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REGIONAL GAS GEOCHEMISTRY OF INDONESIA: GENETIC CHARACTERIZATION AND HABITAT OF NATURAL GASES

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ABSTRACT

Strong growth of gas reserves in Indonesia as mature oil fields are depleted will cause a continued shift from oil to gas production. Exploration during the last ten years has resulted in discoveries of large gas fields widely distributed across the Indonesian archipelago. Understanding the origin, distribution, and habitat of natural gases is important for continued gas exploration. This paper presents the first regional geochemistry study of natural gases in Indonesian basins and has used data from approximately 350 gas occurrences to derive regionally applicable conclusions.

Based on molecular composition and isotope data, both thermogenic and biogenic (bacterial) gas types can be recognized in Indonesia. Mixing between the two types is also commonly observed. The thermogenic gases are characterized by a normalized methane concentration of less than 95 % and carbon isotope ratios ($\delta^{13}C_{CH4}$) heavier (more positive) than -45 ‰. The pure biogenic gases have a methane component of 98% or more and $\delta^{13}C_{CH4}$ values lighter (more negative) than -60 ‰. Mixed thermogenic and biogenic gases have methane components of 95-98 % and $\delta^{13}C_{CH4}$ values in the range -45 to -60 ‰.

Thermogenic gases predominate in most gas provinces in Indonesia and can be found in the basins of Sumatra, Natuna, Java, Kalimantan, Makassar Strait, Sulawesi, Papua, and Timor-Arafura. The gases result from both primary gas generation from gas-prone kerogen and from secondary gas generation from oil cracking. The biogenic gases are found mainly in the fore-arc basins west of Sumatra, in the East Java Basin, and in the foredeep area of the Sorong Fault Zone in northern Papua.

High concentrations of CO_2 mainly occur in North and South Sumatra, East Natuna, and onshore Java. Based on the "heavy" values for $\delta^{13}C_{CO2}$, most CO_2 occurrences have an inorganic origin by either thermal destruction of carbonates or volcanic de-gassing. H_2S concentrations are moderate to high (500 to >10,000 ppm) in some gas fields in North Sumatra, South Sumatra, East Java, East Sulawesi and Salawati Basins. All occurrences of high H_2S relate to thermo-chemical sulfate reduction of deep, hot carbonate sequences.

Indonesia is well known for its mid-Tertiary petroleum systems (Eocene to Miocene) and the bulk of the nation's gas resources have been generated from and are found in rocks 40-5 My. However, there are also significant volumes of natural gas found in Mesozoic and Plio-Pleistocene systems. Paleozoic systems are not important yet but they may contribute to future gas discoveries in some frontier basins in Eastern Indonesia.

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INTRODUCTION

A Shift from Oil to Gas

Oil production in Indonesia peaked 10 years ago at 1.6 MMbpd and is now in decline. The decline is largely structural because the production comes from mature fields. Indeed, some 88 % of Indonesian fields are mature (Newton, 2004). Analysis of discoveries also shows that oil exploration is mature in many areas but there has been strong growth in gas reserves in recent years. This trend is likely to continue (Howes, 2001).

The gas industry in Indonesia is of fundamental importance to the economic and social well-being of the country (Suharno, 1993). Since 1958, gas has been used to support various domestic industries as feedstock for fertilizer and petrochemicals, city gas supply, power generation, and transportation. The potential for gas to displace diesel in power generation remains very high. Since 1977, gas has been exported as LNG and pipeline gas exports to Singapore began in 2001.

In the implementation of the National Energy Policy (Suharno, 1993), it was recognized that the volume of crude oil used domestically must be reduced. Meanwhile, the domestic use of natural gas as fuel should be increased. To implement this policy, exploration is required to find new gas sources and increasing gas demand will see a change in exploration strategy. As well as conventional exploration for oil and gas, there will need to be increased efforts and incentives to explore for gas in remote areas and deep-water regions. The establishment of a new gas pricing methodology is necessary to encourage upstream activities (Suharno, 1995) and indeed there has been upward pressure on gas prices in the last few years. Deep water provinces and the regions surrounding major gas developments are the areas most likely to see significant increases in reserves and production in the short to medium term in Indonesia (Howes, 2001).

Gas Potential of Indonesia

Indonesia has proven gas reserves of 150 tcf and proven and potential gas reserves of 226 tcf (at January, 2006). Currently, daily production of gas in Indonesia is 7828 MMcfd with annual production 2.79 tcf. Cumulative gas production until January 2006 is 56 tcf. There are also several major gas projects either under development or in advanced stages of planning (for example, offshore Natuna Island ("East Natuna"), offshore deep-water Makassar Strait ("Gendalo"), onshore East Sulawesi ("Donggi-Senoro"), onshore and offshore Bird's Head of Papua ("Tangguh") and offshore Arafura Sea ("Abadi")).

Based on recent exploration results and trends, future gas reserves of Indonesia can be expected from

1) deep water and in areas close to major natural-gas development projects ("Gendalo", "Tangguh", and "Abadi" types)

2) fractured basement plays in Sumatra ("Suban" type) and Java

3) exploration beneath the current intra-arc volcanic apron of Sumatra, Java and Nusa Tenggara ("Ombilin" and "Banyumas" types)

4) Pliocene globigerinid sands of East Java ("Terang-Sirasun" and "Maleo" types),

5) reefs of the collided Banggai Platform, East Sulawesi ("Donggi-Senoro" type),

6) wrench-related systems of northern Papua ("Niengo" type).

Less conventional gas resources that may eventually be exploited include gas hydrates in deep-water areas, coal-bed methane, and deep basin tight gas. Commercialisation of gas-to-liquids technology will assist production of significant "stranded" gas reserves (Howes, 2001).

Significance of Understanding the Geology and Geochemistry of Natural Gases

Exploration for natural gas is growing in importance as a result of increased demand (Katz, 2001). This increase in exploration requires a better understanding of how gas accumulations form and change through time. The relative simplicity of gas compared to that of oil limits the amount of information that can be derived from a given accumulation. However, the molecular and isotopic composition of gas can be used to infer its mode of formation (thermogenic versus biogenic; and primary versus secondary cracking) and the level of thermal maturity of the generative sequence. This paper presents the first regional geochemistry study of natural gases in Indonesia. It is intended to assist development of focused strategies that result in efficient and effective gas exploration.

DATA AND METHODS

Gas geochemistry data of natural gases (hydrocarbon and non-hydrocarbon gases) from producing and non-producing basins in Indonesia have been collected (Figure 1). As many as 350 gas sample analyses have been examined. Data from approximately 100 of these samples is shown in Tables 1 to 3. Concentration, molecular composition and ratios, and stable isotopic composition data have been used to characterize natural gases from various source rocks and geologic settings. The gases have been collected from drill stem tests, wireline sampling tools, wellhead samples from producing wells and natural seepages.

The concentration (expressed in either mole or weight percentage) of gas is typically the first factor considered in the classification of natural gas. Most natural gases are mixtures of hydrocarbon gases (methane, ethane, propane, iso-butane, normal butane, pentane) and non-hydrocarbon gases (carbon dioxide, hydrogen sulfide, nitrogen and other more rare gases). Higher carbon number hydrocarbons (C_5-C_7) can also be present in gas samples, but due to possible condensation effects at surface pressure-temperature conditions, the concentration as analysed can be unrepresentative. The molecular ratios used in this study (after normalization by excluding non-hydrocarbon gases) consist of $C_1/\Sigma C_n$, ΣC_{2+} and $C_1/(C_2+C_3)$ (Bernard parameter) and gas wetness ratio (ΣC_2 to $C_5/\Sigma C_1$ to C_5 x 100 %).

The stable isotope ratios include carbon and hydrogen isotope ratios of light hydrocarbons and carbon dioxide ($\delta^{13}C_{CH4}$, $\delta^{13}C_{C2H6}$, $\delta^{13}C_{C3H8}$, $\delta^{13}C_{CO2}$, δD_{CH4}). The carbon and hydrogen isotope signature of natural gas can often provide information about its source rocks, in addition to identifying the genetic type of natural gas.

The interpretation of the gas data follows the methods of Schoell (1983) for characterizing natural gases, Whiticar (1994) for correlating natural gases with their sources and Katz (2001) for understanding formation and alteration processes. Readers are also referred to the references cited in those publications. It should be emphasized that the available geologic, geophysical, and geochemical information are integrated into the petroleum system investigation to understand the gas habitats.

BRIEF DISCUSSION OF GAS GEOCHEMISTRY

The following discussion is summarized from Katz (2001) and references therein, except as otherwise noted.

Genetic Gas Types

There are several modes of formation for commercial gas accumulations. Gas may form at low temperatures through a series of biochemical reactions acting on sedimentary organic matter (bacterial or "biogenic" gas), at more elevated temperatures through the cracking of kerogen, and at even higher temperatures through the cracking of oil (the last two are called "thermogenic" gases).

Biogenic gas usually contains > 98 % methane (normalized) (or < 1 % ethane plus). Primary biogenic methane is isotopically light, the $\delta^{13}C_{CH4}$ values are typically < -60 ‰ (i.e. more negative than -60). There are two primary mechanism of formation of biogenic gas (methanogenesis), CO_2 reduction and fermentation. These two mechanisms can be distinguished by the methane's deuterium content. Isotopically lighter (δD_{CH4} < -200 ‰) methane forms through fermentation. Isotopically heavier (δD_{CH4} > -200 ‰) methane forms through CO_2 reduction. Fermentation dominates in freshwater systems, while CO_2 reduction dominating in marine environments. Biogenic gas usually occurs in temperatures < 80 ºC.

Thermogenic gas may be either wet (normalized ethane and higher homologues > 5 %) or dry (normalized ethane plus < 5 %) depending on the level of thermal maturity. Dry gases are associated with higher levels of thermal stress. Thermogenic methane will typically show a stable carbon isotope > -55 ‰ with values increasing with increasing thermal maturity. The relationship between C_2/C_3 ratio and the difference in the carbon isotopic composition of ethane and propane can be used to differentiate between primary thermogenic gas (from cracking of kerogen) and secondary thermogenic gas (from cracking of crude oil). Thermal cracking of crude oil to methane begins at temperatures of 150 ºC.

Many individual gas accumulations may have multiple sources (mixed biogenic-thermogenic gas). One method proposed to identify the presence of multiple sources for a gas is the use of "natural gas plot" where the carbon isotope ratio is plotted against the inverse carbon number. If not mixed, a gas accumulation in which all of the gas components are co-generated results in a linear trend. A deviation from the linear plot indicates mixing with biogenic gas.

Thermal Maturity

The isotopic composition of individual gas components is a function of thermal maturity and the nature of the original starting material. Individual gas components become isotopically heavier with increasing thermal maturity. There is an empirical relationship between the isotope composition of methane, ethane, and propane and effective source rock thermal maturity.

When the gas is unaltered and co-generated, the estimated thermal maturity level for each component is approximately the same. In the case of multiple sources and the gas may not be co-generated, the thermal maturity estimates for the different components vary. If the maturity estimate for methane is less than that of either ethane or propane it may indicate that there has been a biogenic gas contribution. When the methane maturity value is greater than that of ethane and propane, a more mature source rock system is inferred.

Isotopic composition of the C_1 through C_3 components can be used to estimate the temperature of gas generation. This is accomplished using the difference in isotopic composition of ethane and methane ($\delta^{13}C_2$ - $\delta^{13}C_1$) and propane and methane ($\delta^{13}C_3$ - $\delta^{13}C_1$). In addition to changes in isotopic composition, there also changes in gas composition associated with increases in thermal maturity. For example, the iC_4/nC_4 ratio decreases with increasing thermal maturity as a result of the generation of nC_4.

Alteration

Bacterial alteration of wet gases typically appears as the preferential removal of the C_{3+} components. With the onset of microbial alteration, ^{12}C is preferentially removed from propane, n-butane, and n-pentane resulting in isotopically enriched wet gas components. This isotopic enrichment may exceed 20 ‰. Microbial alteration of methane can also occur. It is, however, much more difficult to recognize compared to that of the wet gas components. The major indicator of such alteration may reside in the deuterium content of the gas. The residual methane is isotopically enriched in both ^{13}C and ^{2}D compared to the initial methane. This enrichment can result in very heavy deuterium values ($\square^{2}D$ > -100 ‰). As biodegradation proceeds, the normal alkanes are progressively eliminated and there is an increase in the $iC4/nC_4$ ratio. This may result in a gas composition that appears to be thermally immature. Gas wetness may increase through water washing as a result of the preferential removal of methane. Methane solubility is about 3, 13, and 50 times greater than ethane, propane, and *n*-butane, respectively.

Non-hydrocarbon Gases

An understanding of non-hydrocarbon gases is of economic importance because of the reduction in calorific content and the acidic corrosive nature of many of these gases. Significant proportions of non-hydrocarbon gases can result in increased production costs because of the needs for corrosion-resistant metal alloys and additional processing of the gas prior to going to market.

Carbon Dioxide (CO_2)

Within the Australasian region CO_2 is the major contaminant, and in some cases it is the dominant gas species in an accumulation (Cooper et al., 1997; Imbus et al., 1998). For example, in the Natuna D Alpha gas field an estimated 157 TCF of CO_2 is present, representing 71% of the gas in-place. Carbon dioxide may be introduced into a petroleum system through a number of means. These include derivation from an organic source, the decomposition of carbonate minerals through catalysis with clays, hydrolysis, high temperature processes, and mantle or volcanic de-gassing. The stable carbon isotopic composition of CO_2 is the primary means of determining the mode of CO_2 formation. Isotopically light CO_2 ($\delta^{13}C_{CO2} < -10$ ‰) is derived from organic matter through maturation. $\delta^{13}C_{CO2}$ values between -4 and -7 ‰ are typically associated with mantle de-gassing. Isotope ratios associated with carbonate decomposition partially overlap those of mantle de-gassing (–10 and 2 ‰). Multiple formation processes may be active in a basin.

Hydrogen Sulphide (H_2S)

Hydrogen sulfide (H_2S) is the deadliest gas produced in large quantities in nature and is a serious occupational hazard in the oil and gas industry (Hunt, 1996). Hydrogen sulfide in gas reservoirs has two major sources: the thermal decomposition of high-sulfur oils and thermo-chemical sulfate reduction (TSR) in pore waters. TSR is the reaction of sulfate minerals (primarily anhydrite) and hydrocarbons (beginning at temperatures of 120-140 ºC) to form H_2S and calcium carbonate. Because anhydrite is often associated with carbonate sequences, TSR is commonly associated with deep, hot, carbonate reservoirs and/or source rocks. TSR is the most important process for formation of high-H_2S gases (>10% H_2S). Some H_2S also comes from the thermal degradation of kerogen and coal.

Nitrogen (N_2)

When abundant in natural gas, nitrogen may be derived from high-maturity coals, especially when the final stages of generation (VR > 4%) are captured by late-formed traps (OilTracers, 2006). Although nitrogen can also be derived from magmatic sources, magmatic nitrogen is not a common component of high-nitrogen gases. In contrast, clay diagenesis is an important nitrogen source. Ammonium substituting for potassium is released during the transformation of meta-stable clays (illite-smectite, or smectite) to illite. This ammonium can then be either inorganically or bacterially oxidized to form molecular nitrogen. Because nitrogen is relatively insoluble in saline pore waters, the nitrogen can readily enter the gas phase, especially when sediments are associated with evaporites. This gas-phase nitrogen can then migrate into shallow traps.

REGIONAL PETROLEUM GEOLOGY OF INDONESIA

Geologically, the Indonesia archipelago occupies one of the most complicated areas on Earth. The archipelago is made up of three major crustal plates and numerous micro-plates of both continental and oceanic origins. This tectonic setting has produced more than 60 sedimentary basins and inter-basin areas in which petroleum accumulations are either proven or possible. Indonesia may also be the most diverse country in the world in terms of petroleum systems with at least 50 proven and probably more than 100 speculative petroleum systems (Howes, 2001).

As of January 2007, following 142 years of exploration, 38 basins have been drilled, 16 are producing oil and gas and the presence of oil or gas has been confirmed in another 8. 14 have been drilled but with no discovery. There are 22 basins undrilled; 20 in Eastern Indonesia and two in Western Indonesia (Satyana, 2006b, c).

The petroliferous basins of Western Indonesia occur mostly onshore or in the shallow waters of Sumatra, Java, and Kalimantan. They demonstrate gross similarities in terms of both structure and stratigraphy reflecting common regional controls throughout their Cenozoic histories (Netherwood, 2000; Satyana, 2005). The characteristics are

- Middle to Late Eocene rifting, fluvio-lacustrine fill and source rock deposition

- mid-Oligocene to Middle Miocene transgression with fluvial reservoirs being succeeded by the main deltaic and carbonate reservoirs in the Late Oligocene to Early Miocene, and regional seals being deposited in the Middle Miocene at maximum transgression,

- Late Miocene to Pliocene compressional structuring events and increased heat flow associated with the collision of the Australian craton with the Asian plate and collision of the Luzon arc with the Asian plate.

Many basins of Eastern Indonesia differ geologically from those of Western Indonesia in that they developed on Gondwanan continental crust and have a Paleozoic and Mesozoic sedimentary history. Break-up of the Gondwana super-continent occurred in the Jurassic and Cretaceous periods. Post-rift clastic sediments continued to accumulate until the Paleogene and the Neogene is characterised by thick carbonate intervals. The collision of the Indo-Australian plate with the Pacific plate in the Tertiary has resulted in Eastern Indonesia being tectonically and structurally complex, comprising slivers of continental blocks, arc fragments and trapped ocean basins. Although many potential petroleum basins are recognized, they tend to be small, geologically poorly understood and in deep water. Some 86% of Eastern Indonesia’s basinal areas are in water depths greater than 200 m. The onshore areas are remote and often jungle covered.

Although geologically complex, Eastern Indonesia is clearly prospective for gas. Giant gas discoveries have been made in Mesozoic reservoirs such as the Tangguh fields (24 tcf) in the Bintuni Basin (Casarta et al., 2004; Marcou et al., 2004), and Abadi (5 tcf, Nagura et al., 2003) in the Arafura Sea. Significant gas discoveries also occur in the Tertiary section of Eastern Indonesia such as the Neogene reef fields of eastern Sulawesi (Hasanusi et al., 2004; Satyana, 2006a) and the Niengo biogenic gas field (>3.5 tcf) in northern Papua (Figure 2).

GASES OF THE SUMATRA BASINS

Significant gas deposits in Sumatra have been found in the North, Central and South Sumatran back-arc basins, in the fore-arc basins of Meulaboh, Sibolga, Mentawai and Bengkulu, and in the intra-arc Ombilin Basin (Figures 1, 2, 3; Table 1).

North Sumatra Basin

The Arun gas field in the northern part of the North Sumatra Basin was discovered in August, 1971. It is reservoired in an Early Miocene reef of the Peutu Formation. The Arun gas field has ultimate recoverable reserves of about 14 tcf and 700 MMbbl condensate and was the largest gas field in Southeast Asia until superseded by the Natuna D-

Alpha gas field. Arun gas has 84.1 mol % CH_4 (C_{2+} of 15.9 %) and $\delta^{13}C_{CH4}$ value of -41 ‰, confirming its thermogenic origin. CO_2 content of the gas is up to 13.76 % and it contains 50-100 ppm H_2S (Alford et al., 1975). Other significant gas fields in the area are Alur Siwah, South Lho Sukon, and offshore NSO. The sources for the Peutu gases are considered to be the latest Oligocene Bampo shales or limestones, Peutu Formation shales, and the overlying Baong shales.

Carbonate reservoirs in the North Sumatra Basin exhibit a positive correlation between CO_2 partial pressure and reservoir temperature. There is a trend towards higher CO_2 content with increasing temperature. .Values of $\delta^{13}C_{CO2}$ between -4 and 2 ‰ indicate an inorganic origin for the CO_2 through carbonate thermal destruction.

Carbonate buildups of the Early Miocene Belumai Formation (a time equivalent of the Peutu Formation) occur in the offshore North Sumatra Basin (NSB area) to the north of Arun. Some 15 exploration wells have been drilled into these reefs and commercial gas and oil reserves have been established. Gas reserves of the order of 2 tcf are present in the A, J1, J2, R, and S Fields (McArthur and Helm, 1982). Based on compositional analysis, the gases of the NSB area are thermogenic containing 92-94 % CH_4 and 6-8 % CH_{2+}. Non-hydrocarbon gases in this area mainly consist of H_2S (10,000-15,000 ppm) and CO_2 (28-31 %). High H_2S content may relate to thermo-chemical sulfate reduction (TSR) of deep carbonate sequences.

Caughey and Wahyudi (1993) studied the pollution of the Peutu Formation by non-hydrocarbon gases in the North Sumatra Basin. The Peutu reservoirs mostly contain only small amounts of H_2S (24 ppm to a maximum of 2000 ppm at Alur Siwah) but can contain up to 82 % CO_2 such as at Kuala Langsa. The relatively shallow fields in the South Lhok Sukon area have 18-22 % CO_2 but the deeper field at Alur Siwah has 30 %.

There are no clear linear relationships between CO_2 content and depth or temperature. The primary control on CO_2 content appears to be the nature of the substrate underlying the Peutu Formation. Higher CO_2 content occurs in fields where limestone or dolomite, such as in the Tampur Formation, subcrop the Peutu. Shale substrates, such as in the Bampo Shale, tend to be associated with lower CO_2 fields. The association with sub-cropping carbonates indicates the CO_2 originates from thermal decomposition of carbonates. Analyses of carbon isotopes support this conclusion with values of $\delta^{13}C_{CO2}$ between –0.95 to -3.97 ‰. Only minute quantities of helium and hydrogen have been detected, supporting the theory that the CO_2 does not have a magmatic origin (Cooper et al., 1997). Consequently, it is concluded that the risk of encountering high CO_2 content can be reduced by avoiding deep, hot areas where the Peutu directly overlies the Tampur Formation and/or basement.

Gas accumulations in the southern part of the North Sumatra Basin occur in the Rantau area (Kuala Simpang Barat, Kuala Simpang Timur and Bukit Tiram fields) and Aru to Langkat/Medan area (Paluh Tabuhan, Paluh Tabuhan Timur, Gebang, Securai, Pantai Pakam Timur and Wampu fields) (Heriana, 1998). The reservoirs are the Mio-Pliocene Keutapang Formation, Middle Miocene Middle Baong Sandstones (MBS), and the Lower Miocene Belumai Formation. Isotopic and compositional data show that all gases have a thermogenic origin ($\delta^{13}C_{CH4}$ -44.94 to -33.74 ‰). The Rantau gas complex contains non-associated dry gas generated at higher thermal maturity than the gases at Aru-Langkat which are associated with oil and condensate. C_{2+} values of Rantau gases are low (1.36-3.29 %), in contrast with the wet gases of Aru-Langkat (C_{2+} 7.5-19.0 %). Both the Rantau and Aru-Langkat gas families were generated from the black shales of the Bampo Formation. The Rantau gases were generated from deeply buried source rocks in the Tamiang Deep to the northwest. The associated gases of Aru-Langkat were generated from the less deeply buried "Gebang Low".

Central Sumatra Basin

Small and large gas fields occur in the Early Miocene Sihapas Sandstone in the southern part of the Central Sumatra Basin (e.g. Libo, Sebanga, Bagan Belada, Mandar, Talas, Putih, and Kelabu gas fields). The gas pools typically have oil legs and there is a strong spatial association with deep troughs. The Putih and Kelabu gas fields are located just east of the Kiri Trough and the Libo gas field, the largest in the Central Sumatra Basin, is located on the southwest flank of the South Aman Trough. The gases are thermogenic and were sourced by Oligocene Pematang non-marine source rocks. Libo contains 80-91 % methane and $\delta^{13}C$ values are isotopically heavy (-29.21 to -35.33 $^{o}/_{oo}$) indicating generation in the late to overmature gas window. Libo has 8-22 % CO_2 but no H_2S has been reported. Biogenic gases occur onshore in the southern part of the Central Sumatra Basin at fields in the Bentu and

Korinci-Baru areas (e.g., Seng, Segat, and Baru). Gas analysis in Segat shows methane content of 97 – 98 mole %, no CO_2, no H_2S and $\delta^{13}C_{CH4}$ value of -67 to -64 ‰. The gases are trapped within the Late Miocene to Pliocene Binio, Petani, and Korinci sandstones. Biogenic gases also occur in shallow reservoirs above some of the oil fields in the northern Central Sumatra Basin (the "Petani gas trend").

South Sumatra Basin

Large quantities of natural gas have been discovered in South Sumatra Basin since the early 1990s. Significant discoveries are Gelam, Dayung, Sumpal, Betara, North Betara, NE Betara, Gemah, Geragai, North Geragai, Rayun, Singa, Suban, Pulau Gading, and Sungai Kenawang fields. The gases are reservoired in Gumai sandstones, Baturaja carbonates, Talang Akar sandstones, and fractured igneous and metamorphic Basement. The sources of gas are considered to be the Lemat and Talang Akar shales (Chalik et al., 2004; Marpaung et al., 2005, 2006). Based on compositional analysis and carbon-13 and deuterium isotopes, the gases are thermogenic. The gases are generally wet with CH_4 content of 59-95 %. Values of $\delta^{13}C_{CH4}$ and δD_{CH4} of these fields, -47.8 to -31.0 ‰ and -228 to -129 ‰, respectively, confirm that the gases are thermogenic in origin and condensate-associated.

Dayung, Sambar, Rebonjaro and Sumpal are, however, post-mature dry gases. The thermal maturity based on $\delta^{13}C_{CH4}$ and δD_{CH4} ranges from 2.0-3.0 %Ro VRE in contrast to Suban and Gelam (1.0-2.9 %Ro VRE) and Betara and Geragai (0.8-2.0 %Ro VRE). Bungkal, Bungin, Rayun, Bentayan, and Puyuh gases are from mixed low and high maturity. The carbon and deuterium isotope maturity correlates positively with gas wetness. Suban, Gelam, Bentayan, Puyuh, Betara and Geragai gases contain more than 5 % C_{2+}, whereas Dayung, Sambar, Sumpal, Rebonjaro, Bungkal, Bungin, and Rayun contain less than 5 % $C_{2+.}$

The distribution of CO_2 throughout the South Sumatra Basin is a key exploration risk, with the concentration ranging from 0 to 98 mole %. Suklis et al. (2004) studied the origin and distribution of CO_2 in the Corridor Block and divided the fields with CO_2 into three groups:

- Group A, CO_2 < 20 mole %, $\delta^{13}C_{CO2}$ -8.3 to -4.0 ‰, (Suban, Gelam fields),
- Group B, CO_2 20-40 mole %, $\delta^{13}C_{CO2}$ -4.8 to -0.1‰, (Dayung, Sambar, Sumpal, Rebonjaro fields),
- Group C, CO_2 > 40 mole %, $\delta^{13}C_{CO2}$ -4.4 to -1.8 ‰, (Bungkal, Bungin, Rayun, Bentayan, Puyuh fields).

Based on these values, the CO_2 of the three groups may come from either mantle degassing (-4 to -7 ‰) or carbonate decomposition (–10 to 2 ‰). There may also be a small CO_2 contribution from maturation of organic matter (-25 to -10 ‰) to the Group A gases. In general, the CO_2 content increases with present-day reservoir temperature and reservoirs with temperature > 165 ºC have a higher risk of CO_2 content > 40 mole %. Granite and metamorphic quartzite reservoirs have lower CO_2 content than schist, phyllite, argillite, limestone and marble reservoirs. H_2S content of the fields is minor, such as 10 ppm in the Suban gas (Pujasmadi et al., 2002).

The gas fields of the Jabung Block in the Jambi Sub-Basin (Betara-Geragai complex) have CO_2 content ranging from 3-57 %. $\delta^{13}C_{CO2}$ values range from -20.79 to -5.01 ‰ showing that the origin of CO_2 gas is both organic and inorganic. Helium isotope values ($^3He/^4He$ 0.865R_A) suggest little contribution from the mantle (Cooper et al., 1997). H_2S is known from Musi (22,000 ppm) and Tanjung Miring (264,000 ppm – the highest recorded in Indonesia). High H_2S content may relate to TSR of deep carbonate sequences.

Fore-arc Basins

The fore-arc basins of Sumatra contain occurrences of biogenic gas. Exploration wells (e.g. Keudapasi, Meulaboh, Suma, Singkel and Ibu Suma) drilled in the fore-arc basin of Meulaboh-Sibolga-Mentawai Basin (west offshore Sumatra) discovered sub-economic biogenic methane in Middle to Late Miocene carbonate reefs (Hariadi and Soeparjadi, 1975; Rose, 1983; Dobson et al., 1998; Yulihanto and Wiyanto, 1999; Netherwood, 2000). The low geothermal gradient in this area (typically < 1.5ºF/100 ft) favors biogenic gas generation. The Late Oligocene to Early Miocene black shales of the Nias beds are interpreted as the source rocks (Yulihanto and Wiyanto, 1999). The carbonate buildups have high relief and it appears that the top seal shales were not deposited until after much of the gas had been generated and escaped. Biogenic gas has not been encountered in the Bengkulu Basin possibly because of the higher (>2.5°F/100 ft) geothermal gradient.

Ombilin Basin

Gas also occurs in the intra-arc Ombilin Basin. The first exploration well drilled in this basin, Sinamar-1 (Caltex, 1983), discovered gas and condensate from the latest Oligocene Sawahtambang sandstones (Koning, 1985). The well flowed wet thermogenic gas at rates exceeding 13 MMcfd and 300 bpd condensate (60º API). Deeply buried (~15,000 ft) Eocene lacustrine shales and Oligocene marine shales are the likely source rocks for the gas and condensate tested in Sinamar-1. The low geothermal gradient (1.47 °F/100 ft in Sinamar-1) supports the deep gas generation concept.

GASES OF THE NATUNA BASINS

Gases discussed here are from gas fields of Buntal, Tembang, Belanak, Hiu-Kerisi and North Belut (West Natuna Basin), and from Natuna D-Alpha ("L" structure) (East Natuna Basin) (Figures 1, 2, 4; Table 1). These gases are considered to be representative of others found in the region.

In the West Natuna Basin, the majority of discoveries have been made in post-rift to syn-inversion sequences (Gabus/Udang to Arang Formations). The main source facies are the older syn-rift sediments (Benua and Lama Formations) which include lacustrine shales and coals, and stacked fan-delta shales. The coals and shales developed in the Arang Formation are commonly oil and gas prone.

Most of the gases studied have 70 to 90 % CH_4 content with most $\delta^{13}C_{CH4}$ values between -31 and -39.6 ‰, confirming their thermogenic origin. However, some mixing with biogenic gas is found in some fields such as Buntal and Tembang with $\delta^{13}C_{CH4}$ value of -50.29 ‰ and δD_{CH4} of -232 ‰. The δD_{CH4} ratio is indicative that the majority of the methane was generated at a level of maturity at which oil may be also expected to be generated. This is confirmed by the methane content (98.1-99.2 %). CO_2 content is generally low (0-3 %), but in some fields like Belanak may be as high as 8-10 %. The CO_2 is isotopically heavy ($\delta^{13}C_{CO2}$ -0.95 ‰), suggesting an origin related to magmatic or volcanic activity. No H_2S has been reported from the West Natuna gas fields.

The East Natuna Basin is well known for hosting one of the world's largest gas fields, the Natuna D-Alpha gas field, with an estimated 222 tcf gas in place of which 71 % is carbon dioxide (Dunn et al., 1996). The gas is trapped in an isolated carbonate buildup in the upper part of the thick, Middle to Late Miocene Terumbu carbonates. . The $\delta^{13}C_{CH4}$ value (-31 ‰) indicates a thermogenic origin from high maturity source rocks (~2.4 %Ro VRE). The source rocks for the hydrocarbon gas are believed to be the coals and shales within the Gabus and Arang Formations. Extensive testing of the wells within this structure showed a CO_2 content ranging from 67 % near the top of the reservoir to about 82 % near the base (Sangree, 1981). There is no published $\delta^{13}C_{CO2}$ data to assess the origin of the CO_2, but based on the high concentration and the geologic setting of this field, it is speculated that the CO_2 has an inorganic origin (thermal degradation of carbonates or from mantle de-gassing). Sangree (1981) considered that the CO_2 had been introduced from deep igneous activity but Cooper et al. (1997) concluded it been introduced by thermal degradation of carbonate. No H_2S content is reported from the gas field.

GASES OF THE JAVA BASINS

The commercially significant gas fields of Java are found in the West Java and East Java Basins. Oil and gas exploration and production from these basins date back to the late 19th century. The gas fields are distributed both onshore and offshore (Figures 1, 2, 5; Table 2).

West Java Basin

Gases derived from both thermogenic and bacterial (biogenic) petroleum systems occur in the West Java Basin (Noble et al., 1997). The gas in deeper reservoirs is primarily of thermogenic origin. The vast majority of gases from the Early to Middle Miocene Main and Massive members of the Upper Cibulakan Formation and deeper reservoirs (Baturaja carbonates and Talang Akar sandstones) have geochemical characteristics of gas generated in association with oil, or gas that was formed from oil-prone source rocks that have entered the gas window. Primary source rocks for these thermogenic gases are the fluvio-deltaic coals and shales and marginal marine shales of the Oligocene Upper Talang Akar Formation which were deposited during the post-rift sag period.

The thermogenic origin of most of the gas in Middle Miocene and older reservoirs is established by the normalized methane content. Example fields are Arjuna (86.3 %), Bojongraong (58.9 %), Cemara (79.9 %), Cemara Selatan (50.9-89 %), Cilamaya Timur (65.1 %), Gantar (79.6 %), Haurgeulis (81.8 %), Kandanghaur (56.2 %), Pamanukan (86.3 %) and Sukatani (71-91 %). Biogenic methane occurs in the Cicauh field (99.4-% CH_4).

In the shallow Parigi reservoirs, biogenic, thermogenic and mixed gases occur. The biogenic gases are derived locally from the fine grained intervals of the Parigi and Cisubuh Formation. The thermogenic gases are sourced from the deep Arjuna source pod and have migrated vertically to the shallow reservoirs.

The carbonate buildups of the Parigi Formation and the Pre-Parigi Member of the Upper Cibulakan Formation are known to contain large quantities of gas. The gas is dry (average 98.65 vol. % methane) and $\delta^{13}C_{CH4}$ values between -51.5 and -46.9 ‰ interpreted to be mixed thermogenic gas (with insignificant amounts of C_{2+} and CO_2). The hydrocarbons were sourced from deeper Talang Akar shales and coals just before, or during, the early phase of oil generation through vertical faults (Yaman *et al.*, 1991).

The CO_2 content of gas in the offshore Java reservoirs is typically less than 5%. In the Sunda Sub-Basin, however, the CO_2 content averages 19.5% in the Gita Member of the Talang Akar Formation (Cooper et al., 1997). Values of $\delta^{13}C_{CO2}$ (-14.06 to -19.43‰) indicate an organic source. Thick paralic coals are widespread in the Gita Member and are at temperatures suitable for CO_2 generation. The amount of CO_2 is higher (over 50 %) in some onshore and coastal regions that have received gas derived from high temperature metamorphism of carbonate minerals or volcanic degassing. For example, the Haurgeulis, Sukatani, Pamanukan, and Cikarang fields are mostly composed of CO_2 (74-92 % of the total gas). Gas from the Baturaja Formation in Pamanukan-2 well has a $^3He/^4He$ value of 4.002R_A indicating a contribution from mantle de-gassing (Cooper et al., 1997). H_2S has not been reported from the West Java gas fields.

East Java Basin

Satyana and Purwaningsih (2003) recognized three gas types in the East Java Basin,

- thermogenic gases commonly associated with oil in Miocene and older reservoirs
- biogenic gases found predominantly in the Pliocene-Pleistocene reservoirs and

mixed gases mostly found in Late Miocene reservoirs but also found in older and younger reservoirs.

The thermogenic gas accumulations are widely distributed across the basin. Examples of fields with thermogenic gases are Suci, Pagerungan, West Kangean, BD, Mudi, Sukowati, Banyu Urip, Kedung Tuban, Rembang, KE 5, KE 40, KE 23, Bukit Tua, Jenggolo, and Payang fields. The fields are reservoired in Eocene to Early Miocene carbonates and sandstones. These fields occur both as non-associated and associated gas. Condensates are generally produced from these fields in addition to gas.

Non-associated, thermogenic gas accumulations occur at Pagerungan, Kedung Tuban, and Rembang. Associated gas is present in Sukowati and KE-23. The Pagerungan gas has a methane composition of 94.24 %, suggestive of a thermogenic origin. No carbon isotope analysis has been published for the Pagerungan gas, but modeling indicates that the gas was generated at high maturity levels. Condensate with an API gravity of 53.6°, 0.01% sulfur and $\delta^{13}C$ whole oil of –25.8 ‰ is produced. The Pagerungan condensate is interpreted to be an oil dissolved in a high maturity non-associated gas derived from a fluvio-deltaic source interval (coals and carbonaceous shales).

Kedung Tuban non-associated gas has methane content of 92.53 % and $\delta^{13}C_{CH4}$ value of -37.5 to –35.5 ‰, indicating a thermogenic origin. The Kedung Tuban condensate has an API gravity of 41.2°, sulfur below 0.1 %, a saturate content of 95 %, pristane/phytane 5.51, $\delta^{13}C$ saturates of –25.29 ‰ and $\delta^{13}C$ aromatics of –23.77 ‰. Based on these values a fluvio-deltaic source is inferred. The low API gravity for condensate and very high saturate content indicate that the condensate is a product of fractionation, or that the retrograde condensate resulted from fractionation during migration rather than expulsion from a very mature source. This is supported by the low maturity (0.59% Ro VRE) calculated from the methyl-phenanthrene index. The Rembang non-associated gas has a normalized methane content of 86.35 %, $\delta^{13}C_{CH4}$ ranges from –39.80 to -33.84 ‰ and δD_{CH4} of –152 to -145 ‰, suggesting a "wet" thermogenic origin. Condensate is also present in the Rembang gas. The condensate is unusual in that is depleted in light alkanes and relatively rich in aromatic and, to a lesser extent, cyclic compounds. It is interpreted that the condensates are a product of mixing of a typical East Javanese waxy crude oil and gas that has subsequently migrated into the reservoir.

Associated gases occur in numerous oil fields, such as Sukowati, Mudi, Banyu Urip, KE-23, KE-40, Bukit Tua, and Jenggolo fields. The Sukowati gas is relatively wet (normalized methane 72.83%) and is considered to be representative of these associated gas accumulations. The KE-23 associated gas is somewhat drier (85.78 % methane, 8.41 % ethane, $C3_+$ 5.81 %). The gas characteristics and habitat suggest that the source rocks are non-marine to marginal marine shales or coals of the Ngimbang or Lower Kujung Formations.

Biogenic gases occur in two belts in the East Java Basin. They are the South Madura Belt (Maleo, MDA, Terang, Sirasun and other smaller fields) and the Muriah-Bawean Belt (centered on the Kepodang Field). The main reservoirs in the South Madura Belt are Early Pliocene Mundu and Paciran sands and carbonates whereas in Kepodang, the main reservoirs are sandstones of the Middle Miocene Tawun Formation. The biogenic gases in these reservoirs are interpreted to be sourced from coeval shales and coals. The primary source beds for the Terang-Sirasun biogenic gas are claystones and other fine-grained lithologies that are interbedded within the reservoir section (Noble and Henk, 1999). Total organic carbon (TOC) levels are typically are about 1 % and the organic matter was derived predominantly from land plants.

Published geochemical data are available for the Kepodang and Terang-Sirasun Fields and some gas seeps in the western Cepu area. In the Kepodang Field, gas in the Middle Miocene Tawun Formation is almost exclusively methane (average 99.82 %). The $\delta^{13}C_{CH4}$ (-67.31 to -67.42 ‰) and δD_{CH4} values (-197 to -198 ‰) are isotopically light and confirm the biogenic origin of the Tawun gas. Kepodang also has gas in the deeper Lower Miocene Prupuh Formation that is somewhat wetter (C_{2+} 1.46 %) and isotopically heavier ($\delta^{13}C_{CH4}$ -58.93 ‰). This suggests the presence of a low maturity thermogenic component.

The gas in the Paciran limestones of the Terang-Sirasun area contains over 99.5 % methane and has a gas gravity of 0.56. The stable isotope ratios ($\delta^{13}C_{CH4}$ and δD_{CH4} values of -65.0 ‰ and - 185 ‰, respectively) indicate that the gas has been generated exclusively by bacterial processes. The gas in the Maleo Field further west in the Madura Strait is also considered to have a predominantly biogenic origin (Triyana et al., 2007). The reservoir is the Early Pliocene Mundu globigerinid limestone unit. A biogenic origin is also interpreted for the Wonolelo gas seep in the Kendeng Deep area, west of the town of Cepu. It is composed of 100 % methane with $\delta^{13}C_{CH4}$ of -70.80 % and δD_{CH4} of - 320 ‰.

Mixing between thermogenic and biogenic gas is observed in the Wunut Field to the south of Surabaya. At Wunut, there are 10 productive zones between 300 m and 1000 m and the increasing influence of the thermogenic component with depth can be seen. The gas becomes denser downwards (0.55 - 0.63), more viscous (0.0121 to 0.0148 cp) and has higher heating value (966 to 1103 BTU/scf). Methane content also decreases with depth (97.43 % at 579 m to 85.36 % at 843 m in Wunut-2) and oils have also been recovered from deeper zones.

Non-hydrocarbon gases in East Java gas fields consist mainly of CO_2. Two areas with high CO_2 pollution are apparent. Onshore, high CO_2 values are seen in the Oligo-Miocene Kujung-Tuban carbonates in the Cepu area. Examples are Kedung Tuban (24.86 %), Sukowati (40.74 %), Banyu Urip (47 %), Rembang (45-65 %) and Gabus (78.57 %). Some gas seeps in the Surabaya area also show high CO_2 content (Deling, 38.72 %; Sepat Kaliasin, 35.59 %). Offshore, high CO_2 content (74 to 91 %) occurs in several Rembang Bay wells (Kutilang-1, Nuri-1, Perkutut-1) and in the Bawean Arch discoveries, Titan-1 and Calypso-1 (75 to 85 %).

Carbon isotope data of CO_2 are available from Kedung Tuban ($\delta^{13}C_{CO2}$ 0.52-1.62 ‰), Rembang (-5.17 to 0.03 ‰) and Gabus (-4.85 ‰). These values are consistent with CO_2 formation by thermal destruction of carbonates. The origin of the CO_2 in the offshore area is not well understood as there is no published isotopic data. However, there is a spatial association with nearby Pleistocene volcanic centres (Muria, Lasem and Bawean) that suggests volcanic de-gassing is responsible.

H_2S occurs in some carbonate reservoirs in the East Java Basin but generally the concentration is less than 1000 ppm. However, BD carbonate reef in the Madura Strait is reported to contain 4500 ppm H_2S. Thermo-chemical sulfate reduction (TSR) related to deep burial of the Oligo-Miocene carbonate sequence may be responsible.

GASES OF THE KALIMANTAN BASINS

The gas fields in the Mahakam Delta of East Kalimantan make up the largest commercial gas province in Indonesia (Figures 1, 2, 6; Table 2). Ultimate recoverable reserves (proven and probable) are estimated as 47 tcf and 4 Bbbl oil (Lambert et al., 2003). Badak, in 1972, was the first significant gas discovery with reserves in excess of 6 tcf and 55 MMbbl condensate and oil (Gwinn et al., 1974). Together with the later Nilam discovery, Badak provided the foundation resource for the Bontang LNG project which began operations in 1977. Giant discoveries were also made in the offshore areas at Tunu and Peciko (>22 tcf gas in place). Other significant gas discoveries are Lampake (onshore) and Tambora, NW Peciko, Sisi and Nubi (offshore). Production occurs from numerous sandstones deposited in Middle Miocene to Pliocene fluvio-deltaic systems.

The gases from Badak, Nilam, and Lampake have a thermogenic origin. The normalized methane content ranges from 86.1 to 92.8 %. The stable isotope values at Lampake ($\delta^{13}C_{CH4}$ -40.23 ‰, δD_{CH4} -190 ‰) and Nilam ($\delta^{13}C_{CH4}$ -30.12 to -29.84 ‰, δD_{CH4} -114 to -116 ‰) are isotopically heavy and confirm the thermogenic origin of the gases. The source rock is interpreted to be at relatively high maturity (1.4 to 2.4 % Ro VRE).

The offshore gas fields of Tambora, Tunu, NW Peciko, Sisi, and Nubi have a mostly thermogenic origin but there is some mixing with biogenic gas observed. The methane proportion ranges from 80.7% to 97.1% and typically decreases downwards in the stacked reservoir sections. This trend is consistent with the methane and deuterium stable isotope values which become isotopically lighter in shallower reservoirs. Values of $\delta^{13}C_{CH4}$ range from -55.19 to -35.18 ‰ but mostly fall between -44 to -49 ‰. The range of δD_{CH4} is -195 to -144 ‰, with typical values between -170 to -185 ‰. The overall trend towards carbon 13 enrichment with depth is not seen in the propane and ethane components; the $\delta^{13}C$ values remain relatively constant (~ -30%).

The non-hydrocarbon component of the Mahakam gases is generally low. Most gas fields have CO_2 below 2 %.Pamaguan in the onshore Kutei Basin is an exception with reported CO_2 content of 46-64 %. There is no published carbon isotope data for the CO_2 at Pamaguan, therefore the mode of CO_2 origin can not be determined. H_2S has not been reported from the Mahakam gas fields.

The source of the Mahakam Delta gases is the thick deltaic succession rich in land plant derived organic matter. The humic source material is concentrated in organic shales and coal beds associated with the fluvial deltaic plain facies and in shales of the tidal delta plain and delta front. Geochemical evidence suggests that the thermal transformation of coaly kerogens in the Mahakam Delta has generated oils and natural gases.

Schoell et al. (1985) discussed the relationship between oil and gas generation in the Mahakam Delta and the effect of overpressuring. According to them, the principal zone of oil formation is approximately 3500 to 4000 m whereas gas is mostly formed deeper (5000 to 6000 m). The depth to the top of overpressure varies in the basin. Where the overpressure is relatively shallow it overlaps with the oil window and oil migration out of the overpressure cell is retarded and gas migrates preferentially. Conversely, where the oil window occurs immediately above the overpressure zone, oil can be expelled and migrated.

GASES OF THE MAKASSAR STRAIT BASINS

Intensive deep-water exploration in Indonesia started in the early 1990s and has resulted in the discovery of large gas fields in the areas outboard of the Mahakam delta (Figures 1, 2; Table 3). Geochemical data are available for some of the fields, Gendalo, Gehem, and Gula, and they are assumed to be representative of other fields in the province. Increasingly heavier gases and higher condensate yields are typically found in deeper reservoirs although localized reversal of these trends do exist (Lin et al., 2005). Waxy, low GOR oils are found in limited quantities in the deep Middle Miocene reservoirs below the gases. The gases of Gendalo, Gehem, and Gula fields are mostly sweet with low volumes of impurities. Nitrogen content is mostly below 0.5 % and CO_2 content below 9 %. H_2S content is mostly below detection limit (<100 ppm).

A majority of the gases in the deep-water Makassar Strait have $\delta^{13}C_{CH4}$ values in the range -52 to -28 ‰. Coupled with the high gas wetness, these values are characteristic of thermogenic origin at “oil window” temperatures (Figure 7). Presumably, the gases were sourced by type III kerogens, as supported by the biological markers in the associated condensates.

The thermogenic gases are predominantly reservoired in upper Miocene turbiditic sands. A subordinate number of gases exhibit characteristics of biogenic-thermogenic mixing with $\delta^{13}C_{CH4}$ values of -65 to -55 ‰. These gases are mostly reservoired in the shallow Pliocene sands and typically have low condensate yields. Two gases from Pliocene reservoirs are almost pure methane and have $\delta^{13}C_{CH4}$ values of ca -75 ‰, indicating a biogenic origin.

GASES OF THE SULAWESI BASINS

Gas data of Sulawesi Basins are from Kampung Baru, Walanga, Sampi-Sampi, Bonge gas fields in the Sengkang Basin, South Sulawesi and from Mantawa, Minahaki, Matindok, Senoro, Anoa, Donggi, Sukamaju, Kampung Bali, and Maleo Raja gas fields, Banggai Basin, East Sulawesi (Figures 1, 2, 8; Table 3).

The Kampung Baru, Walanga, Sampi-Sampi, and Bonge gas fields occur in the Late Miocene Tacipi reefs of the Sengkang Basin, South Sulawesi and contain about 630 bcf gas in total. The gases are relatively dry with CH_4 content of 96-100 %, indicating a mixed thermogenic and biogenic origin. However, Grainge and Davies (1983), based on limited stable carbon isotope data (not shown in their paper), considered that the methane is not of biogenic origin. A possible source interval is speculated to be the lateral argillaceous equivalent of the Tacipi Formation, which could contain gas prone organic matter, deposited in deeper western part of the Sengkang Basin. The absence of other published data makes further interpretation difficult.

The gases discovered in onshore eastern Sulawesi wells appear to be complex, with components derived from biogenic origin (Mantawa and Minahaki gases, $\delta^{13}C_{CH4}$ values of -59 ‰ to -62 ‰) and thermogenic origin (Sukamaju, Kampung Bali, Maleo Raja, Senoro, Matindok gases, $\delta^{13}C_{CH4}$ values of -53 to -32 ‰). 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. The Senoro gas field is a giant gas field with a total estimated reserve of 3.7 tcf gas and 65 MMbbl condensate (Hasanusi *et al*., 2004). 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.

The Kampung Baru gas complex contains traces of CO_2 (0.07-0.2 %) whereas 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 ‰). The gas fields of Anoa, Donggi, Maleo Raja, and Senoro contain 300-800 ppm H_2S.

GASES OF THE PAPUA BASINS

Bintuni Basin

The Bintuni Basin, a foreland basin in Papua's 'Bird's Head' region contains six major gas fields that make up the Tangguh LNG Project currently under development (Figures 1, 2; Table 3). Total reserve potential is estimated at 24 tcf plus an unknown volume of condensate (Casarta et al., 2004; Marcou et al., 2004). The six gas fields are Vorwata, Wiriagar Deep, Ubadari, Roabiba, Ofaweri, and Wos. Permo-Jurassic source beds in the Bintuni Basin kitchen probably generated oil before reaching the gas generation window, and have been geochemically typed as sourcing the Roabiba/Ofaweri/Wos late maturity dry gas (Perkins and Livsey, 1993) as well as the Wasian and Wiriagar shallow oils (Dolan and Hermany, 1988).

Gases of the Wiriagar Deep and Vorwata fields are representative of the Tangguh LNG gas fields (Figure 9). The gases are relatively dry comprising mostly methane with subordinate wet gas components. The gases are generated from a source interval containing mostly humic organic matter. Chemical composition and carbon isotope data show the gases are thermogenic in origin. The composition of the gases is dominated by hydrocarbon gases (72-97 %) of which methane is the most abundant (78-97 %). Heavier hydrocarbon gases are present in sufficient quantities to indicate a thermogenic origin of the gases.

Methane carbon isotope signatures of -34 ‰ to -28.0 ‰ confirm a thermogenic source for these gases and that maturity levels were high. The Wiriagar Deep gas plots as a non-associated, relatively dry gas derived from humic organic material (Figure 9). Deuterium isotope analysis performed on the methane fractions produced comparable isotopic values (-119 ‰ and -122 ‰). While these data confirm a thermogenic origin, the extremely heavy nature of the results ($\delta^{13}C_{CH4}$ values of -28.2 to -28 ‰) suggests generation within the dry gas window. A possible explanation would be that very dry gas (>99 vol. % methane) mixed with lower maturity wet gas during secondary migration.

The Tangguh gas complex contains traces of H_2S and some CO_2 (0-15 %). The largest proportions of CO_2 are located in the deeper reservoirs (ca. 13 vol. %) compared to 1-5 vol. % in the shallower reservoirs. The reason for this may relate to increasing temperature in the deeper reservoirs, differential losses with increasing migration from the source, and/or the presence of sealing beds above the deeper reservoirs. Comparably heavy $\delta^{13}C_{CO2}$ values were recorded (-4.1 to -2.7 ‰). These data suggest that the CO_2 is inorganic in origin and may be associated with carbonate thermal degradation or mantle de-gassing.

Salawati Basin

Gas fields in the Salawati Basin can be grouped into three genetic types (Table 3) : (1) thermogenic gas fields sourced by Miocene Klasafet sources (Salawati N, Arar, WIR) typified by methane content of 93 to 98 %; (2) gas fields/occurrences sourced by pre-Tertiary sources (Walio, Lao-Lao, Maniwar, TBC) typified by wet gas and condensate with methane content of less than 85 %; and (3) biogenic/bacterial gas sourced by Klasaman shales (Terumbu) typified by methane content of 99 % and light $\delta^{13}C_{CH4}$ values less than -60 ‰. WIR gas contains the highest CO_2 content in the basin (20 %). The gas came from thermal degradation of the Kais carbonate which entered the overmature window to the north of WIR. The Lao-Lao gas field and the gas reservoir in Walio Field, Salawati Basin have 500 to 13,300 ppm H_2S. The gas is considered to result from thermo-chemical sulfate reduction (TSR) of a deep hot carbonate sequence.

North Papua Basin

Potentially significant gas fields occur in northern Papua (Figure 2). The North Papua Basin contains the Waropen, Waipoga, Teer River, and Meervlakte depocenters and exploration in the period 1955-1975 indicated the presence of at least one large gas accumulation. Niengo-1 was drilled in 1958 in an onshore part of the Mamberamo River delta. It tested gas at an estimated rate of at least 4.5 MMcfd. To the north-west, Pertamina-Tesoro drilled the R-1 well in 1973 and apparently confirmed the offshore continuation of the Niengo accumulation. R-1 tested 6.8 MMcfd.

The Niengo gas is contained within the Pleistocene Mamberamo sandstones and is composed of 99-100 % methane (Figures 1, 2; Table 3) with no appreciable CO_2, H_2S, or N_2. Based on the geologic setting and hydrocarbon occurrences, biogenic gas is likely to have been the predominant hydrocarbon generated in the Pliocene-Pleistocene northern Papua basins. The area has a low geothermal gradient, rapid sedimentation, and young reservoirs. The Sorong Fault system, a major shear zone on the northern side of Papua, played a significant role in the biogenic petroleum system. Uplift on the southern side of the fault in the Plio-Pleistocene caused large-scale erosion and, in the depocenters to the north, rapid molasse sedimentation. The high sedimentation rates triggered diapirism associated with the generation of biogenic gases (Satyana and Setiawan, 2001).

GASES OF THE TIMOR-ARAFURA SEA BASINS

This area is lightly drilled on the Indonesian side of the border with Australia with the only significant discovery being that at the Abadi gas field (Figures 1, 2, 10; Table 3). Several large gas discoveries have been reported in Australian waters to the south (e.g. Caldita, Evans Shoal and Barossa). Abadi is located in 400-800 m water depth on the continental slope where Australia is being subducted beneath Timor to the north. The trap is a large tilted fault block bounded to the east and south by the Calder-Malita Graben (Nagura et al., 2003) and to the north by the Indonesian Aru Basin. The accumulation contains a significant gas column, approximately 130-140 m, reservoired in the shallow marine Middle Jurassic Plover Formation (Nagura et al., 2003).

The Abadi gas comprises predominantly methane (c.84-88vol.%, normalised) and is moderately wet. Condensate / gas ratios are reported to range from 10.4 to 19.2 bbl/MMscf . Stable carbon isotope ($\delta^{13}C_{CH4}$ -37.06 to -34.76 ‰) and deuterium (δD_{CH4} > -150 to -157 ‰) data suggest that the gas has a thermogenic origin and was generated from source rocks at an advanced maturity level (1.3-1.8 %Ro).. The condensate content and the isotope values for ethane and propane fractions are consistent with gas generated at a late mature stage (1.3-1.8 %Ro).

Moderate amounts of carbon dioxide (9.0 vol.%) are contained in the gas. Based on stable carbon isotope data ($\delta^{13}C_{CO2}$ values of -6.87 to -2.86 ‰), the carbon dioxide components are interpreted to be derived from a common inorganic source (derivation from thermal alteration of carbonate at depth, or mantle/volcanic degassing). The Abadi gas can be classified as 'sweet' natural gas as only traces of hydrogen sulphide have been detected (5-6 ppm).

CONCLUSIONS

1. Both thermogenic and biogenic gases can be recognised in Indonesia based on molecular composition and stable isotope data. Mixing between the two groups is commonly observed.

2. The thermogenic gases of Indonesia are characterized by normalized CH_4 component < 95 % and $\delta^{13}C_{CH4}$ values heavier (more positive) than -45 ‰. True biogenic gases have a dry gas component (CH_4) >98 % $\delta^{13}C_{CH4}$ values lighter (more negative) than -60 ‰. Mixed thermogenic and biogenic gases have methane component of 95-98 % and $\delta^{13}C_{CH4}$ values of around -50 ‰.

3. Thermogenic gases are more common in Indonesia (Figure 2). They are found in Sumatra, Natuna, Java, Kalimantan, Makassar Strait, Sulawesi, Papua, and Timor-Arafura Sea. The gases were generated by both primary gas generation from gas-prone kerogen and secondary gas generation from oil cracking at indicated maturity levels from 1 to 3 % Ro VRE or more. Biogenic (bacterial) gases are found mainly in the fore-arc basins west of Sumatra, in the Kendeng Deep depocenter of the East Java Basin, and in the foredeep area of the Sorong Fault Zone in northern Papua.

4. High concentrations (>50 %) of CO_2 occur in North and South Sumatra, East Natuna, and the onshore Java basins (Figure 11). Generally, values of $\delta^{13}C_{CO2}$ are isotopically heavy and indicate an inorganic origin by carbonate thermal destruction or mantle/volcanic de-gassing. H_2S is moderate to high (500 to > 10,000 ppm) in some gas fields in North Sumatra, South Sumatra, East Java, East Sulawesi and Salawati Basins (Figure 11). All occurrences of high H_2S content are interpreted to relate to thermo-chemical sulfate reduction (TSR) of deep and hot carbonate sequences.

5. The gases of Indonesia are heavily concentrated in Oligo-Miocene reservoirs but there are also numerous significant fields in younger and older rocks. Mesozoic reservoirs are important in Eastern Indonesia where Gondwanan crust is preserved and in fractured basement plays in Western Indonesia. Plio-Pleistocene reservoirs contain a significant proportion of the country's biogenic gas resources as well as thermogenic and mixed gases.

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TABLE 1

ANALYSIS DATA OF GAS FIELDS IN SUMATRA AND NATUNA BASINS

GAS SAMPLE	HC GAS (NORMALIZED)		CO_2 (%)	H_2S (%)	$\delta^{13}C_{C1}$ (‰)	$\delta^{13}C_{CO2}$ (‰)	δD (‰)
	C_1	C_{2+}					
NORTH SUMATRA							
ARUN	84.1	15.9	13.8	traces	-41.00	NA	NA
NSO J1	93.5	6.5	28.3	1.5	NA	-0.95 to -3.97	NA
NSO A	94.1	5.9	31.1	1.5	NA	-4 to 2	NA
RANTAU	96.7	3.3	0.9	NA	NA	NA	NA
PALUH TABUHAN TIMUR	87.2	12.8	0.8	NA	41.6	NA	NA
PALUH TABUHAN BARAT	78.7	21.3	1.14	NA	NA	NA	NA
BATUMANDI	84.2	15.8	4.2	NA	NA	NA	NA
KUALA SIMPANG	89.8	10.2	1.27	NA	41.0	NA	NA
CENTRAL SUMATRA							
BERUK	96.1	3.9	19.8	0	NA	NA	NA
DURI	97.6	2.4	15.5	0	NA	NA	NA
MINAS	80.1	19.9	15.7	0	NA	NA	NA
LIBO	88.1	11.9	8.15 to 22	0	-35.33 to -29.21	NA	NA
LIBO SE	80.1	19.9	22	0	NA	NA	NA
SEGAT	97 to 98	2 to 3	0	0	-67 to -64	NA	NA
SOUTH SUMATRA							
N BETARA	78.4	21.6	2.9	0	-47.83	-10.27	NA
NE BETARA	71.8	28.2	54.6	0	-43.63	-5.01	NA
W BETARA	59.2	40.8	8.8	0	-34.23	-13.03	-167
N GERAGAI	77.7	22.3	NA	NA	-36.5	-20.79	NA
KABUL	70.8	29.2	0.28	0	-48.21	-6.8	-179
SUBAN	93.9	6.1	5.24	0	-41	NA	-200
RAMBA	89.9	10.1	6.76	0	NA	NA	NA
TANJUNG MIRING TIMUR	87.3	12.7	0.5	26.4	NA	NA	NA
TALANG JIMAR	79.1	20.9	2.6	0	NA	NA	NA
NATUNA							
TEMBANG	98.06	1.04	0.85	0	-50.29	NA	-232
UDANG	86.5	13.5	2.77	0	NA	NA	NA
BELUT	73.3 to 99.2	0.8 to 26.7	0.17 to 0.62	0	NA	NA	NA
N BELUT	78.7	21.3	2.45	0	NA	NA	NA
HIU	88.58	11.42	2.98	0	NA	NA	NA
KERISI	87.6	12.4	0.92	0	NA	NA	NA
BELIDA	94.65	5.35	0.53	0	NA	NA	NA
BELANAK	NA	NA	8 to 10	0	NA	-0.95	NA
SOKANG	NA	NA	NA	NA	-39.6 to -34.5	NA	NA
L	NA	NA	71	NA	-31	NA	NA

C1= methane, C2+ = ethane, propane, butane, etc.

$\delta^{13}C_{C1}$ (‰) =carbon isotope relative to PDB (Pee Dee Belemnite)

δD (‰) = deuterium isotope relative to SMOW (standard mean ocean water)

TABLE 2

ANALYSIS DATA OF GAS FIELDS IN JAVA AND KALIMANTAN BASINS

GAS SAMPLE	HC GAS (NORMALIZED)		CO_2 (%)	H_2S (%)	$\delta^{13}C_{C1}$ (‰)	$\delta^{13}C_{CO2}$ (‰)	δD (‰)
	C_1	C_{2+}					
JAVA							
ARJUNA	86.3	13.7	3.7	0	NA	NA	NA
PARIGI BUILD UPS	98.7	2.3	NA	NA	-51.5 to 46.9	NA	NA
FIELD IN SUNDA BASIN	NA	NA	19.5	NA	NA	-19.43 to -14.06	NA
BOJONGRAONG	59	41	92.24	0	NA	NA	NA
CEMARA SELATAN	89	11	2.63	0	NA	NA	NA
CIKARANG	56.4	43.6	92.4	0	NA	NA	NA
CILAMAYA TIMUR	65.1	34.9	63.6	0	NA	NA	NA
GANTAR	79.6	20.4	61.3	0	NA	NA	NA
HAURGEULIS	81.8	18.2	73.9	0	NA	NA	NA
PAMANUKAN	86.3	13.7	89.8	0	NA	NA	NA
SUKATANI	71	29	80.8	0	NA	NA	NA
CICAUH	99.4	0.6	0.86	NA	NA	NA	NA
KEPODANG	99.8	0.2	0.1	NA	-67.31	NA	-198
REMBANG	86 to 91	9 to 14	65	NA	-39 to -33	-5.17 to 0.03	-152 to -145
KEDUNG TUBAN	92.5	7.5	24.9	NA	-37 to -35	0.52 to 1.62	NA
KE 30	78.9	21.1	1.1	NA	NA	NA	NA
KE 39	86	14	0.93	0	NA	NA	NA
PAYANG	87.7	12.3	0.29	0	NA	NA	NA
SUCI	85.8	14.2	6.52	0	NA	NA	NA
WUNUT	93 to 99	1 to 7	0.4	NA	NA	NA	NA
OYONG	93.5	6.5	1.2	0	NA	NA	NA
MALEO	100	0	0.11	NA	NA	NA	NA
MDA	99.8	0.2	0	0	NA	NA	NA
TERANG-SIRASUN	99.5	0.5	0.11	NA	-65	NA	-185
BD	88.8	11.2	6.52	0.45	NA	NA	NA
PAGERUNGAN	94.2	5.8	NA	NA	NA	NA	NA
WEST KANGEAN	90.4	9.6	4.33	0	-29.8	-11.3	NA
KALIMANTAN							
BADAK	91.4	8.6	2.94	0	NA	NA	NA
LAMPAKE	88.5	11.5	1.71	0	-40.23	NA	-190
NILAM	86.2 to 92.8	7.2 to 13.8	5 to 9	0	-30.12	NA	-114
PAMAGUAN	94.04	5.96	46.34	NA	NA	NA	NA
TAMBORA	82.6 to 95.6	4.4 to 17.4	1.71 to 5.26	0	-53.29 to -39.45	NA	-155 to -195
TUNU	85,8 to 95.2	4.8 to 14.2	0.53 to 2	NA	-48.35 to -39.41	NA	-189 to -158
NW PECIKO	82.8 to 97.1	2.9 to 17.2	0.58 to 3.85	0	-50.15 to -35.18	NA	-183 to -144
SISI	83.5 to 90.4	9.6 to 16.5	1.11 to 3.6	NA	-49.57	NA	-186 to -174
NUBI	88.4 to 89.7	10.3 to 11.6	3.17 to 4.75	0	-45.5 to -29.07	NA	-182 to -170

C_1= methane, C_{2+} = ethane, propane, butane, etc.
$\delta^{13}C_{C1}$ (‰) =carbon isotope relative to PDB (Pee Dee Belemnite)
δD (‰) = deuterium isotope relative to SMOW (standard mean ocean water)

TABLE 3

ANALYSES OF GAS FIELDS/OCCURRENCES IN EASTERN INDONESIA BASINS

GAS SAMPLE	HC GAS (NORMALIZED)		CO_2 (%)	H_2S (%)	$\delta^{13}C_{C1}$ (‰)	$\delta^{13}C_{CO2}$ (‰)	δD (‰)
	C_1	C_{2+}					
MAKASSAR STRAIT							
GEHEM	89.5	10.5	NA	TRACES	-30	NA	NA
RANGGAS	87	13	NA	TRACES	-42.5	NA	NA
BANGKA	93.5	6.5	NA	TRACES	-51	NA	NA
WEST SENO	83.5	16.5	NA	TRACES	NA	NA	NA
ATON	99	1	NA	TRACES	-75	NA	NA
SULAWESI							
KAMPUNG BARU	96.5	3.5	TR to 0.2	NA	NA	NA	NA
WALANGA	100	0	NA	NA	NA	NA	NA
SAMPI-SAMPI	100	0	TRACES	NA	NA	NA	NA
MENTAWA	NA	NA	NA	NA	-62	NA	NA
MATINDOK	NA	NA	NA	NA	-32.5	NA	NA
MINAHAKI	NA	NA	NA	NA	-59	NA	NA
DONGGI	96.5	3.5	2.22	0 to TR	NA	NA	NA
SENORO	88 to 91	9 to 12	1.1 to 1.8	0 to TR	-40.5	NA	NA
MALEO RAJA	86.5	13.5	3.05	0.08	-42.59	-10.78	NA
SUKAMAJU	90.5	9.5	3.01	NA	-52.68	-13.43	NA
PAPUA							
ARAR	95.14	4.86	NA	NA	NA	NA	NA
TERUMBU	99.75	0.75	NA	NA	-63.53	NA	NA
WALIO	78 to 93.48	6.5 to 22	4.31	1.33	NA	NA	NA
SALAWATI N	93.72	6.28	0.78	NA	NA	NA	NA
WIR	97.1	2.9	20	NA	NA	NA	NA
LAO-LAO	81.67	18.33	0	0.05	NA	NA	NA
MANIWAR	81.33	18.67	0.28	0	NA	NA	NA
TBC	80	20	NA	NA	NA	NA	NA
MOGOI DEEP	99.5	0.5	4.97 to 7.54	0	NA	NA	NA
VORWATA	88.4 to 96.7	3.3 to 11.6	0.26 to 11.9	0	-33.35 to -28.93	-10.04 to -0.94	-163 to -141
WIRIAGAR DEEP	87 to 97	3 to 13	5.26 to 13.42	0	-33.82 to -28.2	-7.07 t0 -2.7	-168 to -119
TIMOR-ARAFURA SEA							
ABADI	84 to 88	12 to 16	8.8 to 9.7	0	-37.31 to -34.76	-6.89 to -2.86	-157 to -150

C_1= methane, C_{2+} = ethane, propane, butane, etc.
$\delta^{13}C_{C1}$ (‰) =carbon isotope relative to PDB (Pee Dee Belemnite)
δD (‰) = deuterium isotope relative to SMOW (standard mean ocean water)

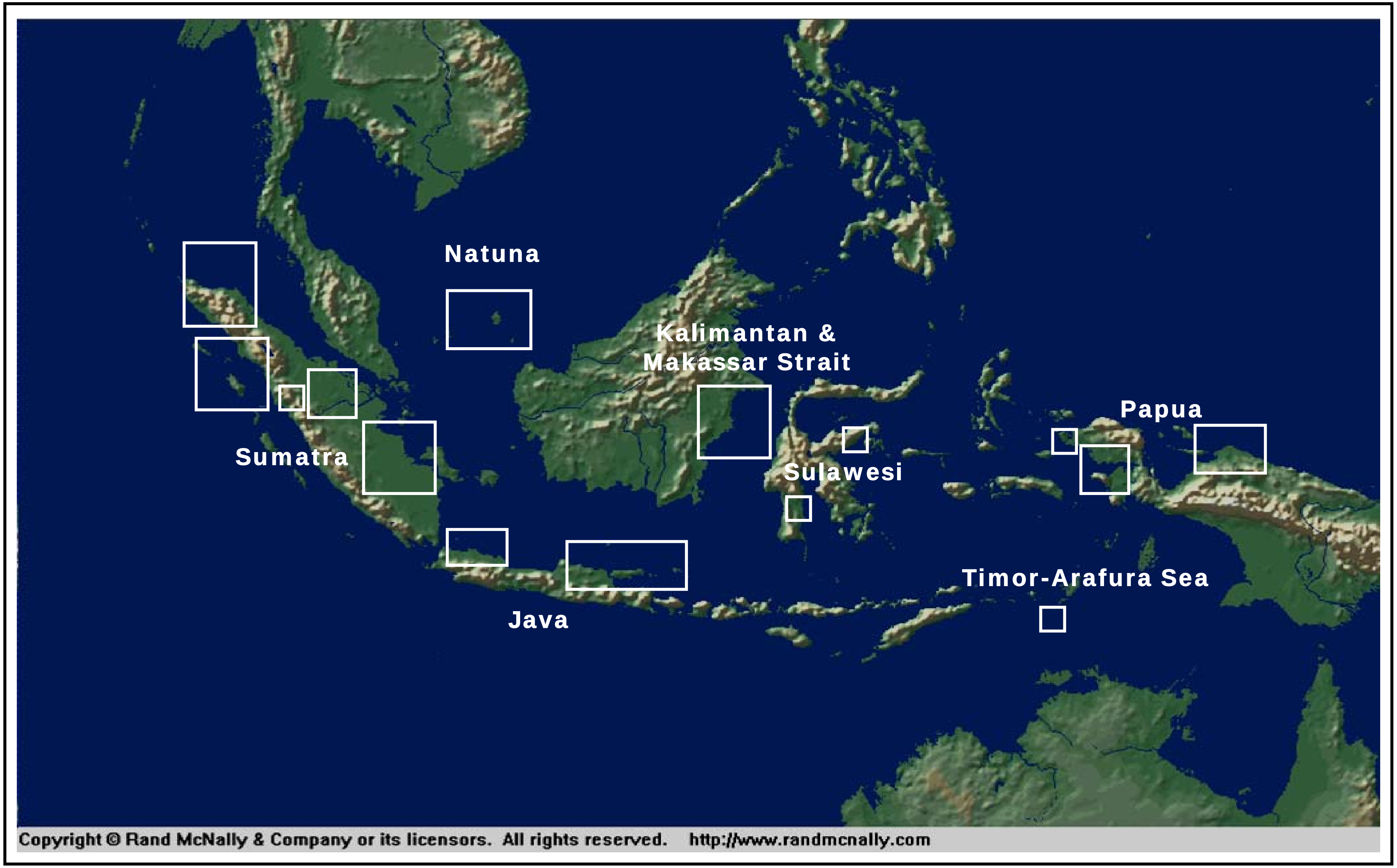

Figure 1 - Study areas of regional gas geochemistry of Indonesia comprising : Sumatra (North-, Central-, South Sumatra Basins; Sibolga forearc, Ombilin intraarc basins), Natuna (West- and East Natuna Basins), Java (West- and East Java Basins), Kalimantan (Kutei), Deepwater Makassar Strait; Sulawesi (Sengkang and Banggai Basins), Papua (Salawati, Bintuni, North Papua Basins), Timor-Arafura Sea (Aru-Malita Calder Basins).

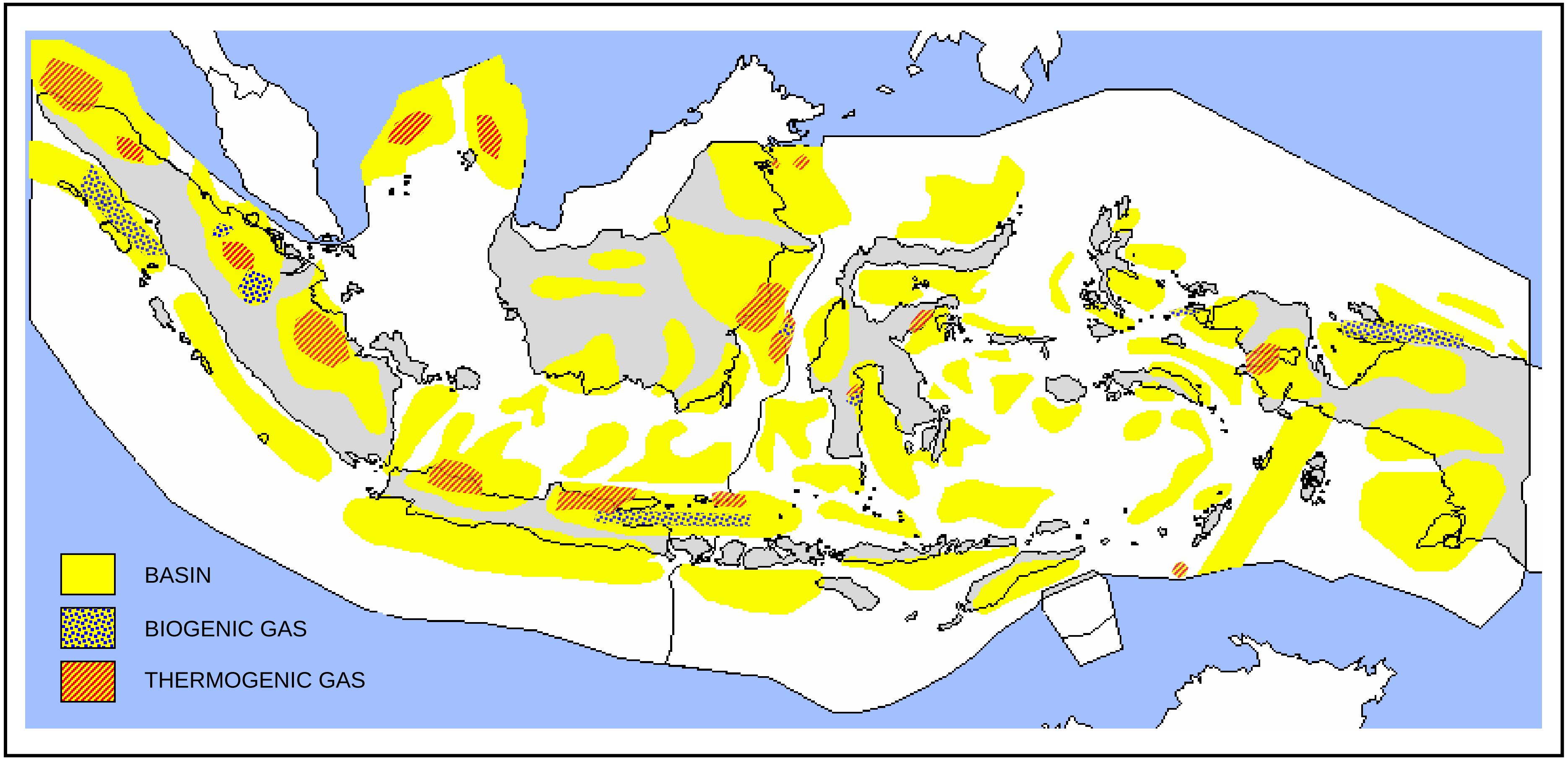

Figure 2 - Genetic gas types of Indonesia. Distribution of the gas accumulation is based on the existing gas fields. Thermogenic gases dominate the genetic types. Significant biogenic (bacterial) gases of Indonesia distribute in three areas : forearc basin of Meulaboh-Sibolga-Mentawai west of Sumatra, enclosed basin of Kendeng Deep-Madura Strait in East Java, and along the foredeep area of the Sorong Fault in northern Papua.

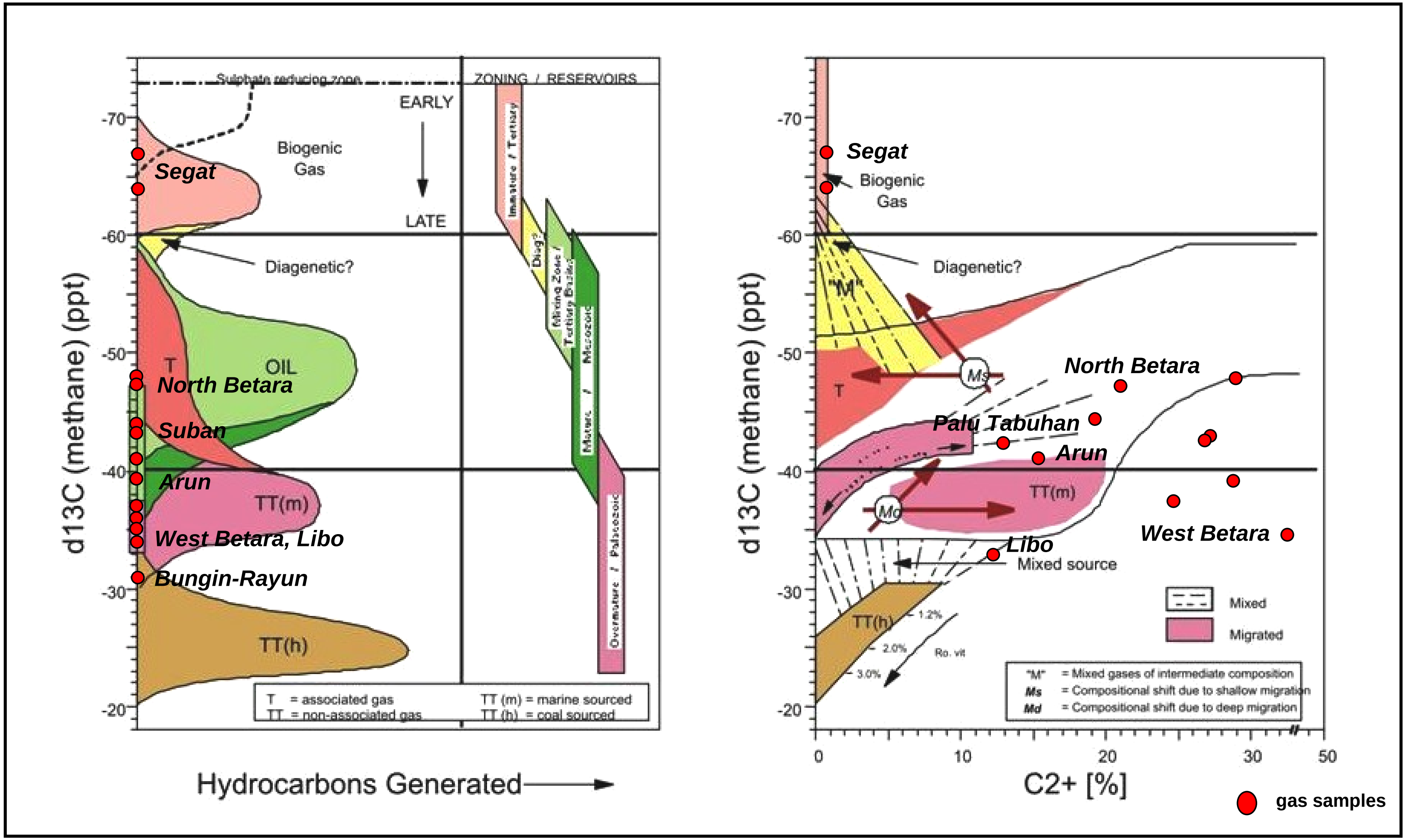

Figure 3 - Genetic types of representative Sumatra gas fields based on cross plot of δ13C CH4 values and C 2+of Schoell (1983). Most of the gases are thermogenic with δ13C CH4 values of -49 to -31 ‰ and wet gas component (C 2+) of more than 15 %. Biogenic gas is shown by samples of Segat gas. Thermogenic gases are both associated and non-associated and both primary from kerogen cracking and secondary from oil cracking. Based on carbon-13 isotope values, most of the gases were generated from maturity level of 0.9-2.1 %Ro.

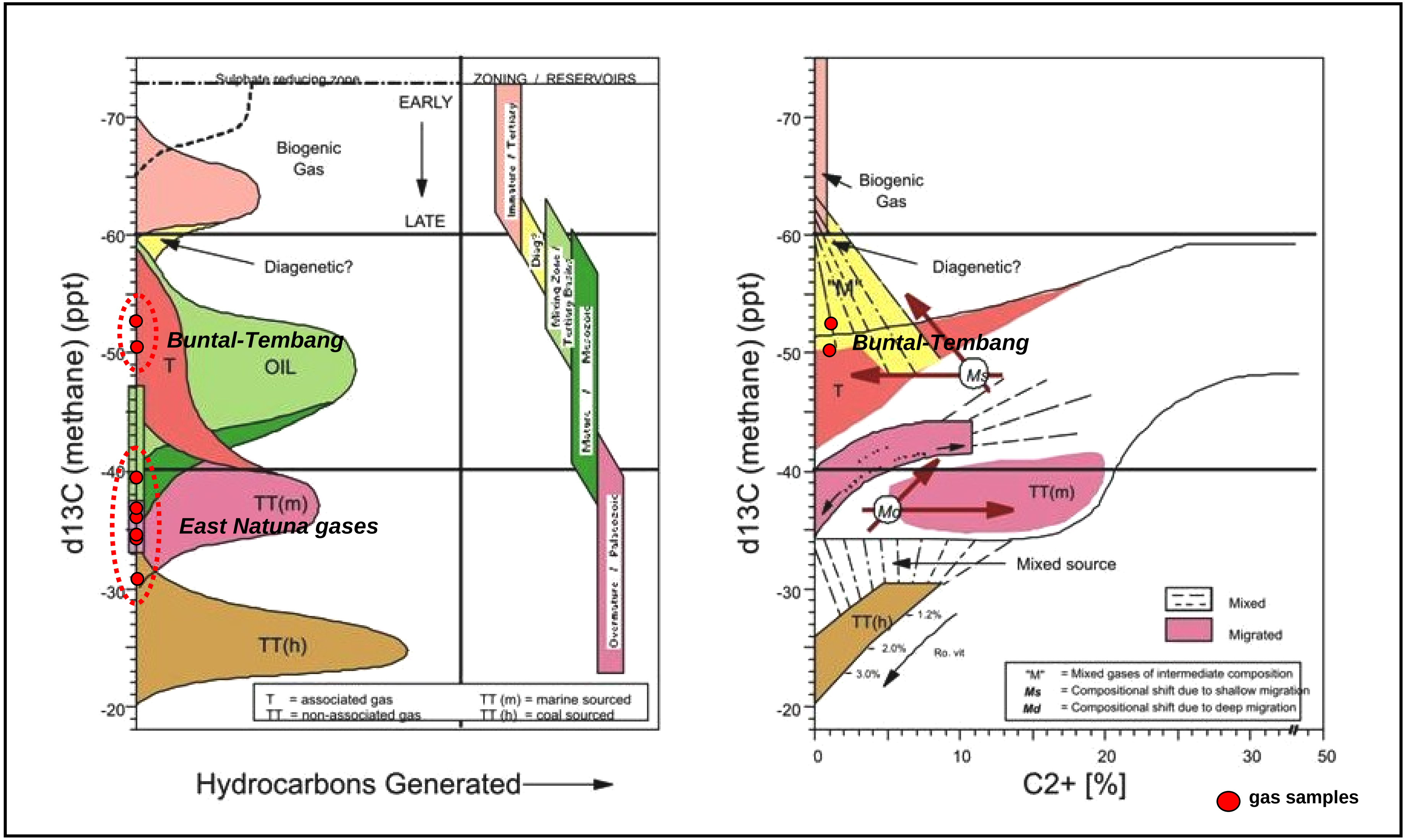

Figure 4 - Genetic types of representative Natuna gas fields based on cross plot of δ13C CH4 values and C 2+. Gases of the East Natuna Basin are all thermogenic with δ13C CH4 values of -39 to -31 ‰. Mixing with biogenic gases occur in the West Natuna Basin as shown by gas samples of Buntal and Tembang with carbon-13 methane of -52 ‰ and small amount of wet gas component (C 2+). Thermogenic gases of West Natuna Basin are related to oil cracking and associated, East Natuna gases are mostly non-associated and from kerogen cracking generated from maturity level of 1.5-2.3 %Ro.

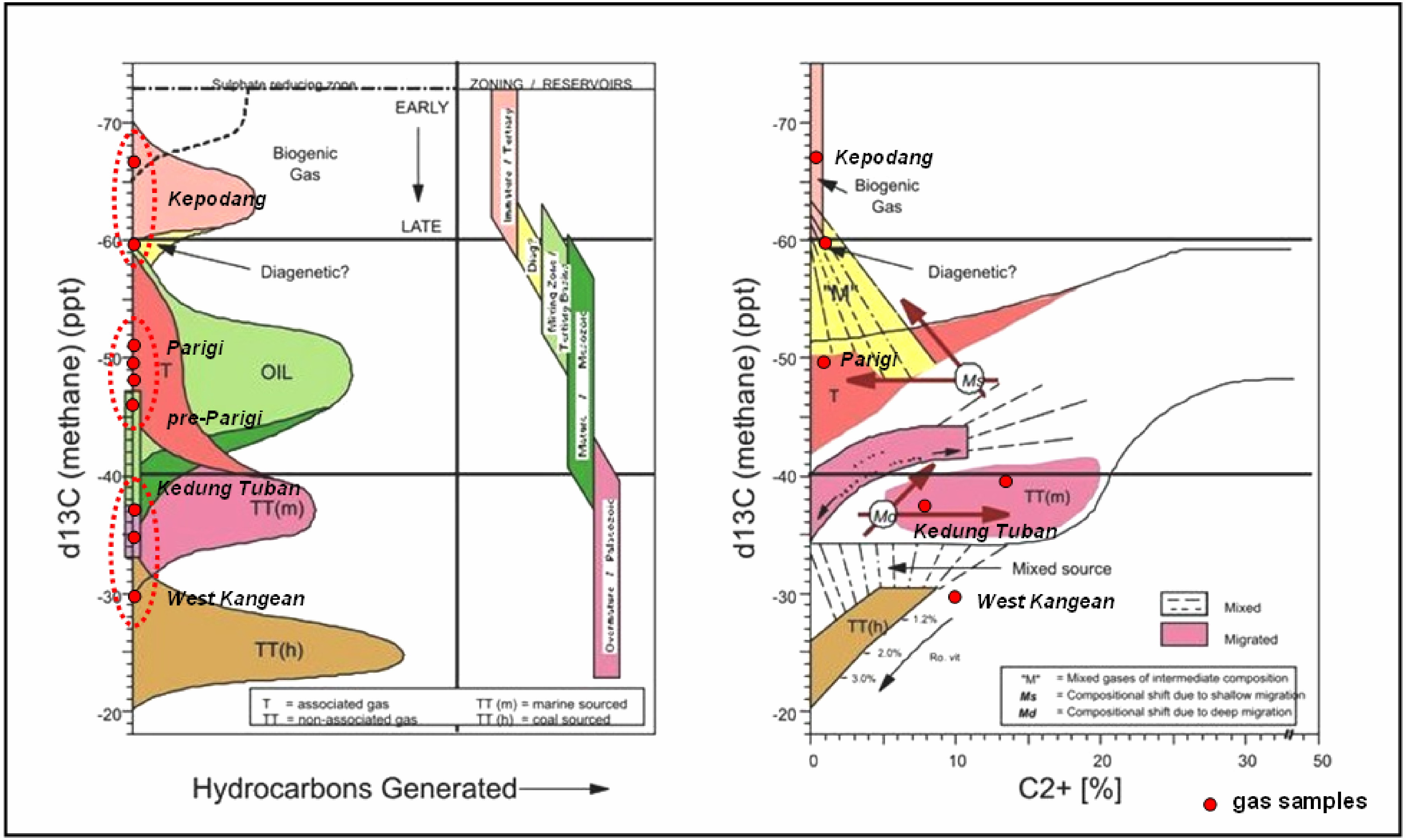

Figure 5 - Genetic types of representative Java gas fields based on cross plot of δ13C CH4 values and C 2+. The gases are both biogenic, thermogenic, and mixed thermogenic-biogenic. Kepodang gas, East Java is mostly biogenic. Some gases of Parigi are mixed with small amount of wet gas component. Thermogenic gases of Java have δ13C CH4 values of -45 to -30 ‰ generated from maturity level of 0.9-2.4 %Ro. West Kangean gas is the most mature gas.

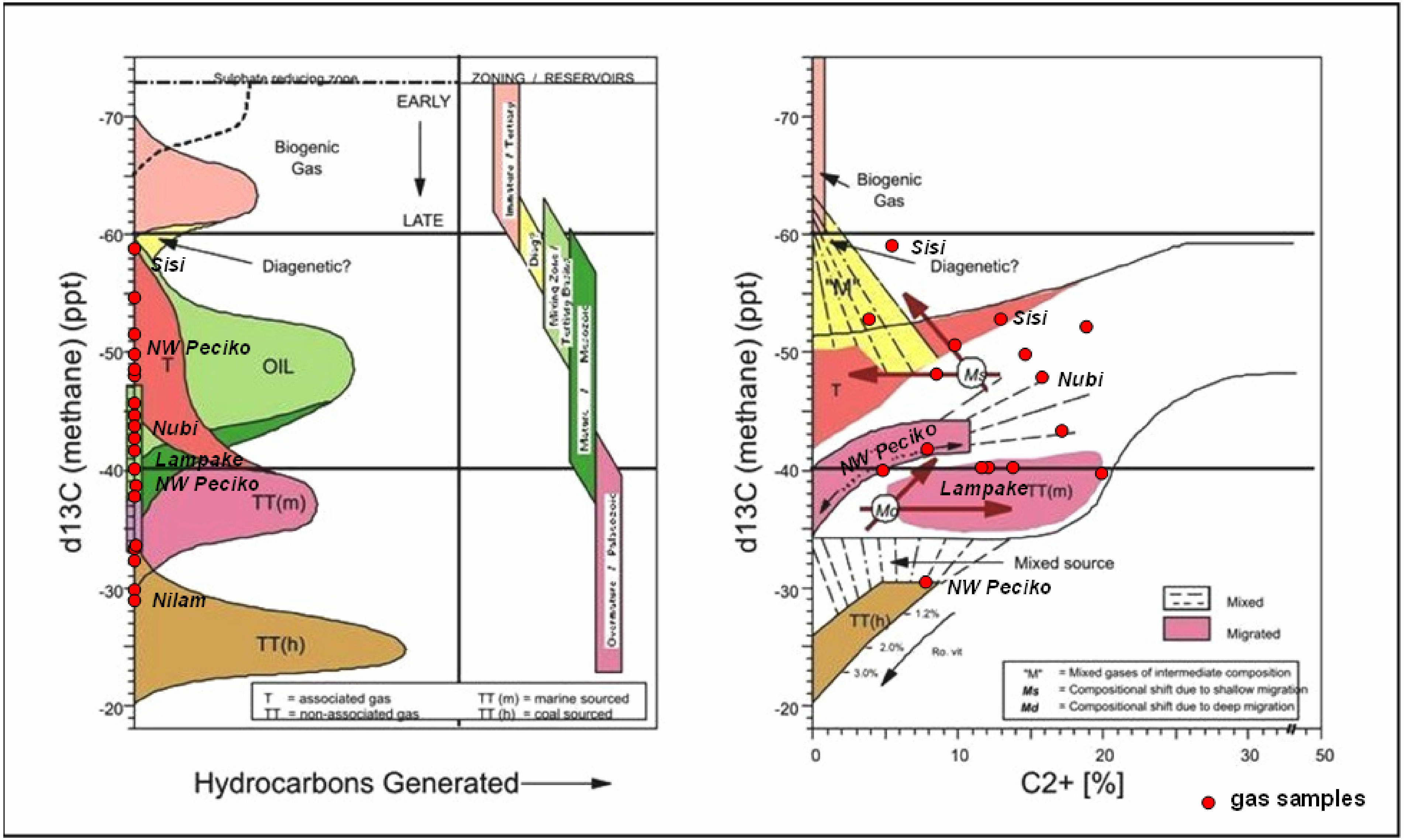

Figure 6 - Genetic types of representative Kalimantan gas fields based on cross plot of δ13C CH4 values and C 2+. The gases are mixed thermogenic-biogenic and thermogenic. Gas fields of onshore Kutei, represented by Nilam (generated at maturity level of 2.5 %Ro), are generally more mature than those of offshore gas fields (e.g. NW Peciko-Nubi fields). Some fields show mixed gas with contribution from biogenic gas as shown by 13-carbon isotope of methane around -55 ‰.

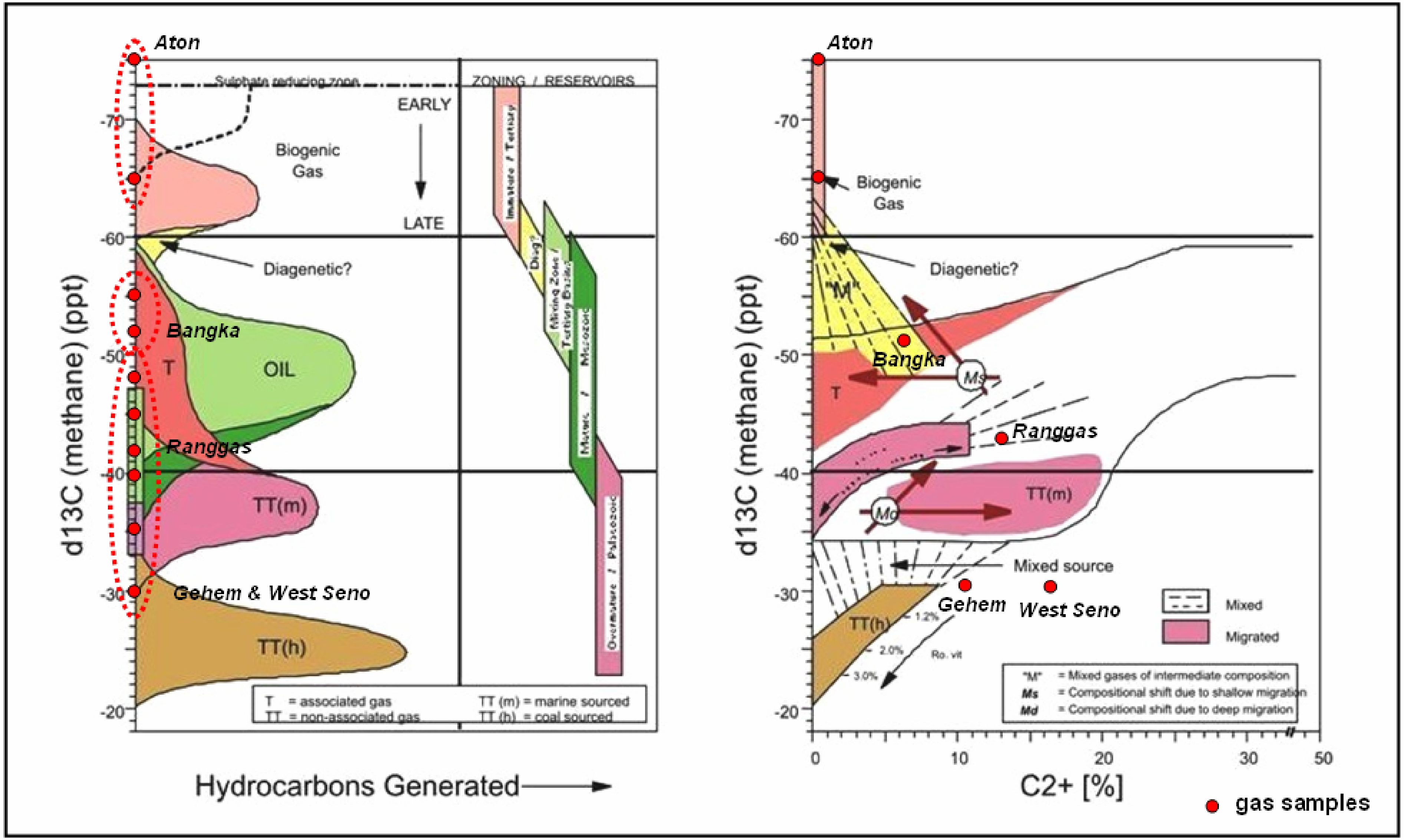

Figure 7 - Genetic types of representative Makassar Strait gas fields based on cross plot of δ13C CH4 values and C 2+. A majority of of the gases in the deep-water Makassar Strait have δ13C CH4 values of -52 to -28 ‰, indicating thermogenic origin. A subordinate number of the gases exhibit characteristics of biogenic-thermogenic mixing with δ13CCH4 values of around -55 ‰. There are gases, made up of almost pure methane, from the Pliocene reservoirs with δ13C CH4 values of -75 to -65 ‰, resulted from biogenic origin.

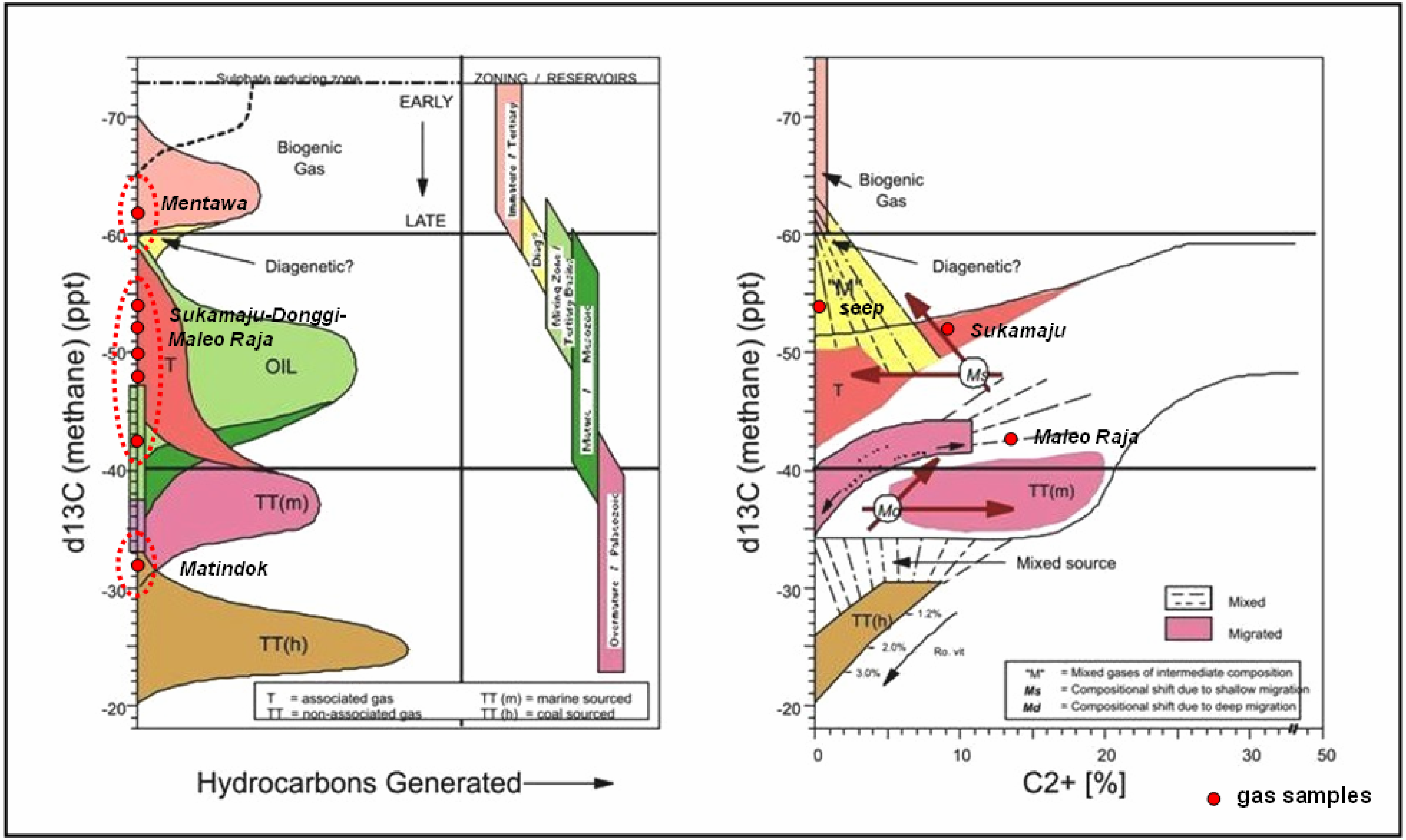

Figure 8 - Genetic types of representative Sulawesi gas fields based on cross plot of δ13C CH4 values and C 2+. The gases shown here are from the Banggai Basin, East Sulawesi indicating thermogenic gases with values of δ13C CH4 -53 to -32 ‰. A subordinate number of mixed gas and biogenic gas occur, like the gas sample from the seep and Mentawa gas sample. The most mature gas is Matindok, generated from a maturity level of 2.2 %Ro.

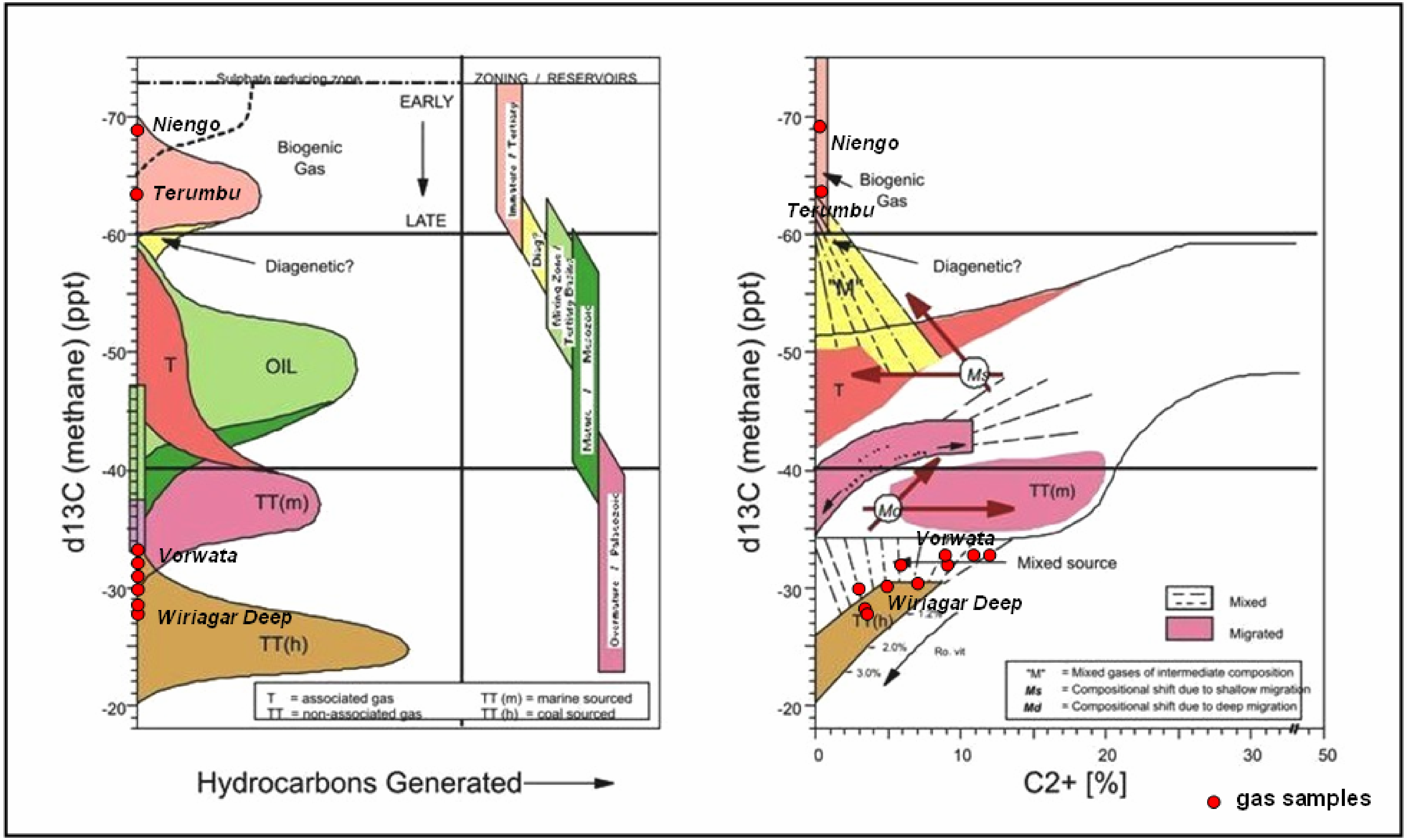

Figure 9 - Genetic types of representative Papua gas fields based on cross plot of δ13C CH4 values and C 2+ of Schoell (1983). The gases in the Bintuni Basin (such as Wiriagar Deep and Vorwata fields) were generated from highly mature coally source rocks of 13-carbon isotope -34 to -28 ‰, equivalent with maturity level of 2.2-2.5 %Ro. Biogenic dry gas with methane content of 99-100 % occur in the northern Papua basins with δ13C CH4 values at least -70 ‰ due to occur in the Pleistocene-aged reservoirs.

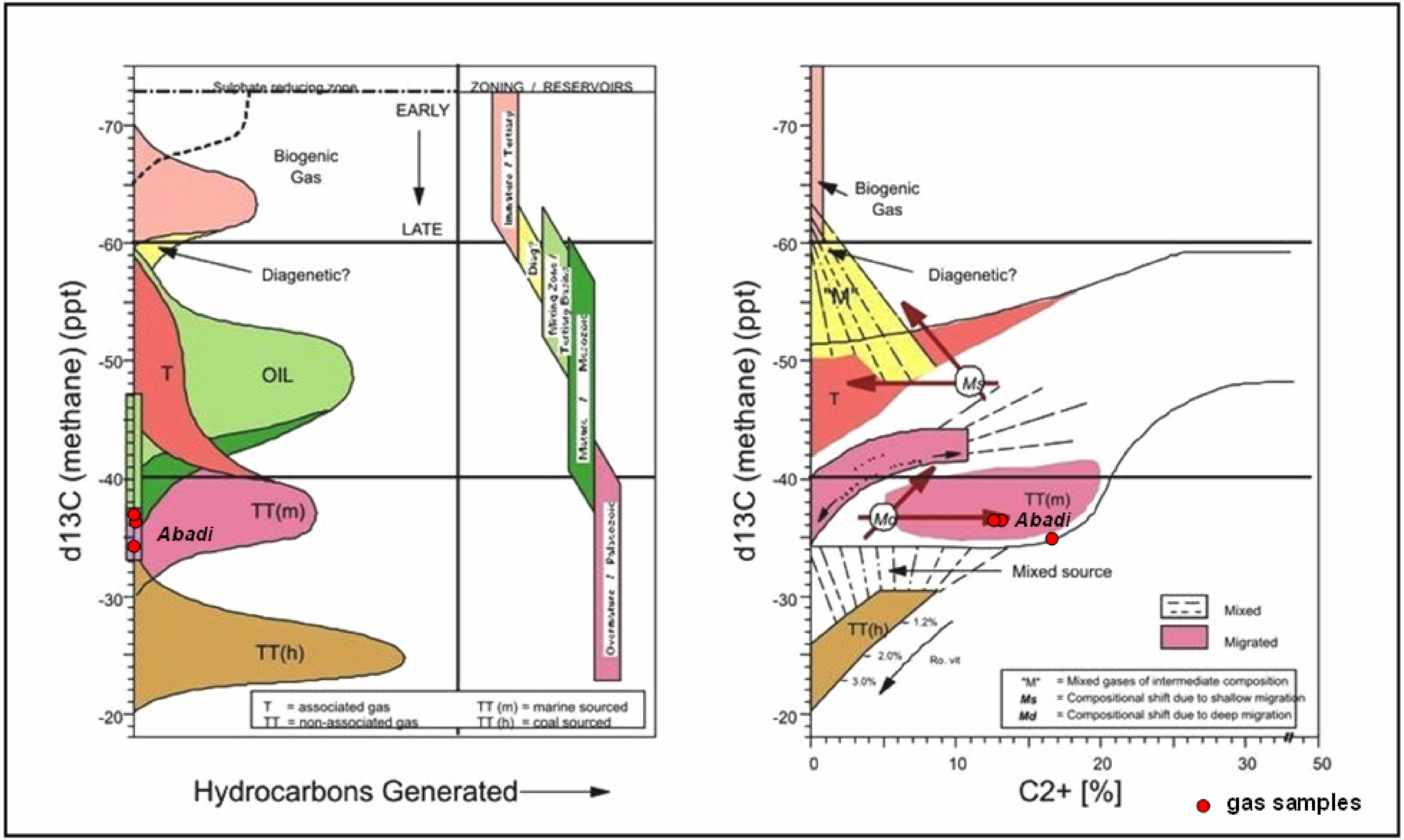

Figure 10 - Genetic types of representative Timor-Arafura Sea gas fields based on cross plot of δ13C CH4 values and C 2+. The gas samples are from Abadi gas field in the Masela block, Aru/ Malita-Calder Basin. The Abadi gas is thermogenic origin, generated from maturity level of around 2.0 %Ro. The sources of gas are shallow marineshales of the Middle Jurassic Plover Formation.

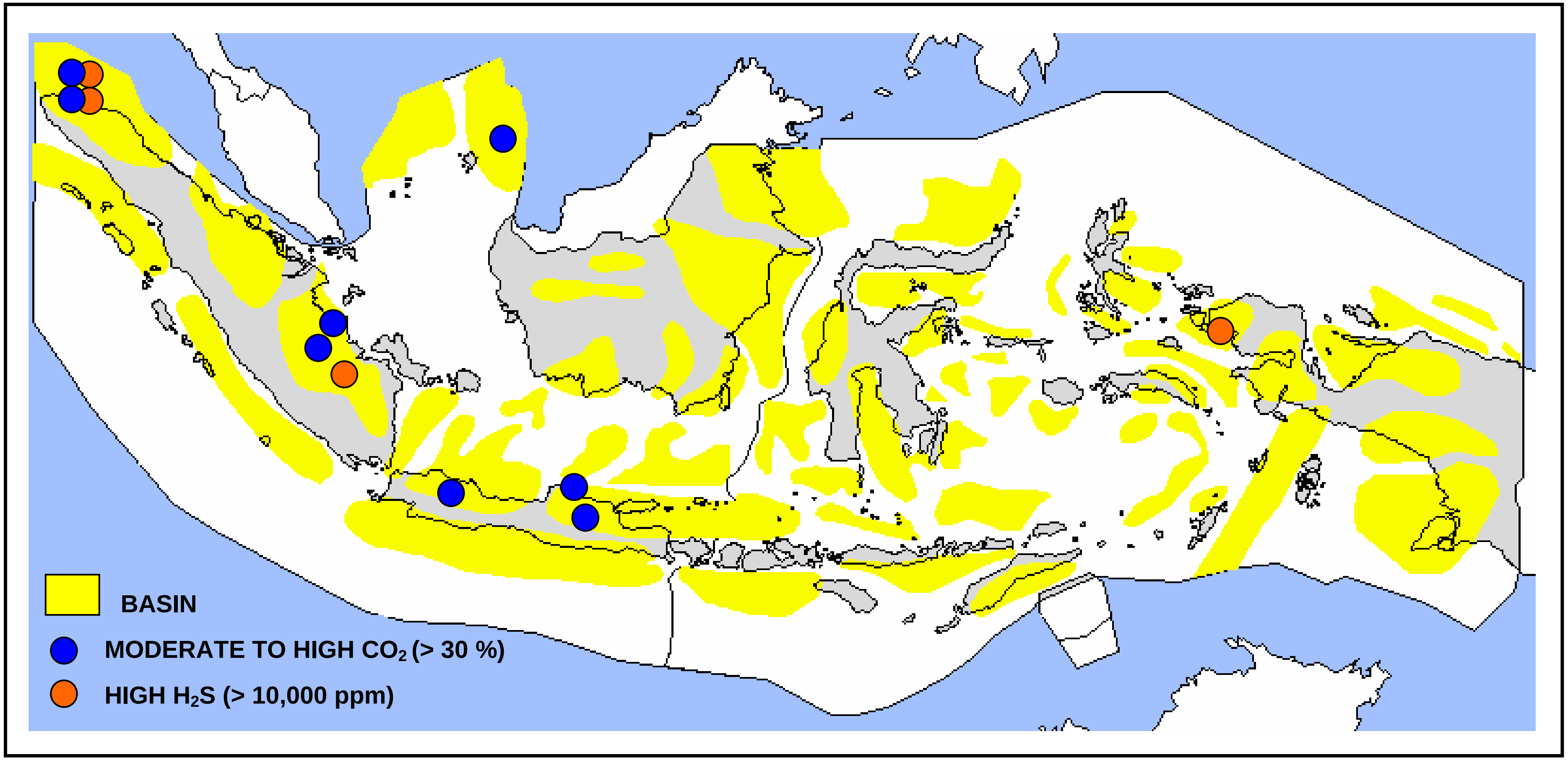

Figure 11 - Moderate-high content (>30 vol %) of nonhydrocarbon CO2 gas occur in some gas fields of North and South Sumatra, East Natuna, and onshore West Java and onshore-offshore East Java Basins. Based on generally heavy values of δ13C CO2, most of CO2 gas occurrences relate to inorganic origin by carbonate thermal destruction or mantle/ volcanic degassing. Concentration of nonhydrocarbon gas of H2S is high (> 10,000 ppm) in some gas fields in North and South Sumatra, and Salawati Basins. All occurrences of high H2S content relate to thermo-chemical sulfate reduction (TSR) of deep and hot carbonate sequences.