

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 reservoirised 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 ($\geq 80\%$; 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 $\delta^{13}\text{C}$ *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 $\delta^{13}\text{C}$ *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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PITFALLS AND POTENTIAL REMEDIES OF THE CURRENT OIL-SOURCE CORRELATION APPROACH: CASE STUDIES IN TWO OF THE WORLD'S LARGEST TERTIARY DELTAIC SYSTEMS

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Biomarkers are used routinely by the oil industry to group genetically related oils, to correlate discovered oils with source rocks and to postulate the probable source rock depositional environments of migrated oils of uncertain origin. Dahl et al. (1994) suggested that biomarker distributions in reservoir oil could be used to monitor lateral facies changes in the underlying source rocks in vertically drained basins. Several case studies showed that this biomarker approach could allow petroleum geologists to constrain source rock quality, one of the key variables in petroleum systems, even when the source rock has not been penetrated. The present study uses geological and geochemical data from two of the world's largest Tertiary deltaic systems to demonstrate the common pitfall of the current oil-source correlation approach and to suggest potential remedies for addressing the problem.

The Beaufort-Mackenzie Basin is a Mesozoic-Cenozoic trough formed by the opening of the oceanic Canada Basin, with sediments prograding northwards across the continental margin from the Late Cretaceous and through the Tertiary period. Molecular, isotopic and elemental data for a set of over 150 oils from the Mackenzie Delta and Canadian Beaufort Sea have been evaluated, and the depositional environment and organic matter characteristics of the potential source units for these oils have been predicted. The deltaic sediments in the Paleogene Aklak, Taglu and Richards sequences of the Beaufort-Mackenzie Basin are molecularly distinctive, containing biomarkers indicative of a major land plant contribution. These include the high C₂₉ sterane abundance relative to other steranes, and high oleananes, 24-norlupanes, 24,28-bisnorlupanes relative to hopanes, and the presence of a battery of partially aromatized, angiosperm and gymnosperm derived polycyclic hydrocarbons. In contrast, biomarker signatures of the marine source rocks in the Upper Cretaceous Smoking Hills/Boundary Creek formations are characterized by little or no oleananoids/lupanoids, abundant C₃₀ 24-n-propylcholestanes, and an almost 1:1:1 ratio of the C₂₇:C₂₈:C₂₉ regular and rearranged steranes.

The Pearl River Mouth Basin also contains a large Tertiary deltaic system developed on the northern continental shelf of the South China Sea, with oils being produced mainly from deltaic-near shore sandstone reservoirs in the upper Oligocene Zhuhai Formation. The

likely source rocks for these oils include the lacustrine shales and mudstones of the Eocene Wenchang Formation and the shallow lacustrine-deltaic coal-bearing sequence of the Eocene-Oligocene Enping Formation. Oils derived from the lacustrine source rocks in the Wenchang Formation typically contain abundant C₃₀ 4-methylsteranes, whereas the deltaic source rocks in the Enping Formation are characterized commonly by high pristane/phytane ratios and significant amounts of C₁₉ tricyclic terpane and bicadinanes.

What is common in both Tertiary deltaic systems is that the chemical compositions across different molecular weight and polarity fractions of a large number of oils in the deltaic reservoirs do not conform to those of the known source rocks, though correlations using the routine m/z 191 and 217 mass fragmentograms would favour one particular source that contains higher biomarker concentrations. For example, the presence of abundant higher plant markers in the Paleogene oils of the Beaufort-Mackenzie Basin appears to suggest a dominant deltaic coaly source with relatively low thermal maturity for these oils. However, GC/MS/MS analyses of the saturate fractions of these oils reveal that the C₂₉ sterane dominance on the m/z 217 mass fragmentograms is in fact a mixture of a group of immature terrestrially-derived C₂₉ steranes superimposed on a group of C₂₆ to C₃₀ steranes with mature structural configurations likely from the Upper Cretaceous marine source. Mass balance calculations indicate that addition of only 5% of the immature intra-reservoir deltaic source rock extract to a mature oil originating from the Upper Cretaceous marine source rocks would turn the mixture into an “immature oil” with an apparent coaly source. This suggests that the presence of abundant higher plant markers in the oil is a necessary but not sufficient indicator for the Paleogene deltaic source. In the Pearl River Mouth Basin, in contrast, laboratory mixing experiments using selected end member oils indicate that even with 50-80% contribution from the deltaic source in the Enping Formation, the mixtures still display biomarker signatures diagnostic of the lacustrine source rocks in the Wenchang Formation. Thus, the presence of abundant 4-methylsteranes in the light oils is also a necessary but not sufficient indicator for the lacustrine source rock in this basin. As mixing is the norm in vertically drained petroleum systems and “source rock” samples are collected commonly from exactly the wrong locations for this purpose, the established paradigms of oil-source correlation in many of the world’s largest Tertiary deltas need to be re-examined.

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CHANGES IN THE BULK AND COMPOUND-SPECIFIC STABLE ISOTOPES ($^{13}\text{C}/^{12}\text{C}$ AND D/H) OF WESTERN AUSTRALIAN CRUDE OILS THROUGH TIME

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This study focuses on the changes in the stable carbon ($\delta^{13}\text{C}$) isotopic composition of the saturated and aromatic hydrocarbons in western Australian crude oils through time. From this extensive dataset, carbon and hydrogen (δD) isotopic compositions of individual C_{7+} *n*-alkanes were obtained for the major genetic oil families. The samples originate from the Arafura, Bonaparte, Browse, Canning and Perth basins, with source ages that span the Cambrian to the Cretaceous. Complementary biomarker analyses provide insights into the type of organisms preserved in the source rock, its lithology and depositional environment, as documented by Geoscience Australia and GeoMark (2005).

This study shows that the line used to separate a global set of marine and non-marine oils by Sofer (1984), is not particularly useful for western Australian oils (Figure 1). Using the combination of bulk and *n*-alkane-specific $\delta^{13}\text{C}$ isotopic profiles, oil families of Palaeozoic and Mesozoic age can be distinguished. From the Early to the Late Palaeozoic, Australian oils have become isotopically more enriched in ^{13}C . The most depleted $\delta^{13}\text{C}$ value of -32.0 ‰ is recorded for the saturated hydrocarbon fraction ($\delta^{13}\text{C}_{\text{sat}}$) of a Cambrian oil-stain in the Arafura Basin. $\delta^{13}\text{C}_{\text{sat}}$ values of about -31 ‰ are recorded for Ordovician oils from the Canning Basin, with slightly more enriched values (mean $\delta^{13}\text{C}_{\text{sat}} = -29.3$ ‰) being obtained for Late Devonian marine oils in this basin. Early Carboniferous marine oils from the Bonaparte and Canning basins have mean $\delta^{13}\text{C}_{\text{sat}}$ values in the order of -28 ‰. Permian terrestrially sourced wet gases/condensates are some of the most ^{13}C -enriched samples from western Australian, with values of around -24.6 ‰ being recorded in the Bonaparte Basin and -25.7 ‰ in the Perth Basin. Early Triassic Perth Basin oils have extremely depleted saturated hydrocarbon isotopic values of around -32 ‰ that are not as pronounced in the aromatic hydrocarbon fraction (mean $\delta^{13}\text{C}_{\text{arom}} = -29.9$ ‰), separating them from the Ordovician Canning Basin oils.

Jurassic oils from the Bonaparte, Browse and Carnarvon basins exhibit a range in their $\delta^{13}\text{C}_{\text{sat}}$ values from -26.1 to -27.8 ‰, due to generation from multiple source rocks

throughout the oil window. Their source rocks were deposited in fluvio-deltaic to marine systems and contain varying amounts of land-plant material. Early Cretaceous marine oils of the Bonaparte and Browse basins have depleted $\delta^{13}\text{C}_{\text{sat}}$ values in the order of -30.2 ‰ and -28.6 ‰ respectively, and can be differentiated from the Early Carboniferous oils on their *n*-alkane-specific isotope profiles.

The *n*-alkane-specific $\delta^{13}\text{C}$ isotopic profiles of the Palaeozoic and Mesozoic oils and condensates characteristically follow the same trend as the bulk $\delta^{13}\text{C}$ isotopic values. The *n*-alkane-specific δD isotopic profiles typically complement those of the carbon isotopic profiles for the oils derived from marine source rocks. The carbon and hydrogen profiles exhibit distinct differences in oils that originate from either non-marine systems, or, in the case of the Triassic aged Perth Basin oils, a restricted anoxic marine environment.

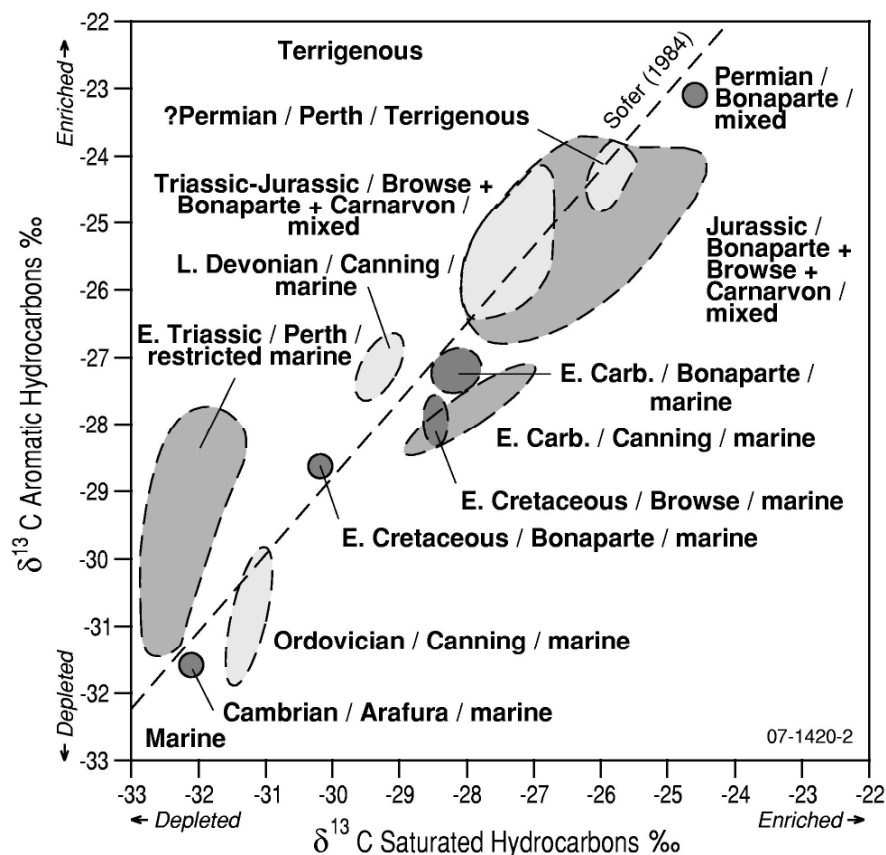


Figure 1. Stable carbon isotopic signatures of western Australian oils through time.

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