CHAPTER I

INTRODUCTION

General

Sedimentary basins are economically important because of their potential of suitable and favourable sites for the accumulation of mineral and energy resources, especially oil, natural gas, and coal. Extensive research on various geological aspects, including structural evolution and tectonic framework, sedimentation and depositional environment, and economic resources, of these basins have been carried out. The majority of petroleum geologists believe that oil and gas originate from organic matter buried in a sedimentary basin. There is no doubt that the search for oil and gas has been the major driving force behind the rapid expansion in sedimentology over the last quarter of this century.

Among all sedimentary basins of different geological ages, Tertiary basins appear to be the most attractive. Due to the fact that most of the petroleum producing strata of Thailand are Tertiary in age. The hydrocarbons have been reported to be generated and found in lacustrine/fluvial strata mainly of Miocene-Oligocene age. From 1981 to the end of 1991, 1.57 trillion cubic feet of gas, 52 million barrels of condensate and 60 million barrels of oil have been produced.

There are 30 Tertiary basins in Thailand have been proven to have the potential generation of petroleum (Figure 1.1) (Chinbunchorn et al., 1989). Among them, 9 basins have generated significant quantities of petroleum : namely Fang,

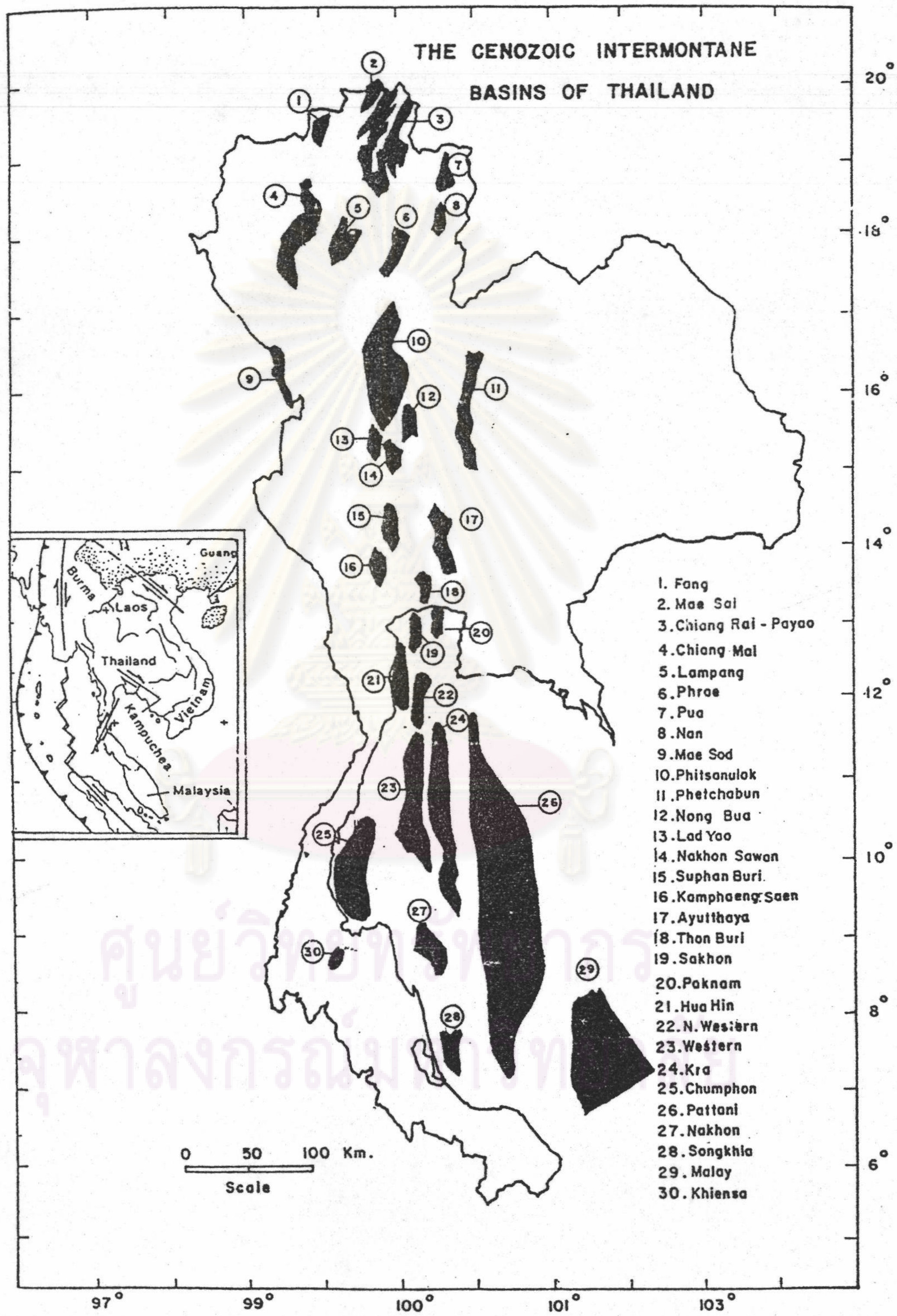

Figure 1.1 Significant Cenozoic basins in Thailand (Chinbunchorn et al., 1989).

Phitsanulok, Petchabun, Suphanburi, Kamphaeng Saen, Pattani, Malay, Chumphon and Songkhla Basins (Lawwongngam and Philip, 1993). This study is focus on the Petchabun Basin where hydrocarbons have been discovered in the Wichian Buri sub-basin. As indicated by drill stem test data, 500 BPD of oil and 5.4 MMSCFPD of gas are obtained from its exploratory wells respectively.

The Wichian Buri sub-basin was selected for its favourable attributes with respect to the thesis's objective including: the geological knowledge of this basin is limited and not fully understood; intensive exploration programmes, notable drilling exploration, geophysical survey, etc., have been undertaken so that reasonable subsurface geological information is properly available. Last, it is expected that the findings from this study may benefit further understanding of the development of other Tertiary basins which have similar geological setting.

Study Area

The Wichian Buri sub-basin is mainly confined to Amphoe Wichian Buri, Changwat Phetchabun in the northern central part of Thailand (Figure 1.2). The basin lies approximately between latitudes $15^{o}15'$N to $16^{o}00'$N and longitudes $101^{o}00'$E to $10^{o}20'$E. It is approximately 1698 km^2 and covered by the SW1A Concession. The basin is distinctly linear in outline with, approximately 80 km long, and varies in width between 36 and 18 km. The basin is currently drained by the Mae Nam Pa Sak and its tributaries flowing form north to south.

Data Source

The studied data have been provided by Department of Mineral Resources (DMR) Thailand. The data consists of seismic sections, six well completion

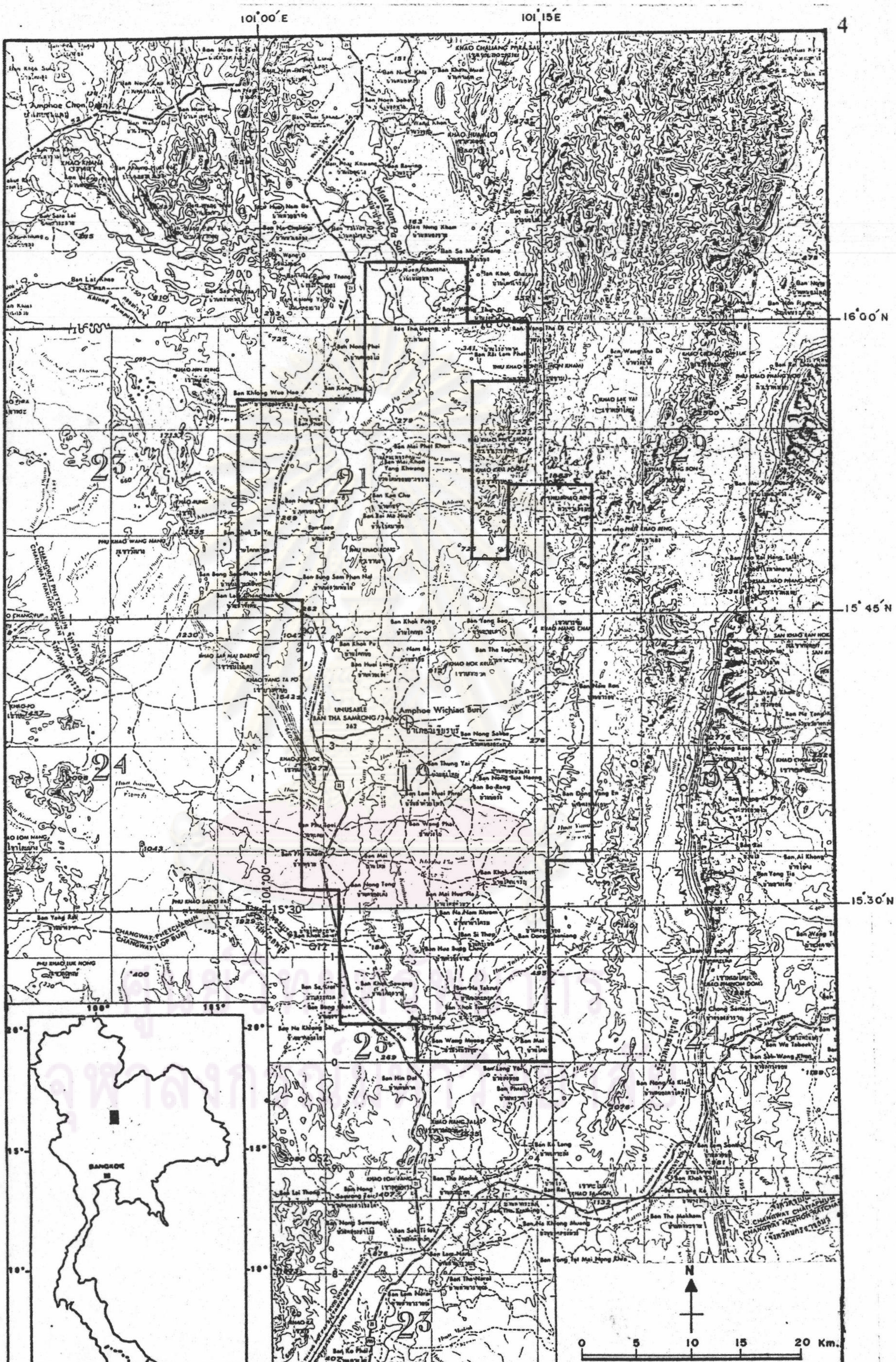

Figure 1.2 Topographic map of the Wichian Buri sub-basin.

biostratigraphy reports, geochemical evaluation reports, electric wireline logs and general geological data. Reflection seismic sections are approximately 703 km. The seismic sections have a vertical scale of 10 cm / second and horizontal scale 1 : 50,000 with 25 m shot point intervals (Figure 1.3). The electric wireline logs are available including caliper, gamma ray, spontaneous potential (SP), resistivity and sonic logs.

Objective of the Study

1. To establish the lithostratigraphic units of the Wichian Buri sub-basin.
2. To reconstruct the evolution of depositional system of the study area in the terms of tectono-sedimentation.
3. To assess the hydrocarbon source potential of the study area.

General Approach and Study Methodology

Basically, the existing information on regional geology of the north central plain of Thailand are review to serve as a background of the present study. Geological setting of the study area from previous investigation has been reviewed in order to understand the geological history as well as tectonic evolution.

Generally, the first effort is to describe the sediments and to attempt to subdivide them into a number of lithostratigraphic units. Cutting samples, sidewall cores, and electric logs were described and used to established the lithostratigraphy of Tertiary sedimentary sequence of the Wichian Buri sub-basin. The recognition of a litho-stratigraphic unit is a two-part process, requiring subdivision of vertical sections and correlation between sections.

In each section , it will be possible to recognize one or more distinctive litho-

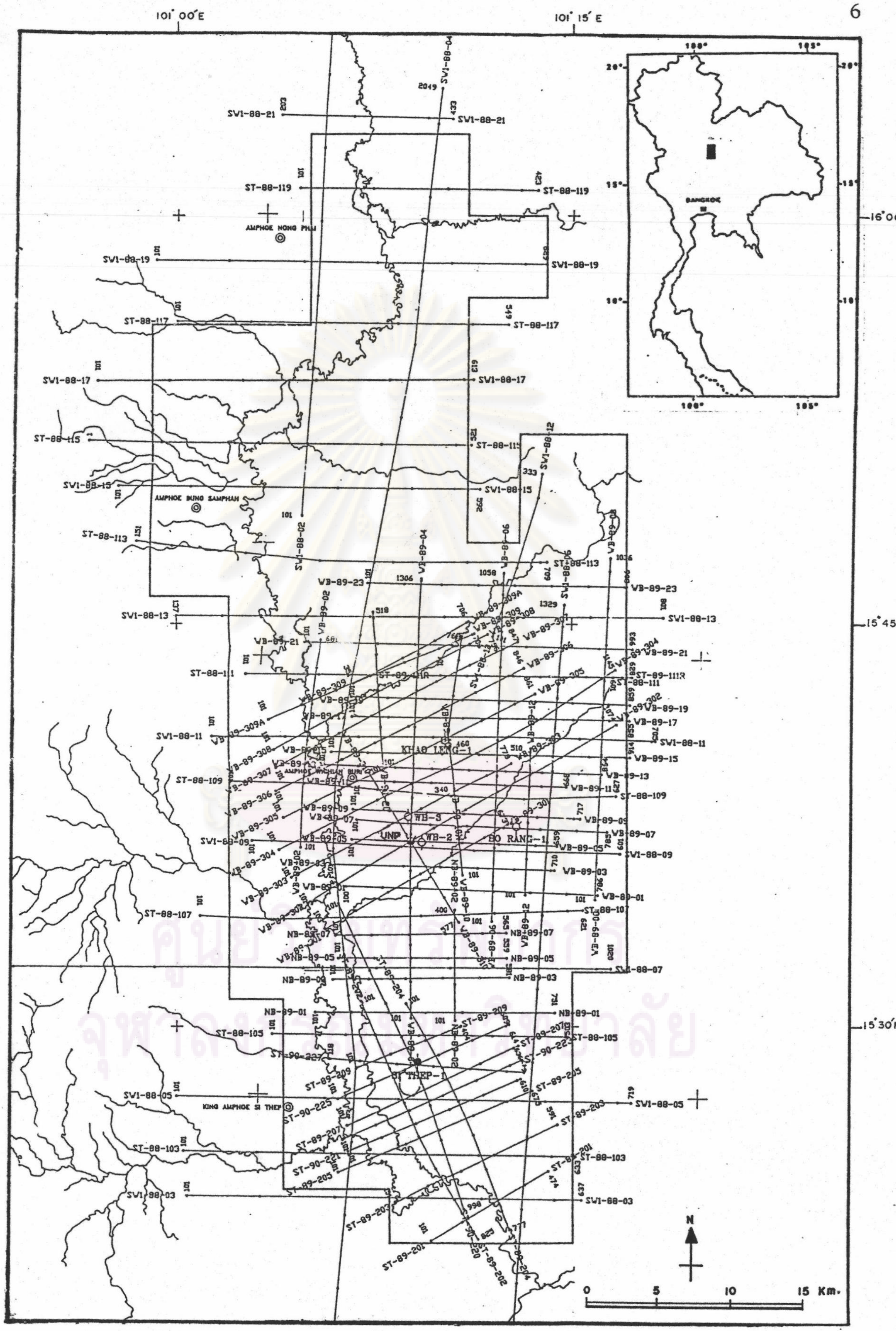

Figure 1.3 Map showing extensive seismic traverse line and well locations.

stratigraphic units based on physical proporties , such as mineralogical composition and grain size. Bedding characteristic, sedimentary structures, cyclic sequences, and fossil content will be used as secondary criteria.

Many attempts have been made for lithostratigraphic correlation. In this study, lithostratigraphic information and electric log signature is used to correlate well sections. Other aids to correlation, including biostratigraphic data, radiometric dating, and seismic data which can derive the broad picture of the depositional system. Each of the lithostratigraphic units were interpreted for depositional environments by using lithologic, palynologic and/or seismic data.

Finally, the evolution of deposition system of the basin is reconstructed by applying the tectonic events to the details of basin stratigraphy and structure.

In addition, step of work cover the assessment of petroleum source potential. The approach and techniques employed in this study are described in the below section.

<u>Analytical Procedures and Techniques in Geochemical Analysis for Petroleum Source Potential</u>

A crucial test in the recognition of a petroleum source rock is the determination of its organic content, both soluble (bitumen) and insoluble (kerogen). A second important step in source-rock assessment is the determination of the type of kerogen. Finally, from optical and / or physiochemical proporties, evolutionary stages of kerogen can be determined. This concept is commonly referred to as the "maturity of source rocks".

There are several analytical techniques to establish the presence, type and level of maturity of a source rock. This section describes these techniques, the data and their interpretation guidelines. Analytical pathways are shown on the flow chart (Figure 1.4).

1. Total Organic Carbon Content

The most fundamental measurement in assessing source rock is the determination of total organic carbon (TOC) content. TOC analysis measured the organic richness of a rock in weight percent organic carbon. This provides the basic screen to identify possible source units.

The measurement is made by combusting the rock in an oxygen atmosphere and measuring the generated CO_2. In order to reduce the effects of potential mineral matrix interference, particularly from carbonate minerals, samples are pretreated with warm HCl.

Statistical work has shown that documented source rocks contain a minimum of 1% TOC (Leeper and Sassen, 1977; Figure 1.5). It is generally found in practice that sediments containing TOC less than 0.3 % are unlikely to have any source potential, those containing TOC between 0.3 % and 1 % may be marginal sources but the better quality sources contain TOC in excess of 1%. It should be noted that sediments containing TOC as high as 10% are excellent source rock and sediments contain 1 to 5% TOC are good to very good source rocks.

Further analysis is may be limited to those horizons with above-average level of enrichment (TOC>1%). However, not all rock containing greater than 1% TOC should be considered source rocks. More information of organic matter must be

SCREENING
ORGANIC CARBON

RICHNESS

- Total Organic Carbon
- Pyrolysis
  (Generation Potential)

PRODUCTS

- Pyrolysis
  (Hydrogen and Oxygen indices, Hydrogen Index and Tmax Ratios)
- Visual Analysis
  (Component Composition)

THERMAL MATURITY

- Vitrinite Reflectance
- Visual Analysis
  (Spore Colouration)
- Pyrolysis
  (Transformation ratio and Tmax)

Figure 1.4 Flow chart for geochemical identification of source rocks.

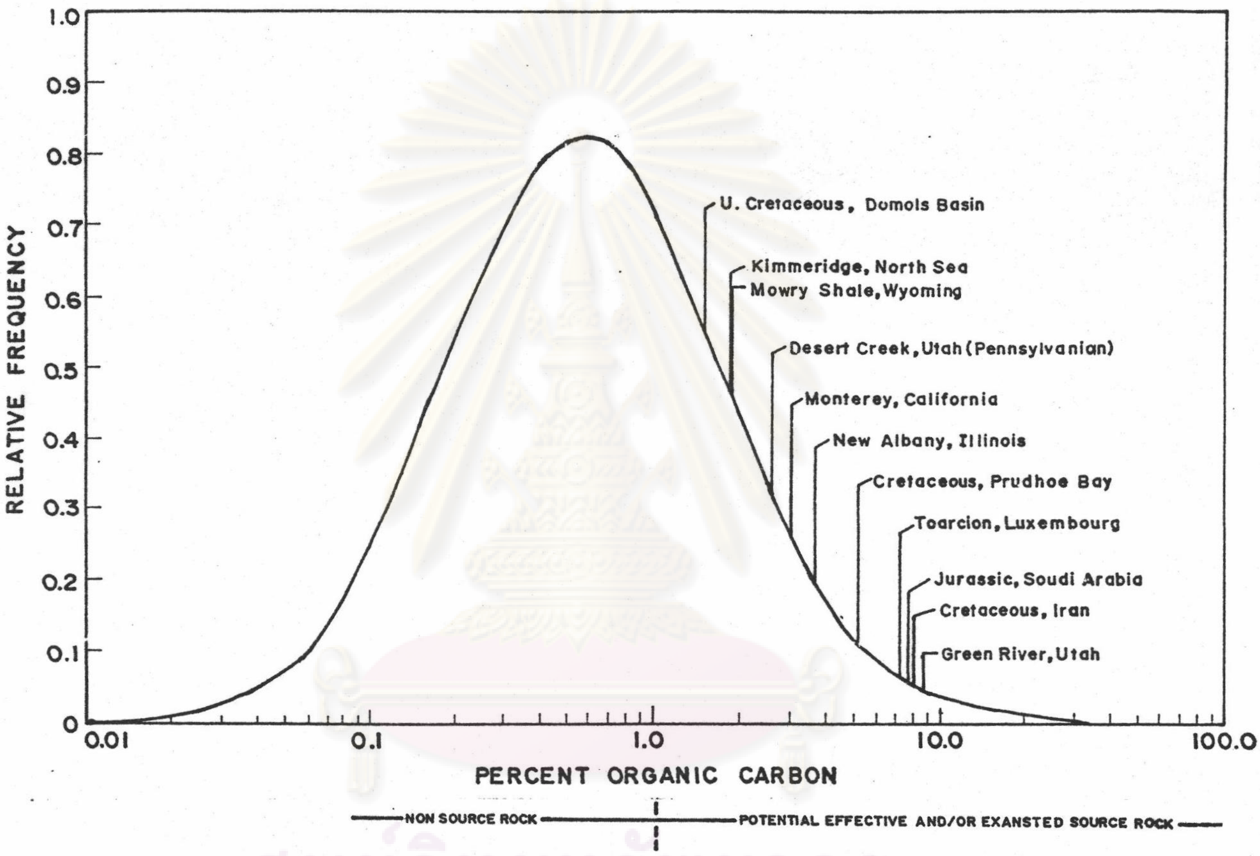

Figure 1.5 Distribution of organic carbon content in a worldwide sampling of fine-grained sedimentary rocks (Leeper and Sassen, 1977).

gathered because TOC values alone do not represent generative capacity. Also, large portions of the organic matter may be inert and thus unable to generate hydrocarbons due to sedimentary reworking, oxidation, or advanced levels of maturation (Espitalie et al., 1985).

2. "Rock-Eval" Pyrolysis

As being noted above, organic carbon content alone does not provide a reliable indicator of source potential because type of organic matter and the level of maturity influence the actual hydrocarbon yield. Pyrolysis is a more direct indicator and widely accepted among exploration geologists as a rapid and effective mean of evaluating hydrocarbon potential of prospective source rocks. The method follows a special pyrolysis device sketched in Figure 1.6.

"Rock-Eval" pyrolysis as being described by Espitalie et al.(1977) provides information on the quantity, type, and thermal maturity of the associated organic matter. Pyrolysis is the programme heating of rock samples in an inert atmosphere , and measuring the amounts of the different products evolved (Figure 1.7).

Products are released from the organic matter in the rocks in two phases :

(1) 100-300 ^{o}C - hydrocarbons already present in the rock in a free or adsorbed state. These are designated as S_1.

(2) 300-550 ^{o}C - the "pyrolysis" stage here hydrocarbons or hydrocarbon-like compounds are distilled or cracked from the solid organic matter (kerogen). These are designed as S_2. During the S_2 heating stage , oxygen-containing compounds , i.e. carbon dioxide and water are also evolved. CO_2 is measured separately and designed as S_3.

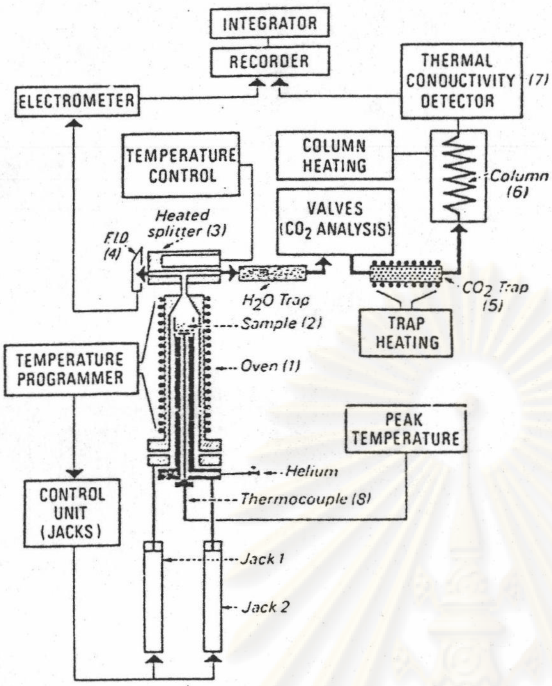

Figure 1.6 Principle of the Rock-Eval pyrolysis device of Espitalie et al.(1977).

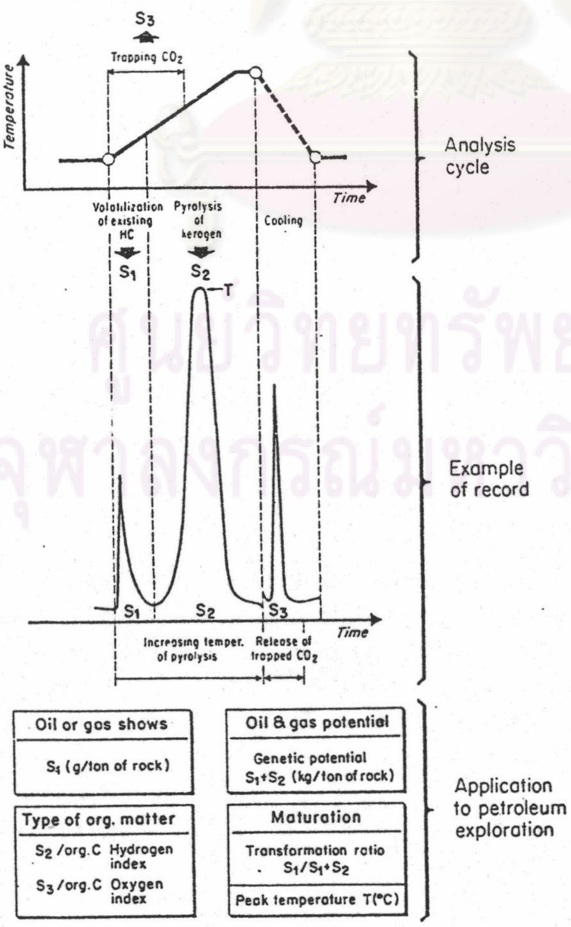

Figure 1.7 Cycle of analysis and example of record obtained by the pyrolysis method of Espitalie et al. (1977).

A statistical study (Katz, 1980) has shown that potential source rocks exhibit S_1+S_2 yields (total hydrocarbon generation potential) above average value (>2.5 mg HC/g rock) relative to a world-wide distribution of generation potential (Figure 1.8). Rocks with average or below average generation potential may be either non-source or overmature. An examination of thermal maturity information will permit differentiation.

Pyrolysis also provides an indicator of the kerogen type. The conventional approch (Espitalie et al., 1977) utlizes a modified van Krevelen diagram in which the Hydrogen Index (S_2/TOC, mgHC/gTOC) and the Oxygen Index (S_3/TOC, mgHC/ gTOC) are substituted for the H/C and O/C ratios of the original van Krevelen diagram. This method assumes that the S_2 hydrocarbon yield is solely dependent on the level of hydrogen enrichment of the kerogen and that S_3 (CO_2) yield is derived solely from organic matter. Figure1.9 and 1.10 show how hydrogen index and oxygen index can be correlated with atomic H/C and atomic O/C respectively. A modified van Krevelen diagram has been designed which allow us to distinguish Type I, II, and III kerogen.

The maturation parameters derived from pyrolysis are transformation ratio (KTR), or production index (PI) which is the ratio of the free hydrocarbons to total hydrocarbons (S_1/ (S_1+ S_2)); and Tmax, the temperature at the point of maximum S_2 hydrocarbon generation during the pyrolysis process.

The transformation ratio ($S_1/(S_1+S_2)$) is a measure of the hydrocarbons available for accumulation. This ratio will increase as a function of depth and make it a valuable index of maturation. From the example of the maturation of kerogen with depth as monitored by pyrolysis is shown in Figure1.11 (Espitalie et al., 1977). The

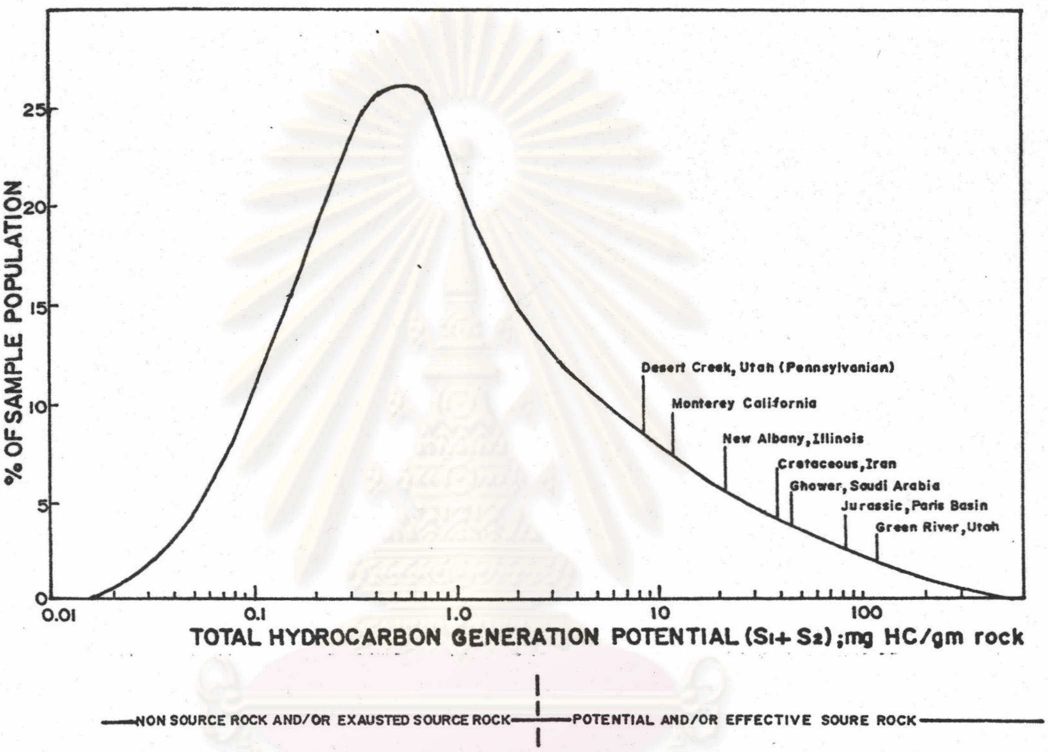

Figure 1.8 Distrbution of total generation potential obtained on fine-grained sedimentary rocks containing a minimum of 0.5% wt TOC (Katz, 1980).

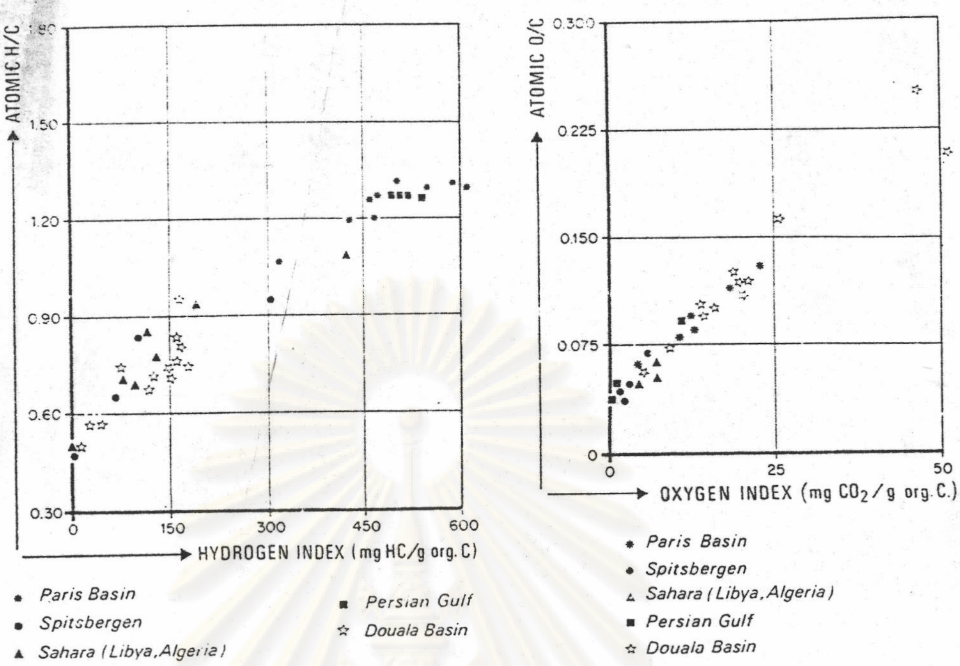

Figure 1.9 Correlation of chemical and visual maturity indices, the Time-Temperature Index (TTI) and hydrocarbon generation and preservation zones (Bissada, 1983).

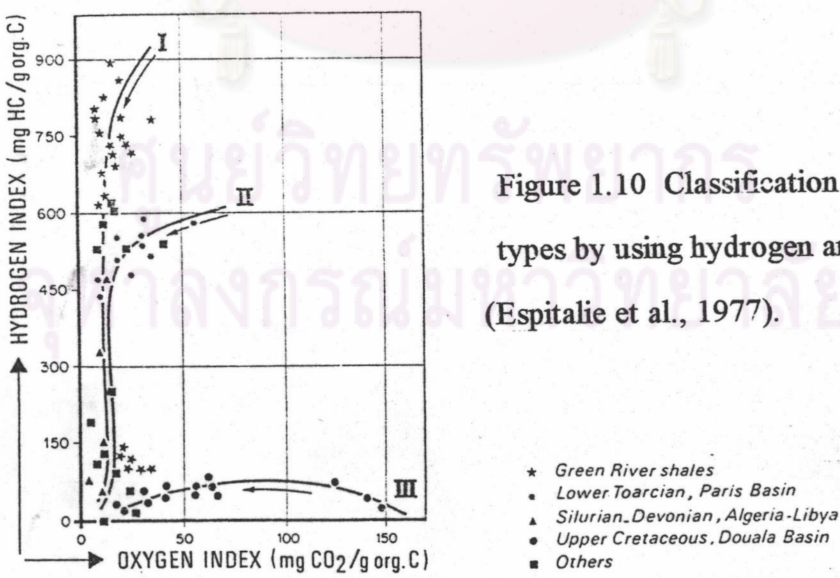

Figure 1.10 Classification of the source rock types by using hydrogen and oxygen indices. (Espitalie et al., 1977).

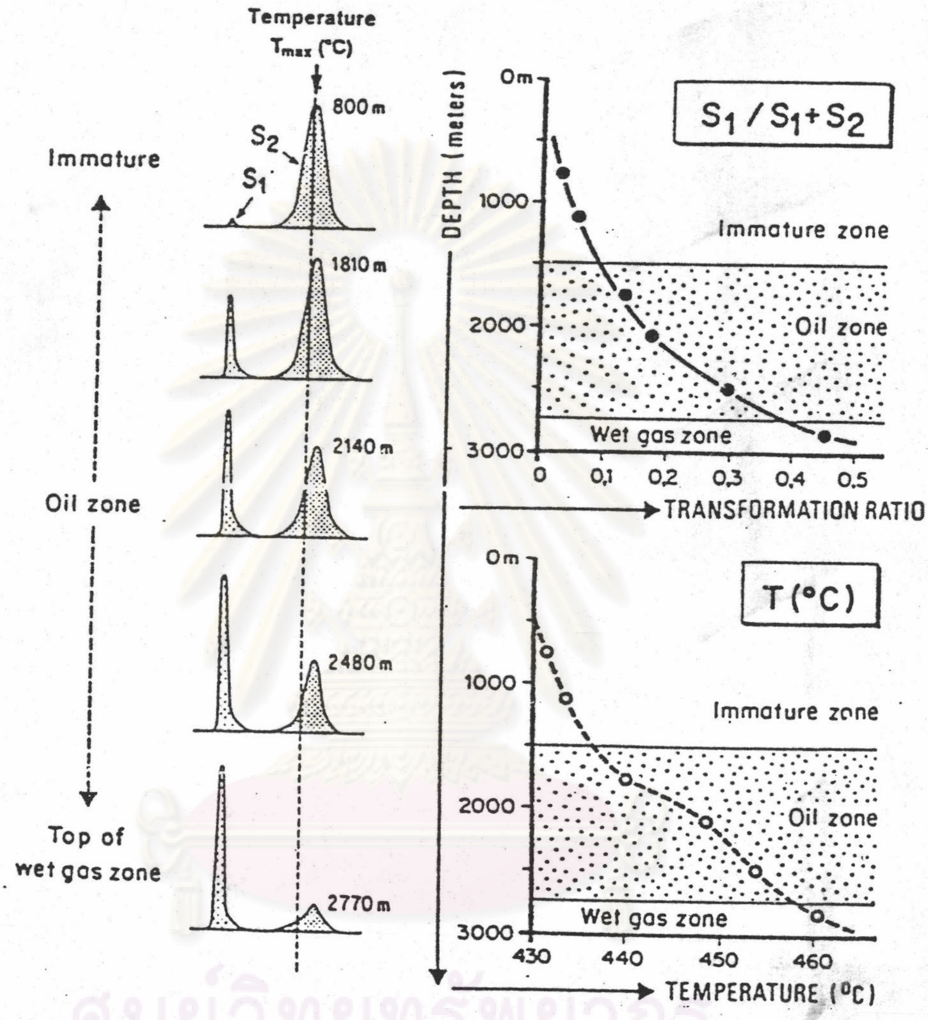

Figure 1.11 Characterization of source rock maturity by pyrolysis methods. Transformation ratio and / or peak temperature Tmax may be used as indicators of thermal evolution (Tissot and Welte, 1978).

free hydrocarbon (S_1) are seen to increase steadily with depth, while the generatable hydrocarbon (S_2) are steadily decreased. The transformation ratio increases accordingly. KTR values of 0.1 and 0.4 mark the entrance to and exit from the oil window (Tissot and Welte, 1978; Hunt, 1979). In rocks with low hydrocarbon yield ($S_1 + S_2$ less than 1 mg HC/g rock), the KTR values are highly variable and do not correlate with other maturity indices.

The temperature Tmax also increases progressively. Figure 1.11 shows how this maxinum temperature shifts slightly higher as maturation increases. Tmax values at the onset of oil generation vary among petroleum source rocks because of differences in organic matter type. In general, the source rocks are mature and will generate oil at a Tmax range of 435 ^{o} to 460 ^{o}C. Tissot and Welte (1978) concluded that the threshold of oil generation for oil prone Type I kerogen is higher than others. The resistance of Type I organic matter to thermal degradation may be due to strong cross-linkage of long, aliphatic chains (Peters, 1986). Tmax can be used to indicate the level of maturity if the dominant kerogen types are known.

3. Visual Kerogen Analysis

High-power microscope examination of kerogen in transmitted or reflected light determining type of organic matter and thermal maturity are favourable for petroleum generation.

Microscopic observations have been used for a long time in coal petrology to identify the various coal macerals and evaluate their ranks along the carbonization path that leads from peat to anthracite. The three main groups of macerals are; liptinite (also called exinite), vitrinite and inertinite. Liptinite macerals are considered to be derived mostly from algae (alginite) or spores (sporinites), with occasionally cutin (cutinite), resins (resinites), waxes, etc. Vitrinite are the remains of woody plant components. For inertinite are coaly fragments and charcoal.

The evolution of coal macerals are plotted as pathways on an H/C vs. O/C plot known as a van Krevelen diagram (Figure 1.12). Because the same coal macerals are recognized in the disseminated form as part of the kerogen of the sedimentary rocks, and chemical change in coal during its evolution through the different rank stages can be compared with the evolution of various kerogen types. So Tissot and Welte (1978) adapted this plot to kerogen as shown in Figure 1.13.

In this study, those have also been applied to describe kerogen type. The kerogen composition is reported as % liptinite, % vitrinite, and % inertinite. The ability of the various kerogen types to yield oil decreases in the following order : liptinite-vitrinite-inertinite.

The colour (Thermal Alteration Index) of the spore and pollen grains present is also used as an indicator of thermal maturation level. Observation of palynological concentrates in transmitted light is the basis for several scales of level of maturity. The progressive change of colour of the spores and pollen when viewed under microscope to measure light absorption and used this to follow the maturation of spores and pollen. The colour is originally yellow, then become orange or brown-yellow (diagenesis), brown (catagenesis), and finally black (metagenesis). However, general kerogen colouration will be used in the absence of good spores.

The 1 to 10 Spore Colour Index (SCI) scale was designed by Batten, 1981 for linearity with increasing depth and temperature and correlated approximately with the following zones of oil generation: 1.0 to 3.5, immature; 3.5 to 5.0, early mature, generation of low gravity oils (28^{o} to 35^{o}API); 5.0 to 7.0, middle mature, generation

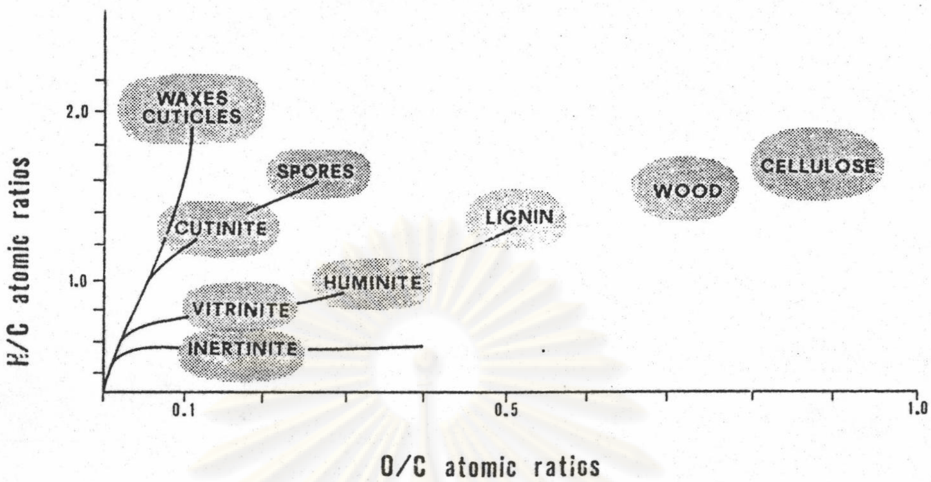

Figure 1.12 Selected plant and coal materials and their respective position in the H/C-, O/C- diagram (van Krevelen diagram)(Tissot & Welte, 1978).

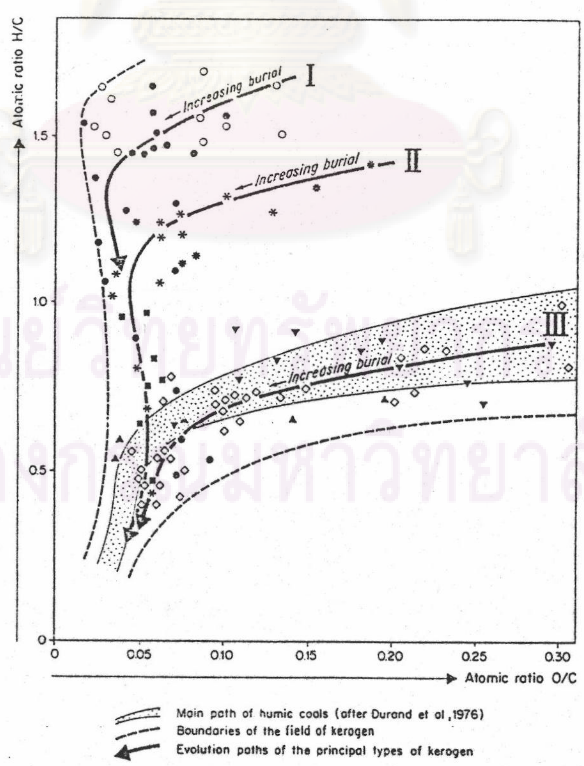

Figure 1.13 Principal types and evolution paths of kerogen: type I, II and III are most frequent (Tissot & Welte, 1978).

of medium gravity oils (35^{o} to 42^{o} API); 7.0 to 8.5, late mature, generation of light oils (> 42^{o} API) and 8.5 to 10, post mature, generation of condensate, wet gas and ultimately dry gas.

4. Vitrinite Reflectance

The primary industry standard for the assessment of thermal maturity is vitrinite reflectance. Vitrinite is one of several coal maceral groups derived from the remains of higher terrestrial plants. It is found highest concentrations in coals and in lesser concentrations in most other sedimentary rocks.

Plant remains are converted to vitrinite during burial of a few thousand feet deep. Continued burial of vitrinite results in additional chemical and physical alteration. These changes are recorded as non-reversible increases in reflectance with increasing intensity and duration of diagenesis and metamorphism. Therefore, the reflectance measurement can be used to determine the degree of thermal maturation of the sediment.

Reflectance measurements have been extended to particles of disseminated organic matter (kerogen) occuring in shale and other rocks. Histograms showing the frequency distribution of reflectance are established, the reflectance increases from liptinite particles to vitrinite and finally to inertinite (Figure 1.14).

In order to determine vitrinite reflectance, the cutting or pulverised rock fragments are embedded in a epoxy resin plug. The hardened plug is polished and the reflectance measurement of the individual vitrinite particles are made on randomly oriented particle under a microscope. The reflectance data collected from each sample were plotted as histograms in an attempt to identify the mean value for the indigeneous

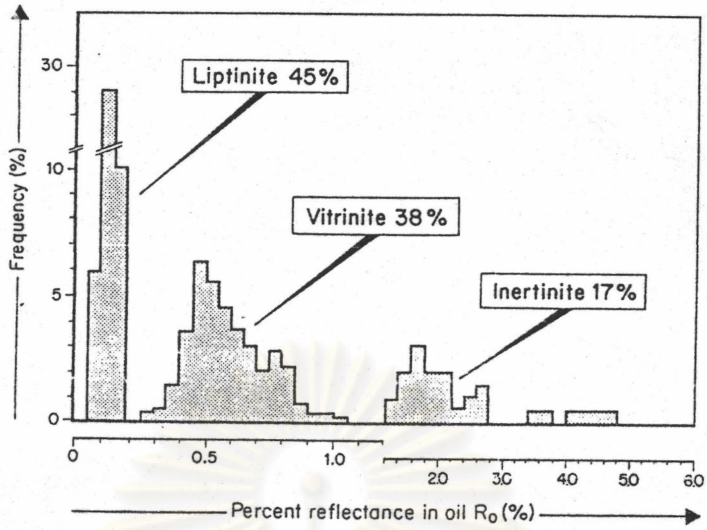

Figure 1.14 Histogram showing the distribution of the reflectance of organic matter, measured by reflected light on a polished section (Tissot & Welte, 1978).

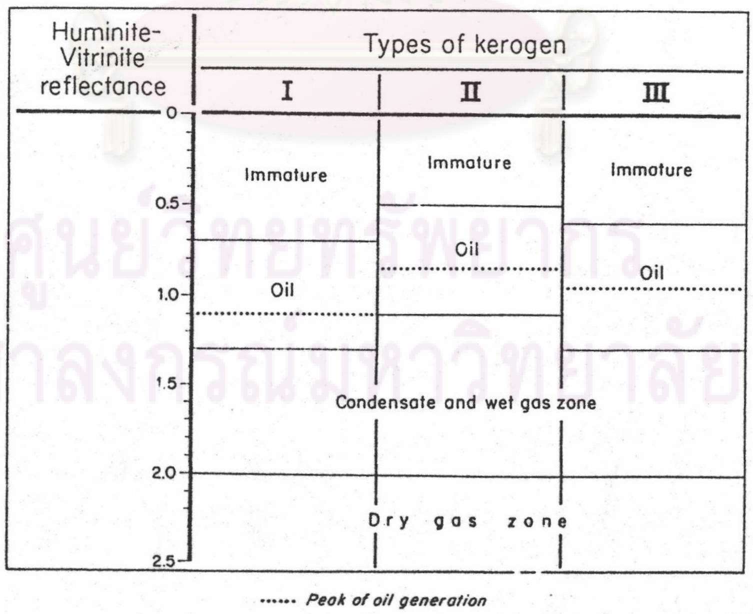

Figure 1.15 Approximate boundaries of the oil and gas zones in terms of vitrinite reflectance (Tissot & Welte, 1978).

population. When mean vitrinite reflectance values are plotted as a function of depth on semi-log paper, a linear profile is commonly created. The construction of linear profiles may be complicated by several factors including : marked increases in the rate of deposition and/or reductions in the geothermal gradient, intrusives, faults and major unconformities.

The notation used is %Ro (R=reflectance, o=oil). For kerogen maturity , the approximately maturity boundaries between different levels of maturation are:

a) $Ro < 0.5$ to 0.7% diagenesis stage, source rock is immature
b) $0.6\text{-}0.7\% < Ro < 1.3\%$ catagenesis stage, main zone of oil generation, also referred to as oil window.
c) $1.3\% < Ro < 2\%$ catagenesis stage , zone of wet gas and condensate.
d) $Ro > 2\%$ metagenesis stage, methane remains as the only hydrocarbon (dry gas zone).

A typical vitrinite reflectance profile is shown in Figure 1.15.

<u>Licence History and Previous Work</u>

The SW1 and SW2 Exploration Concession, located onshore in north central Thailand were initially awarded to Southwest Consolidated Resources PLC under Petroleum Concession No.1/2527/24 on 24 June 1984. In their original form, the blocks covered a combined area of approximately 14,095 km^2 and included two relatively unexplorated Tertiary basins : The Phetchabun Basin in SW1 and Mae Sot Basin in SW2.

Operatorship of the SW1 and SW2 blocks was transfered to Promet Berhard under Supplementary Petroleum Concession No.1 on 25 September 1984, when

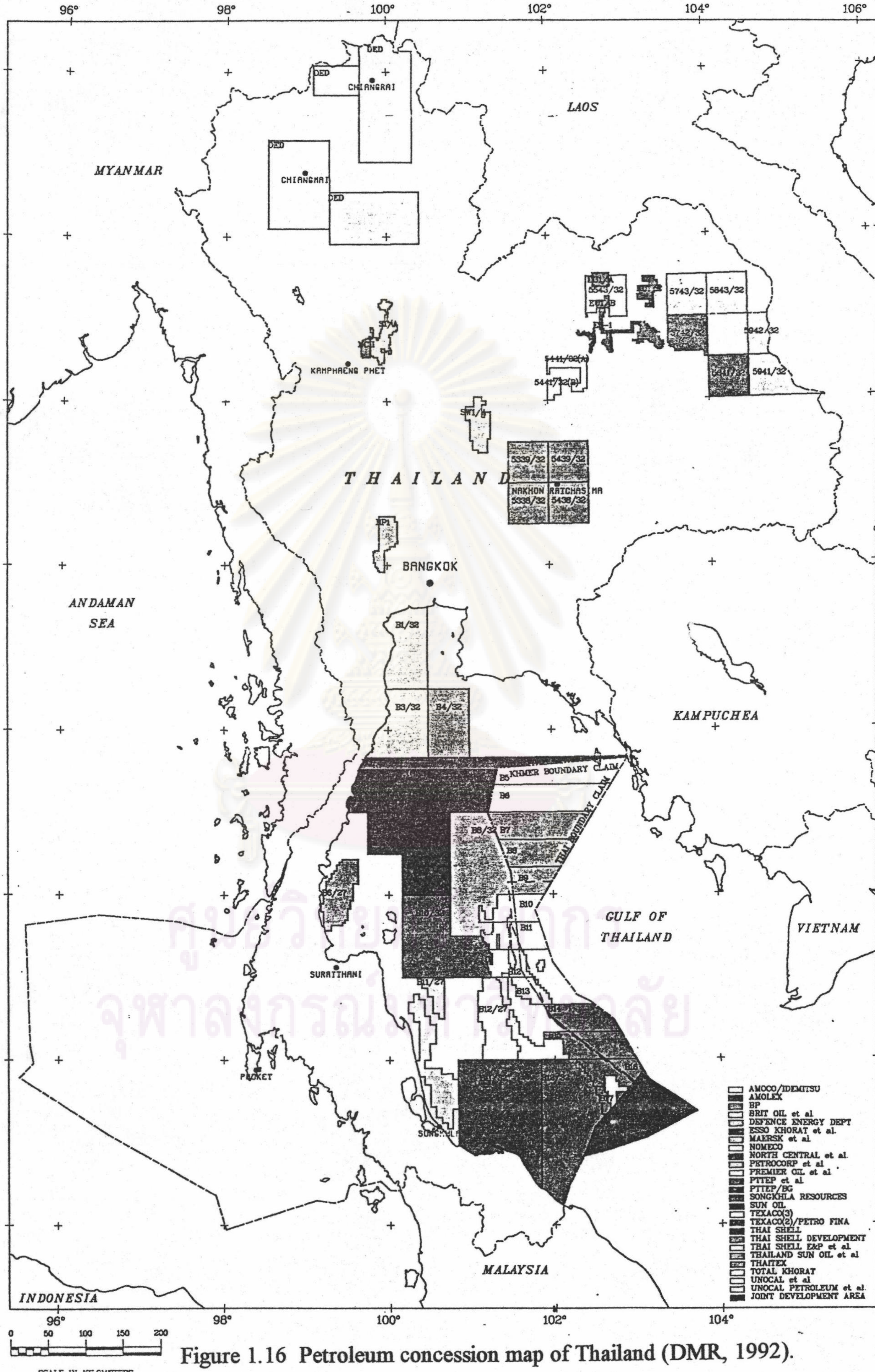

Figure 1.16 Petroleum concession map of Thailand (DMR, 1992).

Promet acquired a 75% interest in the licences. During the three years of the First Obligation Period (24 July 1984 - 23 July 1987) Promet Berhard completed the following work programme:

a) A review of the regional geology.
b) Geological fieldwork in SW1 and SW2 and subsequent palynological, petrographic and geochemical analyses of outcrop sample.
c) A photogeological study of the Tertiary Phetchabun and Mae Sot Basins.
d) Land gravity and magnetic surveys totalling 1425 km. in SW1 and 331 km. in SW2.
e) Geochemical analyses of 60 subsurface core samples from the Mae Sot Basin.

Petrocorp Exploration Limited acquired a 100% interest in the SW1 and SW2 Concessions from Promet Berhard and its partners, Southwest Consolidated Resources (now known as Ultramar Oil & Gas UK PLC) and Oakwood Petroleum, in November 1987. Approval for the transfer was granted by the Department of Mineral Resources in July 1988 and was ratified under Supplementary Petroleum Concession No.2 on 23 September 1988. In order to accommodate work obligations Petrocorp negotiated for a 75% reduction in the concession area; approval was recieved in April 1988; at the same time a total relinquishment of the SW2 block was applied for and granted. At present the SW1 Concession comprises two blocks with a combined area of approximately 2,535 sq.km.

In the first half of 1988 Petrocorp acquired 927 km. of seismic data and undertook geological field work in the block. The 1988 seismic programme defined major Tertiary depocentres within the Phetchabun: the Wichian Buri sub-basin in the south and the North Phetchabun sub-basin in the north. Several possible structural closures were identified within the Wichian Buri sub-basin.

On 15 June 1988 Wichian Buri-1, the first exploration well was drilled on the Wichian Buri structure. The well was designed to penetrate the entire Tertiary sequence at the well location, with the principal objective of testing predicted Miocene sandstones within a seismically defined fault-dissected anticline. The well penetrated a total of 2213m. of Tertiary sediments and intrusives before reaching a total depth of 2304 m. within Permian basement ; the well penetrated several potential hydrocarbon-bearing intervals of which one "F sands", was successfully tested, produced a total of 500 BOPD of oil and 3.5 MMSCFD of gas.

In early 1989 Petrocorp Exploration Thailand Ltd. completed a 703 km. infill seismic vibrosis programme. The closer line spacing and improved data quality of this second seismic programme showed the Wichian Buri Structure to be smaller and structurally more complex than previously mapped. These new seismic data were used to determine the location for Wichian Buri-2 and Wichian Buri-3.

On 13 June 1989 Wichian Buri-2 was the first appraisal well to be drilled on the Wichian Buri structure. Wichian Buri-2 was spudded approximately 750 km. to the east of the Wichian Buri-1 location. The well penetrated a sequence of clay-stones, siltstones and sandstones before reaching a total depth of 1,273 m., within or immediately below an igneous sill. Trace hydrocarbons were recorded within F,G and H sand package.

Wichian Buri-3 was the second well in a two well appraisal drilling programme on the Wichian Buri-1 discovery and was designed to test the F, G and H sands within the north-western fault block of the Wichian Buri structure. The well was spudded approximately 1.68 km. to the north of the Wichian Buri-1 location on 4

July 1989, and reached a total depth of 1199 m. at the top of an igneous intrusive. Trace hydrocarbons were recorded within "G sands".

The 1989 seismic and well data were also used to identify and evaluate additional prospects within the Wichian Buri sub-basin; an additional 75 km. of seismic data were then acquired in January 1990 over three of the prospects identified to confirm probable closures and select well locations.

Bo Rang-1 was the first of three exploration wells drilled in the Phetcabun Basin in 1990. The well was spudded on 21 April 1990 and located approximately 7.5 km. east of the Wichian Buri-2 to test Lower Miocene fluvio-deltaic sands within a faulted dome structure. The well penetrated 1,604 m. of Tertiary sediments and igneous intrusives before reaching a total depth of 1,608 m. within Permo-Triassic sediments. 5.4 MMSCFD of gas were encountered within an altered igneous sills. The well was completed as a gas discovery.

Si Thep-1 was the second of three exploration wells drilled in 1990 to test the hydrocarbon potential of a pre-Tertiary ridge and Miocene sands within overlying fault-dip closures in the southern portion of the Wichian Buri sub-basin. The well was spudded on 14 June 1990 and penetrated 1073m. of Tertiary sediments before reaching a total depth of 1,310m. within Permo-Triassic volcanics. Oil shows were recorded within thin sands, between 661-671 m. and 734-739 m. The well was plugged and suspended as an oil discovery.

Khao Leng-1 was the last of three exploration wells drilled in 1990. The well was spudded on 15 July 1990 approximately 8 km. north-northeast of the Wichian Buri-1 to test Lower Miocene fluvio-deltaic sands within a complexly fault anticline.

The well reached a total depth of 908m. Minor oil shows were encountered within sandstones and igneous units.