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Original Research Article

Assessment of Petroleum Source Rocks of Yola Basin, North-Eastern Nigeria: From the Viewpoint of Bulk Geochemistry and Organic Petrography

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KEYWORDS
Petroleum Generation,
Frontier Exploration,
Cretaceous,
Yola Sub-basin.

ABSTRACT
The Yola Basin is a hydrocarbon exploration frontier basin in Nigeria where to date; minimal subsurface data is available for adequate assessment of its petroleum source rocks. The Bima Formation is the oldest lithogenetic unit in the basin followed by Yolde, Dukul, Jessu, Sekuliye formations, Numanha Shales and Lamja Formation. Source rock geochemical characterisation was conducted on the Cretaceous sequences of Yola Basin with the aim to determine the organic matter type, richness, thermal maturity and hydrocarbon generation potential. The organic matters within the shales of Bima Formation have reached peak oil window to high thermal maturity stage of oil generation. They possess fair source generative potential based on the present-day kerogen Types I, Type III and Type IV, showing minor oil and major gas prospect. The shales of Yolde, Dukul, Jessu, Sekuliye formations and Numanha Shales have reached peak-oil window to mature stage of oil generation and possess fair source rock generative potential based on their present-day kerogens Type II-III, Type III and Type IV and are likely to generate mainly gas although, minor oil could be expected owing to the presence of small amount of Type II kerogens. The Lamja Formation shales and coals are at early to peak oil generation window and possess poor to very good source generative potential based on the present-day Type III and Type II-III kerogens, expected to generate major gas and liquid components of hydrocarbons. The high thermal maturity has effect on the original nature of the organic matter and any oil-prone organic matter if present would have been cracked into thermogenic gas probably due to the intense thermal event attributed by the Tertiary volcanic intrusion known to be present in the basin.

CITATION
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INTRODUCTION

The Yola Sub-basin is a frontier exploration basin located in the Northern Benue Trough of Nigeria (Fig. 1). There is no reported drilled well or core hole in the Yola Sub-basin to date. In 1994, the Federal Government of Nigeria implored the multinational oil companies (Shell, Chevron and Elf) to explore the possibility of hydrocarbon fields in the Benue Trough. It wasn't only the scanty geological data that warranted that decision. Perhaps, it was due to the discovery of commercial quantities of oil and gas in the neighbouring countries of Chad (Doba, Doseo and Bongor Fields), Niger (Termit-Agadem Fields) and Sudan (Muglad Field) within the same rift system (Sarki Yandoka, 2015). The discovery was related to three petroleum systems; the

Lower Cretaceous oil-prone lacustrine sediments, the Upper Cretaceous gas-prone marine sediments and the Paleogene oil-prone lacustrine and marine sediments (Sarki Yandoka, 2015; Makeen et al., 2014; Abubakar, 2014; Abubakar et al. 2008). These prospective sedimentary basins of Chad, Niger and Sudan Republics occur within the West and Central African Rift System (WCARS).

They have the same geological setting, time equivalence and origin with the Northern Benue Trough of Nigeria. Also, they have been affected by similar geological activities and therefore, they are likely to yield similar results. This is confirmed from one of the exploratory wells (Kolmani River – 1 well) drilled by Shell in the Gongola Sub-basin of the Northern Benue Trough where 33 billion cubic feet of gas with little oil was found which authenticates the presence of a full petroleum system in the basin. The recent discovery of oil and gas in Kolmani River II well by NNPC in 2019 in the Gongola Basin also supports this earlier discovery. Therefore, it is expected that the integration of geochemical studies of sedimentary organic matters could provide the necessary impetus to research on the viability of the Cretaceous petroleum source rocks in the Yola Sub-basin which in turn, could help in risk-reduction associated with the current hydrocarbon exploration campaigns in region. The study also aimed to provide information on hydrocarbon generation potential of the Cretaceous sequences of Yola Sub–basin of the Northern Benue Trough.

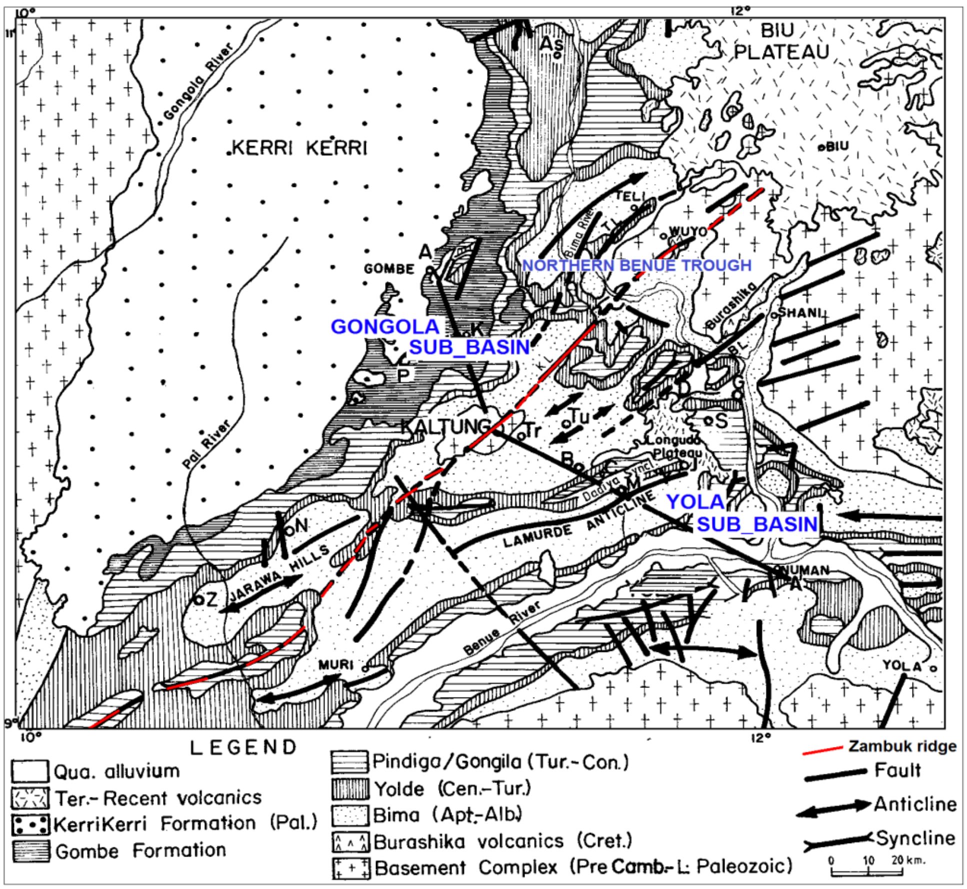

Figure 1: Simplified geological map of Nigeria showing the Yola Sub-basin within the Northern Benue Trough (modified after Akande et al., 1998)

Geological setting

The Benue Trough is part of the mega-structure termed "West and Central African Rift System" (WCARS). It is filled with up to 6000 m of sediments associated with Tertiary volcanics. It is sub-divided geographically into Southern, (Lower) Central (Middle) and Northern (Upper) Benue portions. The Northern Benue Trough is made up of two major sub-basins; the N-S trending Gongola Basin and the E-W trending Yola Basin (Fig. 2). The study area is located in the Yola Basin of the Northern Benue Trough (Fig. 2). The stratigraphic succession comprises the continental Lower Cretaceous Bima Formation, the Cenomanian transitional marine Yolde Formation and the marine late Cenomanian–Santonian Dukul, Jessu, Sekuliye Formations, Numanha Shales and Lamja Formation. The Bima Formation is the oldest lithogenetic unit occupying the base of the Cretaceous successions. The sediments were derived from basement rocks of older granites and gneisses deposited in a continental environment under widely varying conditions of alluvial fan, braided river and lacustrine (Carter et al., 1963; Sarki Yandoka et al., 2014). It is differentiated into Lower Bima (B1), Middle Bima (B2) and Upper Bima (B3) members. The Cenomanian (coastal-shallow marine) Yolde Formation has been recognized as a sequence of sandstones and shales that marked the transition from continental to marine sedimentation. The base is defined by the appearance of marine shales and the top by the disappearance of sandstone and the commencement of limestone-shale series. This was followed by the sedimentation of Dukul Formation.

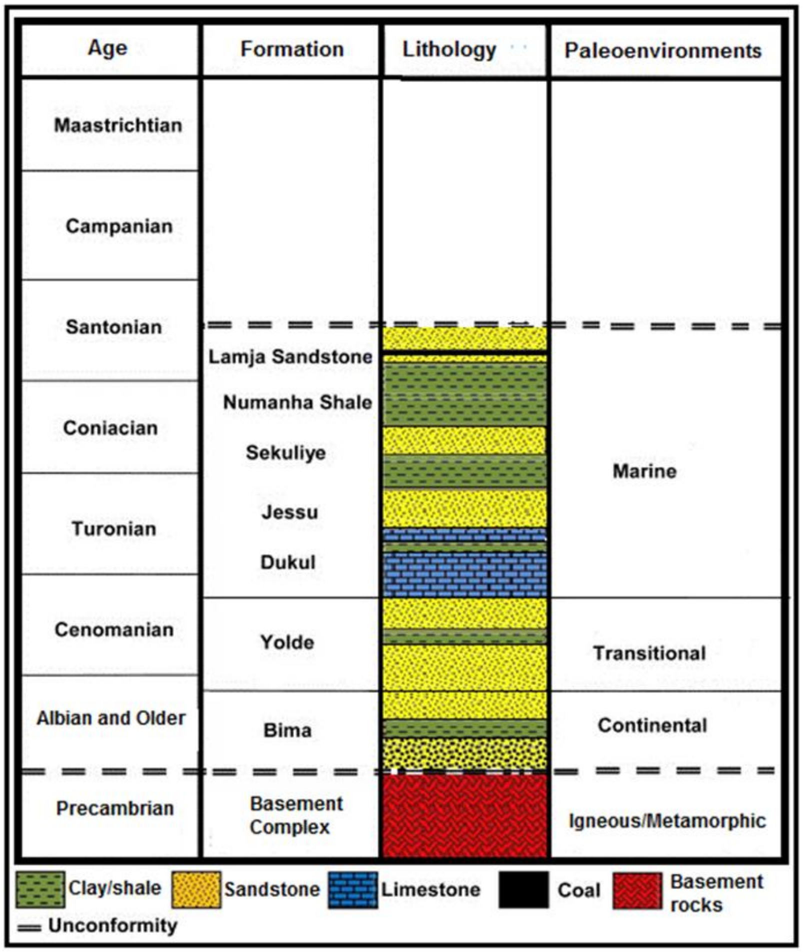

Figure 2: Stratigraphic succession of Yola Sub-basin (after Sarki Yandoka, 2015)

The Dukul Formation was earlier recognized as “limestone – shale series” assigned to the Lower Turonian (e.g. Carter et al., 1963). It consists of shale and thick limestone interbeds. It represents a shallow marine (carbonate ramp) sedimentation in Yola Sub – basin and conformably overlies the Yolde Formation (Sarki Yandoka, 2015). The Jessu Formation was deposited by brief regression and consists of sandstones, mudstones and shales. It was termed earlier as “Mudstone Shale Series” deposited by a brief regressive phase (Carter et al., 1963). Sandy mudstones are predominant in the lower part. Shale also became more common at higher horizons. It is considered to have being deposited during Upper Turonian and conformably overlies Dukul Formation (Nwajide, 2013; 2023). The Sekuliye Formation is a sequence of shale and limestone. The formation conformably overlies the Jessu Formation. It consists of pale greenish – grey shale with bands of siliceous limestone. Upper Turonian – Santonian age was assigned. The Numanha Shales composed of shale with bands of mudstone, sandstone and limestone. The formation was first recognized as argillaceous beds and deposited in marine environment (Carter et al., 1963). The lower part consists of grey – black shale and nodular beds of mudstones (Carter et al., 1963). It conformably overlies the Sekuliye Formation and was assigned to the Upper Coniacian. The Lamja Formation consists of sandstone, shale and coal. This formation was first described under the name “Carbonaceous Beds" and conformably overlies the Numanha Shales. It marks the end of sedimentation in the Yola Sub-basin during the Santonian. Tertiary volcanic plugs were reported and are localized at the boundary between the Gongola and Yola Sub – basins.

MATERIALS AND METHODS

This study is based on field investigations of outcrops, sedimentary logs and laboratory analyses of samples collected during field studies (Fig. 3). Kerogen analysis is carried out by chemical analyses (e.g. Rock-Eval pyrolysis). Fieldwork was carried out on the outcropping areas where the formations of Yola Sub-basin are well exposed. Shale and coal samples were collected. Sedimentary logs were recorded using measuring tape and log sheet (Fig. 4) whilst field photographs were collected using camera. Prior to analysis, the samples were crushed into fine powder (<150 µm) and screened with Source Rock Analyzer (SRA) Weatherford instrument. The pyrolysis (SRA) analysis was performed on 80 mg shale samples. The samples were all heated at 600oC in a helium atmosphere and parameters such as S1, S2 and Tmax (temperature at maximum pyrolysis S2 yield) were measured. Total organic carbon (TOC) content was determined from MultiEA2000 Analyzer. The organic richness, kerogen type, petroleum generation potential and thermal maturity are characterised based on pyrolysis data and TOC as outlined following the works of Horsefield (1989, 1997), Peters and Cassa (1994).

RESULTS AND DISCUSSION

Bulk geochemistry

Organic geochemical characterisation of kerogen such as Rock-Eval Pyrolysis for the shale samples of Yola Basin was conducted. The geochemical results were used to determine the amount of the remaining organic matter and the hydrocarbon generation potential. The minimum TOC limits generally accepted as essential for a source-rock are more than 1% for sediments (e.g. Peters and Cassa, 1994; Tissot and Welte, 1978, 1984). The Rock Eval pyrolysis analysis data of the Bima, Yolde, Dukul, Jessu, Sekuliye and Numanha and Lamja samples are presented in Table 1. The total organic carbon (TOC) values of Bima shales range from 0.38-0.86 wt %. The free hydrocarbons (S1) are in the range 0.03-0.15 mg HC/g rock while the hydrocarbon yield (S2) generated during pyrolysis range from 0.16 to 0.68 mg/g. The pyrolysis HI versus and the Tmax data also range from 24–127 mg HC/g TOC and 448–489°C respectively as presented in Table 1.

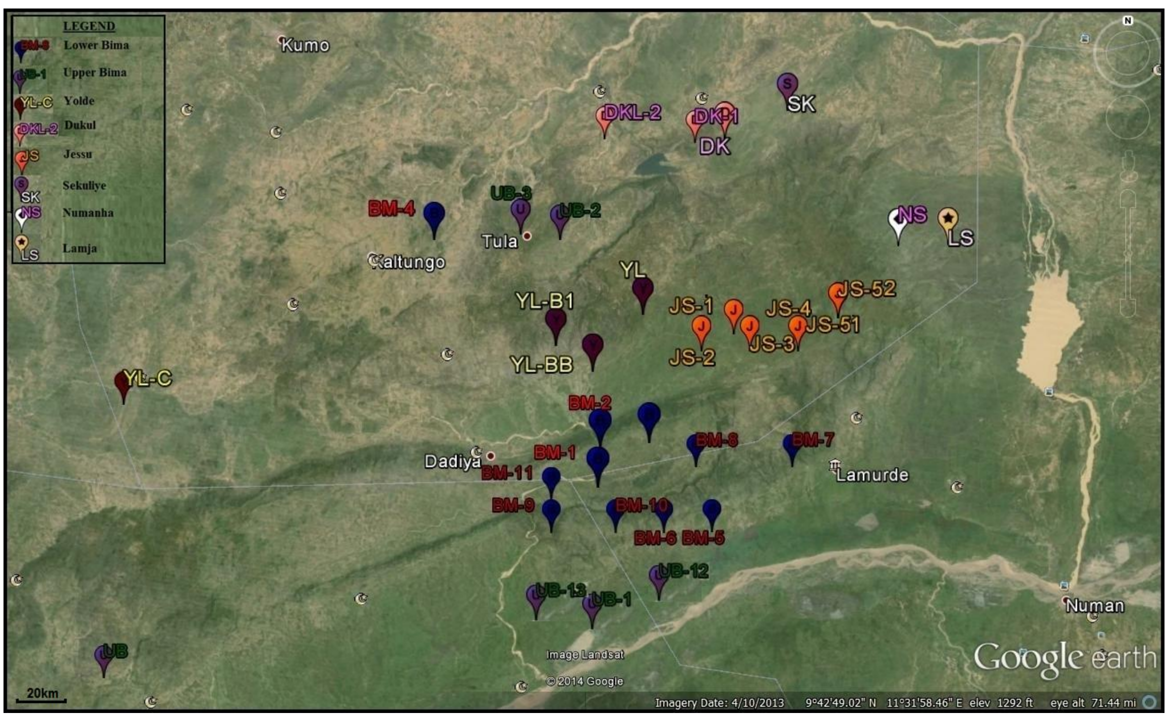

Figure 3: Location of the sampling points/areas from the Yola Basin (Google Earth, 2025)

The shale samples of Yolde, Dukul, Jessu, Sekuliye and Numanha have a total organic carbon (TOC) value of 0.24 to 0.91 wt %. The free hydrocarbons (S1) range 0.03-0.23 mg HC/g rock while the hydrocarbons (S2) yields generated during pyrolysis of kerogen range 0.04-0.74 mg HC/g rock. The shale samples have low HI values in the range of 18-130 mg HC/g TOC and Tmax values between 440°C and 491°C. The shale samples of Lamja have low to fair total organic carbon (TOC) content ranging from 0.88-1.16 wt% whereas the coaly sediments as expected contain higher total organic carbon (TOC) content in the range 45.23-67.85 wt%. The free hydrocarbons (S1) ranges from 0.22-0.33 mg HC/g rock in shales and 0.77-2.89 mg HC/g rock in coaly sediments whereas the pyrolysis S2 yield for shales ranges from 0.82 to 1.41 mg HC/g rock and 45.49 to 125.53 mg HC/g rock in coals. The HI values of the shale and coaly sediments are in the range of 90-130 mg

HC/g TOC and 95 – 228 mg HC/g TOC respectively, while the Tmax values ranges from 436–451°C (Table 1).

Organic petrography

Organic facies studies are used in the prediction of the likely occurrence of hydrocarbon source potential as a function of depositional environment (Tyson, 1993, 1995). Organic facies characterisation was carried out using organic petrographic (reflected white and fluorescence lights) and palynological (transmitted white light) methods using polished blocks and palynological slides respectively. Vitrinite reflectance (%Ro) measurements are widely accepted by petroleum exploration geologists as a powerful technique for measuring the thermal maturity of source rocks (Tissot and Welte 1984). Thermogenic oil is thought to be generated from marine and lacustrine source rocks at vitrinite reflectance values between 0.5% and 1.3%, suggest oil-generation window while vitrinite reflectance greater than 1.3 % indicates gas window. The vitrinite reflectance (Ro) measurements were performed on the shale samples. The Bima lacustrine shales have high vitrinite reflectance values in the range of 1.12-2.0 VRo% which suggest late-oil window and higher maturity stage. The marine shale samples of Yolde, Dukul, Jessu, Sekuliye and Numanha have high reflectivity with vitrinite reflectance (%Ro) values ranging from 0.63-2.1. The mean reflectance of vitrinite particles of Lamja shale and coal sediments ranges from 0.57 to 0.82 %.

Organic petrographic features indicate a dominance of vitrinites macerals in Bima shale samples with weak fluorescence under UV light excitation. The shales of Yolde, Dukul, Jessu, Sekuliye and Numanha contain insufficient vitrinites and most of the organic petrographic features have weak to almost non-fluorescence under UV lights excitation. The Lamja shales indicate the presence of mostly terrestrially derived organic matters e.g. amorphous organic matter (AOM) as viewed under normal reflected white light and UV light. The coal samples are rich in terrigenous liptinites especially resinite, sporinite and cutinite. Macerals of the vitrinite group are identified as dark grey or medium grey tellinite, lighter colored vitrodetrinite and relatively darker desmocollinite. None of the vitrinites show any fluorescence. The macerals of the vitrinite group are significantly higher in abundance compared to the other maceral groups. The inertinite macerals have the lowest abundance in the coal samples and they are present as micrinite, fusinite, semifusinite, funginite and inertodetrinite.

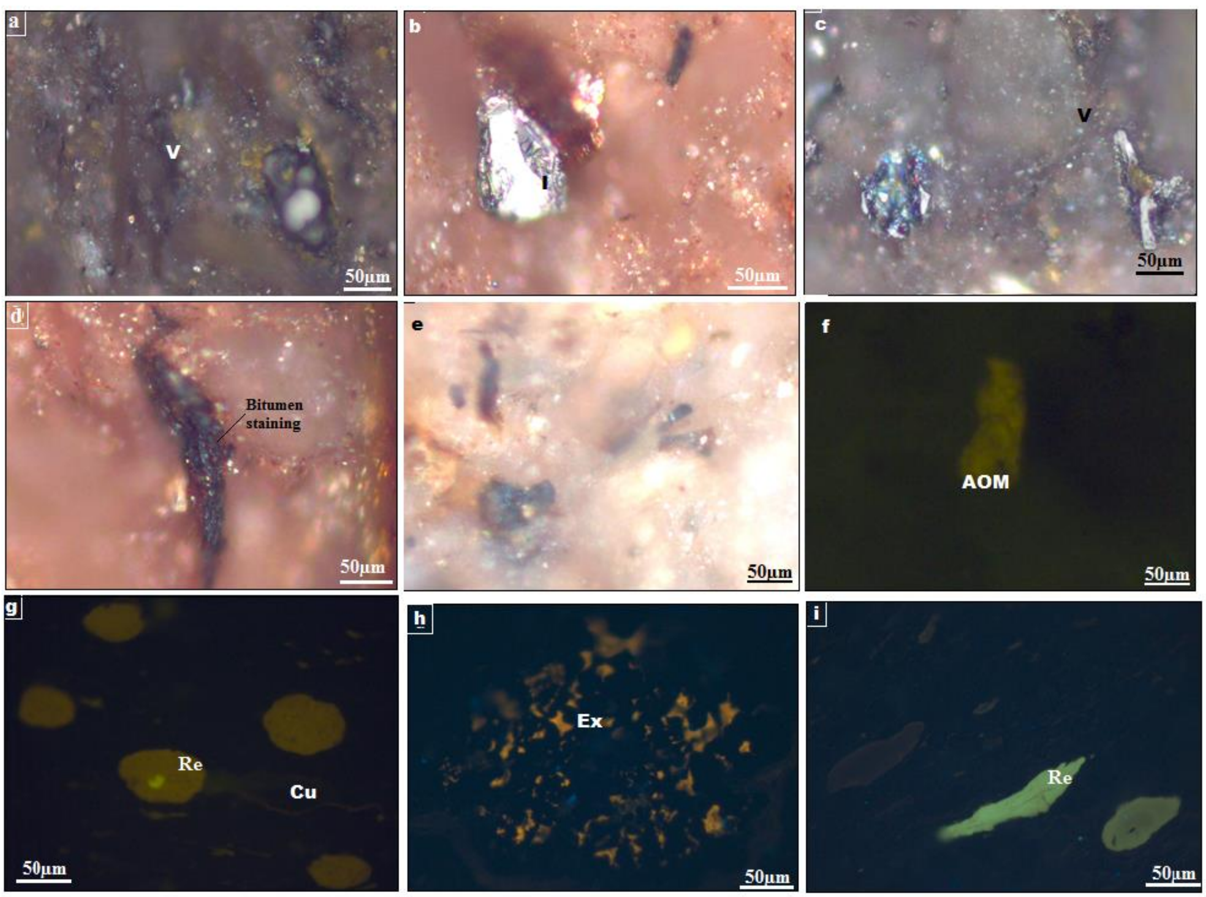

Figure 4: Photomicrographs of (a-b) vitrinites and inernites from Bima shales, (c-d) vitrinites and bitumen staining from marine shales, (e-f) amorphous organic matter of Lamja shales, (g-i) cutinite, semifusinite associated with resinite (Re) under reflected light viewed under fluorescent light of Lamja coals

Source rock quality and quantity

The bulk geochemical results were used to determine the amount of remaining organic matter and the present-day hydrocarbon generation potential. Minimum TOC limit that is generally accepted as essential for a good potential source rock is 1% (Peters and Cassa, 1994). The entire lacustrine shale samples can be generally regarded as having fair source rock generative potential with TOC values ranging from 0.38 to 0.96 wt. %. The shallow marine shale samples of Yolde, Dukul, Jessu, Sekuliye and Numanha have TOC values ranging from 0.24 to 0.91 wt% ranking them as fair source rocks (as defined by Peter and Cassa, 1994). The analysed shales have pyrolysis S2 yield values in the range of 0.04-0.14 mg HC/g rock. The TOC content and pyrolysis S2 yield values meet the accepted standards of a source with a fair to relatively good source generative potential. Lamja Formation shales have relatively low to fair TOC content (0.88-1.16 wt%) whereas the coaly sediments as expected contain higher TOC content in the range 45.23-67.85 wt% which classify them as possessing good to excellent source rocks generative potential (Figs. 4-6). The hydrocarbon yields (S2) are in agreement with TOC content, indicating that the Lamja coal and shale sediments possess fair to excellent source rock-generative potential based on classification given by Peters and Cassa, (1994).

For kerogen quality (typing), Type I and II kerogen are derived from lacustrine and marine source rocks are capable of generating liquid components hydrocarbons. Type III kerogen are mostly composed of woody materials consist of mainly gas prone while Type IV composed of inert materials with no hydrocarbon generating potential (Peters and Cassa, 1994). The lacustrine shales of Bima Formation reflected the present-day generation potential and indicates that the organic matters composed of predominantly Type III and Type IV kerogens (Mukhopadhy, et al., 1995) (Fig. 10). Most of the shale samples that have hydrogen index values more than 50 mg HC/g TOC can be expected to possess mainly gas generation potential, while samples with hydrogen index less than 50 mg could only produce inert carbon as indicated by high maximum temperature Tmax and PI values (Table 1).

Organic matter type within the marine shales of Yolde, Dukul, Jessu, Sekuliye and Numanha formations have HI values in the range of 8-113 mg HC/g TOC reflecting the present-day generation potential. This indicates that the organic matter in the shales is predominantly of Type III and Type IV kerogens although, minor oil-prone could be expected based on the presence of small amount of Type II kerogen. Most of the shale samples have hydrogen indices of approximately 50 mg HC/g TOC thus, can be expected to be mainly gas-prone, while those samples with hydrogen indices less than 50 mg HC/g TOC do not possess any hydrocarbon potential and can only produce inert carbon (non-hydrocarbon). The sediments of Lamja Formation contain both Type II and mixture of Type II-III kerogens. The pyrolysis data (HI against Tmax) indicated that the analysed Lamja Formation samples generally plot in the mature zone of mixed Type II-III kerogens grading to Type III kerogen (Figs. 7-9). This corresponds to the HI values ranging 90-228 mg HC/g TOC. Most of the samples are plotted in the Type III field in this diagram, while some coal samples are plotted within the mixed Type III-II kerogens which suggest that the Lamja sediments can be expected to generate mainly gas with limited capability to generate of liquid hydrocarbons.

Table 1: Rock-Eval Pyrolysis data (SRA), TOC contents, vitrinite reflectance (%Ro) and thermal alteration index (TAI) of the analysed Bima, Yolde, Dukul, Jessu, Sekuliye, Numanha and Lamja shales and Lamja coal samples

Sample ID	TOC and Rock-Eval Pyrolysis Data					
	S_1 (mg/g)	S_2 (mg/g)	T_{max} (°C)	HI	PI	TOC (wt. %)
BM3A	0.08	0.28	469	44	0.22	0.63
BM3B	0.05	0.23	496	45	0.11	0.51
BM4	0.09	0.26	443	63	0.26	0.41
BM5	0.13	0.39	455	35	0.41	0.55
BM8B	0.04	0.24	448	63	0.14	0.38
BM9A	0.03	0.42	452	106	0.07	0.49
BM9B	0.07	0.68	450	127	0.04	0.55
BM10	0.06	0.56	468	30	0.19	0.96
YOL1	0.05	0.14	475	30.0	0.26	0.47
YOL2	0.03	0.04	446	8.17	0.43	0.49
YOL3A	0.07	0.12	447	25.0	0.37	0.48
YOL3B	0.05	0.06	488	18.2	0.45	0.33
DKL1	0.06	0.23	444	39.6	0.21	0.58
DKL2	0.06	0.25	443	35.2	0.19	0.71
DKL3	0.07	0.18	442	35.3	0.28	151
DKL3B	0.12	0.39	443	64.0	0.23	0.61
DKL6	0.09	0.22	454	44.0	0.29	0.50

JES1	0.07	0.19	458	35.8	0.26	0.53
JES1B	0.08	0.13	456	26.0	0.38	0.51
JES2	0.04	0.09	445	19.0	0.31	0.48
JES3	0.08	0.15	449	33.3	0.35	0.45
SEK1	0.08	0.26	447	48.1	0.24	0.54
SEK2	0.11	0.37	446	82.2	0.23	0.45
SEK3A	0.09	0.29	444	80.6	0.24	0.36
SEK4A	0.12	0.34	454	62.0	0.26	0.55
NS1	0.13	0.31	440	94.0	0.29	0.33
NS5	0.04	0.13	449	25.0	0.24	0.52
NS9	0.11	0.38	443	97.4	0.22	0.39
NS10	0.23	0.71	443	113	0.24	0.63
NS12	0.06	0.34	451	109	0.15	0.31
NS16	0.20	0.74	443	113	0.21	0.65
LSS2	0.22	0.82	445	93.2	0.21	0.88
LSS5	0.23	1.38	445	129	0.14	1.07
LSS8	0.35	1.04	451	90.0	0.25	1.16
LSS55	0.33	1.41	446	130	0.20	1.08
LSS6A	0.52	56.15	442	100	0.01	56.17
LSS6B	0.77	55.17	443	95.0	0.01	58.10
LSS7A	2.51	100.67	437	209	0.02	48.28
LSS7B	2.64	102.59	438	151	0.03	67.85
LSS9A	1.88	92.42	439	188	0.02	49.15
LSS9B	2.34	96.98	438	167	0.02	58.32
LSS10A	2.89	125.53	436	194	0.02	64.67
LSS10B	0.66	59.85	445	111	0.01	53.88
LSS13A	2.61	100.79	437	158	0.03	63.98
LSS13B	2.17	94.1	438	152	0.02	62.12

(S1: Volatile hydrocarbon (HC) content, mg HC/g rock; S2: Remaining HC generative potential, mg HC/g rock, HI: Hydrogen Index = S2 x 100/TOC, mg HC/g TOC; TOC: Total organic Carbon, wt. %, PI: Production Index= S1/(S1+S2); Tmax: Temperature at maximum)

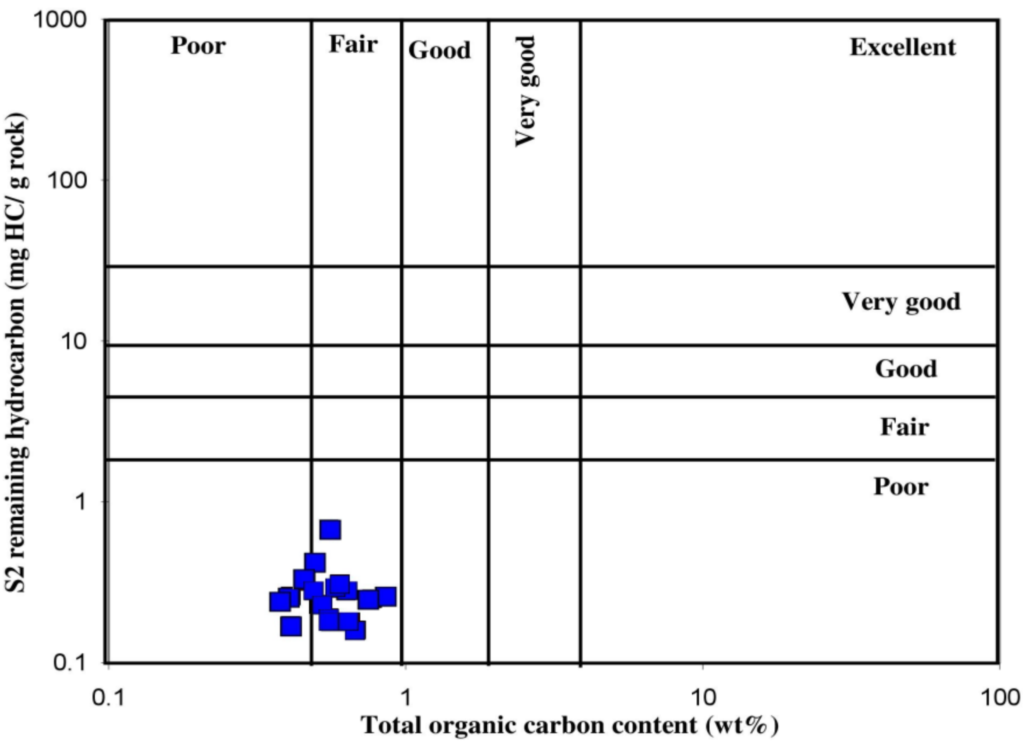

Figure 5: Plot of total organic carbon (TOC) versus S_2 remaining hydrocarbons of the Bima shale samples

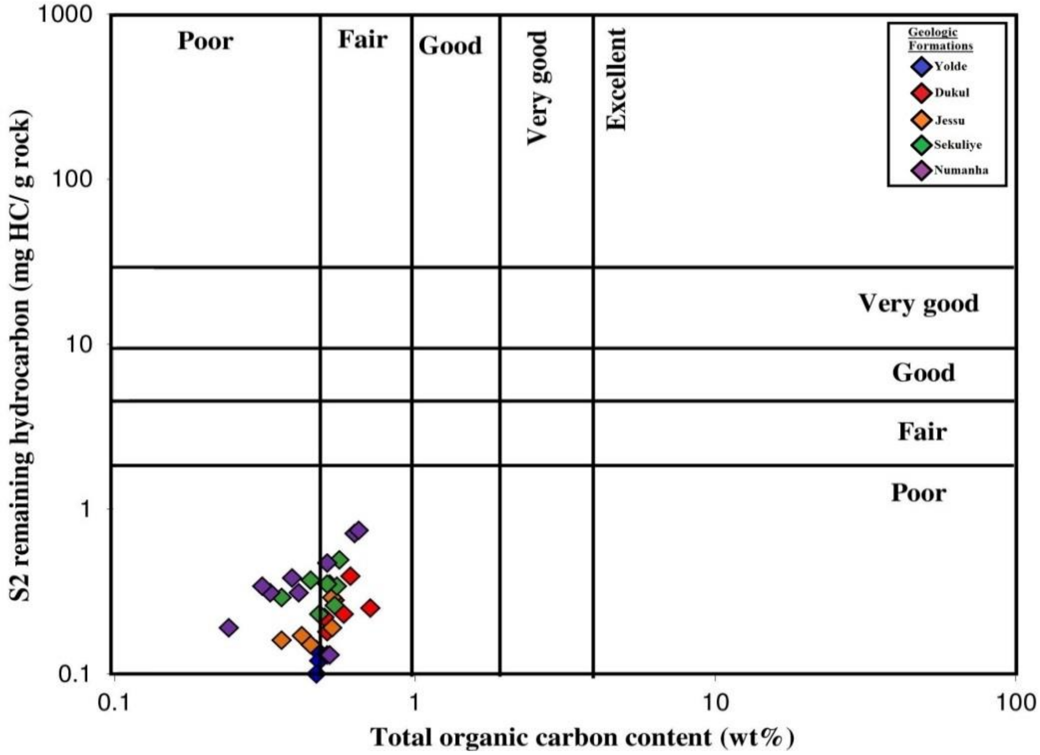

Figure 6: Plot of total organic carbon (TOC) versus S_2 remaining hydrocarbons of the Yolde, Dukul, Jessu, Sekuliye and Numanha shale samples

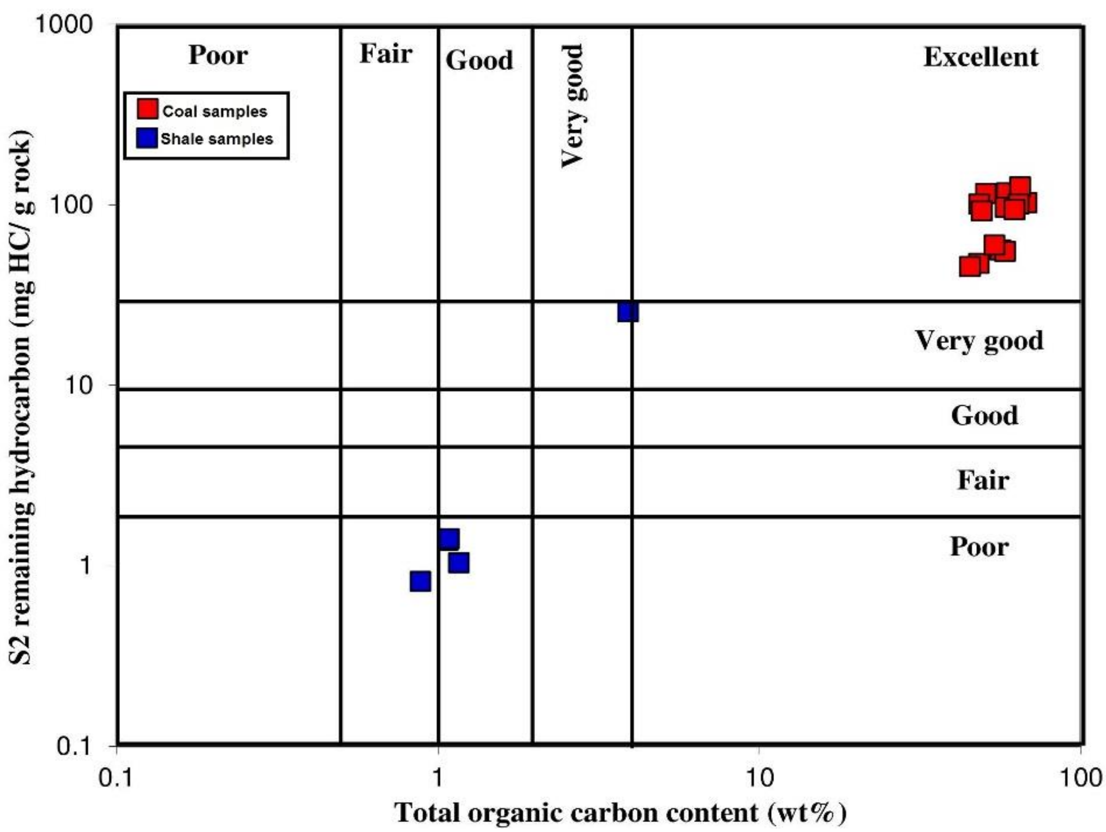

Figure 7: Plot of total organic carbon (TOC) versus S_2 remaining hydrocarbons of the Lamja shale and coal samples

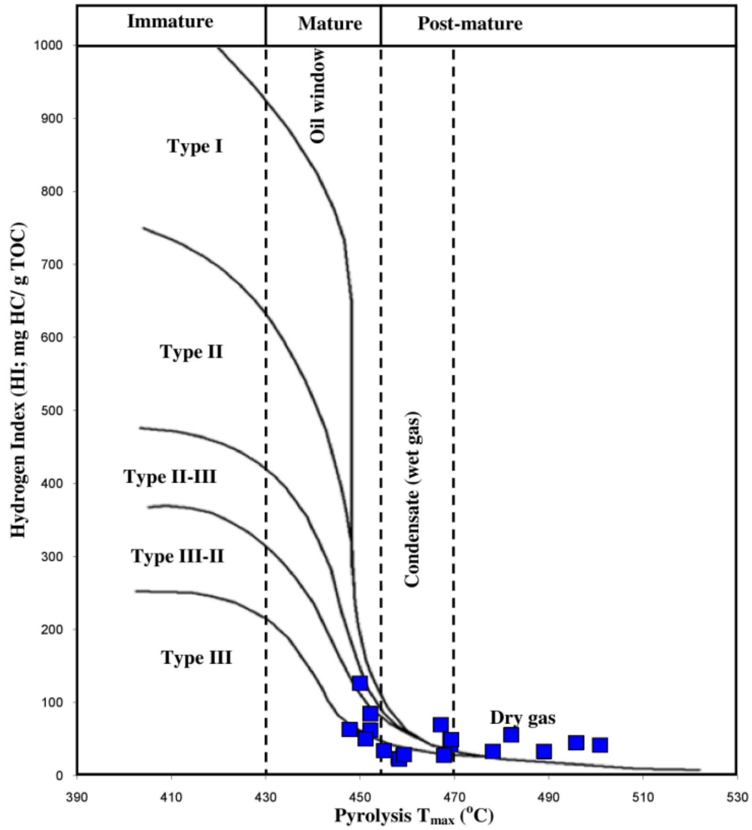

Figure 8: Plot of hydrogen index (HI) versus pyrolysis Tmax for the analysed Bima shale samples showing kerogen quality

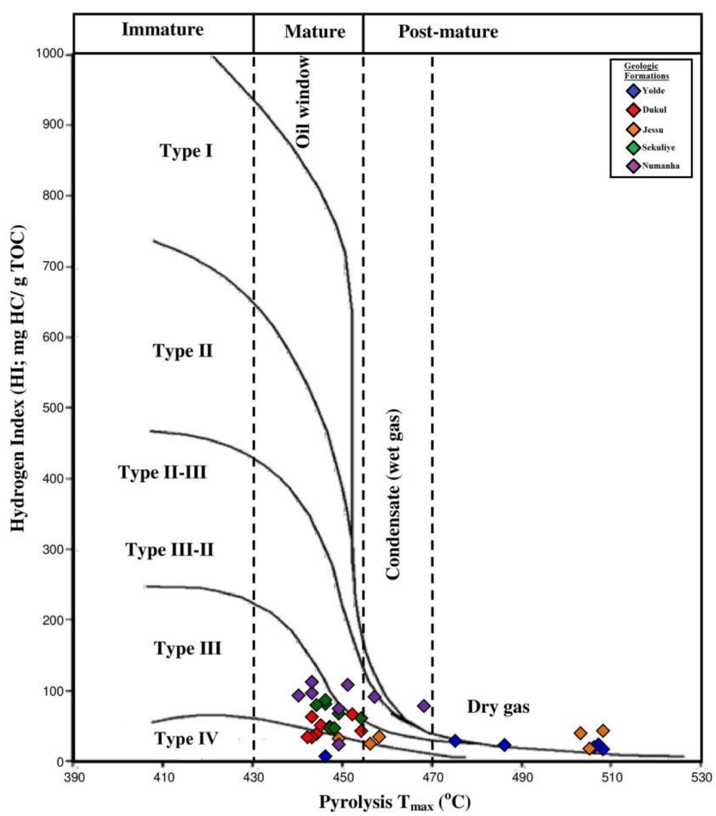

Figure 9: Plot of hydrogen index (HI) versus pyrolysis Tmax for the analysed Yolde, Dukul, Jessu, Sekuliye and Numanha shale samples, showing kerogen quality

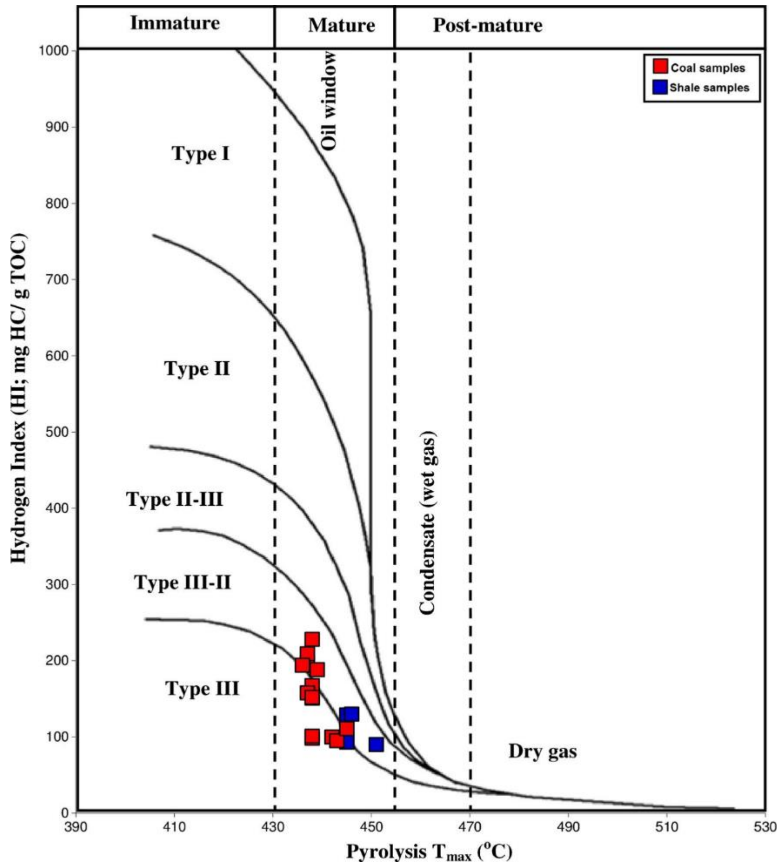

Figure 10: Plot of hydrogen index (HI) versus pyrolysis Tmax for the analysed Lamja shale and coal samples, showing kerogen quality

Source rock thermal maturity

For organic rich source rock to become effective, it must reach a maturity level sufficient to generate hydrocarbon (Tissot and Welte, 1984). Thermal exposures convert kerogen to bitumen, then to petroleum. A number of data types were used to assess the level of thermal maturity of organic matter in the Cretaceous sediments of Yola Sub-basin. The maturity data includes; vitrinite reflectance (%Ro), pyrolysis Tmax values, palynofacies analysis and biomarker maturity ratios. Table 5.3 shows maturity parameters and their ranges based on Peter and Cassa, (1994). Tmax values may be affected by mineral matrix effect (e.g. Espitalie et al., 1980; Sarki Yandoka et al., 2015a). Vitrinite reflectance may also be affected by depositional environment (organic facies) and matrix lithology (e.g. Hutton and Cook, 1980). Integration of pyrolysis parameters, petrography (vitrinite reflectance) and molecular geochemistry (biomarkers) could give more insight into the thermal maturation of organic matter in sediments (Mustapha and Abdullah, 2013; Hakimi et al., 2011, 2013, 2014 and 2015).

The lacustrine shales of Bima Formation have an average Ro value of 0.95% which correspond to peak-late-oil window stage of oil-gas generation (Peter and Cassa, 1994). The Tmax values are in good agreement with the measured vitrinite reflectance data as illustrated by a very good correlation (r2 = 0.95) (Figs. 10 - 12). The shallow marine shale samples of Yolde, Dukul, Jessu, Sekuliye and Numanha formations have an average vitrinite reflectance value of 0.68 %Ro which correspond to peak oil window stage of oil-gas generation. The Tmax values indicates that the shales are thermally mature and have entered peak-oil window. These values are in good agreement with the measured vitrinite reflectance data, as illustrated by a good correlation between Tmax and Ro (r2 = 0.82). Furthermore, production index (PI) values also indicated the same level of thermal maturity. The mean average vitrinite reflectance of vitrinitic particles of Lamja shales and coals is 0.68% Ro, which corresponds to early mature to peak oil window maturity as indicated in good a agreement as illustrated by a good correlation between Tmax and %Ro (r2 = 0. 68).

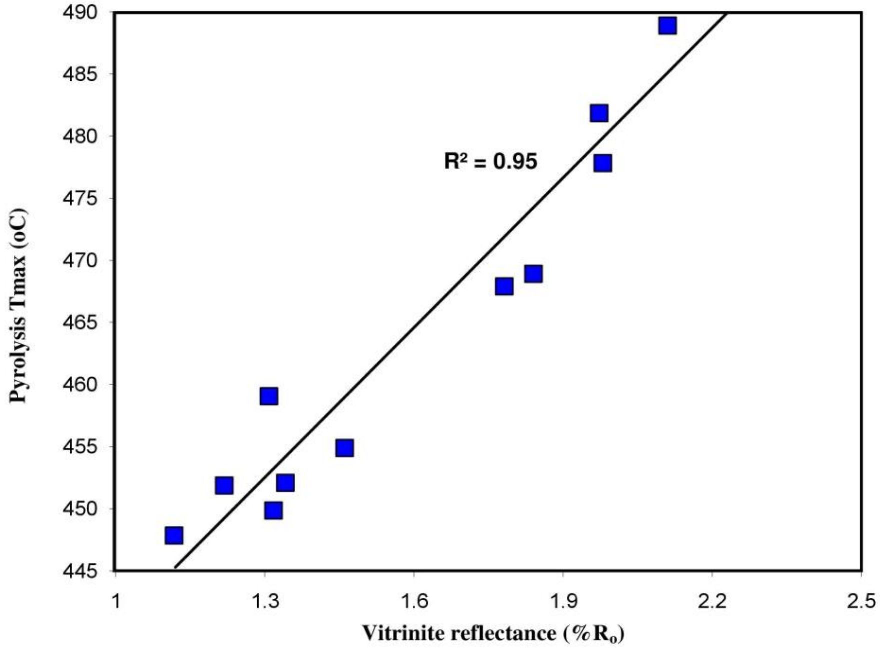

Figure 11: Cross-plot of pyrolysis T_{max} versus vitrinite reflectance (%Ro) showing the maturation of the Bima shale samples

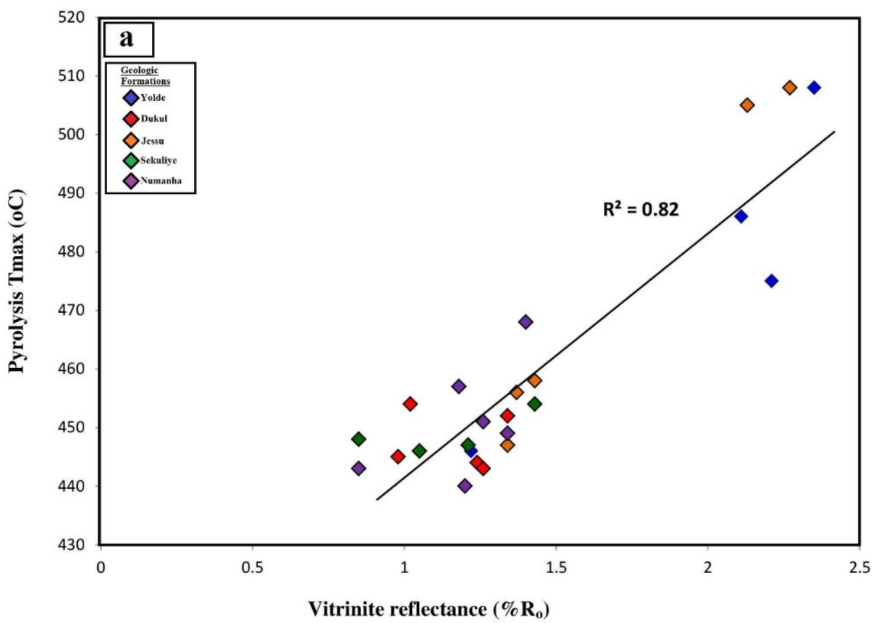

Figure 12: Cross-plots of pyrolysis T_{max} versus vitrinite reflectance (%Ro), showing the maturation of the Yolde, Dukul, Jessu, Sekuliye and Numanha shale samples

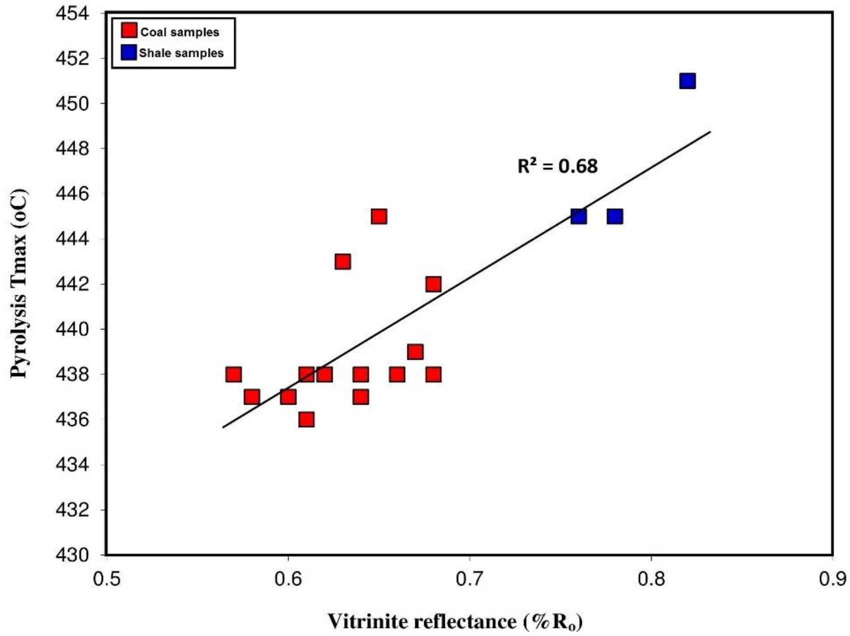

Figure 13: Cross-plots of pyrolysis T_{max} versus vitrinite reflectance (%Ro), showing the maturation of the Lamja shale and coal samples

Petroleum Source Rocks Potential

The pyrolysis HI data offer the first approach for the hydrocarbon generation potential (Espitalie et al. 1980; Hunt 1995, Hunt et al. 2002; Hakimi et al. 2011; Sarki Yandoka et al., 2015). Organic matter dominated by marine components have HI values of 200–500 mg HC/g TOC or less in immature sedimentary rocks (Peters, 1986). However, interpretations have limitations in highly matured sediments (Peters, 1986) and therefore, should be made with caution and supported by other methods (Stein, 1991). The kerogen types are of Type I and Type III for Bima shales, Type II and mixed Type II-III for Yolde, Dukul, Jessu, Sekuliye and Numanha shales whilst Type III kerogen for Lamja shales and coals and thus, can be considered to generate major gas and liquid component of oil. However, the major gas generation potential based on the present-day kerogen typing (Type IV) is probably due to high thermal maturity not by the original nature of the organic matter as supported.

Thermal maturity data indicate that the analysed samples have reached peak oil window and higher and thus, have consequently led to the low HI values and ultimately affected the present-day kerogen typing. As a result of high thermal maturity experienced by the analysed shales which is probably due to Tertiary volcanic intrusion, the Cretaceous source rocks have generated oil and thus, most of the oils have probably been cracked into thermogenic gas due to the volcanic intrusion. Sedimentary basins that experienced volcanic activity would as a consequence experienced thermal effects that resulted in expulsion of volatile components and caused alteration to the organic matter (e.g. Zhu et al. 2007). In the Yola Sub-basin, Tertiary volcanics were known to be present as reported by Carter et al., (1963). The heat flow introduced by the volcanics may have significantly influenced the source rocks through prompting maturity and accelerated hydrocarbon generation as indicated in this study. This is strongly supported by the cross plot of Pyrolysis Tmax against Production Index (PI) (Figs. 13 - 15) showing that the Cretaceous source rock samples of Yola Sub-basin are within the main hydrocarbon generation. However, as reported earlier, pyrolysis GC data are more reliable in terms organic matter and oil-gas generation potential.

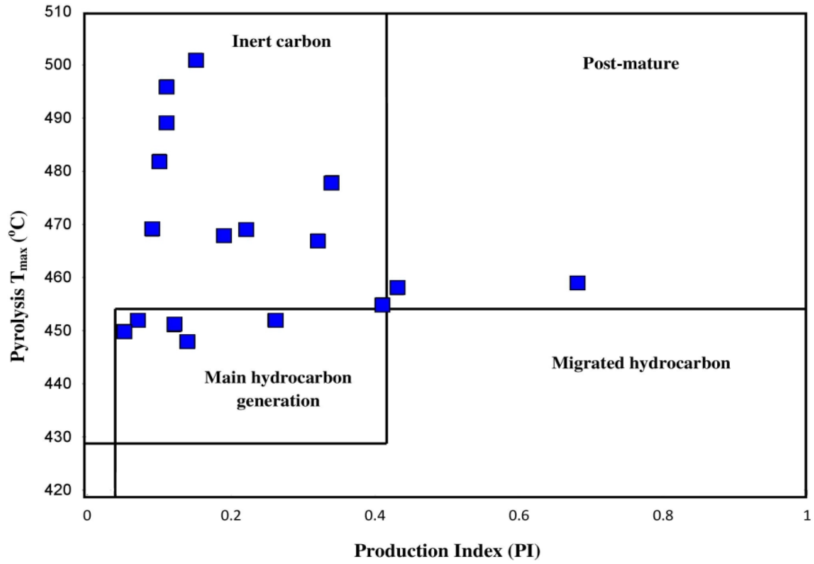

Figure 14: Cross-plot of pyrolysis T_{max} versus production index (PI) showing the nature of the hydrocarbon products of the analysed Bima shale samples

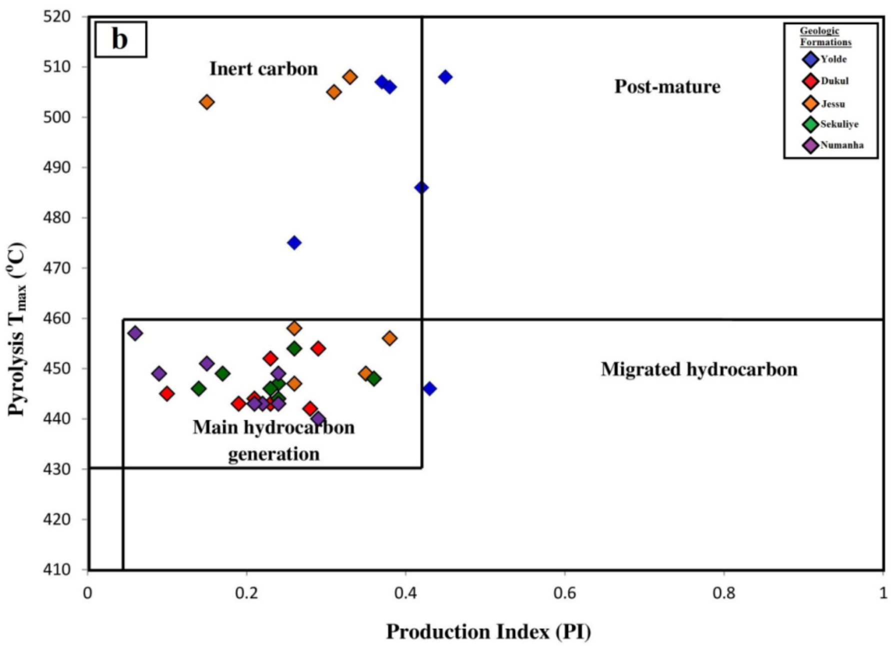

Figure 15: Cross-plot of pyrolysis T_{max} versus production index (PI) showing the nature of the hydrocarbon products of the analysed shallow marine shale samples

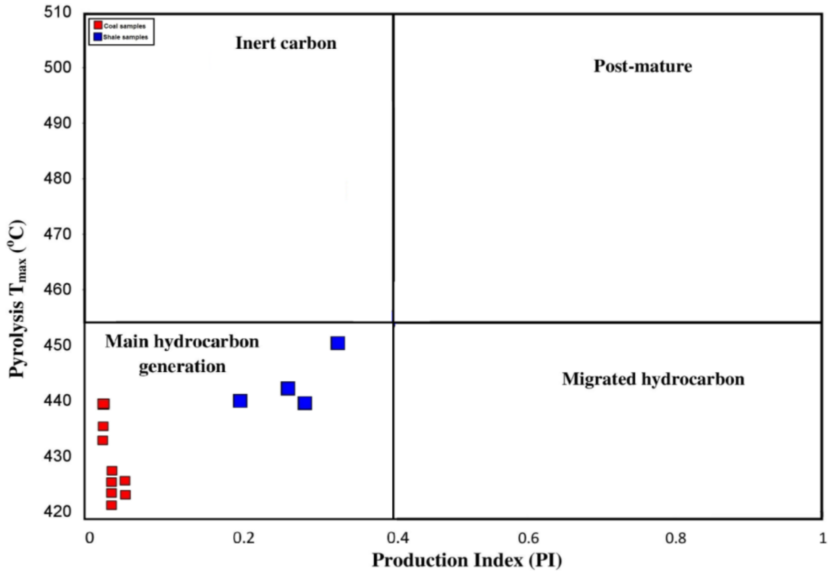

Figure 16: Cross-plot of pyrolysis T_{max} versus production index (PI) showing the nature of the hydrocarbon products of the analysed Lamja samples

CONCLUSION

Petroleum generation characteristics of the Cretaceous source rocks of Yola Basin based on bulk geochemistry revealed information on the organic matter type, richness, thermal maturity, influence of volcanic on the potential source rocks maturity and their relationship to oil-gas generation potential. The lacustrine shales of Bima Formation contain about 0.90% TOC and possess fair source rock generative potential. The organic matters of Bima, Yolde, Dukul, Jessu, Sekuliye and Numanha shales are of Type I, Type II-III and Type III kerogens based on the present-day kerogen typing and are likely to generate major gas and liquid components of oil. Thermal maturity data confirm high maturity level as late-oil window to post-mature stage of oil-gas generation. More so, most of the oils have been cracked into thermogenic gas probably due to high thermal maturity associated with Tertiary volcanic intrusion as envisaged by the present-day Type III and IV kerogens. The high thermal maturities have significantly influenced the nature of the organic matter thereby cracking them into thermogenic gas due to the Tertiary volcanic intrusion. The Lamja shales and coals possess poor to occasionally very good petroleum source generative potential. Coals have better generative potential compared to the shales, on account of more organic matter richness and kerogen types. High gas-generation potential is anticipated from the Lamja Formation shales based on the present-day Type III kerogens. Coals are dominated by Type III and mixture of Type II-III kerogens and are expected to generate gas and limited components of liquid hydrocarbons. Thermal maturities of the Cretaceous Lamja Formation sediments indicate early to peak oil generation window. These sediments possess major gas and minor oil generative potential.

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