Oil vs. Gas: What are the limits to prospect-level hydrocarbon phase prediction?

Andrew Murray[1] and Zhiyong He[2]

Murray Partners PPSA Pty. Ltd., [2]Zetaware Inc.

In ranking and assigning value to exploration prospects we are required to judge whether they will contain oil, gas or both. In other words to predict the hydrocarbon phase. We can only justify the word "predict" if our method results in a material reduction in uncertainty and a common assumption is that basin models, combined with petroleum geochemistry are capable of this. Herein we challenge that assumption, explore the inputs required to predict phase and suggest a practical approach.

Typical petroleum system analysis combines top-down (observation) with bottom up (modeling) approaches. It is convenient to consider these separately with respect to phase prediction. The top-down approach applies in areas with many fields discovered and the first step is an estimate of the "system" gas-liquids ratio (GLR). This is the surface-condition volume ratio of the all C_1-C_4 to C_5+ molecules (free gas, solution gas, oil and condensate) found to date. It is useful as a "Bayesian Prior" for the gas *vs*. oil supply to any individual prospect.

The "bottom-up" approach is basin modeling applied to a frontier basin or an emerging province: the Bayesian prior system GLR from the model is determined mainly by the choice of source rock type. Experience has shown that the classic "organofacies" defined by Pepper and Corvi (1995) – with some modification – provide good priors for system GLR. For example, the volume ratio of gas to oil expelled by a "D/E" source rock (at 90% kerogen conversion) is about 4 times that of a "B" source. This is reflected in the higher frequency of single phase gas pools e.g. in the Taranaki Basin of New Zealand *cf*. offshore West Africa.

We may try to improve prediction of system GLR using kinetics and oil *vs*. gas tendency measured on source rock samples (rather than using default source types). However, it is debatable whether such measurements are sufficiently representative or realistic to reduce uncertainty rather than adding to it. Another approach relies on geochemical inversion of fluid samples to define the source type and maturity. In the common situation where more than one source rock is contributing, "families" of fluids are are identified, often by multi-parametric statistics of biomarker ratios or concentrations. While this approach provides an integrated picture of the contributing source rocks, it is prone to a fundamental bias when applied to mixed oil and gas petroleum systems. This will be demonstrated by application to the UK/Norway North Sea and several other petroleum systems.

A good estimate of system GLR in a frontier basin should help to determine how much gas and oil in total will be found when the basin if it is ever extensively drilled. Generally, though, we want to know which hydrocarbon phase will be found in the next prospect. Modification of the system GLR "prior" for prospect-specific phase prediction relies on:

- An estimate of the "local" GLR (maturity in the fetch cell and migration lag)
- A comparison between reservoir pressure and the estimated saturation pressure (P_{sat} = bubble point or dew point) for that GLR
- An understanding of processes which may differentially affect gas *vs*. oil retention such as fill/spill/leak and in reservoir alteration

The local GLR is an output of a basin model and the saturation pressure can (in theory) be derived either from an equation of state (EOS) or from empirical correlations . In both cases P_{sat} for any given GLR is highly dependent on fluid composition which is usually poorly constrained: On the oil (bubble point) side it depends mainly on gas wetness whereas on the gas-condensate (dew point) side it depends mainly on the density and molecular weight of the liquids. This results in large variability, especially on the dew point side, because liquid composition is intrinsically far more variable than that of gas. The difference between P_{sat} for two gas-condensates having the same CGR but with a liquids API of 48° *vs.* an API of 55° can be as much as 3000 psi. This equates to an approximately 2 km uncertainty in the depth to the boundary between mono-phase and dual-phase fluids from this factor alone. Where the GLR is between 3000 and 5000 scfs/bbl fluids it becomes difficult not just in practice but also in principle to differentiate between oil and gas.

A further uncertainty in the depth or pressure of phase separation arises from the fact that many oil pools are not in thermodynamic equilibrium (i.e. not fully mixed). This was discussed by Stainforth (2004) and his conclusions are borne out by examination of large PVT data collections. It is not at all uncommon for an oil with a gas cap to be more than 200 psi under saturated and in a trap with high vertical relief it may be 1000 psi or more.

In addition to the primary factors discussed above, in-reservoir alteration has a dramatic effect on fluid phase behaviour. For example, water-washing of gas-condensates in the Cooper-Eromanga Basin has created numerous small (yet material) pools of extremely under saturated yet volatile oil.

The aims of this talk are (a) to discuss how practical it is to predict fluid phase a the prospect level, especially using a purely “bottom-up” approach and (b) suggest some pragmatic ways to frame prospect phase risk and convey it effectively to management.

Speaker biography

Andrew Murray is a former principal advisor on petroleum systems at Woodside Energy Ltd. After retiring from full-time work in 2014 he started Murray Partners PPSA (practical petroleum systems analysis) to offer consulting, training and support to exploration geoscientists. Clients have included 11 integrated exploration companies and several governments and academic institutions. Andrew holds M.Sc. and Ph.D. degrees in petroleum geochemistry and has 30 years of experience spread across most regions of the world, across government, academia, and industry, and across the basin modeling, geochemistry and reservoir engineering disciplines.