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Review of principal hydrocarbon-bearing basins around the South China Sea

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Abstract: As a consequence of exploration for hydrocarbons, and of research programmes conducted by academic and international institutions, substantial progress has been made in recent years in definition of hydrocarbon-bearing basins, and those potentially so, in southeast Asia and especially in the vicinity of the South China Sea. Basins and depositional provinces now recognized include: the Thai Basin, the Khorat and Panjang Basins, the Malay Basin, West Natuna and Penyu Basins, Saigon (Ho Chi Minh) and Mekong (Vung Tau) Basins, East Natuna area, the Greater Sarawak Basin including Central Luconia and Balingian depositional provinces, the Baram Delta/Brunei-Sabah Basin and the Northwest Palawan Shelf.

Where hydrocarbons have been encountered, the deposits are commonly associated with rocks of Middle and Upper Miocene age. Oliogene and Pliocene occurrences are locally significant.

With some exceptions, most sedimentary basin-fill was deposited within continental to coastal environments. Such sediments are commonly gas-prone. Where oil-prone, there are suggestions that the oil has been generated under conditions of greater thermal maturity.

Stratigraphic correlation depends largely on recognition of cyclic successions by means of integration of information derived from seismic stratigraphic, and palaeontologic and environmental analysis.

Structures are commonly anticlinal and fault-associated; the anticlines are commonly suspected to have diapiric cores. Major transcurrent faults of regional extent may have been instrumental in formation of depositional provinces and anticlinal trends.

INTRODUCTION

Recognition of the composition and framework of the shelves in the neighbourhood of the South China Sea began in the late 1960's and early 1970's as a result of interest in the potential of the area for producing hydrocarbons. As a consequence of that interest, geophysical surveys were run by, or under the sponsorship of, leading academic and international institutions. Consequent to the development of appropriate working relationships between industry and the concerned governments, further exploration was undertaken in the offshore waters of the area.

Reports concerned with the geology and hydrocarbon resources of the region appear more or less regularly in publications associated with south-east Asia (Adams, 1980; Beddoes, 1980; Fletcher & Soeparjadi, 1976; Hamilton, 1979; Kenyon & Beddoes, 1977; Murphy, 1975; Paul & Lian, 1975; Sander *et al.,* 1975; Soeparjadi, 1975). With a few notable exceptions, there have been few attempts to inventory the basins and to relate individual basin occurrence and contents to the presence or absence of hydrocarbons. It is the purpose of this paper to make such an inventory and to review the available published information concerning hydrocarbon occurrence.

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A major problem has been the absence of regional structure maps for the shelf areas. With the publication of Hamilton's *Tectonic Map of Indonesia*, there is now a regional map illustrating the thickness of Tertiary sediments of the shelf areas. That map serves in large part as a framework within which the hydrocarbon occurrences may be placed.

The principal basins are arranged in a double-festoon, extending from the Gulf of Thailand, generally southeastward, thence northeast around the Natuna Arch, and southeastward, subsequently northeastward parallel the northwest coast of Borneo (Kalimantan) continuing to the Northwest Palawan Shelf. Because of geographic proximity, the pre-Tertiary basins of Khorat (Thailand) and Panjang (southwest Kampuchea) are included.

The basins are reviewed in sequence below:

Khorat Basin
Panjang (Cardamome) Basin
Thai Basin
Malay Basin
West Natuna Basin
Penyu Basin
Saigon (Ho Chi Minh) Basin
Mekong (Vung Tau) Basin
East Natuna Area
Greater Sarawak Basin
- Balingian Province
- Central Luconia Carbonate Province

Brunei-Sabah Basin
- Baram Delta Province
- Other Brunei-Sabah

Northwest Palawan Shelf

KHORAT BASIN

General

The Khorat Plateau (Fig. 1) of northeastern Thailand is the site of two large basins, a northern Udon-Sakon Nakhon Basin of approximately 17,000 km^2, and a southern Khorat-Ubol Basin of approximately 33,000 km^2. The two basins are generally flat-lying, have a similar geologic history, and are separated by the uplifted Phu Phan mountain range.

Stratigraphy

The stratigraphic sequence (Fig. 2) is dominated by the Khorat Group of rocks which range in age from uppermost Triassic to Cretaceous. Thickness are as follows:

Formation	Thickness (m)
Salt (Maha Sarakhan) Formation	610 +
Ban Na Yo (Khok Kruat) Formation	432 – 709
Phra Wihan Formation	
Phu Phan member	82 – 183
Sao Kua member	404 – 720
Lower Phra Wihan member	56 – 136
Phu Kradung Formation	
Upper Phu Kradung member	800 – 1100
Nam Phong member	0 – 1465

The Phu Kradung formation consists of siltstone, sandstone and conglomerate with a thickness of about 2400 m at the type locality. The age is Upper Triassic to Lower Jurassic. Contained fossils include plant remains and occasional bone fragments. Thin seams of lignite are present.

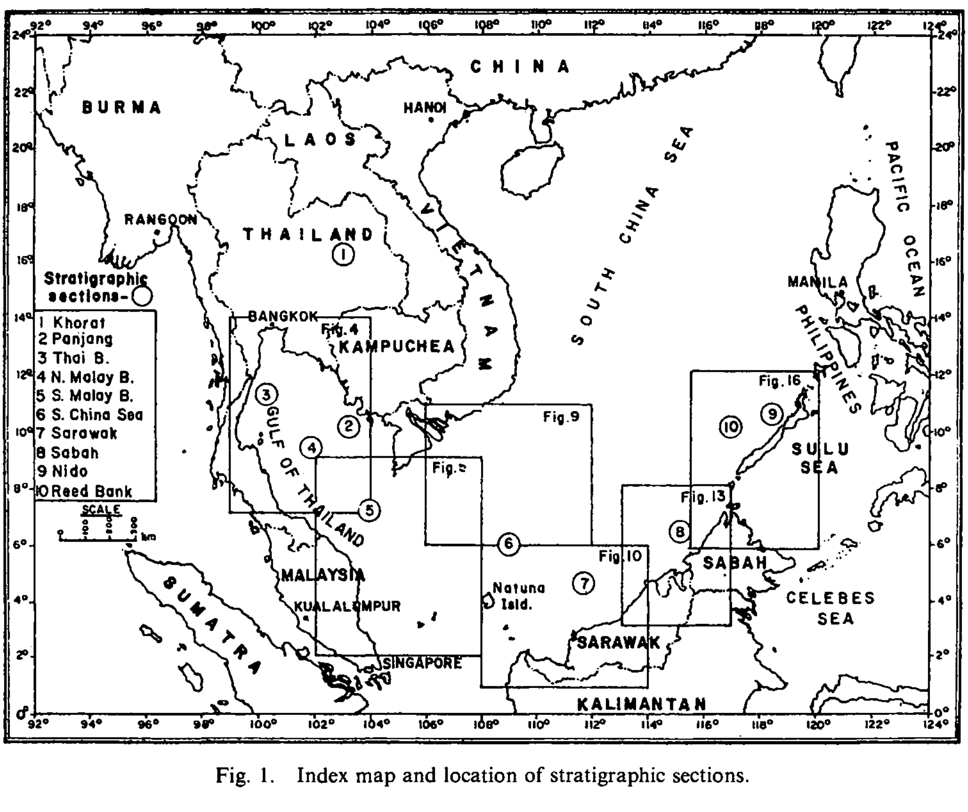

Fig. 1. Index map and location of stratigraphic sections.

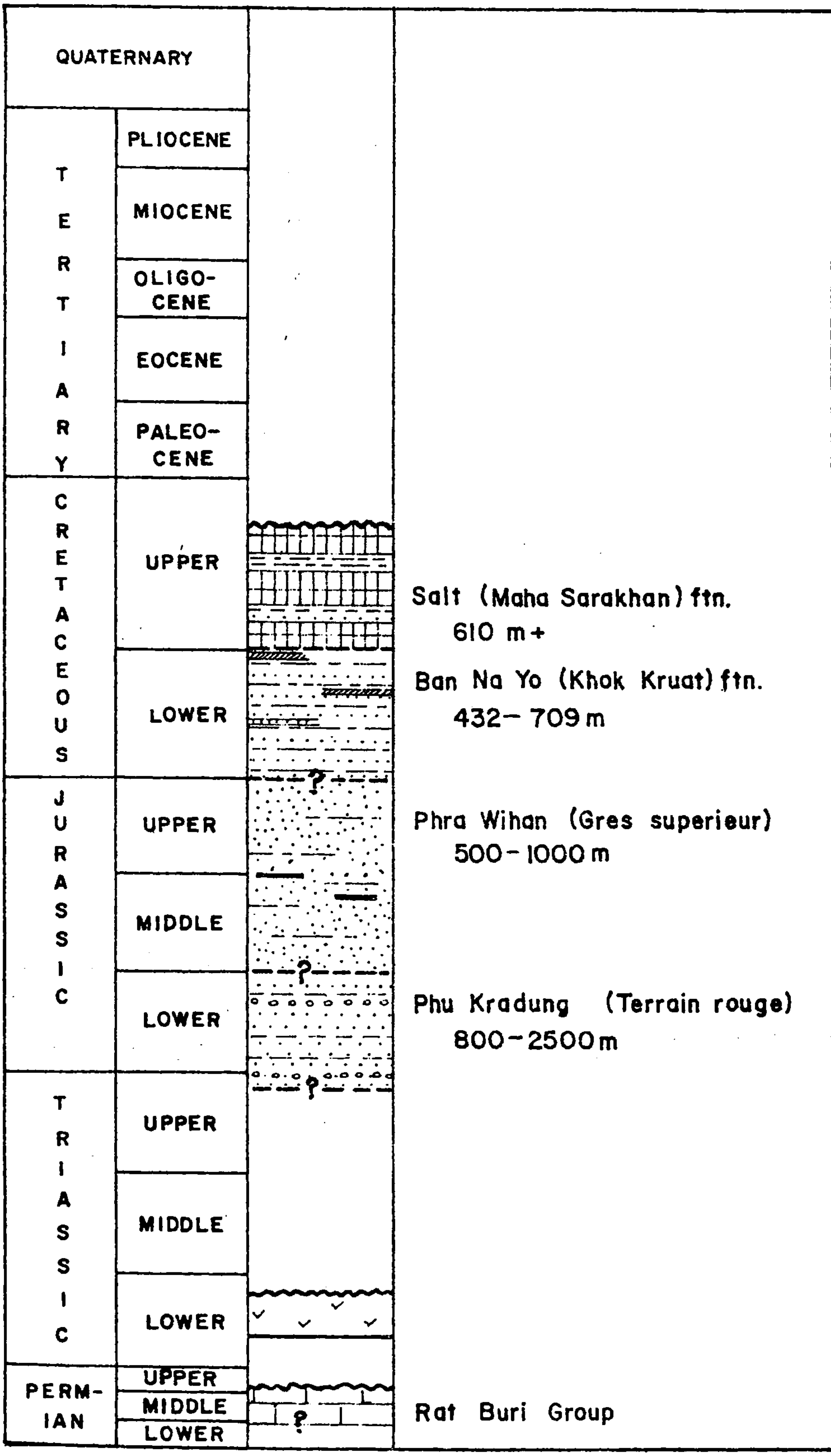

Fig. 2. Khorat Basin, Thailand, stratigraphic section 1.

The overlying Phra Wihan Formation consists of three members: a lower mainly massive cross-bedded sandstone with minor siltstone and shale and occasional lenses of lignite; a middle unit of sandstone, siltstone and occasional conglomerate, and with lignite and coaly remains; and an upper member of massive, cross-bedded sandstone and conglomerate. Marine pelecypods in the middle member indicate a probable Liassic age.

The Ban No Yo (Khok Kruat) Formation consists of sandstone, siltstone and shale, with minor amounts of calcareous conglomerate, siltstone, and sandy limestone. The formation contains Lower Cretaceous pelecypods, teeth and bone fragments.

The Salt (Maha Sarakham) Formation consists of siltstone, shale, mudstone, rock salt, and minor sandstone. Individual rock-salt beds are as thick as 240 m, and gypsum thicknesses of 50 m are recorded. Accessory deposits of carnallite, sylvite and boracite are present. The formation is believed to be of Upper Cretaceous age.

The Khorat Group may be underlain by rocks of the Rat Buri Group. The latter consists of massive limestones interbedded and interfingering with thin-bedded limestone-marl-shale sequences. Environment is shallow marine. The age of the Rat Buri Group is predominantly Permian as evidenced by a rich invertebrate fauna.

Hydrocarbon

No hydrocarbons are known in the area.

Many shallow core holes have been drilled to assess the quantity and distribution of salt and accessory minerals. Only one deep hole, Union Kuchinarai-1, has been drilled, reaching a TD of 3356 m (11,010′) before being plugged and abandoned on April 17, 1972[1]. Esso is now exploring the area.

The absence of recorded hydrocarbons may be due to the scarcity of deep drilling. It appears likely, with the presence of lignite and woody fragments, associated with a continental and/or near shore sequence of clastics, that gas may have been generated and will ultimately be found.

The marine shales and limestones of the Rat Buri Group constitute an additional target at depth.

PANJANG (CARDAMOME) BASIN

General

The island of Poulo Panjang, located south of Kompong Son Bay, Kampuchea, at approximately 9° 15′ N., 103° 30′ E., consists of sediments of the "Upper Sandstone" (= Gres superieur, = Phu Phan member of Phra Wihan formation of the Khorat Basin) which are regarded as of Jurassic age (Workman, 1977a). Nearby islands exhibit outcrops of Palaeozoic sandstone and Permian limestones.

[1]Kuchinarai—1: 16° 42′ 36″ N, 104° 04′ 07″ E.

Seismic refraction profiles in the vicinity of Poulo Panjang suggest the presence of 3 km or more of Mesozoic sediments underlain by rocks of probable Palaeozoic age which range in thickness from 3 to 4.5 km (Dash *et al.*, 1970). It is probable that the rocks exposed in the islands and disclosed by the seismic surveys are closely related to those which outcrop in the Cardamome mountains of western Kampuchea.

The rocks of the Cardamome mountains (Fig. 3) bear close resemblance to those of the Khorat Basin. The Middle Permian is represented by fossiliferous limestones and shales. The limestones bear abundant fusulinids and crinoids. The overlying Triassic-Liassic consists of polymict conglomerates, sandstones, mudstones and rhyolitic tuffs. These beds are in turn overlain by rocks equivalent to the Phu Kradung (= Indonsinias moyennes, Terrain rouge) and Phra Wihan (Gres superieur) formations of the Khorat area. These include as much as 1000 m of sandstone with interbeds of conglomerate, shale, sandy shale and marl, and occasional beds of lignite. Pollen analysis indicates a Lower Cretaceous age for rocks within the upper part of the section.

The basin is believed to be limited on east and west sides by major north-south trending faults. These faults are oriented similar to those of the Thai Basin (and the Chao Phraya depression) and no doubt have a common origin.

No hydrocarbons are known. The continental nature of the Cretaceous sediments suggests that they may constitute a gas-bearing target below the Tertiary deposits of the Thai/Malay Basins (assuming that they are within reach of the drill). It is also possible that the Permian carbonates may constitute an additional target at considerably greater depth (or where tectonic events have brought them within drilling reach). An additional play may be present in those areas where tectonic uplift has been followed by draping of Tertiary source sediments over Mesozoic and Palaeozoic reservoirs.

THAI BASIN

General

The Thai Basin (Fig. 4) occupies the northern part of the Gulf of Thailand, and is flanked on the east by the Indochina Peninsula, on the west by peninsular Thailand. The basin is distinguished from the adjacent Malay Basin by a marked difference in strike of its component elements and by a difference in structural habit.

The Basin consists of a parallel series of north-south oriented horsts and grabens which effectively divide the overall basin complex into a number of smaller troughs and ridges (Woollands & Haw, 1976). The most prominent ridge is the Ko Kra Ridge, which extends in a north-south direction for several hundreds of kilometres and separates the deep Pattani Trough on the east from a series of shallower more restricted troughs on the west. The major north-south elements of the Thai Basin may be counterpart features of the Western and Central Mineral Belts of Peninsular Malaysia to the south.

The eastern part of the Basin is not well known but named features include the

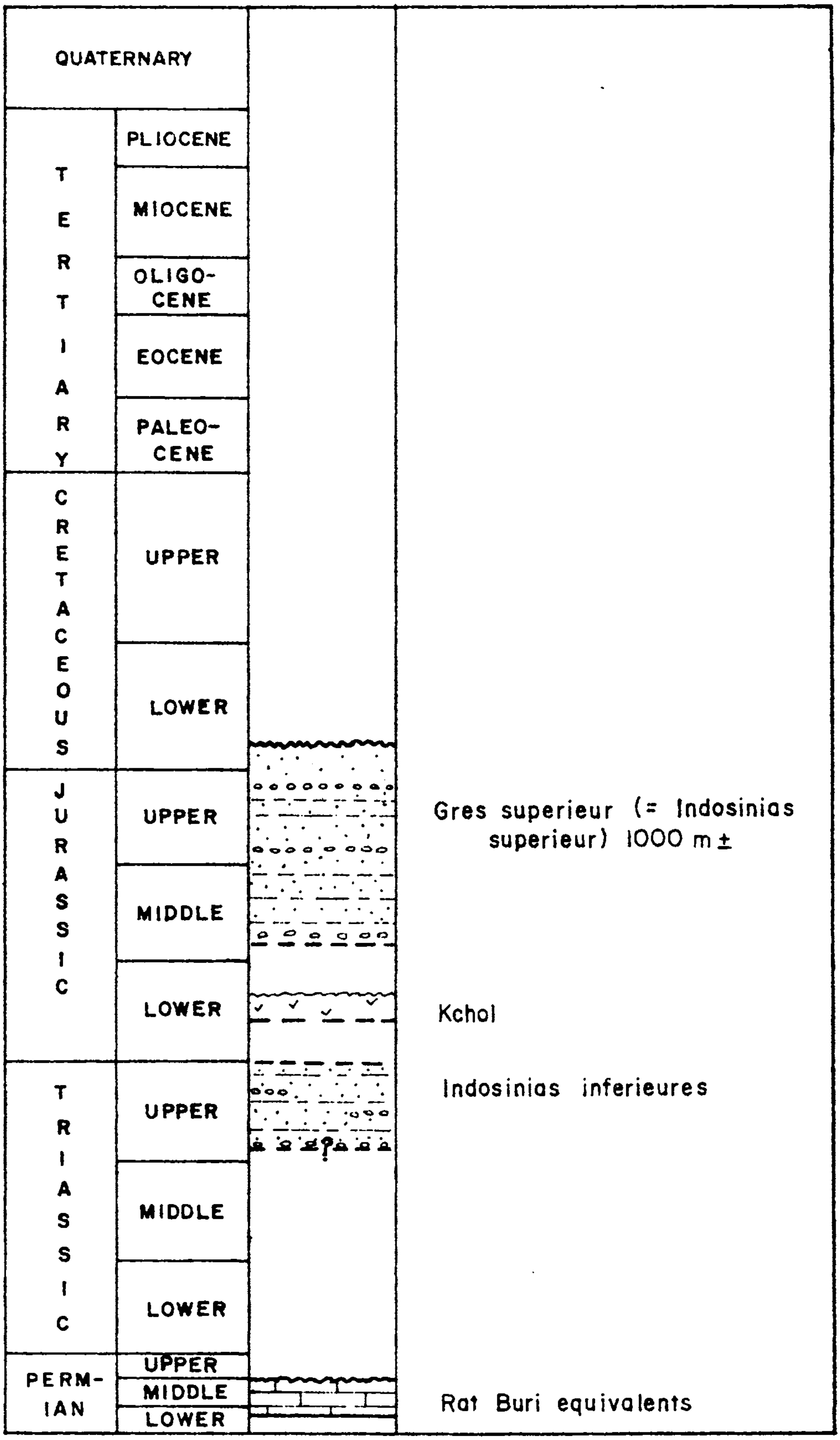

Fig. 3. Panjang Basin, northeast Gulf of Thailand (after Fontaine & Workman, 1978) stratigraphic section 2.

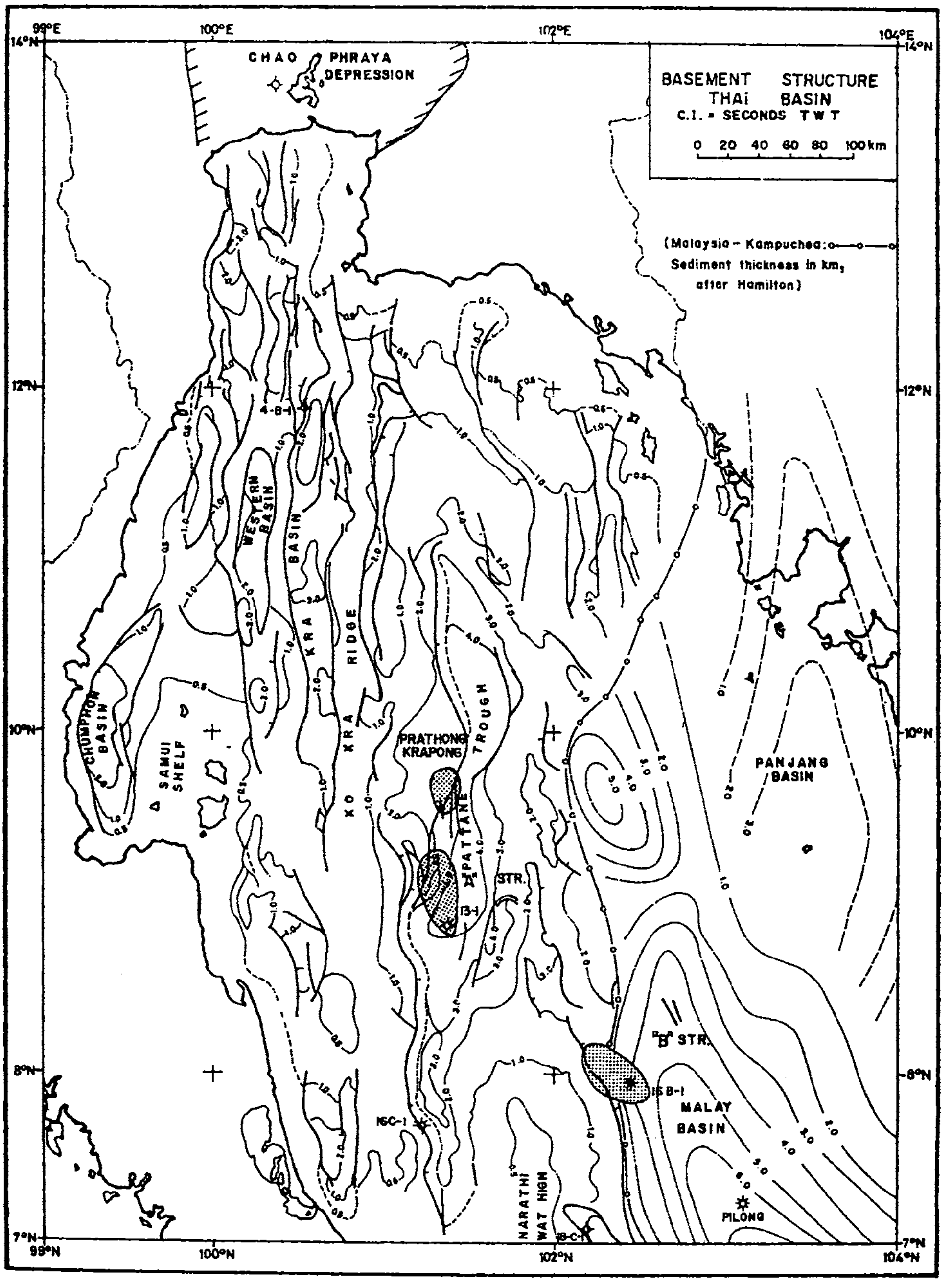

Fig. 4. Thai Basin basement structure in seconds TWT and Panjang Basin sediment thickness (after Woollands & Haw, 1976).

Khmer Shelf, the Khmer Trough, the Central Basin High, and the pre-Tertiary Panjang Basin.

Stratigraphy

The deeper part of the Basin (i.e., the Pattani Trough) contains more than 8000 m of Tertiary sediments, which thin to a veneer eastwards onto the Khmer Shelf, and to less than 1000 m to the west, within the smaller troughs of the western part of the Gulf of Thailand (Woollands & Haw, 1976).

The contained sediments (Fig. 5) consist of fluvial, marshswamp, delta plain and occasional shallow marine facies. The sediments change rapidly within short distances and correlations are difficult to make, even between adjacent wells. Because of the terrestrial content of the sediments, and the absence of reliable marine makers, correlation is carried out by means of palynological zonation and recognition of cyclic sedimentary sequences.

Three cycles of sedimentation are recognized, particularly in the Pattani Trough and the contiguous northwestern end of the Malay Basin. Cycles I and II are offlap regressive sequences, reflecting infilling of the basin(s), while Cycle III is a definite marine transgression culminating in the open marine conditions of the present Gulf. Cycle I is Oligocene (?) and part early Miocene; Cycle II early Miocene to late Middle Miocene; and Cycle III, late Middle Miocene to Recent in age.

With variations in lithology, the three-cycle classification can be recognized in most wells within the Thai Basin. Variations in lithology are attributed to differing positions within the continental coastal environment characteristic of the area as a whole and are revealed by differing proportions of coal, as well as maturity, sorting, composition and grain character of the sandstones.

Well 4-B-1 (Fig. 5), located near the north end of the basin, consists mainly of terrestrial sediments with abundant red sandstones and conglomerates. Except for the upper part of the well, dating is somewhat speculative. Cycle I consists of barren polymict conglomerates and breccias believed to be of Palaeogene age. The conglomerates and breccias show distinct cross-bedding and dip patterns which suggest water-lain deposits. Cycle I conglomerates are followed unconformably by a thin sequence of coals which carry good microfloras indicating Early Miocene age. The coaly interval is followed above by thick sandstones and conglomerates which exhibit evidence of deposition under fan and channel conditions. A decrease in the proportion of coarse sands and conglomerates appears to mark the top of Cycle II, and Cycle III sediments consist predominantly of sands, clays and lignites deposited under flood plain, coastal swamp and littoral conditions.

The Union—Seapec well 13-1, drilled in the southern portion of the Pattani Trough, is said to be representative of the central Gulf area and encountered 1153 m of sediments equivalent to Cycle III (Quaternary to M. Mioc.), 1187 m of Cycle II (M., L. Mioc.), and 957 m of Cycle I (Oligocene?), without completely penetrating the last named. A regional unconformity lies within the upper part of the Middle Miocene (believed to correspond with the contact between Cycles II and III), and though there is

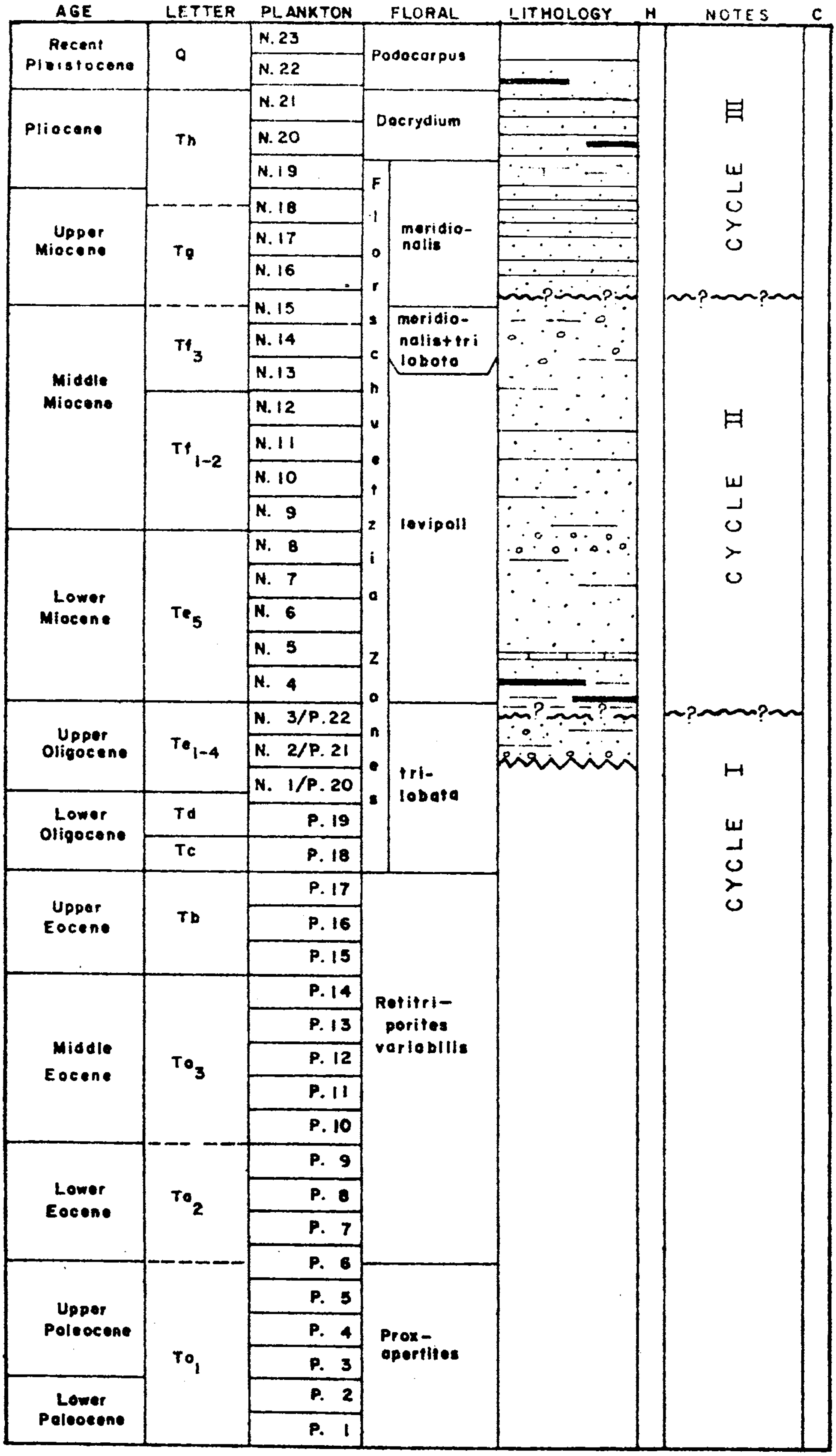

Fig. 5. Northern Thai Basin, well 4-B-1, stratigraphic section 3 (after Woollands & Haw, 1976).

no pronounced formation change at the unconformity, there is a break in the compaction curve for shales. Interval velocities are uniformly higher within the preunconformity section. Erosional truncation is apparent on seismic cross sections, and most structural deformation pre-dates the late Middle Miocene unconformity. The well encountered to a total depth of 3368 m interbedded sandstones and shales with, at various levels, abundant interbeds of coal suggesting delta plain environment. The sandstones are attributed to crevasse splay and distributary bar deposits.

Well 16-C-1, located in the southern extremity of the Pattani Trough, locally developed as a half-graben, exhibits three cycles of deposition, the lower two of which characteristically coarsen in an upwards direction and comprised entirely of continental sediments. The sequence of sedimentation is influenced by close promixity to the Narathi Wat High on the east and the Ko Kra Ridge (extended) on the west.

The Tertiary has been penetrated in only a few wells near the northern end of the basin. Pre-Tertiary rocks consist of Cretaceous igneous and Late Palaeozoic (Permo-Carboniferous) sediments and/or metamorphics. Mesozoic rocks may be present locally (e.g., Panjang Basin) and in deeper parts of the basin.

Structure

Subsidence of the present Gulf of Thailand began in Late Cretaceous to Early Tertiary time and the characteristic north-south aligned troughs and ridges owe their origin to renewed movement along pre-existing tectonic lines indicated in peninsular Thailand and in parts of Indochina.

Local structural features are secondary to the major lineaments (i.e., horsts, grabens, half-grabens) and consist of splay faults, faulted anticlines, drape structures and the like.

Pre-Tertiary sediments are preserved locally within the more depressed parts of the basin.

Heat Flow

Geothermal gradients tend to be high within the drilled portions of the basin, i.e., in the range of 4 to 5 C°/100 m. In wells in the central Gulf, below 2600 m the temperature gradient is of the order of 7.3 C°/100 m, and critical temperature of 176°C (350°F) is reached at about 3200 m. Gradients decrease on the flanks of the basin and to the north.

Hydrocarbons

The Thai Basin is gas prone (Achalabhuti, 1976; Achalabhuti & Ondom-Ugsorn, 1978; Asnachinda & Pitragool, 1978; Nakanart, 1978). Until October 1979, 52 wells had been drilled, of which natural gas had been encountered in 25, with a small amount of crude being found in three others.[1] Producing horizons are within deltaic sands of Lower and Middle Miocene age.

[1]Includes "B" structure, Thai waters of Malay Basin

Only one field in the Thai Basin (proper) is now regarded as commercial, that is the "A" (now, Erawan) structure of Block 12[2]. Recent drilling in Block 10, some 50 kms north of the Erawan structure, has revealed additional reserves in the Prathong and Krapong structures. Discoveries at Structure "B" commonly associated with the Thai Basin, are discussed below in connection with the Malay Basin.

The Erawan (ex-"A") structure is an elongate anticlinal feature in the southern part of the Pattani Trough with several gas condensate reservoirs at depths between 1525–2650 m. The quantity of condensate increases with depth but averages 30 barrels per million cubic feet of gas. Carbon dioxide content ranges as high as 18%. As of February 1979, seven wells capable of production had been drilled.

Test results for the nearby Union 13–1 well reveal that most of the sands below 1800 m had gas shows though of varying quality. Three sands between 2057 and 2371 m were capable of production rates from 8.6 million cubic feet of gas plus 269 barrels of condensate per day to 14.4 million cubic feet with 384 barrels of condensate.

Proven reserves for Erawan are 1.6 trillion cubic feet; those for Prathong—Krapong are 0.75 trillion cubic feet.

It is assumed that hydrocarbons are generated from the relatively abundant coals and carbonaceous shales are reservoired in nearby sands of deltaic and paralic origin. Structures are complex and associated with draping over fault blocks or with structural reversals associated with the faults themselves. Time of folding/faulting appears to have been about late Middle Miocene with early migration taking place during Upper Miocene. Interbedded shales served as caprocks.

MALAY BASIN

General

In contrast to the Thai Basin, with its dominant north-south grain, the Malay Basin (Fig. 6) exhibits a well-defined northwest-southeast orientation. The far northwest part of the basin displays both north-south and northwest-southeast structural components (e.g., in the vicinity of the "B" structure) and there appears to be an intermediate zone of transition between the two basins.

Commercial production of oil has been established in the southeast portion of the basin and gas, in probable commercial amounts, is present in the northwest end of the basin, that is, in Thai waters.

Stratigraphy

The Malay Basin contains as much as 10,000 m of sediments, dominantly non-marine clastics, but with marine influences increasing above and to the southeast (Armitage, 1980). The oldest generally known sediments are non-marine sands and shales of questionable Oligocene age.

[2] Pending pipeline construction, not yet on production.

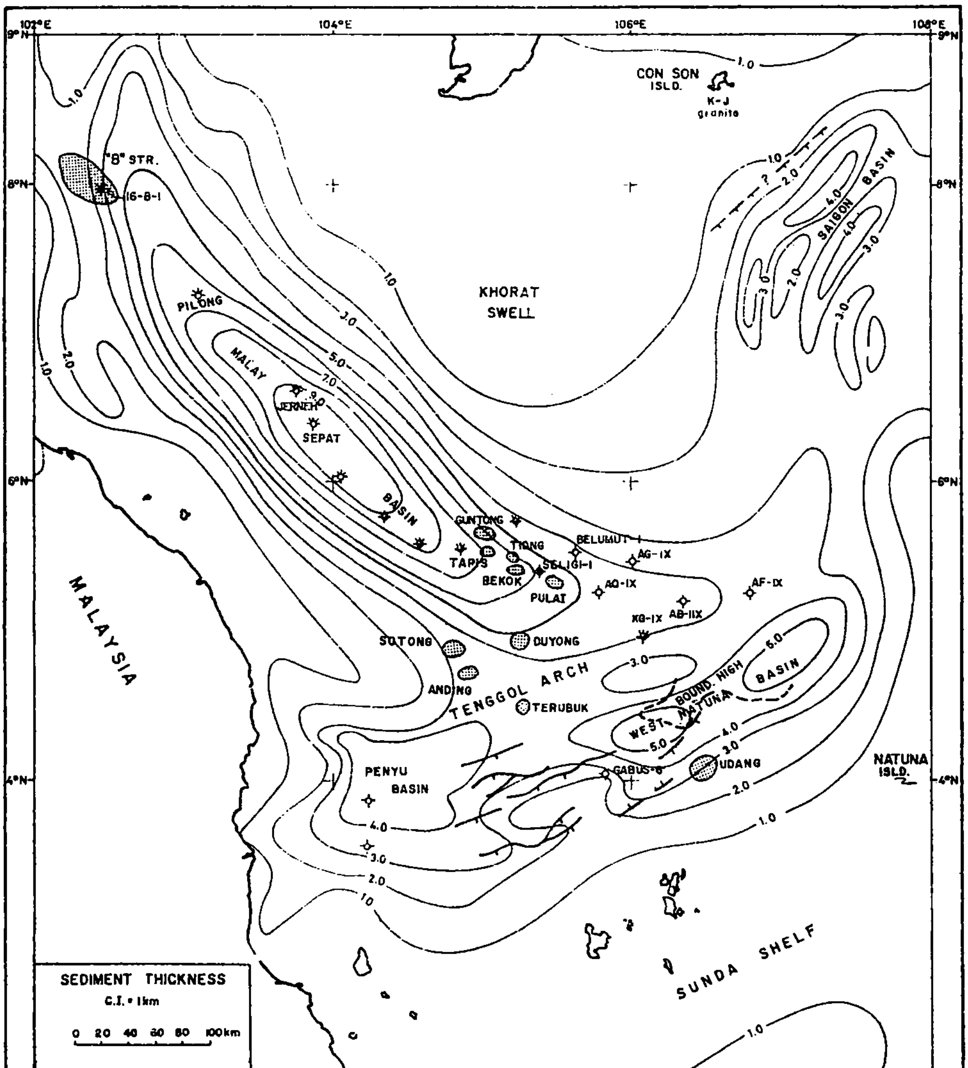

Fig. 6. Malay, West Natuna and Penyu Basins, sediment thickness (after Hamilton, 1979).

Stratigraphically, conditions resemble those of the Thai Basin (Woollands & Haw, 1976). As in that area, correlation by traditional means is difficult. Reliance is placed on seismic stratigraphy (Dahm & Graebner, 1980), locally assisted by palynological zonation, analysis of depositional sequences and foraminiferal studies.

To the northwest, the three-cycle system of correlation of the Thai Basin has been extended into adjacent parts of the Malay Basin. Thus, in well 16-B-1 (Fig. 7), the oldest known sediments (i.e., Cycle I) consist of undated red-beds with fluvial channel sands of possible Oligocene age. Dipmeter evidence suggests a structural break at the top of the sequence and a hiatus may mark the boundary between Cycle I and the overlying Cycle II sediments.

Cycle II, of Early to Middle Miocene age, begins with a thin sequence of brown shale and sandstone, of fluvio-marine environment, followed by a thick series of interbedded dark gray to black shale, sandstone, and abundant coal, representing coastal swamp, deltaic and tidal environments. This is in turn followed by coarser sands, moderately to well sorted, with interbedded shales and frequent coal beds. The environment is delta plain with distributary channels and marsh deposits. Cycle II terminates above with a coarse porous sandstone containing thin limestone beds.

The basal beds (Late Miocene) of the overlying transgressive Cycle III consist of a coarse lag deposit of poorly sorted pebbly sandstone with abundant rounded shale pebbles, followed by littoral sandstones with interbedded limestones containing benthonic foraminifera. No marked structural discontinuity has been recognized at the contact of Cycles II and III. The basal beds (of Cycle III) are followed by interbedded sands and siltstones, and clay with interbedded lignite. Environment of deposition is coastal mangrove swamp alternating with shallow marine.

In the southern end of the Malay Basin (Fig. 8), occasional wells have encountered igneous and metamorphic basement of Cretaceous and older age. The oldest known non-metamorphosed sediments are within the so-called "Undifferentiated Complex" and consist of fine grained sandstone, shale and siltstone of probable Oligocene age (Armitage & Viotti, 1977). Except for occasional long ranging palynormorphs, these beds are barren.

The "Undifferentiated Complex" is overlain by sands and shales, suggesting an environment which is non-marine but with some coastal influences, terminating above with clastics laid down under brackish water conditions. Age is Upper Oligocene to Lower Miocene. The rocks represented are included within the massive Sambas shale formations, and the Semala and Telukbutun formations, each of which consists of a lower sandstone member and an upper shale member. The Semala and Telukbutun formations comprise the Natuna Group, the latter name being derived from Natuna Island, and are equivalent to the Gabus formation.

The Telukbutun is followed by a series of four formations (Ledang, Seligi, Pulai and Tapis) each of which consists of a lower sand member and an upper shale member. Together they comprise the Trengganu Group of Middle to Early Miocene age and are generally equivalent to Cycle II of the Thai Basin terminology. Although some of the

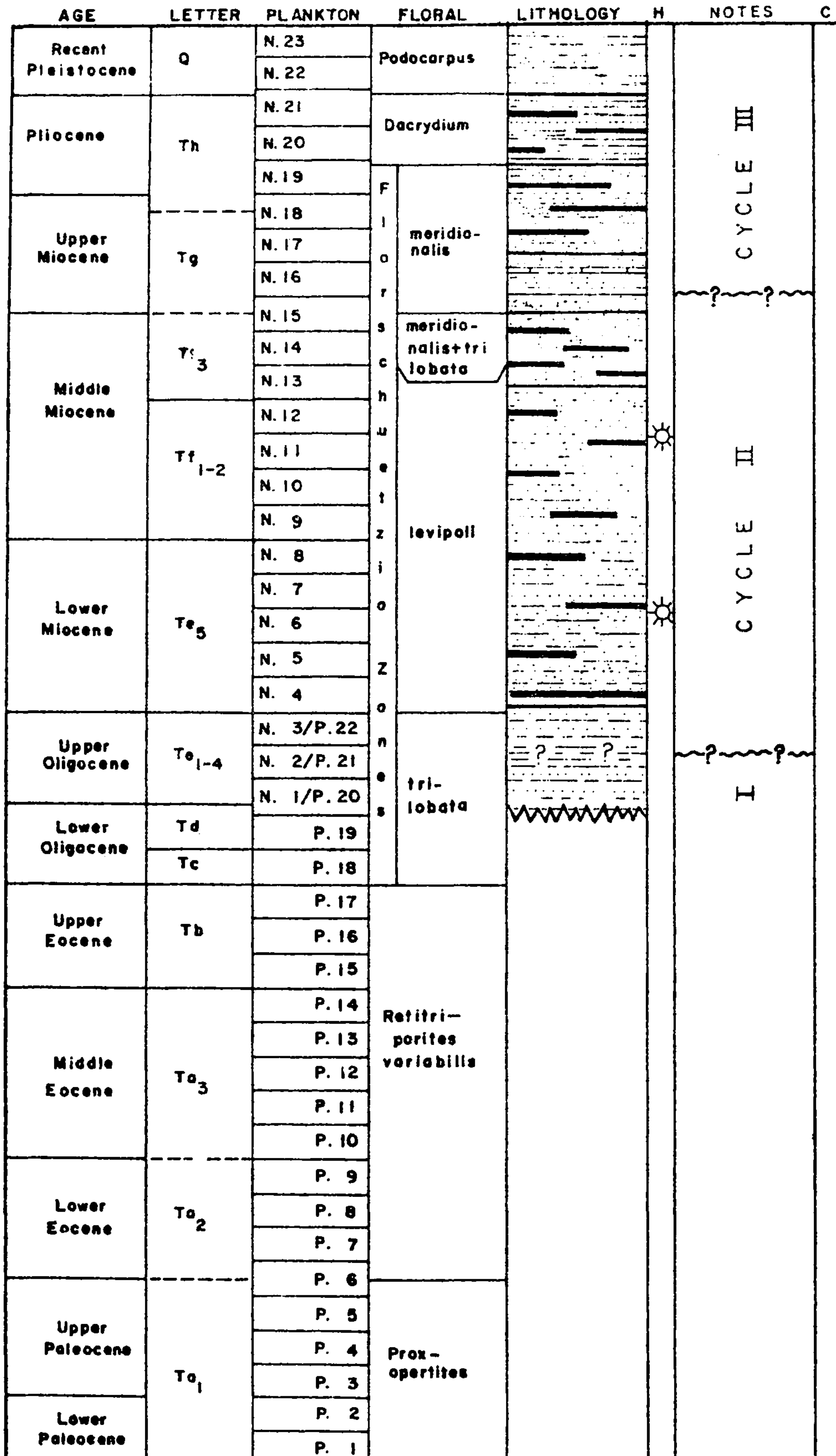

Fig. 7. Northern Malay Basin, well 16-B-1, stratigraphic section 4 (after Woollands & Haw, 1976).

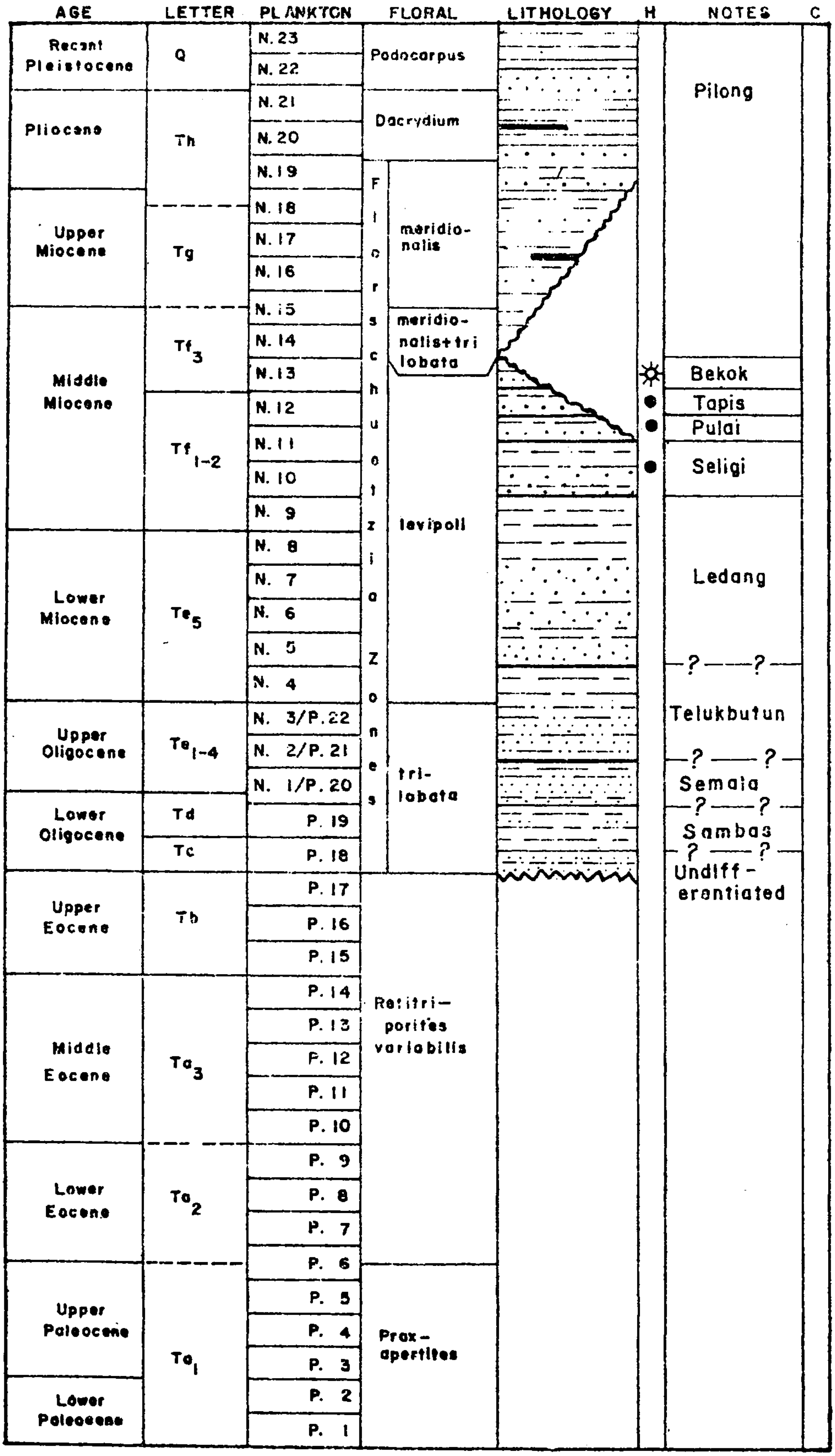

Fig. 8. Southern Malay Basin stratigraphic section (after Armitage and Viotti, 1977).

zones are barren of foraminfera, there appears to be a general increase in marine influence in the younger formations.

The overlying Bekok formation, of claystone, siltstone and sandstone, is Middle Miocene in age. In the southern part of the Malay Basin, a strong regional unconformity marks the top of the Bekok, cutting down locally at least to the Seligi formation (in the vicinity of Pulai and AQ wells). Basinward, i.e., to the northwest, the Bekok becomes considerably thicker and contains additional sands not yet formally named.

The overlying Pilong formation, of Early Pliocene to Recent age, consists of claystone with interbeds of lignite, sandstone and dolomite. The formation was deposited under shallow marine conditions and corresponds to Cycle III of Thai Basin nomenclature. The contact between the Pilong and the Bekok formation is an excellent seismic reflector throughout most of the Malay Basin.

Structure

As noted above, the Thai and Malay Basins are distinguished, among other reasons, for their orientation. The former basin appears related to the north-south family of linears which characterize eastern Bangladesh, the Arakan Yoma, the Central Valley of Burma, the Shan Plateau and the northern part of the Andaman Sea. The Malay Basin, on the other hand, reflects northwest-southeast directional trends of the Java Trench, the Mentawi Trough, the Semangko (Great Sumatran) rift fault, the island of Sumatra itself, the Strait of Malacca, the Malay Peninsula, and major lineaments of the Indochina Peninsula.

The southwestern flank of the Malay Basin is characterized by a major fault, or series of faults, which parallel the general course of the basin and effectively form the basin boundary in that area.

A major uplift in the southeastern part of the basin, in the vicinity of Pulai, Belumut and AQ wells, is associated with subsidiary faulting and folding. Grabens, half-grabens, and compressional folds occur in the area with as much as 4000 feet of uplift being locally present. Most of the oil within the basin occurs in this area.

Northwestward, i.e., basinward, folding becomes less pronounced, assumes a dominantly east-west orientation, and structural relief may be of the order of a few hundred feet. Orientation of the folding suggests the presence of a major northwest-directed strike-slip fault at depth.

The far northwestern end of the basin appears to abut against the feature termed the "Central Basin High", associated with the Thai Basin. Seismic information in the vicinity of the "B structure" gas accumulation (Thai waters) suggests that this end of the basin displays in part the north-south grain of the Thai Basin as displayed in north-south faulting, associated folding and local graben development.

Heat Flow

Geothermal gradients are moderate to high (3.5° to 5.5° C/100 m) and temperatures of 150° C below 2135 m are common. Such temperatures seem to preclude the existence of liquid hydrocarbons below the depth of 3000 m.

Hydrocarbons

Commercial production (or the possibility thereof) has apparently been established at both ends of the Malay Basin. A number of gas discoveries have been made within the central part of the basin but have not yet been developed.

In Thai waters, structure "B" is located near the northwest extremity of the basin (Fig. 6) and consists of a complex of three closely related areas in which (by February 1979) ten successful wells had been drilled. The accumulations are apparently associated with north-south oriented faults, and accompanying structural reversals, which may in turn be related to the southwest bounding fault (or faults) of the basin. Proven reserves are 1.3 trillion cubic feet while proved probable reserves are estimated at 5.8 trillion cubic feet. Carbon dioxide increases with depth and averages about 32%. Illustrative of test results are those from well 16-E-1 which flowed gas at a combined rate of 55 million cubic feet per day, plus 630 barrels of condensate, from six sands.

In the far southeastern end of the basin, numerous discoveries have been made. Of these, Tapis, Pulai and Bekok are in the initial stages of development and production, and Guntong and Tiong have recently been declared commercial. The fields are complexly faulted anticlinal structures with sandstone reservoirs topped by claystones seals. Depths are relatively shallow, pressures are normal, and there is good porosity and permeability. Pulai, at least, has a strong water drive and a large gas cap over each of the sands. Within the explored area, oil occurs in sandstones of the Seligi, Pulai, Tapis (Trengganu Group) formations and in the overlying Bekok formation.

Non-associated gas discoveries within the central part of the basin are attributed to sandstones within a more fully developed Bekok formation.

Within that part of the basin explored by Esso, 50 structures have been mapped. Of these 40 have been tested. Hydrocarbons have been encountered in 35. Oil has been encountered in 16 of the structures, with lesser shows of oil in 7 others. Non-associated gas was found in over half of the 40 structures.

Prior to the discovery of Guntong and Tiong, Esso's Malaysia fields were estimated to contain 500 million barrels of reserves, virtually all in offshore peninsular Malaysia (Tapis, 300 million; Pulai, 70 million; Bekok, 70 million). Guntong has recently been said to contain approximately 500 million barrels (including Tiong?), and total proven reserves for the Malay Basin must now be of the order of one billion barrels. The discovery at Sotong is variously cited as comprising 20 or 50 million barrels of oil. Substantially more oil has been discovered but awaits confirmation drilling.

Non-associated gas reserves within the Malay portion of the basin are 6.6 trillion cubic feet, possibly higher. Additional unconfirmed gas reserves are no doubt present.

With respect to the gas-occurrences in the central and northern parts of the basin, it is apparent that the gas is derived from coals and associated carbonaceous debris within the Middle Miocene Bekok formation and correlative beds of the Cycle II sequence of the Thai Basin.

The presence of oil in the southern part of the basin is attributed to a generally more marine environment in that direction, and (probably) a more advanced stage of thermal maturation associated with a more complex structural history and (possibly) deeper burial than is now the case.

BASINS ASSOCIATED WITH NATUNA AND SOUTH CHINA SEAS

This is a complex area (Fig. 6 and 9) which consists of tectonic elements of the northern end of the Sunda Platform, parts of the Indochina craton, and the southern end of the China Sea Basin. The shelf areas appear to represent a foundered and fragmented continental shelf which has been the site of deposition of continental and locally marginally marine sediments. The latter fault-related, no doubt influenced by a

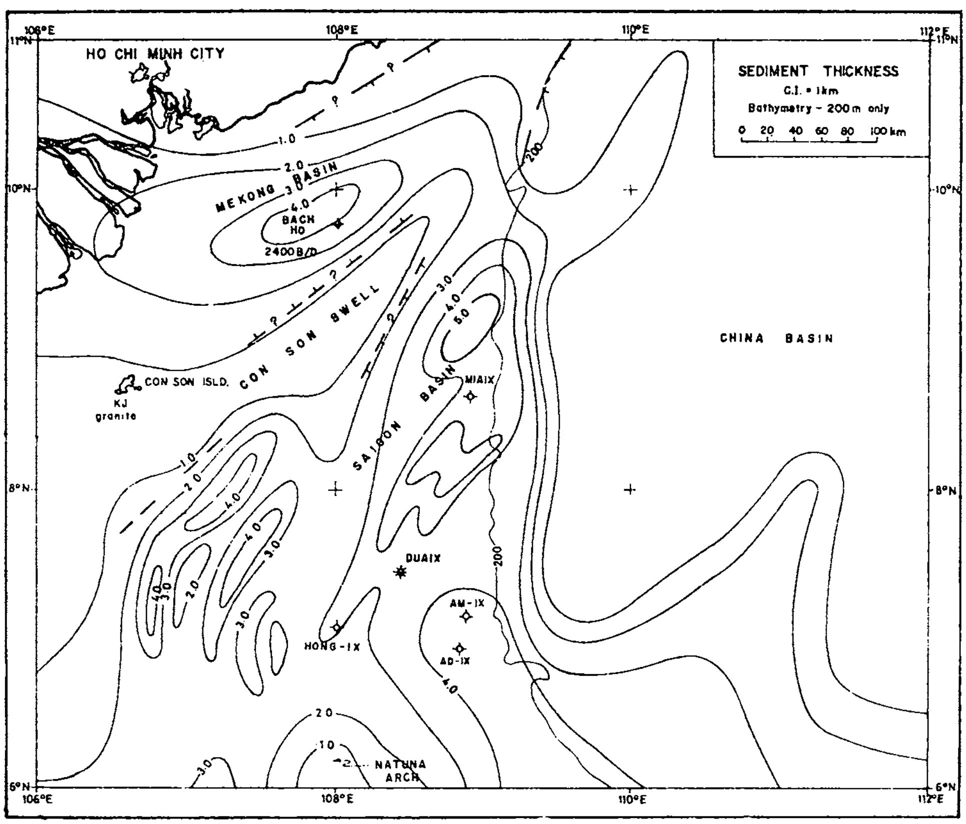

Fig. 9. Mekong and Saigon Basins, sediment thickness (after Hamilton, 1979).

pre-Tertiary fault mosaic, and complicated by rapid Tertiary sedimentation and mud diapirism (Ben-Avraham & Emery, 1973; Emery & Ben-Avraham, 1972; Haile, 1976; Maingry, 1970; Parke *et al.*, 1971; Pupilli, 1973; White & Wing, 1978; Workman, 1977a; Workman, 1977b).

Natuna Island (Fig. 10) forms a part of the exposed core of the Natuna Arch, a tectonic and structural high composed largely of Mesozoic rocks which extends northward from the Kuching area of Borneo, past Natuna Island, to terminate in a poorly understood fashion against a complex basin variously known as the Saigon or Ho Chi Minh Basin. The north and northeastern flanks of the Natuna Arch consist of complexly faulted basement blocks overlain by relatively thin (3000 m or less) Tertiary cover. A northeasterly trending basement high, the Con Son Swell, separates the Saigon (Ho Chi Minh) Basin from the Mekong (Vung Tau) Basin. West Natuna and Penyu Basins lie west of the Natuna Arch; the East Natuna (Sokang) Basin lies to the east (Fig. 10).

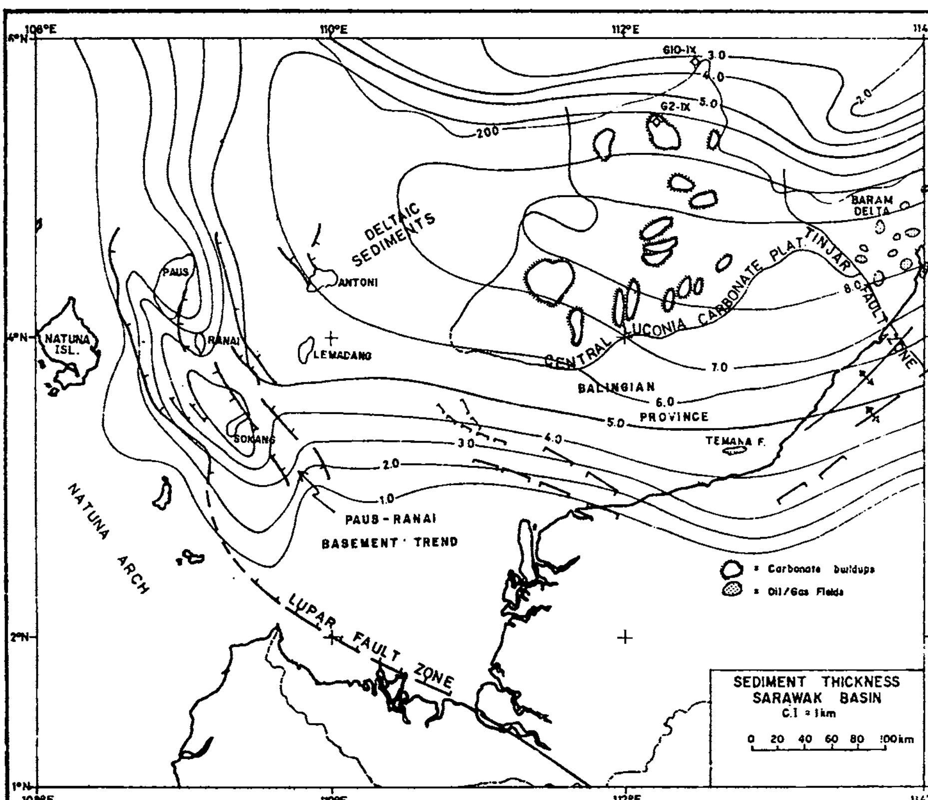

Fig. 10. East Natuna and offshore Sarawak, sediment thickness (after Hamilton, 1979).

WEST NATUNA BASIN

General

The West Natuna Basin strikes in a generally east-northeastward direction and is separated from the southern end of the Malay Basin by the Tenggol Arch. Sediments attain a thickness of 4500 m or more. Although production is associated with the Tenggol Arch, and with the south flank of the West Natuna Basin, no production is recorded from the central part of the basin.

Stratigraphy

The Gabus formation (Fig. 11) is the oldest generally recognized sedimentary unit and consists of silty clays interbedded with thick massive layers of friable sandstone and sand. Cross-bedding, bioturbations and ripple marks are commonly noted in cores and a moderate amount of carbonaceous material is present. A deltaic origin is probable. The age is considered to be Oligocene and the formation is probably equivalent to the Natuna Group (Telukbutun and Semala formations) of the nearby southern end of the Malay Basin. The Gabus is a primary exploration objective within the area.

The overlying Barat formation consists of fissile brownish shales, sometimes silty, often containing organic matter of plant origin. The upper limit is locally marked by an unconformity. The age appears to be late Oligocene and/or earliest Miocene. It may be equivalent to the upper shale member of the Telukbutun formation of the Malay Basin and the base of Cycle II of the Thai Basin. The Barat is considered to be a probable source and seal for hydrocarbons within the underlying Gabus.

The Barat is trangressively overlain by the Arang formation which latter consists of alternating shales, sand and sandstone, essentially similar and equivalent to the Trengganu Group and Bekok formation of the Malay Basin. Thin layers of coal are present. The age appears to extend from early to middle Miocene.

The Arang is overlain transgressively by the Muda formation, which consists mainly of plastic clays with associated carbonaceous matter, and ranges in age from the upper part of the Middle Miocene to Recent. The Muda is equivalent to the Pilong formation of the Malay Basin and to most or all of Cycle III of the Thai Basin.

Structure

A principal feature of the West Natuna Basin is the so-called (north) Boundary High (Fig. 6), a major uplift, faulted on the south, and with a northward directed dip slope. It is probable that it is an outlier block related to the Tenggol Arch. The southern flank of the basin, north of the basin edge, is marked by numerous sub-parallel faults. It is likely that no single explanation can account for the faulting and that strike-slip faulting, as well as thrust faults associated with compressional stress are involved.

Little information is available on the Tenggol Arch. Evidence for its presence is based on the occurrence of shallow basement in drill-holes and from geophysics (most of which has not been published). A well at Terubuk encountered, below the Tertiary,

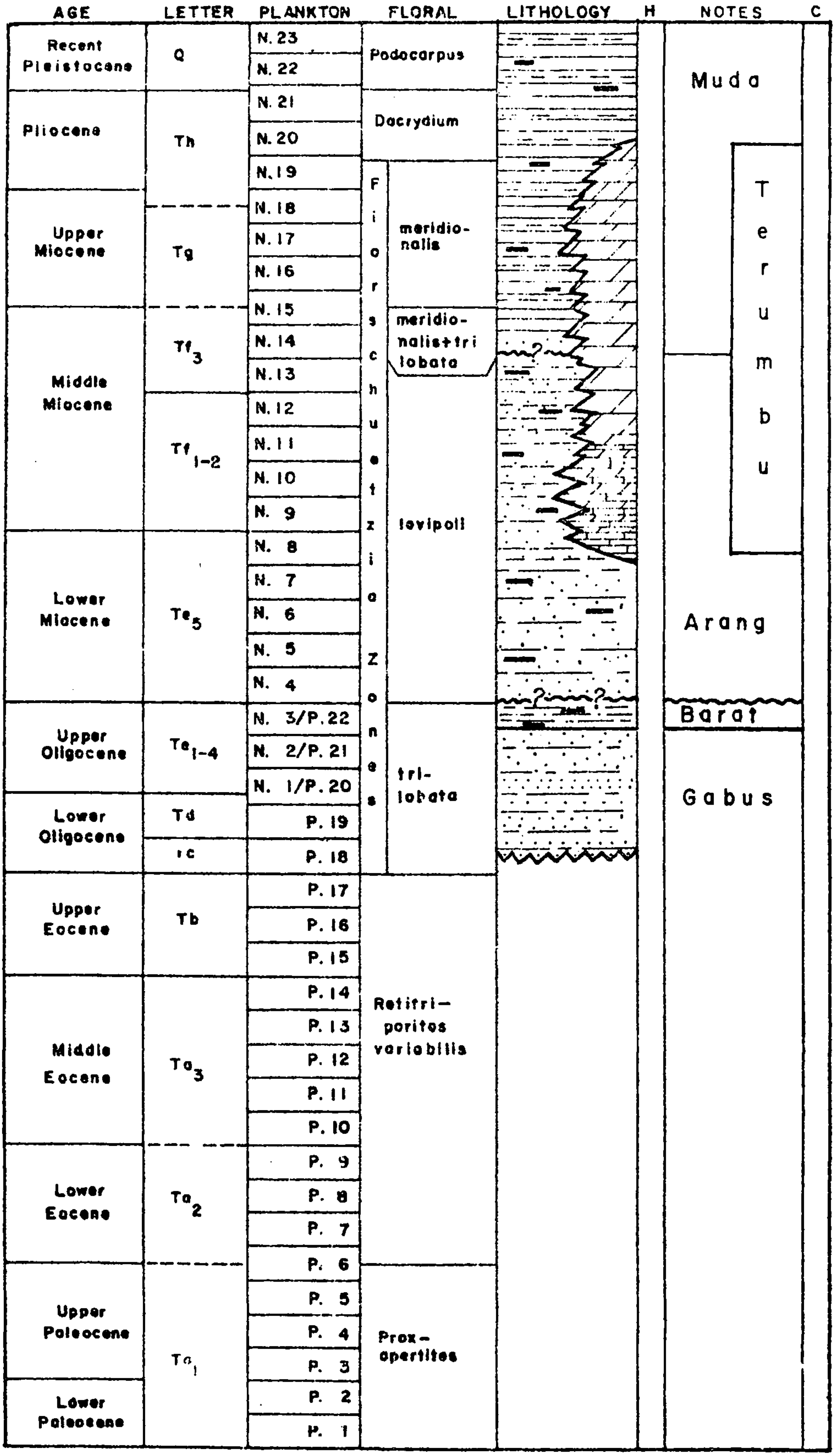

Fig. 11. South China Sea stratigraphic column 6 (after Pupilli, 1973).

at 2564 m, metamorphosed lavas, of probable andesitic nature, dated as Middle Jurassic. Well AB-1X encountered amphibolites between 2618–2786 m dated as Middle Jurassic (although a Cretaceous date also is reported). Well AF-1X, between 3048–3094 m encountered probable altered andesite dated as Cretaceous in age. On the south flank of the basin, Gabus–6 encountered biolite-hornblende adamellite at 1301 m, also of Cretaceous age.

Geothermal Gradient

Geothermal gradients are somewhat elevated within the basin ranging, in a group of wells, from 3.47 to 4.96° C/100 m, with an average of 4.1° C/100 m. A similar number of wells, mostly located along the Tenggol Arch, exhibit a range from 2.72 to 4.60° C/100 m, with an average of 3.57° C/100 m. The difference appears to be significant.

Hydrocarbons

Drilling within the West Natuna Basin is believed to have been directed principally at structural reversals associated with the system of southwest-northeast directed faults. Considerable drilling has also taken place along the Tenggol Arch for which essentially no structural information is available.

Udang Field, near the south edge of the basin, is situated on an anticlinal closure, trending northeast-southwest, about 12.5 km long by 2.5 km wide. The structure is limited by faults on the southeast and northeast. Initial production from five completed wells is 18,000 barrels oil per day. Producing formation is the Gabus (probable Oligocene) sand which is here divided into two units: the Upper Gabus composed of interbedded sands and shales and believed to be a fan delta depositional system, and the Main Gabus, composed of individual channel sands with intervening claystones. Initial tests of the discovery well, Udang 1, resulted in a flow of 4700 barrels of oil per day with 26.5 million cubic feet of gas.

Discoveries at Terubuk-2 (4320 barrels/day plus 24 million cubic feet of gas) and Kapak (KG-1X) are apparently associated with the Tenggol Arch. The Kapak well tested five zones at rates ranging from 364–2973 barrels/day (combined flow = 6700 barrels/day) between 1220–1770 m.

PENYU BASIN

General

The Penyu Basin, some distance west of the West Natuna Basin, may be structurally related to the latter feature but appears to be distinct from the Malay Basin with which it has sometimes been associated. Sediments attain a thickness of 4000 m or more and are assumed to consist of Oligocene, Miocene and younger continental-derived sands and shales, with some marine influence in the upper part. "Red-Beds" are reported to be present. Two wells have been drilled in the basin with negative results.

SAIGON (HO CHI MINH) BASIN

General

Little information is available on this basin (Fig. 9) which is entirely in Vietnamese waters. Seismic sections suggest a northeast trending basin, possibly with a restricted opening to the South China Sea, and terminating in a westerly and southwesterly direction against the Khorat Swell (extended). Three thousand to forty-five hundred meters of sediments are present and the central part of the basin is apparently characterized by numerous large scale mud diapirs (or shale-cored anticlines).

The stratigraphic section (of the Saigon Basin) is not available but is assumed to be intermediate between the dominantly continental-derived sediments typical of the basins previously reviewed, and the open marine conditions believed characteristic of the South China Sea Basin.

Dua 1-X, drilled to 4049 m, was an oil discovery with three hydrocarbon-bearing zones. Tests produced 17.6 million cubic feet/day of gas and 2230 barrels/day of oil. Another well drilled by the same operator, Hong 1-X, had shows of hydrocarbons but was plugged and abandoned. Conflicting reports suggest that well Mia 1-X, subsequently abandoned, may have been an oil discovery in Palaeogene sandstone.

MEKONG (VUNG TAU) BASIN

General

The Mekong Basin lies north and northwest of the Con Son Swell, off the mouth of the Mekong River. The existence of the Con Son Swell is documented by the presence of Jurassic (?) granites on Con Son Island and by seismic traverses in the area. The basin itself may be largely fault-controlled, at least on its southeast flank (against the Con Son Swell), and on some part of its northwest flank (where it borders the Hercynian Dalat massif of Viet Nam). The basin may be closed or restricted to the northeast by a barrier of Recent basalts and conditions antecedent to the basalt flows.

Stratigraphic content of the basin is not known but the offshore portion is assumed to consist of deltaic and associated sediments derived from the Mekong River. Onshore, the thickness of Quaternary alone is locally said to exceed 1500 m while aeromagnetic studies suggest depths to magnetic basement of 5,000 to 8,000 m for the lower part of the Mekong delta (Bosum *et al.*, 1971).

The Bach Ho well, drilled to a total depth of 3026 m, encountered an oil-bearing zone between 2749–2796 m which tested at a rate of 2400 barrels/day of 35° API oil. An upper zone at 2700 m tested 200 barrels/day.

Production has been reported from the onshore part of the basin. Details are lacking and it is assumed that the occurrence is minor.

EAST NATUNA AREA

General

The East Natuna area (Fig. 10) includes the Paus-Ranai (= Tuna?) Basement

Ridge, the Sokang Sub-basin, lying between the Natuna Arch and the Paus-Ranai Ridge, and an ill-defined area northeast of the Basement Ridge but east of the Central Luconia Carbonate Depositional Province of the Sarawak Basin.

The Paus-Ranai Basement Ridge consists of an uplifted block or blocks, sub-parallel to the neighbouring flank of the Natuna Arch. It is supposed that in this area the flanks of the Natuna Arch and of the Paus-Ranai Basement Ridge are controlled by major (transcurrent?) faults related to those which separate the tectonic provinces of adjacent onshore Sarawak. The core of the Ridge consists of pre-Tertiary and Palaeogene phyllites and metamorphics and the Ridge exerted a strong influence on mid- and late Tertiary depositional patterns. During Oligocene and early Miocene times, the feature served to trap sand derived from the uplands of the Natuna Arch until the Ridge was covered in mid-Miocene. Structural anomalies are related to burial and compaction drape over the buried blocks. Paus and Ranai uplifts are examples.

Within the Sokang sub-basin (i.e., west of the basement ridge) a more complete Tertiary section is present, and sands of reservoir quality may exist at least within the Oligocene and early Miocene. In the vicinity of the Sokang well, which tested a diapiric-associated anticline, the Oligocene consists of outer shelf to abyssal sediments.

East and northeast of the Basement Ridge, Tertiary sediments (Fig. 11) consist of deltaic and deep water deposits, at least until mid-Pliocene times, and structural anomalies are predominantly associated with diapirs (e.g., Antoni and Lemadang). Reservoirs may be generally poorly developed. However, to the north, the Terumbu carbonate formation (with reef and platform members) is locally developed and may provide porosity where developed. The formation ranges from early Miocene to early Pliocene in age and is assumed to be equivalent to the carbonates of the Central Luconia Depositional Province.

In the southern part of the East Natuna Area (i.e., in the region where Basement Ridge and Sokang sub-basin are most typically developed), geothermal gradients are high, ranging in a group of seven wells from 4.58 to 6.40°/100 m and with calculated formation temperatures of 150° C commonly being reached in the vicinity of 2100–2450 m. Northward, well beyond the tectonic influences of the Natuna Arch, and in an area perhaps better regarded as an extension of the Central Luconia Platform, the range in a group of five wells is from 2.92° C to 3.63° C/100 m, with an average for the five wells of 3.15° C/100 m. In this group of wells, geothermal gradients perceptibly increase in a southerly direction as the area of tectonic disturbance associated with the Natuna Arch is approached.

No production has been established in the East Natuna area, though hydrocarbon indications are not entirely absent. The best prospects may be associated with the diapiric features since, with exception of reefal production to the east, all production thus far developed in the closely related Sarawak Basin is believed to come from structures having a diapiric core. The Terumbu carbonate formation may afford an additional target.

GREATER SARAWAK BASIN

The Greater Sarawak Basin (Fig. 10) is in part equivalent to the Northwest Borneo Sedimentary Complex. The area described below consists of that part of the Sarawak Shelf made up of the Central Luconia Carbonate Province and the Balingian Province which lies generally to the south (Doust, 1978; Haile, 1974; Schaub, 1953). The eastern limit of the area is taken to be approximately at the abrupt southward bend in the 100 fathom bathymetric contour marking the outer limit of the shelf.

As developed below, the distinction between the Central Luconia and Balingian Provinces is based on stratigraphic makeup and tectonic history.

BALINGIAN PROVINCE

General

The Balingian Province (Fig. 10) is characterized by a Tertiary history of near-shore, deltaic and continental sedimentation, interrupted by periods of non-deposition, and with numerous complexly faulted anticlinal structures arrayed in two principal belts of folding. Principal drilling objectives consist of sandstones of Lower Miocene—Oligocene age.

Stratigraphy

Clarification of the Tertiary stratigraphy offshore Sarawak has come about through recognition and definition of cyclic deposition in the area. Generally, eight regional regressive cyclic units are recognized within the Oligocene to Recent succession, separated by thin intervals of transgression (Fig. 12).

Cycles I and II (Upper Eocene—Lower Miocene) form the bulk of the sediments drilled in Balingian and are locally several kilometers thick. To the southwest, the sediments consist of fluvial and estuarine channel sands with overbank clays and coals, corresponding in part to the Setap shale and Nyalau formations. These sediments grade, in a northeasterly direction, into marine shales with interbedded limestones.

Following uplift in Lower Miocene time, succeeding cyclic sequences, well defined in Central Luconia , are absent or thinly developed in Balingian. Where present, they are represented by coastal plain, coastal and fluvio-marine sediments during Cycles III and IV (late Lower Miocene to early-Middle Miocene), and by fluvio-marine sediments during Cycle V (Middle Miocene to Upper Miocene).

Structure

Two periods of structural deformation are recognized (McManus & Tate, 1976). The first is dated as Lower Miocene, affecting much of the western part of the province, and resulted in the formation of highly faulted ridges, depressions and, in westernmost Balingian, deep narrow half-grabens. In the Upper Miocene, eastern Balingian was uplifted and folded, resulting in the development of a northeast-southwest trending fold-belt in which the individual folds are generally asymmetric and bounded by reverse faults. Many Balingian anticlines appear to have diapiric cores and are visible in offshore seismic traverses.

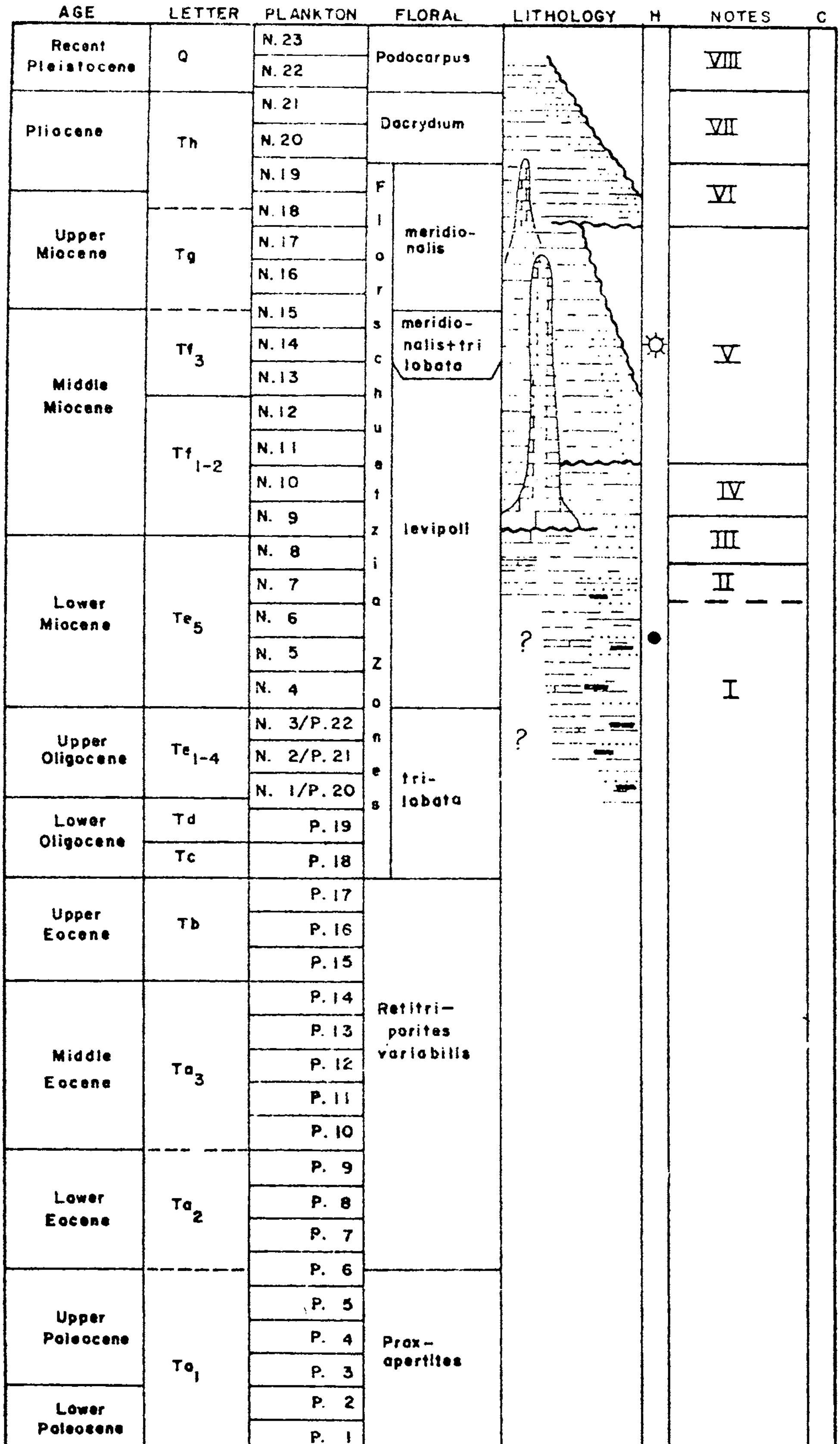

Fig. 12. Offshore Sarawak, Balingian and Central Luconia provinces, stratigraphic section 7 (after Doust, 1978).

As is apparent from the preceding, individual structures are complex. Temana anticline (and field) is divided by oblique cross-faults into a number of blocks of varying size and development. Likewise, the Patricia structure, an elongated northeast-southwest anticline, is bounded by reverse faults on both flanks and broken up by oblique normal cross-faults.

Geothermal Gradient

A group of four wells yield an average geothermal gradient of 4.2° C/100 m, consistent with that of the Central Luconia Carbonate Province (4.36° C/100 m) (Young, 1976).

Hydrocarbons

Principal reservoirs are sands of coastal plain and nearshore origin within the Lower Miocene and Oligocene. The sands are interbedded with sand-silt-clay sequences which contain coal. Individual sands are commonly less than 20 m thick and may have limited lateral continuity.

Although several wells have encountered hydrocarbons, only one field, Temana, is considered commercial. Temana was expected to go on-stream at year-end 1979 at 8000 barrels per day. Production is from the Lower Miocene and reserves have been estimated at 30 million barrels.

Source beds are considered to be coals and organic-rich clays of Oligocene to Lower Miocene age. Kerogen compounds within the same beds constitute a secondary source.

CENTRAL LUCONIA CARBONATE PROVINCE

General

The Central Luconia Carbonate Province (Fig. 10) comprises a large area, on the Sarawak Shelf, characterized by the presence of a carbonate platform of Middle Miocene age from which rise carbonate mounds and pinnacle reefs. Strong folding is absent. Gas production is associated with the carbonate mounds and reefs.

Stratigraphy

Carbonate deposition (Fig. 12) began during the extensive phase of subsidence of the Middle Miocene (Cycle IV) at a time when this part of the shelf lay well away from the coastline and in an open marine environment. Bank deposits to a thickness of 200–300 metres were developed on areas of structural elevation. Widest transgression took place during the Middle to Upper Miocene (Cycle V) and wide spread reefs and reef-associated carbonates were developed. Some carbonate buildups exceed 20 kms in length and 1.5 km in thickness. During this period, the Baram and Rajang-Lupar deltas began to prograde offshore and by the end of Cycle V had extended over much of Balingian and the southern part of Luconia, burying several of the smaller buildups in their path. Carbonate deposition was succeeded by open marine and coastal plain environment and deposition of more than 1000 m of clays and sands, smothering the reefs and providing a seal for the hydrocarbons.

Structure

The province is characterized by a network of north northeast-south southwest trending faults which have the effect of dividing the zone into a somewhat elevated central block and flanking depressions and basinal areas. To the east and west, the basin floor descends below younger deltaic sediments associated with the Baram Delta and the East Natuna area.

The principal localized structures are associated with the pinnacles and the flat-topped mounds and platforms.

Geothermal Gradient

Geothermal gradients are relatively high, a group of eight wells, ranging from 3.72°–5.44° C/100 m, have an average of 4.36° C/100 m. Two wells, outside of this cluster of records, but within the general area of carbonate buildups (G-2-1X and G-10-X), have gradients of 3.50° and 1.86° C/100 m, well below the measurements for the other wells in the area. Both are located near the shelf edge, as are wells AM-1X and AD-1X, northeast of the Natuna Arch, also with low values of geothermal gradient.

Hydrocarbons

A number of gas discoveries have been made within the area of carbonate platform buildups and pinnacles. Commonly only one reservoir unit is involved. Occasional oil accumulations are observed, usually in the form of oil-rims about the base of the gas column. Gas columns may reach down to the structural spill-point. Lithology includes limestone, dolomitic limestone and dolomite. Within the reefoid sections, porosities range from 10–40% and permeabilities up to 2000 millidarcies.

By the end of 1978, 200 structures had been mapped, 43 of which had been drilled, resulting in 20 gas discoveries. Proved reserves are estimated at 9.7 trillion cubic feet, proved and probable at 14.4 trillion.

The source of the gas is poorly understood. Source beds are occasionally noted near the base of the carbonate buildups and may also be present within the time-equivalent off-reefs beds. The carbonates themselves may supply the source.

BARAM DELTA/BRUNEI-SABAH BASIN

It is apparent that the northeast shelf of Borneo (i.e., Sarawak, Brunei, Sabah) is divisible into two physiographic provinces (Fig. 10 and 13). Broadly, these consist of the wide shelf off the Sarawak coast, and the narrow shelf off the Brunei-Sabah coast. The area of wide shelf is the site of the Balingian and Central Luconia Carbonate Provinces and, at least insofar as the latter is concerned, is fairly stable tectonically. The area of narrow shelf off Brunei-Sabah in contrast, is marked by substantial down-warping, and throughout much of its extent, generally deeper water conditions of Tertiary sedimentation.

The Basin is limited onshore by the right-lateral transcurrent Mulu Shear zone which parallels and determines the north-northeast direction of the Sabah coast; by the

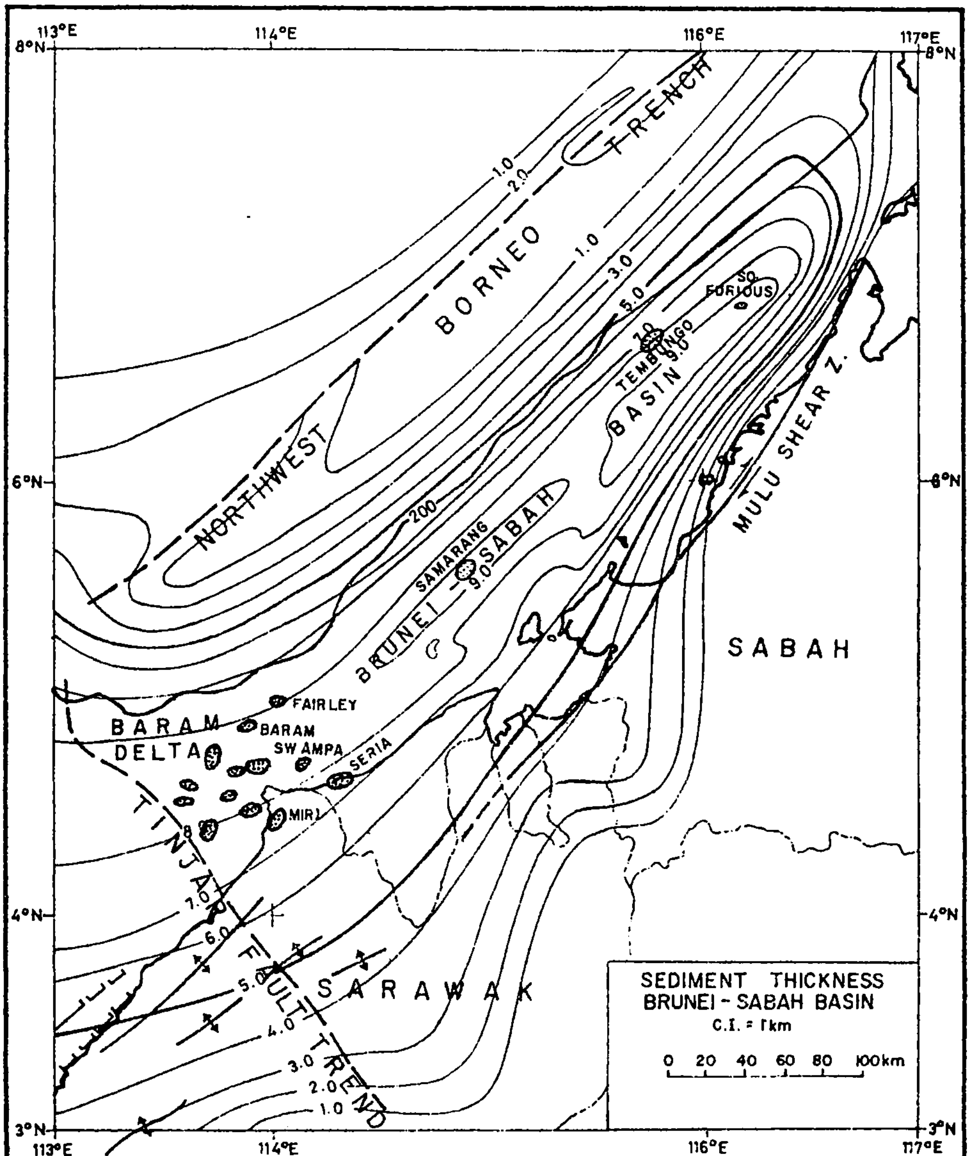

Fig. 13. Baram Delta and offshore Sabah, sediment thickness (after Hamilton, 1979).

sub-parallel offshore Northwest Borneo Trench (= Palawan Trough); and by the onshore northwest-directed Tinjar Fault Trend and its offshore projection.

Two hydrocarbon-producing regimes are distinguished: the Baram Delta (= Miri Zone), and the Brunei-Sabah Basin proper.

BARAM DELTA PROVINCE

General

The southwest corner of the combined Baram Delta/Brunei-Sabah Basin is the site of the Baram River palaeodelta. Oil was first encountered in the area in 1910 with the discovery of Miri Field; Seria, discovered in 1929, confirmed the existence of a major hydrocarbon province.

The Baram delta is comprised of some 30–40,000 m of largely deltaic and delta-associated sediments. Principal development was subsequent to folding of Cretaceous and Eocene sediments during late Eocene time. The depo-center is limited to the southwest by a tectonic line (or "hinge") thought to be the offshore projection of the Tinjar Fault Trend of mainland Sarawak. The tectonic line separates the subsiding Baram sedimentary pile from the more stable Central Luconia Platform. Production is dominantly from regressive sands within the Upper Miocene and Pliocene (Said, 1980).

Stratigraphy

As elsewhere in Northeast Borneo, the stratigraphic succession of the offshore is based on the recognition of eight cycles of trangression-regression. In the Baram Delta, Cycles V (Middle to Upper Miocene) to VII (Upper Pliocene) are well developed (Fig. 14). Each of the cycles has a coastal plain environment to the south (i.e., sands, silts and clays) and grades in a northerly direction into holomarine neritic sediments (i.e., clays, silts and minor sands). The regressive sands of Cycles V and VI may be up to several thousand feet in thickness and constitute excellent reservoirs.

Structure

The most apparent class of structural features of the Baram Delta consists of a series of generally east-west growth faults which curve to the northwest, sub-parallel the Tinjar Fault Zone (projected offshore), but which to the south and southeast are directed northeast-southwest, sub-parallel the Mulu Shear Zone. The time of faulting is generally older to the south (i.e., lower Cycle V), becoming progressively younger to the north (i.e., Cycles VI, VII and VIII). Anticlinal axes across these faults, commonly in a northerly or northeasterly direction, and form the trends along which the principal field are located. Northward, away from the compressional folding near the coast, structural deformation is less pronounced and growth faults predominate.

Geothermal Gradient

Geothermal gradient is relatively low. A group of 13 wells, distributed through the Baram Delta area of Sarawak, and adjacent portions of Brunei, averages 2.58° C/100 m, with a range of from 1.82°–3.25° C/100 m, and for Balingian is 4.2° C/100 m.

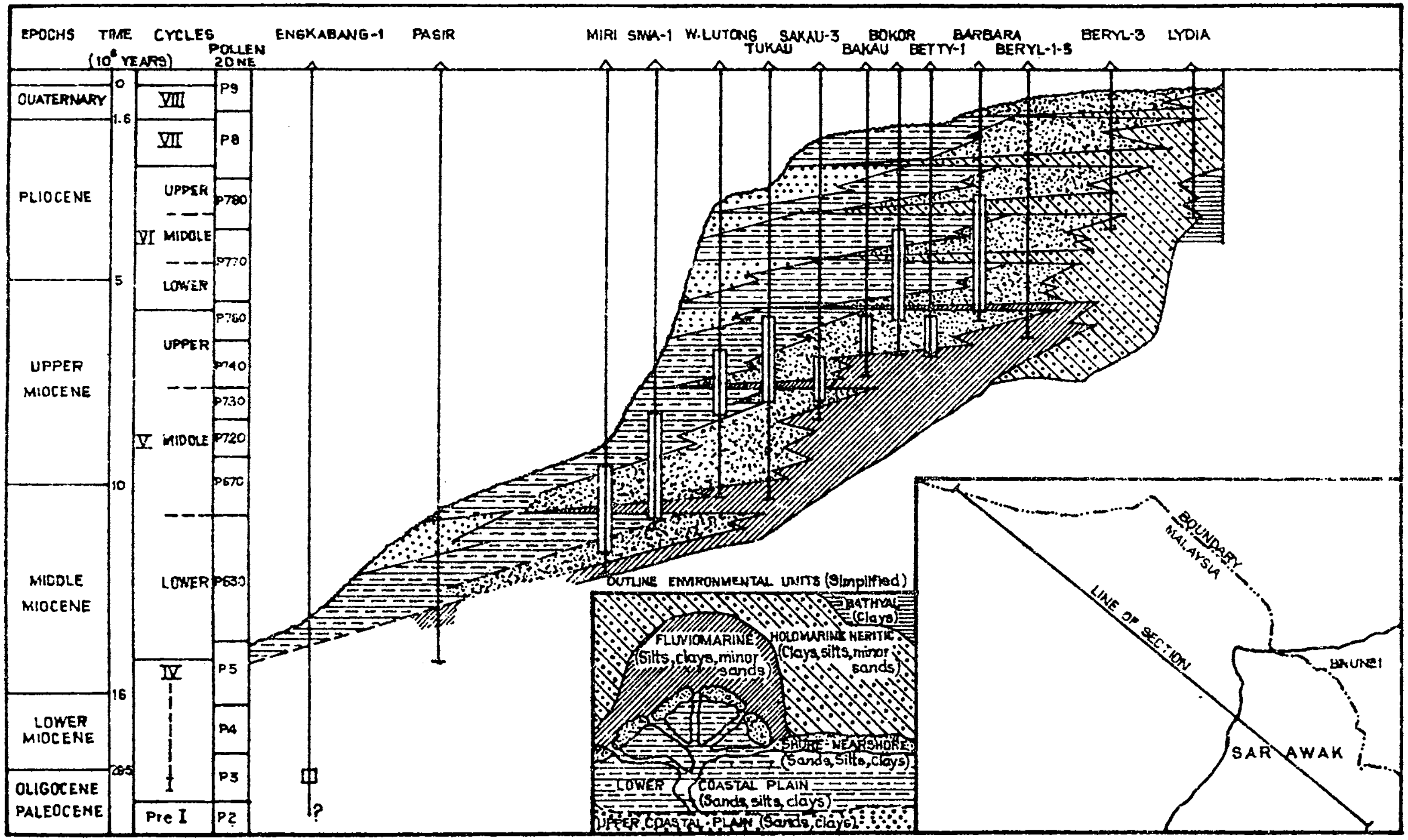

Fig. 14. Stratigraphic cross-section, Baram Delta, offshore northeastern Sarawak (after document CCOP (XIII)/18, Proc. 13th Session, CCOP).

Hydrocarbons

A number of fields have been found in the Baram Delta Province. These include Miri (onshore), Baram, West Lutong, Baronia, Bakau and Tukau in Sarawak, and Seria (onshore), Southwest Ampa and Fairley in Brunei.

Regressive sands, mostly associated with Cycles V and VI, form the principal reservoirs. In Baronia, the sand bodies range from 3.05–73.15 m in thickness, and have permeabilities to 1000 millidarcies, and porosities to 30%.

In some instances production is associated with normally compacted zones with inflated geopressures which overlie overpressured and undercompacted zones (Schaar, 1976). In such cases, it has been theorized that migration of hydrocarbons has taken place from the undercompacted zone upwards into the region of inflated geopressures.

Ultimate discovered reserves in the Baram Delta part of Sarawak are of the order of 600 million barrels. Baram, Baronia, and West Lutong fields all have cumulative productions which indicate that ultimate recoveries may reach 100 million barrels or more; Miri, now shut in, has an ultimate recovery of about 80 million barrels.

In Brunei, Seria Field had, by year-end 1979, attained a cumulative production of 882 million barrels, Southwest Ampa 409 million barrels and Champion 124 million barrels of oil. Total cumulative production had reached 1492 million barrels to mid-year 1979 and remaining reserves were estimated at 1800 million barrels at the beginning of 1980. To this, must be added an additional estimated 7.7 trillion cubic feet of gas reserves located mostly in Southwest Ampa.

Source beds appear to consist of those sediments deposited under coastal plain environments and to include land-plant derived material discharged in front of the deltas. Such sediments commonly grade up-dip into the regressive sand sequences where the contained hydrocarbons are trapped against sealing faults.

OTHER BRUNEI-SABAH

General

The extent of the Baram palaeodelta, to the northeast, has not been made public. Offshore Sabah, information is essentially restricted to the Tembungo Field which lies in water depths of 84.43 m about 80.46 km north and slightly west of Kota Kinabalu (formerly Jesselton) on the coast of Sabah. The field was discovered in 1971.

Stratigraphy

The section penetrated (Fig. 15) ranges in age from Recent to Middle Miocene. The Middle Miocene consists of shallow water clastics: dominantly inner littoral claystones, silts and poorly developed sandstones deposited under conditions of rapid sedimentation and burial. Abnormal pore pressures are present.

The overlying Upper Miocene/Lower Pliocene sediments constitute a major progradational wedge overlying a regional unconformity. The reservoir sands consist

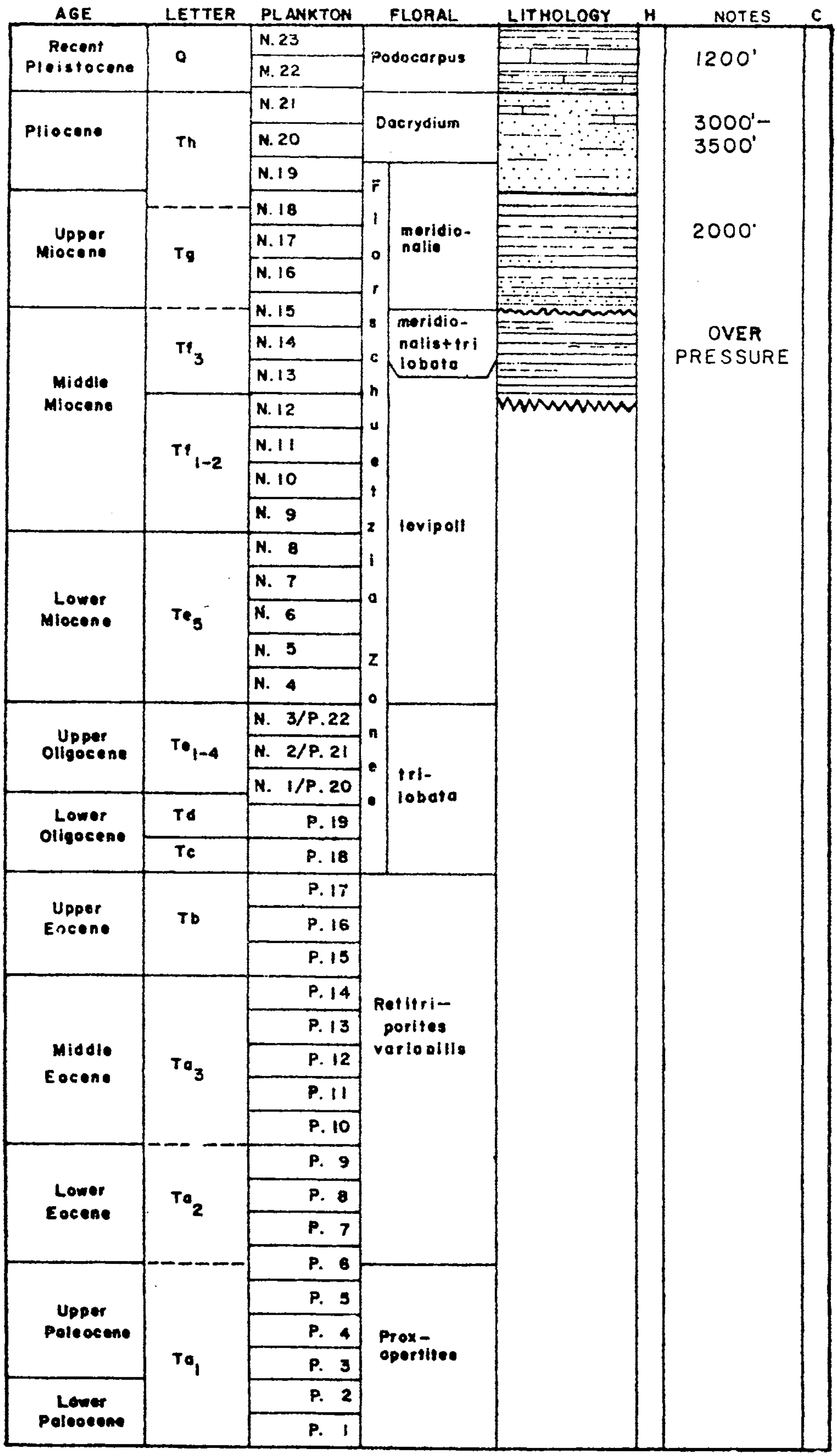

Fig. 15. Offshore Sabah, Malaysia, Tembungo field. Stratigraphic section 8 (after Whittle & Short, 1978).

of bathyal turbidite sandstones interbedded with claystones, and are overlain by slope-deposited claystone with minor siltsone interbeds. The turbidite reservoir sands are up to 30 m thick, generally massive, with permeabilities of the order of hundreds of millidarcies and porosities of 18–25%. It is believed that the turbidite sands are reworked, having been dumped over the shelf edge at the time of a major drop in sea-level at the end of Middle Miocene. A series of major turbidite fan complexes may extend along the base of the Sabah palaeocontinental slope.

Structure

The Tembungo feature appears to be a wrench-initiated, shale supported anticline approximately 17.70 km long and 8.05 km wide. There is over 600 m of structural relief on top of the Middle Miocene and a large number of tensional faults on the crest. The faults act as barriers to fluid migration and the field is divided into a number of fluid systems.

Hydrocarbons

Reserves at Tembungo are 15 million barrels of recoverable oil. Gas/Oil ratio is 600. The oil is 38° API and sulfur free.

Source beds are assumed to be the bathyal clays with which the turbidite sands are interbedded.

A number of discoveries have been made in offshore Sabah. Conditions of generation and accumulation may in part be similar to those described for Tembungo. Most discoveries are small and only Samarang, in addition to Tembungo, has been commercially developed. Samarang, to mid-1979, had a cumulative production of 80 million barrels and must have an estimated ultimate recovery of well over 100 million barrels.

NORTHWEST PALAWAN SHELF

General

One of the newest producing provinces in the vicinity of the South China Sea (Fig. 16) is that revealed by exploratory wells drilled a few kilometres west of the northern end of Palawan Island (Philippines) and further suggested by limited results from drilling in the Reed Bank area which lies some 200 km further west in waters of the South China Sea. Production from the Northwest Palawan wells is from reef limestones of Upper Oligocene-Miocene age, while strong shows of gas encountered in the Reed Banks (Sampaguita No. 1) are from sandstones of Eocene age.

Stratigraphy

The stratigraphy (and structure) of Palawan and adjacent islands, and that of the related offshore is, except for the Tertiary, poorly known and incompletely worked out.

Basement in northern Palawan consists of metamorphics (schists, phyllites, slates and quartzites) and is overlain to the north by cherts, siliceous clastics, arkosic wacke, and fusulina-bearing limestones of Permian age.

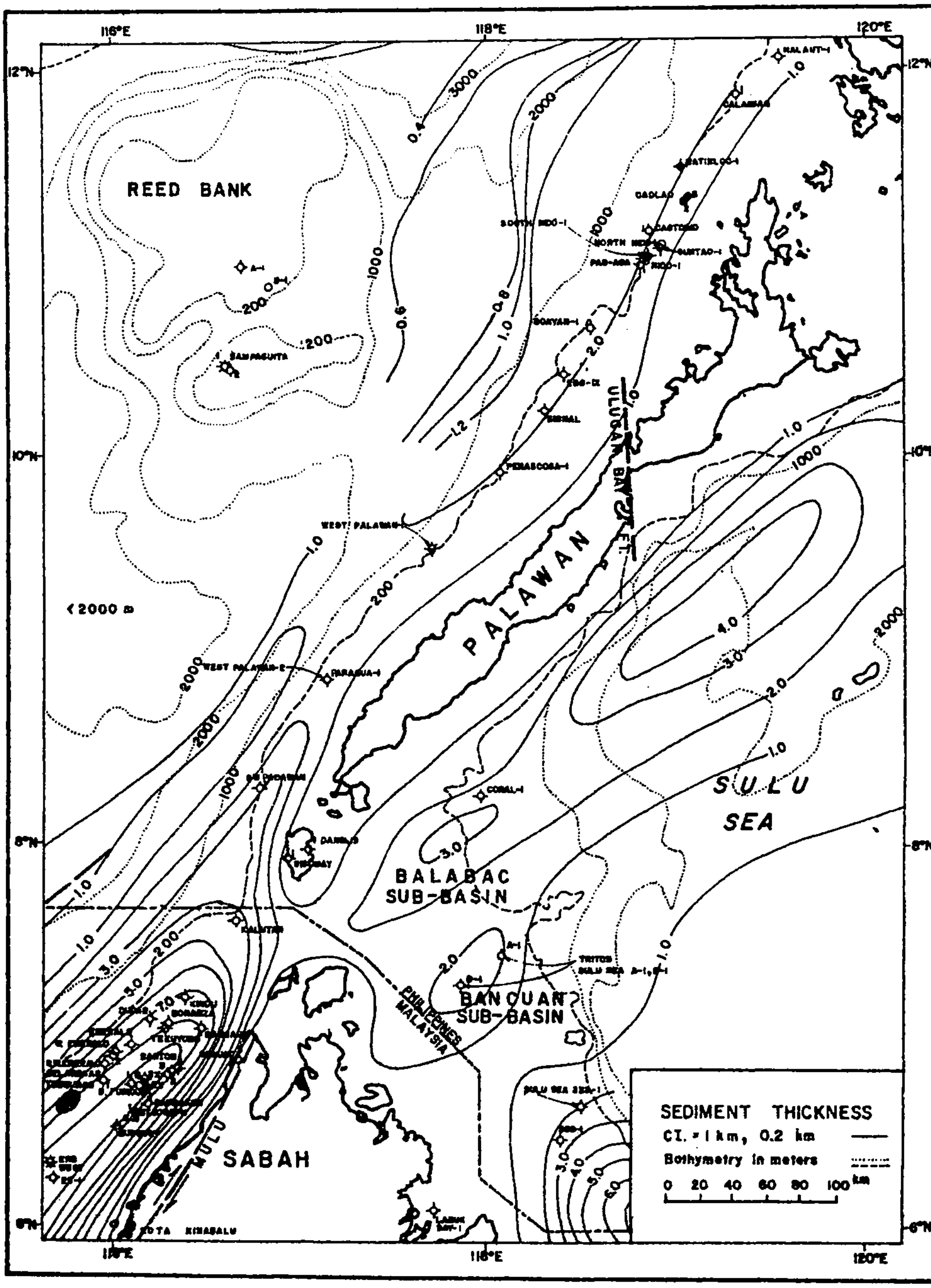

Fig. 16. Northwest Palawan—Reed Bank, sediment thickness (after Hamilton, 1979; Ludwig *et al.*, 1979).

On the nearby islands of the Calamian Group, the oldest known rocks consist of radiolarites of questionable Triassic age which may reach a thickness of 1000 m or more (Fontaine, 1979). Apparently overlying the radiolarites are several hundred meters of shale with interbedded sandstone which carries a flora which ranges in age from Triassic to Lower Cretaceous. Of uncertain stratigraphic relation are discontinuous outcrops of limestone which attain apparent thicknesses of several hundred metres or more and which locally bear a fauna indicating deposition under turbulent environmental conditions. Invertebrate fossils suggest a late Triassic or early Jurassic age. Sandstones and conglomerates locally crop out on northern Palawan and adjacent islands and may be of basal Tertiary age.

Stratigraphic columns for Northwest Palawan (i.e., the Nido area) and of the Reed Bank (Sampaguita No. 1) are shown in figures 17 and 18. The oldest known beds, of Lower Cretaceous age, consist of coal-bearing sandstones, with conglomerates, siltstones and shales deposited under marginal marine conditions. The thickness of Cretaceous and (?) Jurassic sediments may reach 4572–6096 m in the southeastern portion of the Reed Bank (Tamesis *et al.*, 1973).

The Lower Cretaceous, in Sampaguita-1, is unconformably overlain by a thin basal Palaeocene limestone, followed by Palaeocene clastics, apparently of shallow water origin. Bathyal shales characterize the Lower and Middle Eocene, and are overlain unconformably by near-shore marine sandstones, siltstones and mudstones of Upper Eocene-Oligocene age. The Upper Oligocene to Recent sediments consist of over 2000 m of white to buff limestone, apparently comprising a major long-lasting reef complex, comparable to that of the Nido area, and the Central Luconia Province, off Sarawak.

The situation in the Palawan Shelf area is not dissimilar although the principal time of reef development is somewhat earlier, i.e., Lower Oligocene and Upper Eocene carbonate platform development, followed by reef growth in Upper Oligocene-Lower Miocene times. Increased depth of water in Middle Miocene time led to smothering of the reef. Middle and Upper Miocene sediments are (generally) shallow water clastics, overlain unconformably by Pliocene to Recent shallow water clastics and carbonates.

The stratigraphy of both areas suggests a dominantly shelfal environment, interrupted by episodes of shallow water clastic deposition, and occasional periods of bathyal conditions.

Structure

Detailed consideration of the structure of the area is beyond the scope of this paper. Controlling features may be the Ulugan Bay (strikeslip?) fault and the postulated extension of the Northwest Borneo-Palwan Trench (between the Reed Bank and the Palawan Shelf).

Two major unconformities of regional extent are known from seismic surveys of the area, viz., between the Middle and Upper Miocene, and between the Upper Miocene and the Pliocene.

Also from seismic surveys, the area is known to contain "down-to-the-basin"

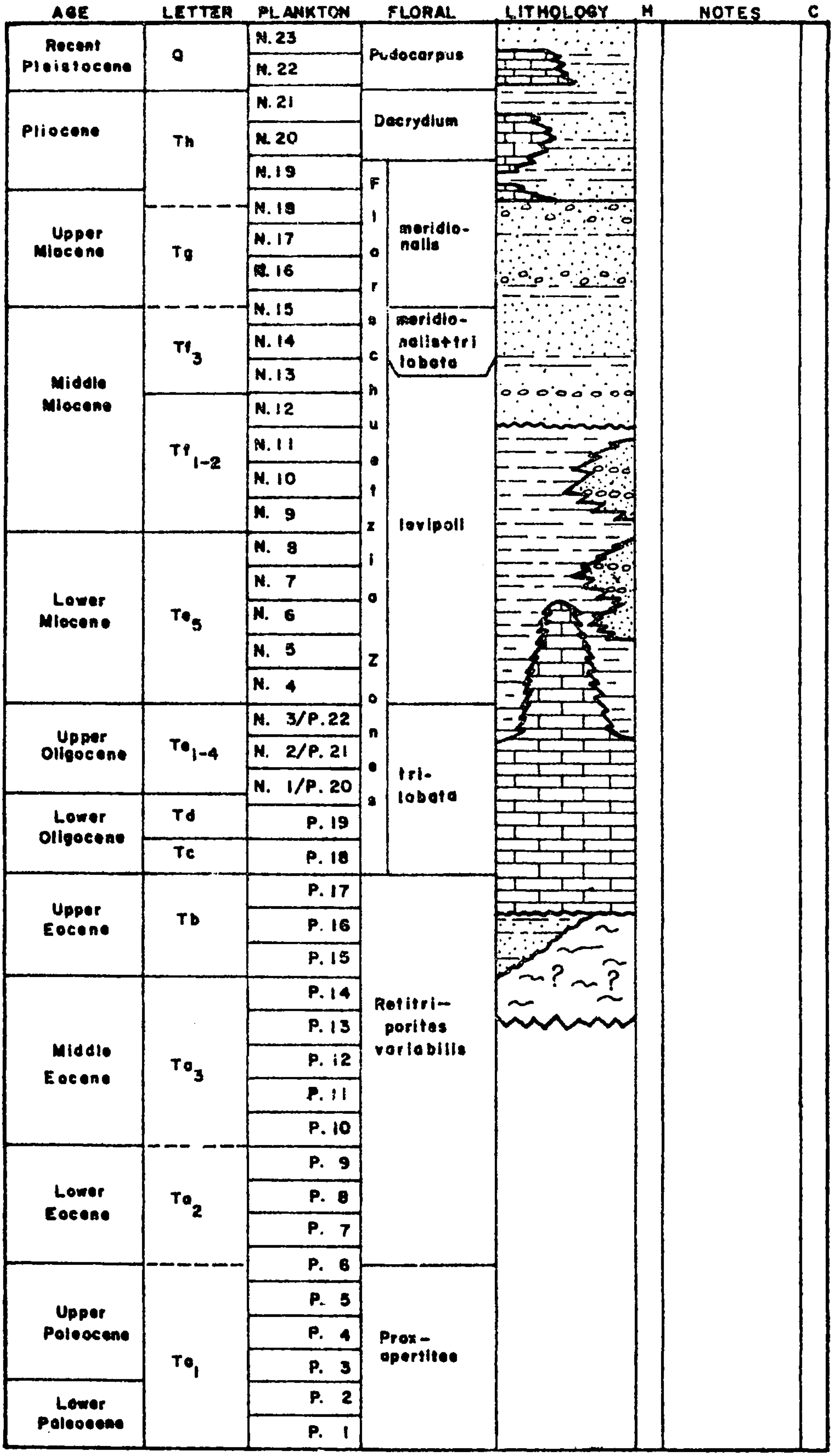

Fig. 17 Offshore Northwest Palawan, Philippines, Nido Field. Stratigraphic column 9 (after Hatley, 1980)

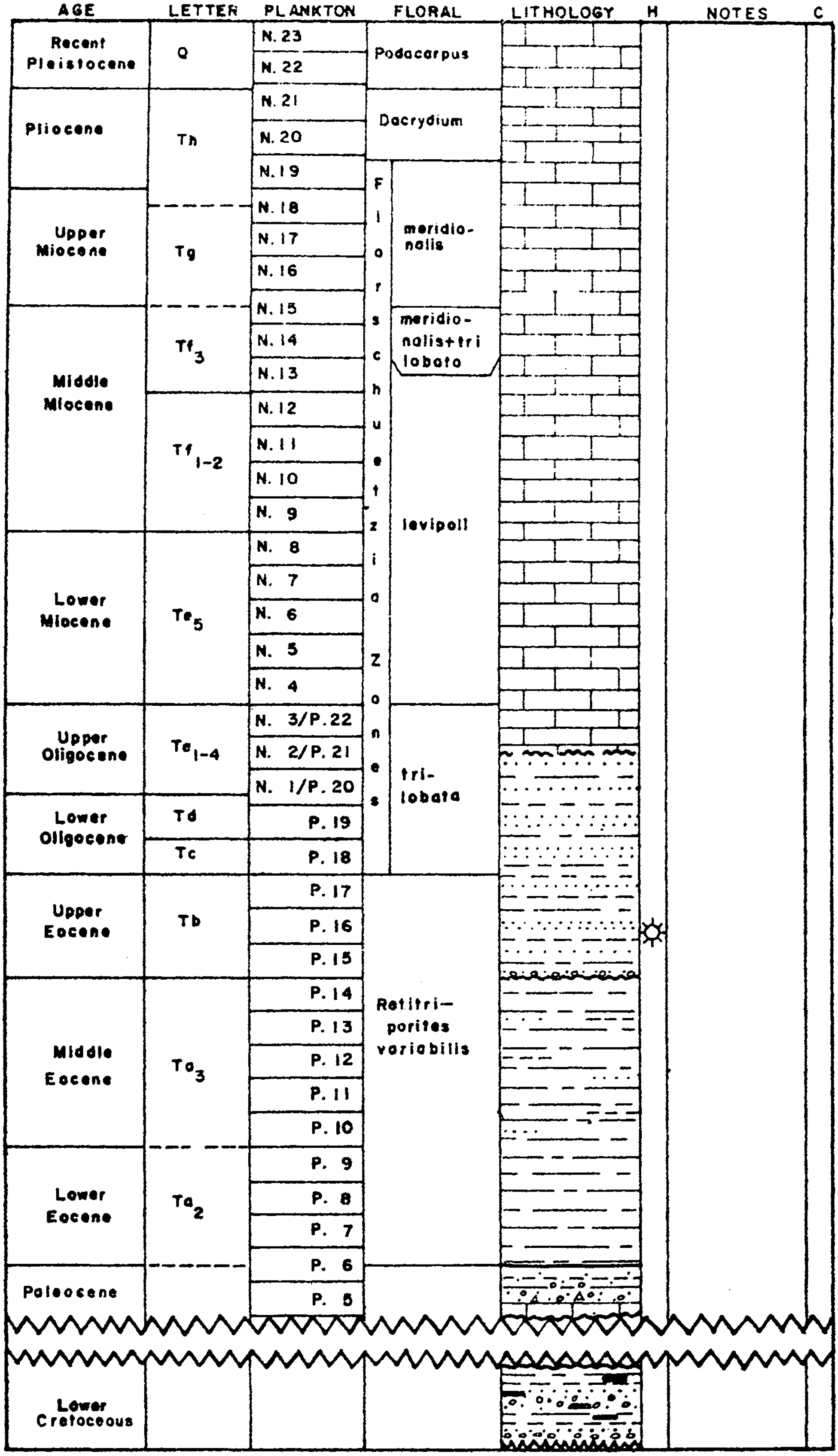

Fig. 18. Reed Bank, South China Sea, Sampaguita well. Stratigraphic section 10 (after Taylor & Hayes, 1979).

faults, horsts and grabens, and compressional folds bounded by steep faults. Most of the faulting is pre-Pliocene, but some faults are still active and are reflected in the sea-floor topography.

Hydrocarbon accumulations are associated with porosity within the reefs and reef-complexes. Locations of the reefs are in turn partly dependent on the presence of (generally) slowly subsiding fault blocks which now dip to the northeast. Within the Reed Bank area, Reed Bank, Southern Bank, Templer Bank and Brown Bank are described as being tilted fault blocks and located within a belt connecting the Reed Bank with the Nido-Cadlao reef complex.

Heat Flow

Geothermal gradients are in the normal range, i.e., between 2.28° C/100 m in Penascosa-1, and 4.12°C/100 m at Paragua-1. Geothermal gradient at Pagasa-1, within the Nido area, is 3.16°C/100 m.

Hydrocarbons

Several discoveries have been made in the area. Those at Nido and Matinloc were made by Cities Service; that at Cadlao by Amoco (Hatley, 1978).

The Nido reef complex consists of several small separate but related reef build-ups, distributed in a more or less linear fashion atop a carbonate platform which dips to the northwest (Hatley, 1980). The reefs began their development in late Oligocene times and terminated their growth in late early Miocene, at which time the carbonate platform was tilted seaward, submerged, and buried by sediments, the composition of which ranged from regressive clastics to bathyal shales.

Nido-1, spudded January 31, 1976, was drilled to 2751 m, encountered shows of oil and gas near the top of the carbonate section between 1820–1841 m. Crude oil was tested at a maximum rate of 1440 BOD but was considered to be non-commercial.

North Nido-1, 3 ½ miles away and updip drilled in late 1976, encountered oil shows in the comparable interval but was plugged and abandoned.

South Nido-1, 3 ½ miles southwest of Nido-1, was drilled in mid-1977, in a down-dip position from Nido-1, and encountered oil shows at 2075 m, a short distance into the carbonates. The well produced up to 7343 BOD on test.

Tests on West Nido-1, in early 1978, yielded 9540 BOD.

Nido oil has an average gravity of 27° API, is undersaturated with a gas-oil ratio of 7–10 scrubbed cubic feet/stock tank barrel, and with 1200–2000 PPM of hydrogen sulfide.

The Nido discoveries were followed up by the drilling in late 1978 of Matinloc-1, 54 km north of Nido, which yielded on drill stem test a stabilized flow rate of 7000 BOD and 2.14 MMCFGD.

Discoveries at Cadlao, in a position intermediate between Matinloc and Nido, appear to establish the presence of reef prospects throughout an area some 60 km in length. Cadlao-1 tested at 3630 BOD; Cadlao-2 was dry; and Cadlao-3 yielded 6600 BOD on test.

In the Reed Bank area, Sampaguita-1, was drilled to a total depth of 4124 m (13,533′) in August 1976. Tests of the interval 3000–3120 m yielded 6 MMCFGD from Eocene sands believed to have been deposited under deltaic conditions.

The Nido field went on production in early 1979 and reached a peak production of 42,000 barrels of oil per day. Problems with water incursion soon developed and the field was cut back (in May 1980) to 14,000 barrels/day. Estimated ultimate recovery is between 17–27 million barrels of oil and total production (to April 30, 1980) was 10.4 million barrels leaving remaining reserves at 7 to 17 million barrels. Reserves at Cadlao and Matinloc may be of a comparable order of magnitude.

It is assumed that the source for the Nido oil (as well probably for that of Cadlao and Matinloc) is contemporary shale and claystone deposited under bathyal to outer sublittoral conditions in the deeper water areas surrounding and downdip from the reef complex.

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