IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982.Volume 6, Issue 1 Ver. II (Jan. – Feb. 2018), PP 54-64
www.iosrjournals.org

Source Rock Characteristics and oil-Source Rock Correlation in the Offshore Gippsland Basin, Southeast Australia

A.M. Bello[1], M.B. Abubakar[2], B.M. Sarki Yandoka[2], M.B. Usman[1], U. Abubakar[1], I.A. Kwami[1] & D. Auwalu[1]

[1]Department Of Geology, Gombe State University, Gombe, Nigeria
[2]National Centre For Petroleum Research And Development, ATBU, Bauchi, Nigeria
Corresponding Author: A.M. Bello1

Abstract: *The Golden Beach, Emperor and Halibut Subgroups and Strzelecki Group are the major hydrocarbon source rocks in the Gippsland Basin. The principal objective of this work was to study the source rocks characteristics and to employ bulk geochemical parameters along with biomarker characteristics to identify and distinguish crude oils samples from three oil fields (Bignose, Gudgeon, and Halibut Fields) in the basin and correlate them with their potential source rocks in order to establish the genetic relationship between them. The study also focused on gas correlation to understand the occurrence of oil in the middle part of the basin and gas towards the basin margins. To investigate the possible oil-source rock correlation, the source rock characteristics and geochemistry of the four potential source rocks was studied in order to understand their hydrocarbon generative potentials, levels of maturation, and to select the best quality source rocks for correlation studies. Six crude oil samples from the three oilfields were correlated with the source rock extracts to determine the genetic relationship between the source extracts and the oils. Different parameters employed for the correlation include gross composition of oils and source rock extracts, gas chromatography and mass spectrometry (GCMS) of biomarkers, and paleo-environmental analysis for more reliable results. Results of the source rocks characterization indicate that all the three source rocks have the potentials of generating hydrocarbons based on their TOC values which are greater than the minimum threshold value of 0.5 wt.% and good quality type II/III kerogens that are oil and gas prone. The results of the oil-source correlation studies indicate that there is a positive correlation between the extracts of the Golden Beach and Strzelecki source rocks and the oils from Gudgeon and Halibut Fields, whereas the oils from Bignose Field show negative correlation. This indicates that the Golden Beach and Strzelecki source rocks act as major source rocks to the oils in the Gudgeon and Halibut Fields, and probably to the less mature oils from the Bignose Field. Results of the paleoenvironmental analysis of the source rocks also indicate that the oils were sourced from terrestrial source rocks that were deposited under oxic conditions. The gas correlation results showed that the type of natural gas in the various oil and gas fields studied is mainly thermogenic in origin, formed due to thermal cracking of organic matter into gaseous and liquid hydrocarbons.*

Keywords *- Source Rock Characteristics, Oil-source Rock Correlation, Gippsland Basin*

Date of Submission: 12-02-2018 Date of acceptance: 26-02-2018

I. Introduction

The Gippsland Basin is one of Australia's most prolific hydrocarbon provinces that is situated in Southeastern Australia (Fig. 1). The basin covers an onshore and offshore area of Victoria that is approximately 4,600 km^2 [1]. It is characterised by giant oil and gas fields and has proven to be a world-class hydrocarbon province [2]. More than 70% of the basin lies offshore. Most of the basin's (>80%) of the hydrocarbon discoveries are reservoired within the siliciclastic sediments of the Late Cretaceous to Paleogene Latrobe Group (Fig. 3) and nearly all the currently producing oil and gas fields are situated in the offshore shallow water.Comprehensive geochemical studies of the basin's four major organic-rich source rocks (Emperor, Golden Beach and Halibut Subgroups and the Strzelecki Group) indicate that the source rocks are effective and terrestrial in origin [1, 3]. Although all the source rocks show similar origin, there is a strong variation in their hydrocarbon generating potentials. 1D petroleum systems and basin modelling studies have indicated that the source rocks have generated and expelled hydrocarbons [4].In this study, we investigated the geochemical characteristics of the major source rocks and oils samples from three oil fields (Bignose, Gudgeon and Halibut Fields) in the Central Deep (or Central Depression) of the offshore Gippsland Basin, in order to effectively understand the source rocks hydrocarbon generation potentials and to establish the genetic relationship between the source rocks and crude oil samples. Three principal wells (Bignose-1, Gudgeon-1 and Halibut-1) from the three oil fields were used for oil-source correlation studies (Fig. 2).

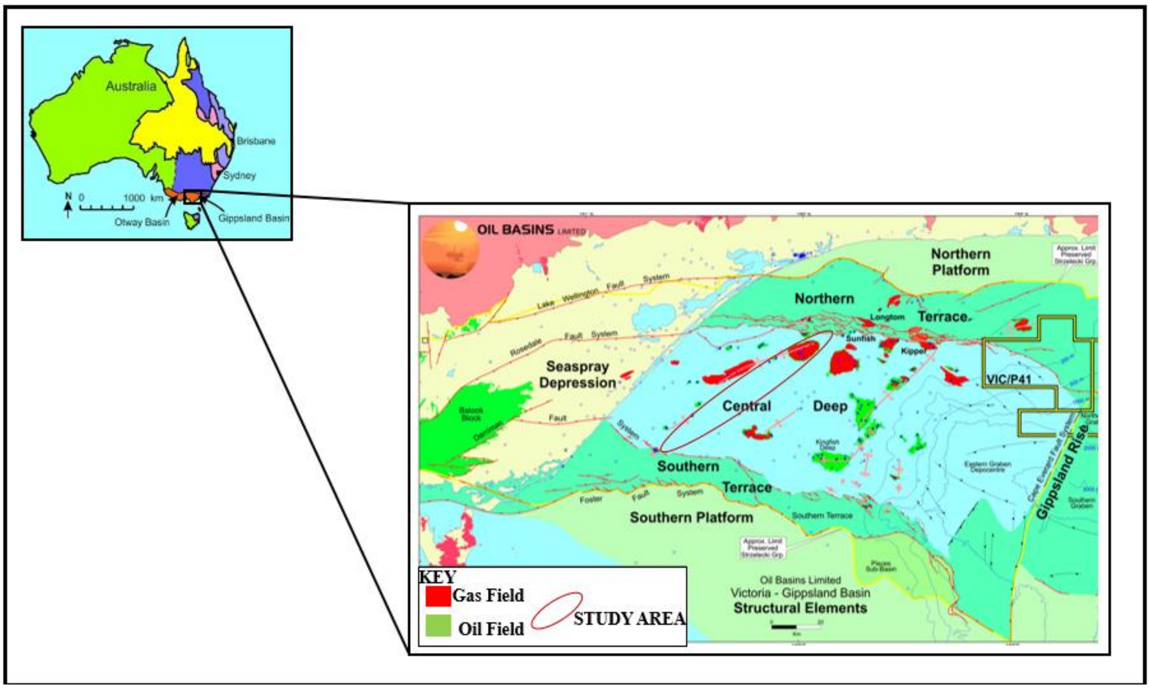

Fig. 1. Location map of Gippsland Basin showing the study area (modified from O'Brien et al, 2008).

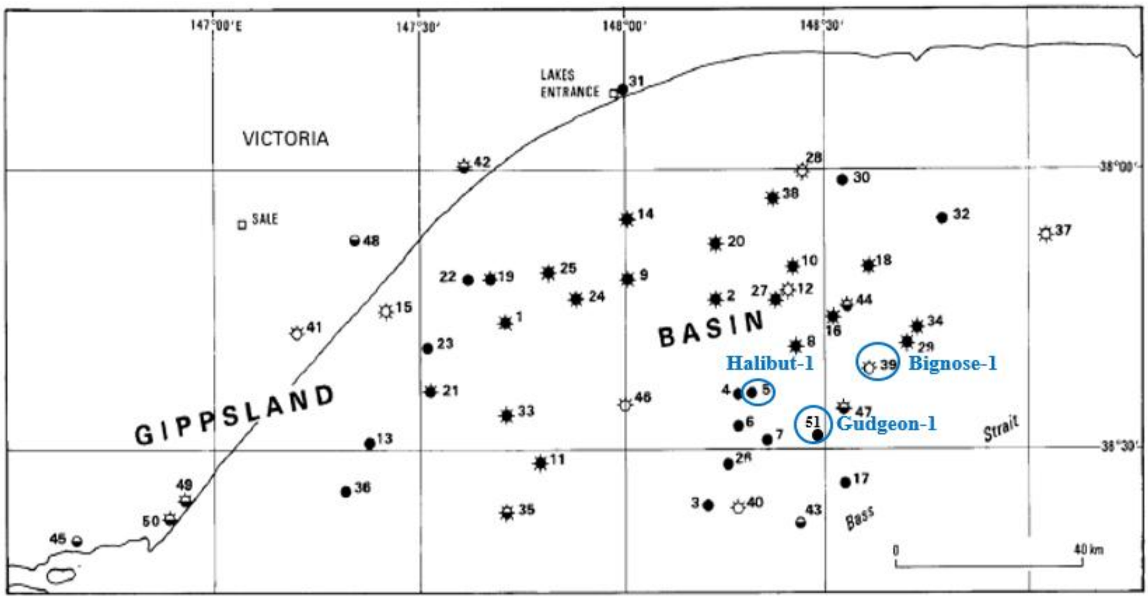

Fig. 2. Location map of Gippsland Basin showing the principal wells selected for oil-source correlation study (modified from Ozimic et al., 1987).

II. Basin Evolution and Stratigraphy

The evolution of Australia's southern passive continental margin commenced during the Late Jurassic to Early Cretaceous, as a result of the N-S extensional event that caused the separation of Australia and Antarctica [1, & 5-6]. The extension continued along the entire continental margin of southern Australia and into the Otway, Bass, and Gippsland Basins, thereby forming a complex rift valley system that cuts through the Paleozoic igneous and metamorphic rocks of the Tasman Fold Belt.Sedimentation in the basin began in the Lower Cretaceous with the deposition of volcaniclastic-rich Strzelecki Group (Fig. 3). These continental sediments exceed 4 km in the Central Deep [7]. Faulting prevailed throughout the period of the Strzelecki deposition. By the end of the Lower Cretaceous (Albian), the Australian and Antarctic Plates finally separated, with the subsequent evolution of the Southern Ocean [1 & 5]. The Otway angular unconformity marks the end of deposition of the Strzelecki Group (Fig. 3). The Late Cretaceous (Cenomanian) rift episode commenced with the deposition of the non-marine Golden Beach Subgroup (Lower Latrobe Group) [8] (Fig. 3). This sequence is made up of mainly lithic and siliciclastic sediments. Faulting, volcanism, and deposition were prevalent at this time. The deposition of the Golden Beach Subgroup ceased at the end of Cretaceous (Campanian), represented by the Seahorse Unconformity [5] (Fig. 3). This was followed by the opening of the Tasman Sea (75 Ma ago) [9]. During the Late Cretaceous to Late Eocene times, the non-marine to marginal marine sequences of Cobia and Halibut Subgroups were deposited (Fig. 3). An episode of basin inversion marked the end of their deposition, thereby creating wrench movements on the Tasman Sea fracture zones [10]. This led to the creation of anticlinal structures by reversing the movements on several pre-existing fault zones to form major structural traps [5]. Subsequent uplift generated incised channels at the top of Latrobe (Fig. 3).Loading and thermal subsidence continued during the Oligocene as a result of the deposition of the Seaspray Group (Fig. 3), which consists of marine sediments of the Lakes Entrance Formation and Gippsland Limestone.

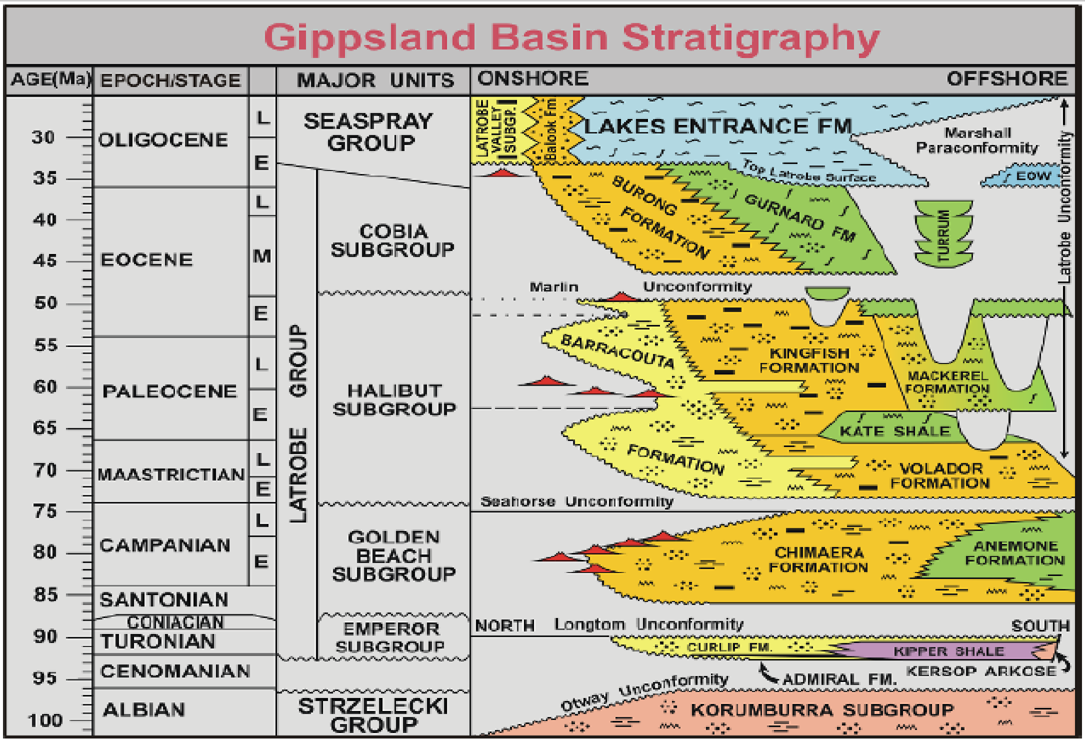

Fig. 3. Generalised stratigraphic chart of the Gippsland Basin (from O'Brien et al., 2008).

III. Materials and Methods

We first studied the geochemistry of the four potential source rocks (Golden Beach, Emperor and Halibut Subgroups and Strzelecki Group) in order to understand their organic richness, source, levels of maturation, and to select the best source rocks for correlation studies. Six crude oil samples from three oilfields; Bignose, Gudgeon, and Halibut Fields were correlated with the best quality source rock extracts using bulk geochemical parameters and biomarker characteristics. For correlation purposes, points were allotted to relevant correlation parameters and some cut-off values were determined for the parameters based on the work of [11].

IV. Results and Discussion

4.1 Organic matter richness and generative potential

Organic matter richness and hydrocarbon generative potentials from shales and coals of the Golden Beach, Emperor and Halibut Subgroups and Strzelecki Group were evaluated using pyrolysis S2 yield and TOC content data (Figure 4). The Golden Beach, Emperor and Halibut Subgroups and Strzelecki Group have total organic carbon (TOC) values ranging from 0.17-60.55 wt. % (averaging 7.0 wt. %), 0.01-10.01 wt. % (averaging 5.0 wt. %), 0.15-63.38 wt. % (averaging 12.10 wt. %), and 0.17-18.22 wt. %, (averaging 5.2 wt. %), respectively. This indicates that the source rocks have wide range of hydrocarbon generative potentials, ranging from 'poor to excellent' with most of the source rocks plotting in the 'excellent' generative potentials category (Fig. 4).

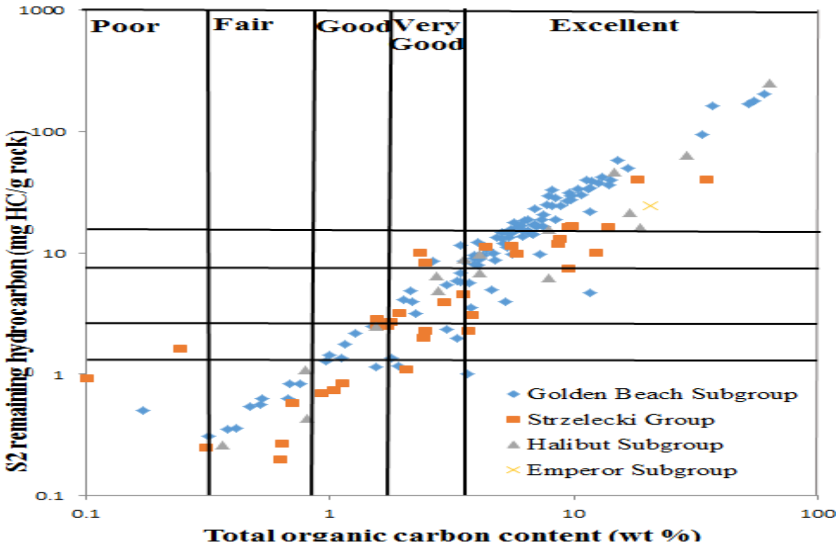

Fig. 4. Plot of pyrolysis S2 against TOC showing variation in organic richness and hydrocarbon generation potential in the source rock intervals.

4.2 Organic matter quality

Kerogen typing has been considered to produce different types of hydrocarbons (Sarki Yan Doka et al., 2014) [12]. Generally, type I and II kerogens commonly derived from lacustrine and marine source rocks, respectively, and are capable of generating liquid hydrocarbons (Hakimi et al. 2011) [13]. Type III kerogen is mostly composed of woody materials and gas prone, and type IV is composed primarily of inert or dead group of organic materials and has no potential of generating hydrocarbons. Based on the pyrolysis data, the kerogen classification diagrams were constructed using a plot of hydrogen index (HI) against pyrolysis oxygen index (OI) (Fig. 5). The plot indicates that the source rock samples contain predominantly type II-III organic matter (oil and gas prone), with some samples that plot in the type III (gas prone) zones (Fig. 5). Therefore, based on the kerogen typing (Fig. 5) and organic matter richness (Fig. 4), all the four source rock intervals have potentials to generate hydrocarbons.

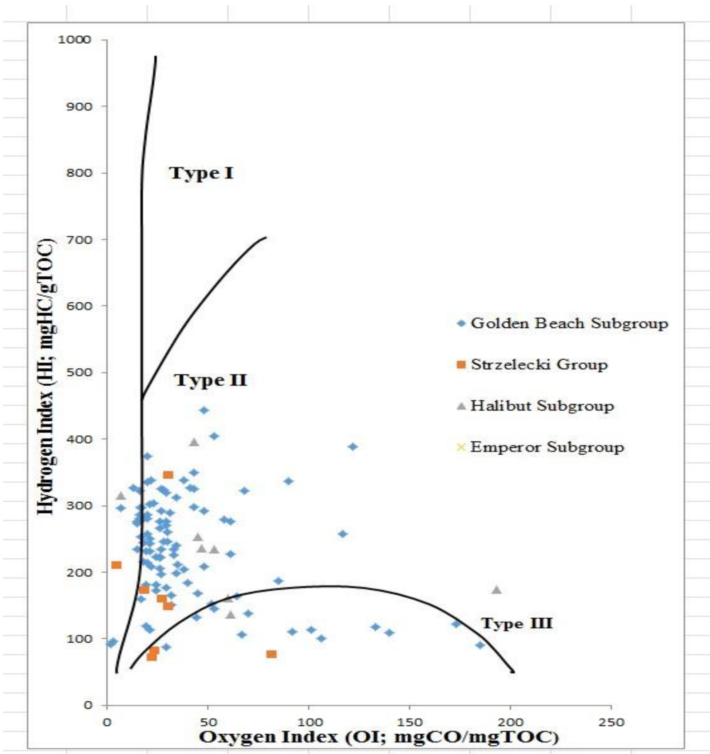

Fig. 5. Plot of hydrogen index (HI) against oxygen index (OI) showing kerogen type in the studied source rock intervals.

4.3 Thermal maturity of organic matter

The thermal maturity of the source rock intervals was assessed using a plot of hydrogen index (HI) versus pyrolysis Tmax (Fig. 6). The Tmax values for the Golden Beach, Emperor, Halibut, and Strzelecki source rocks range from 432-506 °C, 407 °C, 411-439 °C, and 406-550 °C, respectively. This indicates that the Golden Beach source rocks are within the mature oil generating window and post-mature dry gas window; whereas the Emperor and Halibut source rocks mostly plot in the immature zone (Fig. 6). On the other hand, the Strzelecki source rocks plot in the immature, mature, and post-mature zones, indicating that the source rocks have wide range of maturity. Based on the thermal maturity plot (Fig. 6), the organic-rich and thermally mature source rocks selected for correlation studies are the Golden Beach and Strzelecki source rocks.

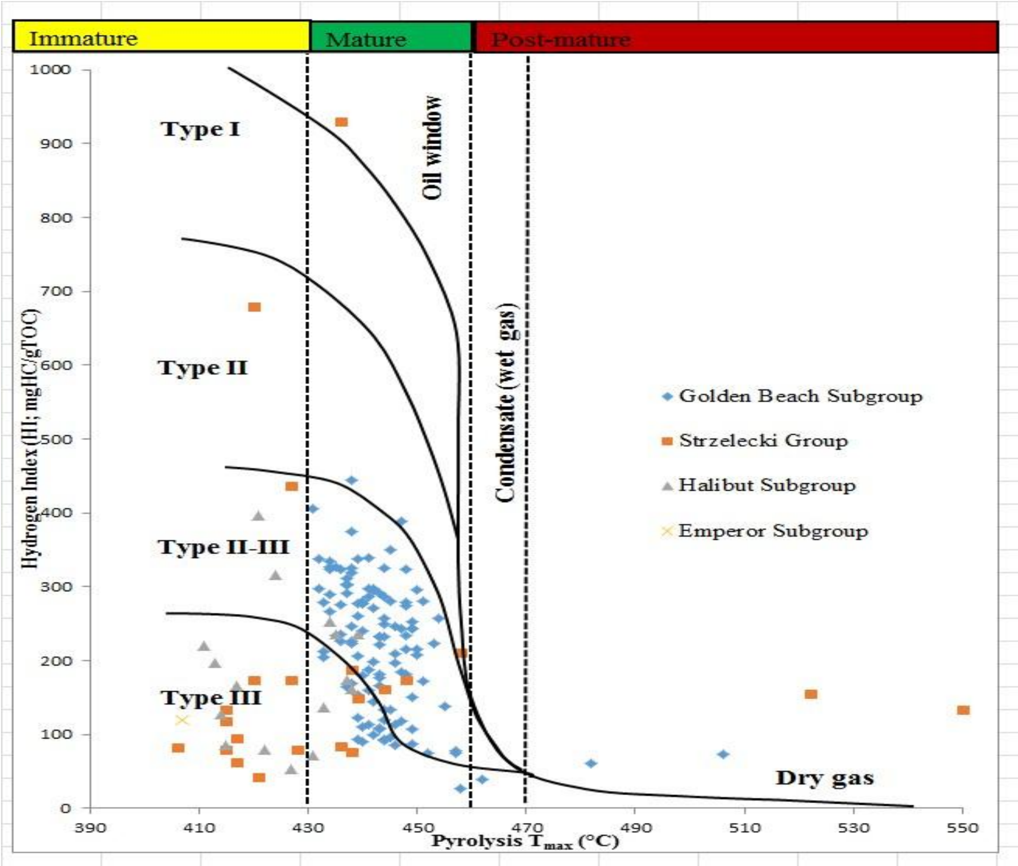

Fig. 6. Plot of HI against pyrolysis Tmax illustrating the kerogen type and organic maturity of the studied source rocks intervals

4.4 Biomarkers

4.4.1 n-Alkanes and isoprenoids

The ratios and distributions of Pr/n-C_{17}, Ph/n-C_{18}, and Pr/Ph are good indicators of organic matter source and depositional environment [14]. The Pristane/Phytane (Pr/Ph) ratios are used as good indicators of redox conditions [15]. Pr/Ph ratios in the range of 1-3 indicate oxic and suboxic conditions. Very low Pr/Ph ratios (less than 1) signify highly reducing conditions. Terrigenous organic matter deposited under oxic conditions have Pr/Ph ratios >3 [15]. In the present study, both the oils and extract samples have Pr/Ph values greater than 5.0 (Table 1), indicating terrestrial and oxidising depositional environment.The ratios of Pr/n-C_{17} and Ph/n-C_{18} provide valuable information on organic matter maturation, diagenetic conditions, and crude oil biodegradation [15] (Fig. 7). It is apparent that the studied source rock extracts have Pr/n-C_{17} and Ph/n-C_{18} ratios in the range of 0.68-1.39 and 0.12-0.19 (Table 1), respectively, indicating largely mature organic matter that developed primarily from terrigenous sources deposited under oxidising conditions (Fig. 7).The gas chromatograms (GC) of the representative source rock extracts is shown in Figure 8 below. All the extracts show unimodal distribution of n-alkanes, indicating relatively high maturity.

Table 1. Geochemical parameters of crude oils and extract samples studied

Samples	Depth (m) /tag	Sat. %	Arom. %	Sat. /Arom.	NSO	$C_{21}+C_{22}/C_{28}+C_{29}$	CPI	Pr/Ph	Pr/nC$_{17}$	Ph/nC$_{18}$	Pr + n-C$_{17}$/ Ph + n-C$_{18}$
Oils											
Gudgeon	CH19	88.40	9.10	9.71	2.40	2.30	1.10	7.01	0.53	0.10	2.27
	CH71	88.30	8.40	10.51	3.30	2.06	1.10	7.09	0.53	0.10	2.32
Halibut	-	78.80	14.60	5.40	6.40	0.78	1.20	7.3	0.67	0.10	1.62
	-	78.90	11.90	6.63	9.00	0.75	1.10	7.2	0.67	0.11	1.58
Bignose	3591	27.50	28.90	0.95	43.60	13.77	1.70	9.95	4.06	0.36	3.26
	3729	32.30	24.8	1.30	42.90	13.24	1.40	7.33	2.93	0.33	2.46
Extracts											
Golden Beach Subgroup	Hermes1/4360	41.10	18.10	2.28	40.80	1.43	1.10	6.45	1.15	0.18	1.8
		40.80	13.60	3.00	45.60	2.37	1.10	6.52	1.00	0.15	1.74
Strzelecki Group	Omeo1/3159	5.80	4.60	1.26	89.60	2.22	1.40	6.31	1.39	0.19	1.73
	Omeo1/3369	5.80	2.80	1.07	91.40	9.19	1.60	5.86	0.68	0.12	1.54

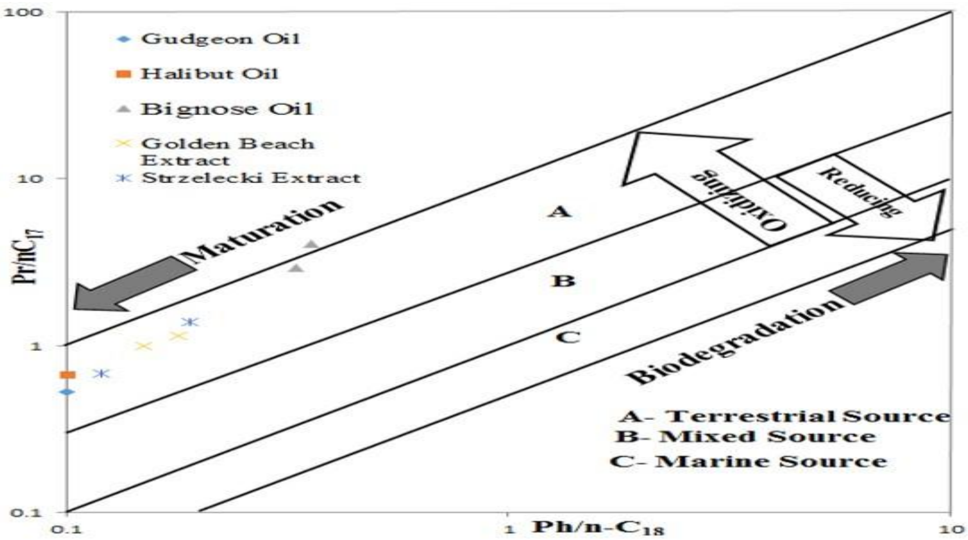

Fig. 7. Plot of Pr/n-C17 against Ph/n-C18 (Shanmugam, 1985) showing organic matter source, maturation, and biodegradation for the studied oils and extract samples

.

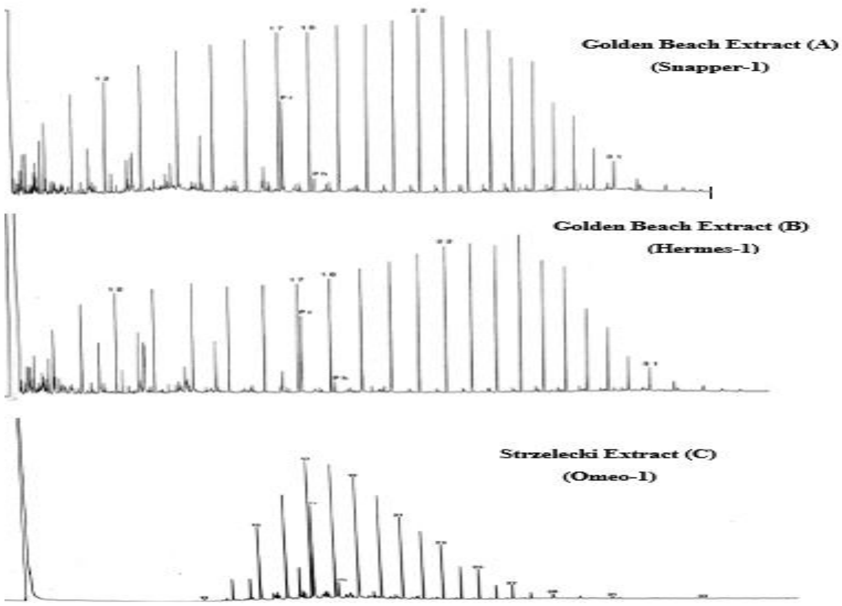

Fig. 8. Gas chromatograms of the representative source rock extracts

4.4.2 Sterane compositions of the source extracts

Steranes are useful correlation parameters that provide valuable information on organic matter type, paleoenvironment, and level of biodegradation [15]. C_{27} and C_{28} steranes are predominant in marine organisms and lacustrine algae, respectively, whereas C_{29} steranes are associated with land plants organic matter [16]. The Steranes mass chromatograms (mz 217) of the Golden Beach source rocks are shown in Figure 9 below. The C_{29} steranes have higher distribution, with slight predominance of C_{27} steranes (Fig. 9).

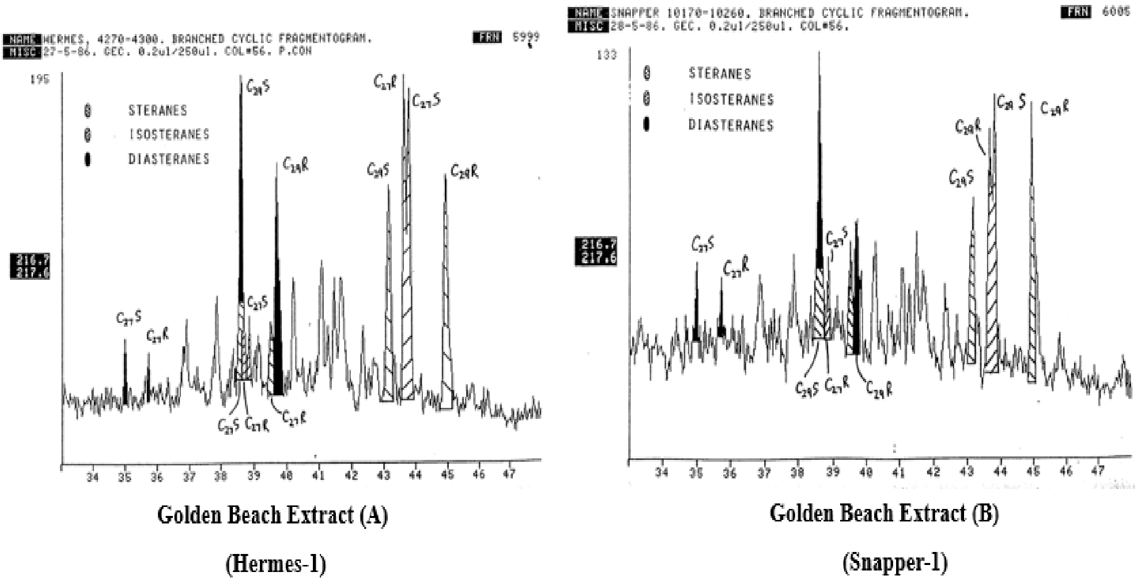

Fig. 9. The steranes (mz 217) chromatograms of Golden Beach source rock extracts showing distribution of C27 and C29.

4.3 Crude Oil Geochemistry

4.3.1 n-Alkanes and isoprenoids

As shown in Table 1, the isoprenoids Pr/Ph ratios of the studied oils are greater than 3.0, indicating an oxidising and terrestrial environment (Fig. 7). Oils from the Bignose Field have relatively high Pr/n-C_{17} and Ph/n-C_{18} ratios, ranging from 2.93-4.06 and 0.33-0.36, respectively, indicating low maturity, whereas the oils from Gudgeon and Halibut Fields have relatively low Pr/n-C_{17} and Ph/n-C_{18} ratios, ranging from 0.53-0.67 and 0.10-0.11, respectively, indicating more mature oils (Table 1).

4.3.1 Sterane composition of the oil samples

As shown in Fig. 10 below, the relative distribution of C_{27} and C_{28} steranes in the studied crude oil samples show predominance of C_{29} steranes, which indicates terrestrial input.

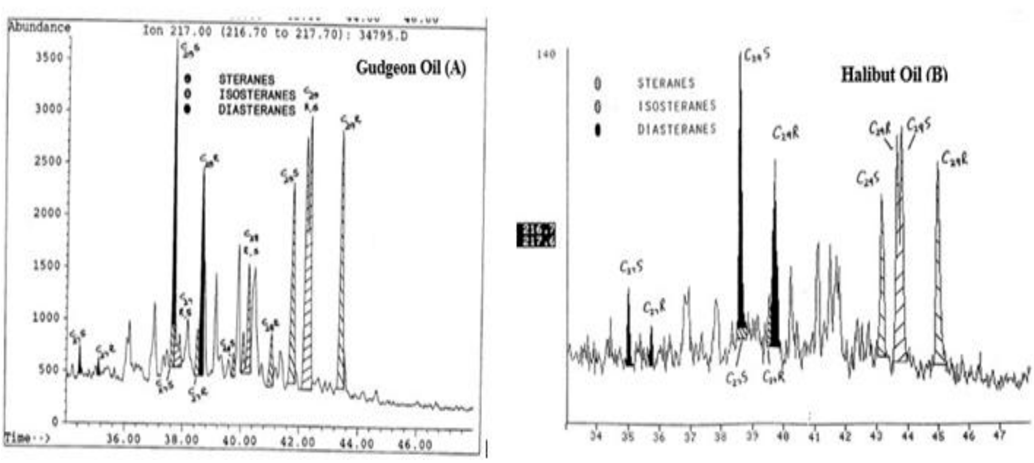

Fig. 10. Sterane (mz 217) chromatograms of the studied crude oils showing the distribution of C27 and C29 steranes.

4.4 Oil-Source Correlation

4.4.1 n-Alkanes distributions of the crude oil samples and source extracts

Table 2 below shows the normalized composition (%) for the crude oils and extract samples and their carbon distribution is shown in Fig. 11. The positive correlation in the molecular distribution between Gudgeon and Halibut oils and Golden Beach extracts suggests a genetic relationship between them. Furthermore, Bignose oils and Strzelecki extracts appear to have similar molecular distributions and are genetically related (Fig. 11).

Table 2. Molecular distribution of n-alkanes of the studied crude oils and extract samples

Carbon Number	Bignose Oil	Gudgeon Oil	Halibut Oil	Golden Beach Extract	Strzelecki Extract
C12	2.5	5.66	5.98	6.2	0
C13	2.6	5.92	8.39	6.6	0.1
C14	2.9	5.37	9.93	6.5	2.1
C15	3	5.34	9.33	6.2	7.1
C16	3.4	4.23	6.56	6	10.2
C17	4	6.37	9.06	5.9	13.4
C18	4.8	3.89	5.36	5.9	13.1
C19	11.8	3.76	5.04	5.9	11.9
C20	1.6	3.77	4.5	5.8	10.1
C21	9.3	3.76	3.79	5.5	8
C22	10.8	3.66	3.59	5.2	6.7
C23	11	3.65	3.12	4.8	5.3
C24	6.8	3.52	2.92	4.3	3.2
C25	5.2	3.45	2.86	4.4	3
C26	1.8	2.92	2.52	3.6	1.3
C27	2	2.78	2.39	3.6	1.4
C28	0.7	2	2.04	2.4	0.8
C29	0.8	1.59	1.86	2.1	0.8
C30	0.3	1.02	1.64	1.3	0.4
C31	0.4	0.85	1.29	1.2	0.4

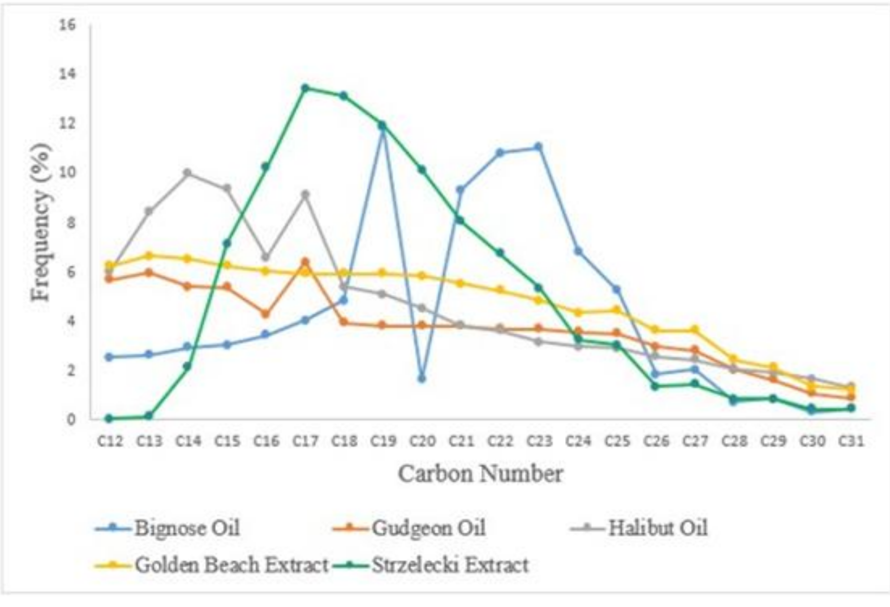

Fig. 11. Carbon distributions for the studied extracts and crude oil samples (based on data in Table 2).

4.5 Correlation Evaluation

The oil-source correlation was evaluated based on the parameters presented in Table 1. The present study adopts [11] method of oil-source correlation using eight correlation parameters (Table 4) based on their ability to reveal the genetic relationship between crude oils and their potential source rocks.The score points allotted to the correlation parameters as suggested by [11], are shown in Table 3 below. For each oil and source extract, the total score was calculated by summing up the input from each correlation parameter as shown in Table 4. The parameter match (ratio of correlation parameter to the total parameters) has also been considered in determining the correlation rate. According to [11], oils and extracts samples showing a 5/8 parameter match and score 50 points, or more are classified as ‘correlatable’ whereas samples with less than 4/8 parameter match and score 40-50 points are interpreted as ‘difficult to correlate’ (Table 4).

Table 3. Points allotted to the correlation parameters (modified from Alexander et al., 1981).

Parameter	Points Allotted
Saturates (%)	15
Saturate/Aromatics	5
NSO	10
C_{21} + C_{22}/ C_{28} +C_{29}	15
CPI	5
Pr/Ph	15
Pr + n-C_{17}/ Ph + n-C_{18}	25
Pr /n-C_{17}	10
Total	100

Table 4. Oil-Source rock correlation evaluation

Samples	Sat. (%) >50	Sat./Arom >2.00	NSO >30	C_{21} + C_{22}/ C_{28} + C_{29} >2	CPI 1.0 ± 0.1	Pr/Ph >3	Pr/n-C_{17} 0.7 ± 0.6	Pr + n-C_{17}/ Ph + n-C_{18} 1.2 ± 0.6	Score +=5 0=Nil	Parameters Matching	Correlation Ratings
OILS											
Bignose											
3591 m	0	0	++	+++	0	+++	0	0	40	3/8	Difficult to correlate
3729 m	0	0	++	+++	0	+++	0	0	40	3/8	Difficult to correlate
Gudgeon											
CH19	+++	+	0	+++	+	+++	++	0	65	6/8	Correlatable
CH71	+++	+	0	+++	+	+++	++	0	65	6/8	Correlatable
	+++	+	0	0	0	+++	++	+++++	70	5/8	Correlatable
Halibut	+++	+	0	0	+	+++	++	+++++	75	6/8	Correlatable
Extracts											
	0	+	++	0	+	+++	++	+++++	70	6/8	Correlatable
Golden Beach	0	+	++	+++	0	+++	++	+++++	80	6/8	Correlatable
	0	0	++	+++	0	+++	++	+++++	75	5/8	Correlatable
Strzelecki	0	0	++	+++	0	+++	0	+++++	65	4/8	Fairly Correlatable

4.6 Gas Geochemistry

The origin of the natural gas in most of the Gippsland Basin’s oil and gas fields was determined using a crossplot of dryness (C_1/C_2+C_3) against isotopic composition of methane (Vienna Pee Dee Belemnite, VPDB) (Fig. 12). Table 5 below shows the data on dryness and isotopic compositions of methane from various fields in the basin. The correlation results show that the type of natural gas in the studied oil and gas fields is formed from thermogenic degradation of organic matter (Fig. 12). This indicates that the gas is formed at great depths by thermal cracking of organic matter into liquids and gaseous hydrocarbons or by thermal cracking of oil at very high temperature into gas. However, it is most likely that the gas is related to the processes that formed the oil. Therefore, the gas is co-genetic with the oil, which also proves the effectiveness of the basin’s petroleum system.

Table 5. Gas geochemical parameters

Field	Dryness ($C_1/C_2 + C_3$)	Methane Isotope ($\delta\ ^{13}C\ CH_4$)
Grunter	7.82	-40.6
Marlin	10.43	-40.6
Archer	2.06	-41.3
Angelfish	11.83	-40
Moonfish	9.88	-35.4
Whiting	50	-36.2
Perch	58.17	-37.2
Barracouta	49.93	-37.4
Hermes	15.3	-41.5
Bream	61.6	-42.3
Tuna	18.18	-38.2
Snapper	71.35	-36.5
Kipper	66.3	-37.3
Wirrah	93.91	-37.4

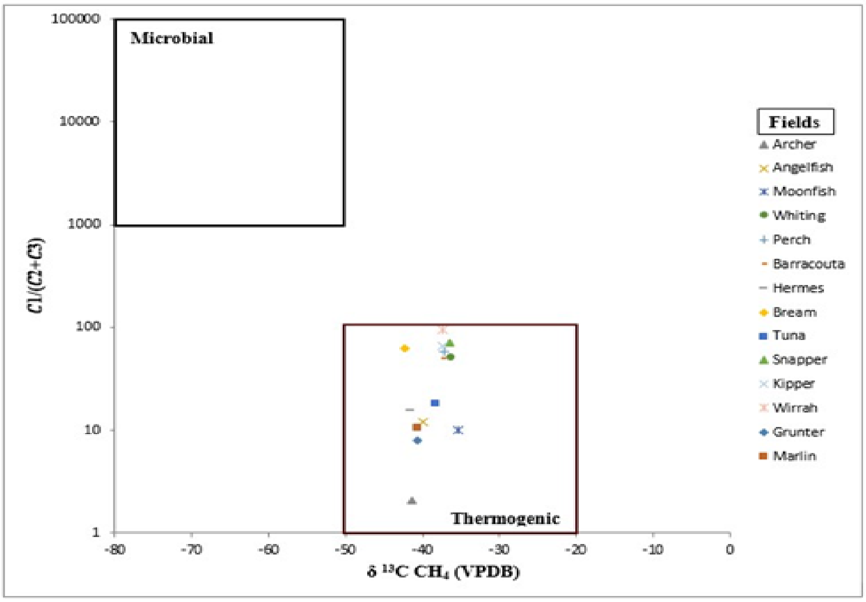

Fig. 12. Plot of dryness against methane carbon isotope showing the origin of the natural gas in most of the Gippsland Basin's oil and gas fields (based on data in Table 5) (Adapted from Waples, 1985).

4.7 Conclusions

a) Results from geochemistry of source rock extracts and oil samples indicate that all the source rocks and crude oil samples studied were mainly sourced from terrestrial organic sources deposited under oxidising conditions
b) Results of the crude oil to source rock correlations indicate:
c) Genetic relationship between oil samples from Bignose, Gudgeon and Halibut oilfields, and extracts from Golden Beach and Strzelecki source rocks
d) The crude oil of Gudgeon and Halibut oil fields appear to have been sourced from the source rocks of the Golden Beach Subgroup, whereas oils from the Bignose Field show fair genetic relationship with the Strzelecki source rocks
e) Results from gas geochemistry indicate that the gas in all studied oil and gas fields is thermogenic in origin, formed during thermal cracking of organic matter into gaseous and liquid hydrocarbons. This shows that the gas is co-genetic with the oil
f) All above results indicate that both the Golden Beach Subgroup and Strzelecki Group act major source rocks to the Gippsland's various oil and gas fields.

Acknowledgements

The authors gratefully acknowledge the State Government of Victoria for providing access to well and geochemical data. The authors thank Petroleum Technology Development Fund (PTDF), Nigeria, for providing scholarship that enabled the successful completion of this research work.

References

[1]. Bishop, M.G. (2000). Petroleum System of the Gippsland Basin, Australia. U.S Geological Survey, Open-File Report 99-50-Q, p.1-24.
[2]. O'Brien, G. W., Tingate, P. R., Divko, L. M., Harrison, M. L., Boreham, C. J. and Liu K. (2008). First Order Sealing and Hydrocarbon Migration Processes, Gippsland Basin, Australia: Implications for CO2 Geosequestration, Eastern Australasian Basins Symposium III, pp. 1-7.
[3]. Rahmanian, V. D., Moore, P. S., Mudge, W. J. and Spring, D. E. (1990). Sequence Stratigraphy and the Habitat of Hydrocarbons, Gippsland Basin. In: Classic Petroleum Provinces, ed. J. Brooks. pp. 528-541. Geological Society Special Publication No. 50.
[4]. Moore, P. S., Burns, B. J., Emmett, J. K. and Guthrie, D. A. (1992). Integrated Source Maturation and Migration Analysis, Gippsland Basin, Australia, The Australian Petroleum Exploration Association Journal, 32,313-324.
[5]. Featherstone, P., Aigner, T., Brown, L. and King, M. (1991). Stratigraphic Modelling of the Gippsland Basin, The Australian Petroleum Exploration Association Journal, pp. 105-107.
[6]. [6] Holdgate, G. R., Rodriquez, C., Johnstone, E. M., Wallace, M.W. and Gallagher, S. J. (2003). The Gippsland Basin Top-Latrobe Unconformity and its Expression in Other SE Australia Basins, The Australian Petroleum Exploration Association Journal, p. 151.
[7]. Chiupka, J.W. (1996). Hydrocarbon Play Fairways of the Onshore Gippsland Basin, Victoria. Victorian Initiative for Minerals and Petroleum Report 30, pp. 8-20.
[8]. Lowry, D. C. (1988). Alternative Cretaceous History of the Gippsland Basin, Australian Journal of Earth Sciences, 35, 23-36.
[9]. Shaw, R. D. (1978). Sea Floor Spreading in the Tasman Sea: A Lord Howe Rise-Eastern Australia Reconstruction, Bulletin of the Australian Society of Exploration Geophysics, 9, pp. 3-4.
[10]. Smith, G. C. (1982). A Review of the Tertiary-Cretaceous Tectonic History of the Gippsland Basin and its Controls on Coal Measure Sedimentation, Australian Coal Geology, 4, pp. 1-37.
[11]. Alexander, R., Kagi, R.I. and Woodhouse, G.W. (1981). Geochemical Correlation of Windalia Oil and Extracts of Winning Group (Cretaceous) Potential Source Rocks, Barrow Subbasin, Western Australia. AAPG, pp. 235-250.
[12]. Sarki Yandoka, B.M., Abdullah, W.H., Abubakar, M.B., Hakimi, M.1.H., Mustapha, K.A., Adegoke, K.A. (2014) Organic geochemical characteristics of Cretaceous Lamja Formation from Yola Sub-basin, Northern Benue Trough, NE Nigeria: implication for hydrocarbon generating potential and paleodepositional setting, Arabian Journal of Geosciences, DOI 10.1007/s12517-014-1713-3.
[13]. Hakimi MH, Wan HA, Shalaby MR (2011). Organic geochemical characteristics and depositional environments of the Jurassic shales in the Masila Basin of Eastern Yemen. GeoArabia 16: 47–64.
[14]. Didyk, B., Simmoneit, B., Brassell, S.C. and Eglinton, G. (1978). Organic Geochemical Indicators of Palaeoenvironmental Conditions of Sedimentation, Nature, 272, 216-222.
[15]. Waples, D. W. (1985). Geochemistry in Petroleum Exploration, D. Reidel, p. 155-173.
[16].] Peters, K. E., Walters, C. C. and Moldowan, J. M. (2005). The Biomarker Guide. Biomarkers and Isotope in Petroleum Exploration and Earth History. Volume 2, Cambridge University Press, Second Edition, pp. 475-492.

IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG) is UGC approved Journal with Sl. No. 5021, Journal no. 49115.

A.M. Bello " Source Rock Characteristics and oil-Source Rock Correlation in the Offshore Gippsland Basin, Southeast Australia." IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG) 6.1 (2018): 54-64.