

Hydrocarbon generation potential of the coals and shales around the Eucalyptus Campsite area, Maliau Basin, Sabah

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Abstract— Six shales and four coals of the Kapilit Formation (Early to Middle Miocene) from the adjacent area of Eucalyptus campsite, Maliau Basin, Sabah were analysed using organic petrological and organic geochemical methods to determine their hydrocarbon generating potential, maturity and depositional environment. The organic richness of the shale samples is generally good to very good, whilst for the coals, as usual, show very good organic carbon richness. The shale samples also show good to very good hydrocarbon generating potential (S₂ values from 5.0 to 37.3 mg HC/g rock), except for two samples which possess poor hydrocarbon generating potential (S₂ <1.0 mg HC/g rock). Hydrogen Index (HI) for the shale samples are less than 200, except for sample S₂₅ (HI = 228), and this suggests that the shales contain mainly gas prone, Type III organic matter. The hydrocarbon generating potential for the coals are very good (S₂ values from 126.8 to 228.4 mg HC/g rock) and their hydrogen indices are also quite high (197 to 327), indicating that the coals have some potential for liquid hydrocarbon generation, in addition to gas. Evaluation on thermal maturity shows that the samples are in the early to main stage of oil generation as indicated by VRo values of between 0.57% and 0.80%. Visual organic matter typing show that both shales and coals contain mainly terrigenous derived organic matter. In the shale samples, vitrinite and inertinite are the dominant macerals and constitute more than 70% of the total kerogen, while fluorescing organic matter content which basically consist of liptinite and fluorescing amorphous, ranges from 10 to 20%. In the coal samples, vitrinite is the most dominant maceral (~70%), while liptinite content range from 20% to 30%. Inertinite content is low (10% or less). Some hydrocarbon generative features, such as oil smears or hydrocarbon haze and vesicles can be observed in the coal samples, suggesting that some hydrocarbons were generated from the coals. The biomarker characteristics also suggest that the rocks analysed contain high abundance of land plant organic matter as shown by the high pristane/phytane (Pr/Ph >5.0) ratio, odd-over-even *n*-alkane distributions, presence of oleananes and dominance of C₂₉ sterane homologs. Tricyclic terpanes and C₃₀ steranes which are derived mainly from algae organic matter are present in very low relative abundance or are virtually absent. The depositional environment for the shales and coals is probably in a coastal plain or deltaic setting under oxic condition.

Keywords: *Kapilit Formation, hydrogen index, vitrinite, inertinite, liptinite, maceral, kerogen, biomarker*

INTRODUCTION

Maliau Basin is located in the south central region of Sabah, covering an area of about 390 km² (Figure 1). This saucer shaped basin is almost circular in perimeter and sharply delimited by cliffs or very steep slopes on all sides. Relatively gentle slopes characterize the inner basin with general inclinations ranging from 15 degrees along the outer rim to almost flat at the center of the basin. The inner basin is carved by a series of radiating tributaries of the Maliau River, creating meso-land form of erosion ridges, V-shaped river valleys and gently sloping peneplains. The highest point is Gunung Lotung, which is about 1,675 m in elevation, but has yet to be accurately surveyed.

This 25 km diameter Basin is in fact a sedimentary formation comprised mainly of gently inclined beds of sandstone and mudstone. A large coal reserves was found in this Maliau Basin.

One scientific expedition to the Maliau Basin was organized by the Academy of Science Malaysia (ASM) and

Sabah Foundation from 15-24 June 2006. This expedition was called “Maliau Basin Scientific Expedition: Journey Through Sabah’s Lost World”. The expedition was organized in collaboration with Universiti Kebangsaan Malaysia, Universiti Malaysia Sabah and Sabah Parks, with support from Universiti Malaya and Universiti Putra Malaysia. A total of 51 scientists and research assistants from various local universities and institutions participated in the expedition. The participants were camping at a base camp named The Eucalyptus Camp. The Eucalyptus Camp is a nearly established base camp and is located about northwest of Maliau Basin Conservation area. This camp is about 1000 m above sea level and is located close to two streams. A lot of samples were collected during this expedition and several rock samples (coals and shales) were sent to Petronas Group Research Laboratory for geochemical study; the results of which are presented in this paper.

In this study, a total of ten outcrop samples, comprising of six shales and four coals from the Kapilit Formation, Maliau Basin, Sabah were analysed using organic

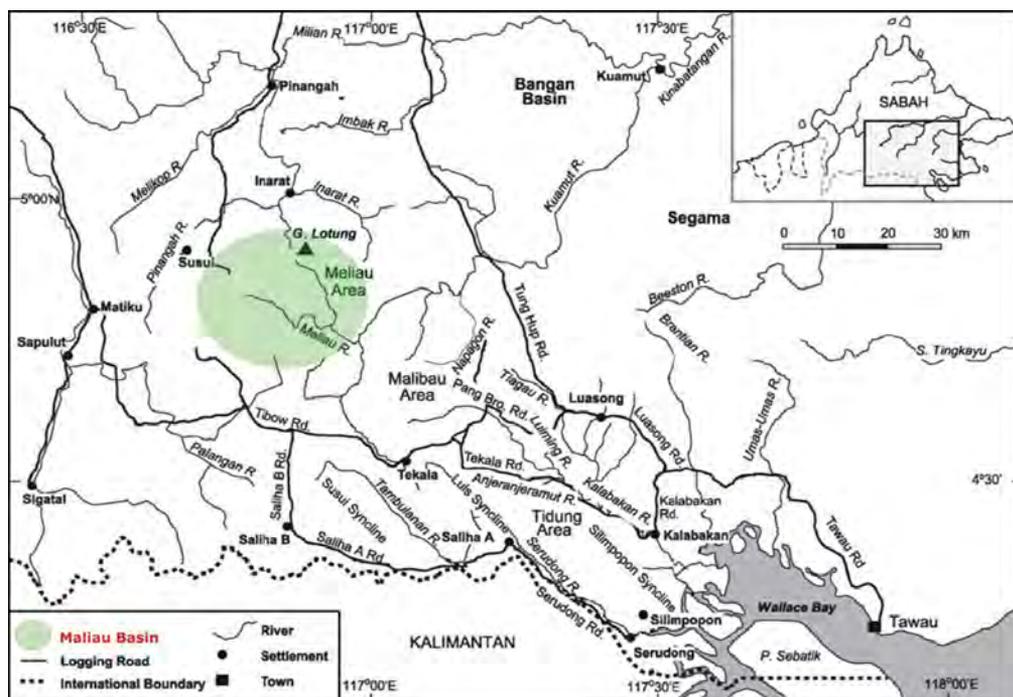


Figure 1: Location map of Maliau Basin.

petrological and organic geochemical methods. The samples were subjected to screening analysis (Rock-Eval and TOC), petrographic (maceral distribution and VRo measurement) and biomarker analyses (GC and GCMS) in order to characterize the coal and shales in term of organic richness, organic matter composition (typing), thermal maturity and depositional environment. The study also attempt to evaluate the hydrocarbon generating potential of the analysed samples and to try to recognize oil generative features in coal samples.

GEOLOGICAL BACKGROUND

The Maliau Basin is made up of sedimentary rock of Kapilit Formation. The Kapilit Formation was deposited in an ancient deltaic-coastal environment around 9-15 million years ago (Early to Middle Miocene). The Kapilit Formation is one of the formation belong to Serudong Group. Other formations or members in the Serudong Group are Burdigalian carbonate and the Tanjong, Kalabakan and Simengaris formations. Kapilit Formation was deposited above the Tanjong Formation, after a major transgressive event. An incised erosional surface marks the boundary between them. Previously, the Tanjong and Kapilit formations were thought to be lateral equivalents of the same age (Figure 2).

Study by Balaguru and Nicol, 2004, placed the Kapilit Formation above the Tanjong Formation, separated by an erosional surface. The age of the Kapilit Formation is dated as Middle Miocene to Late Miocene, whilst the Tanjong and Kalabakan formations are dated as Early Miocene to Middle Miocene. Previously the Tanjong and Kapilit formations were thought to be lateral equivalents of the same age. The Kalabakan Formation is now considered

to be a lateral equivalent of the Tanjong Formation. The youngest formation of the Serudong Group is the Simengaris Formation, which was deposited during the latest Miocene to Early Pliocene.

In the area adjacent to the Eucalyptus Camp, the Kapilit Formation comprises a succession of layers of mainly sandstone, mudstone and siltstone, with some associated coal. In this study area, the succession of Kapilit Formation is estimated about 300 m thick and has been divided into two lithofacies, namely Sandstone Dominated Unit and Mudstone Dominated Unit. Based on geological cross-section of the study, the Sandstone Dominated Unit is underlain by Mudstone Dominated Unit. (Figure 3).

The Sandstone Dominated Unit consists of thick sandstone bed, interbedded with thin mudstone. Cross-bedding and ripple mark structures are very common in the sandstone layers, and together with channel geometry, indicate that the deposition occurred due to the flow of currents in high regime environment.

Thick layer of mudstone, interbedded with sandstone, siltstone and coal seams, dominated the Mudstone Dominated Unit. Parallel laminations, bioturbations and traces of rootlets are common. The mudstone layers are dark grey in colour and contain high organic materials. The thickness of coal seams ranges from a few cm up to 350 cm thick. The occurrence of coal beds indicated that substantial amount of plant material did accumulated during deposition of this unit, probably in peat swamps environments.

SAMPLES AND METHODS

A total of ten samples, comprising of four coals and six shales, were analysed in this study (Figure 4). The samples were subjected to total organic carbon (TOC)

content determination and Rock-Eval pyrolysis to gauge their organic carbon richness and hydrocarbon generating potential, respectively. Nine of the samples were also selected for vitrinite reflectance measurements to determine their thermal maturity levels.

TOC content analysis of the coal and carbonaceous shale/siltstone were determined by combustion in LECO RC-412 Multiphase Carbon Analyser. The whole rock samples (~100 mg) were heated over a temperature range of 400°C to 950°C. The results were reported as weight percent of total weight of sample. Rock Eval pyrolysis was performed using the Vinci Rock Eval 6 Pyrolyser. For shale or non-coal samples, an approximately 100 mg of pulverized samples were pyrolysed while for coal samples, only about 2 mg of samples were used. The sample was heated over a temperature range of 300°C to 650°C, giving S1 and S2 peaks representing free hydrocarbons and hydrocarbons from cracking of kerogen in mg hydrocarbons per gram of rock, respectively. Maximum temperature (Tmax) of S2 peak is also reported to represent maturity of the samples.

Microscopical studies were performed using a MPM 400 Zeiss photometer microscope under both normal reflected white light and UV light excitation. Maceral composition for coal samples were observed and described visually on polished block section. Vitrinite reflectance (VRo) measurements were also carried out using the same microscope. Prior to the measurement, the microscope was calibrated using a sapphire standard of known reflectance. Vitrinite reflectance is a measure of the proportion of light reflected from the polished surface of a sample compared to that of a standard. Vitrinite reflectance is a standard method for determining the thermal maturity (or rank) of coals and

dispersed organic matter in sediments. The maturity is a measure of the degree of chemical and physical changes experienced by a coal or organic matter with increasing depth of burial.

The organic matter type in the shale samples were observed on strewn slide using transmitted white light and ultra violet light microscope. The strewn slide of isolated organic matter was prepared by treated the shale sample with concentrated HCl acid to remove carbonate cement and followed by a treatment with HF acid to remove silicate materials. Zinc bromide solution (SG=2.2) was used to further separate kerogen or organic matter from the minerals. The composition of organic matter was estimated visually and given in percentage of individual maceral types.

Using the TOC and Rock-Eval pyrolysis results as a basis for selection, seven samples were extracted for gas chromatography (GC) and gas chromatography – mass spectrometry (GCMS) analyses to study their biomarker distributions.

About 20 g of powdered rock samples were continuously extracted (using soxhlet technique) for 32 hours or until the solvent in the soxhlet is colourless in azeotropic mixture of dichloromethane and methanol (93:7). The rock extracts were separated into saturated hydrocarbon fraction, aromatic hydrocarbon fraction and NSO compounds using the liquid column chromatography (LCC) technique.

Gas chromatography (GC) analysis of the saturated hydrocarbon fraction of the extracts were carried out using a HP5890A Gas Chromatograph equipped with a flame ionization detector (FID) and a 60 m, 0.25 mm id fused silica capillary column coated with crosslinked methyl siloxane (DB-1). The GC oven temperature was ramped at 4°C/min from 50°C to 300°C (30 min. hold). *N*-alkane ratios were determined using peak height.

Biomarker analyses were conducted using a Micromass Quattro micro GCMS coupled to Agilent 6890 GC system fitted with a HP-1MS capillary column (60 m, 0.25 mm id., 0.25 µm film). Helium was used as carrier gas (1.5 mL/min). The oven temperature was ramped from 60°C to 200°C at 4°C/min and then to 300°C at 2°C/min and held at final temperature for 20 min. The saturated hydrocarbon fractions were analysed twice: first using selected ion monitoring (SIM) mode of the GCMS and secondly using multiple reaction monitoring (MRM) mode, monitoring daughter to

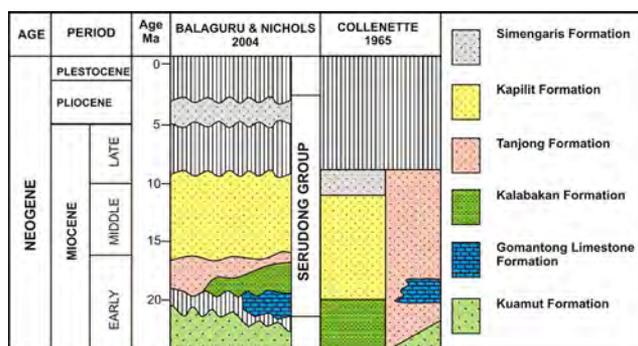


Figure 2: Stratigraphy of study area.

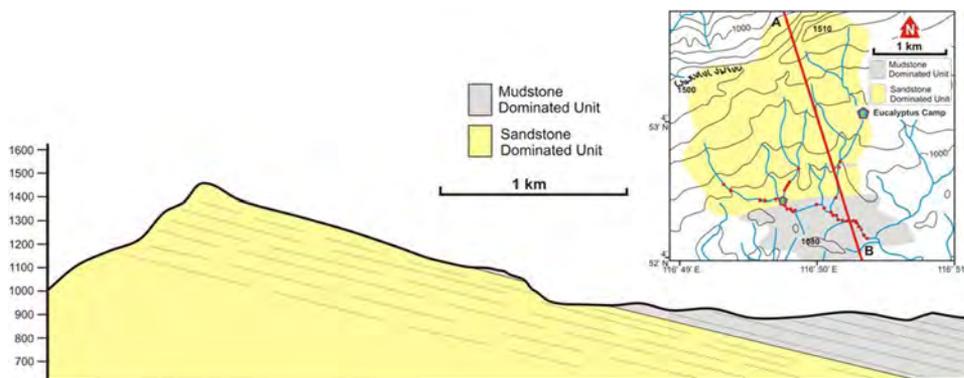


Figure 3: Cross section and correlation. Based on the geological map and cross-section of the study area, the Sandstone Dominated Unit is underlain the Mudstone Dominated Unit.

Table 1: Source rock screening data (TOC and Rock-Eval).

Sample No	Formation	Lithology	TOC (wt.%)	S1 (mg/g)	S2 (mg/g)	Tmax (°C)	HI	PI
S1	Kapilit	Coal	70.47	0.88	202.63	430	288	0.00
S1B	Kapilit	Shale	3.73	0.05	5.03	443	135	0.01
S1C	Kapilit	Coal	64.52	0.61	126.84	431	197	0.00
S4	Kapilit	Shale	0.44	0.01	0.42	447	95	0.02
S9	Kapilit	Shale	1.04	0.05	0.96	439	92	0.05
S12	Kapilit	Coal	67.22	0.54	173.04	430	257	0.00
S13	Kapilit	Shale	5.74	1.21	9.24	425	161	0.12
S13B	Kapilit	Coal	69.82	1.11	228.40	429	327	0.00
S25	Kapilit	Shale	16.38	0.62	37.27	438	228	0.02
S26	Kapilit	Shale	12.95	0.16	18.57	441	143	0.01

PI - production index (S1/S1+S2); HI - hydrogen index (100*S2/TOC)

Table 2: Measured vitrinite reflectance (VRo) results.

Sample No.	Lithology	No. of Readings	VRo Range (%)	VRo Mean (%)
S1	Coal	20	0.54 - 0.69	0.60
S1B	Shale	30	0.67 - 0.87	0.76
S1C	Coal	20	0.53 - 0.68	0.60
S4	Shale	20	0.61 - 0.77	0.67
S9	Shale	20	0.57 - 0.70	0.64
S12	Coal	20	0.64 - 0.77	0.70
S13	Shale	21	0.52 - 0.64	0.57
S25	Shale	20	0.61 - 0.76	0.69
S26	Shale	20	0.71 - 0.87	0.80

Table 3: VR boundaries used for maturity assessment.

VR Range	Petroleum Generation
< 0.50%	Immature with respect to petroleum generation
0.50 – 0.70%	Early stage of oil generation
0.70 – 1.00%	Main stage of oil generation
1.00 – 1.35%	Late stage of oil generation, condensate generation
1.35 – 2.00%	Wet gas and methane (dry gas) generation
> 2.00%	Methane generation only

parent ions transition of the steranes and triterpanes. The injector and interface temperatures were set at 275°C. The mass spectrometer was operated with electron ionization energy of 70 eV and ion source temperature of 220°C. Data were acquired and processed using MassLynx V4.0 software.

RESULTS AND DISCUSSION

Source potential

Source potential of the ten samples analysed in this study was assessed using Rock-Eval pyrolysis (Rock-Eval 6) and LECO carbon analyser. The results of these analyses are given in Table 1 and graphically displayed in Figure 5.

The results of total organic carbon (TOC) analysis show that the shales possess good to very good organic carbon richness as shown by TOC values ranging from 1.04wt% to 16.38 wt%, except for one sample (S4) which has poor organic carbon richness (TOC value of 0.44 wt%). The shales also possess good to very good hydrocarbon generating potential as suggested by S2 values ranging from 5.03 to 37.27 mg HC/g rock, except for two samples (S4 and S9) which have poor hydrocarbon generating potential (S2 <2.5 mg HC/g rock). The very good TOC and pyrolysis results for some of the shale samples such as S25 and S26 are probably due to presence of coaly organic matter. The four coal samples, as expected, possess very good organic carbon richness and hydrocarbon generating potential as indicated by TOC values of between 64.52 wt% and 70.47 wt% and S2 values of 126.84 – 228.40 mg HC/g rock, respectively. However, both the shale and coal samples show very low S1 (free hydrocarbons) values, which may be related to highly weathered samples. This may also affect the S2 and TOC values to a certain extent.

Although majority of the outcrop samples analysed contain good to very good organic carbon richness and hydrocarbon generating potential, their ability to generate liquid hydrocarbons depends on the type of organic matter present in the sample. Hydrogen index (HI) can be used to give general indication of the kerogen type present in the sample. It is commonly accepted that samples with HI lower than 50 have no potential for hydrocarbon generation while those with 50 to 200 are mainly gas prone. Samples with HI of between 200 and 300, in addition to gas, are also capable of generating some liquid hydrocarbons. Samples with HI above 300 are normally considered as having good potential for liquid hydrocarbon generation (Peters, 1986; Peters and Moldowan, 1993). HI for the shale samples are generally low (<200), except for one sample (S25) which gives HI of 228, while for the coals, their HI range from 197 to 327. Therefore, the HI values suggest that the shales contain mainly Type III organic matter which is capable of generating mainly gaseous hydrocarbons. The coals, in addition to gas, also have some potential for liquid hydrocarbon generation upon reaching optimum thermal maturity. The plot of HI versus Tmax (Fig. 5B) shows that most of the shales plot below the Type III curve, while the coals are plotting slightly above the Type III curve.

Thermal maturity

Vitrinite reflectance analysis was carried out on 9 samples. The samples comprise of three (3) coals and six (6) shale/carbonaceous shale samples. The vitrinite reflectance (VR) data of the investigated samples are shown in Table 2. The Tmax from Rock Eval pyrolysis, thermal alteration index (TAI) and various biomarker maturity ratios are also available to complement the vitrinite reflectance data.

For maturity assessment, the VR boundaries shown in

Table 4: Organic matter typing data.

Sample No.	Lithology	Type of Organic Matter (%)							Thermal Alteration Index
		Inertinite	Vitrinite	Liptinite	Alginite	Fluores. Amorphous	Non Fluores. Amorphous	Total Fluores. Org. Mat.	
S1	Coal	20	60	20	NA	NA	NA	20	NA
S1B	Shale	20	50	5	TR	10	15	15	NA
S1C	Coal	15	60	25	NA	NA	NA	25	NA
S4	Shale	30	60	10	TR	TR	TR	10	NA
S9	Shale	25	40	5	TR	10	20	15	3-/3
S12	Coal	10	60	30	NA	NA	NA	30	NA
S13	Shale	20	40	15	TR	10	15	25	2+/3-
S13B	Coal	10	70	20	NA	NA	NA	20	NA
S25	Shale	25	50	5	TR	10	10	15	2+/3-
S26	Shale	35	50	5	TR	5	5	10	2+

Table 3 were used as a guide to the level of thermal maturity for petroleum generation.

The VR values for most of the samples range from 0.57% to 0.70%, indicating that the samples are in the early stage of oil generation, except for two shale samples (S1B and S26) which give higher VR values (0.76% and 0.80%, respectively) suggesting that the samples are already in the main stage of oil generation. Tmax values (Table 1), ranging from 425° to 447°C, are also generally in agreement with the VR values. This is also shown by the biomarker data (discussed below).

Organic petrology

The six shale and four coal samples were also subjected to organic petrological analysis. Relative proportions of organic matter (macerals) are quantified visually under microscope. The organic matter typing data are shown in Table 4.

Shale

The results of visual organic matter typing analysis (Table 4) show that all of the shale samples contain mainly terrigenous derived organic matter. Vitrinite and inertinite are the main organic matter type present, constitute more than 70% of the total kerogen (Figure 11D). Total fluorescing organic matter range from 10 to 20%, and basically consist of liptinitic and fluorescing amorphous materials.

Coal

All four coal samples are dominated by vitrinite maceral (approximately 60%) which is of predominantly structureless vitrinite (desmocollinite). Liptinite content ranges from 20% – 30% and most commonly being cutinite, suberinite and resinite (Figures 11A, 11B and 11C). Some minor amount of sporinite is also present. The highest liptinite content was observed in sample S12 which is representing 30% of total organic matter. Inertinite content is low ranging from 10% to 20% (Table 1).

The oil generating potential of coals, although long debated, is now generally accepted. It should, however, be stressed that every situation should be judged by it's own merit. As an example, the coastal and offshore areas of Sarawak contain abundant of Late Oligocene to Early

Miocene coals and their oil prone nature of these coals have been discussed in several publications (e.g. Mazlan & Abolins, 1999). The coal and coaly shale from Talang Akar Formation is accepted as a source rock for oil and gas in South Sumatra Province and is a major source for petroleum in the Ardjuna sub-basin, northwest Java (Noble *et al.*, 1991). The Jurassic coals and their associated organic rich mudstone are the source rock for oil and gas accumulations for southern Junggar, northern Tarim and Turpan basins within Xin Jiang, China (Jin *et al.*, 1999).

One of the objectives of the study is to recognize any oil or hydrocarbon generative features in the coal samples. The moderately high content of liptinitic oil prone organic matter (more than 20%) would indicate oil generative potential; whereas the dominant content of vitrinite would render them generally gas prone. The microscopic observation of coal samples show that the liptinite macerals are commonly associated with some oil generative features namely oil smears or hydrocarbon haze (Figures 12A and 12B). Features like vacuoles and vesicles are commonly found within desmocollinite (Figures 12C and 12D). The vesicles are thought to represent the formation of gaseous vacuoles that is associated with the hydrocarbon (normally gas) generation taking place in the coal.

Source and environment of deposition

A combination of GC and GCMS data were used to assess the organic matter source and environment of deposition of the outcrop samples. GC traces of aliphatic hydrocarbons of the rock extracts show the presence in high abundances of the *n*-alkanes, ranging from about *n*-C₁₂ up to *n*-C₃₅. However, the low molecular weight (MW) hydrocarbons (especially those below *n*-C₂₀) are severely depleted, particularly in samples S12 and S13 (Figure 6). The lost of low MW hydrocarbons is most likely due to weathering effects as the samples are outcrops. This is in agreement with the low S1 values obtained from the Rock-Eval pyrolysis.

Pristane (Pr) is the most dominant peak in the GC traces and all the extracts give very high pristane to phytane (Pr/Ph) ratio with values ranging from 5.5 to 13.0, particularly the coals and carbonaceous shales (Pr/Ph >9.0). The high molecular weight (MW) hydrocarbons (>*n*-C₂₀) are less

effected by weathering and their distributions show higher abundances of the odd carbon number *n*-alkanes over even carbon number (CPI of 1.07 - 1.52). The very high Pr/Ph ratio and coupled with high MW *n*-alkanes which show predominance of odd over even carbon number, suggests that the extracts contain high abundances of land plant organic matter, deposited in an oxic environment.

The GCMS traces (m/z 191 and m/z 217) of the rock extracts are given in Figures 7 and 8. The triterpane (m/z 191) distributions show the presence of both hopane and non-hopanoid biomarkers. The hopanes range from C₂₇ up to at least C₃₃ with very low abundances of extended hopanes, particularly those above C₃₃. The low abundances of the extended hopanes are in agreement with the Pr/Ph ratio which suggests that the organic matter was deposited in an oxic environment, probably a coastal plain or deltaic setting. Of the C₂₇ hopanes, Tm (C₂₇ 18α(H)-22,29,30-trisnorneohopane) is present in much higher concentration relative to Ts (C₂₇ 17α(H)-22,29,30-trisnorhopane), as commonly observed in extracts containing high abundances of land plant organic matter. The tricyclic terpanes which are often associated with algal input (e.g. Aquino Neto *et al.*, 1989; Volkman

et al., 1989) and are commonly observed in the marine and lacustrine oils are absent or present only in trace amount in these extracts of terrigenous coals and shales.

The non-hopanoids, which are mainly derived from land plant materials, are also present. They include oleananes (O) and unknown triterpenoids (x). The non-hopanoids are abundant in the extract of shale (S9: O/C₃₀H ~0.75), but are low or present only in trace amount in the extract of coals (O/C₃₀H ~0.01 - 0.06, Figure 7). The presence of oleananes suggests that the organic matter were derived from Tertiary source rocks containing abundant of land plant organic matter (Philp and Gilbert, 1986; Riva *et al.*, 1988). The low abundances of the oleananes in the coal samples are probably related to the environmental conditions under which the organic matter was deposited. It has been suggested that oleanane formation is not favourable in acidic environment such coal swamps, therefore less of the compounds such as those with oleanane skeletons were preserved (Sosrowidjojo *et al.*, 1994; Murray *et al.*, 1997). Alternatively, the high degree of bacterial reworking that occurs in some peat-performing environments could produce excessive quantities of hopanes (bacterial-derived compounds) which subsequently have diluted the oleananes (Wan Hasiah & Abolins, 1998). The unidentified triterpenoids (peaks labeled x) which are abundant in the shale, are most likely related to the oleananes and lupanes (Curiale, 2006). The presence of these triterpenoids which so far have only been found in terrigenous oils and rock extracts is also interpreted as an indicator of terrigenous input.

The bicadinanes or resin derived compounds, which are commonly observed in oils from Southeast Asia region including Sarawak and Sabah basins (e.g. Grantham *et al.*, 1983; Awang Sapawi *et al.*, 1991), are also absent or present only in trace amount, as commonly observed in rock extracts. Bicadinanes are thought to be derived from polycadinenes, biopolymers present in dammar resin produced from trees of

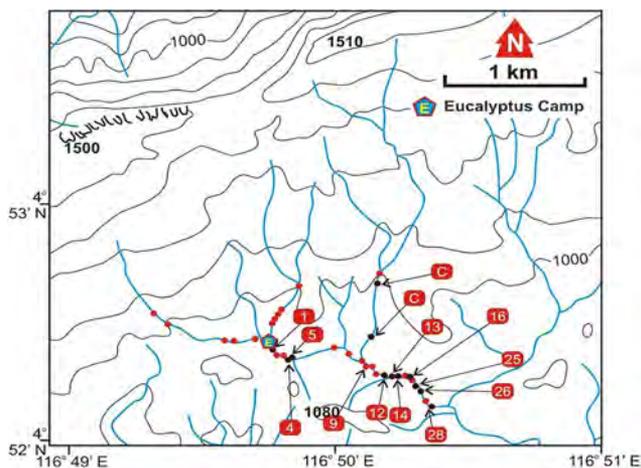


Figure 4: Samples location map.

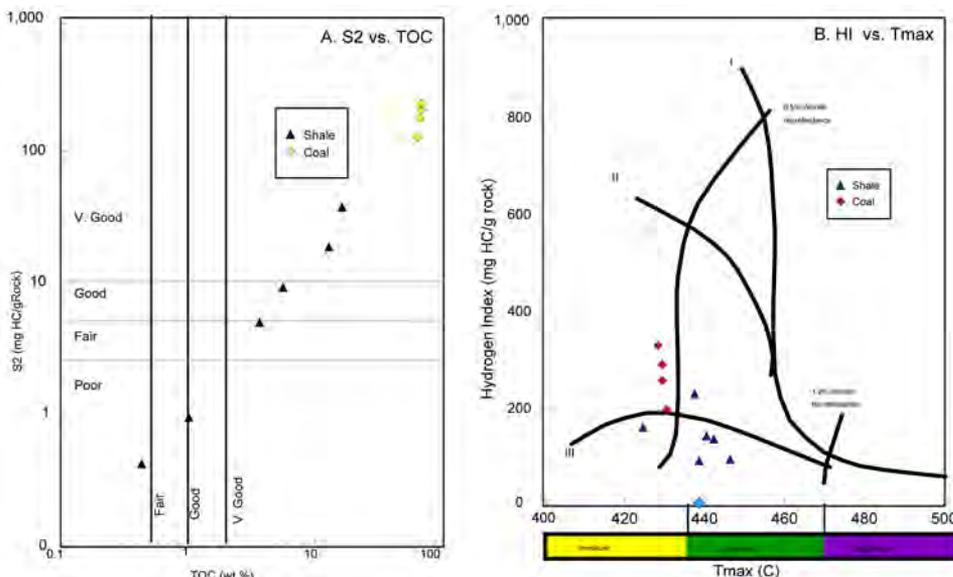


Figure 5: Plots of S2 versus TOC and HI versus Tmax.

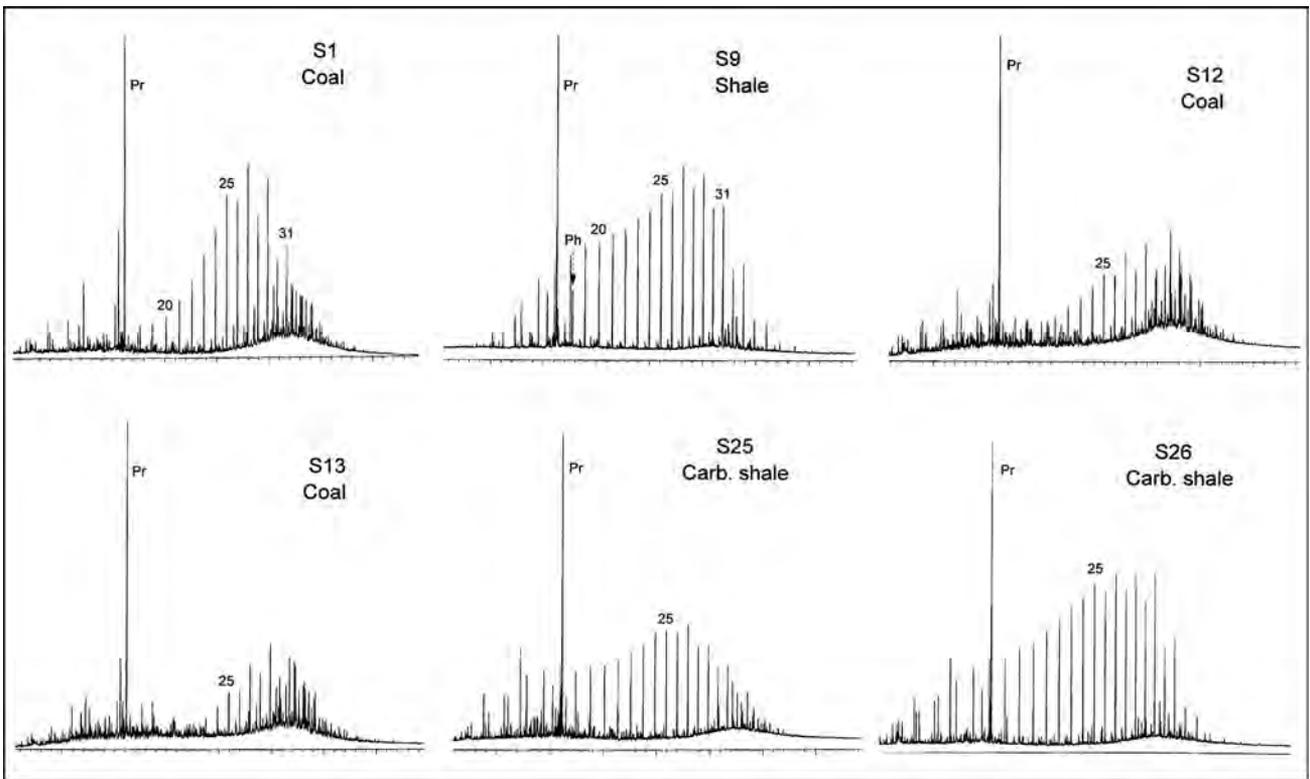


Figure 6: Gas chromatograms of saturated hydrocarbon fractions of outcrop samples, Maliau Basin, Sabah.

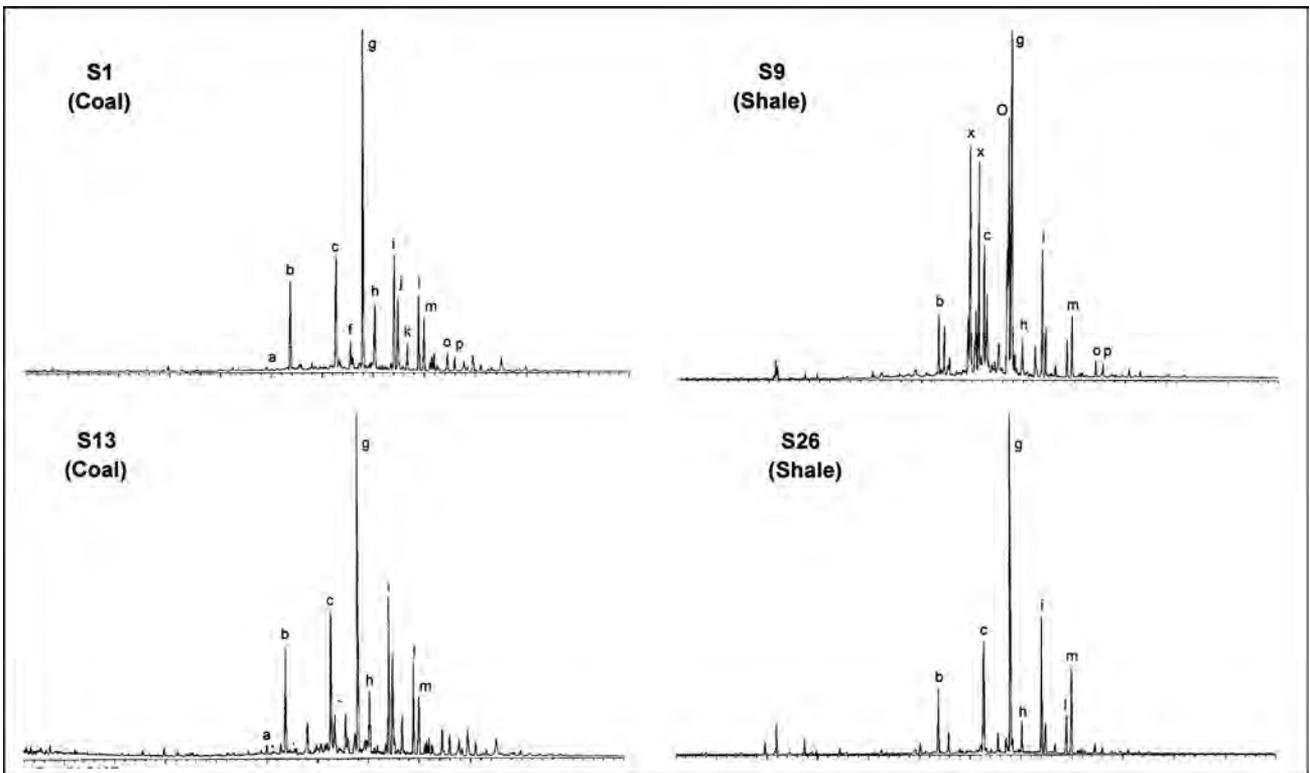


Figure 7: The m/z 191 (triterpanes) mass chromatograms of saturated hydrocarbon fractions of outcrop samples, Maliau Basin, Sabah.

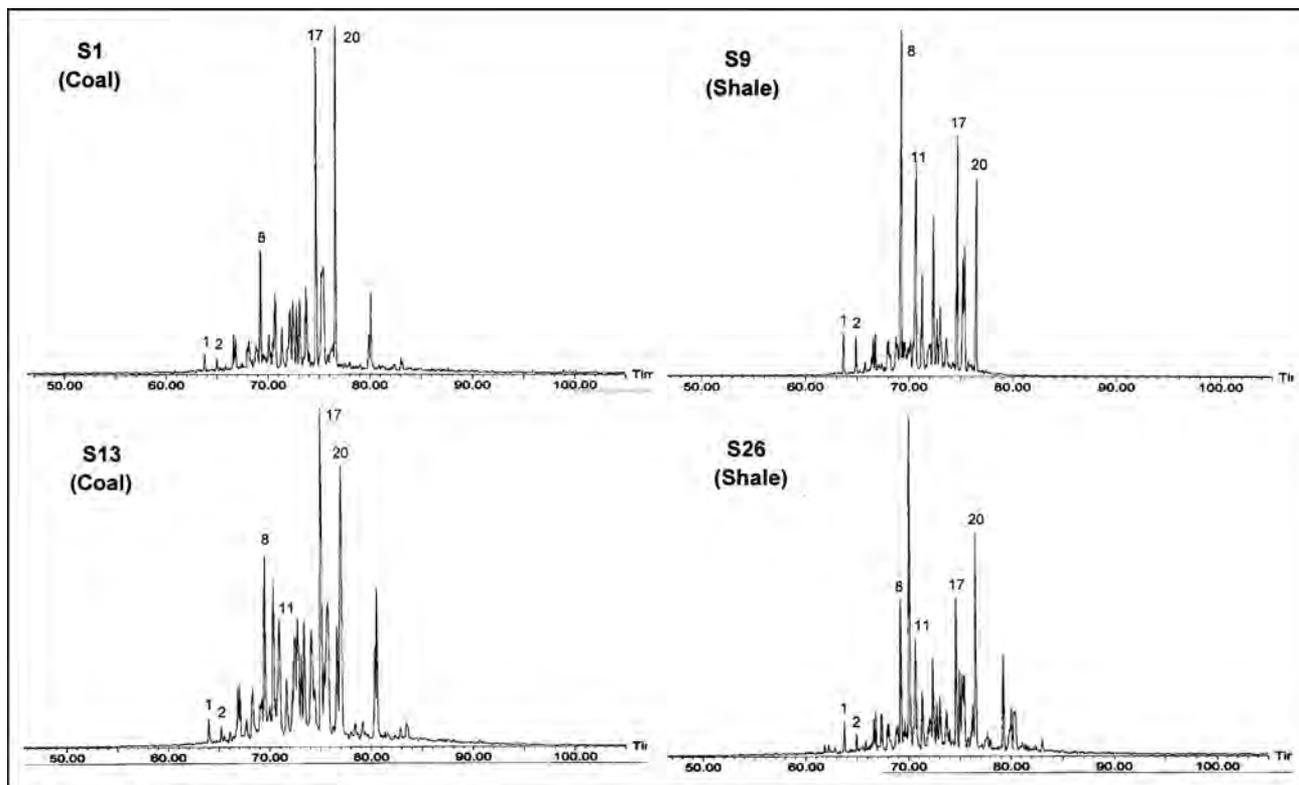


Figure 8: The m/z 217 (steranes) mass chromatograms of saturated hydrocarbon fractions of outcrop samples, Maliau Basin, Sabah.

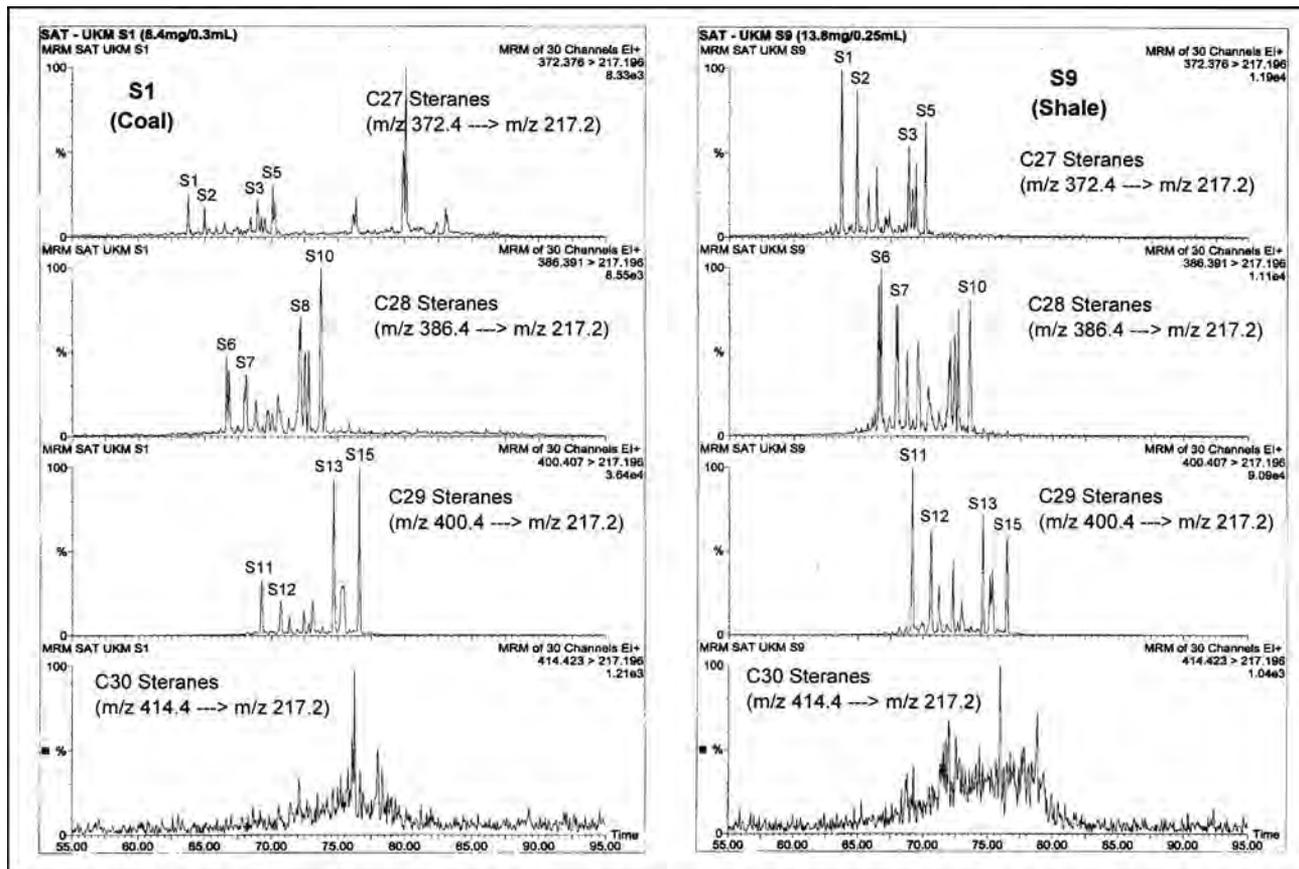


Figure 9: The MRM (steranes) mass chromatograms of saturated hydrocarbon fractions of outcrop samples, Maliau Basin, Sabah. Peak identification is given in Appendix A.

Table 5: Biomarker source parameters.

Sample	Lithology	Pr Ph	Tm Ts	C29H C30H	O C30H	C29 Dia C29 Reg	Reg. Sterane Distribution (%)			Diasterane Distribution (%)			C30 Steranes
							C27	C28	C29	C27	C28	C29	
S1	Coal	12.96	27.50	0.33	0.02	0.28	3.5	18.2	78.3	11.3	21.8	66.9	Absent
S1B	Shale	9.67	18.33	0.46	0.01	0.58	9.4	12.3	78.3	16	14.5	69.5	Absent
S9	Shale	5.54	12.22	0.37	0.75	1.25	11.4	12.7	76.0	10.5	8.7	80.9	Absent
S12	Coal	11.00	27.50	0.41	0.01	0.40	6.3	26.2	67.5	11.8	23.6	64.6	Absent
S13B	Coal	9.40	18.33	0.42	0.06	0.45	8.0	24.1	68.0	9.9	19.6	70.5	Absent
S25	Shale	11.20	27.50	0.52	0.01	0.57	13.0	14.8	72.1	20.0	12.9	67.1	Absent
S26	Shale	10.77	15.71	0.33	0.05	0.70	6.6	14.2	79.2	15.0	17.1	67.9	Absent

Hopane ratios are based on peak height; H – Hopane; Ts & Tm (C27 Hopanes) – calculated from MRM traces; sterane data are from MRM traces, calculated based on peak area; O – Oleananes; C29 Reg - C29 regular steranes (peaks S13+S15); percentage composition of regular steranes: peak S5:S10:S15; Pr – Pristane; C29 Dia - C29 Diasteranes (peaks S11+S12); percentage composition of diasteranes: peak S1:S6b:S11; Ph - Phytane.

Table 6: Biomarker maturity parameters.

Sample	Lithology	n-Alkanes	Triterpanes						C29 Steranes	
		CPI	Ts Ts+Tm	C29M C29H	C30M C30H	C31H S/(S+R)	C32H S/(S+R)	C33H S/(S+R)	20S (20S+20R)	% Rc
S1	Coal	1.24	0.04	0.27	0.20	0.64	0.65	0.60	0.49	0.71
S1B	Shale	1.09	0.05	0.22	0.09	0.60	0.61	0.61	0.46	0.69
S9	Shale	1.08	0.08	0.24	0.12	0.65	0.46	0.57	0.55	0.80
S12	Coal	1.19	0.04	0.17	0.16	0.59	0.66	0.63	0.50	0.74
S13B	Coal	1.52	0.05	0.28	0.19	0.58	0.62	0.61	0.55	0.80
S25	Shale	1.07	0.04	0.16	0.11	0.59	0.64	0.60	0.50	0.74
S26	Shale	1.11	0.06	0.18	0.09	0.70	0.53	0.56	0.43	0.65

CPI - Carbon Preference Index; Ts/Ts+Tm ratio was calculated from MRM traces; $CPI = [(C23+C25+C27+C29)+(C25+C27+C29+C31)]/2*(C24+C26+C28+C30)$; H – Hopane; M – Moretane; Homohopanes & C29 sterane ratios were calculated from MRM traces; Rc (vitrinite reflectance equivalent) estimated from 20S/20S+20R of C29 steranes (Peters & Moldowan, 1993)

the *Dipterocarpaceae* family (van Aarssen *et al.*, 1990). The absence of bicadinanes is probably also due to environmental conditions, the plant species responsible for bicadinanes not flourishing in coal swamp environment.

The sterane (m/z 217 and MRM) traces of the rock extracts are dominated by the regular steranes, especially the $\alpha\alpha\alpha$ -20R steranes (Figures 8 and 9). The distribution shows a high abundance of C₂₉-steranes, ranging from about 67.5 to 79.2%, with relatively low abundances of the C₂₇- (~3.5 to 13.0%) and C₂₈-steranes (~12.3 to 26.2%) reflecting high input of land-plant organic matter (Table 5, Figure 10). Diasteranes are also present in all of the extracts and also show predominance of the C₂₉ counterparts (>60%). The diasteranes are abundant in the shale (C₂₉ diasteranes/reg. steranes ~1.25), but are low in the coals (C₂₉ diasteranes/reg. steranes ~0.28 – 0.70). This is expected as the formation of diasteranes is thought to be from clay-catalysed conversion of diasterenes (Rubinstein *et al.*, 1975) and in the coals only limited conversion occur as coals contain lower clay content compared to shales. The C₃₀-steranes, the presence of which would indicate contribution from marine organic matter (Peter and Moldowan, 1993), are absent or present only in trace amounts (Figure 9).

Maturity based on biomarker distributions

A number of biomarker maturity parameters can be applied to assess the level of thermal maturity of the extracts (Table 6). The 22S/(22S+22R) epimer ratio of the C₃₁ and C₃₃ 17 α (H)-hopanes, with values of 0.58 - 0.65 and 0.56 - 0.63, respectively, show that the ratios have generally reached the equilibrium value (0.55-0.62). This suggests that the hydrocarbons were generated from source rock at higher maturity level which had surpassed the early oil window maturity level (VR > 0.6%). The C₃₂ hopanes ratio (particularly for samples S9 and S26) is unreliable probably due to coelution of its R epimer with other compound rather than reflecting low maturity. The high maturity of the oils is also shown by the low abundances of the moretanes (C30M/C30H ~0.1 – 0.2).

The maturity parameter based on the C₂₉-sterane epimer ratios also suggest that the rock samples are at early to main oil window maturity. This is as shown by the ratio of 20S/20S+20R which gave vitrinite reflectance equivalent (Rc) values of between about 0.65 to 0.80% Rc (Table 6; Peters & Moldowan, 1993). These values are generally in agreement with the maturity data obtained from vitrinite reflectance (0.57 – 0.80%).

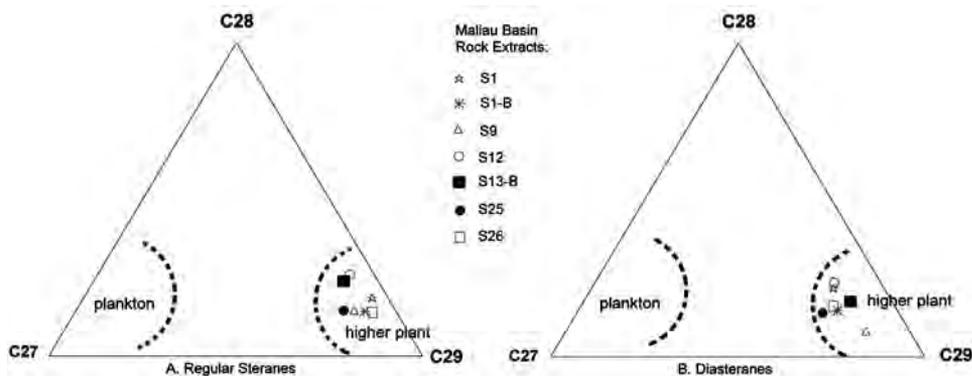


Figure 10: Ternary plots showing the relative abundances of C27-, C28- and C29- of (a) regular steranes ($\alpha\alpha\alpha$ 20R) and (b) diasteranes ($\beta\alpha$ 20S) of the rock extracts of outcrop samples from Maliau Basin, Sabah.

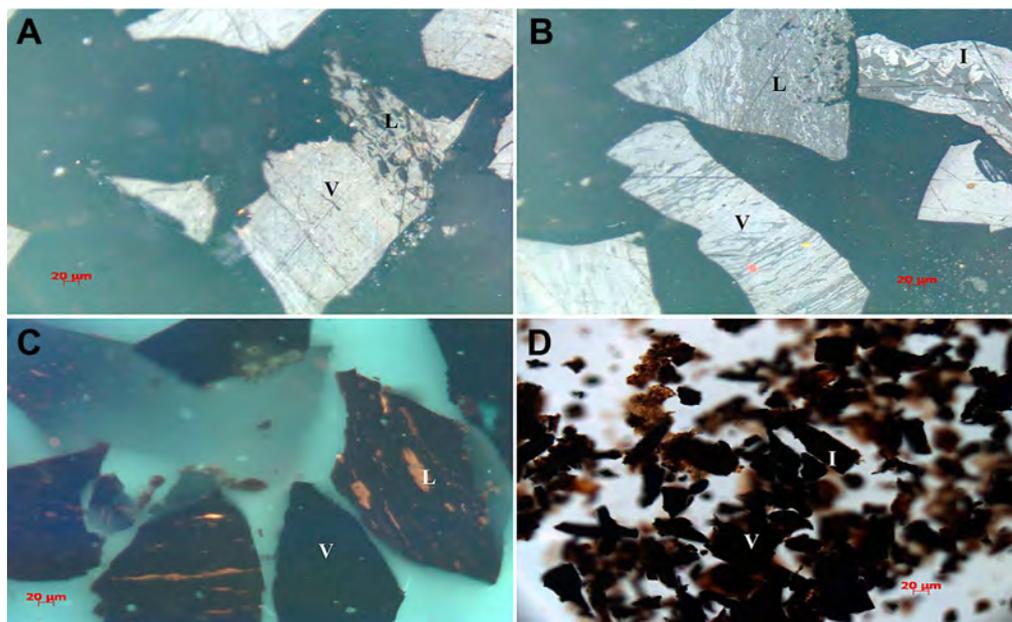


Figure 11: A to C: Photomicrographs show the type of organic matter in coal samples and D shows the type of organic matter in shale sample. A: Sample S1, under reflected white light. B: Sample S12 under reflected white light. C: Sample S1C, under UV light. D: Sample S1B, under transmitted white light. V: Vitrinite, I: Inertinite, L: Liptinite.

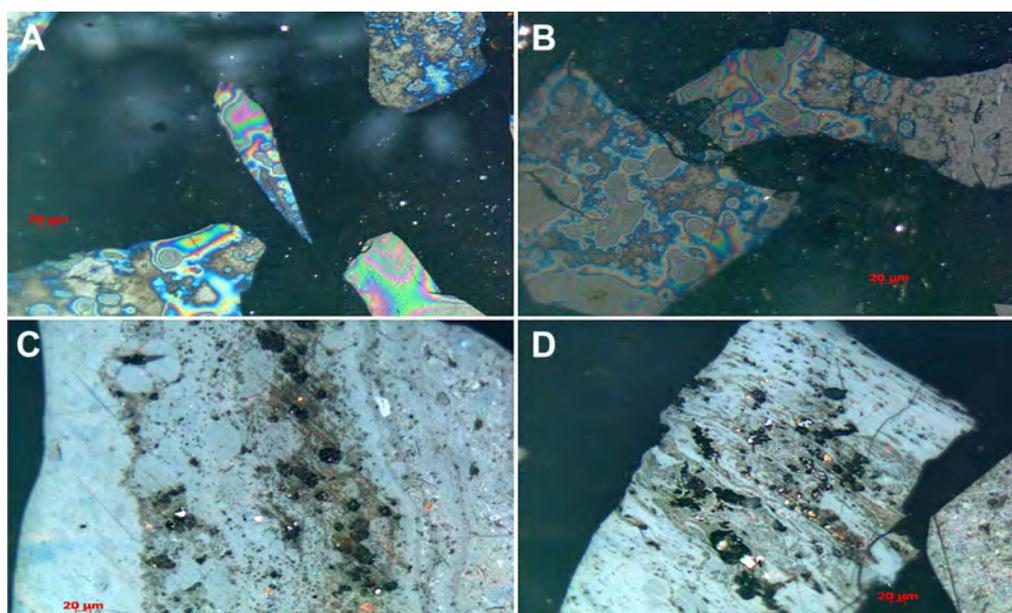


Figure 12: A and B are photomicrographs showing an oil smear or hydrocarbon haze and C and D are photomicrographs showing a vacuoles and vesicles in coal sample. All features indicate that the hydrocarbon was generated in the samples. A: Sample S12, reflected white light. B: Sample S12, under reflected white light. C: Sample S13, under reflected white light. D: Sample S13, under reflected white light.

CONCLUSIONS

A total of ten samples, comprising of six shales and four coals, of the Kapilit Formation from the adjacent area of Eucalyptus campsite, Maliau Basin, Sabah were characterised using organic petrological and organic geochemical methods. The results obtained show that the shales possess generally good to very good organic carbon richness, whilst for the coals, as usual, show very good organic carbon richness. The shale samples also show good to very good hydrocarbon generating potential (S₂ values from 5.0 to 37.3 mg HC/g rock), except for two samples which possess poor hydrocarbon generating potential (S₂ <1.0 mg HC/g rock). Hydrogen Index (HI) for the shale samples are generally less than 200 and this suggests that the shales contain mainly gas prone, Type III organic matter.

The hydrocarbon generating potential for the coals are very good (S₂ values from 126.8 to 228.4 mg HC/g rock) and their hydrogen indices are also quite high (197 to 327), indicating that the coals have some potential for liquid hydrocarbon generation, in addition to gas.

Evaluation on thermal maturity shows that the samples which were collected from the same Kapilit Formation are in the early to main stage of oil generation as shown by V_{Ro} values of between 0.57% and 0.80%.

Microscopic observation shows that the shales and coals contain mainly terrigenous derived organic matter. Vitrinite and inertinite are the dominant macerals. Oil prone, fluorescing organic matter content is higher in the coal samples than in the shales. This shows that the coals have a better quality organic matter for oil generation than the shales. Some hydrocarbon generative features can be observed in the coal samples, suggesting that some hydrocarbons were generated from the coals.

The biomarker characteristics also suggest that the rocks analysed contain high abundance of land plant organic matter as shown by the high pristane/phytane (Pr/Ph >5.0) ratio, odd-over-even *n*-alkane distributions, presence of oleananes and dominance of C₂₉ sterane homologs. The depositional environment for the shales and coals is probably in a coastal plain or deltaic setting under oxic depositional environment.

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APPENDIX A: GCMS PEAK IDENTIFICATION

A. Triterpanes (m/z 191)

a	18 α (H)-22,29,30-trisnorhopane (Ts)
b	17 α (H)-22,29,30-trisnorhopane (Tm)
x	unknown triterpenoids
c	C ₂₉ -17 α (H), 21 β (H)-norhopane
d	18 α (H)-norhopane (C ₂₉ -Ts)
e	17 α (H)-diahopane
f	C ₂₉ -17 β (H), 21 α (H)-normoretane
O	18 α + 18 β - Oleananes
g	C ₃₀ -17 α (H), 21 β (H)-hopane
h	C ₃₀ -17 β (H), 21 α (H)-moretane
i	C ₃₁ -17 α (H), 21 β (H)-homohopane (22S)
j	C ₃₁ -17 α (H), 21 β (H)-homohopane (22R)
k	C ₃₁ -17 β (H), 21 α (H)-homomoretane (22R+22S)
l	C ₃₂ -17 α (H), 21 β (H)-bishomohopane (22S)
m	C ₃₂ -17 α (H), 21 β (H)-bishomohopane (22R)
o	C ₃₃ -17 α (H), 21 β (H)-trishomohopane (22S)
p	C ₃₃ -17 α (H), 21 β (H)-trishomohopane (22R)
q	C ₃₄ -17 α (H), 21 β (H)-tetrakishomohopane (22S)
r	C ₃₄ -17 α (H), 21 β (H)-tetrakishomohopane (22R)
s	C ₃₅ -17 α (H), 21 β (H)-pentakishomohopane (22S)
t	C ₃₅ -17 α (H), 21 β (H)-pentakishomohopane (22R)

B. Steranes (m/z 217)

1	C ₂₇ $\beta\alpha$ 20S diacholestane
2	C ₂₇ $\beta\alpha$ 20R diacholestane
3	C ₂₇ $\alpha\beta$ 20S diacholestane
4	C ₂₇ $\alpha\beta$ 20R diacholestane
5	C ₂₈ $\beta\alpha$ 20S diacholestane
6	C ₂₈ $\beta\alpha$ 20R diacholestane
7	C ₂₈ $\alpha\beta$ 20S diacholestane + C ₂₇ $\alpha\alpha$ 20S cholestane
8	C ₂₉ $\beta\alpha$ 20R diacholestane + C ₂₇ $\beta\beta$ 20R cholestane
9	C ₂₇ $\beta\beta$ 20S diacholestane + C ₂₈ $\alpha\beta$ 20R diacholestane
10	C ₂₇ $\alpha\alpha$ 20R cholestane
11	C ₂₉ $\beta\alpha$ 20R diacholestane
12	C ₂₉ $\alpha\beta$ 20S diacholestane
13	C ₂₈ $\alpha\alpha$ 20S cholestane
14	C ₂₉ $\alpha\beta$ 20R diacholestane + C ₂₈ $\beta\beta$ 20R cholestane
15	C ₂₈ $\beta\beta$ 20S cholestane
16	C ₂₈ $\alpha\alpha$ 20R cholestane
17	C ₂₉ $\alpha\alpha$ 20S cholestane
18	C ₂₉ $\beta\beta$ 20R cholestane
19	C ₂₉ $\beta\beta$ 20S cholestane
20	C ₂₉ $\alpha\alpha$ 20R cholestane

C. Steranes (MRM Traces)

S1	C ₂₇ $\beta\alpha$ 20S diacholestane
S2	C ₂₇ $\beta\alpha$ 20R diacholestane
S3	C ₂₇ $\alpha\alpha$ 20S cholestane
S4	C ₂₇ $\beta\beta$ 20R+20S cholestane
S5	C ₂₇ $\alpha\alpha$ 20R cholestane
S6	C ₂₈ $\beta\alpha$ 20S diacholestane
S7	C ₂₈ $\beta\alpha$ 20R diacholestane
S8	C ₂₈ $\alpha\alpha$ 20S cholestane
S9	C ₂₈ $\beta\beta$ 20R+20S cholestane
S10	C ₂₈ $\alpha\alpha$ 20R cholestane
S11	C ₂₉ $\beta\alpha$ 20S diacholestane
S12	C ₂₉ $\beta\alpha$ 20R diacholestane
S13	C ₂₉ $\alpha\alpha$ 20S cholestane
S14	C ₂₉ $\beta\beta$ 20R+20S cholestane
S15	C ₂₉ $\alpha\alpha$ 20R cholestane
S16	C ₃₀ $\beta\alpha$ 20S diacholestane
S17	C ₃₀ $\beta\alpha$ 20R diacholestane
S18	C ₃₀ $\alpha\alpha$ 20S cholestane
S19	C ₃₀ $\beta\beta$ 20R+20S cholestane
S20	C ₃₀ $\alpha\alpha$ 20R cholestane