CHAPTER 2

LITERATURE REVIEW.

2.1 Introduction.

This chapter is comprised of literature review and discussion of the regional geology and petroleum system of the Thai-Vietnam overlapping area, such as geologic setting, tectonic evolution, stratigrphy, possible sources rock reservoir type, trap system and the distribution of its Tertiary strata. Because the Thai-Vietnam overlapping area is a frontier area and has a few geological data, therefore, most of the geological data used in this study will be derived and applied from its adjacent areas, which are the northern and the southern of the study area.

The regional geology of the Pattani Basin has been summarized by Achalabhuti and Oudomugsorn[42] and Lian and Bradley[43]. The stratigraphy and history of sedimentation have been studied by Woollands and Haw[44], and Bunopas and Vella[45]. Tectonic elements and structural evolution of the Gulf of Thailand have been the subject of discussion by various authors (Bunopas and Vella[45]; Molnar and Tapponier[46]; Ohnstad [47]; Polachan and Sattayarak [48])

Many studies suggested that a number of Tertiary basins occur in the Gulf of Thailand, usually orient parallel in a N-S direction, as grabens and half grabens. The Ko Kra Ridge splits the region into two parts. The western portion contains ten main basins of various sizes, including the Chumporn, Western, Kra, Nakhon and Songkla basins. The eastern part has three main basins, the Pattani, northern Malay, and Khmer (Figure 2.1). The N-S running Central Ridge separates the central parts of the Pattani and Khmer basins. Most of the latter, however, is located in the Cambodian sector or overlapping zone in the Gulf.

2.2 Regional Geology

This study concentrated investigating on petroleum, system of the most two important petroleum prolific basins located in the Gulf of Thailand, the Pattani Basin and the north Malay Basin.

Geologic setting of the Gulf of Thailand.

Burton [49] and ASEAN Council of Petroleum [ASCOPE] [50] had studied and summarized the geologic setting of the Gulf of Thailand as the Thai and Malay basins have different orientations (Figure 2.2 ,2.3 and 2.4). Thai basins appear to relate to the N-S family of linears that characterize eastern Bangladesh, the Arakan Yoma, the central valley of Burma, the Shan Plateau, and the northern part of Andaman Sea, and possibly to the familiar oriented Ninety East Ridge as well as the pre-Tertiary trends in the subsurface of north Sumatra. Lian and Bradley [43] mentioned that the Gulf of Thailand is a northwest-trending re-entrant into Sundaland, the southwestern most part of the Eurasian plate (It lies near the intersection of two major transcurrent fault systems (Figure 2.5). The first fault system, the NW-SE trending Three Pagoda fault, extends from the Burmese border through the Three Pagoda pass and may extend to the northeastern part of the Gulf of Thailand. The second fault system, comprising the

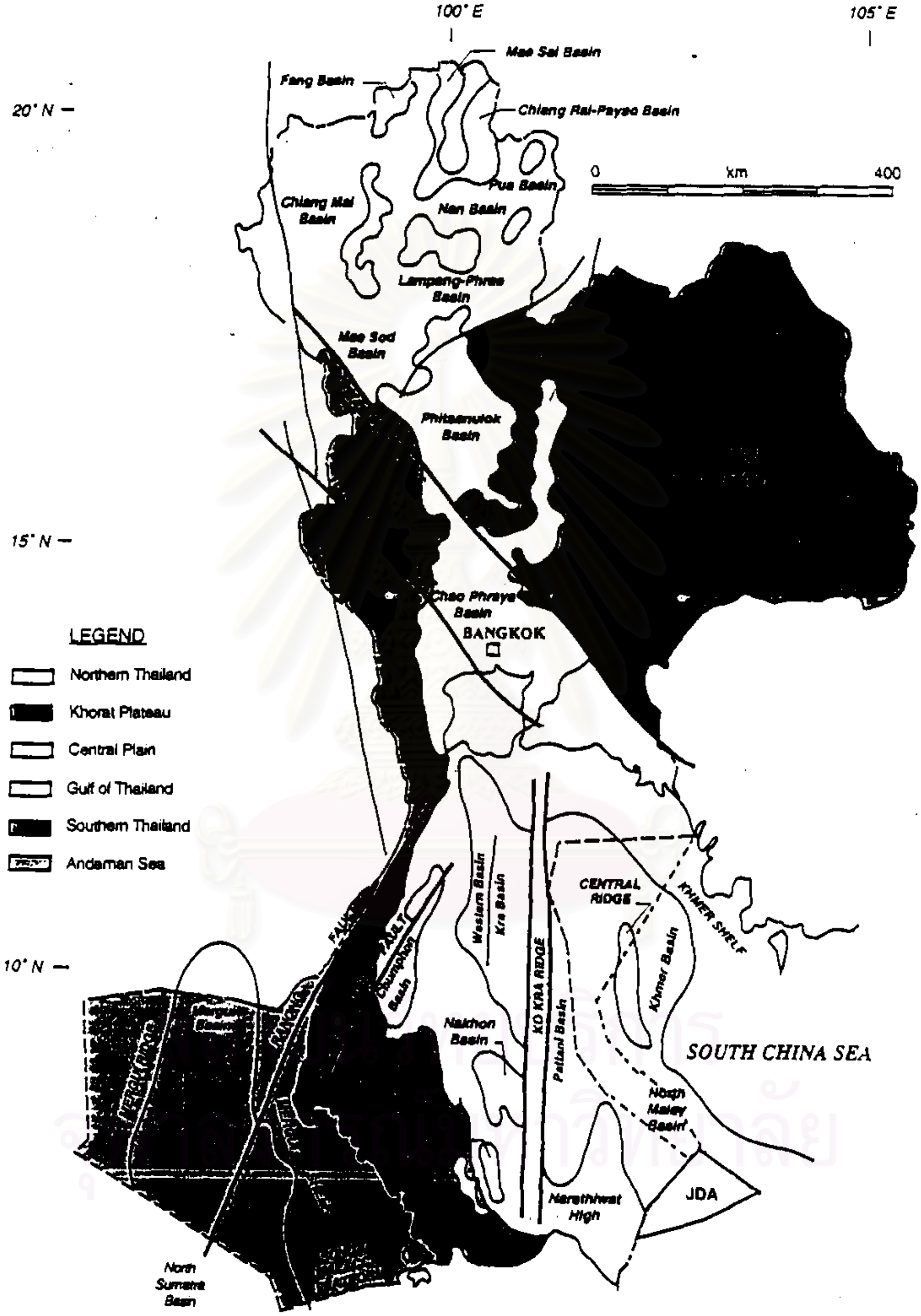


Figure 2.1 Significant Tertiary basins in Thailand (After DMR, 1997)

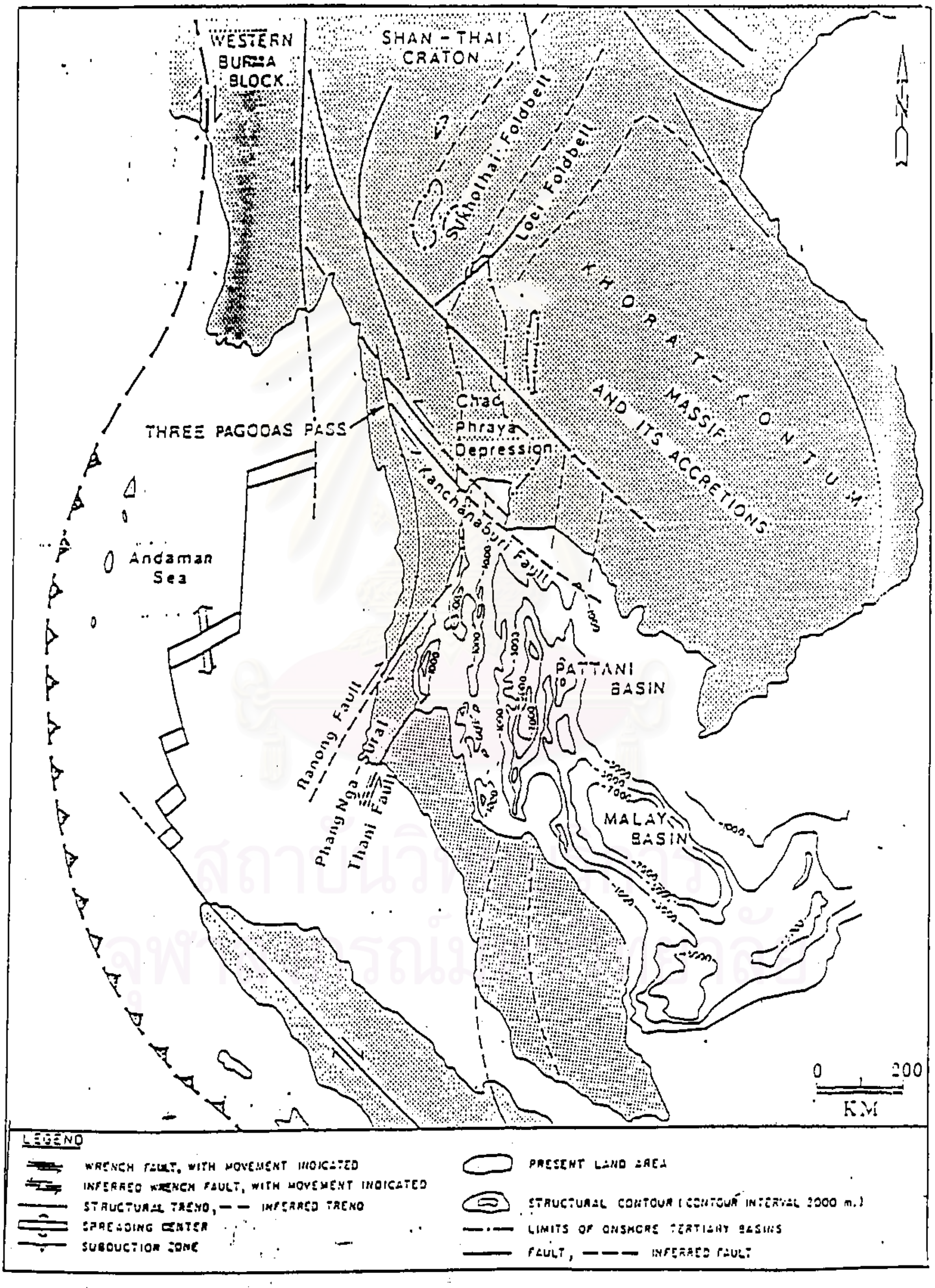


Figure 2.2 Regional tectonic setting of the Gulf of Thailand.(After Burton, 1984)

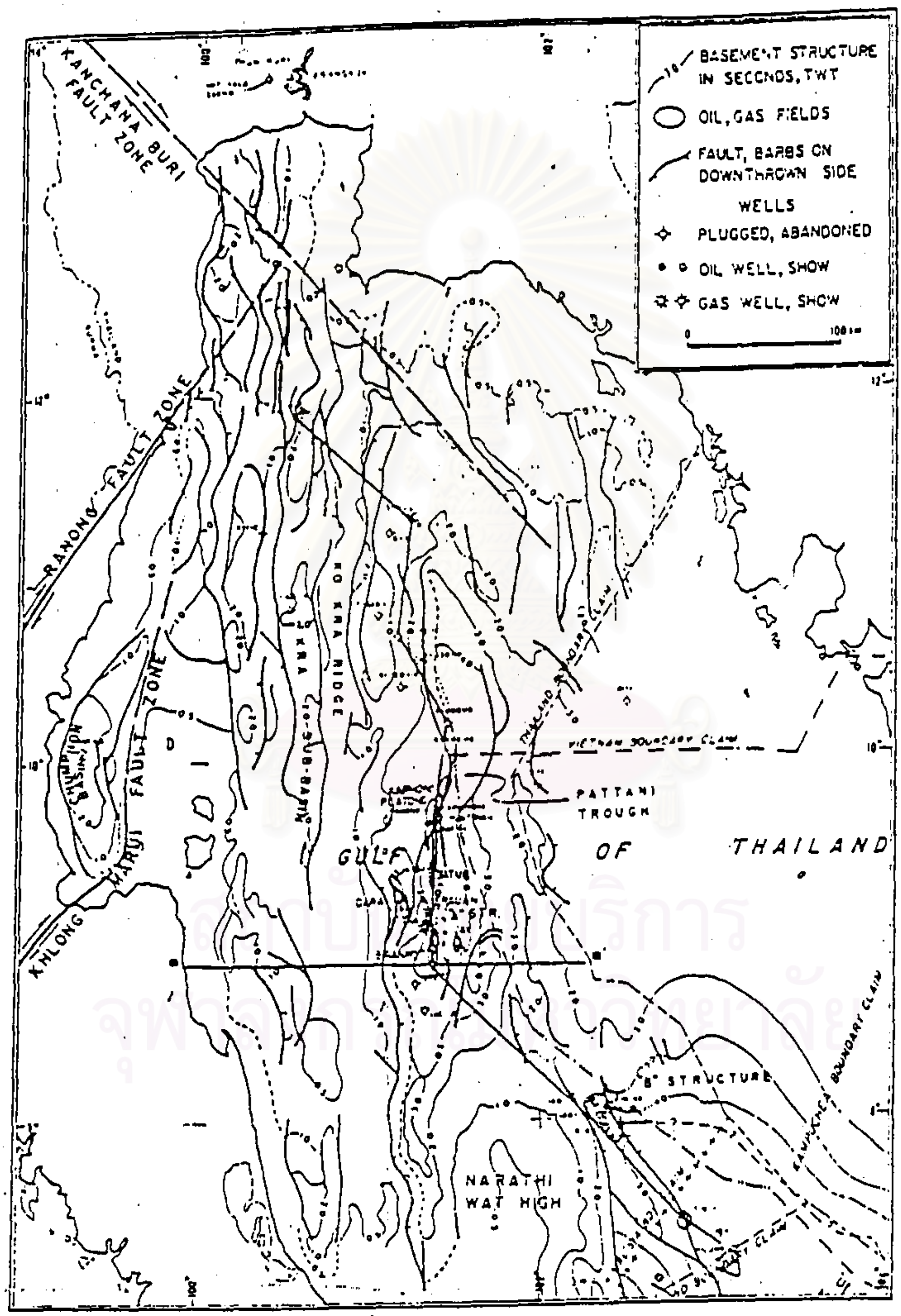


Figure 2.3 Thai basins; basement structure (After ASCOPE, 1991)

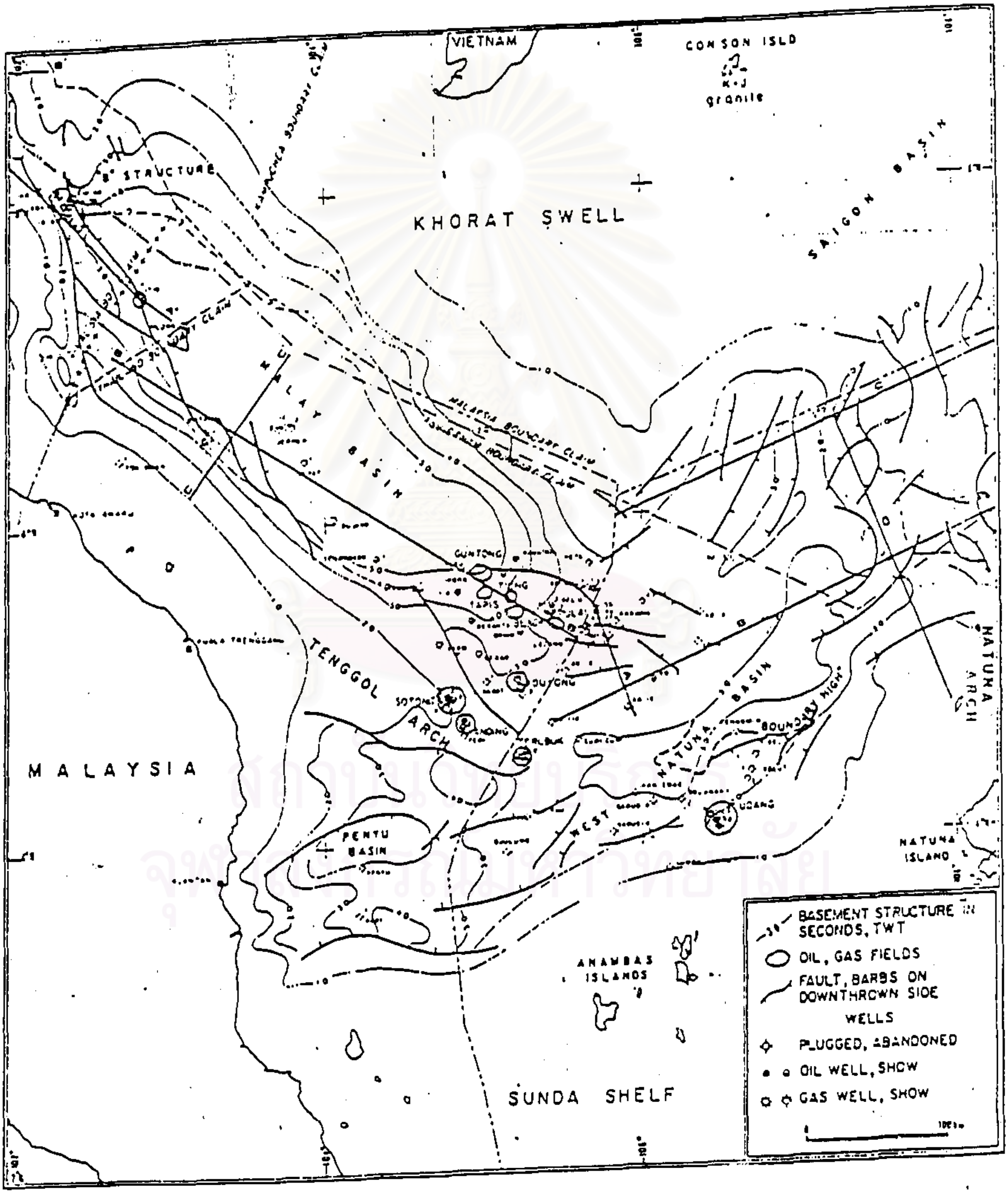


Figure 2.4 Malay basins; basement structure (After ASCOPE, 1991)

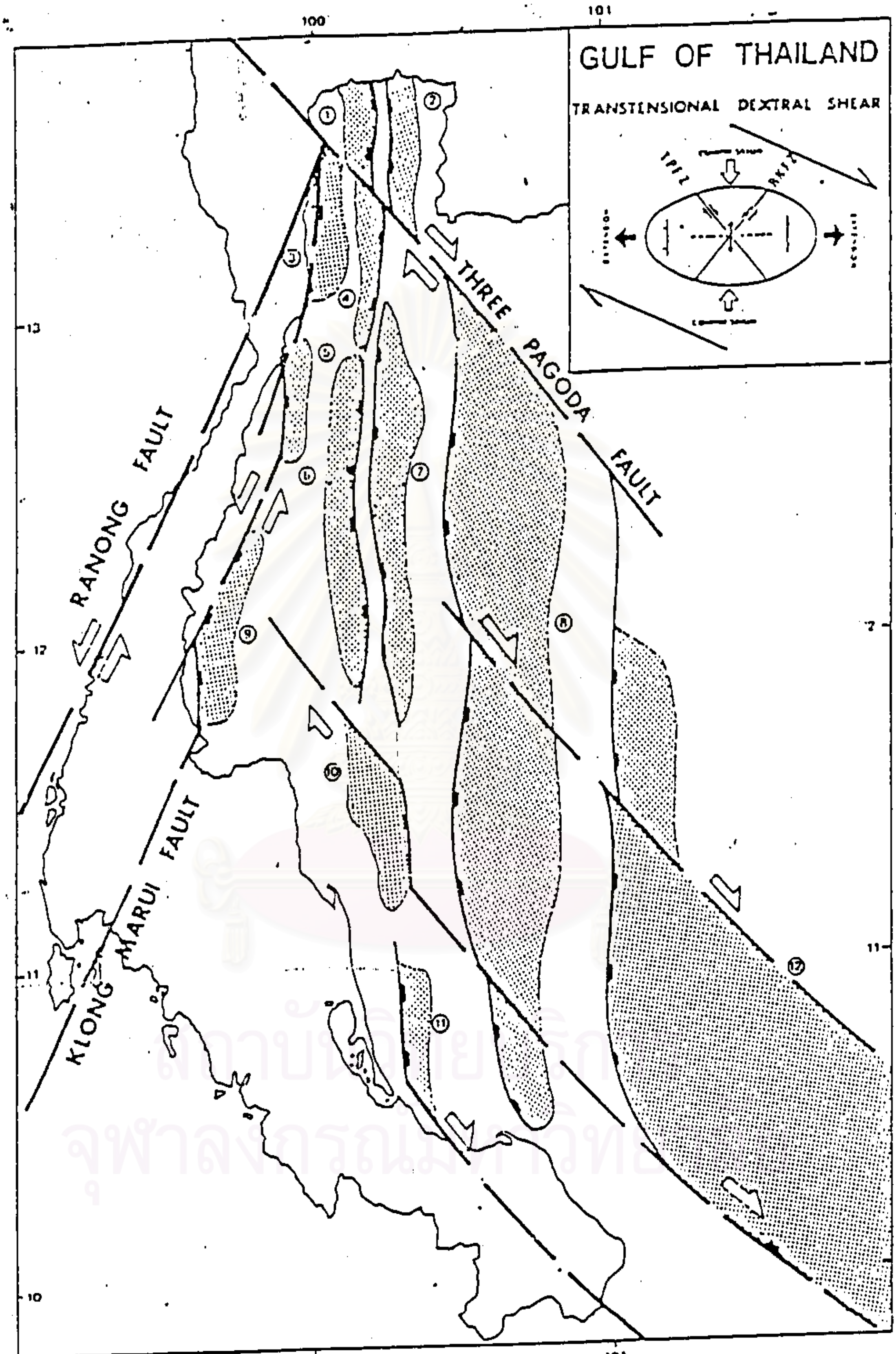


Figure 2.5 Structural map of the Gulf of Thailand, showing relationship between conjugate strike-slip faults and the development of N-S trending pull-apart basins. 1) Sakhon; 2) Paknam; 3) Hua Hin; 4) North Western; 5) Prachuap; 6) Western; 7) Kra; 8) Pattani; 9) Chumphon; 10) Nakhon; 11) Songkhla; 12) Malay (After Polachan and Sattayarak, 1989)

NNE-SSW trending Phang Nga - Surat Thani and Ranong faults, cuts across the southern Thai Peninsula and extends into the western part of the gulf.

Polachan *et al.* [51] concluded that the geological structures seen in Tertiary sections in the Pattani Basin and adjacent areas comprise a series of N-S trending elongate grabens, half grabens, and horsts. Further south, in the Malay Basin, grabens and half grabens have a NW-SE trend.

ASCOPE [50] mentioned that the initial basin formation in the Gulf of Thailand have taken place in early Tertiary time with a period of basement-induced block faulting . This faulting resulted in the formation of a series of grabens and half-grabens.

The Pattani Basin.

The Pattani trough is approximately 300 km long and 50 to 80 km wide. It is bounded on the west by the Ko Kra Ridge, on the east by the shallow Cambodian shelf, and to the southeast by the Narathiwat High (Figure 2.1). It is filled with Tertiary nonmarine fluvio-deltaic clastic sediments up to 10 km thick in the graben and in places less than 1 km thick on horsts. Drilling has not reached basement in the deepest part of the basin due to high temperature resulting from high geothermal gradients.

Chonchawalit [40] suggested that geological structures within the Pattani Basin, the largest basin in the Gulf of Thailand, and adjacent basins indicate a multitude of closely spaced N-S trending normal faults. Many of these normal faults transact pre-Tertiary basement, suggesting a basement-involved extension. He also mentioned that the oldest sediments penetrated by drilling within the basin are Oligocene in age.

The North Malay Basin.

Armitage [52] studied tectonic setting the northwestward of the north Malay Basin, i.e., basinward, and suggested that folding become less pronounced, assumes a dominantly E-W orientation, and structural relief is commonly of the order of a few hundred feet. Orientation of the folding suggests the presence of a N-S directed strike-slip fault at depth.

Dahm and Graebner [53] investigated seismic information in the vicinity of the Bongkot structure gas accumulation (Thai waters) and suggested that this end of the basin shares the N-S grain of the Thai basins as displayed in the N-S directed faulting, associated folding and local graben development. The Thai-Vietnam overlapping area is located in this transition zone between the southern part of the Pattani Basin and the north Malay Basin.

Stratigraphy of Tertiary sequences in the Gulf of Thailand.

The Tertiary sequences in the Gulf of Thailand were largely deposited in marginal marine and non-marine settings. Lithologically the sediments comprise clastics with coals, mudrocks and occasional freshwater limestones deposited in a variety of lacustrine, fluviatile, lagoonal and shallow marine environments. A number of hybrid lithostratigraphic or sequence stratigraphic schemes have been defined, with unit boundaries being based on a mixture of interpreted sequence boundaries, palaeoenvironmental, and lithological features. The resultant schemes are therefore not lithostratigraphic schemes, but are the schemes that developed for practical application in the absence of a formal lithostratigraphic framework. These schemes are referred to as "sedimentary stratigraphic" schemes.

Lian & Bradley [43] used variations in seismic response and gross palaeoenvironmental characteristics to subdivide the succession into four unit (I-IV). They concluded that unit I comprised fluvial-deltaic sediments, while unit II comprised a transgressive cycle of restricted marine sediments. Unit III was identified as comprising a succession of non-marine and deltaic sediments capped by the mid-Miocene unconformity and overlain by the coastal marine sediments of unit IV which pass upwards into present day marine sediments.

Polachan [51] used a modified version of the Lian & Bradley [43] scheme, with the addition of the selected palynomorph taxa characteristic of units I-IV, and categorized the Tertiary sediment in the Pattni Basin as showed in Table 2.1. These

Table 2.1 Stratigraphy of Cenozoic basins in the Gulf of Thailand (After Polachan, 1991).

STRATIGRAPHY OF CENOZOIC BASINS IN THE GULF OF THAILAND

AGE	UNIT	THICKNESS (UP TO)	LITHOLOGY		ENVIRONMENT	FOSSILS
LATE MIOCENE - RECENT	IV	1,700 m.	WESTERN GRABEN AREA CLAYS/SHALES/SANDSTONES Clays/Shales, brown - grey, varicoloured, silty Sandstones, fine - very coarse grained, occasionally gravel.	PATTANI & MALAY BASINS CLAYS/SHALES/SANDSTONES) Clays/Shales, grey, silty Sand(stones), grey fine - very coarse grained, channel characteristics.	Flood Plain with more Mangrove Swamp and Marine in upper part	Dacrydium Podocarpus Florschuetzia meridionalis Stenochlaena laurifolia
MIDDLE MIOCENE - LATE MID-MIOCENE	III	1,200 m.	SHALES / CLAYSTONE / SANDSTONES Shales / Claystones, varicoloured, redbrown, silty, sandy. Sandstones, brown, varicoloured, fine - coarse grained, average thickness 3 m. restricted lateral extent. Limestone streaks & lignite are occasionally present.		Flood Plain with Local Delta Plain	Florschuetzia meridionalis Spinizonocolpites echinatus
EARLY MIOCENE - MIDDLE MID-MIOCENE	II	800 m.	SHALES / SANDSTONES Shales / grey, organic rich Sandstones, brown - grey, very fine - medium grained, average thickness 4.5 m., significant lateral extent.		Lacustrine and Restricted Marine	Florschuetzia levipoli Echiperiporites estelae Pediastrum
? LATE OLIGOCENE - EARLY MIOCENE	I	5,000 m.	SHALES / SANDSTONES Shales, brown - grey, varicoloured. Sandstones, brown - grey, fine - coarse grained, fining upwards, channel characteristics.		Alluvial & Flood Plains with Ephemeral Lacustrine	Monoporites annulatus Magnastriatites howardi Picea, Pinus, Pediastrum
PRE-TERTIARY BASEMENT			MESOZOIC CLASTICS AND GRANITES, PALEOZOIC CLASTICS AND CARBONATES			

palynomorphs are however inconsistent with the proposed palaeoenvironmental settings of these units and the age or stratigraphical position of the regional unconformity.

In this study, the Tertiary sediments in the Pattani Basin and the north Malay Basin can be divided into four units based on the study of Polachan (1991) because this category is widely accepted and used in practical as follows;

Unit I (Late Oligocene to Early Miocene; 32-25 Million years ago [Ma.])

This unit is the oldest and overlies unconformably the basement rock, which is older than Tertiary. The thickness of the unit is probably more than 6,000 m. The strata consist of brownish - grayish shale interbedded with fine - coarse grained sandstone in the lower part. This sequence indicates alluvial and flood plain and ephemeral lacustrine environments, whereas the sedimentary environments of the upper part of the unit are generally alluvial and flood plain.

Shale that was deposited in the ephemeral lacustrine environment of this unit has a high organic matter content and is appropriate to be a petroleum source rock. Two sandstones that were deposited in channel and lacustrine delta environments are expected to have low porosity and permeability. The thick bedded sandstones are interbedded with shale, which varied in the thickness from thin layers to 30 m. Because these sandstones are deeply buried, they are not suitable as petroleum reservoir rocks. However, some sandstones such those at the margin of the basin where they occur at relatively shallower depths, may be reservoirs.

Unit II (Early Miocene to Middle mid-Miocene ; 25 - 15 Ma.)

This unit continuously overlies unit I and its thickness is 800 m. The rocks are mainly grayish shale that was deposited in a lacustrine environment and has thin interbeds of brownish - grayish, fine - medium grained sandstone. The sandstone was deposited in a lacustrine deltaic environment. The lateral distribution of the sandstone has good continuity. Some beds of the sandstone are marine strata and were derived from a marine incursion into the basin from the south. This sandstone has good porosity and permeability. The shale of the unit has a high organic content and is appropriate as a good petroleum source rock.

Unit III (Middle Miocene to Late of Mid-Miocene ;15 - 11 Ma.)

Unit III conformably overlies unit II. The maximum thickness of the unit is 1,200 m, and the unit consists mainly of shale and red - brown mudstone, with interbedded brown, fine - coarse grained sandstone. The upper part of the unit especially has thick silty sandstone interbeds. In contrast, sandstone in the lower part is deltaic sandstone and interbedded with shale and some lenses of limestone and coal. The sedimentary environments of unit III are flood plain and coastal environments. Sandstone of the unit has good porosity and permeability, so, it can be an important petroleum reservoir in the Thai - Vietnam overlapping area, as well as in other Tertiary basins in the Gulf of Thailand.

Unit IV (Late Miocene to Recent ; 10 Ma. to Recent)

Unit IV unconformably overlies unit III. It is believed that the basin was uplifted between 10 - 11 Ma. ago and this generated some areas that on seismic sections have truncation characteristics (evidence of the extreme uplift of the basin, whereas its center was slightly uplifted and has only toplap characteristics).

The thickness of this unit may be up to 1,700 m, and the unit consists of claystone and shale interbedded with sandstone (deposited in a flood plain environment in the lower part and in littoral and marine environments in the upper part). Most of the strata are gray shale ,with some lenses of limestone and coal.

2.3 Petroleum Geology of the Thai-Vietnam Overlapping Area

The basin fill in the Pattani basin since Oligocene time is comprised of non-marine and marginal marine siliciclastic sediments shade from adjoining highlands to the north, the east, and the west. The various provinces provided sediment influx of differing characteristics, creating variability in reservoir sizes, reservoir quality, and source richness across the basin. The major sequence packages are identified, reflecting low-order relative sea level changes during the Neogene.

Structural evolution.

Polachan and Sattayarak [48] suggested that the Tertiary basins in Thailand originated and developed through dextral transtentional shear. At present, this model is well accepted. With dextral shear and the presence of N-S structure grain of Pre-Triassic rocks, N-S extensional faults were extensively formed. These bounding faults control extensional rifting of the basins (Figure 2.3). Whereas, the Malay Basin reflects the NW-SE directional trend of the Java Trench, the Mentavi Trough, the Semangko (Great Sumatran) rift fault, the island of Sumatra itself, the Strait of Malacca, the Malay Peninsula (Figure 2.4), and major lineaments of the Indochina Peninsula. The Kanchanaburi southeast directed transcurrent fault, believed to tranverse the northern part of the Gulf of Thailand, may also to be related.

Dahm and Graebner [53] mentioned that the far northwest part of the basin displays both N-S and NW-SE structural component (e.g., in the vicinity of Bongkot field in Thai waters) and these appear to be an intermediate zone of transition between the two basins

Another basin which may be the source of petroleum and possibly migrated to the Thai-Vietnam overlapping area is the north Malay Basin. The Malay Basin is oriented in a NW-SE direction and continues to the southeast. Most of the Malay Basin lies in Malaysia, though its northeast part bordered the Narathiwat Ridge. Its northern part is close to Pattani Basin of Thailand. There are groups of NW-SE faults occur parallel to the margin of the basin. Strata in the basin consist of 12,000 m or more of non-marine to marginal marine deposits. The thickness of sediment increases in the southern part of the basin. The basin is believed to have originated in the Oligocene or the latter part of the Eocene (32-40 Ma.). Fault structures that occur in the basin are the result of the activity of NW - SE oriented strike - slip fault system.

Play Types.

Prадidtan [54] suggested that structural maps of the basins indicate no high relief folding, with only broad and gentle anticlines, rollovers and tilted blocks present (Figure 2.2). Therefore, based on the stratigraphy and tectonics, several conceptual plays have been defined. They are broad gentle anticlines, rollovers and tilted fault blocks of the Tertiary synrift sequences.

In addition, Sattayarak [55] suggested that two types of petroleum field found in the Pattani and the north Malay basin are gas and condensate in the area close to the depocenter and oil in the basin flank. He also suggested that beside the Miocene sediments, thick Oligocene lacustrine sequences are inferred to be good source rocks, providing they are located not too deep. These Oligocene lacustrine sequences could also be good source rocks for the Thai-Vietnam overlapping area as well. Other than faulted sand, exploration play types that might suitable are faulted anticline at the basin center and at the basin flank, draped structures and buried hill. Figure 2.6 shows the major play types in the Gulf of Thailand.

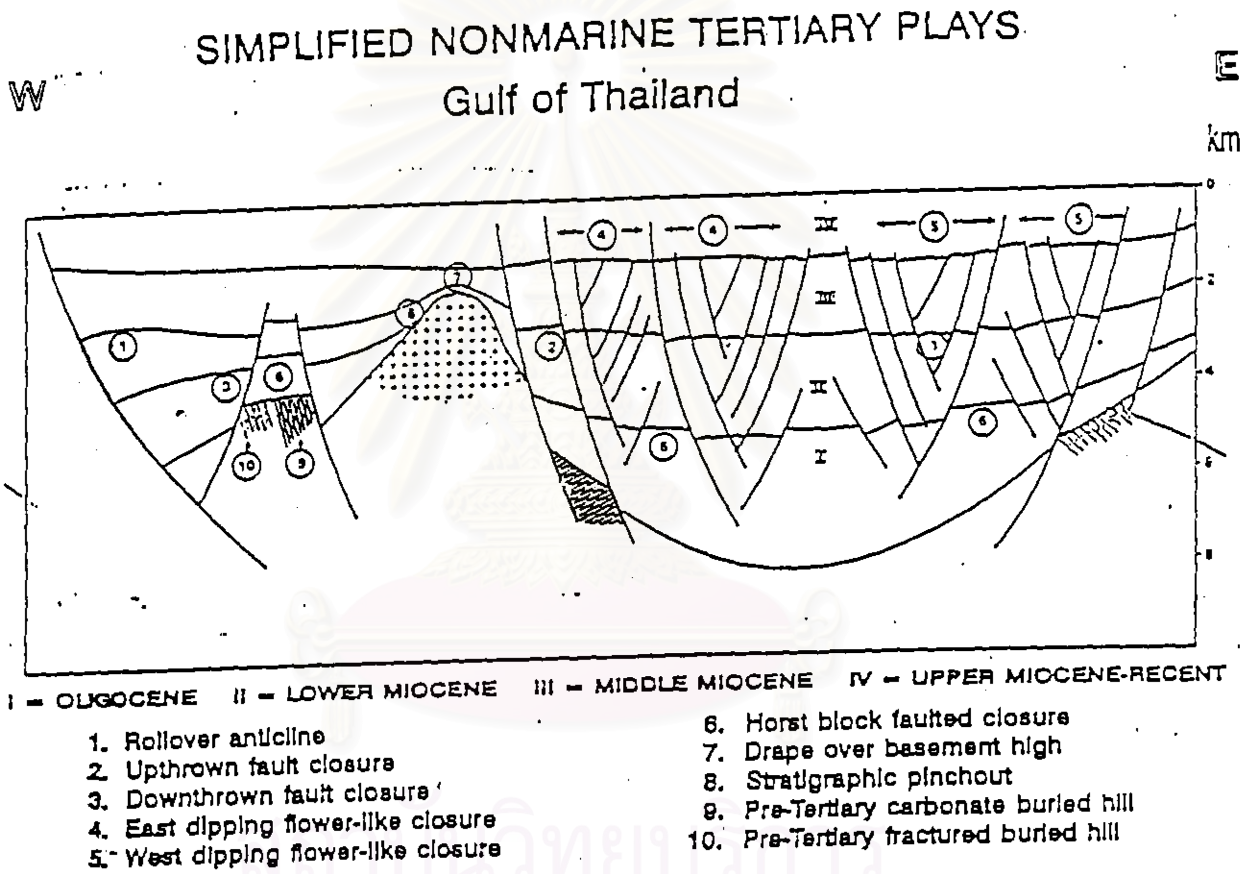


Figure 2.6 Simplified non-marine Tertiary Exploration Plays of the Gulf of Thailand
(After DMR, 1997)

Source rocks.

Results from source rock mapping, geochemical analysis, and thermal modelling of Lin and Mudford [56] show that the primary source sections in the Pattani basin are gas-prone coals and coaly shales in unit II, III and oil-prone lacustrine shales in unit I and lower part of unit II. In this study assume that these sequences could be primary source rocks and could extend to the Thai-Vietnam overlapping area. Regionally, the coaly source rocks become less abundant updip along basin flanks, towards bordering emergent highlands. Greater concentration of coal-bearing lithologies occur near the center of the basin, where more persistent lowland areas with marsh and swamp habitats existed, protected (by distance) from concentrated alluvial clastic influx. Early shallow lakes formed in isolated half-graben settings where a mix of lacustrine (algal) and terigenious organic matter accumulated in varying proportions.

Reservoir.

Sattayarak [55] mentioned that the main petroleum reservoir rocks in the Thai-Vietnam overlapping area is probably the sandstone of Unit III referred from the existing production formation of Bongkot field and JDA, which was deposited in flood plain, fluvial, and deltaic environments. The sandstone of the upper part of the unit was deposited in channels and is very thick and has good porosity and permeability. The lower part of the unit consists mainly of deltaic sandstone beds, that have good continuity and distribution.

The sandstone of unit II, which is a lacustrine deltaic sandstone, may also be a petroleum reservoir because there are some petroleum produced from this formation in the Bongkot field and in some wells of JDA.

Timing of hydrocarbon generation, migration and trapping.

Timing of source rocks maturity is directly related to the relative position of the source rocks in the developing basin center, basin flanks, and on the shallow basin margins. A secondary maturity control is increased heat flow from north to south in the basin, which results in earlier maturation in the southern part of the Pattani trough relative to the north.

The timing of the structural evolution of the Pattani basin was favorable for entrapment of the expelled gas and oil. The main phase of rifting and basin subsidence which initially created the productive graben systems occurred in the Early and Middle Miocene. Therefore, the major fault systems existed to trap hydrocarbons (mostly gas) expelled from unit II and unit III over a relatively long period of time (over 15 Ma), from the Middle Miocene to the present. Continued fault movements since the mid-Miocene is an important factor controlling variations of hydrocarbon pool sizes and abundance's throughout the Pattani. Old stable basement highs (Surat and Dara areas, located at the southwestern part of the Gulf of Thailand) were present to trap early hydrocarbons expelled from mature oil-prone unit I strata. More recent oil generation and preservation occurs in cooler, shallower areas along the basin flanks, particularly in the northern Pattani basin where heat flows are lower.

Migration.

The majority of the generate petroleum perhaps migrated towards the gentle dip flank of the half graben basins. Vertical migration along fault planes during reactivation periods is likely. Therefore, flank prospects situated on the gentle dip flank and falling within or near to the kitchen area are the most favorable.

Sealing and trapping.

The geological formation in the Thai-Vietnam overlapping area which forms the seal for trap is may be the claystone of unit III. It is interbedded with reservoir rocks, especially in the upper part of the unit. In the 17-B-1 well, results of log interpretation indicated that seal rock is a shale bed 30 m thick. Therefore, this shale could be the main upper vertical seal. The lateral seals are generated from the tilting and faulting of the formation and become to be the fault traps in finally. These structures were probably formed simultaneously with the uplift of the basin during the Middle Miocene.

2.4 Petroleum Geochemistry

Source rocks study of the Pattani Basin.

Lin and Mudford [56] studied the source rock richness, as measured by percentage of Total Organic Carbon (TOC). The results indicate that TOC varies both laterally and vertically across the Pattani basin. Wells drilled in the region showed the pronounced TOC variances with depth that are facies controlled. They also constructed the regional mapping of coal distributions and TOC across the Pattani basin and mentioned that source rock potential is greatest near basin axial lows and decreases updip along basin flanks.

Jardine [57] mentioned that gas and condensate make up the majority of the hydrocarbon reserves in the Pattani basin, and also mentioned that the correlation of hydrocarbon and source rock chemistries strongly suggest that coal and coaly shales in Unit II,II are the primary source of gas and condensate in the region. This study assume that these coal and coaly shale of Unit II and Unit III could extend to the Thai-Vietnam overlapping area and should be the primary source rocks for this overlapping area as well.

Lin and Mudford [56] studied the optical and chemical kerogen typing of well cuttings and core samples and concluded that the remains of terrestrial vascular plant material (Type III kerogen) is the dominant organic matter making up the coal and coaly shales. They also reported that the organic matter is hydrogen-poor but vitrinite-rich, and is prone to gas/condensate generation (Figure 2.7). From their experiments, they also concluded that the younger unit IV contains type III and Type II kerogens (terrestrial and marginal marine) and shows the potential for gas/condensate and oil generation, but is presently immature across the basin.

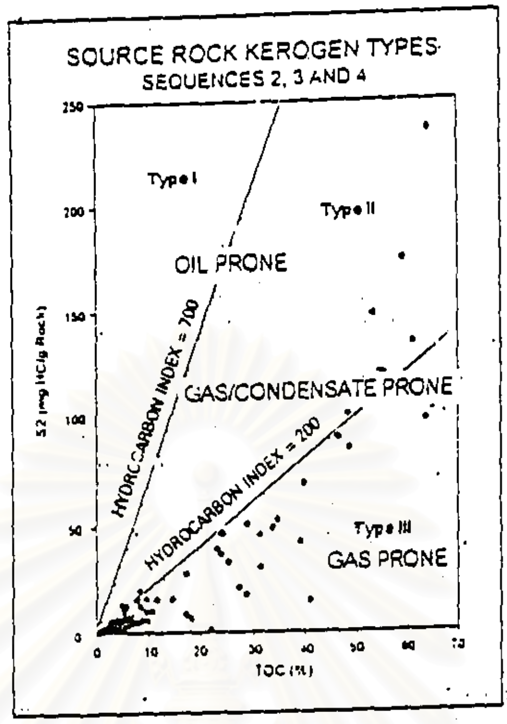


Figure 2.7 Cross plot of total organic carbon (%) and source rock pyrolysis hydrocarbon yields (mgHC/g Rock) for Pattani sequences II and III. Hydrogen indexes are depicted with the dashed lines which separate oil-prone and gas-prone kerogen types. Results show that Unit II and Unit III source rocks contain predominately gas-prone and gas/condensate-prone Type III kerogens (Jardine, 1997)

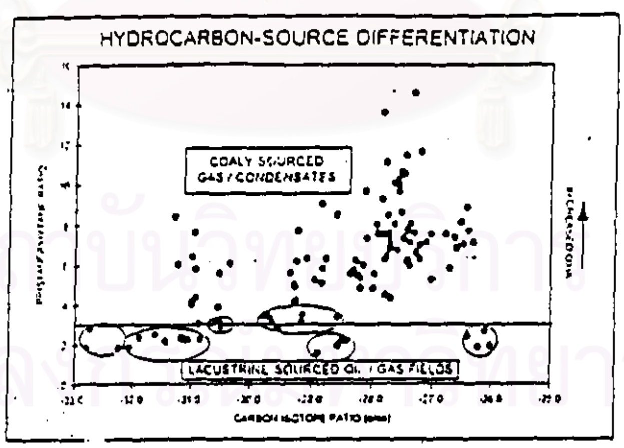


Figure 2.8 Cross plot of carbon isotope ratios nd pristane/phytane (Pr/Ph) ratios of Pattani basin hydrocarbons. Solid horizontal line near Pr/Ph ratio of 3.0 differentiates samples sourced from more oxic coaly swamp conditions versus less oxic lacustrine environments. Hydrocarbon samples above the approximates Pr/Ph boundary of 3.0 are predominately gas/condensate and those below the boundary are mixed oils and gases. Grouping of oil/gas fields may represent sourcing from separate lake environments (Jardine, 1997)

Geochemical analysis of Pattani gas-condensates yields relatively high phristane/phytane ratios (Figure 2.8) indicative of oxic source conditions typical of terrestrial (i.e. fluvial-coal swamp) depositional environments.

Unit I have been penetrated by only a small number of wells in the Pattani basin along the southern border. Jardine [57] believed that at the basin margin, Unit I is comprised mostly of alluvial and fluvial sands with interbedded shales. Measured total organic carbon in the unit I shales averages well below 1 percent but some richer intervals contain up to 3 percent TOC. Source rock quality is expected to improve downdip in half-graben axial areas where lager and deeper lakes persisted, as evidenced by high-amplitude/low-frequency seismic events at these localities (Figure 2.9). They are believed to be the main source areas for oil in the Pattani basin, but are now deeply buried and have not been penetrated by drilling to date. Whereas geochemical analyses of well samples from southern edge of the Pattani basin show that unit I shales have the potential for both oil and gas generation.

Jardine [57] also mentioned that a secondary contribution to the oil in the Pattani trough may come from younger, more hydrogen-rich source rocks (Figure 2.7). These rocks may be related to the short-lived shallow marine transgressions (unit III) and concentration of more hydrogen-rich in land plant marcerals (i.e. cutinnite and sporinite). However, although additional source rock types may exist, the bulk of the oils discovered in the Pattani basin are typed to algal lacustrine sources.

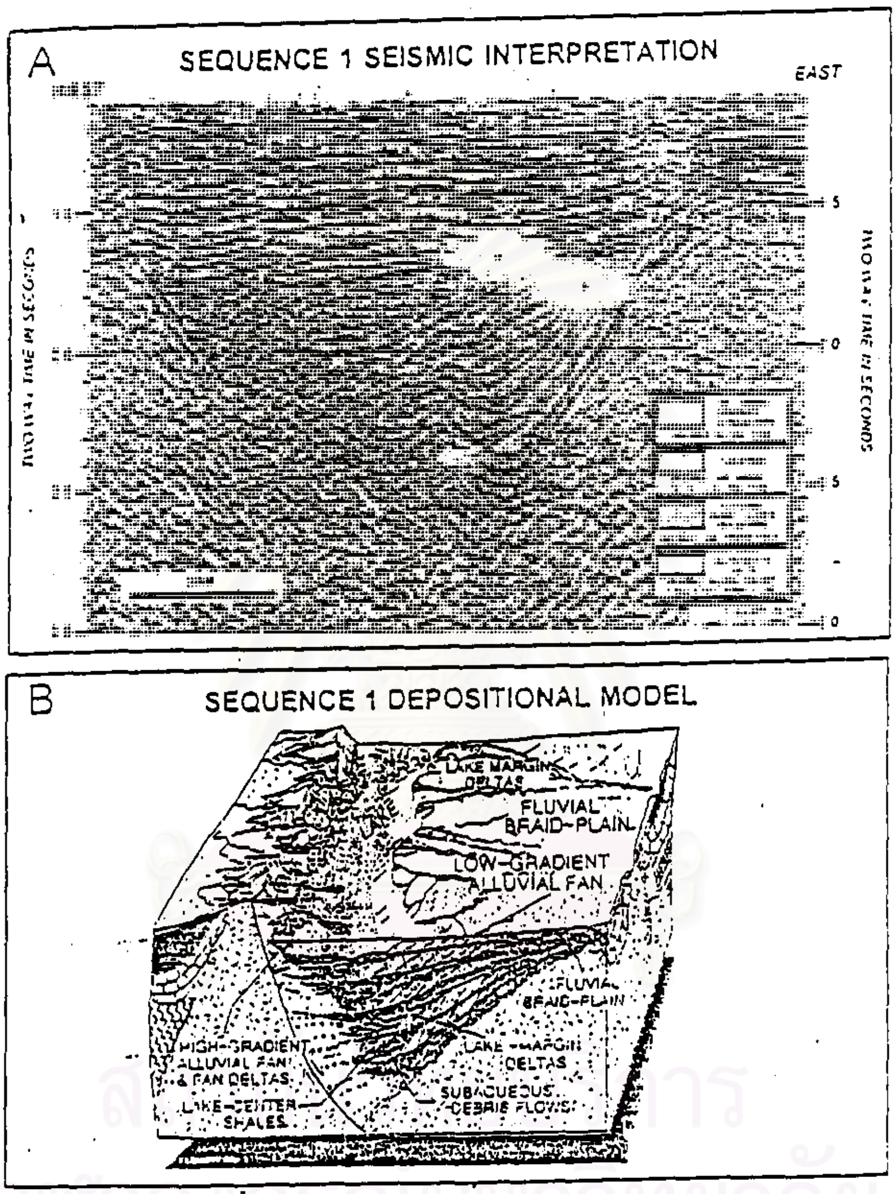


Figure 2.9 Seismic Facies interpretation of Unit I in the southern Pattani basin (A) with a corresponding schematic block model depicting the inferred the depositional setting and palaeo-environments of Unit I facies)B). Note that high-amplituude, low -frequency reflections in the central portion of the basin (A) interpreted to be lake center shales representing the primary source rock facies within Unit I (After Jardine, 1997)

Heat flow modeling.

Heat flow modelling of the basin linked to well temperature and vitrinite reflectance data shows that present-day heat flow in the Pattani Basin increases towards the basin axis with slightly increase. This is indicated that the primary driver governing source rock maturity laterally across the basin depth of burial.

Lekuthai *et al.* [58] studied and constructed the heat flow map of the Gulf of Thailand as shows in Figure 2.10. He also concluded that factors controlling this regional heat flow trend are related to the changes in crustal thickness and shallowing of the asthenosphere (starting in the south and progressing to the north) during the opening of the Gulf of Thialnd.

Hydrocarbon generation.

Lin and Mudford [56] generated the basin modeling of the Gulf of Thailand and concluded that oil-prone unit I source rocks began generating hydrocarbons in latest Oligocene/early Miocene time along the axis of the Pattani basin. However, maturation of unit I occurred progressively later up-dip across the shallower Pattani basin flanks. Today, Unit I remains in the main oil expulsion window in the shallowest flank areas, particularly in the northern Pattani basin. The present-day maturity of oil-prone Unit I section correspond with oil discoveries in the northern and shallow flank portions of the Pattani basin (Figure 2.11).

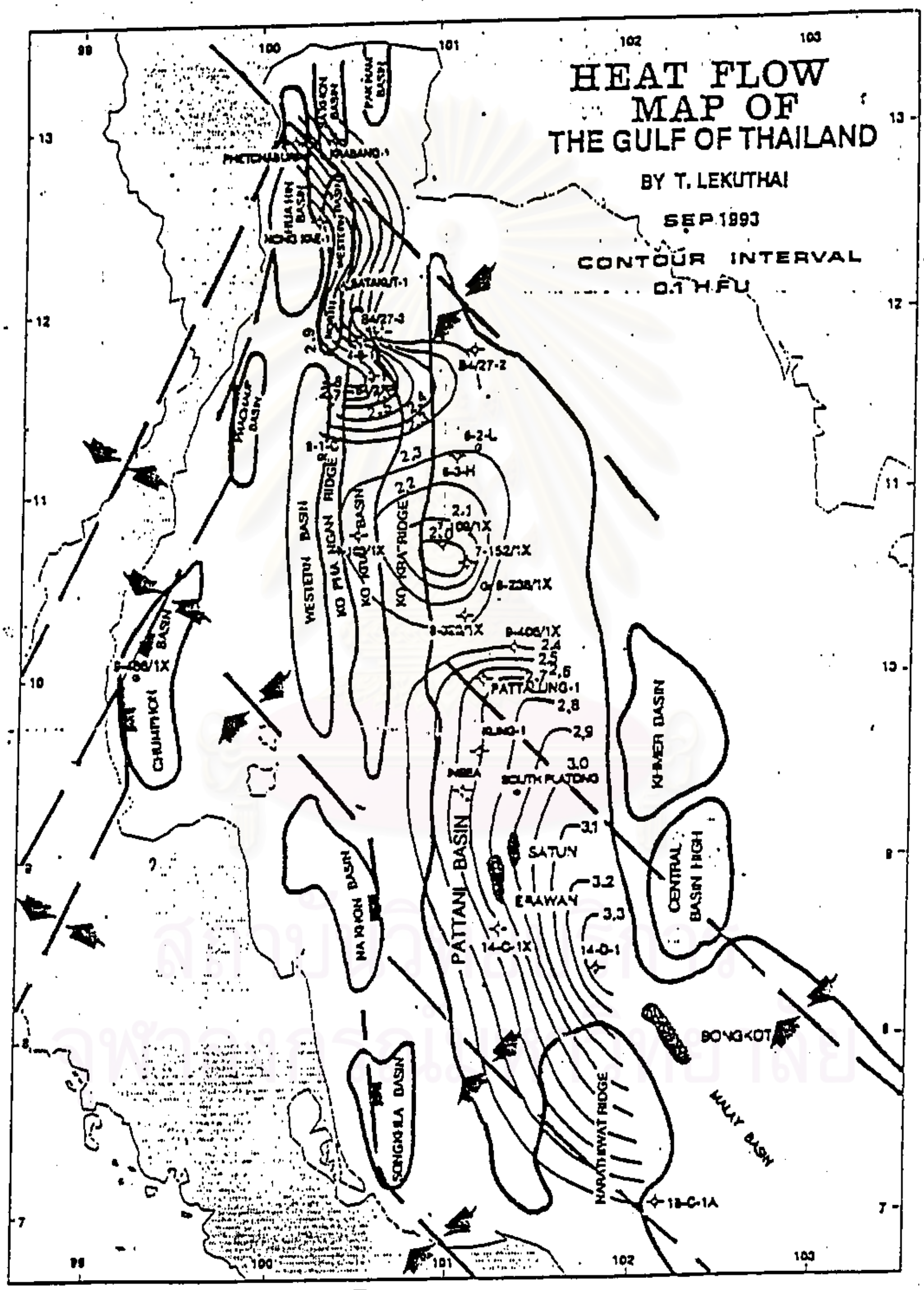


Figure 2.10 Heat flow map of the Gulf of Thailand (After Lekuthai et al., 1995)

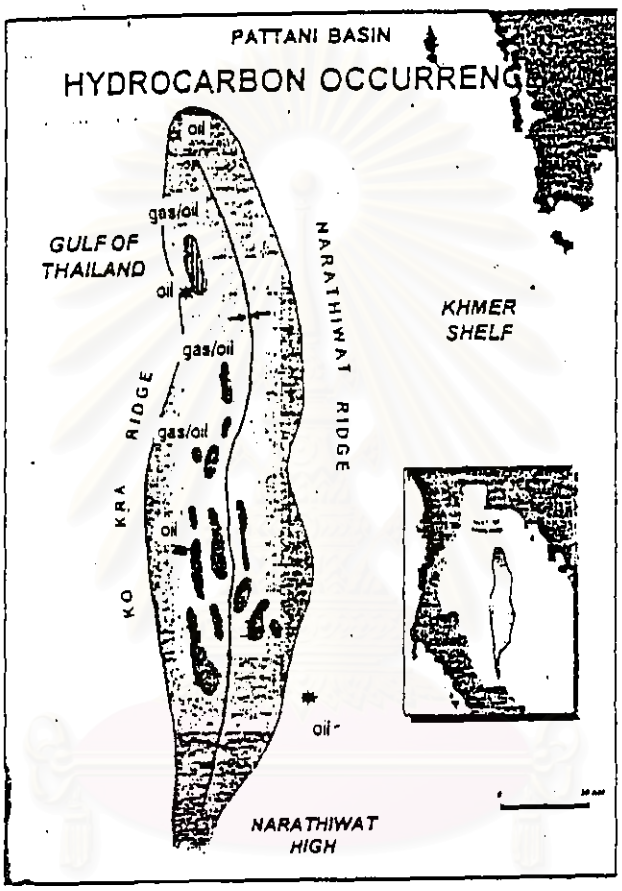


Figure 2.11 Simplified map showing gas fields, mixed gas and oil fields, and oil discoveries in the Pattani basin. Note that oil occurences aretypically located in upper basin flank and ridge areas, and gas generally occurs nearer to the basin center. Also note that the larger mixed oil and gas fields in the northen Pattani where heat flows are lower (After jardine, 1997)

Generation of hydrocarbons from gas-prone (and some oil-prone) unit II source rocks began in the early Miocene within the deepest portions of the Pattani basin. Gas-prone unit III source rocks began generating hydrocarbons in latest Miocene/earliest Pliocene time along the Pattani basin axis. Unit III continues to generate hydrocarbons today across the axial portion of the basin. Source strata in Unit IV have not yet begun to expel hydrocarbons.

Source rock study of the North Malay Basin.

Sattayarak [41,55] found that the main petroleum source rocks of the north Malay Basin, in the Gulf of Thailand is the gray shale of unit II and unit I, which deposited in lacustrine environments. This study also assume that these gray shale of unit I and unit II could extend to the Thai-Vietnam overlapping area and could be primary source rocks for this overlapping area.

The results of geochemical analyses indicate that the total organic carbon (TOC) and extractable organic matter (EOM) from shale samples of the 17-B-1 well are generally good (Table 2.2). The results of vitrinite reflectance analyses (Table 2.3 and 2.4) also indicate that there are good petroleum source rocks, that are matured, and which can yield petroleum at depth below 1,800 m. In contrast, shale shallower than 1,800 m is in the under mature. The results from the analyses are as follows; at depths between 1,800-2,300 m the rocks are in the oil window (oil yield), at depth more than 2,300 m the rocks are in the condensate - gas window (gas-condensate yield).

Table 2.2 Results of Total Organic Carbon (TOC, percent) and Extractable Organic Matter (EOM, ppm.) of 17-B-1 well.

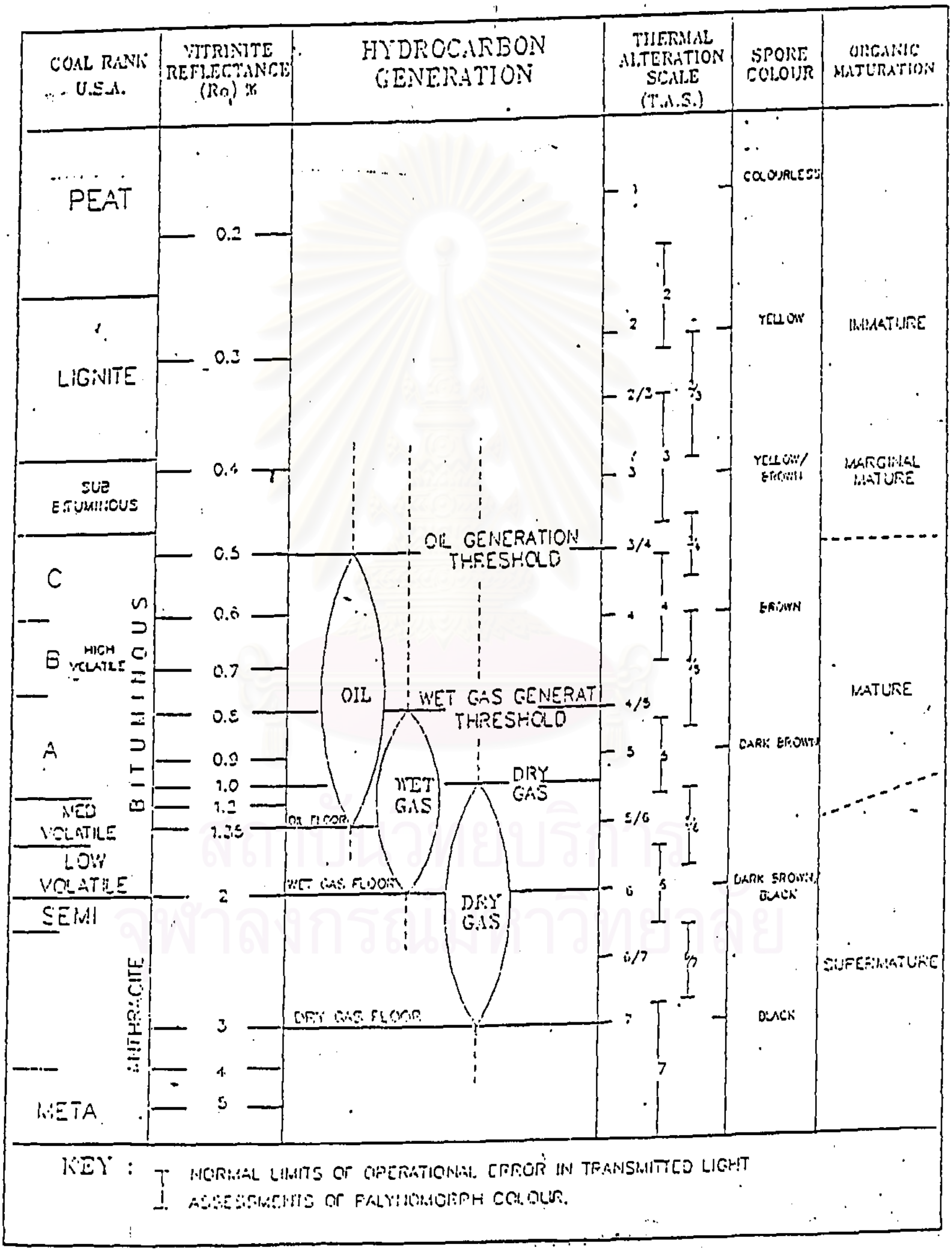
Depth (ft)	TOC (percent)	EOM (ppm.)
4020	0.35	-
4475	1.04	648
4950	0.54	237
5550	1.41	1444
5775	0.64	386
6000	0.93	0
6375	1.17	839
6800	0.81	0
7300	1.11	162
7800	34.59	0

Table 2.3 Results of Vitrinite reflectance (Ro) analyses of 17-B-1 well.

Depth (ft)	Vitrinit Reflectance (Ro)
4020	0.43
4475	0.43
4950	0.45
5550	0.48
5775	0.49
6000	0.53
6375	0.56
6800	0.62
7300	1.29
7800	1.5

Sattayarak [41] also studied the geothermal gradient analysis of the 17-B-1 well and mentioned that the geothermal gradient of the area is 3.5°F/100 ft or 6.38°C/100 m. Therefore, considering if the depths at which rocks can yield the petroleum on

Table 2.4 Petroleum maturation interpretation chart (After Batten, 1982)



the basis geothermal gradient analysis (given that petroleum source rocks will crack and yield oil at 60-150^0 C and yield gas at 200^0 C), the results generally accord with the results from the vitrinite reflectance analysis. Although, there is no direct indication of kerogen type from analyses, the kerogen type can be predicted mainly to be type III on the basis of depositonal environment.

2.5 Discussion.

Exploration in the Thai-Vietnam overlapping area should be mainly relied on the presence of adequate lacustrine source rocks, the definition of which is the first priority. Even though the prospects are very small, they seem to have considerable thick lacustrine sediments. The majority of the generate petroleum perhaps migrated towards the gentle dip flank of the half graben basins. Vertical migration along fault planes during reactivation periods is likely. Therefore, flank prospects situated on the gentle dip flank and falling within or near to the kitchen area are the most favorable. Accumulation size of the synrift plays perhaps tends to be small.

Lian and Bradley [43] suggested that the economic gas production in the Pattani Basin and its adjacent basins is determined by the combination of pressure, temperature and degradation of formation permeability. They also suggested that the economic basement occurs near a depth of 2,740 meters.