CHAPTER 1

1.1 Introduction

In Malaysia, Cenozoic coals are very common and have been analysed based on organic geochemical and petrographic characteristic (e.g. Wan Hasiah, 1997, 1999, 2003; Zulkifli et al., 2008; Azlan et al., 2011; Hakimi and Abdullah, 2012). Sabah, one of the 16 states of Malaysian Federation, located in Borneo Island, has emerged as one of the potential coal powers in South East Asia. The area that forms the scope of this study lies in the west Middle Block of Pinangah located in the central part of southern Sabah (Fig 1.1). Pinangah which is located in the central of Sabah is one area undergoing coal exploration and research since the Maliau Basin, was proven to contain coal by Collenette in 1965. Previous studies in southern and eastern Sabah suggested that the age of the Tanjong Formation is Early to Middle Miocene (Collenette, 1965; Leong, 1974; Clennell, 1992) and palynological studies carried out by shell (Balaguru, 1996, 1997) showed an Early Miocene age. Dating using nanofossils has refined the age to Late Early Miocene (Balaguru and Nichols, 2004). Organic geochemistry studies of the Tertiary coals and coaly sediments carried out in area adjacent to the Pinangah (e.g. by Zulkifli et al. (2008), however no analysis were performed on samples within the Pinangah area.

The aim of this study is to evaluate the hydrocarbon generation potential of the Tanjong Formation and interpret their depositional environments. Outcrop samples were collected from twelve locations within the Tanjong Formation of the Pinangah coalfield. These outcrops are located in the dense tropical rain forest regions and are yet to be explored in detail. Results from this research provide relevant information of Pinangah coals that has not been documented before. Field sedimentological study although were carried out, but are not extensive due to limited exposures, very rugged terrains and poor accessibilities.



Fig 1.1: Location map of the study area (Pinangah area is located at the central of Sabah).

The aim of this study is to perform detailed organic petrological and organic geochemical evaluation of the Tanjung Formation coals in Pinangah area. The objectives of this study are:

1) To classify the coals based on organic petrological characteristics:

i) To determine the coal rank based on vitrinite reflectance analysis.

ii) To interpret the depositional environment of the coals- bearing strata based on maceral

analysis and palynological analysis

iii) To identify the type of kerogen

2) To classify the coal based on organic geochemical characteristics:

i) To determine the hydrocarbon potential of the coal.

ii) To determine the thermal maturity of the coal based on selected biomarker parameters

and Tmax pyrolisis result.

iii) To interpret the depositional environment and thermal maturation of the coalbearing

strata by using biomaker distributions.

iv) To identify the kerogen type.

1.3 An introduction of Sabah

Sabah is the second largest state in Malaysia after Sarawak which is the covering 73, 619 square km. Kota Kinabalu is the capital of Sabah which is known before as Jesselton.

Sabah is located at the eastern side of Borneo consists of more than 30 different ethnic races with more than 80 local dialects. Sabah's 2 million residents are a diverse mix of races, with the Kadazan, Bajau and Murut forming the main indigenous groups.

The climate of Sabah is generally hot and sunny (22 °C and 33 °C) all year round which is influenced by North-East and South-West Monsoons which change alternately during the year. The North-East Monsoon blows approximately from November till April hence bringing heavy rain to the east coast of Peninsular Malaysia, Sabah and Sarawak. On average, Sabah receives 2,908.7mm of rainfall annually in most part of the state (wikipedia.org/wiki/Sabah).

1.4 Location of study area

The study area is located in the central part of southern Sabah, namely Pinangah. The Pinangah area has been divided into four blocks which are Pinangah North Block, South Block, East Middle Block and West Middle Block. The study area under investigation is located at the west Middle Block of Pinangah (Fig 1.1). The study area is underlain by the Tanjong Formation of Early to Mid Mioecene age and was described by Collenette (1965) and consists of a sequence of mudstone, siltstone, limestone, conglomerate and coal. The study area is bounded by lines of latitudes 04° 56'U- 04° 53'U and longitudes 116° 40'T- 116° 42'T. The distance of the study area is about 110km from Keningau to Matiku up to the western border by road. Within the area, there is a main logging road accessible by four wheeled drive, as the red-logging activity has just started in the northwestern and northern part of the study area. The road crossed from the southwest towards the northeast and located at the west bank of Sungai Pinangah. There is no road access to the east of the area, which has a good coal potential. There is a village (Kg. Ulu Sungai Pinangah) located in

the area, which consist of a few houses located along the river. The area is located in the jungle thus would not be possible to reach without assistance offered by officer and workers from Jabatan Mineral & Geosciences Sabah.



Fig 1.2: Geographic location of Study area (circle red), Borneo Island (after Salleh et al., 2008)

CHAPTER 2

GENERAL GEOLOGY OF SABAH

2.1 Introduction

Sabah, located at the northern part of Borneo Island, lies in adjacent to the actively moving plates which consist of Eurasian, Indo-Australia, Pacific and Philipinnes Sea plates. Sabah has a complex geological history due to its complex tectonic settings. The main tectonic event of Sabah include the major fold-thrust belt trending Northeast in the west and bending to the east and southeast towards the north and eastern part of Sabah (Balaguru et al., 2003). According to Rangin et al., 1990; Tongkul, 1990; Hall, 1996, this belt consists of the deep marine Eocene to Oligocene accretionary complex. Five distinct tectono-stratigraphic provinces can be recognized in Sabah (Tongkul, 1995)

(a) An ophiolite complex, which is considered to form the basement of the sedimentary succession of Sabah (Hutchinson, 1989).

(b) The Rajang-Crocker accretionary prism, an arcuate belt consisting of deformed deep- marine, Eocene-Oligocene strata (Rangin et al., 1990; Tongkul, 1990; Hall, 1996).

(c) Broken formations and mélanges which show characteristics of tectonic, sedimentary and diapiric origin and are thought to have formed series of related events in the early to Middle Miocene (Clenell, 1991).

(d) Neogene sedimentary rocks, which are mostly shallow marine to fluvio-deltaic facies deformed into subcircularto elliptical, fault bounded areas which are known as the 'circular basin' of Sabah (Tongkul, 1990; Balaguru, 1996).

- (e) The Semporna-Sulu Arc, a region andesitic to dacitic volcanic activity of Miocene
- to Quaternary age in the Dent and Semporna peninsulas.

2.2 Tectonic evaluation and Basin development in Sabah

Tectonic evaluation of Sabah has been the subject of a number of studies (e.g.Tongkul, 1991; Tan and Lamy, 1990; Balaguru and Nichols, 2003; Balaguru, 2006a, 2006b; ISIS, 2005). Throughout this study, the regional palinspastic reconstruction by Tongkul (1991) and ISIS (2005) was adopted as a series of model diagram that describe the regional plate tectonic evaluation of Sabah. According to Tongkul (1991) the complex and diverse structures in the Sabah were resulted from five episode of deformation which started in the early Cretaceous (see section 2.2.1) until Pliocene. However, the Neogene Sabah Basin was probably initiated in the Late Eocene and undergone an episode structure evaluation in response to the plate collition and extension with subsequence sedimentation (Noad, 2003). Meanwhile, the Dent group sediment in Dent Peninsula has been undergone three major tectonic events according to Ismail Che Mat Zin (1994).

2.2.1 (a) Early Cretaceous to Early Eocene (~42.5 Ma)

According to Hutchinson (1989) the Cretaceous-Eocene oceanic crust is believed to be the oldest rock in Sabah. The Cretaceous-Eocene is represent by the stabilized of the newly form oceanic basement, the fine grained sediment deposited which is the source of the sediment came from the uplift older oceanic basement and continental crystalline basement

of Borneo. Fig 2.1 shows the illustration of the tectonic evaluation of Cretaceous to Eocene. Hutchinson (1988) suggested that the Celebes Sea, floored by Cretaceous oceanic crust, could be the undeformed section of this basement rock. During the Early Eocene, the oceanic basement was deformed and it caused part of the oceanic basement to be uplifted as indicated. The major compressional tectonic trending NE-SW (Mid Eocene to Early Miocene) caused the deformation and imbrications of the oceanic basement as can be seen in the Lubok Antu Melange, Lupar Valley of Sarawak (Tan, 1982) and its continuation in Eastern Sabah Ophiolitic Melange of the chert – spilite formation and crystalline Basement (Leong, 1974). These events also deformed and gradually uplifted the overlying Eocene to Early Miocene sediment in the Western area (Balaguru, 2006a). The break up of Celebes Sea, at the same time, has developed the Sea pacific margin accreationary complex on Cretaceous oceanic crust and deposited deep marine sediment. Balaguru (2006b) reported that the late Eocene deformation controlled development of an elongate basin trending approximately NE-SW in Sabah. The Late Eocene appears to be a period of continued deposition of deep marine turbidites. The basin was segmented by uplifted basement and was filled later by shallow water facies on the relatively uplifted side of the basin (part of the Kudat, Labang, Temburung and Kulapis Formations) (Tongkul, 1991).



Fig 2.1: Schematic NW- SE cross- sections across Sabah (modified after Tongkul 1991a) of Cretaceous- Eocene.

2.2.2 (b) Oligocene- Early Miocene (~42.5-20.5 Ma)

Sediment is filling axially from the south and southwest, and laterally from the north, northwest, northeast and east due to elongated geometry of the basin (Fig 2.2). Shallow water sediment were deposited on the relatively uplifted side of the basin (part of the Kudat, Labang, Temburung and Kulapis Formations), while deep water sediments were deposited in the centre of the basin (Crocker, Trusmadi, part of Sapulut, Kudat, Labang, Kulapis and Temburung Formations). According to Tongkul (1991), as the result of the sedimentation, Mid Eocene to Early Miocene sediment were compressed into NE-SW trending fold-thrust belt in the western part of Sabah and NW-SE in the northern and eastern part of Sabah.



Fig 2.2: Schematic NW- SE cross- sections across Sabah (modified after Tongkul 1991a) of Oligocene- Early Miocene.

2.2.3 (c) Early Miocene

In Early Miocene, the NW-SE compression imbricate, deformed and gradually uplifted both the oceanic basement and overlying Eocene-Early Miocene sediment in a NE-SW direction mainly in the western part of the basin (Fig 2.3). The later more dominant N-S compression deformed the northern end of the basin to form a NW-SE fold and thrust belt. The consequence of the N-S compression was probably subduction towards the southeast producing the Early- Middle Miocene volcanic arc in Dent Peninsula.



Fig 2.3: Schematic NW- SE cross- sections across Sabah (modified after Tongkul 1991a) of Early Miocene.

2.2.4 (d) Early- Middle Miocene

Major NW-SE extension occurred after the NW- SE fold and thrust belt was more or less fully established by the Early- Middle Miocene (Fig 2.4). The extension, coinciding with the opening of the Sulu Sea Basin during the Early- Middle Miocene, is thought to be accompanied by extrusion of the younger basalt in Labuk Valley along NW-SW trend. This extension fragmented the older imbricate sediment and underlying oceanic basement which subsequently shed blocks of itself to form most of the extensive chaotic deposits in eastern, Sabah.



Fig 2.4: Schematic NW- SE cross- sections across Sabah (modified after Tongkul 1991a) of Early- Middle Miocene.

2.2.5 (e) Pliocene

Horst and graben structure produced after the extension, coupled with the NW-SE fold and thrust belt in the older sediments, probably controlled the development of most of the circular basins for the deposition of the thick Early- Late Miocene sediments in central and eastern Sabah (Fig 2.5). The subduction was initiated on the eastern end of the stretched area to produce the extensive volcanic activity in the Semporna and Tawau regions, and compression in western Sabah during Late Miocene- Quaternary times. The presence of mud volcanoes in northern, western and eastern Sabah (Ficth, 1958, Wilson and Wong, 1964, Haile and Wong 1965, Tongkul, 1989b, 1989c, Tahir and Mazlan 1990) indicates the continued tectonic activity in this region.



Fig 2.5: Schematic NW- SE cross- sections across Sabah (modified after Tongkul 1991a) of Late Miocene- Pliocene.

2.3 Stratigraphy of the Sabah

The central Sabah begins with Oligocene Labang Formation on the western sides of the basins (Po) with Miocene paralic and low energy deposition of the Tanjong Formation towards the depocentre. The stratigraphic column of the Pinangah area of the Southern Sabah area is as shown in Fig. 2.6.

The Tanjong Formation is one of the Formations belonging to the Serudong Group. The boundary between the Labang/ Kuamut formations and the overlying Tanjong (and locally the Gomantong Limestone) formations is significant because it is a regional unconformity which separates a succession of deformed and indurate deep water sediments and mélanges below the unconformity from more gently folded, less cemented, shallow marine and deltaic deposits above. The unconformity can be identified separating deformed mélange of the Kuamut Formation from the less tectonised strata of the Tanjong Formation. It is interpreted to mark a major tectonic event, the Sabah orogeny (Hutchison, 1996) with associated uplift and erosion providing detritus to supply the deltaic to shallow marine Middle to Upper Miocene succession.

The trend in the Tanjong, Kalabakan and Kapilit formations of more muddy facies towards the northeast shows the detritus eroded from uplift strata of the Rajang and Kinabatangan Groups in the west was deposited in deltaic to shallow marine system which prograded towards the northeast. Fluvial- deltaic deposition of unit II of the Tanjong Formation was ended by a relative sea level rise, and Unit I of the Kapilit Formation was deposited in an open shelf setting (Balaguru & Nichols, 2004).



Fig 2.6: The stratigraphy of the southern Sabah study area based on data from field relationships and biostratigraphic information (after Balaguru & Nichols., 2004)

2.4 Tanjong Formation

The Tanjong Formation occurs in four sub-circular areas, the Meliau, Malibau, Melikop and Bangan Synclinal Basins. The Tanjong Formation extends to the Maliau Basin in the east, which is the type area of the formations as described by Collenette (1965). Tanjong Formation is divided into two units as classified by Balaguru and Nichols (2004). Unit I consists of a mudstone and siltstone-dominated sequence and Unit II consists of coarse grained sandstone, conglomerate, carbonaceous mudstone and coals seams (Balaguru and Nichols, 2004). The mudstone is mostly dark gray and soft and thick mudstone up to 2m thick is commonly observed. The sandstone that usually exposed at waterfalls or within the steep hills is generally fined grained and gray to brownish gray in colour. The depositional environment of the remainder of the formation is uncertain, but a neritic condition is assumed by previous workers. The Tanjong Formation is Early to Middle Miocene in the southern and eastern parts of Sabah Basin (Collenette, 1965; Leong, 1974; Clennell, 1992). The Early to Middle Miocene age of the Tanjong Formation is recognized by several researchers using palynological and nanofossils studies (Balaguru, 1996, 1997; Balaguru and Nichols, 2004).

Coal seams as much as 5 feet thick have been recorded or reported from the Tanjong Formation, but the occurrences are confined to single exposures, and there is no evidence to suggest that the seams extend laterally sufficiently to make the coal of economic interest. Outcrops of the Tanjong Formation are located along the Darupak and Mantutung Rivers on the northern side of the Bangan Basin, in the Apuo River, and the Meliau Basin. Coal float in the Saburan and Nasan Rivers indicate outcrops in the southewest part of the Meliau Basin and in the north of the Maliau Basin (Collenate, 1965).

CHAPTER 3

LITERATURE REVIEW

3.1 Introduction

This chapter aims to introduce the definition and interpretation of the depositional environment of coal, the organic geochemical and organic petrological application and significant. All relevant information was noted and coal outcrops information plotted onto the base map. Data available are search as information in the study area. Detailed investigation has been made by BHP Mineral (M) Sdn. Bhd. a coal prospecting company, from 1996 to 1990. However, the report is not published.

Environmental analysis is the determination of the depositional environment of sediment from the biological, physical and chemical aspects of sedimentary rocks (Selley, 1996, 2000). Thus the application of organic petrology analysis is useful to discover the provenance of terrigenous rocks and the environment of the coal while the organic geochemistry analysis concerns with the generation and maturation of coal, crude oil and natural gas. These analysies are combination of biology and chemistry which can be used to point to the origin of sedimentary rock (Selley, 2000).

3.2 Defination of Sedimentary facies and Coal Facies

Sedimentary facies are defined as a unit of rock that is distinguished its individual sedimentological character such as, fossil content, lithology, geometry and paleocurrent pattern (Selley, 2000). Sedimentary facies reflect the physical, chemical and biological conditions and processes of the deposition environment. Tyson (1995) defined the organic facies as "a body of sediment containing a distinctive assemblage of organic constituents, who can either be recognized by microscopy, or is associated with a characteristic bulk organic geochemical composition".

The characteristic of coal deposit depend on the temperature and pressure by the length of time of coal formation. Coal are heterogeneous sedimentary rock that were derived via burial and compaction of major constituents of organic matter consisting of vascular plant (forested or marsh vegetation) and nonvascular plant (aquatic vegetation) with minor mineral matter inorganic constituents. It consists of a complex mixture of microscopic components, termed macerals. Maceral components can be indicator to diagnose the paleo-environment of coal deposition by plotting on the coal facies diagram comprising "Tissue Preservation Index" (TPI) and "Gelification Index" (GI), (Diessel, 1986, and Kalkreuth and Leckie, 1989, Wan Hasiah, 2002).

3.3 Coal Depositional Environment

Coal can form in the various deltaic subenvironments, such as interdistributary bays, within, or on the crest of channel sands, as well as regionally uniform beds (Selley, 2000). Peatland is precursor depositional environment of coal which accumulates in environment ranging from subarctic marsh to tropical rain forest. Fig 3.1 shows modern peatland depositional environment area. Marsh is the areas were predominantly covered by herbaceous plants (Martini and Glooschenko, 1984; Moore, 1987; Lamberson et al., 1991), however marshes with a large proportion of solid inorganic matterin substrate are considered as minerotrophic peatland. Peatland can be equally common in all the depositional systems except the deep-water area (Rahmani and Flores, 1984; Lyons and Alpern, 1989; McCabe and Parrish, 1992). Peatland system can occur associated with fluvial in several way which is some channel are abandoned and become sites for peat formation (Franchi et al., 2004; Selley 2000) and have been reported occur along modern river systems of the Amazon Basin (Shrier, 1985; Shimada, 2005). Coals at the Permian Gondwana have been reported deposits in the backswamp environment on the active fluvial channel (Zakir H.M., 2002). The deposition of coal in the fluvial environment commonly associated with braided alluvial fan and usually contain high amount of sediment deposition to allow the accumulation and preservation of large deposit of peat. Nowsday, the example of modern peat accumulation area is river flood plain Miocene of Barito and Asam Asam Basin of Kalimantan (Friederich et al., 2009), Batang Hari River area of Sumatra and in delta/ coastal plain of the Rajang River in Sarawak, Malaysia (Esterle and Ferm, 1994, Staub et al., 1991 and Friederich et al., 2009).



Fig. 3.1: The diargram shows suberielly depositional of modern peatland area. These diagrams are provided by Encik Munif from Biostrat Company Services.

3.4 Fluvial sedimentation and sedimentary structure

There are generally four pattern of fluvial which is namely as straight, meandering, braided and anabranching pattern. In this study review, the discussion of meandering fluvial sedimentation and sedimentary structure were disscussed in relation to interpretation that have been make on the study area. Meandering channel is normally associated with finegrained sediment, gentle gradient and steady discharge (Selley, 2000). This characteristic is due when increasing distance of channel from the source thus the gradient of river profiles become less, decreasing of the sediment grain size, channel diminish in number on the floodplain and increase sinuosity. Therefore, the meandering deposition is much higher of silt and clay and less of sand and gravel. According to Shanter (1951) and Allen (1965), there are two classification of meandering subenvironment which is overbank deposit and channel deposit. Overbank deposit is the assemblage of levee, flood basin and swamp sediment while channel deposit is the defined as active channel and abandoned channel.

Fluvial channels are characterized as a unidirectional currents deposition. Several sediment structures that are considering related to the study area are discussed. Ripples are the wave which occurs in fine sandstone subjected to gentle traction current. In the fluvial environment, assembleric ripples are commonly found which were produced by unidirectional traction channel (Selley, 2000). Cross-laminated and cross-bedded sand are normally found in the fluvial area that were generated from ripples bed form and dunes. They were formed during the transportations of sand grains from the back slopes over the ripple crests and deposited on the downstream. The different of both structure is, cross-laminated individually exceed 2-3cm in thickness while crossbedding normally >50cm thick. Cross-bedding is the most important of structure sediment consist of inclient dipping bedding and bounded by subhorizontal surface. These structures may give the indication of

the flow direction of currents depositional environment area. Cross-bedding form in channels is infilled cross-bedding parallel by mean the deposition occurs parallel to the flow direction of channel (Lyell, 1865).

Dessiccation crack and sand dikes is the sedimentary structure form after sediment has been deposited. This sedimentary structure is formed in the subarielly environment area and formed when the top layer of sediment shrinks and form a crack. Sand dikes are vertical sheet of sand that have been intruded the muds from the parent sand bed below. This sedimentary structure often show ptygmatic compaction effect and sometimes polygonally arranged same as desiccation crack but they can be differentiate by their tendency to die upward. Particullary sand dikes is sedimentary boundinage structure which is typically formed by tensional spiliting of clay bed accompanied by quicksand, interbedded and unconsolidated. Fig 3.2 shows the illustration diagram of desiccation crack and sand dikes structures. Some of these features were observed in the study area and were discussed in section 5.3.



Fig 3.2: (Upper) Desiccation cracks coused by the contraction of mud to form downward-tapering fissures arranged in polygons. (Lower) Sandstone dikes showing ptygmatic contortions due to compaction and attachment to underlying parent sand bed. Modified after Selley (2000).

3.5 Coalification of coal

Coal refers to rock comprised of at least 50% by weight and 70% by volume carbonaceous material (Schorpf, 1956; Bates and Jaackson, 1980; ASTM, 1991). According to Levine (1993), coalification is a combination of physical, chemical and biological processes and is comprised of five successive but overlapping stages. At the early stage of the coalification, the processes begin by microbially metabolized biochemical reaction and purely physical processes such as maceration, compaction and expulsion of interstitial water. Then the stages of changes to have more abiogenic chemical reaction such as depolymerization, polymerization, and cracking. At the last of coalification processes which is at anthracite rank, the graphitization appears to be influenced by physical processes.

The degree of coalification, also called the rank of the coal, increases progressively from lignite to low rank coal to high rank coal to anthracite. Five major stage of coalification used by ASTM is: 1) peat, 2) lignite and subbituminous, 3) high volatile bituminous, 4) medium and low volatile bituminous, and 5) semi-anthracite and anthracite (Fig 3.2). At each stage of coalification process, volatiles matter (H₂O, CH₄, CO₂ and CO) decrease and enriched hydrogen and oxygen and remain as part of residual coal in the form of 'fixed carbon' (dry, mineral matter-free basis). Thus as coal rank increase, volatile matter yield decrease from over 50% in low rank coals to less than 8% in anthracite therefore coals provide more energy at the high rank. The effect of coal petrographic characteristic during the coalification is the vitrinite maceral increase more or less steadily and it's used as a rank parameter, while the reflectance of liptinite initially much lower than the vitrinite, increase rapidly at rank of around 0.8- 1.3 % $R_{o,vit}$ to match the associated vitrinite (2nd coalification "jump") (Teichmuller, 1974).

3.6 Organic Petrology

3.6.1 Characteristic of Macerals

This term "maceral" was first introduced by Stopes (1935). Maceral in coal are analogous to term 'minerals' in inorganic rock. The macerals were all plant tissue or plant degradation products, chemically change by diagenetic process during maturation. According to the Stopes-Heerlen System of classification, three maceral groups are usually identified by their greyness in reflected light (ICCP, 1971; Stach et al., 1982), virinite, liptinite and liptinite/ exinite. This classification is based on either on similar origin (e.g. the liptinite group) or/ and on differences in preservation (e.g. the vitrinite and inertinite groups). Morphology and reflectance under incident light are the main properties in distinguishing macerals and maceral group under the microscope (Teichmuller, 1989). All maceral groups can either be primary or of secondary origin. Primary macerals are those that either derived or formed from various plant, bacteria fungi, and animal remains at the time of deposition or during early diagenetic stage (Teicmuller, 1974; Mukhopadhyay et al., 1985) and secondary maceral formed at the expense of some primary macerals due to coalification during late diagenesis or catagenesis (Teicmuller, 1974; Stach et al., 1982; Mukhopadhyay et al., 1985). Table 3.1 describes the classification of macerals sheeme, based on the Australian Standard system (1986).

3.6.2 Vitrinite Group

Vitrinite maceral are the major components in coal and originate from ligno-cellulosic part of plant and have the intermediate reflectance under oil immersion. Vitrinite is the coalified remains of cell walls, woody tissue of stems, branches, leaves and roots of plants and the precipitated gels from these materials, which have been subjected to humification of varying intensity. The chemistry of vitrinite changes with rank (degree of heating) but is generally comprised of carbon, hydrogen and oxygen with trace amounts of sulfur and nitrogen. Under the microscope, vitrinite has a pale-grey to grey colour in white light and has no or poor fluorescence in ultraviolet light.

3.6.3 Liptinite/ exinite Group

The liptinite/ exinite group is derived from leaf cuticle, spores, pollen, plant waxes, fats, oils and resins. Chemically, the liptinite group is a suite of aliphatic, hydrogen rich macerals. All liptinite maceral fluoresce under the blue light excitation and the fluorescence intensity varies widely at a given rank. Liptinite group of macerals are consist of sporinite, cutinite, resinite, alginite, suberinite, liptodetrinite, fluorinite, bituminite and exudatinite. Exudatinite is the secondary maceral of liptinite which started forming at lignite stage and is recognizable until medium volatile bituminous coal stages. Liptinite maceral generally possess kerogen type I and II.

3.6.4 Inertinite Group

Inertinite maceral have high carbon content. Under oil immersion, inertinite macerals show the highest reflectance with generally no fluorescence, due to relatively hydrogen poor and chemically inert. In reflected light, inertinite material is highly reflective gray to white in colour, and structural elements can be observed. Macerals of this group originated from oxidized component of plant constituents such as lignin, cellulose, exine, fungi, lipid and fauna remnants during the early peat stages of burial diagenesis. Inertinite generally possess kerogen type IV and III/IV. **Table 3.1**: Classification of coal macerals into subgroups and groups, based on the Australian Standard system of nomenclature AS2856, (1986) (after Tissot and Welte, 1984 and Diesel, 1992).

Maceral Group	Maceral Subgroup	Maceral	Characteristic	Kerogen Type	
Vitrinite	Telovitrinite	Textinite Texto-ulminite Eu-ulminite Telocollinite	Structured		
	Detrovitrinite	Attrinite Densinite Desmocollinite	Unstructured and dispersed	Type III	
	Gelovitrinite	Corpogelinite Porigelinite Eugelinite	Gellified	_	
Liptinite		Spornite Cutinite Resinite Liptodetrinite Alginite Suberinite Fluorinite Exsudatinite Bituminite	Characteristics are based on progenitors	Type I/II	
Inertinite	Teloinertinite	Semifusinite Sclerotinite	Structured	Type IV	
	Detroinertinite	Inertodetrinite Micrinite	Unstructured and disperse	_	
	Geloinertinite	Macrinite	Gellified	_	

3.6.5 Vitrinite reflectance

Reflectance may be defined as the proportion of a normally incident light that is reflected by a plane, polished surface of the substance under consideration. Vitrinite reflectance measurement is a technique to determine the rank of the coals and the organic matter in sedimentary rocks described by Teichmuller (1958). McCartney and Teichmuller (1972) have observed that vitrinite reflectance is the best single parameter of rank for coals with less than 30% volatile matter, and it is nearly comparable to other parameters for high volatile bituminous coals (Table 3.2). Vitrinite maceral was use as the main parameter to determine the rank of the coals because: (a) vitrinite is the maceral that preponderant maceral in the most coals; (b) it's often appears homogeneous under the microscope; (c) particles of vitrinite are usually large enough to permit measurement easily; (d) behavior of the vitrinite principally responsible for the plastic and agglutinating properties of coals. The Handbook of the International Committee for Coal Petrology (ICCP, 1971) state, to measure the vitrinite reflectance it should be measures on the homogeneous collinite which generally occurs in wide layer (telocollinite, gelocollinite and corpocollinite) rather than measure on the other type of vitrinite such as desmocollinite. The reflectance of telocollonite is usually higher than desmocollinite which contains a fine liptinitic matrix (Mukhopadhyay, 1994). The maturation stages according to several different authors based on vitrinite reflectance values are shown in the Table 3.3.

Table 3.2: Coalification stages according to the German and North American classification, their distinction by different physical and chemical rank parameters and the applicability of the parameters at the different rank stages (after Teichmuller, 1987).

Coal r Class	ank Group	Vitrinite reflectance (random)	Volatile matter (wt.% dmmf)	Bed moisture (wt %)	Calorific value MJ/kg (moist,mmf)	Hydro- carbon generation	Principal uses
Anthracitic ²	Meta-anthracite Anthracite Semianthracite	2.50	- 2 - 8			Dry Gas	Space heating Chemical production
	Low volatile bituminous Medium volatile bituminous	— 1.92 — 1.51	— 14 — 22			Wet Gas	Metallurgical coke production Cement production Thermal electric power generation
Bituminous	High volatile A bituminous High volatile B bituminous	0.75	31		32.6	nd Gas —	
	High volatile C bituminous	0.75			- 30.2	– Oilar	
Subbituminous	Subbituminous A ³ Subbituminous B Subbituminous C	0.50 ?	- 24.4 Conv - 25 22.1 8 - 25 22.1 8	Thermal electric power generation Conversion to liquid and gaseous petroleum substitutes			
Lignitic	Lignite A Lignite B			35	19.3 14.7	ß	Thermal electric power generation Char production Space heating
	Peat			/5			

1) dmmf – Dry, mineral matter free

2) Non- agglomerating: if agglomerating, classified as low volatile bituminous

3) If agglomerating, classified as high volatile C bituminous

Stage maturity b on Ro%	ased	Peter & Cassa, 1994	Tissot & Welte, 1984	Taylor et al 1998
Immature		0.2- 0.6%	< 0.5- 0.7%	< 0.4- 0.5%
Mature	Early	0.6- 0.65%		
	Peak	0.65- 0.90%	0.7- 1.30%	~1.0%
	Late	0.9- 1.35%	1.30- 2.0%	1.0- 1.35%
Mature for Gas		> 1.35%	> 2.0%	1.35- 3.0%

Table 3.3: Vitrinite reflection value for maturity indicator (Peter & Cassa, 1994, Tissot & Welte, 1984, Taylor et al, 1998).

3.7 Organic Geochemistry

3.7.1 Biomarkers (Biological markers)

Biomarker is a group of complex "molecular fossil" composed of carbon, hydrogen and other elements which are found in oil, bitumen, rocks and sediments which is show little or no change in structure from their parent organic molecules in living organism (Peters et al., 2005). Biomarkers are the best indicator in petroleum exploration to indicate source facies determination, maturity determination, correlation studies, age determination and biodegradation because biomarkers retain most of the original carbon skeleton of the original natural product. It's composing of carbon, hydrogen, and other element. Different depositional environments are characterized by different assemblages of organisms and biomarkers. Marine, terrestrial, deltaic and hypersaline environment may show characteristic differences in biomarker composition. Biomarker and nonbiomarker geochemical parameters are best used together to provide the most reliable geologic interpretation to help solve exploration problems. The general sequence of increasing resistance to biodegradation of biomarker is N-paraffins, isoprenoids, steranes, hopanes/diasteranes, aromatic steroids, porphyrins (Chosson et al., 1992; Moldowan et al., 1992). Because of their differential resistance to biodegradation, comparisons of the relative amounts of biomarkers types can be used to rank oils as to extent of biodegradation. In this current study, n-alkanes isoprenoids parameter, triterpanes and steranes are use as an indicator to interpret the thermal maturity and to determine the organic facies of the analysed samples. The relative abundance of odd even carbon numberd n-alkanes has been used to determine maturity and the type of organic matter in crude oil and source rocks (Peters and Moldowan, 1993).

Triterpanes are believed to originated from bacteria (prokaryotic) membrane lipid (Ourisson et al., 1982) while steranes are derived from sterols that are found in higher plants and algae but rare or absent in prokaryotic organisms (Volkman, 1986, 1988) (Table 3.3). The composition of biomarker compounds, especially steroid and triterpenoid derivatives, in sedimentary rocks and oils, are of special interest because these compounds may reflect the depositional environment, origin and diagenetic/maturation history of geological organic matter (Peters and Moldowan, 1993). Triterpanes contain three to six rings, with five- ring species being common and steranes contain four rings, the D-ring of which always contains five carbon atoms.



Fig 3.3: Chemical structures of hopanoid and sterol. This illustration shows the stereochemistry of hopanoid and sterol from the precursor (after Waples & Machihara, 1991).

3.7.2 Biomarker as a maturity Indicator

Biomarker maturity indicator have been apply to source rock, oils (including tars, biodegraded oils, atc.), and even to fluid produced from very young sediments by hydrothermal activity (e.g., Simoneit, 1990; Simoneit et al., 1990; Kvenvolden et al., 1990; Michaelis et al., 1990; Clifton et al., 1990, Peter and Moldowan; Peters et al., 2005).

The relative abundance of odd versus even carbon numbered n-alkanes can be used to obtain a crude estimate of thermal maturity of petroleum. CPI value significantly above (odd preference) or below (even preference) 1.0 indicates low thermal maturity; values of 1.0 suggest, but not prove, that an oil or rock extract is thermally mature (Peters and Moldowan, 1993). If the total even and odd numbers of paraffins are equally abundant the value of the (CPI) will be equal to one, as is generally observed in high maturity samples (Tissot and Welte 1984). The Pr/Ph ratio typically increases with the maturity of the organic matter. Pr/n-C₁₇ versus Ph/n-C₁₈ plot has been widely used as indicators of oxicity and organic matter in the source rock depositional environment (Connan and Cassou, 1980, Peters et al., 1999, Duan et al., 2006).

The most commonly used biomarker parameter to measure maturity for triterpanes are isomeration at the C-22 position in the C₃₁ to C₃₅ 17a (H)-hopanes (Ensminger et al., 1977). The proportion of 22R and 22S can be calculated from C₃₁ to C₃₅ but typically C₃₁ or C₃₂ are usually used. The 22S/ (22S+22R) ratio rises from 0 to 0.6 (0.57 to 0.62= equilibrium- end point; Peter and Moldowan, 1993) during maturation. After reaching equilibrium at the early oil-generative stage, no further maturity information is available because the 22S/ (22S+22R) ratios remains constant. The end point occurs at the beginning of oil generation zone (Brocks et al., 1992).

The 22S/(22S+22R) ratio in the range 0.50 to 0.54 have barely entered the zone of oil generation, while the ratio in the range 0.57 to 0.62 indicate that the main phase of oil generation has been reached (Peter and Moldowan, 1993). Other biomarker for triterpanes group use to measure the maturity is moretane/hopane. Moretane are much less stable than hopane and during the thermal maturity, when the temperature is increase, the concentration of moretane decrease and thus with futher increasing temperature, moretane are converted to hopane (e.g., Kvenvolden and Simoneit, 1990, Peter & Moldowan, 1993). In Tertiary source, Gratham (1986b) noted the ratio of moretane/hopane often have higher ratio (0.1-0.3), with values of 0.15- 0.2 being common than do older samples, which are generally less than 0.1 thus he suggest the short time available for maturation may play a role in controlling the ratios. The other triterpanes group is Tm/Ts. The Tm/Ts ratio is most reliable as a maturity indicator when evaluating oil from a common source of consistent organic facies. When the maturity increase, the 17α (H)-trisnorhopane (Tm) gradually disappears and the 18α (H)-trisnorneohopane (Ts) increase in relative concentration therefore the Tm/Ts ratio begin to decrease quite late during maturation (>0.9% Ro: van Graas, 1990).

The proportion of two epimeric forms (20R and 20S) is the most important to measure maturity of the $\alpha\alpha$ sterane. The C₂₉ steranes are practically used to determine the maturity because least susceptible to overlapping peaks in mass chromatograms. The isomeration at C20 in the steranes causes the 20S/ (29S+20R) ratio to rise from 0 to 0.5 (0.52- 0.55= equilibrium, Seifert and Moldowan, 1986) with increasing maturity. However,

other controls on the C₂₉- steranes 20/ (20S+20R) ratio have been suggested such as weathering, facies effects, partial biodegradation and source rock (Moldowan *et al*, 1986; Marzi and Rullkotter, 1992). The other maturity parameter derived from steranes is proportion of 14 β (H), 17 β (H) and 14 α (H), 17 α (H) form ($\beta\beta/\alpha\alpha$ ratios). The $\beta\beta/\alpha\alpha$ ratio can be strongly affected by diagenetic condition as it is by maturity (ten Haven et al., 1986; Peakman and Maxwell, 1988; Peakman et al., 1989) and it's usually pronounced in lowmaturity sample (e.g., Dahl and Speers, 1985).

3.7.3 Biomarker as Organic Facies Indicator

Distribution of n-alkanes with a marked predominance of odd carbon number alkanes to even carbon alkanes in C_{25} - C_{35} of the gas chromatogram region are, in the majority of cases, derived from higher plant waxes (Eglinton & Hamilton, 1963) while rich in low carbon number n- alkanes (C_{15} to C_{19}) indicate aquatic organism. Due to this indication, the bimodal pattern of chromatogram is indicating the transitional environment with high terrestrial organic matter influx while unimodal pattern of chromatogram with high carbon number of alkanes indicate high terrestrial higher plant input. Tissot and Welte 1984, CPI values represent an odd carbon number preference over even, and occur in response to chemistry in higher plant of surface waxes (an important precursor of waxy components in sedimentary organic matter). Triterpanes and steranes are both derived from biological precursor molecules which is triterpanes derived mainly from bacteria, more to indicate the depositional and diagenetic whereas steranes are generally indicate for photosynthetic biota, both terrestrial and aquatic (Moldowan et al, 1986); Marzi and Rullkotter, 1992). The ratio of pristane and phytane (Pr/Ph) is common geochemical parameter used to infer depositional environment (particularly oxicity or anoxicity) and source rock organic matter, Pr/Ph <1 indicates anoxic deposition, whereas Pr/Ph >1 indicated oxis condition (e.g., Powell and McKirdy, 1973; Didyk et al., 1978, 1987; Killops and Killops, 1993; Peters and Moldowan, 1993; Zulkifli et al., 2008). For samples within the oil generating window, high Pr/Ph ratio (>3.0) are indicative of terrestrial organic matter input under oxic conditions and low values (<0.6) typify anoxic, commonly hypersaline environments (Peters and Moldowan, 1993).

Tetracyclic, terpanes, hopanes, oleanane and other compound of triterpanes group are commonly used to relate oil and source rocks (Seifert and Moldowan., 1980; Peter et al., 2005). Tetracyclic terpanes are derived by degradation of the pentacyclic hopane type triterpanes (Aquino Neto et al., 1983). Philp and Gilbert (1986) report that the C_{24} tetracyclic in Australian oils that were believed to be sourced mainly from terrestrial organic matter. Hopanes has a great impact on the petroleum geochemistry and are believed to be derived from prokaryotes membrane (Ourisson et al, 1982). The high concentration of the extended hopane C_{31} has been reported to have a correlation with the peat and coal (Villar et al., 1988) and high abundance of moretanes are found in organic material of terrestrial origin (Connan et al., 1986; Mann et al., 1987).

The another application of hopanes based on Brook (1986) that the high abundance of C₂₉ hopanes are consider related to a terrestrial indicator because they occur in samples that contain oleanane and bisnorlupanes. The C₂₉ and C₃₀ 17 α (H) hopanes are the most abundant triterpanes found in petroleums and bitumens. Brooks (1986) noticed that the higher C₂₉/C₃₀ hopane ratio was found to characterize sediments and coals from terrestrial source rocks. Forest swamp coal extracts show relatively higher ratio C_{29}/C_{30} hopane and identified C_{29} as a terrigenous marker (Wan Hasiah and Abolins, 1998). The 17 α (H) trisnorhopanes (Tm)/18 α (H) trisnorneohopanes (Ts) ratio is affected by both maturity and diagenetis conditions of deposition (Moldowan et al., 1986 and Peter et al., 2005). Wan Hasiah (1999) reported that higher Tm/Ts ratios were observed in coaly sediments compared to shaly sediments of Sarawak, and is considered indicative of terrestrial environment within oxic depositional condition of a fluvio-deltaic setting as previous described by Robinson (1987).

The $18\alpha(H)$ oleanane (X), has been reported in a number of oils thought to be derived from coals or rocks with abundant coaly organic matter and the present of oleanane (angiosperms derived) are believed to be characteristic of only Tertiary and Cretaceous rocks and oils (Grantham et al., 1983; Ten Haven and Rullkotter, 1988; Moldowan et al., 1994). According to Murray (1997), the present of oleanane compound in the mature sediment are related with the contact of land plant matter with seawater during early diagenesis, thus the oleanane precursors can be altered in freshwater environments such as fresh coal swamp and fluvio-deltaic environment (Zhou, 2003). This is also envisaged for the studied samples as described by Alias et al., (2012).

The steranes relative proportion of the C_{27} - C_{29} as shown by Huang and Meinschein (1979) are related to specific environment and has been suggested that steranes in sediment might provide valuable paleoenvironment information. The relative proportion of these three steranes is the dominant of C_{29} sterol (or steranes) may indicate input of higher plant of terrestrial environment, whereas the dominant of C_{27} may indicate a strong marine phytoplankton input and the abundant of C_{28} which is generally the lowest of these three steranes indicate a heavy contribution by lacustrine algae. Robinson (1987) noted that in Indonesia, C_{29} regular steranes and diasteranes dominant among fluvio-deltaic oil and reflecting the strong contribution of terrestrial plant material.

3.7.4 The Principle of Source Rock Evaluation

A source rock is a rock that has a potential to generate, or has already generated petroleum (Tissot and Welte, 1984). Potential petroleum source rocks are described in terms of quantity, quality and level of thermal maturity of the organic matter. These three principles of source rock can be evaluated by using Rock- Eval screening technique analysis. The parameter by Peter and Cassa, (1994) are used in this study to assess the quality, quantity and maturity of hydrocarbon content are as shown in the Table 3.4.

3.7.4.1 Quantitiy of Organic Matter

The ability of potential source rock to generate hydrocarbon is dependent on the contents of organic matter (Hunt, 1996). It can be determine by using total organic carbon (TOC) analysis. Total organic carbon (TOC %) describes the weight percentage of organic carbon in whole rock including bitumen and kerogen (Peter & Cassa, 1994). The minimum amount of organic carbon for potential source rock is 0.5 % (Tissot & Welte, 1984; Peter & Moldowan, 1993; Peters & Cassa, 1994) while the amount of organic carbon higher than 4 % have excellent potential to generate hydrocarbon (Peter & Cassa, 1994).

3.7.4.2 Quality of Organic Matter

A good quality of source rock must have capability to generate oil or gas or both. Therefore the good quality of source rock should contain high amount of Hidrogen Index (HI= $S2/TOC \times 100$).

The amount of hydrogen content in the organic matter can be estimates from S2 value. S2 is the quantification of hydrocarbon from kerogen cracking during the thermal decomposition. The type of kerogen can be achive by plotting hydrogen index versus oxygen index on Van Krevelen diagram (Tissot & Welte, 1984). Type I kerogen has potential for oil generation and gas generation possessing relatively high HI index and low OI index. These types of kerogen consist largely of structured alga material and maybe mixed with amorphous organic matter. Type II kerogen have same potential to generate oil and gas but less compared to type I. The oxygen content in the type II kerogen is higher than type I kerogen and it's consist of a large proportion of a mixture of marine palnktonic remnants and some land derived material. Type III kerogen have capability to generate gas with relatively low of HI index and OI index. Type III kerogen consists of humic material which is mostly derived from terrestrial higher plant. Type IV is essentially inert with no hydrocarbon generating potential (Tissot and Welte, 1984).

3.7.4.3 Maturity of Organic Matter

Hydrocarbon will generate when the organic matter has been heated sufficiently during the burial of sediment. The maturity parameter known as Tmax are corresponding to indicate the value of temperature at which the maximum releases of hydrocarbons occur from cracking of kerogen during the pyrolysis. Tmax value less than 435°C indicate rock are
thermally immature to generate hydrocarbon while value of Tmax that range from 435°C to 460°C indicate rocks are ideal to generate hydrocarbons (Peter and Cassa, 1994).

3.7.4.4 Vitrinite Reflectance

Vitrinite reflectance (% Ro) is used to determine the maturation of organic matter in sedimentary rocks as initially described by Teichmuller (1958). Based on classification of Peter and Cassa, (1994) the "oil-window" maturation stages supported by geochemical and fluorescence analysis are as follows: % Ro values in the range of 0.20 to 0.6% were considered immature for oil generation, % Ro values that range from 0.60 to 0.65% were considered early mature for oil generation, % Ro values in the range of 0.65 to 0.90% were assigned as peak of oil generation, whilst % Ro values that range from 0.90 to 1.35% were considered late mature. Vitrinite reflectance more than 1.35% were considered as gas window (Table 3.4).

(a)				Rock- Eval (mg/g rock)							
Potential (Quantitity)		TOC (Wt %)		S1		S2		Bitumen (ppm)		Hydrocarbon (ppm)	
Poor	r	<0.5		<0.5		<2.5		<500		<300	
Fair	air 0.5-1			0.5-1		2.5-5		500-1000		300-600	
Goo	bood 1-2			1-2		5-10		1000-2000		600-1200	
Very good		2-4		2-4		10-20		2000-4000		1200-2400	
Excellent		>4 >4		>4		>20		>4000		>2400	
(b)											
] (Kerogen Quality)	Hydr (mg hydro	ogen ocarb	ı Index bon/g TOC)		S2/S3		Atomic H/C		Main Product at peak maturity	
I >600						>15		>1.5		Oil	
II		300-600				10-15		1.2-1.5		Oil	
II/III		200-300			5-10		1.0-1.2		Oil/Gas		
III		50-200			1-5			0.7-1.0		Gas	
IV		<50			<1			<0.7		Non	
(c)											
Maturity		I	Maturation					Generation			
		R ₀ (%)	T 1 (°	max °C)	TA	۸I	Bitumen/TO C		Bit (mg roc	umen g/g k)	PI [SI/(SI+S2)]
Immature		0.20- 0.60	<43	5	1.5-2	2.6	< 0.05		<50		<0.10
	Early	0.60- 0.65	435-	5-445 2.6-		2.7	0.05-0.10		50-100		0.10-0.15
	Peak	0.65- 0.90	445-	450 2.6-		2.7 0.15		-0.25 15		0-250	0.25-0.40
lre	Late	0.90- 1.35	450-	-470	2.9-	3.3					>0.40
Postmature		>1.35	>47	>470 >3.3		3					

Table 3.4: Parameter by Peter and Cassa, (1994) to assess the quality, quantity and maturity of hydrocarbon content.

CHAPTER 4

METHODOLOGY

4.1 Introduction

This study was carried out on several coal samples in the West Middle Block of Pinangah, Sabah. This chapter discusses the research work from the beginning of the study until the completion of research analyses that were performed in laboratories. Based on field study, thirteen outcrop samples were collected using channel sampling and were subsequently analysed by organic petrological and organic geochemical methods. Investigation in the field involves observations on lithology and sedimentary structures whereas for the laboratory analysis involves the determination of bitumen extraction, biomarkers, evaluation of thermal maturity and assessing the potential as a petroleum source rock for the analysed samples.

Prior to field study, meeting with the supervisors were conducted as well as performing literature reviews of the study area. To obtain more detailed information, discussion with staff of the JMG, Sabah were carried out to help in preparing map of the study area and to identify sampling localities.

4.2 Fieldwork

The literature review carried out emphasized on highlights properties and description of the stratigraphic column in the study area. Three fieldtrips were carried out during this research project. The first trip was carried out on October 2010 for one weeks and the second and third field trip was carried out on March and Jun 2011 respectively to complement the first field trip. The outcrops on the different location of study area were plotted on the map using the aid of a Global Positioning System (GPS). On the outcrops, care in sediment description is essential for a given lithology. The descriptions are short and comprise of sediment name, color, texture, primary feature and sedimentary structure. Photographs were taken for several purposes and were developed during the fieldwork.

Sample taken using a channel sampling technique were the dipping of coals layer were identified and channel made of tilted perpendicular to the coal dipping. Samples were taken from a freshly exposed coal bed by cutting a 2- to 4 cm in channel into the bed from top to bottom and collecting all the coal from the channel (Fig 4.1a). In order to produce reliable results, sampling was done very carefully to avoid contamination from extraneous material. Samples were packed in polythene bags which is place at the bottom of the channel (Fig 4.1b). The sample was placed accordingly and locality of the samples was marked. The observations were recorded in a field notebook. Same method, repeated at the next locality.



Fig 4.1: (a) Samples taken using channel sampling technique; (b) samples put into polythene bags

4.3 Laboratory Analysis

The laboratory work was performed on the organic petrology and organic geochemistry analysis. For the organic petrology analysis, vitrinite reflectance and maceral counting were performed to determine the rank and organic facies of the analysed coal samples. The organic geochemistry analyses performed include, bitumen extraction, GC, GC-MS and SRA analyses to evaluate thermal maturity and interpret the source rock potential to generate liquid hydrocarbons. Coal samples were prepared as granular section and were allowed to dry overnight (Fig 4.2).



Fig 4.2: Sample of coals collected from Pinangah were dried overnight.

4.4 Organic Petrology

Petrographic examinations were performed using a Leica CTR 6000-M microscope with white and UV (ultraviolet) light sources and using 50x oil immersion objective (Fig 4.3). The organic matter types were described from whole rock blocks; first in reflected, plane-polarized light and secondly, in 'blue light' excitation to examine fluorescing liptinite macerals. The percent random vitrinite reflectance (Ro) was performed using plane – polarized reflected white light.

4.4.1 Polish Block Preparation

The coal samples were dried and crushed to about 2 mm size and placed in plastic mounting moulds. Resin mixture (resin mixed with hardener) was poured into the mould covering the crashed rock, stirred carefully, and left to harden. The sample was taken out from mould and then ground until its surface is flat. Then the sample is polished using caborandom powder mixed with water on a glass plate; initially with 240 grade, followed by 340 and finally on 600 grade. The blocks were polished on hyprocel pello paper initially with 5/20 grade alumina, followed by 3/50 and finally on gamma alumina. Water was used as lubricant for coal sample and isopropyl alcohol was used for shale samples. Finally, the polished blocks were rinsed under running water to get rid of the alumina. The polished block should be free from scratches, clean, free of grinding and polishing compounds under the microscope.

4.4.2 Vitrinite Reflectance

Vitrinite reflectance (Ro) is the most used organic maturation indicator because it is accurate, quick, non-destructive and inexpensive. The chemical and optical properties of vitrinite alter more uniformly during coalification than other types of macerals (Mukhopadhyay P.K., 1994). This is why vitrinite are use for measuring the level of rank of coals and sedimentary organic matter. It serves as a parameter to estimate the degree of diagenesis. The reflectance of the vitrinite in coals and other sediment depend on the level of their coalification. Vitrinite reflectance is comparative measure of the intensity of light reflected from calibrated standard, such as sapphire, of known mean Ro of 0.589% to unknown samples using a 50x oil immersion objective. Standardization was made before do a measurement and then reflectance reading are taken on the block. The measurement of vitrinite reflectance was performed randomly on the width layers of one of the vitrinite maceral commonly on tellocollinite. 50 readings were taken on each block and the result reported as the mean of the random reflectance. The Window- based DISKUS FOSSIL software package was used to acquire the vitrinite reflectance data.



Fig 4.3: Microscope model, Leica DM6000M used for organic petrological study.

4.4.3 Maceral Analyses

The purpose of maceral analysis is to interpret the depositional environment and also to assess the oil generating potential of coals at different localities within the Tanjung Formation. Maceral analyses were obtained through identification and random point counting in reflected white light and UV light taken on each polished block for each sample. At least 500 points on each sample were counted and calculated in percentage. Images of the macerals and minerals were taken under white light and UV light as a reference to differentiate the maceral using both types of light and to determine the potential for liquid hydrocarbon generation.

4.4.4 Tissue Preservation Index and Gelification index of petrogical analysis

The petrography of coal and its relation to the environment of deposition under which its precursor materials were deposited has been subject of various studies (e.g. Diessel, 1982, 1986; Kalkreuth et al. 1991; Wan Hasiah, 2002). The gelification index (GI) vs tissue preservation index (TPI) analysis was carried out which is used to characterize the depositional environment based on point counting of 500 macerals for each sample. The Tissue Preservation Index (TPI) is the ratio of:

TPI= <u>telinite+ telocollinite+semifusinite+fusinite</u> Desmocollinite+macrinite+ inertodetrinite

And Gelification index (GI) is the ratio of:

The result plotted on a cross plot diagram modified after Diessel (1996) and Kalkreuth and Leckie (1989).

4.4.5 Palynology

Standard palynological preparation was applied for the coal samples and examination of the palynomorphs. The sample were prepared and studied in the palynological laboratory of the Biostrax Company under the direct supervision of a research officer. Ten samples collected from outcrop were crushed to a grain size of ~1mm. The samples were first treated using nitric acid (65%) for 24 hour and continuously shake for 3 to 4 hour. Sample was washed thoroughly with distal water. For slide preparation, the treated samples were taken and place into test tube centrifuge and water was poured out. The zinc chloride was added to the samples in the tubes and again centrifuged for 3 minute with 1500 speed. The slides

were prepared and palynomorf were identified using Quaternary methods (at least 100-200 counts) up to species level. The microscopic examination was carried out using a Leica 750 transmitted light microscope.

4.5 Organic Geochemistry

4.5.1 Source Rock Analysis (SRA)

The quantity, quality and maturity of the organic matter in the analysed coals were determined using a SRA (Source Rock Analyzer) run in TPH/TOC (Total Petroleum Hydrocarbon/Total Organic Carbon) mode. This method is more convenience and reliable as it only require small amount of samples yet still can produce for numerous repeating analysis. The parameters derived from the SRA are equivalent to that produced by Rock-Eval technique. The parameters obtained from this instrument include: total organic carbon (TOC) content, Hydrogen Index (HI= S2 × 100/TOC), Oxygen Index (OI= S3 × 100/TOC), Tmax (temperature where the maximum amount of hydrocarbons are artificially generated during pyrolysis), S1 peak (represents free hydrocarbon in the sample), S2 peak (represents hydrocarbon generating through thermal cracking of non volatile organic matter), S3 peak (represents carbon dioxide (CO^2) produced during pyrolysis of kerogen) and Production Index (PI)

Prior to the SRA analysis, all coal samples were crushed into rock powder. Approximately 0.2-0.5 milligram powdered coal samples were placed into small and specific vials. These samples then were analyzed using Weatherford SRA TPH/TOC (Fig. 4.4) to evaluate the petroleum generative potential of the coals. The coal samples were heated to a programmed temperature, between 340-700°C, in an inert atmosphere. Helium gas was used to create the inert condition. During the assays, three peaks were generated as to the temperature changes. S1 peak was generated at 340°C. The second peak, S2 peak appear at temperature 500°C. The laboratory analyses were performed at University Malaya, Kuala Lumpur Malaysia.



Fig 4.4: Source Rock Analyzer (SRA)

4.5.2 Biomarkers

A combination of GC and GCMS data were used to assess the organic matter source input and depositional condition of the analysed samples. The analytical procedures for biomarker characterisation follow the sequence of sample extraction, extract fractionation, and finally saturate fraction analysis by GC and GCMS (Fig 4.5). The biomarkers result for the steranes (m/z 217) and triterpanes (m/z 191) were identified by comparasion of their retention times and mass spectra with previously published literature (e.g Ahmed et al., 2009; Hakimi et al., 2010, 2011; Kashirtsev et al., 2010; Peters and Moldowan, 1993; Philp, 1985; Wan Hasiah, 1999; Waples and Michihara, 1991).

4.5.2.1 Sample extraction

Samples were crushed to fine powder and placed in the preextracted thimble capped with preextracted cotton wool. Then using the Soxhlet apparatus, samples were extracted for 72 hour by using an azeotropic mixture of dichloromethane and methanol (93:7). To prevent the rigorous boiling and to remove sulfur on the samples, anti bubbling granules and copper was added into the reservoir flask (250ml). Throughout the analysis, reservoir flask was monitored to avoid sample passes upward through the side arm of the apparatus. The solvent (dichloromethane and methanol) put into the reservoir flask periodically using siphon to ensure exhaustive extraction. The extraction operates until the solvent in the thimble side becomes clear and typically for the coal samples this takes about 5 days. The solvent in the reservoir flask is then reduced using a Butchi rotary evaporator. The organic extract is place in vials and weighed. Then the total amount is calculated. Extracts were separated into saturated hydrocarbon, aromatic hydrocarbon and NSO- compound fractions by liquid column chromatography.

4.5.2.2 Column Chromatography

Column chromatography using pipette is an alternative technique for the preparation separation of mixture (a few milligrams up to ten grams) into aliphatic, aromatic and NSO (nitrogen, sulphur, oxygen). A pipette is filled with cotton wool and washed with DCM followed by methanol. Then, the pipette and cotton are dried in an oven at 30°C for 10 minutes. A Pasteur pipette is filled with approximately 5-7 cm of activated silica gel as slurry with petroleum spirit. To avoid air bubbles the column is tapped slowly while

pouring the slurry. The column is made uniform by passing 3 bed volumes of n-pentane under light pressure (a pipette teat can be used). The silica gel will become translucent. The solvent is then reduced by Butchi evaporation and the recovered effluent is divided into two parts. One part is left to dry with a stream of nitrogen and its weight recorded. The total amount recovered was calculated. The undried fraction was used in GC and GCMS analysis.

4.5.2.3 Gas Chromatography- Mass Spectrometry (GCMS)

The saturated hydrocarbon fractions were analyzed by gas chromatography-mass spectrometry (GC-MS). Computerized Gas chromatography-Mass Spectrometry (GCMS; Mc Fadden, 1973; Watson, 1985) is the principal method used to evaluate biomarkers. A GCMS is used to detect and identify compounds using their relative GC retention times, evaluation patterns and the mass spectral fragmentation patterns characteristic of their structures (Peters and Moldowan, 1993; Philp, 1985). GC-MS experiments were performed on a V 5975B inert MSD mass spectrometer with a gas chromatograph attached directly to the ion source (70 eV ionization voltages, 100 mA filament emissions current, 230° C interface temperatures). A saturated fraction of each sample (0.1 MI) was injected into gas chromatograph mass spectrometer. The separated compounds were transferred to the source of a gas chromatograph mass spectrometer where they were ionized by an electron beam and the resulting mass spectra obtained. Ions monitored were m/z 191 for triterpanes and m/z 217 for steranes. Identification of biomarkers was performed by comparison of GCMS retention time data and mass spectra with published data of Phillip (1985), Peters and Moldowan, (1993) and Peters et al (2005).



Fig 4.5: Sample preparation workflow for GC-MS and GC analysis.

CHAPTER 5

RESULT & DISSCUSION

5.1 Introduction

This chapter describes the organic petrological and organic geochemical characterization of coals in the West Middle Block of Pinangah Sabah. A brief lithological/ lithofacies description was also performed. Results of coals analysis includes observations made during field work and from laboratory analysis. Field observations consist of description of sediment color, lithology, sedimentary structures and thickness of the coals. Twelve samples of coal from each outcrop were collected and photographs were taken during fieldwork. The analyses performed in the laboratory are to determine the thermal maturity, carried out source rock evaluation, hydrocarbon characterization and to interpret depositional setting of the study area.

5.2 Sample description

Twelve coal outcrops are present in the study area. Outcrops position and survey point were record using compass and GPS. Outcrop descriptions were derived through standard sedimentary logging techniques based on structural, textural and compositional observations. The outcrops are labelled BDD 1, BDD 2, BDD 3, BDD 4, BDD 13, BDD 24, BDD 28, BDD 30, BDD 31, BDD 49, BDD 50 and BPC 2. The locations of the study point in the map are as shown in Fig 5.1.



Fig 5.1: The location of twelve coal outcrop in the study area.

This location of the coal outcrop has been a base mark for the location of study area. The Global Positioning System (GPS) reading for this location is N 04° 54.6' 03" and E 116° 41' 119". The thickness of the coal is 0.28 m respectively with the strike/dip NE 3 /4 E. The coal is interbedded of the mudstone and bounded by carbonaceous shale and mudstone. From the field description, the coal is classified as coaly shale. Plate 5.1a shows the photo of the coal outcrop in this locality.

b) **BDD 2**

This outcrop is the largest coal outcrop in the study area (Plate 5.1b). Plate 5.2 show the sedimentary log of this coal outcrop. The thickness of the coal is more than 9m with a strike and dip of 75/5. The succession consists mainly of coal bedding and this succession represented by mudstone at the base of the outcrop and toward upward, coals interbeded with the mudstone and carbonaceous shale.

c) **BDD 3**

The coal oucrop in this locality are located along the small river banks (Plate 5.1c). The coal outcrop covered by large sand pebbles transported by the floods during heavy rain. The strike/dip of the coal bedding is 302/ 39. The coal is classified as bright coals which are characterized by alternating lustrous and dull bands of black coal. The Global Positioning System (GPS) reading for this location is N 04° 54.6' 0" and E 116° 41' 58.4"



Plate 5.1: Field photograph of the coal outcrop for the localities (a) BDD 1 (b) BDD 2(c) BDD 3 (d) BDD 4 (e) BDD 13 (f) BDD 24. Arrow shows the location of coal outcrop.



Plate 5.1: (Continue) Field photograph of the coal outcrop for the localities (g) BDD 28 (h) BDD 30 (i) BDD 31 (j) BDD 49 (k) BDD 50 (l) BPC 2



Plate 5.2: Field photograph and stratigraphy log for the coal outcrop BDD 2.

d) BDD 4

This location is nearest to the BDD 3 coal outcrop which is located along the small river banks (Plate 5.1d). The strike/dip of the coal outcrop here is 345/39 and shows the correlate as same bedding with coal in the locality BDD 3 due to same reading of dipping. The coal outcrops in this location are not completely exposed as the bottom is under water level. The Global Positioning System (GPS) reading for this location is N 04° 53' 58.4" and E 116° 41' 57.7".

e) BDD 13

The coal outcrops for these localities exceedd more than 4m thickness. Coal here classified as bright coal by using the hand specimen. Coal outcrops in this location are located on the logging road and the Global Positioning System (GPS) reading for this location is N 04° 53' 23.2" and E 116° 41' 32.1". Plate 5.1e show the coal outcrop BDD 13.

f) BDD 24

The coal outcrop here is not completely exposed as the bottom is covered by densed soil (Plate 5.1f). Coal is interbeded with the carbonaceous rock which is consisting of coaly shale, carbonaceous shale, and mudstone with the thickness more than 2.7 m respectively. The Global Positioning System (GPS) reading for this location is N 04° 54' 29.7" and E 116° 41' 49.3".

g) BDD 28

The coal outcrop here is located along small river banks (Plate 5.1g). The coal is bed up 6.75 m thick and toward upward the mudstone and siltstone are interbedded forming a layering with thickness of 2 m respectively. The mudstone and siltstone show cyclic sedimentation with the color of mudstone being dark yellow with a rounded bed and the color of siltstone is grey with massive bedding. The reading for strike/ dip of the coal bed is 130/ 17. The Global Positioning System (GPS) reading for this location is N 04° 54' 37.4" and E 116° 41' 17.7".

Log interpretation has been done to indicate the deposition environment of the coal in this area. Few of sedimentary structure are found in this location are record. The coal is lying on the logging road and the thickness of coal is 3.15m respectively (Plate 5.1h). The succession consist mainly of sandstone, shale, mudstone and coaly shale with coal identified as bright coal by the hand specimen. The reading of strike/dip for the coal bedding is 144/ 26 and GPS reading is N 04° 54' 26.6" and E 116° 41' 16.7". The detailed descriptions of log interpretation are present in section 5.3.

i) BDD 31

The coal outcrop here is not completely exposed as the bottom covered by densed soil (Plate 5.1i). The thickness of the coal outcrop in this study is 1.4m. Hand specimen indicates, coal in this locality is a shaly coal with the dark brown color and has the brittle structure. The reading of strike/dip for the coal bedding is 155/32 and GPS reading is N 04° 54' 23" and E 116° 41' 19.4".

j) BDD 49

The thickness of the coal outcrop in this study is more than 3 m (Plate 5.1j). The reading of strike/dip for the coal bedding is 135/22 and GPS reading is N 04° 54' 30.1" and E 116° 41' 51.3". Coals in this location are indentifying as bright coal base on hand specimen characteris.

k) BDD 50

This coal outcrop located at the bottom of the location of BDD 24 (Plate 5.1k). The thickness of the coal outcrop is more than 2 m and the reading of dip/ strike is 120/45. In

the hand specimen, the coals are classified as the bright coal. The Global Positioning System (GPS) reading for this location is N 04° 54' 28.8" and E 116° 41' 47.7".

l) BPC 2

The coal outcrops in these localities are lying on the road that extend for about 1.5m (Plate 5.11). The surrounding area of this outcrop is sandstone and the reading for the strike/ dip for this coal outcrop is 160/ 20 and the GPS reading is N 04° 54' 22.4" and E 116° 41' 49.7". The hand specimen of the coal shown it's a bright coal.

5.3 Sedimentary description for BDD 30

Previous work on Pinangah coals exposed in the West Middle Block Pinangah is very limited. In this study an exposure (Plate 5.3) of coal outcrop namely BDD 30 located in the central part of Southern Sabah was described.



Plate 5.3: Outcrop section show the coal outcrop at the BDD 30, the bedding up to 2m thick.



Fig 5.2: Stratigraphic log for the BDD 30 coal outcrop, Pinangah Sabah show fining upward sequence.

5.3.1 Lithofacies Description

Five lithofacies are identified on the BDD 30 coal outcrop. Fig 5.2 show the sedimentary log sequence which consists predominantly of sandstone, reddish shale, grey mudstone, coaly shale and coal. The thickness of this sedimentary log is more than 15 meters.

The stratigraphy section represents fining upward sequence. The lowest part of the sequence consists of reddish shale and moving upward the section characterized by weathered surface of reddish medium grained sandstone with 2 m thickness and interbedded with the grey mudstone. The upper sandstone beds mainly medium to fine grained sandstone characterized by light gray to gray of to 5m thick. Cross-bedding tabular planar present in the medium grained sandstone body and moving upward, organic matter, pseudonodules, sandikes, ripple mark, desiccation crack, cross lamination, parallel lamination are the major sedimentary structure present in the fine grained sandstone body. These sedimentary structures are shown in Plate 5.4 & Plate 5.5. The present of sandikes structure (Plate 5.5e) and a few siderites are indicating of subarially deposition environment area (Selley, 2000). Cross-bedded sandstones are interpreted to represent the point bar deposit of the meandering channel. The coal seam occurring in the upper part of the sandstone sequence and the thickness is about 3m thick are interpreted as peat swamp or flood pain deposited. According to Zakir, H.M., 2002, the thick coal indicates a long persistent, slowly subsiding, moderately drained and densely vegetated backswamp.

These sedimentary log sections of the coal outcrop are interprete as floodplain deposition environment of point bar deposit of a meandering channel.



Plate 5.4: Sedimentary structure photograph for (a) parallel lamination, (b) symmetric wave- ripple lamination, (c) cross lamination, (d) Organic matter in the sandstone.



Plate 5.5: Photographs of sedimentary structure photograph for (e) sandike, (f) pseudonodules, (g) desiccation crack, (h) chemical weathering- oxidation in the sandstone.

5.4 Organic Petrology Analysis

5.4.1 Vitrinite Reflectance Data

The reflectance of vitrinite in coals and sediments is dependent on the level of the coalification. Random vitrinite reflectance readings were taken on a surface not affected by liptinite, i.e. predominantly on tellocollinite maceral for each of the analysed samples. The value for the vitrinite reflectance (%Ro) of the coal and carbargillite samples range from 0.42 to 0.66% (Table 5.1). According to ASTM standard, the sample are classified as subbituminous C-A to high volatile bituminous B in rank. Peter & Cassa (1994) proposes vitrinite reflectance (Ro%) values in the range of 0.2% and 0.6% were considered the lowest values for oil-generation, while Ro% values in the range 0.65- 0.9% were assigned to the peak for oil generation (see section 3.7.4.4). These vitrinite reflectance values indicate that the coal and carbargillite samples are interpreted as thermally immature to early mature of oil generation.

No	Sample no.	Sample Lithology	%Ro Mean of	% Ro Mean
			Tellocollinite	Desmocollinite
1	BDD 1	Carbargillite	0.49	0.36
2	BDD 2	Coal	0.47	0.34
3	BDD 3	Carbargillite	0.50	0.34
4	BDD 4	Coal	0.66	0.48
5	BDD 13	Coal	0.50	0.39
6	BDD 24	Carbargillite	0.49	0.33
7	BDD 28	Coal	0.51	0.31
8	BDD 30	Coal	0.51	0.36
9	BDD 31	Carbargillite	0.42	0.38
10	BDD 49	Coal	0.62	0.40
11	BDD 50	Coal	0.62	0.40
12	BPC 2	Coal	0.55	0.38

Table 5.1: Summary of Organic petrological data of vitrinite reflectance (%Ro) for tellocollinite and desmocollinite reflectance.

5.4.2 Tellocollinite versus Desmocollinite

The vitrinite reflectance (%Ro) also has been measured on the dispersed layer (desmocollinite) under reflected white light (Table 5.1). The purpose of this analysis is to compare the reflectance values on two different types of vitrinite macerals. The values of the vitrinite reflectance for desmocollinite are lower compared to the values of reflectance for tellocollinite (Fig 5.3). The values are in the range of 0.31 to 0.48 for desmocollinite and 0.42 to 0.66 for tellocollinite and are classified as sub-bituminous C- A in rank (according to ASTM standard) and interprets as immature of oil generation. Fig 5.7(a & b) demonstrates that desmocollinite reflectance is low due to the influence of the liptinite maceral that fluorences under blue light excitation. Figs 5.4 show two different types of vitrinite maceral which is tellocollinite (TI) and desmocollinite (Dc).



Fig 5.3: The value of tellocollinite and desmocollinite reflectance of the coal samples analyses.



Fig 5.4: Two subgroup of vitrinite maceral; Tellocollonite (Tl) characteristic as a clear banded layer & Desmocollinite (Dc) characteristic in the form of a dispersed layer.

5.4.3 Maceral Analyses

Maceral composition was determined by maceral analyses based on 1000 points, both under white and blue light excitation. Twelve coal samples were determined by counting the maceral distribution and mineral content on polished blocks. Result of petrographic examinations and maceral determination show that two types of organic rich rocks are identified. These two organic-rich rock types identified are coal (MM < 15%) and carbargillites (MM among 15%- 65%). Three maceral groups (vitrinite, liptinite and inertinite) were present in these samples and the results were shown in Table 5.2 and plotted on a ternary diagram (Fig 5.5). The percentage of maceral for each coal sample are shown on the pie chart (Fig 5.6). The petrographic study reveals that Pinangah coals are dominated by vitrinite classified humic maceral and as coal.

Sample name	Sample Lithology	%Ro	Vitrinite	Inertinite	Liptinite	Clay & MM
BDD 1	Carbargillite	0.49	39	0	21	40
BDD 2	Coal	0.47	81	3	16	0
BDD 3	Carbargillite	0.50	50	2	8	40
BDD 4	Coal	0.66	85	1	11	3
BDD 13	Coal	0.50	82	4	14	0
BPC 2	Coal	0.55	75	3	20	2
BDD 24	Carbargillite	0.49	35	1	3	61
BDD 28	Coal	0.51	79	7	13	1
BDD 30	Coal	0.51	77	11	12	0
BDD 31	Carbargillite	0.42	47	7	20	26
BDD 49	Coal	0.62	78	5	14	3
BDD 50	Coal	0.62	80	9	11	0

Table 5.2: Organic petrological data for vitrinite reflectance (%Ro) analysis and maceral analysis.

i) Coals: Nine samples have been identified as coal based on the low abundance of mineral matter and high content of organic matter. The petrographic study shows that the organic content of the Pinangah coals are dominantly vitrinite. Average vitrinite percentage of the nine samples is 77% which range from 75 to 85% consisting mainly of tellocollinite and desmocollinite. Coprocollinite are present in small amounts. Telocollinite is characterized by structure of homogenous bands and dark grey in colour under reflected white light and didn't fluorescence under blue light excitation. Desmocollinite show a very finely porous to granular structure which is filled with liptinite and inertinite maceral and grey in colour under reflected white light the desmocollinite fluorescence vaguely due to the existence of a few liptinite macerals (Fig 5.8i,j).

Liptinite is the second main maceral (8%) in the range of 11-20% and is dominated by suberinite, liptodetrinite, sporinite, cutinite and resinite among other minor liptinite macerals. Under blue light excitation, liptinite macerals display yellow fluorescence which does indicates that the coal samples may possess hydrocarbon generating potential. Intense fluoresces however indicate the sample are early mature to mature for hydrocarbon generation. Suberinite is present in of all the coal samples and fluoresces dull yellow color under blue light (Fig 5.9k,l; Fig 5.9o,p). Large resinite appear in the study sample and possess low yellow fluorescence under blue light excitation (Fig 5.8g,h). Fluorinite maceral possesses brighty yellow fluorescence in the sample BDD 1 which indicates it is rich in hydrocarbon constituents (Fig 5.9m). Under normal reflected light, oil smears were observed (Fig 5.8i) and hydrocarbon haze is observed under blue light excitation (Fig 5.7e,f). The secondary maceral, exudatinite show associated with telocollinite layer (Fig 5.7a,b) and present seen cutting the telocollinite layer which is association with suberinite and occur in a form of a fault (Fig 5.7c,d). Three of these coal samples contain 20% liptinite (Table 5.2), which is considered as sufficient amount of liptinite required for a source rock a source rock considered capable of generating oil (Wan Hasiah, 1999). Based on analysis shown in Table 5.2, these coals contain significant amount of liptinite type II kerogen. Type II kerogen is moderately hydrogen-rich with its primary products being both oil and gas prone (Tissot & Welte, 1984).

Inertinite maceral group is present in very small amount ranging from 3-11 % and mainly consists of sclerotinite, semifusinite and inertinite. Scelerotinite is the common maceral of inertinite group to be associated with desmocollinite (Fig 5.8g & Fig 5.9n). The low amount of inertinite macerals in the coals sample suggest it is related to weathering or fungal decomposition. Inertinite macerals posses a higher reflectance than other macerals and the colour of the inertinite under white light is greyish yellow and yellow white (Fig 5.9r). Under 'blue light' excitation, the lumen of sclerotinite fluoresces, because it is filled with liptinite macerals, probably resinite or exsudantie (Fig 5.9n).

ii) Carbargillite: Four samples namely BDD 1, BDD 3, BDD 24 and BDD 31 have been identified as carbargillites due to the mineral content more than 15%. These carbargillite samples contain moderate vitrinite (58-48%) of mainly desmoscollinite maceral. The type of mineral matter identified in the samples is dominated by clay and lesser amount of pyrite mineral (26-40%).

`The liptinite content ranges from 10-20% and being dominated by liptodetrinite and bituminite. The presence of the maceral bituminite in carbargillites may play an important role in hydrocarbon generation as described by Wan Hasiah (2003). The author reported that the maceral bituminite in Sarawak coals were considered to have been generated from suberinite maceral. The amounts of liptinite in the carbargillite samples are higher than in the coal samples and this means that the carbargillite samples may be capable of generating more liquid hydrocarbon than the coal samples. Inertinite is a minor type of maceral in all the analysed samples which is in a range of 3-6% consisting predominantly of sclerotinite and inertodetrinite.



Fig. 5.5: The ternary diagram of maceral composition coals in study area.
5.4.4 Interpretation of Macerals and Kerogen Assemblage

The abundant vitrinite macerals in coal and carbargillite samples in the study area generally indicate gas-proneness but some samples contain higher liptinite maceral (more than 20%) indicating oil-proneness. The high percentage of the sub-maceral desmocollinite in coal could contribute to the oil- prone nature of source rock (Wan Hasiah, 1999). Teichmuller and Durrand (1983), Wan Hasiah (1997) and Teichmuller et al., (1998) suggested that suberinite and resinite expell most of their liquid hydrocarbons at a much lower maturity than do sporinite and cutinite. Coal samples in the study area contain abundant suberinite macerals (Fig 5.9q,r) indicating that the analysed coals sample could generate waxy crude oil. Both the coal and carbargillite samples contain exudatinite maceral (Fig 5.3c,d) which shows primary migration of hydrocarbon within the coal network as previously reported by Mukhopadhyay et al., (1991) ,and Wan Hasiah (1999). The formation of exudatinite has long been regarded as representing the very beginning of hydrocarbon generation in coal (Teichmuller, 1974; Wan Hasiah, 1997 & 2003; Hakimi and Abdullah, 2012).

The presence of hydrocarbon indicators such as oil smear, suberinite and secondary maceral exudatinite clearly demonstrate the early generation of liquid hydrocarbon from the coal and carbargillite samples in the Pinangah study area. The significant representation of terrestrial liptinitic macerals indicated that both liquid hydrocarbons of waxy nature and naphthenic oils and condensates could be generated by these coals (e.g. Mukhopadhay and Hatcher 1993; Wan Hasiah, 1997; 1999, 2003; Rongxi et al., 2008; Zulkifli et al., 2008; Ogala, 2011; Hakimi and Abdullah, 2012).

No. sample	חח <u>פ</u>	2 DD 2	BDC 2	BUD 3		BDD	BDD	BDD	BDD	BDD	BDD	BDD
Maceral		BDD 2	DIC 2	BDD 5	BDD 4	13	24	28	30	31	49	50
Tellocollinite	9	0	20	4	33	17	12	19	26	7	27	35
Telinite	0	0	0	0	0	0	0	0	0	0	0	0
Desmocollinite	30	81	53	46	47	50	23	60	51	40	51	40
Corpocollinite	0	0	2	0	5	15	0	0	0	0	0	5
Vitrinite group	39	81	75	50	85	82	35	79	77	47	78	80
Sporinte	4	5	1	0	0	1	0	1	1	6	4	2
Cutinite	0	4	5	0	2	3	0	2	5	6	2	4
Suberinite	0	0	9	0	1	7	0	7	4	4	1	0
Liptodetrinite	9	7	1	5	6	2	0	2	0	0	6	5
Resinite	0	0	0	0	0	1	0	0	0	3	0	0
Exsudatinite	0	0	2	0	1	0	1	1	1	1	1	0
Bituminite	8	0	2	3	1	0	2	0	1	0	0	0
Liptinite group	21	16	20	8	11	14	3	13	12	20	14	11
Sclerotinite	0	1	1	1	0	1	0	1	2	4	1	0
Fusinite	0	0	0	0	0	0	0	0	6	1	2	3
Semifusinite	0	1	0	0	0	1	0	0	2	1	2	4
Inertodetrinite	0	1	1	1	0	1	1	2	0	1	0	2
Micrinite	0	0	1	0	1	1	0	4	1	0	0	0
Macrinite	0	0	0	0	0	0	0	0	0	0	0	0
Inertinite group	1	3	3	2	1	4	1	7	11	7	5	9
Clay minerals	35	0	0	40	3	0	60	1	0	25	1	0
Quartz + pyrite	4	0	2	0	0	0	1	0	0	1	1	0
Total Macerals	60	100	98	60	97	100	39	99	100	74	98	100
GI	0	40.5	75	50	0	41	0	39.5	9.6	15.7	20	8.9
TPI	0.3	0.01	0.4	0.09	0.7	0.4	0.5	0.3	0.7	0.2	0.6	1

Table 5.3: The composition of maceral and mineral matter (%) based on petrological data.



Fig 5.6: Pie chart showing the maceral component (%) of each maceral in the analysed coal samples from Pinangah Sabah.



Fig 5.6: (continue) Pie chart showing the maceral component (%) of each maceral in the analysed coal samples from Pinangah Sabah



Fig. 5.7: Photomicrograph of macerals in Pinangah coals, Sabah under reflected white light (left) and blue light excitation (right). (**a** & **b**) exudatinite (ex) in desmocollinite (ds); (**c** & **d**) exdudatinite (ex) dispalce suberinite (Sb) and form a fault; (**e** & **f**) Bituminite associated hydrocarbon Haze (bt).



Fig 5.8: Photomicrograph of macerals in Pinangah coals, Sabah under reflected white light (left) and blue light excitation (right). (g & h) resinite (re); (i & j) oil smear associated with vaguely fluorences suberinite (Sb), macrinite (Mc) and semifusinite (sm); (k & l) suberinite (Sb) in telocollinite(tl) and desmocollinite (ds).



Fig 5.9: Photomicrograph of macerals in Pinangah coals, Sabah under reflected white light and blue light excitation.(m) fluorinite (fl) shows intense yellow fluorence under blue light excitation indicate rich in hydrocarbons. (n) Cutinite (cu) show yellow fluorence; (o) Suberinite (Sb) and micrinite (Mc) under reflected white light; (p) suberinite (Sb); (q) Resinite (re) shows intense yellow fluorence; (r) Scleroctinite(Sc) in desmocollinite (ds).

5.4.5 Coal facies

Maceral analysis provides a wealth of information that may be useful in defining depositional environments if facies-critical macerals can be selected (Kalkreuth and Leckie, 1989). The petrology of coal and its relation to the environment of deposition under which its precursor materials were deposited has been subject of various studies (Diessel, 1982; Teicmuller, 1989; Kalkreuth et al., 1991).

The abundant vitrinite macerals in the coal and carbargillite samples are considered to be originally derived from terrestrial higher land plant. The presence of cutinite, suberinite and resinite (Fig 5.8 & Fig 5.9n,p) suggest an accumulation in a forest-type swamp, while the presence of sporinite shows reedmarsh vegetation (Flores, 2002). Sclerotinite and semifusinite (Fig 5.8i & Fig 5.9r) are the common inertinite macerals in the coal and carbargillite samples analysed in this study. The low amount of inertinite macerals in the coal and carbargillite samples may not be due to forest fires, but more likely that the coal and carbargillite samples in the Pinangah area have been influenced by fungal decomposition or prior to deposition to the weathering after the deposition.

Coal facies analysis was determined under reflected white light and is ploted on the coal facies diagram (Gelification Index (GI) versus Tissue Preservation Index (TPI)) which may provide important information for interpretation of the paleo-environment of the peat formation. TPI is a measure of the degree of humification of plant tissue and the proportion of woody plants in the original peat forming assemblages whereas GI measures the relative dryness or wetness of autochthonous peat forming conditions (Alkande et al., 1992; Diessel, 1992; Kalkreuth et al., 2000; Lamberson et al., 1991; Silva and Kalkreuth, 2005). The high value of GI and high value of TPI are indicative of wet conditions, while low value of GI and low value of TPI indicative of dry conditions of peat formation. The coal

facies diagram (TPI vs GI) modified by Diesel, (1996) and Kalkreuth and Leckie, (1989) comprises eight different depositional environments: limno-telmatic, telmatic, marsh, fen, limnic, wet forest swamp, dry forest swamp, and terrestrial. The TPI vs GI values of the analysed samples shown in the Table 5.4.

In this study the formula of TPI and GI applied are as given by (Diesel, 1992) and are calculate based on maceral analysis performed on polished blocks of the coal samples. Most of the studied samples show low value range of Tissue Preservation Index (TPI) from 0.01 to 1.0, and high value of Gelification Index (GI) range from 9.6 to 75. The low value of TPI in these coal samples is due to a high content of the structureless vitrinite which is mainly desmocollinite and the high value of GI resulting indicates that the coal samples are deposited in a wet condition of the peat formation. From the facies diagram (TPI vs GI), it showed that most of the coals analysed were deposited in an open marsh to fluvial-lower deltaic environment under limnic to limno-telmatic setting with brackish condition as suggest by the presence of Rhizopora (see section 5.4.6). The presence of biomarker oleanane (see section 5.5.3.3) also support the occurrence of marine-influenced as suggested by organic petrological analysis.



Fig 5.10: (a) Coal Facies (GI vs TPI), proposed by Diesel (1986), modified after workers (e.g Kalkreuth &Leckie, 1989; Wan Hasiah, 2002); (b) depositional setting.

5.4.6 Palynology

The palynological analysis of the studied samples has been carried out by BiostratEx, private laboratories in Kuala Lumpur and palynomorphs identification were carried out based on guidance from expertise. A total of 10 coals and carbargillite samples were palynologically examined and the purpose of this study was to identify the paleoenvironment of the analysed samples. The result of palynomorph analysis is present as percentage in Table 5.4.

They are 58 species of pollen and spore present in the analysed coal/carbargillite samples. Almost all of the coal/carbargillite samples contain the following: *Asplenium type, Stenochlaenapalustris, Pandarus, Blumeodendran, Cephalomappa type 20, Ilex, Eugenia, Impatiensidites, Rhizopora, Sapotaceae, Calophyllum, Blumeodendron, cephalomappa type 20, Sapotacea type278 and Dactylocladus and Pinuspollenites.*

Cassuriana commonly associated with *Calophylum*, *Padocarpus*, *Blumeodendron* and *Dactylocladus* is the type of pollen which is abundant in the BDD 31 coal samples whereby this type of pollen are usually found in coastal plain environment. *Stenochlaena* display abundance in the sample BDD 28 (9% respectively) usually associated with climbing fern, indicating the transition phase occurs at the coastal plain environment. *Rhizopora* is the type of pollen that is typically found in mangrove swamp plant and is abundant in the coal sample BDD 30. *Pinuspollenites* has been found in the sample BDD 3 and BDD 28 has been attributed to spread of pine woods on coastal areas (Atherden et al., 1993).

Overall, pollen and spore present in the coal/ carbargillite samples in that the Pinangah coals are deposited in a coastal plain environment. Fig 5.8 and Fig 5.9 show the picture of pollen found in the analysed samples.

													Paly	nom	orpl	hs															
Sample name	Lithology	Excoecaria	Asplenium type	Calophyllum	Casuarina	Sapotaceae	Quercus	Calophyllum type 299	Podocarpus	Stenochlaena palustris	Shorea	Chantium	Pandanus	Magnolia	Papilionaceae	Eugenia	Pinuspollenites	Tricolpites	Polypodiisporites spp.	Proxapertites spp.	Ficus	Blumeodendron	Cephalomappa type 20	llex	Stemonurus	Betula	Caesalpiniaceae	Dactylocladus type 76	Cephalomappa type 46	Lithocarpus	
BDD 1	Carbargillite		3	Ŭ		1	Ū			1			1	1										2			3			3	
BDD 2	Coal		1							1					1							2					3				
BDD 3	Carbargillite		5	5		2	3			2			2		1	2	1					7	2	5	3			1	2		1
BDD 4	Coal		2				2			2			8			2		1			1	15		1	6					3	
BDD 13	Coal			2	4	3				1			8			4		4		1		1	4		3				1		1
BDD 24	Coal		4	2				4		9			1			2		5				5		3	3		4	1		2	
BDD 28	Coal	1	2	3	21	2	3	1	2	2	1	1	1	2	1	2	1	5	2	1	2	1	1	2							1
BDD 30	Coal		1	3	1	1				1			6			2		5			2	4	4		5		5	2			
BDD 31	Carbargillite		2		30	1							4	1							1	1	2	2	3	5	3	1	1	1	
BPC 2	Coal		2			3		2					3			5						2	2	1	2		2	1			

 Table 5.4: Palynomoph data for coal samples in Pinangah, Sabah.

											Paly	ynon	orp	hs														
Sample name	Lithology	Verrucatosporites usmensis	Corsinopollenites	Impatiensidites	Magnolia	Bosedinia	Spore type	Graminae	Nenga	Palmaepollenites	Bosedinia infragranulata	Dactylocladus type 88	Rizophora	Palmae type 497	Dicolpopolis malesianus	Milfordia	Verrucosisporites usmensis	Calamus	Sapotacea type 278	Pteris type	Florschuetzia type 321	Palmaepollenites	Croton	Discoidites borneensis	Dipterocarpus	Arengapollenites	Nyssapollenites	Camnosperma
BDD 1	Carbargillite				1	8	2	3	1	3	4	1	2	2	1	1	1											
BDD 2	Coal					1	1																					
BDD 3	Carbargillite			1	1			2				2		2			1	2	2		3			2		1	1	1
BDD 4	Coal			1									7					2	1									
BDD 13	Coal												2						3	1		2	1					
BDD 24	Coal			1								4		1					3	1	1							
BDD 28	Coal	5	1																									
BDD 30	Coal			2			1			2			8											1	2			
BDD 31	Carbargillite			1																								
BPC 2	Coal			2									2	1					4							2		

Table 5.4: Palynomoph data for coal samples in Pinangah, Sabah.

Г



Fig 5.11: Photomicrograph of palynomoph in coals sample in the study area of Pinangah, Sabah. (a)Austroboxus nitidus,(b) calophyllum, (c) cassuriana, (d) dectylocladus, (e) laevigatosporites and (f) malvaceae.



Fig 5.11: (continue) Photomicrograph of palynomoph in coals sample in the study area of Pinangah, Sabah. (g)Palaquium (sapotaceaae), (h) podocarpus type,(i) stenochlaena palustr and (j) tricolpate.

5.5 Organic Geochemistry Analyses

5.5.1 Result of Source Rock Analysis

5.5.1.1 Generative Potential

Source rock properties of the Tertiary Pinangah coals were investigated for the purpose of characterizing the organic richness, hydrocarbon potential of the organic matter and its thermal maturity level. Source rock generative potential was evaluated using total organic carbon content (TOC wt. %) and pyrolysis S2 yields (Table 5.5). In the pyrolysis analysis, free hydrocarbons (S1) in the rock and the amount of hydrocarbons (S2) and CO2 (S3) expelled from pyrolysis of kerogen are measured and shown in Table 5.5. The amount of hydrocarbon yield (S2) expelled during pyrolysis is a useful measurement to evaluate the generative potential of source rocks (Peters, 1986; Bordenave, 1993). The samples have pyrolysis S2 yield values in the range of 151.9 - 347.6 mg HC/g rock (Table 5.5). Such values meet the accepted standards of a source with excellent generative potential (Peters and Cassa, 1994) (Fig. 5.12).

5.5.1.2 Total Organic Carbon

Total organic carbon content (TOC) and source rock analysis were performed on 12 coal samples (potential source rock). As expected, the coal samples contain high total organic carbon content (TOC) ranging from 51.2 to 77.7 wt. % with the average 66.52 wt %. According to Peter and Cassa (1994) the TOC value more than 0.4 wt% indicate excellent source potential for hydrocarbon.

Samples	Lithology	TOC	Pyroly	Pyrolysis data (SRA)											
		(Wt %)	<i>S</i> 1	<i>S</i> 2	<i>S</i> 3	Tmax (oC)	HI	OI	PI	PY					
BDD 1	Carbargilite	64.7	9.5	246.4	0.65	424	381	1	0.04	255.9	0.49				
BDD 2	Coal	62.8	3.5	167.6	7.54	433	267	12	0.02	171.1	0.47				
BPC 2a	Coal	67.0	5.7	199.0	6.03	429	297	9	0.03	204.8	0.55				
BPC 2b	Coal	67.2	14.5	308.2	0.67	423	459	1	0.01	322.6	0.49				
BDD 3	Carbargillite	68.2	15.5	282.0	0.68	451	414	1	0.05	297.5	0.50				
BDD 4	Coal	77.7	30.1	347.6	0.78	437	448	1	0.08	377.7	0.66				
BDD 13	Coal	73.6	5.8	285.5	3.68	430	388	5	0.02	291.3	0.50				
BDD 24	Carbargillite	57.3	7.7	281.6	3.63	440	203	17	0.03	289.3	0.48				
BDD 28	Coal	56.3	3.5	115.9	9.97	428	270	5	0.03	119.5	0.49				
BDD 30	Coal	67.1	14.4	309.6	2.68	419	462	4	0.04	324.1	0.51				
BDD 31	Carbargillite	51.2	3.8	178.2	2.05	423	348	4	0.02	181.9	0.42				
BDD 49	Coal	76.8	7.8	326.7	1.54	429	425	2	0.02	334.5	0.62				
BDD 50	Coal	67.0	3.4	203.2	5.36	434	303	8	0.02	206.6	0.62				

Table 5.5: Bulk geochemical results of pyrolysis analysis with calculated parameters and vitrinite reflectance data of the analysed coals and coaly sediments in the Pinangah area

SRA: Source rock analyzer

TOC: Total organic Carbon, wt. %

S1: Volatile hydrocarbon (HC) content, mg HC/ g rock

S2: Remaining HC generative potential, mg HC/ g rock

*S*₃: carbon dioxide yield, mg CO2/ g rock

HI: Hydrogen Index = S₂x 100 / TOC, mg HC/ g TOC

OI: Oxygen Index = S₃x 100 / TOC, mg CO2/ g TOC

PI: Production Index = $S_1/(S_1+S_2)$

PY: Potential Yield = S1+S2

5.5.1.3 Thermal maturity of organic matter (Tmax)

Thermal maturity provides an indication of the maximum paleotemparature reached by a source rock. The Tmax values for these area ranges from 419 to 451°C, which commonly reflect on maturity but may also be influenced by kerogen type (Hunt, 1996) thus the defined maturity windows on this diagram are only approximate. The average Tmax value in for Pinangah Tertairy coals is 430°C. According to Peters (1986), Tmax and PI values less than 435°C and 0.1 respectively, indicate immature organic matter while Tmax greater than 470°C points to the wet-gas zone. Both values mentioned indicate that that these coals samples are thermally immature to early mature with respect to the hydrocarbon generating potential. The Tmax values are in good agreement with the mean vitrinite reflectance data (0.42-0.66%; Table 5.5).

5.5.1.4 Types of organic matter

Hydrogen index (HI) values ranging from 203 to 462 mg HC/g TOC and oxygen index (OI) values are low (1-17 mg CO₂/g TOC). A plot of hydrogen index (HI) and pyrolysis Tmax (Fig. 5.13), which can be used to classify the maturity and type of organic matter (Mukhopadhyay et al., 1995), shows that the coals are mixed Type II-III kerogen and that Type II kerogen possess both oil and gas generating potential.



Fig 5.12: Pyrolysis S_2 versus total organic carbon (TOC) plot showing generative source rock potential for coal and carbargillite in the Pinangah area.



Fig 5.13: Plot of hydrogen index (HI) versus pyrolysis Tmax for the analysed coal and coaly sediments, showing kerogen quality and thermal maturity stages.

5.5.2 Extractable organic matter

Soluble organic matter can be analysed to obtain both oil source quality and maturity information (Tissot and Welte 1984). The mass of the extractable organic matter measure shows variation amount with the higher value for all entire coal and carbargillite samples. The parameters by Peter and Cassa, (1994) are used to assess the quality of hydrocarbon content as shown in the Table 3.4.

Extraction amounts obtained from the analysed samples from Pinangah coal field are given in Table 5.6 and range from 57300 ppm to 14000 ppm. Coal and carbargillite samples in this study area yield high extractable organic matter (EOM) ranging from 5.8% to 14% indicating excellent source potential for hydrocarbon generation (Peter and Cassa, 1994) as indicated by the TOC versus pyrolysis S2 yields plot (Fig. 5.12).

Table 5.6: The	data for extra	ction analysis	of extractable	organic matter	coals sample.
		2		0	1

no	Sample	Lithology	Before Ex	traction		After extract	tion		Percentage EOM in rock (%)	Percentage EOM (ppm)
			Weight of empty thimble (g)	Weight of sample+ thimble +cotton	Weight sample (g)	Weight of empty beaker (g)	Weight of beaker + EOM (g)	Weight of EOM (g)		
1	BDD 1	Carbargillite	2.91	8.55	5.64	59.48	60.27	0.79	14	140000
2	BDD 2	Coal	2.75	13.37	10.62	56.48	57.10	0.62	5.84	58400
3	BDD 3	Carbargillite	4.12	16.52	12.4	53.24	53.95	0.71	5.73	57300
4	BDD 4	Coal	2.91	9.71	6.8	52.72	53.20	0.48	7.04	70400
5	BDD 13	Coal	2.78	13.75	10.97	54.60	55.45	0.85	7.75	77500
6	BDD 24	Coal	2.79	12.49	9.7	52.60	53.26	0.66	6.80	68000
7	BDD 28	Coal	3.08	13.69	10.61	52.70	53.34	0.64	6.03	60300
8	BDD 30	Coal	3.98	18.36	14.38	52.72	54.00	1.28	8.90	89000
9	BDD 31	Carbargillite	2.83	13.91	11.08	50.79	51.75	0.96	8.66	86600
10	BDD 49	Coal	3.08	13.29	10.21	52.72	53.50	0.78	7.64	76400
11	BDD 50	Coal	2.75	11.49	8.74	52.62	53.27	0.65	7.44	74400
12	BPC 2	Coal	2.83	12.40	9.9	52.64	53.30	0.66	6.67	66700

5.5.3 Biomarker Distribution

5.5.3.1 The n- Alkanes Distribution (GC)

The n-alkanes distributions obtained from gas chromatogram (GC) were used to interpret the organic sources and depositional environment. The distribution of n-alkanes of the saturated hydrocarbon are shown in Fig 5.14 and calculated parameters are shown in Table 5.8. The chromatograms of the entire sample show pristane (C_{19}) being much more abundant than phytane (C_{20}).

The GC traces of the coal and carbargillite samples display waxy appearance with unimodal pattern shown by the abundance of higher molecular weight n-alkanes (nC₂₀₊) generally ranging from n-C₁₅ to n-C₃₃ and maximized at nC₂₅. This pattern which shows higher concentration of the regular long chain n-alkanes tend to being derived from terrestrial organic matter input (Tissot & Welte, 1984; Hunt, 1984). According to Eglinton and Hamilton (1963), Hunt (1996) and Philp (1994) long- chain alkanes are typically correlating with terrestrial higher plants because plant with the surface expose to atmosphere usually contains wax layer (cuticle) that act as a proctective function to preserve the water balance of plant. Using the n-alkane distributions in gas chromatograms, the odd/even carbon number n-alkanes (CPI) index was calculated using the formula proposed by Bray and Evans (1961):

$$CPI = 0.5 \text{ x} / [C_{25} + C_{27} + C_{29} + C_{31} + C_{33} / C_{26} + C_{28} + C_{30} + C_{32} + C_{34}] + [C_{25} + C_{27} + C_{29} + C_{31} + C_{33} / C_{24} + C_{26} + C_{28} + C_{30} + C_{32}].$$

Both coal and carbargillite samples have CPI value > 1 ranging from 1.19 to 1.41 (Fig 5.18), which indicate terrestrial organic matter input. According to Wan Hasiah (1992), the

value of CPI ranging from 1.2-1.4 are indicative of early mature for coals and coaly sediment from the North Sea. Although the CPI value can be use for source information, but it may not be consistent because the bacteria degradation can remove the n-alkanes from source rock extract thus may eliminate their potential utility as source indicator (Winters and Williams, 1971).

5.5.3.2 Isoprenoid

The regular isoprenoid pristane (Pr) and phytane (Ph) are present in all the samples with pristane (Pr) being dominant peak over phytane (Ph). According to ten Haven et al., (1987) high values of Pr/Ph greater than 3 are interpreted as terrigenous input deposited under oxic conditions and values of pr/ph less than 0.8 indicate deposition under anoxic or carbonate environment. According to Lijmbach (1975) values of pr/ph< 2 are commonly found in aquatic depositional environments including marine, fresh and brackish water (reducing conditions). Awang Sapawi et al., (1991) suggest values of pr/ph >3 indicate deposition in peat swamp environment. All of the coal and carbargillite samples analysed display high values of pr/ph in the range of 8 to 18 with most value greater than 12 (Table 5.7). These values are significantly higher than 3 are confirming deposition in the peat swamp environment under oxic conditions.

Pristane/n- C_{17} and phytane/n- C_{18} cross plot were used to determine environmental conditions during sediment deposition (after Hunt, 1996). The ratio of pristane/ n- C_{17} expresses a higher value in the range 7.14 to 20.4 and phytane/n- C_{18} expresses value in the range 0.42 to 1.22. Referring to the cross plot diagram (Fig 5.16), it shows that the all coal and carbargillite samples in the Pinangah coal field plot just outside the field representing a

peat swamp environment due to exceptionally high pristane. Coal and carbargillite samples in the study area were deposited under a highly oxidizing condition of deposition.

Samples	ТОС	Extractable organic m	atter	n-alkane and isoprenoids							
ID	(Wt. %)	Total extract (ppm)	Bitumen/TOC	СРІ	Pr/Ph	Pr/C17	Ph/C18				
BDD 1	64.7	140000	0.21	1.37	8.3	7.1	0.43				
BDD 2	62.8	58400	0.10	1.34	17.5	9.3	0.53				
BPC 2	67.2	66700	0.09	1.19	13.1	13.1	0.64				
BDD 3	68.2	57300	0.08	1.41	18.0	10.0	0.42				
BDD 4	77.7	70400	0.09	1.15	12.3	8.2	0.44				
BDD 24	72.5	68000	0.09	1.31	14.1	14.1	0.75				
BDD 28	56.3	60300	0.11	1.41	18.0	10.0	0.42				
BDD 30	67.1	89000	0.13	1.30	9.3	20.4	1.22				
BDD 31	51.2	86600	0.17	1.27	12.3	14.0	0.62				
BDD 49	76.8	76400	0.10	1.26	17.0	14.6	0.66				
BDD 50	67.0	74400	0.11	1.22	13.9	13.9	0.70				

Table 5.7: Bitumen extraction and normal alkane parameters of the studied Pinangah samples.



Fig 5.14: The typical gas chromatograms n-alkanes $(C_{17}-C_{33})$ and isoprenoids (pr&ph) distributions for the analyses samples from Pinangah, Sabah area.



Fig 5.14: The typical n-alkanes $(C_{17}-C_{33})$ and isoprenoids (pr&ph) distributions of GC chromatograms for analyses samples from Pinangah, Sabah area.



Fig 5.15: Graph of CPI values show that coal and carbargillite samples in Pinangah area are in the early mature stage for generating hydrocarbon.



Fig 5.16: Plot of pristane/n- C_{17} vs. Phytane/n- C_{18} showing oxic condition of depositional environment (Adapter after Shanmugam, 1985).

5.5.3.3 Triterpanes Distribution

The triterpanes distribution was determined using peak identification on m/z 191. Peak assignments of terpanes and steranes are shown in Table 5.9. The triterpanes distribution of the analysed coal and carbargillite samples are shown in Fig 5.17 and calculated ratios are shown in Table 5.8. From the m/z 191 chromatograms, its shows that all the samples have high abundance of $17\alpha(H)$ - hopanes and $17\beta(H)$ - moretane with high relative abundance of 18α -oleanane compounds. Trace amount of tricyclic terpanes maybe present but could not be identified with certaintly in this study.

In all the analysed coal samples, the 17α (H), 21β (H)-hopane (C₃₀ $\alpha\beta$) are the dominant triterpane followed by C₂₉ norhopanes. The ratios of the C₂₉/C₃₀ for all of the analyzed samples are almost the same ranging from 0.7 to 1.0. The C₂₉/C₃₀- hopane values of less than 1.0 within the study area are consistent with a terrestrial origin of the analyzed samples by ten Haven et al., (1988); Fan et al., (1987) and Peters & Moldowan (1993).

Ts[17 α (H) 22, 29, 30- trisnorhopane]/Tm[18 α (H) 22, 29, 30- trisnorneohopane] sometimes reported as The Ts/ (Ts + Tm) ratio, depends on both source and maturity (Moldowan et al., 1986). Ts/Tm shows the lower value ranging from 0.03 to 0.28 while Tm/Ts ratio expressed rather higher values in the range of 3.56 to 30.0.

The chramotograms shows all of the analysed coal and carbargillite samples are dominated by 17 α (H)- hopanes rather than 17 β (H)- moretanes compounds with Moretane/ hopane (30m/30) ratios in the range of 0.31 to 0.58. These ratios indicate mature source rock (Mackenzie et al., 1980; Seifert & Moldowan, 1980) though these values could be a consequence of high terrestrial organic matter input (Waples and Michihara, 1991).

The stereoisometry ratios (22S/(22S+22R)) have been used as maturity indicators (Peters & Moldowan, 1993) showing the C₃₂ hopane isomerization reaching values in the range of 0.55 - 0.60. During maturation, the ratio of hopane isomerization rise from 0 to about 0.6 (0.57 to 0.62 i.e.at equilibrium) and after reaching equilibrium, no further maturity information is available at early oil- generative stage (Seifert and Moldowan, 1986).

The entire extracted coals and carbargillite samples from West Middle block of Pinangah show the presence of oleanane and display ratio of oleanane/ C_{30} less than 1 ranging from 0.15 to 0.66. The presence of oleanane compound with ratio of oleanane/hopanes > 0.25 is characteristic of Tertiary source rocks and oil, and has been suggested as a marker for flowering plants (Moldowan et al., 1994). According to Murray et al., (1997) during early diagenesis the enhanced of oleanane compound in a mature sediments and oil are suggest by contact of plant matter with seawater, and that the oleanane precursors can be altered to aromatic oleanoids in freshwater environment such as fresh coal swamp and fluovio- deltaic environment. The high abundance of oleanane compound in this study suggests that the coal and carbargillite samples are deposited in a terrestrial coastal swamp environment with present of marine influence. This is probably due to marine transgression during the increasing sea water level over geological time.

Bicadinane (denoted bc in Fig 5.17) present in most of the coal and carbargillite samples suggest terrigeneous input in the organic matter (Philp, 1985) and its correlate with tropical angiosperm sources (van Aarssen et al., 1992). Bicadinane was identified by comparing other author's biomarker result. The presence of tetracyclic terpane (C_{24}) compound in almost all of the studied samples suggest it was derived from terrestrial sources input due to this compound commonly abundant as reported in Australian oil (Philp, 1985).

			Terpanes				Sterane							
No.	22/	Tm/Ts	Ts/Tm	C_{20}/C_{20}	30M/30	01/	208/	$\frac{\beta \beta}{\beta \beta}$	C_{27} - C_{20} - C_{20}	Sterane/Honane				
Samples	$(22S+22R)C_{22}$	1112 15	10, 111	029/030	2011220	C ₂₀	$(20S+20R)C_{20}$	pp; (pp ·)	(%)	Sterane, Hopane				
BDD 1	0.55	-	_	0.80	0.56	0.17	0.40	0.30	13-14-73	0.70				
	0.000			0.00	0100	0117	0110	0.00	10 11 70	0.70				
BDD 2	0.56	-	-	0.97	0.58	0.15	-	-	-	-				
BPC 2a	0.58	30.00	0.03	0.73	0.31	0.17	0.40	0.30	9-20-71	0.80				
BPC 2b	0.59	19.25	0.05	0.80	0.33	0.64	0.40	0.30	12-22-67	0.90				
BDD 3	0.58	3.56	0.28	1.00	0.49	0.41	0.50	0.30	26-14-60	0.90				
BDD 4	0.58	15.00	0.06	0.87	0.54	0.17	0.40	0.20	14-7-79	0.80				
BDD 13	0.60	27.00	0.04	0.82	0.50	0.28	0.50	0.20	11-7-82	1.20				
BDD 24	0.58	28.00	0.03	0.94	0.43	0.25	0.40	0.20	13-9-78	0.90				
BDD 28	0.56	6.33	0.14	0.73	0.53	0.66	0.40	0.40	15-5-80	0.70				
BDD 30	0.60	20.75	0.05	0.77	0.42	0.57	0.30	0.30	24-20-56	0.60				
BDD 31	0.59	-	-	0.81	0.33	0.41	0.40	0.30	21-16-63	1.20				
BDD 49	0.58	24.00	0.04	0.90	0.53	0.15	0.40	0.30	5-23-72	0.80				
BDD 50	0.60	13.67	0.07	1.00	0.33	0.28	0.40	0.30	5-5-70	-				

Table 5.8: Terpane and sterane data of coal samples in the study area



Fig. 5.17: The typical m/z 191 fragmentograms (terpane distributions) for the analyses coal samples from Pinangah, Sabah area.


Fig. 5.17: (continue) The typical m/z 191 fragmentograms (terpane distributions) for the analyses coal samples from Pinangah, Sabah area.



Fig. 5.17: (continuation)The typical m/z 191 fragmentograms (terpane distributions) for analyses coal samples from Pinangah, Sabah area.

Table 5.9: Peak assignments for alkane hydrocarbon (I) m/z 191 mass chromatograms and (II) m/z 217 mass chromatograms.

	Compound	Abbreviation
(I) Peak No.		
C ₂₄ T	C ₂₄ tetracyclic terpane	Tetracyclic hopane
Ts	18α(H)-22,29,30-trisnorneohopane (Ts)	Ts
Tm	17α(H)-22,29,30- trisnorhopane (Tm)	Tm
29	17α,21β(H)-norhopane	С29 Нор
Ol	18α(H)-Oleanane	Ol
bc	Bicadinane	Bc
30	17α,21β(H)-hopane	Hopane
30M	17β,21α(H)-moretane	C30Mor
31S	17α,21β(H)-homohopane (22S)	C ₃₁ (22S)
31R	17α,21β(H)-homohopane (22R)	C31(22R)
32S	17α,21β(H)-homohopane (22S)	C32(22S)
32R	17α,21β(H)-homohopane (22R)	C ₃₂ (22R)
33R	17α,21β(H)-homohopane (22R)	C ₃₃ (22R)
33\$	$17\alpha,21\beta$ (H)-homohopane (22R)	C ₃₃ (22S)
(II) Peak No.		
a	$13\beta(H), 17\alpha(H)$ -Diasterane (20S)	Diasteranes
b	13β(H),17α (H)-Diasterane (20R)	Diasteranes
с	13α(H), 17β (H)-Diasterane (20S)	Diasteranes
d	13α(H), 17β (H)-Diasterane (20R)	Diasteranes
e	$5\alpha(H), 14\alpha(H), 17\alpha(H)$ -sterane (20S)	ααα20S
f	$5\alpha(H), 14\beta(H), 17\beta(H)$ - Sterane (20R)	αββ20R
g	$5\alpha(H), 14\beta(H), 17\beta(H)$ - Sterane (20S)	αββ20S
h	$5\alpha(H), 14\alpha(H), 17\alpha(H)$ -Sterane (20R)	ααα20R

5.5.3.4 Sterane Distribution

Sterane can be indicators that are useful in source rock depositional environment interpretation and also can be applied in maturity assessment. From the m/z 217 mass chromatograms of the coal samples (Fig 5.18), the relative abundances of the C₂₇, C₂₈ and C₂₉ steranes and 20S and 20R epimers have been determined (Table 5.18). The distributions of sterane is dominated by C₂₉ followed by the C₂₇ and C₂₈ and the calculation of sterane distribution shows that C₂₉ > C₂₈ > C₂₇ for all of the analysed coal and carbagillite samples. The predominance of C₂₉ over C₂₈ and C₂₇ sterane suggest a terrestrial source rock as should be the case considering the analysed samples are coals. Steranes are commonly reported to be in low concentrations in coals with high terrigenous inputs and waxy humic coals generally display a strong dominance of C₂₉ steranes (Peter & Moldowan, 1993).

The isomerisation of 20S/(20S+20R) ratio for C₂₉ 5 α (H), 14α (H), $17(\alpha)$ (H)steranes) and $\beta\beta/(\beta\beta+\alpha\alpha)$ ratio are used as sterane maturity indicator. The measurement are shown to be in the range of 0.2- 0.4 for 20S/(20S+20R) and 0.4- 0.5 for $\beta\beta/(\beta\beta+\alpha\alpha)$ -C₂₉, respectively and these relatively low values suggest the sterane transformations are not completely equilibrated. Sterane/hopane ratio has been calculated for all the study samples and the value is generally low ranging from 0.7 to 1.2 which is indicative of terrigeneous and/ or microbial reworked organic matter (Tissot and Welt, 1984).



Fig.5.18: The typical m/z 217 fragmentograms (terpane distributions) for the analyses coal samples from Pinangah, Sabah area.



Fig.5.18: (continue) The typical m/z 217 fragmentograms (terpane distributions) for the analyses coal samples from Pinangah, Sabah area.

5.6 Integration of organic petrological and organic geochemical data

5.6.1 Thermal maturity

A variety of maturity indicators were used to evaluate the level of thermal maturity of the Pinangah coals; these include vitrinite reflectance (%Ro), pyrolysis Tmax data and biomarker maturity parameters (Peters and Moldowan, 1993; Peters et al., 2005). The maturity analysis performed here suggest that all of the coal and carbargillite samples are interpreted as immature to early mature for petroleum generation based on vitrinite reflectance values ranging from 0.42 to 0.66%. Therefore, the analysed coal samples are ranked as sub-bituminous C-A to high volatile bituminous C. The pyrolysis Tmax values that range from 415-451°C, are in good agreement with vitrinite reflectance data.

Biomarker maturation parameters such as C_{32} 22S/(22S+22R) homohopane, moretane/hopane and 20S/(20S +20R) and $\beta\beta/(\beta\beta+\alpha\alpha)$ C₂₉ sterane ratios, was used as maturity indicators (Waples and Machihara, 1991; Mackenzie et al., 1980). The 22S/(22S+22R) of the C₃₂ hopane isomerization value of the samples in the range of 0.55 -0.60 suggesting that the samples have reached equilibrium which is an indication that these samples are at early the early top of oil window. However 20S/(20S +20R) and $\beta\beta/(\beta\beta+\alpha\alpha)$ C₂₉ sterane ratios ranging from 0.30 to 0.50, and 0.25–0.40, respectively are not completely equilibrated. Some of the variance in the extent of sterane isomerization may be attributed to other factors such as organic facies, environment and lithology (Korkmaz and Gülbay, 2007). The moretane/hopane ratio ranges from 0.30 to 0.70, which indicates maturity less than the oil window, though these values could be a consequence of high terrestrial organic matter input (Waples and Machihara, 1991). The relationship between isoprenoids $Pr/n-C_{17}$ and $Ph/n-C_{18}$ ratios reflects the same interpretation and consistent with the observed biomarker maturity parameters (Fig 5.16). The biomarker maturation parameters are consistent with the observed vitrinite reflectance data. Overall, the biomarker maturation parameters indicate that the investigated coals have entered early mature of oil window (Fig 5.19).



Fig 5.19: Cross- plot of two biomarker parameters sensitive to thermal maturity of the Pinangah sediments (modified from Peters and Moldowan, 1993).

5.6.2 Liquid hydrocarbon generation potential

Coals have long been recognized as a source for gas, primarily methane and carbon dioxide, but its importance as a generator of economic accumulations of oil is difficult to prove as coals are often interbedded with shales, which may be the source beds. However, coals are now known to be a potentially significant source of liquid hydrocarbons and there are some basins in the world where the evidence is very strong that coals are contributing to significant accumulations of liquid hydrocarbon (e.g. Murchison 1987; Hunt 1991; Hendrix et al., 1995; Wan Hasiah, 1997, 1999, 2003; Obaje and Hamza, 2000). Pyrolysis data have revealed that the hydrocarbon richness of the samples is dependent on the amount and nature of liptinite and vitrinite macerals. Samples that contain a Type III vitrinitic kerogen would be expected to generate gas with hydrogen index < 200 mg HC/g TOC. On the other hand, the samples which contain a significant amount of type II liptinitic macerals with hydrogen index > 200 mg HC/g TOC would be expected to generate gas with minor components of liquid hydrocarbon (Curry, 1994; Hunt, 1996; Koeverden et al., 2011). The abundance of liptinite macerals is, therefore, the major criterion when considering any sedimentary rock (including coal) as a potential source rock for liquid hydrocarbons (Stach et al. 1982; Mukhopadhay and Hatcher 1993; Hendrix et al. 1995). A minimum of 15-20% liptinite content (by volume) of total macerals in sediments is considered as important criteria for a rock to be characterised as a potential oil source rock (Thompson et al., 1985; Hunt, 1991). In the study area, liquid hydrocarbon generation is anticipated from the Tertiary Tanjong coals and coaly sediments based on significance of terrestrial liptinitic constituents (Type II kerogen) and their apparent capability to generate hydrocarbon as seen under the microscope. Most of the analysed samples have liptinitic content exceeding 15% of the total macerals and three samples have 20% liptinite content (Table 5.2). The significant representation of terrestrial Type II liptinitic macerals (sporinite, suberinite, resinite, bituminite and cutinite), indicates that liquid hydrocarbons could be generated by these Tanjong coals as indicated by previous studies(e.g. Hunt, 1991; Fowler et al., 1991; Mukhopahyay et al., 1991; Wan Hasiah., 1999).

The coal samples that are suberinite-rich (Fig 5.8 k,l) can be expected to generate abundant waxy oil at a much lower maturation than do sporinite and cutinite (Teichmuller and Durrand, 1983; Wan Hasiah, 1997). Pyrolysis analyses (HI > 300 mg HC/ g TOC) are consistent with the observed maceral distributions (Fig 5.13). In addition, coals are very varied and represent complex group of source rocks and in particular; the expulsion mechanisms are also complex and depend on several factors influence the timing of oil generation from coals (e.g. Hunt, 1991; Scott and Fleet, 1994). The importante factors that have been identified are maceral type, maceral association, coal micro-texture (e.g. exsudatinite crack network) and also interrelated with original precursor material, depositional environment, microbial activity and mineral matter (e.g. Teichmuller, 1974, 1989; Hunt, 1991; Littke et al., 1989; Scott and Fleet, 1994; Snowdon, 1995; Wan Hasiah, 1997, 1999, 2003). As for the coals from Pinangah area, the maceral type (its abundance and their association) and micro-texture (e.g. exsudatinite crack network) are among the important factors influencing a liquid hydrocarbon generation. The characteristic behaviour of exsudatinite that commonly formed crack networks (Fig 5.9a,b,c,d), although not as extensive compared to the Tertiary coals of Sarawak (e.g. Wan Hasiah, 1999; Hakimi and Abdullah, 2012) suggests a potential significant role in hydrocarbon expulsion into carrier beds. However, the generation of liquid hydrocarbon from liptinitic macerals such as suberinite, cutinite and sporinite (Fig 5.9n,r) represent an early mature stage, which takes place at about 0.66 % Ro or less. This falls within the generally considered "early oil window" that commonly occurs within 0.5-0.7% vitrinite reflectance values (Peter & Cassa, 1994; Tissot & Welte, 1985).

5.6.3 Organic Matter Input and depositional environment

In this study, field log interpretation, organic geochemical (biomarker distributions), maceral assemblages and palynology analysis have been used to describe source input and condition of depositional environment of the Pinangah coals.

Depositional environment condition and source input were examined through based on sterane and triterpane distributions recorded using m/z 217 and m/z 191 mass chromatograms, respectively. The gas chromatogram distribution of n- alkanes displays a waxy appearance with the dominance of heavier n-alkanes members (nC_{20+}) with the maxima at C₂₉ and extending beyond C₃₄ and show a unimodal pattern. This waxy appearance and unimodal pattern of the GC fragmentograms indicate depositional source input of terrestrial higher plant (e.g., Philp, 1985; Peters and Moldowan, 1993; Powell and Boreham, 1994). The pristane/phytane (Pr/Ph) ratio is one of the most commonly used geochemical parameters and has been widely invoked as an indicator of the redox conditions in the depositional environment and source of organic matter (Powell and McKirdy, 1973; Didyk et al., 1978; Tissot and Welte, 1984; Chandra et al., 1994; Large and Gize, 1996). Organic matter originating predominantly from terrestrial plants would be expected to contain high Pr/Ph > 3.0 (oxidizing conditions), whilst low values of (Pr/Ph) ratio (<0.6) indicate anoxic conditions, and values between 1.0 and 3.0 suggest intermediate conditions (suboxic conditions) (Powell, 1988; Peters and Moldowan, 1993). Within SE Asian region, for example, Wan Hasiah and Abolins (1998) and Zulkifli et al (2008) showed that the coals with Pr/Ph ratio exceeding 4 are typically deposited within a peat-swamp depositional setting indicating the oxic condition, and this statement also is consistent with the depositional settings of the analysed Pinangah coal samples which possess Pr/Ph ratios > 4. Using the cross plot of pristane/n-C₁₇ vs phytane/n-C₁₈, its show that the studied sample were deposited under highly oxic environment thus support the indication by Pr/ Ph ratio.

The analysed coal samples contain high abundance of C_{31} homohopane and show the dominance of Tm over Ts. Waples and Machihara (1991) noted that the C_{31} homohopane is dominant in all coal samples and this type of distribution is suggested to be associated with coal and peat. High Tm/Ts ratios have been associated with terrigenenous organic matter (Philp and Gilbert, 1986) and have been observed in fluvial- deltaic oils (Robinson, 1987). The statement are consistent with the depositional setting of the analysed coal samples from Pinangah Coalfield, which possess higher value of Tm/Ts ratio >6. Tm/Ts ratios have been observed in oxic sediments compared to anoxic sediment (Moldowan et al., 1986).

The relative distribution of C_{27} , C_{28} and C_{29} regular steranes is graphically represented in the form of a ternary regular steranes diagram in Fig. 5.20 (adapted after Huang and Meinschein, 1979). This diagram has often been employed to represent the relative proportions of these three steranes. The original classification of Huang and Meinschein (1979) related C_{27} regular steranes to strong algal influence and C_{29} regular steranes to strong higher plant influence.

Applying oleanane parameter to indicate angiosperm input in rocks of late Cretaceous or younger age to the coals of the Pinangah Coalfield shows that the investigated coals with measurable amounts of oleanane (Fig. 5.17) is a strong indicator of terrestrial angiosperm plant as initially reported by Ekweozor and Telnaes (1990). The presence of oleanane, however suggests probable marine influence as indicated by previous work of Murray et al (1997). The influence of marine in the peatland area (coal precursors) probably due to transgression process when the sea levels increase thus it indicate that the coals in the Pinangah area were deposits on the lower delta plain.



Fig 5.20: Ternary diagram of regular steranes (C_{27} - C_{29}) showing the relationship between sterane compositions, source input, and depositional environment for the analysed samples (modified after Huang and Meinschein 1979).

The depositional environment of the Pinangah coals has also been interpreted using maceral assemblages and petrographic facies. Based on maceral analysis, the analysed coal samples are shown to be dominated by vitrinite with subordinate amounts of liptinite and inertinite. The presence of terrestrial liptinite maceral (cutinite, sporinite, suberinite and resinite) further confirms they are coalfield originated from terrestrial peats. The presence of cutinite, suberinite and resinite suggest an accumulation in a forest-type swamp, while significant presence of sporinite shows reed-marsh vegetation (Flores, 2002). The present of fusinite and semifusinite in the coal samples may be derived from charcoal produced during fires which burned through the swamp (Cohen & Spackman, 1977; Scott & Collinson, 1978; Teichmuller, 1982), but with the low amount of this inertinite maceral may not give any indication about the deposition of coal in Pinangah area.

Diessel (1986) developed a scheme to interpret the paleoenvironmental settings in relation to the type of mire with the help of two petrographic facies indices derived from maceral analyses, namely the Tissue Preservation Index (TPI) and the Gelification Index (GI) as defined in Table 5.3, both of which have been extensively used to interpret peat-forming conditions of coal deposits. The value of Tissue Preservation Index (TPI) and gelification Index (GI) of coal samples are plot on the Diessel's diagram and its shows that the studied sample plotted on the open marsh to fluvial field in the lower deltaic setting environment. From the palynological result, most of the pollen such as *Rhizophora, cassuriana, Pandarus* and else (Table 5.4) which is known as angiosperm (flowering plant) present almost in the studied samples. Some of pollen present in the studied sample that are usually found in the lower coastal plain environment could have been reworked from relatively higher coastal plain setting.

Overall, the coals under current investigation are believes to have been derived from terrestrial origin and deposited in a coastal swamp environment under oxic conditions on a lower delta plain. Log interpretation on the coal outcrop localities BDD30 suggest that the coals were deposited on a floodplain associated with point bar deposits on meandering channels (see section 5.3.1). This schematic diagram shows a floodplain depositional environment on a coastal plain setting.

5.7 Conclusion

The samples studied have a humic composition dominated by vitrinite macerals with significant liptinite up to around 20% of the whole rock. The organic matter quality in coal samples as classified on pyrolysis HI versus Tmax diagram shown to be predominantly mixed Type II-III kerogen (oil & gas prone) grading into Type II kerogen (oil prone) as indicated by hydrogen index values (267-462 mg HC/g TOC). Liptinitic Type II kerogen was also identified based by petrographic analysis. The analysed coals are at most marginally mature in conventional terms indicating early oil window stage based on mean vitrinite reflectance of 0.42-0.66 % Ro. The pyrolysis Tmax and biomarker maturity ratios support this attained thermal maturity level. Saturate geochemistry of the Pinangah coals is characterised by high CPI values, high Pr/Ph (8.4-18.0), high Tm/Ts ratios (6-28), dominance of C_{29} regular steranes, the present of $18\alpha(H)$ -oleanane, type of pollen from palynology analysis consistent with an origin as terrestrial peats deposited in a swamp environment deposited under probable minor marine influence. Overall, evaluation of the organic geochemical and petrographic data imply that these Tertiary coals possess good potential for liquid hydrocarbon generation as suggested by the presence of exsudatinite which suggests incipient migration even at this relatively low level of thermal maturity.

REFERENCE

Ahmed, M., Volk, H., George, S.C., Faiz, M., Stalker, L., 2009. Generation and expulsion of oils from Permian coals of the Sydney Basin, Australia. Organic Geochemistry 40, 810–831.

Alkande, S.O., Hoffknecht, A., Erdtmann, B.D., 1992. Rank and petrographic composition of selected Upper Cretaceous and Tertiary coals of southern Nigeria. International Journal of Coal Geology 20, 209–224.

Allen, J. R. L. (1965). A review of the origin and characteristics of Recent Alluvial sediments.

Sedimentology, Spec. Issue 5, No. 2.

Alias, F.H., Abdullah, W.H., Hakimi, M.H., Azhar, M.H, Kugler, R.L., 2012. Organic geochemical characteristics and depositional environment of the Tertiary Tanjong Formation coals in the Pinangah area, onshore Sabah, Malaysia. International Journal of Coal Geology, 104, 9-12.

Alpern, B., Lemos de Sousa, M.J., Flores, D. (1989). A progress report on the alpren coal classification. Int. Jour. Coal Geol., 13, 1-19.

American Society for Testing and Materials (ASTM), in Annual Book of Standards., 1991: Section 5, Vol. 5.05, Gaseous Fuel, Coal and Coke, ASTM, Philadelphia.

Amijaya, H., Littke, R., 2005. Microfacies and depositional environment of Tertiary Tanjung Enim low rank coal, South Sumatra Basin, Indonesia. International Journal of Coal Geology 61, 197–221.

Anderson, J.A.R., 1983. The tropical peat swamps of Western Malesia. In: Gore, A.J.P. (Ed.), Ecosystems of the World 4B - Mires: Swamp, Bog, Fen and Moor. Elsevier, Amsterdam.

Atherden, M., Hall, J., Wright, J.C., 1993. A pollen diagram from the northeast Peloponnese Greece: implication for vegetation history and archaeology. The Holocene 3, 351-356.

Aquino Neto, F.R., J.M. Trendel, A. Restle, J. Connan and P.A. Albrecht, 1983. Occurrence and formation of tricyclic and tetracyclic terpanes in sediments and petroleums, *in* Organic Geochemistry 1981: Chichester, John Wiley, p. 659-667. Awang Sapawi, A.J., Mona Liza, A., Eric Seah, P.K., 1991. Geochemistry of selected crude oils from Sabah and Sarawak. Bulletin of the Geological Society of Malaysia, 28, 123-149.

Balaguru, A., 2001. Tectonic evolution and sedimentation of the southern Sabah Basin, Malaysia. PhD Thesis, University of London (unpublished), 392pp.

Balaguru, A., 1997. Structure and Sedimentology of the Malibau Area, Sabah. Msc Thesis, National University of Malaysia, Sabah.

Balaguru, A., 1996. Sedimentologi dan stratigrafi batuan sedimen Miosen di Lembangan Malibau, Sabah. Warta Geologi, Geological Society of Malaysia Newsletter, 22(3), 240-241.

Balaguru, A., and Nichols, G., 2004. Tertiary stratigraphy and basin evaluation, Southern Sabah (Malaysian Borneo). Journal of Asian Earth Sciences, 23, 537-554.

Balaguru, A,G., Nichols and R. Hall, 2003. The origin of the "circular basins" of Sabah, Malaysia, Bull. Geol. Soc. Malaysia, 46, May 2003, p. 335-351.

Basir, J., Sanudin, T., Samsuddin, A.R., 1985. Lower Cretaceous from the Chert-Spilite Formation, Kudat, Sabah. Warta Geologi, Geological Society of Malaysia Newsletter 11 (4), 161-162.

Bates, R.L. and Jackson, J.A., 1980. Glossary of Geology. American Geological Institute, Washington, D.C., U.S.A. 416pp

Bordenave, M.L., 1993. Applied Petroleum Geochemistry. Editions Technip, Paris.

Bray, E.E., and Evans, E. D., 1961. Distribution of n- paraffins as a clue to recognition of source beds. Geochemice et Cosmochemica Acta, 22, p. 2-15.

Brock, T.G., Burg, J., Ghosheh, N.S., Kaufman, P.B., (1992). The role of calcium in growth induced by indole-3-acetic acid and gravity in the leaf sheath pulvinus of oat (Avena sativa). J Plant Growth Regul 11:99–103.

Brook, P.W., 1986. Unusual biological marker geochemistry of oils and possible source rock, offshore Beaufort – Mackenzie Delta, Canada, in D. Leythaeuser and J. Rullkotter, eds., Advances in Organic Geochemistry 1985: Oxford, Pergamon, p. 401- 406.

Chandra, K., Mishra, C. S., Samanta, U., Gupta, A., Mehrotra, K. L., 1994. Correlation of different maturity parameters in the Ahmedabad-Mehsana block of the Cambay basin. Organic Geochemistry, 21, 313 – 321.

Chosson, P., Connan, J., Dessort, D.y Lanau, C., 1992. En: Biological markers in sediments and petroleum, Prentice Hall, 320-349.

Clennell, M.B., 1992. The mélanges of Sabah, Malaysia. PhD Thesis, University of London (Unpublisged), (pp. 404).

Clennell, M.B., 1991. The origin and tectonic significance of mélanges in Eastern Sabah, Malaysia. Journal of South East Asian Earth Sciences, 6, 407- 429.

Clifton, C.G., C.C. Walters, and B.R.T. Simoneit., 1990. Hydrothermal petroleums from Yellowstone National Park, Wyoming, U.S.A., Applied Geochemistry, v.5, p.169-191.

Cohen, A.D. and Spackman, W., 1977. Phytogenic organic sediments and sedimentary environments in the Everglades-Mangrove complex. Part II: The origin, description and classification of the peats of South Florida. Paleontographica, Abt. B, 162: 71-I 14.

Collenete, P., 1965. The Geology and Mineral Resources of the Pensiangan and Upper Kinabatangan Area Sabah, Malaysia. Vincent Kiew Fah San, Government Printer.

Connan, J. Cassou, A. M., 1980. "Properties of gases and petroleum liquids derived from terrestrial kerogen at various maturation levels", Geochemica et Cosmochimia Acta, 44, 1-23.

Connan, J., Bouroullec, J., Dessort, D. and Albrecht, P., 1986. The microbial input in carbonate- anhydrite facies of a Sabkah paleoenvironment from Guatemala: A molecular approach. Organic geochemistry, Vol. 10, p. 29- 50.

Curry, D.J., 1994. Variations in the geochemistry of closely interbedded oil-prone coals and shales. American Association of Petroleum Geologists Bulletin 78, 11-40.

Dahl, B. and G.C. Speers, 1985. Organic geochemistry of the Oseberg Field (I), in B.M. Thomas et al., eds., Petroleum Geochemistry in Exploration of the Norwegian Shelf: London, Graham and Trotman, p. 185-195.

Didyk BM, Simoneit BRT, Brassell SC, Eglinton G., 1978. Organic Geochemical indicators of paleoenvironmental conditions of sedimentation. Nature 272: 216-222.

Diesel, C.F.K., 1992. Coal Bearing Depositional Systems. Springer- Verlag, Berlin, 721 pp.

Diesel. C.F.K., 1986. On the correlation between Coal facies and deposition environment advance in study basin. Proc. 20th Symposium, Punbl., 246, 19- 22, In Dissel C.F.K (1992). Coal Bearing Depositional Systems, Springer, Berlin, 721 pp.

Diesel, C.F.K., 1982. An appraisal of coal facies based on maceral characteristics. In: C.W Mallet (ed) Coal Resources. Origin, exploration and utilization in Australia. Sympo. Proc. Geol. Sympo. Proc. Geol. Soc. Austr. In. Coal Group, 474-483.

Diessel, C.F.K., 1965. Correlation of macro- and micropetrography of some New South Wales coals. In: Woodcock, J.T., Madigan, R.T. and Thomas, R.G. (eds.), Proceedings-General, vol.6, 8*th* Commonwealth Mineral and Metallurgy Congress, Melbourne, p.669-677.

Duan Y., Wang Z.P., Zhang H., Zhang X.B., Qian Y.R., and Zheng G.D., 2006. Biomarker geochemistry of crude oils from Qaidam basin, northwestern China [J]. Journal of Petroleum Geology. **29**, 175–188

Eglinton, G. and Hamilton, R.J., 1963. The distribution of alkanes. In: T. Swain (Editor), Chemical Plant Taxonomy, Academic Press, pp. 187-208.

Ekweozor, C.M., Telnaes, N., 1990. Oleanane parameter: Verification by quantitative study of the biomarker occurrence in sediments of the Niger delta. Organic Geochemistry, 16, 401-413.

Ensminger, A., Albrecht, P., Ourisson, G. and Tissot, B., 1977. Evolution of tricyclic alkanes under the effect of burial (Early) Toarcian shales, Paris Basin. In: advances in Organic Geochemistry 1975 (R. Campos and J. Goni, eds.). ENADIMAS. Madrid. p. 45-52.

Esterle, J.S., Ferm, J.C, 1994. Spatial variability in modern tropical peat deposits from Sarawak, Malaysia and Sumatra, Indonesia. Internatioanal Journal of Coal Geology 26, 1-41.

Fan Pu, King, J.D., and Claypool, G. E., 1987. Characteristics of biomarker compounds in Chinese crude oils. In: Petroleum Geochemistry and Exporation in the Afro-Asian Region (R.K Kumar et al., eds.) Balkema, Rotterdam, p. 197-202.

Fitch, F.H., 1958. The geology and mineral resources of the Sandakan area, North Borneo, Malaysia Geological Survey Borneo Region, Memoir 9, 202pp.

Flores, D., 2002. Organic facies and depositional palaeoenvironment of lignites from Rio Maior Basin (Portugal). International Journal of Coal Geology 48, 181–195.

Fowler, M. G., Goodarzi, F., Gentzis, T., Brooks, P. W., 1991. Hydrocarbon potential of middle and upper Devonian coals from Melville Island, Arctic Canada: Organic Geochemistry 17, 681-694.

Franchi, J.G., Motta, J.F.M., Uosukainen, H. & Sigolo, J.B. 2004. Peat in Brazil: geology, reserves, production and use. In J. Paivainen, ed. Wise Use of Peatlands. Proceedings of the 12th International Peat Congress, Tempere. Saarijarvi, IPS, 1: 627-632.

Friederich, M., Esterle, J., Moore, T., Nas, C., 2009. Variations in the Sedimentological Characteristics of Tertiary Coals in SE Asia; and Climatic Influences on Tertiary Coals and Modern Peats. AAPG Hedberg Conference, Jakarta, Indonesia.

Fuller, M., Haston, R., Lin, J.-L., Richter, B., Schmidtke, E., Almasco, J., 1991. Tertiary paleomagnetism of regions around the South China Sea. Journal of Souheast Asian Earth Science 6, 161- 184.

Grantham, P.J., 1986b. Sterane isomeration and moretane/ hopane ratios in crude oils derived from Tertiary source rocks, Organic Geochemistry, v. 9, p. 293- 304.

Grantham, P. J., Posthuma, J., and Baak, A., 1983. Triterpanes in a number of Far-Eastern crude oils. In; Advances in Organic Geochemistry 1981 (M. BjorØy et al., eds.) J. Wiley and Sons, New York, p. 675- 683.

Haile, H. S. and Wong, N. P. Y., 1965. The geology and mineral resources of the Dent Peninsula, Sabah. Br. Borneo Geol. Surv. Mem.16.

Hakimi, M.H., Abdullah, W.H., 2012. Liquid hydrocarbon generation potential from Tertiary Nyalau Formation coals in the onshore Sarawak, Eastern Malaysia. International Journal of Earth Sciences. http://dx.doi.org/10.1007/s00531-012-0793-0.

Hakimi, M.H., Abdullah, W.H., Shalaby, M.R., 2010. Source rock characterization and oil generating potential of the Jurassic Madbi Formation, onshore East Shabowah oilfields, Republic of Yemen. Organic Geochemistry 41, 513–521.

Hall, R., 2002. Cenozoic geological and plate tectonic evoluation of SE Asia and the SW Pacific: computer- based reconstructions, model and animations. Journal of Asian Earth Sciences 20, 353-431.

Hall, R., 1996. Reconstructing Cenozoic SE Asia. In: Hall, R., Blundell D.J. (Eds.), Tectonic Evolution of SE Asia, Geological Society of London Special Publication 106, pp. 153-184.

Hamilton, W., 1979. Tectonics of the Indonesian region. United States Geological Survey Professional Paper, No. 1078.

Hazebroek, H.P., Tan, D.N.K., 1993. Tertiary tectonic evaluation of the NW Sabah continental margin. Bulletin of Geologic Society of Malaysia 33, 195-210.

Hendrix, M.S., Brassell, S.C., Carroll, A.R., Graham, S.A., 1995. Sedimentology, organic geochemistry, and petroleum potential of Jurassic coal measures, Tarim, Junggar, and Turpan Basins, Northwest China. American Association of Petroleum Geologists Bulletin, 79, 929-959.

Hood, A., Gutjahr, C.M., Heacock, R.L., 1975. Organic metamorphism and the generation of petroleum. Bulletin of the American Association of Petroleum Geologist 59(6), 986-996.

Huang, W.Y., Meinschein, W.G., 1979. Sterols as ecological indicators. Geochim. Cosmochim. Acta, 43, 739-745.

Huang, W.Y., Meinschein; W.G., 1976. Sterols as source indicators of organic materials in sediments. Geochimica Cosmochima. Acta, 40, 323-330.

Hunt, J.M., 1996. Petroleum Geochemistry and Geology, Second Edition. W.H. Freeman, San Francisco.

Hunt, J.M., 1991. Generation of gas and oil from coal and other terrestrial organic matter. Organic Geochemistry, 17, 673-680.

Hunt, J.M., 1984. Generation and migration of light hydrocarbons. Science, 226, p. 1265-1270.

Hutchison, C.S., 1996. The 'Rajang Accretinary Prism' and 'Lupar Line' Problem of Borneo, in R. Hall and D.J. Blundell, (eds.), Tectonic Evolution of SE Asia, Geological Society of London Special Publication, p. 247-261.

Hutchison, C.S., 1989. Geological evolution of South-East Asia, Oxford, Monographs on Geology and Geophysics 13, 376pp..

Hutchison, C.S., 1988. Stratigraphic- Tectonic Model for Eastern Borneo. Geol. Soc. Malaysia Bull., 22, p. 135-141

Hutchison, C. S. 1978. Ophiolite metamorphism in Northeast Borneo .Lithos 11, 195-208.

Hutchison, C. S. 1975. Ophiolite in Southeast Asia. Geol. Soc. Am.Bull. 86, 797-806.

ICCP International Committee for Coal Petrology, 1971. International Handbook of Coal Petrography, 1st supplement to 2nd edition. Centre Nationalde la Recherche Scientifique, Paris, France.

Ismail Che Mat Zin. (1994). Dent Group and its equivalent in the offshore Kinabatangan area, East Sabah. Bulletin of the Geological Society of Malaysia, 36, 127-143.

Kalkreuth, W., Marchioni, D., Utting, J., 2000. Petrology, palynology coal facies, and depositional environments of an Upper Carboniferous coal seam, Minto Coalfield, New Brunswick, Canada. Canadian Journal of Earth Science 37, 1209–1228.

Kalkreuth., W.D. Marchioni D.. Calder J.H., Lamberson M.N. Naylor R.D. and Paul J., 1991. Relationship between coal petrography and depositional environments from selected coal basins in Canada. Int. Jour. Coal Geol. 19, 21-76.

Kalkreuth, W. and Leckie, D.A., 1989. Sedimentological and petrographical characteristics of Cretaceous strandplain coals: a model for coal accumulation from the North American Western InteriorSeaway, International Journal of Coal Geology, 12: 381-424.

Kashirtsev, V.A., Moskvin, V.I., Fomin, A.N., Chalaya, O.N., 2010. Terpanes and steranes in coals of different genetic types in Siberia. Russian Geology and Geophysics 51, 404–411.

Killops S.D. and Killops, V.J., 1993. An Introduction to Organic Geochemistry,. Longman, Harlow.

Koeverden, J.H.V., Karlsen, D.A., Backer-Owe, K., 2011. Carboniferous non-marine source rocks from Spitsbergen and Bjørnøya: comparison with the western Arctic. Journal of Petroleum Geology 34 (1), 53–66.

Korkmaz, S., Kara Gülbay, R., 2007. Organic geochemical characteristics and depositional environments of the Jurassic coals in the eastern Taurus of Southern Turkey. International Journal of Coal Geology 70, 292–304.

Kvenvolden, K.A. and B.R.T. Simoneit., 1990. Hydrothermally derived petroleum: examples from Guaymas basin, Gulf of California, and Escanaba Trough, northeast pacific Ocean, Bulletin of the American Association of Petroleum Geologists v. 74, p. 223-237.

Lamberson, M.N., Bustin, R.M., Kalkreuth, W., 1991. Lithotype (maceral) composition and variation as correlated with paleowetland environments. Gates Formation, Northeastern British Columbia, Canada. International Journal of Coal Geology 18, 87–124.

Large, D. J., Gize, A. P., 1996. Pristane/phytane ratios in the mineralized Kupferschiefer of the Fore-Sudetic Monocline, Southwest Poland. Ore Geology Reviews 11, 89-103.

Leong, K.M., 1974. The geology and mineral resources of the Upper Segama Valley and Darvel area, Sabah, Malaysia. Geological Society of Malaysia Memoir 4, 354pp.

Levine, K.D., 1993. Self- Confirming Equilibrium. Econometria 61, 523- 545.

Lijmbach, G.W.M., 1975. "On the origin of petroleum", Proc. 9th World Petrol. Cong.2, 357-369.

Littke, R., Horsfield, B., Leythaeuser, D., 1989. Hydrocarbon distribution in coals and in dispersed organic matter of different maceral compositions and maturities. Geologische Rundschau 78 (1), 391–410.

Lyell, C. (1865). "Elements of Geology." John Murray, London. 794pp.

Lyons, P.C., and Alpern, B., eds., 1989. Peat and Coal: Origin facies and depositional models: International Journal of Coal Geology, v.12, 798p.

Mackenzie, A.S. and., 1984. Applications of biological markers in petroleum geochemistry, in J. Brooks and D. Welte, eds., Advances in Petroleum Geochemistry, Volume 1: London, Academic Press, p. 115-214.

Mann, A. L., Goodwin, N.S. and Lowes, S., 1987. Geochemical characteristic of lacustrine source rocks: A combined palynological/ molecular study of study of a Tertiary sequence from offshore China. In: Proceedings of the Indonesian Petrol. Assoc., 6th Ann. Conv. Jakarta, Indonesian Petrol Assoc., Vol. 1, p. 241-258.

Marzi. R. and Rullkotter.J., 1992. Qualitative and quantities evoluation and kinetics of biological marker transformatios- laboratory experiments and application to the Michigan basin. In: Biological Markers in sediment and petroleum (J.M. Moldowan, P. Albrecht, and R.P. Philp, eds.) Prentice Hall, Englewood cliffs, N.J., P.18-41).

Martini, I.P. & Glooschenko, W.A., 1985. Cold climate peat formation and its relevance to Lower Permian coal measures of Australia, Earth- Sci. Rev., 22, 107-140.

McCabe, P.J., and Parrish, J. T., 1992. Tectonic and climatic controls on the distribution and quality of Cretaceous coals, in McCabe, P.J., and Parrish, J.T., eds., Controls on the Distribution and Quality of Cretaceous Coals, Geologic Society of America Special Paper 267, p. 1-16.

McCabe, P.J., 1987. Facies studies of coal and coal-bearing strata. In: Scott, A.C. (ed.), Coal and Coal-bearing Strata: Recent Advances. Geological Society of London, Special Publication, 32, p.51-66.

McCartney, J.T., Teichmuller, M., 1972. Classification of coals according to degree of coalification by reflectance of the vitrinite component. Fuel, 64–68.

Michaelis, W., A. Jenisch, and H.H. Richnow., 1990. Hydrothemal petroleum generation in Red Sea sediments from the Kebrit and Shaban Deeps, Applied Geochemistry, v.5, p. 103-114.

Moldowan, J.M. and Fago, F.J., 1986. Structure and significance of a novel rearranged monoaromatic steroid hydrocarbon in petroleum. Geochimica et Cosmochimica Acta, 50, 343-351.

Moldowan, J.M., Dahl, J., Huizinga, B. and Fago, F., 1994. "The molecular fossil record of oleanane and it's relation to angiosperm. Science, 265, 768-771.

Moldowan, J. M., Sundararaman, P., Salvatori, T., Alajbeg, A. Gjukie, B., Lee, C.Y. and Demaison, G.J., 1992. Source correlation and maturity assessment of selected oils and rocks from the Central Adriatic Basin (Italy and Yugoslavia). In: Biological Markers in Sediments and Petroleum (J.M. Moldowan, P. Albrecht, and R. P. Philp, eds) Prentice Hall, England Cliffs, N.J., P. 370-401.

Moore, P.D., 1989. The ecology of peat-forming processes: a review. *International Journal of Coal Geology*, 12, p.89-103.

Moore, P.D., 1987. Ecological and hydrological aspects of peat formation. *In*: Scott, A.C. (ed.), Coal and Coal-bearing Strata: Recent advances. *Geological Society of London, Special Publication*, 32, p.7-15.

Moore, P. D. & Bellamy, D.J., 1974. Peatlands. Elek Science, London. 221 pp.

Mukhopadhyay, P.K., 1994. Vitrinite reflectance as maturity parameter. Petrographic and molecular characterization and its application to basin modeling. In: Mukhopadhyay, P.K., Dow, W.G. (Eds), Vitrinite reflectance as Maturity Parameter; Applications and Limitations. ACS Symp. Ser., vol. 570, pp. 1- 24.

Mukhopadhay, P.K., Hatcher, P.G., 1993. Composition of coal. In: Law, B.E, Rice, D.D (Eds.) Hydrocarbons from coal. American Association of Petroleum Geologists Studies Geology 38, 79-118.

Mukhopadhyay, P.K., Hatcher, P.G., Calder, J.H., 1991. Hydrocarbon generation from deltaic and intermontane fluviodeltaic coal and coaly shale from the Tertiary of Texas and Carboniferous of Nova Scotia. Organic Geochemistry 17, 765–783.

Murchison, D.G., 1987. Recent advances in organic petrology and organic geochemistry: an overview with some reference to "oil from coal". Geological Society Special Publication, 32, 257-302.

Murray, A.P., Sosrowidjojo, I.B., Alexander, R., Kagi, R.I., Norgate, C.M., Summons, R.E., 1997. Oleananes in oils and sediments: Evidence of marine influence during early diagenesis? Geochimica et Cosmochimica Acta 61, 1261–1276.

Obaje, N. G., Hamza, H., 2000. Liquid hydrocarbon source-rock potential of mid-Cretaceous coals and coal measures in the Middle Benue Trough of Nigeria. International Journal Earth Science, 89, 130-139.

Ogala, J. E., 2011. Source rock potential and thermal maturity of the Tertiary lignite series in the Ogwashi-Asaba Formation Southern Nigeria. Asian Journal of Earth Sciences 4, 157-170.

Ourisson, G., Albrecht, P. and Rohmer, M., 1982. Predictive microbial biochemistryfrom molecular fossils to prokaryotic membranes. Trends in Biol. Sciences, 236-239.

Peakman, T.M. and J.R. Maxwell., 1988. Early diagenetic pathways of steroid alkenes, in L. Mattavelli and L. Novelli, eds., Advances in Organic Geochemistry 1987: Oxford, Pergamon Press, p. 583- 592.

Peakman, T. M., Ten Haven, H. L., Rechka J.R., De Leeyv, J. W., and Maxwell, J. R., 1989. Occurrence of (22R) and (22R)- $\Delta 8$ (H) and $\Delta 14$ (H)- Steranes and the origin of 5 α (H). 14 β (H)- steranes in an immature sediment. Geoch. Et Cosm. Acta. Vol. 53, PP. 2001-2009.

Peters, K. E., Walters, C. C., Moldowan, J. M., 2005. The Biomarker Guide, second ed. Cambridge University Press, Cambridge, UK., 1155 p.

Peters, K. E., Cassa, M. R., 1994. Applied source rock geochemistry. In: Magoon, L.B., Dow, W.G. (Eds.), the Petroleum System – From Source to Trap. American Association of Petroleum Geologists Memoir, 60, 93 – 120.

Peters, K.E., Kontorovich, A.E., Moldowan, J.M., et al., 1993. Geochemistry of selected oils and rocks from the central portion of the West Siberian Basin, Russia. American association Of Petroleum Geologist Bulletin, 77, 863-87.

Peters K.E., Fraser T.H., Amris W., Rustanto B., and Hermanto E., 1999. Geochemistry of crude oils from eastern Indonesia [J]. American Association of Petroleum Geologists Bulletin. 83, 1927–1942.

Philp R.P., 1994. Geochemical characteristics of oil derived predominantly from terrigenous source materials. In Coal and Coal-bearing Strata as Oil Prone Source Rocks? (eds. Scott A.C. and Fleet A.J.) (Geol. Soc.Special Publication) [M]. The Geological Society, London. **77**, 71–91.

Philp, R.P., 1985. Fossil Fuel Biomarker: Amsterdam, Elsevier, 294 p.

Philp, R.P. and Gilbert, T.D., 1986. Biomarker distributions in Austalian oils predominantly derived from terrigenous source material. Organic Geochemistry, 10, 73-84.

Powell, T.G., Boreham, C.J., 1994. Terrestrially sourced oils: where do they exist and what are our limits of knowledge? a geochemical perspective. In: Scott, A.C., Fleet, A.J. (Eds.), Coal and coal-bearing strata as oil-prone source rocks? Geological Society Special Publication 77, London, pp. 11-29.

Powell T.G and Makriday D.M., 1973. Relationships between ratio of pristine to phytane, rude oil composition and geological environments in Australia [J]. Nature. **243**, 37–39.

Rahman, R. A., and Flores, R. M. (1984). "Sedimentology of Coal and Coal-bearing Sequences,"Spec. Publ. No. 7. Int. Assoc. Sedimentol. Blackwell, Oxford. 417pp.

Rangin C., and Silver E., 1990. Geological setting of the Celebes and Sulu Seas. In: Rangin, C., Silver, E., von Breymann, M.T., et al. Proceedings of the Ocean Drilling Program, Scientific Result, Vol. 124. Pp. 35-42.

Reineck, H. and Singh, I., 1980. Depositional Sedimentary Environments. Springer-Verlag, New York, 550p.

Robinson, A., 1987. An overview of source rock in Indonesia. In: Proceedings of the Indonesia Petroleum Association (pp. 97-122), Jakarta, Indonesia.

Rongxi, L, Kuili, J., Daniel, J. L., 2008. Hydrocarbon potential of Pennsylvanian coal in Bohai Gulf Basin, Eastern China, as revealed by hydrous pyrolysis. International Journal of Coal Geology 73, 88–97.

Selley, R. C., 2000. Applied sedimentology, Academic Press, San Diego.Selley, R. C., 1996. Ancient Sedimentary Environments and Their Sub- surface Diagnosis.p. 43-181.

Schorph, J.M., 1956. A definition of coal. Econ. Geol. 51, 521-527.

Scott, A.C., Fleet, A.J., 1994. Coal and coal-bearing strata as oil-prone source rocks: current problems and future directions. In: Scott, A.C., Fleet, A.J. (Eds.), Coal and coalbearing strata as oil-prone source rocks? Geological Society Special Publication 77, London, pp. 201-205.

Scott, A.C. & Collinson, M. E., 1978. Organic sedimentary particles: result from scanning electron microscope studies of fragmentary plant material. In: Scanning Electron Microscopy in the study of sediments (ED. By W. B. Whalley), pp. 137-168. Geo Abstracts, Norwich.

Seifert, W. K. and Moldowan, J. M., 1986. Use of biological markers in petroleum exploration. In; Methods in Geochemistry and Geophysics (R. B. Jhons, ed.), 24, p. 261-290.

Seifert, W.K and Moldowan, J.M., 1980. The effect of thermal stress on source-rock quality as measured by hopane stereochemistry. Physics and Chemistry of the Earth, 12, 229-37.

Shier, C.W., 1985. Tropical peat resources- an overview. Proceeding of Tropical peat resources- Prospects and Potentials Symposium, Kingston, Jamaica, 1985. International Peat Society, Helsinki University Press. pp. 29-46.

Shimada, H., 2005. It's time Brazil finds and uses its peat. Brazil Magazine, June.

Sia, S.G., Abdullah, W.H., 2012. Geochemical and petrographical characteristics of lowrank Balingan coal from Sarawak, Malaysia: Its implications on depositional conditions and thermal maturity. International Journal of Coal Geology 96, 22-38.

Simoneit, B.R.T., 1990. Petroleum generation, an easy and widespread process in hydrothermal systems: an overview, Applied Geochemistry, v.5, p. 3-15.

Simoneit, B.R.T., P.F. Lonsdale, J.M. Edmond, and W.C. Shanks III., 1990. Deep-Water hydrocarbon seeps in Guaymas basin, Gulf of California, Applied Geochemistry, v.5, p. 41-49.

Silva, M.B., Kalkreuth, W., 2005. Petrological and geochemical characterization of Candiota coal seams, Brazil — implication for coal facies interpretations and coal rank. International Journal of Coal Geology 64, 217–238.

Shantzer, E. V., 1951. Alluvium of river plains in a temperate zone and its significance for understanding the laws governing the structure and formation of alluvial suites. Akad. Nauk. S.S.S.R. Geol. Ser. 135, 1-271.

Shanmugam, G. 1985. Significance of coniferous rain frost and related organic matter in generating commercial quantities of oil, Gippsland basin, Australia. AAPG Bull., 69:1241-1254.

Snowdon, L.R., 1995. Rock-Eval Tmax suppression: documentation and amelioration. American Association of Petroleum Geologists Bulletin 79 (9), 1337–1348.Stach, E., Mackowsky, M.T., Teichmüller, M., Taylor, G.H., Chandra, D., Teichmüller, R., 1982. Stach's textbook of coal petroloy. Borntraeger, Berlin.

Stach, E., Mackowsky, M- Th., Teichmuller, M., Taylor, G.H., Chandra, D., and Teichmuller, R., 1982. Stach's textbook of Coal Petrology. Gebruder Borntraeger, Berlin-Stuttgart, 535pp.

Staub, J.R., Esterle, J.S. and Raymond, A.L., 1991. Comparative geomorphic analysis of Central Appalachian coal beds and Malaysia peat deposits. Bulletin Geol. Soc. France, v. 162(2), 339-351.

Stopes, M. C., 1935. On the petrology of banded bituminous coals: Fuel, v. 14, p. 4-13.

Tahir, S. and Mazlan, G., 1990. Effects on the mud volcano activity on the morphology of the Pulau Tiga. Sains Malaysiana 20(1), 91-102.

Tan, D.N.K., and Lamy, J.M., 1990. Tectonic evaluation of the NW Sabah continental margin since the Late Eocene. Geol. Soc.Malaysia, Bull., 27, pp. 241-260.

Tan, D.N.K., 1982. The Lubuk Antu Melange, Lupar Valley, West Sarawak. A lower Tertiary subduction complex. Geol. Soc. Malay. Bull., 15, 31-46.

Taylor, B., Hayes D.E., 1983. Origin and history of South China Sea Basin. In; Hayes D.E (ed), The Tectonic and Geology Evaluation of Southeast Asian Seas and Islands Part 2. Geophysical Monograph Series, vol. 27. American Geophysical Union. pp. 23-56

Teicmuller, M., Littke, Robert, P., (1998). Coalification and Maturation. In Organic Petrology. Gebrüder Borntraeger. p. 86-174.

Teichmuller. M., 1989. The genesis of coal from the view point of coal petrology.Int. journal Coal Geol 12. 1-87.

Teichmüller, M., 1982. The geological basis of coal formation. In: Stach, E., Mackowsky, M-Th., Teichmüller, M., Taylor, G.H., Chandra, D., and Teichmüller, R. (Eds.), Stach's Textbook of Coal Petrology. Gebrüder Borntraeger, Berlin, 3rd ed., p.5-86.

Teichmuller, M., 1974. Generation of petroleum-like substances in coal seams as seen under the microscope, in Tissot, B. and Gienner, F. (Eds.), Advances in Organic Geochemistry 1973, (pp 321-348).

Teichmüller, M., 1972. Classification of coals according to degree of coalification by reflectance of the vitrinite component. Fuel, 51, 64-64.

Teicmuller. M., 1958. Metamorphisme du charbon et prospection du petrol. Rev, Ind. Mineral, special issue, 1-15.

Ten Haven, H. L., and Rullkotter, J., 1988. The diagenetic fate taraxer-14-ene and oleanane isomers. Geochemica et Cosmochemica Acta, 52, p. 853-855.

Ten Haven, H. L., De Leeuw, J. W., Rullkotter, J. and Sinninghe Damste, J. S., 1987. Restricted utility of the pristine/ phytane ratio as a paleoenvironment indicator. Nature, Vol. 330, p. 641-643.

Ten Haven H.L, de Leeuw J.W., Peakman, T.M. and axwell, J.R., 1986. Anomalies in steroid and hopanoid maturity indices. Geoch et Cosm. Acta, 50, 853-855.

Thompson, S., Cooper, B., Morely, R.J., Barnard, P.C., 1985. Oil generating coals. In: Thomas, B.M., et al. (Ed.), Petroleum Geochemistry in Exploration of the Norwegian Shelf. Graham & Trotman, London, pp. 59–73.

Tissot, B.P. and Welte, D.H., 1984. Petroleum Formation and occurrence. Springer-Verlag, New York.

Tongkul, F., 1995. The Paleogene basins of Sabah, East Malaysia. In: Teh, G.H., (Ed.), Proceedings of the AAPG-GSM International Conference 1994. Southeast Asian Basins: Oil and gas for the 21st Century, Bulletin of the Geological Society of Malaysia 37, pp. 301–308.

Tongkul, F., 1991. Tectonic evolution of Sabah, Malaysia. Journal of Southeast Asian Earth Sciences. Special Issue: Orogenesis in Action Tectonics and Processes at the West Equatorial Pacific Margin 6 (3/4), 395–406.

Tongkul, F., 1990. Structural styles and tectonics of Western and Northern Sabah. Bull. Geol. Soc. Malaysia 27, 227- 240.

Tongkul, F., 1989c. Geological control on the birth of the Pulau Batu Hairan mud volcano, Kudat, Sabah. *Warta Geologi* 14(4), 153-165.

Tongkul, F., 1989b. Recent strike-slip fault movement associated with a mud volcano in the Lahad Datu area. Sains Malaysiana 18, 23-31.

Tyson, R.V., 1995. Sedimentary Organic Matter. Organic Facies and Palynofacies. Chapman & Hall, London.

van Graas, G.W., 1990. Biomarker maturity parameters for high maturities: calibration of the working range up to the oil/ condensate threshold, Organic Geochemistry, v. 16, p. 1025-1032.

Villar, H. J. W. Puttmann, and M. Wolf, 1988. Organic geochemistry and petrography of Tertiary coals and carbonaceous shales from Argentina, in L. Mattavelli and L. Novelli, eds., Advance in Organic Geochemistry 1987: Oxford, Pergamon Press, p. 1011-1021.

Volkman, J.K., 1988. Biological marker compounds as indicators of the depositional environments of petroleum source rock, in A.J. Flee, K. Kelts, and M.R. Talbot, eds., Lacustrine Petroleum Source Rocks: Oxford, Blackwell, p. 103-122.

Volkman, J.K., 1986. A review of sterol biomarkers for marine and terrigenous organic matter, Organic Geochemistry, v. 9, p. 83-99.

Wan Hasiah, A., 2003. Coaly source rocks of NW Borneo: role of suberinite and bituminite in oil generation and expulsion. Geological Society of Malaysia Bulletin 47, 153-163.

Wan Hasiah A., 2002. Organic petrological characteristic of limnic and paralic coals of Sarawak. Geol. Soc. Malaysia Ann. Geol. Conf. 26- 27 May 2002, Kota Bharu, Kelantan, Malaysia, p. 65-69.

Wan Hasiah A., 1999. Oil generating potential of the Tertiary coals and other organic rich sediments of the Nyalau Formation, onshore Sarawak. Journal of Asian Earth Science, 17, 255-267.

Wan Hasiah, A., 1997. Common liptinitic constituents of Tertiary coals from the Bintulu and Merit- Pila Coalfield, Sarawak, and their relation to oil generation from coal. Bull. Geol. Soc. Malaysia, 41, Dec. 1997, p. 87-93.

Wan Hasiah, A., 1994. A regional organic geochemical evoluation of sedimentary rocks of Spitsbergen and their hydrocarbon potential. Ph.D. thesis, University of Newcastle upon Tyne.

Wan Hasiah A., 1992. An organic petrological and organic geochemical study of North Sea Middle Jurassic Brent Coals and coaly sediment. Bull. Geol. Soc. Malaysia 32, Spec. Iss. On Petrol. Geol., vol. III, p. 155-164.

Wan Hasiah, A., Abolins, P., 1998. Organic petrological and organic geochemical characterization of the Tertiary coal-bearing sequence of Batu Arang, Selangor, Malaysia. Journal of Asian Earth Sciences 16 (4), 351–367.

Waples, D.W., Machihara, T., 1991. Biomarkers for geologists- a practical guide to the application of steranes and triterpanes in petroleum geology. Methods in Exploration series. American Association of petroleum Geologists No. 9 (pp 85).

Wilson, R.A.M., Wong, N.P.Y., 1964. The geology and mineral resources of the Labuan and Padas Valley areas, Sabah, Geological Survey of Malaysia, Borneo Region, Memoir 17, 150pp.

Winters, J.C. and Williams, J.A., 1971. Microbiological alteration of crude oil in Muddy sandstone and other reservoir (abs.): Am. Assoc. Petroleum Geologist Bull., 55(2): 369.

Zakir, H.M., Islam, M.M., Shamsuddin, A.H.M., Hossain, I., 2002. Analysis of sedimentary facies and depositional environments of the Permian Gondwana sequence in borehole GDH- 45, Khalaspir Basin, Bangladesh. Geoscience Journal. V. 6p. 227- 236.

Zulkifli, S., Awang, S. A. J., Kamal, R. M., Che Aziz A., 2008. Hydrocarbon generation potential of the coals and shales around the Eucalyptus Campsite area, Maliau Basin, Sabah. Geological Society of Malaysia, Bulletin 54, 147 – 158.

Zhou, Y., Sheng, G., Fu, J., Geng, A., Chen, J., Xiong, Y., Zhang, Q., 2003. Triterpaneand sterane biomarkers in the YA13- 1 condensates from Qiongdongnan Basin, SouthChinaSea.ChemicalGeology199,343-35