

Article

Subsurface Characterization and Petroleum System Evaluation of the Onshore Southern Lake Albert Rift Basin, Uganda: Insights from Basin and Petroleum Systems Modeling

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Abstract

The onshore southern Lake Albert Rift Basin in Uganda represents a geologically complex and hydrocarbon-prone segment of the western branch of the East African Rift System. This study integrates seismic, well and geochemical data, and 2D Basin and Petroleum Systems modeling to reconstruct the petroleum system of the basin. Results highlight spatial variations in source rock maturity and indicate a predominantly oil-prone character. Migration modeling reveals hydrocarbon expulsion and vertical migration into both the overlying Middle—late Miocene Kakara and underlying early Miocene Kisegi sandstone reservoirs, facilitated by fault-controlled pathways. The late Miocene—early Pliocene Oluka Formation proves to be an effective regional seal, supported by its low modeled porosity, while overpressure zones enhance migration and accumulation efficiency. Present-day thermal maturity profiles and porosity–depth relationships indicate favorable conditions for hydrocarbon generation, migration, and preservation. These findings redefine our understanding of petroleum system dynamics in the Albert Rift and underscore the exploration potential of underexplored structural and stratigraphic traps in the southern sector of this rift and analogous rift settings.

Keywords: Albert Rift; East African Rift System; petroleum system; source rock; hydrocarbon migration; hydrocarbon accumulation; 2D Basin modeling; shale gouge ratio



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1. Introduction

The Albert Rift is recognized as the more petroliferous of the two confirmed hydrocarbon-bearing basins within the East African Rift System (EARS), with the Albert Rift located in the western branch and the Lokichar Rift in the eastern branch [1,2]. The onshore southern Lake Albert Basin, the primary focus of this study, encompasses the southern onshore region of present-day Lake Albert and lies directly north of the Rwenzori Mountains, and south of Lake Albert (Figure 1). This area harbors Turaco and Kanywataba prospects adjacent to Kingfisher oil field all hosting Early Miocene to Holocene geology. Exploratory drilling has been conducted at single locations within both the Turaco and Kanywataba prospects, but no commercial success has been achieved thus far. In contrast, the Kingfisher field stands out as one of the most successful fields in the Albert Rift. It is

plausible to infer that with thorough evaluation, the Turaco and Kanywataba areas could also demonstrate commercial viability. Furthermore, similar to other areas within this rift, these prospects share the same early to mid-Miocene lacustrine basin characteristics [3–5].

Within this sector of the Albert Rift, only two exploration wells have been drilled to date. One well was declared dry and subsequently abandoned, whereas the second encountered significant oil and gas shows but was not tested due to elevated CO₂ concentrations. Notably, the latter well penetrated organic-rich shale intervals presently within the oil window at depths of approximately 2400 m, confirming active thermal maturation.

Geochemical characterization of these source intervals indicates mixed kerogen assemblages, dominated by Type I with subordinate Type III components, suggesting primarily lacustrine organic matter input with minor terrestrial contributions [6,7]. Well reports show that Total Organic Carbon (TOC) values generally range from 1 to 3.6 wt.%, with localized organic-rich facies reaching 5.7–8.0 wt.%. Still from well reports, Hydrogen Index (HI) values vary between 283 and 503 mg HC/g TOC, and selected intervals record exceptionally high values of up to 600 mg HC/g TOC. These parameters collectively indicate good to excellent oil-prone generative potential.

Despite this strong geochemical evidence and documented hydrocarbon shows, no comprehensive petroleum systems evaluation of this basin segment is publicly available. A previous 1D Basin and Petroleum Systems Modeling (BPSM) study [8] suggested that hydrocarbon generation commenced during the Pliocene and is ongoing. However, 1D modeling is inherently limited to vertical burial and thermal histories at single well locations and does not adequately capture lateral variability, fault-controlled migration pathways, structural compartmentalization, or trap formation dynamics.

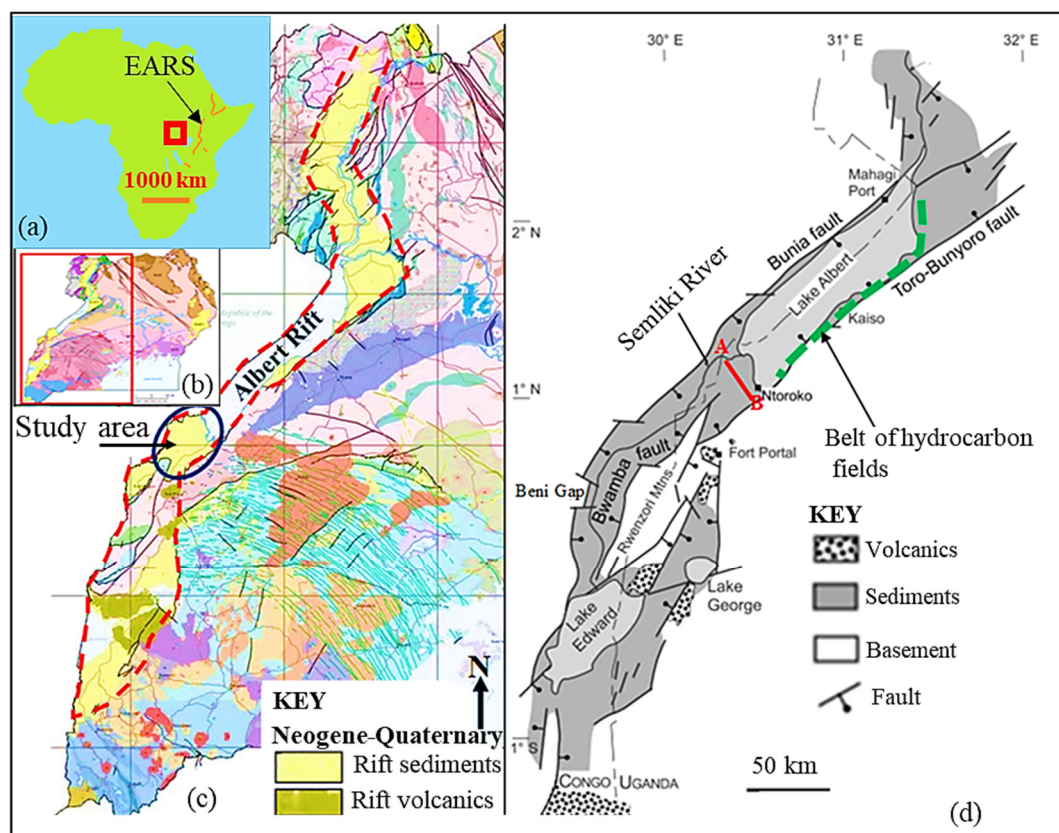


Figure 1. (a) Map of Africa showing the location of Uganda within the East African Rift System (EARS). (b) Regional geological map highlighting the position of the Albert Rift within the western branch of the East African Rift System. (c) Geological map of western Uganda showing

the distribution of Neogene–Quaternary Albert Rift sediments and associated volcanic centers (dashed red outline) and the location of the study area (blue circle). (d) Simplified geological and structural map of the Albert Rift indicating major border faults, sedimentary depocenters, volcanic occurrences, and the belt of hydrocarbon fields. The red line AB marks the location of the geological cross-section used for basin modeling in this study. Modified after [9,10].

To date, no published 2D or 3D BPSM studies exist for this part of the Albert Rift. Consequently, the spatial evolution of source rock maturity, migration pathways, hydrocarbon accumulation remain poorly constrained. This lack of integrated structural–stratigraphic and petroleum systems analysis represents a critical hinderance to understanding the petroleum potential of this basin, particularly given the confirmed presence of mature source rocks and hydrocarbon shows. Addressing this gap through multi-dimensional BPSM is therefore essential to properly evaluate the hydrocarbon potential and prospectivity of this underexplored basin.

This study utilizes 2D BPSM with Schlumberger PetroMod 2D to enhance basin-scale geological characterization and petroleum system evaluation in the Albert Rift, where previous assessments were largely restricted to 1D modeling approaches. The analysis primarily focuses on data from the southern Lake Albert area, which serves as the core region for assessing Neogene to Quaternary geology and petroleum systems. BPSM is a quantitative computerized workflow extensively employed to characterize and analyze petroleum systems and their constituent elements within sedimentary basins [11–15]. This methodology is designed to enhance understanding of the geological elements and processes contributing to hydrocarbon accumulations within a specific basin. BPSM is based on fundamental principles of physics, chemistry, and geological processes that interact to facilitate the formation of hydrocarbon accumulations. It serves as a critical tool integrating processes such as petroleum generation, migration, and accumulation in a quantitative manner. As a result, it has become indispensable in modern petroleum geology research and exploration, covering aspects such as frontier basin geological analysis, hydrocarbon resource assessment, and the delineation of reservoir plays and fairways in mature basins [16–19]. Furthermore, BPSM’s capability to quantitatively estimate generated, migrated, accumulated, and preserved hydrocarbons over geological time has contributed to its widespread adoption by oil and gas companies, government agencies, and academic institutions [20].

The selection of Schlumberger PetroMod 2D software (Petromod 2016) for this study was driven by its proven suitability for analyzing geological and petroleum systems, especially in cases where data availability is limited to constructing a 2D geological cross-section. This software is well-suited for such scenarios, facilitating comprehensive basin modeling and assessment even with sparse data sets, thereby enabling a thorough evaluation of petroleum prospectivity in the study area. Schlumberger PetroMod 2D comprises four key modules: PetroBuilder 2D, Simulator, Viewer 2D, and Viewer 1D. These modules collectively support detailed basin modeling and analysis based on the available geological data, particularly when the data may not allow a more comprehensive 3D BPSM. A comprehensive 2D basin model was developed to predict subsidence, porosity, temperature, and thermal history, while also evaluating hydrocarbon generation, migration, accumulation history, and present-day geopressures. This approach was specifically tailored to the geological context of the area, focusing on key modeling aspects pertinent to understanding the petroleum potential within the Albert Rift region.

This study illustrates the application of BPSM to enhance the understanding of petroleum systems, mitigate exploration risk, and improve exploration outcomes in frontier basins. Moreover, it highlights the effectiveness of BPSM as a powerful tool for integration into geological investigations, especially in regions where tectonic and stratigraphic under-

standing is still evolving—provided there is evidence of hydrocarbon presence and organic geochemical information of these hydrocarbons is available.

2. Geological Setting

The Albert Rift constitutes the northern segment of the western branch of the Paleogene to Recent EARS, representing the latest phase of Gondwana's polyphase break-up [10]. Rifting in this region commenced diachronously between the Eocene (approximately 35 million years ago) and Early Miocene (around 20 million years ago). According to [21], the East African Rift System features narrow elongate zones of thinned lithosphere attributed to asthenospheric intrusion in the form of mantle plumes. Recently, [22] propose that rifting in East Africa resulted from a combination of lithospheric stretching and mantle plume activity rather than exclusive active rifting as earlier thought. The rift system comprises interconnected basins and sub-basins segmented by intracontinental transform faults, transfer zones, and accommodation zones [21], with some of these basins, including the Albert Rift, exhibiting petroleum potential.

The development of the western branch, including the Albert Rift, occurred along Precambrian weakness zones where the Proterozoic mobile belts wrap around the Archean Craton [23–25].

The Albert Rift is filled with Early Miocene to Recent fluvial-lacustrine sediments and intermittent mantle derived volcanics (Figure 1). Structurally, it is divided into three domains: The Northern domain trending NNE-SSW, the Central domain striking NE-SW, and the Southern domain also trending NNE-SSW [24]. The Southern Lake Albert Sub-basin, considered in this study, constitutes the southernmost extension of the central domain.

The evolution of the Albert Rift has been influenced by three to four tectonic/rifting phases from its initiation to the present [3,4,26–29]. This tectonic evolution has been punctuated by several climatic pulses that have contributed to the development of a functioning petroleum system [30]. These climatic variations, occurring over geological time scales, have played a significant role in shaping the sedimentary environments, source rock deposition, and maturation processes critical for hydrocarbon generation and accumulation within the rift. The interplay between tectonic dynamics and climatic fluctuations has ultimately led to the establishment of key elements of the petroleum system observed in the Albert Rift.

3. Materials and Methods

3.1. Input Data

PetroMod 2D BPSM requires structural geometry from balanced cross-sections, stratigraphic data (layer thicknesses, ages, and lithologies), source rock geochemical parameters (TOC, HI, and kinetics), boundary conditions (heat flow, surface temperatures, and paleowater depths), fault properties (e.g., Shale Gouge Ratio), and facies distributions to simulate the basin's structural and thermal evolution and assess petroleum generation, migration, and accumulation [12,31].

3.1.1. Structural and Stratigraphic Data

Structural and stratigraphic input data for PetroMod 2D BPSM typically include balanced cross-sections or seismic interpretations to define basin geometry, stratigraphic units, and fault systems. Layers are characterized by thickness, lithology, and age, while structural elements, such as faults, are parameterized with properties like throw and Shale Gouge Ratio. These inputs establish the framework for modeling depositional history, tectonic evolution, and the interaction of petroleum system elements, providing a detailed

basis for simulation of hydrocarbon processes. In this study, a NW-SE geological cross-section (Figure 2) interpreted from seismic data was used for 2D modeling.

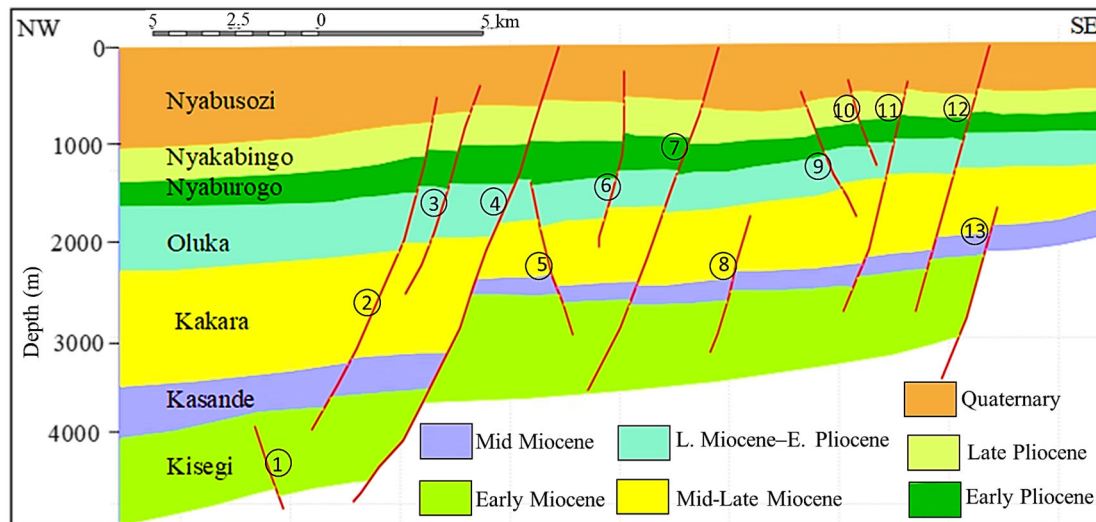


Figure 2. The Geological cross-section used for 2D modeling. The location of the cross-section is presented as red line AB on Figure 1d.

3.1.2. Organic Geochemistry and Organic Petrography Data

This Organic geochemistry and organic petrography data in PetroMod 2D BPSM are essential for defining source rock properties and hydrocarbon generation potential. Key inputs include TOC, HI, and kerogen types obtained from well reports or laboratory analyses. These parameters are used to assign source rock kinetics, typically following predefined models (e.g., Burnham Type II or III). Calibration with measured vitrinite reflectance (R_o) and T_{max} values ensures the accuracy of the thermal maturity modeling, aiding in hydrocarbon generation predictions. In this study, organic geochemical and petrographic data were compiled and interpreted from well reports provided by the Ministry of Energy and Mineral Development (MEMD), Uganda. These data comprise TOC, HI, and kerogen type information derived from the only available offset well that penetrated the organic-rich intervals within the study area. TOC values in the dataset range from 1 to 3.6 wt.%, with localized organic-rich intervals reaching 5.7–8.0 wt.%. HI values vary between 283 and 503 mg HC/g TOC, with isolated measurements up to 600 mg HC/g TOC. For the 2D BPSM, representative average TOC and HI values were assigned to the gross source rock lithology in PetroMod. This approach was necessitated by limited vertical sampling density and insufficient stratigraphic resolution to confidently subdivide the source interval into multiple internally consistent geochemical units. Accordingly, the source rock was modeled as a single effective unit characterized by averaged geochemical parameters.

3.2. Basin and Petroleum Systems Modeling Workflow

Basin and petroleum system modeling integrates seismic, geological, and organic geochemical data to simulate the structural and thermal evolution of a region over geological time. Using a conceptual framework that synthesizes all geological history of the study area, a numerical model was developed through discretization. This process involved defining vertical grid lines and horizontal event lines to create a grid. Each grid cell was characterized by input data, including layer thickness, age, lithological properties, fault characteristics, heat flow, surface temperatures, and paleowater depths. For source rock intervals, additional parameters such as TOC, HI, and kinetic data were included. The model simulated petroleum generation, migration timing, and entrapment, revealing key factors

influencing these processes [32,33]. In this study, PetroMod 2D software was employed for deterministic forward modeling of the basin and petroleum system evolution for the Onshore Southern Lake Albert Basin. The theoretical and numerical foundations of this approach were described by [31]. The modeling workflow is detailed the subsections below.

3.2.1. Image Input and Digitization

In PetroMod 2D BPSM, geological cross-sections derived from seismic interpretation or structural balancing are imported into the PetroBuilder module. These images are digitized to delineate horizons, faults, and stratigraphic units, ensuring accurate spatial representation. Key parameters such as thickness, lithology, and fault properties are assigned during digitization. This step bridges raw data with the model's numerical framework, providing the geometric basis for simulations of basin evolution and petroleum systems. The balanced cross-section from Midland Move was imported into the PetroMod 2D Builder and digitized to define horizons and faults.

3.2.2. Horizon Age Assignment

Horizon age assignment in PetroMod 2D BPSM involves defining the deposition ages of stratigraphic layers based on geological data. This process ensures accurate temporal calibration of basin evolution and petroleum system processes. Age values are typically derived from biostratigraphy, radiometric dating, or regional chronostratigraphic frameworks. These ages are input during model construction to establish a timeline for sedimentation, erosion, and tectonic events, providing a foundation for simulations of thermal history, source rock maturation, and hydrocarbon generation. In this study, ages of lithological units were picked from published data [3,4,34].

3.2.3. Facies Assignment

Facies assignment in PetroMod 2D BPSM involves defining lithological and depositional characteristics for each stratigraphic layer, as determined from well logs, core data, or seismic interpretation. These facies are crucial for modeling physical properties such as porosity, permeability, and thermal conductivity, which influence fluid flow and heat transfer in the basin. By correlating facies with depositional environments, the model accurately represents the spatial distribution of reservoirs, seals, and source rocks, enabling detailed petroleum system simulations. Each stratigraphic layer was assigned facies such as shale, sandstone based on subsurface lithological logs and outcrop information.

3.2.4. Source Rock Geochemical Data Assignment

In PetroMod 2D BPSM, source rock intervals are assigned geochemical parameters such as TOC, HI, and kerogen types. These values are typically derived from well data, laboratory analyses, or regional geochemical studies. The kinetic parameters for hydrocarbon generation are selected based on the kerogen type (e.g., Burnham Type II or III). Accurate assignment of these properties ensures realistic modeling of source rock maturation, hydrocarbon generation, and expulsion timing within the basin. In this study, the source rock formation was characterized by average TOC and HI values derived from well reports (e.g., 3.5% TOC and 367 HI) as indicated in Section 3.1.2.

3.2.5. Fault Property Assignment

Fault property assignment in PetroMod 2D BPSM involves defining fault age, throw, and flow properties, such as Shale Gouge Ratio Shale Gouge Ratio, calculated as the ratio of cumulative shale thickness to fault throw, determines fault sealing or leakage potential. These properties are critical for modeling hydrocarbon migration pathways and trap effectiveness. Data for fault properties are normally derived from seismic interpretation,

geological reports, or empirical models, ensuring realistic representation of structural controls on petroleum systems. According to [35] classification, faults with low ratio values (<20%) contain little shale and are therefore more likely to act as conduits for fluid migration, whereas medium ratio values (20–40%) reflect moderate shale content and suggest partial or semi-sealing behavior, and high ratio values (>40%) signify substantial shale incorporation along the fault plane, implying strong sealing capacity and an increased likelihood of hydrocarbon entrapment due to the low permeability of shale-rich fault gouge. In this study, the Shale Gouge Ratio (Table 1) was determined by first integrating outcrop observations, well log data, and seismic interpretation to quantify the thickness and distribution of sand and shale units across the stratigraphic sections, after which the ratio was calculated using the standard formula:

$$\text{SGR} = \frac{\Sigma(\text{Shale bed thickness})}{\text{Fault throw}} \times 100\%$$

Table 1. Shale gouge ratios for the characterized faults that were in modeling.

Fault Number	Fault Throw (m)	Σ (Shale Bed Thickness) (m)	SGR (%)	Leak/Seal
1	616	388	63	Seal
2	1900	1483	78	Seal
3	1824	1445	79	Seal
4	2219	1698	77	Seal
5	1220	959	79	Seal
6	646	560	87	Seal
7	2172	1678	77	Seal
8	2172	579	73	Seal
9	1060	919	87	Seal
10	565	544	96	Seal
11	1963	1538	78	Seal
12	1952	1538	79	Seal
13	1990	1553	78	Seal

Note: SGR = Shale Gauge Ratio.

3.2.6. Gridding

Gridding in PetroMod 2D BPSM involves creating a structured numerical grid by discretizing the geological model into cells defined by vertical grid lines and horizontal event surfaces. Each grid cell represents a specific volume with assigned properties such as thickness, lithology, porosity, permeability, and thermal conductivity. This framework allows for the simulation of geological processes, including sediment deposition, heat transfer, fluid migration, and hydrocarbon generation, ensuring spatially resolved modeling of the petroleum system. After all the properties were assigned, gridding was done prior to simulation as a normal routine.

3.2.7. Boundary Conditions Assignment

Boundary conditions in PetroMod 2D BPSM are critical for simulating thermal and pressure regimes in the basin over time. Parameters such as surface temperature, basal heat flow, paleo-water depth, and sediment-water interface temperature are assigned based on regional geological and geophysical studies. These values, often sourced from literature or measured data, are calibrated to match borehole temperature and vitrinite reflectance trends. Proper boundary condition assignment ensures accurate modeling of heat transfer, maturation processes, and hydrocarbon generation. In this study, the model was constrained using time-dependent basal heat flow and sediment–water interface

(SWI) temperature histories. Basal heat flow was defined using two calibration points: 73 mW m^{-2} at 20 Ma and 60 mW m^{-2} at present day (0 Ma), representing progressive post-rift thermal decay from elevated Miocene heat-flow conditions to the current geothermal regime [25,36]. Linear interpolation between these values was applied to simulate temporal heat-flow evolution.

Surface boundary conditions were constrained using location-specific sediment–water interface (SWI) temperatures of 25°C at 20 Ma and 24°C at present day, derived from the global paleotemperature model of [37]. These values were implemented as the upper thermal boundary condition in the conductive heat-flow framework, thereby governing surface temperature evolution through time.

Together, the lower (basal heat flow) and upper (SWI temperature) boundary conditions govern the reconstructed thermal history and directly influence modeled maturity evolution and hydrocarbon generation timing.

3.2.8. Simulation Execution

Simulation execution in PetroMod 2D BPSM involves running the configured model to simulate basin evolution, petroleum generation, migration, and accumulation. The process employs algorithms such as hybrid (Darcy + Flow path) migration to track fluid movement through the modeled grid. Input parameters, including stratigraphy, fault properties, thermal conditions, and source rock geochemistry, are iteratively calibrated against measured data like vitrinite reflectance (Ro) and borehole temperatures. Post-simulation, results are analyzed for hydrocarbon generation timing, migration pathways, and entrapment potential. In this study, the model was executed using the 2D Simulator with hybrid migration (Darcy + Flow Path).

3.2.9. Calibration

Calibration in PetroMod 2D BPSM ensures the accuracy of the model by aligning simulation results with observed data. This process involves adjusting input parameters—such as heat flow, source rock maturity, and stratigraphy—to match measured borehole temperatures, vitrinite reflectance (Ro), or other geochemical indicators. Iterative calibrations refine the model, enhancing the reliability of hydrocarbon generation and migration predictions. This step is crucial for validating the geological and thermal history of the basin and achieving robust simulation outcomes. In this study, results of the simulation were calibrated against measured borehole temperature and vitrinite reflectance (Ro) trends. Iterative adjustments performed until an optimal match between modeled and measured parameters was achieved.

4. Results and Discussion

4.1. Geopressures and Petroleum System Implication

The modeled dataset (Table 2; Figure 3) presents hydrostatic, pore, and lithostatic pressures at different depths. These parameters are essential for interpreting basin evolution and evaluating petroleum system behavior. Hydrostatic pressure increases from 0.01 MPa at 11 m to 50.09 MPa at 4901 m. Pore pressure rises from 0.1 MPa to 50.44 MPa over the same depth interval. Lithostatic pressure increases consistently from 0.1 MPa at 11 m to 115.55 MPa at 4901 m. This progressive increase reflects normal burial and compaction processes in sedimentary basins. The hydrostatic gradient represents the equilibrium condition of pore fluids. Pore pressure begins to diverge from hydrostatic pressure below ~2309 m, where pore pressure (24.01 MPa) slightly exceeds hydrostatic pressure (23.65 MPa). This divergence indicates the slight onset of slight overpressure, and corresponds to the approximate depth of the Kasande organic rich shale. This slight overpressure development

is likely related to disequilibrium compaction, organic matter maturation, or fluid expansion during hydrocarbon generation [38]. The slight difference between hydrostatic pressure and pore pressure is evident in the numerical data (Table 2) but less apparent in the plotted curves, where the two profiles appear to overlap. The continuous increase in lithostatic pressure reflects the growing sediment overburden and provides the stress necessary for seal integrity. Overpressure reduces effective stress and can enhance permeability along faults and fractures, thereby facilitating hydrocarbon expulsion and migration. Overall, the pressure relationships indicate a potential petroleum system, with hydrocarbon migration driven by pressure gradients and trap effectiveness controlled by the balance between lithostatic and pore pressures.

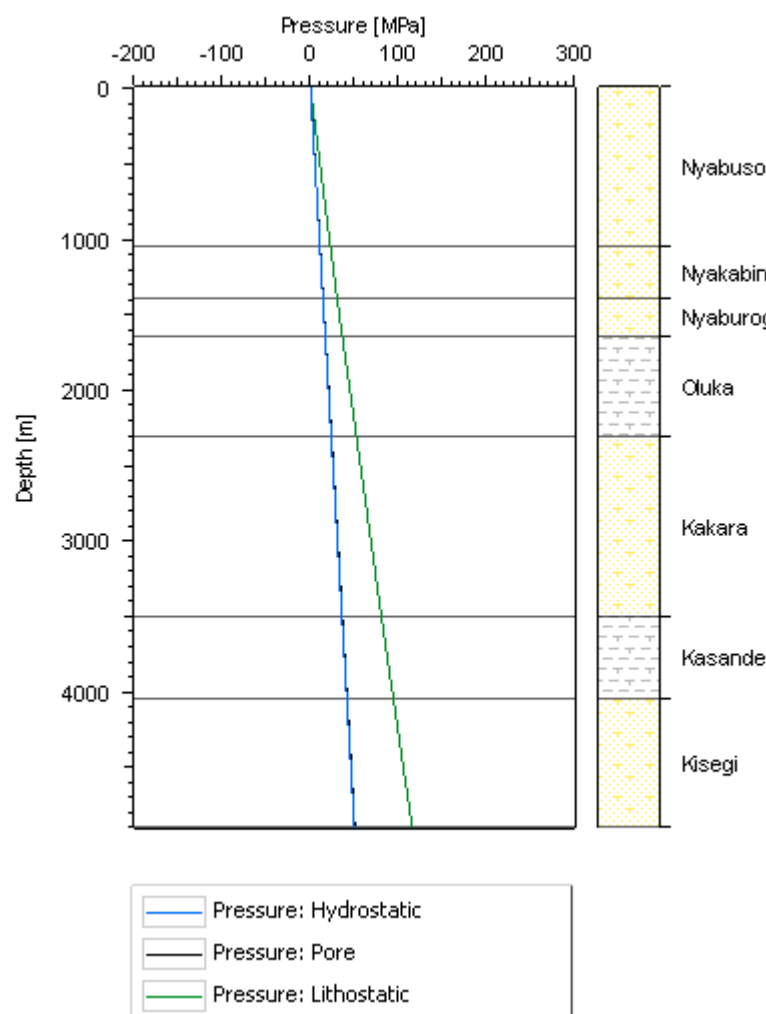


Figure 3. Subsurface pressure trends at a model-derived virtual well located at the northwestern (structurally deepest) end of the model. The plot illustrates that hydrostatic and pore pressures substantially overlap and are consistently lower than the lithostatic pressure across the modeled section.

Table 2. Present-day subsurface pressures from a virtual well at the northwestern (deepest) end of the 2D model.

Depth (m)	Hydrostatic Pressure [MPa]	Pore Pressure [MPa]	Lithostatic Pressure [MPa]
11	0.01	0.10	0.10
1040	10.70	10.83	22.56
1388	14.26	14.39	30.39

Table 2. Cont.

Depth (m)	Hydrostatic Pressure [MPa]	Pore Pressure [MPa]	Lithostatic Pressure [MPa]
1643	16.85	16.98	36.10
2309	23.65	24.01	52.41
3498	35.78	36.13	80.56
4043	41.34	41.69	94.17
4901	50.09	50.44	115.55

4.2. Porosity Evolution and the Petroleum System

The modeled porosity history of the Onshore South Lake Albert Basin reveals a progressive evolution of reservoir and seal properties controlled by burial, tectonic subsidence, lithology, and diagenesis (Table 3; Figure 4a). This evolution directly governs the effectiveness of the basin's petroleum system elements through time.

Table 3. Modeled formation porosities at varying depths.

Formation	Lithology	Depth (m)	Porosity (%)
Nyabusenzi	Sandstone (Clay rich)	11	33.71
Nyakabingo	Sandstone (clay rich)	1040	27.30
Nyaburogo	Sandstone (typical)	1388	25.50
Oluka	Shale (typical)	1643	12.34
Kakara	Sandstone (clay poor)	2309	17.21
Kasande	Shale (organic rich, typical)	3498	3.48
Kisegi	Sandstone (typical)	4043	10.64

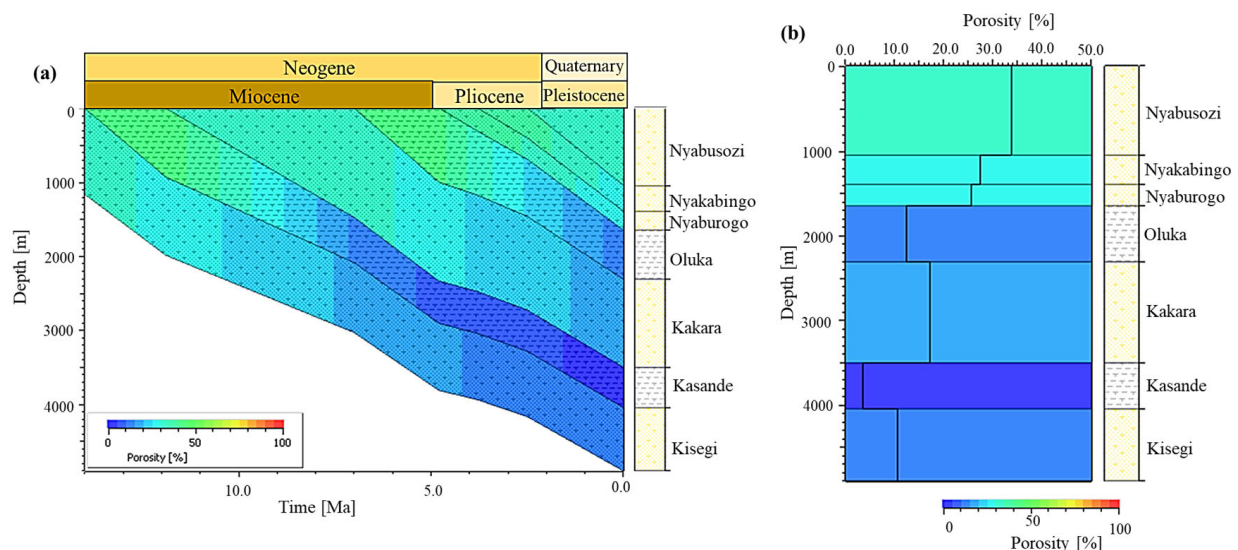


Figure 4. (a) Porosity evolution with burial over time. (b) Porosity changes with burial depth at a model-derived virtual well located at the structurally deepest end of the 2D section.

During the Miocene syn-rift phase, rapid sediment accumulation in fluvial and lacustrine environments led to the deposition of loosely consolidated sandstones of the Kisegi and Kakara formations with very high initial porosities, locally exceeding 50% (Figure 4a). These high values reflect limited compaction during early burial under active extensional tectonics. With continued subsidence into the Pliocene, progressive burial resulted in mechanical compaction, grain rearrangement, and pressure solution, driving a substantial reduction in porosity, particularly within the deeper parts of the Kisegi and

Kakara formations where values decline to 10–20%. This trend follows the well-established porosity–depth relationship observed in sedimentary basins worldwide [39]. Chemical diagenesis further reduced pore volume through quartz overgrowths and gypsum and calcite cementation, processes documented from outcrop analogues within the Albert Rift [28,29]. Locally higher porosity preserved at intermediate depths in the Kakara Formation likely reflects lithological heterogeneity and the development of secondary porosity through dissolution and tectonic fracturing, features commonly associated with rift-related deformation [40].

Fine-grained units followed a different evolutionary pathway. The Kasande Formation, composed of organic-rich shales, maintained persistently low porosity throughout burial. This behavior is consistent with studies showing that early compaction, cementation, and the presence of organic matter lead to tight pore networks in shales [40]. Similarly, the Oluka Formation exhibits a steady porosity decline with depth, enhancing its capacity to function as an effective regional seal. In contrast, the younger Late Neogene to Quaternary formations (Nyaburogo, Nyakabingo, and Nyabusozzi) retain relatively high porosities due to shallow burial and limited diagenetic overprint.

Present-day porosity variations with depth further illustrate the strong lithological and burial controls on reservoir quality (Table 3; Figure 4b). The shallow Nyabusozzi and Nyakabingo formations exhibit high modeled porosities of 33.71% and 27.30%, respectively, consistent with their limited burial depths and minor compaction. Comparable trends have been reported in the Albert Rift from well logs and petrographic studies [6,41,42], and align with global compaction models that describe the inverse relationship between depth and porosity [31,43,44]. With increasing depth, porosity progressively decreases: the Nyaburogo Formation at 1388 m retains 25.50%, whereas the deeper Kakara Formation at 2309 m shows a reduced porosity of 17.21%, reflecting intensified compaction and cementation. Such depth- and lithology-controlled trends are widely documented in sedimentary basins [40,45].

Shale formations show markedly lower porosity. The Oluka shale at 1643 m has a porosity of 12.34%, while the deeply buried Kasande organic-rich shale at 3498 m exhibits only 3.48%, reflecting advanced diagenesis and compaction. These low values reinforce the sealing capacity of these units, a key requirement for hydrocarbon entrapment. Similar shale seal behavior is reported in numerous petroleum basins worldwide [31,40]. At the greatest depth, the Kisegi sandstone at 4043 m retains 10.64% porosity, indicating substantial burial diagenesis but still preserving some storage capacity, potentially enhanced by secondary porosity such as fractures.

From a petroleum system perspective, this porosity architecture defines a vertically organized system of overburden, seal, source, and reservoir units. The Nyabusozzi, Nyakabingo, and Nyaburogo formations form a relatively porous but fine-grained overburden that helps maintain burial and thermal conditions in deeper intervals while restricting vertical fluid escape. Beneath them, the Oluka Formation acts as a regional seal, where low porosity and permeability inhibit hydrocarbon leakage, consistent with global shale seal analogues [46–48]. The Kasande Formation represents the principal source rock; its very low porosity reflects advanced compaction and diagenesis associated with hydrocarbon generation processes described by [49]. Limited pore space in the source rock promotes hydrocarbon expulsion into adjacent carrier beds.

The expelled hydrocarbons migrate into the Kakara and Kisegi formations, which constitute the primary reservoirs. The Kakara Formation, with moderate burial depth and porosity of 17.21%, provides favorable storage and flow characteristics, consistent with studies highlighting the preservation of reservoir quality at intermediate burial depths [50]. Although the deeper Kisegi Formation has lower porosity (10.64%), fracture development

and secondary porosity may enhance its effective reservoir performance, analogous to deeply buried sandstone reservoirs such as the Brent Group of the North Sea [51]. Together with structural traps, these formations provide the principal storage sites for hydrocarbons generated from the Kasande source and retained beneath the Oluka seal.

Overall, the modeled porosity evolution demonstrates how burial history and diagenesis progressively modified primary depositional properties to produce the present-day distribution of reservoirs, seals, and source rocks. This integrated porosity framework is fundamental to understanding the efficiency and spatial organization of the petroleum system in the Albert Rift.

4.3. Subsurface Thermal Regime and Maturity Evolution

The subsurface temperature framework of the onshore southern Lake Albert Basin records the progressive thermal evolution of a fault-controlled rift system in which burial history, lithology, and tectonic subsidence collectively regulate heat distribution. Modeled temperature histories (Table 4; Figure 5a) show a consistent increase in temperature with depth and time, reflecting continued sediment accumulation and crustal thinning typical of extensional basins. The smooth nature of the isotherms indicates a relatively stable geothermal regime without strong localized anomalies such as magmatic intrusions, suggesting that regional heat flow has been primarily controlled by lithospheric stretching and conductive heat transfer.

Table 4. Evolving temperatures of the source rock over time at the NW end of the model.

Time (Ma)	Temperature °C
11.90	49.70
7.00	73.87
4.80	110.31
3.80	113.28
2.00	116.55
0.00	131.25

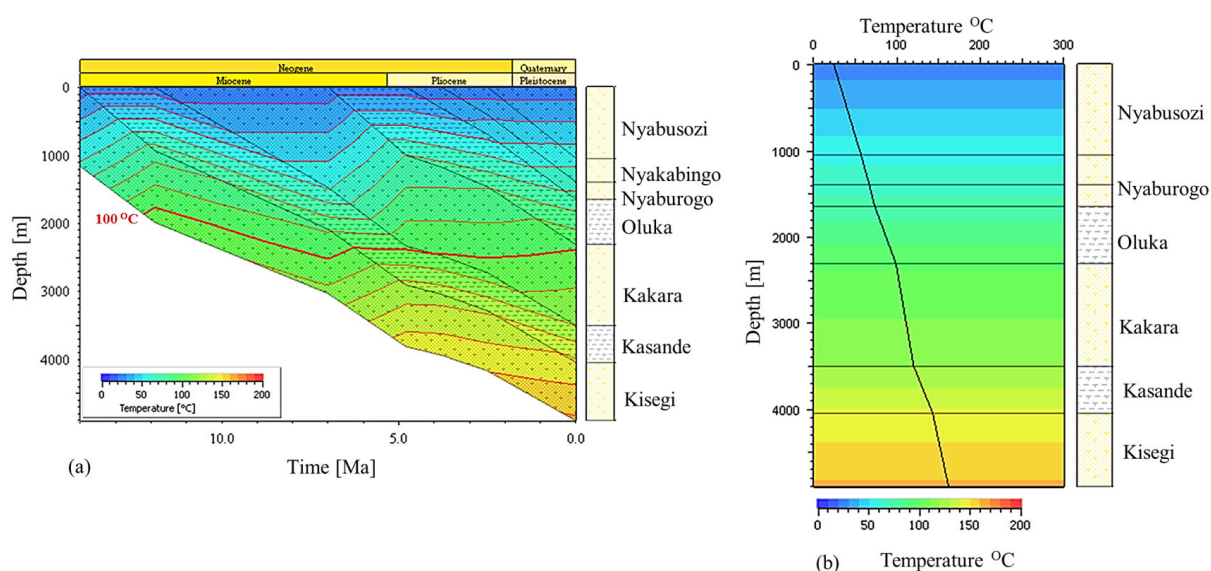


Figure 5. (a) Temperature evolution of the entire sedimentary section through time. (b) A plot of modeled present-day temperature versus depth at a model-derived virtual well located at the structurally deepest end of the 2D section.

The stepped geometry of isotherms observed in the burial–thermal history plot reflects variations in sedimentation rates, erosional episodes, and structural movements. Periods of

rapid sedimentation increased burial rates and drove isotherms downward, while episodes of uplift or reduced deposition produced temporary upward shifts. Lithological contrasts further influenced the temperature structure: shale-dominated units such as the Oluka Formation exhibit lower thermal conductivity and tend to insulate underlying strata, whereas sandstone-rich intervals such as the Kakara and Kisegi Formations promote more efficient heat transfer, producing smoother vertical thermal gradients.

Present-day temperature–depth profile (Table 5; Figure 5b) display a near-linear geothermal gradient averaging approximately 28 °C/km, consistent with global rift basins [52]. Surface temperatures near 24 °C increase steadily to over 160 °C in the deepest modeled intervals. This predictable gradient confirms a stable conductive thermal regime governed by progressive burial rather than transient thermal events. Shallow formations, including Nyabusozzi and Nyakabingo, remain at relatively low temperatures due to limited burial, while deeper formations such as Kakara, Kasande, and Kisegi occupy progressively warmer thermal domains reflecting their greater burial depths.

Table 5. Present-day temperatures versus depth at the NW end of the model.

Horizon	Depth (m)	Temperature °C
Top Nyabusozzi	0	24.00
Base Nyabusozzi	1040	56.58
Base Nyakabingo	1388	66.71
Base Nyaburogo	1643	73.26
Base Oluka	2309	98.67
Base Kakara	3498	119.87
Base Kasande	4043	142.66
Base Kisegi	4901	161.84

The thermal structure also interacts closely with lithological architecture. Fine-grained shale units, particularly the Oluka Formation, act as thermal insulators that moderate vertical heat transfer, while thicker sandstone intervals enhance conductive heat flow. Fault systems locally perturb the temperature field by juxtaposing units of different thermal properties and by facilitating fluid movement, which may redistribute heat on a localized scale. These structural and lithological controls create subtle lateral variations in the geothermal gradient across fault blocks.

From a basin evolution perspective, the observed temperature distribution confirms long-term subsidence and sediment loading as the dominant controls on the thermal regime. Overburden formations contribute to heat retention at depth, while variations in burial thickness between structural highs and lows produce corresponding temperature contrasts. The resulting thermal architecture supports ongoing diagenetic modification of reservoir rocks, influencing cementation, compaction, and the development of secondary porosity. Thus, the subsurface temperature regime is a key factor linking tectonic subsidence, burial history, and the progressive modification of reservoir and seal properties throughout the basin.

Overall, the South Lake Albert Basin exhibits a stable, burial-driven geothermal system characteristic of continental rifts. The integration of temperature history with stratigraphy and structure highlights the strong coupling between tectonic subsidence, lithological variation, and subsurface heat distribution, all of which play a central role in controlling basin evolution and reservoir quality.

The 2D vitrinite reflectance model (Table 6; Figure 6) also show a systematic increase in calculated vitrinite reflectance (VR) with depth and toward the structurally deeper parts of the basin, expressed by sub-parallel VR isolines that broadly mimic the basin geometry. These isolines provide an independent and quantitative constraint on the spatial

distribution of thermal exposure. Lower VR values occur in the shallow basin margins and uplifted structural blocks, reflecting limited burial and reduced thermal loading. In contrast, progressively higher VR contours are concentrated within the depocentres, where thicker sedimentary successions and greater subsidence histories have promoted higher palaeotemperatures.

Table 6. Vitrinite reflectance (VR) values derived from a virtual well location at the northwestern margin of the 2D model.

Horizon	Depth (m)	VR (%Ro)
Top Nyabusozi	11	0.20
Base Nyabusozi	1040	0.34
Base Nyakabingo	1388	0.37
Base Nyaburogo	1643	0.41
Base Oluka	2309	0.55
Base Kakara	3498	0.70
Base Kasande	4043	0.90
Base Kisegi	4901	1.21

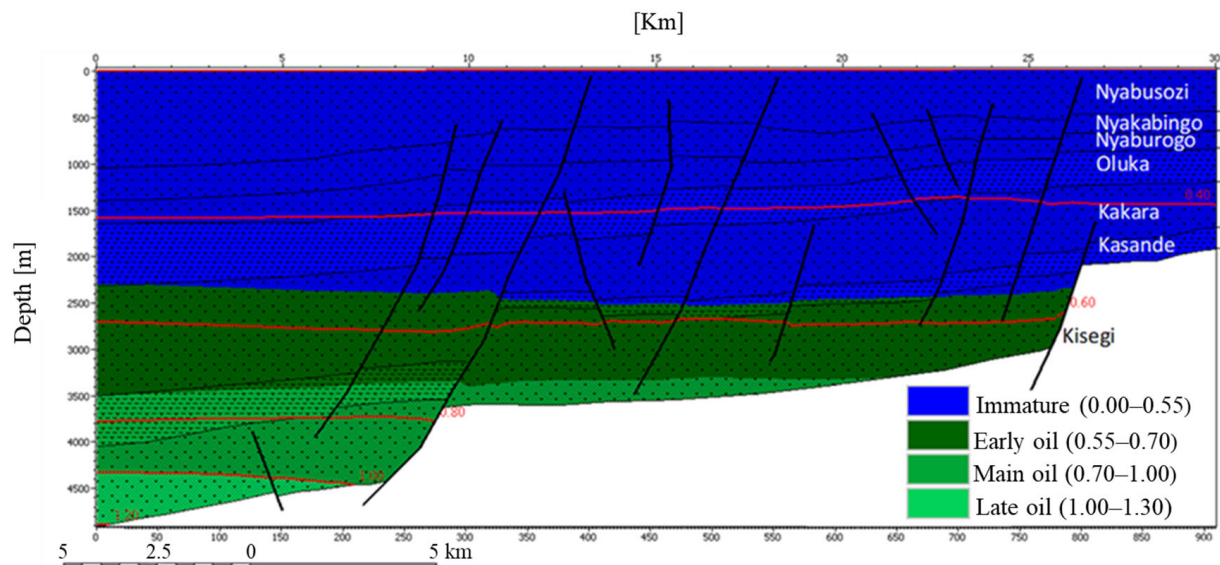


Figure 6. Modeled present day maturity trends. Red lines denote Vitrinite reflectance isolines.

The geometry of the VR isolines is consistent with conductive heat flow dominated by burial depth rather than localized magmatic or hydrothermal anomalies, as no abrupt thermal gradients or distortion of the contours are observed near major faults. Instead, the smooth, basinward-deepening pattern indicates regionally controlled thermal evolution linked to syn-rift subsidence and post-rift sediment loading. The coincidence of higher VR zones with maximum stratigraphic thickness supports a burial-driven thermal regime and reinforces the reliability of the modeled thermal history.

Furthermore, the progressive tightening of VR isoline spacing in the deeper basin sectors suggests increasing thermal gradients at depth, which is typical of rift basins with high sedimentation rates and enhanced lithospheric heat flow during active extension. This spatial VR distribution therefore provides robust corroboration of the basin's burial architecture and thermal structure, strengthening confidence in the overall basin evolution framework derived from the model.

4.4. Hydrocarbon Mass Bulk Generation, Migration and Entrapment History

The hydrocarbon production history of the South Lake Albert Basin (Table 7) highlights the fundamental control of source rock development on the evolution of the petroleum system. The Kasande Formation is interpreted as the principal source rock in the basin and shows a progressive increase in hydrocarbon mass generation through time, closely linked to burial evolution and tectono-sedimentary processes.

Table 7. Modeled hydrocarbon bulk generation mass through time.

Time (Ma)	Mass (Megatons)
7.00	0.00
4.80	0.02
3.80	0.03
2.50	0.06
0.00	0.31

At 7.00 Ma, the Kasande Formation was in an early burial stage and had not yet begun measurable hydrocarbon production (0.00 megatons). By 4.80 Ma, continued sedimentation increased burial conditions, and modeled bulk hydrocarbon generation reached 0.02 megatons, marking the initial phase of petroleum generation. Regional rifting during this period likely enhanced heat flow within the basin, supporting the onset of hydrocarbon generation in the Kasande Formation. Regional analogs from East African rift systems confirm that rifting during this period likely increased heat flow, enhancing hydrocarbon generation potential [53].

By 3.80 Ma, progressive burial resulted in bulk mass generation increasing to 0.03 megatons. This phase represents a key period in the petroleum system, when generation became sufficiently active to allow hydrocarbons to migrate into adjacent reservoir units, notably the Kisegi and Kakara Formations, thereby improving the basin's exploration potential. At 2.50 Ma, hydrocarbon bulk mass generation increased further to 0.06 megatons, coinciding with continued tectonic subsidence that accelerated burial rates and geothermal input. This stage was characterized by sustained hydrocarbon generation and the establishment of effective migration pathways into structural and stratigraphic traps.

At the present day (0.00 Ma), modeled cumulative hydrocarbon bulk mass generation is approximately 0.31 megatons, reflecting long-term, continuous petroleum generation within the Kasande Formation. This prolonged generation history demonstrates the formation's importance as a long-lived contributor to the basin's petroleum charge system and its capacity to support multiple hydrocarbon plays across the Albert Rift.

Migration vectors and accumulations (Figures 7 and 8a) indicate that hydrocarbons predominantly migrated upward into the Kakara Formation, with secondary downward migration into the Kisegi Formation. Oil migration is largely concentrated near the source rock kitchen areas, while gas migration extends farther toward the southeast. The absence of significant accumulations in distal zones likely reflects migration losses or insufficient charge volumes to fill available traps. Similar localized migration patterns have been documented in other East African Rift basins [1], where proximity to active source kitchens strongly controls accumulation efficiency.

Fault systems play a critical dual role in hydrocarbon migration and entrapment, leading to four principal accumulations within the Kisegi and Kakara Formations (Figure 8a). These accumulations are structurally controlled and positioned close to the main source rock depocenters. The lowermost accumulation occurs near the Kisegi–Kasande contact, where hydrocarbons migrated downward into a fault-bounded trap, similar to scenarios described in other fault-sealed reservoirs in rift settings [54,55]. Another accumulation

occurs in the Kakara Formation adjacent to a major fault segment, where upward migration led to structural trapping. A central accumulation in the Kakara Formation is bounded by faults, illustrating fault-controlled migration and entrapment. The rightmost accumulation, also within the Kakara Formation, marks the southeastern limit of effective oil migration, beyond which migration losses or limited charge volumes likely prevented further trapping. These scenarios underscore the dual role of faults as both migration pathways and barriers, as documented in similar systems [35,55].

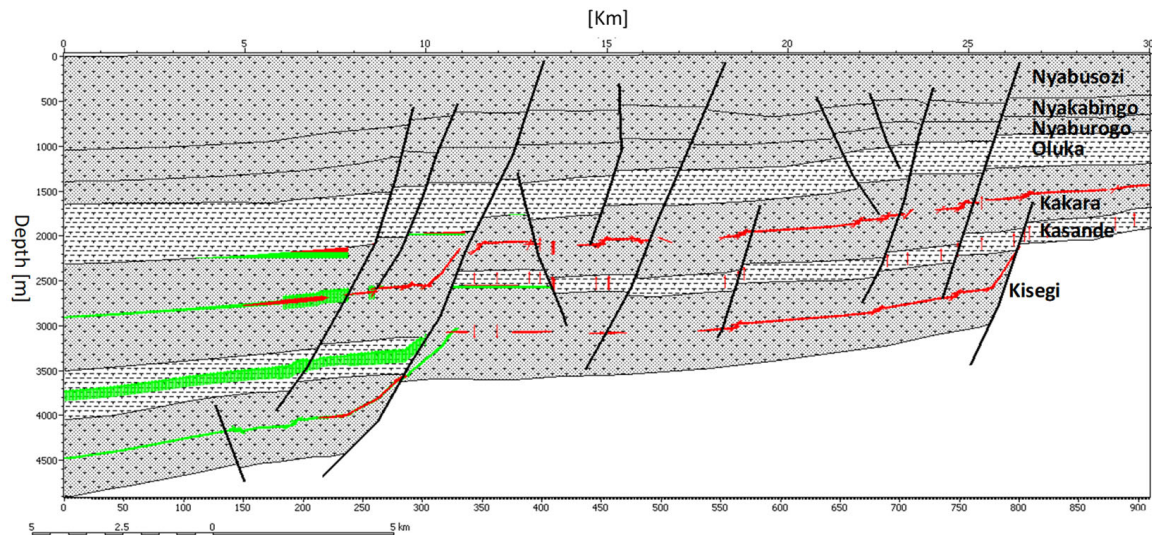


Figure 7. Migration vectors and hydrocarbon accumulations. Green color areas denote oil vectors while red ones represent gas vectors.

These examples highlight the dual function of faults as both migration conduits and sealing barriers. Hydrocarbon distribution patterns indicate that most faults acted predominantly as barriers that restricted eastward migration, while a smaller proportion allowed vertical or lateral transfer. Calculated Shale Gouge Ratio (SGR) values for the mapped faults range from 63–96%, suggesting strong sealing capacity following established fault seal interpretation schemes. Although the calculated Shale Gouge Ratio (SGR) values (Table 1) suggest that the major faults exhibit strong sealing capacities (77–79%), the modeled migration vectors (Figure 7) and observed hydrocarbon accumulations (Figure 8a) indicate that fault seal integrity is not uniform. The presence of accumulations southeast of Fault 4, despite the mature and actively generating source rock being located northwest of this structure, implies localized leakage across the fault plane.

This apparent contradiction can be geologically explained by along-fault heterogeneity in shale smear continuity, clay distribution, and mechanical behavior. While an average SGR of 77% would typically indicate a high capillary entry pressure and effective sealing potential, local zones of insufficient shale smear, sand-on-sand juxtapositions, or tectonic reactivation (e.g., brittle fracturing during later extensional or transtensional phases) could create permeable pathways for cross-fault migration. In rift settings, episodic tectonic reactivation commonly modifies fault rock properties, reducing seal capacity even where bulk SGR values remain high.

Nevertheless, the spatial confinement of the accumulations within the structural framework defined by Faults 2 (SGR = 78%), 3 (SGR = 79%), 4 (SGR = 77%), and 5 (SGR = 79%) demonstrates that, at the trap scale, these faults exert a dominant control on fluid distribution. Their relatively high SGR values likely increase capillary threshold pressures sufficiently to restrict large-scale lateral escape, thereby compartmentalizing hydrocarbons and promoting localized charge retention.

Therefore, the results suggest that fault seal behavior in this basin is not binary (sealed versus leaking) but scale-dependent: regionally effective in restricting bulk migration, yet locally breached where mechanical or lithological heterogeneities reduce shale smear continuity.

This sealing behavior likely contributed to the dry outcome of wells such as KTB, where hydrocarbons may have been compartmentalized or prevented from migrating into the drilled structure.

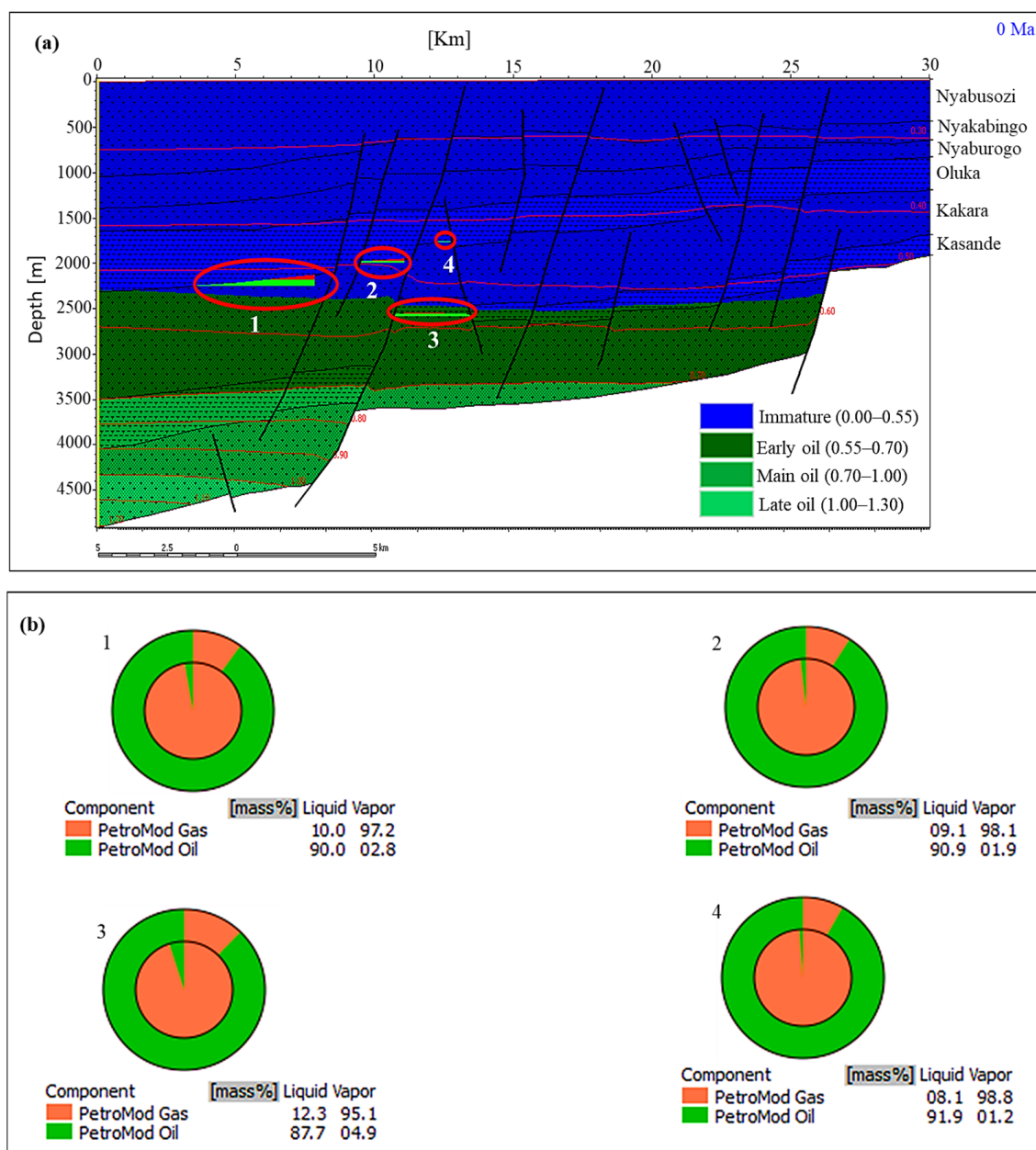


Figure 8. (a) Four oil and gas accumulations. (b) Cell components for different accumulations along the modeled NW-SE cross-section located just south of Lake Albert.

The predicted dominance of oil with minor gas volumes in this study is attributed primarily to variations in organic matter type rather than thermal conditions. Well data indicate that organic matter in the Kasande Formation is predominantly Type I, with subordinate Type III, consistent with published geochemical fingerprinting studies [7,56]. This composition explains the modeled oil-to-gas proportions (Figure 8b) and aligns with observations from comparable lacustrine source rock systems worldwide [57,58].

4.5. Model Sensitivity and Reliability

Thermal calibration was performed by comparing measured downhole temperatures and vitrinite reflectance (%Ro) data with modeled present-day values. Modeled temperatures were interpolated to measured depths to allow direct statistical comparison.

Temperature calibration yields an RMSE of 14.17 °C and an MAE of 13.59 °C, with a positive mean residual (+13.59 °C indicating lower modeled subsurface temperatures compared to measured temperature from TRC well. This error margin still lies within the threshold for frontier basins (<10–20 °C) such the south Lake Albert Basin [59,60]. It should also be acknowledged that the location of the modeled well extract lies approximately 14 km from the calibration well, which is situated near hot spring occurrences (~15–20 km). Localized geothermal effects may therefore elevate measured temperatures relative to the regional thermal regime represented in the model.

Maturity calibration yields an RMSE of 0.1403 %Ro and an MAE of 0.1238 %Ro. These deviations are within an acceptable range for basin modeling [15] and do not significantly affect the interpreted position of the oil window or the timing of hydrocarbon generation.

Another important consideration is that, although the absolute error in temperature exceed the commonly accepted optimal threshold (<10 °C), deviations of this magnitude are not unusual in frontier rift basins, where uncertainties in heat-flow evolution, erosion magnitude, and lithological thermal properties remain significant. Figures 9 and 10 display graphical comparisons of measured and modeled temperature and vitrinite reflectance (VR), providing a basis for model calibration and uncertainty assessment.

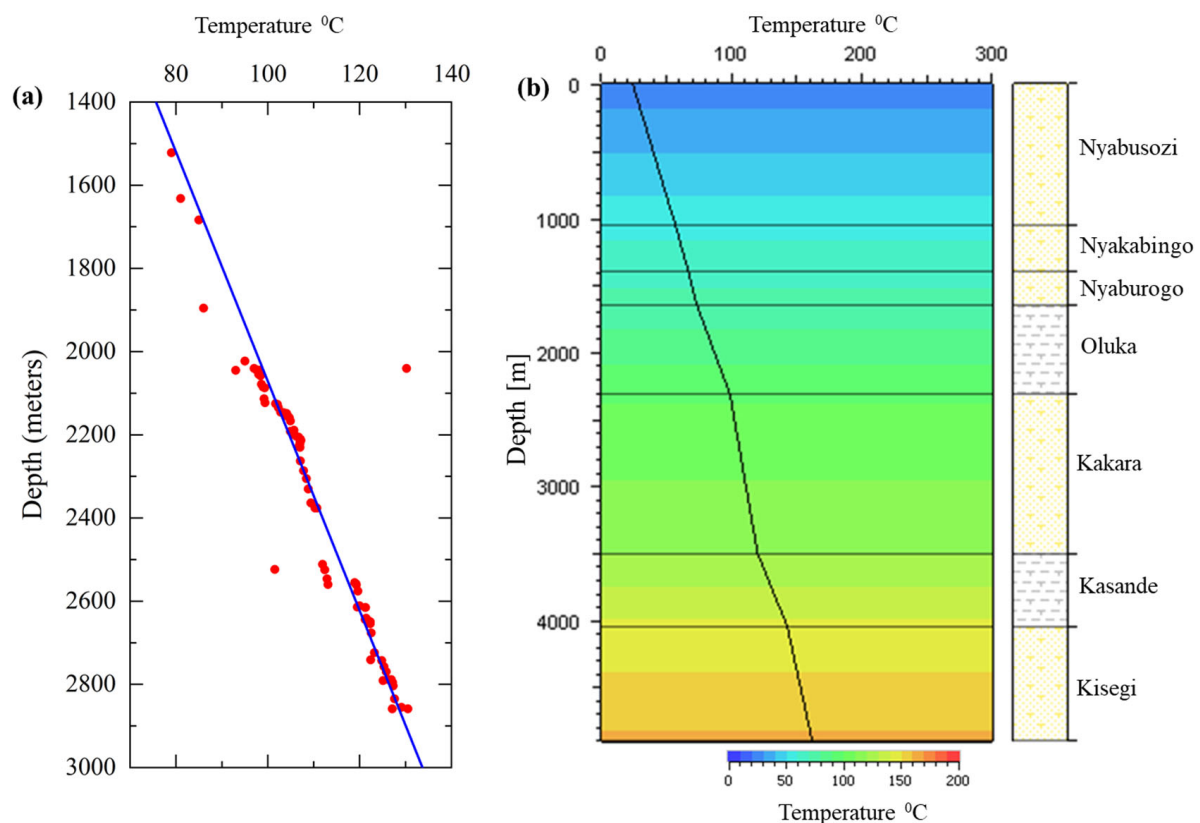


Figure 9. (a) Measured temperature from a calibration well. (b) Modeled temperature at the NW end of the model.

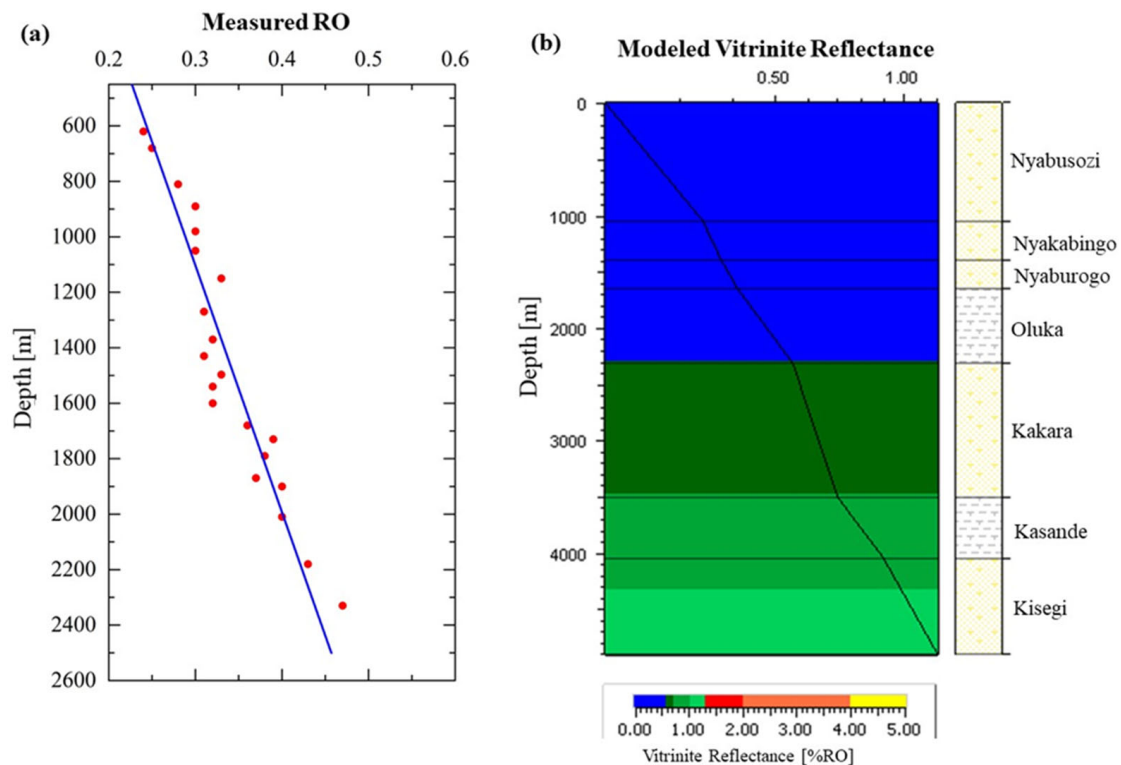


Figure 10. (a) Measured Vitritine reflectance from a calibration well. (b) Modeled Vitritine reflectance from the well extracted at the NW end of the model.

5. Conclusions

This study offers valuable insights into the subsurface conditions and petroleum system of the Southern Lake Albert Rift Basin using 2D Basin and Petroleum Systems Modeling. The results indicate the presence of a viable source–trap configuration and suggest potential zones of hydrocarbon accumulation. Modeled burial, thermal maturity, and migration pathways imply that post-maturation vertical migration into the Miocene Kisegi and Kakara sandstone reservoirs was primarily influenced by fault systems with variable sealing capacities. The spatial distribution of modeled accumulations highlights the importance of proximity to mature source intervals and structurally favorable fault geometries as key controls on hydrocarbon prospectivity. Porosity evolution and thermal history simulations suggest conditions that are generally consistent with hydrocarbon generation, migration, and accumulation within the modeled section. These results are fundamental to understanding the basin’s petroleum prospectivity but remain suboptimal due to uncertainties associated with limited datasets such as thermal boundary conditions, source rock parameters, and structural simplifications inherent in two-dimensional analysis. Accordingly, the model represents an initial two-dimensional geologic and petroleum system framework constrained with limited data availability that may be further refined with higher-resolution data and three-dimensional modeling. Nevertheless, this study constitutes an important step toward constraining petroleum system evolution and reducing exploration uncertainty in this frontier lacustrine rift setting.

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Data Availability Statement: The datasets (e.g., seismic, wireline logs, well reports) used in this study are a confidential property of the government of Uganda and can only be availed with permission.

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