Chapter

Perspective Chapter: Understanding Thermal Maturity Evolution and Hydrocarbon Cracking – Implication for Cretaceous Awgu and Nkporo Shales, Southeastern Nigeria

Jerry Danwazan, Adesina Mutiu Adeleye, Trust-Paul Bakyu, Mamidak M. Iliya and Joseph Kehinde Egunjobi

Abstract

One-dimensional basin modeling was carried out using Schlumberger's PetroMod modeling software that provided understanding on the thermal evolution, timing of hydrocarbon generation and expulsion of the Coniacian Awgu Shale and the Campanian Nkporo Shale penetrated by Nzam-1 and Akukwa-2 wells in the lower Benue Trough, Nigeria. The burial temperature and vitrinite reflectance values ranged from 30 to 145°C and 0.5 to 2.9%Ro for Awgu Formation, 28 to 125°C and 0.5 to 1.5%Ro for Nkporo Formation in Nzam-1 well model; 29.5 to 145°C and 0.8 to 2.4%Ro for Awgu Formation, and 28.5 to 95°C and 0.6 to 0.8%Ro for Nkporo Formation in Akukwa-2 well model. Awgu Shale reached the required threshold of the oil generation window during mid Campanian (75Ma) and late Santonian (82Ma) in Nzam-1 and Akukwa-2 well models, respectively. Nkporo Shale entered the required oil window threshold during early Paleocene (65Ma) in Nzam-1 well model and late Maastrichtian (67Ma) in Akukwa-2 well model. This study revealed that valid petroleum system elements exist in Anambra basin, and some amount of gaseous hydrocarbons and little oil may have been generated and expelled. Exponential decrease in temperature over time has favored the preservation of the gas reservoirs and the survival of hydrocarbons in the deep strata. The early maturity of Nkporo Shale can be attributed to lack of the requisite burial depth, temperature and pressure in favor of oil generation and expulsion. Post-maturity status of Awgu Shales may be associated with deeper burial depth and possibly due to the effect of Santonian tectonic episode.

Keywords: one dimensional modeling, transformation ratio, thermal maturity, hydrocarbon generation, Awgu and Nkporo Shales

1. Introduction

Petroleum (oil and gas) accounts for up to 95% of the Nigeria's foreign earnings and has remained the major supporter of its economy since it was first discovered in commercial quantity in 1956. Globally, petroleum as an energy source will continue to dominate other primary energy sources and is expected to account for up to 56% of the world energy demand in the year 2030 [1]. This makes source rock studies and evaluation now to be of key interest to oil industry players, the Academia and other research interest groups and as a result research has also been intensified in the Lower Benue Trough as well.

The thermal states of sedimentary basins affect hydrocarbon generation, migration, and accumulation processes, and therefore reconstructing a basin's thermal history is significant for petroleum accumulation analyses. The maturity of organic matter is primarily controlled by the temperature of the source rock [2].

We are interested in thermal evolution and hydrocarbon cracking because of its importance in modeling the oil degradation processes that compete with oil expulsion during maturation of petroleum source rock over geologic time periods.

As a source rock begins to mature, it generates hydrocarbons. As an oil-prone source rock matures, the generation of heavy oil is succeeded by medium and light oils and condensates. Above a temperature of approximately 100°C, only dry gas is generated and incipient metamorphism is imminent. The maturity of a source rock reflects the ambient temperature as the conditions favorable for hydrocarbon generation. Understanding the maturation and thermal cracking of hydrocarbon helps to define the quality of the expected products.

Following the increased interest in the exploration of petroleum resources, Assessment of generative potential and characteristics of source rocks is fundamental in hydrocarbon exploration and its success depends largely on the employed organic geochemical method and this calls for a more refined and integrated approach by both the industry and the academia so as to discover more hydrocarbon prospects and despite the fact that published data gives a vast amount of information on the geology, sedimentology, lithostratigraphy and the hydrocarbon generation potentials of the Lower Benue Trough yet of the several Geochemical approaches for source rock evaluation employed in the studied area by some of the existing works which include using vitrinite as a maturity tool; there are only but a few among these previous researches that integrated the other source rock evaluation techniques with burial history and Maturity Modelling which could have given a clearer and better understanding of the thermal evolution, hydrocarbon generation and timing of the organic matter (kerogen) in this section (Nkporo and Agwu Formations) of the Lower Benue Trough.

Ehinola [3] investigated and presented results on subsurface geological models of the Anambra basin using the Petromod Software. The models produced were based on a clear understanding of how sedimentary rocks are formed, modified and perform as source rocks, reservoirs and traps employing lithostratigraphic principles, rock mineralogy and depositional modeling. The study revealed that thermal maturity of the source rock units in Anambra basin increases toward the Abakaliki Anticlinorium and with depth towards the western part of the basin. Imo shale, Mamu Formation, Nkporo Shale, Awgu Shale, Eze-Aku shale and Asu River group reached hydrocarbon generation at 51.23, 61.42, 56.30, 66.11,84 and 92Ma respectively which show that the Asu River Group and Ezeku-Aku Formation shale commenced Hydrocarbon generation prior to the Santonian tectonism. This maybe reflected by the presence of seepages, oil and gas in the Owelli, Agwu and Eze-Aku Formation interval respectively in the Anambra Basin while the matured Post Santonian succession would generate and charge both the upper Cretaceous reservoir and possibly the sub-Niger Delta successions in the subsurface. The study also revealed that the Maastrichtian-Paleocene sediment in the South-western part of the basin maybe considered as the major strata with liquid hydrocarbon potential whereas the Pre-Santonian sediment exhibit potential for gaseous hydrocarbon.

Oluwajana [4] carried out a hydrocarbon-charge modeling and its consequence on shale gas and shale oil resource systems within the Cretaceous strata of the Anambra Basin using organic geochemical data, 2D seismic line and stratigraphic well data of exploratory wells drilled in the basin to generate conceptual models, improve understanding on hydrocarbon generation and timing, and identify potential shale plays in the basin and the study helped to identify potential shale resource system in the Anambra basin namely the upper Cenomanian–lower Turonian marine facies. Two main shale play types involving the upper Cenomanian–lower Turonian were identified.

Akaegbobi et al. [5] revealed that the organic matter in majority of Nkporo samples and few of Owelli samples can be classified as predominantly Type II-III kerogen, while the organic matter in the rest of Owelli and Mamu formation samples is majorly Type III and Type IV kerogens and further revealed that the analyzed samples were deposited in normal marine environment with samples from Mamu Formation tending towards freshwater depositional millieux".

Akaegbobi et al. [5] investigated the shales, siltstones and shale heteroliths, collected from the Nkporo, Owelli and Mamu formations of Anambra Basin were subjected to bulk and molecular geochemical analyses (total organic carbon content determination, pyrolysis analysis, bitumen extraction and gas chromatography) to provide further insight on the quantity, quality and thermal maturity of organic matter within the sediments, the source input and paleodepositional conditions of the organic matter, hydrocarbon generation potential and the study revealed that the organic matter has fair to good hydrocarbon generation potential and the majority of the analyzed sediments from Nkporo Formation are oil and gas prone, while the others are mainly gas prone. The Molecular geochemical data further suggested that the organic matter within the sediments was derived from mixed aquatic algae and land plant source input and was deposited under suboxic paleodepositional conditions.

Adeleye et al. [6] attempted to evaluate aspects of the source rock potential for hydrocarbon generation of the Imo Shale Formation penetrated by the Akukwa II and Nzam-Iwells in Anambra basin, and concluded that the sediments have potential for hydrocarbon generation with possibility of gas. Organic matter contained in the sediments is predominantly type IV kerogen sourced from terrestrial materials which does not yield significant amounts of hydrocarbon. Thermal maturity derived from Rock-eval data revealed that the Imo Formation samples are immature with respect to hydrocarbon generation.

Adeleye et al. [7] employed Total Organic Carbon (TOC) content and Rock-eval Pyrolysis to evaluate source rock potential for hydrocarbon generation of Nkporo Formation in the Lower Benue trough penetrated by Nzam-1 well and it was revealed that the sediments contain poor to fair source rock for hydrocarbon with kerogen type III as the predominating organic matter, which is capable of generating dry gas. Tmax and other pyrolysis data suggest that the organic matter in the Nkporo Formation is at the peak of thermal maturity to post maturity with respect to hydrocarbon generation.

And the study revealed that the heat energy generated from post mature part of the studied section together with the thermal maturity peak to late maturity generally observed for the sediments may have resulted in the dry gas prospect.

Adebayo et al. [8] carried out a Palynological, organic petrographic, and organic geochemical analyses of the Campanian-Maastrichtian sediments in Akukwa-2 well to infer their paleoenvironments, origin of the organic matter, and hydrocarbon generation potentials and the study revealed that the organic matter within the sediments is also likely to generate mainly gas. This is in agreement with the petrographic observations, which revealed that the analyzed shale samples contain abundant vitrinite macerals, apart from bituminite, alginite, cutinite, and resinite. Also, the sediments are immature to early mature in terms of hydrocarbon generation as indicated by vitrinite reflectance, biomarker maturity, and pyrolysis Tmax data. Biomarker distribution ratios, palynomorphs assemblage, and organic petrographic observations further point out that the organic materials within the sediments were of mixed aquatic and terrigenous origin and were deposited under suboxic paleodepositional conditions. Based on sedimentological, palynological, and biomarker characteristics, the environment of deposition of the analyzed sediments was inferred to be a relatively quiet, shallow marine with fluvial incursion, most especially at the upper part of the intervals studied and consequently, it is a delta associated depositional environment with a fluviatile influence. The sediments were therefore suggested to be deposited in a paleogeographic setting close to vegetation source.

Following the increased interest in the exploration of petroleum resources, Assessment of generative potential and characteristics of source rocks is fundamental in hydrocarbon exploration and its success depends largely on the employed organic geochemical method and this calls for a more refined and integrated approach by both the industry and the academia so as to discover more hydrocarbon prospects and despite the fact that published data gives a vast amount of information on the geology, sedimentology, lithostratigraphy and the hydrocarbon generation potentials of the Lower Benue Trough yet of the several Geochemical approaches for source rock evaluation employed in the studied area by some of the existing works which include using vitrinite as a maturity tool; there are only but a few among these previous researches that integrated the other source rock evaluation techniques with burial history and Maturity Modelling which could have given a clearer and better understanding of the thermal evolution, hydrocarbon generation and timing of the organic matter (kerogen) in this section (Nkporo and Agwu Formations) of the Lower Benue Trough.

Therefore, this current study attempts to evaluate the characteristics of the source rocks and their viability, hydrocarbon generation potential and timing, and predict the various thermal maturity levels of the possible shale plays in the Coniacian Agwu Formation and late Campanian Nkporo Formation sediments within this section of the Lower Benue Trough as penetrated by the Nzam-1 well and Akukwa-2 wells respectively. A quantitative one dimensional basin modeling was carried out for evaluating the thermal histories and timing of hydrocarbon generation and expulsion of the Coniacian and late Campanian source rocks in the part of Lower Benue Trough. More so, the reconstruction of the burial, thermal and maturity histories were modeled in order to evaluate the remaining hydrocarbon potential using Schlumberger's PetroMod (1D) modeling software so as to provide the basis for Petroleum resource evaluation of the Upper Cretaceous sediments of the basin. Also, in this study, a detail evaluation of the acquired TOC and Rock-Eval pyrolysis data was carried out which provided information on the quantity, quality and maturity of the organic matter which served as the verification for the results and interpretations from the model.

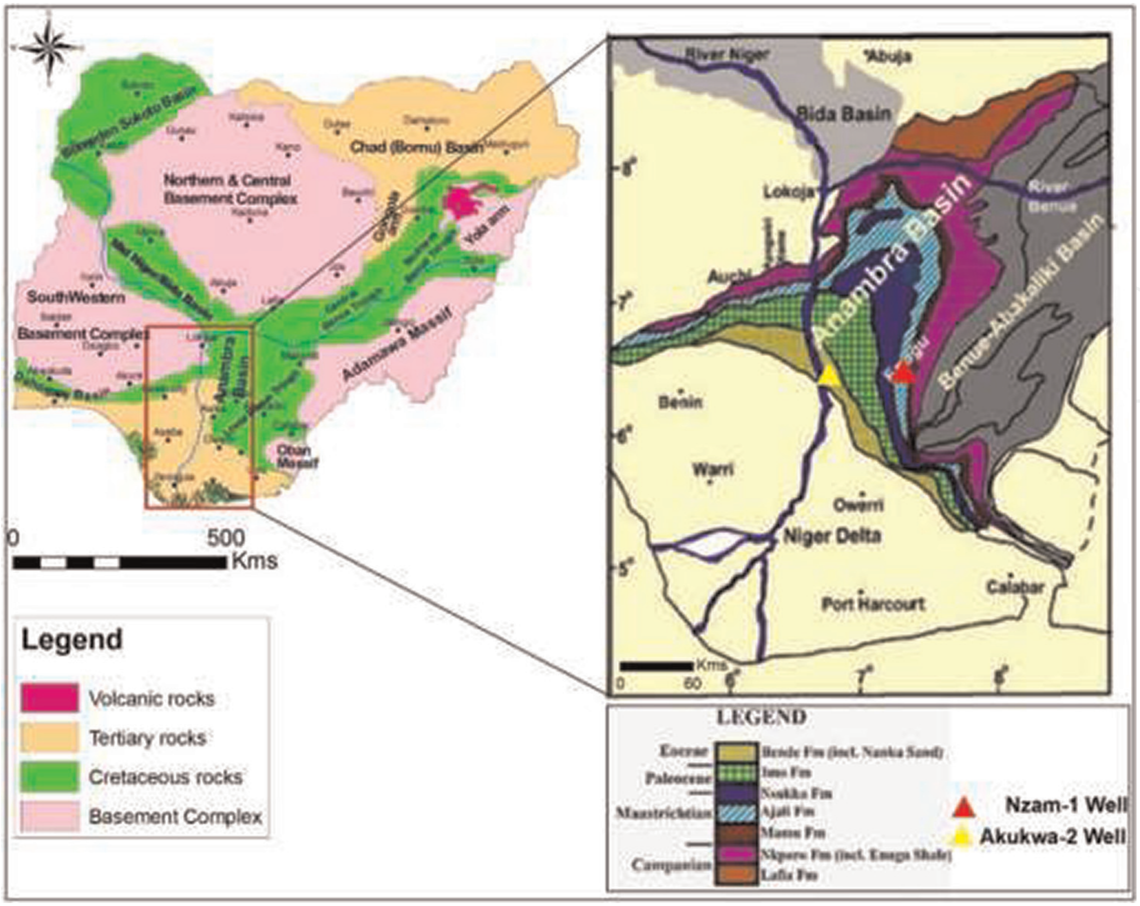

Figure 1.
A Geological map of Nigeria showing the location of the studied exploratory well, Nzam-1 [8].

The study area is carved out of the Lower Benue Trough (**Figure 1**), in South Eastern Nigeria as penetrated by the Exploratory wells, Nzam-1 and Akukwa-2. The area comprises the geographical location of the following states: Abakaliki, Anambra, Ebonyi, Enugu, and Imo and lies within Latitude N 6°27′17.07″ and Longitudes E6° 43′10.75″ on the Geological map of Nigeria employing the ArcGIS Software (**Figure 1**).

2. Aim and objectives of study

This chapter is aimed at reconstructing the burial and thermal history of the organic matter in the Anambra Basin as it affects the maturity and thermal cracking of the Coniacian Awgu Shales and the late Campanian Nkporo Shales through the thermal evolution conditions for oil and natural gas accumulation.

Therefore, this chapter attempts to achieve the following objectives:

i. To generate one dimensional burial/thermal history model of the two wells (Nzam-1 and Akukwa-2) which penetrated the Coniacian-late Campanian Source rocks in the Anambra Basin

ii. To determine the thermal regime changes during hydrocarbon generation and preservation

iii. To determine organic matter evolution, timing of hydrocarbon generation/cracking, accumulation and expulsion

iv. To Identify the reservoirs and the possible seal through the interpretation of the Petroleum system elements (PSE)Models

v. To utilize the deductions from this study to provide information necessary to optimize exploration activities in the Lower Benue Trough with a view of improving past investigation in the study area.

3. Methodology

Geohistory diagrams and similar diagrams have been widely used in geology, particularly in hydrocarbon exploration. These diagrams were adapted to perform numerical modeling of burial, erosion, and thermal histories in sedimentary basins, e.g. [9, 10].

In this study, quantitative one dimensional basin modeling (1-D) is performed for evaluating the thermal histories and timing of hydrocarbon generation and expulsion of the Agwu and Nkporo source rocks in the Lower Benue Trough. The 1-D Basin modeling, was used for the reconstruction of the burial and temperature histories of the two studied wells (**Figure 2**). The reconstruction of the burial, thermal and maturity histories were modeled in order to evaluate the remaining hydrocarbon potential using Schlumberger's PetroMod (1D) modeling software and Lithology data comprising of sandstone, shale and absolute ages.

The modeling approach adopted requires input data which describe the present day geological situation as a result of past events (**Figure 3**). On this basis, the geological history is simulated from the oldest to the most recent. This also involves modeling and calibration of single-point data, whereby geologic and geochemical information are integrated to model the Formations and evolution of a sedimentary basin. As a stand-alone tool, the single point data (well) is constructed and imported from the well editor. The total sedimentary column (lithology) was determined based on well data. Erosion and heat flow changes were established through calibration against maturity data, giving rise to the generation of a conceptual model of the subsidence and thermal history of the region. This model of present day architecture represents the final result of all the processes acting on the basin throughout geologic time. Summarily, the following input data are required for reconstruction of burial history:

i. Depositional thickness

ii. Depositional age in Ma (millions of years)

iii. Lithological Composition

iv. Thickness and age of eroded intervals, Petroleum Systems Essential Elements (Underburden, Source Rocks, Reservoir rocks, Seal Rock and Overburden rock

v. Possible source rock properties (TOC & HI).

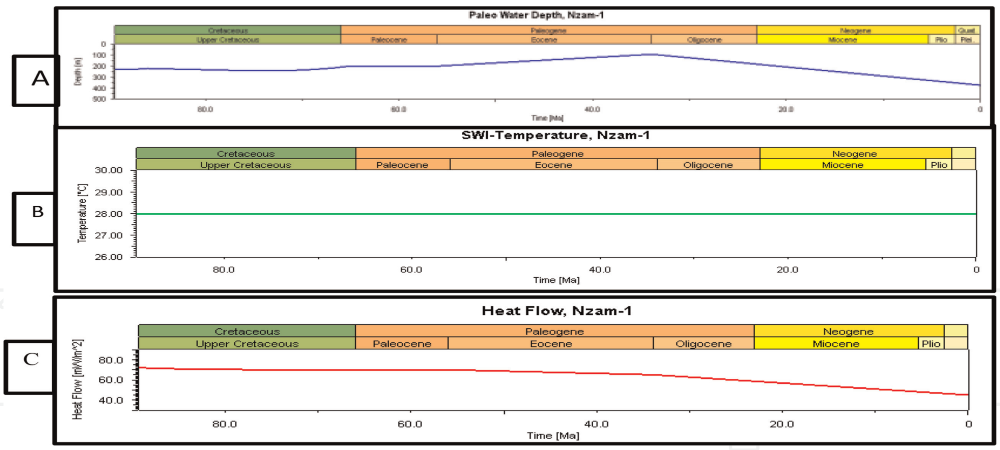

Figure 2.
Plots of Boundary conditions for the studied well (Nzam-1) ; (A) Paleo Water depth Versus geologic Age in million years, notice its fairly constant value of about 240 m between upper Cretaceous and Paleocene and between late Eocene and early Oligocene witnessed to about 50 m and its rapid increase by Oligocene to present day value of about 400 m (B) Sediment Water Interface-Temperature versus geologic Age in Million years, notice the fairly constant value of 28°C (C) Heat flow versus geologic Age in Millions years, notice maximum value of 72 m/Wm² between upper Cretaceous and Paleocene and a constant decline from Eocene to a present day value of 48 m/Wm².

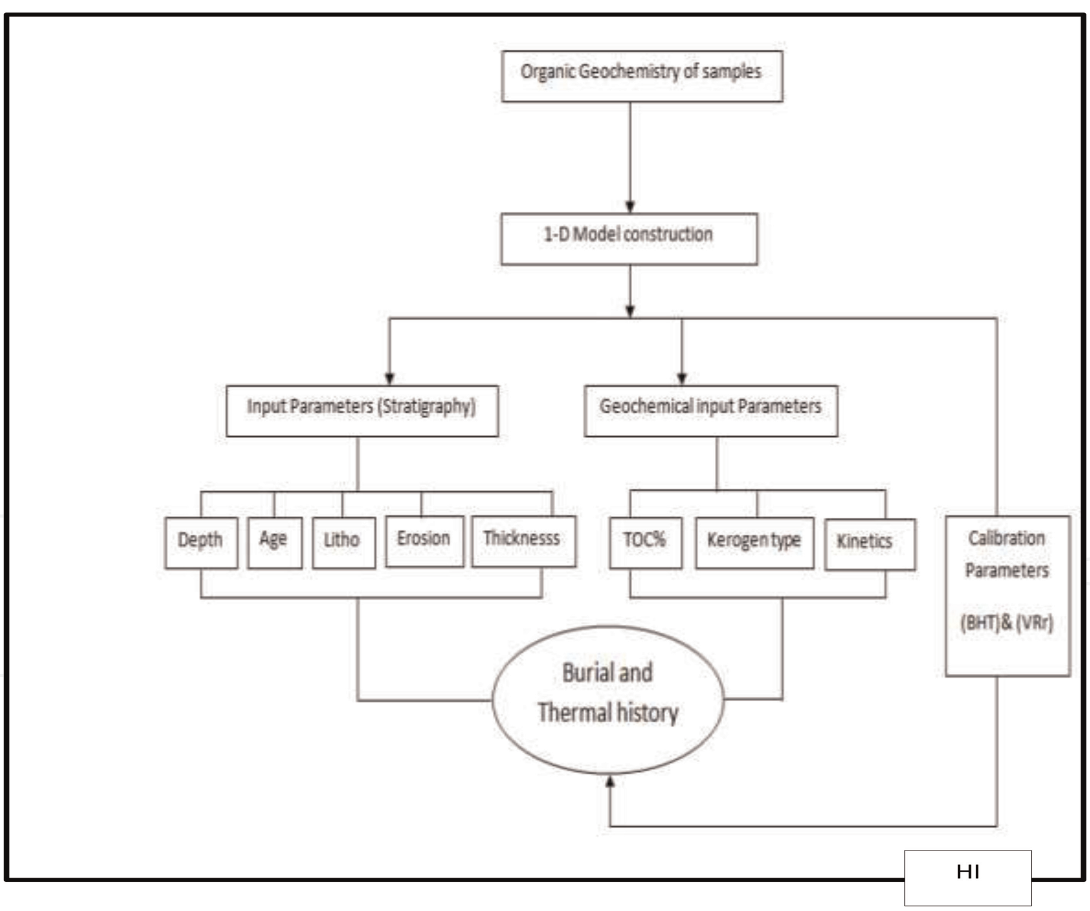

Figure 3.
Flow chart indicating the steps involved in the construction of the one dimensional burial/thermal history Modeling.

The geologic model consisting of the depositional, non-depositional and erosional events, was compiled using stratigraphic data which were provided from well reports, bank of Shell Petroleum Development Company (SPDC) of Nigeria and previous stratigraphic studies (**Figures 4** and 5). Hydrocarbon generation modeling was based on TOC and HI of the Coniacian Awgu and the upper Campanian Nkporo source rocks in the Lower Benue Trough. The modeling results were also calibrated with computed vitrinite reflectance after [11] and borehole temperatures (BHT) in the study area. Geochemical data (TOC and pyrolysis data), Vitrinite reflectance (**Tables 1**–**3**), Paleo water depth, well log, and geologic data (**Tables 4** and 5) were used for the construction of the geologic model showing thermal maturity stages of the Agwu and Nkporo Source rocks in the study area. Lithology data comprising of sandstone, shale and absolute ages were put into use (**Figures 4** and 5). The hydrocarbon generation modeling was based on TOC and HI of the Agwu and Nkporo source rocks in the Lower Benue Trough. The maturity modeling was calculated using the EASY% Ro model of [14, 15]. The TOC and Pyrolysis data of Coniacian Agwu Shales in Nzam-1 were extracted from [12] while those of the upper Campanian Nkporo Shales in Nzam-1 were extracted from [7]. TOC and Pyrolysis data for upper Campanian Nkporo Source Rock in Akukwa-2 were extracted from [8] and the TOC and HI values for Coniacian Awgu Source Rock in Akukwa-2 were extracted from Abubakar [1] (**Figure 6**).

The Modelled Vitrinite Reflectance as calculated after [14] has been related to calculated vitrinite reflectance data after [11] so as to enable the calibration of thermal history (**Figures** 7 and **8**).

Paleo-water depth values were used to define the paleogeometry while heat flow and sediment water interface temperatures were the key boundaries conditions that were defined in the course of modeling. Thermal evolution is simulated on the basis of boundary assignments applied to certain time steps. The assigned parameters are heat flow densities in mW/m^2 and surface temperatures in °C. Acquired Total Organic Carbon Content (TOC) and Rock eval pyrolysis of the Agwu and Nkporo Shales from Nzam and Akukwa-2 wells in the Lower Benue Trough are presented here with some additions in respect of some calculated pyrolysis parameters for the purpose of this study. Acquiring these data became necessary because the values of

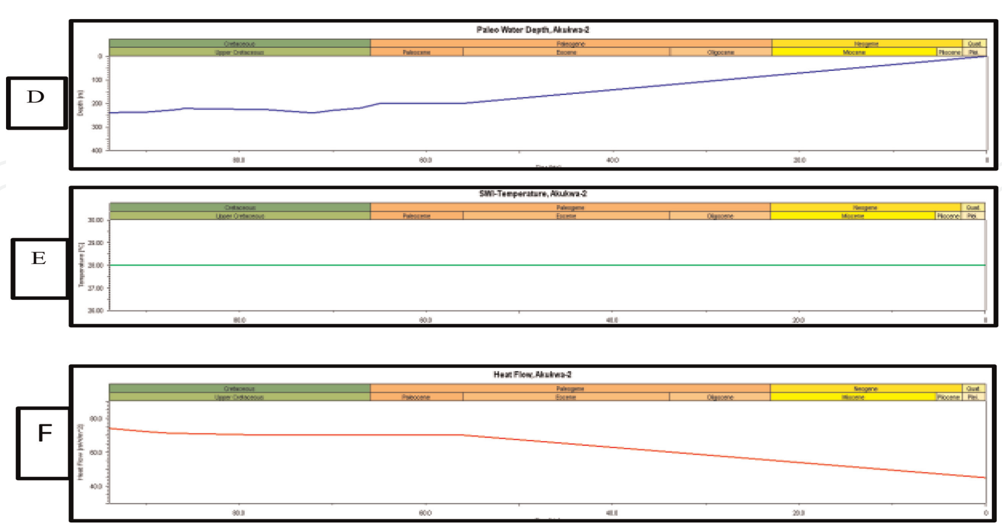

Figure 4.
Plots of Boundary conditions for the studied well (Akukwa-2); (D) Paleo Water depth Versus geologic Age in million years, notice its fairly constant value of about 240 m between Upper Cretaceous and Paleocene and between late Eocene and early Oligocene witnessed decline to about 50 m and its rapid decrease by Oligocene to present day value of about 0 m (E) Sediment Water Interface-Temperature versus geologic Age in Million years, notice the fairly constant value of 28°C (F) Heat flow versus geologic Age in Millions years, notice maximum value of 72 m/Wm^2 between upper Cretaceous and Paleocene and a constant decline from Eocene to a present day value of 48 m/Wm^2.

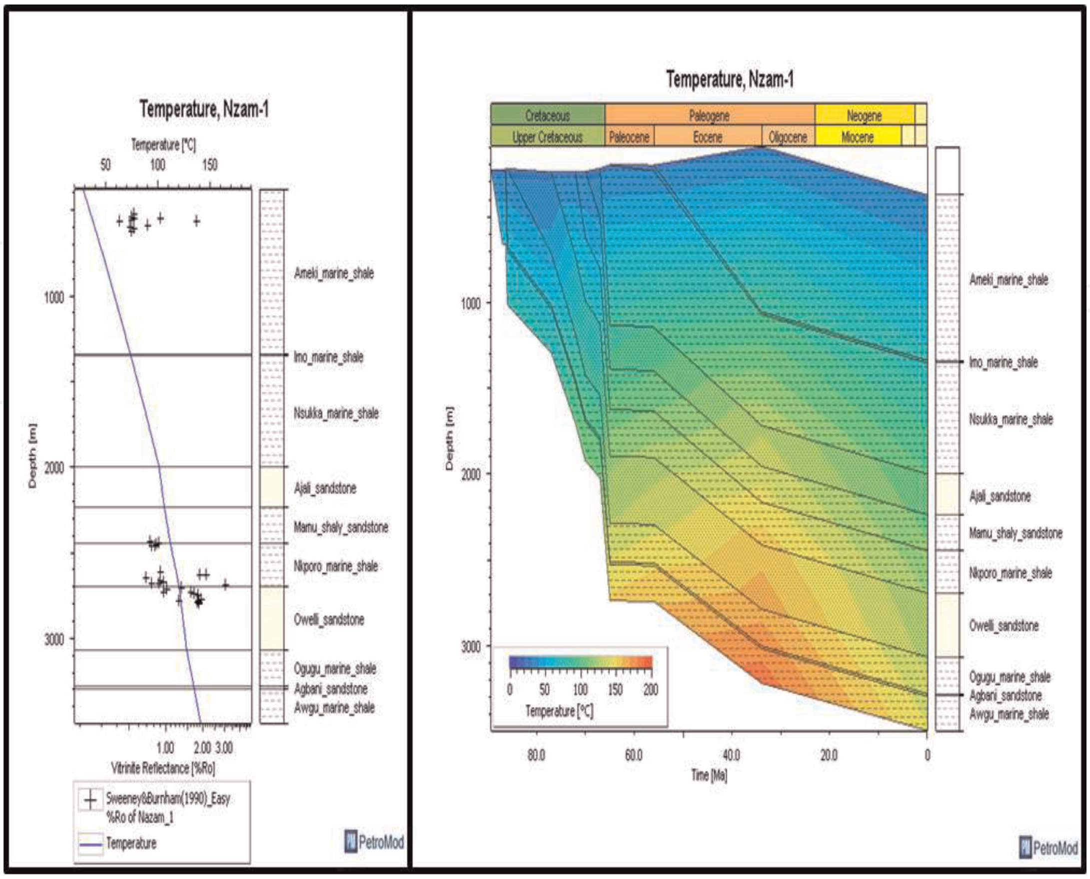

Figure 5.
Paleo-temperature modeling in Nzam-1 well calibrated using borehole temperature; showing correlation among Burial history with temperature overlay, measured temperature and modeled Temperature for the studied well, notice that the maximum temperature values of 120°C–145°C in the area was attained between mid-Paleocene and mid Miocene (60-15ma) on Coniacian Agwu Source strata, higher temperatures are associated with Santonian tectonic episode

Hydrogen Index (HI), TOC, Vitrinite reflectance forms vital input parameters in the one dimensional burial/thermal history model construction.

4. Results from 1-D burial/thermal history modeling

The input parameters used for constraining 1-D models/plots constructed for the studied sections of Nzam-1 and Akukwa-2 wells in the Lower Benue Trough are shown in **Tables 4** and **5** and the outcomes of the 1-D models/plots constructed for the studied sections of Nzam-1 and Akukwa-2 wells in the Anambra Basin, Lower Benue Trough are shown in **Figures 3–7**, **9–12**.

5. Discussion

5.1 Organic matter evolution, thermal regime changes during hydrocarbon generation, preservation and expulsion

Figures 2 and **4** illustrate that the end of the Cretaceous era saw uplift, denudation, subsidence and basin cooling in the Lower Benue Trough as well as increased

Depth (m)	Formation	TOC wt.%	S1 (Mg HC/ g TOC)	S2 (Mg HC/ g TOC)	S4 (Mg HC/ g TOC)	S1+S2 (Mg HC/ g TOC)	Tmax (°C)	Calc %Ro	*Calc %Ro	%Ro Diff.	HI Mg HC/ g TOC	PI	(%) PC	OSI (Mg HC/ g TOC)
2467	Nkporo	1.12	0.16	0.24	10.9	0.4	439	0.74	0.69	0.05	21	0.4	0.03	14.29
2477	Nkporo	0.99	0.14	0.24	9.54	0.38	446	0.87	0.80	0.07	24	0.37	0.03	14.14
2482	Nkporo	1.03	0.21	0.38	9.83	0.59	444	0.83	0.77	0.06	37	0.36	0.05	20.39
2487	Nkporo	1.09	0.22	0.36	10.43	0.58	442	0.81	0.74	0.07	33	0.38	0.05	20.18
2492	Nkporo	1.07	0.18	0.24	10.37	0.42	440	0.76	0.71	0.05	22	0.43	0.03	16.82
2647	Nkporo	1.16	0.17	0.31	11.23	0.48	448	0.90	0.83	0.083	27	0.35	0.04	14.66
2652	Nkporo	0.08	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2657	Nkporo	1.4	0.21	0.31	13.57	0.52	516	2.13	1.84	0.29	22	0.4	0.04	15.00
2662	Nkporo	1.25	0.18	0.25	12.11	0.43	503	1.89	1.64	0.25	20	0.42	0.04	14.40
2677	Nkporo	1.14	0.14	0.25	11.05	0.39	436	0.69	0.65	0.04	22	0.36	0.03	12.28
2692	Nkporo	1.08	0.15	0.23	10.53	0.38	448	0.90	0.83	0.07	21	0.39	0.03	13.89
2702	Nkporo	1.12	0.13	0.24	10.93	0.37	451	0.96	0.87	0.09	21	0.35	0.03	11.61
2707	Nkporo	1.03	0.13	0.24	9.99	0.37	446	0.87	0.80	0.07	23	0.35	0.03	12.62
2712	Nkporo	1.45	0.12	0.2	14.2	0.32	440	0.76	0.71	0.05	14	0.38	0.03	8.28
2717	Nkporo	0.08	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Table 1.
Acquired TOC content and pyrolysis data with calculated parameters of the studied samples of Nkporo Formation, Nzam-1 well [7].

Sample I.D	Depth (m)	Formation	TOC wt.%	S1 (Mg HC/ g TOC)	S2 (Mg HC/ g TOC)	S3 (Mg HC/ g TOC)	S4 (Mg HC/ g TOC)	S1+S2 (Mg HC/ g TOC)	Tmax (°C)	Calc %Ro	*Calc %Ro	% Ro Diff	HI (Mg HC/ g TOC)	OI (Mg HC/ g TOC)	PI	PC (%)	OSI (Mg HC/ g TOC)
A16	2722	Agwu	1.13	0	0.01	2.26	11.34	0.01	568	3.06	2.61	0.45	1	200.39	0	0	0.00
A17	2737	Agwu	1.27	0.19	0.32	2.51	12.28	0.51	470	1.33	1.15	0.18	25	197.73	0.37	0.04	14.96
A18	2742	Agwu	0.44	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
A19	2747	Agwu	1.39	0.19	0.3	2.76	13.5	0.49	454	1.01	0.91	0.10	22	198.34	0.39	0.04	13.67
A20	2757	Agwu	1.45	0.21	0.32	2.89	14.05	0.53	486	1.59	1.39	0.20	22	`199.30	0.4	0.04	14.48
A21	2762	Agwu	1.33	0.17	0.28	2.65	12.92	0.45	451	0.96	0.87	0.09	21	199.56	0.38	0.04	12.78
A22	2772	Agwu	1.42	0.16	0.27	2.85	13.83	0.43	493	1.71	1.50	0.21	19	200.59	0.37	0.04	11.27
A23	2777	Agwu	1.4	0.19	0.25	2.8	13.63	0.44	499	1.82	1.59	0.23	18	199.82	0.43	0.04	13.57
A24	2803	Agwu	1.78	0.2	0.25	3.56	17.44	0.45	505	1.93	1.67	0.26	14	199.76	0.44	0.04	11.24
A25	2808	Agwu	1.44	0.19	0.24	2.85	14.07	0.43	469	1.28	1.14	0.14	17	197.87	0.44	0.04	13.19
A26	2813	Agwu	1.25	0.14	0.17	2.48	12.27	0.31	500	1.84	1.60	0.24	14	198.42	0.45	0	11.20
A27	2818	Agwu	1.38	0.16	0.22	2.8	13.45	0.38	501	1.86	1.61	0.25	16	202.65	0.42	0.03	11.59
A28	2823	Agwu	1.31	0.15	0.2	2.66	12.77	0.35	497	1.79	1.56	0.23	15	203.29	0.43	0.03	11.45
A29	2828	Agwu	1.4	0.22	0.23	2.83	13.59	0.45	501	1.86	1.61	0.25	16	201.96	0.49	0.04	15.71
A30	2833	Agwu	0.07	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Table 2.
Acquired TOC content and pyrolysis data with calculated parameters of the studied samples of Agwu Formation, Nzam-1 well (modified after [12]).

Depth (m)	Formation	TOC (Wt. %)	S1 (Mg HC/ g TOC	S2 (Mg HC/ g TOC)	Tmax (°C)	Ro	Calc (% Ro)	*Calc (% Ro)	%Ro Diff.	HI (Mg HC/ g TOC)	PI	OSI (Mg HC/ g TOC)
1348	Nkporo	0.89	0.1	1.44	430	N/A	0.58	0.56	0.02	162	0.06	11.24
1351	Nkporo	0.81	0.14	0.82	434	N/A	0.65	0.62	0.03	101	0.15	17.28
1354	Nkporo	1.27	0.22	1.21	431	N/A	0.60	0.57	0.03	95	0.15	17.32
1357	Nkporo	0.68	0.14	0.93	433	N/A	0.63	0.60	0.03	137	0.13	20.59
1360	Nkporo	0.63	0.13	1.13	430	N/A	0.58	0.56	0.02	179	0.10	20.63
1373	Nkporo	1.8	0.41	1.36	427	0.56	0.53	0.51	0.02	76	0.23	22.78
1376	Nkporo	1.76	0.22	1.16	431	N/A	0.60	0.57	0.03	66	0.16	12.50
1379	Nkporo	1.88	0.26	1.73	430	N/A	0.58	0.56	0.02	92	0.13	13.83
1400	Nkporo	0.27	0.16	0.47	431	0.56	0.60	0.57	0.03	174	0.25	59.26
1410	Nkporo	1.92	0.15	1.45	428	N/A	0.54	0.53	0.01	76	0.09	7.81
1425	Nkporo	1.5	0.13	1.05	432	0.55	0.62	0.59	0.03	70	0.11	8.67
1428	Nkporo	1.52	0.2	1.2	428	N/A	0.54	0.53	0.01	79	0.14	13.16
1443	Nkporo	1.29	0.09	0.89	433	N/A	0.63	0.60	0.03	69	0.09	6.98
1467	Nkporo	1.07	0.05	0.93	429	N/A	0.56	0.54	0.02	87	0.05	4.67
1473	Nkporo	1.43	0.14	1.1	434	N/A	0.65	0.62	0.03	77	0.11	9.79
1482	Nkporo	1.16	0.17	0.95	433	N/A	0.63	0.60	0.03	82	0.15	14.66
1485	Nkporo	0.98	0.1	1.01	431	N/A	0.60	0.57	0.03	103	0.09	10.20
1492	Nkporo	1.67	0.14	1.24	431	N/A	0.60	0.57	0.03	74	0.10	8.38
1495	Nkporo	1.56	0.18	0.55	434	N/A	0.65	0.62	0.03	35	0.25	11.54
1498	Nkporo	0.4	0.07	0.65	433	N/A	0.63	0.60	0.03	163	0.10	17.50
1504	Nkporo	1.43	0.16	1.19	430	N/A	0.58	0.56	0.02	83	0.12	11.19
1513	Nkporo	0.95	0.15	1.61	431	N/A	0.60	0.57	0.03	169	0.09	15.79
1516	Nkporo	3.02	0.13	1.19	431	N/A	0.60	0.57	0.03	39	0.10	4.30
1525	Nkporo	1.42	0.07	1.02	429	N/A	0.56	0.54	0.02	72	0.06	4.93
1535	Nkporo	1.84	0.05	1.06	433	0.6	0.63	0.60	0.03	58	0.05	2.72
1541	Nkporo	1.62	0.12	1.36	431	0.57	0.60	0.57	0.03	84	0.08	7.41
1589	Nkporo	1.48	0.07	1.23	433	0.58	0.63	0.60	0.03	83	0.05	4.73
1632	Nkporo	2.3	0.13	2.36	437	0.57	0.71	0.66	0.05	103	0.05	5.65
1663	Nkporo	1.95	0.18	1.82	434	N/A	0.65	0.62	0.03	93	0.09	9.23
1702	Nkporo	2.31	0.21	3.14	441	0.6	0.78	0.72	0.06	136	0.06	9.09

Table 3.
Acquired TOC content and pyrolysis data with calculated parameters of the studied samples of Nkporo Shales in Akukwa-2 well (modified after [7]).

geothermal gradient to have caused complex processes of uplift, denudation, and basin cooling and heating (**Figure 13**).

The geology of Lower Benue Trough is associated with the tectonic activities that were recorded during the Cenomanian which produced uplift with a NE-SW trend

Formation	Age in millions years	Heat flow (mw/m^2)	Eustatic sea level (m) [13]
	0	45	52
Ameki	56.0–33.9	70–65	201
Imo	65–56.0	70	200
Nsukka	67.0–65.0	70	220
Ajali	70.0–67.0	70	238
Mamu	72.1–70	70	241
Nkporo	**77.3–72.1**	**70**	**240**
Owelli	80.0–77.3	71	227
(Non-deposition)	86.0–80.0	71	222
Ogugu	86.3–86.0	71	225
Agbani	87.0–86.3	71	228
Awgu	**89.8–87.0**	**72**	**`237**

Table 4.
Input Parameters (age, Heat flow and Eustatic Sea level) of Lower Benue Trough used to constrain the model.

Age [Ma]	Name top/well pick	Depth [m]	Thickness [m]	Event type	Name layer/event	Paleodeposition/ erosion [m]	Lithology	PSE	Kinetic	TOC [%]	HI [mgHC/gTOC]
33.90	Ameki	375	963	↓ Deposition	Ameki_marine_shale		Shale (black)	Seal Rock			
56.00	Imo	1338	15	↓ Deposition	Imo_marine_shale		Shale (black)	Seal Rock			
65.00	Nsukka	1353	647	↓ Deposition	Nsukka_marine_shale		Shale (black)	none			
67.00	Ajali	2000	237	↓ Deposition	Ajali_sandstone		Sandstone (typical)	Reservoir Rock			
70.00	Mamu	2237	209	↓ Deposition	Mamu_shaly_sandstone		Shale (organic lean, sandy)	none			
72.10	Nkporo	2446	248	↓ Deposition	Nkporo_marine_shale		Shale (organic rich, typical)	Source Rock	Vandenbroucke_et_al(1999)_TIII-(NorthSea)	1.45	37.00
77.00	Owelli	2694	372	↓ Deposition	Owelli_sandstone		Sandstone (typical)	Reservoir Rock			
86.00	Ogugu	3066	214	↓ Deposition	Ogugu_marine_shale		Shale (organic rich, typical)	Source Rock			
86.30	Agbani	3280	15	↓ Deposition	Agbani_sandstone		Sandstone (typical)	Reservoir Rock			
87.00	Awgu	3295	200	↓ Deposition	Awgu_marine_shale		Shale (organic rich, typical)	Source Rock	Vandenbroucke_et_al(1999)_TIII-(NorthSea)	1.78	25.00
89.30	Awgu_Base	3495									

(A)

Age [Ma]	Name top/well pick	Depth [m]	Thickness [m]	Event type	Name layer/event	Paleodeposition/ erosion [m]	Lithology	PSE	Kinetic	TOC [%]	HI [mgHC/gTOC]
56.00	Imo	0	284	↓ Deposition	Imo_Marine shale		Shale (black)	Seal Rock			
65.00	Nsukka	284	225	↓ Deposition	Nsukka_Marine shale		Shale (black)	Seal Rock			
67.00	Ajali	509	430	↓ Deposition	Ajali_sandstone		Sandstone (typical)	Reservoir Rock			
70.00	Mamu	939	332	↓ Deposition	Mamu_shaly-sandstone		Shale (organic lean, sandy)				
72.10	Nkporo	1271	204	↓ Deposition	Nkporo_Marine shale		Shale (organic rich, typical)	Source Rock	Vandenbroucke_et_al(1999)_TIII-(NorthSea)	1.92	179.00
77.00	Owelli	1475	174	↓ Deposition	Owelli_sandstone		Sandstone (typical)	Reservoir Rock			
86.00	Ogugu	1649	924	↓ Deposition	Ogugu_Marine shale		Shale (organic rich, typical)	Source Rock			
86.30	Agbani	2573	198	↓ Deposition	Agbani_sandstone		Sandstone (typical)	Reservoir Rock			
87.00	Awgu	2771	640	↓ Deposition	Awgu_Marine shale		Shale (organic rich, typical)	Source Rock	Vandenbroucke_et_al(1999)_TIII-(NorthSea)	1.88	174.00
89.80	Eze-Aku	3411	90	↓ Deposition	Eze-Aku_Marine shale		Shale (organic rich, typical)	Source Rock			
93.90	Eze-Aku-Base	3501									

(B)

Table 5.
Inputed data (Lithology, Geologic age in Million Years (Ma), Petroleum system elements(PSE), TOC) for the burial history and maturity model construction of Coniacian and late Campanian source rocks, Lower Benue Trough, Nzam-1 (A) and Akukwa-2 (B) wells.

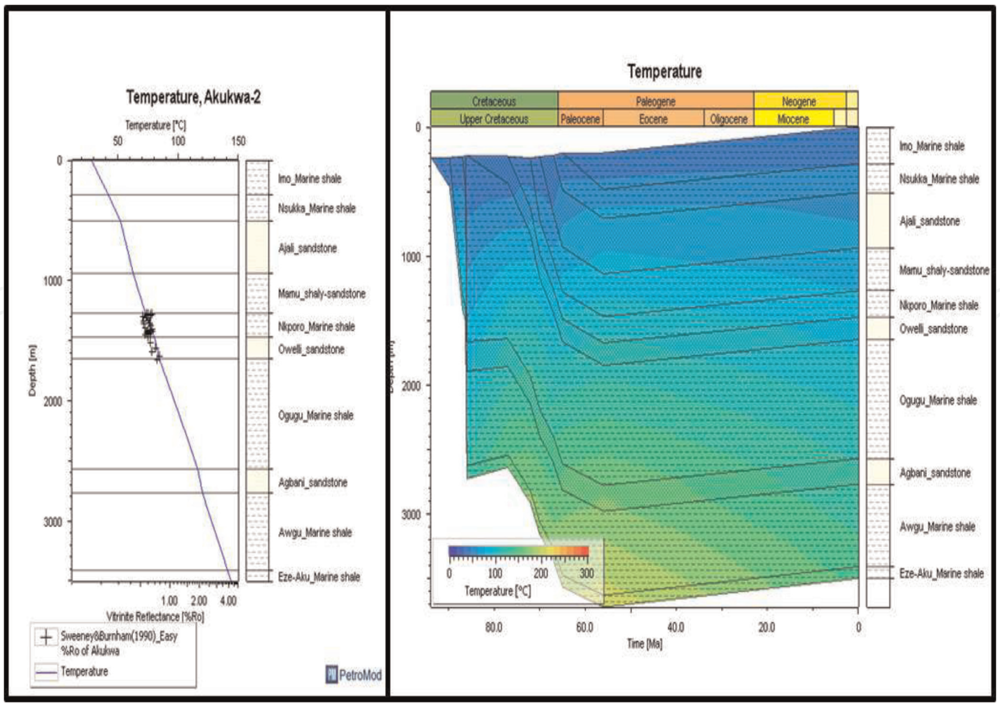

Figure 6.
Paleo-temperature modeling in Akukwa-2 well calibrated using borehole temperature; showing correlation among Burial history with temperature overlay, measured temperature and modeled Temperature for the studied well, notice that the maximum temperature values of 120–145°C in the area was attained between mid-Paleocene and mid Miocene (60-15ma) on Coniacian Agwu Source strata, higher temperatures are associated with Santonian tectonic episode.

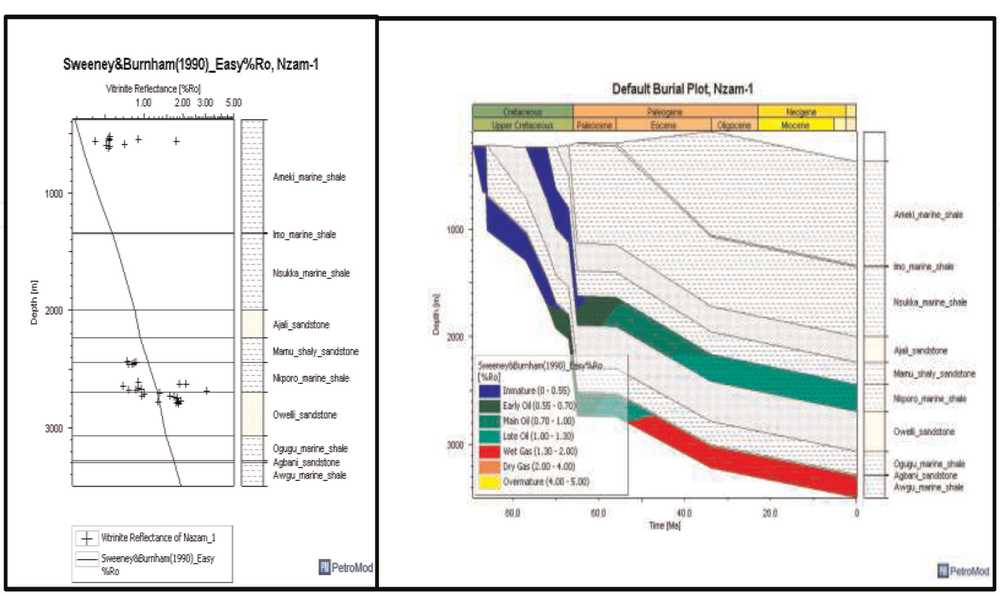

Figure 7.
Burial and thermal maturity histories of the Coniacian and upper Campanian source rocks for the studied well (Nzam-1 well) showing the positions of the oil window and the various hydrocarbon generation phases. Notice that Agwu Source rocks have entered the post maturity gas evolution and still generating gas to present day while the late Campanian Nkporo Source has entered the oil window and has marginal maturity. To the right the depth versus mean vitrinite reflectance plot indicating reasonable correlation between the measured and the modeled vitrinite reflectance.

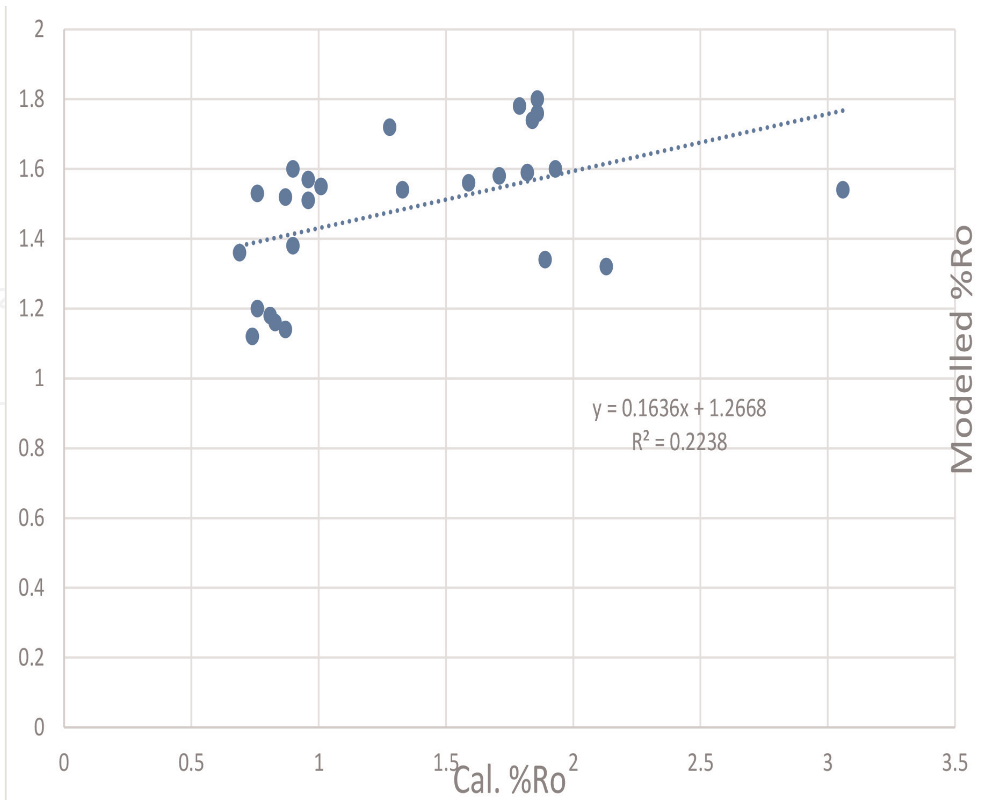

Figure 8.
Showing a reasonable correlation between the modeled and the calculated vitrinite reflectance and the R^2 of 0.2238 shows the correctness of the model.

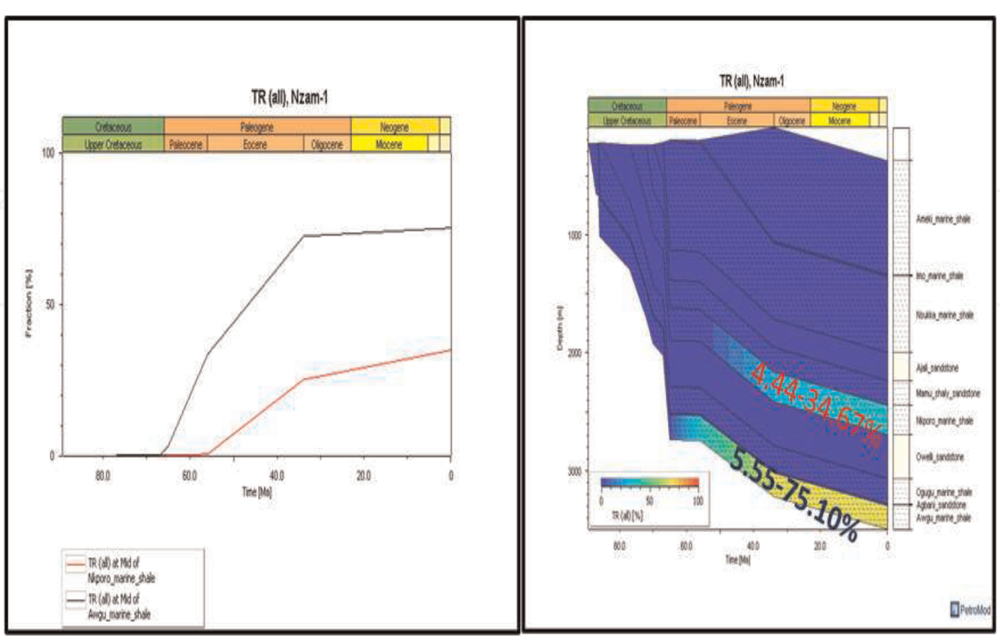

Figure 9.
Evolution of the transformation ratio and rate of hydrocarbon generation with age from the Coniacian and late Campanian source strata in the studied well (Nzam-1 well). Notice the Coniacian Agwu Shale has a higher transformation ratio which lies between 5.55 and 75.10% and greater than that Nkporo Source strata with transformation ratio between 4.44 and 34.67%.

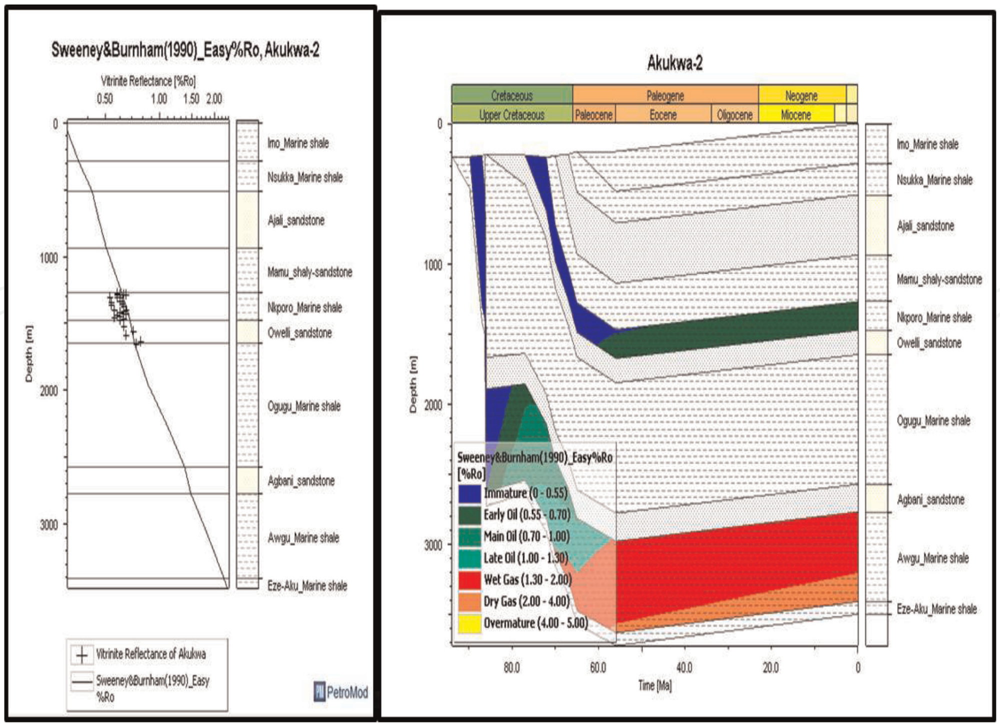

Figure 10.
Burial and thermal maturity histories of the Coniacian and late Campanian source rocks for the studied well (Akukwa-2 well) showing the positions of the oil window and the various hydrocarbon generation phases. Notice that Agwu Source rocks have entered the postmaturity gas evolution and still generating gas to present day while the late Campanian Nkporo Source has entered the oil window and is at the early generation stages. To the right the depth versus mean vitrinite reflectance plot indicating reasonable correlation between the measured and the modeled vitrinite reflectance.

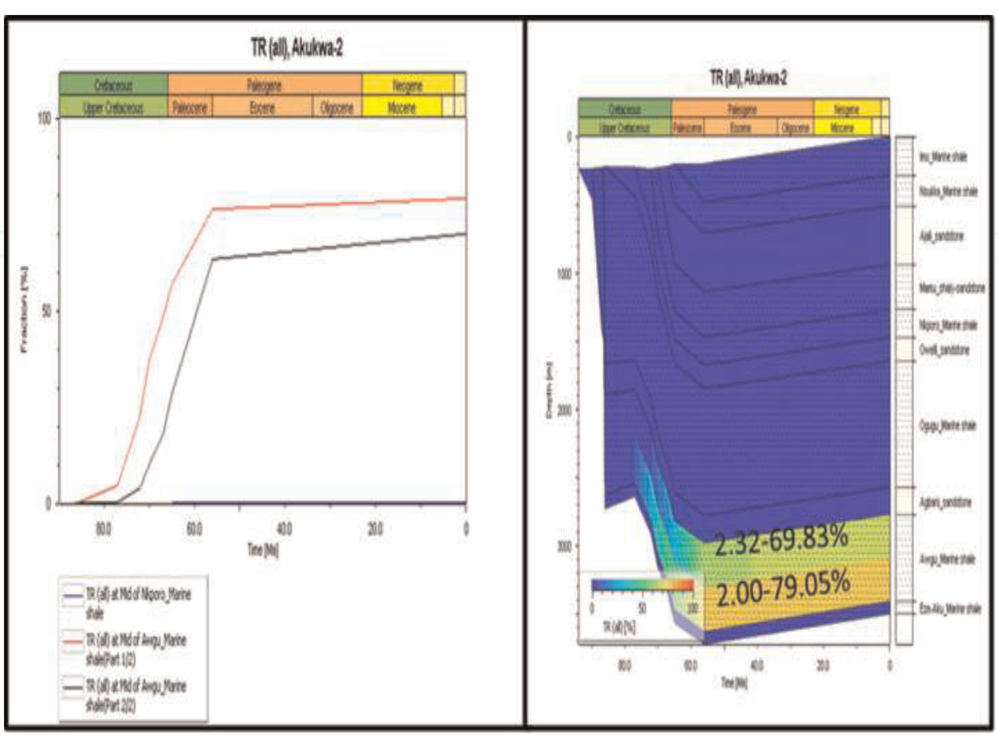

Figure 11.
Evolution of the transformation ratio and rate of hydrocarbon generation with age from the Coniacian-late Campania source rocks in the studied well (Akukwa-2).

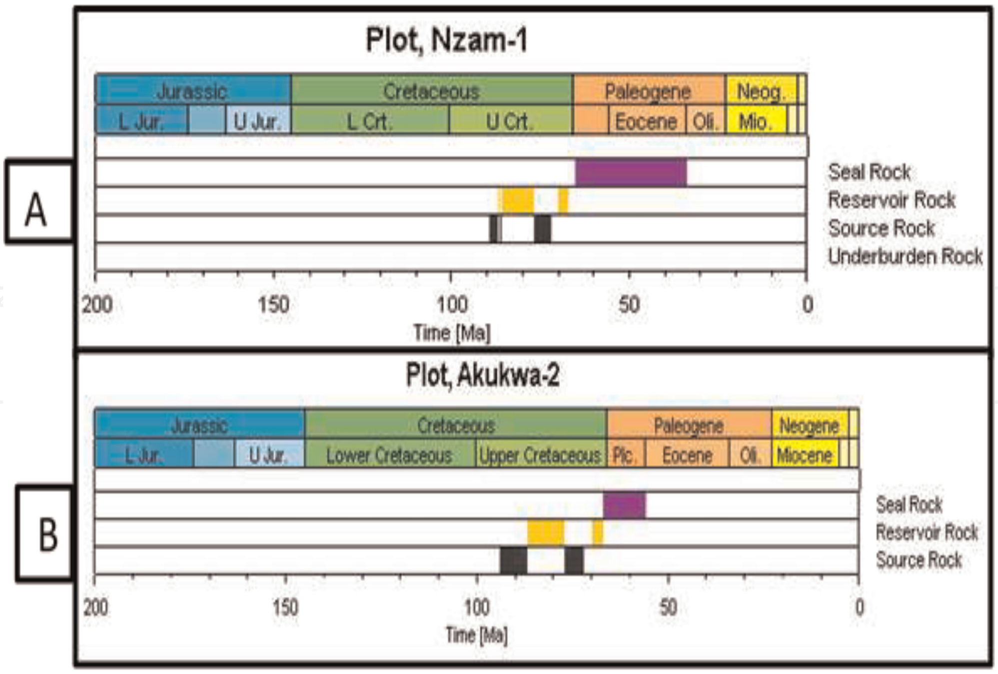

Figure 12.
Modeled Petroleum system elements of the studied (A) Nzam-1 and (B) Akukwa-2 Wells respectively; Both showing the positions of the two source strata under study (Coniacian Awgu and late Campanian Nkporo Source rocks, the positions of the Reservoir Rocks (Coniacian Agbani Sandstone and the Campanian Owelli Sandstone) and the positions of the Paleogene seals (majorly Imo Shale) all of which have demonstrated favorable conditions for Petroleum accumulations.

Figure 13.
Heavy crude seepage from the Owelli Sandstone at Egwueme, Lower Benue Trough [1].

and it gave way to the tectonic activities that took place in Santonian times, which resulted in the folding and uplifting of the Abakaliki Sector of the Trough and the subsidence of Anambra Platform. The latter event led to the formation of the

Anambra Basin and this constituted a major depocentre of clastic sediments and deltaic sequences [17, 18]

Based on the burial/thermal history model; the burial temperature within Agwu Formation in Nzam-1 well ranges from 30 to 145°C and that of Nkporo Formation ranges 28 to 125°C (**Figure 5**); From the burial/Thermal history of Akukwa-2 well the burial temperature in Agwu and Nkporo Formation ranges from 29.5 to 145°C and 28.5 to 95°C (**Figure 6**) respectively.

From the burial history model in Nzam-1 well (**Figure 5**), it was observed that before the Santonian tectonic episode (Pre-rift periods), the Kerogen in the Coniacian Awgu Shale experienced lower temperatures between the ranges of 30 and 55°C, it further experienced increased temperatures ranges between 120°C and 145°C between the Santonian and Miocene (83-15Ma) and (post-rift Periods) while in the burial model of the Lower Benue Sector in Akukwa-2 (**Figure 6**), the Kerogen in the Coniacian source strata has experienced lowest temperatures ranges of between 29.5 and 50°C before the Santonian times (Pre-rift) and exponential increased temperature ranges of 120 and 145°C between Santonian (83ma) up to present day. Consequently, the relatively high temperature and geothermal gradients experienced by the Coniacian Awgu strata between the Santonian and Miocene times aided the quickening of the organic matter maturation, oil generation and subsequent cracking of the oil to form gas. Since the temperature continued to decrease exponentially to the present day and such decrease in temperature have favored the preservation of the gas reservoirs and therefore the survival of hydrocarbons in the deeper strata can be guaranteed. More so the geothermics, the configuration of the hydrocarbon generation timing and reservoir cap development has favored accumulation (**Figure 12**) and the low geothermal field background after the formation of cracked gas has increased its chances of survival in their respective reservoirs within the Lower Benue Trough due to basin cooling and the resulting present day low heat flow (48m/Wm$^{-2)}$. The moderate temperature values of up to 125°C of Nkporo Formation for the studied Nzam-1 has aided its maturity and this happened due to basin heating and considerable burial depth which has placed the organic matter of Nkporo on an advantage position to mature relative to the organic matter of the same Formation in Akukwa-2 well with the highest temperature value of less than 95°C has entered the threshold of oil generation in Late Maastrichtian (65Ma) and continues to remained within the onset of generation owing to lack of sufficient heat and shallow burial depth that is needed for it to exit this present hydrocarbon generation phase.

It may therefore be said that Temperature evolution affected the development of organic matter pores in strata and their gas adsorption capacity. In sum, a higher temperature and a greater extent of thermal evolution should have resulted in highly developed organic matter pores [19], whereas a lower temperature should have enhanced the gas adsorption capacity. As shown in **Figures 5** and **6**, the high temperature of the Coniacian Agwu source rocks, which may be attributed to the high temperature gradient and deeper burying level of these rocks and more so predates Santonian tectonic episode, was highly favorable for the maturity of organic matter and the development of their pores, whereas the increased heat process after the main hydrocarbon aided the oil cracking gas generation periods but however the reduction in heat benefited the preservation of source rock gas should the cooling continues.

The one-dimensional burial and maturity model of Nzam-1 and Akukwa-2 wells was modeled after [14, 15] kinetic models to ascertain the hydrocarbon generation potential of upper Cretaceous organic rich shaly intervals.

Once source rocks have reached their expulsion threshold, they may expel the hydrocarbons upward into the reservoirs [19]. The timing of hydrocarbon generated and expelled from the Coniacian Awgu and upper Campanian Nkporo source rocks were modeled. Oil generation is defined in this study by transformation ratios between 10% and 50% [19]. Immature source rocks have transformation ratios less than10% (no generation). Peak oil generation occur at a transformation ratio of 50% when the main phase of oil generation is reached. And transformation ratio greater 60% when gas phase of the hydrocarbon generation is reached. The calculation of the transformation ratios is based on the Vandenbroucke et al., (1999)-TIII- (North Sea) kinetic model for the Coniacian Agwu and late Campanian Nkporo source rocks (**Figures 9** and **11**).

From the burial history model of Nzam-1 well with transformation overlay (**Figure 9**), it is clear that the Awgu has a higher transformation ratio as compared to Nkporo and this is consequent to their thermal maturity which is confirmed in the Transformation-Time plot with Awgu shale having higher curve. The transformation ratio of Awgu and Nkporo Shales in Nzam-1 well is 5.55–75.10% and 4.44–34.67% respectively (**Figure 9**) while the transformation ratios for Agwu Formation in Akukwa-2 well are 2.32–69.83% for upper strata and 2.00–79.05% for the lower strata while the Nkporo Formation had no transformation ratio (**Figure 11**). The transformation- Time plot shows that the thermal maturity and the transformation of organic matter increase with time and depth. Therefore, a reasonable correlation can be drawn between the burial plot and Transformation Time plot (**Figures 9** and **11**).

The hydrocarbon generation and expulsion modeling of Nzam-1 well model shows that the Agwu Shale reached early phase of oil generation in late Campanian and extended from 75 Ma to 69 Ma. Subsequently, main phase of oil generation began during early Paleocene and extended from 65 Ma to 62 Ma. The gas phase began at mid Eocene and extended from 48Ma to present day. The model has also shown that the expulsion of hydrocarbon from Agwu Source rocks occurred between 62 Ma up to present day and peak expulsion at 34 Ma during late Eocene (**Figures 7** and **9**).

As for the late Campanian Nkporo Source rock, the Model of Nzam-1 has shown that the Nkporo Shale reached early phase of oil generation in early Paleocene and extended from 65 Ma to 60 Ma. Subsequently, main phase of oil generation began during late Paleocene and extended from 56 Ma to 42 Ma. The model has also shown that the expulsion of oil from Nkporo Source rocks occurred between 42 Ma to present day and peak expulsion at 30 Ma during early Oligocene (**Figures 7** and **9**).

The hydrocarbon generation and expulsion modeling of Akukwa-2 well shows that the Agwu Shale reached early phase of oil generation in early Santonian and extended from 85 Ma to 78 Ma. Subsequently, main phase of oil generation began during late Campanian and extended from 75 Ma to 70 Ma. The gas phase began at mid Paleocene and extended from 58Ma up to present day. The model has also shown that the expulsion of hydrocarbon from Agwu Source rocks occurred between 70Ma and up to present day and peak expulsion at 57 Ma during late Paleocene (**Figures 10** and **11**).

The hydrocarbon generation and expulsion model of Akukwa-2 well has also shown that the late Campanian Nkporo Source rocks has just entered the early phase of oil generation late Maastrichtian (67Ma) to present day; However, the late Campanian Nkporo Formation did not reach the main phase of oil generation and expulsion owing to the fact that it lacks the requisite burial depth, temperature and pressure in favor of oil generation and expulsion prevent further generation and expulsion in the upper Campanian source strata in this Formation (**Figures 10** and **11**). From the above, it can be said that the organic matter in Coniacian Awgu source rocks has reached the post maturity evolution phase and the expected hydrocarbon product is gas. While the late Campanian Nkporo source rocks on the other hand is at early maturity to peak maturity evolution Phase and the expected hydrocarbon product is oil.

Petroleum accumulation depends on the configuration of hydrocarbon generation as well as migration, Formation, and evolution of the reservoir and its sealing conditions [19]. Considering the Petroleum System Elements (PSE) models, the Coniacian Awgu source rocks reached their oil and gas generation peaks in the Late Paleocene to early Eocene (58-52ma) and continued to generate gas to present day in the Nzam-1 model (**Figures 7, 9**, and **12**) whereas reached its peak generation in late Campanian to msid Paleocene (80-58ma) and continued to generate gas to present day in Akukwa-2 well (**Figures 10**–**12**) and the generation took place later than the formation of the regional reservoir rocks (Coniacian Agbani and late Campanian Owelli Sandstone Members) and the Paleogene seal rocks majorly Imo Shales (**Figure 10**). While the late Campanian Nkporo source rocks reached their oil generation peaks in the early Eocene to mid Oligocene (55-32ma) and continued to present day in Nzam-1 well (**Figures 7, 9** and **12**) and only entered the hydrocarbon generation threshold up to present day in Akukwa-2 well (**Figures 10**–**12**). The Petroleum System Elements (PSE) model revealed a viable petroleum system comprising of two source rocks dated Coniacian (89Ma) and Campanian (78Ma); two reservoir rocks dated also Coniacian (88Ma) and Campanian (78Ma) and the cap rock is dated Paleocene (65Ma) which indicates that hydrocarbon generation and expulsion occurred later than the formation of the regional reservoir rocks basically Coniacian Agbani and late Campanian Owelli Sandstone members and the seal rocks majorly the Juxtaposed Paleocene Imo Shales. The hydrocarbon generation period provided favorable conditions for the accumulation of oil and gas from these Coniacian and late Campanian source rocks in the Lower Benue Trough. Given the multiple phases of hydrocarbon generation, the Coniacian Agwu source rocks had more favorable conditions for hydrocarbon accumulation than those of the late Campanian Nkporo Source rocks (**Figure 12**). The Paleogene Shale Units within the Lower Benue Trough are the most important oil and gas seal. Therefore, it is possible hydrocarbons were generated and expelled from Agwu Shale and evidence can be seen in heavy crude seepage from the Owelli Sandstone at Egwueme, Lower Benue Trough. And valid petroleum system elements exist in the basin with relative differences in the generation and expulsion periods of hydrocarbon generation.

A plot of measured vitrinite reflectance against the modeled vitrinite reflectance was computed and the RSME is found to be 0.2238 which indicates good correlation and hence the correctness of the model (**Table 6** and **Figure 8**).

From the Plot of Hydrogen Index (HI) against Maximum Temperature (Tmax), calculated Vitrinite Reflectance after [11] and calculated Vitrinite Reflectance after [16] showing Kerogen quality and thermal maturity stages for the studied sediments Nkporo Marine Shale and Agwu Marine Shales in the Lower Benue Trough sedimentary section of the Nzam-1 well indicated that Kerogen from Nkporo is immature to early maturity and is also Predominantly type II-III kerogen which is mixed oil/gas prone with minor occurrences of type II and type III While kerogen from Agwu shale has attained peak maturity to post maturity and the organic matter is predominantly consist of type II-III kerogen perhaps with minor occurrences of type II Kerogen (**Figure 14**).

Cross plot of Production Index against Tmax revealed that samples from Agwu Formation fall within the oil and gas window and the organic matter has experienced high level conversion which is also an indication of Peak maturity to post maturity (**Figure 15**).

Measured %Ro	Modeled %Ro	Model	Residual	Residual Square	RMSE
0.74	1.12	1.387864	0.267864	0.071751122	0.178092
0.87	1.14	1.409132	0.269132	0.072432033	
0.83	1.16	1.402588	0.242588	0.058848938	
0.81	1.18	1.399316	0.219316	0.048099508	
0.76	1.2	1.391136	0.191136	0.03653297	
0.9	1.6	1.41404	−0.18596	0.034581122	
2.13	1.32	1.615268	0.295268	0.087183192	
1.89	1.34	1.576004	0.236004	0.055697888	
0.69	1.36	1.379684	0.019684	0.00038746	
0.9	1.38	1.41404	0.03404	0.001158722	
0.96	1.51	1.423856	−0.08614	0.007420789	
0.87	1.52	1.409132	−0.11087	0.012291713	
3.06	1.54	1.767416	0.227416	0.051718037	
0.76	1.53	1.391136	−0.13886	0.01928321	
1.33	1.54	1.484388	−0.05561	0.003092695	
1.01	1.55	1.432036	−0.11796	0.013915505	
1.59	1.56	1.526924	−0.03308	0.001094022	
0.96	1.57	1.423856	−0.14614	0.021358069	
1.71	1.58	1.546556	−0.03344	0.001118501	
1.82	1.59	1.564552	−0.02545	0.000647601	
1.93	1.6	1.582548	−0.01745	0.000304572	
1.28	1.72	1.476208	−0.24379	0.059434539	
1.84	1.74	1.567824	−0.17218	0.029644575	
1.86	1.76	1.571096	−0.1889	0.035684721	
1.79	1.78	1.559644	−0.22036	0.048556767	
1.86	1.8	1.571096	−0.2289	0.052397041	

Table 6.
Showing the calculated and the modeled vitrinite reflectance values with the resultant Root mean square error of 0.178092

And from the cross plot of Production Index against Tmax and calculated Vitrinite Reflectance after [11] and [16] suggested that the Kerogen from Agwu Formation has undergone an intensive generation expulsion and the samples fall within the oil window and gas window, it also indicated that the organic matter has undergone high level conversion and has entered the over mature zone (**Figure 15** and **16**). This implies that the expected hydrocarbon type is oil, Condensate-wet gas and dry gas. It can therefore be inferred that the samples from Agwu Formation of the Nzam-1 Well have attained peak to post thermal maturity.

The measured Vitrinite reflectance (Ro) in both Nzam-1 and Akukwa-2 wells (**Figures 7, 8** and **10**) has a reasonable correlation with the modeled vitrinite reflectance after [14]. The heat flow histories used in the calculations are also plotted in

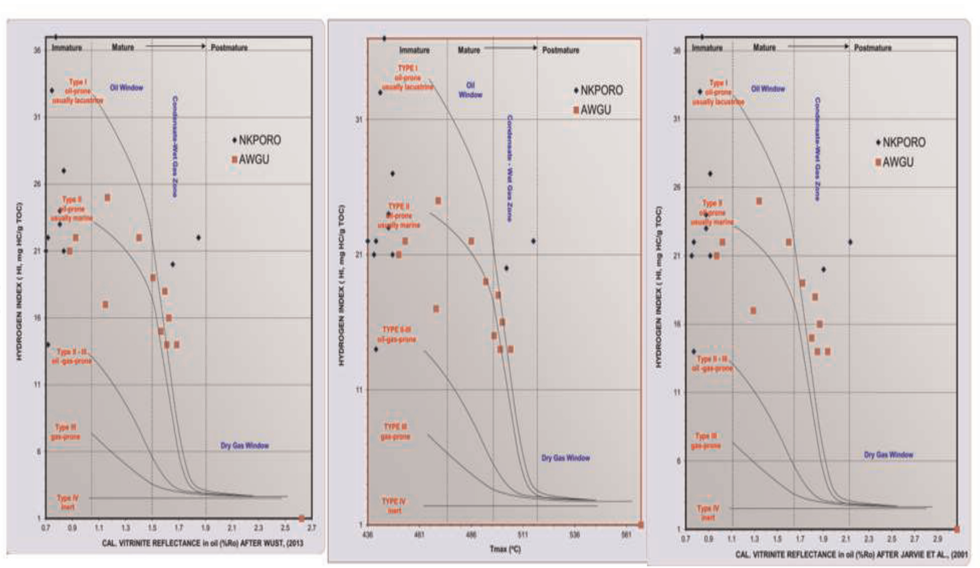

Figure 14.
Plot of Hydrogen Index (HI) against Maximum Temperature (Tmax), calculated Vitrinite Reflectance after [11] and calculated Vitrinite Reflectance after [16] showing Kerogen quality and thermal maturity stages for the studied sediments Nkporo Marine Shale and Agwu Marine Shales in the Lower Benue Trough sedimentary section of the Nzam-1 well indicating that Kerogen from Nkporo is immature to early maturity and is also Predominantly type II-III kerogen which is mixed oil/gas prone with minor occurrences of type II and type III While kerogen from Agwu shale has attained peak maturity to post maturity and the organic matter is predominantly consist of type II-III kerogen perhaps with minor occurrences of type II Kerogen.

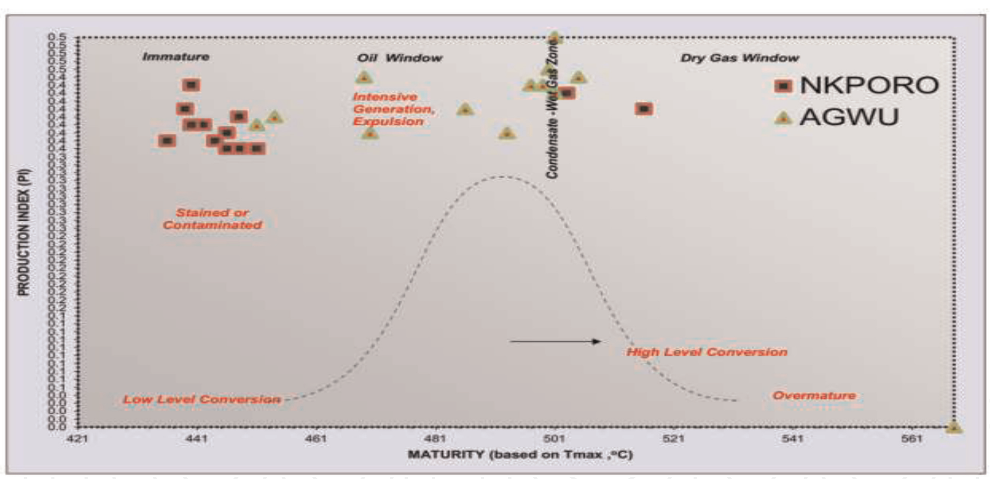

Figure 15.
Plot of Production Index against Tmax showing Kerogen Conversion/Maturity of late Campanian Nkporo Shales at immature-early mature stages and Coniacian Awgu Shales at peak maturity to post maturity stages in the sedimentary section of the Lower Benue Trough, Nzam-1 well indicating that the Nkporo Shale is at early maturity stages while Awgu is at peak/post maturity stages and has expelled hydrocarbon.

(**Figures 2** and **4**). In Nzam-1 well, heat flow values range between 48 and 72 mW/m^2 while in Akukwa-2 well it ranges 48 and 75 mW/m^2 and this can be attributed to the variability of heat flow and geothermal gradient in the earth subsurface.

6. Conclusions

Results of the investigation of burial/thermal histories and timing of petroleum generation/expulsion modeling of the Coniacian Agwu and the late Campanian

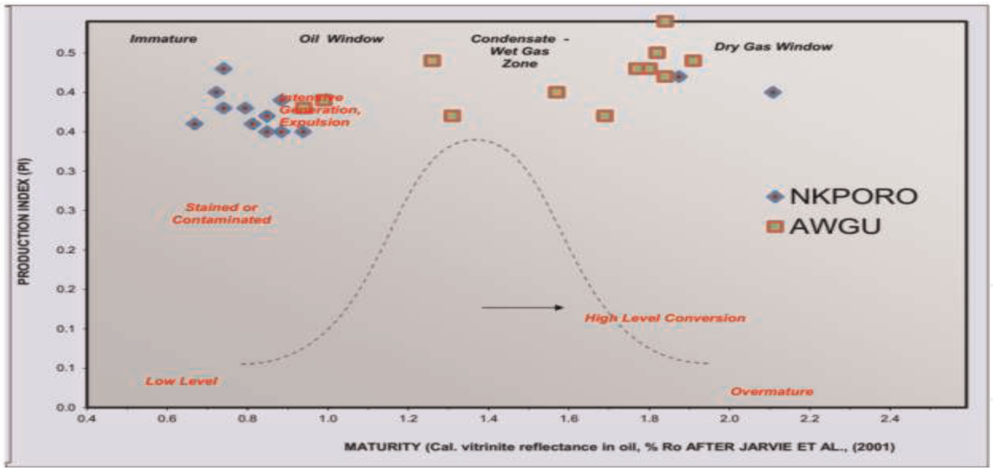

Figure 16.
Plot of Production Index against calculated Vitrinite reflectance after Jarvie at al., 2001 showing Kerogen Conversion/Maturity of late Campanian Nkporo Shales at immaturity-early maturity stages and Coniacian Awgu Shales at peak to post maturity stages in the sedimentary section of the Lower Benue Trough, Nzam-1 well indicating that the Nkporo Shale is at immaturity-early maturity stages while Awgu is at peak/post maturity stages and has expelled hydrocarbon.

Nkporo source rock intervals using Schlumberger's one dimensional modeling software indicates that:

The maximum temperature has been recorded in Agwu Formation where it reached 145°C at depth of 3400m and is responsible for the cracking of the oil to gas. There is also a strong indication that the high temperatures within the Formation were occasioned by deeper burial depth and possibly the Santonian tectonic episode which increased the geothermal gradient in the area. These further confirmed that the end of the Cretaceous era saw uplift, denudation and subsidence in the Lower Benue Trough as well as increased geothermal gradient to have caused complex processes of uplift, denudation, basin heating and cooling.

The hydrocarbon generation and expulsion modeling of the Lower Benue Trough shows that the Agwu Shale reached early phase of oil generation in late Campanian and extended from 75 Ma to 69 Ma in Nzam-1 well while it occurred at early Santonian and extended from 85 Ma to 78 Ma in Akukwa-2 well., Subsequently, main phase of oil generation began during early Paleocene and extended from 65 Ma to 62 Ma in Nzam-1 well and began during early Paleocene and extended from 75 Ma to 70 Ma in Akukwa-2 well. The gas phase began at mid Eocene and extended from 48Ma to present day in Nzam-1 well and began at mid Paleocene and extended from 58Ma to present day in Akukwa-2 well. As for the late Campanian Nkporo Source rock, the Model of Nzam-1 well has shown that the Nkporo Shale reached early phase of oil generation in early Paleocene and extended from 65 Ma to 60 Ma. Subsequently, main phase of oil generation began during late Paleocene and extended from 56 Ma to 42 Ma, whereas hydrocarbon generation and expulsion model of Akukwa-2 well has also shown that the late Campanian Nkporo Source rocks has entered the early phase of oil generation in late Maastrichtian (67Ma) to present day and did not reached the main phase of oil generation and expulsion owing to the fact that it lacks the requisite burial depth, temperature and pressure in favor of oil generation and expulsion.

The above shows that Awgu source rocks are overmature and are at post maturity gas evolution stage, generating gas to the present day whereas the Nkporo Shales are at early to peak maturity stage generating and expelling oil to the present day. Since the temperature continued to decrease exponentially to the present day and such decrease in temperature have favored the preservation of the gas reservoirs and therefore the survival of hydrocarbons in the deep strata can be guaranteed. More so the geothermics, configuration of the hydrocarbon generation timing and reservoir cap development has favored accumulation and the low geothermal field background after the formation of cracked gas has increased its chances of survival in their respective reservoirs within the Lower Benue Trough due to basin cooling and the resulting present day low heat flow (48 m/Wm$^{-2)}$. It can also be said that the hydrocarbon generation period provided favorable conditions for the accumulation of oil and gas from these Coniacian and late Campanian source rocks in the Lower Benue Trough. Given the multiple phases of hydrocarbon generation, the Coniacian Agwu source rocks had more favorable conditions for hydrocarbon accumulation than those of the upper Campanian Nkporo Source rocks. Drift sediments accompanying Coniacian- late Campanian periods possibly formed the major reservoir for the expelled hydrocarbons of the Agwu and Nkporo Shales and could represent potential reservoir units (Agbani and Owelli sandstones member) for hydrocarbons generated in the upper Cretaceous and time equivalent source rocks of Lower Benue Trough. This study suggest that valid petroleum systems exist in the basin with relative differences in the generation and expulsions periods of hydrocarbon generation in the two Formations and Paleogene Shale unit especially Imo Shales is the most important oil and gas cap rocks sealing the Owelli and Agbani sandstones that are being charged by the Coniacian Agwu and the late Campanian Nkporo Shales.

It is recommended that exploration processes be focused on the known deeper location of the Agwu and Nkporo Formations to predict the source kitchen. A 2D and 3D Burial History and Maturity modeling of the upper Cretaceous sediments of the Lower Benue Trough should be carried out and interpreted so as to identify the possible migratory path ways of the generated hydrocarbon by integrating structural information and hydrocarbon timing and generation. This will require the integration of Seismic, Geochemical and stratigraphic information.

Author contributions

Conceptualization and Data curation: Danwazan, J. and Adeleye, M. A.
Writing-original draft: Danwazan, J.
Writing-review & editing: Danwazan J. and Adeleye M.A,
Resources: Adeleye, M. A.
Investigation: Danwazan, J.
Supervision: Adeleye, M. A.

Author details

Jerry Danwazan[1,2*], Adesina Mutiu Adeleye[2], Trust-Paul Bakyu[2], Mamidak M. Iliya[1] and Joseph Kehinde Egunjobi[2]

1 Nasarawa State University, Keffi, Nigeria

2 University of Ibadan, Ibadan, Nigeria

*Address all correspondence to: danwazanjerry1000@gmail.com

References

[1] Abubakar MB. Petroleum potentials of the Nigerian Benue Trough and Anambra Basin: Regional studies. Natural Resources. 2014;**5**:25-58

[2] Tissot BP, Welte DH. Petroleum Formation and occurrence. 2nd ed. Berlin: Springer-Verlag; 1984. p. 699

[3] Ehinola OA, Ajala AA. Thermal Maturity and burial history modelling of Anambra basin. In: 6th NAPE-UAP Mini-conference Book of abstract A7. Southeastern Nigeria; Nigerian Association of Petroleum Explorationists (NAPE); 2012

[4] Oluwajana OA, Ehinola OA. Hydrocarbon-charge modelling of Anambra basin, Southeastern, Nigeria: Implications for Cretaceous-sourced plays. Arabian Journal of Geoscience. 2016;**9**(3):1-16

[5] Akaegbobi MI, Adegoke KA, Onyehara TI, Adeleye AM. Organic geochemical characterisation of the Campano-Maastrichtian sediments in Anambra Basin, SE, Nigeria: Implication for Paleodepositional Conditions, Provenance and Petroleum Generation Potential. Journal of Environment and Earth Science. 2017;**7**:18

[6] Adeleye MA, Adeniyi VA, Oke AO. Aspects of hydrocarbon potential of the Tertiary Imo Shale Formation in Anambra Basin, Southeastern Nigeria. A Journal of Applied Geology and Geophysics. **2017**;**5**:74-83

[7] Adeleye AM, Yuhong L, Abiodun AJ. Geochemical Evaluation of Nkporo Formation from Nzam-1 Well, lower Benue Trough. Journal of Petroleum and Coal. 2016;**58**(3):328-338

[8] Adebayo FO, Adeleye AM, Adegoke KA. Paleonenvironmental Reconstruction and Hydrocarbon Potentials of Upper Cretaceous Sediments in the Anambra Basin, Southeastern Nigeria. International Journal of Coal Geology. 2018;**192**:56-72

[9] Lopatin NV. Temperature and geologic time as factors in coalification. Altai Izvestiya AkademiyaNauk Kazakh SSR. SeriyaGeologicheskaya. 1997;**3**:95-106

[10] Littke R, Buker C, Luckge A, Sachsenhofer RF, Welte DH. A new evaluation of palaeoheat flows and eroded thicknesses for the Carboniferous Ruhr Basin, western Germany. International Journal of Coal Geology. 1994;**26**:155-183

[11] Jarvie DM, Claxton BL, Henk F, Breyer JT. Oil and shale gas from the Barnett Shale, Fort Worth basin, Texas. AAPG Bulletin. 2001;**85**:A100

[12] Adeleye AM, Adeigbe OE, Yuhong L. Source Rock Evaluation of the Agwu Formation from Nzam-1 well, lower Benue Trough, Nigeria. NAPE Bulletin. 2014;**26**(1):87

[13] Hardenbol J, Jacquin T, Farley MB, de Graciansky P-C, Vail PR. Mesozoic and Cenozoic chronostratigraphy and cycles of sealevel changes. In: de Graciansky P-C, Hardenbol J, Jacquin T, Vail PR, editors. Mesozoic and Cenozoic Sequence Stratigraphy of European Basins. Vol. 60. SEPM Special Publication; 1998. pp. 3-13

[14] Sweeney JJ, Burnham AK. Evaluation of a simple model of vitrinite reflectance based on chemical kinetics. AAPG Bulletin. 1990;**74**(10):1559-1570

[15] Vandenbroucke M, Behar F, Rudkiewicz JL. Kinectic modelling of

petroleum formation and cracking: Implications from the high pressure/high temperature Elgin Field (UK, North Sea). Organic Geochemistry. 1999;**30**(9): 1105-1125

[16] Wust RAJ, Hackley PC, Nassichuk BR, Willment N, Brezovski R. Vitrinite Reflectance Versus Pyrolysis Tmax Data: Assessing Thermal Maturity in Shale Plays with Special Reference to the Duvernay Shale Play of the WesternCanadian Sedimentary Basin. Alberta, Canada: SPE Unconventional Resources Conference and Exhibition-Asia Pacific held in Brisbane, Australia; 2013

[17] Obaje NG. Geology and Mineral Resources of Nigeria. Berlin Heidelberg: Springer-Verlag; 2009. pp. 57-65

[18] Fatoye FB, Gideon YB. Geology and mineral resources of the lower Benue Trough Nigeria. Advances in Applied Science Research. 2013;**4**:21-28

[19] Al-Areeq NM, Albaroot MA. Source rocks evaluation and thermal maturity evolution of the dhamarali field, sab'atayn basin, Yemen. Asian Journal of Science and Technology. 2019;**10**(01): 9364-9374