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Geochemical fingerprinting of western offshore Niger Delta oils

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ABSTRACT

This study reports the findings based on analyses of saturated (normal alkanes and aliphatic isoprenoid) hydrocarbons and biomarkers in twenty four (24) crude oil samples from western offshore Niger Delta of Nigeria using gas chromatography (GC), gas chromatography-mass spectrometry (GC-MS) and carbon isotopy. The major objectives were to apply reservoir geochemistry and oil fingerprinting to characterize the oils in order to determine their origin and to identify the existence of reservoir continuity and/or compartmentalization. Results from this study using the distributions of normal alkanes, tricyclic and tetracyclic terpanes as well as source specific maturity and facies controlled biomarker ratios of the oils including pristane/phytane (Pr/Ph), Pr/n-C_{17}, Ph/n-C_{18}, C_{31}:22S/(22S + 22R) homohopane, C_{29}:αα(20S/(20S + 20R)) steranes, moretane/C_{30}-Hopane and Ts/(Ts + Tm), showed that the entire crude oil samples from three reservoir units are the same, the differences are small. The oils originated from same source rocks which were deposited under oxidizing condition with mixed marine/terrigeneous organic source inputs and thermal maturity. This genetic classification is supported by stable carbon isotopic compositions ($\delta^{13}C$) of the hydrocarbon fractions and multivariate statistical (Principal Component and Cluster) analyses. Geochemical, fingerprinting and multivariate statistical data provided corroborative evidence of a single compartment with vertical and lateral reservoir continuity across the fault complex within the studied fields. This information can be utilized by geologists and petroleum engineers in solving production related problems such as optimising hydrocarbon production via drilling horizontal wells to arrest the reservoir communication that occurs with existing vertical wells.

1. Introduction

A major consideration in the management of both brown field and green field is how to maximize the amount of recoverable petroleum. In green discoveries, much attention is devoted to delineating the reservoirs before full scale development is undertaken. For instance, in accurate reservoir modeling, geologist and engineers seek for data on core materials, detailed analyses of the sediments and well logs. Often ignored or partially utilized is the chemical composition of the oils. It is a common observation that oil within a continuous reservoir has a uniform hydrocarbon composition when sampled away from the oil/water and oil/gas contacts, and oils in separate reservoirs almost always have measurable compositional differences (Kaufman et al., 1990). Owing to the fact that oils within a field usually have a similar geologic history (e.g. similar source and maturation), the differences may not be detected by bulk properties such as viscosity, gravity, sulfur and isotopic composition. Therefore, the most successful tool for the measurement of the molecular composition of the oils is gas chromatography.

The chemical composition of oil measured using gas chromatography is often thought of as a fingerprint and characteristics of a particular reservoir. For example, fingerprinting technology can be used to resolve reservoir development and production engineering challenges such as determining if a reservoir penetrated by a particular well is the same reservoir as has been penetrated by other well. This technology regionally has assisted in the determination of the size or the extent (reservoir continuity) and volume of a field and has also been useful in planning the development of a field and specifically the number and location of wells required to drain the field. Oil geochemistry (oil fingerprinting) applied to reservoir continuity assessment in a diverse range of geological settings include a wide range of field sizes, structural environments, reservoir lithologies, and oil types (Slentz, 1981; Kaufman et al., 1990; Hwang and Baskin, 1994; Hwang et al., 1994; Sundararaman et al., 1995; Ross

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and Ames, 1988; Nederlof et al. 1994; 1995; Westrich et al., 1996; 1999, Noyau et al., 1997; Kaufman et al., 1997; Edman and Burk, 1999; Smalley and England, 1992, 1994; England et al., 1995; Smalley and Hale, 1996). As demonstrated above by numerous published case studies, petroleum geochemistry provides an effective tool for identifying vertical and lateral fluid flow barriers within oil and gas fields (Dugstad et al., 1999; Beeunas et al., 2000; Chopra and McConnell, 2004). This technique applied to petroleum exploration and production provides especially useful and cost-effective tools for evaluating reservoir continuity and allocating commingled production (Kaufman et al., 1990, 1997; McCaffrey et al., 2006; Hwang et al., 2000). It is highly complementary to engineering methods for deriving reservoir continuity information, and can effectively replace some engineering methods for allocating commingled production (Hwang et al., 1994). It provides a better understanding of the characteristics of reservoirs and fluids and allows engineers to maximize the recovery of hydrocarbon fluids in a field and to determine how many wells should be drilled, where wells should be drilled, and how to maximize the production. The geochemical technique is especially useful because it provides an independent line of evidence for evaluating the reservoir continuity implications of other data types (data such as RFT pressures, pressure decline curves, oil-water contact depths, fault juxtaposition or Allen diagrams, etc.). Exploration efficiency has been increased using geochemical techniques by accounting for many of the variables that control the volumes of petroleum available for entrapment (charge), including source rock quality and richness, thermal maturity, and the timing of generation-migration-accumulation relative to trap formation (Hunt, 1996).

Several articles have been written about the contribution of multivariate statistics in oil and gas industry (de Freitas et al., 2012 and references therein; Yaohui et al., 2012). This is the first attempt in the western offshore Niger delta of Nigeria, as a case study, to evaluate vertical and lateral reservoir continuity using reservoir geochemical fingerprint data and multivariate statistical approach. The major objective of this study was to apply reservoir geochemistry and oil fingerprinting to 1. Characterize the oils in order to determine their origin, 2. Identify existence of reservoir continuity and/or compartmentalization in the studied field.

2. Geological setting

The Niger Delta (Fig. 1a) which is on the Atlantic coast of West Africa is one of the largest and most prolific hydrocarbon provinces in the world. It covers an area of about 75,000 km^2 with a siliciclastic fill that reaches a maximum thickness of 9000–12,000 m. The stratigraphy of the Niger Delta consists of mainly three thick rock units (Short and Stäuble, 1967; Frankl and Cordry, 1967; Evamy et al., 1978; Lambert-Aikhionbare and Ibe, 1984), which are from shallowest to the deepest (Fig. 1b): (1) the Benin Formation, composed of sandstone in a fluvial and coastal environment, (2) the Agbada Formation, composed of interbedded sandstones and shales deposited in a transitional to marine environment and (3) the Akata Formation, composed of massive marine shales.

Petroleum occurs throughout the Agbada Formation. Tuttle et al. (1999) suggest that reservoirs occur along northwest-southeast “oil rich belts,” which roughly correspond to the transition between continental and oceanic crust within the axis of maximum sediment thickness. To some authors, these oil rich belts are related to certain factors, 1. structural or depositional controls, 2. an increase in the geothermal gradient, and 3. basin-ward shifts in deposition within subsequent depobelts (Doust and Omatsola, 1990; Haack et al., 2000). In the Agbada Formation, reservoir intervals have been interpreted to be proximal shallow ramp deposits of high stand and transgressive system tracts and range in thickness from less than 45 ft. (13.7 m) to more than 150 ft. (45.7 m) (Evamy et al., 1978). The most common reservoir locations within the Niger Delta include structural traps formed during syn-sedimentary deformation of the Agbada Formation and stratigraphic traps formed preferentially along the delta flanks (Beka and Oti, 1995).

The principal sources for oil and gas in the Niger Delta are Type II, Type II–III and Type III kerogens (Haack et al., 2000). Deposits formed in marine deltaic environments are derived mainly from allochthonous material (Coleman, 1988; Galloway and Hobday, 1996). Continental derived materials, such as spores/pollen and other terrigenous organic matter (peat, coal and plant debris) are transported to the ocean via rivers and the wind.

It is generally assumed that oil and gas in the Niger Delta originated mainly from terrigenous and nearshore marine source rock (Haack et al., 2000). The occurrence of oleanane in Nigerian oils points to Late Cretaceous or younger source rocks (Ekweozor and Daukoru, 1994). Eneogwe and Ekundayo (2003) identified three different families of Nigerian oil based on light hydrocarbon distributions and biomarker parameters, e.g., the oleanane/hopane ratio, which suggests multiple source rock organofacies. Recently, Samuel et al. (2009) proposed that differences between the deepwater and the onshore oils implicate the likelihood of three source rock organofacies, which are a more marine organofacies that dominates the deepwater accumulations, a terrigenous intra-delta organofacies that is pervasive over the entire delta and a mixed source rock facies common in shallow water accumulations.

3. Study area

The study area lies in the western offshore Niger delta of Nigeria (Fig. 1a) and consists of four oil fields (A-D). These oil wells penetrated vertically three oil producing reservoirs (stratigraphic units): X, Y and Z within a depth range (1394.76–2296.67 m). Substantial amounts of oils are produced from a small number of drilled vertical wells within this area. A number of faults (Fig. 1c) have been mapped in the study area, and these may act as lateral barriers to fluid flow or may act as conduits reservoir fluid communication. Vertical compartmentalization of the field, both in geologic and production time frames, is also a possibility.

Petroleum in the region and in the study area is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. Reservoirs in the Agbada Formation are controlled by depositional environment and by depth of burial. The reservoir rocks in this area are Eocene to Pliocene in age, and are often stacked, ranging in thickness from less than 15 m to 10% having greater than 45 m thickness (Evamy et al., 1978). However, Edwards and Santogrossi (1990) describe the primary Niger Delta reservoirs as Miocene paralic sandstones with 40% porosity, 2 darcys permeability, and a thickness of 100 m. Composite bodies of stacked channels (Doust and Omatsola, 1990) characterized the thicker reservoirs. The most important reservoir types according to geometry and quality are point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels Kulke (1995). The lateral variation in reservoir thickness in the Niger delta region is strongly controlled by growth faults; the reservoir thickens towards the fault within the down-thrown block (Weber and Daukoru, 1975).

The physical and chemical properties of the oil in the Niger delta region are highly variable, characterized by a nonbiodegradation and moderately biodegradation, even down to the reservoir level. The oils specific gravity ranged from 16 to 50° API, with the lighter oils having a greenish-brown coloration (Whiteman, 1982). The oils are grouped into two. The first group are oils from deeper reservoirs characterized by low paraffin and waxy oils (wax content between 5 and 20%) and high *n*-paraffin/naphthene of 0.86 (Kulke, 1995; Doust and Omatsola, 1990). The second group of oils from shallow reservoirs are biodegraded with lower API gravity (average API of 26°) and are naphthenic non-waxy oils (*n*–paraffin/naphthene = 0.37 (Kulke, 1995)). Biodegradation and washing is extreme in some Pleistocene sands of the Agbada Formation, forming extra heavy oils (API 8–20°). The concentration of sulfur in most oils is low, between 0.1% and 0.3%, with a few samples having concentrations as high as 0.6% (Nwachukwu et al., 1995).