Irish Interdisciplinary Journal of Science & Research (IIJSR)
Volume 9, Issue 1, Pages 01-12, January-March 2025

Organic Geochemical Evaluation of Hydrocarbon Potential and Thermal Maturity of Source Rock in Well #A1 Located in Greater Ughelli DepoBelt Niger Delta, Nigeria

Oghogho Oghosa Oriakhi[1*] & Francis Samuel Okosun[2]

[1]Department of Urban and Regional Planning, University of Central Florida, United States. [2]Department of Physics and Geology, University of Perugia, Italy. Corresponding Author (Oghogho Oghosa Oriakhi) Email: oghogho.oriakhi@ucf.edu[*]

DOI: https://doi.org/10.46759/IIJSR.2025.9101

Article Received: 05 December 2024 *Article Accepted: 12 February 2025* *Article Published: 21 February 2025*

ABSTRACT

There have been many discussions about the source rock for petroleum in the Niger Delta region of Nigeria. A few of these previous works have been reviewed based on organic matter content and type. This research overviews the hydrocarbon generation potential of the source rock accessed by drill, subjecting the samples to organic geochemical techniques. Rock-eval VI pyrolysis and Total Organic Carbon content (TOC) were utilized to study the shale's organic matter quantity, quality, and thermal maturity. Five (5) ditch-cutting samples with intervals 7655-7670 (Ft.), 7805-7820 (Ft.), 8300-8315 (Ft), 8360-8375 (Ft.), and 8960-8975 (Ft.), characterized by grey, non-calcareous shales were studied. The organic richness accessed based on TOC suggested poor to good potential, the genetic potential (Gp) and hydrogen index value range from 0.11- 0.27 mgHC/g rock and 35 - 86 mgHC/g, indicating the sediments have poor rock potential with little or no oil generation capacity but varying potential for gas. The organic matter type was evaluated using hydrogen and oxygen indices, and a plot of HI against Tmax demonstrates three (3) Type IV and two (2) Type III kerogen. The studied intervals for well #A1 indicate a high source capacity to generate gas and poor petroleum potential.

Keywords: Greater Ughelli DepoBelt; Hydrocarbon Potential; Total Organic Carbon (TOC); Thermal Maturity; Niger Delta Basin; Source Rock; Caustic Wedge; Aulacogen; Kerogen; Regression; Over-pressure; Non-Calcareous Shale.

1.0. Introduction

The study area lies within the Greater Ughelli Depo belt, Niger Delta sedimentary basin of southern Nigeria. The sedimentary sequence of the well shows changes in lithological characteristics (facies) or properties in the samples collected. Based on organic-matter content and type, [1] used αβ−hopanes and oleananes to fingerprint crude concerning their source and proposed that the shales of the paralic Agbada formation sourced the oil on the eastern side of the delta while the Akata and marine-paralic (Agbada formation) sourced on the western side of the delta. [2] further constrained this hypothesis using geochemical maturity indicators, including vitrinite reflectance data, showing that rocks younger than the deeply buried lower parts of the paralic sequence are immature. Source rocks are sedimentary rocks that are, or may become, and may have the potential to generate petroleum [3]. They form one of the necessary elements of a working petroleum system. They are organic-rich sediments deposited in various environments, such as deep-water marine, lacustrine, and deltaic environments.

Studies on the Tertiary Niger Delta have revealed three lithostratigraphic units [4] which are from bottom to top. The Akata Formation, which underlies the entire delta, is dominantly of overpressure shale with age Paleocene to Recent. The Agbada formation is a paralic sequence of interbedded sandstones and shale, and its age is Eocene to recent. Benin formation is composed of coarse grain sand with gravelly admixtures, clay, and silts and is also called continental sandstone. The age of the sediment is Miocene to recent.

1.1. Objectives of the Study

This study's objectives are: (1) To ascertain the hydrocarbon generation potential of the source rock, (2) To identify facie types and analyze the characteristics of the sample, (3) To determine the organic matter type of the shale samples, (4) To determine the quantity of the shale samples' organic matter (organic richness), and (5) To define the thermal maturity of the source rock or main hydrocarbon generation zones.

1.2. Location of Well #A1

The #A1 Well is a drilled deep well located in the Greater Ughelli Depo belt of the Niger Delta basin.

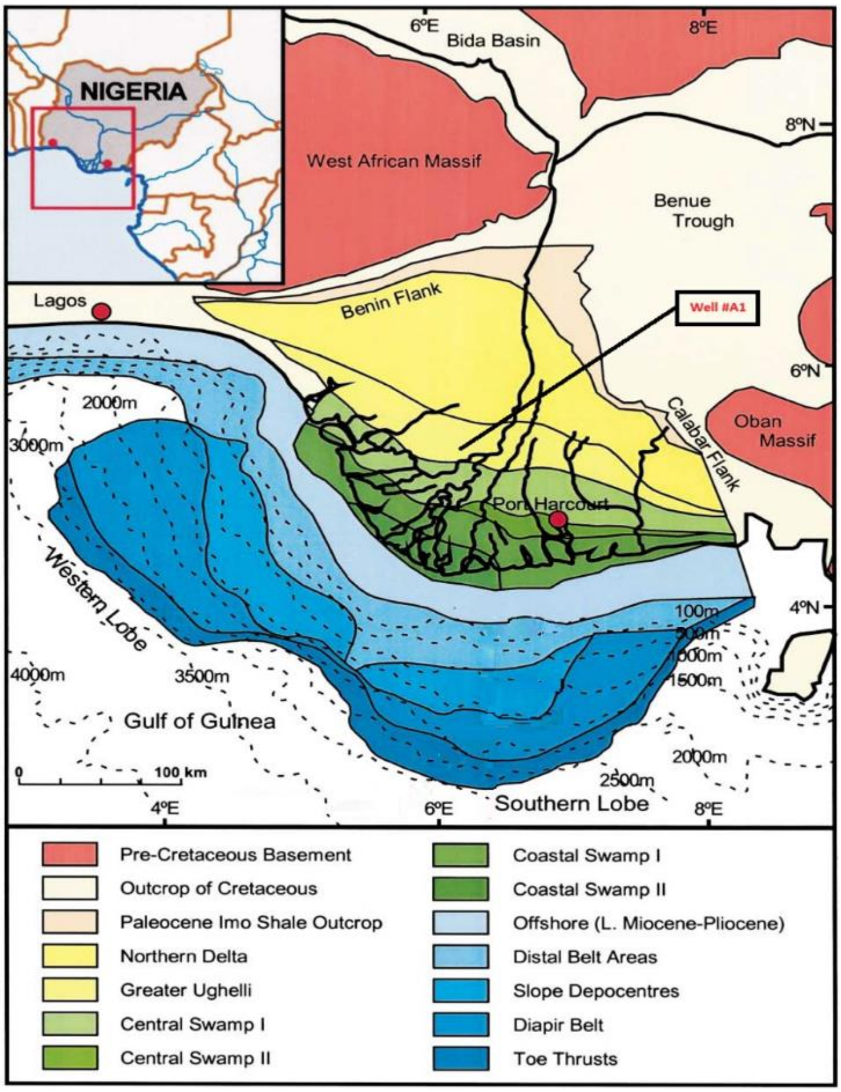

Figure 1. Location Map of Well #A1 in the Depo Belt of the Niger Delta [5]

1.3. Stratigraphy of the Niger Delta

The Niger Delta caustic wedge formed along a failed arm of a triple junction system (aulacogen) that originally developed during the breakup of the South American and African plates in the late Jurassic [6],[7]. The two arms that followed the southwestern and southeastern coast of Nigeria and Cameroon developed into the passive continental margin of West Africa. In contrast, the third failed arm formed the Benue Trough. Other depocenters along the African Atlantic coast also contributed to deltaic build-ups (Figure 2). Although the stratigraphy of the Niger Delta clastic wedge has been documented during Oil exploration and production, most stratigraphic schemes remain proprietary to the major oil companies operating concessions in the Niger Delta Basin. The stratigraphic evolution of the tertiary Niger Delta and underlying Cretaceous strata is described by [4]. The Petroleum Geology of the Niger Delta is represented in [8],[9],[10]. [11] developed a hydrocarbon habitat model for the Niger Delta based on sequence stratigraphic methods. [12],[13] described depositional Environments, sedimentation, and physiography of the modern Niger Delta. The three major lithostratigraphic units defined in the subsurface of the Niger Delta (Akata, Agbada, and Benin Formations, Figure 2) decrease in age basin-ward, reflecting the overall regression of depositional environments within the Niger Delta clastic wedge. Stratigraphic equivalent units to these three formations are exposed in Southern Nigeria.

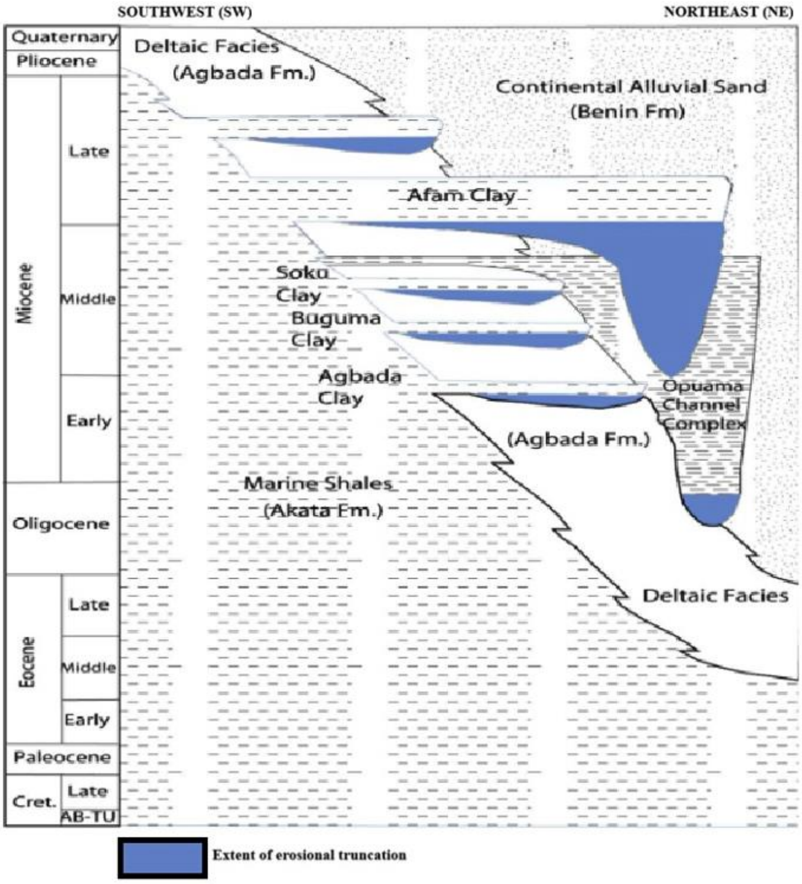

Figure 2. Stratigraphic column showing the three Formations of the Niger Delta, the Marine Akata shale, the paralic Agbada formation, and the continental Benin sandstone [10] Modified from [9]

1.3.1. Akata Formation

The formation underlies the entire delta and forms the lowermost unit. It is a uniform shale development consisting of dark grey, sandy, silty shale with plant remains at the top. The Akata formation is typically over-pressured and believed to have formed during low stands when terrestrial organic matter and clays were transported to deep water areas characterized by low energy conditions and oxygen deficiency [11]. It is over 4000 ft thick and ranges in age from Eocene to Recent and is believed to have been deposited in front of the advancing delta.

1.3.2. Agbada Formation

The formation is a sequence of sandstones and shales, with sandstone dominant in the upper unit and thick shales in the lower unit. It is very rich in microfauna at the base, decreasing upwards, suggesting an increase in deposition rate at the delta front. The grains are coarse and poorly sorted, indicating a fluviatile origin. The Agbada formation

Irish Interdisciplinary Journal of Science & Research (IIJSR)
Volume 9, Issue 1, Pages 01-12, January-March 2025

covers the entire subsurface of the delta and may be continuous with the Ogwashi-Asaba and Ameki formations of the Eocene -Oligocene age. It is over 10,000 ft thick and is the major hydrocarbon-bearing unit in the delta.

1.3.3. Benin Formation

The formation comprising over 90% sandstone with shale intercalations, extends from the west across the entire Niger Delta area and southward beyond the present coastline. The thickness, though variable, is estimated at 6000 ft. It is coarse-grained, gravelly, poorly sorted, sub-angular to well-rounded, and bears lignite streaks and wood fragments. The formation is characterized by structural units such as channel fills, point bars, etc., which indicate the variability of the shallow water depositional medium. The Benin Formation is thicker in the central onshore part of the delta, where it reaches about 2,000 ft [14] and thins outwards towards the delta margins. The Benin formation, with very little hydrocarbon accumulation, ranges in age from Miocene to recent.

2.0. Methods and Materials

Five (5) ditch-cutting samples and five shale facies were obtained from Well #A1. The samples were collected at different depths and analyzed for lithofacies description using rock-eval pyrolysis, TOC content, and sedimentology. Ditch-cutting samples collected from the well were prepared and labeled, indicating the name and depth of the well.

2.1. Sedimentology

A total of FIVE (5) ditch-cutting samples were collected from the well, and lithological description using a reflected light microscope to obtain Physical characteristics such as color, texture, hardness, fissility, shapes/roundness, mineral composition, and post-depositional diagenetic effect, etc. were noted. 10% of HCl Chemical tests were used to determine the presence of calcareous materials. These properties are vital for the analysis of lithofacies. Consequently, the well's sedimentary succession was generated by a geological model embracing lithofacies, associated minerals, and heterogenetic and homogenetic zones. The lithofacies units present are Shale. The five studied intervals with depths 7655-7670 (Ft.), 7805-7820 (Ft.), 8300-8315(Ft), 8360-8375 (Ft.), 8960-8975(Ft.) are shales, Grey in color and non-calcareous.

Table 1. Lithostratigraphic Model of the Well Penetrated by the Drill (Well #A)

LITHOSTRATIGRAPHIC MODEL OF THE WELL PENETRATED BY THE DRILL (B1-WELL)

S/N	DEPTH[FEET]	LITHOLOGY	MUD (CLAY, SILT) / SAND (V/F, F, M, C, V/C) / GRAVEL (GRANUL, COBBLE, boulder)	TEXTURE: Grain Size and other notes[structures,fossils,colours]	LITHOFACIES	SHALE/SAND PERCENTAGE	LITHOZONE	ASSOCIATED MINERALS	ASSOCIATED MINERAL UNITS	HETEROGENETIC ZONE	HOMOGENETIC ZONE
1	8440			Grey fissile shale.Non calcareous	Shale	Shale(100%)		mica	1	Nil	
2	8564			Grey fissile shale.Non calcareous	Shale	Shale(100%)		Nil	Nil	Nil	
3	8604			Grey fissile shale.Non calcareous	Shale	Shale(100%)	1	Nil	Nil	Nil	1
4	10687			Grey fissile shale.Non calcareous	Shale	Shale(100%)		Nil	Nil	Nil	
5	10961			Grey fissile shale.Non calcareous	Shale	Shale(100%)		Nil	Nil	Nil	

KEYS

SHALE

2.2. Rock-Eval Pyrolysis

The hydrocarbon generation potential, maturity, type of kerogen, and Hydrogen Index (HI) values were determined using DELSI –NERMAG Rock-Eval II PLUS TOC MODULE. The sample chosen to be measured on the Rock-Eval is usually subsurface from freeze-dried material previously crushed for analyses on the coulometer and CNS. The Rock-Eval pyrolysis method consists of a programmed temperature heating (in a pyrolysis oven) in an inert atmosphere (helium) of a small sample (100mg) to quantitatively and selectively determine the free hydrocarbons present in the sample, and the hydrocarbon and oxygen-containing compounds (HCO2) that are volatilized during the cracking of the un-extractable organic matter in the sample (kerogen). During the pyrolysis process, the oven is kept isothermally at 300°C for 3 minutes, and the free hydrocarbons are volatilized and measured as the S1 peak (detected by Flame Ionization Detector] P87FID). The temperature is then increased from 300°C to 550°C (at 25°C/min). This is the phase of volatilization of the very heavy hydrocarbon compound (>C40) as well as the cracking of non-volatile organic matter. The hydrocarbon released from this thermal cracking is measured as the S2 peak. The temperature at which S2 reaches its maximum depends on the nature and maturity of the kerogen and is called Tmax. The CO_2 issued from kerogen cracking is trapped in the 300°- 390°C range. The trap is heated, and CO2 is released and detected on a TCD during the cooling of the pyrolysis oven (S3 peak). S1= the number of free hydrocarbons (gas and oil) in the sample (in milligrams of hydrocarbon per gram of rock). If S1 >1 mg/g, it may be indicative of an oil show. S1 normally increases with depth. Contamination of samples by drilling fluids and mud can give an abnormally high value for S1.

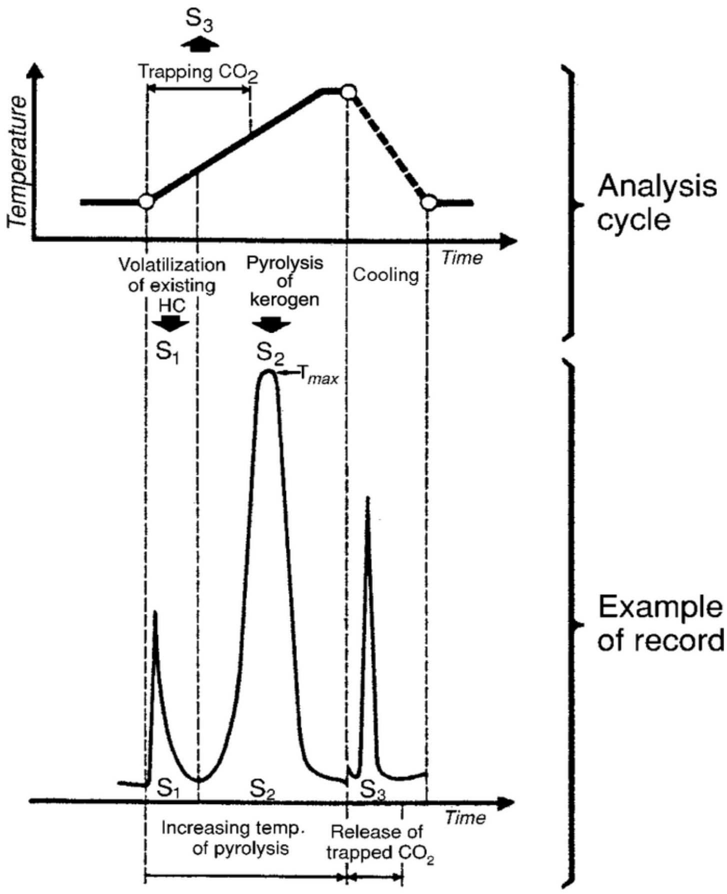

Figure 3. Cycle of analysis and the corresponding recording [3]

Irish Interdisciplinary Journal of Science & Research (IIJSR)
Volume 9, Issue 1, Pages 01-12, January-March 2025

2.3. Source Rock Potential (S2)

This is the amount of hydrocarbon generated through the thermal cracking of nonvolatile organic matter, S2 indicates the quality of hydrocarbons that the rock has the potential to produce should burial and maturation continue. This parameter normally decreases with depth >1km.

2.4. Source Rock Potential (S3)

This is the amount of CO_2 (in milligrams of CO_2 per gram of rock) produced during the pyrolysis of kerogen. S3 indicates the amount of oxygen in the kerogen and is used to calculate the oxygen index. Contamination of the sample should be suspected if abnormally high S3 values are obtained.

2.5. Tmax

The temperature at which the maximum release of hydrocarbon from cracking of kerogen occurs during pyrolysis (top of S2 peak). Tmax is an indication of the stage of maturation of the organic matter.

3.0. Results and Discussions

3.1. Total Organic Carbon (TOC) and Source Rock Richness

Five (5) samples comprising five (5) shales were collected from well #A1, washed, pulverized, and analyzed for Total Organic Carbon (TOC) using a DELSI –NERMAG PLUS TOC MODULE analyzer. Approximately 100mg of each sample was used, and the standard pulverization and hydrochloric acid (HCl) treatment for carbonate removal was utilized before measurement.

Table 2. Organic carbon contents and rock-eval pyrolysis data analysis for shale samples #A1 Well

Sample	**TOC (wt.%)**	**S1 (mgHC/g)**	**S2 (mgHC/g)**	**S3 (mgCO$_2$/g)**	**GP (S1+S2)**	**Tmax (^{o}C)**	**PI**	**HI (mgHC/g)**	**OI (mgCO$_2$/g)**
7655-7670	0.17	0.05	0.06	0.24	0.11	413	1.06	35	141
7805-7820	1.22	0.06	0.1	0.28	0.16	421	1.1	8	23
8300-8315	0.17	0.08	0.1	0.25	0.18	435	1.1	59	147
8360-8375	1.13	0.04	0.06	0.19	0.1	415	1.06	5	16
8960-8975	0.22	0.08	0.19	0.27	0.27	0	1.19	86	123

Table 3. Organic matter calculations

Hydrogen Index (HI)	(S2/TOC)×100
Oxygen Index (OI)	(S3/TOC)×100
Production Index (PI)	S1/(S1+S2)
Vitrinite Reflectance (RC)	0.0180×Tmax–7.16

Irish Interdisciplinary Journal of Science & Research (IIJSR)
Volume 9, Issue 1, Pages 01-12, January-March 2025

Table 4. Organic matter measurements interpretation

TOC	Total Organic Carbon
HI	Hydrogen Index
PI	Production Index
RC	Vitrinite Reflectance
MgHC/g	Milligram Hydrocarbon per gram
MgCo2/g	Milligram carbon dioxide per gram
Tmax	Maximum Temperature
OI	Oxygen index
GP	Genetic Potential
MgC/g	Milligram carbon per gram
Weight %	Weight Percentage

3.2. Source Rock Richness

The organic matter richness of source rocks is usually determined using the total organic carbon content, which is the total amount of organic material (kerogen) present in the rock, expressed as a percentage by weight (TOC wt.%). By and large, the higher the TOC, the better the chance and potential for hydrocarbon generation. The TOC values between 0.5 and 1.0% indicate a fair source-rock generative potential, TOC values varying from 1.0 to 2.0% reflect a good generative potential, whilst values between 2.0 and 4.0% refer to a very good generative potential, and rocks with TOC greater than 4.0% are considered to have excellent generative potential.

Based on this criterion, the TOC results of rock samples in this study reveal that three (3) of the samples have poor hydrocarbon-generating potential, and two (2) of them have good hydrocarbon-generating potential regarding their TOC values, as shown in the table below.

Table 5. Total organic carbon interpretation of the sampled interval

Sample	**TOC (wt. %)**	**Interpretation**
7655-7670	0.17	POOR
7805-7820	1.22	GOOD
8300-8315	0.17	POOR
8360-8375	1.13	GOOD
8960-8975	0.22	POOR

Irish Interdisciplinary Journal of Science & Research (IIJSR)
Volume 9, Issue 1, Pages 01-12, January-March 2025

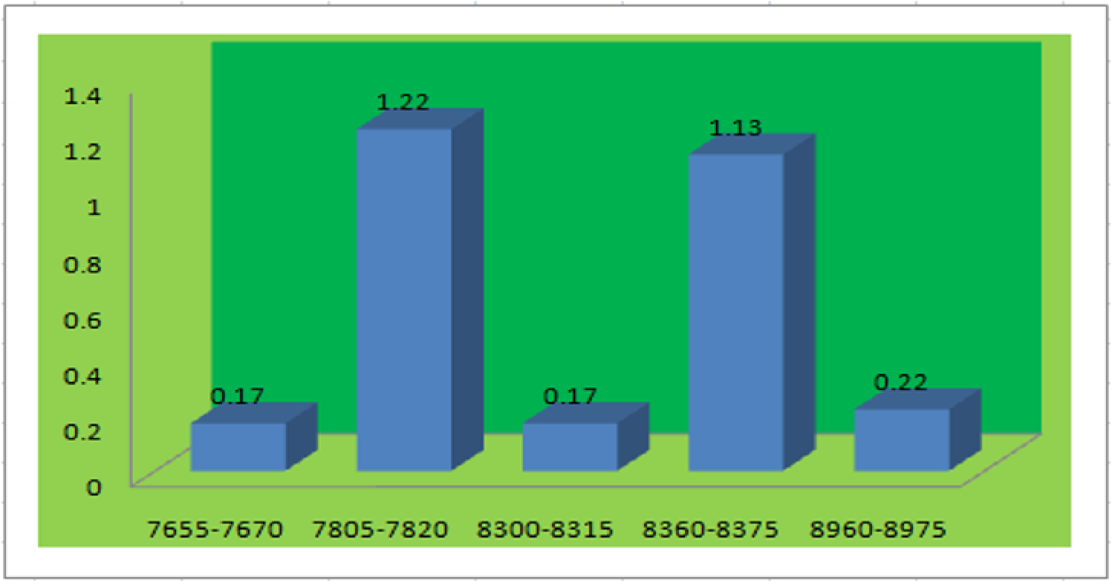

Figure 4. Histogram showing TOC values for the five (5) samples

3.3. Organic Matter Type/Organic Matter Quality

Type I kerogen: They are hydrogen-rich HI greater than 600 mg HC/g TOC, and this is predominantly oil-prone. They are mainly generated by algae structureless debris.

Type II Kerogen: They are characterized by HI between 350 and 600 mg HC/g TOC, and this can generate both oil and gas at appropriate levels of maturity. They are mainly generated by structureless planktonic and microbial materials, primarily of marine organisms.

Type III Kerogen: Characterized by low to moderate HI of between 75 and 200 mgHC/g TOC and could generate gas at the appropriate level of thermal maturity. However, humic coals (with Type III kerogen) may have HI up to 300 mgHC/g TOC and possess the capacity to generate oil. They are mainly generated by plant materials.

Type IV Kerogen: Exhibits very low HI, less than 50 mgHC/g TOC, and is formed under oxic (wildfire) conditions. [16] suggested that at a thermal maturity corresponding to a vitrinite reflectance of 0.6% (Tmax 435°C). Rocks with HI above 300 mg HC/g TOC will produce oil; those with HI between 300 and 150 will produce oil and gas; those with HI between 150 and 50 will produce gas, and those with HI less than 50 are inert.

Table 6. Guidelines for accessing the richness of kerogen type after [16]

Kerogen Type	**Mg HC/g TOC**	**S2/S3**
I	>600	>15
II	300-600	10-15
II/III[b]	200-300	5-10
III	50-200	1-5
IV	<50	<1

Table 7. Hydrogen Index (HI) Interpretation

Sample	HI (mgHC/g)	Interpretation
7655-7670	35	TYPE IV
7805-7820	8	TYPE IV
8300-8315	58	TYPE III
8360-8375	5	TYPE IV
8960-8975	86	TYPE III

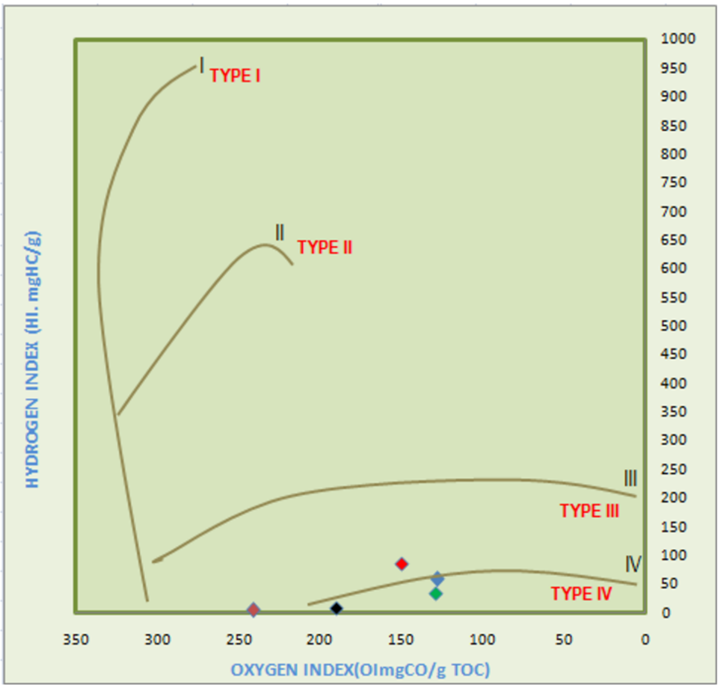

Figure 5. Diagram Showing Organic Matter Type Modified after [17]

3.4. Thermal Maturity

Table 8. Guidelines for accessing the thermal maturity of the source rock [16]

Stage of Thermal Maturity for Oil	Maturation		
	R_o °C	**Tmax (°C)**	**PI ($S_1/(S_1+S_2)$)**
Immature	0.2-0.6	<435	<0.10
Mature			
Early	0.6-0.65	435-445	0.10-0.15
Peak	0.65-0.9	445-450	0.25-0.40
Late	0.9-1.35	450-470	>0.40
Postmature	>1.35	>470	-

Table 9. Interpretation of the sample's thermal maturity

Thermal Maturity			**Interpretation**
SAMPLE	Tmax °c	Ro	Maturity Level
7655-7670	413	0.274	Immature
7805-7820	421	0.418	Immature
8300-8315	435	0.67	Peak mature
8360-8375	415	0.31	Immature
8960-8975	0	Undefined	Immature

4.0. Environment of Deposition

Terrestrial organic matter such as pollen, spores, and cuticles (Type III & IV kerogen) is formed from higher terrestrial plant matter lacking lipids or waxy matter. It forms from cellulose, the carbohydrate that forms the rigid structure of terrestrial plants, and lignin, a non-carbohydrate polymer formed from phenyl-propane units that bind the strings of cellulose together. Terpenes and phenolic compounds present in the plant of the samples suggest the continental environment of deposition.

5.0. Conclusion

The organic geochemical analysis of Well #A1, located in the Greater Ughelli Depo belt, investigated lithofacies, organic richness, source rock quality (kerogen type), hydrocarbon potential, and thermal maturity. The five studied intervals with depths 7655-7670 (Ft.), 7805-7820 (Ft.), 8300-8315(Ft), 8360-8375 (Ft.), 8960-8975 (Ft.) are shales, Grey in color and non-calcareous. The richness of organic matter suggests poor to good source rock potential. The genetic potential (GP) value indicates S1+S2< 2.0mgHC/g, which means that sediments have poor source rock potential (little or no oil potential but some potential for gas). The type of organic matter evaluated using hydrogen and oxygen indices and a plot of HI against Tmax shows Type III and Type IV kerogen, respectively. Thermal maturity of the sample deduced from vitrinite reflectance calculated and Tmax suggest that one (1) of the sample has a value ≥435°c for Tmax and Ro >0.65% is matured for 8300-8315 (Ft), whereas three (3) of the sample intervals had Tmax < 435°c and Ro <0.65% indicating immaturity 7655-7670 (Ft.), 7805-7820 (Ft.), 8360-8375 (Ft.), 8960-8975(Ft.). A continental environment was suggested due to the presence of Type IV and Type III kerogen in the selected samples from well #A1, which were investigated for lithofacies, organic richness, source rock quality (Kerogen Type), Hydrocarbon Potential, and Thermal Maturity. The richness of source rocks was determined using the total organic carbon content, the total amount of organic material (kerogen) present in the rock, expressed as a percentage by weight (TOC wt.%). The higher the TOC, the better the chance and potential for hydrocarbon generation. The TOC values between 0.5 and 1.0% indicate a fair source-rock generative potential, TOC values varying from 1.0 to 2.0% reflect a good generative potential, whilst values between 2.0 and 4.0% refer to an excellent generative potential, and rocks with TOC greater than 4.0% are considered to have excellent generative potential. Based on this criterion, the TOC results of rock samples in this study reveal that three (3) of the samples have poor Hydrocarbon-generating Potential, and two (2) of them have good Hydrocarbon-generating Potential regarding their TOC values. Type IV kerogen contains mostly decomposed organic matter in polycyclic aromatic hydrocarbons with no potential to produce hydrocarbons, often referred to as inert in the endmember on the hydrocarbon generative spectrum. The studied intervals for well #A1 indicate a high source capacity to generate gas and poor petroleum potential. Based on the findings, given that the studied intervals show a high potential for gas generation due to the presence of Type III and Type IV kerogen, it would be beneficial to focus on **gas exploration and production** rather than oil by further probing and investigating the **gas-bearing zones**. Continued studies to further determine the organic matter's thermal maturity, especially in the deeper sections, are recommended to verify whether the kerogen types could evolve further toward oil generation under varying conditions. Further studies should be carried out through regional geology investigations to re-evaluate and correlate the kerogen types laterally for potential petroleum zones or if other areas may show favorable conditions for oil generation.

Declarations

Source of Funding

This study did not receive any grant from funding agencies in the public, commercial, or not-for-profit sectors.

Competing Interests Statement

The authors declare no competing financial, professional, or personal interests.

Consent for publication

The authors declare that they consented to the publication of this study.

Authors' contributions

Both the authors took part in literature review, analysis, and manuscript writing equally.

Acknowledgments

Author’s sincere appreciation goes out to Dr. Ilesanmi for their unwavering support and persistent encouragement to complete this study. Also, author is grateful to his co-author for his invaluable contribution to ensuring the success of this work. Overall, thanks to almighty God for his wisdom and understanding.

References

[1] Ekweozor, C.M., Okogun, J.I., Ekong, D.E.U., & Maxwell J. (1979). Preliminary organic geochemical studies of samples from the Niger Delta (Nigeria). Analyses of shale for triterpenoid derivatives, Chemical Geology, 27(2): 29–37. https://doi.org/10.1016/0009-2541(79)90101-3.

[2] Ekweozor, C.M., & Okoye, N.V. (1980). Petroleum Source-Bed Evaluation of Tertiary Niger Delta. American Association of Petroleum Geologists Bulletin, 64: 1251–1259. https://doi.org/10.1306/2f919472-16ce-11d7-86450 00102c1865d.

[3] Tissot, B.P., & Welte, D.H. (1984). Petroleum Formation and Occurrence (2nd Eds.). Springer Verlag, Berlin.

[4] Short, K.C, & Stauble, A.D. (1967). Outline of the Geology of the Niger Delta. AAPG Bulletin, 51: 761–79.

[5] Hooper, R.J., Fitzsimmons, R.J., Grant, N., & Vendeville, B.C. (2002). The role of deformation in controlling depositional patterns in south-central Niger Delta, West Africa. Journal of Structural Geology, 24: 847–859. https://doi.org/10.1016/s0191-8141(01)00122-5

[6] Burke, K. (1972). Longshore drift, submarine canyons, and submarine fans in the development of the Niger Delta. American Association of Petroleum Geologists, 56: 1975–1983.

[7] Whiteman, J. (1982). Nigeria: Its Petroleum Geology Resources, and Potential. Geology, Environmental Science. https://doi.org/10.1007/978-94-009-7361-9.

[8] Evamy, B.D., Haremboure, J., Kamerling, W.A., Knaap, F.A., & Rowlands P.H. (1978). Hydrocarbon habitat of Tertiary Niger Delta. AAPG Bulletin, 62(1): 1–39. https://doi.org/10.1306/c1ea47ed-16c9-11d7-8645000102c1865d.

[9] Doust, H., & Omatsola, E., (1990). Niger Delta. In Edwards, J.D., & Grossi, P.A. (Eds.). Divergent/Passive Margin Basins, AAPG Memoir, 48: 239–248.

[10] Tuttle, M.L.W., Charpentier, R.R., & Brownfield, M.E. (1999). The Niger Delta petroleum system: Niger Delta Province, Nigeria, Cameroon, and Equatorial Guinea, Africa. USGS, Open-File Report 99-50-H. https://doi.org/10.3133/ofr9950h.

[11] Stacher, P. (1995). Present Understanding of the Niger Delta hydrocarbon habitat. In Oti & Postma (Eds.), Geology of Deltas: Rotterdam, A.A. Balkema, Pages 257–267.

[12] Allen, V.L. (1965). Conformity and the Role of Deviant. Journal of Personality, 33(4): 584–597. https://doi.org/10.1111/j.1467-6494.1965.tb01404.x.

[13] Omkens, E. (1974). Lithofacies relations in the Late Quaternary Niger Delta Complex. Journal of International Association of Sedimentologists, 21(2): 195–222. https://doi.org/10.1111/j.1365-3091.1974.tb02 056.x.

[14] Avbovbo, A.A. (1978). Tertiary lithostratigraphy of Niger Delta. Assoc. of Petr. Geol. Bulletin, 62: 295–306. https://doi.org/10.1306/c1ea482e-16c9-11d7-8645000102c1865d.

[15] Tissot, B.P., & Welte, D.H. (1984). Petroleum Formation and Occurrence (2nd Eds.). Springer Verlag, Berlin.

[16] Peters, K.E., & Cassa, M.R. (1994). The Petroleum System: From Source to Trap, Applied Source Rock Geochemistry. AAPG Special Volumes, Pages 93–120.

[17] Krevelen, V.D.W. (1950). Coal Typology, Chemistry, Physics, Constitution (1st Eds.). Elsevier Publishing Company: Amsterdam, The Netherlands, Pages 45.