well placements and problems occur!

While we tend to focus on production issues it is clear after many years of looking at the oil sands that there is much regional and local variation in oil properties related again to the mechanistic origins of heavy oil and bitumen from the competition between slow geological timescale charging of fresh oils to the reservoirs from multiple source rocks and slow geological timescale biodegradation and alteration of the oils in the reservoir. Oils nearer the charge points are better than oils further away. Late charge is good and water is bad for oil quality. As the oil sands formed, fresh oils from a least two source rocks gradually became more viscous as they became biodegraded during charging. Locally the oils likely became so viscous they froze and stopped charge and the oil charge rivers moved elsewhere in a manner similar to the stop-flow behaviour of those 70s student gimics-lava lamps. Add to this the local vertical and lateral viscosity gradient generating mechanisms we understand well and we can start to see why the oil sands have such variability at a range of scale in oil viscosity. Oils at the top of reservoir can have native reservoir dead oil viscosities as low as a few thousands of cP while oils at the bottom can

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have viscosities up to several tens of millions. The range of oil viscosities in the oil sands is colossal, opening up many innovative opportunities for alternate recovery strategies and packages of processes for companies who understand the giant geobioreactor that is the Albertan oil sands and its impact on the nature and distribution of the reservoired oils.

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