

# CHAPTER 1

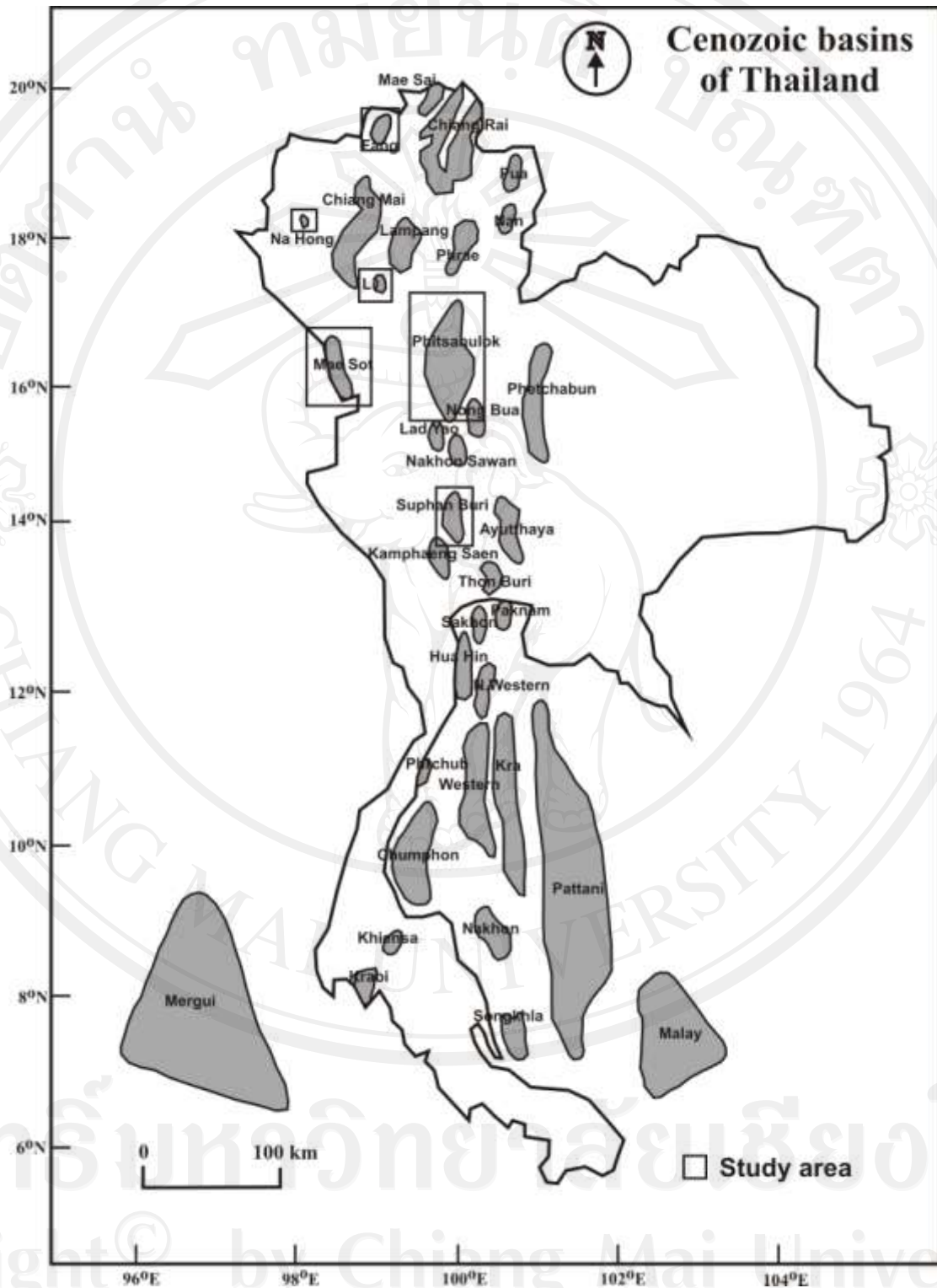
## INTRODUCTION

### 1.1 Background and problems

Terrestrial source rocks in Thailand are known in petroleum-prone basin both onshore and offshore. Most of the petroleum production in Thailand has been obtained from Tertiary basins. The onshore petroleum fields are located in northern Thailand; Fang, the central plain; Phitsanulok, Suphan Buri, Kamphaeng Saen and Petchabun basins (Figure 1.1). The offshore petroleum fields are located in the Pattani, Chumphon and Malay basins (Figure 1.1). The onshore Mae Sot Basin has been recognized as the largest oil shale deposit in Thailand (Tantisukrit *et al.*, 1982).

Organic components in coals and source rocks can be classified into three maceral groups: liptinite, vitrinite and inertinite (Taylor *et al.*, 1998). The liptinite group macerals are characterized by high hydrogen content, and include the macerals alginite, resinite, cutinite and sporinite. Alginite (type I kerogen) is considered to be an excellent source material for oil. Resinite, cutinite, sporinite (all type II kerogen) are considered to be good source. Vitrinite (type III kerogen) has a potential for both gas and oil (Petersen, 2002).

Terrestrial source rocks (lacustrine shales, type III kerogen shales, and coals) contain organic matter of freshwater algal origin and organic matter derived from the woody parts of higher land plants (Taylor *et al.*, 1998). Terrestrial organic matter varies in source potential and generation characteristics (Tissot *et al.*, 1987). Although they are considered homogeneous, the timing of the hydrocarbon generation varies considerably. Recently a revision of the “oil window” for humic coal source rocks has been proposed (Petersen, 2002). A considerable variability between different source rocks in terms of initial hydrocarbon generation was observed. The variability of the generative potential and composition of the terrestrial source rock is crucial in the evaluation of the timing of hydrocarbon generation (maturity level) and the volumes of the generated hydrocarbons.



**Figure 1.1** Cenozoic basins in Thailand (modified from Chaodumrong *et al.*, 1983). The study areas are in the blocks.

Nevertheless, the detail on organic geochemistry is rare. This was an interesting point to study organic geochemistry to carry out compositional characteristics and determining the maturity of source rocks.

## **1.2. Previous investigation**

### **1.2.1 Tectonic setting of Tertiary basins in Thailand**

Polachan and Sattayarak (1989) reported that Tertiary basins in Thailand are mainly N-S trending half-grabens or grabens which have developed since the Oligocene. Seismic data has revealed that the N-S trending syn-sedimentary normal faults are clearly associated with NW-SE and NNE-SSW trending strike-slip faults. Most of the movements along these faults occur along the Pre-Cenozoic structures (but the movements had different patterns). The geometrical relationships of strike-slip and extensional faults together with the evidence of clockwise rotation of crustal blocks and earthquakes can be related to the strain ellipsoid of dextral simple shear. The NW-SE trending faults including the Red River Fault, Mae Ping Fault, Three Pagodas Fault and Sumatra Fault represent the master right lateral strike-slip faults. The NNE-SSW trending faults including the Northern Thailand Fault, Uttaradit Fault, Ranong Fault and Klong Marui Fault are left-lateral which can be interpreted as a conjugate set.

### **1.2.2. Stratigraphic Sequence**

Chinbunchorn *et al.* (1989) reported that thick, at least 10 km, Cenozoic sedimentary rock was preserved in the deepest parts of the major basins, Pattani, Malay and Phitsanulok. Stratigraphic sequence in the Tertiary basins can be broadly divided into 2 sequences: syn-rift (Oligocene-middle Miocene) and post-rift sequence (late Miocene-Quaternary).

#### **1. Syn-rift Sequence (Oligocene-middle Miocene)**

The dominate period of rifting of the Tertiary basin lasted about 20 Ma and was bounded by 2 major unconformities. The syn-rift sequence can be divided into 3 units. The lower unit (late Oligocene-lower Miocene) generally started with fluvial system containing some interbedded redbeds. In onshore area, the central part of the basins is dominated by fluvial and swamp deposits. For example, in the Phitsanulok basin the

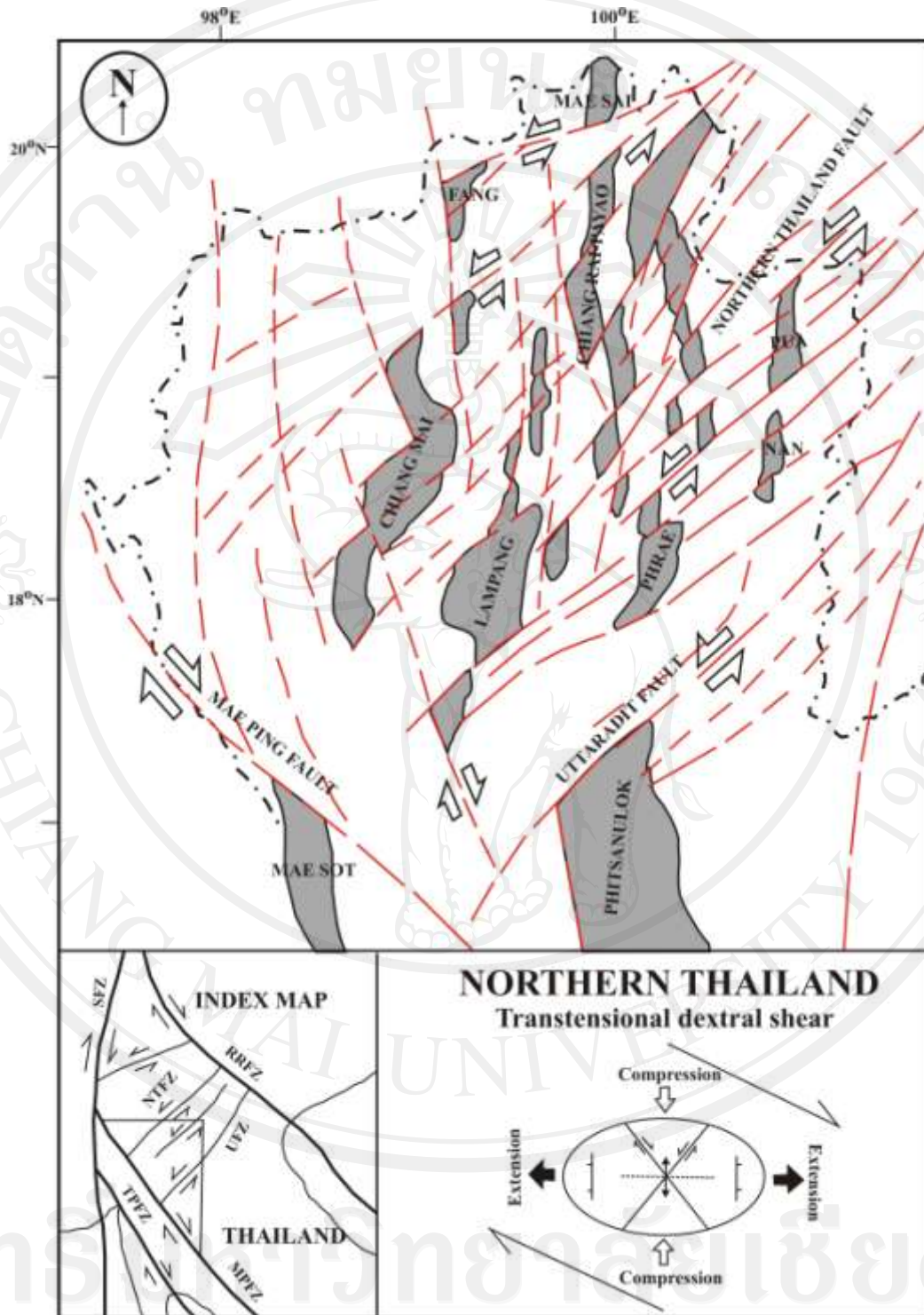
Nong Bua formation, up to at least 1,000 m, consists mainly of low-energy, alluvial plain, red brown claystone with minor coarse to fine lithic sandstone. In the gulf of Thailand, e.g. in the Pattani basin, the early syn-rift sequence consists mainly of low-energy, alluvial plain and lacustrine deposits and its thickness is probably up to 5,000 m (Lian and Bradley, 1986). The middle unit (lower Miocene-middle Miocene) is similar in every basin and contains considerably thick lacustrine sediments in the central part of the basins. This unit consists mainly of high organic claystone/shale with minor thin-bedded sandstone especially in the shallower lacustrine unit is over 2,000 m thick (Lan Krabu and Chum Saeng formations in the Phitsanulok basins). In the Pattani and Fang basins the equivalent middle units are about 1,000 and 700 m respectively. The upper unit (middle Miocene-late Miocene) generally is composed of fluvial deposits with some ephemeral lacustrine sediment in the central part of the basins. In the Phitsanulok basins, this unit is over 2,000 m thick (Pratu Tao and Yom formations).

## 2. Post-rift Sequence (Late Miocene-Quaternary)

This sequence is composed of sediments up to 1,700, 1,250 and 700 m thick in the Pattani, Phitsanulok and Fang basins respectively (Chinbunchorn *et al.*, 1989). Generally, it consists of high-energy, fluvial coarse sand and gravel with some interbedded varicolored clay in Phitsanulok and Fang basins. The sand is probably deposited by braided river on coalesced fans around the margin of the basins. On the other hand, the Pattani and Malay basins post-rift sequence of in the gulf of Thailand is a transgressive section with thin coal bed and organic-rich but immature clay (Chinbunchorn *et al.*, 1989).

Polachan *et al.* (1991) reported that in Northern Thailand there are over 40 Cenozoic basins with sizes ranging from 30 to 1400 km<sup>2</sup>. They are mainly N-S trending half grabens and grabens (Figure 1.2) with sediments ranging in thickness from 1000 to 3000 m. The underlying pre-Tertiary basements are complex igneous, metamorphic and sedimentary rocks. The stratigraphy of the basins is quite poorly established due to inadequate exploration and shallow penetration of drilled wells.





**Figure 1.2** Structural map of Northern Thailand showing the relationship between conjugate strike-slip faults and the development of N-S trending pull-apart basins, SFZ: Sagaing Fault Zone; RRFZ: Red River Fault Zone; NTFZ: northern Thailand Fault Zone; UFZ: Uttaradit Fault Zone; TPFZ: Three Pagoda Fault Zone; MPFZ: Mae Ping Fault Zone (Polachan and Sattayarak, 1989).

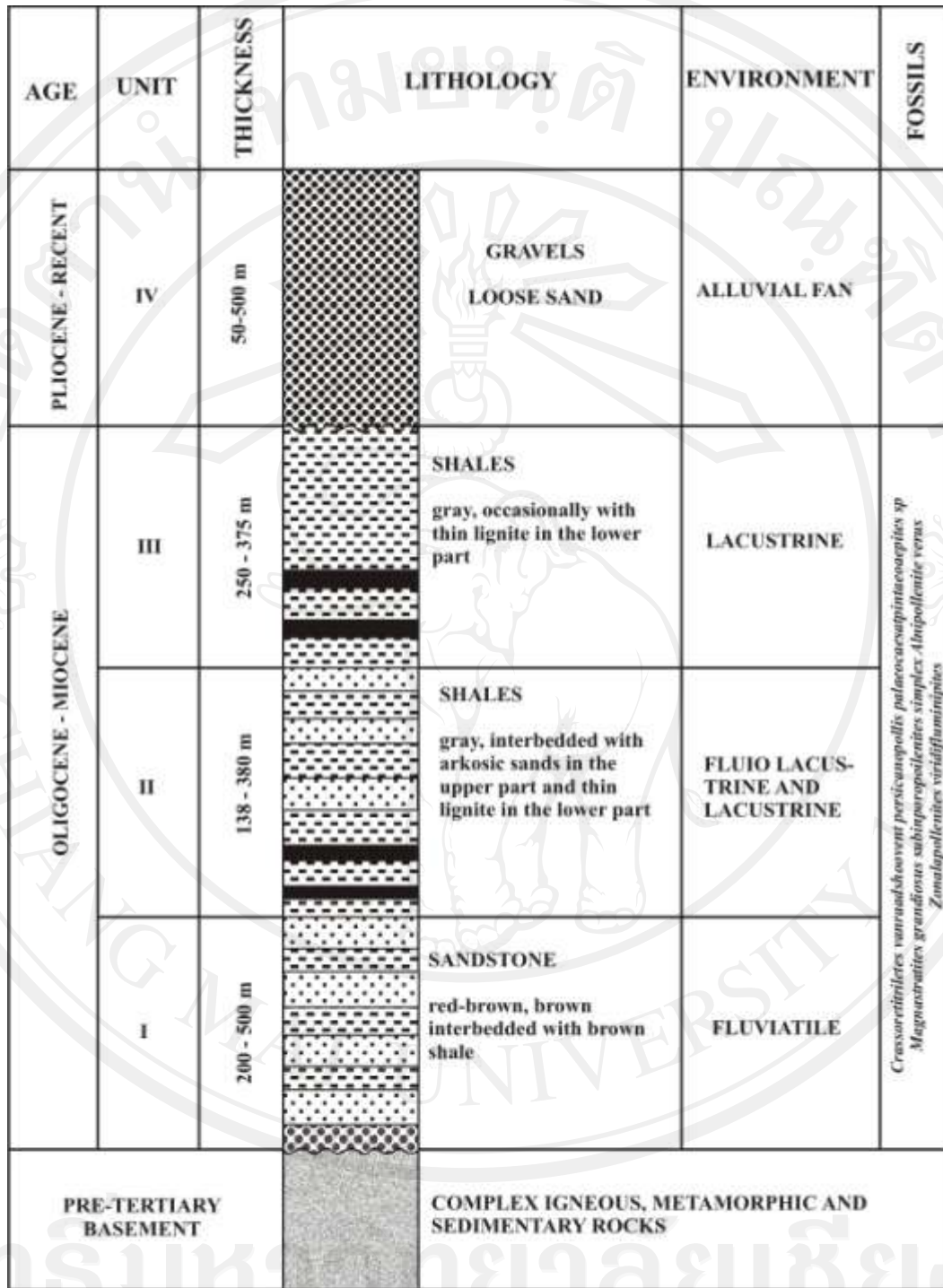
Fang is the only basin where extensive drillings for oil have been conducted for more than 30 years. Cenozoic sediments in Northern Thailand can be divided into four stratigraphic units as summarized in Figure 1.3.

There are seven major Cenozoic basins in Central Thailand: Phitsanulok, Phetchabun, Nong Bua, Suphanburi, Kamphaeng Saen, Ayutthaya and Thon Buri. These basins are formed as N-S trending, elongated half grabens (Figure 1.4). The Phitsanulok basin is the largest and deepest basin in this area. It contains up to 8,000 m of sedimentary fill (Knox and Wakefield, 1983). Sediments deposited in other basins in the area range in thickness from 2,000 to 4,000 m. The pre-Tertiary basement underlying these sediments comprises of Mesozoic-Palaeozoic sedimentary, volcanoclastic, metamorphic and igneous rocks. Studies of seismic data and drilling results suggest a similar stratigraphic succession in other basins of this area. The generalized stratigraphy of the basins in Central Thailand consisting of four stratigraphic units is summarized in Figure 1.5.

### 1.2.3. Organic petrography

In the Fang basin, Belay (1992) found that liptinites are the principal organic components of the lower lacustrine shale, which are dominated by algal material. *Botryococcus* related telalginite is the major algal form, but lamalginites are also ubiquitous. The maceral composition of the upper part of the fluvio-lacustrine shales is consistent with a higher plant source; vitrinite is typically the most abundant maceral and inertinite is also present.

Ratanasthien (1997) reported that lacustrine oil source rocks in northern Thailand basins are dominated by alginite B or lamalginite which formed thick bands of oil shale. Alginite A or *Botryococcus* or *Botryococcus*-related alginite were usually found disseminated throughout the oil shale bed. *Pila* algae are found to be the most abundant throughout the Tertiary oil source rocks, whereas other *Botryococcus*-related alginites were found in limited amount. However, *Botryococcus brownii* seems to be restricted to temperate climatic condition during deposition. *Reinschia* is restricted to the shallow margins of the lake. In the oil shales that are associated with coal-bearing strata, suberinite, resinite and sporinite are also the sources of oil. These components contributed to more hydrocarbon than cutinite.



## Legends



Gravel and loose sand



Sandstone



Shale



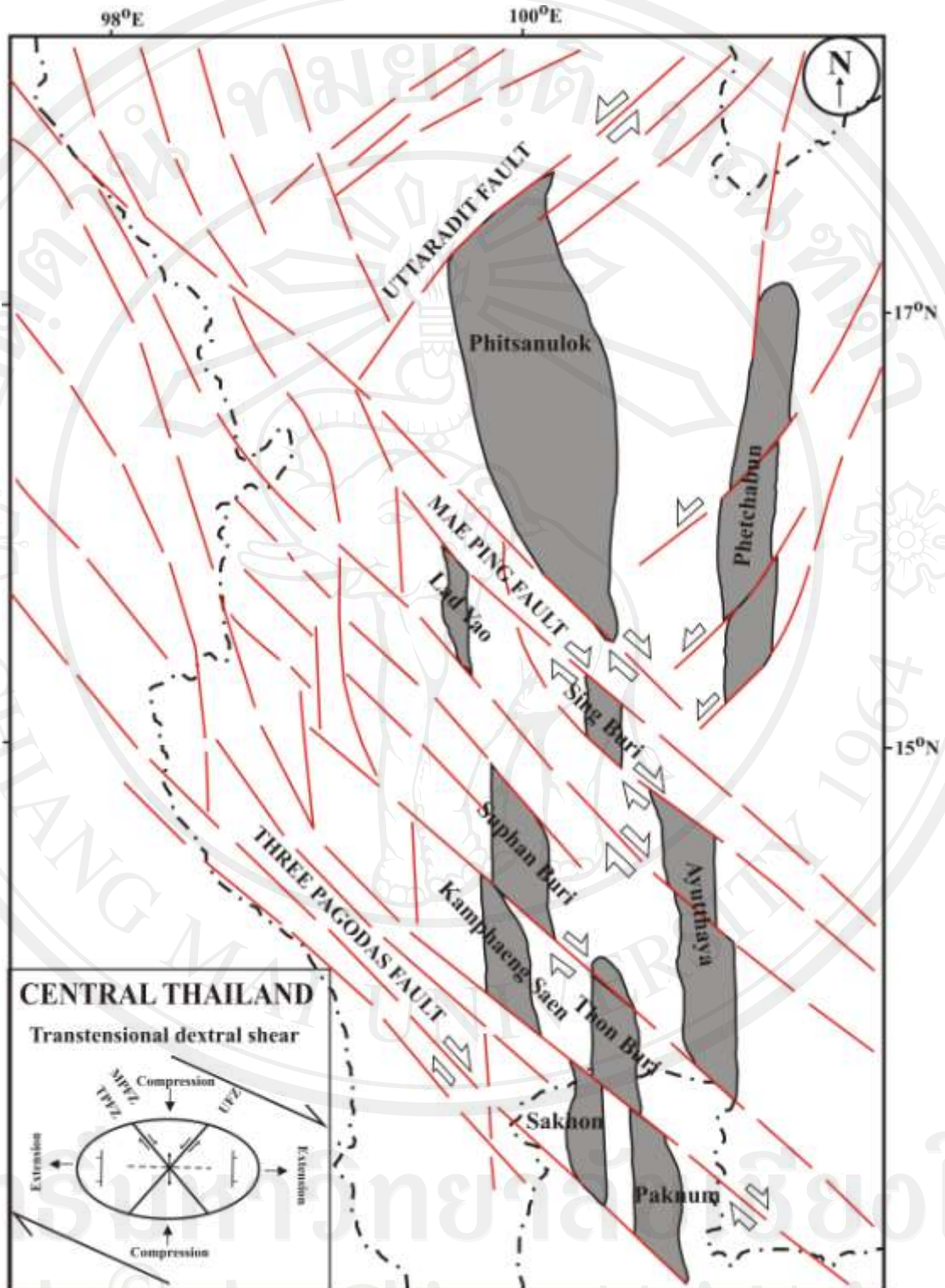
Lignite



Unconformity

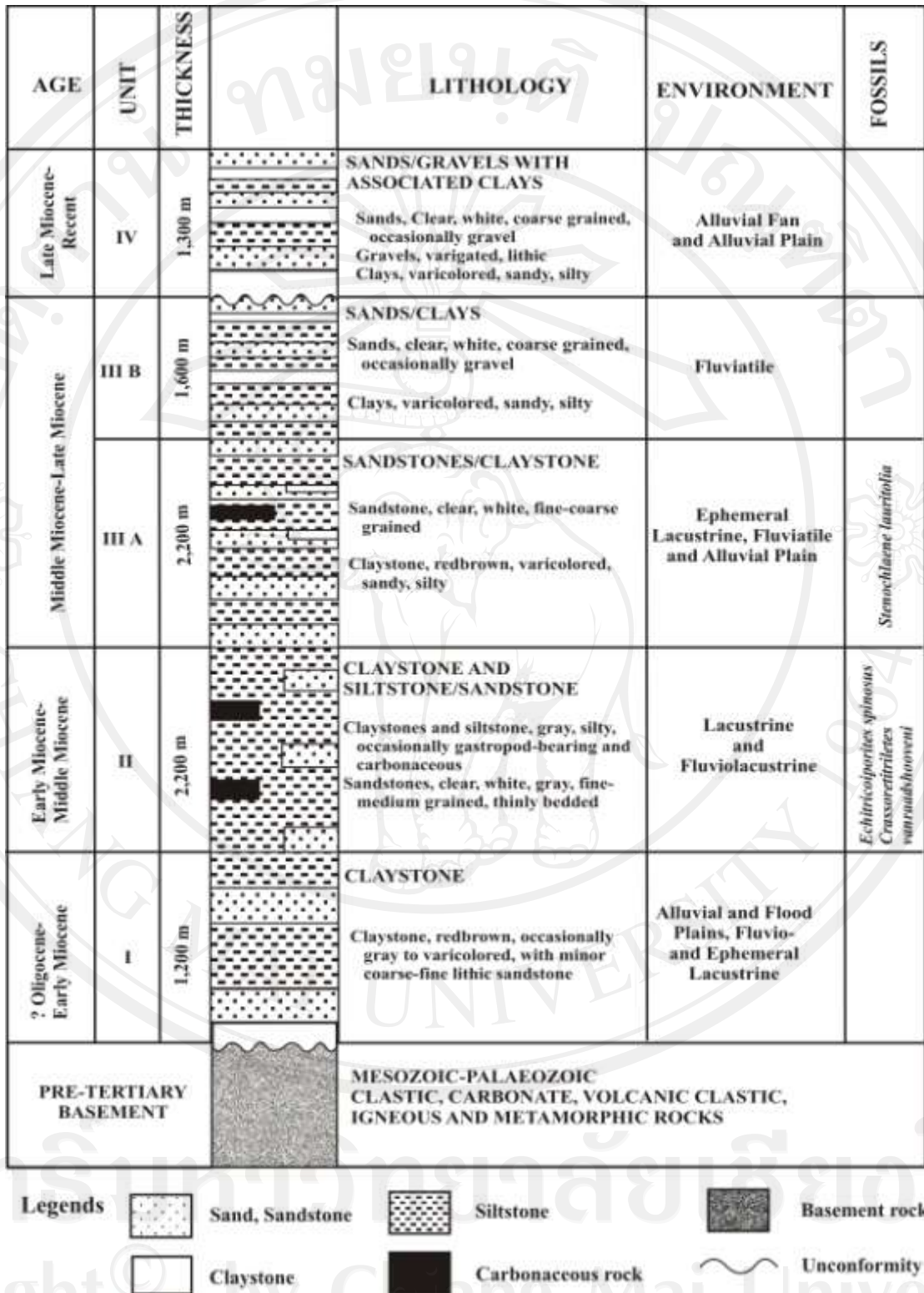
**Figure 1.3** Generalized stratigraphy of Cenozoic basins in Northern Thailand (modified from Polachan and Sattayarak, 1989).





**Figure 1.4** Structural map of Central Thailand showing relationship between conjugate strike-slip faults and the development of N-S trending pull-apart basins, TPFZ: Three Pagodas Fault Zone; MPFZ: Mae Ping Fault Zone (Polachan and Sattayarak, 1989).





**Figure 1.5** Generalized stratigraphy of Cenozoic basins in Central Thailand (modified from Polachan and Sattayarak, 1989).

Ratanasthien (1999) reported that in the lower part of the Tertiary organic-rich deposits of northern Thailand, especially in the Fang Oilfield, alginite A (a*Botryococcus* sp.) was the only type of algal material found. The association of *Botryococcus braunii*, *Pila* algae, thick-walled alginite B, and temperate palynomorphs were recognized in many coalfields such as *Pinus*, *Alnu* and *Taxodium*, as well as in the middle part of the deposits in the Fang basin. In the upper part of the deposits, alginite B dominate many basins, together with *Botryococcus*-related taxa such as *Pila* algae, *Reinschia* and fresh-water-dwelling ferns. In the Mae Sot basin, *Reinschia* was found to be dominant in the northern part, whereas lamalginite dominate in the south. These different associations indicate changes in depositional environments in northern Thailand, resulting from climatic and/or sea level changes during Tertiary time.

Ratanasthien *et al.* (1999) reported that the oldest coal and lacustrine deposits in northern Thailand basins are of Late Oligocene to Early Miocene age; and were dominated by *Botryococcus* sp. or *Botryococcus*-related algae. Thick-walled lamalginites and spores and pollens of temperate affinity are found in some areas. By contrast, thin-walled lamalginite dominates the upper Middle Miocene deposits. Resinite, suberinite, and cutinite are dominant in forest swamp coal deposits whereas alginite, cutinite and lycopodium spores are dominant in lacustrine sediments. Exsudatinitite is common at early levels of maturation. These liptinite macerals can be major sources of oil and gas.

### 1.3. Objective

The objectives of this research are to (1) use geochemistry and petrography data to determine the compositional variability of the organic matter, (2) identify characteristics of maceral assemblages and (3) assess petroleum generation potential of the source rock samples in the study area (Fang basin, Phisanulok basin, Suphanburi basin, Mae Sot basin, and comparative areas in Li and Na Hong coal fields).

### 1.4. Scope, Planning and Methodology

#### 1.4.1. Review previous work and data collection

1.4.2. Field work and sample collection (from outcrop and well sample) for petrographic and geochemical analyses

- Approximately 70 unwashed cutting samples were collected from the Fang basin.
- Approximately 100 unwashed cutting samples were collected from the Phisanulok basin
- Approximately 150 unwashed cutting samples from Suphanburi basin (wells SP1 and SP2).
- Approximately 50 outcrop samples from Mae Sot basin, Li and Mae Chaem coal fields.

1.4.3. Samples preparation for geochemical analyses

1.4.4. Geochemical analysis of source rocks using Rock-Eval analysis, Gas Chromatography-Mass Spectrometer (GC-MS) and Total Organic Carbon (TOC) analyzer to determine composition and assess the petroleum generation potential of source rocks

1.4.5. Making polished section of samples for petrographic analyses

1.4.6. Petrological study using reflected light and fluorescence light microscopes for classification of organic maceral and determination vitrinite reflectance measurement.

1.4.7. Data analysis and interpretation

1.4.8. Thesis writing

## **1.5. Education advantages**

The characteristics and maturity of petroleum source rocks as well as petroleum potential of each basin will be determined. The knowledge from this research can be applied in exploration and production of petroleum in the study areas.