

MAASTRICHTIAN ARAROMI SHALE AS THE PRINCIPAL SOURCE ROCK FOR PETROLEUM GENERATION IN DAHOMEY BASIN, SOUTHWESTERN NIGERIA

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Dahomey Basin extends from South-eastern Ghana through Togo and Benin republic to the south-western Nigeria on the continental margin of the Gulf of Guinea. Recent exploration and prospect re-evaluation efforts in the Nigeria segment of the basin have been encouraged following oil discovery and production in the Benin republic sector west of the basin and the social unrest in the prolific Niger Delta east of the basin.

From four exploratory wells, source rock potentials have been evaluated for over 100 core samples from potential petroleum source beds namely Araromi, Akinbo, and Oshosun formations. Total organic carbon (TOC) and hydrogen Index (HI) values range from 0.37 – 2.08wt% and 10.61-167mgHC/gTOC for Oshosun, 0.17 - 1.05wt% and 20-125mgHC/gTOC for Akinbo, 0.51-6.37wt% and 12-327mgHC/gTOC for Araromi samples analysed. Macerals compositional analysis reveals low level of liptinite macerals (av.8.9 %) and abundance of vitrinite (av. 38.1% and inertinite (av. 52.9 %) macerals in all samples, except for samples of Araromi Formation having average liptinites and vitrinite of 30.0% and 31.8% respectively. Vitrinite reflectance values vary from 0.45-0.68 %R_o and Tmax vary from 408 - 440 suggesting immature to marginally mature petroleum source beds.

Samples in the Araromi Formation were further selected for detailed geochemical and micropaleontological studies based on their comparatively higher hydrocarbon prospectivity as revealed by TOC (av. 1.5 wt %), Rock Eval HI (av. 110 mgHC/gTOC) and macerals analyses (high liptinites content). The Araromi shales are buried to oil window at depths of 1010m and 555m in the wells from eastern margin and centre of the basin. Though type II, II/III and IV kerogen types are obtainable based on calculated hydrogen indices for Araromi shale, biomarker analyses reveal a nearly uniform source of organic matter of marine algae (%C₂₇ sterane av.52% and positive detection of C₃₀ sedimentary *n*-propyl cholestane, av. 3.7%), thus suggesting that the control on the HI as an indication of source rock quality is varying level of organic preservation.

Foraminiferal biostratigraphy reveals the occurrence of the following species *Bolivina* sp., *Afrobolivina* *afra*, *Textularia* *hocklyhensis*, *Vanadium* sp., *Planulina* sp., *Eponides* sp., *Gavelinella* sp., *Praebulimina* sp., and *Lenticulina* sp., which dominate sub-oxic

and anoxic shallow marine environments. The palaeo-depositional conditions inferred from foraminifera ecology is corroborated by the presence of C₃₀ *n*-propyl cholestane in the shale samples and low pr/ph ratios (average pr/ph = 0.9). Comparatively, given the combination of organic quantity and quality as well as good level of preservation, the Araromi Formation is thus considered to be the principal source rock for oil generation in the basin. With improved preservation and thermal maturity as a function of burial depth, enhanced petroleum source beds quality is predicted for deep offshore of the basin. The massive to nodular Limestone of Ewekoro Formation and the Afowo sandstones lying above and below the Araromi Formation respectively are likely candidates to reservoir any generated hydrocarbons from the Araromi shale at deep burial depth. The shales of the Akinbo and Oshosun formations lying conformably on the Ewekoro Formation are thus considered as potential seals.

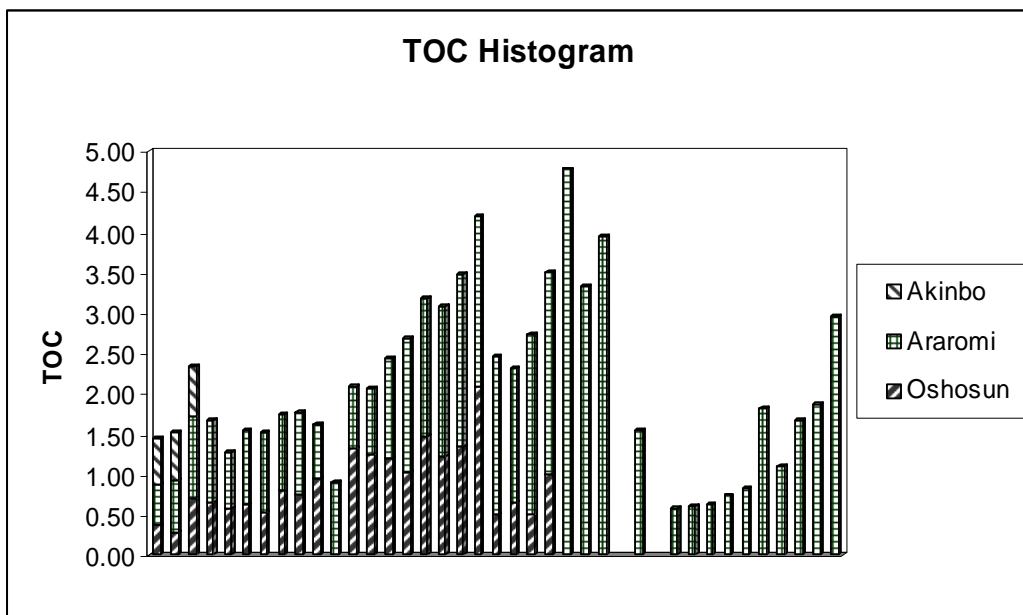


Figure 1. Histogram showing TOC values for shale sediments of Akinbo, Araromi and Oshosun formations. (Total number of core samples =104)