

MASTER OF SCIENCE
PETROLEUM GEOSCIENCE

SUBSIDENCE AND THERMAL HISTORY EFFECT ON SOURCE ROCK MATURITY IN THE SEMLIKI BASIN, ALBERTINE GRABEN – UGANDA

Vivianne Maria NAIGA
PAU-UI-0380
PETROLEUM GEOSCIENCE

The research study focused on the analysis of subsidence and thermal history effect on source rock maturity in the Semliki Basin. The study utilised the back stripping approach and was accomplished using PetroMod Software. The research utilized previous data sets obtained from geochemical reports and final well data reports to generate a basin model of eight (08) Sedimentary Formations ranging in age from Lower Miocene to Pleistocene sediments i.e., Surface, Nyabusozi-Nyakabingo, Nyaburogo, Oluka, Kakara, Kasande, Kisegi and Basement formations. The general trend of subsidence observed is a rapid deepening (13.0 to 11.5 Ma and 3.5 to 2.0 Ma) during the main and later rift phases respectively, followed by an exponential decline in the rate of tectonic subsidence. The maximum heat flow (77.59 mWm⁻²) at 3.5 Ma corresponds to the Late Pliocene to Pleistocene thus deep burial conditions and represents maximum paleo-temperatures. The medium/dark shales of the Kasande-Kakara formations (2070 - 2100m and 2480 - 2488m) are the most prospective source rocks and comprise organic matter (TOC c.2.0%) and an oil-prone Type I/II source rock quality. The source rock maturity plots indicate that the source rock entered the early oil zone at 2.0 Ma whereby the top of the oil generation window is observed with Ro 0.5%, corresponding to the Kasande-Kakara formations at a depth of 2400-2500m. This corresponds to the second subsidence event, however, there was no commencement of oil generation. Though limited by the scope of the data set, this study allowed for a quantification of tectonic subsidence and thermal maturity effects on the identified source rock horizons of the Semliki Basin sediments.

CO₂ CONTAINMENT AND STORAGE POTENTIAL OF E-RESERVOIR UNIT, AKASO FIELD, NIGER DELTA, NIGERIA

**JASSEM GACHA
PAU-UI-0770**

PETROLEUM GEOSCIENCE

Carbon dioxide (CO₂) storage in depleted oil and gas fields offers both challenging and sustainable opportunities. Despite the significant hydrocarbon potential of the Niger Delta Basin, there has been limited carbon capture and storage (CCS) studies in the specific geological context of the region. This research aims to find a sustainable solution for the oil and gas industry in the Niger Delta Basin, minimizing CO₂ emissions and preventing climate change by studying the CO₂ storage potential of Akaso Field. This research involved detailed structural and petrophysical analyses complemented by a 3D modeling workflow, followed by a CO₂ storage volumetric approach, applying field screening criteria for CO₂ containment. The study identified the E reservoir sand unit, separated by thin shale layers. The reservoir is characterized by good effective porosity ranging between 20% and 22% and good permeability with values higher than 400 mD. A deep Horst structure-oriented E- W was identified and served as a potential closure to contain CO₂. Based on the analyses, lateral continuity of the E reservoir unit was established and the presence of a continuous seal with an average thickness of 80 m was identified. The 3D static model of the E reservoir unit allowed a 3D visualization of the structural closure. The vertical and lateral petrophysical properties variation confirmed good lateral and vertical porosity and permeability in Akaso Field. The hydrocarbon potential of the E reservoir unit was evaluated indicating 53 Mstb of Stock Tank Initially in Place (STOIIP) and 18.6 Bscf Gas Initially in Place (GIIP). The integration of these results allowed the calculation of the CO₂ storage potential of the E reservoir unit indicating a good theoretical CO₂ storage capacity of 40 MT and a considerable effective CO₂ storage capacity ranging from 0.4 to 6.4 MT depending on the storage efficiency coefficient (Ce) ranging from 1% to 15%. Compared with the standard and based on screening criteria, the E reservoir unit in Akaso Field, Niger Delta Basin, is suitable for CO₂ storage.

Key Words: Carbon capture and storage, Climate change, Depleted oil and gas fields, 3D static model, CO₂ storage.

GEOCHEMICAL ASSESSMENT OF SELECTED SEDIMENT IN THE NKHATA BASIN, MALAWI

**LUZANA KAMTANGWALA
PAU-UI-0772**

PETROLEUM GEOSCIENCE

The Nkhata Basin, situated within the Malawi Rift System of the East African Rift System, is an underexplored frontier basin for hydrocarbon potential. This study integrates lithological, Total Organic Carbon (TOC), Rock-Eval Pyrolysis and elemental analysis to evaluate the source rock characteristics of the studied interval (GLAD7_MAL05_1B, 1C and 1D). This was supplemented by X-ray fluorescence (XRF), machine learning and high-resolution core images. Five lithological units were identified: clayey silt, silty clay, carbonate mud, sandy silty clay and mud, dominated by siderite and pyrite, indicative of reducing conditions conducive to organic matter preservation. The TOC values range from 0.25 to 7.22 wt.% with 82- 88% of the samples exceed the 1% threshold, classifying them as good to excellent source rocks. S1/S2 pyrolysis revealed moderate to excellent hydrocarbon generation capacity, particularly in silty clay and carbonate mud. Rock Eval Pyrolysis revealed Hydrogen Index (HI) values of 21.05 - 1256 mg HC/g TOC reflecting oil prone Type II and mixed Type II/III kerogen, while low Oxygen Index (OI) values (14-393 mg CO₂/g TOC) confirmed effective organic matter preservation. Production index (PI) values (<0.1) and Tmax (327–444°C) indicated immature to early maturation stages, limiting current hydrocarbon generation. Elemental ratios and redox proxies Fe/Al, V/(V+Ni), K/Rb, V/Cr and S/Fe confirmed the fluctuating in reducing depositional conditions, oscillating between oxic to anoxic conducive for organic matter preservation. Machine learning algorithms validated these geochemical interpretations, with ensemble models achieving >93% accuracy in predicting kerogen types and hydrocarbon potential. The silty clay, carbonate mud units, enriched in Types II, II/III kerogen and high TOC emerge as primary targets for hydrocarbon generation. While current immaturity restricts immediate exploitation, the basin's organic richness and favourable preservation conditions position it as a promising exploration target, contingent on deeper burial and maturation. The study advances understanding of the source rock from the rift basins which will guide future regional exploration and resource development.

Key Words: Depositional conditions, Hydrocarbon potential, Nkhata Basin, Source rock, Thermal Maturity.

GEOCHEMICAL EVALUATION OF THE MIOCENE-PLIOCENE SUBSURFACE PETROLEUM SOURCE ROCKS FROM THE ALBERTINE GRABEN, UGANDA.

Henry SENTALO
PAU-UI-0773

PETROLEUM GEOSCIENCE

Albertine graben is a 570 km long and 45 km wide geological structure that forms part of the East African Rift System (EARS). Given its geologic extent, potential source rocks are inadequately characterized limiting the identification of new plays during hydrocarbon exploration. The study attempted to establish the hydrocarbon generation potential, kerogen type and maturity of the potential source rocks using geochemical techniques. At specific depth intervals, rock samples of the Miocene–Pliocene interval were selected from ten wells and analyzed for total organic carbon (TOC), bitumen content and pyrolysis parameters. Samples with TOC greater than 0.5 wt. % were selected for bitumen extraction. Bulk geochemical analysis revealed poor to very good hydrocarbon generative source rock potential, with TOC, S₂ values, and extractable organic matter (EOM) content ranging from 0.19 to 2.36 wt. %, 0.12 to 7.91 mgHC/g of rock, and 940 to 3456 ppm respectively. Hydrogen index (HI), and T_{max} values ranged from 61 to 335 mgHC/g TOC, and 360 to 438 °C respectively. Plots of S₂ versus TOC and HI versus OI indicate dominant oil–prone Type II kerogen, mixed Type II/III kerogen, and gas–prone Type III organic matter. The HI versus T_{max} plot and bitumen/TOC ratios show immature to early oil window maturity source facies. The calculated vitrinite reflectance, R_o and PI vs. T_{max} plot indicate source rocks are consistently immature to early oil window maturity with low–level kerogen conversion to hydrocarbons. The Miocene–Pliocene source rocks in the graben have the potential to generate oil and gas. A mix of Type II and Type III kerogen, indicates a lacustrine depositional environment with terrestrial organic matter input. Further geochemical studies including petrography should be conducted for robust kerogen typing and maturity assessment.

Key Words: Albertine Graben, Source Rocks, Bitumen, Kerogen Typing, Hydrocarbon Generation Potential.

SOURCE ROCK CHARACTERIZATION OF LOWER CRETACEOUS TO EOCENE SEDIMENTS, MAFIA BASIN, TANZANIA

Mohamed Mussa KAYAMBA
PAU – UI – 0774

PETROLEUM GEOSCIENCE

The Mafia Basin (MB), located off the eastern coast of Tanzania within the Bigwa-Rufiji-Mafia exploration block, has reported accumulation of natural gas. However, no significant record of hydrocarbon discovery has been reported in the Mafia Basin. Understanding the source rock characteristics such as quantity, quality and thermal evolution of the associated sediments within the basin is crucial for unraveling its hydrocarbon prospectivity. This study involved investigation of subsurface data from Well Q, within the Mafia Basin. A detailed analysis of mud logs and programmed rock-eval pyrolysis data was performed. Results revealed that the main lithologies included; marlstone, limestone, claystone/shale/siltyclaystone, sandstone and siltstone. The Eocene sediments have TOC values, ranging from 0.50 – 0.53 wt% (av. 0.52 wt%), S₂ (av. 0.29 mgHC/g rock), HI (av. 83.21 mgHC/ g TOC) indicating a fair hydrocarbon generating potential. Conversely the Paleocene sediments have TOC values, ranging from 0.50 – 0.96 wt%, S₂ (0.16 – 0.66 mgHC/g rock av. 0.32 mgHC/g rock); HI (29.85 – 132 mgHC/ g TOC av. 53.43 mgHC/g TOC) indicating that the sediments have fair to good hydrocarbon generation potential. The Upper Cretaceous sediments have the following values; TOC from 0.50 – 0.71 wt% with av. 0.53wt%; S₂, range from 0.09 – 2.26 mgHC/g rock; (av. 0.31mgHC) for the whole interval and for the upper interval (depth 3170m – 3190m) S₂ av. 1.91 mgHC/g rock and HI range, 16.67 – 337.31 mgHC/g TOC with av. 277.53mgHC/g TOC, indicating fair hydrocarbon potential and good hydrocarbon potential. The Lower Cretaceous interval have the following ranges of values; TOC from 0.58 wt% - 0.78 wt% with av. 0.58 wt%, S₂, 0.16 – 0.57 mgHC/g rock, with av. 0.26mgHC/g rock and HI av. < 50mgHC/g rock indicates that the rock is inert. Cross plots of HI vs OI and HI vs TOC revealed that both the Eocene and Paleocene sediments have terrestrial organic matter with type III kerogen which is gas prone. The Upper Cretaceous sediments at depth (3170m – 3190m) revealed type II/III kerogen, indicating a mixed oil and gas prone source of organic matter. The lower interval of Upper Cretaceous sediments contains type III kerogen. The average T_{max} values for Eocene sediments is 408⁰C indicating immature source rock while that of the Paleocene ranged from 410⁰C – 488⁰C, indicating immature through mature to post mature. Calculated vitrinite reflectance for Eocene sediments is 0.46 Rc%, indicating immature source rock while the Paleocene sediments ranged from 0.22 – 1.62 Rc%, indicating immature through mature and post mature. On the other hand, the Upper Cretaceous and Lower Cretaceous are thermally immature source rocks. This study suggests that the Paleocene sediments are the main source rock which could have extended from Mafia Island, suggesting a potential hydrocarbon charge in the Mafia Basin. The Eocene sediments are immature while the Cretaceous sequences have mixed organic matter sources with immature status.

Key Words: Source rock, Characterization, Paleocene shales, Mudlog, Pyrolysis

BIOSTRATIGRAPHY AND ORGANIC GEOCHEMISTRY OF THE LOWER MAYO-TAFAL SECTION IN BABOURI-FIGUIL BASIN, NORTHERN CAMEROON

TOKALA STEVIA JOSIANE VERIDIANA
PAU-UI-0776

PETROLEUM GEOSCIENCE

A Mesozoic intracratonic sedimentary basin with notable organic matter accumulations is the Babouri-Figuil Basin in northern Cameroon. In order to ascertain the age, depositional environment, and hydrocarbon source rock potential of the lower Mayo-Tafal section, this study combines palynofacies, palynology, and organic geochemistry. In order to create biostratigraphic constraints, palynological investigation concentrated on identifying important palynomorphs, such as pollen, spores, and dinoflagellate cysts. Using the palynofacies technique, organic matter was examined under a microscope to determine preservation conditions and distinguish between terrestrial and marine sources. In order to assess the kerogen type and maturation stage, organic geochemistry, which was based on Rock-Eval pyrolysis, supplied information on Total Organic Carbon (TOC), hydrogen index (HI), oxygen index (OI), and T-max. With organic input primarily from terrestrial sources and sporadic marine impact, the palynological assemblage suggests a likely Lower Cretaceous age. Palynofacies examination indicates a mixture of amorphous and structured terrestrial organic materials (phytoclads), indicating deposition in a shallow to deltaic lacustrine environment with varying redox conditions. Organic geochemistry results from Rock-Eval pyrolysis indicate low to moderate TOC values (0.02–26.30 wt%), with hydrogen index (HI) ranging from 78 to 733 mgHC/g TOC, suggesting the presence of Type II-III kerogen. Tmax values vary between 420°C and 445°C, corresponding to a thermal maturity range from immature to peak oil window conditions. The genetic potential ($GP = S1 + S2$) shows values up to 197.53 mgHC/g rock, indicating variable but locally significant hydrocarbon generation potential. A lacustrine-deltaic depositional environment is reflected in the mixed organic matter input and intermediate preservation found in the lower Mayo-Tafal section. The presence of possible source rocks is confirmed by the organic geochemistry, with certain intervals achieving sufficient thermal maturity for the production of hydrocarbons. A foundation for additional research and an evaluation of the Babouri-Figuil Basin's hydrocarbon prospects is provided by this study

RESERVOIR CHARACTERISATION AND STATIC MODELLING USING SEISMIC AND WELL LOGS OF MAR FIELD IN THE NIGER DELTA, SOUTHERN NIGERIA

YOUNI BABACAR MAR
PAU-UI-0777

PETROLEUM GEOSCIENCE

The integrated study of the MAR Field in the Niger Delta involves characterization of the reservoir properties, lithology, and structural features influencing hydrocarbon potential through an integrated well logs and seismic approach. Lithostratigraphic correlation and petrophysical evaluation undertaken for the four wells (MAR-01, MAR-02, MAR-03 and MAR-04) provided delineation of three major reservoirs, namely; M1, M2, and M7. These had gross intervals of 166.3 m, 134.0 m, and 99.7 m, respectively, with high net-to-gross ratios in the range of 63.62 to 68.88% and good petrophysical properties: effective porosity as high as 17.9% and permeability values over 1,000 mD. Water saturation lower than 60% indicates high hydrocarbon saturation. Directions that enhance structural compartmentalization for effective traps to minimize cross-boundary fluid migration. This compartmentalization in relation to sand and shale facies distribution as modeled through Sequential Gaussian Simulation (SGS) underpins the hydrocarbon prospectivity of the MAR field. Sand facies are laterally continuous, but with interbedded shales providing vertical seals that preserve the reserves and ensure targeted extraction strategies. Reservoir M1 has a high porosity and permeability, hence may be ideal for long-term production; with an estimated 106 million STB of STOIP, while M2 also shows similar properties with an estimated 117 million STB, the most promising reservoir is M7 at 147 million STB due to its high bulk and pore volume. The 3D static model integrates seismic, petrophysical, and structural data into one comprehensive framework in order to optimize well placement and enhance recovery strategies. This study represented the importance of the integration of multidisciplinary data in understanding the reservoir characteristics and developing hydrocarbon resources effectively. The findings demonstrated best practices for maximizing hydrocarbon recovery and extending the MAR field's productive lifespan.

Key Words: Niger delta, Petrophysical properties, reservoir characterization, 3D Static modelling, Facies Modelling

RESERVOIR DESCRIPTION AND MODELLING USING INTEGRATED SEISMIC AND PETROPHYSICAL DATA OF AKDB-FIELD, OFFSHORE NIGER DELTA, NIGERIA

**KOUADIO DIEUDONNE BAUDELAIRE ATTOUMAN
PAU-UI-0778**

PETROLEUM GEOSCIENCE

The Niger Delta basin is one of the most famous, prolific, and exploited sedimentary basins in Africa. This research aims to enhance reservoir characterisation, optimise production, and minimise uncertainties in exploration and exploitation. To optimally characterise the reservoirs, well logs and 3D seismic data were utilised in the Petrel interface. Acoustic impedance and the prediction of rock properties were also carried out by the probabilistic neural network of the emerge algorithms using HampsonRussel 10.5. In the AKDB field, the correlation of wells led to the identification of four major reservoirs (AKDB F, D, C, and B). The petrophysical properties of the reservoirs revealed that gross thickness varies from 2.59 m to 35.3 m, volume of shale ranges from 18.1% to 34.89%, effective porosity ranges from 15.28% to 35.85%, while hydrocarbon saturation is up to 72.732% and permeability ranges from 891.9951 mD to 6266.6394 mD. Furthermore, thirty-six (36) faults were identified, and seven were classified as major faults. The structural analysis highlights the presence of growth faults and rollover anticlines. The volumetric analysis exhibits variable reservoir quality. Among them, reservoir C demonstrates the highest Stock Tank Oil Initial in Place (STOIIP) of 4170.20 MSTB, which underscores the significant hydrocarbon potential of the field. The integration of seismic inversion with the conventional modelling approaches has provided a more comprehensive reservoir heterogeneity and fluid distribution. It provided high-resolution acoustic impedance models that closely aligned with petrophysical properties. The application of probabilistic neural network analysis resulted in a porosity correlation coefficient of 88% with an average error of 0.0298, a permeability correlation coefficient of 77% with an average error of 589.731 mD, and a water saturation correlation coefficient of 66% with an average error of 0.4364. These results show that the AKDB field has potential for hydrocarbon reserves. In conclusion, knowledge from this study has aided the understanding of the subsurface geologic complexities, the planning for future development, and enhance hydrocarbon prospectivity of the studied field.

Key Words: Acoustic Impedance, Offshore Niger Delta Reservoir Characterization, Seismic Inversion, Static Modelling

DOCTOR OF PHILOSOPHY
PETROLEUM GEOSCIENCE

SEDIMENTOLOGY, DIAGENESIS, AND 3D MODELING OF RESERVOIR UNITS OF THE LOWER CRETACEOUS ABU-GABRA, BENTIU, AND ARADEIBA FORMATIONS IN LALOBAL OILFIELD, MUGLAD RIFT BASIN, SUDAN

ABDASEED KUBUR BOKHARI KUBUR

PAU-UI-0437

PETROLEUM GEOSCIENCE

The Lower to Middle Cretaceous Abu-Gabra, Bentiu and Aradeiba Formations are considered as the main reservoir in Muglad Rift Basin, Sudan. However, exploration and research work carried out in the basin reported significant challenges related to reservoir geometry and quality. In order to fill the above-mentioned gap, this study aims to; conduct a detailed sedimentologic and petrographic analyses, highlight and predict reservoir geometry and architecture at different scales, and evaluate the impact of depositional and diagenetic processes on the reservoir units of Abu-Gabra, Bentiu and Aradeiba sequence in the southeast part of Muglad Rift Basin. A core samples retrieved from two wells - namely; LLAG01, for exploration, and LL-09, for development – drilled in Laloba Oilfield. Based on the core description and analysis, seven lithofacies have been generated including; fine laminated sandstone (Fl), siltstone and mudstone, ripple marked siltstone (Sr), trough crossbedded sandstone (St), planar cross-bedded sandstone (Sp), massive sandstone (Sm), and intraformational conglomerate-size mud clast (Sco). The Aradeiba Formation lithofacies are interpreted for having been deposited in fluvial system, meandering channel and overbanks deposits. Similarly, Bentiu Formation is of fluvial system but with braided channel deposits. However, Abu-Gabra Formation is fluvio-deltaic to lacustrine deposits. In addition, the GR log motif used to generate electrofacies which confirmed the existence of channel and crevasse splay sands and flood plain silts and muds of overbank deposits, a typical vertical stacking pattern of fluvial system. Also, the electrofacies of LLAG-01 showed the typical pattern of fluvio-deltaic to lacustrine depositional setting. The multi-scale-based depositional analysis has revealed the periodic tectonic movements and its role to control the development of studied sequences. The 3D facies model using sequential indicator simulation (SIS) algorithm has properly reproduced the sandstone bodies according to their depositional setting e.g. braided and meander channels. Based on the interpreted GR logs, the 3D framework was constructed which comprises of three zones separated by four surfaces. The bottom zone represents braided channels deposits of Bentiu Formation, however middle and upper zones reflect the fluviodeltaic setting deposits of the Aradeiba Formation. The average porosity and permeability values were 24.9% and 1286.5 mD, respectively for core samples of LL-09. In contrast, these values were 10.7% for porosity and 4.0mD for permeability, for samples obtained from LLAG01. Furthermore, the studied interval of LL-09 was classified into three hydraulic flow units (HFUs). Diagenetic processes, such as kaolinite and Fe-dolomite cementation, mechanical compaction, and k-feldspar dissolution, are responsible for the main features encountered in the studied sandstone. The Aradeiba Formation interval exhibited prevalent precipitation of authigenic minerals (e.g., kaolinite and quartz cements) and extensive k-feldspar dissolution in the upper part of the interval. The Bentiu Formation underwent deep burial diagenesis, as evidenced by concavo-convex and sutured grain contacts. Abu-Gabra Formation facies exhibit low porous reservoir bodies as the authigenic mineral e.g. kaolinite, chlorite, calcite and siderite are predominant. Generally, integrated core and well log data analyses provide insight into the impact of depositional and diagenetic processes on reservoir quality, thus improving reservoir quality prediction.

INTEGRATED RESERVOIR CHARACTERISATION AND 3D PROPERTY MODELING OF THE UPPER CRETACEOUS FORMATIONS, MUGLAD BASIN, SUDAN

Yasir Yousif Fadlelmula

PAU-UI-0438 PETROLEUM GEOSCIENCE

This thesis presents an integrated reservoir Characterisation and 3D property modeling study of the Upper Cretaceous formations in the Muglad Basin, Sudan. The Aradeiba, Zarga, and Ghazal formations were investigated using a multidisciplinary approach integrating well logs, seismic data, and rock physics modeling. Petrophysical properties derived from well log analysis facilitated stratigraphic correlation. 3D seismic cube interpretation defined seismic-scale sedimentary strata, structural frameworks, and depositional stacking patterns. Rock physics modeling calculated elastic properties, aiding lithology discrimination and clay content assessment. Deterministic post-stack inversion and Bayesian classification with Markov chain Monte Carlo were employed to derive 3D facies and porosity models and predict depositional environments. Structurally, the area exhibits regional, deep-seated normal faults trending NW. Petrophysical results indicate the Upper Cretaceous reservoirs consist predominantly of sandstone interbedded with thin clay intervals, interpreted as laterally continuous at the basin scale. Average effective porosities are approximately 21%, 20%, and 22% for the Ghazal, Zarga, and Aradeiba formations, respectively, with variations in water saturation and clay volume. Clay mineral analysis reveals smectite dominance in Ghazal, while Zarga and Aradeiba exhibit kaolinite dominance with minor smectite. At the reservoir scale, seismic inversion enabled division of the studied strata into subsequences. The Ghazal and Zarga formations exhibit high porosity (23% and 21%, respectively), while Aradeiba shows relatively lower porosity (17%). The lower Aradeiba (Ara_3) is dominated by a deltaic environment with sub-lacustrine fans, while the upper part is characterized by meandering rivers. The findings confirm the vertical extent and continuity of the studied strata at a basin scale, revealing a complex paleoenvironment. Variations in petrophysical parameters offer valuable insights into the intricate relationship between lithological heterogeneity and depositional environments. Wells exhibiting lower clay volume (VCL) and higher effective porosity (PHIE) suggest fluvial and fluvio-deltaic depositional intervals, aligning with previous research. In such settings, coarser-grained sediments with lower clay content result in higher porosity. Conversely, deltaic and deltaic-shallow lacustrine dominated environments indicate higher clay volumes and lower effective porosity, consistent with established patterns. The calibrated rock physics model demonstrates a strong fit between measured and modelled properties, proving effective even in wells lacking shear and sonic logs. Cross-plots of petrophysical parameters against elastic properties derived from rock physics models prove superior in lithology discrimination compared to measured data, enabling a more accurate distinction between shale, sands, and gas-bearing sands facies. The study proved that the seismic facies prediction using seismic inversion is extremely useful in such deposition environment. In this study, seismic inversion was used to identify the reservoir facies of the Upper Cretaceous Formations, encompassing the Aradeiba, Zarga, and Ghazal Formations. The high porosity sand observed is highly correlated to the lower acoustic impedance; while the lower quality sand/shale facies observed high acoustic impedance and low porosity. the continuity of sand bodies is mainly controlled by faults, moreover the reservoir properties of Upper Cretaceous Formations showing heterogeneity at different scales. The sand thickness, sand continuity together with porosity distribution turns out to be reduced downwards (from Ghazal to Aradeiba)

NON-INVASIVE GEOPHYSICAL MONITORING OF CRUDE OIL CONTAMINANT IN COASTAL SOILS – A LABORATORY SANDBOX STUDY

ADENIRAN MARGARET ADENIKE (PAU-UI-0580 PETROLEUM GEOSCIENCE)

Monitoring the distribution of crude-oil spillage in a coastal environment is challenging due to variable soil and fluid properties. Traditional methods, such as soil sampling and tracer-tests, can be invasive, expensive, and time-consuming with low spatial resolution. Electrical Resistivity Tomography (ERT) method offers a high-resolution approach to monitoring the spatial distribution of crude-oil contaminant but its effectiveness in highly resistive unsaturated and saturated coastal sand with varying salinity remain unexplored. Thus, this research seeks to assess the effectiveness of ERT for soil property estimation and crude-oil contamination monitoring under varying saturation and salinity levels. Two laboratory experiments were performed: column test for formation factor estimation and 3D sandbox electrical monitoring of crude-oil distribution. A 5/15cm transparent cylinder column was used with six samples (3 each for sand without and with crude-oil). The samples were saturated with distilled water (0.0001S/m) for 48hours after which the bulk resistivity of samples was measured using Wenner array with 5cm electrode spacing. Subsequently measurements involve gradually increase in fluid conductivity up to 100S/m. A 240/60/60cm 3D sandbox experimental setup was constructed using a 10mm plexiglass and filled with medium-fine-grained-sand under saturated and unsaturated conditions. Two litres of crude-oil were spilled under controlled conditions and monitored for 48hours using two surface ERT transects with 98 electrodes spaced every 2cm and a dipole-dipole electrode array. The influence of varying salinity was simulated by varying the pore-fluid conductivities at four-levels (0.6, 20, 50, and 85mS/cm). The estimated formation factor ranged from 4.1 to 4.9 for samples without crude-oil and 8.1 to 9 for samples with crude-oil. The background ERT measurement, a 3330% increase in fluid conductivity (0.6 to 20mS/cm), resulted in a reduction of 1500% and 167% for unsaturated and saturated conditions. However, as fluid conductivity increased from 50 to 85mS/cm, the rate of resistivity reduction became less pronounced. After 48 hours post-spillage, the results showed a maximum percentage resistivity increase of 1700%, 1200%, 85%, and 110% for 0.6, 20, 50, and 85mS/cm, respectively, for unsaturated conditions. For saturated condition, a maximum percentage resistivity increase of 60%, 28%, 400%, and 22% for 0.6, 20, 50, and 85mS/cm, respectively. The result showed that a non-linear relationship exists between pore-fluid conductivity and bulk resistivity. At low salinity, crude-oil migrated more freely, producing broader resistivity anomalies across the sandbox under saturated and unsaturated conditions. In contrast, in high salinity, the lateral spread of crude-oil was confined to the top 15cm. Crude-oil migration patterns varied with pore-water salinity as higher salinity enhanced the crude-oil retention at shallow-depths. High salinity produces a smaller resistivity contrast thus limiting the sensitivity of ERT indicating crude-oil contaminant. Overall, ERT proved successful in imaging the non-ideal behaviour of crude-oil pollutants and the associated spatial changes in coastal sand. However, the sensitivity of ERT to crude-oil contamination significantly reduced with increase in salinity thus highlighting the limitation of ERT in subsurface imaging in this context. These findings underscore the need to account for salinity variations when using ERT for crude-oil contaminant monitoring, particularly in coastal environment.

Key Words: *Crude Oil Contamination, Coastal Sands, Surface Monitoring, Electrical Resistivity Tomography, Formation Factor*

HYDROCARBON GENERATIVE POTENTIAL AND RESERVOIR QUALITY OF THE SOKOR-1 FORMATION, FANA LOW UPLIFT, TERMIT BASIN, SOUTHEASTERN NIGER

Abdourahamane Ibrahim Ari Maïna (PAU-UI-0609 PETROLEUM GEOSCIENCE)

The Sokor-1 Formation, in the Fana low uplift, Termit Basin, is a key hydrocarbon-bearing units in southeastern Niger. Variations in depositional environments, diagenetic processes, and thermal maturity influenced in various ways the source rock generation potential and reservoir quality. These factors, combined with the structural complexity of the basin, created reservoir heterogeneity, uncertainty in estimating hydrocarbon reserves and understanding reservoir performance. This study aims to investigate the hydrocarbon generative potential and reservoir quality of this formation. Thirty-five (35) source rock samples were analyzed using Rock-Eval pyrolysis and vitrinite reflectance, whereas eight crude oil samples were analyzed using Gas Chromatography (GC), and Gas Chromatography-Mass Spectrometry (GC-MS) techniques. Reservoir quality was examined by petrographic study, sieve analysis, and X-ray diffraction. Three-dimensional seismic volume, well logs, and gas data from six wells (F-1 to F-6) were processed using Petrel and Interactive Petrophysics. The source rock samples were taken from deltaic front and prodeltaic mudstones. The TOC contents ranged from 0.38 wt.% to 4.66 wt.%, with an average of 1.37 wt.%, revealing poor to excellent source rocks. The deltaic front mudstones had the highest TOC values, between 0.31 and 4.66 wt.%, whereas those of the prodeltaic mudstones ranged from 0.36 wt.% to 1.83 wt.%. These are dominated by types II and III kerogen, indicating oil and gas generation potential. Approximately 80% of the samples are good hydrocarbon source rocks and mostly located between 1280-1420 m and 1520-1620 m. The Tmax values ranged from 302°C to 444°C, with an average of 373°C and the vitrinite reflectance values ranged from 0.21% to 1.02% (av. 0.62%). These revealed that the samples were in the early to middle-maturity stages, with heterogeneity influenced by faults and variations in the geothermal gradient. Crude oils are classified into paraffinic-naphthenic, aromatic-intermediate, and aromatic-asphaltene types. The precursor organic matter of the oil samples was generated from terrestrial organic material mixed with algae. They were in lacustrine and delta environments, with marine influences under anoxic to suboxic conditions as well as fresh to saline water contributions. Biomarker indicators of thermal maturity, such as Ts/Ts+Tm (0.34–0.42), moretane/hopane (0.11–0.14), C29 steranes $\beta\beta/(\beta\beta+\alpha\alpha)$ (0.34–0.5), C29 steranes 20S/(20SS+20RR) (0.50–0.61), C32 homohopane 22S/(22S+22R) (0.50–0.58), and MPR (1.05–1.59), suggested the early to middle-maturity stages. The sandstones are texturally and mineralogically sub mature to mature, comprising mostly lithic quartz sandstones. Diagenetic processes negatively impacted slightly to moderately the reservoir quality. The medium-grained sand group E-1, which was deposited in low-energy distributary channels, overbanks, and delta plain environments, offers good reservoir properties, with average porosity and permeability values of 29.9% and 91 mD, respectively. Conversely, sand group E-5 has the lowest reservoir quality, with an average porosity and permeability of 27.32% and 51 mD, respectively, but has the highest hydrocarbon saturation (45.5%). The gas ratios revealed that most reservoirs produce gas and little oil due to the highwater content in some reservoirs. The total estimated hydrocarbon reserves across all the studied wells amount to 767227.38 MMB. The Fana low uplift has good source and reservoir characteristics and hosts considerable hydrocarbon reserves. Consequently, uplifted zones should be explored with great interest.

Key Words: Fana low uplift, Niger, source rock potential, diagenetic process, reservoir quality, hydrocarbon reserves

EVALUATION OF THE PETROLEUM SYSTEM OF KOLMANI FIELD, GONGOLA SUB-BASIN, NORTHEASTERN NIGERIA

DIDI CHEKWUBE NNAMDI

PAU-UI-0704 PETROLEUM GEOSCIENCE

The Kolmani field, located in the Gongola arm of the Benue Trough in northeastern Nigeria, has been reported to be petroliferous with evidence of gas shows in only Kolmani-1 well, in addition to oil stains found around the faulted Bima Formation. However, the basin which remained underexplored with limited seismic data and three drilled wells (Kolmani River-1, Nasara-1, and Kuzari-1) was significantly influenced by the Santonian tectonism that reshaped its petroleum system, affecting Total Organic Carbon (TOC), maturity levels, and structural styles. This study was therefore designed to evaluate the petroleum play elements of Kolmani field and confirm the ability of the petroleum systems of the basin to generate, store and preserve commercial hydrocarbon quantity. A structured workflow comprising of detailed field mapping, laboratory analyses, well log interpretation, seismic analysis, and petroleum system modeling was adopted in this study. Field mapping was carried out to identified formation boundaries, outcrop characteristics, and structural styles. Laboratory analyses focused on the geochemistry of shale and limestone, as well as the petrography of limestone and sandstone. Palynomorph and foraminifera analyses were carried out to define the stratigraphy of Kolwell-1 well. Well log interpretation determined petrophysical parameters employed in volumetric analyses. Seismic interpretation which includes fault mapping and horizon delineation were employed to define the structural framework and lateral distribution of the delineated reservoir units. Basin modeling combined several generated results to define key petroleum plays. Outcrop studies revealed diverse lithologies deposited in continental to marine depositional environments. Sandstones were classified as quartz arenite, indicating compositional maturity but textural immaturity due to poor sorting and angular grains, suggesting rapid deposition in high-energy settings. Limestone samples were identified as biosparite and packstone, suggesting shallow marine deposits. Five palynological assemblages spanning Cenomanian to Maastrichtian were identified. Predominantly arenaceous foraminifera species and seven peaks which indicate maximum flooding surfaces and sequence boundaries were delineated. TOC values were rated poor to fair (0.03-0.85wt%) with Type III kerogen dominating. The Yolde Formation emerged as a key candidate for hydrocarbon exploration. Structural interpretation identified faulted structures, horsts, grabens, flower structures, synclines, and anticlines, confirming intense Santonian tectonism and potential hydrocarbon traps. Petrophysical evaluation of Kowell-1 and Kowell-2 indicated gross thicknesses of 55.01 to 172.79 m, net-to-gross ratios of 0.42 to 0.87, porosity values of 0.17 to 0.34, water saturation between 0.30 and 0.51, and permeability values of 400.86 to 900.25 mD, suggesting good reservoir quality. Two leads and one prospect were identified, with fault-assisted two-way closures. The stock tank gas initially in place for the Gas Top reservoir was 26 BCF while the stock tank oil initially in place for the Sand A Top reservoir was 69.47 MMbbl. One petroleum play was identified which comprise of the source and the reservoir rocks of the Yolde Formation, and the seals (shales) of Yolde and Pindiga Formation. The integrated methods generated results for improved understanding of the petroleum system elements of the Kolmani field. Yolde Formation is the most promising formation for hydrocarbon Exploration.

Key Words: Total Organic Carbon, Basin Modeling, Santonian Tectonism, Type III Kerogen, Yolde Formation

BASIN MODELING AND PETROLEUM PLAY SYSTEM OF THE UPPER CRETACEOUS-NEOGENE STRATA, SOUTHERN RIO DEL REY BASIN, CAMEROON

MOUSSA AHMED (PAU-UI-0700 PETROLEUM GEOSCIENCE)

The Rio Del Rey Basin, located on the Central Cameroon shear zone, is the most hydrocarbon productive and has been the main source of foreign exchange in Cameroon since the 1980s. This basin has faced the problem of declining output due to limited integration of multidisciplinary datasets and a lack of a proper basin model for proper understanding. This study aims to investigate the petroleum play system of the Upper Cretaceous to Neogene strata of the Southern Rio Del Rey Basin, Cameroon, using geochemistry and geophysics. Eleven (11) outcrop samples comprising seven (07) shale/claystones and four (04) sandstones were acquired from the field study. Organic geochemistry by Rock Eval Pyrolysis and Biomarker through GC-MS was performed on the source rocks (shales/claystones) to determine the source rock richness, maturity, and kerogen type. Thin-section petrography was done on the sandstone samples to determine their mineralogy. Well log suites from 10 exploration wells and seismic volumes were obtained and analyzed using Petrel, Neuralog, and Interactive Petrophysics to determine the reservoir units and structural features. Petrophysical analysis included porosity, permeability, water saturation, net to gross, and shale volume estimation. Moreover, fluid and rock mechanics were determined through Nuclear Magnetic Resonance (NMR), and Sand/Silt/Clay Malay (SSC) models. Hydraulic flow units were classified using the Lucia Plot to assess reservoir heterogeneity and flow capacity. Two major petroleum plays were revealed: the Paleogene-Neogene play, dominated by the S1 and Rubble Bed reservoirs, and the Cretaceous-Paleocene play represented by the Oongue sands, the Kita, and Masambi shales. Several reservoir units were identified in the Paleogene-Neogene play: S1.0, S1A1, S1A2, S1A3, S1A4, S1.1, S1B, and Rubble beds. These units exhibit superior properties with porosities ranging from 0.10 to 0.45 % and permeabilities exceeding 10,000 mD in some intervals. Stock tank oil initially in place (STOIIP) estimates for S1A and Rubble Beds were 11.2MMBO and 10.8MMBO, respectively. Seismic interpretation identified 10 major faults, multiple structural traps, and amplitude anomalies associated with hydrocarbon accumulations. Burial history and thermal maturity models suggested that hydrocarbon generation peaked in the Paleogene, with migration pathways influenced by fault-assisted and overpressure regimes. The Rubble Bed and the S1 correspond to the Akata and the Agbada formations, while the overlying units, like the IM1, IM, and shallower units, correspond to the Benin Formation. Organic geochemistry depicted TOC values of 0.39788- 1.14335 wt.% and kerogen type III, Steranes, n-alkanes (C15-C35), and terpenes. These indicate that the basin contains both mature and immature source rocks with marine and terrestrial inputs. The Cretaceous-Paleocene units have been proven to be underexplored, and their spatial distribution is refined by biomarkers and thermal maturity. The majority of the hydrocarbons produced in the Rio Del Rey Basin originated from the Cretaceous period to the present. The Kita produced the majority of the hydrocarbons despite the fact that it has a lower total organic carbon. The Paleogene-Neogene S1 and Rubble beds, as well as the Paleocene Oongue sands, are potential reservoirs for hydrocarbon accumulation, while the Kita and Masambi shales are potential source rocks, although they do not have sufficient maturity.

Key Words: Basin Modeling, Petroleum system, Well log petrophysics, Seismic interpretation, Geochemistry, Rio Del Rey Basin, Reservoir characterization.

GEOCHEMICAL, MINERALOGICAL AND PALYNOLOGICAL ANALYSES OF KOUUM BASIN (NORTHERN CAMEROON): IMPLICATIONS FOR HYDROCARBON POTENTIAL, AGE AND PALAEOCLIMATE

NGO MANDENG Glwady (PAU-UI-0579 PETROLEUM GEOSCIENCE)

The Koum Basin (KB) in northern Cameroon is the largest intracratonic basin in that region, formed by the Benue Trough. However, the exact time of its formation remained uncertain. Additionally, the hydrocarbon potential of this basin and the relationships among the basin's sedimentary history, its development, and its connection to global climate patterns are still underexplored. This study aims to re-examine the age, assess the hydrocarbon potential, constrain the paleoenvironmental and paleoclimatic conditions during deposition and define the Cretaceous-Paleogene boundary (KPB) in the Koum Basin. To achieve this goal, a variety of datasets, including sedimentological, palynological, geochemical (total organic carbon, major, trace, and rare earth elements) and mineralogical (both bulk rock and clay) data, were employed. Claystone units interbedded with calcareous siltstones dominate the sedimentary sequence, including few clay beds, fine to medium-grained sandstone, rare marl layers and conglomerates. The palynomorph assemblage suggests a previously unknown Maastrichtian-Paleocene age in this basin. The examination of organic matter and palynoflora assemblages indicates the presence of Type III kerogen, and some Type II-III and Type II kerogens, which is consistent with a continental paleodepositional environment characterized by an open rainforest to savannah vegetation with marine incursion. Rock Eval analysis revealed total organic carbon (TOC) values ranging from 0.01wt.% to 4.24wt.%, with S1 and S2 values of the samples with a minimum of 0.5 wt.%, ranged from 0.01 to 0.22 mgHC/g and 0.18 to 28.56 mgHC/g, respectively. This suggests that the Koum Basin has the potential to be a source of rock per unit area within the basin. These rocks underwent low detritism (Si/Al: 2.51–4.43; K/Al: 0.11–0.36; Ti/Al: 0.05–0.10) and chemical weathering (CIA:55–64; PIA: 56–68) within the supply region; consequently, the deposits are immature (ICV values > 1) and weakly recycled (SiO₂/Al₂O₃ ratios ≤5). These sediments can be traced back to intermediate igneous parent rocks, with a notable presence of felsic materials. The slightly negative to slightly positive Ce anomalies (ranging from 0.8955 to 1.0345), indicate a suboxic - to - anoxic depositional environment. The weak positive correlations of elements such as Al₂O₃, Fe₂O₃, K₂O and TiO₂ with REEs (R² < 0.5) are indicative of a weak contribution of terrigenous input in the KK section whereas, the significant contribution of terrigenous input is marked by positive correlations of Al₂O₃ and K₂O (R² >0.5) with REEs in the KM section. Furthermore, the analysis of two discrimination diagrams based on major elements indicates that the precursor rocks of clastic sediments were predominantly created within a continental arc system, with substantial input from the rift system and a minimal contribution from the oceanic island arc; suggesting that the sediments formed under compressional conditions. Clay mineral distribution suggests moderate illitization and chloritization processes and thus moderate burial diagenesis at temperatures ranging from 70 to 90°C, which is also indicated by immature to mature T_{max} values (≤436°C) marginally for most of the analyzed samples. The presence of low CIA values and minimal kaolinite contents suggests the prevalence of arid environmental conditions. A boundary between the Cretaceous and Palaeogene periods has been identified, marked by a thin (4-5 cm) layer of grey clay. This layer shows a mineralogical anomaly, notably lacking smectite and chlorite, and instead being dominated by kaolinite. Additionally, preliminary analyses of the spatial distribution of major elements, trace elements, and rare earth elements along the KK section indicate slight enrichment or depletion in this specific area.

Key Word: Koum Basin, Cretaceous-Paleogene, source rock, Paleoclimate.

**SEDIMENTOLOGICAL HETEROGENEITY AND RESERVOIR
CHARACTERISTICS OF THE CRETACEOUS BENTIU AND ARADEIBA
FORMATIONS IN SIMBIR WEST (SIW) OILFIELD, MUGLAD RIFT BASIN,
SUDAN**

**IBRAHIM MOHAMED YOUSIF MOHAMED
PAU-UI-0512
PETROLEUM GEOSCIENCE**

In the Simbir West (SIW) Oilfield of the Bamboo subbasin in the southeastern Muglad Rift Basin, the Cretaceous Aradeiba and Bentiu Formations constitute significant reservoir targets. A key challenge in Sudanese oilfields is the lithofacies heterogeneity of fluvial and fluvio-deltaic systems, coupled with rift structural and stratigraphic complexities. This study integrated, multi-scale sedimentological and petrophysical methods using wireline logs from five wells and three conventional cores from two wells. Sedimentological analysis includes core analysis, well log interpretation, thin-section petrography, Scanning Electron Microscopy (SEM-EDX) as well as Quantitative Evaluation of Minerals by Scanning Electron Microscopy (QEM-SCAN) and X-Ray Diffraction (XRD). Nine major lithofacies were identified from core analysis of Aradeiba and Bentiu reservoir rocks; massive sandstone (Sm), ripple-marked sandstone and siltstone (Sr), planar cross-bedded sandstone (Sp), trough cross-bedded sandstone (St) and low-angle cross-bedded sandstone (SI). Others include conglomeratic sandstone (Sco), mud conglomerates (Gm), laminated siltstone and shale (Fcf/Fm), and massive to blocky mudstone/siltstone (Fm). Electrofacies inferred from well logs indicated fluvial channel-floodplain, deltaic, and lacustrine environments, classifying three depositional facies associations. The integration of core and electrofacies interpretation confirmed the presence of meandering channels and bars capped by overbank and floodplain deposits in the Aradeiba Formation, while the Bentiu Formation showed mainly braided channels and overbank environments. These differences reflect variations in tectonics, sediment sources, and paleoclimates. The sandstones are quartz-rich with less than 15% matrix, indicating mature to submature compositions. The grain shapes are predominantly subangular to subrounded, derived from transitional tectonic settings, particularly stable cratons and uplifted basement blocks. The clay minerals are mainly kaolinite, smectite, illite, and chlorite occurs as detrital and authigenic clays. Petrophysical evaluation indicates high clay volumes ($V_{cl} = 0.36\text{--}0.39$) in Aradeiba shale's upper and lower intervals, while the Aradeiba Main Sand (AMS) has a lower value ($V_{cl} = \sim 0.21$). The effective porosity (PHIE) values are 0.19 in AMS, and 0.12 in Bentiu, with corresponding water saturation (S_w) values of 0.74 and 0.97, respectively. The core-based porosities in Aradeiba and Bentiu ranged from 12% to 27.2% (avg. 20.76%) and 3.0 to 14.33% (avg. 7.2%), respectively. The permeability in Aradeiba ranged from 0 to 285 mD (avg. 60 mD), whereas these values are extremely low in Bentiu (avg. 0.13 mD). In Aradeiba, the Sm and Sp facies displayed the greatest porosity and permeability values. On the other hand, in Bentiu, all lithofacies generally indicate poor reservoir properties. Rock physics modules have been shown to be effective in discriminating the lithology of Aradeiba from that of Bentiu Formation. Five hydraulic flow units (HFUs) were identified in Aradeiba (HFU-1 to HFU-5), and two were recognized in Bentiu (HFU-1 and HFU-2). The highest-quality reservoir intervals of the Aradeiba Formation are found in HFU-1 (Avg. Reservoir quality index (RQI) = 1.59; Flow zone indicator (FZI) = 6.10; Normalized porosity (NPI) = 0.27) and HFU-2 (Avg. RQI = 0.65; FZI = 2.38; NPI = 0.28). These HFUs units are characterized by very coarse to

medium-grained sands with dominantly primary interparticle pores, and minimal influence of clay matrix and authigenic cement. In contrast, the Bentiu Formation has significantly low values of RQI (avg. 0.04), FZI (avg. 0.49) and NPI (avg. 0.08), and is associated with feldspathic arenites and wackes. The grain size, sorting, and clay content were key controls on reservoir quality in Aradeiba, with the Sm and Sp facies showing relatively higher porosity. However, deeper sections in Bentiu revealed decreased porosity due to compaction and cementation. Authigenic calcite partially occluded the pores in Aradeiba, whereas, cementation and compaction significantly reduced reservoir quality in Bentiu. Generally, the Aradeiba reservoir has better reservoir properties and quality than the Bentiu reservoir. These findings are expected to improve reservoir characterization, prediction, and optimization strategies in SIW. It provides guide for completion design (e.g., prioritizing Aradeiba HFUs), stimulation in low-permeability Bentiu, and improved static–dynamic reservoir models, thereby enhancing recovery efficiency and lowering development risk and cost across the Muglad Basin analogs.