

AAPG HEDBERG CONFERENCE
“NATURAL GAS GEOCHEMISTRY: RECENT DEVELOPMENTS, APPLICATIONS, AND
TECHNOLOGIES”
MAY 9-12, 2011 – BEIJING, CHINA

**Interpretations of the Formation of Two-Phase Accumulations Using Gas Isotopic
Composition, Source Rock Gas Pyrolysis and PVT Properties**

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Two-phase (liquid and vapour) accumulations, i.e. oil fields with a gas cap, can have multiple origins. Determination of the process which led to the formation of a two-phase accumulation may aid in understanding the phase distribution in a petroleum exploration area. This is the motivation for this study where we compare the gas isotopic compositions from oil leg and gas cap in order to find diagnostic means for the discrimination of different two-phase accumulation formation mechanisms.

We found that gas isotopic compositions in both phases appears to be identical in most cases, pointing to homogenisation of compositional differences being very fast in geologic time (England *et al.*, 1991; Larter *et al.* 2006), also across phase boundaries. Therefore additional diagnostic parameters were required to obtain the basis for interpretations. Additional observations from organic geochemical molecular ratios for light hydrocarbons (LHC) and biomarkers were considered. Also gas fraction as generated from the source rock (estimated by using pyrolysis) was compared with accumulated *field-gas-mass-fractions*, and PVT properties of the accumulated fluids were evaluated. Literature review indicates that investigations on this topic commonly assess gas compositions and isotopic compositions but rarely focus on the related aspects of phase/ PVT properties, or that studies occupied with studying the source rock and PVT aspects do not consider the organic geochemical properties of the fluids in any greater detail.

We base this discussion on case studies from the Norwegian continental shelf (NCS). The main oil-prone source rock here is the Late Jurassic Kimmerdige Clay equivalent (Draupne/Spekk Formation, type II/III) but additional source rocks of Mid Jurassic and Early Jurassic/Late Triassic ages - dominated by mixed type III/II and type III kerogen - may contribute to accumulations with gas, gas-condensate and possibly oil. Discoveries may therefore contain mixtures of different charges from these source rocks, expelled at different stages of their thermal maturity. Secondary processes like biodegradation, fractionation, water washing, and oil to gas cracking can affect the observed compositions in addition.

We discriminate here the following categories of two-phase accumulations:

- 1.) *Petroleum charge from a single source rock***
 - 1.a) *Exsolution of gas from a liquid petroleum charge***

1.b) Liquid drop-out of an undersaturated gas / condensate or a supercritical phase charge

2. Petroleum charge from multiple source rocks.

2.a) An oil accumulation receives one or multiple petroleum charges from different source rocks, mixing of the different charges is complete or incomplete and happens in the structure

2.b) Same as 2.a) but mixing happens prior to charging the trap, i.e. in a structure downflank

2.c) A gas accumulation receives an additional oil charge.

1.a) This is a common case where undersaturated oil migrates upwards and exsolves gas upon hitting the bubble point which leads to the formation of a gas cap. In this case the gas isotopic composition from liquid and vapour phase is expected to be identical in both phases since phase separation is not having any significant isotope fractionation effects (e.g. van Graas et al., 2000). We present here, for comparison, the gas isotopic composition of an associated gas of undersaturated oil, which has apparently not hit the bubble point (Figure 1 & 2, open and filled crosses).

1.b) We present a special case where the accumulated petroleum represents the partial trapping of a late high maturity charge from a marine source rock in the Tampen area. The gas isotopic composition in the oil and gas phase is identical (Figure 1 & 2, open and half filled triangles), and fits with generation at high maturity from a marine source rock. This is in both respects in agreement with the organic geochemical signal from the LHC and the biomarkers. The gas fraction of the accumulated total petroleum was calculated as 0.44 (mass fraction). Comparison with pyrolysis data from both open and closed systems shows that the virgin fluids expelled from Draupne Formation never reach such high fractions even at high maturities unless secondary cracking is involved. The PVT data indicate that the fluids are close to saturation which supports a simple Exsolution scenario. The reconstructed bubble dew point curve of the charge fluid indicates that the charge was either a gas phase or a supercritical fluid so that the oil leg evolved as a condensate drop out. If one considers secondary cracking to be unlikely an alternative explanation for the high gas mass fraction can be that the migrating fluid lost liquid fraction during migration, prior to entrapment.

2.a) For the case of adding a gas with a different isotopic composition into an oil accumulation one might expect gas from the vapour phase to equilibrate into the liquid phase but not the other way round since oil associated gas molecules would need to move against a compositional gradient. Therefore the gas composition in the liquid phase should be expected to represent a mixture of the oil associated gas and the additional gas charge, whereas in the vapour phase the newly added gas signal should dominate. This assumes that there was no initial gas cap prior to the second gas charge. An example where different isotopic compositions were observed in the gas and liquid phase, respectively, is shown in Figure 2 (open and half filled squares). The gas-phase is only represented by methane to propane since higher molecules are having too low concentrations (no test sample but mud gas was analysed). Heavier isotope values than in the oil associated gas point to the gas being of a more terrigenous origin or of a higher maturity. The oil accumulation appears to be saturated (Figure 1, open and half filled squares).

2.b) Here we look at a case where an initial oil accumulation was biodegraded and additional charges of oil and gas, from both predominantly terrigenous organic matter and from a marine source, were identified. However, identical compound specific gas isotopic compositions are observed for both phases, moreover the gas is isotopically heavy (Figure 1 & 2, open and half filled circles). Oil and gas are trapped in three reservoir levels and the degree of undersaturation is increasing with depth. The geochemical signal for heavier than gas components points to different origins of light and heavy components both in terms of source rock facies and maturity.

We conclude that it is rather the rule than the exception that isotopic compositions in liquid and vapour zones in two-phase accumulations are identical. Apparently molecular movement in the subsurface is fast also across phase boundaries. Therefore cases where differences in isotopic composition are detected should fall into category 2 b or c, in which case observations on other geochemical parameters as well as on phase properties should fit those scenarios. Differences in isotopic compositions may also represent cases where gas and oil zones are not really in communication. On the other hand the observation of identical compositions supports but does not prove communication between compartments since mixing of fluids may happen in yet undetected pools downdip on a migration pathway.

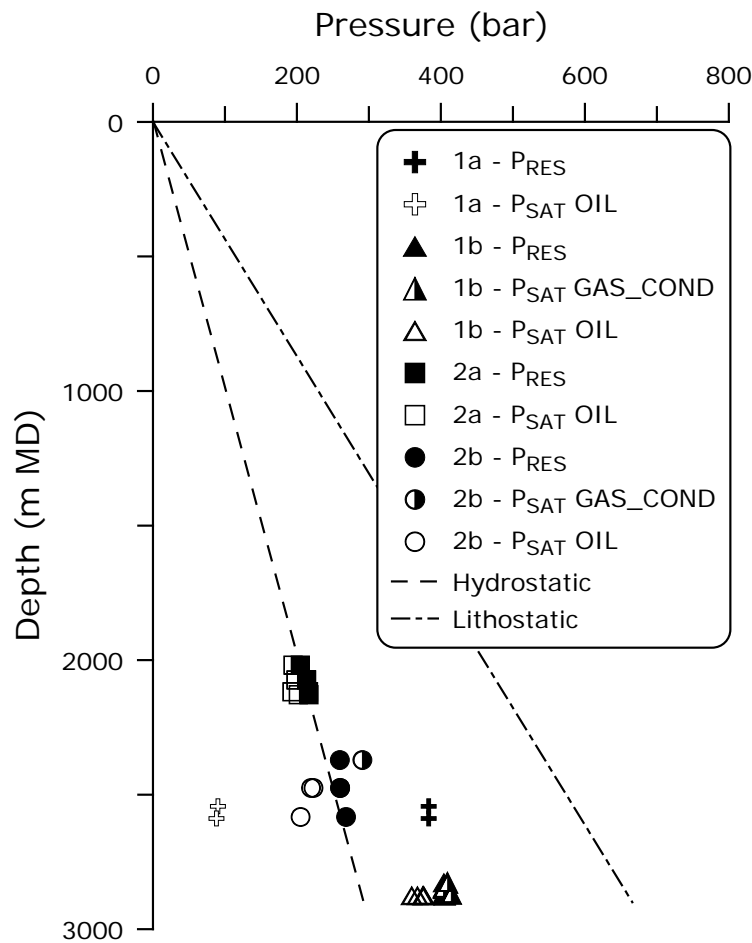


Fig. 1: Reservoir (P_{RES}) and saturation pressure (P_{SAT}) shown as a function of total vertical depth below mean sea level (TVD MSL) of selected fluids of the Norwegian Continental Shelf.

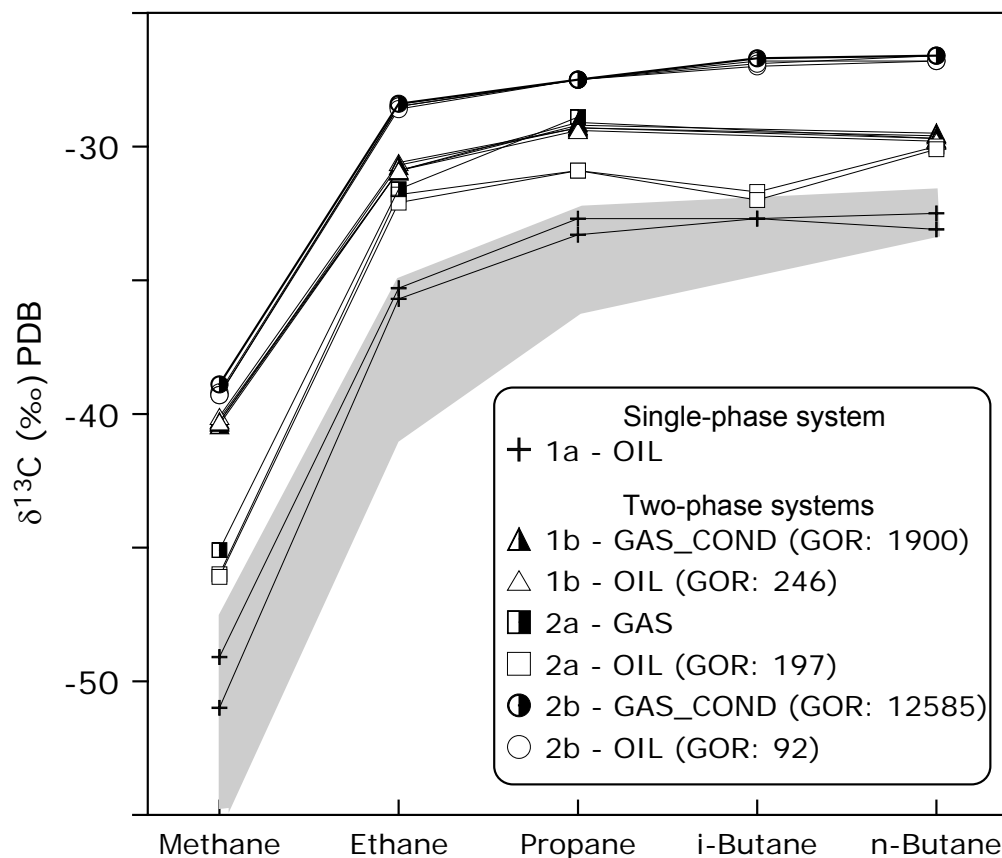


Fig. 2: Compound specific carbon isotope profiles of oil-associated and free gases/gas-condensates of single-phase and two-phase systems. Mean gas-oil-ratios (GOR) are given in brackets. The grey shaded area represents the carbon isotopic range of the gas generation index (GGI) according to Clayton (1991). The lower (GGI = 0.1) and upper (GGI = 1.0) limits are calculated for a labile kerogen $\delta^{13}\text{C}$ of -30‰ PDB, to match the distribution of the single-phase oil-associated gas.

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