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ORIGINS OF OILS AND GASES AT BANGGAI – SULA MICROCONTINENT, EASTERN SULAWESI – NORTH MOLUCCAS: CONSTRAINTS FROM BIOMARKERS AND ISOTOPE GEOCHEMISTRY – IMPLICATIONS FOR FURTHER EXPLORATION OF CENOZOIC AND PRE-CENOZOIC OBJECTIVES

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ABSTRACT

Banggai Basin with its productive Miocene objectives in Eastern Sulawesi has positioned as foreland basin since Mio-Pliocene time, when the collision of Banggai-Sula microcontinent and East Sulawesi Ophiolite Belt took place. To the east of the basin there is Sula (Taliabu-Mangole) platform preserving Pre-Cenozoic grabens (Sula Basin). Before the collision, the Banggai-Sula microcontinent drifted to its present area bringing syn-rift Jurassic passive margin siliciclastic sediments and Cretaceous to Miocene syn-drifting carbonates. All of these rocks have been potential to be elements (sources, reservoirs, seals, overburdens) and processes (trap formation, petroleum generation-migration) of petroleum system. Collision of the microcontinent significantly affected all processes of petroleum system.

This study is based on geochemical characteristics of oils (bulk properties, isotopes, biomarkers) and gases (carbon and deuterium isotopes) and rock geochemistry of expected Cenozoic and Pre-Cenozoic sources. The study investigates the origins of existing oils and gases in the Banggai-Sula microcontinent. Existing and new data oils and gases from wells, fields, and seeps as well as rock geochemistry of well cuttings and outcrops are examined.

This study reveals that all oils in the Banggai Basin are sourced by Early Miocene Tomori carbonates and shaly carbonates (resulting in type "A" oils) and Middle Miocene Matindok shales and calcareous shales (resulting in type "B" oils). As for the gases, isotope data show that gases in the Banggai Basin are products of both thermal cracking of oils and primary gas generation from Miocene source rocks with humic kerogens. No significant evidence of petroleum contribution from Pre-Cenozoic source rocks in the Banggai Basin. However, gas seepages in the Sula Basin are geochemically related to generation from Pre-Cenozoic source rocks deposited in graben areas of offshore Taliabu-Mangole Shelf.

This study points towards new directions for further exploration in the Banggai-Sula area, both Cenozoic and Pre-Cenozoic objectives can be exploration targets.

INTRODUCTION

The Sulawesi Islands in Central Indonesia were assembled by a collision of terranes and have been modified by post-collision escape tectonics (Figure 1, Satyana, 2006). The collision of the two microcontinental blocks of Buton-Tukang Besi and Banggai-Sula with the eastern part of the island during the Miocene initiated the Neogene orogeny in Sulawesi (Simandjuntak and Barber, 1996). The collision of the microcontinents formed collisional foreland basins of Buton and Banggai respectively, which bear petroleum and productive. The formation of the foreland basins relates to the collision of the microcontinents in this area and was discussed first by Davidson (1991) for Buton, and by Garrard et al. (1988) for Sula and Davies (1990) for Banggai. Updated evaluation on petroleum geology of Banggai Basin was provided by Hasanusi et al. (2004) and Satyana et al. (2013) for Buton Basin.

Gas and oil fields have been discovered in the Banggai Basin (Figures 2, 13, 14), including: the Minahaki, Matindok, Senoro, Donggi, Sukamaju, and Maleo Raja gas fields; and the Tiaka oil field. The play types recognized in the Banggai collision zone are: (1) carbonate reefal build ups, (2) thrust-sheet anticlines, (3) wrench related anticlines, and (4) thrusted anticlines of basement related faults (Hasanusi et al., 2004). The Miocene carbonate reefal build up play type is the largest stratigraphic

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play as proved by discoveries in the Minahaki, Senoro, Donggi, Sukamaju, and Maleo Raja gas fields. The trap is related to pre-collision tectonics where reefal build ups grew at the front of the Banggai-Sula microcontinent during its drifting to the present area. The thrust-sheet anticline play type involves structural closures at the leading edges of a series of imbricated collisional thrust sheet of the Miocene platform carbonates. The trap is related to collision and post-collision tectonics. The Tiaka oil field proves this play type. The wrench fault anticline play type involves thrusted anticlines where traps have been formed as en echelon folds along strike-slip faults formed during Pliocene post collision escape tectonics. The Matindok discovery and southern Senoro field prove this play type. The play of thrusted anticlines related to basement faults is observed in the Taliabu shelf, Sula islands. Pre-Cenozoic sediments were deposited as a syn-rift sequence in grabens of the Banggai-Sula microcontinent. When collision of the micro-continent took place in the Late Miocene, the rift grabens were overprinted by compressional tectonics resulting in thrusted anticlines. Some thermogenic gas and minor oils seep occurred in this area (Figures 2, 15) (Garrard et al., 1988).

Hasanusi et al. (2004) updated the petroleum system of the Banggai Basin. There are two potential hydrocarbon source rock sequences recognized in the Tomori area: Jurassic marine shales and Miocene marine shales and coals. However, geochemical analyses to date indicate that oil seeps and all of the oils and gas tested from the wells are most likely related genetically to shales and coals within the Early to Middle Miocene Tomori Formation. Hydrocarbon generation commenced during the Early-Middle Pliocene due to burial of the source rocks by rapidly deposited Pliocene sediments and loading by thrust sheets. Proven and potential reservoirs are provided by Miocene carbonates of the Tomori Formation and the Minahaki Formation, including the Mantawa Member reefal facies limestones, which contain excellent porosity and permeability. Bathyal shales of the Pliocene Kintom Formation, at the base of the post-tectonic sediments of the Sulawesi Group provide an effective regional seal for the Miocene carbonate reservoirs.

The origin of oils have been investigated since the publication of Davies (1990) for Banggai Basin and Garrard et al. (1988) for Sula Basin. Based on the organic geochemistry, Davies (1990) concluded that the oils of Banggai Basin are correlated to Miocene sections of carbonates and clastics coals source rocks. As for Sula Basin, surface geology, seismic and well data show that the Sula Basin Pre-Cenozoic sections which regionally can be analogue to Pre-Cenozoic sections developed in Northwest Shelf of Australia and Eastern Indonesia. This can be understood since before rifting and drifting, the Banggai-Sula microcontinent was part of northern Gondwana (Australoid) with its Pre-Cenozoic sedimentary rocks. Buton microcontinent also bears Pre-Cenozoic sections and its Triassic Winto marine shales are the proven source rocks for Buton biodegraded oils/ asphalt deposits (Satyana et al., 2013). Pre-Cenozoic source rocks are exposed to the west of Banggai Basin, showing its existence. However so far it is known there is no petroleum contribution from Pre-Cenozoic sections into Banggai Basin.

This paper will update the understanding of the petroleum geochemistry of the Banggai and Sula Basins. It investigates the origins of oils and gases in the basin based on previous and new geochemical analyses and interpretation, examining the contribution of Pre-Cenozoic sections. Knowing the origin of petroleum will definitely affect petroleum system analysis and eventually, exploration strategy. The Banggai Basin and mainly Sula Basin have not yet been fully explored and have therefore a remaining exploration potential in various objectives ranging from Pre-Cenozoic to Late Cenozoic

DATA & METHODS

Geochemical data from previous publications and new analyses form the main body of data for this study. Oils, condensates, and gases from wells of fields, discovery wells, and seeps have been analyzed. The oil analyses include bulk properties of oils (API gravity, wax, sulfur, metal content), biomarkers in saturates and aromatics and carbon istopes of oils. The gas analyses include gas composition and isotopes of carbon and deuterium. Geologic data of Banggai and Sula Basins based on surface geology, well data, and seismic were used to synthesize with geochemical analyses and interpretation.

Bulk properties, biomarkers, and isotopes of oils reflect the geologic and geochemical parameters of their sources, including: organic matter, source depositional environment, source lithology, source maturity, source age, and migration history (using geochemical inversion method, Bissada et al., 1992). Based on these parameters, the oils can be grouped. Gas composition and carbon-deuterium isotopes of gases reflect the genetic types of gas and their relation to existing oils.

After knowing the origins or grouping of oils and genetic types of gases, petroleum geology and petroleum system analysis of the Banggai and Sula Basins are discussed. The results provide inputs for further exploration or building new play concepts of the basins.

RESULTS & DISCUSSIONS

Pre-Cenozoic to Cenozoic Tectono-Stratigraphy of the Banggai-Sula Microcontinent

The Banggai and Sula Islands, encompassing the main islands of Peleng, Banggai,Taliabu, Mangoleand Sanana located east of Sulawesi and immediately north of the North Banda Basin (North Moluccas), are widely believed to have originated in the Australia-New Guinea region and to have been transported as a microcontinent to their present position colliding the East Arm of Sulawesi – Figure 3 (Hamilton,1979; Garrard et al., 1988; Davies, 1990). Satyana and Purwaningsih (2011) reviewed the mechanism of the collision proposed by previous authors.

Garrard (1988) detailed the detachment and emplacement of the Banggai-Sula microcontinent, interpreted to be a fragment of the north Australia-New Guinea continent. This is supported by similarities in the age and type of basement, in the Pre-Cenozoic stratigraphy and in the age of a Pre-Cenozoic unconformity that marks the beginning of rifting from northern Australia and New Guinea. During the late Pre-Cenozoic the Banggai-Sula micro-continent broke away and drifted west towards the Asiatic Plate. This extensional period is represented by a transgressive phase of continental to shallow marine Jurassic clastics overlain by deeper water anoxic shales. Essentially passive margin sedimentation took place through the Cretaceous and into the Cenozoic during the drifting westwards. Bathyal conditions probably existed with little clastic sediment input on the micro-continent. Figure 4 shows the stratigraphy of Banggai and Sula Basins overlying the microcontinent. The sequence begins with an early Jurassic continental to shallow marine coarse clastic formation (Bobong) and is then followed by deeper marine argillaceous facies (Buya). Late Cretaceous to Paleocene deep water carbonates (Tanamu Formation) represent the top of the sequence. Deposition is believed to have taken place initially within a rift-graben setting, followed by restricted shallow marine conditions and finally by subsidence and open, deep water marine conditions. Rock sections (Tomori, Matindok, Minahaki, Mentawa) of Cenozoic age follow unconformably and are dominated by shallow water platform carbonates. There then followed an Oligocene-Middle Miocene phase of carbonate deposition onto a stable shelf area covering all of Banggai-Sula. Localized reef growth occurred around the margins of the microcontinent, whilst deeper water, low-energy carbonate deposition occurred to the west of the reefal build-ups under what is now the eastern arm of Sulawesi (Davies et al., 1990; Hasanusi et al., 2004).

The collision of Banggai-Sula with the Asiatic Plate took place from Middle Miocene to Pliocene (Garrard et al., 1988) and resulted in Asiatic oceanic crust, the Sulawesi ophiolites, being overthrusted to the east onto the Banggai-Sula micro-continent. Overthrusting of the ophiolites onto the western edge of Banggai-Sula micro-continent occurred in the latest Miocene (Davies, 1990) indicating that collision of the Sula platform with East Sulawesi must have occurred at 5 Ma (end of Miocene). This compressive episode was responsible for producing imbricate thrust structures developed mainly in foreland Banggai Basin. Following overthrusting and uplift of eastern Sulawesi, eastward directed molasse deposition of the Kintom Formation began in the Early Pliocene. Pliocene and Pleistocene molasse sediments prograded eastward and filled basinal areas west of Peleng Island. Elsewhere, Late Pliocene to Pleistocene normal faulting, caused partly by relaxation of earlier compressive stresses, resulted in subsidence of the Peleng Strait. The uplift of Peleng, Banggai and Taliabu Islands appears to have been a relatively recent event. Present-day erosion has left the Miocene exposed on West Peleng and Jurassic and Basement exposed on East Peleng and Banggai Island. The uplift and exposure of late Cretaceous and Paleocene sediments occurred only in northern Taliabu and Mangole (Garrard et al., 1988).

Basis for Oil Grouping

In order to simplify the understanding of crude oil characteristics and origins, it is useful to classify oils into distinct groups. A number of oils in an area can be grouped using their properties.

To understand origin of oil we have to characterize the geochemical properties of oil such as bulk properties, in this case API gravity, sulfur and wax content; carbon isotopes for saturate and aromatic fractions; and biomarkers of saturate and aromatic fractions. From these data, the information on source rock can be derived, including the lithology, depositional environment, source facies, geological age age, level of maturity, oil alteration, etc.

Oils in the reservoir reflect the organic matters in the source rock. We are using Clayton and Fleet (1991)'s to group oils into five categories: A, B, C, D, or E (Figure 5). Oils in categories A and B are both derived from a mixture of algal and bacterial remains which have accumulated in a marine environment. The difference between A and B is in the associated lithology, either non-clastic (A) or clastic (B). Class C oils are sourced mainly from algal organic remains with some bacterial input. This type of organic matter is often found in lacustrine environments where green algae are a major contributor of the kerogen. Classes D and E represent kerogen derived mainly from higher land plants. Such organic matter is oil prone if it contains hydrogen rich components such as waxes from cuticle or resin from leaves and trunks. Class D source material differs from class E in having a higher proportion of resin. and Many Indonesian source rocks can serve as example for group E.

The method of oil grouping uses bulk properties of oils which can be affected by biodegradation and maturity. To overcome this problem, the biomarkers of oils, which are far much resistant to biodegradation and maturation effects, are employed, which also show variation representing source facies, source lithology, source age, source maturation (Peters et al., 2005).

A summary of general characteristics of oil geochemistry is as follows. API gravity records crude oil maturity, it increases with increasing maturity. It lowers much (< 20°) when it is biodegraded. As for wax content, wax content of lower than 10 wt.% represents marine sources, whereas when wax content is between 10 – 40% or higher, the oil was sourced by organic materials deposited in terrestrial sediments. High (> 1 %) sulfur content of oil related to marine carbonate source, between around 0.3 – 1 % the oil was sourced by marine non-carbonate sources, terrestrial oil has very few sulfur content (0 around 0.2 %). Biomarker data using gas chromatography derives normal alkanes and isoprenoids (the most famous isoprenoids are pristane (Pr) and phytane (Ph) and their ratios such as Pr/nC_{17}, Ph/nC_{18}, Pr/Ph. These ratios show oxidizing or reducing conditions of the source depositional environment. When Pr/Ph < 1, this shows an aquatic anoxic condition of depositional enviroment – aquatic means fresh water/lacustrine and marine, Pr/Ph between 1 and 3 shows aquatic suboxic condition, and Pr/Ph >3 shows terrestrial oxic condition. When the Pr/Ph in between 0.8 and 3.0, the usage of Pr/Ph should be careful because it is affected by maturity therefore, the interpretation of source facies and redox condition in this case should be associated with other methods (Peters et al., 2005). Biomarkers using gas-chromatograph-mass spectrometry (GC-MS) mainly measured on two families: terpane and sterane from saturate fraction, and some biomarkers from aromatic fraction (methyl phenanthrene, aromatic dino-steroid). Based on these, the source lithology, source age, source facies, source maturation can be known.

Previous Investigations on Oil Characteristics

Davies (1990) was the first who detailed the geochemistry of discovered oils and oil seeps in the Banggai Basin. The oils tested in Minahaki-1 and the Tiaka Field have fairly low API gravities, approximately 28 degrees API, are non-waxy, and are rich in both aromatic and NSO compounds. The oils are high sulfur contents of the oils: 1.8% in Minahaki-1, 1.93% in Tiaka-1 and 0.78 % in Dongkala- 1. The saturates are generally low, about 25%. The carbon preference indices are generally equal to 1.0 and indicate the oils are relatively mature. The carbon isotope composition of the oils is relatively heavy and shows appreciable variation, values vary from - 24.5ppt (saturates) in Dongkala-1 to -20.5 ppt in Minahaki-1.

Davies (1990) also stressed the occurrence of oleanane on oil samples (Figure 6). Angiosperms form a significant portion of the Cenozoic to Recent floras. One of the positive indicators for the presence of angiosperm remains in the source section, or in the section between it and the reservoir, is the abundance of the angiosperm derivative, oleanane. Oleanane is common in the oils tested in the study area. The abundance and the consistency of the presence of the oleanane peak, in the m/z 191 mass spectrometer scans suggests that it is related to the main source of oil and not a contaminant acquired by the oil during migration. The oleanane peak occurs not only on the mass spectrometer scans of the reservoired oils but also on the scans of the biodegraded oil seeps at Dayuk and Kolo. Oleane is also present in the thermal extract scans from source rocks in the Minahaki-1 and Tiaka-3 wells. However, oleane is absent in the thermal extracts of the Jurassic rocks sampled in the outcrop north of the area. Thus the ubiquitous nature of the oleanane suggests that the Miocene rocks, reservoired oils and surface oil seeps are all closely related in origin.

An investigation was made on the Sonoro-2 condensate. The origin of condensates was analyzed and reveals a source of calcareous marine clastic, deposited within a facies with heavy carbon isotope. The maturity of condensate remains unclear, and is based on source maturity which is between 0.8 – 0.9 % Ro. There is a similar biomarker pattern between Senoro condensate and sediments from Miocene Tomori Formation.

An investigation was made on the oil seeps in Kolo-Kolo area, also on onshore and offshore sediments East Sulawesi and Peleng Island. They concluded that five oil seeps from Kolo-Kolo area in western margin of Banggai Basin are from one family, with organic matters containing higher land plant, deposited in anoxic deltaic marine and lacustrine rich in clay/shale materials. Based on sterane biomarkers, they expected that Pre-Cenozoic sediments from Bobong and Nambo/ Buya show similar patterns with oil biomarker, but based on vitrinite reflectance, Jurassic sediments are not mature to early mature. Based on the triterpane biomarker, the oil was generated from younger sources than that of Jurassic source due to the existence significant oleanane on all samples analyzed, and the oleanane is absent from Jurassic sediments (Figure 7). Oils relatively contain abundant diasterane, showing that the source sediments were deposited within clay rich-marine environment or closed lacustrine delta. Biomarkers on Jurassic sediments show different patterns with oil biomarker, but Cenozoic sediments show a correlation. The study concluded that marine algae and higher plant materials were the main contributor of the oils in Banggai Basin. High concentration of tricyclic terpanes show a long history of migration, and all of oil samples contain oleanane.

Current Data on Oil Characteristics

Tiaka-1 oil

The oil properties are based on several tested intervals. The API gravity ranges from 21-25.6°, wax content 0.31-0.33 % wt., sulfur content 1.93 % wt., Pr/Ph 1.26-1.27, oil fraction is dominated by aromatic of 42.6-45.1 %, Tm/Ts 2.54-2.96, sterane is dominated by C_{27} 36.9-43.4 %, oleanane index (oleanane/olenane+hopane) 0.38-0.42, δC_{13} saturates -23.6 ‰, δC_{13} aromatics -22.7 to -23.8 ‰.

Tiaka-5 oil – Figure 8

No analysis of bulk oil properties was carried out. Pr/Ph 1.32, oil fraction is dominated by saturate of 61.6 %, Tm/Ts 3.39, sterane is dominated by C_{29} 48.6 % with C_{27} 32.06 %, oleanane index 0.43, δC_{13} saturates -24.4 ‰, δC_{13} aromatics -23.7.

Tiaka-7ST condensate

The API gravity 63.5°, sulfur content <0.01% wt., Pr/Ph 1.8, oil fraction is dominated by saturate of 76.9 %, Tm/Ts 0.89, sterane is dominated by C_{27} 52.16 % with C_{29} 30.32 % , oleanane index 0.16, δC_{13} saturates -26.7 ‰, δC_{13} aromatics -26.5 ‰.

Senoro-1 oil

The API gravity 35.4°, wax content 8.74 % wt., sulfur content 0.85 % wt., Pr/Ph 1.71-1.73, oil fraction is dominated by saturate of 48.7 %, Tm/Ts 3.38, sterane is dominated by C_{27} 41.8 % with C_{29} 37.06 %, oleanane index 0.44, δC_{13} saturates -20.1 ‰, δC_{13} aromatics -19.6 ‰.

Senoro-2 oil

The API gravity 45.4°, wax content 1.39 % wt., sulfur content 0.37 % wt., Pr/Ph 1.73, oil fraction is dominated by saturate of 77.4 %, Tm/Ts 2.55, sterane is dominated both by C_{27} and C_{29} of 38 %, respectively, oleanane index 0.47, δC_{13} saturates -20.0 ‰, δC_{13} aromatics -20.4 ‰.

Minahaki-1 oil

The API gravity 26.3°, sulfur content 1.6 % wt., Pr/Ph 1.85, oil fraction is dominated by saturate of 53.7 %, Tm/Ts 2.53, oleanane index 0.43.

Minahaki-1 condensate

The API gravity ranges from 50.2-60.2°, sulfur content 0.35-0.41 % wt., Pr/Ph 1.7-2.4, oil fraction is dominated by saturate of 75.2-78.6 %, Tm/Ts 2.04-2.32, sterane is dominated by C_{27} 37-44 %, oleanane index 0.28-0.42.

Matindok-1 oil

The API gravity 33.3°, wax content 7.97 % wt., sulfur content 0.16 % wt., Pr/Ph 2.42, oil fraction is dominated by NSO 65.97 %, sterane is dominated by C_{27} 44 %, δC_{13} saturates -26.24 ‰, δC_{13} aromatics - -25.52 ‰.

Maleo Raja-1 oil

The wax content 0.07 % wt., Pr/Ph 2.04, oil fraction is dominated by both saturate and NSO of 48.6 %, respectively, sterane is dominated by C_{27} 50 %, δC_{13} saturates -25.3 ‰, δC_{13} aromatics -24.7 ‰.

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Kolo Bay oil seep – Figure 8

The API gravity 11.5°, Tm/Ts 1.33, sterane is dominated by C_{27} 43.5 %, oleanane index 0.34.

Dayuk oil seep – Figure 8

The API gravity 15.1°, Tm/Ts 3.2, sterane is dominated by C_{27} 45.6 %.

Toili oil seep

oleanane index 0.14.

KTD-2B oil seep

Oil fraction is dominated by saturate of 57 %, sterane is dominated by both C_{27} and C_{27} of 36 and 35 %, respectively, oleanane index 0.39, δC_{13} saturates -29.28 ‰, δC_{13} aromatics -29.30 ‰.

TOS 19-21 oil seep

Oil fraction is dominated by aromatic of 43-52 %, sterane is dominated by both C_{27} 33-38 % and C_{29} 32-36 %, oleanane index 0.31-0.33, δC_{13} saturates -29.38 to -29.58 ‰, δC_{13} aromatics -29.36 to -29.49 ‰.

Oil Grouping

Based on the oil grouping classification of Clayton and Fleet (1991) with parameters of bulk properties and pristane/phytane ratio, it can be concluded that oils of Banggai Basin fall under Group A or Group B. As discussed in section of basis for oil grouping, oils in classes A and B are both derived from a mixture of algal and bacterial remains which have accumulated in marine environments; the difference is in the associated lithology – either non-clastic/carbonate (class A) or silici-clastic/ shale (class B).

Determination of source lithology, source facies/ depositional environment, source age, and source maturity uses biomarkers, especially groups of terpane (m/z 191), sterane (m/z 217) – both from saturated oil fraction and aromatic methyl phenanthrene (m/z 192 and m/z 178).

General characteristics of oil group A (source rocks are marine carbonate and other non-sliciclastic sediments) are API gravity between 25-30°, wax content < 10 % wt., sulphur content > 1.0 % wt., pristane/phytane < 3.0, N (nitrogen) content 1000-5000 ppm, trace metal between 50-300 ppm.

General characteristics of oil group B (source rocks are marine siliciclastic sediments) are API gravity between 30-35°, wax content < 10 % wt., sulphur content between 0-1.0 % wt., pristane/phytane < 3.0, N (nitrogen) content 500-1500 ppm, trace metal between 0-50 ppm.

Determination of source lithology is based on biomarker triterpane m/z 191 using ration between C_{29} norhopane to C_{30} hopane. Shale lithology is shown by low ratio (< 0.5) of C_{29} norhopane to C_{30} hopane. High ratio of C_{29} norhopane and C_{30} hopane (> 0.9) shows source lithology of carbonate. In between these values show both calcareous shales or shaly carbonates.

Determination of source facies uses portion of C_{27}, C_{28}, C_{29} sterane (m/z 217)

Oil grouping of Group/Class A in the Banggai Basin is represented by oils from wells of Tiaka-1, Senoro-1, Minahaki-1, Maleo Raja; oil seeps of KTD-2B, Toili A, Kolo Bay and Dayuk; and condensates of Minahaki-1 and Tiaka-7ST (Figure 11). Available data of this group shows 11.5 (biodegraded) – 35.4° API or 50.2-62.5 ° API, wax content of 0.07-8.74 % wt., and sulfur content of 0.85-1.93 % wt. Higher C_{27} portion than those of C_{28} and C_{29}, ranging from 37 – 52,16% show that the oils sourced by sediments deposited in marine facies (Figure 9). Pristane/phytane ratio of the oils 1.26 to 2.04, showing source deposition in anoxic – suboxic environments. Analysis on chromatogram distribution of triterpane m/z 191 norhopane (C_{29}) and hopane (C_{30}) show higher peaks of C_{29} norhopane than peaks of C_{30} hopane (C_{29}/C_{30} > 1.0) – Figure 10, or peaks of C_{29} norhopane approach peaks of C_{30} hopane (C_{29}/C_{30} > 0.9). These values show source lithology of carbonates.

Oil grouping of Group/Class B in the Banggai Basin is represented by oils from wells of Tiaka-5, Dongkala-1, Senoro-2, Matindok-3; oil seeps from TOS-19, TOS-20, TOS-21A (Figure 11). Available data of this group shows 12.10 – 45.40° API, wax content of 1.39-7.97 % wt., and sulfur content of 0.16-0.78 % wt. Distributions of C_{27}, C_{28} and C_{29} show that the oils sourced by sediments deposited in estuarine to marine facies (Figure 9). Pristane/phytane ratio of the oils 1.32 to 2.42, showing source deposition in anoxic – suboxic environments. Analysis on chromatogram distribution of triterpane m/z 191 norhopane (C_{29}) and hopane (C_{30}) show lower peaks of C_{29} norhopane than peaks of C_{30} hopane ($C_{29}/C_{30} < 0.5$) – Figure 10. These values show source lithology of shales.

Based on the cut-off value of oleanane index (oleanane/oleanane + hopane) for determining source age as oleanane index > 0.20 indicating Cenozoic in age (Peters et al., 1999), almost all of Banggai oils were sourced by Cenozoic source rocks as the oleanane index ranges from 0.28-0.47. Three samples however, show oleanane index lower than 0.20: Tiaka-7ST as 0.16, Dongkala-1 oil 0.16, and from Toili oil seep as 0.14. Low value oleanane index of Tiaka-7ST may relate to condensate sample as a product of oil cracking which could affect the biomarker peaks. Low value oleanane index of Dongkala-1 and Toili oils may indicate two possibilities: (1) contribution of oil generation from pre-Cenozoic source rocks, or (2) the area of source deposition not received erosional debris of Angiosperm tree materials from which oleanane came from. The possibility of (1) should be examined by other biomarkers which more sensitive for source ages.

As for the oil maturity, some oils in the Banggai Basin were analyzed to derive methyl phenanthrene (from aromatic fraction, using m/z 178 and m/z 192). Methyl phenanthrene index (MPI) can be calculated to derive maturation level like vitrinite reflectance called Ro calculated (Rc). The Banggai oils were generated when the source rocks entered the maturity levels of 0.59 – 1.12 % equivalent Ro.

Genetic Types of Gases

There are a number of gas fields and discovery gas structures in the Banggai Basin. Volumetrically, the gas fields in this basin is much larger than the oil field/structures. The two largest gas fields are Senoro and Donggi gas fields which are currently under development. The Senoro gas field is estimated to have reserve of 362 MMBOE, whereas the Donggi gas field 84 MMBOE (IHS Energy, 2016).

The gases discovered in onshore eastern Sulawesi wells appear to be complex (Satyana et al., 2007), with components derived from biogenic origin (Dongkala, Mantawa and Minahaki gases, $\delta^{13}C_{CH4}$ values of -50 ‰ to -62 ‰) and thermogenic origin (Sukamaju, Kampung Bali, Maleo Raja, Senoro, Matindok gases, $\delta^{13}C_{CH4}$ values of -53 to -32 ‰). This is also confirmed by crossplot of $\delta^{13}C$ methane and $\delta^{13}D$ methane, and crossplot between $\delta^{13}C$ methane and $\delta^{13}C$ ethane showing thermogenic origin. Based on carbon isotope data, there is a significant variation in the maturity of the thermogenic source rocks from Sukamaju (least mature) to Matindok (most mature). Compositional data confirm the thermogenic origin with CH_4 content of 86.5-96.5 %.

In the Senoro field, geochemical data suggest that biogenic gas initially filled the trap shortly after deposition of reefal facies (Hasanusi et al., 2004). Later, when thermogenic source rocks reached oil maturity, oil migrated and filled the Senoro structure. Finally, late thermogenic gas displaced most of the oil, leaving a small oil rim below a large gas column.

Further thermogenic gas classification is carried out for Senoro and Matindok gases (Figures 12-14). Genetic type gas cross plot between $\delta^{13}C$methane and C_{2+} shows that Matindok gas is a thermogenic gas derived from mixed source with $\delta^{13}C_{CH4}$ -32,7 ppt and C_{2+} of 4,79 %. Based on $\delta^{13}C_{CH4}$, the gas is a non-associated gas forming from humic organic matter at the maturity level of 2.36% Ro. Crossplot between $\delta^{13}C_2 – \delta^{13}C_3$ with C_2/C_3 shows that Senoro gas was formed by secondary cracking from oils rich in heavy component (NSO fraction –nitrogen, sulfur, oxygen) with $\delta^{13}C$methane of around -40 ppt and deuterium isotopes of -154 and -160 ppt. To know the temperature level of the gas cracking, the Faber plotting is carried out to correlate between values of $\delta^{13}C_2$ and $\delta^{13}C_3$ to maturity level, and the result shows that cracking occurred at Ro of 2.0 to 2.1 %. This maturity level is equivalent to around 200°C.

As for the non-hydrocarbon gases, Senoro and the other gas fields of East Sulawesi have 1-5 % CO_2. Sukamaju, Kampung Bali, and Maleo Raja have isotopically light $\delta^{13}C_{CO2}$ values (-10.78 to -13.81 ‰) suggesting the CO_2 originates from maturation of organic matter ($\delta^{13}C_{CO2} < -10$ ‰). During maturation the sulphur rich vitrinite compounds would contribute sulphur to the oils. It should also be remembered that hydrogen sulfide is abundant in the gases at Minahaki-1 and Matindok-1.The gas fields of Anoa, Donggi, Maleo Raja, and Senoro contain 300-800 ppm H_2S.

There are two potential source rocks sequences recognized in East Sulawesi: Jurassic marine shales and Miocene marine shales and coals. Geochemical analyses to date indicate that oil seeps and all of the oils and gas tested from the area are most likely related genetically to shales and coals within the early to middle Miocene Tomori Formation.

Wet Gas Seepages of Sula Basin (Taliabu-Mangole Platform)

Garrard et al. (1988) reported several active wet gas seepages in northern Mangole, eastern part of the Sula microcontinent. Detailed geochemical analysis was undertaken on the gas to determine composition, maturity and possible origin (Figure 15).

At least seven wet gas seepages occur over a distance of more than 20 km near Falabisahaya in northern Mangole. Only one is associated with carbonates of the Cretaceous Tanamu Formation and the remainder are from the late Jurassic part of Buya Formation. Samples were collected from the four key localities. The composition of the different gas samples is very similar, suggesting derivation from a common source. The gas consists mostly of methane (> 94.0% of normalized hydrocarbons) with lower concentrations of C_2-C_7 hydrocarbons and CO_2. The methane content increases and the C_2-C_7 decreases in the samples from west to east. Carbon isotope analysis of the methane (- 27.98 to - 29.32 ppt) and ethane (- 26.55 to - 23.98 ppt) indicates the gas is of thermogenic origin and was probably derived from humic organic matter (Type III kerogen) and probably not generated in association with oil.

The methane is unusually enriched in carbon 14 with isotope values similar to those normally associated with coals. The compositional analysis of 5.46 % to 2.93 % gas wetness is also consistent with a humid coal source. No Jurassic coals have yet been identified in this area and the nearest known coal outcrops are reported to occur in western Taliabu to the west of Mangole. Carbon isotope values of - 40.85 to - 39.41 ppt for the CO_2 likewise indicate a definite organic origin.

The gasoline range composition displays a similar signature for three of the samples but differs slightly in the eastern-most sample. The C_7 composition of the gases (high C_7 cyclic and low C_7 normal content) is typical of generation from Type III terrestrially derived kerogen. The isoheptane values (0.92 to 1.0) for the three compositionally similar gas samples is consistent with generation in the middle to lower part of the oil window (Ro 0.8 to 1.2%). The heptane and isoheptane values on other sample are significantly greater than the other samples suggesting higher maturity levels (Ro 1.0 to 2.0). This sample also contains less wet gas.

Source Identification

Previous studies (Garrard et al., 1988; Davies et al., 1990; Hasanusi et al., 2004) have shown that there are two potential source rock sequences in the Banggai Basin: Jurassic restricted marine shales, and Miocene marine shales and coals within the Tomori and Matindok Formations. Jurassic shales which crop out on Peleng, Taliabu, Mangole Islands and Nambo River onshore East Sulawesi, indicate a fair source rock quality.

Davies (1990) mentioned that source rocks have been identified in the Lower Platform Limestone (Lower Miocene, Tomori Formation), Clastics/Coal Unit (Middle Miocene, Matindok Formation), and the Pliocene Celebes Molasse. The Upper Platform and Reefal Limestones (Minahaki Formation and Mantawa Member) generally contain very little organic matter, with the exception of a thin section at the base of the unit. In both the Matindok Formation and the Celebes Molasse, organic matter is concentrated in shales and siltstones. Shales, coaly shales and coals within the Tomori Formation all contain significant amounts of organic matter, whereas the limestones contain only small amounts. Davies (1990) suggested a relationship between the Miocene section and the reservoired oils. Oleanane is common in the oils tested, also presents in the thermal extract scans from Miocene source rocks in the wells. However, it is absent in the thermal extract scans of the Jurassic rocks sampled in outcrop. The ubiquitous nature of the oleanane suggests that the Miocene rocks, reservoired oils and surface oil seeps are all closely related in origin. Davies (1990) presented another line of evidence which suggests a relationship between the Miocene section and the reservoired oils is the high sulphur contents of the oils: 1.8% in Minahaki-1, 1.93% in Tiaka-1 and 0.78% in Dongkala-1. These values may be consistent with an origin from higher plant material.

Detailed geochemical analyses of the various potential source rocks from wells indicate that the hydrocarbons are most likely genetically related to shales within the Tomori Formation source rocks of Early to Middle Miocene age, with no apparent contribution from Jurassic source rocks (Hasanusi et al., 2004). The Tomori Formation contains excellent potential for source rocks, and consists of limestones with marine shales, coals and coaly shale interbeds, which contain a significant amount of organic matter.

This study based on numerous biomarkers of oils showing that oils in this basin (field, discovery well, seep) derived from a mixture of algal and bacterial remains which have accumulated in marine environments. The study detailed that the oils can be distinguished into two groups/ classes: one which was sourced by non-clastic/carbonate (class A), and the other sourced by or siliciclastic/ shale (class B). Based on the cut off value of oleanane index (oleanane/oleanane + hopane) for determining source age as oleanane index > 0.20 indicating Cenozoic in age (Peters et al., 1999), almost all of Banggai oils were sourced by Cenozoic source rocks since the oleanane index ranges from 0.28-0.47. Based on the stratigraphy of the Banggai Basin, and oil to source correlation, the most fit source rocks of the oils are carbonates of the early Miocene Tomori Formation for class a oils, and shales of the middle Miocene Matindok Formation for class B oils (Figure 4). Mixture between class A and class B oils occurred and sourced by transitional lithology between carbonate and shale, like calcareous shales or shaly carbonates.

Hasanusi et al. (2004) discussed the source potential of Tomori and Matindok Formation based on wells penetrating the rock units. Geochemical data of the Tomori Formation in the Matindok-1 well proved approximately 178 ft of source rocks comprised of interbedded argillaceous limestones, coal and carbonaceous shales containing total organic carbon up to 32%, and a very good potential yield of S2, of up to 72 mg HC/g rock. The hydrogen index (HI) and kerogen type data indicate that the Tomori Formation shales are oil and gas prone source rocks (Type II/III kerogen). Ro data indicates the source rocks will be mature at 9100 ft depth. Equivalent calcareous shale source rocks in the Tomori Formation are identified in the Minahaki-1, Mantawa-1 and Senoro-2/2ST wells. In Senoro-2/2ST well, the Tomori Formation displays source rock potential for mixed oil and gas. The upper section of the formation, which is influenced by deltaic sedimentation, contains Type II/III kerogen, and has a good TOC of 2 to 4 % with potential yield of S2 up to 19.2 mg HC/g rocks. Deeper in the section, the sediments are more Type II marine and contain TOC at or below 1 %, but the hydrogen content is significantly higher, with HI up to 690. The entire penetrated section in Senoro-2/2ST is immature, displaying a low Ro with 0.5% Ro at about 7200 feet. Mature source rock is projected to occur at around 11,300 feet. The Matindok Formation in the Matindok-1 and Senoro-2/2ST wells consists of interbedded shales, sandstone, limestones and coals, which have fairly good organic richness. However, the formation contains mainly gas prone Type III kerogen and has poor hydrocarbon generating potential.

Jurassic-Early Cretaceous Source Potential

Based on their field investigation in Sula area on the eastern Banggai-Sula microcontinent, Garrard et al. (1988) suggested that black anoxic shales of the Late Jurassic - Early Cretaceous Buya Formation should represent a potentially attractive source rock interval. The Late Jurassic - Early Cretaceous samples were analyzed for organic richness (TOC) – the bulk of which gave only low to average values (around 1% TOC). Twenty five were classified as good and one as excellent. In general the richer samples are from the Middle to early Upper Jurassic interval. Much of this section contains TOC values in the range of 1% to 2%.

Measurements of the HI were obtained and most of the samples are either lead spent or gas prone. Two are of mixed composition and two are oil prone. The spent samples were collected in southern Mangole where the Jurassic shales have undergone intensive thermal alteration. The total pyrolysate yield incorporating both free (S1) and evolved (S2) hydrocarbons gives some idea of the kerogens ability to produce hydrocarbons. With the exception of six samples all indicate only poor oil generating potential. Despite this, some samples (based on microscopic examination) do contain very good oil-prone kerogen which could generate moderate amounts of oil at optimum maturities. The maturity of the late Jurassic to early Cretaceous section was calculated using vitrinite reflectivity, spore colour and T_{max} measurements. The results indicate interesting regional variations. The reliable results display two distinct populations of samples with the majority falling in the immature to early mature category for oil generation group. The second and smaller group falls into the post-mature oil range.

When the organic maturities are classified into geographical areas, distinct regional trends can be seen (Figure 16). There is a progressive increase in the organic maturity of the Jurassic from west to east and to a lesser extent from south to north (Mangole and Taliabu only). In North-East Sulawesi, the majority of the samples are immature to early mature for oil generation while in the Peleng and Banggai Area, they are early mature to fully mature. In Taliabu, immature to fully mature for oil generation values were recorded with the bulk of the more mature samples occurring in the east of the island. The same sediments along the south coast of Mangole are all post mature for oil generation and in some cases even for gas. On the northern side of the same island, however, the majority of samples lie within the early to fully mature oil window. It is concluded that parts of the eastern Banggai-Sula Microcontinent had (prior to the first Cenozoic sediments) been buried very deeply and/or subjected to a major thermal/tectonic event. The degree of organic diagenesis progressively decreases towards the west and north. Optimum maturities for oil generation might be present offshore in the North Taliabu-Mangole Shelf and Taliabu Shelf areas.

The Toili oil seep and Dongkala-1 oil in the Banggai Basin show low value of oleanane index as 0.14-0.16, this may indicate a contribution from pre-Cenozoic source rocks, since pre-Cenozoic source rocks show oleanane index of < 0.20 (Peters et al., 1999). However, its low value may also indicate that the area of source deposition was not received erosional debris of Angiosperm tree materials from which oleanane came from. Therefore, the possibility of pre-Cenozoic contribution should be examined by other biomarkers which more sensitive for source ages only, not affected by depositional environment.

Implications for Further Exploration

Source rock is the most important element of the petroleum system since it generates petroleum. It means that if there is no source rock there will be no petroleum. To generate petroleum, the source rock should fulfill two requirements: (1) it should be organically rich and (2) it should be thermally mature.

Oil and gas fields, oil and gas discovery wells have been discovered in the Banggai Basin since late 1980s. Oil and gas seeps occur in Eastern Arm of Sulawesi and several islands to the east. Geochemical studies have been carried out quite intensively in this area by several companies operating here. All existing oils in this area are correlated into Miocene source rocks of Tomori and Matindok Formations (Davies, 1990; Hasanusi et al., 2004). This study confirms the conclusion, with further subdivision that the existing oils in the Banggai Basin can be grouped into classes A and B sourced by early Miocene Tomori carbonates for A oils and by middle Miocene Matindok shales for B, respectively. This study also shows that gas field, gas discovery wells, and gas seep were sourced by Miocene source rocks, as well as derived from oil cracking due to thermal breakdown. Based on all of these studies, proven source rocks for oils and gases in the Banggai Basin – especially which are close to the eastern arm of East Sulawesi are early-middle Miocene of Tomori and Matindok Formation.

None of the biomarker data shows a firm evidence for the contribution from pre-Cenozoic source rocks for the existing oils. A low oleanane index (0.14) analyzed in the Toili oil seep does not necessarily indicate pre-Cenozoic source rocks since oleanane is not solely age-diagnostic biomarker, it also shows a control of depositional environment accordingly, it needs further confirmation by more and solely age-diagnostic biomarkers.

Considering that the proven source rocks in the area are the Miocene carbonates and shales of Tomori and Matindok Formations, and considering that there is no evidence for the contribution of pre-Cenozoic source rocks, further exploration evaluation would be concentrated on Miocene source rocks and objectives only. Pre-Cenozoic source rocks, may exist, as shown by Jurassic shale outcrops in Nambo River, Eastern Arm of Sulawesi and could be possibly be identified on seismic. However, thirty years of exploration in the Eastern Arm of Sulawesi have never found Pre-Cenozoic oils and gases.

There are three possible explanations: (1) Pre-Cenozoic source rocks in the frontal part of the Banggai-Sula microcontinent which is now part of the Eastern Arm of Sulawesi has never been deposited, (2) The Pre-Cenozoic source rocks organically have poor quality due to deposited in oxidized open marine environment since the sediments positioned the frontal part of the microcontinent, (3) the Pre-Cenozoic source rocks were rapidly deposited and became overmature due to very thick tectonic loading by structural imbrication when the microcontinent collided Eastern Sulawesi Ophiolite Belt. The last two reasons are the most likely explanation.

Pre-Cenozoic objectives are also seismically difficult to image due to a very thick cover of tectonic loading and complicated structural deformation, existence of very thick Cenozoic limestones of Salodik Group which may absorb seismic energy significantly, and static problem related to rugged topography. The lack of evidence that Pre-Cenozoic source rocks have contributed petroleum, and the difficulty to image the Pre-Cenozoic, make Cenozoicthis objective unattractive.

Targeting the Pre-Cenozoic will be worthy in trailing part of the microcontinent in offshore areas of the North Taliabu-Mangole Shelf and Taliabu Shelf areas as suggested by Garrard et al. (1988). There was no further exploration in this area since the drilling of Loku-1 exploration well in 1990 therefore, its potential remain open. Pre-Cenozoic sediments were deposited as syn-rift sequence in grabens of this area. Intensive field studies and geochemical analysis (Garrard et al., 1988), seismic sections, and exploration well of Loku-1 (Britoil, 1990, sub-commercial gas discovery, tested gas, reserve 4 MMBOE – IHS Energy, 2016) indicate some potential in the Pre-Cenozoic of this area.

CONCLUSIONS

1. Historic and new geochemical data (bulk properties, biomarkers, isotopes) on oil and gas fields, discovery wells, and oil-gas seepages in the Banggai-Sula microcontinent, Eastern Sulawesi to North Moluccas show that in the Banggai Basin all oils and gases were sourced by Miocene source rocks. There is no evidence for the contribution of Pre-Cenozoic source rocks.

2. Geochemical studies show that the Banggai oils can be grouped into class “A” which was sourced mostly by carbonates of Lower Miocene Tomori Formation (Tiaka-1, Senoro-1, Minahaki-1, Maleo Raja; oil seeps of KTD-2B, Toili A, Kolo Bay and Dayuk; and condensates of Minahaki-1 and Tiaka-7ST) and class “B” which was sourced mostly by shales of Middle Miocene Matindok Formation (Tiaka-5, Dongkala-1, Senoro-2, Matindok-3; oil seeps from TOS-19, TOS-20, TOS-21A). Both classes are sourced by organic matters of a mixture of algal and bacterial remains which have accumulated in marine environments

3. The origin of gases discovered in Banggai Basin appear to be complex with components derived from biogenic origin (Dongkala, Mantawa and Minahaki gases and thermogenic origin (Sukamaju, Kampung Bali, Maleo Raja, Senoro, Matindok gases). Further classification of thermogenic gas shows the genetic type of gas is related to non-associated gas from humic organic matter (Matindok) and associated gas formed by secondary cracking of oils rich in heavy components (Senoro).

4. Based on isotope geochemistry, field geology, seismic sections, gas seeps in Sula Basin (Taliabu-Mangole platform and Loku-1 exploration well are considered to be sourced by Jurassic marine shales which were deposited as late synrift sections in the grabens of the microcontinent.

5. Based on this study of origins of oils and gases in the Banggai-Sula microcontinent, the future exploration should target: (1) Miocene objectives in the Banggai Basin, and not Pre-Cenozoic targets and (2) Pre-Cenozoic objectives in the offshore areas of North Taliabu-Mangole Shelf and Taliabu Shelf in Sula Basin.

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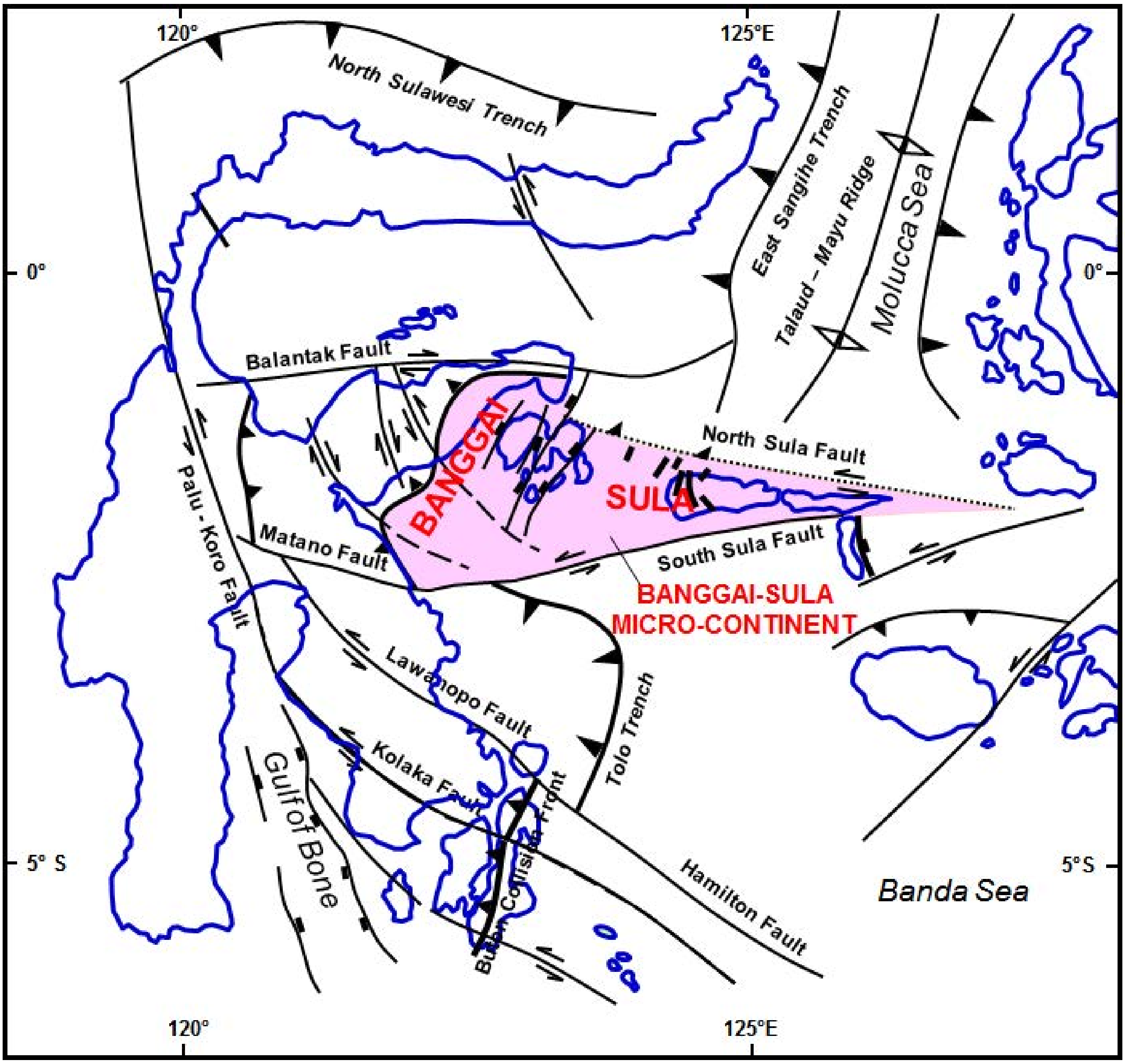

Figure 1 - Location of Banggai-Sula microcontinent and associated Banggai and Sula Basins. The microcontinent collided the eastern part of Sulawesi. Most structures developing in Eastern Sulawesi formed in response to this collision.

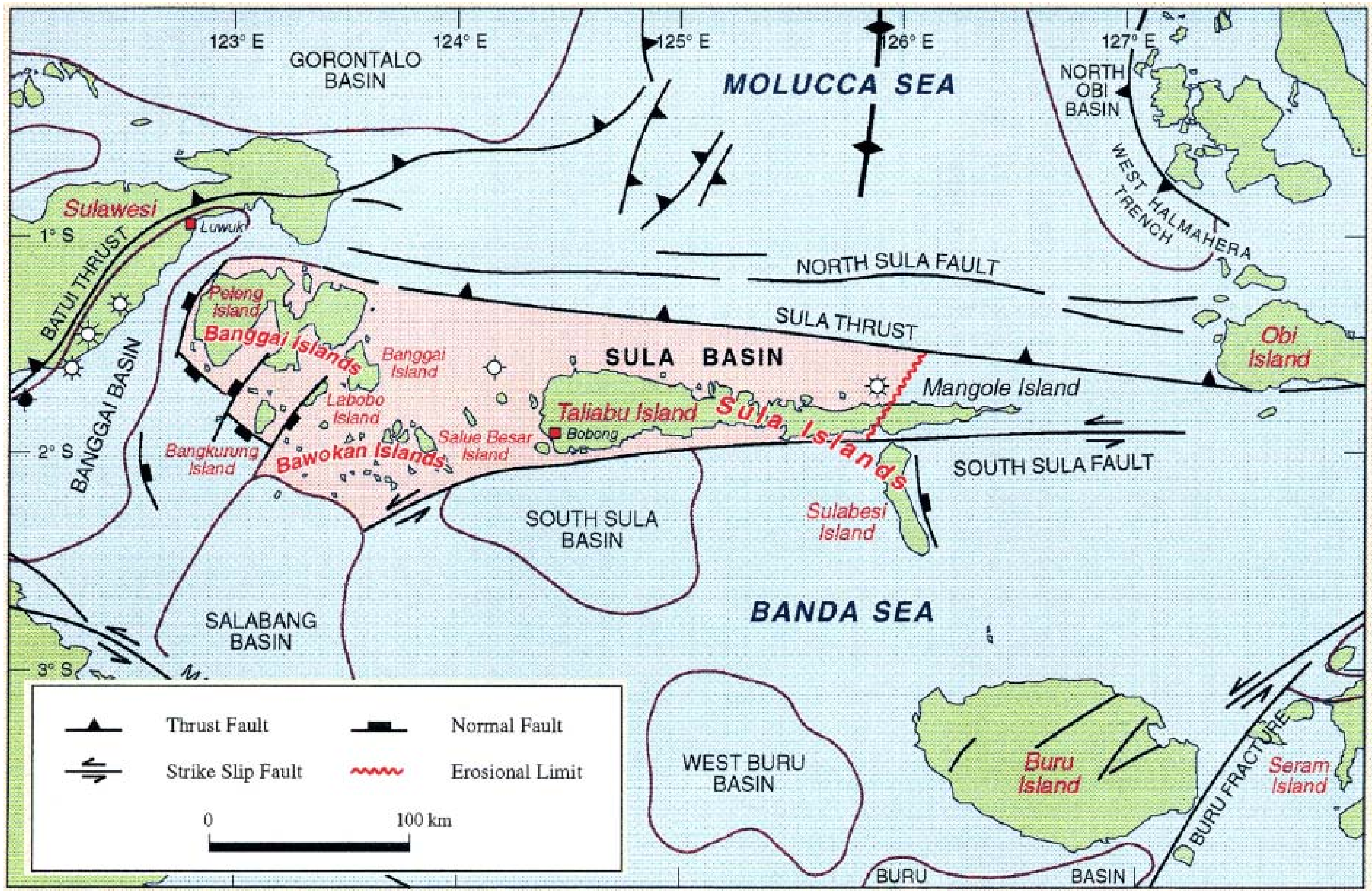

Figure 2 - Location of Banggai and Sula Basins and some occurrences of oil and gas wells (IHS Energy, 2016).

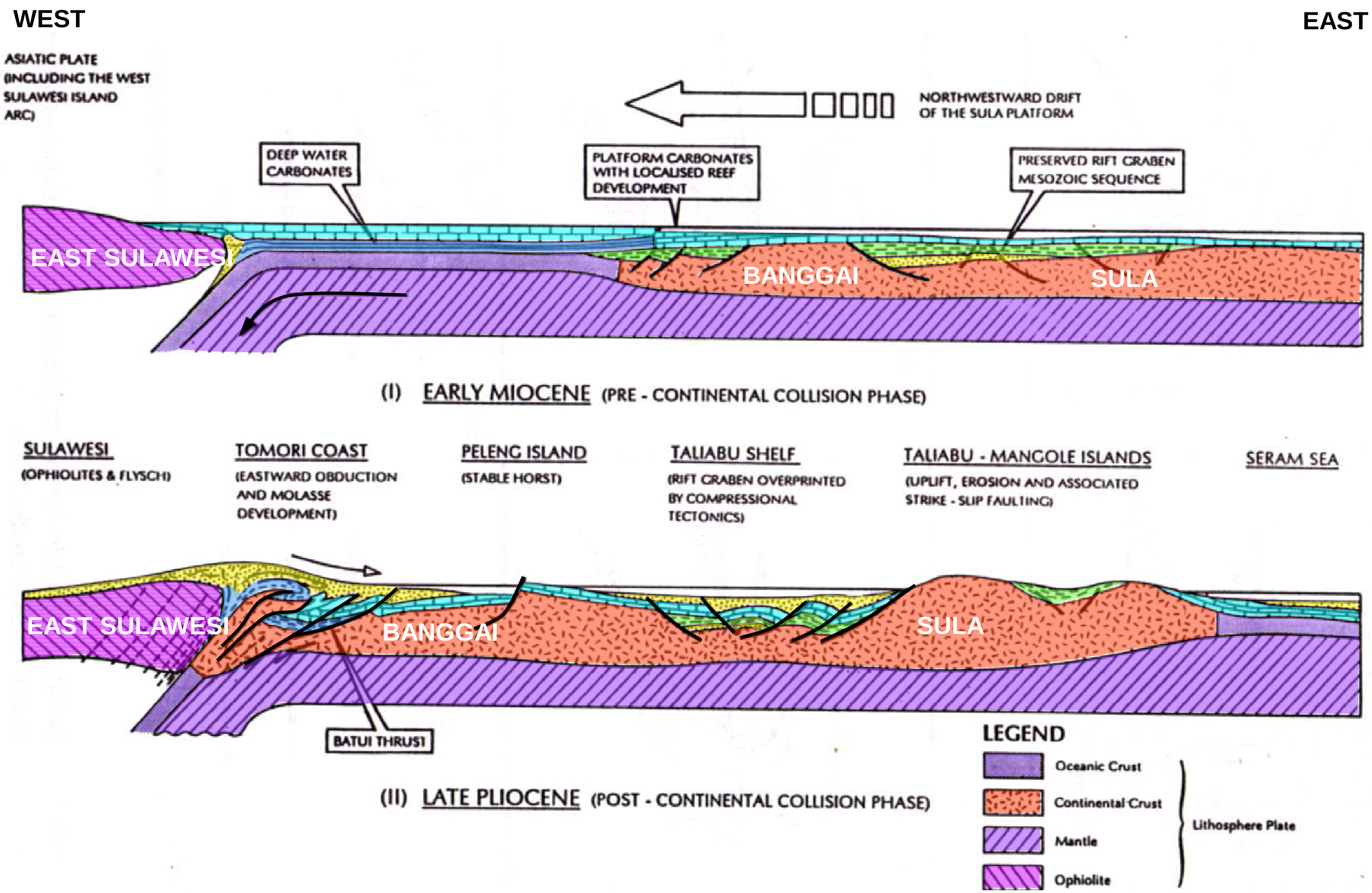

Figure 3 - Possible tectonic development of collision of Banggai-Sula microcontinent to East Sulawesi. Note schematic rifted structures development on the microcontinent containing sediments (Pre-Cenozoic), also syndrifting Cenozoic carbonate development (Garrard et al., 1988).

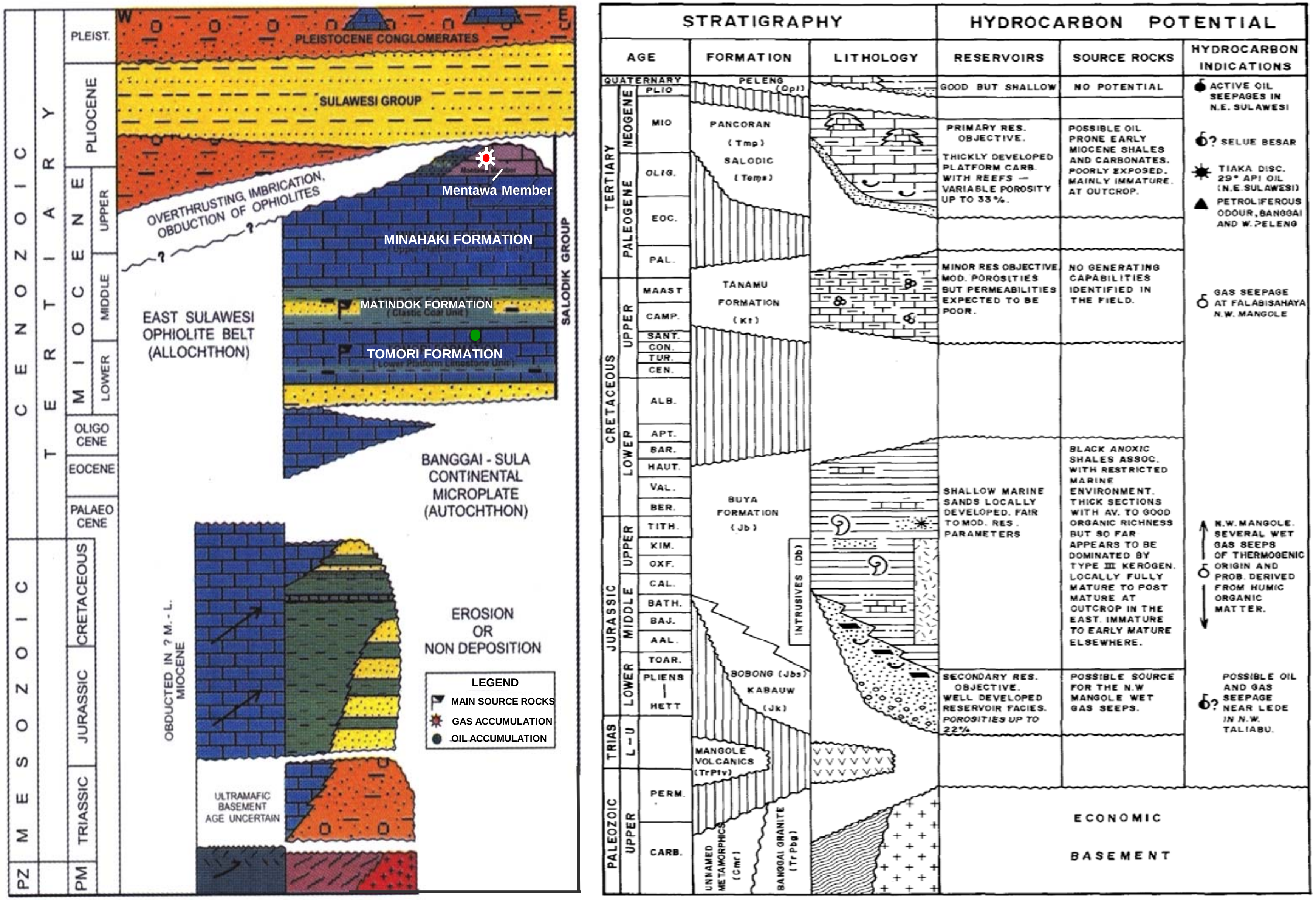

Figure 4 - Stratigraphic columns of Banggai Basin (left side) and Sula Basin (right side, after Garrard et al., 1988)

OIL CLASS	ORGANIC MATTER INPUT INTO KEROGEN	API (deg.)	WAX (% wt)	sulphur (% wt)	pr/ph	N (ppm)	trace metal (ppm)	nickel/ vanadium	DEPOSITIONAL ENVIRONMENT OF SOURCE
A	PHYTOPLANKTON BACTERIA	25 - 30	< 10	> 1.0	< 3.0	1000 - 5000	50 - 300		MARINE (carbonate and other non-siliciclastic sediments)
B	PHYTOPLANKTON BACTERIA	30 - 35	< 10	0 - 1	< 3.0	500 - 1500	0 - 50		MARINE (siliciclastic sediments)
C	PHYTOPLANKTON BACTERIA	varies (bimodal)	up to 40	little	< 3.0	500 - 1500	0 - 50	> 2.0	LACUSTRINE (freshwater)
D	HIGHER LAND PLANT (angiosperm dominated) DEBRIS, BACTERIA	35 - 45	up to 40	little	> 3.0	< 500	little		NON-MARINE
E	HIGHER LAND PLANT (gymnosperm dominated) DEBRIS, BACTERIA	35 - 45	up to 40	little	> 3.0	< 500	little		NON-MARINE

Figure 5 - Oil grouping/ classification subdivided into five classes from A to E based on source facies and organic matter inputs, recognized based on bulk and molecular parameters (Clayton and Fleet, 1991).

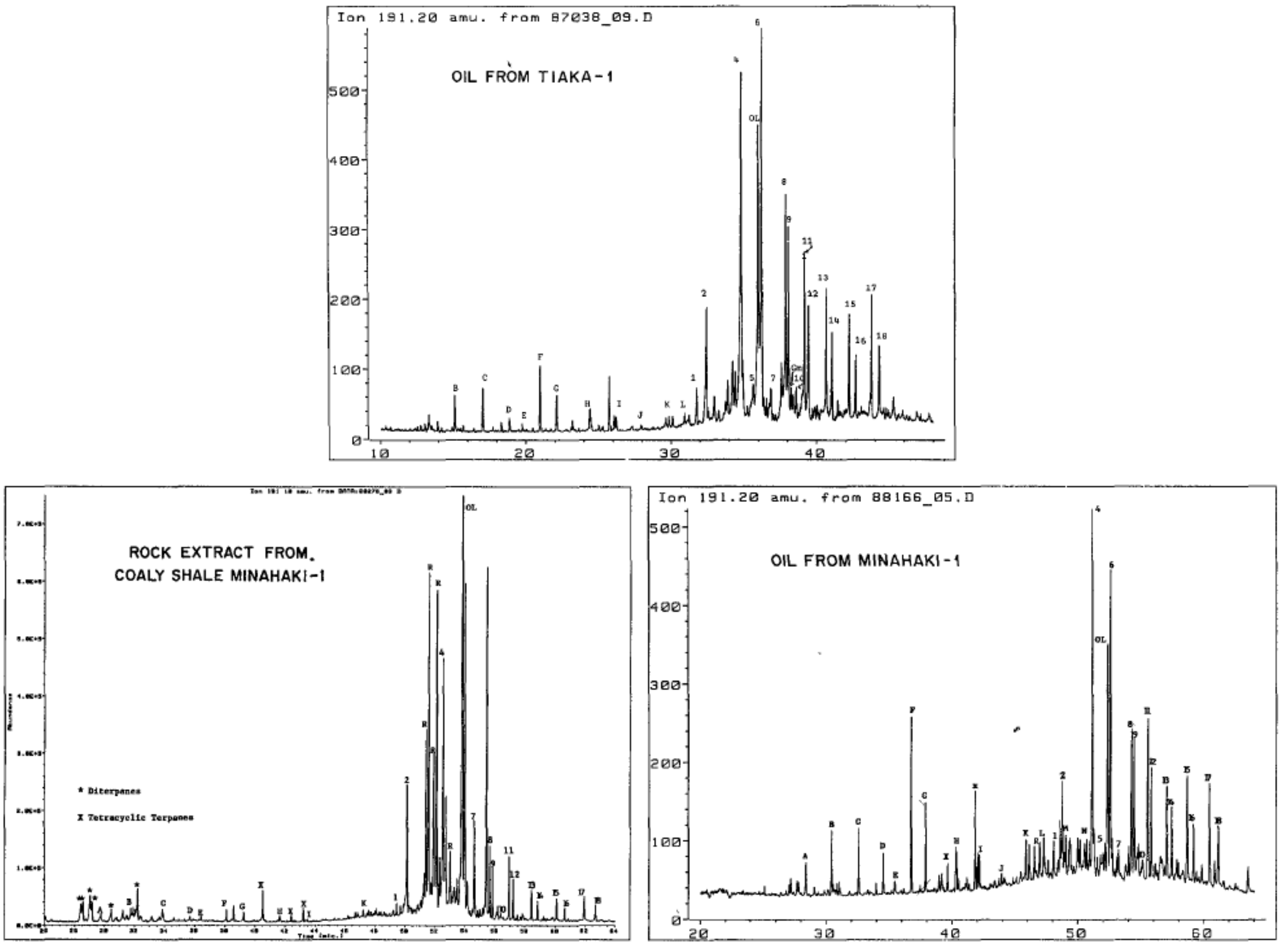

Figure 6 - Triterpane m/z 191 biomarker scan from Tiaka-1 and Minahaki-1 oils, and rock extract of Minahaki-1 Middle Miocene coaly shale, showing similar distribution or good correlation. Note the abundant oleanane (OL) occurrences on all samples, indicating Miocene-age source rocks (Davies, 1990).

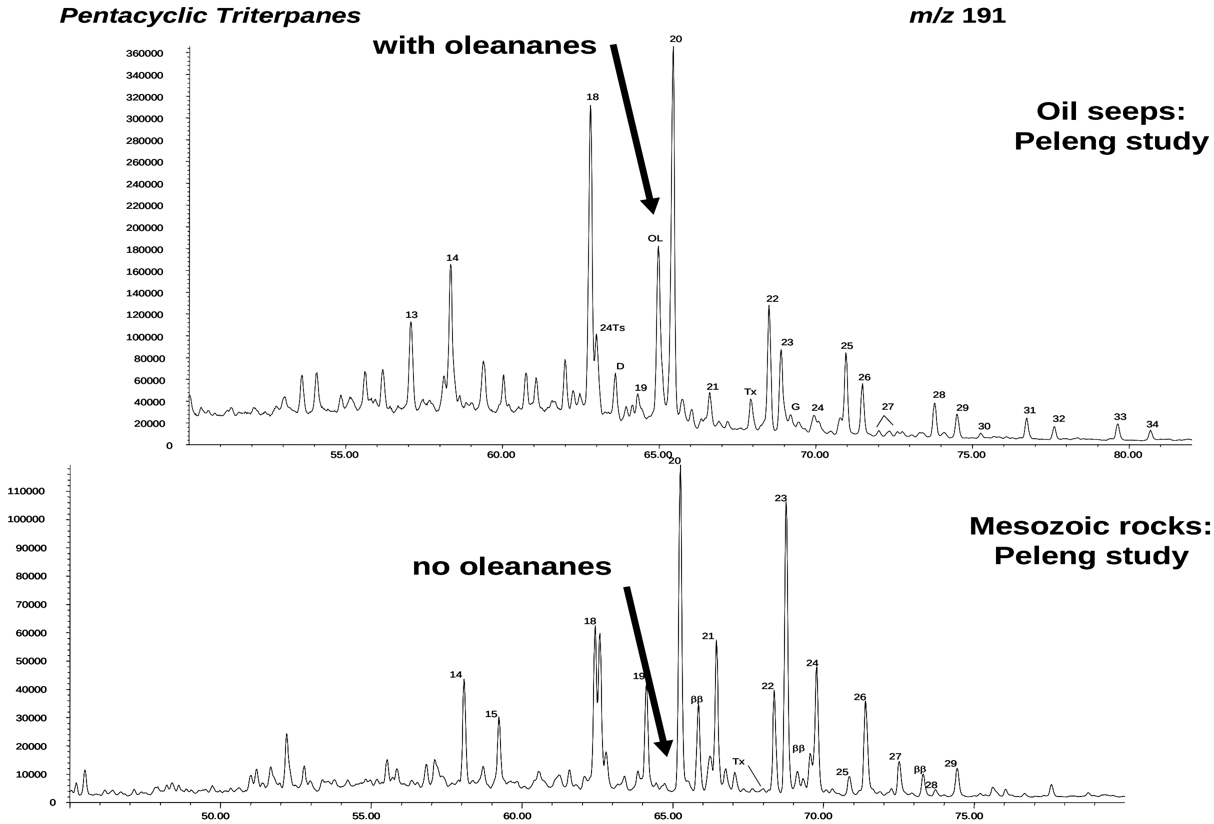

Figure 7 - Triterpane m/z 191 biomarker comparison between an oil seep in Peleng Island and Pre-Cenozoic rock sample exposed on Peleng Island. Note the existence of oleanane biomarker on oil sample, but it is absent from Pre-Cenozoic rock sample. Oleanane is mostly Cenozoic biomarker and very few (< 20 %) in rock samples older than Late Cretaceous.

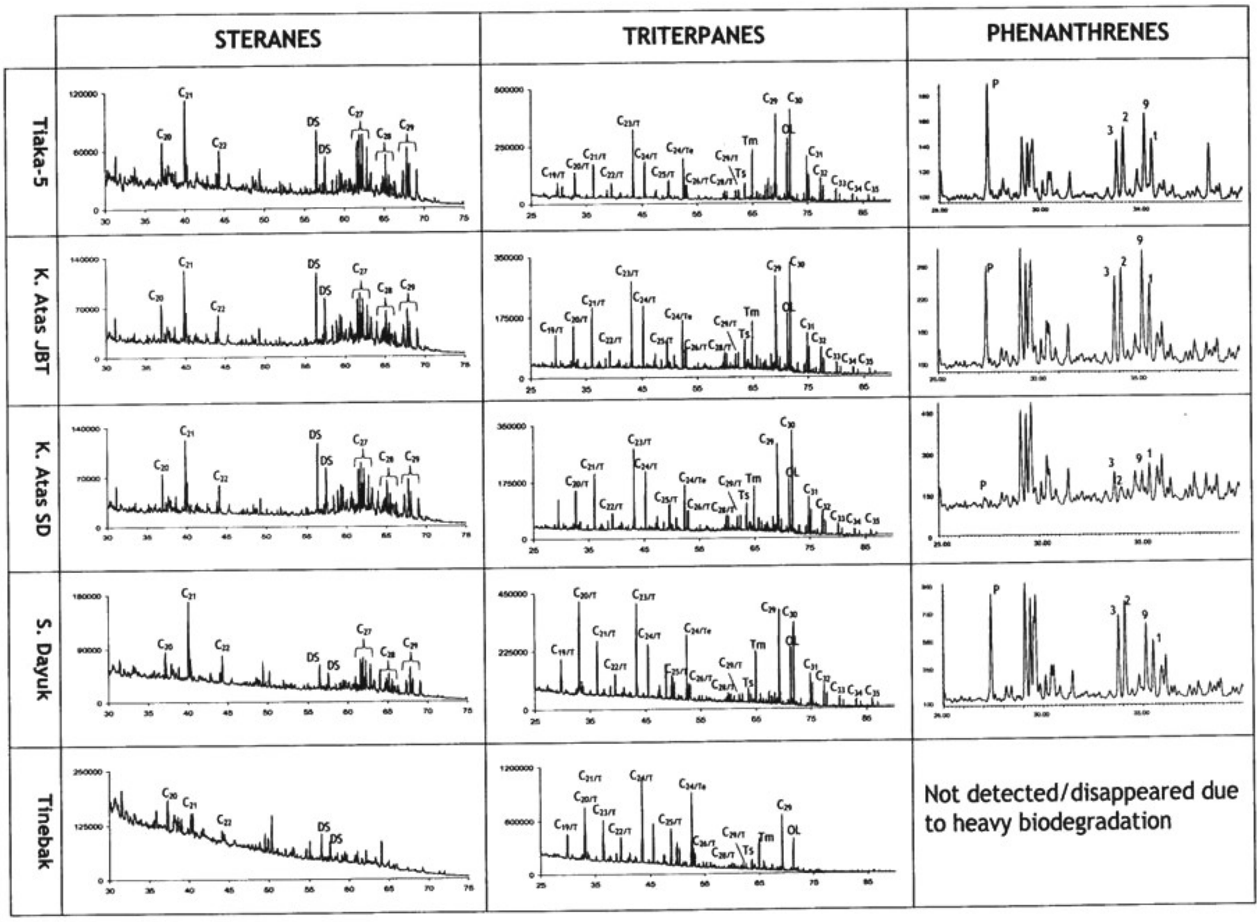

Figure 8 - Sterane, terpane, and phenanthrene biomarkers comparison of oils from Tiaka-5 well and oil seeps. Note the dominant C_{27} in sterane indicating marine environment, and presence of oleanane (on terpane) at all samples.

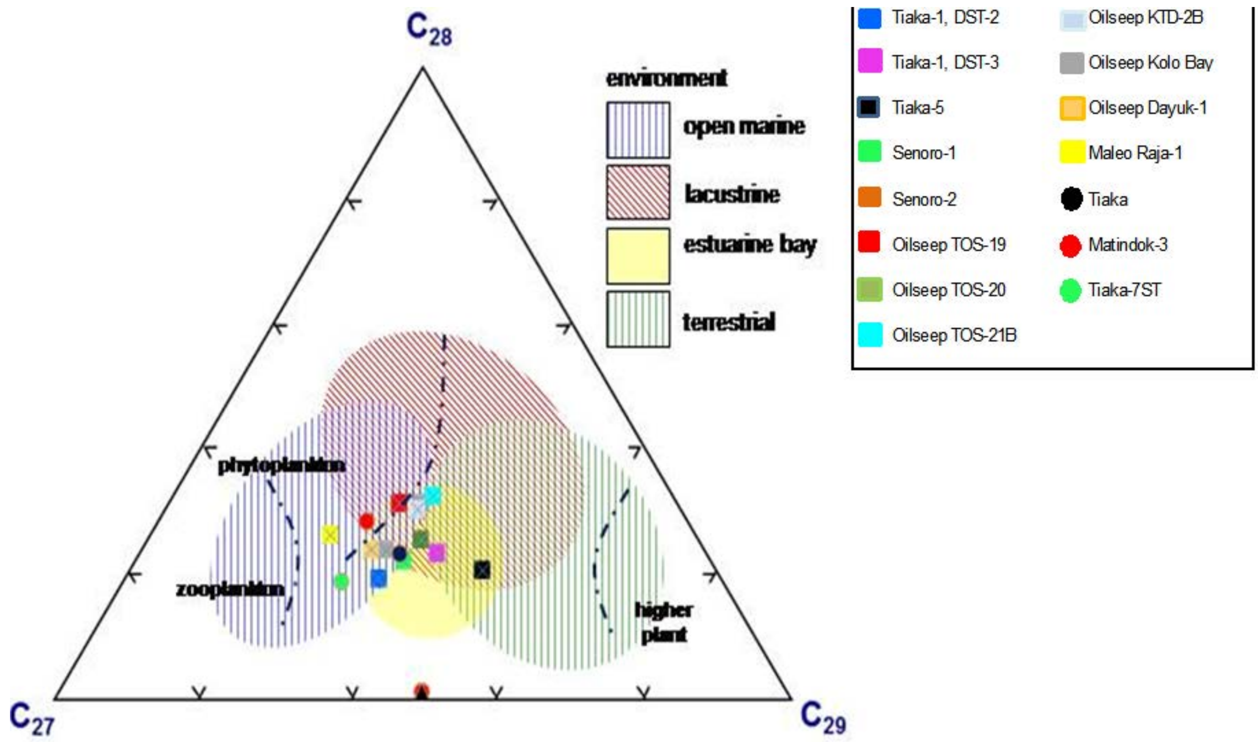

Figure 9 - Triangular distribution of Huang & Meinschein (1979) of steranes C_{27}, C_{28}, C_{29} for depositional environments of source rocks based on oil samples, showing source facies of estuarine to open marine.

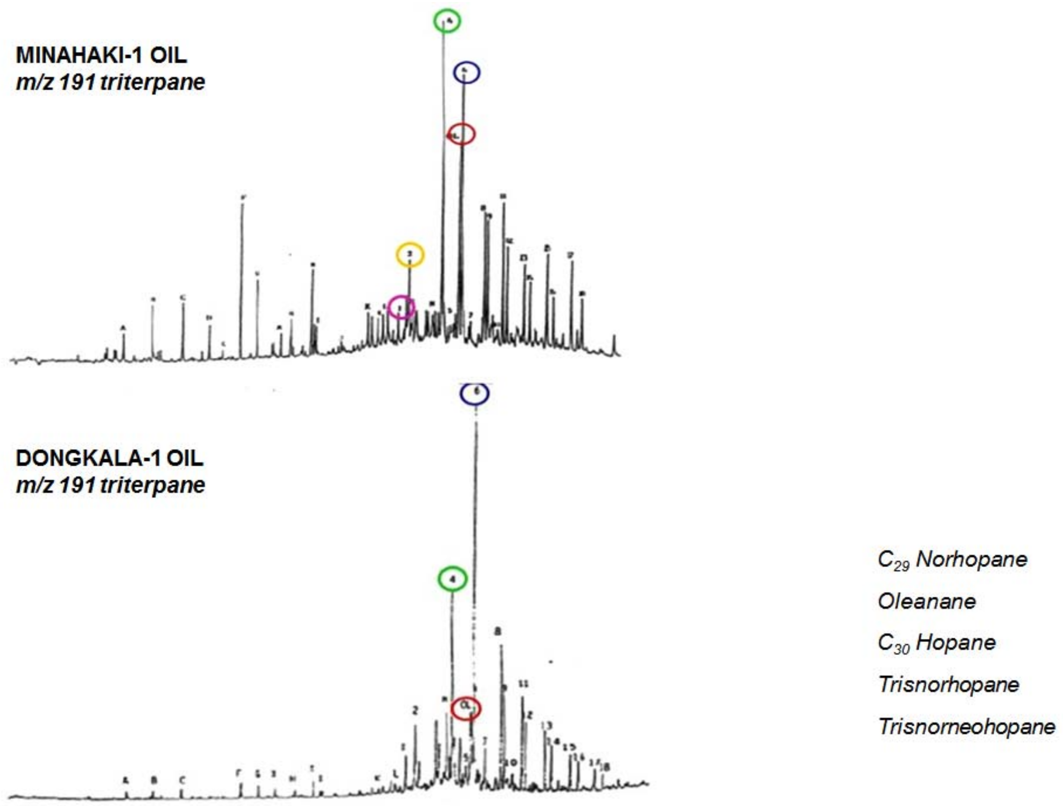

Figure 10 - Triterpane distribution of Minahaki-1 oil (above) and Dongkala-1 oil (below). Note the ratio between C_{29} norhopane and C_{30} hopane, high ratio (>1.0) showing carbonate source rocks like Minahaki oil, low ratio (< 0.5) showing siliciclastic/ shale source rocks like Dongkala oil.

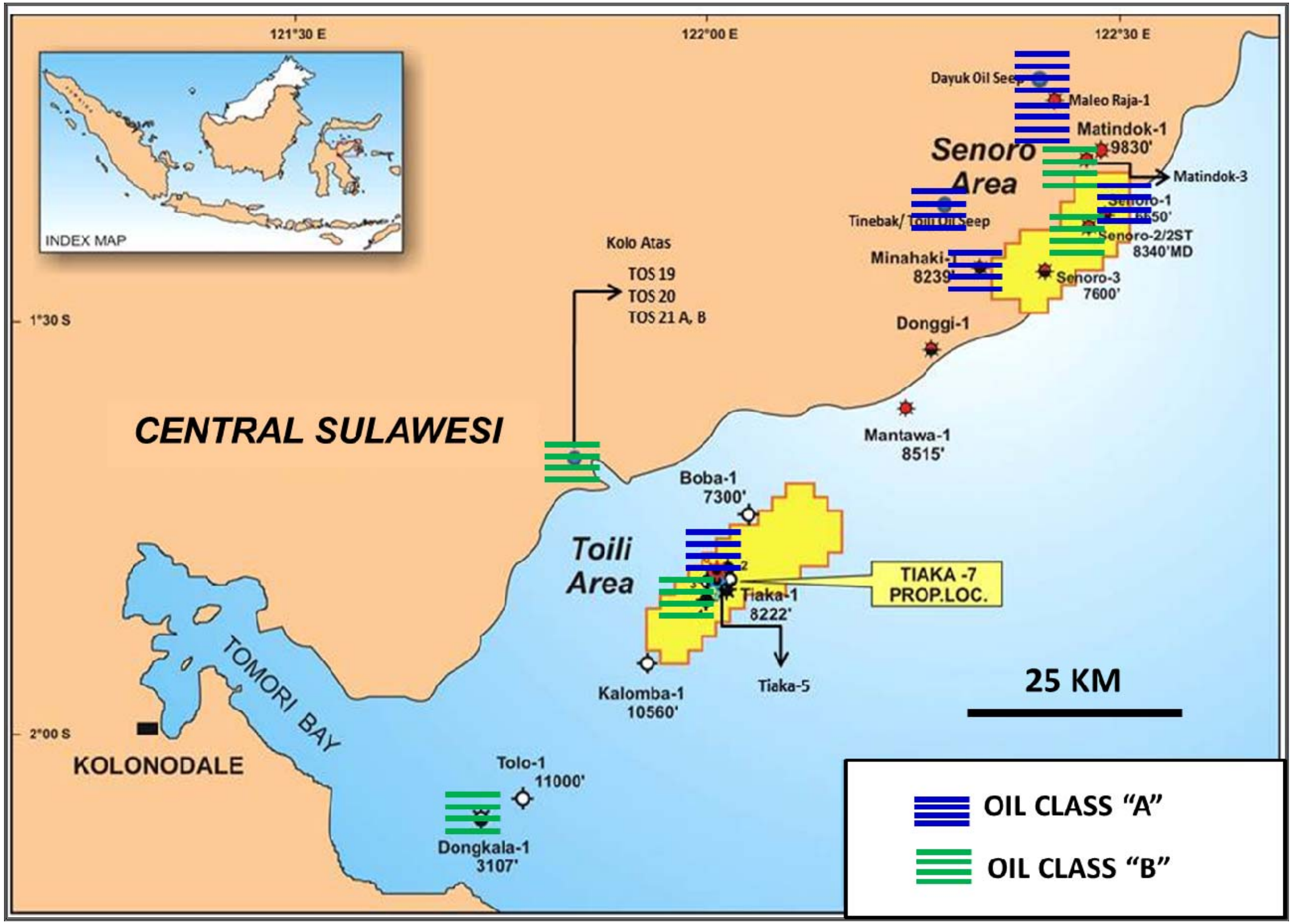

Figure 11 - Distribution of oil grouping and classification of oils in Banggai Basin, subdivided into classes "A" and "B". The two classes are both derived from a mixture of algal and bacterial remains which have accumulated in marine environments; the difference is in the associated lithology – either non-clastic/carbonate (class A) or siliciclastic/ shale (class B).

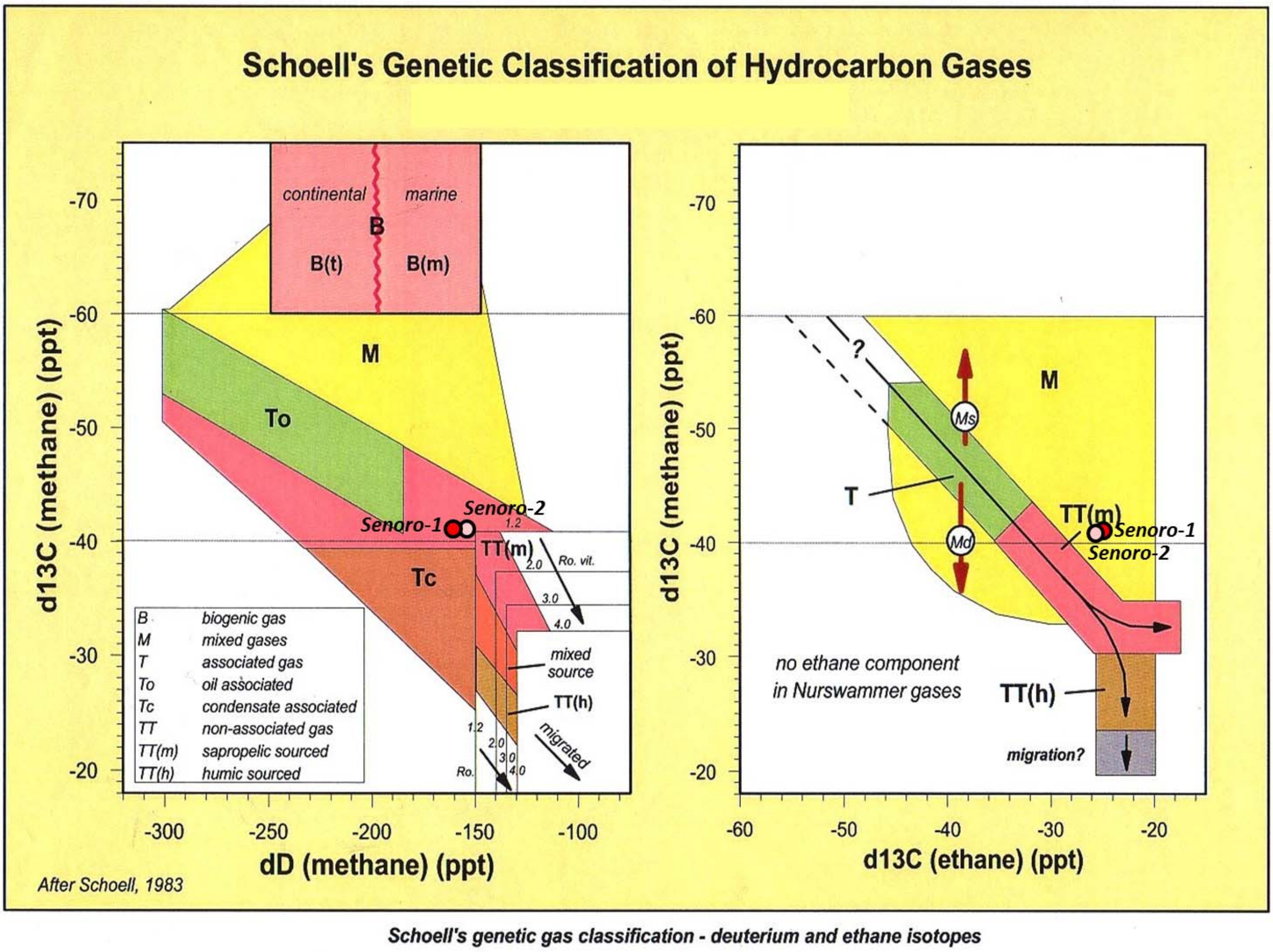

Figure 12 - Cross plots to characterize genetic types of gas for Senoro-1 and -2 gases. The gases are thermogenic associated gas related to oil.

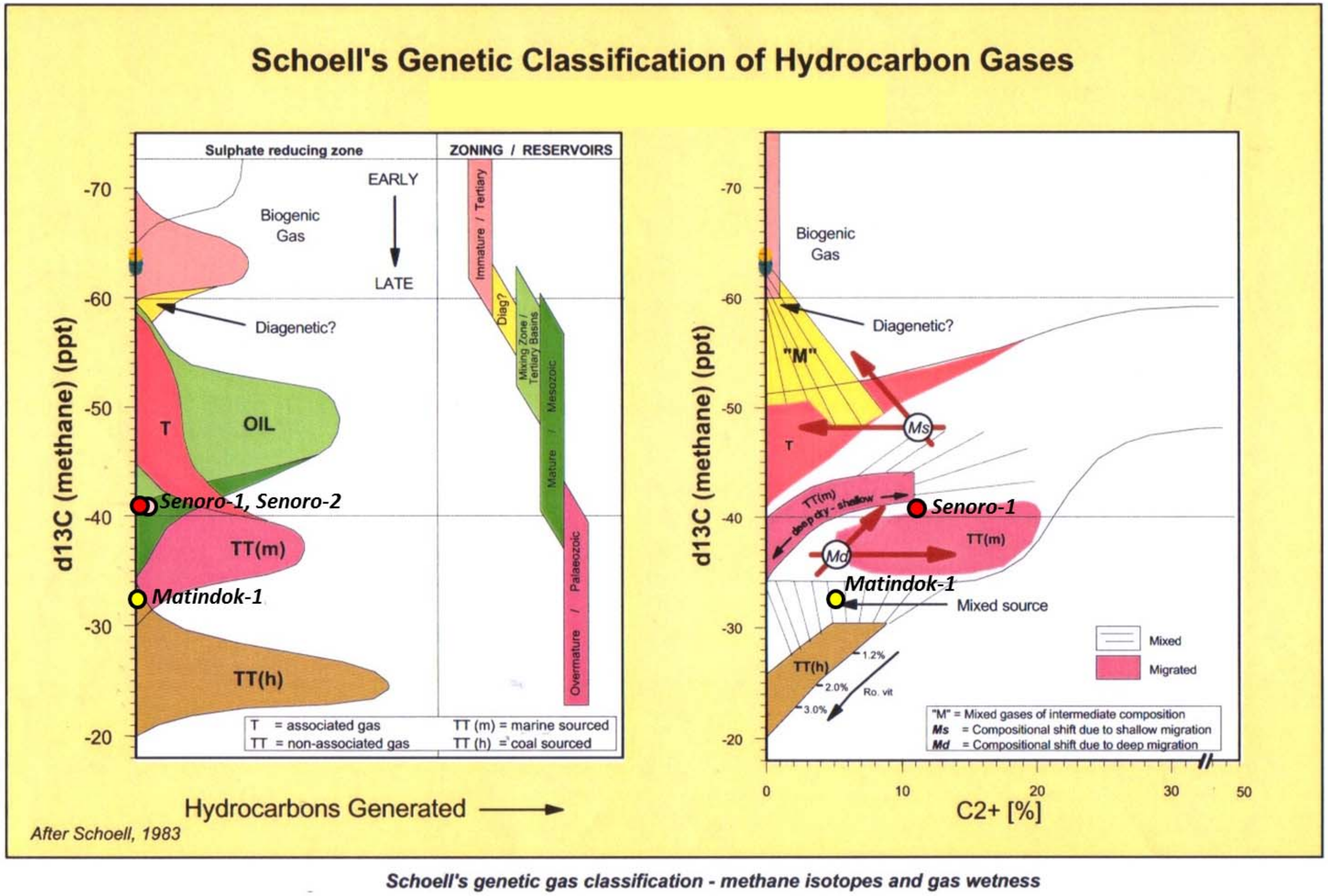

Figure 13 - Cross plots to characterize genetic types of gas for Senoro-1 and -2 gases and Matindok-1. Senoro gases are thermogenic associated gas related to oil (formed by thermal cracking of oils), and Matindok-1 gas shows a thermogenic non-associated gas generated from humic kerogen.

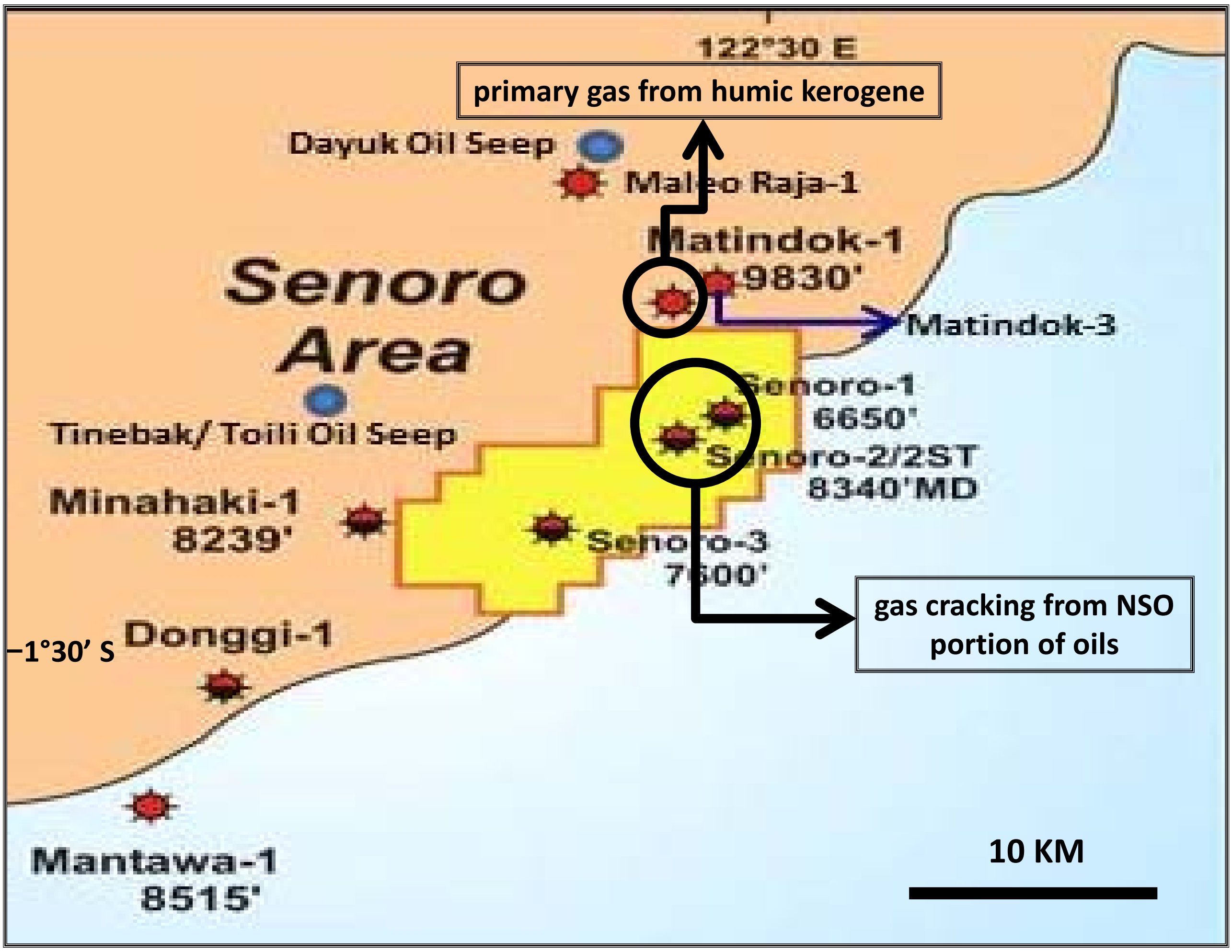

Figure 14 - Genetic types of gases for Senoro and Matindok. Senoro gas is genetically derived from cracking of oil rich in NSO (nitrogen, sulfur, oxygen) components. Matindok gas is genetically derived from generation of gas-prone humic kerogen.

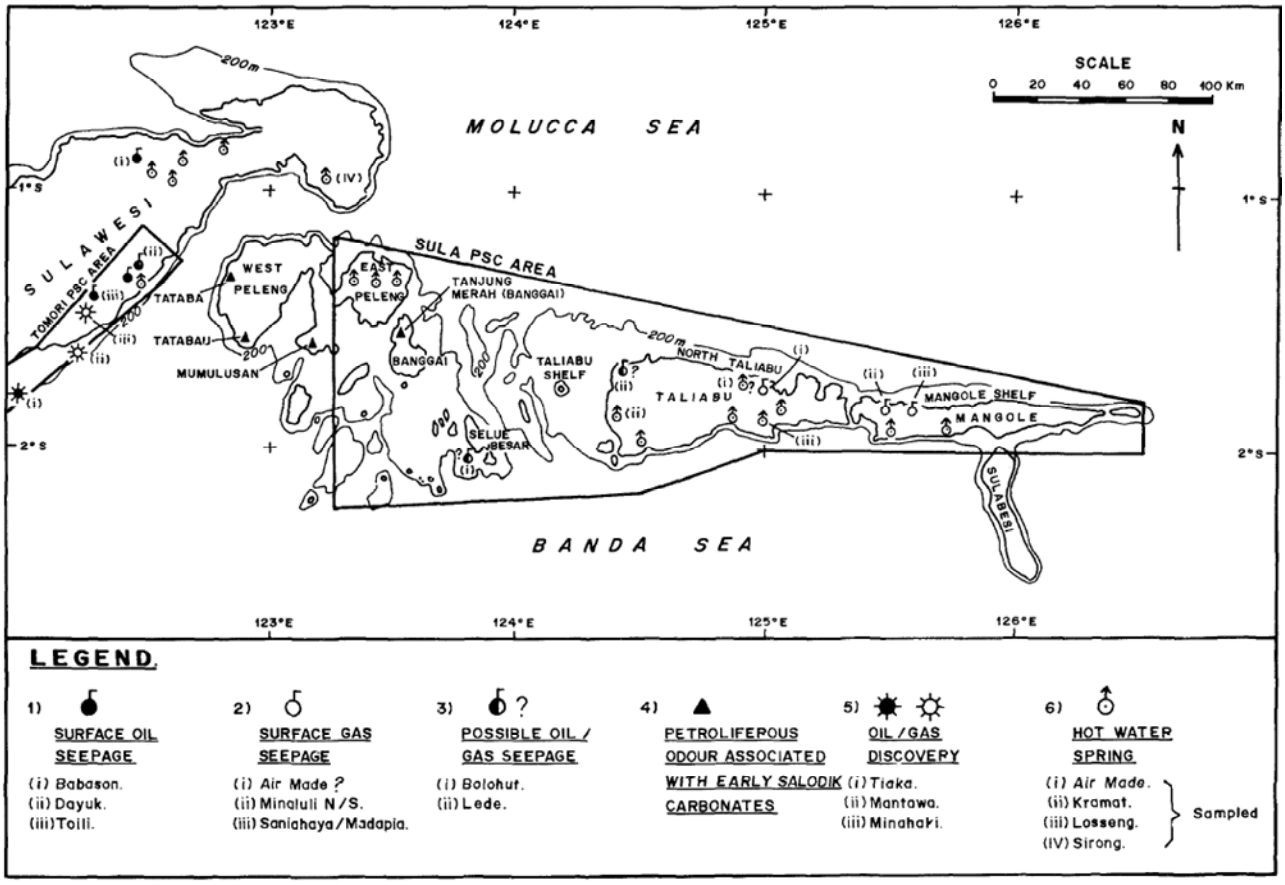

Figure 15 - Surface hydrocarbon indications in the Banggai-Sula area. Previous block boundaries (Sula PSC and Tomori PSC areas are outlined (Garrard et al., 1988).

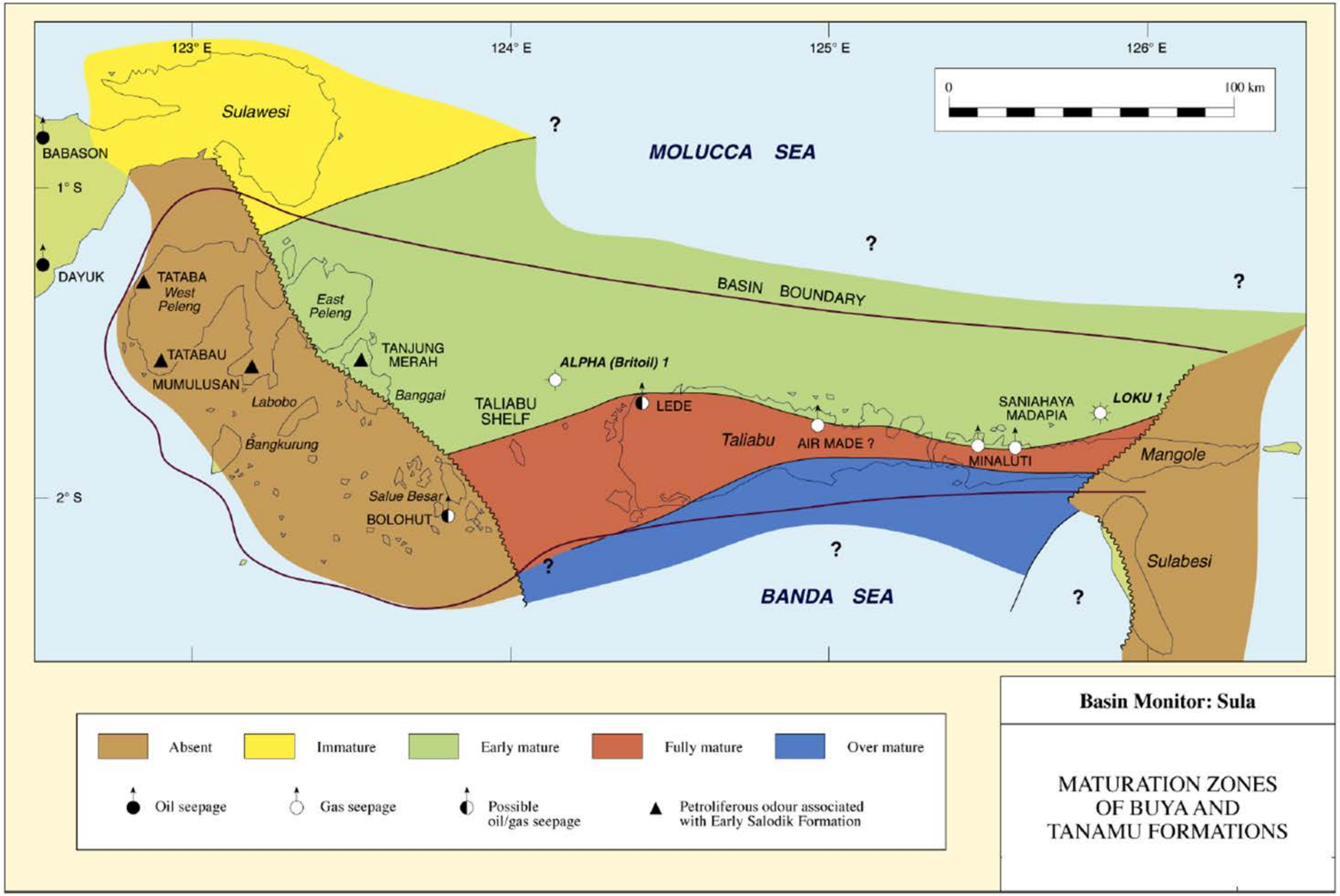

Figure 16 - Maturation zones of Jurassic to Cretaceous Buya and Tanamu Formations in Sula Basin (IHS Energy, 2016)