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Original Article

Geochemical Evaluation of the Miocene-Pliocene Subsurface Petroleum Source Rocks from the Albertine Graben, Uganda

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Abstract *- The Albertine Graben, a 570 km long and 45 km wide geological structure in Uganda, is a significant area for hydrocarbon exploration. However, potential source rocks are inadequately characterized, limiting identifying new plays. The study used geochemical techniques to establish the source rocks' organic richness, hydrocarbon generation potential, kerogen typing, and thermal maturity. 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 a 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 ℃, respectively. Plots of S2 versus TOC and HI versus OI indicate dominant mixed oil-prone Type II and gas-prone Type III kerogen. The source facies are immature to early oil window maturity as indicated by the HI versus* T_{max} *plot, bitumen/TOC ratios and calculated vitrinite reflectance, Ro. The Miocene-Pliocene interval source rocks in the Graben have the potential to generate oil and gas. A mix of kerogen types indicates a lacustrine depositional environment with a terrestrial organic matter input. Further geochemical studies, including petrography, should be conducted for robust kerogen typing and maturity assessment.*

Keywords *- Albertine Graben, Bitumen Content, Hydrocarbon Generation Potential, Kerogen Typing, Source Rocks.*

1. Introduction

Petroleum source rocks form part of a working petroleum system and must be geochemically analyzed before they can be used for hydrocarbon exploration (Peters and Cassa, 1994; McCarthy et al., 2011). Accurate identification of hydrocarbon pools and plays during petroleum exploration depends on the detailed geochemical characterization of source rocks and crude oils within the basin (Eiserbeck et al., 2012; Lukaye et al., 2017). Source rocks are where hydrocarbons are made when the organic matter deposited with source sediments is heated and turned into carbon dioxide and water (Jacobson, 2021). These fine-grained sedimentary rocks that contain carbon- and hydrogen-rich organic matter are formed due to the interplay of geological, biochemical, and physical processes (McCarthy et al., 2011). The environment of deposition and depositional conditions determine the amount and type of organic matter in source rocks (Ndip et al., 2021). Source rocks generally form in environments with a good rate of organic matter deposition, non-oxidizing conditions, or limited oxygen supply, which inhibits organic matter decay and favours its preservation (Peters and Moldowan, 1993).

These areas include marine, lacustrine, deltaic, and estuarine environments (Peters and Cassa, 1994). Source rocks are called immature or potential sources until they are buried deep enough to reach the proper pressure and temperature conditions for hydrocarbon generation. Once all of the source rock's potential hydrocarbons have been made, they are considered over-mature and discarded (Al-Areeq, 2018). We do not consider sedimentary rocks containing minimal quantities of organic matter (less than 0.5 wt.% of TOC) source rocks (Akande, 2012). Because of this, excellent source rocks have much high-quality organic matter, usually

Types I and II, which are oil- and gas-prone kerogen (Akintola et al., 2021). Algal or animal remains are the main components of Type I and II kerogen, while gas-prone Type III kerogen is mainly composed of plant remains, including coal (Makeen et al., 2019).

The Albertine Graben in Uganda forms part of the East African Rift System (EARS), which spans from the Afar Triple Junction in Ethiopia to Mozambique in the south. The Graben is an important geological and economic feature with much hydrocarbon potential (Lukaye et al., 2015). Wayland established the hydrocarbon potential of the Graben in 1925, and 17 of these seeps remain active (Lirong et al., 2004).

Despite the Graben's geologic extent, researchers have conducted few geochemical studies on potential source rocks from the Albertine Graben. The hydrocarbon potential of the Graben remains untapped mainly due to a lack of detailed information regarding the characteristics of petroleum source rocks, especially the Miocene-Pliocene sequence in this basin. This knowledge gap hinders vast and efficient hydrocarbon exploration activities of the Graben to discover unidentified plays.

Source rocks in the Albertine Graben are fairly new. They were all formed in the Cenozoic period, and their quality ranged from fair to good. They include Miocene to lower Pliocene lacustrine mudstones and lacustrine shale (Lukaye and Okello, 2015; Ji et al., 2024), to name but a few. These source rocks are distributed throughout the Graben with varying quality (Abeinomugisha and Kasande, 2012). Mudstones are algal-organically rich because East Africa is located along the equator with a warm climate and receives abundant rainfall, favouring algal survival (Ji et al., 2024).

A good source rock is the middle Miocene mudstone in the Kisegi formation with a TOC value of 6-7 wt. % and contain Type II/III kerogen, which can generate 2–10 mg/g of hydrocarbons (Ji et al., 2024). The lacustrine shale from the middle Miocene of the Kasande formation has a TOC value of 5 to 8 wt. %, Type III kerogen, and a T_{max} of about 440 °C. Lacustrine shales from the middle to upper Miocene Kakara formation have 2 to 6 wt TOC values. %, Type I and II kerogen (Mutebi et al., 2021; Ji et al., 2024)

The study's goal was to use petroleum geochemistry principles to fully characterize Miocene–Pliocene interval subsurface potential source rocks in the Albertine Graben in order to (a) find out the source facies' organic richness and hydrocarbon-generating potential, (b) find out the quality of the organic matter and figure out what kind of hydrocarbons can be generated; and (c) find out how thermally mature the potential source rocks are. The quality of organic matter is used to determine the origin of the source rocks and how they were deposited, which helps find new plays in the Graben (Tissot and Welte, 1984; McCarthy et al., 2011).

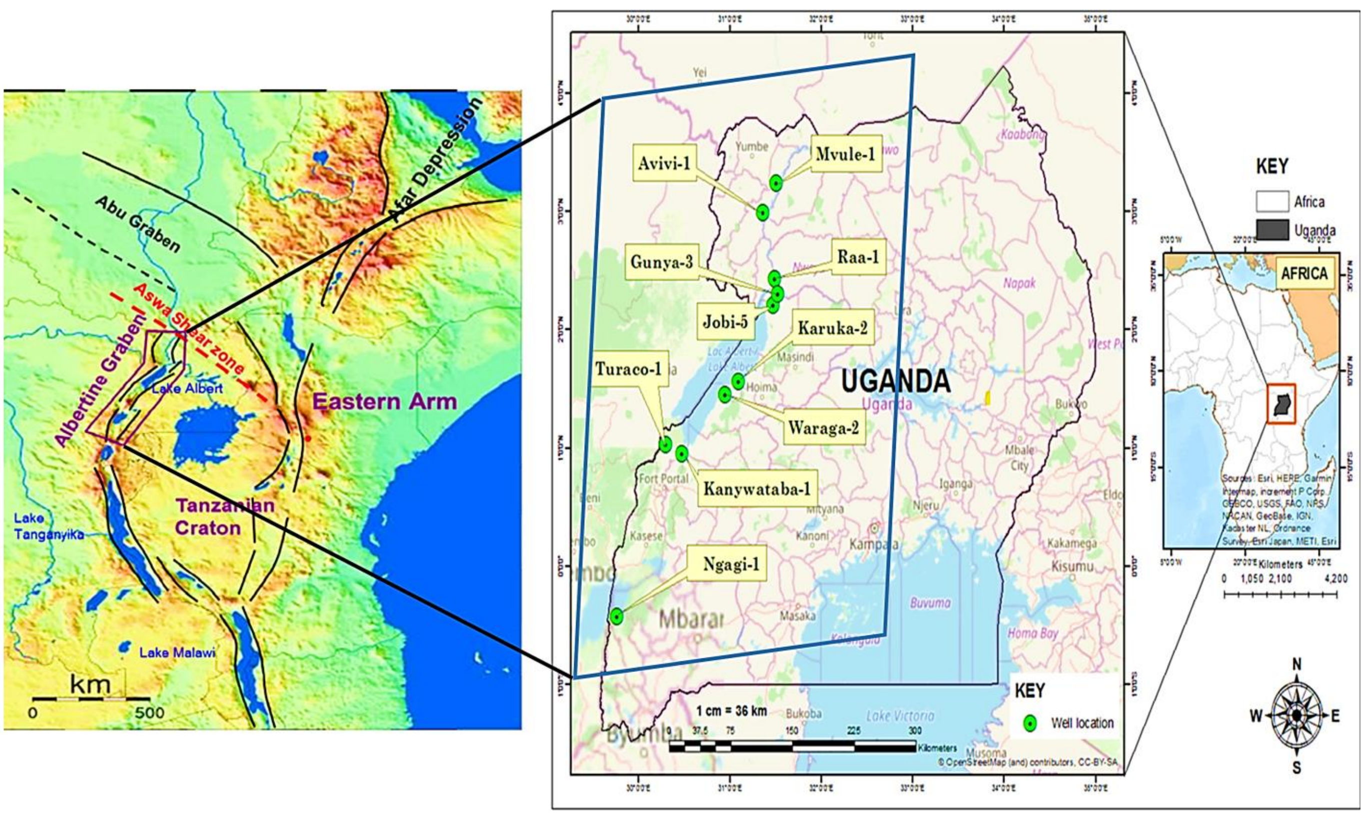

Fig. 1 Geologic extent of the EARS and location of the study area

2. Geological Background

2.1. Location of the Study Area and Geologic Extent of the EARS

The Albertine Graben in Uganda is a 570 km long and 45 km wide geological structure of the East African Rift System (EARS). The EARS spans from the Afar Triple Junction at the Gulf of Aden and the Red Sea in Ethiopia to Mozambique in the south at the Okavango Delta (Lukaye et al., 2016; Tumushabe et al., 2022). It is divided into two arms in South Sudan, forming the western and eastern arms. Thus, the northernmost section of the EARS is a single valley. The eastern arm continues southwards through Kenya, and the western arm stretches further southwards through Uganda and passes through Lake Tanganyika to the Mbeya triple junction. The two arms merge and propagate through Lake Malawi as a single arm (Figure 1). The western arm of the EARS consists of Lakes Albert, Edward and George in Uganda, Lake Kivu in Rwanda and Lake Tanganyika and Lake Rukwa in Tanzania (Mutebi et al., 2019). Mvule-1 and Avivi-1 wells were drilled in the Rhino Camp sub-basin; Raa-1, Gunya-3, and Jobi-5 wells were drilled in the Pakwach sub-basin; Waraga-2 is located in C. L. A sub-basin, the Karuka-2 well, is located in the N.L.A. sub-basin; Kanywataba-1 and Turaco-1 are drilled in the Semliki sub-basin; and the Ngagi-1 well is in the Lake George-Edward sub-basin (Figure 2).

2.2. Tectonic Evolution and Structural Setting

The tectonic evolution of the Albertine Graben in Uganda is described in many aspects, including processes that span millions of years and involve several stages of rifting, faulting, and sedimentation (Lirong et al., 2004; Macgregor, 2015). About 100-50 million years ago, the East African Rift system started to form due to the divergent motion of the African plate (Peters and Moldowan, 1993; Lukaye et al., 2015). The Graben's geological history thus began during the Late Mesozoic to Early Cenozoic era. The evolution of the Albertine graben was mainly attributed to various rifting stages between the Mesozoic and Cenozoic (Lirong et al., 2004; Dou et al., 2004). An intra-cratonic evolution occurred in the Graben during the Carboniferous to Permian (Abeinomugisha and Kasande, 2012). Metamorphism occurred when the strong magmatic activity deprived the formations before the Mesozoic of being hydrocarbon-bearing. Thus, the basement rocks within the Graben are mainly metamorphic rocks and mafic intrusive rocks with no hydrocarbon potential (Bauer et al., 2010).

The first stage of rifting is considered faulting of unknown age, which occurs before the middle Jurassic to the middle Cretaceous (Lirong et al., 2004). During the early Cretaceous, the sediment thickness within the rift trough had exceeded 5000 m. The formations in the Graben during this time were characterized by red lacustrine facies with fish and hexapod fossils (Dou et al., 2004). The intercalated siltstone and sandstone, which are finely grained, are the main Jurassic to Cretaceous strata thickness of about 350 m, and they are interlain with shale, which is bituminous, with a thickness of about 70 m (Lirong et al., 2004; Abeinomugisha and Obita, 2011). These Jurassic to Cretaceous sediments contain hydrocarbons and have been found to also exist in Turkana, Kenya and, Muglad and White Nile basins in Sudan (Lirong et al., 2004; Macgregor, 2015). In Uganda, within the Albertine graben, the bituminous shale and fluvial-lacustrine clastics were encountered in the Butiaba Waki-1 well located east of Lake Albert (Tumushabe et al., 2022). During the late Eocene, a second rifting stage occurred within the Graben at a minor scale and largely developed in the rift basins in Sudan and the Anza basin in Kenya. The third rifting stage occurred during the Neogene to Quaternary (Lirong et al., 2004).

This was the main event that resulted in the formation of Albertine graben, where the subduction of the Africa-Arabian plate was accelerated by drifting towards the Eurasian plate (Lukaye et al., 2016). During the stages of rifting, extensional forces pulled the Earth's crust apart, and tensional stresses led to the development of rift valleys along pre-existing fault lines and weakened zones (Lirong et al., 2004). The Graben experienced further extension and faulting during the Tertiary period approximately 65 million years ago, accompanied by volcanic activity that resulted in the emplacement of volcanic rocks within the Graben (Peters and Moldowan, 1993). This period of tectonic activity led to the development of the modern graben structure, characterized by a series of north-northeast trending faults that control the structural architecture of the basin (Macgregor, 2015).

The Graben is shaped by various tectonic episodes, including extensional and compressional regimes, and divided into three domains: northern, central, and southern (Mutebi et al., 2019). Its shape is controlled by fault systems, folds, and other features that are connected to them. These also affect the distribution of sedimentary deposits and hydrocarbon resources (Tumushabe et al., 2022). Along its edges are high-angle faults that are mostly extensional, and fold structures, either anticlinal or synclinal, affect how hydrocarbons are distributed and trapped within the Graben (Ji et al., 2024). Where crustal subsidence creates space for sediment accumulation, accommodation zones form along fault segments.

The Graben has two depocenters, the North Albertine depocentre and the South Albertine depocentre (Ji et al., 2024), and strike-slip faults between them (Figure 2). Sediments eroded from the surrounding highlands accumulated within the Graben, forming thick sequences of sedimentary rocks, including sandstones, mudstones, and conglomerates, which record the geological history of the region (Abeinomugisha and Obita, 2011; Tumushabe et al., 2022). The accommodation zones serve as important exploration targets for oil and gas companies seeking to exploit the basin's hydrocarbon potential (Abeinomugisha and Njabire, 2012).

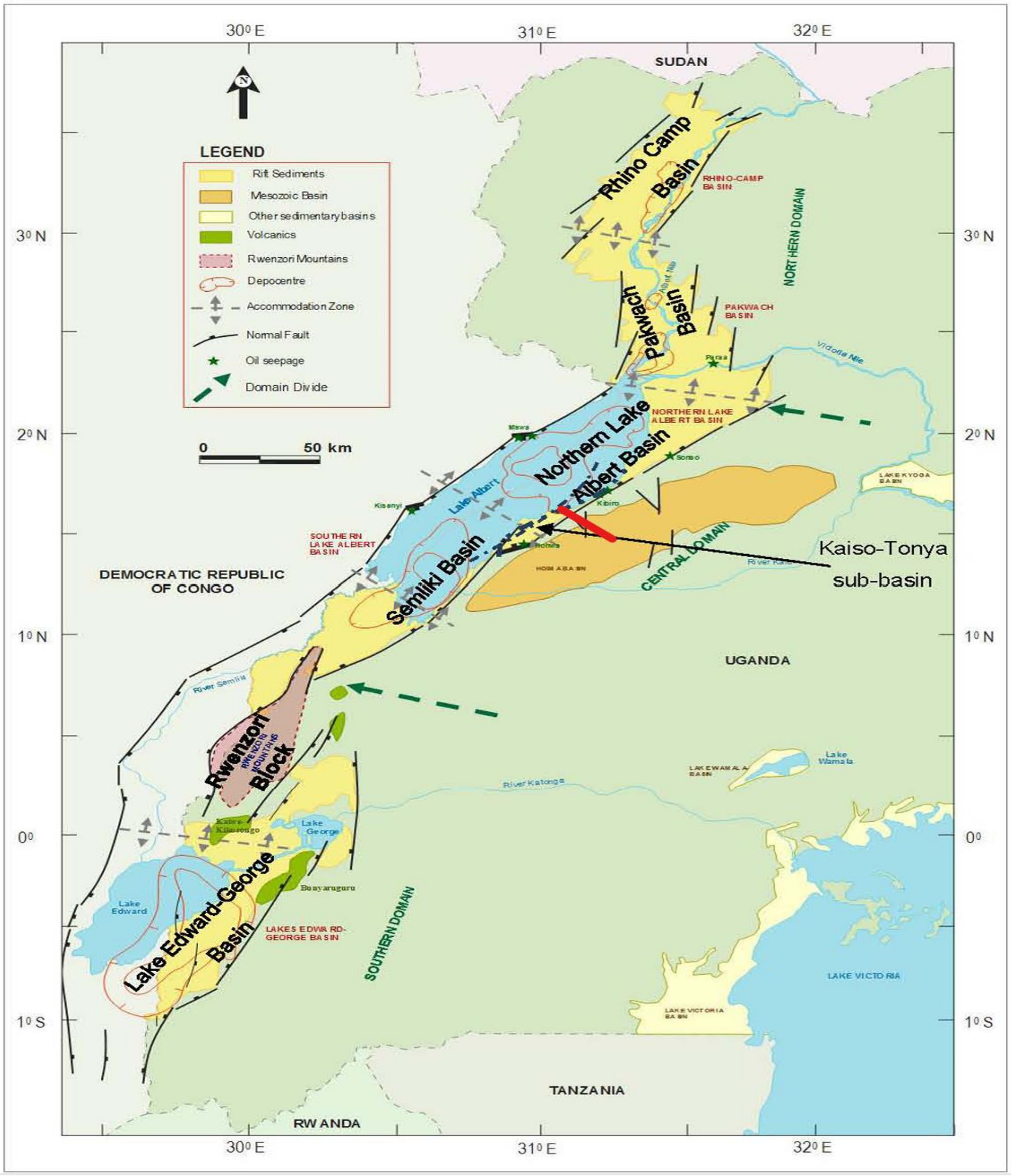

Fig. 2 Division of Albertine Graben into domains and sub-basins (Lukaye et al., 2015)

The East African Rift System is still a tectonically active area. The African continent is undergoing extensional forces that create rift valleys and other geological features such as horsts and grabens (Peters and Moldowan, 1993). Local geological forces of multiple phases of rifting, faulting, sedimentation and plate tectonic movement thus drive the Albertine Graben tectonic development. The East African Rift Valley system is a typical example of the divergent plate boundary where the African plate is breaking apart (Lirong et al., 2004; Lukaye et al., 2016).

2.3. Stratigraphy

The Albertine Graben is divided into sub-basins, with the most complete sedimentary succession exhibited within the Semliki sub-basin (Lukaye et al., 2016). The Graben consists of the Lake Edward-George, Lake Albert, Semliki, Kaiso-Tonya, Pakwach, and Rhino Camp sub-basins (Figure 2).

The Turaco exploration wells penetrated over 3 km of sedimentary sequence in the Southern Lake Albert sub-basin, revealing formations such as Kisegi, Kasande, Kakara, Oluka, Nyaburogo, Nyakabingo, and Nyabusosi (Figure 3). Kisegi is 110 m thick and consists of basal conglomerates, sandstones, silts, and clays (Tumushabe et al., 2015). Kasande is believed to be from the early to mid-Miocene and early Pliocene, with mudstones, clay stones, sandstones, and shales (Lukaye et al., 2016; Mutebi et al., 2021). Ironstones, ferruginous sandstones, and lacustrine shales make up Kakara, which has a thickness of 542 m. Oluka is of middle Miocene and late Pliocene to early Pleistocene age, as polymorphs from Turaco cuttings suggested. This interval is considered a transition between the Miocene and Pliocene (Peters and Moldowan, 1993), with a 390 m and 50 m thickness. Nyaburogo is of late Miocene and early Pleistocene age, with clay stones, siltstones, ironstones, and sandstones in the uppermost parts of exposures (Mutebi et al., 2021). Nyakabingo is of late Miocene to late Pleistocene age, with clay stones, siltstones stained with ironstones, and sandstones. Nyabusosi is the most recent formation, with a thickness of 648 m and 47 m (Lirong et al., 2004; Mutebi et al., 2019).

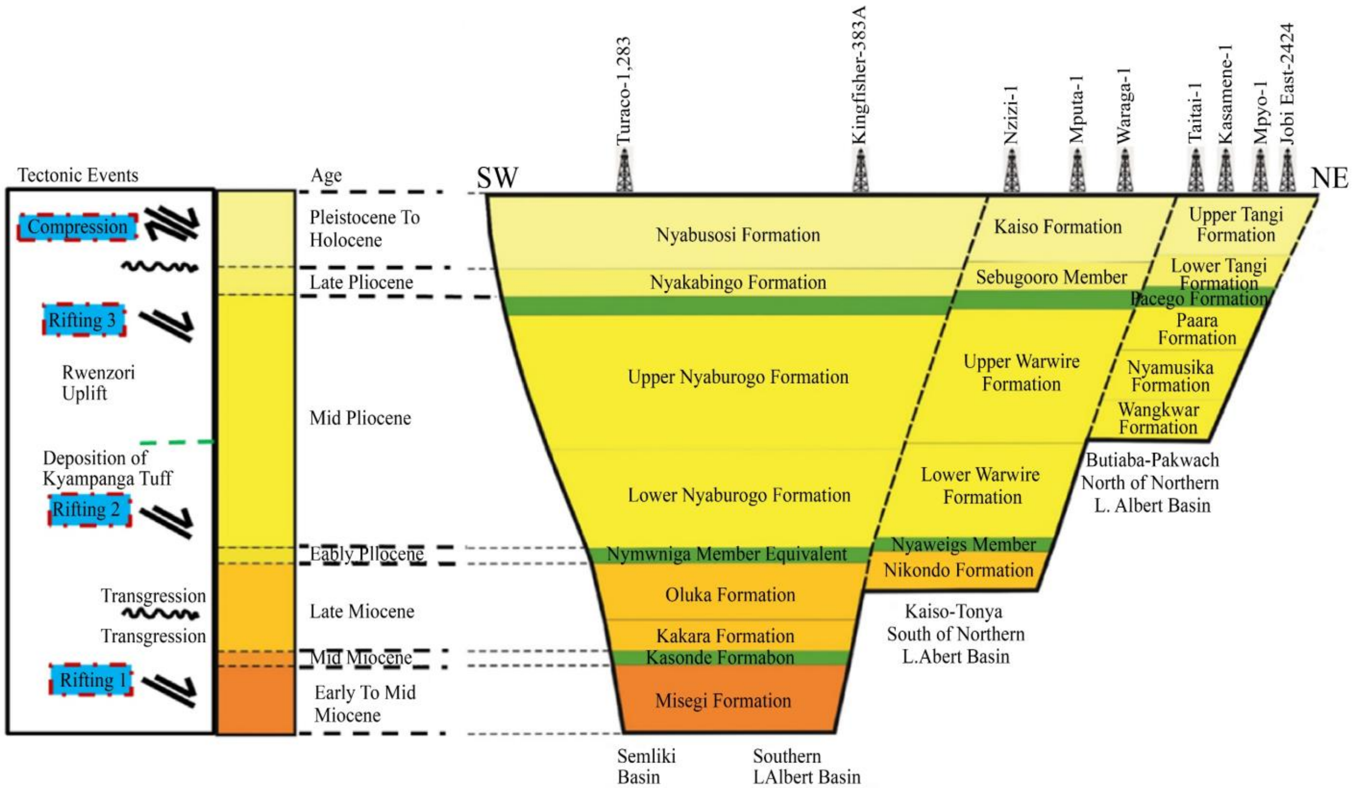

Fig. 3 Sedimentary formations and stratigraphic sub–division of the Albertine graben (https://www.petroleum.go.ug). The succession consists of the Miocene-Pleistocene sediments

Table 1. Ro range of values for hydrocarbon generation stages (modified after Dembicki, 2022)

Oil-Prone kerogen	Generation stage	Gas-Prone kerogen
<0.6	Immature	<0.8
0.6 – 0.8	Early	0.8 – 1.2
0.8 – 1.0	Peak	1.2 – 2.0
1.0 – 1.35	Late	>2.0
1.35 – 2.0	Wet gas	–
>2.0	Dry gas	–

2.4. Vitrinite Reflectance, Ro as a Maturity Indicator

When coal is heated in the subsurface during burial, a vitrinite maceral of coal changes gradually in its reflecting properties and forms a polished surface (Passey et al., 2011). When white light or UV light is incident on this polished organic substance, a certain amount of light is reflected, known as vitrinite reflectance (Feng et al., 2023). Vitrinite reflectance, Ro, is a strong measure of maturity in coal and organic-rich source rocks. Other maceral groups exist, such as liptinite and inertinite. However, the vitrinite group is the most commonly used thermal maturity indicator because it is the most abundant maceral and changes uniformly throughout the coalification series (Akintola et al., 2021). A range of %Ro values is used to imply a particular stage of oil or gas generation, as shown in Table 1. A study by Jarvie et al. (2001) provided a formula, as shown in equation 1, for the calculated vitrinite reflectance from T_{max};

$$\text{Calc. } R_o = 0.0180 \times T_{max} - 7.16 \qquad (1)$$

3. Materials and Methods

The lithology from different wells representative of all the sub-basins in the Graben was interpreted from lithologs and identified depths at which potential source rocks, i.e., shale and mudstones of the Miocene-Pliocene interval, occurred. Wells drilled to the basement were considered, and potential source rocks that occurred above the basement were considered at specific target intervals for sampling. Potential source rock-cutting samples were selected from specific depths from ten wells drilled to the basement in different sub-basins along the entire stretch of the Albertine graben. The intention was to account for the sub-basin variability and the complex graben geologic history. The water-based mud samples were crushed in a motor using a pestle and washed using running water in a sieve, which was dried in an oven at about 60 ℃. 60-100 mg of powdered, washed, and dried samples were measured using the Sartorius analytical balance and analyzed by the Hawk Pyrolysis instrument 2049. The equipment performance was checked by running the blank before the actual analysis of samples. 60 ml of calibration standard and 61.6 mg of quality standards were run to calibrate the equipment and quality check the data, respectively. The samples were then analyzed using the Hawk instrument for TOC and pyrolysis parameters, which were retrieved from the Hawk-Eye r8638 (the system software). Pyrolysis parameters like the Hydrogen Index (HI), Oxygen Index (OI) and Productivity Index (PI) are computed from formulae as shown:

$$HI = \frac{100 \times S2}{TOC} \% \tag{2}$$

$$OI = \frac{100 \times S3}{TOC} \% \tag{3}$$

$$PI = \frac{S1}{(S1+S2)} \tag{4}$$

Samples with TOC > 0.5 wt. % were identified and selected for bitumen extraction. About 10 g of each sample was measured using the Mettler PM2000 weighing balance except for TU11, whose only available amount was 2.72 g. The thimbles were pre-extracted in the Soxtec^{TM} 2050 instrument, which uses Tecator^{TM} technology for about one and a half hours using a 1:1 azeotropic mixture of cyclohexane and acetone as solvents in extraction cups. The thimbles containing samples were put in the Soxtec instrument. 50 mL of 1:1 azeotropic mixture of acetone and cyclohexane were put in extraction cups, which were, in turn, put in the Soxtec instrument. The system was run for about two hours to facilitate bitumen extraction from each source rock sample. The system was left to run for over 48 hours for complete extraction. Extraction cups were weighed before and after extraction, and the difference was used to obtain the weight of the extract, and thus the amount of bitumen in ppm was computed using the formula:

$$EOM\ in\ ppm = \frac{Weight\ of\ EOM\ in\ g}{Weight\ of\ rock\ sample} \times 1{,}000{,}000 \tag{5}$$

Analysis was done using Excel, and pyrolysis-derived parameters HI and OI were obtained using equations 2 and 3. HI/OI cross plots were constructed and used to delineate kerogen types. Source rock organic richness was determined using TOC and bitumen content obtained using equation 5. Maturity assessment was determined using HI/T_{max}, PI/T_{max}, bitumen/TOC ratios, and vitrinite reflectance was calculated. PI values were obtained using equation 5, whereas calculated vitrinite reflectance values were obtained using equation 1.

4. Results and Discussion

4.1. Quantity and Hydrocarbon Generative Potential of Source Rocks

The total organic carbon (TOC) and the amount of bitumen that is extracted show how organically rich a source rock is, and the S1 and S2 parameters show how much hydrocarbon it can produce (Tissot and Welte, 1984; McCarthy et al., 2011). By rule of thumb, a rock with TOC < 0.5 wt. % is categorized to be poor (Peters and Cassa, 1994). The analyzed samples had TOC values ranging from 0.19 to 2.36 wt. % (Table 6) is described as poor to very good source rocks. A TOC-depth plot asserts low to good organic richness of the studied samples from shale and mudstones of the Albertine graben. Using the TOC classification by Peters and Cassa (1994), the analyzed samples ranged from poor through fair and good to very good. Three samples, KA22, KA21 and TU11, were identified to have good to very good organic matter richness. These were representative samples from wells drilled in the Central Lake Albert sub-basin and Semliki sub-basin, respectively. Therefore, Miocene-Pliocene shale and mudstones have the potential to generate hydrocarbons. Based on pyrolysis S2 values, the source rock can be classified as poor, fair, good to very good and then excellent (Peters and Cassa, 1994) (Table 2). S2 values ranged from 0.12 to 7.91 mg/g of rock sample. S2 is a kerogen yield measure, representing the amount of hydrocarbons yielded due to thermal cracking (Jacobson, 2021). Based on the S2 values classification by Peters and Cassa (1994), three samples, RA12, KA22 and KA21, had S2 values greater than 2.5 mg/g of sample and thus have good generative potential. The amount of bitumen extracted for the nine samples ranged between 940 to 3456 ppm, which indicates that the generative potential of source rocks is fair to very good (Table 3). A cross plot of TOC versus EOM shows fair to very good source generative potential with bitumen ranging between 10-20 % of the total organic content (Figure 4). With the fair to good organic richness and hydrocarbon generative potential of shale and mudstones of the Miocene – Pliocene interval in Albertine graben, it implies that there was deposition of organic matter-rich source sediments in non-oxidizing conditions or limited oxygen supply. This inhibited the decay of organic matter and favored their preservation in a lake environment (Lukaye et al., 2017). Furthermore, organic matter richness in analyzed shale and mudstones is attributed to a warm climate with abundant rainfall, favouring algae survival. This is because Uganda is located along the equator and thus has the equatorial climate conditions (Mutebi et al., 2021).

Table 2. Quantity of source rocks' evaluation criteria (Modified after Peters and Cassa, 1994)

Potential (Quantity)	TOC (Wt. %)	S2 mgHC/g of rock	EOM in ppm
Poor	< 0.5	<2.5	<500
Fair	0.5 – 1	2.5 – 5	500 – 1000
Good	1 – 2	5 – 10	1000 – 2000
Very Good	2 – 4	10 - 20	2000 – 4000
Excellent	>4	>20	>4000

4.2. Organic Matter Characterization

The quality of organic matter in source rocks is crucial as it influences the type and quantity of hydrocarbons found within them and the hydrocarbons expelled (Welte and Horsfield, 1997; Curiale and Curtis, 2016). The quality of source rocks is directly related to the paleo-environmental conditions of source sediments (Lukaye et al., 2017). Organic matter is classified into four categories: Type I, II, III, and IV kerogens (Al-Areeq, 2018). Type I kerogen is derived from algal or lacustrine sources is rich in hydrogen, and mainly generates oil (Korkmaz et al., 2013).

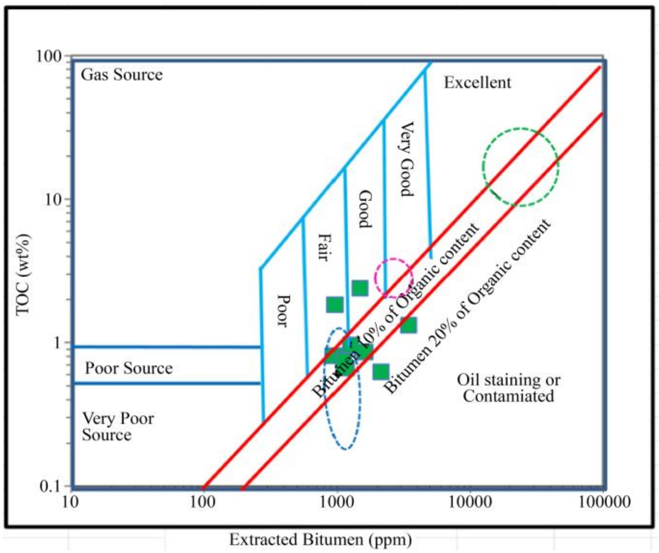

Fig. 4 A plot of TOC versus Extractable Organic Matter (EOM) showing fair to very good hydrocarbon generative potential of samples with TOC greater than 0.5 wt. %

Type II kerogen is the most prolific source of rocks, derived from marine or mixed organic matter, and generates oil and gas. Algal biomass is the main contributor to organic matter to Type-II kerogen (Tissot and Welte, 1984). Terrestrial plant material, with an elevated oxygen content, is the main source of Type-III kerogen. Type-III kerogens are gas-prone and condensate upon exposure to surface temperatures. Type-IV kerogen, or inert kerogen, is highly oxidized and has no potential to generate hydrocarbons (Tissot and Welte, 1984; Peters and Cassa, 1994; Wotanie et al., 2022). The studied samples showed a mix of Type II, Type II/III and Type III organic matter in source rocks from the Albertine graben. This analysis was based on a modified Van Krevelen HI versus OI cross plot (Figure 5). Based on the kerogen potential cross plot of S2 versus TOC, the Miocene-Pliocene source rocks have oil-prone type II organic matter capable of generating oil, a mixture of Type II/III organic matter capable of generating both oil and gas and gas-prone type III organic matter (Figure 6). However, the depth plot of S2/TOC shows seven samples are derived from source rocks containing organic matter that are capable of generating a mixture of oil and gas (Figure 7, Track 1) and thus contain Type II kerogen and a mixture of Type II/III kerogen. This means source sediments with organic matter were deposited and preserved in a lacustrine setting with terrestrial input of higher land plants (Tissot and Welte, 1984; Lukaye et al., 2017).

4.3. Source Rocks' Thermal Maturity

Source rock maturity is a tool used to determine the extent to which organic matter in source rocks has been exposed to heat and pressure over time, leading to the generation of hydrocarbons (Ndip et al., 2021). The source rock undergoes thermal maturity stages, with burial as temperature and pressure increase, leading to chemical changes in kerogen (Jacobson, 2021).

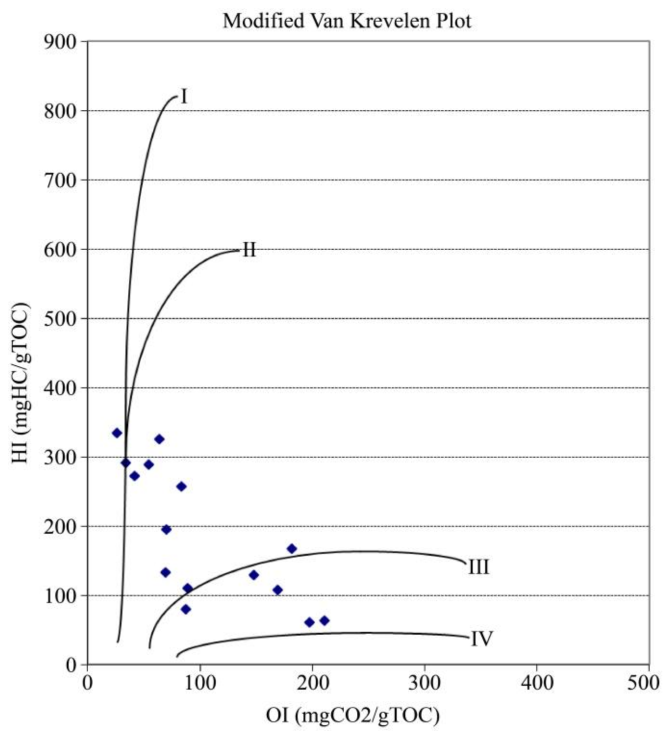

Fig. 5 Modified Van Krevelen plot showing a mix of Type II and Type III kerogen

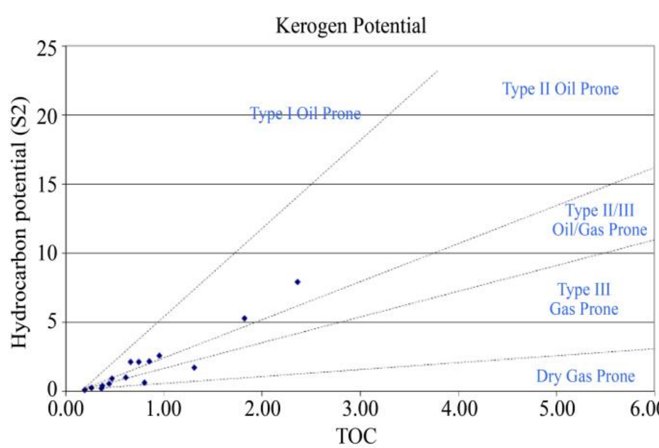

Fig. 6 Hydrocarbon potential, S2 versus TOC cross plot showing oil and gas prone-kerogen potential

Table 3. Showing the quantity of bitumen extracted

Sample ID	Sample amount before extraction (g)	Extraction cup weight (g)	Weight of extract + cup (g)	Weight of extract (g)	Bitumen/ EOM (ppm)	TOC (wt.%)	Bitumen/TOC
KA21	10	39.2107	39.2256	0.0149	1490	2.36	0.006
KA22	10	39.5371	39.5468	0.0097	970	1.82	0.005
MV11	10	39.5121	39.5215	0.0094	940	0.8	0.012
JB51	10	39.7092	39.7307	0.0215	2150	0.61	0.035
WA23	10	39.7873	39.7985	0.0112	1120	0.74	0.015
JB52	10	39.5935	39.6098	0.0163	1630	0.85	0.019
RA12	10	39.5121	39.5248	0.0127	1270	0.95	0.013
RA11	10	39.2107	39.2224	0.0117	1170	0.66	0.018
TU11	2.72	39.5371	39.5465	0.0094	3456	1.31	0.007

TOC: Total Organic Carbon (wt. %); EOM: Extractable Organic Matter

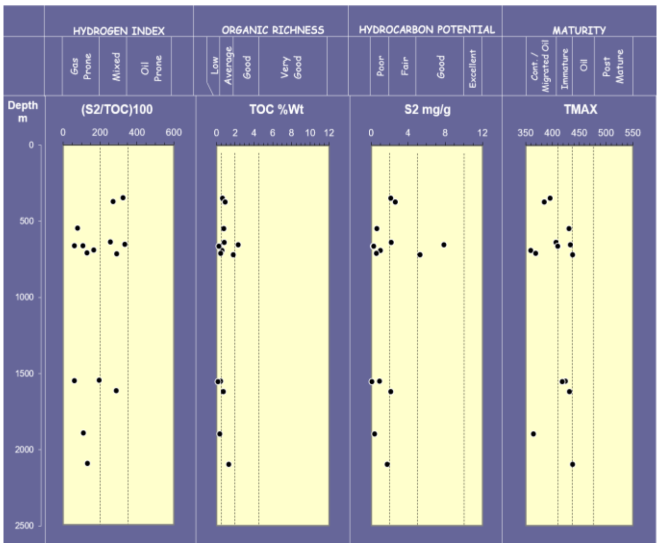

Fig. 7 Depth plots for hydrogen index, organic richness, hydrocarbon generative potential and thermal maturity as displayed in tracks 1, 2, 3 and 4, respectively, showing poor to good hydrocarbon generative potential with immature to early oil window gas and oil-prone source facies

Table 4. Maturity stages are based on T_{max} and PI values (Modified after Peters and Cassa, 1994)

Maturity		T_{max} (°C)	PI	Bitumen/TOC ratio
Immature		<435	<0.10	<0.01
Mature	Early	435-445	0.10-0.15	0.01-0.04
	Peak	445-450	0.25-0.40	0.05-0.1
	Late	450-470	>0.40	0.1-0.2
Postmature		>470	…	>0.2

The maximum temperature at which hydrocarbon generation occurs, T_{max} values, Productivity Index, PI versus T_{max} cross plot, HI versus T_{max} cross plot, and bitumen/TOC ratios were the parameters used to assess the thermal maturity of Miocene-Pliocene source rocks. Based on T_{max}, two samples, TU11 and KA22, had T_{max} values of 438 ℃ (Table 4), indicating they were in their early stages of oil generation given that Type II and III kerogen were found to occur within the shale and mudstones of the Graben, which was inferred based on studied samples. Based on productivity index criteria by Peters and Cassa, 1994, seven samples were immature with PI values < 0.1, while eight samples had PI values between 0.1 and 0.4, indicating they are within early to peak thermal maturity levels. Based on a plot of HI versus T_{max}, five samples were within and near early oil window maturity, while others were oil-prone, oil/gas-prone, and immature (Figure 8). Bitumen/TOC ratios varied from 0.005 to 0.035, implying samples were consistently immature to early oil window maturity. Based on the PI vs. T_{max} plot, source rocks are consistently immature with low-level kerogen conversion to hydrocarbons (Figure 9) and about half of the studied samples have a high quantity of free hydrocarbons (S1), where the enrichment is attributed to hydrocarbon primary migration or contamination owing to oil seeps that have been encountered in the Graben. Source sediments within the Graben have varying maturity levels due to variations in burial depths and location within the tectonically active Graben.

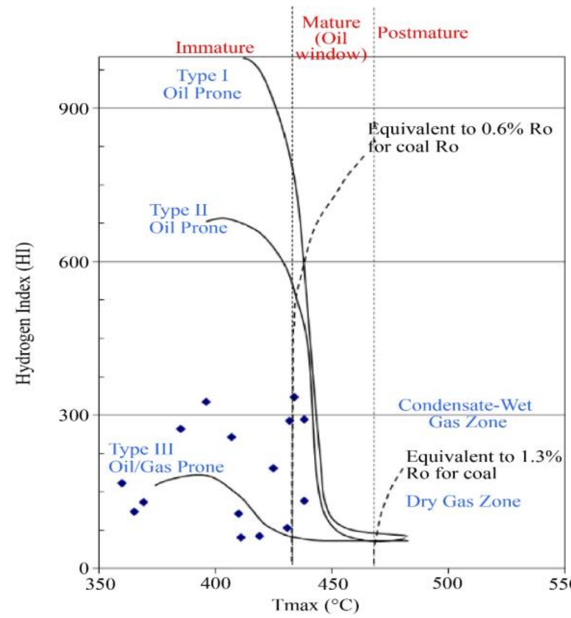

Fig. 8 A plot of Hydrogen Index versus T_{max} showing immature to early oil window maturity oil and gas-prone source rocks

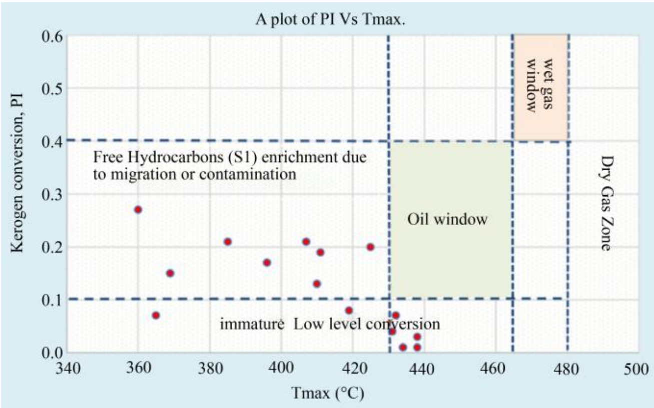

Fig. 9 A plot of PI versus T_{max} showing a few samples that are immature with low levels of kerogen conversion

In some places, the thermal gradient is between 85-138 ℃/km, compared to the global continent average of 25-30 ℃/km (Ji et al., 2024). Given the tectonic activity of the Graben and high thermal gradients, some young Miocene-Pliocene source rocks have attained maturity near or within the oil-generating window (Macgregor, 2015).

Table 5. Onset of oil window and range of oil generation window for various kerogen types (Modified after McCarthy et al., 2011)

Type of Kerogen	Onset of oil window	Oil generation window	Hydrocarbon type
Type-I	445℃	50-150℃	Oil
Type-II	435℃	150- 200℃	Oil and little gas
Type-III	440℃	>150℃	Mainly Gas
Type-IV	460℃	-	None

4.4. Factors that Possibly Favoured Organic Matter Input, Preservation and Thermal Maturity of Source Facies

The Albertine Graben in Uganda is located along the equator with the equatorial climate, where plenty of rainfall is received (Tumushabe et al., 2015). This favours the survival of algae and higher plants that can be washed by running water and rivers with source sediments and deposited into lakes (Ji et al., 2024). This justifies the Type II kerogen, Type III kerogen, and the mixture of Type II/III encountered in the Miocene-Pliocene source rocks within this study. The Graben is tectonically active and up to date with high heat flow (Abeinomugisha and Obita, 2011), especially in the south, evidenced by hot springs like the Kitagatta and Sempaya hot springs. The Graben is characterized by a generally high thermal gradient of about 4 ℃/100m, which has quickened the thermal maturity of young Miocene-Pliocene shale and mudstones (Mutebi et al., 2021). The thermal gradient in some places in the Graben, like Kibiro (located in the C.L.A sub-basin), is between 85 and 138 ℃/km as opposed to the global average of 25-30 ℃/km (Lahsen, 2012). The deepest part of the Graben exceeds 2100 m, which implies the source sediments are sufficiently buried. Oil-prone samples include TU11, KA22 and KA21 within the oil-generating window based on the HI versus T_{max} cross plot. The TU11 sample was obtained at a depth of 2100 m from the Turaco-1 well in the Semliki sub-basin, and KA22 and KA21 were obtained at depths of 720 m and 655 m respectively from the Karuka-2 well in N. L. A sub-basin. Therefore, these source rocks were exposed to higher pressures and temperatures, favouring organic matter maturity.

The rifting process dominated by extensional stress regimes created accommodation spaces for the accumulation of sediments (Natukunda, 2010). There are two depocentres in the Graben, i.e., the Northern Lake Albert depocentre and the Southern Lake Albert depocentre, where sediments have accumulated over time (Ji et al., 2024). The accommodation zones are bounded by high-angle faults (Abeinomugisha and Njabire, 2012). These faults trend north-negwest, like the Kibiro, Nkusi, and Aswa faults, and have been reactivated multiple times throughout their geological history (Bauer et al., 2010). These faults create a series of alternating down-thrown blocks known as grabens with uplifted blocks known as horsts, like mountain Rwenzori, forming the characteristic basin-and-range topography of the Graben (Bauer et al., 2010; Macgregor, 2015). Extensional forces typically uplift blocks of crust along high-angle faults, forming horsts along the Graben's margins. The sediments are eroded from the surrounding highlands, including the Rwenzori Mountains to the west and the western rift escarpment to the east (Abeinomugisha and Njabire, 2012). These sediments have accumulated within the Graben over millions of years, forming thick sequences of sedimentary organic-rich source rocks (Katumwehe et al., 2015).

Table 6. TOC results and pyrolysis data

Sample ID	Depth (m).	Sequence	Weight (mg)	TOC (wt. %).	S1 (mgHC/g rock)	S2 (mgHC/g rock)	S3 (mgCO2/g rock)	HI (mgHC/g TOC)	OI (mgCO2/g TOC)	PI	T_{max} (℃)	Calc. Ro
MV11	550	Pliocene	78	0.8	0.03	0.64	0.7	80	88	0.04	431	0.6
AVII	665	Pliocene	80	0.36	0.05	0.22	0.71	61	197	0.19	411	0.24
JB52	639	Miocene	81	0.85	0.58	2.19	0.71	258	84	0.21	407	0.17
JB51	693	Miocene	91	0.61	0.38	1.02	1.11	167	182	0.27	360	–0.68
RA11	350	Miocene	97	0.66	0.45	2.15	0.42	326	64	0.17	396	–0.03
WA23	1621	Miocene	87	0.74	0.17	2.14	0.4	289	54	0.07	432	0.62
WA22	1552	Miocene	105	0.47	0.23	0.92	0.33	196	70	0.2	425	0.49
RA12	375	Miocene	85	0.95	0.67	2.59	0.4	273	42	0.21	385	–0.23

GU32	665	Miocene	89	0.26	0.04	0.28	0.44	108	169	0.13	410	0.22
GU31	713	Miocene	96	0.44	0.1	0.57	0.65	130	148	0.15	369	–0.52
KA22	720	Miocene	84	1.82	0.06	5.3	0.61	291	34	0.01	438	0.72
KA21	655	Miocene	80	2.36	0.08	7.91	0.62	335	26	0.01	434	0.65
KA11	1900	Miocene	78	0.37	0.03	0.41	0.33	111	89	0.07	365	–0.59
TU11	2100	Miocene	76	1.31	0.06	1.74	0.91	133	69	0.03	438	0.72
NG11	1554	Miocene	101	0.19	0.01	0.12	0.4	63	211	0.08	419	0.38

S1: Represents the amount of free hydrocarbons, S2: Represents the amount of pyrolysable hydrocarbons, HI: Hydrogen Index; OI: Oxygen Index, Calc. Ro: Calculated vitrinite reflectance.

5. Conclusion

The Source rocks of the Miocene-Pliocene interval in the Albertine graben have a good generative potential of 1 and 8 mgHC/g of rock with TOC values between slightly less than 0.5 wt.% and about 4 wt.%. Kisegi formation shale and mudstone from Pakwach, Central Lake Albert, Northern Lake Albert, and Semliki sub-basins contain sufficient organic matter between 1 and 3 wt. % except those from Rhino Camp and L. Edward and George sub-basins with poor to fair source rock generative potential. C.L.A, N.L.A and Packwach sub-basins have quality source rocks of the Miocene-Pliocene interval with good hydrocarbon generative potential, implying quality source input in the N.L.A depocentre compared to the S.L.A depocentre. Kerogen typing reveals a mix of Type II, Type II/III, and Type III kerogen encountered in the Albertine graben source rocks of the Miocene-Pliocene interval. This shows a mixed depositional environment, including a lacustrine setting with terrestrial input. Source rocks of the Miocene-Pliocene interval in the Albertine graben have varying maturity, with most consistently immature and others reaching early oil window maturity. Shale and mudstones at depths greater than 650 m are near or within the early oil-generating window.

Recommendations

Petrographic analysis should be conducted for robust kerogen typing and maturity assessment, emphasizing geochemical studies conducted on subsurface source rocks of the Miocene–Pliocene interval from the Rhino Camp and Southern L. Edward sub-basins. A genetic relationship between Miocene–Pliocene source rocks and oil accumulations within the Graben should be established. This will enable geoscientists to trace the genetic origin of hydrocarbon accumulations within the Albertine graben and locate the ‘kitchen’, guiding further exploration for more hydrocarbon discoveries. This is because the potential source rocks of the Miocene-Pliocene interval at depths <2km are consistently immature to early oil window maturity. A correlation study will establish the strata variation of Miocene source sediments in the Graben. A detailed study should explain why some young source rocks of the Miocene-Pliocene interval have attained early oil window maturity and its implication on hydrocarbon generation and expulsion within the Graben.

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