Reading the Rocks and Fluids to Design Geotailored and Geotolerant Strategies for Heavy Oil and Bitumen Recovery: The need for High Resolution Fluid Mobility Logs

Jennifer Adams*
University of Calgary and Gushor Inc, Calgary, AB
adamsjj@ucalgary.ca

and

SR Larter, ID Gates, H Huang and B Bennett
University of Calgary and Gushor Inc, Calgary, AB, Canada

Summary

Reservoir and reservoir fluid heterogeneities are ubiquitous in heavy oil and tar sand (HOTS) reservoirs and impact reservoir processes such as SAGD that depend on uniform oil mobility for optimal recovery. These variations can impact optimal recovery process design, well placement and field management, here we discuss the use of integrated fluid and reservoir characterisation coupled with optimised reservoir engineering solutions and our improved understanding of heavy oil origin to reduce emissions and energy requirements. For process optimisation, detailed fluid mobility logs and maps are needed, based on both high resolution core analysis (absolute and relative permeability) and viscosity logs. In addition, HOTS oil composition documents mass transport efficiency within a reservoir due to biodegradation and can be used to assess reservoir connectivity and to chemically monitor the progress of production across a reservoir. For any reservoir, customisation of well placements and operating strategies to measured reservoir and fluid heterogeneities, which we call *geotailoring*, greatly improves predicted recovery performance. Similarly, recovery processes designed for more sustainable recovery of HOTS include well configurations and production strategies that work with observed geological barriers and oil mobility gradients of natural reservoirs, resulting in greater geotolerance and energy efficiency and reduced emissions.

Introduction

HOTS oils and bitumens are becoming significant in world and Canadian production, yet current employed recovery technologies are inefficient in terms of recovery, energy and water intensity, and cost to the environment (CSS, SAGD, mining). The HOTS reservoirs across Alberta exist at a range of reservoir conditions, exhibit heterogeneity in fluid connectivity, reservoir geometry and water distribution and contain oil of highly variable quality on regional and local reservoir scales. However, existing recovery methods are ineffective in reservoirs with restricted vertical permeability (SAGD and VAPEX), or are limited to reservoirs that can withstand high pressure processes (CSS). Concerns about greenhouse gas emissions and water usage, combined with societal pressure to implement more sustainable energy recovery procedures require the development of much more effective recovery processes. An understanding of the geological and fluid heterogeneity typically found across heavy oil and bitumen provinces will assist in the transition from current processes (SAGD, CSS) to reduced and zero emission to atmosphere recovery (REAR and ZETAR) processes, which may combine advances in fueling systems, carbon capture and sequestration, in-situ heat and gas generation, in-situ and surface upgrading, process monitoring, and the business/regulatory environment. Here, we review our recent work on integrated reservoir characterization of fluids and geology to inform process design for more sustainable recovery of HOTS.

Biodegradation Theory

Recent advances in understanding the origin of heavy oil and tar sand bitumen (HOTS) have shown that the process is anaerobic in the subsurface (Aitken et al. 2004) involving predominantly methanogenic biodegradation of oils in reservoirs as the main process producing heavy oil and bitumen (Head et al. 2003). This involves crude oil hydrocarbons reacting with water to produce methane via intermediate hydrogen and carbon dioxide (Jones et al. 2007) as well as residual heavy oil or bitumen. This process is mediated by a consortium of syntrophic bacteria and methanogenic archaea (Jones et al. 2007) and operates over geological timescales (Larter et al. 2006) in oil-water transition zones. Biodegradation rates are controlled by thermal history of the reservoir and with a pasteurisation temperature at 80oC (Wilhelms et al. 2001; Adams et al. 2006).

In Western Canada, charging of early mature, sulphur-rich oils at Laramide time into shallow Lower Cretaceous reservoirs ideal for biodegradation, followed by uplift in the early Tertiary has resulted in huge bitumen reserves with little associated gas, characterized by parabolic or hyperbolic gradients in oil viscosity down column (Erno et al. 1991; Larter et al. 2008). Basal oil column degradation processes preferentially remove certain hydrocarbon compounds at varying rates such that detailed compositional profiles depending on the level degradation and the degradation susceptibility of the compounds are recorded in the reservoir fluids (Huang et al. 2004, 2008). The light end hydrocarbons are removed most quickly, causing dead oil viscosity to increase by up to 10 to 100 times at in-situ reservoir temperature towards the base of a 50 m vertical reservoir section and laterally by up to 10 times over a kilometre scale (Gates et al. 2007). Compositional gradients strongly impact the mobility of the oil especially in the high water saturation, residual oil zones where relative permeability and the discontinuous oil phase limit the effective permeability. These vertical and lateral gradients commonly persist to steam temperatures and exert a large effect on performance of thermal recovery processes such as SAGD and CSS as well as cold recovery operations (Larter et al. 2008). Also, where oil removed by biodegradation has exceeded the rate of fresh oil charge, reservoirs can have a basal residual oil zone up to 15 m thick characterized by steeper gradients in oil composition and substantially higher viscosities than found in the main oil column. These basal bioreaction or burnout zones may have moderate bitumen content but have very low oil mobility, which adversely affect thermal gravity drainage processes such as SAGD or CSS for which well placement is in the lowest parts of a reservoir.

Fluid Mobility and Recovery Processes

Production rate is proportional to fluid mobility (ratio of oil effective permeability to viscosity), which is a measure of the efficiency of fluid movement though a reservoir. Mobility of each reservoir fluid is dependent on its relative permeability which changes significantly with relative pore saturation in fluid transition zones. Our current understanding of reservoir and fluid heterogeneities in heavy oilfields suggests that oil mobility at native and steam temperatures varies both vertically and laterally. Oil viscosity variations often dominate HOTS oil phase mobility, which thus decreases generally towards base of pay. In tandem, water mobility often increases as water saturation increases towards base of pay or within top or middle water zones. Across HOTS reservoirs, the combination of intersecting viscous fluid domains and sedimentologically controlled permeability domains produces complex mobility distributions in which any recovery process must operate.

For process optimisation and field development, detailed fluid mobility logs or maps can be generated from both high resolution core analyses (absolute and relative permeability) and oil viscosity logs. For example, Figure 1 shows a typical Peace River Bluesky-Gething reservoir with decreasing porosity and permeability towards base of pay. The oil saturation is high in the upper 20 m of pay but decreases below 68 m to ca. 45 to 60% in the basal water zone, which is approximately 8 m thick. Viscosity of mechanically extracted oil from core was measured in only 5 locations because samples at 72 and 75 m yielded no oil. To produce a high resolution viscosity log across the whole pay zone, 15 solvent-extracted cores were analyzed for molecular geochemistry. Aromatic hydrocarbon concentrations decrease with depth, and correlate with an increase by an order of magnitude in dead oil viscosity. Detailed characterization of the oil chemistry can be used to assess reservoir connectivity (i.e., local geological barriers to fluid flow, not apparent on logs), to identify zones of poor quality bitumen for which viscosity could not be measured and subsequently, to monitor the progress of production (e.g., steam chamber growth) by using produced oil chemistry by numerically allocating production from a well against observed oil properties from core or cuttings.

Using typical relative permeability curves for Albertan oil sands (Figure 1 inset), the live oil mobility decreases with depth by three orders of magnitude due to increasing viscosity and the decreasing effective oil permeability, accentuated by decreasing oil saturation. However at reservoir conditions, water mobility (dashed blue line) is always greater than live oil mobility due to the poor oil quality. At temperatures found at the outside limits of a steam chamber (where gravity flow occurs ~150°C), the most mobile fluid phase in the upper part of the reservoir is oil, but in the lower part it transitions to water despite oil saturations greater than 50%. Also, between 68 and 72 m the bitumen content is 5 to 6.5 wt%, i.e. it is at the recoverable reserves threshold. A decision to locate the production wells in this basal water zone in an effort to maximize recovery would result in a thermal recovery operation producing mostly water especially at start-up, due to poor bitumen mobility. Recovery processes designed for reservoirs that assume high vertical permeability and uniform mobility of oil will not operate efficiently in vertically stratified reservoirs with mobility gradients. Detailed mobility logs can identify thief zones or low mobility areas that would cause non-uniform steam growth down well (Gates et al. 2007) and optimization software can locate wells to maximise recovery at economic steam to oil ratios. In real reservoirs, well configurations that cut geological barriers and take advantage of, rather than oppose, observed oil mobility gradients show greater geotolerance and reduced emissions (cSOR) as well as greater energy efficiency (JagD). Similarly, customisation of well placements and operating strategies to actual measured reservoir/ fluid heterogeneities, what we call *geotailoring*, greatly improves predicted performance. We discuss geological constraints such as viscosity gradients, shale barriers and reservoir thickness on the design and performance of such processes. In the future, acceleration of microbial processes in situ to recover energy as methane *may* be feasible under special conditions in heavy oil reservoirs (LEMUR).

Figure 2 qualitatively summarises the performance of various recovery processes in real reservoirs. An ideal recovery process is tolerant of unpredictable geological heterogeneity (*geotolerant*), is energy efficient and has minimal environmental impact (i.e., low water usage and low emission of CO2 and others gases). For example, mining of bitumen is very geotolerant in that shale barriers do not inhibit recovery but it has poor energy efficiency and emissions. Thermal recovery processes such as SAGD have lower emissions but may fail in vertically compart-mentalised reservoirs with shale barriers and the more geotolerant CSS based processes use fracturing to deal with geological hereogeneity and are thus less energy efficient and have high surface emissions.

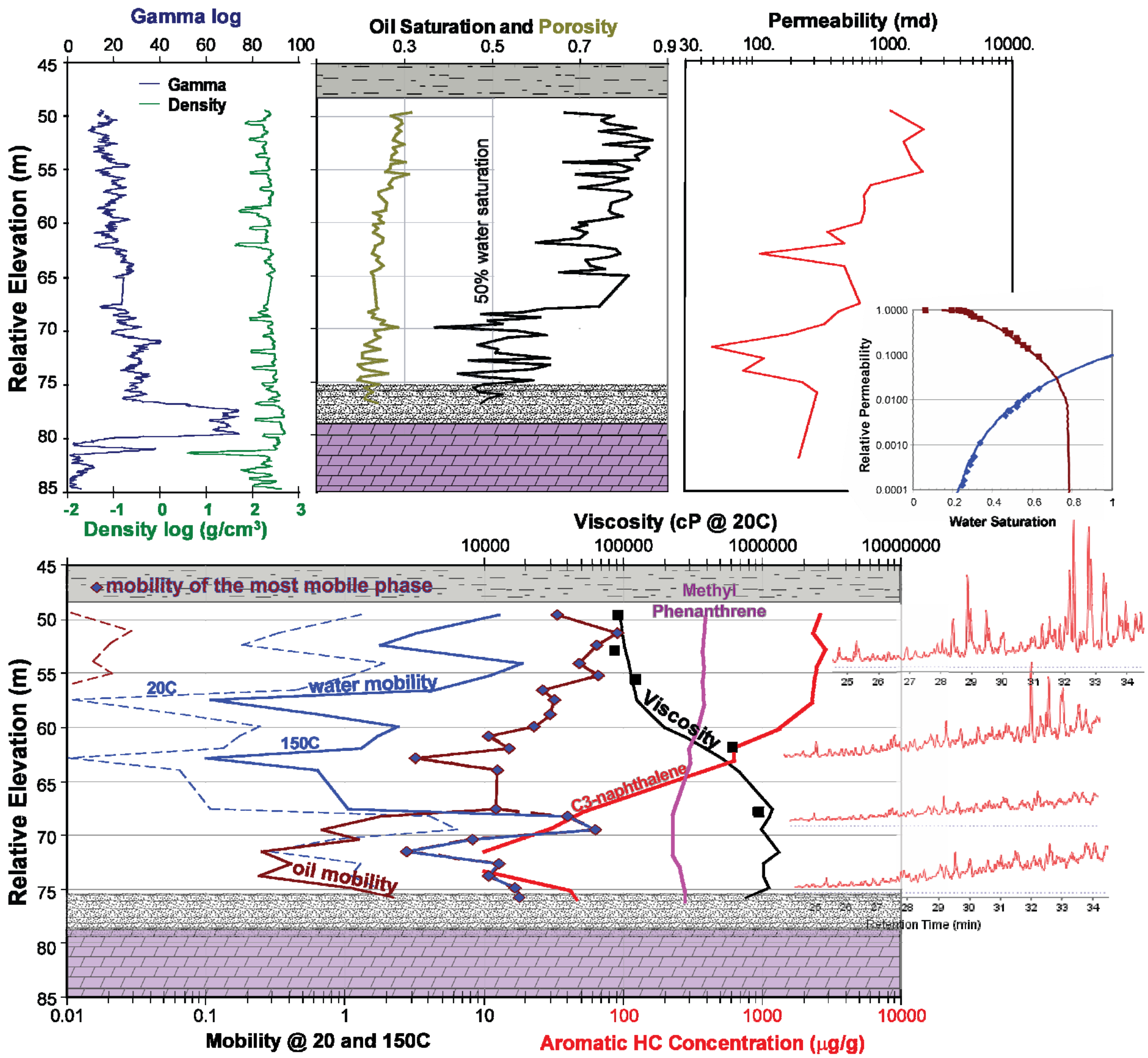

Figure 1: An example of the geological and fluid variations in a Peace River bitumen reservoir with increasing porosity and permeability with depth, and decreasing oil saturation (all determined from core analyses). The decrease in aromatic hydrocarbon concentrations (total C3 alkylnaphthalene x 10 and total methyl phenanthrene) with depth and the related alkylnaphthalene GC-MS fragmentograms showing preferential removal of lower molecular weight compounds and the associated increase in dead oil viscosity (black line is geochemically estimated viscosity and black squares are the measured viscosity). The live oil mobility at reservoir conditions (dashed brown line), based on the measured water saturation and a relative permeability curve typical of thermal recovery simulation studies in such reservoirs, decreases with depth by three orders of magnitude as water mobility increases. At 150°C (shown as solid mobility lines), the most mobile fluid phase transitions from oil in the upper part of the reservoir to water in the lower part of the reservoir at 40 to 50% water saturation as shown by the blue diamonds.

Conclusions

Reservoir and reservoir fluid heterogeneities are ubiquitous in HOTS reservoirs and impact reservoir processes such as SAGD that depend on uniform oil mobility to work effectively. High resolution fluid mobility logs based on high resolution core analyses and viscosity logs, are useful to target sweet spots and avoid thief zones, to optimize recovery operations and to design geotolerant recovery strategies tailored to the fluid and geological heterogeneities. In real reservoirs well configurations that cut geological barriers and take advantage of, rather than oppose, observed oil mobility gradients will show greater geotolerance and reduced emissions as well as greater energy efficiency (cSOR). One shoe size does not fit many feet! Similarly, customisation of well placements & operating strategies to reservoir/fluid heterogeneity (geotailoring), greatly improves performance.

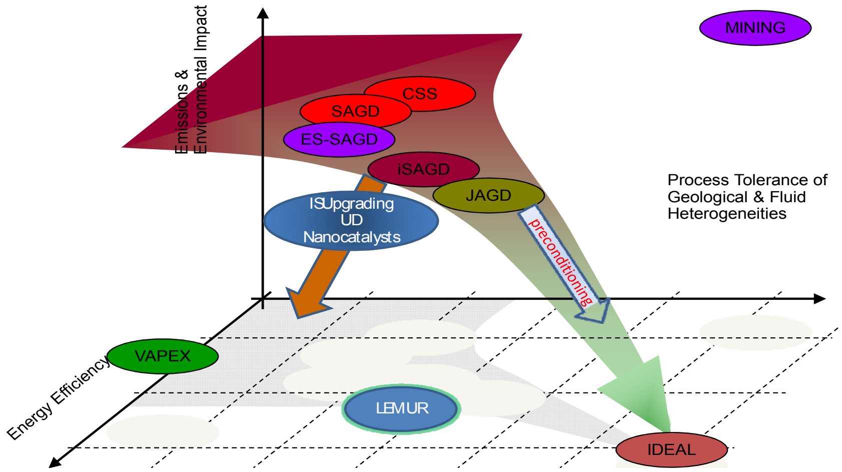

Figure 2: Geotolerance, emissions & efficiency of current recovery processes.

Acknowledgements

We thank NSERC, Alberta Ingenuity Fund and Gushor Inc. for support.

References

Adams, J.J., Riediger, C.L, Fowler, M.G. and Larter, S.R., 2006. Thermal Controls on Biodegradation around the Peace River Tar Sands: Paleo-Pasteurization to the West: Journal of Geochemical Exploration, 89, 1-4.

Aitken, C.M., Jones, D.M. and Larter, S.R., 2004. Anaerobic Hydrocarbon Biodegradation in Deep Subsurface Oil Reservoirs: Nature, **431**, 291.

Erno, B.P. and et al., 1991.Depth-Related Oil Viscosity Variation in Canadian Heavy Oil Reservoirs: J. Canadian Petroleum Technology, 36-41.

Gates, I.D., Adams, J.J. and Larter, S.R., 2007. The Impact of Oil Viscosity Heterogeneity on the Production Characteristics of Tar Sand and Heavy Oil Reservoirs. Part II: Intelligent, Geotailored Recovery Processes in Compositionally Graded Reservoirs: CIPC, June 12-14, Calgary, AB.

Head, I.M., Jones, D.M. and Larter, S.R., 2003. Biological Activity in the Deep Subsurface and the Origin of Heavy Oil. Nature: **426**, 344-352.

Huang, H., Bennett, B., Oldenburg, T., Adams, J.J. and Larter, S.R., 2008. In Review. Geological Controls on the Origin of Heavy Oil and Tar Sands and their Impacts on In Situ Recovery: Journal Canadian Petroleum Technology.

Huang, H., Larter, S.R., Bowler, B.F.J. and Oldenburg, T.B.P., 2004. A Dynamic Biodegradation Model Suggested by Petroleum Compositional Gradients within Reservoir Columns from the Liaohe Basin, NE China: Organic Geochemistry, **35** (3), 299-316.

Jones, D.M., Head, I.M., Gray N.D., Adams, J.J., Rowan, A.K., Aitken, C.M., Bennett, B., Brown, A., Bowler, B.F.J., Oldenburg, T., Larter, S.R., 2008. Crude-Oil Biodegradation via Methanogenesis in Subsurface Petroleum Reservoirs: Nature **451** (7175), 176-79.

Larter, S.R., Huang, H., Adams, J.J., Bennett, B., Jokanola, O., Oldenburg, T., Jones, D.M., Head, I., Riediger, C. and Fowler, M., 2006. The Controls on the Composition of Biodegraded Oils in the Deep Subsurface: Part II - Geological Controls on Subsurface Biodegradation Fluxes and Constraints on Reservoir-Fluid Property Prediction: AAPG Bulletin, **90**, 921-938.

Larter, S., Wilhelms, A., Head, I.M., Koopmans., M., Aplin, A.C. Di Primio, R., Zwach, C., Erdmann, M. and Telnaes, N., 2003. The Controls on the Composition of Biodegraded Oils in the Deep Subsurface- Part 1: Organic Geochemistry, **34** (4), 601-613.

Larter, S.R., Adams, J.J., Gates, I.D., Bennett, B. and Huang, H., 2008. The Origin, Prediction and Impact of Oil Viscosity Heterogeneity on the Production Characteristics of Tar Sand and Heavy Oil Reservoirs: Journal of Canadian Petroleum Technology, **47** (1), 52-61.

Wilhelms, A., Larter, S.R., Head, I. et al., 2001. Biodegradation of Oil in Uplifted Basins Prevented by Deep-Burial Sterilization: Nature **411**, 1034.