IMPROVED UNDERSTANDING OF TERTIARY DELTAIC PETROLEUM SYSTEMS BASED ON CSIA: AN EXAMPLE FROM THE NIGER DELTA, NIGERIA

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Recent developments in hydrocarbon exploration focus on processes and efficiencies contributing to petroleum systems. Arguably, this statement is least true for Tertiary deltas in general and the Niger Delta in particular. Despite more than four decades of active exploration, the petroleum systems operating in the Niger Delta still remain controversial. Notable is the fact that some oil accumulations reservoired within Tertiary sands show poor molecular and isotopic correlations with alleged delta source rocks.

Several studies of source rocks and oils of the Niger Delta have provided the foundations of our current understanding (e.g. Ekweozor and Okoye, 1980; Bustin, 1988; Haack et al., 2000; Eneogwe and Ekundayo, 2003). Kerogens of the deltaic source rocks have been described as terrigenous in terms of organic matter provenance with vitrinite being the most abundant maceral (≥ 80%; Ekweozor and Okoye, 1980; Bustin, 1988). Most studies of Niger Delta crude oils rely on physical properties of oils and stable carbon isotope ratios of hydrocarbon fractions, in combination with molecular ratios from gas chromatography separation of gasolines and heavier hydrocarbons. However, molecular information can be misleading, where long distance migration increases the chance of leaching molecules from organic-rich rocks leading to migration contamination (Curiale, 2002). Deltaic sedimentary geometries, with multiple distal sands combining proximally, promote both leaching and the mixing of end-member oils, which confuses oil-source rock correlations based on both organofacies and expulsion maturity as measured by biological marker (biomarker) parameters.

Compound specific stable carbon isotopes analyses (CSIA) of individual compounds, particularly *n*-alkanes, in combination with a range of biomarkers, arguably offer a more reliable definition of organo-facies and hence approach to correlation. Despite successful application of CSIA in a number of basins such as the North Sea (e.g. Bjorøy et al., 1993) , this technique has not been widely applied as a complementary tool to better assess the Niger Delta oil systems. CSIA data can on its own merit help to unravel and quantify the degree of oil mixing, (e.g. Rooney et *al*., 1998).

In this work, CSIA data are combined with high resolution biomarker and light hydrocarbon data on a suite of oils from twenty-three fields from the west, central and eastern shallow water of the delta, together with three deepwater fields. No source rocks were analysed. Based on these data, at least two petroleum systems are present in the Niger Delta, the first being a terrigenous system that is pervasive and characterized by negatively sloping $\delta^{13}C$ *n*-alkane stable carbon isotope profiles, dominant C_{29} steranes (~ 51%), indicating expulsion from a source rock deposited under oxic (Pr/Ph >2.5) and non-stratified conditions (lack of gammacerane). The second petroleum system shows evidence of generation from a source rock of marine organofacies (detection of C_{30} *n*-propyl cholestane and high %C_{27} steranes, ~ 30 %) deposited under sub-oxic (Pr/Ph ratios <2.5) and stratified (presence of gammacerane) conditions as well as positive to flat $\delta^{13}C$ *n*-alkane isotope profiles. The marine system comprises deepwater oils and some shallow water oils from the west and east. Oils of intermediate properties could reflect expulsion from an intermediate organofacies, leaching during migration or mixing. The marine system is thought to indicate expulsion from discrete *sub-delta* source rocks envisaged to have been laid down during the early opening of the central South Atlantic (mid-late Cretaceous) prior to the delta build-up, and hence are now underneath the main delta prograde. The terrigenous oils are sourced from *intra-delta* source rocks**,** either delta top coals or large volumes of leaner shales containing land plant exinites.

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