UNITED STATES DEPARTMENT OF THE INTERIOR

GEOLOGICAL SURVEY

Undiscovered petroleum resources of South Asia

By

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This report is preliminary and has not been reviewed for conformity with U.S. Geological Survey editorial standards and stratigraphic nomenclature.

[1] Santa Barbara, California

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ILLUSTRATIONS

ILLUSTRATIONS (continued)

UNDISCOVERED PETROLEUM RESOURCES OF SOUTH ASIA

By John Kingston

ABSTRACT

Undiscovered recoverable petroleum resources in the 15 major basins of South Asia are estimated. The principal geologic and historic factors requiring consideration in the assessment, especially for the play-analysis approach, are described and estimated, and, as required in this approach, are numerically quantified even though in many cases the information is tenuous. These estimates are expressed in ranges which are summarized in a play-analysis form for each play or basin (Appendix A).

With the play analyses as guides, final ranges of assessments were made by a consensus of 10 USGS geologists, and the results are shown as probability curves (Appendix B).

Aggregation of the mean probability for groups of basins within each country (Table 1, Appendix B) indicates that the undiscovered petroleum resources of Pakistan amount to 0.35 billion barrels of oil (BBO) and 34.37 trillion cubic feet (Tcf) of gas; India, 2.91 BBO and 27.83 Tcf of gas; Bangladesh, 0.09 BBO and 18.91 Tcf of gas; and Burma 1.43 BBO and 8.44 Tcf of gas.

INTRODUCTION

South Asia for this assessment is taken to be the areas of Pakistan, India, Bangladesh, and Burma. The sedimentary basins considered have an area of some one million square miles and a volume of 3.4 million cubic miles (fig. 1). The number of major basins is 15, of which five produce oil and gas and two produce essentially gas. Exploration of the remaining eight unproductive basins has reached the drilling stage. An additional 15 minor sedimentary basins are of such low petroleum potential they are not considered in this study.

Exploration to date has apparently established original reserves of approximately 6 billion barrels of oil (BBO) and 50 trillion cubic feet (Tcf) of gas. "Discoveries" (or at least appreciable shows) have been made in 10 of the 15 basins being considered.

The purpose of this study is to provide a basis for a quantitative assessment of the undiscovered recoverable hydrocarbon of the region. To this end, every appropriate estimate of a geological or historical factor is quantified numerically even though it may be only a guess; the rationale for the numerical estimate is explained. Later information may cause the revision of the number, which then can be plugged back individually into the system, effecting a corresponding change in the overall resource estimate.

Although background geology is presented briefly as necessary, the focus of this study is directly on the significant geologic factors concerning petroleum occurrence. The study is structured to support what is essentially a play-analysis approach to the assessment of undiscovered petroleum resources.

The 15 petroleum basins of South Asia, with the exception of the three oil producing basins, are in an immature to early-mature stage of exploration. The resulting knowledge of the geologic factors affecting the hydrocarbon prospects of the area are published in varying degrees of completeness, but with enough detail for a play-analysis approach rather than relying solely on gross volumetric-yield analogies to tectonically similar basins.

There are eight generally recognized assessment methods for undiscovered petroleum: 1. geologic analogy, 2. Delphi, 3. areal yield, 4. volumetric yield, 5. geochemical balance, 6. field number and size, 7. summation of prospects, and 8. extrapolation of discovery rate (White and Gehman, 1979). Four of these methods are commonly used in this assessment: 1. geologic analogy, 2. extrapolation of discovery rate, 3. volumetric yield (considering individual geologic factors only), and 4. modified Delphi (our final step after play analysis). Gross areal and volumetric yield methods are not herein used. Geochemical balance, field number and size, and summation of prospect methods usually require more data than available for South Asia and likewise are not used.

The play-analysis method used here is a modified volumetric yield method with each of the appropriate geologic factors considered separately (Roadifer, 1979). The analysis is built up of seven principal estimates, i.e., acres of

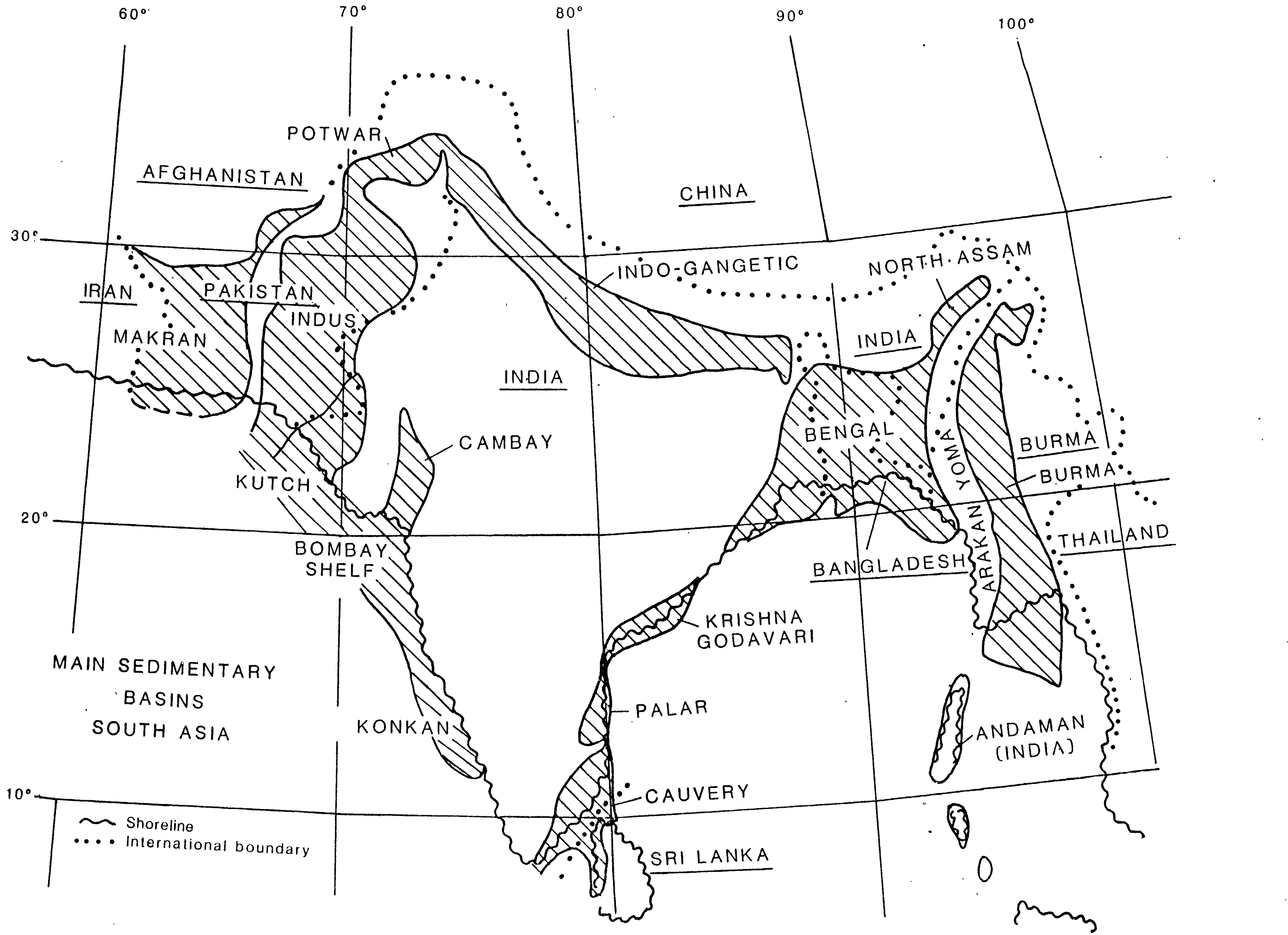


Figure 1.--MAIN SEDIMENTARY BASINS, SOUTH ASIA

untested trap area, percent of untested trap area which is presumed to be productive, feet of average effective pay, percent of oil (versus gas), primary oil recovery in barrels per acre-foot (BBLS/AF) (a function of reservoir characteristics), gas recovery in thousands of cubic feet per acre-foot (MCF/AF), and natural gas liquids (NGL) recovery in barrels per million cubic feet of gas (BBLS/MMCF). The estimates are made in ranges of values to indicate varying degrees of certainty. These ranges are summarized in the play-analysis forms shown in Appendix A. For brevity's sake, only the most likely case, or mode, of each range is used in the text discussion of the rationale for the various estimates.

The most difficult of the estimates is the first one, that of trap area, since detailed seismic maps are rarely available. One usually must depend on extrapolation of available mapped portions of the play area, the estimated number of future discoveries of average-sized fields, or structural analogs to tectonically similar plays or basins. In some play analyses, in essence, we skip over the first estimate and begin with the second one, e.i. "trap area which is productive" (i.e. potential field area).

As a preliminary guide, the most likely, or mode, probabilities of the estimated factors have been multiplied together on the play-analysis forms in Appendix A to give a general overall estimate of the undiscovered recoverable resources of oil, gas, and NGL.

The reader must be aware that only if all the factors are equally credibly known can they rationally be aggregated to obtain a realistic overall estimate of resources. Usually this is not the case, and the amount of resources actually is controlled by the weakest or limiting factor or factors. For example, in the Indo-Gangetic Basin of India, the untested traps are so large and numerous and the reservoirs are so thick that, when multiplied by the minute probability of the traps being productive, the product could indicate a reasonable hydrocarbon potential. Actually, the large amount of trap and reservoir in this case is superfluous, and the petroleum potential is only negligible, being limited by the lack of source rock. To emphasize this point, each of the play's description sets forth the overriding limiting factor, or factors, as a check on the estimates.

The basins of South Asia often have more than one play, but lack of more precise and detailed data usually requires the lumping of the plays within the basin. In several basins, however, the plays were too significantly diverse to be lumped and are handled separately, e.g., the plays of Bombay, Kutch, Indus, Krishna-Godavari, and Bengal Basins. Future studies of South Asia will attempt to break out more of the plays for separate handling.

This study is part of The World Energy Resources Program (TWERP) of the U.S. Geological Survey (USGS) whose objective is to assess the undiscovered petroleum resources of the world. The petroleum geology as expressed in this report, including the play analyses, was presented to a board of 10 USGS geologists, who, after an in-depth discussion and deliberation from the perspective of individual experiences, arrived at a subjective consensus as to the amount of recoverable undiscovered petroleum in each basin or convenient group of basins. Because the unknown cannot be recorded with precision, a curve of probabilities better conveys the true nature of the estimate rather than a single average value. Conditional upon recoverable resources being present, initial assessments are made for each of the assessed provinces as follows:

(1) A low resource estimate corresponding to a 95-percent probability of more than that amount; this estimate is the 95th fractile (F_{95}).

(2) A high resource estimate corresponding to a 5-percent probability of more than that amount; this estimate is the 5th fractile (F_5).

(3) A modal ("most likely") estimate of the quantity of resource associated with the greatest likelihood of occurrence.

The results of the final estimates are averaged, and those numbers are computer processed by using probabilistic methodology (Crovelli, 1981) to show graphically the resource values associated with a full range of probabilities and to determine the mean, as well as other statistical parameters. (See Appendix B.)

The mean probability is an important objective of this study. It not only embodies with due emphasis the most likely quantities of the probability range, but, significantly, includes the appreciably higher but less likely quantities; that is, it takes into account the possibility of substantial "sleepers," e.g., subtle traps and unknown plays.

REGIONAL GEOLOGY

Geologic History

The basins of South Asia are closely related tectonically to two events: (1) the Mesozoic break-up of Gondwana, and (2) the continental blocks' northward movement on the Indian Plate and eventual docking at the Tertiary subduction zone on the south edge of the Asian continental mass. The principal blocks concerned are the Indian Continental Block, the Afghan Continental Block, the Sunda Continental Block (Burma, Malaysia, Indonesia, Thailand), and the Asian Continental Block (fig. 2).

The regional events pertinent to the formation of the hydrocarbon provinces are as follows:

1. Late Jurassic-Early Cretaceous. The pull-apart of India from Australia-Antartica created a rifted continental-margin along the east coast of peninsular India and the foreland of the Bengal and Assam Basins, which resulted in rifted continental margin basin formation with typical horst and graben structure.

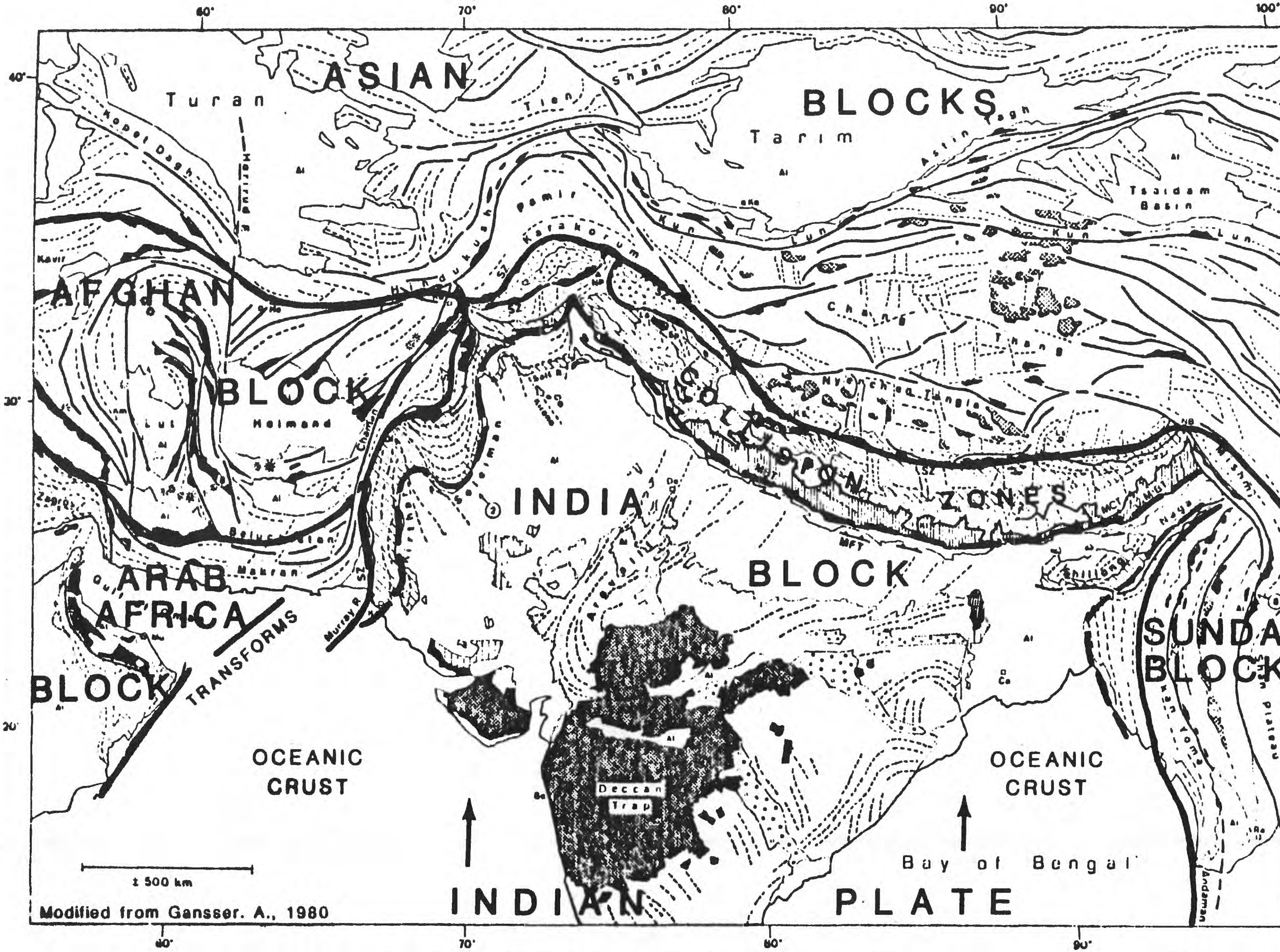
2. Mid-Cretaceous. The pull-apart of India from Africa also created a rifted continental margin along the west coast of peninsular India and the foreland of the Indus Basin, which resulted in continental margin basin formation with typical horst and graben structure.

3. End of Paleocene. The northward moving Indian Continental Block contacted an Asian fore-arc island or, more likely, the previously-arrived Afghan Continental Block. The Indian Plate began oblique subduction under the Afghan and, somewhat later, the Sunda Blocks.

4. Early Eocene. The Indian Continental Block achieved a relatively stationary and high position, especially in the west (Indus Basin) where it was wedged against the Afghan Continental Block. Widespread carbonate rocks developed over the shallow margins of the Indian Continental Block (main Bombay-Shelf productive reservoirs), with flysch being deposited over the oceanic continental crust areas (mainly Bengal Basin vicinity) and deltas being deposited in grabens of the western pull-apart margins (main clastic reservoirs of west India).

5. Oligocene. Collisions and subduction of the northward-moving Indian Block were renewed with the Afghan Block, and possible first contact was made with the Asian continental mass. Erosion took place in the vicinity of the Indus Basin, and deposition of deltas occurred in Assam, and probably Bengal, (main clastic oil reservoir of east India).

6. Miocene and younger. The Indian Plate has continued to move northward, directly subducting beneath the Himalayas and being obliquely subducted under the Afghan and Sunda Continental Blocks. The Kirthar Range ("Axial Ridge") of Pakistan (range between Indus and Makran Basins) and the Arakan Yoma (range between Bengal and Burma Basins) rose and shed sediments; most sediments (flysch and deltaic facies), however, derived from Asian continental mass. Fold-structure formation occurs along the Himalayas, Kirthar Range, and Arakan Yoma.



MAIN SOUTH ASIA CONTINENTAL BLOCKS

FIGURE 2

Regional Trends

This plate action results in a number of basinal and structural trends listed below with associated basins (fig. 1):

1. West Indian Rifted Continental Margin - Konkan, Bombay, Cambay, Kutch Basins, and foreland of the Indus Basin

2. East Indian Rifted Continental Margin - Cauvery, Palar, Krishna-Godavari Basins, and foreland of the Bengal and Assam Basins

3. West Indian Collision Belt - Indus Foldbelt (Kirthar Range, between Indus and Makran Basins)

4. East Indian Collision (accretionary) Belt - Bengal Foldbelt, Assam Thrust Belt (Arakan Yoma, between Bengal and Burma Basins)

5. North India Trench - Indo-Gangetic Basin and elements of Potwar and Assam Basins.

6. Burma largely Fore-arc Trend - Burma and Andaman Basins

7. Makran Fore-arc Basin - largely an accretionary wedge

Regional Thermal Gradient

The area is generally cool, the average thermal gradient ranging from 1 to 2° F per 100 ft; the area has little of the high-heat trends such as characterize back-arc basins. An exception is the Bombay-Cambay region where the heat gradient reaches 3°+ F per 100 ft; coincidentally, this region contains most of the oil production of South Asia.

INDIVIDUAL BASIN ASSESSMENTS

Bombay Shelf

Introduction

The Bombay Shelf and Cambay Graben are part of the West Indian Rifted Continental Margin Trend. They are discussed first, because these more thoroughly explored basins serve as analogs for the lesser known basins to be discussed later (fig. 1).

Location and size of area

The Bombay Shelf is on the central part of the eastern continental shelf of peninsular India and is centered around Bombay. As here defined, it extends northward from the Panjim (Goa) High (16° N.) to the Saurashtra Arch (about 22° N), including most of the so-called "Saurashtra Basin." It has an area of approximately 56,000 mi^2 and a sedimentary volume of 140,000 mi^3 (figs. 1 and 3).

Exploration and production history

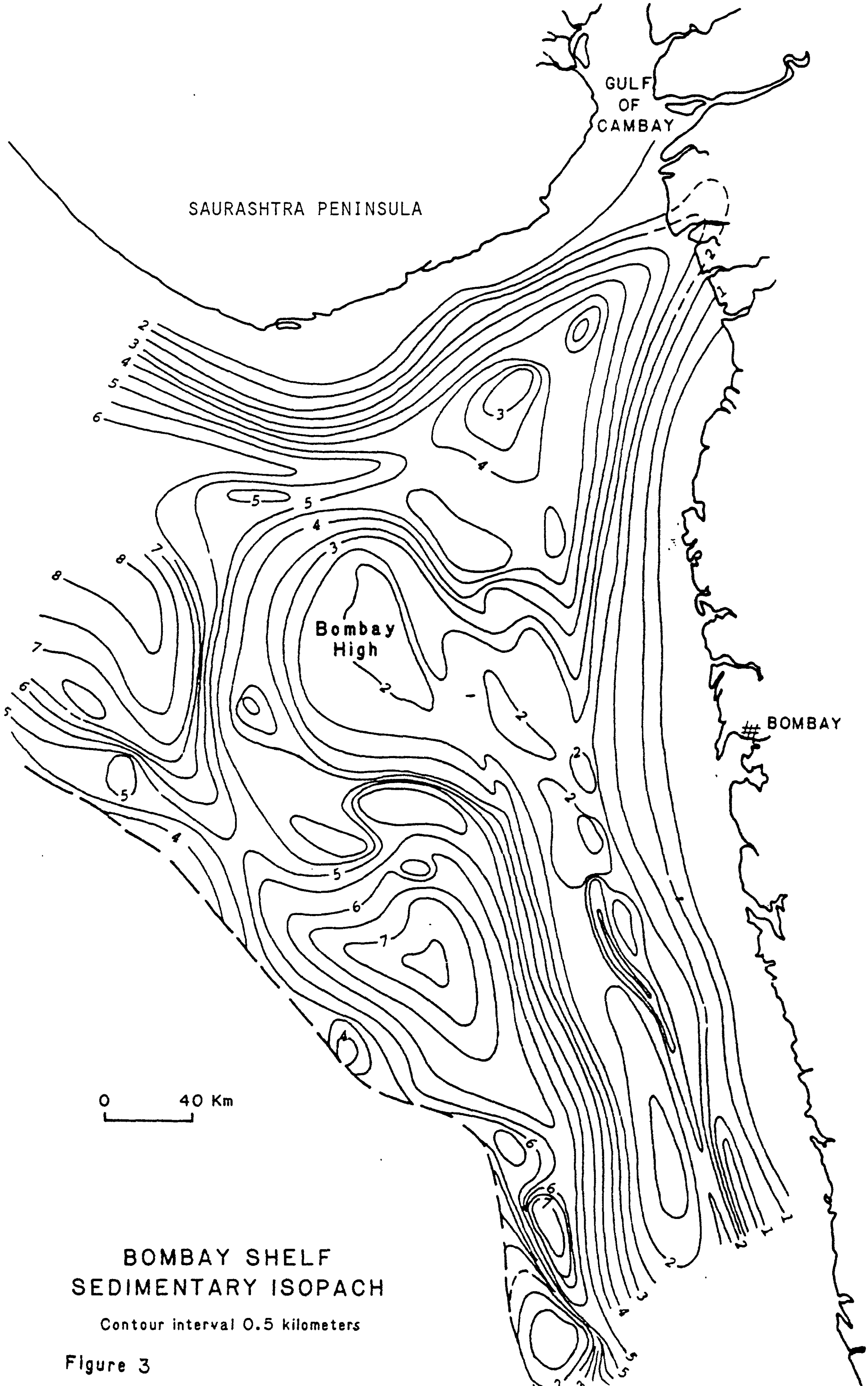
Exploration of the Bombay Shelf led from the successful exploration of the Cambay Graben, commencing in 1961 and 1962 with marine seismic surveys. In 1971 the Bombay High was first mapped, and in 1974 the first wildcat was the Bombay High discovery. As in other basins of South Asia, a single field, the Bombay High, has a major part of the basin's reserves. Prominent smaller oil and gas fields are Panna, Bassein, Heera, Ratna, R-9, R-7, South Tapti, Mid Tapti, Dahanu, (fig. 4). Evidently the offshore seismic data are of good quality, and the exploration of the Indian Oil and Natural Gas Commission (ONGC) is vigorous; so, even though only a decade has elapsed since the first discovery, we deem the exploration campaign to be in an early mature stage, possibly 75 percent complete. During this period several plays were established, the principal one being drapes over Cretaceous-Paleogene horst/graben features. Other very subsidiary plays are drag folds, rollovers associated with growth faults, carbonate buildups, and pinchouts. Exploration to date has resulted in some 22 discoveries or substantial shows. The wildcat success ratio is indicated to be about 30 percent (Sahay, 1984), perhaps a reflection of the good quality of the seismic data.

From various sources, Indian Petroleum and Petrochemicals Statistics (1981-82) and the Center for Monitoring Indian Economy (1984), we estimate original recoverable reserves of 2.70 billion barrels of oil (BBO) and 13.35 trillion cubic feet (Tcf) of gas for the Bombay Shelf (a total of 5 BBOE). Mitra, P. and others (1983) indicate slightly higher quantities, i.e., 18.83 barrels of oil equivalent (BBOE) in place (or about 6 BBOE recoverable).

Structure

General tectonics

The structure of the Bombay Shelf is that of a typical rifted continental margin formed when India pulled apart from Africa during the Cretaceous. The north-northwest-trending horst and graben structure is indicated on the depth



BOMBAY SHELF
SEDIMENTARY ISOPACH

Contour interval 0.5 kilometers

Figure 3

After Mitra, P., et al., 1983

to effective basement map (fig. 3) and cross-sections A-A' and B-B' (figs. 5 and 6). This north-northwest-trending rift-structure is transected, in the northern part of the shelf, by east-northeast trending sinistral wrench faults such as the Narmanda Fault and parallel faults, which cause the alignment of Ankleswar Field, the Kosamba and Olpad Fields and, likely, the Saurashtra, Diu, and Dahanu closures (fig. 4). Listric faults and associated roll-over anticlines are reported along the shelf edge (Mitra, P. and others, 1983).

Untested trap area

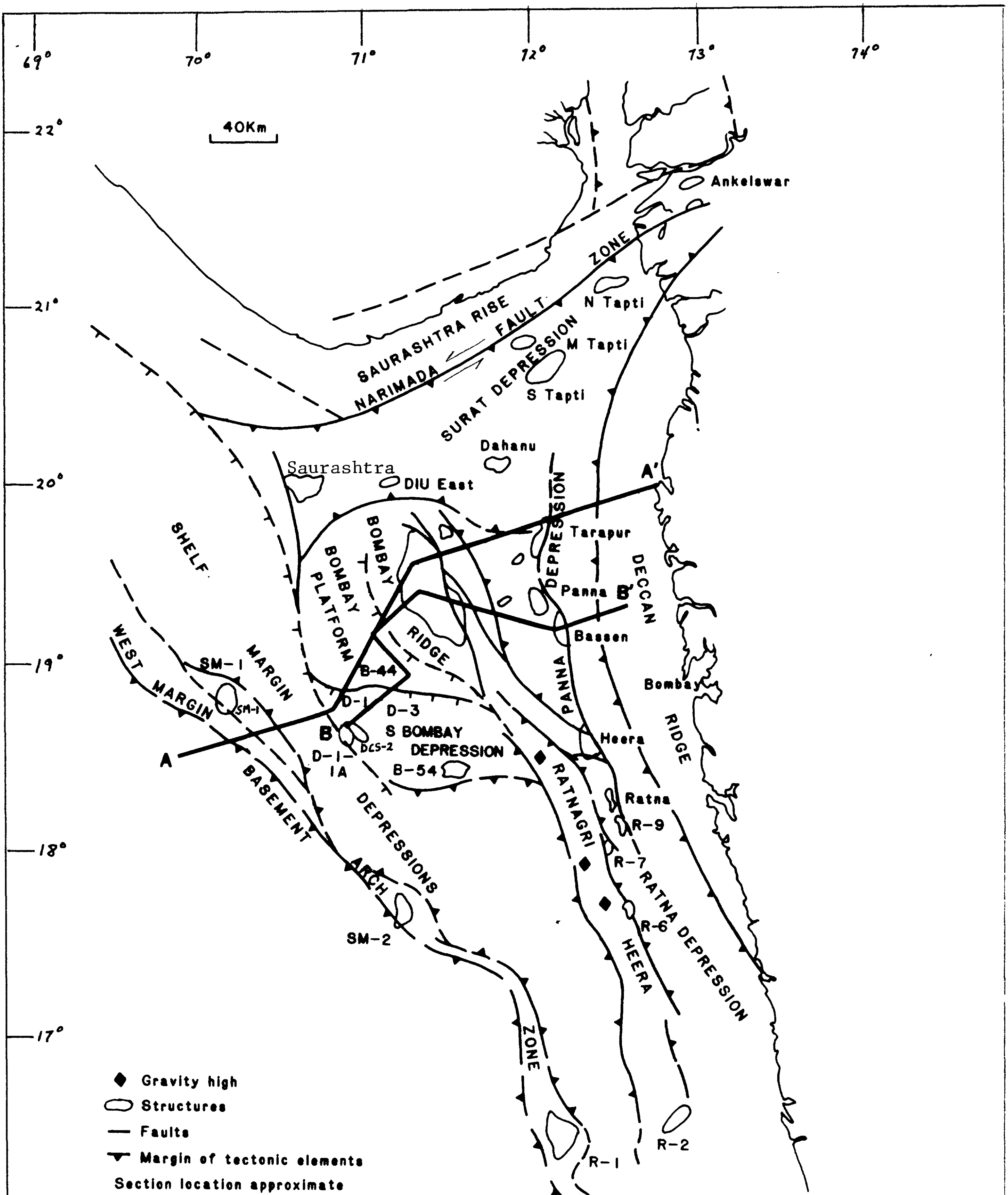
The principal play is for petroleum accumulations trapped in carbonate and sandstone reservoirs in drapes or fault-closures associated with horst-graben tectonics (but probably including some indistinguishable traps of drag-fold origin in the Narmanda Fault vicinity). The area of play is limited to the so-called platform area (as opposed to the shelf marginal areas) of some 26,000,000 acres (figs. 4 and 5). Excluding the unique giant, the Bombay High, 970,000 acres of trap have been mapped as indicated by the prospect maps of Sahay (1984) and Berger and others (1983). At this early-mature stage of the exploration, a decade after the first discovery, we estimate that 70 percent of the ultimately discoverable trap area (exclusive of the Bombay High) has been mapped, indicating that 1,390,000 acres of trap (5 percent of the play area) will eventually be tested. Assuming an area approximately equivalent to the already mapped trap-area has been tested, 420,000 acres of trap remain to be tested in this play.

There are additional secondary plays to the drape folds, which apparently are as yet unproductive although they have been subject to some exploration. Mitra and others (1983) say there are some 80 leads for rollover and other growth-fault associated closures in the shelf margin area of approximately 10,000,000 acres (figs. 4 and 5). The prospect maps of Sahay (1984) and Berger and others (1983) indicate that about 300,000 acres of trap in 20 separate structures have apparently been drilled. Assuming these 20, presumably larger structures, tested half the trap area, there would be 300,000 acres of trap in 60 closures remaining to be tested.

Another secondary play is for accumulations in carbonate buildups and mud mounds. Mitra and others (1983) indicate more than 200 buildups ranging in size from 185 acres to 9,400 acres. We estimate from their map that there are some 250,000 acres of buildup and mud-mound trap areas, little of which has been tested.

Other possible plays may be Miocene sand pinchouts in the northern deltaic area and traps in Mesozoic sediments beneath the Deccan traps (assumed as basement at this stage of the exploration). These latter plays may have some potential but are speculative and of unknown quantity and are not treated separately in this assessment.

To summarize the untested trap area, we estimate 420,000 acres remain of the primary play. Additionally in rather unknown and less prospective plays, there are 300,000 acres of rollover traps associated with shelf-edge listric faulting and 250,000 acres of carbonate buildups and mud mounds.



after P Mitra et al.,1983

BOMBAY OFFSHORE-BASIN-TECTONIC ELEMENT MAP

(Showing principal structures)

FIGURE 4

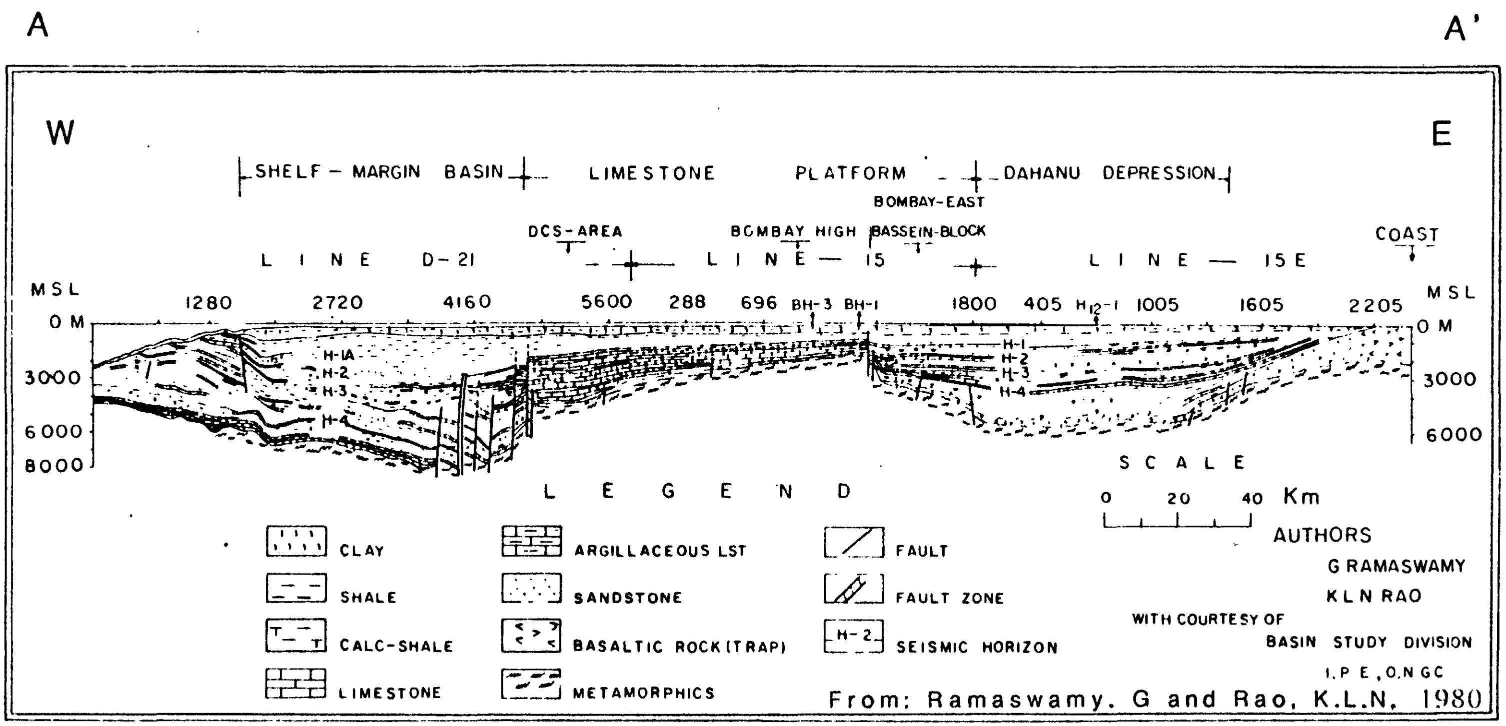
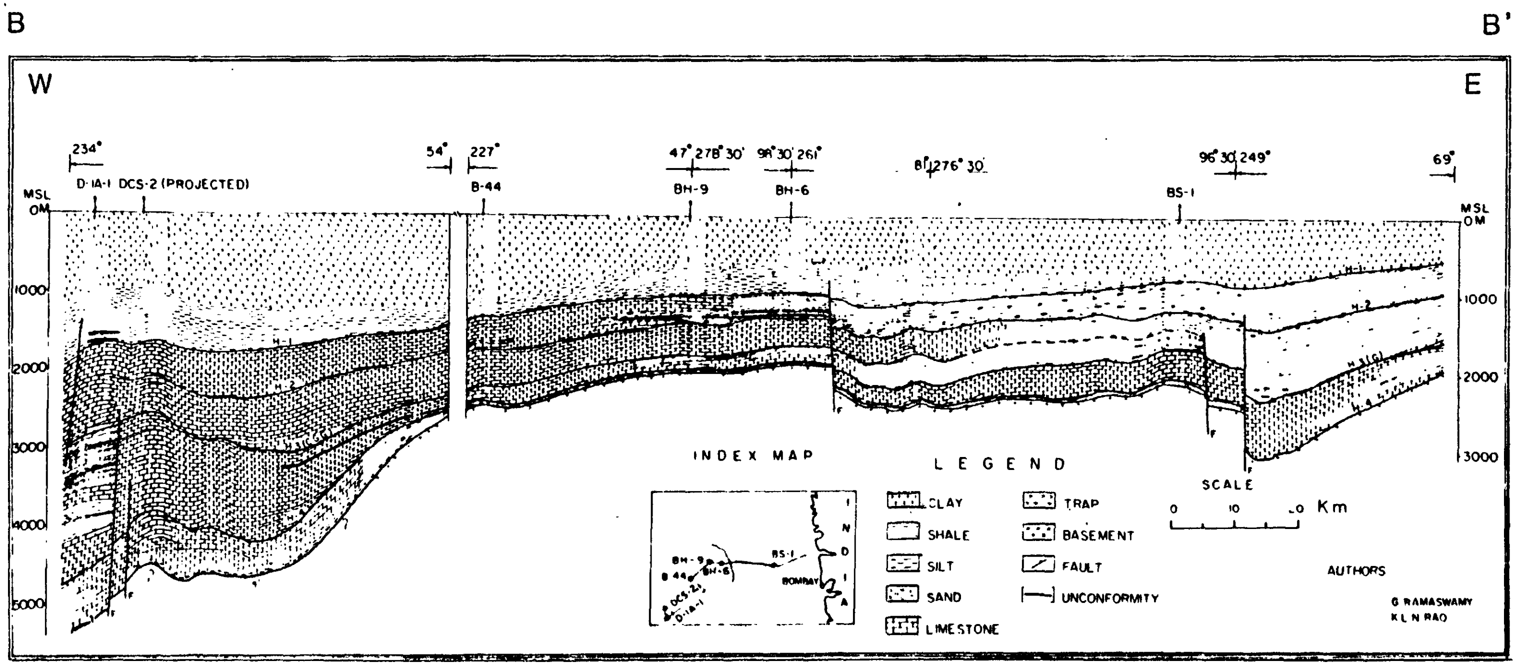


Figure 5.--Bombay offshore basin: Seismogeological cross section (see figure 3 for location).



From Ramaswamy, G. and Rao, K.L.N., 1980

Figure 6.--Bombay offshore basin: Geological section across the basin (see figure 3 for location).

Percentage trap area productive

On the basis of 50 to 60 percent fill in the Bombay High (Rao and Talukdar, 1980), and nearly 100 percent on the smaller Bassein trend fields (fig. 4), an average of 60 percent fill is assumed. This, together with the reported 30 percent success ratio, indicates a petroleum productive area of about 18 percent of the untested trap area in the principal drape play.

The untested traps of the two main secondary plays, the growth-fault rollovers and the carbonate buildups, would be less productive. The position of the roll-over play adjacent to the presumably organically-poor outer margin basin indicates less fill. Furthermore, none of the tests to date apparently have been successful. We estimate that the percentage of trap area productive is half that of the drape play or 9 percent. Similar factors affect the productivity of the carbonate traps; the buildups, occurring at the top of the carbonate section, are surrounded by younger and presumably organically-poorer shales, and there is no reported drilling success. The percentage of trap area productive for this play is also judged to be 9 percent.

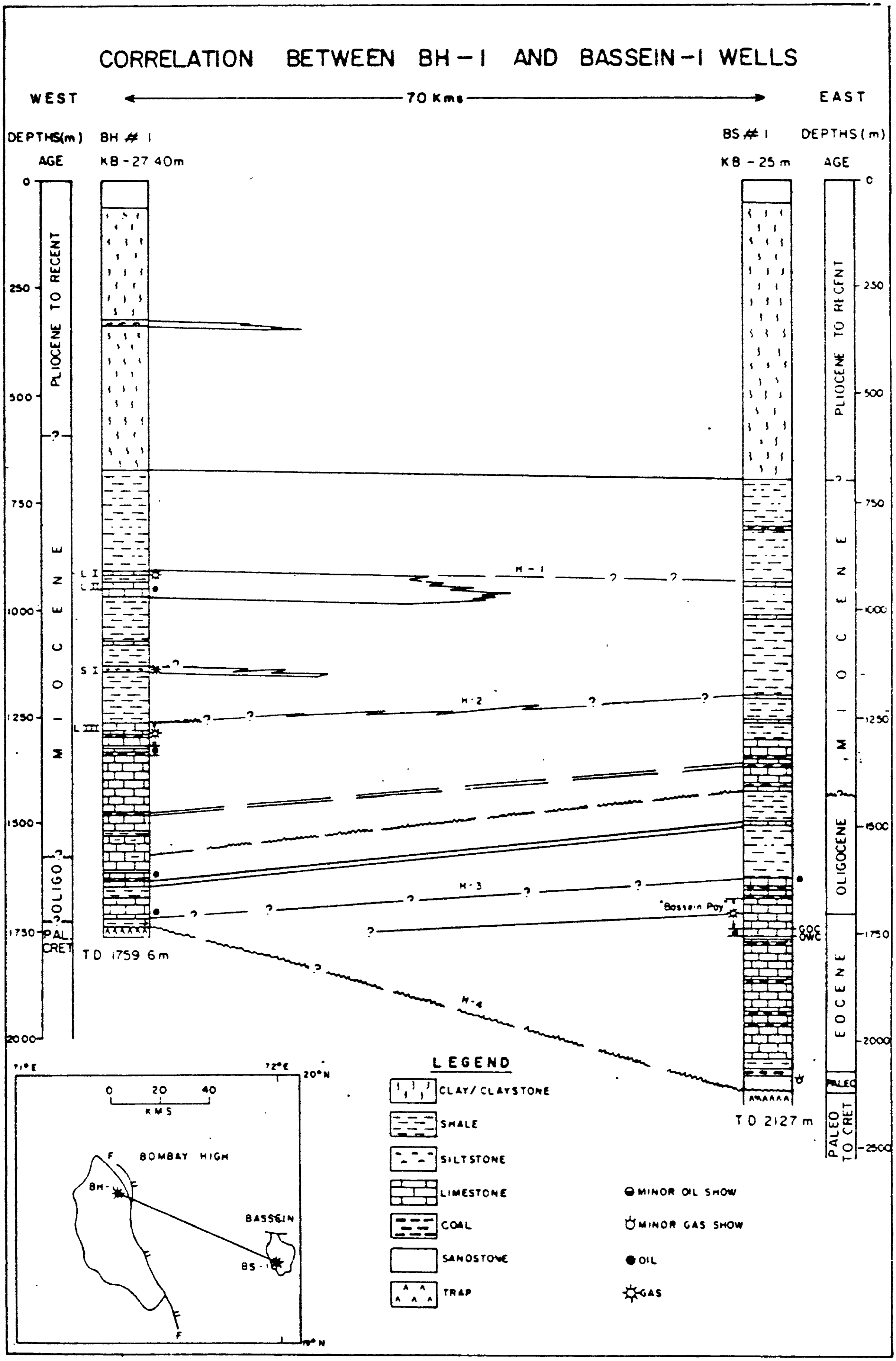
Stratigraphy

General stratigraphy

The general stratigraphy is displayed in figure 7 showing the correlation between the Bombay High and Bassein Field. The sedimentary section is limited to the Tertiary. Except for a basal sand section, the lower part of the stratigraphic column is dominantly carbonates giving way to clastics, largely shales, upward in the section but at laterally varying levels; e.g., at Bassein the top of the carbonates is in the late Eocene and on the Bombay High in early Miocene. The lateral distribution of carbonates versus clastics, as shown on section A-A' and B-B' (figs. 5 and 6), is strongly localized by the horst and graben-influenced bottom-topography. Though the clastics are largely shale, appreciable thicknesses of delta sands occur in the northern part of the shelf adjoining the Cambay Basin.

Reservoirs

The producing reservoirs are principally carbonates. As indicated in figure 7, the significant reservoirs are concentrated near the top of the carbonate section. On the Bombay High, the producing pay, the L III zone, has an effective thickness of 56 ft. A second pay, the L II zone, is of unknown thickness. Since there is no apparent attempt to produce it, we estimate it to be quite thin, perhaps 20 ft, giving an overall thickness of 76 ft for the Bombay High reservoirs. The L III zone is made up of a number of thin, individual reservoirs, each with its own oil-water and oil-gas contacts, so that a large number of precisely-targeted, deviated holes are required, each limited in production. This, combined with the general shallowness of the field of around 5,500 ft, requires a large number of small production platforms around the structure. It appears that the thinness of reservoirs may be the overriding factor limiting the hydrocarbon resources of the basin. Other thinner reservoir zones are present but are evidently uneconomical to produce



From: Sahay, B. 1978

at this time (fig. 7). The main reservoirs are micritic carbonates with about 25 percent of the porosity of secondary origin; the overall average porosity appears to be about 20 percent. Elsewhere in the play area the carbonate reservoirs appear to be less developed. At Bassein there are 56 ft of net pay.

There are also sand reservoirs in this drape structure play. In a few wells Paleocene-Eocene basal sands are oil bearing, namely, at the Bombay High, east of the Bombay High, B-57, and parts of R 12 and R 13 structures of the Ratna area. These clastic sequences reach thicknesses of 2,000 ft in the Ratna area, but the amount of effective reservoir thickness appears to be minor, discontinuous, and of limited area. Also Miocene deltaic sands in the northern part of the shelf adjoining the Cambay Basin are oil bearing. These sands appear to be discontinuous and are generally developed in areas where the carbonate reservoirs are less developed.

We assume that the drape play extends over both the areas of carbonate and sand development and that the reservoirs of both areas have a comparable thickness and quality. Considering all factors, we assume that the average net reservoir thickness probably averages around 60 ft over the play area.

Additional reservoirs of other plays are those involved with the rollover features associated with growth faults along the shelf margin and those of the carbonate buildups and mud lumps. No thickness data are available, but the shelf margin reservoirs are probably thin, possibly averaging 50 ft.

The carbonate buildups are probably several hundred feet thick but the amount of porosity is unknown. If they have been tested no results have been published; we surmise that similar to carbonate reservoirs of the drape play, the effective pay will be thin, perhaps 50 ft thick. The distribution of the reefs and mounds is discussed under Untested Trap Area.

Seals

Since the section from mid-Miocene upwards is primarily shale, seals should generally be good. However, there are some nonproductive closures with oil residues found on the ridge adjacent to the Ratna discovery area (Basu and others, 1980), and the shallower Bombay High is 50 to 60 percent filled, while the more deeply covered Bassein trend is nearly 100 percent filled, all of which may indicate leaking.

Source-rock section

From organic richness and maturity considerations discussed below, the source section is limited to Paleocene to early Miocene shales.

Generation and Migration

Richness of source

The shales which have enough organic content (Total Organic Carbon (T.O.C.) >.5 percent) range from Eocene to Early Miocene; the younger strata are generally deficient (Basu, 1980). It appears, however, that the source shales are only moderately rich, perhaps not averaging much over 1.0 percent T.O.C.

The Eocene to early Miocene strata in the graben area east of the Bombay High area and in the low around Dahanu are in a generally deltaic facies, and the organic matter is presumably of terrestrial origin. This origin is confirmed by the high wax content of the Bombay Shelf oil.

Most of the fields appear concentrated around the graben areas east of the Bombay High; to date, little oil has been discovered adjacent to the thick shale depocenter to the west. It is postulated that the organic matter was better preserved in the graben areas versus the more open-sea area to the west, and this is confirmed by higher T.O.C. values where sampled.

Depth and volume of mature sediments

The average thermal gradient of the Bombay Shelf is 3°F per 100 ft or higher. This, together with the rate of subsidence, places the top of the mature zone at about 5,000 ft. By coincidence, this depth is close to that of the top of sufficiently rich organic content, thus supporting the limitation of the source shales to the Eocene-Early Miocene section. With a top at 5,000 ft, the volume of mature (and partly overmature) sediments is 92,000 mi^3.

Oil versus gas

Production to date from the Bombay Shelf is largely oil, but perhaps selectively so. On the basis of the terrigenous source and fair seals, it is estimated that the areal fill of most traps may be 55 percent oil and 45 percent for gas. The rollover/growth-fault play of the margin edge, however, involves largely a shale section where some primary oil migration may be impeded so that accumulations may be only 40 percent oil.

Migration timing versus trap formation

Assuming a constant subsidence rate and high thermal gradient through the Tertiary, generation and migration would commence as soon as the source strata reach a depth of 5,000 ft (1,500 m), which happened in the shale deeps about Oligocene time (H_3, fig. 4). Although this is somewhat prior to the Bombay High reservoir and seal deposition (Early Miocene) possibly allowing some hydrocarbon to escape from the system, the migration timing ensures that oil could have entered the reservoir early, preserving it to some extent from later destructive diagenesis.

Limiting Factors

It appears that the single overriding limiting factor regarding hydrocarbon accumulation is the thinness of the reservoirs.

Cambay Graben

Introduction

Location and size of area

The Cambay Graben extends northward on land from the Bay of Cambay (Lat. 21° N.) on the west coast of India (figs. 1 and 8). It is contiguous and geologically related to the Bombay Shelf. The Cambay Graben has an area some 20,000 mi^2 and a sedimentary volume approximately 22,000 mi^3.

Exploration and production history

Seismograph surveys began in this area in the middle fifties. The first wildcat was drilled in 1958 and discovered the Cambay Gas Field. In 1960, the Ankleswar Oil Field, the largest field, containing apparently about half of the Cambay Graben's reserves, was discovered. Since then a very vigorous exploration went after more subtle traps, pinchouts, lenses, and very small one-well fields, leading to the discovery of some 54 oil and gas accumulations. Although trap size decreased, a rather high success ratio of approximately 38 percent (or 556 bbls/ft) has continued; however this may be expected to decrease in the future. We deem the Cambay Graben to be in a mature exploration stage, i.e. possibly 80 percent complete. From Indian Petroleum and Petrochemical Statistics (1981-82), we estimate original reserves of 1.17 BBO and 0.9 Tcf of gas.

Structure

General tectonics

The structure of most of the Cambay Graben is that of a typical and relatively symmetrical graben (figs. 8 and 9). The southern quarter, however, has apparently been displaced eastward by a series of sinistral wrenches (figs. 3, 8, and 10); the Ankleswar structure appears to be an associated drag feature. There are a number of plays in the basin (drape closures, drag closures, and stratigraphic traps), but in the absence of detailed information, the Cambay Graben is treated as one play.

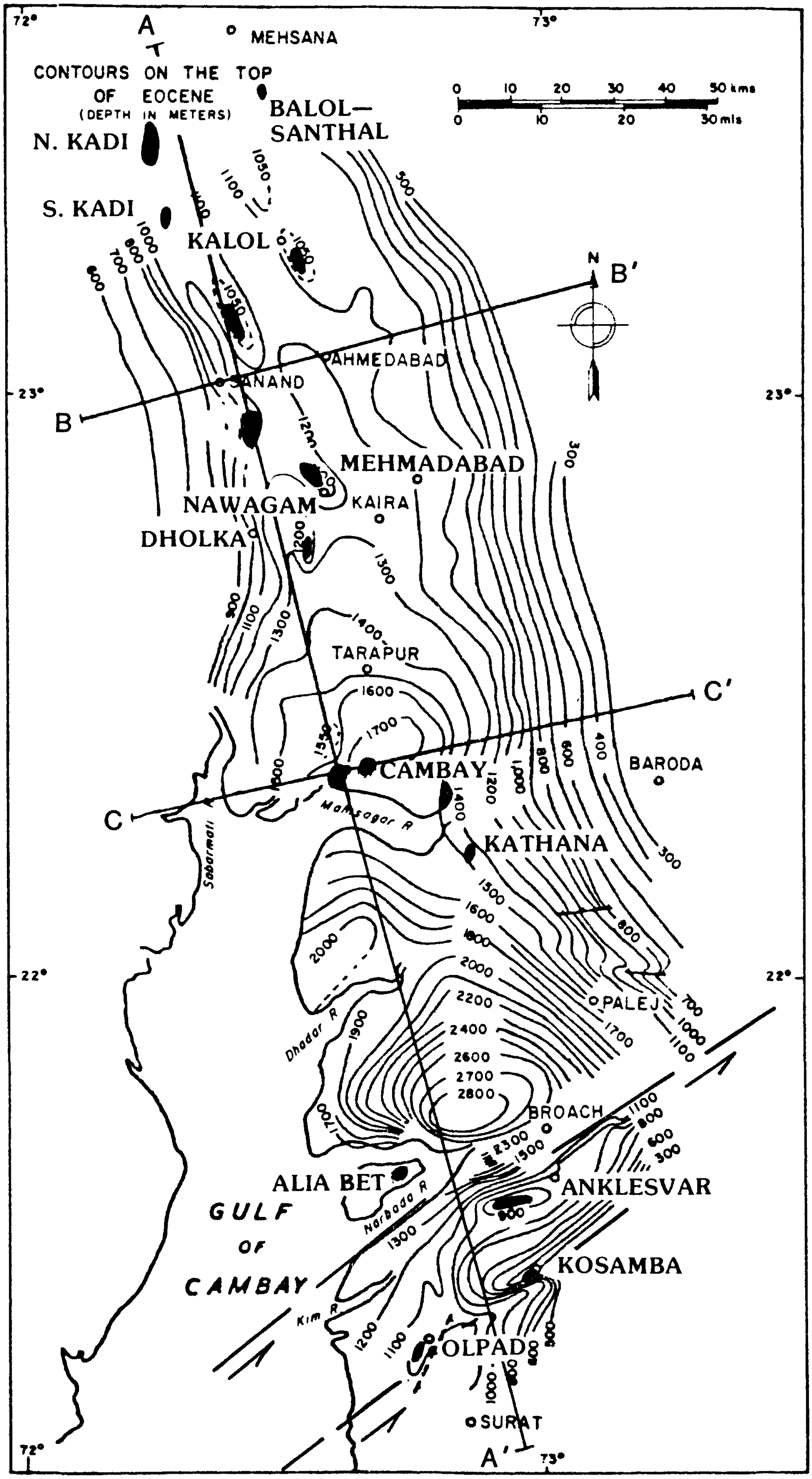
Untested trap area

By estimate of closure area in a mapped part of the basin (Avasthi and Venkataraman, 1979), we extrapolate that 6.3 percent of the basin is under closure (806,000 acres). Owing to the rather mature stage of exploration, we estimate possibly 80 percent of the Cambay Basin closures have already been tested, leaving 161,000 acres untested.

Percentage trap area productive

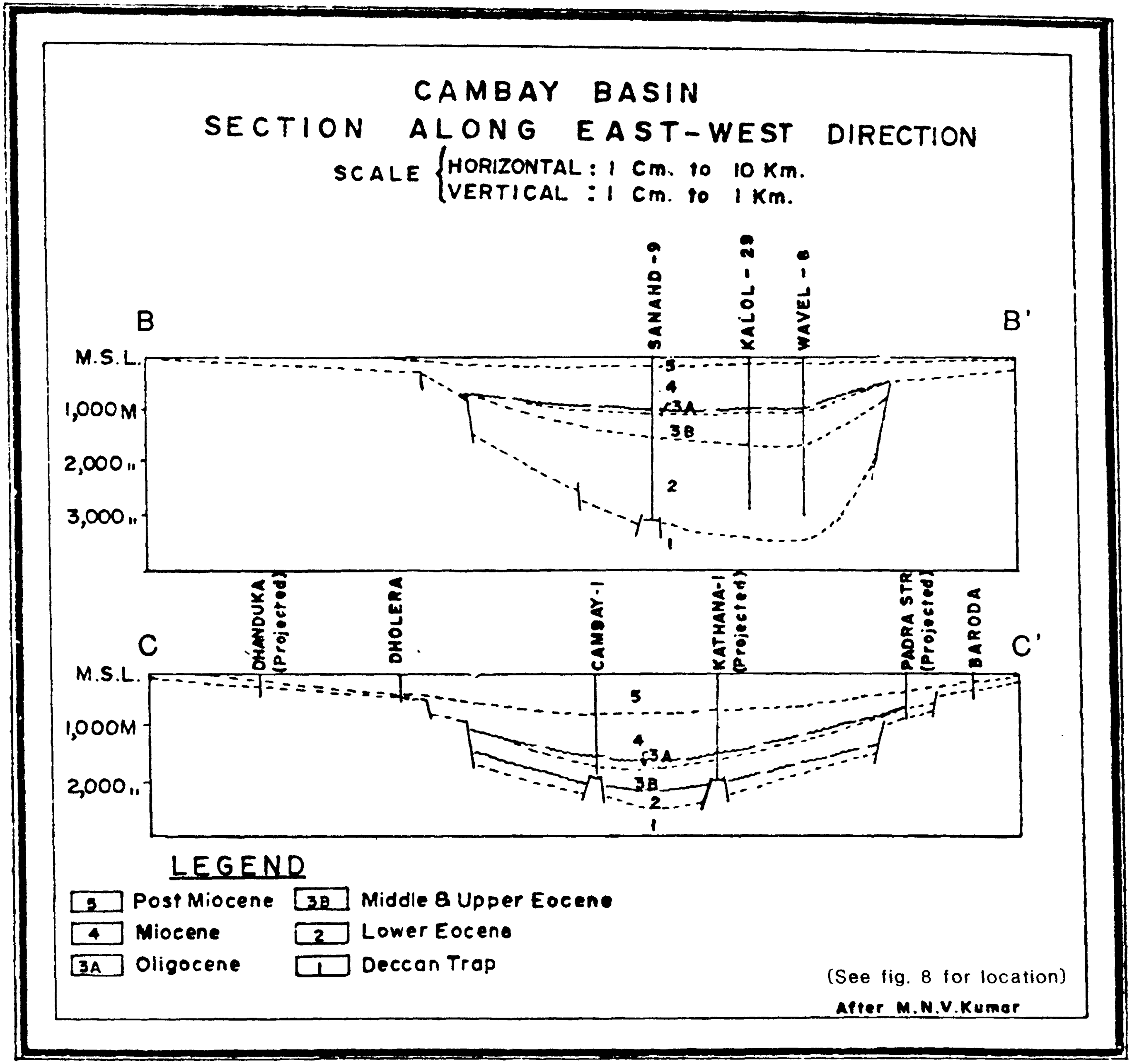
Few data are available concerning hydrocarbon fill. Inspection of the Nawagam Field cross-section (Mehrotra and others, 1979) indicates a fill of perhaps 60 percent (although the section does not include the spill point, and the oil-water contact varies erratically from sand to sand). Sixty percent is taken to be an average figure for the Cambay Graben. This figure, along with the historical success ratio of 38 percent, diminishing to perhaps 25 percent, indicates petroleum production in about 15 percent of the untested trap acreage.

STRUCTURE MAP OF THE CAMBAY BASIN
SHOWING PRINCIPAL OIL/GAS FIELDS



PETROCONSULTANTS LTD. From Mather and Evans, 1964

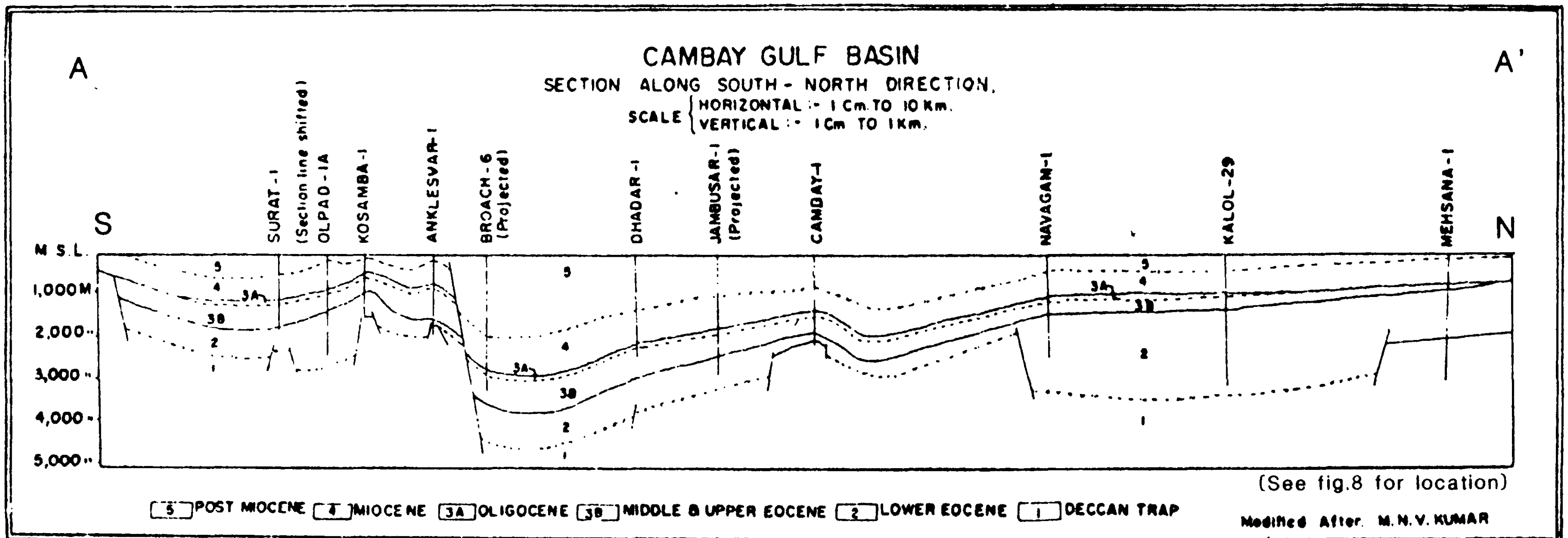
FIGURE 8



From: Dehadrai, PV 1970

EAST-WEST CROSS SECTIONS THROUGH THE CAMBAY BASIN, WESTERN INDIA

FIGURE 9



From: Dehadrai, PV 1970

NORTH-SOUTH CROSS SECTION THROUGH THE CAMBAY BASIN, WESTERN INDIA

FIGURE 10

Stratigraphy

General Stratigraphy

The general sequence is shown in figure 11. This Tertiary section, unlike the adjoining Bombay Shelf, is made up almost entirely of deltaic shales and sandstones. The lateral distribution of sandstones and shales is shown diagrammatically in figure 12, where Eocene deltaic sands may be seen shaling out southward away from the sediment source.

Reservoirs

The Nawagam Field has an estimated 82 ft of effective sand porosity; Ankleswar has 62 ft and Cambay 38 ft; others may be thinner, an average is possibly 60 ft.

Seals

There is considerable shale in the section and seals generally should be efficient; however, there is a profound Oligocene unconformity just above the Ankleswar Field reservoirs, so there could have been some leakage. An average seal efficiency of 70 percent is assumed for the basin.

Source-rock section

From reservoir-shale associations and thermal maturation considerations, the source rock of the basin is almost surely the Cambay Shale and related Tarapur Shale. The main reservoir sands of the Cambay Graben interfinger, or are isolated within, these shales (fig. 12).

Generation and Migration

Richness of source

The chief source strata are the Cambay Shale which have a thickness of 1,500 to 5,000 ft. The average T.O.C. is about 2.5 percent with a maximum of 14.08 percent (Berger and others, 1983). The deltaic Cambay Shale (as well as the Tarapur Shale) should contain mostly terrigenous organic matter, and this is supported by the fact that the oil of adjoining sands has a uniformly high wax content. Preservation of organic matter in this graben, partly isolated from the sea, should be near optimum.

Depth and volume of mature sediments

Thermal gradients of 2.33 to 3.32°F per 100 ft have been recorded, and an average of about 3.0°F per 100 ft is assumed for the basin. This gradient, along with the rate of subsidence, places the top of the thermally mature sediments at 5,000 ft (1,500 m), which is about the same as for the Bombay Shelf. The volume of mature (and over-mature) sediments would amount to 5,250 mi^3.

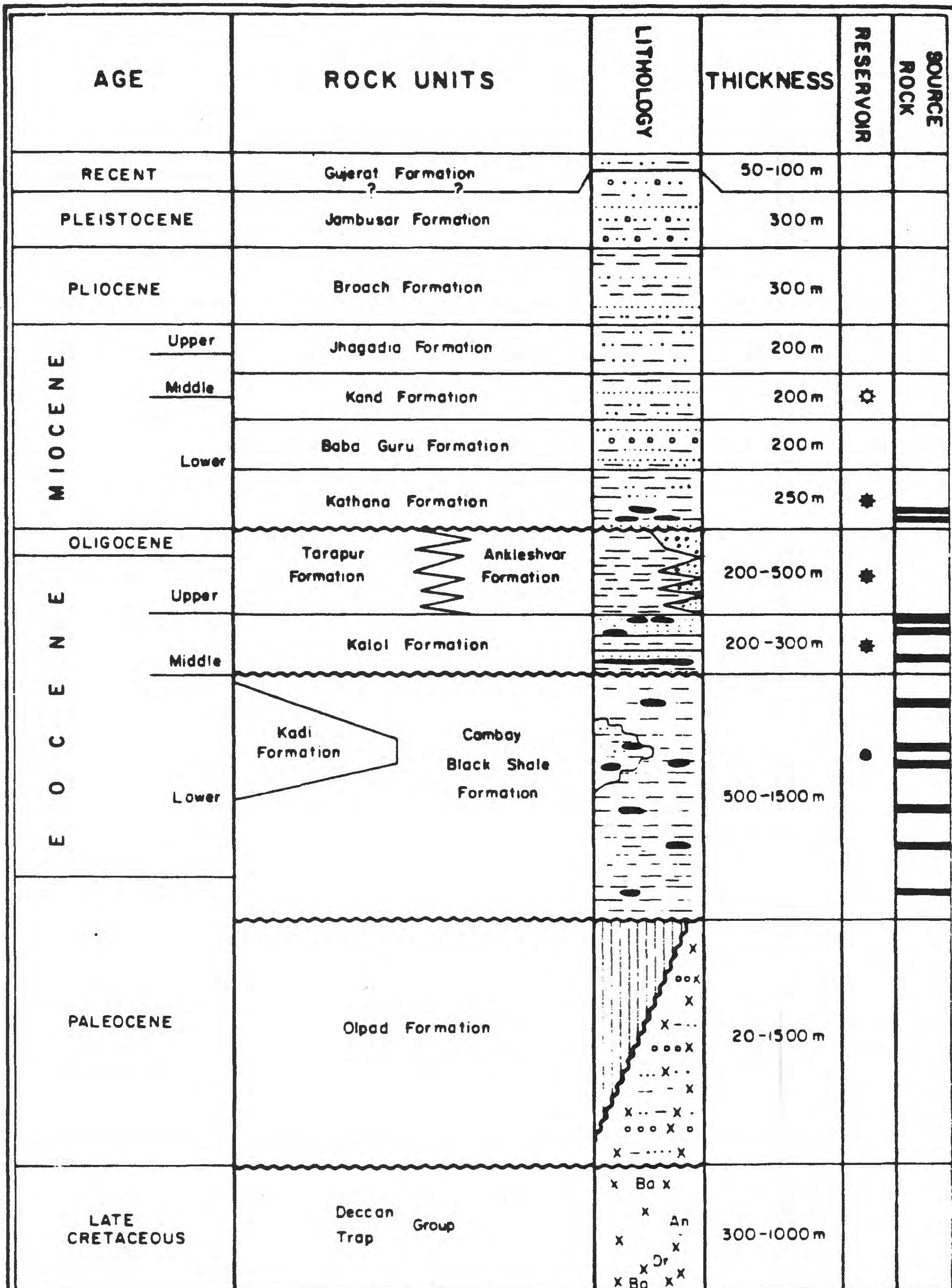
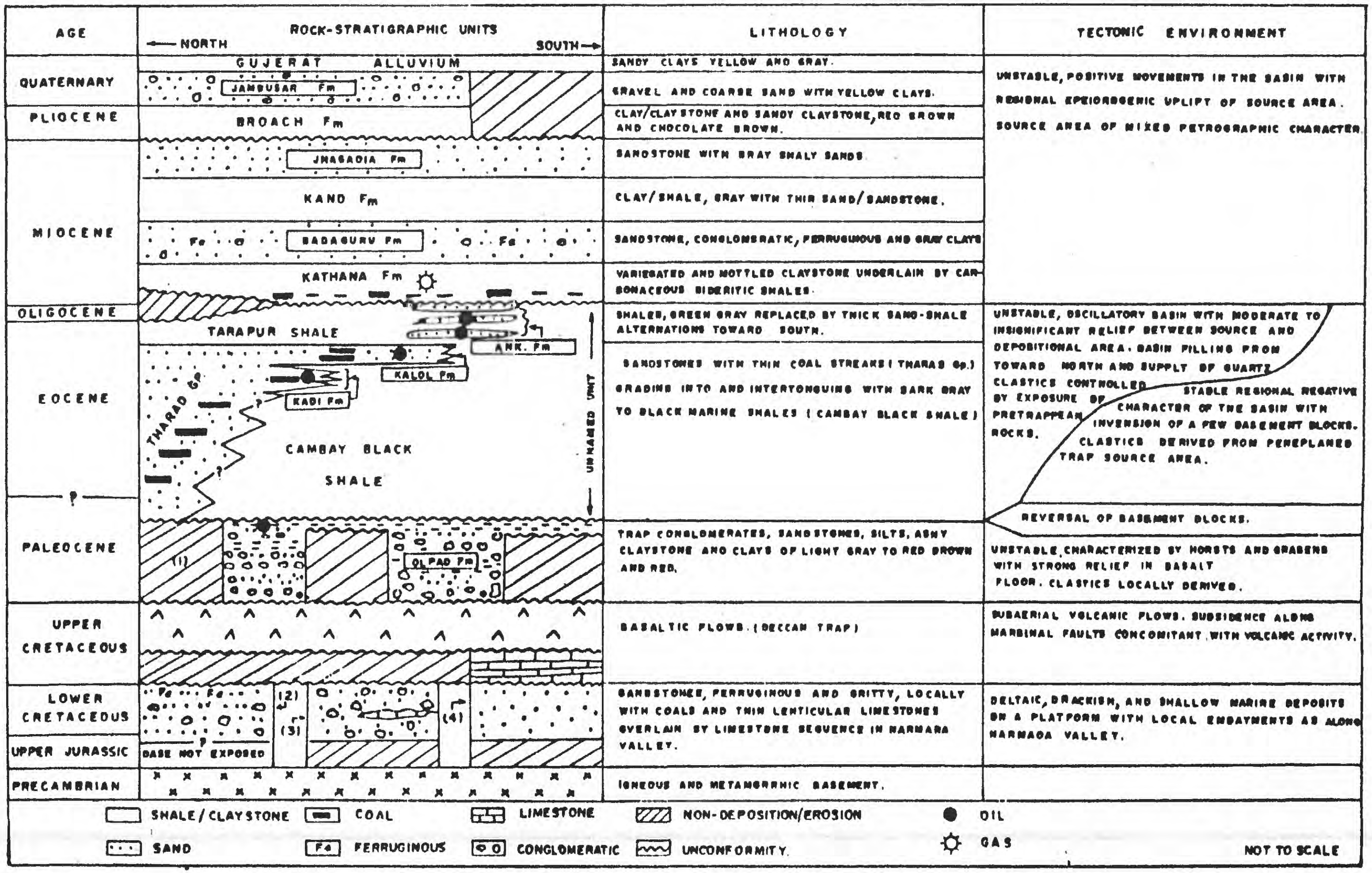


Figure 11.-**STRATIGRAPHIC SEQUENCE IN CAMBAY BASIN (INDIA)**

From Petroconsultants



—Rock-stratigraphic units, lithology, and tectonic environment of deposition in Cambay basin (compiled from Raju, 1968; Chandra and Chowdhary, 1969; and unpublished reports of ONGC). (1) Generalized distribution of Olpad Formation in local horsts and grabens; (2) western margin of basin; (3) eastern margin of basin; (4) Narmada Valley.

From: Chowdhary, L.R 1975

FIGURE 12

Oil versus gas

Most of the hydrocarbon produced to date has been oil, but this may have been done selectively. ONGC is reportedly planning deeper drilling and may be going for gas. The organic source matter is predominantly terrigenous, which commonly indicates a high percentage of gas. Seals are deemed fairly good. Given the above, along with the reserve numbers, gas should constitute a large percentage of the hydrocarbon. We estimate that oil makes up 50 percent of the petroleum fill of the closure areas.

Migration timing versus trap formation

The traps are largely Eocene reservoir sands draped over fault blocks which came into existence during the Cretaceous. Assuming a uniform average rate of subsidence and thermal gradient through the Tertiary, petroleum generation and primary migration would begin in the Oligocene, after subsiding to a depth of some 5,000 ft or 1,500 m, but perhaps not until the Miocene in the shallower Ankleswar area. Maximum generation and migration, however, were in the post-Miocene when maximum subsidence took place (fig. 10). This migration, a considerable length of time after trap formation and reservoir deposition, may have allowed for some reservoir deterioration, but at least traps were present during the whole period of migration.

Limiting Factors

The two overriding factors limiting the amount of undiscovered petroleum are the mature stage of exploration in a small basin and the thin pays.

Konkan Shelf

Introduction

Location and size of area

An irregularly shaped shelfal area off the west coast of India south of the Bombay Shelf including the Laccadive Islands has been considered by some to be a prospective petroleum province (fig. 13). The area consists of the outer, deeper Laccadive Shelf at a water depth of 6,500 ft (2,000 m) and the shallower continental shelf at water depths of less than 600 ft (200 m) adjoining the shoreline (fig. 14). The northern part of the continental shelf, the Konkan Shelf, is separated from the southern part, the Kerala Shelf, by an apparent low ridge near Calicut.

In our opinion, only a small part (about 12 percent concentrated in the Konkan Shelf area) of this general shelfal province may have sufficient sedimentary thickness to be considered for any appreciable petroleum potential. Largely on the basis of the 9,744-foot (2,970 m) depth of wildcat KG-1, we believe the thicker sediments are concentrated in the outer shelf area of the Konkan Shelf vicinity in an area of some 12,000 mi^2, with an estimated sedimentary volume of some 18,000 mi^3.

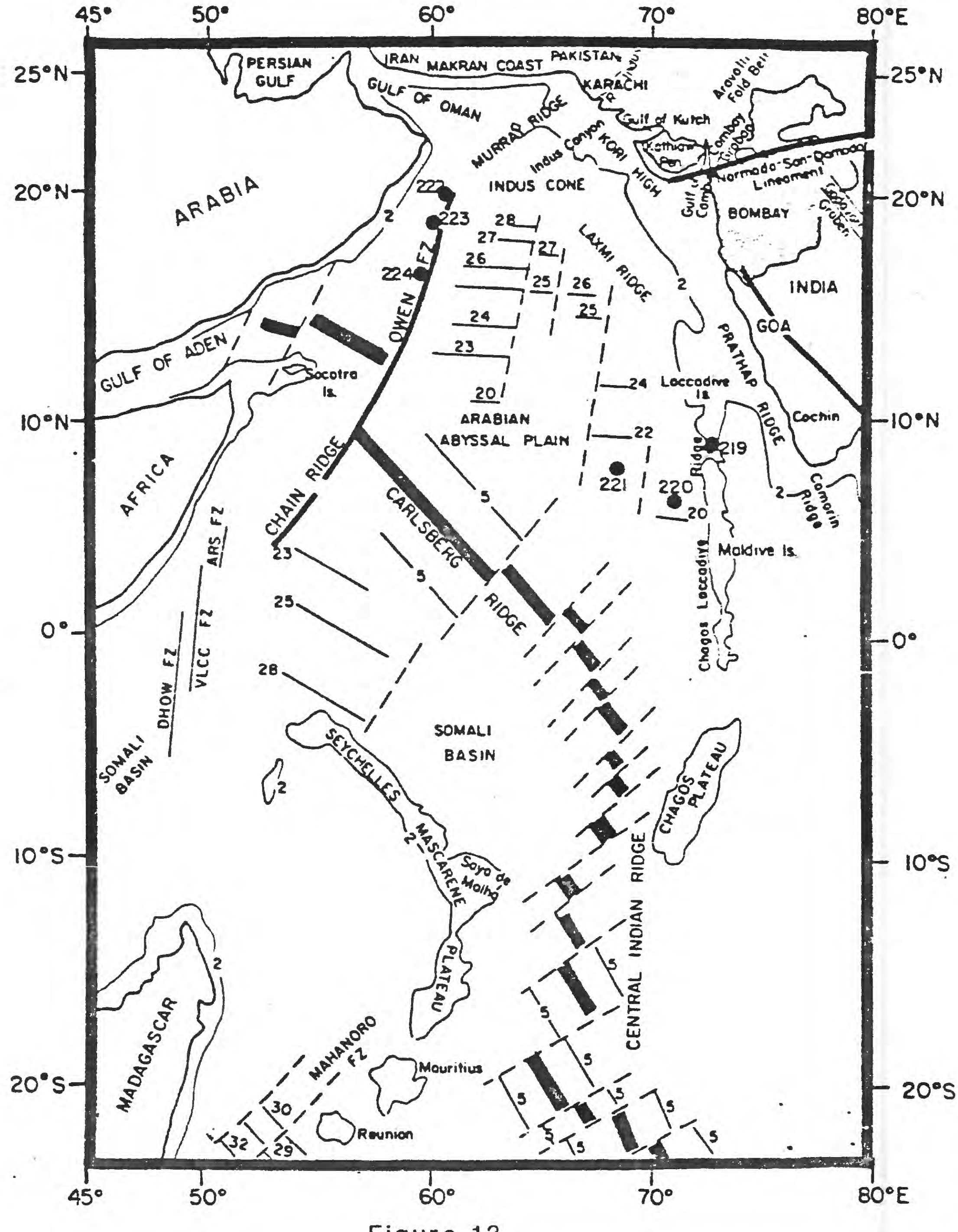


Figure 13

From Naini, B R., 1980

TECTONICS, WEST INDIAN OCEAN

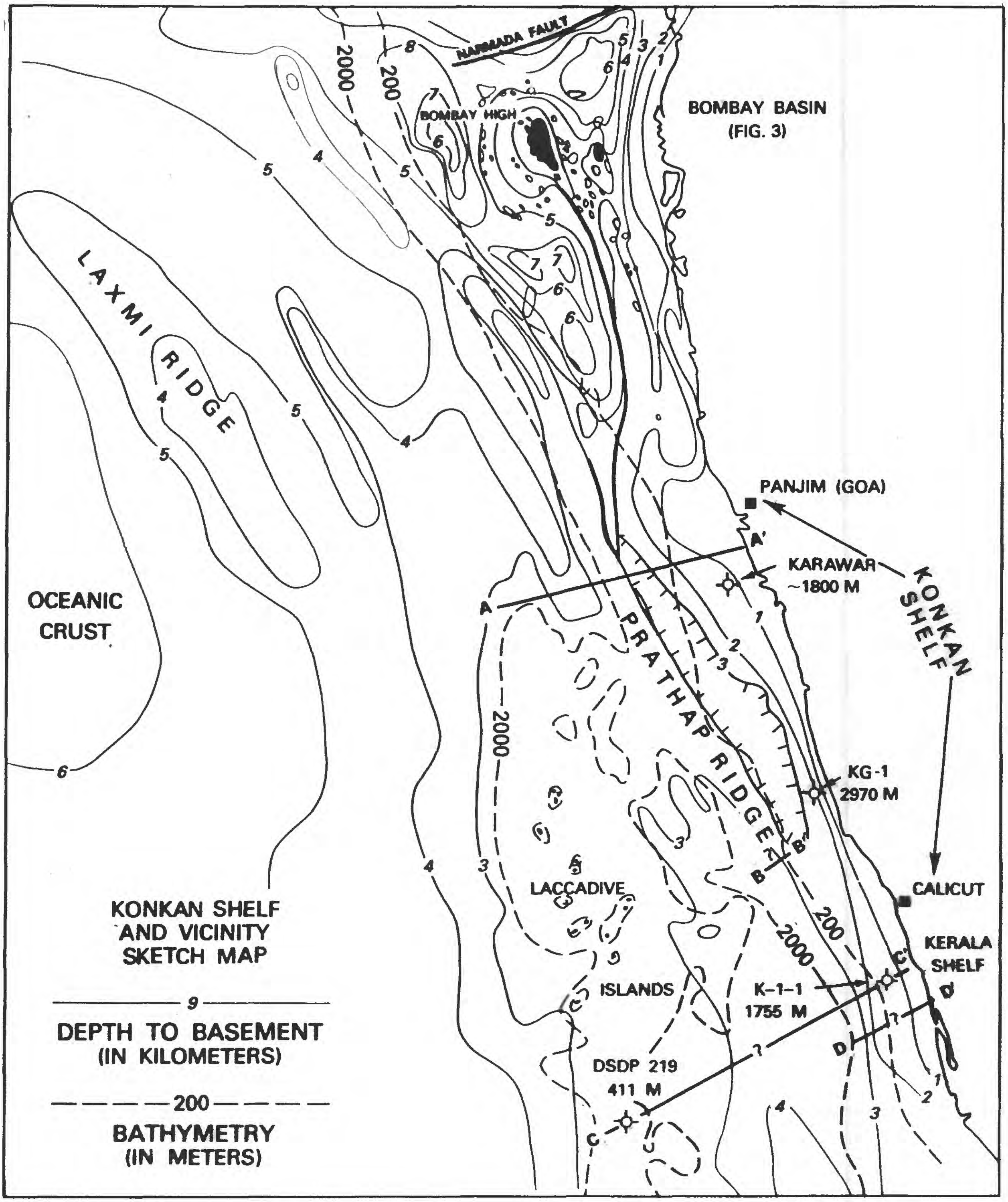


Figure 14.--Depth to basement, Konkan Shelf and vicinity

Exploration and production history

Four wells have been drilled in the vicinity: KG-1 and Karawar on the Konkan Shelf, K-1-1 on the Kerala Shelf, and DSDP-219 on the Laccadive Shelf (fig. 14). None of these wells encountered hydrocarbon shows. Reconnaissance and probably some detailed seismic work was done to locate the continental shelf wells. The exploration of the area is in a very immature stage, possibly about 5 percent explored.

Structure

General tectonics

This shelfal area is part of the rifted continental margin of India. As such, its structure is dominated by horst and graben features, trending north-northwest parallel to the Indian coast and to similar features in the Bombay Shelf area (figs. 14 and 15).

Untested trap area

There are no data available concerning closures. It is assumed that any closures would be structurally similar to those of the Bombay Shelf (excluding the Bombay High) and would have about the same size and distribution; i.e. an overall trap area of 5 percent of the play area. On this basis, the Konkan Shelf would have 385,000 acres of untested trap area.

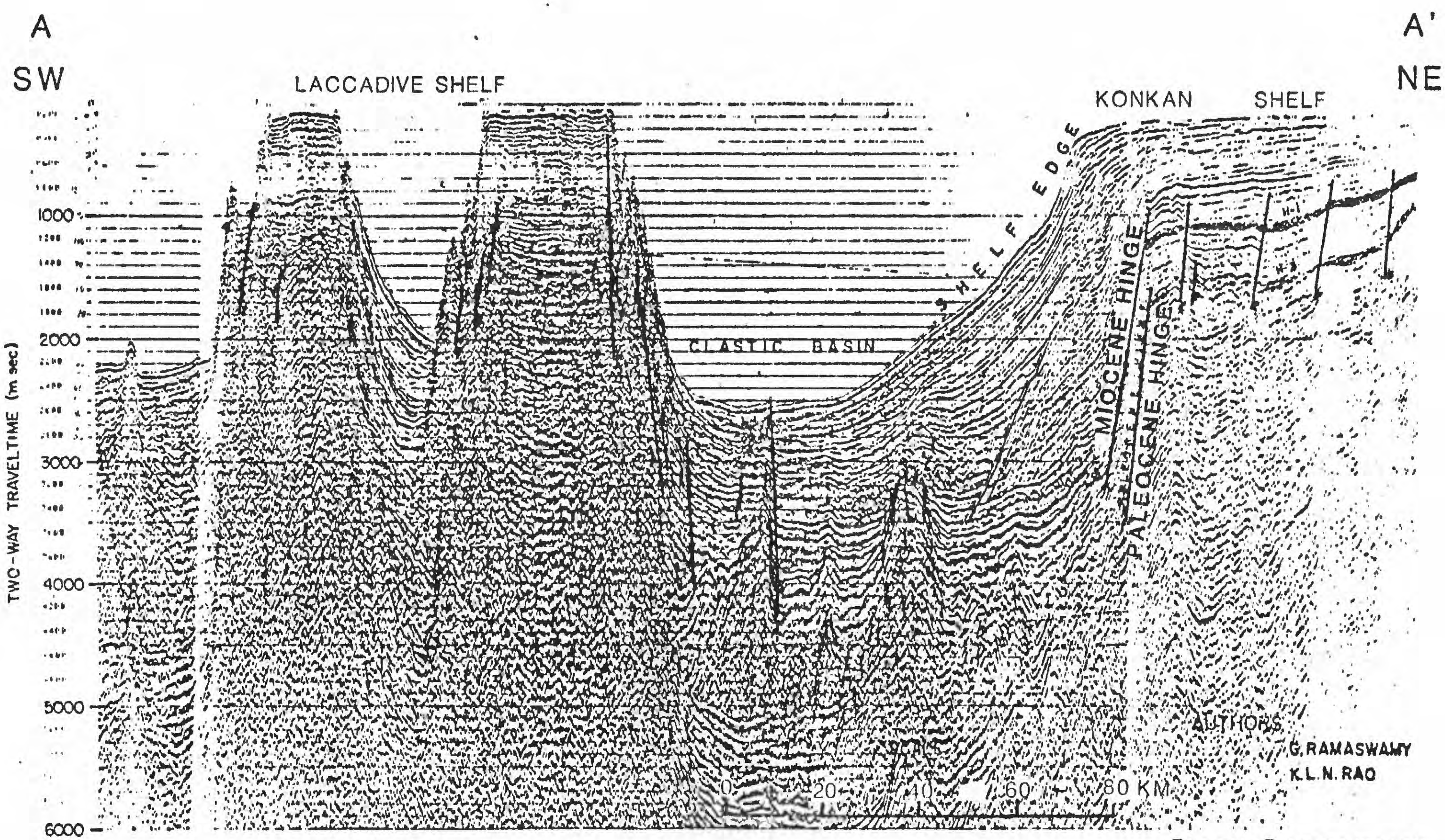
Percentage trap area productive

The percentage of trap area which may be productive appears to be less than the adjoining Bombay Shelf. There has been no discovery to date, but perhaps a discovery rate of 10 percent (versus 30 percent for Bombay Shelf) may be assumed. The trap fill may be half that of the Bombay Shelf, or 30 percent, reflecting the smaller volume of source rock, indicating that 3 percent of trap area would be productive.

Stratigraphy

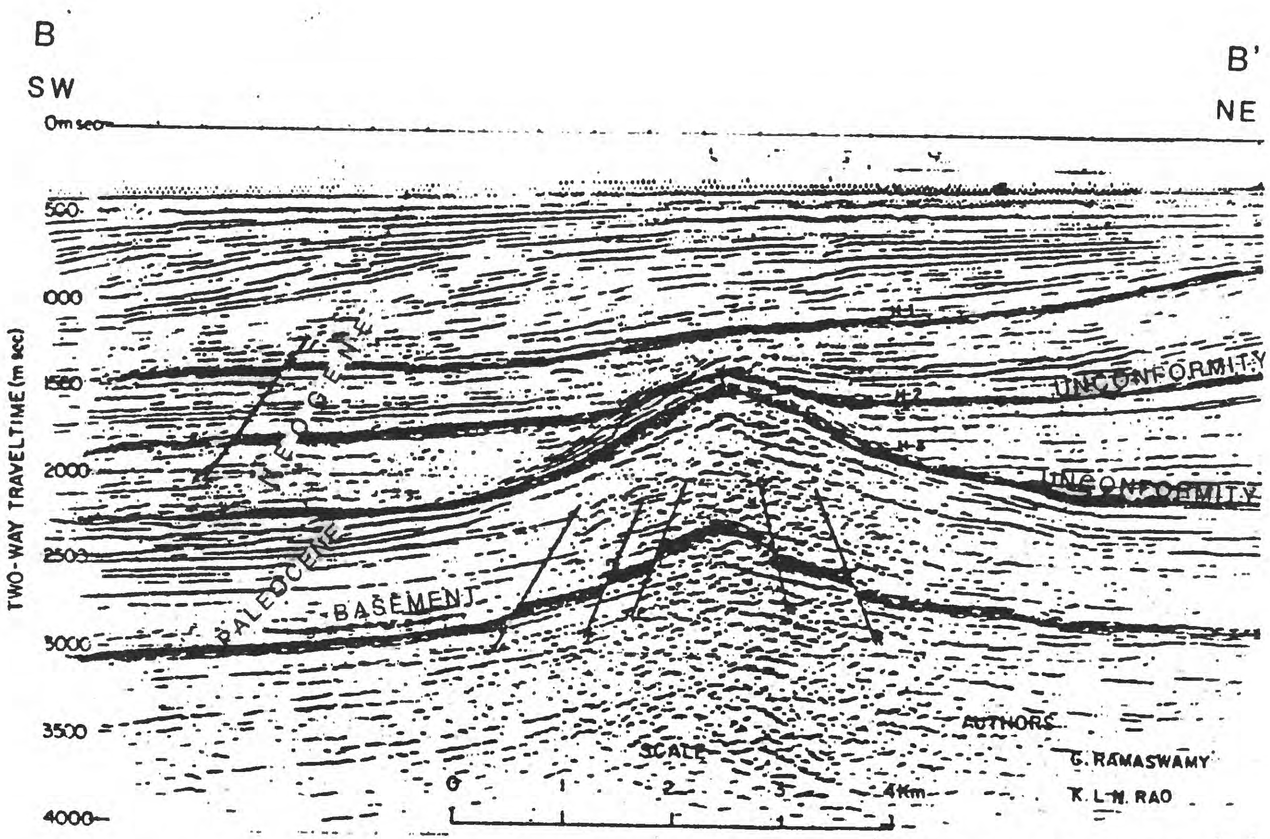
General stratigraphy

The prospective sedimentary section is a thin Tertiary sequence overlying Cretaceous-Paleocene volcanics (the Deccan Traps). The Konkan Shelf sedimentary cover is apparently around 10,000 ft at K.G.-1 (fig. 16). This is in contrast to the Kerala Shelf further south where the sedimentary cover is only some 1,600 to 3,500 ft (fig. 17). The sedimentary cover on the Laccadive Shelf also appears thin; for well DSDP 219 penetrated strata representing all the Tertiary epochs in 1,300 ft, bottoming in Paleocene freshwater strata indicating nearness to the base of the sedimentary section as drilled through at K-1-1 on the adjoining Indian continental shelf. The presence of pre-Tertiary sediments appears unlikely since it has not been found in any tests of the Indian shelf from the Bombay High southward. The depth-to-basement seismic compilation map (fig. 14) shows that after subtracting water depth, less than 2 km (6,260 ft) of sediment is present over most of the shelfal area outside the Konkan Shelf.



From: Ramaswamy and Rao KLN 1980

Fig. 15 Konkan Offshore Basin: seismic section along line RM-01 off Karwar.
(See fig. 14 for location)

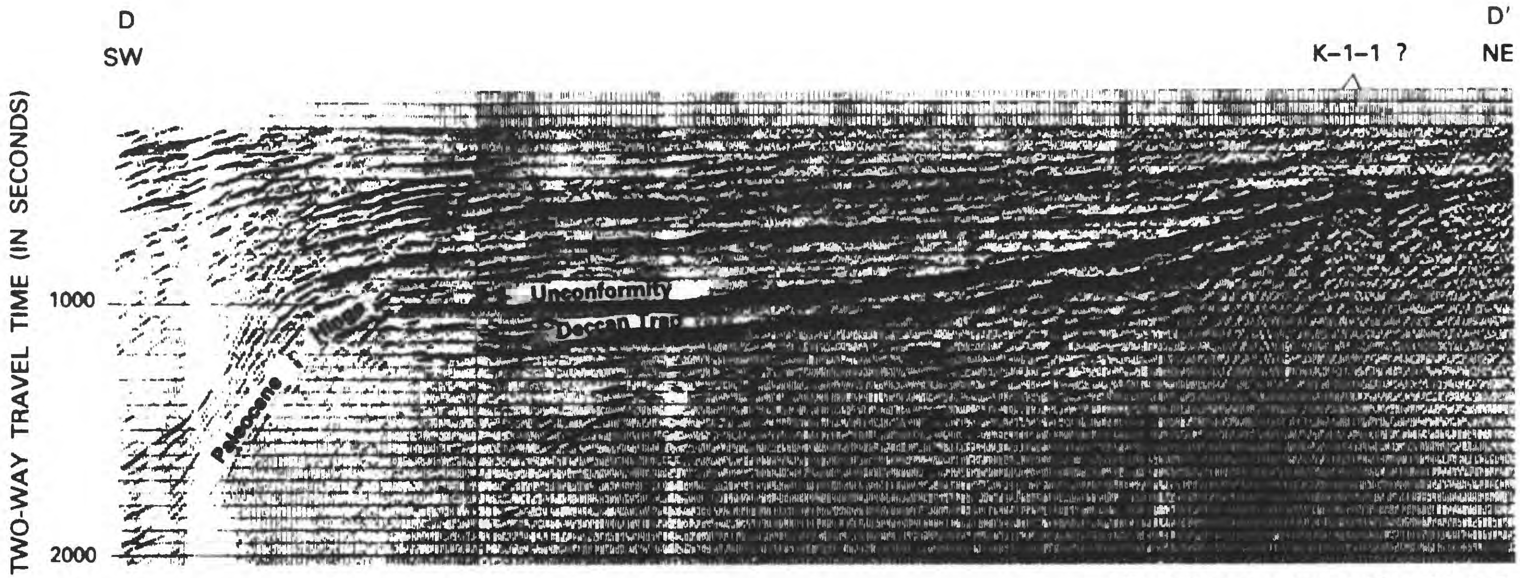


(See fig. 14 for location)

Konkan Offshore Basin: seismic section along line MC-01 off Kasargode.

From: Ramaswamy G and Rao KLN, 1980

FIGURE 16



(From: Ramaswamy, G. and Rao, KLN 1980)

Figure 17.--Kerala offshore basin: Seismic section D-D'

The general stratigraphy of the vicinity is best shown in the schematic section between holes DSDP-219 and K-1-1 (fig. 18). It may be seen that the prospective sediments of the continental shelf are limited to the post-early Paleocene and that the depositional environment of the province was continental up through early Miocene when it changed to a marine environment. (The Laccadive Shelf deposition was deep marine from Eocene onward.)

Reservoirs

There are no data concerning reservoirs. They are probably mainly concentrated in the shallow-water to continental part of the section. It would appear that effective reservoirs are as well developed here as on the adjacent Bombay Shelf. However, the section is thinner and it is assumed, therefore, that the average reservoir thickness is proportionately thinner or only two-thirds of that of the Bombay Shelf, i.e., about 40 ft.

Seals

Seals are thought to be of low efficiency in this province. The section is generally thin, and it appears that the reefs have poor cover since many of them have grown uninterruptedly to the present. The overall effectiveness of the seals is put at 30 percent.

Source rock section

The thickness and volume of source rock is limited by the thinness of the stratigraphic section. Mature source rock, if present, would be necessarily at the base of the section.

Generation and Migration

Richness of source

No data are available. By analogy to the adjoining Bombay Shelf, some source rock may be expected; in any case, richness of source is probably not a limiting factor.

Depth and volume of mature sediments

Depth and volume of mature sediments may be the limiting factor concerning undiscovered petroleum in this province, as the stratigraphic section is relatively thin. In the absence of local data, a somewhat warmer than average thermal gradient for a rifted continental margin is assumed, i.e., 2°F/100 ft, which puts the top of the mature zone at a depth of about 9,000 ft. This limits the prospective area of the offshore shelf of southwest India to the Konkan Shelf where the sediments seem to be sufficiently thick (approximately 10,000 ft) to contain some volume of mature sediment.

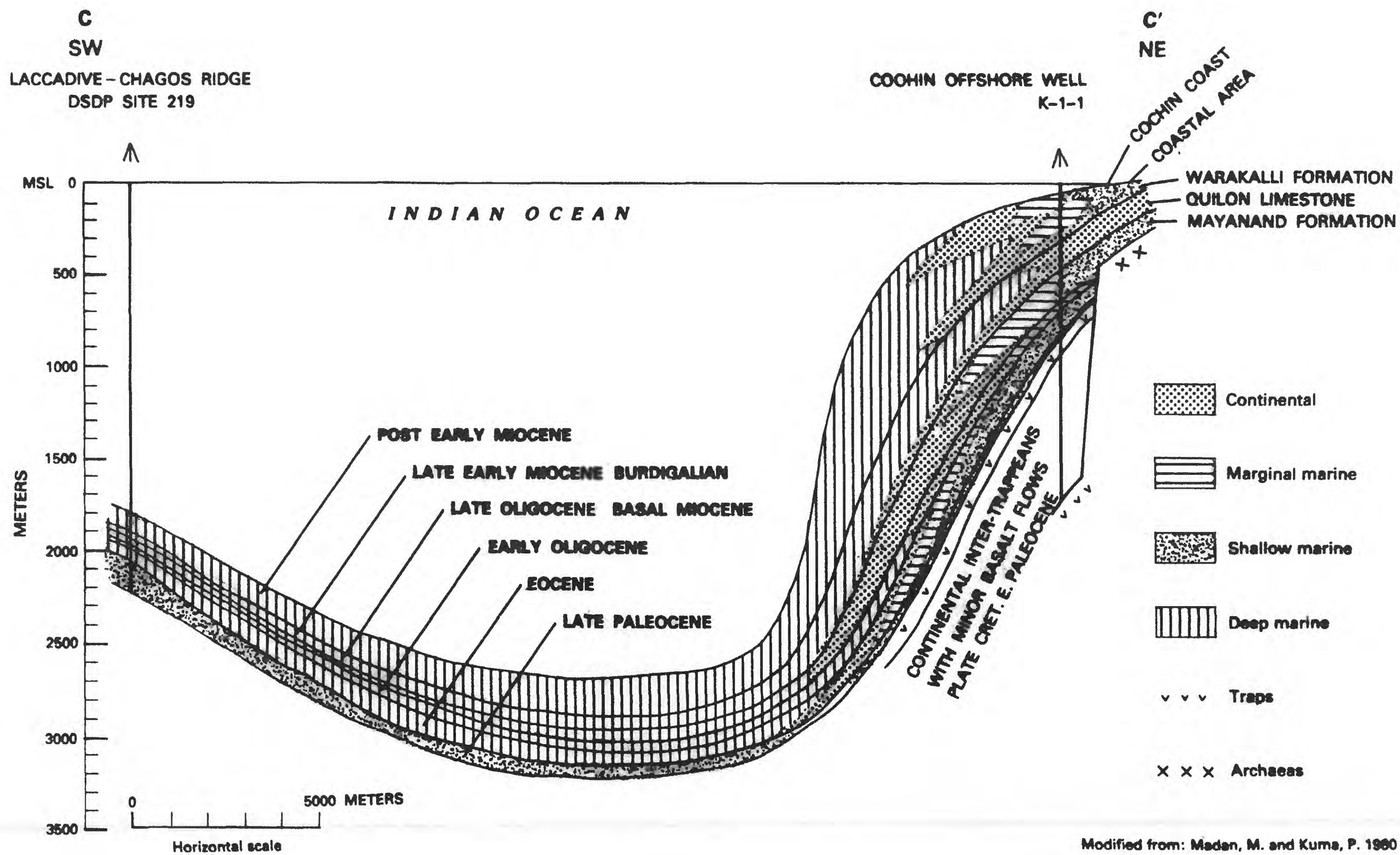


Figure 18.--Laccadive Shelf to Kerala Shelf: Schematic stratigraphic Section C-C'.

Oil versus gas

In the absence of local data and using analogy to the contiguous Bombay Shelf, the distribution of hydrocarbon fill is deemed to be 55 percent oil and 45 percent gas.

Migration timing versus trap formation

Migration in this province of thin sedimentary cover would necessarily be late (i.e., Miocene or later). Because reservoirs with any appreciable cover are probably of Paleocene age, there would be some time for reservoir deterioration.

Limiting Factors

The overriding limiting factor appears to be the volume and maturity of source rock. Other serious limiting factors are the weakness of the seals and the generally thin section.

Kutch Shelf, Onshore and Offshore Plays

Introduction

Since the hydrocarbon potential is so different for the onshore versus the offshore portion of the Kutch Shelf, they should be regarded separately and are here treated as two different plays (separate onshore and offshore Play Analysis summary sheets, Appendix A).

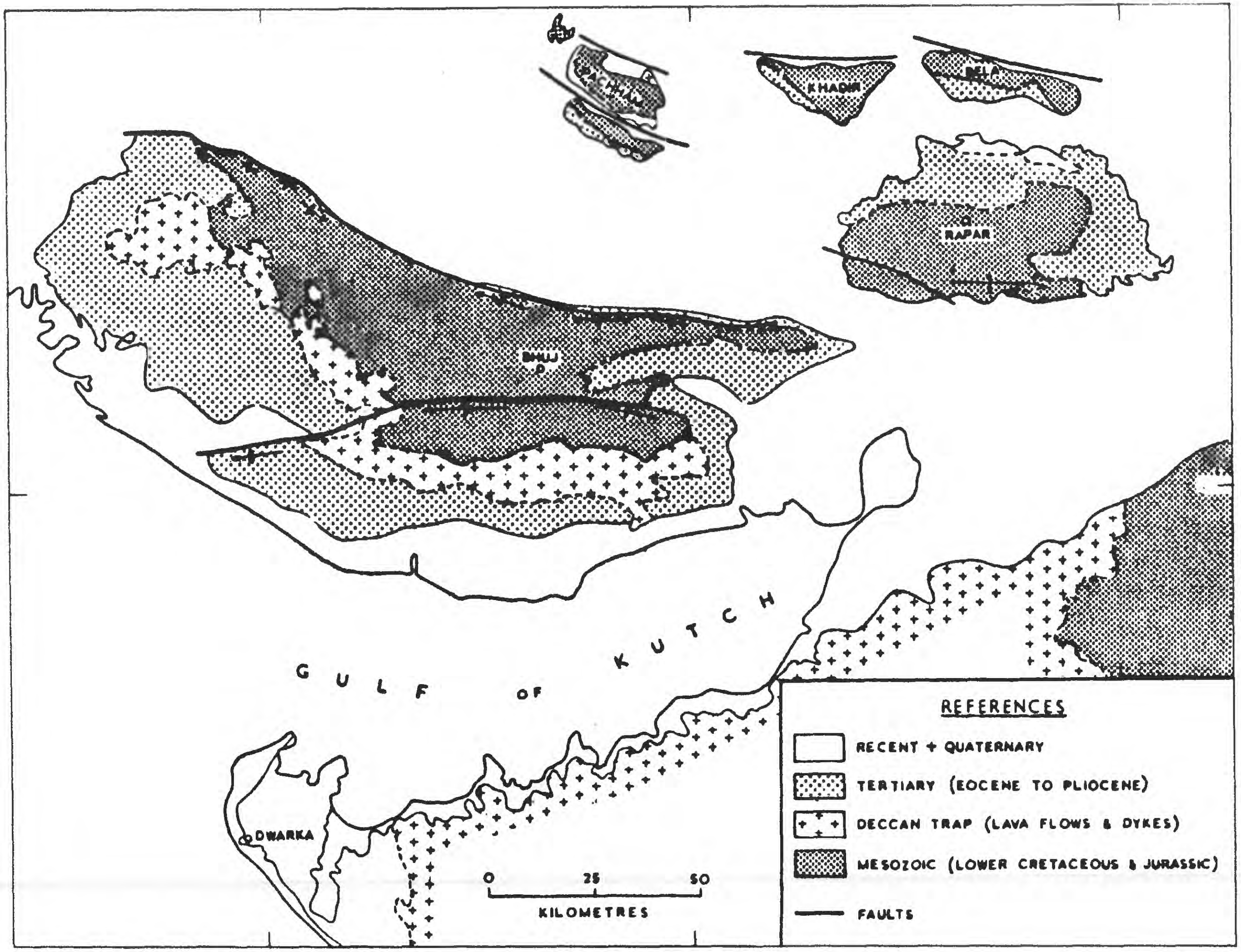
Location and size of area

The Kutch Shelf is located along the Indian Coast adjacent to the Pakistan border (fig. 1). It is contiguous with the Indus Basin to the north and the Bombay Shelf to the south. The limits of the province are taken to be at the Pakistan border, i.e. the east-trending Nagar Parkar Ridge on the north and at the Gulf of Kutch on the south. The onshore portion has an area approximately 23,000 mi^2 (15 million acres) and a sedimentary volume 26,000 mi^3 (fig. 19). The offshore shelf has an area about 12,000 mi^2 (7.4 million acres) and a sedimentary volume 50,000 mi^3 (fig. 21).

Exploration history

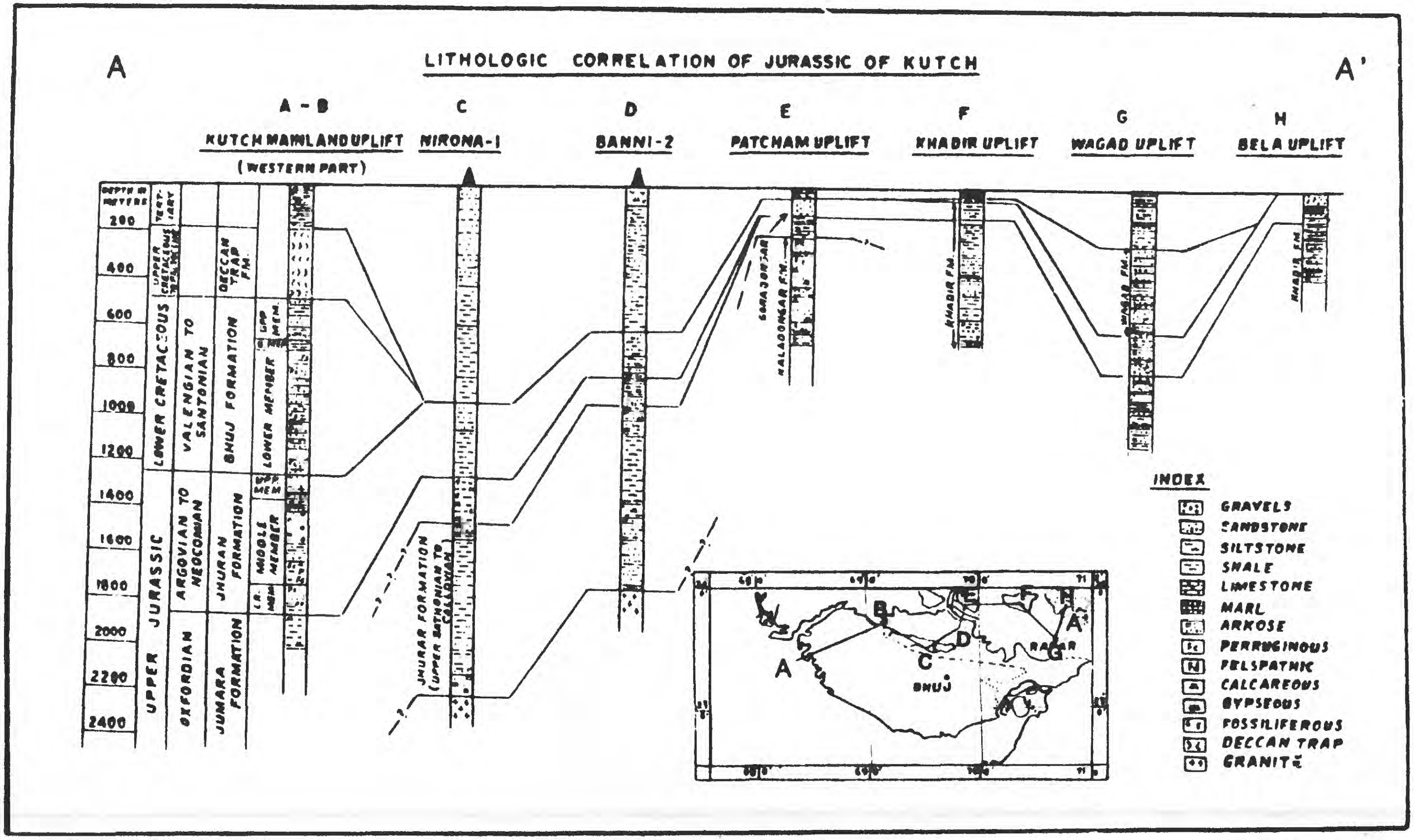
Onshore considerable surface geological and some reconnaissance geophysical surveys appear to have been accomplished. Two holes have been drilled, Nirona-1 and Bonni-2 (fig. 20). Apparently no shows were encountered.

Offshore there have been seismic surveys sufficient to locate several large structures, one of which has been drilled (fig. 21). The wildcat, GKH-1, found oil and gas shows but was abandoned and the acreage relinquished by the concessionaire. The area has not been reoffered to industry by ONGC.



From: Mathur L.P. and
Evans,P. 1964

Figure 19.--Geologic map of Kutch.



From: Patil,M 1976

FIGURE 20

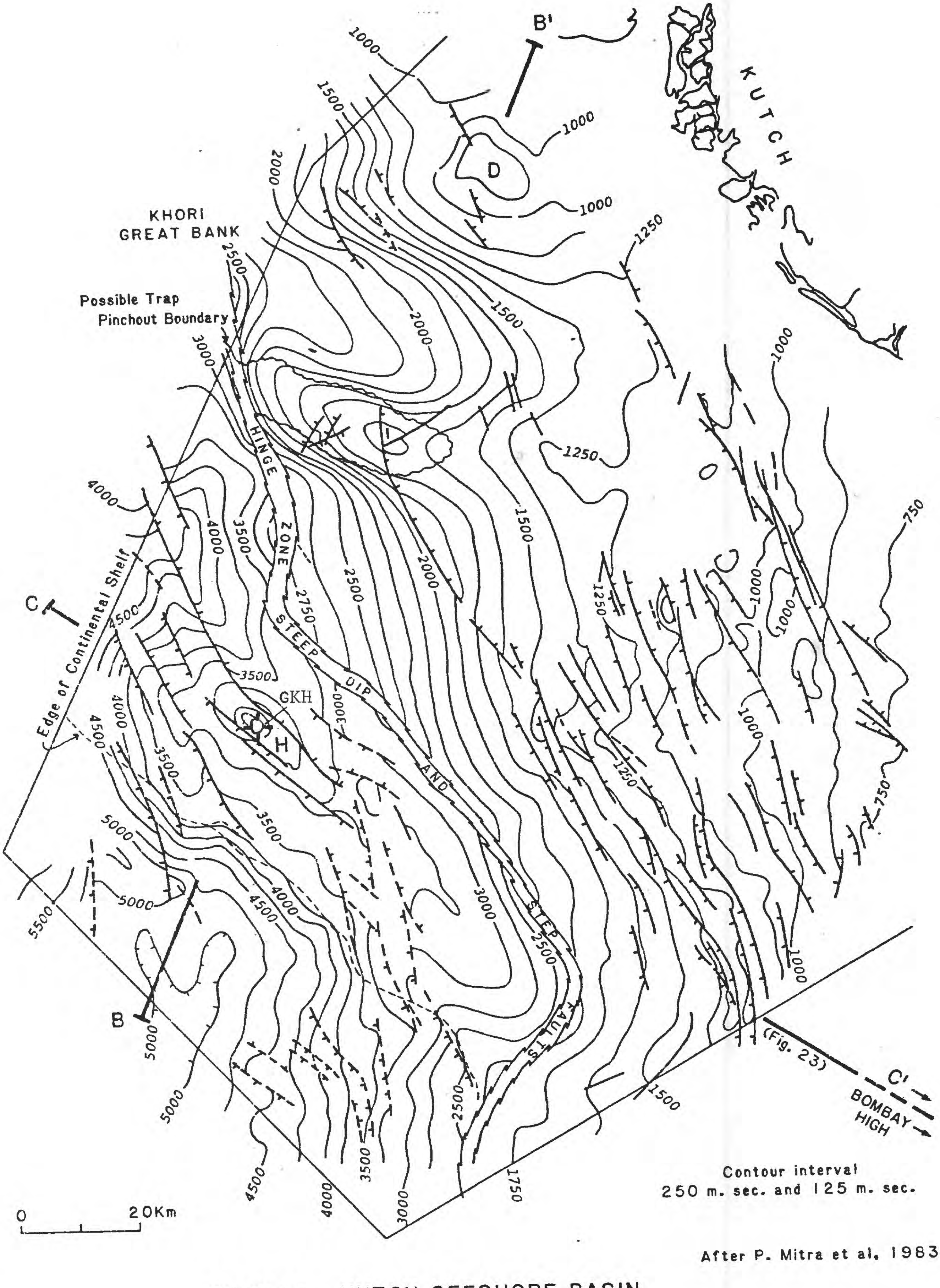


FIGURE 21 KUTCH OFFSHORE BASIN

Structure

General tectonics

The outer Kutch Shelf structure is generally part of the rifted continental margin of India, but the structure of the onshore (and innermost offshore portions) is older and of a diverse trend. The two areas or plays are discussed separately.

The structure of the onshore area (15.0 million acres) is dominated by a number of east-west regional faults and related folds of Mesozoic (L. Jurassic-E. Cretaceous) age (figs. 19 and 21), which follow the Precambrian so-called Delhi Trend. As indicated in figure 19, a number of small closures are concentrated along the major faults, which are probably wrenches. These small closures are characterized by intrusions and rather tight folding. This east-west structural trend extends into the offshore area at least as far as the zone of steep dips (fig. 21). Westward this trend becomes increasingly over-printed and obscured by the later and more dominant northerly-trending Cretaceous rifting.

The dominant structural trend of the offshore area (7.4 million acres) is that of the Cretaceous continental margin rifting, which is almost at right angles to the Mesozoic and older structure seen onshore and on strike with the horst and graben features of the Bombay Shelf (figs. 21 and 22). The pre-Tertiary structure, as shown by the seismograph, apparently is more gentle than onshore, having relatively low dips with no severe faulting. The hinge zone (marked by steeply dipping faults, figs. 21 and 22) separates the completely rift-dominated northerly-trending stucture on the west from an area more affected by the older east-west-trending structure in the east.

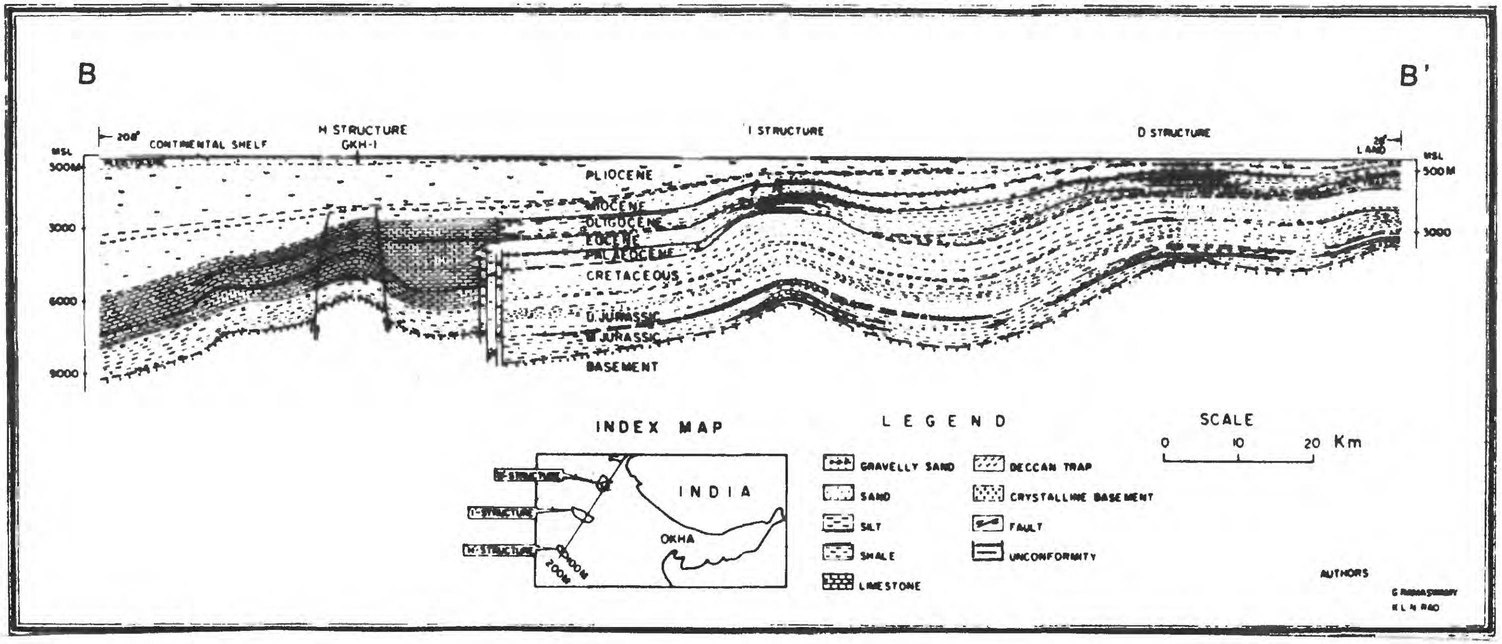
Untested trap area

Onshore the structure is assumed to be wrench-dominated and by analogy to the wrench-dominated Burma Basin should have a drag fold trap area of some 5.5 percent of the total play area. However, taking into account the relatively thin section which is less subject to folding and development of drag folds, it is estimated that the Burma analogy may be discounted by half or about 2.8 percent of the play area. We estimate that some 420,000 acres may be viable drag fold trap area.

Offshore, although it is dominated by the Cretaceous continental margin rifting, the over-printed, older, east-west structure is evident and perhaps should represent another play. However, in the absence of more data, it is grouped with the later and dominant rift-related structure. Assuming the same size and density of traps as exists in the Bombay Shelf (excluding the Bombay High), 5 percent of the offshore area, or about 370,000 acres, is untested trap.

Percentage trap area productive

Onshore traps are less likely to be productive than adjacent offshore areas in view of unfavorable factors discussed below, such as general thinness of section, intrusives, advanced induration, and tectonization in the pre-Deccan trap sediments. It is estimated that the onshore traps are less than one-tenth as productive as either the Bombay Shelf or offshore Kutch; that is, about 2 percent of the trap area might be productive.



From: Ramaswamy, G.
and Rao, K.L.N., 1978

Figure 22.--Kutch offshore basin: Geological section B-B'.
(See figure 21 for location.)

Offshore traps which may be productive are assumed to have about half the percentage of productive area as that of the adjacent Bombay Shelf (i.e. 9 percent) since the geology, particularly the stratigraphy, though similar, is only partly analogous to the very favorable situation of the Bombay Shelf.

Stratigraphy

General stratigraphy

Onshore sediments are relatively thin (up to 8,000 ft) and are older, the strata being predominantly Jurassic, with the Cretaceous and Tertiary forming a relatively thin, discontinuous cover (fig. 20). At the coast, the Cretaceous and Tertiary strata thicken, being about 10,000 ft thick just offshore (northeast end section B-B', figs. 21 and 22). Part of the onshore is covered by the Deccan Trap, a thick (1,400-foot) section of largely volcanic rock of Upper Cretaceous-Paleocene age. The pre-Deccan Trap sediments were intruded (and presumably heated) by igneous rock at this same time.

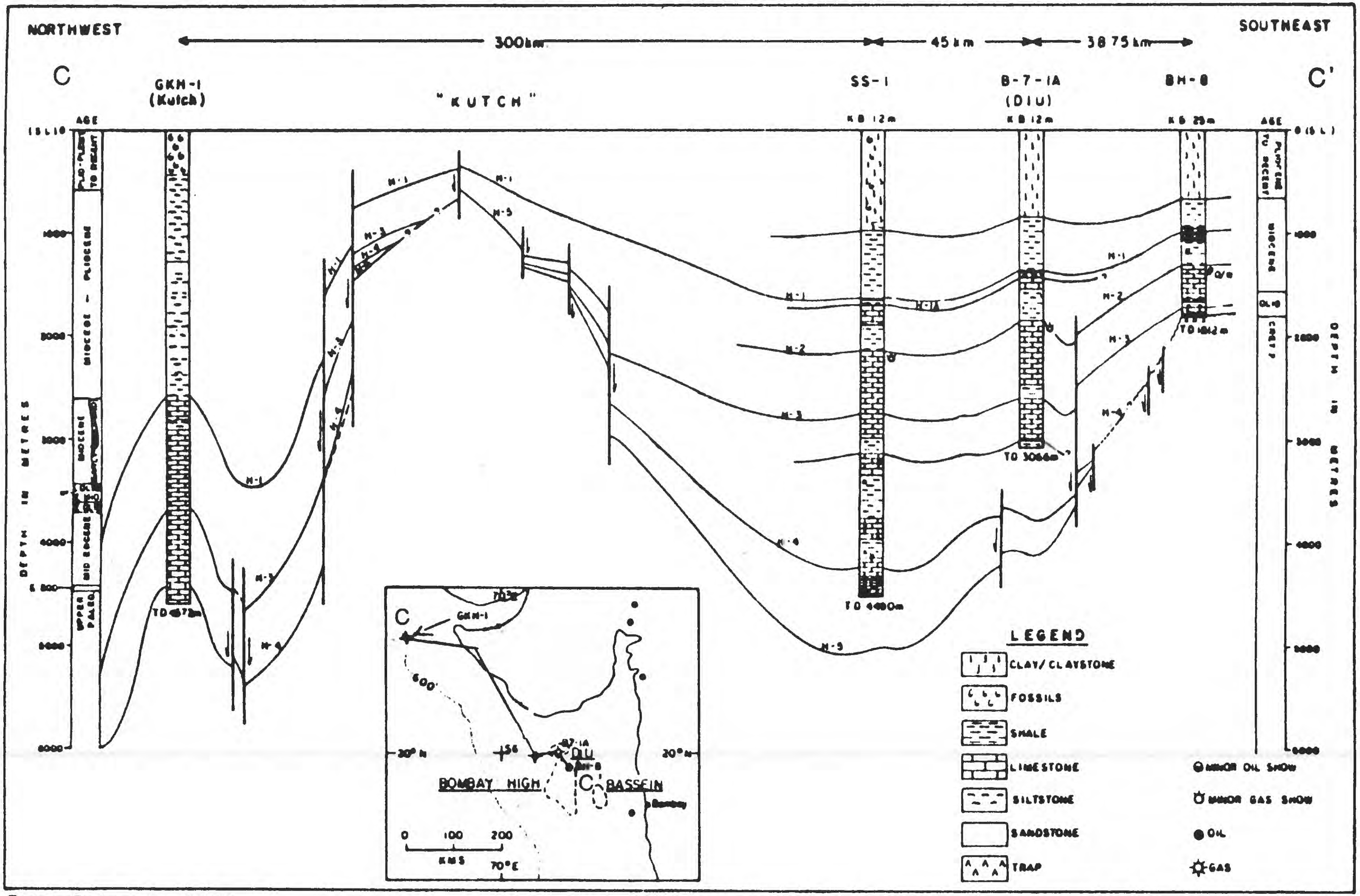
The offshore stratigraphy is well displayed in sections B-B' and C-C' (figs. 22 and 23). The sedimentary section is up to 30,000 ft thick and is some two-thirds Mesozoic and one-third Tertiary (fig. 22). This is in contrast to the Bombay Shelf section which is completely Tertiary and approximately half the thickness. The Deccan Trap, which floors the Bombay Shelf and extends over a good portion of the onshore Kutch area, appears absent in offshore Kutch west of the hinge line. The nature of the strata in the offshore area, except at the drilled H-structure, is largely unknown. However, ONGC has interpreted the strata east of the hinge line to be largely clastics, in contrast to the carbonate section to the west as substantiated by wildcat GKH-1 (figs. 22 and 23).

Reservoirs

Onshore definitive data concerning reservoirs are unavailable, but it is supposed that owing to the thinner section, the older and perhaps more indurated rock, the tectonization, and the igneous intrusions, the thickness of effective reservoirs would be considerably reduced. It is assumed that only about half the average effective reservoir thickness of the Bombay Shelf or the offshore area is present, i.e., 30 ft.

The offshore has been penetrated by one wildcat, GKH-1 (H Structure), which found no appreciable reservoirs. We believe, however, that this one well should not condemn the area as far as reservoirs are concerned. It tested none of the Mesozoic, and section B-B' (fig. 22) indicates an entirely different Tertiary facies over most of the shelf to the east of the hinge line. Section B-B' also indicates that the drilled structure, the H Structure, may be younger and therefore less prospective than the untested I and D Structures, each of which shows some thinning and carbonate development in the crestal area. In the absence of any reservoir data over most of the area, we assume that the thickness of average effective reservoirs would be about the same as that of the adjoining Bombay Shelf, i.e., 60 feet (in any case, a conservative value). If carbonate development exists over the drape features "I" and "D" as indicated on section B-B', the reservoirs could be much thicker.

GEOLOGICAL SECTION ACROSS KUTCH, SAURASHTRA, DIU & BOMBAY HIGH



From Sahay B. 1978

OIL & NATURAL GAS COMMISSION
BOMBAY OFFSHORE PROJECT

FIGURE 23

Seals

Onshore seals are probably inefficient given the more severe faulting and thinness of the section. Offshore it can only be assumed that the seals are probably as effective as those of the Bombay Shelf, which have been deemed 70 percent effective.

Source-rock section

By analogy to the adjacent on-trend Bombay Shelf to the south, some source rock may be expected in the Paleocene to Early Miocene part of the section. However, by analogy to the Indus Basin to the north, source rocks are more likely limited to the Mesozoic part of the section, and this is supported by the lack of source rock found in the single Tertiary test, GKH-1 (see Generation and Migration below).

Generation and Migration

Richness of source

The single offshore wildcat, GKH-1, penetrated the Tertiary section down to the upper Paleocene and found the "organic carbon in the drilled section unusually low" (Mitra, P. and others, 1983). On the other hand, "samples from the shallower part of the basin (onshore Kutch Shelf) show immature but adequate organic content" (Biswas, 1982); these rocks are presumably Mesozoic since the outcrops are largely of that age.

Offshore wells of the adjoining gas-rich Indus Basin, drilled just to the north of the Kutch Shelf, have encountered no adequately rich source rock. Since the drilling penetration was largely limited to the Tertiary, we have assumed that the gas-source rocks of the Indus Basin must be of pre-Tertiary age.

On the above basis, it appears that there may be adequate organic material on the Kutch Shelf, but it would be largely confined to the Mesozoic.

The source rock of the Bombay Shelf adjoining to the south appears to be largely shales of deltas of ancestral rivers emerging from the Cambay estuary, which are largely missing in the Kutch sedimentary section (Tertiary and Mesozoic). Accordingly, it is assumed, for evaluation purposes, that the average quantity of organic matter in the offshore Kutch sedimentary section may be only half that of the Bombay Shelf and would produce proportionately less petroleum accumulation.

Depth and volume of mature sediments

No thermal information is available, but the proximity of the Bombay Shelf and Cambay Graben, with thermal gradients of around 3° F/100 ft, and the Indus Basin immediately to the north with gradient of 2° F/100 ft suggests an intermediate gradient, which places the depth to thermally mature rock at 7,000 or 8,000 ft. This indicates a large volume of mature or over-mature source rock in the offshore play, 35,000 mi^3, most of which is Mesozoic strata. The onshore portion of the basin, however, with an estimated average depth of only 8,000 ft can only have a negligible thickness of source strata.

Oil versus gas

In the absence of any production, it is assumed that the percentage of undiscovered oil versus gas would be intermediate to the adjoining basins or about 30 percent (Bombay Shelf 55 percent oil and Indus Basin 5 percent).

Migration timing versus trap formation

Offshore, as in the other rifted continental margin basins, the closures are largely fault-traps or drapes over basement ridges formed near the end of the Mesozoic during the India-Africa pull-apart. Figure 22 shows, however, that features I and D were growing during the Mesozoic, and in fact are older east-west-trending features in line with the onshore structure. In any case, it appears that trap formation could be as early as Jurassic. If there was a uniform subsidence rate and a thermal gradient of 2.5° F/100 through the Tertiary and late Mesozoic, generation and migration would commence when sediments had subsided to 7,000 or 8,000 ft (2,500 m). Assuming Jurassic sediments were sufficiently organically rich, generation and migration would, accordingly, have begun in the early Cretaceous and filled the indicated potential Jurassic carbonate reservoirs, depending on reservoir preservation. Much of this hydrocarbon would be too early, however, for Bombay Shelf type of drape traps occurring in the early Tertiary. Eocene shales, such as generated oil in the Bombay Shelf and Cambay Graben, however, would under the above assumptions begin to generate and migrate in the Miocene filling Eocene reservoirs.

Onshore, however, little generation or migration would occur owing to insufficient depth of subsidence.

Limiting Factors

In the absence of more complete information, it appears that the overriding limiting factor in this area would be the same as that for the adjoining Bombay Shelf, namely the thinness of effective reservoirs. This apparent limitation is supported by the lack of reservoirs in the wildcat, GKH-1. In the onshore area, lack of sufficient reservoir is joined with the small volume of source rock.

Indus Basin, Foreland and Foldbelt Plays

Introduction

Location and size of area

The Indus Basin occupies the eastern two-thirds of Pakistan (figs. 1 and 24). Its western boundary is the Kirthar Range, its eastern boundary is approximately the Indian boundary (about 8 percent extends into India), its northern boundary is the Sargodha High and Salt Range (figs. 24 and 31), and its southern boundary is taken, for simplicity, to be the edge of the offshore continental shelf (thereby omitting the large but poorly prospective volume of the Indus Cone). The Indus Basin, as defined, has an area of some 125,000 mi^2 and a volume of sediments of approximately 400,000 mi^3 (fig. 24).

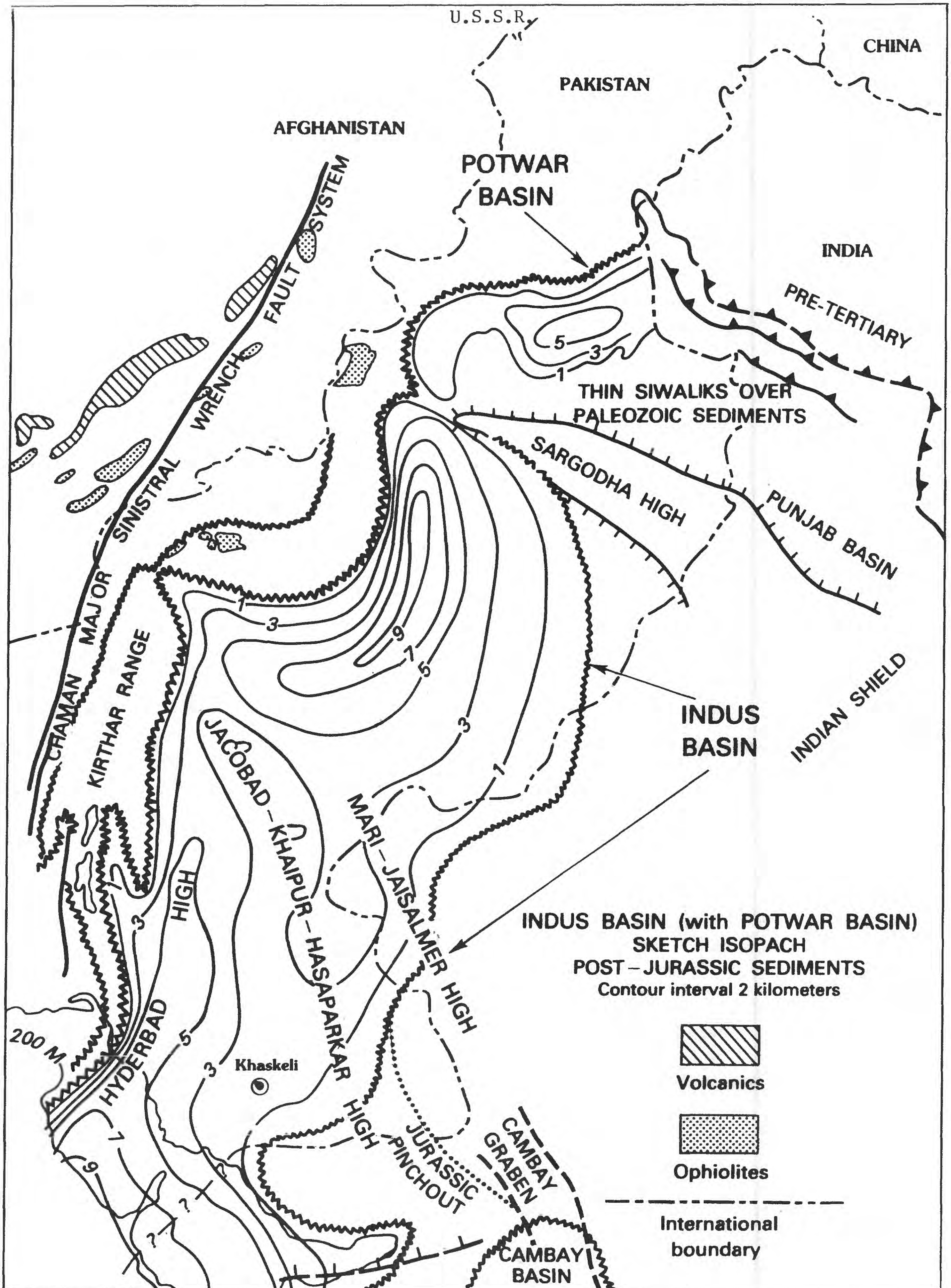

U.S.S.R.
CHINA
PAKISTAN
AFGHANISTAN
POTWAR BASIN
INDIA
PRE-TERTIARY
THIN SIWALIKS OVER PALEOZOIC SEDIMENTS
SARGODHA HIGH
PUNJAB BASIN
CHAMAN MAJOR SINISTRAL WRENCH FAULT SYSTEM
KIRTHAR RANGE
INDUS BASIN
INDIAN SHIELD
JACOBAD-KHAIPUR-HASAPARKAR HIGH
MARI-JAISALMER HIGH
HIGH
HYDERBAD
200 M
Khaskeli
JURASSIC PINCHOUT
CAMBAY GRABEN
CAMBAY BASIN
INDUS BASIN (with POTWAR BASIN)
SKETCH ISOPACH
POST-JURASSIC SEDIMENTS
Contour interval 2 kilometers
Volcanics
Ophiolites
International boundary

Figure 24

Hydrocarbon exploration and production history

Some petroleum exploration goes back to the period from 1886 to 1894, when 20,000 barrels of oil were produced from Khattan (fig. 25), a small accumulation in the central part of the foldbelt. Oil exploration and production have been active in the basin immediately to the north in the Potwar Basin through the years since; but serious, comprehensive exploration in the Indus Basin did not begin until after World War II. The Sui gas field was discovered in 1952 (fig. 25), and since then some 13 gas discoveries have been announced, but apparently only four fields are being produced: Sui, Mari, Sari Sing, and Hundi, of which Sari Sing and Hundi are of minor importance. The Sui production makes up over 80 percent of the country's gas production. From a count of the modern wells, a successful wildcat ratio of 12 percent is estimated as applied to gas. For oil it is much lower; after many years of wildcatting, a discovery was made in 1981 at Khaskeli (figs. 27 and 24). This discovery, along with several nearby subsequent oil discoveries, has been developed into small oil fields with overall estimated reserves on the order of 50 million barrels of oil. It is judged that the exploration of the basin is at a stage of early maturity, that is, about 70 percent of the hydrocarbon may have already been found. Gas reserves amounting to approximately 22 Tcf appear to be established.

Structure, Foreland

The structure of the Indus Basin is in two plays, the foreland and the foldbelt, which are of different structural styles and tectonic history and therefore are discussed separately.

General tectonics

The foreland has an area 80,000 mi^2 and a sedimentary volume of approximately 165,000 mi^3. The structure is hidden beneath an alluvial plain on the eastern part of the basin; however, some data indicate the existence of subsurface low-amplitude fault-blocks and drape features (figs. 24 and 25). We believe that horst and graben features associated with the rifted continental margin of the western India Continental Block provide the structural framework for the area (our north-trending contours drawn from meager information suggest this trend, fig. 24).

Untested trap area

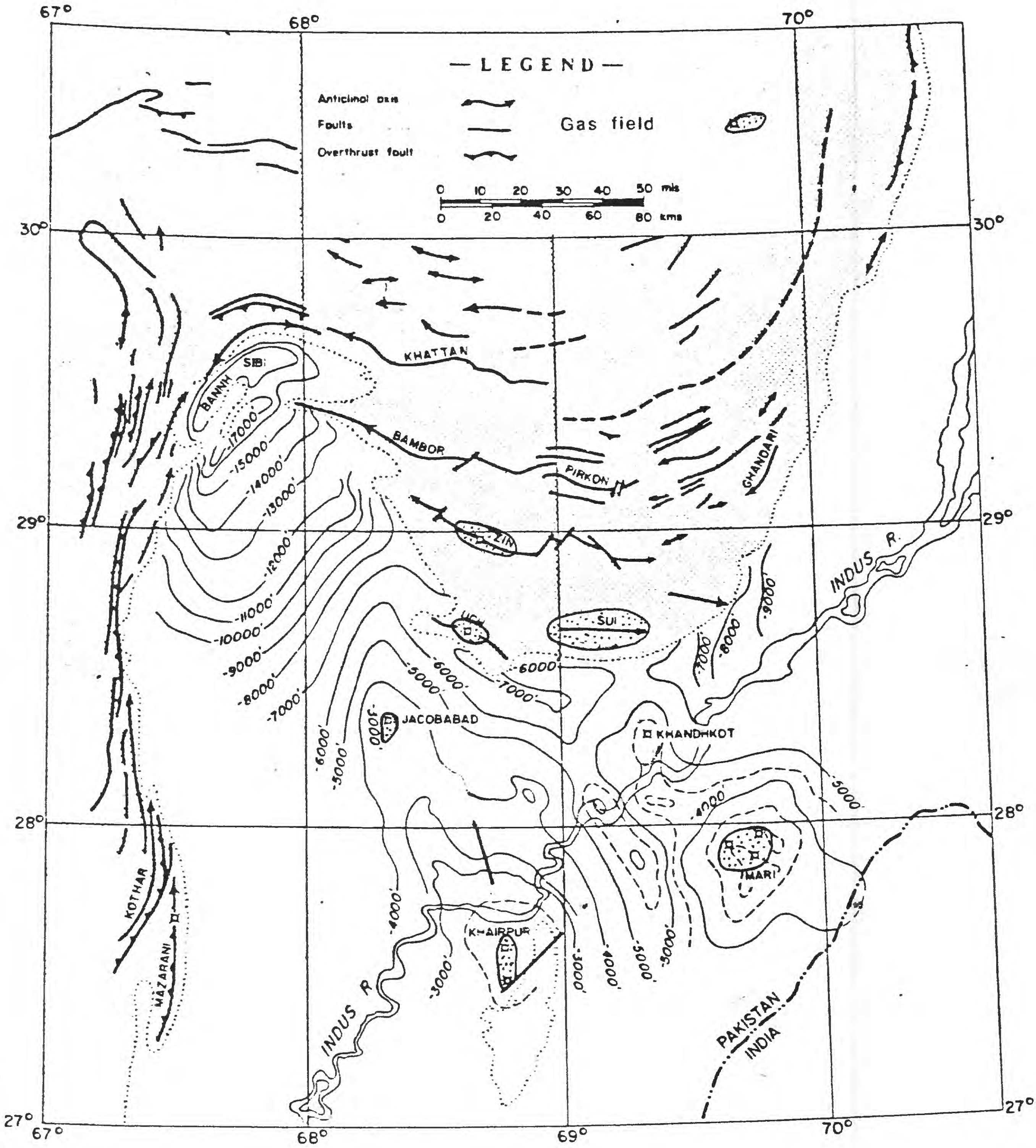
We assume that the foreland area is on the Cretaceous rifted continental margin of the India Continental Block and has a subsurface structure similar to the on-trend basins of the present Indian west coast. Assuming that the size and density of traps are similar to those of the Bombay Shelf, excluding the Bombay High (i.e., approximately 5 percent of the play area), the trap area of the Indus Basin foreland is 2.5 million acres. However, an estimated 0.5 million acres of closure have been tested, leaving 2 million acres of trap area untested for one reason or another.

Percentage untested trap productive

Only data from one closure (fig. 25), Khairpur, were available to make an estimate of petroleum areal fill. It appears to be about 45 percent

PAKISTAN

STRUCTURAL TRENDS IN GAS FIELDS REGION



After Khan, A.H. and Azad, J., 1963

Modified from Petroconsultants Ltd.

Figure 25.

filled, and this is assumed to be the average for all the closures of the Indus Basin foreland. Considering all the small announced discoveries, it is estimated that the wildcat success ratio is about 12 percent, indicating that an overall 5.4 percent of the shelf's untested closure-area has petroleum.

Structure, Foldbelt

General tectonics

The foldbelt has an area some 45,000 mi^2 and a sedimentary volume of approximately 181,000 mi^3. The belt is an elevated zone which extends along the west boundary of the basin and is characterized by compression features such as anticlinal folds and thrusts. It appears to be the result of an oblique collision between the north-moving Indian Continental Block and the previously docked Afghan Blocks, including a large wedge of flysch and melange which has accreted south of the Afghan blocks along the Makran coast (figs. 24 and 32). Accompanying the collision there appears to have been a certain amount of oblique subduction, the India Continental Block riding under both the Afghan Block and the southern accretionary prism as the block wedged northward between the Afghan and Sunda Blocks (fig. 2). A line of ophiolites is seen along the axis of the foldbelt. Extensive, regional, sinistral wrenches occur largely in the block being underthrusted, i.e. the Afghan Blocks (fig. 24).

Untested trap area

By measurement from a 1:2,000,000-scale geologic map (Baker and Jackson, 1964), it is estimated that anticlinal traps make up some 3,000 square miles, or 7.6 percent, of the area, and approximately half of this remains as viable, untested trap area of some 1 million acres.

Percent trap area productive

The Sui gas field (fig. 25) has an estimated hydrocarbon areal fill of 37.5 percent, which number we will assume as an average fill for the Indus Basin foldbelt closures. The petroleum (gas) wildcat success rate is about 12 percent, indicating that 4.5 percent of the remaining untested closure area contains petroleum.

Stratigraphy

General stratigraphy

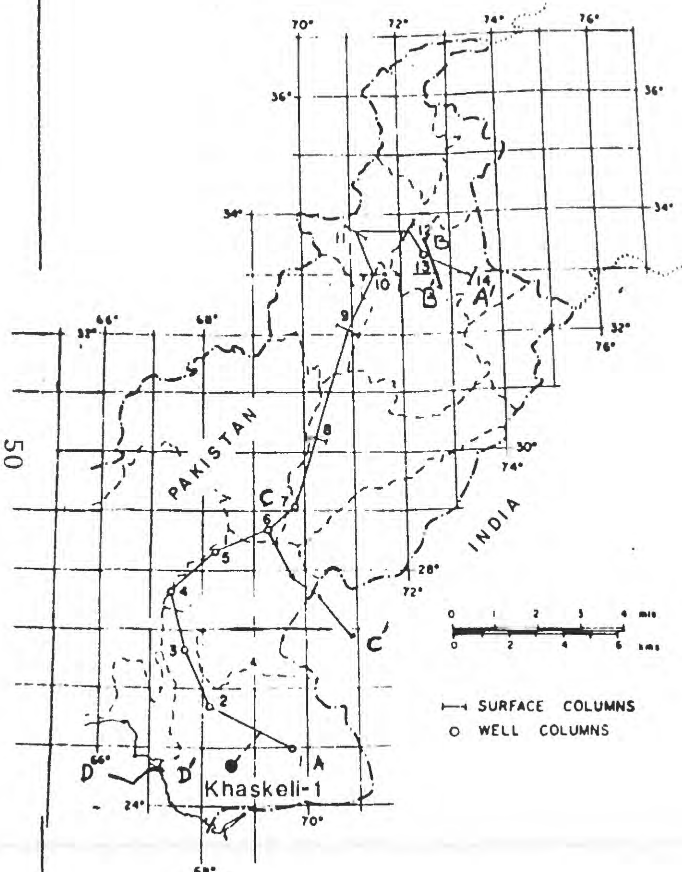
The stratigraphy for both the foreland and the foldbelt is similar. A general stratigraphic column and section are shown in figures 26 and 27. The total thickness of the stratigraphic section is really not known. The sketch isopach of the Indus Basin (fig. 24), limited by lack of deep data, shows only the post-Jurassic thickness. In the northeast foreland, the section actually extends down into the pre-Cambrian (Rahman, 1963), and sections measured on the western perimeter of the basin (C-C', fig. 28) indicate the Jurassic and pre-Jurassic basin is very deep and thick. On the basis of the post-Jurassic isopach, the volume of the Indus Basin sediments is calculated to be 260,000 mi^3, but the total volume of sediments is estimated to have an approximate volume of at least 400,000 mi^3. As may be seen from the general

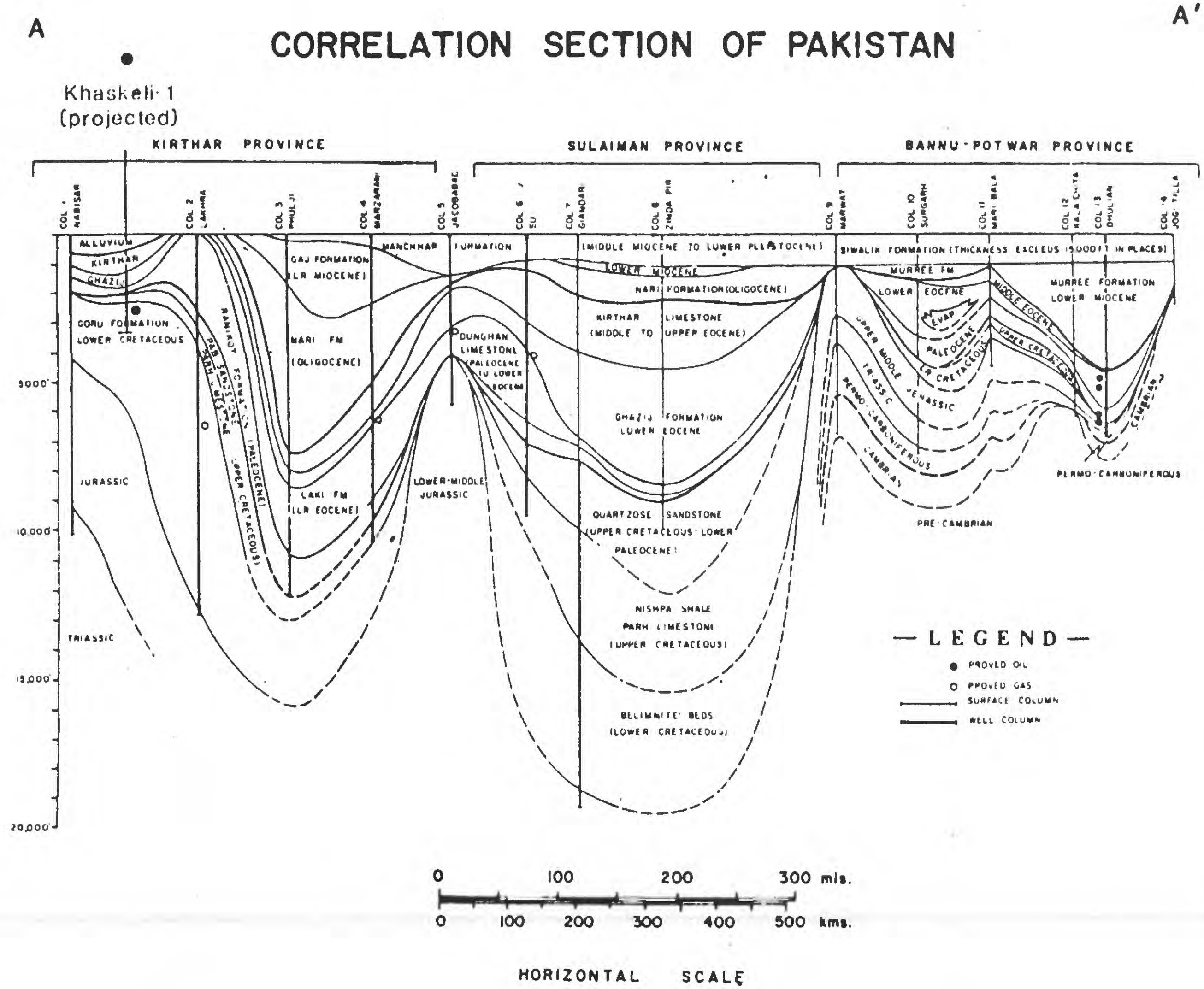
AGE		ROCK UNITS	LITHOLOGY	THICKNESS	RESERVOIR
QUATERNARY		Alluvium			
MIOCENE	Upper, Middle	SIWALIK SIBI GROUP		0–4500 Var	
MIOCENE / OLIGOCENE	Lower	Nari Formation		Var	
EOCENE	Upper	Kirthar Formation: Pirkoh Lst, Habib Rahi Lst.		300-500m	☼
EOCENE	Middle, Lower	Sui Upper Lst., Ghazij Formation, Sui Main Lst.		350-600m	☼ ☼
PALEOCENE		Dunghan Formation		Var max 600m	☼
PALEOCENE		Ranikot Formation		Up to 60m	
CRETACEOUS	Upper	Pab Sandstone		0–500m	
CRETACEOUS	Upper	Mughal Kot Formation: Fort Munro Limestone Member		45–100m	
CRETACEOUS	Upper	Mughal Kot Formation		270–330m	
CRETACEOUS	Upper	Parh Limestone		Up to 300m	
CRETACEOUS	Lower	Goru Formation		Up to 500m	●
CRETACEOUS	Lower	Sembar Formation		Up to 260m	
JURASSIC	Upper	SULAIMAN LIMESTONE GROUP: Takatu Limestone, Anjira Formation, Loralai Limestone		Up to 1400m	
JURASSIC	Middle, Lower	Spingwar Formation		650-1800m	
TRIASSIC		Wulgai Formation		1170m	
PERMIAN		?		?	

Figure 26.--STRATIGRAPHY OF SULAIMAN SUB-BASIN (PAKISTAN).

From Petroconsultants Ltd.

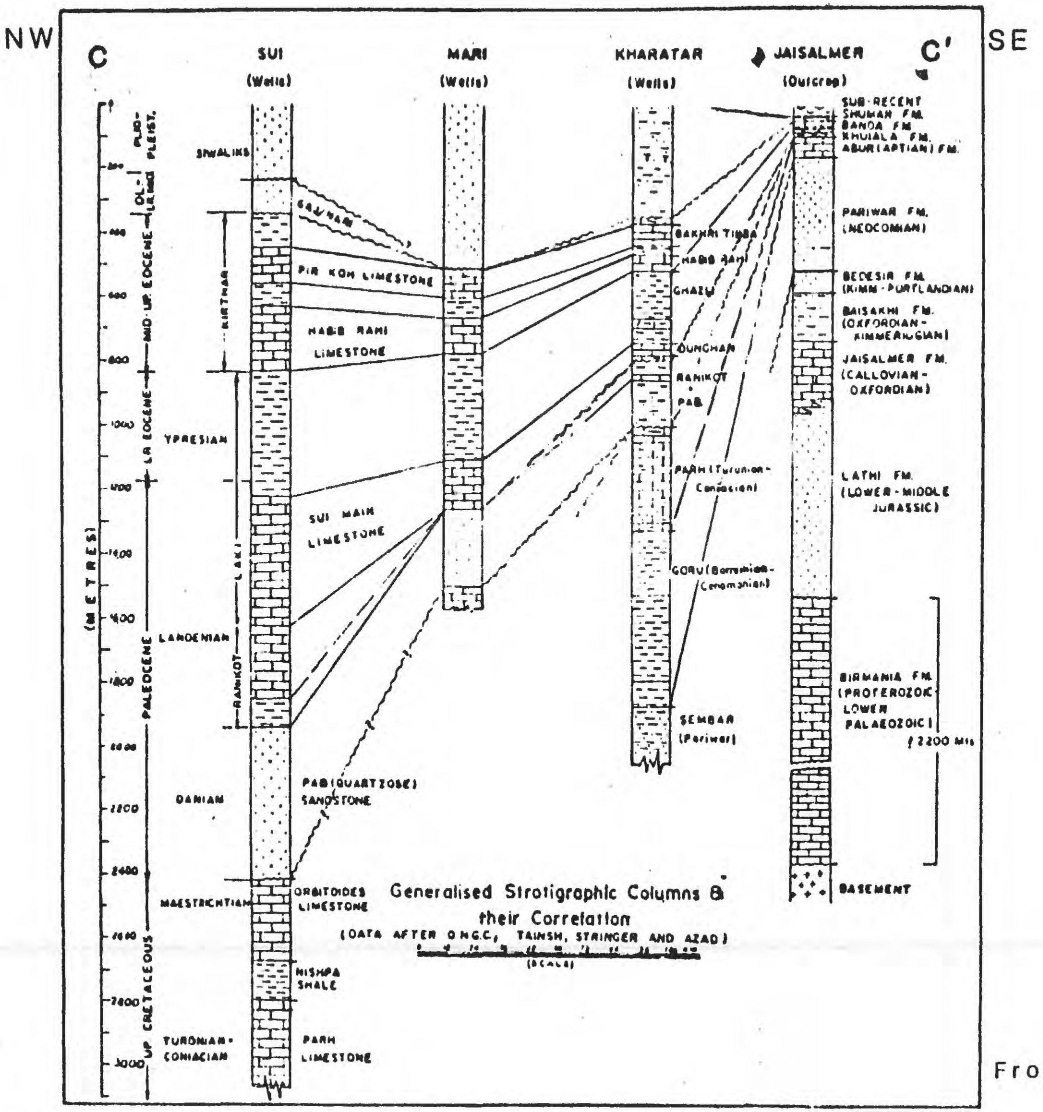
PAKISTAN

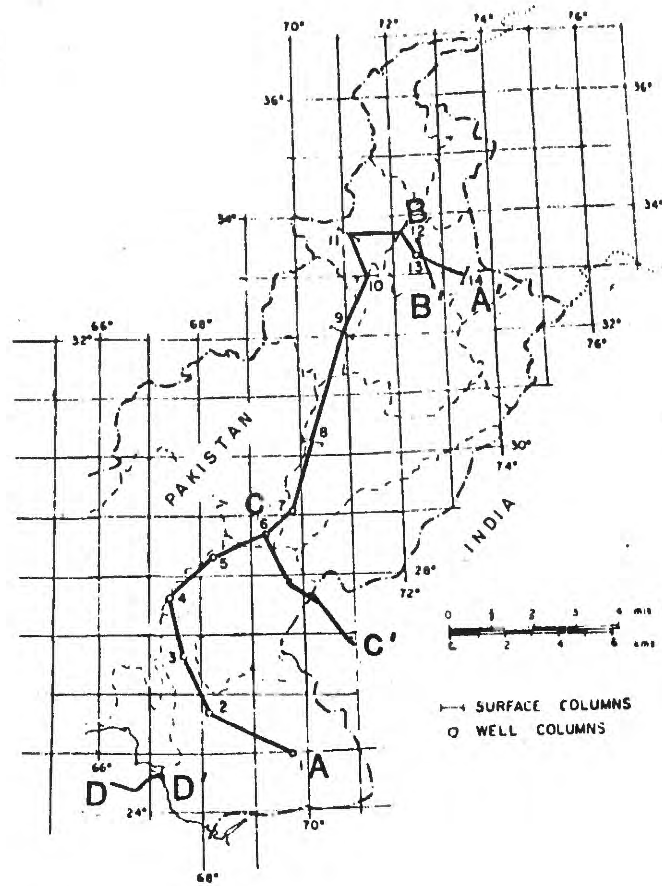




After: Rahman, H. 1963

Figure 27.





From: Rao V.R. 1972

Figure 28.--Generalized stratigraphic columns, C-C'.

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stratigraphic column, the section is largely carbonate and shale. There are three relatively coarse clastic zones: the Early Cretaceous (particularly the Goru Formation), the Paleocene-Late Cretaceous, and the Oligocene to Present (fig. 26). These coarser clastic zones may be related successively to the early rifting associated with the pull-apart, to the first collision with the Afghan Blocks, and to the collision with the Asian continental mass.

The Indus Cone, part of which is omitted by limiting this study to the continental shelf, reaches a thickness (Miocene to Recent) of some 10,000 ft and has an area more than 50,000 mi^2. A lack of reservoirs and sufficiently rich source beds downgrades this wedge of sediments, particularly for oil versus gas (see Richness of source).

The lateral distribution of the Indus Basin formations is displayed in section A-A' (fig. 27). Particular notice should be taken of the lack of Neogene deposition/subsidence and widespread Neogene erosional unconformities.

Reservoirs

The gas discoveries to date are in carbonate reservoirs of Paleocene to Eocene age, i.e., the Sui Main Limestone, the Sui Upper Limestone, and the Habib Rabi Limestone (fig. 26). The total thickness of effective reservoir (Sui Main and Sui Upper Limestones) is 206 plus 50, or 256 ft (Tainsh, 1959). In the absence of any other values this is taken to be the average effective pay for the foldbelt play. Apparently the foreland closures have thinner reservoirs. The Khairpur effective pay thickness of 130 ft is taken as an average for the foreland play. The carbonate porosities appear to be low, averaging 12 to 19 percent at Sui (Main Sui Limestone); the average for the whole basin is taken to be 17 percent.

The Khaskeli oil reservoir is in the Goru Sandstone and would be handled as a separate play if more data were available. The effective reservoir thickness at Kashkeli is apparently 60 ft. Sand porosities average near 17 percent (21 percent Cretaceous sandstone at Dhodak, perhaps 15 percent at Mazarini, and 13 percent in Paleocene sandstones at Hundi).

Seals

In general, with about 50 percent shale in the section, the present seals should be good, say 70 percent effective. Probably, however, much hydrocarbon leaked out of the basin during the Neogene when the area was high and being eroded.

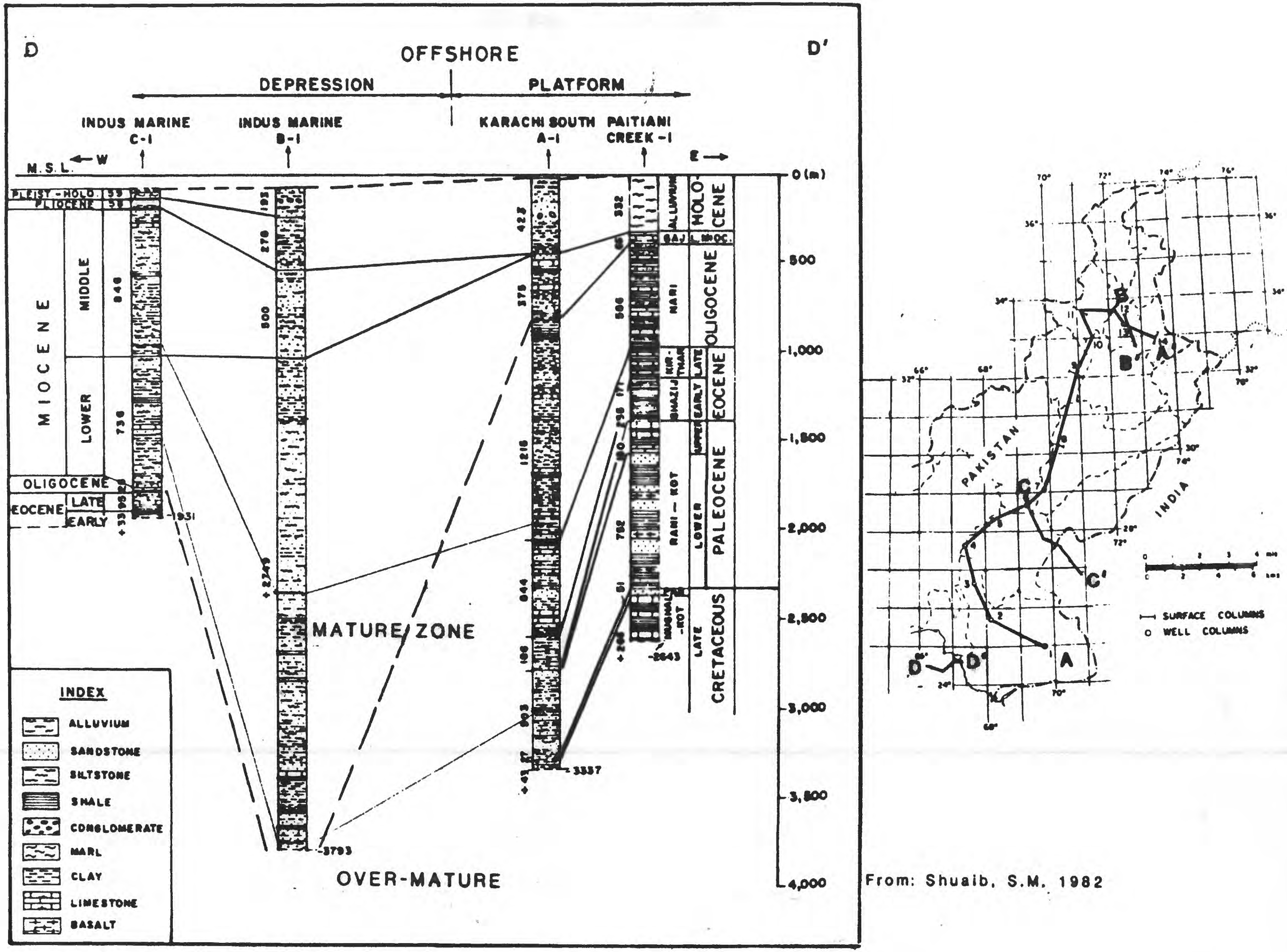
Source rock section

Source rocks apparently have not been identified in the Indus Basin, but for reasons given below, they are believed to be largely confined to the pre-Tertiary.

Generation and Migration

Richness of source

No information is available indicating strata sufficiently organically rich to source petroleum. The only available data are from four offshore wells, Indus Marine A, B, C, and Karachi South A (fig. 29), which completely



From: Shuaib, S.M. 1982

Figure 29.--Offshore Indus basin, section D-D'.

penetrated the Tertiary but barely entered the Mesozoic strata. They found that "no rich source rocks are present in any of these wells, due to insufficient hydrocarbon content and poor quality of organic material" (Shuaib, 1982). The offshore Tertiary stratigraphy is of the same open-marine shelf environment as the remainder of the Indus Basin, and it therefore is assumed that the Tertiary of the whole basin is probably organically poor. Source rock is present, however, as indicated by the large quantities of gas, and it appears that the principal source rock must be in the pre-Tertiary section. The richness of this source is in part indicated by the trap fill, 37.5 percent in the folds (the Sui field) and 45 percent in the foreland (at Khairpur).

Depth and volume of mature sediments

From a number of thermal gradient determinations, it appears that the basin is relatively cool, having an average gradient of about 2° F per 100 ft of depth. This, together with the rather low subsidence rate, especially in the Neogene, puts the calculated top of the mature zone between 8,000 and 9,000 ft and the top of the over-mature zone from 11,000 to 13,000 ft. Very approximately, over a good part of the basin, this places the mature zone in the lower Tertiary and upper Cretaceous, and the over-mature zone in the older rock (compare depth to Section A-A', fig. 27). Actual measurements of maturity on four offshore wells show the mature zone somewhat shallower but confirm this general concept (fig. 29).

It would appear that the present mature zone is a section of Tertiary sediments which are organically poor, while the over-mature zone is primarily pre-Tertiary rock of unknown organic richness, but which must be presumed to contain enough organic material to source the Indus Basin gas fields. We estimate there is at least 180,000 mi^3 of mature or over-mature sediment.

Oil versus gas

The Indus Basin is generally considered a gas-prone basin, and reserves of some 22 Tcf have been established. The gas is relatively dry (1.7 percent hydrocarbons other than methane) and may contain up to 70 percent carbon dioxide and up to 38 percent nitrogen. The ethane to methane ratio is .015, suggesting a mixture of epimorphic (thermally over-mature) gas and petroleum (thermally mature) gas. Oil seeps and shows, however, have been found in the foldbelt emanating from Cretaceous and Tertiary strata. Recently, oil discoveries were made at Khaskeli and at several nearby fields in the south-central foreland area from upper Cretaceous (Goru F.) sandstone (fig. 27). These appear to be small accumulations, but significant since they are oil. The gas-proneness or general lack of oil in the basin may be explained (as indicated above) by the fact that in general the thermally mature zone (i.e. "the oil window") largely coincides with only the low-organic-content Tertiary sediments. The presence of gas, on the other hand, is attributed to over-maturation of the presumably richer pre-Tertiary rock.

This gas-prone generality, however, does not mean that oil may not occur in commercial quantities within the basin. For instance, the Khaskeli structure is situated on the edge of the basin where the presumably rich Cretaceous and even perhaps Jurassic strata are shallow enough (7,000 to 13,000 ft) to be within the mature zone (or oil window). Oil, besides gas, could generate from the pre-Tertiary strata and migrate into the Khaskeli structure and other structures in a similar shallow basin position (figs. 24 and 27 where the Khaskeli has been projected onto regional section A-A'). Oil seeps in the foldbelt may be similarly explained. For evaluation purposes it is estimated that the oil portion of the hydrocarbon fill of untested traps is perhaps 5 percent.

Migration timing versus trap formation

Assuming a constant subsidence and thermal rate through the Tertiary and Mesozoic, generation and migration would have begun when the sediments reached a depth of 8,000 to 9,000 ft, which would be sometime in the Jurassic or even Triassic. The horst and graben features of the foreland presumably originated in the Cretaceous, but the draped reservoirs and seals could be Tertiary. The anticlines of the foldbelt are largely Neogene. The Indus Basin area has been high during the Neogene, resulting in widespread erosional unconformities. It would appear, therefore, that migration began before formation of present traps and petroleum leaked to the surface during the Mesozoic and perhaps the early Tertiary so that a considerable portion of the petroleum derived from the 180,000 mi^3 of mature or over-mature sediment was lost. The lost hydrocarbon could have been largely oil; only the remnant, locked-in, originally unmigrated petroleum may have finally migrated after continued subsidence and heating cracked it to epimorphic methane gas.

Limiting factors

The overriding limiting factor as concerns oil is that the younger strata (i.e. Cretaceous to Tertiary), which are within the "oil window" and which could have generated oil, are organically poor. Older rocks may have yielded oil but it has escaped. Gas is generating and migrating, presumably from remnant, cracked petroleum molecules in pre-Tertiary strata.

Potwar Basin

Introduction

Location and size of area

The Potwar Basin is located in northern Pakistan and is separated from the on-trend Indus Basin to the south by the Salt Range and the Sargodha High. It is also in part an extension of the Indo-Gangetic trough of India, which lies along the base of the Himalayas (figs. 1, 24, and 31). It is a relatively small basin, having an area some 8,500 mi^2 and approximately 38,000 mi^3 of sediment.

Exploration and production history

Exploration around oil seeps began in 1912, and the first oil field, Khuar, was discovered in 1915, followed in 1935 by Dhulian, both on the basis of outcrop geology. Joya Mair was found in 1944 on the basis of seismic survey, followed in short order by Balkassar and Karsal. Tut and Meyal were found in 1968 and Adhi in 1978. A promising but as yet unevaluated discovery, Dhurnal, was made in 1984. The success ratio was reported as 33 percent in 1963 but since then has declined probably to 20 percent. We estimate that

AGE		ROCK UNITS		THICKNESS	RESERVOIR	SOURCE ROCK
QUATERNARY		Alluvium		Var		
PLIOCENE		SIWALIK GROUP		Var up to 5000m		
MIOCENE	Upper					
	Middle	RAWALPINDI GROUP	Kamlial Formation	Up to 3000m		
	Lower		Murree Formation		●	
OLIGOCENE						
EOCENE	Middle	CHHARAT GROUP	Kohat Formation	10-20m		
			Mamikhel Clay	Var		
			Chor Gaili Fm. / Bhadrar Fm.	50-200m	●	
	Lower	Panoba Shale		Var		▬
		Sakesar Limestone / Shekhan Limestone		100m	●	
		Nammal Formation		40-100m		
PALEOCENE		Ranikot - Patala Formation		40-70m		▬
		Lockhart Limestone		10-50m	●	
		Hangu Formation		5m		▬
		Dhok Pass Formation		20m		?
CRETACEOUS	Upper	Darsamand Limestone / Kawagarh Marl		Up to 100m		▬
		Lumshiwal Sandstone		Up to 300m		?
	Lower	Chichali Formation				▬
JURASSIC	Upper	Samana- Suk Limestone		Up to 500m		
	Middle	Datta Formation			●	▬
	Lower					
TRIASSIC	Upper	Kingriali Dolomite		50m		
	Middle + Lower	Khatkiara Sandstone Member Landa Member Narmia Member		50m		
		Mittiwali Member		100-200m		
PERMIAN	Upper	ZALUCH GROUP		90-230m		
	Middle	NILAWAN GROUP		30-100m		
				100-150m		
	Lower			20-50m		▬
CARBONIFEROUS		Talchir Boulder Formation		0-60m		
CAMBRIAN		JHELUM GROUP		100m		▬
				20-75m		
				40-60m		▬
				150-200m		
		Salt Range Formation		Up to 2000m		
		Igneous and metamorphic rocks				

Figure 30.--STRATIGRAPHY OF KOHAT-POTWAR SUB-BASIN (PAKISTAN).

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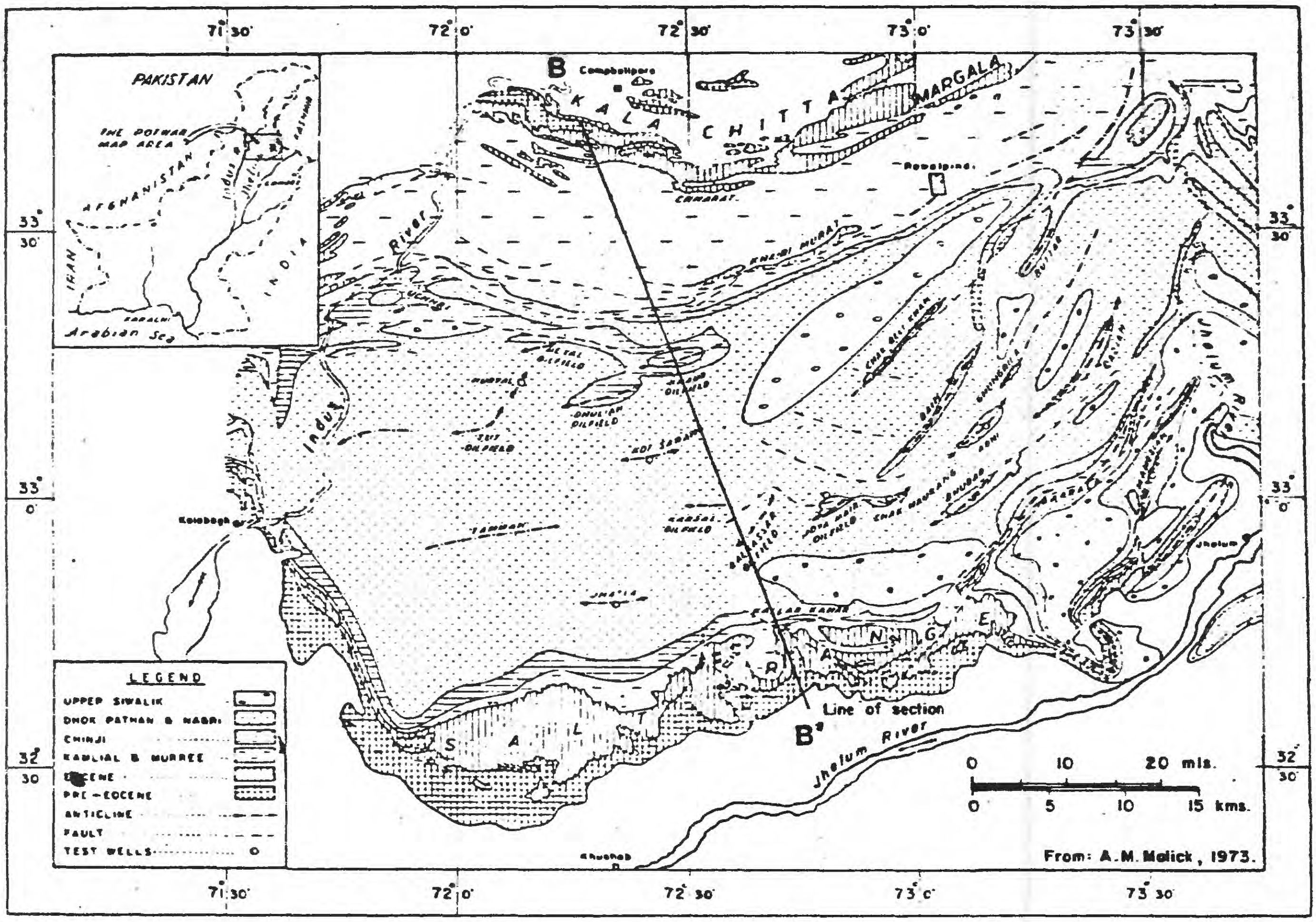
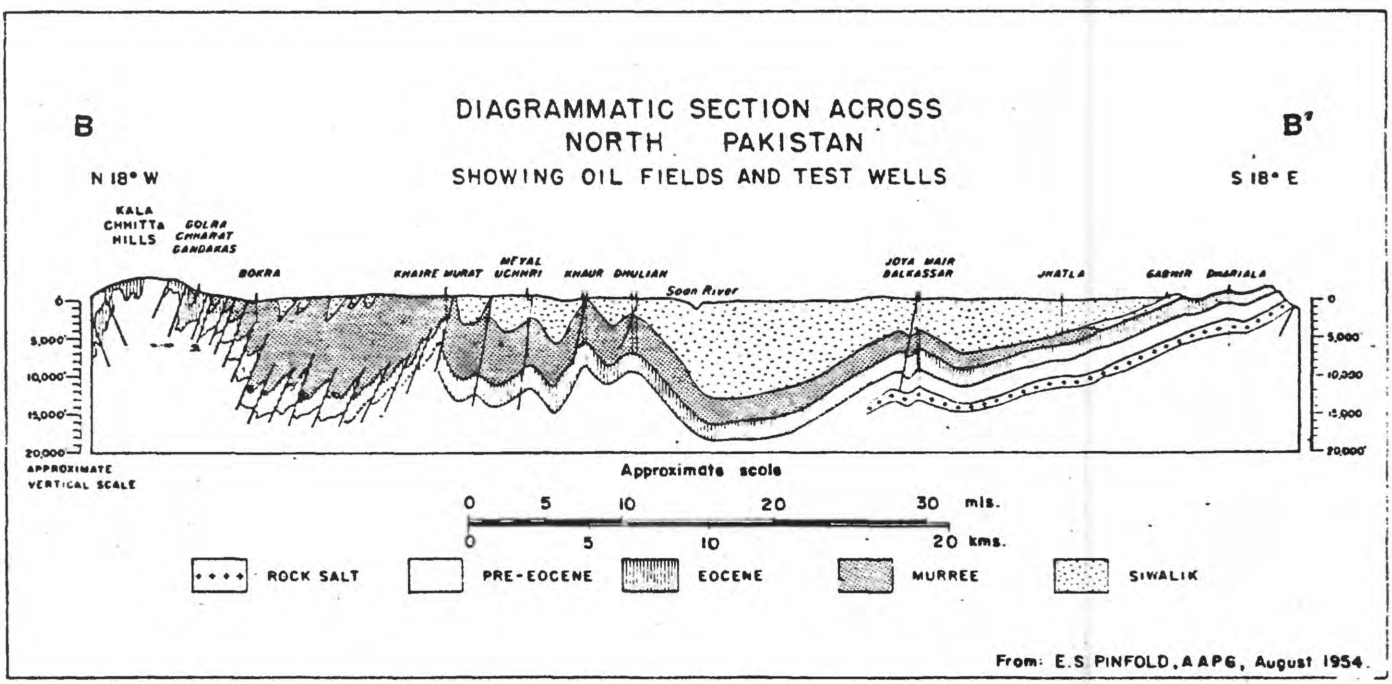
GEOLOGICAL MAP OF THE POTWAR BASIN





After : Petroconsultants LTD

Figure 31.--Geologic map and diagrammatic section, B-B', Potwar basin.

over 100 wildcat/appraisal wells have been drilled, and this small basin may be considered maturely explored; perhaps 80 percent of the hydrocarbon has been found. The approximate reserves are estimated to be 200 million barrels of oil and minor amounts of associated gas.

Structure

General tectonics

From the pre-Cambrian through the Mesozoic, the basin area was part of a craton margin basin, as attested by the relatively thin, shelf formations (figs. 27 and 30). During Late Mesozoic and Tertiary, it may have been affected somewhat by the India-Africa pull-apart continental margin rifting, probably triggering movement of the Cambrian salt and restricting the basin to some extent from the open sea. In the Miocene, a deep trough or foredeep developed in association with the collision of the Indian Continental Block with the Asian mass.

Untested trap area

No detailed structural data are available. The estimated total size of present fields is about 28,000 acres. On the basis of 30 percent areal petroleum fill and 20 percent wildcat success ratio (Percentage Trap Area Productive below), 467,000 acres of trap area were tested in discovering the fields. Assuming the exploration is 80 percent complete (Hydrocarbon Exploration History), there are 117,000 acres of untested trap remaining.

Percentage trap area productive

The present wildcat success rate (i.e., the percentage of tested traps which contain recoverable petroleum) is estimated to be 20 percent. The percentage of fill of those traps containing hydrocarbon ranges from an estimated 7 percent for Laki (Lower Eocene) oil in Dhulian to 47 percent for Ranikot (Paleocene) oil in the same structure (Day, 1963). In the absence of further information, 30 percent is assumed to be the average hydrocarbon fill for Potwar traps. Thirty percent times 20 percent yields 6 percent as the area of the untested traps likely to contain hydrocarbon.

Stratigraphy

General

A general stratigraphic column for the Potwar Basin is shown in figure 30. Except for unconformities which cut out the middle Paleozoic and the Oligocene, almost a complete section from the Cambrian to Quaternary is present in the west, but to the east the Oligocene unconformity gap widens so that at the east end of the basin, Miocene rests on Cambrian strata. The total thickness and lithology of the lower part of the section are rather unknown quantities owing to lack of deep data. A post-Jurassic maximum thickness of 17,000 ft is estimated, but the total thickness may be much more. A maximum sedimentary volume of 38,000 mi^3 is assumed.

Reservoirs

The producing reservoirs are mainly Paleocene and Eocene carbonates, although some oil comes from Jurassic and from Lower Miocene sandstones (Day, 1963). The carbonate reservoirs are generally thin and of poor quality. The only precise thickness data is from Dhulian, where the total effective thickness of two producing reservoirs is 62 ft. Sixty feet is therefore assumed to be an average effective reservoir thickness for the basin. The porosity is fracture-produced and is generally low, ranging from 6 to 11 percent at Tut; perhaps 11 percent can be assumed for the average produceable zone. The Jurassic sandstones are reportedly "the best." Lower Miocene reservoirs may be good, but are of minor importance because of weak seal.

Seals

There is some leakage as indicated by surface seeps. However, in light of the generally poor porosity (and presumed poor permeability) of the whole section, including producing reservoirs, seals should be good, perhaps 80 percent effective below the Miocene clastics.

Source rock section

There is no information available concerning source, but evidence points to varied sources from the Cambrian to Eocene (Generation and Migration below).

Generation and Migration

Richness of source

No measurements of organic content have been published, but the type of oil (some waxy, some asphaltic) and its distribution point to several sources widely spread over the section. The deepest source may be from the Cambrian, as thick bitumen was discovered in a wildcat at Karampur (200 miles south of the basin). The Jurassic production is probably from adjoining or underlying shales. The source of the Paleocene-Eocene reservoired oil is probably from adjoining shales, the organic matter being preserved in a restricted environment as indicated by evaporites. Source richness is probably not the factor limiting hydrocarbon accumulation in this basin.

Depth and volume of mature sediments

The average thermal gradient for the Potwar Basin is somewhat lower than the Indus Basin (2°F/100 ft) and is taken to be 1.76°F/100 ft (gradient at Dhulian). This, taken with the rather high post-Oligocene subsidence rate, places the top of the mature zone at 9,000 ft. The volume of mature sediments is approximately 30,000 mi^3.

Oil versus gas

Only associated gas production is mentioned in the literature, which altogether amounts to some 50,000 ft^3/day. There is no nonassociated gas production, and commercial amounts of undiscovered non-associated gas appear unlikely unless it comes from deeper zones; some gas was tested from Cambrian reservoirs at Adhi. We estimate that oil makes up 90 percent of the hydrocarbon fill of untested traps.

Migration timing versus trap formation

Assuming the present thermal gradient was constant, the top of the mature zone remained around 9,000 ft. In the central part of the subsiding Potwar Basin, this depth was not reached by any of the potential source horizons (i.e., Cambrian, Jurassic, or Paleogene) until the accelerated subsidence of the foredeep (or trench) in the Lower Miocene. This is indicated diagrammatically in section A-A', fig. 27 (except that this section does not cross the maximum depths of the Potwar basin as does the section of figure 31). Hydrocarbon migration therefore began in early Miocene, which was about the time that the compression anticlines associated with the Himalayan (Neogene) orogeny were also beginning to take shape. It would appear that migration timing versus structure formation was near optimum. The migration, however, may have been too late to forestall deterioration of the principal Eocene reservoirs, which appear to be very low on primary porosity, leaving only fracture porosity.

Limiting Factors

The primary overriding factor limiting the amount of undiscovered hydrocarbon is the poor reservoirs. A second limiting factor is the small size of the basin combined with the advanced maturity of the exploration.

Makran Basin

Introduction

Location and size of area

The Makran Basin occupies all of Pakistan west of the Kirthar Range (Axial Belt) and continues westward along the north coast of the Arabian Sea to the Straits of Hormuz. The Pakistan portion, in which this study is concerned, has an area some 60,000 mi^2 and contains approximately 360,000 mi^3 of sediment (figs. 1 and 32).

Exploration history

Outcrop and photo-geology, carried out since World War II, were the main onshore exploration performed in this very rugged area. Offshore seismic survey was carried out, at least in the eastern part of the area. Six wildcats have been drilled, five onshore and one offshore (fig. 32); no oil shows are reported, but some gas was probably encountered. Exploration is immature, say 20 percent, but in light of the discouraging results may not advance substantially further.

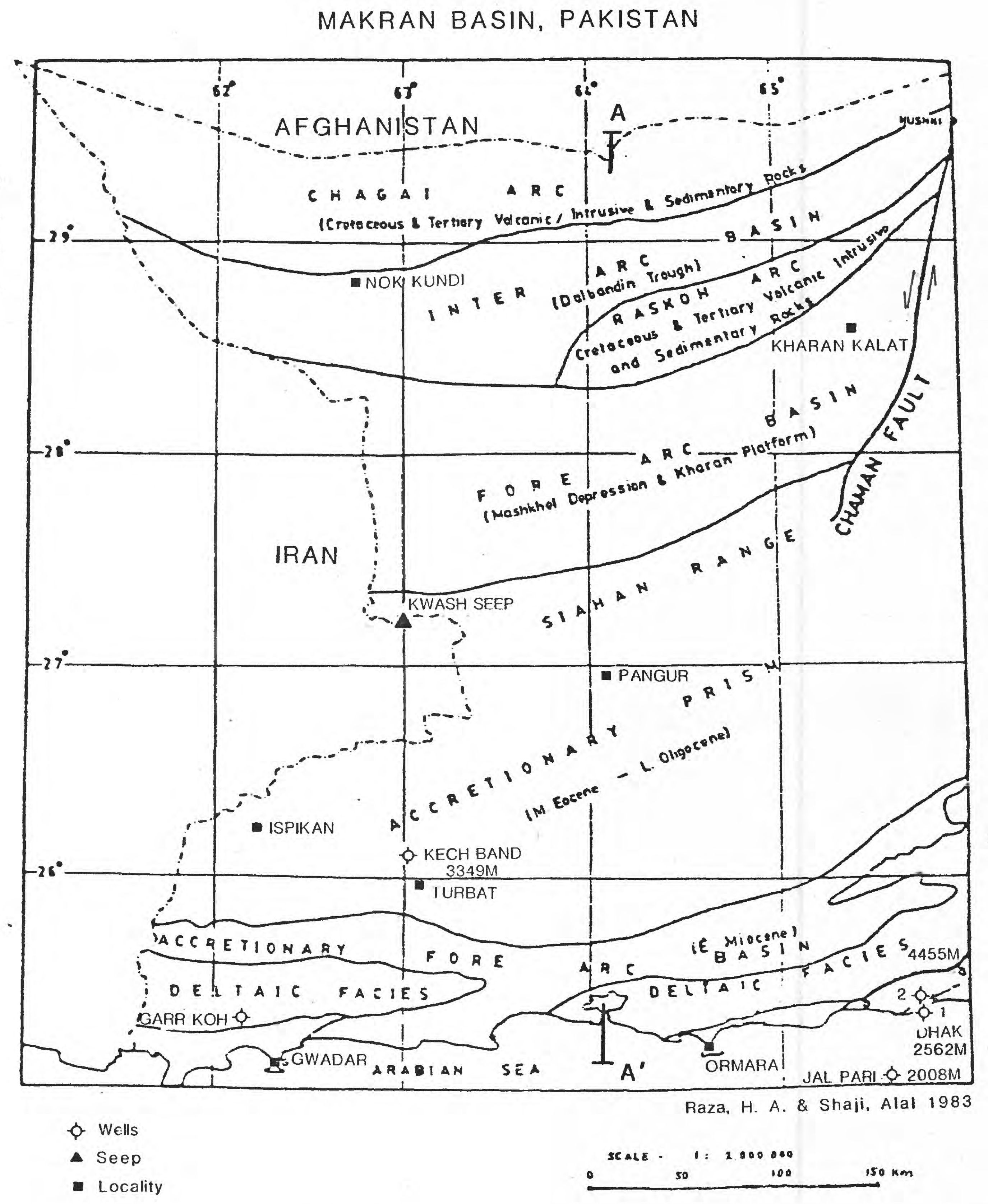


FIGURE 32.--Geology of the Makran area, Pakistan.

Structure

General tectonics

Although termed a basin, the area appears to be essentially a series of fore-arc basins and accretionary wedges of flysch and melange fore-arc material piled up as the Indian Plate subducted northward beneath the previously docked Afghan Continental Block (figs. 2, 32, and 33). On the east, the structure is further complicated by extensive north-trending sinistral wrench faulting related to the Indian Continental Block's northward movement past the eastern side of the Afghan Continental Block and associated accretionary wedge making up the Makran Basin (figs. 2, 24, and 32).

Untested trap area

The local structure is in part anticlinal, but the structures tend to be steep-dipped, thrusted and generally very complicated. Wide-spread diapirism, accompanied by mud volcanoes, increases the complexity. Valid structures are very few; it is estimated that less than two percent of the basinal area (768,000 acres) is under any kind of effective closure.

Percentage trap area productive

Six wells on what must have appeared to be the most favorable petroleum traps were dry and apparently with only minor gas shows. The percentage of the trap area likely to be productive is deemed very low, perhaps 3 percent.

Stratigraphy

General stratigraphy

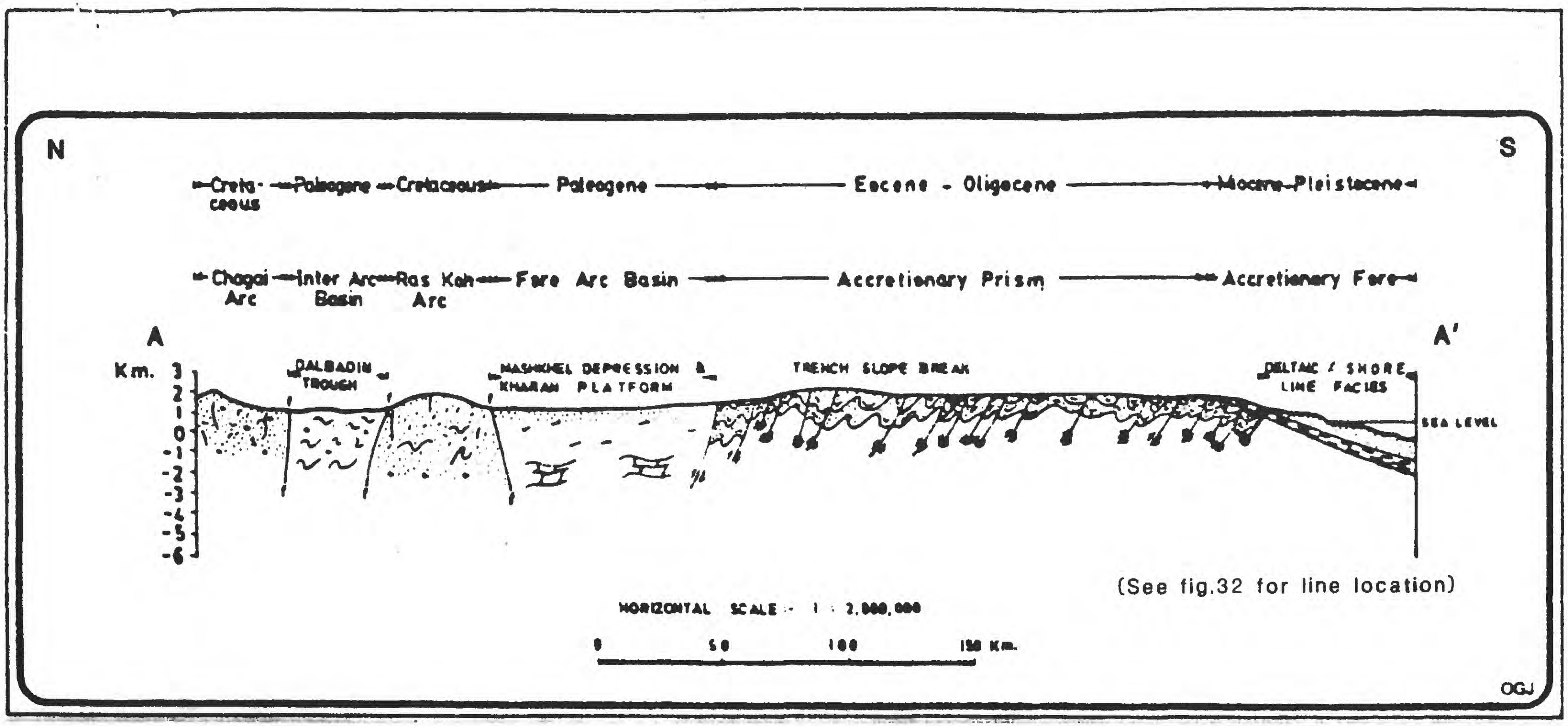
The strata of the Makran area are exposed in a series of east-trending structural ridges, which become progressively younger from the Afghan border southward to the coast (figs. 32 and 33). The older (Cretaceous and Paleocene) slices to the north contain large oceanic crust fragments (ophiolites). The accretionary wedge as a whole is largely made up of flysch containing a high shale content. The shales, in particular, have been tectonized to the extent that in some areas, in the east near the wrench faults, strong cleavage has developed, predominating over bedding planes. It is estimated that there are over 30,000 ft of sediment in the Makran area.

Reservoirs

There are no data, but flysch type of sedimentation would preclude well developed reservoirs. It is optimistically assumed that the average thickness of an effective reservoir in any trap would be 50 ft.

Seals

Considering the amount of faulting and fracturing in the area, it would appear that effective seals would be minimal.



Raza, H. A. and Shaji, A., 1983

Figure 33.--Makran north-south geologic section, A-A'.

Source rock section

There is some source rock in the area, as is attested by gas seeps and rare oil seeps. From their distribution, it appears that the source may be concentrated in the Neogene part of the section.

Generation and Migration

Richness of source

In this flysch-type sedimentation any organic matter would be diluted and dispersed in the rapid deposition. Subsurface samples range from 0.22 to 0.96 total organic carbon (Harms and others, 1982).

Depth and volume of mature sediments

The thermal gradient is low, 1°F/100 ft (Harms and others, 1982), as is the usual case in fore-arc areas of the world. The sedimentary wedge is thick enough, however, that some generation of petroleum could have taken place. A considerable volume of mature or over-mature sediments probably exists.

Oil versus gas

Mainly methane is widely reported issuing from extensive mud volcanoes or vents in the coastal part of the area. In one reported analysis (Christie, 1912, in Ahmed, 1963), the ethane/methane ratio is 12 percent, indicating gas generated in the thermal window for petroleum. Two minor oil seeps have been reported (Ahmed, 1963). Based mainly on the predominance of gas seeps, it is estimated that the oil would occupy about 25 percent of the petroleum fill in the average Makran trap.

Migration timing versus trap formation

Trap formation and generation and migration of hydrocarbon may theoretically take place at about the same time, i.e., while source rocks are being subducted deep enough for generation, crumpling and folding of up-dip strata may be forming traps.

Limiting factors

The overriding factors limiting undiscovered petroleum resources are the lack of sufficient traps and reservoirs in this wedge of structurally complicated melange and flysch deposition.

Cauvery Basin

Introduction

Location and size of area

The Cauvery Basin is partly onshore and offshore on the east side of the south tip of peninsular India, extending onto the west coast of the island of

Sri Lanka. The basin has an area of some 30,200 mi^2 (of which approximately two-thirds is in India) and contains approximately 39,000 mi^3 of sediment (figs. 1 and 34).

Exploration history

Exploration of the onshore area began in 1958; the first geophysical survey was in 1960; and the first wildcat (Karakat-1) was drilled in 1964. It had an Eocene oil show, but 18 subsequent wildcats and 10 stratigraphic holes found no commercial onshore accumulation. As of 1983 a total of 28 deep wells had been drilled.

Offshore seismic survey began in 1964, but the first wildcat apparently was not drilled until 1979. Wildcat PH-9-1 in August 1979 discovered oil (1,500 BOD with a 1/2" choke). Of the five wells drilled on this same structure, only PH-9-1 can be considered commercial. PY-1-4 drilled in 1982 tested 400 BOD and 2,472 MCFD (fig. 34). Although only one of the two discoveries is doubtfully commercial, an eventual wildcat success ratio of about 10 percent is assumed. As of 1983, 18 offshore wells had been drilled; the wildcats appear to be located on the basis of good marine seismic data, and the maturity of the exploration is judged to be as much as 20 percent.

Structure

General tectonics

Regionally, the Cauvery Basin is on the margin of the Indian Continental Block and is classified as a rifted continental margin basin. It is characterized by northeast-trending horst and graben structure formed in the early Cretaceous when India pulled apart from Australia-Antarctica (figs. 34 and 35).

Untested trap area

No detailed structural maps are available. As a rifted continental margin basin, it would be analogous to the Bombay Shelf (excluding Bombay High), which has about 5 percent of its area under closure, or to the Upper Assam, which also has 5 percent under closure. Assuming 5 percent of the Cauvery Basin is under closure, there is a trap area of about 965,000 acres. Given that 20 percent of the exploration is completed, 772,000 acres would remain to be tested.

Percentage untested trap area productive

It is assumed that the petroleum fill of Cauvery Basin traps would be about average for the Indian rifted continental margin basin, or about 60 percent (ranging from 30 to 75 percent). The wildcat success rate has been estimated at 10 percent, indicating that 6 percent of the remaining untested trap area will have petroleum.

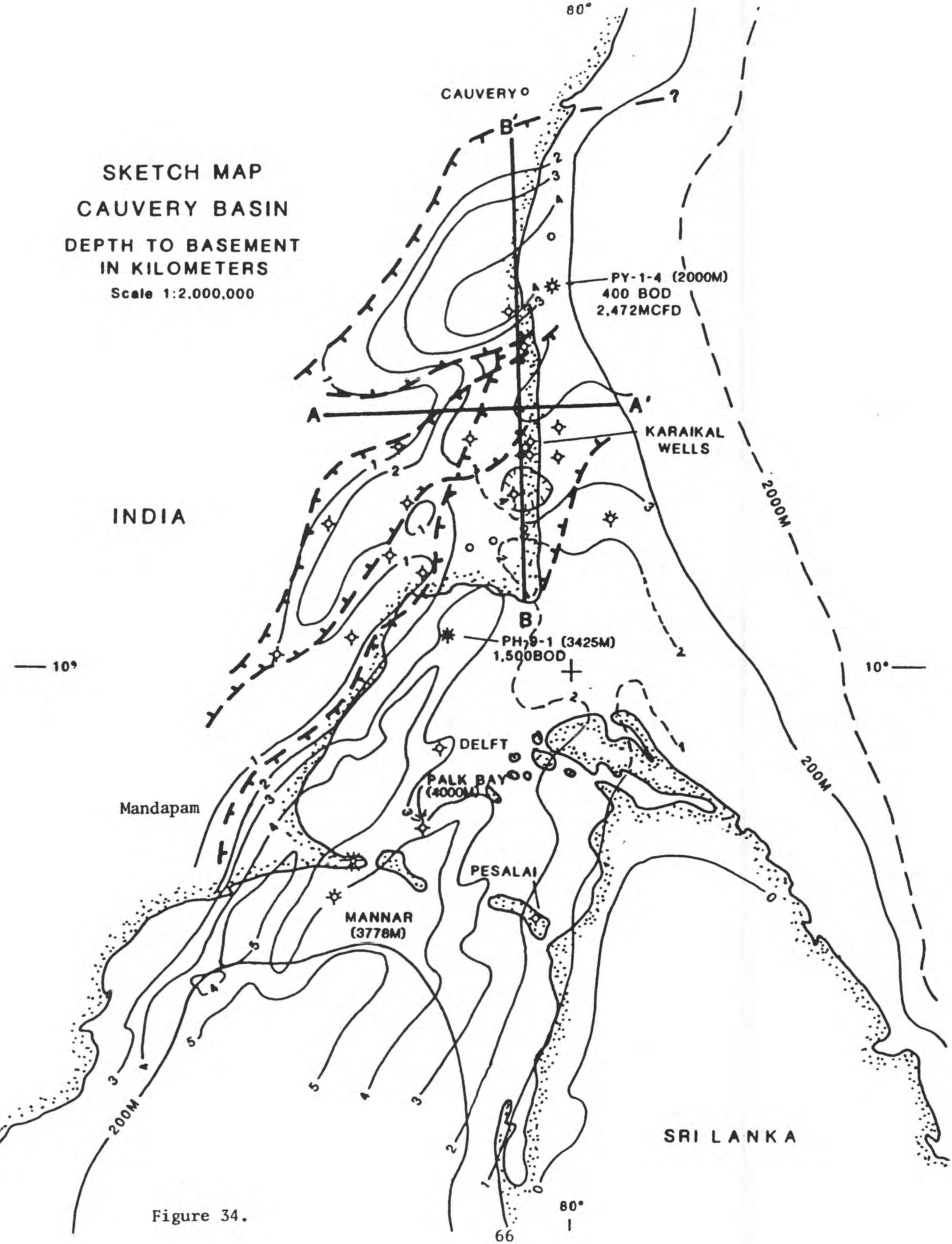

SKETCH MAP
CAUVERY BASIN
DEPTH TO BASEMENT
IN KILOMETERS
Scale 1:2,000,000
80°
CAUVERY
B'
PY-1-4 (2000M)
400 BOD
2,472MCFD
A
A'
KARAIKAL
WELLS
INDIA
2000M
B
PH-9-1 (3425M)
1,500BOD
10°
10°
DELFT
PALK BAY
(4000M)
Mandapam
200M
PESALAI
MANNAR
(3778M)
200M
SRI LANKA
80°

Figure 34.

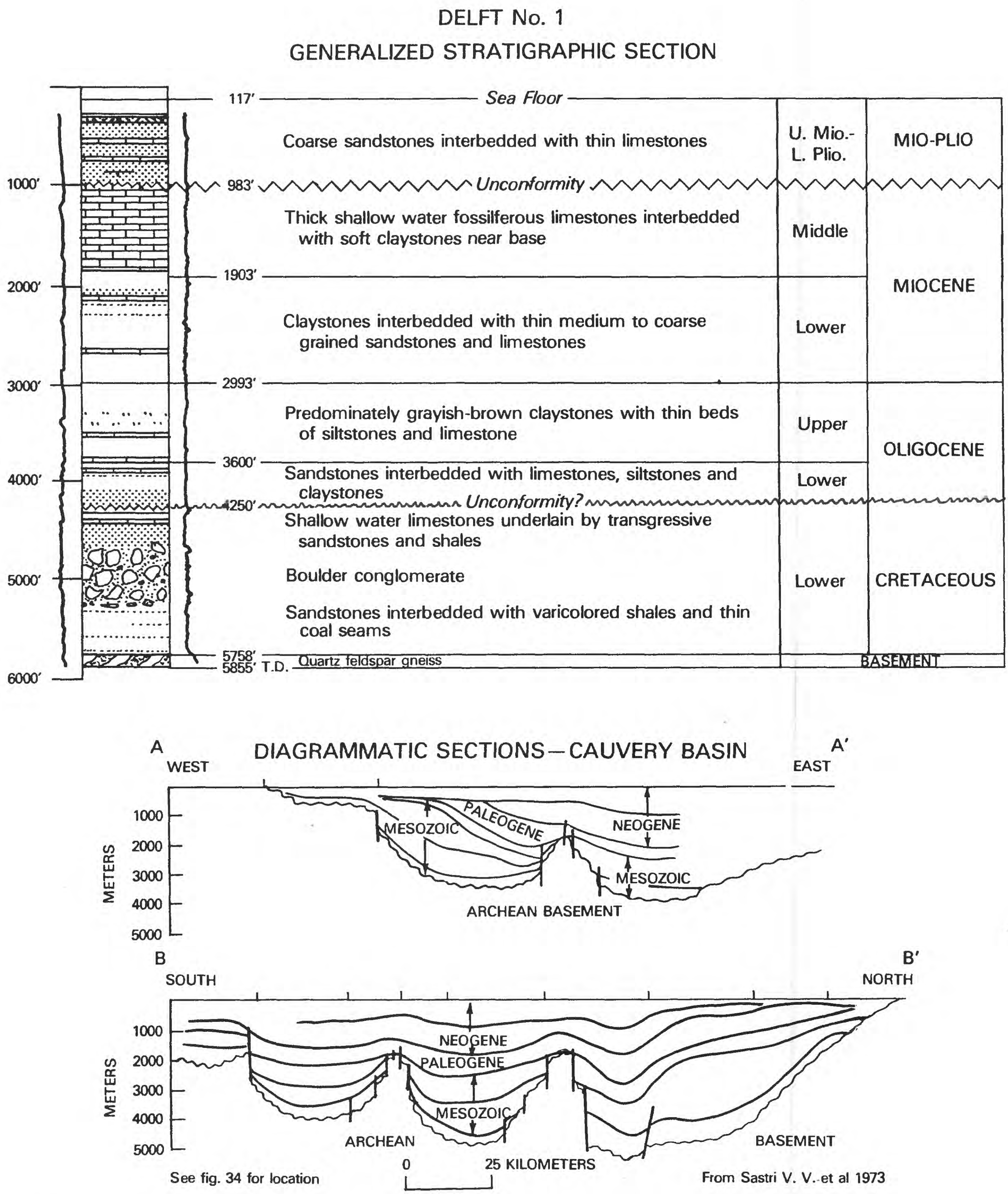


Figure 35.--Stratigraphic column and diagrammatic sections, Cauvery Basin.

Stratigraphy

General stratigraphy

Figure 35 shows a 5,758-foot stratigraphic section as penetrated in the central part of the basin by wildcat Delft No. 1. This test, like other wildcats, was drilled at the crest of a basement ridge; much of the section, probably largely Paleogene and Cretaceous shales, of the adjoining graben area is not seen (fig. 35). Geophysical surveys indicate a total sedimentary thickness of 23,000 feet in some areas. Except for approximately 1,000 to 1,500 ft at the base, the sequence appears to be mainly marine, though deltaic deposits are reported in the early Tertiary in the western part of the basin. There is a prominent unconformity between the Cretaceous and Paleogene strata.

Reservoirs

According to ONGC (Talukdar, 1982), thick reservoir rocks have not been found to date. This lack may be the principal limiting factor in regard to hydrocarbon accumulation. However, on the Sri Lanka side of the basin, "potentially good reservoir rocks...throughout...the section" are reported (Cantwell, 1978). This seeming disagreement may be a difference in reservoir evaluation rather than an actual difference in reservoir thicknesses. Potential reservoirs would likely be largely Cretaceous sands plus some possible Neogene carbonates. A few gross sandstone reservoir thicknesses noted on the Sri Lanka side of the basin are: 1,000 ft at Pesalai, 200 ft at Palk, and 50 ft at Delft. Oil was found in small quantities in fractured basement in two Indian wildcats. The Indian discovery well PH-9-1 tested a net thickness of 36 ft of Lower Cretaceous sandstone, and in the absence of any other net values this is taken, for evaluation purposes, as the average net reservoir thickness in untested traps.

Seals

Considering the large amount of shale in the section and the fact that the faults generally do not cut the Neogene strata (fig. 35), seals are probably good and are assumed to be 80 percent effective.

Source rock section

The source section for reasons discussed below appears to be in the Cretaceous shales occupying the undrilled graben deeps.

Generation and Migration

Richness of source

ONGC reports "moderately lean, gas-prone immature source beds" (Talukdar, 1982). Samples from three wells of the Sri Lanka side of the basin (i.e., Pesalai, Palk Bay, and Delft) found that in general the entire sampled section from Lower Cretaceous to Miocene was of source-rock richness, i.e., had greater T.O.C. than 0.5 percent (Cantwell, 1978). The Lower Cretaceous had values up to 6.92 percent and averaged 2.16 percent, which is considered "very good" source-rock richness. Upper Cretaceous averaged 1.14 percent, which is only "fair" (the richer "good" section being in the Pesalai well). No analyses are available from the Paleocene; the Eocene source was analyzed as poor to good; the Oligocene and Miocene averaged 0.79 percent, which is a lean source.

Depth and volume of mature sediments

Vitrinite reflectance data places the top of the mature zone (R_o = 0.7) at about 9,000 ft (Chandra and Samanta, 1984). This depth limits the source rock to the deeper graben areas and to the Cretaceous part of the section. This, along with the richness of source, further substantiates the Cretaceous shales as the source rock. The source rock, confined as it is to the deeper graben areas, requires a certain amount of lateral migration and appears to be of rather limited volume, about 5,000 mi^3.

Oil versus gas

Gas is reported from five wells though no detailed test results are available. Gas analyses from both sides of the basin indicate the gases to be wet (e.g., onshore Mandapan found hydrocarbons up to pentane, and Pesalai up to butane) and are probably formed within the mature (petroleum) window, rather than being cracked molecules from the over-mature zone. The generally shallow configuration of the basin also precludes a large volume of over-mature source rock. The kerogen type, as reported from India, is gas-prone (Talukdar, 1982) and from Sri Lanka a mixture of gas- and oil-prone (Cantwell, 1978). However, on the basis of substantial oil finds at PH-9-1 and the probable wetness of the gas, it is estimated that the basin is only slightly gas-prone, i.e., about 40 percent of the hydrocarbon fill of the untested traps is oil.

Migration timing versus trap formation

Trap formation must have begun with the development of horst and graben features in the Lower Cretaceous during the pull-apart of India from Australia-Antarctica. Penecontemporaneous Cretaceous reservoirs may have developed around the highs, and later reservoirs would be in the overlying, draped Tertiary section.

Assuming the same geothermal gradient and subsidence rate through the Mesozoic and Tertiary, hydrocarbon would have begun generating and migrating when the source sediments had subsided to 9,000 feet, which would be about Paleogene, and would continue until the present. It would appear that this timing of migration would be favorable as the hydrocarbons would have access to all the reservoirs. There may have been time, however, for Cretaceous reservoirs to have deteriorated to some extent before the hydrocarbon arrived, and some hydrocarbon would escape at the Paleogene unconformity.

Limiting Factors

The overall limiting factor, at least on the Indian side of the basin, appears to be adequate reservoir development. As of 1982, ONGC (Talukdar, 1982) planned to seek better reservoir development on the flank of the basement ridges rather than the crests where erosion may have removed promising reservoirs. Another limiting factor may be the small volume of thermally mature sediment.

Palar Basin

Introduction

Location and size of area

The Palar Basin is on the east coast about one-third of the way up from the south tip of peninsular India, just north of Cauvery Basin and south of Krishna Godavari Basin (figs. 1 and 36). It has an area some 4,100 mi^2 and a volume 4,400 mi^3.

Exploration history

Very little exploration has been done. Surface geology of scanty outcrops and a few shallow water-well sections supplied the only data concerning the Palar Basin (fig. 36).

Structure

General tectonics

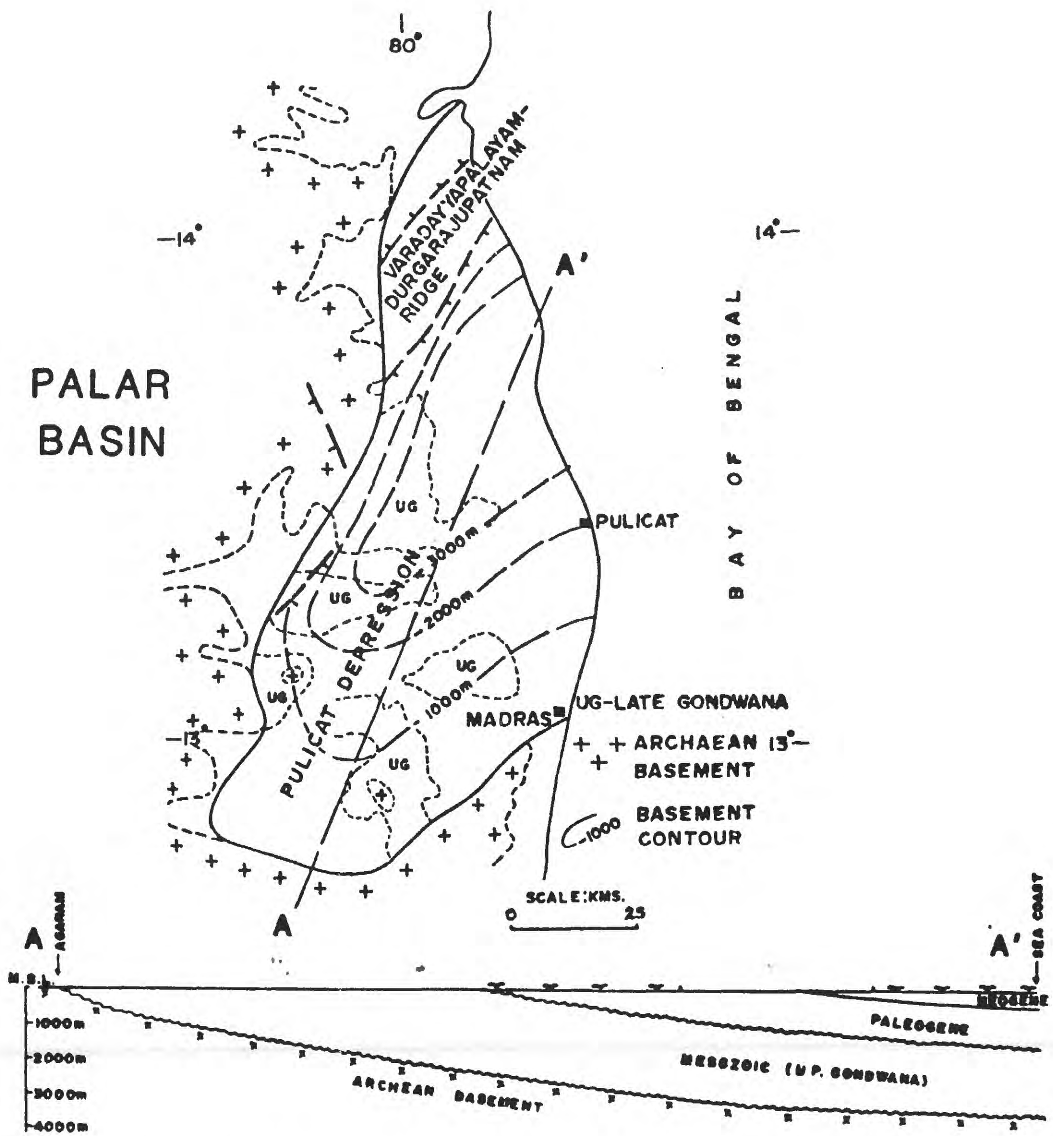
This basin, along with others along the east coast of peninsular India, is a rifted continental-margin basin formed when India pulled apart from Australia-Antarctica. As such, it would be characterized by horst and graben structure. From the limited data at hand, the basin appears to be essentially a shallow graben, perhaps no deeper than 12,000 ft (fig. 36).

Untested trap area

Because of the lack of data and the apparent geologic similarity to the Cauvery Basin, we assume that the percentage of the basin area that would be under trap is the same as the Cauvery Basin, or 5 percent. This gives an untested trap area of 130,000 acres.

Percentage trap area productive

The percentage of trap area considered likely to be productive in the geologically analogous Cauvery Basin is 6 percent. As will be discussed below, however, the Palar Basin is deficient in respect to the Cauvery Basin in that it is smaller and may be too shallow to generate much hydrocarbon. The 6 percent of the Cauvery Basin is therefore discounted to 3 percent for this basin.



After: Sastri V.V. 1973

Figure 36.--Basement depth map and geologic section, Palar Basin.

Stratigraphy

General stratigraphy

Sparse data limits the knowledge of the general stratigraphy to that shown diagrammatically on section A-A', figure 36.

Reservoirs

There is likewise no reservoir information; by analogy to the Cauvery Basin the average reservoir thickness found in any trap would be 36 ft.

Seals

Massive argillaceous sediments are reported, and, as in the case of the Cauvery Basin, the major faults are largely pre-Neogene. Therefore, seals are expected to be good.

Source rock section

Source beds would be near the base of the section and therefore likely to be Lower Cretaceous.

Generation and Migration

In the absence of data, it is assumed that the generation and migration factors would be analogous to those of the Cauvery Basin, except that the Palar Basin is smaller and, more significantly, shallower (12,000 versus 23,000 ft at their deepest parts).

Limiting Factors

Analogous to the Cauvery Basin, reservoir development may be the overriding limiting factor. In the shallower Palar Basin, the volume of thermally mature source sediments is smaller and also a significant limiting factor.

Krishna-Godavari Basin

Introduction

Location and size of area

The Krishna Godavari Basin is about at mid-point of the east coast of peninsular India. It has an area of some 13,000 mi^2 and contains approximately 18,000 mi^3 of sediment (figs. 1 and 37).

Exploration history

Geological and geophysical surveys were begun in 1960. The first onshore well, Narsapur-1, encountered a gas blow-out at an Upper Cretaceous level (fig. 37) and a second, Rozole-1, also encountered gas (3.5 million CFGD from Paleogene fractured/vesicular trap flow). The first offshore well, G-1-1 (June, 1980), obtained a flow of 600 BOD on a 1/2" choke at a depth of 7,218 ft

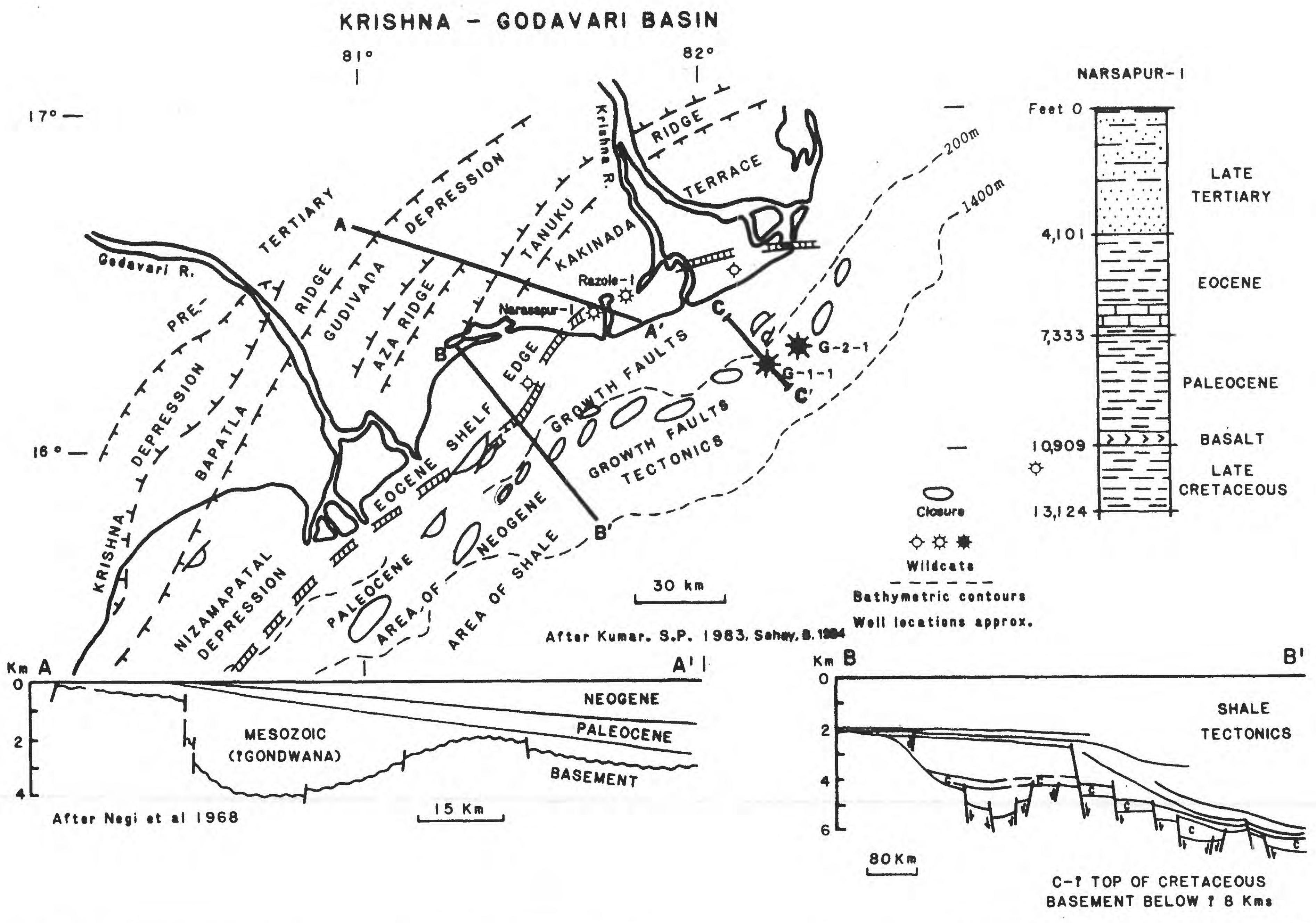


Figure 37.--Basement tectonic map and geologic sections, Krishna-Godavari Basin.

from an upper Miocene sandstone in a rollover anticline associated with a growth fault (figs. 37 and 38). The appraisal well did not reach its objective. G-2-2 (March, 1983) obtained a flow of 3,200 BOPD and 1,090 MCFGD with an unknown choke size at a depth of 6,647 to 6,663 ft, presumably from a Miocene sand (fig. 37). It appears that at least some dozen wells altogether have been drilled offshore and onshore. A hydrocarbon success rate of 16 percent is estimated. The exploration is immature, we assume about 20 percent complete. The steep slope of the offshore shelf inhibits exploration and eventually perhaps production (fig. 37).

Structure

General tectonics

The tectonic framework is essentially the same as the other basins along the Indian east coast, i.e., a rifted continental margin characterized by northeast-trending horst and graben features. This basin, however, differs somewhat from the similar basins to the south in two respects: 1) A Paleocene unconformity developed on a broad erosional surface across the in-filled Cretaceous horst and graben structure, forming a basinward-dipping shelf (section A-A', fig. 37); and 2) an Eocene shelf-edge fault system (presumably northeast-trending) is present at about the coast line. This Eocene shelf-edge generally marks the updip western limit of an offshore, thick Tertiary deltaic sequence (section B-B'; fig. 37). Growth-faults with associated rollover anticlines and diapiric ridges prevail in this thick Tertiary section (Rao, Y.S.N., 1980). There appear to be two separate plays in the basin: 1) The Cretaceous drapes associated with horst and graben structure, and 2) Tertiary deltaic growth-fault and associated rollover anticlines and diapirs. The estimated shelf area of the Cretaceous drape play is 9,250 mi^2 (5.9 million acres), and the area of the Tertiary growth-fault and flow structure play is some 6,500 mi^2 (4.2 million acres) from the shelf edge out to 3,000 ft (1,000 m) water depth.

Untested trap area

By analogy to the rifted continental margins of the Bombay Shelf and the Assam Basin, drape traps should make up about 5 percent of the play area, or 300,000 acres (240,000 acres of untested trap, assuming 20 percent of the trap area has been tested).

The growth-fault-associated anticlinal rollovers and diapir trap areas in the thick Tertiary delta section are indicated in figure 38. These indicated closures of some 193,000 acres make up about 4.6 percent of the play area; assuming they constitute about 70 percent of the area which will eventually be found under trap, there are 275,000 acres of trap. (We assume 20 percent of the trap area has been tested, leaving 221,000 acres of untested trap.)

Percentage trap area productive

For the Cretaceous drape play, the percentage of trap area productive is deemed to be analogous to the Cauvery Basin or 6 percent.

For the Tertiary growth-fault-associated closures, 60 percent of the trap area is assumed to be petroleum filled, analogous to the Tertiary deltaic traps of the nearby Bengal Basin. This, together with the estimated success rate of 16 percent, indicates that 10 percent of the trap area may be productive.

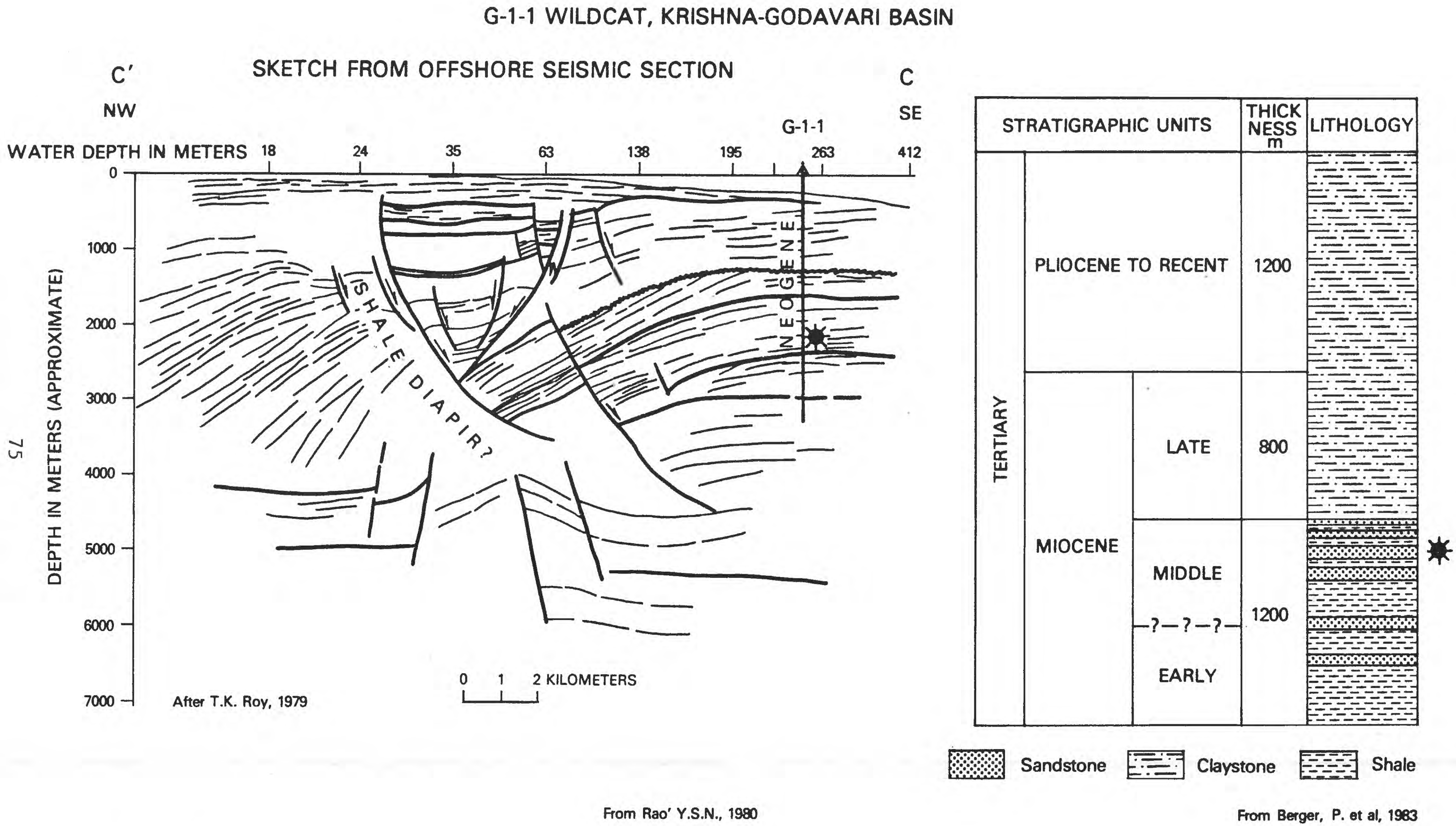


Figure 38.--Cross section and stratigraphic column, G-1-1 Wildcat, Krishna-Godavari Basin.

Stratigraphy

General stratigraphy

Figure 37 shows the stratigraphy of the shelf area at Narasapur. The stratigraphy appears to be affected by strong facies changes from coarsely clastic up-dip facies to finer-grained marine facies down-dip. Generally, the Mesozoic and Tertiary onshore section is a sandstone and shale sequence but with some carbonates in the Upper Cretaceous and Paleocene-Eocene. Platform facies developed over the Paleocene-Eocene unconformity surface (section A-A', fig. 38).

Neogene deltaic deposits of "enormous" thicknesses developed in the offshore down-dip from the Eocene "hinge" (Talukdar, 1982) (sections B-B', C-C', figs. 37 and 38).

Reservoirs

Although the Cretaceous section is coarsely clastic along the outcropping west edge of the basin and presumably along the ridge crests, it is largely in a shale facies in the down-dip and deeper basin areas and generally has poor reservoir development. The platform Paleocene-Eocene sequence, immediately over the Paleocene unconformity, reportedly has carbonate and sandstone beds of good reservoir characteristics (Talukdar, 1982). It is assumed that for the rifted-margin, drape play, the average net reservoir thickness is analogous to the Cauvery Basin, i.e., 36 ft.

The late Tertiary deltaic sands appear to be of reservoir quality. The first discovery well, G-1-1, reportedly encountered 197 ft of net pay in two 98-foot zones (fig. 38); the second discovery well, G-2-2, had only 16 ft. One hundred feet is taken to be the average reservoir thickness of the deltaic play.

Seals

With the abundance of shale reported both in Cretaceous and Tertiary sections, and with the apparent lack of strong faulting above the Paleocene unconformity, it would appear that sealing would not be a problem in the drape play, but there is probably leakage in the zone of the Tertiary growth-faults.

Source rock section

It appears that the main limitation on source rock distribution for the drape play is the relative shallowness of the basin, permitting only a thin source section restricted to the Mesozoic (Lower Cretaceous) strata. The Tertiary deltaic sand play is deep enough to allow a thick thermally mature and probably overmature source section.

Generation and Migration

Richness of source

According to Talukdar (1982) of ONGC, "the Cretaceous in a large part of the basin can be considered to have given rise to gaseous hydrocarbons from its preponderant humic organic content." Talukdar also states "Qualitatively, the Paleocene-Eocene shales and possibly the Eocene limestones can be considered good source rocks for the generation of liquid hydrocarbons."

The Tertiary deltaic shales of the offshore would be expected to contain organic matter, but probably of terrigenous source, so that gas, as well as oil, may be expected.

Depth and volume of mature sediment

The thermal gradient of the basin appears high for the region, 2.52°F per 100 ft (Raju, 1980). This, together with the subsidence rate, places the top of the thermally mature sediments at about 6,000 ft (2,000 m) and indicates a volume of thermally mature (and overmature) sediments of some 3,500 cubic miles in the Cretaceous. Tertiary thermally mature sediments of greater but unknown volume exist in the down-dip, offshore area (section B-B', fig. 37; section C-C', fig. 38).

Oil versus gas

The Narasapur-1 and Rozoli-1 onshore gas apparently came from Cretaceous reservoirs. ONGC sites the humic organic content of the Cretaceous strata as evidence for gaseous hydrocarbons. We estimate that oil makes up 40 percent of the petroleum in the onshore drape folds.

The offshore Tertiary deltaic sediments have tested oil and gas. Although this Tertiary section is overpressured and therefore may be considered gas prone as is the case in the Fold Belt play of the Bengal Basin, the presence of well-developed growth faults provides avenues for primary oil, as well as gas, migration. From test results we estimate the petroleum mix to be 60 percent oil.

Migration timing versus trap formation

Assuming a relatively constant subsidence rate and the relatively high thermal gradient through the Mesozoic and Tertiary, petroleum would begin generating and migrating when the source beds subside to a depth of 6,000 ft (2,000 m). For the Mesozoic play, migration would begin sometime in the Cretaceous-Paleocene, depending on local basin depth. Timing would be excellent for the filling of Cretaceous draped reservoirs, but some hydrocarbon may have escaped during the Paleocene erosion (fig. 37). Timing would be good for the filling of Tertiary reservoirs in the offshore, down-dip area where presumably a significant portion of the Tertiary deltaic wedge would have been below the 6,000-foot depth level, generating and migrating petroleum when trap formation began (figs. 37 and 38).

Limiting Factors

The factor limiting petroleum accumulation in the Cretaceous drape play is reservoirs; oil, rather than gas, is further limited by the apparent relatively small amount of oil source rock. The limiting factor concerning the Tertiary delta play is the steep slope of the offshore shelf inhibiting offshore wildcatting and development.

Bengal Basin, Foreland and Foldbelt

Introduction

Location and size of area

The Bengal Basin area coincides approximately with Bangladesh, but also includes large portions of two Indian provinces, West Bengal on the west and Assam on the east; it also includes a portion of Western Burma (i.e., the Arakan Coast). We include the so-called Mahanadi Basin, i.e., the onshore and offshore area southeast of the main delta mouths, adjoining peninsular India (figs. 39 and 40). The approximate distribution of the Bengal Basin area is Bangladesh - 48 percent, India - 38 percent, and Burma - 14 percent (figs. 1, 39, and 40). The area of the basin is some 178,500 mi^2. The volume of sediment appears to reach the enormous figure of 1,500,000 mi^3, but considering that those sediments below about 30,000 ft are likely to be highly altered, they will be excluded from consideration, leaving a volume of 700,000 mi^3.

Exploration and production history

Oil was produced in minor amounts from at least the 18th century from primitive bore holes on the Arakan coast of Burma (southeastern corner of the Bengal Basin, fig. 39). The first modern exploration was the sinking of shallow dry holes along gas seeps in the Sitakund areas of southeastern Bangladesh in 1914 (fig. 41). In 1933, some unsuccessful wildcats were drilled at Pataria in northeastern Bangladesh (fig. 41).

Sustained exploration did not begin until after World War II; some 60 wildcat wells, including 13 offshore wells, have been subsequently drilled in Bangladesh and India. The discovery rate for gas in the folded east side of the basin appears to be about 27 percent; no appreciable amounts of oil have been found, except for minor fields of the Arakan coast and the abandoned Badarpur Field (2 MMBO) in India (at the north end of the foldbelt, fig. 39). The status of exploration in the eastern foldbelt is considered to be immature to early mature, perhaps 60 percent complete. Reserves of some 11 Tcf of gas have been established.

The discovery rate for the foreland (i.e. the area west of the Paleogene shelf edge, fig. 39) is nil. The exploration is considered immature (about 40 percent complete), since the pre-Tertiary, which has tested some petroleum in the Cauvery and Krishna-Godavari basins, has not been sufficiently explored.

Structure

General tectonics

The basin is assymetrical, sloping eastward into a very deep trough some 25 km deep at the eastern side where it is bounded by a subduction zone (figs. 39 and 40). It is bounded on the north by the Dawki Fault, a regional dextral wrench fault of Oligocene age, which was subsequently affected by enormous Neogene isostatic vertical movement (60,000 ft, downthrown to the south) (fig. 39).

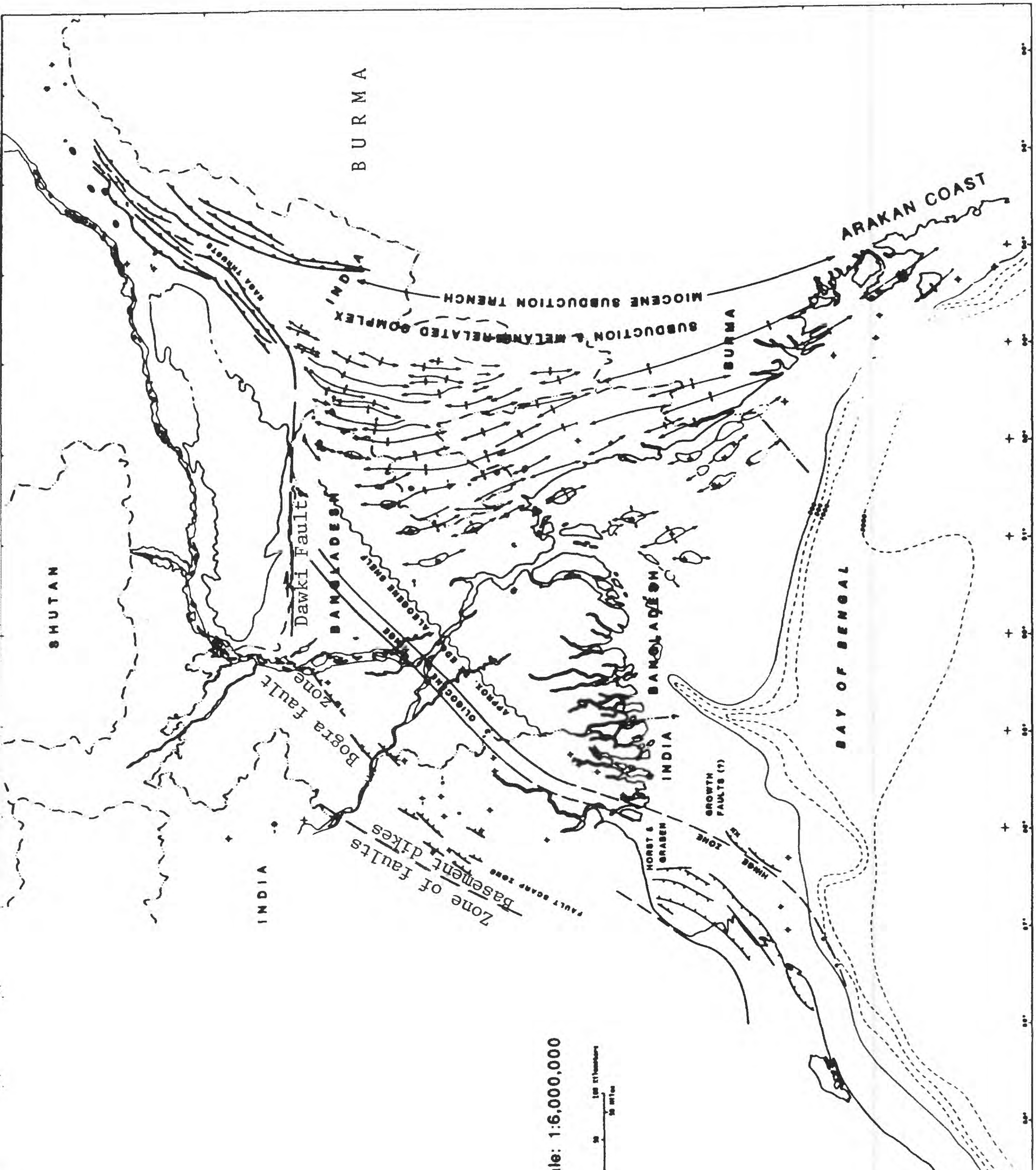


FIGURE 39

BENGAL BASIN

TERTIARY TECTONIC/STRATIGRAPHIC FEATURES AFFECTING HYDROCARBON PROSPECTS

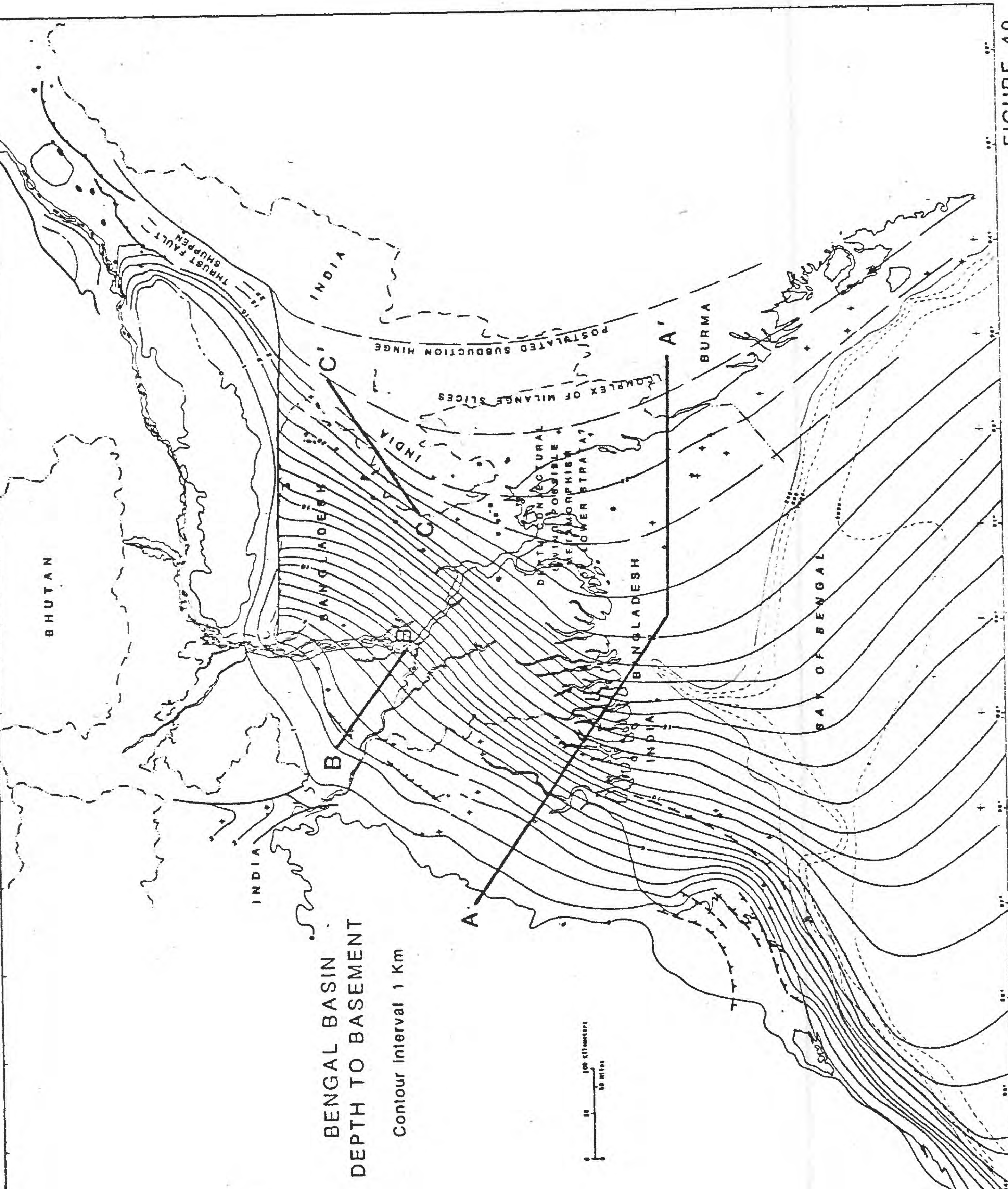


FIGURE 40

BENGAL BASIN
SKETCH DEPTH-TO-BASEMENT MAP

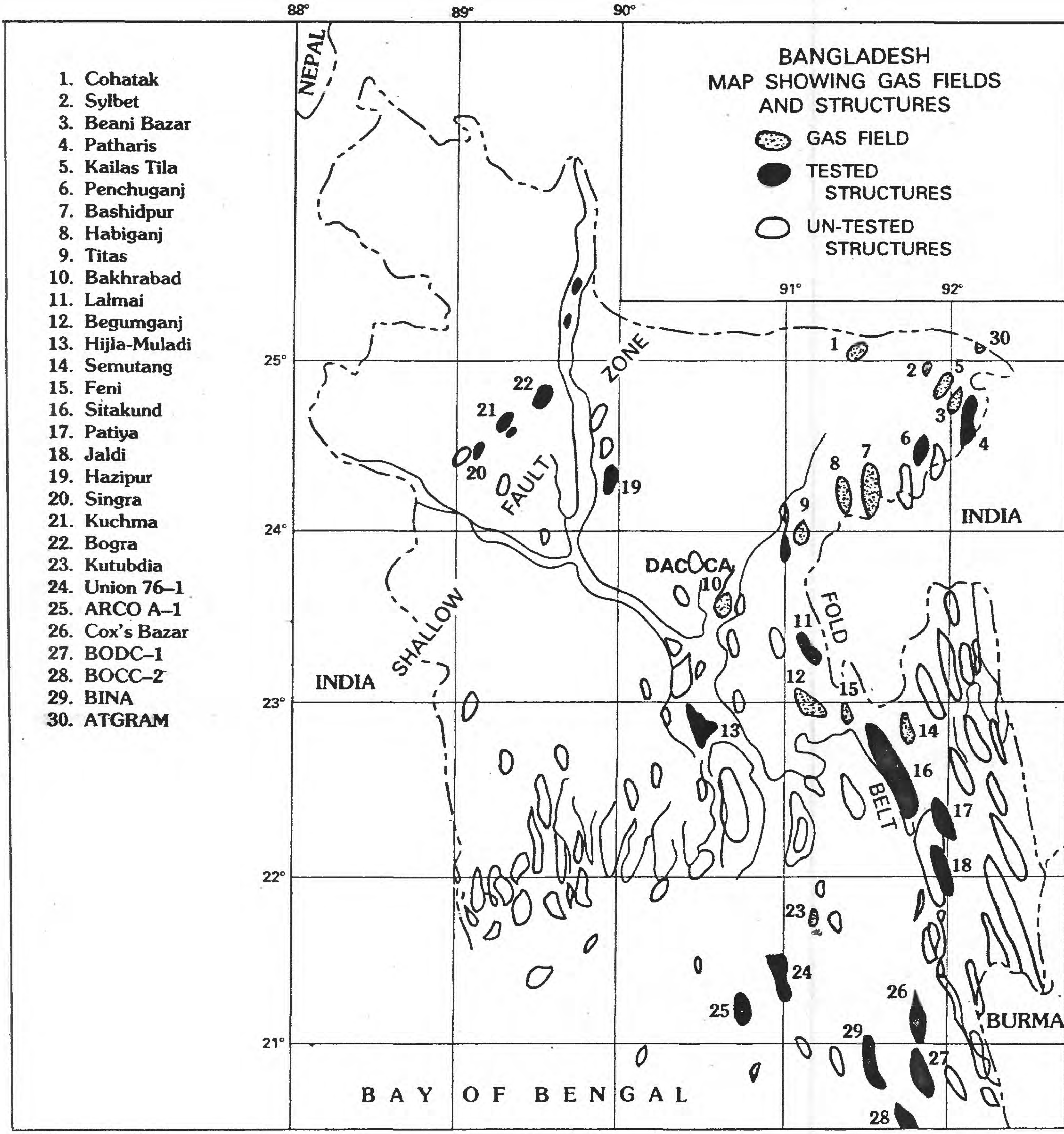


Figure 41.--Bangladesh gas fields. Potentially productive structures identified by Petrobangla include known gas fields, tested structures, and untested structures. Numbered names refer to structures mentioned in text (after Khan, 1980; from Ball, M., et al., 1981).

The tectonic history is complicated and somewhat obscure, but briefly it appears that:

1) Australia-Antartica pulled apart from India in the early Cretaceous along a northeast-trending line through the basin approximately coinciding with the Paleocene Shelf edge (fig. 39).

2) The India Plate began in the Paleocene to obliquely subduct northward beneath the Sunda and Afghan Continental Blocks previously docked against the Asia continental mass (fig. 2).

3) Collision of India Continental Block, riding on the Indian Plate, with the previously-docked Afghan Block in the Oligocene with consequent uplift to the west.

4) Collision of India Continental Block with Asian continental mass in Miocene and rise of the Himalayas. Continued oblique subduction and wrenching along the India Block-Sunda Block suture involving Assam thrusting and Bengal Basin folding.

The Bengal Basin contains two major plays, the structure of which is discussed below.

1) The Foreland Play concerns the area west of Paleogene shelf edge (fig. 39). It is primarily a rifted continental margin with horst and graben and accompanying drape features, affecting Mesozoic and Paleogene reservoirs. It has an area some 65,000 mi^2 and a sedimentary volume of approximately 125,000 mi^3.

2) The Foldbelt Play to the east is primarily compressional folds caused by the oblique subduction of the India plate under the Sunda continental mass. It has an area some 113,500 mi^2 and a volume of approximately 575,000 mi^3 of unaltered sediments.

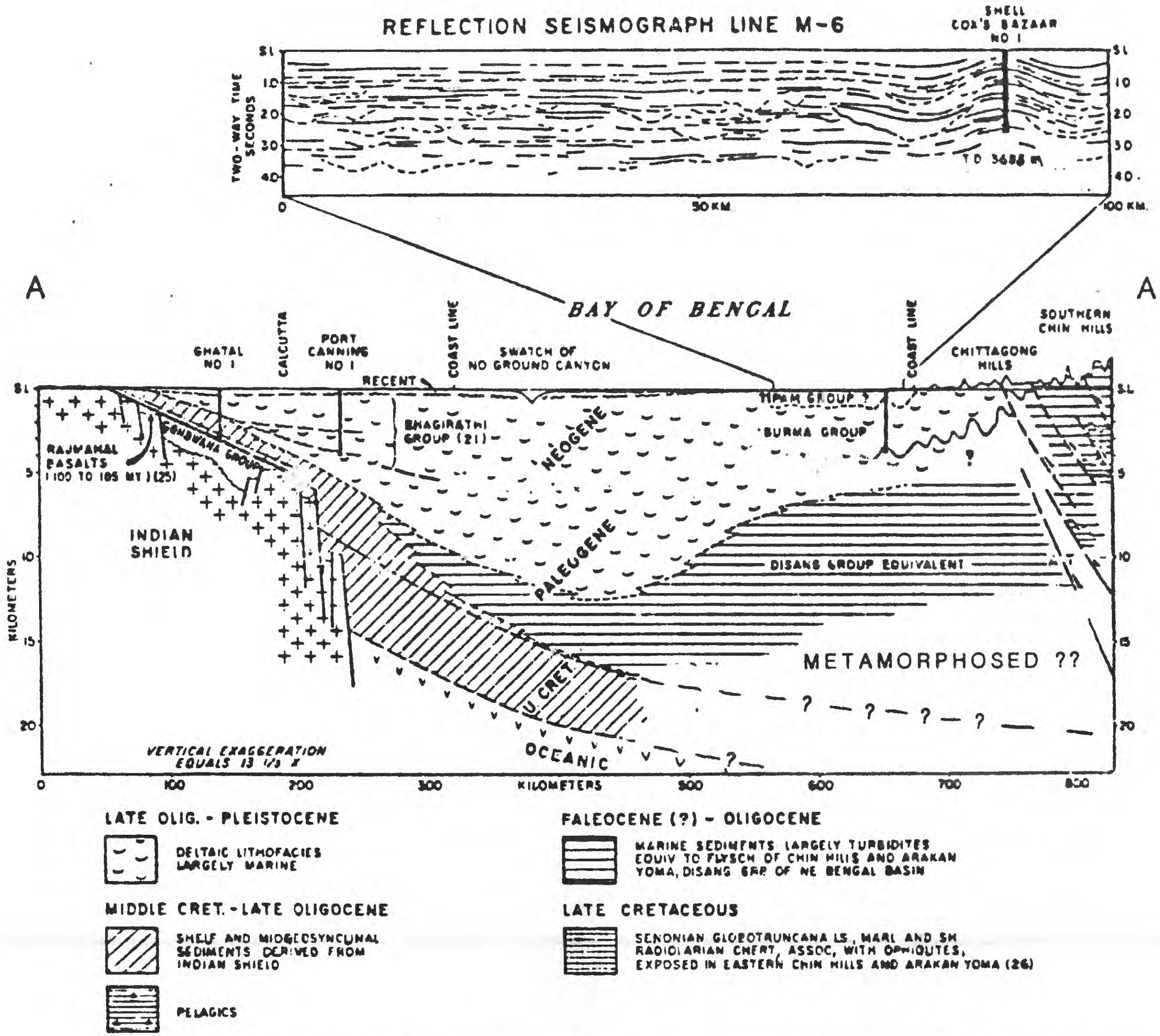
Structure, Foreland Play

Untested trap area

The Foreland structure is shown in figures 39, 40, 42, and 43. There are essentially two structural trends:

1) A western, up-dip, relatively shallow zone of normal faults, Bogra Fault zone (figs. 39 and 41). As seen in figure 39, these faults trend in an arc around the northwest side of the basin; the regional dip increases basinwards of this trend (Singra, fig. 43). There is some apparent rollover on the down-thrown side of some faults. At least 26 closures have been identified along this trend; 20 have been drilled, and although there were a few minor shows, all have been dry.

2) Further eastward, down-dip, there is a more pronounced hinge line (Oligocene Hinge Line) where Mesozoic-Paleogene fault-associated closures and pinchouts, and Eocene reefs may be expected (figs. 39 and 43). Presumably, because of the depth of these objectives, i.e., 16,000 to 20,000 ft, this trend has not been drilled.



-*Regional cross-section across Bengal basin and reflection seismograph line* M-6 (*Bangladesh Shell Oil Co. Ltd.*, 1967). . (See fig. 40 for location)

Modified after Paul, D.D
and Lian HM, 1975

Figure 42.--Regional cross section A-A', Bengal Basin.

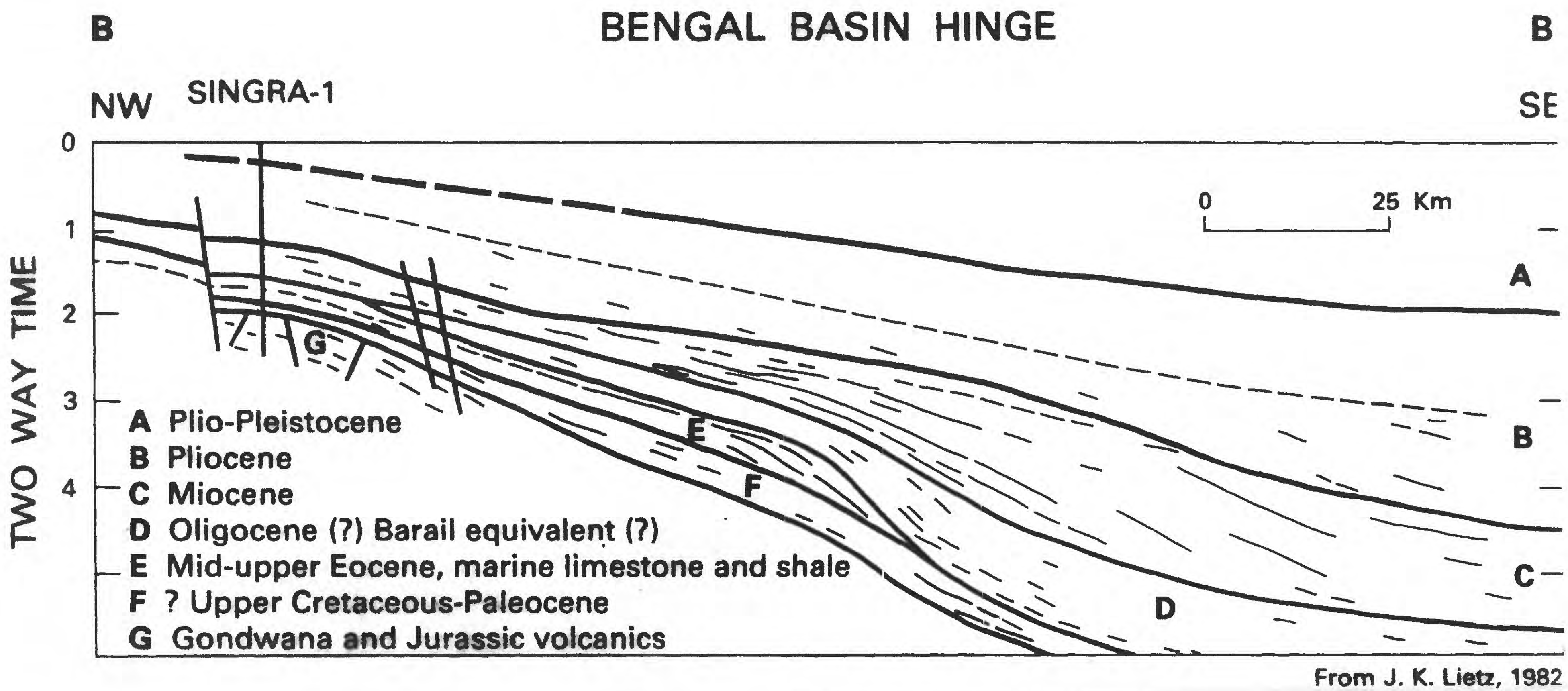


Figure 43.--Hinge area cross section B-B', Bengal Basin

Taking both these trends together, the structure of which is attributed to a rifted continental margin, it is assumed that trap density (i.e., percentage of play area under trap) is analogous to the other Indian rifted margins. It is assumed, therefore, that about 5 percent of the play area is under closure or 2,080,000 acres. Subtracting the 20 tested closures at assumed size of 10 thousand acres each, gives 1,880,000 acres of untested closure.

Percentage trap area productive.

All twenty wildcats have been dry, but some of the traps drilled may have been too far up-dip to have been accessible to migrating petroleum. Reservoirs on the deep, eastern trend have never been drilled presumably for economic reasons, i.e., high drilling costs and likelihood of gas. It is judged, therefore, that in spite of the completely unfavorable results to date, some 7 percent of the untested traps of the Foreland will have petroleum. These faulted traps are assumed to be 30 percent filled, indicating that 2 percent of the untested trap area will be productive.

Structure, Fold-belt Play

Untested trap area

As the Indian Continental Block and its festoon of thick flysch deposits moved northward on the Indian Plate, it wedged past the previously docked, and therefore relatively stationary, Sunda Continental Block. The Indian Plate subducted obliquely eastward and northward under the Sunda Continental Block carrying down thick wedges of sediment derived firstly from the Indian Continental Block and later from the collided edge of the Asian continental mass. Thus, the outer-arc ridge, the Arakan Yoma range (between India and Burma), buoyed by a thick wedge of accreted sediments is a high mountain chain, where further south (in Indonesia) the on-trend outer-arc zone is only a chain of islands or a submarine ridge. This oblique subduction results in compressional features, mainly anticlines and thrusts on the subducting block (Bengal Basin), and folds and especially dextral wrenches on the Sunda side of the subduction zone (Burma and Andaman Basins).

The folds of the Bengal Basin involve a tremendously thick section of argillaceous flysch and delta sediments (fig. 42), with the results that the anticlines, though perhaps initiated by compressive forces, are dominantly formed by diapirism with steep dips in the cores (fig. 44). This diapiric action appears less dominant westward.

Faults, although numerous, appear of little primary importance in the thick, plastic sedimentary volume of the Bengal Basin foldbelt; they are frequently around the steep flanks of the folds and criss-cross the synclinal areas but do not appear to penetrate deeply. Of special significance is the apparent lack, or at least dominance, of growth faults in the foldbelt (not mentioned in any of the considerable available literature), which one might expect in this huge wedge of deltaic sediments. This lack may be ascribed to the compression of the basin resulting in folds and diapirs, or to the fact that the Bengal Delta wedge continues thinning gradually southward under the Indian Ocean for hundreds of miles, without the usual abrupt, steep, delta-front termination which results in an absence of lateral support permitting down-dip, bedding-plane slippage, and consequent growth fault movement.

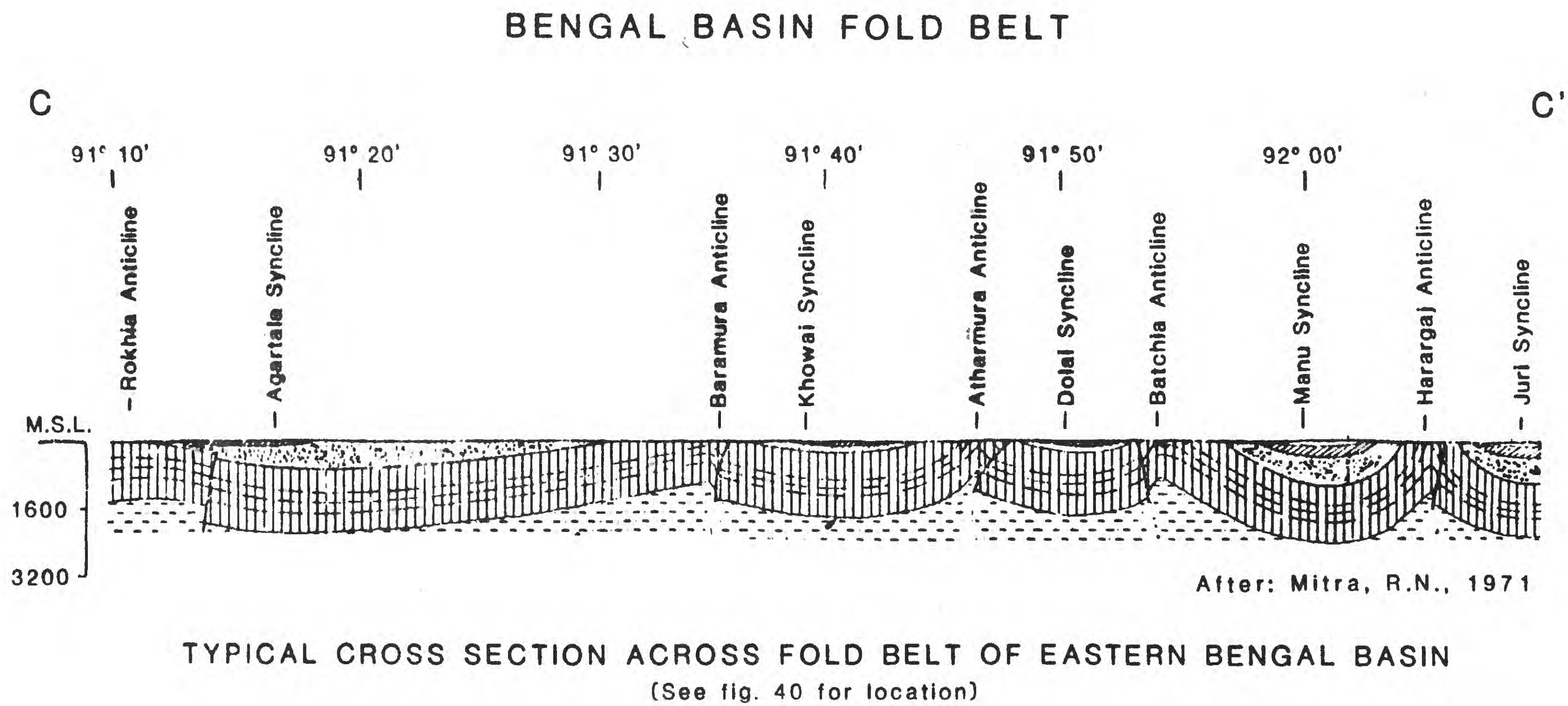


Figure 44.--Fold-belt section, C-C', Bengal basin.

There is, however, one area of growth faults. It is a zone just to the east of the Paleogene hinge or shelf edge of the southwestern basin (fig. 39) (the so-called Mahanadi Basin). This zone extends southwestward into the Krishna-Godavari Basin where a roll-over structure associated with a growth fault has yielded petroleum, G-1-1 (fig. 38). How far this zone extends northeastward along the shelf edge under the land portion of the basin is not known, but it may extend past the India-Bangladesh border. The zone is narrow, perhaps 5 to 10 miles wide (fig. 14, Rao, Y.S.N., 1980). This is really a separate play, but because of data lack and its relative small area it is grouped with the foldbelt.

There is a vast area of anticlinal folds (some 113,500 square miles) along the east side of the Bengal Basin (fig. 39). The anticlines, however, take up only a small percentage (about 20 percent) of the area, being narrow compared to the synclines. Further, as mentioned, they are largely diapiric with steep dips in the axial areas. A study of a surface geologic map of part of the area (Bakr and Jackson, 1964) with this in mind, leads to our estimate of only 360,000 acres of untested valid trap closure, the trap area being confined to the relatively flat tops of some anticlines.

Percentage of untested trap area productive

From one sample (Sylhet Field (Government of Pakistan, 1963), which has an areal hydrocarbon fill of 60 percent), it is assumed that the Bengal folds have an average 60 percent areal fill. As mentioned, the wildcat success rate is about 27 percent; this would make the productive area of untested trap about 16 percent.

Stratigraphy

General stratigraphy

The general sedimentary sequence of the Bengal Basin is shown in figure 45. Not shown in any detail is a Cretaceous wedge of sediments which has only been penetrated in a few wells in the upper hinge zone; this wedge varies from marine with some limestone, to fresh-water sands and shale. The configuration and thickness of this wedge is not available. Apparently Cretaceous traps have not been primary drilling objectives.

The Tertiary sequence may be divided into three major groups:

1) The Jaintia Group is a Paleocene-Eocene, largely marine clastic sequence, containing a prominent shelfal limestone unit, the Sylhet Formation (a strong seismic marker), which extends over the foreland areas of the Bengal Basin. The basinal equivalent of this group is largely shale, which is in a flysch facies in the Arakan Yoma range. The edge of the shelf (figs. 39 and 43) may be a locus of Sylhet reef development.

2) The Barail Group is also a shelf deposit. It is made up of Eocene-Oligocene sands and shales in a largely deltaic facies. It contains the primary oil reservoirs of the adjoining Assam Basin and is a drilling objective of the Bengal Basin Foreland Play. In the deeper, down-dip basinal areas, the equivalent section is a thick flysch section in which none of the Barail formations can be recognized.

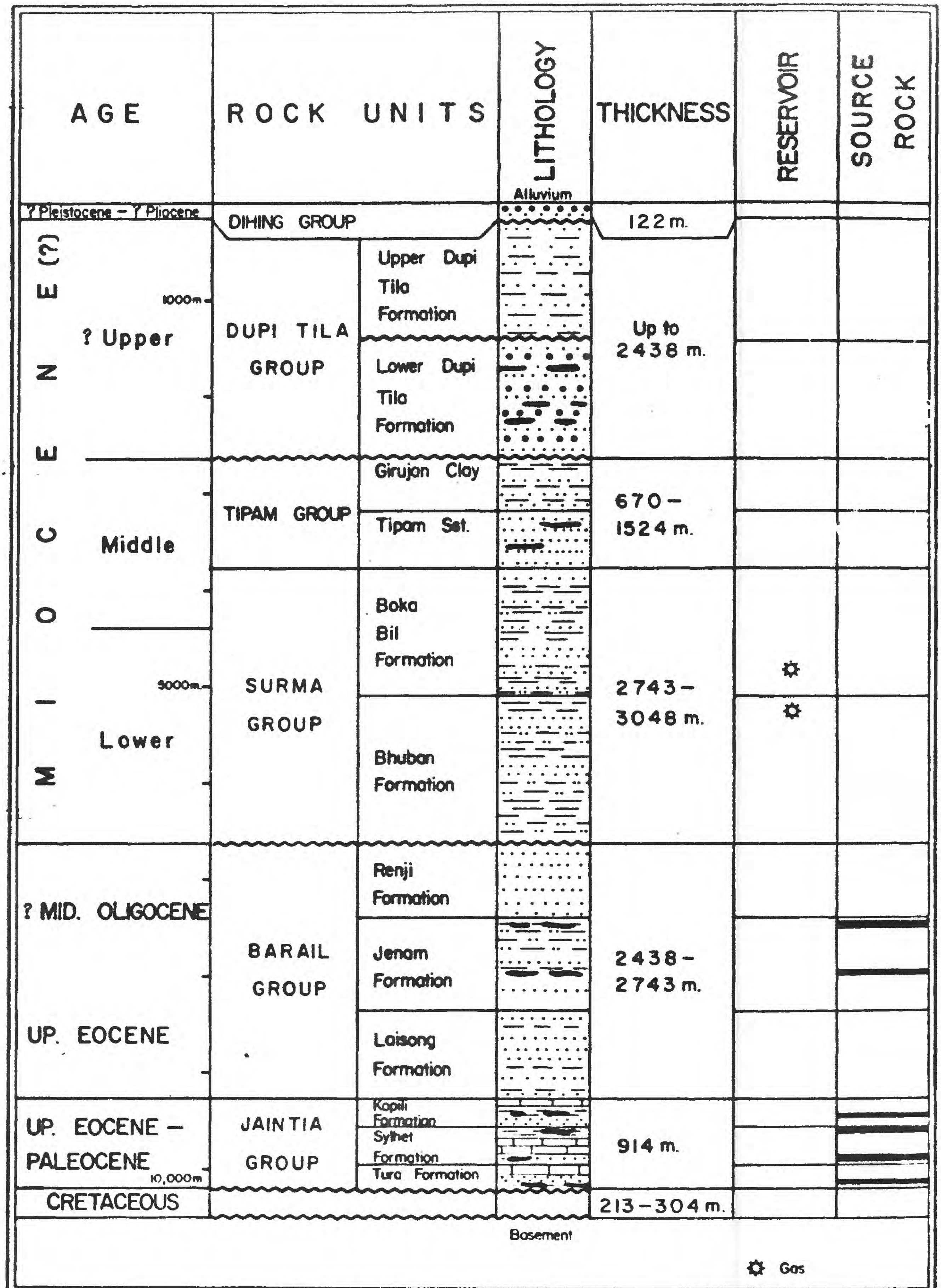


Figure 45.--STRATIGRAPHIC SEQUENCE OF BANGLADESH.

This group of sediments apparently is largely derived from the Indian Continental Block, raised in its western part after its collision with the Afghan Blocks.

3) The Neogene (Surma, Tipam, and Dupi Tela Groups) deltaic and flysch sediments are sandstones and shales largely derived from the upraised collision zone (Himalayas) between the Indian Continental Block and the Asian continental mass. The Bengal Basin gas reservoirs are in these sediments, and the Surma Group is the principal objective of the Fold-belt Play.

Reservoirs

Foreland.--The primary objective reservoirs of the Foreland Play would be the sands of the Barail Group. In only two places in the northern Bengal Basin was the Barail Group encountered, the wildcat at Atgram (fig. 41), and one small 1914 oil field (Badurpur, north end of Fold Belt), but the oil-bearing Barail sands were extensively drilled and produced to the north in the adjoining Assam Basin. These reservoirs are typical deltaic sands and of irregular thickness and distribution. In Assam, effective net sand thicknesses range from 62 ft to an estimated 320 ft; an average of 200 ft is assumed. For evaluation purposes, perhaps, 100 ft would be a good average net reservoir thickness for the more basinal Foreland Play of the Bengal Basin.

Other potential reservoirs of the Foreland Play might be Sylhet shelf-edge reefs or Cretaceous sands. These, however, only remain possibilities and for evaluation purposes are lumped with the 100-foot thickness of the Barail reservoirs.

The Neogene sands are shallow, lacking in cover, and with little access to migrating hydrocarbon; they are not regarded as highly potential reservoirs of the Foreland Play and are also lumped with the 100 ft of average reservoir thickness.

Foldbelt.--The primary objective reservoirs of the Foldbelt are those of the Neogene. All the gas produced to date has been found in Bhuban and Boka Bil Formations of the Surma Group (fig. 45). These formations are predominantly shale but have good deltaic sands varying in thickness (net?) from 200 ft (Sylhet) to 768 ft (Bakrabad) (Ball, 1981). It is assumed for assessment purposes that the average net effective pay is 250 ft.

Seals

With a large amount of shale in the section and the apparent minor role of faults (i.e., no mention of growth faults except in a narrow zone in the southwestern basin), it would appear that for the Fold-belt play at least seals should be good. The Foreland, which is less shaley and more faulted, may be somewhat less efficiently sealed.

Source rock section

The source rock potential of the Tertiary section appears to be limited to the Paleogene for several reasons discussed in "Generation and Migration" below.

Generation and Migration

Richness of source

The wildcats of Bengal, restricted by drilling depth limitations to the younger strata, Surma, Tipam, and Dupi Tila Groups (fig. 45), penetrated no major source rock (Lietz, 1982). These young strata, however, may qualify as a meager source since 40 percent of the section in two recent wells, Beani Bazar and Atgram, have T.O.C. values from 0.5 to 0.9 percent and are reportedly gas generating (Hillar, K., unpublished communication). The only well (except those of the old Badupur oil field) which did bottom in the deeper Barail Group, Atgram, found T.O.C. values of up to 4.2 percent (Hillar, unpublished communication). This confirms that these Barail are organically rich by analogy to the adjoining Assam Basin where the Barail Group is the richest source rock and, together with the Jaintia Group, the source of the Assam oil (see Assam Basin). Carbon 12/13 isotope analysis indicates that Bengal gas is derived from a marine source (Lietz and Kabir, 1978). This suggests that the deep marine Jaintia Group, or perhaps a marine equivalent of the Barail Group, is the source rather than the relatively shallow deltaic Surma or Tipam Group.

Depth and volume of mature sediment

The thermal gradient of the Bengal Basin is generally low, averaging about 1.4°F per 100 ft. This, with the subsidence rate, places the average depth to the thermally mature zone at more than 9,000 ft. This depth is corroborated to a certain extent by the fact that vitrinite reflectance in the Bangladesh discovery wells with depths of 8,000 to 15,000 ft "indicates that the sections are chiefly immature or partly at the beginning of the oil window maturity stage" (Leitz, 1982). Thus, a deep source is indicated by both thermal- and organic-richness considerations.

On the basis of an average 9,000-foot depth to the thermally mature rock, there is a tremendous volume of mature and over-mature sediments, some 550,000 mi^3.

The base of the mature zone calculates to be 14,000 to 20,000 ft deep, averaging about 17,000 ft; this puts some of the deeper hinge traps in the gas (over-mature) zone.

It should also be noted that the over-pressured shales are prevalent below depths from 6,000 to 12,500 ft (Lietz, 1982), depths which coincide approximately with the top of the thermally mature zone.

Oil versus gas

As attested by the reserves of 11 Tcf of gas and no oil, the Bengal Basin is a gas-prone basin.

Minor oil (or condensate) seeps occur along the north boundary near the Dawki Fault (fig. 39), and oil was produced from the abandoned Badurpur oil field (2 MMBO) at the north end of the foldbelt. Minor oil fields are on

Ramree Island in the south (Arakan coast - Burma) end of the foldbelt. The oil in the northern locations appears to be coming from the lower part of the section, Barail or older; the Ramree Island oil is reportedly from Lower Miocene reservoirs. On the foreland side, very minor oil shows are reported in the Kutchma wildcat (fig. 41) and in the nearby on-trend Indian wildcat, Bogra, near the upper hinge line, and traces of residual oil were found in Hazipur well (fig. 41) located more down-dip (at a depth of about 10,000 ft) (Lietz, 1982). The ages of the strata containing these hinge-line shows are disputed, but they may be as young as Miocene.

Carbon 12/13 isotope analysis (Institute for Geosciences, Hannover, Germany, Lietz, and Kabir, 1978) indicates that the Bengal Basin gas is from marine source rock. Not only does this indicate a deep source, as discussed above, but also indicates that the gas-prone nature of the basin cannot be ascribed to terrigenous source rock.

These carbon isotope studies also indicate that the Bengal Basin gas was generated in the same thermal window as oil generation, and is not higher hydrocarbons cracked to methane in thermally over-mature sediments. This, together with the marine origin of the gas and the great volume of sediment, leads to the conclusion that at least some oil must have been generated with the gas. The absence of oil production leads further to the conclusion that the oil must have been separated from the gas during migration. Apparently, migration has a strong vertical component, since, as discussed, the probable source rocks are Paleogene strata. These strata are below 9,000 ft, considerably below the gas reservoirs whose average depth is less than 7,000 ft.

The basin has a great volume of over-pressured shale, which appears to include the thermally mature shales. Growth faults, which have been taken as upward escape channels of hydrocarbon from over-pressured shale sections in other delta areas, apparently are absent from the generally compressed part of the Bengal Basin. Recent studies (Leythaeuser, 1982) indicate that perhaps molecular diffusion is the only means of primary hydrocarbon migration through over-pressured shale sections. Further, it has been shown that diffusion is an effective process for primary migration of gas, but not oil. Hydrocarbon molecules of the C_1 to C_6 (gas fraction) have sufficient mobility through wet shale, while the larger molecules (oil fraction) move more slowly or not at all, remaining behind locked in the source shale. This appears to be the case in the Bengal Basin.

Another attribute of diffusion is that migration may take place without the necessity of the gas concentration exceeding saturation in the water (so as to enter a gas phase), but the molecules can move independently of concentration. In the Bengal Basin, where rapid sedimentation has in many cases undoubtedly diluted the T.O.C. below the accepted 0.5 percent, gas molecules could still migrate.

The better oil, versus gas, prospects would be on the periphery and the foreland of the basin where more sands and faults would have bled off the over-pressure, allowing pressure-driven migration processes to affect the petroleum in an oil, gas, or solution phase. Oil may also be expected in the area of growth faults just down-dip from the Paleogene shelf edge (fig. 39) in the south-western part of the basin on trend with some Krishna-Godavari discoveries (figs. 37 and 38).

For evaluation purposes it is assumed that 15 percent of the undiscovered petroleum is oil in the Foreland and 3 percent is oil in the foldbelt.

Migration timing versus trap formation

Assuming that the rate of subsidence and the thermal gradient remained more or less constant through the late Mesozoic and Cretaceous, hydrocarbon generation would have started when the sedimentary thickness exceeded about 9,000 ft. In the central part of the basin, this would have been in the Late Cretaceous-early Paleogene, and on the Foreland, late Paleogene to middle Neogene.

Foreland.--The Foreland traps are, from oldest to youngest: drapes over Cretaceous-Paleogene fault blocks, possible Eocene reefs, possible Oligocene pinchouts, and Miocene fault traps. All of these but the Miocene fault traps formed early with respect to hydrocarbon formation/migration and would be in a position to receive a major portion of the hydrocarbon generated. Some reservoir deterioration might have affected the older traps.

Foldbelt.--The Foldbelt traps did not reach their present form until sometime in the Pliocene; the present reservoirs were not deposited until the Miocene. Since petroleum had been generating and migrating since the Paleogene (or earlier), much petroleum must have escaped the system. In general, the fold traps are too late for efficient accumulation of the Bengal Basin oil and gas. Furthermore, as discussed above, over-pressured shales block most of the oil, rather than gas, migration.

Limiting Factors

Foreland.--One limiting factor regarding petroleum in the western (Bogra) fault zone may be the small volume of available source (i.e., Oligocene or older) so far up-dip on the shelf. Oil, rather than gas, may be limited in the down-dip hinge area (where traps appear likely) by the depth (i.e., thermal over-maturity) and by the presence of over-pressured shale. It appears there is only a limited, narrow zone where oil generation and optimum migration (lack of over-pressure) and entrapment may occur. Gas is not so limited down-dip and can be expected wherever good traps occur. Trap definition of older structures may be a difficult exploration problem.

Foldbelt.--The overriding limiting factor to gas and oil accumulation appears to be the poor quality and paucity of valid closure. Concerning oil, the limiting factor appears to be the lack of migration avenues through thick over-pressured shale.

Assam Basin

Introduction

Location and size

The Assam Basin is located in northern Assam, the northeastern province of India (fig. 1). It is closely related to the Bengal Basin (figs. 39 and 40) of which it could be considered an offshoot. It coincides approximately with the upper Brahmaputra Valley and is bounded on the northwest by the Himalayas and on the southeast by the northern Arakan Yoma Range (Chin Hills). As here defined, the basin is relatively small, having an area of 8,000 mi^2 and a sedimentary volume of about 28,000 mi^3 (fig. 46).

Exploration and production history

Exploration began in 1866 in the thrust and foldbelt on the southeast side of the basin, and the first discovery, the Digboi Oil Field, was made in 1889. In spite of more-or-less continuous effort in the thrust and fold belt, no further appreciable find was made until the geophysical discovery of Nahorkatiya in 1953 on the foreland in the central part of the basin. Since that time, there have been some four or five fair discoveries and an equal number of smaller discoveries, increasing the original reserves of the Assam Basin to about 708 million barrels of oil (Center for Monitoring Indian Economy, 1984) with almost half in the Nahorkatiya Field. No major discoveries have been made during the last decade. Gas reserves amount to 2.7 Tcf.

The historical wildcat discovery rate appears to be about 20 percent. The basin is relatively small and the exploration rather thorough; it is estimated to be about 80 percent complete.

Structure

General tectonics

The tectonics of the Assam Basin are similar to those of the Bengal Basin, except that it is much narrower (in an east-west direction) as a result of the relative eastward movement (150 miles?) of the India Block north of the east-trending Dawki dextral wrench fault of Oligocene to recent age (figs. 39 and 40). The Assam Basin has two major plays as does the Bengal Basin.

(1) The foreland appears to be the rifted continental margin of the India Block (where it separated from Australia-Antartica) and is characterized by horst and graben structure with accompanying Tertiary drape structures. The normal faulting was active until mid-Miocene (end of Tipam time, fig. 47). As may be seen in Sections C-C' and D-D' (figs. 46 and 47), the Foreland play extends partially under the thrust and foldbelt. It has an estimated area of 4.48 million acres.

(2) The thrust and foldbelt, i.e., the zone of thrusts and steeply-dipping anticlines, is the result of compression forces associated

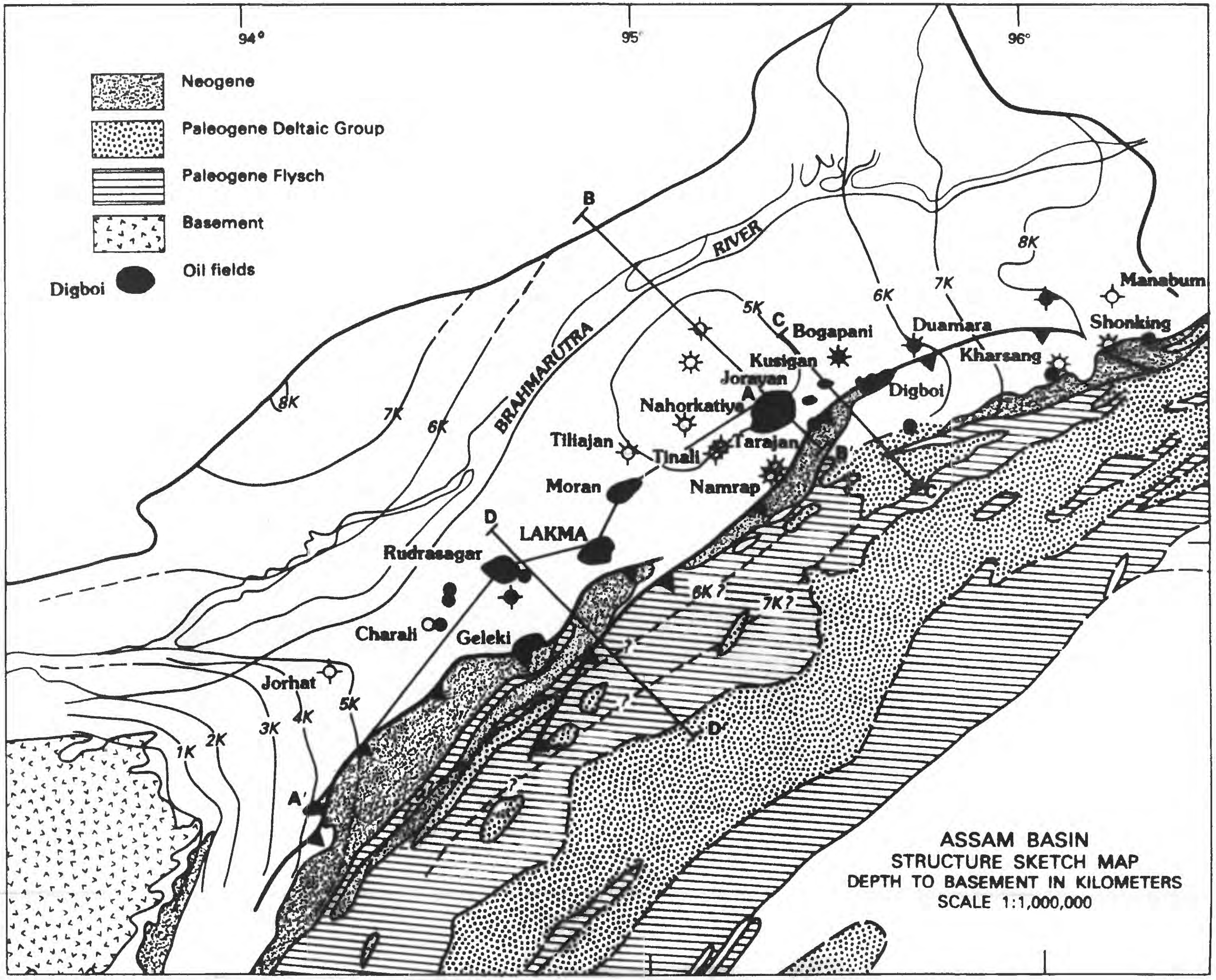


Figure 46.--Depth to basement map, Assam Basin.

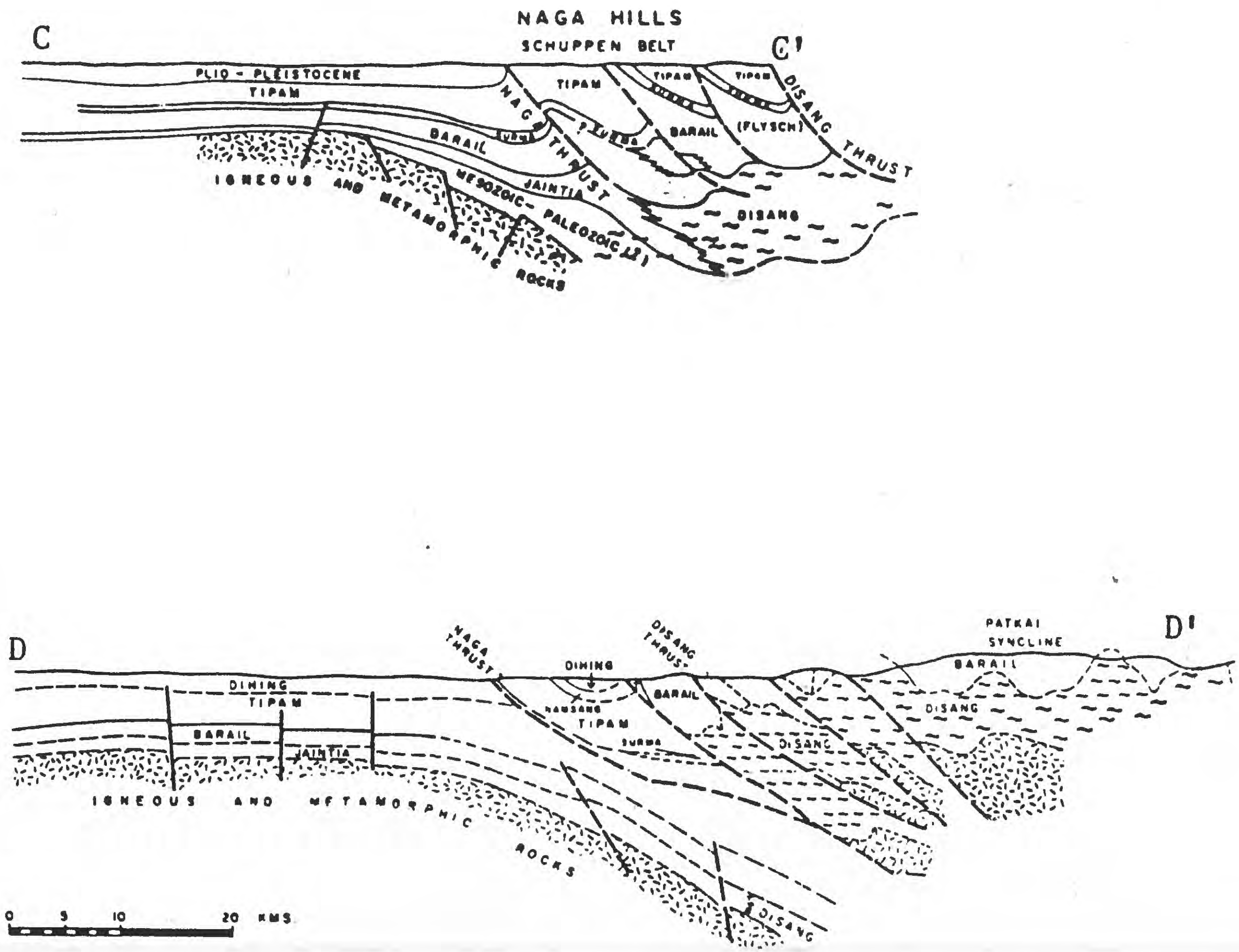


Figure 47.--Diagrammatic sections: C-C' across Naga Hills and D-D' across upper Assam

(See fig. 46 for location.) After A.T.R. Raju, 1968.

ASSAM BASIN THRUST BELT

with the oblique collision of the India and Sunda Continental Blocks (figs. 2, 46, and 47). The closures in this zone are small and much broken by faulting; furthermore they have been thoroughly explored. The future hydrocarbon potential of this play is considered negligible and is not discussed further.

There is an adjoining basinal area or perhaps a third play which should be mentioned. The floor of the Assam Basin dips northwestward under the Himalayan thrust sheets as the Indian Plate subducts beneath the Asian continental mass, forming a small Neogene foredeep basin. This is shown on the depth to basement map (fig. 46) and in cross-section B-B' (fig. 48). However, as discussed under the Indo-Gangetic Basin, the Neogene sediments occupying the subbasin are in a continental molasse facies. The Paleogene source section thins eastward and is missing in this part of the foredeep basin. On this basis, the play has negligible hydrocarbon potential and is discussed no further.

Untested trap area

A very approximate area count of present fields indicates about 168,000 acres of structural closure. Assuming exploration is approximately 80 percent complete and the present discovery rate will continue, 42,000 acres of trap will be discovered.

Percentage trap area productive

The success ratio is estimated to be about 20 percent. The average petroleum fill from the only available field data (Nahorkatya) is indicated to be 45 percent. On this basis it is estimated that 9 percent of the area of closure found would be productive.

Stratigraphy

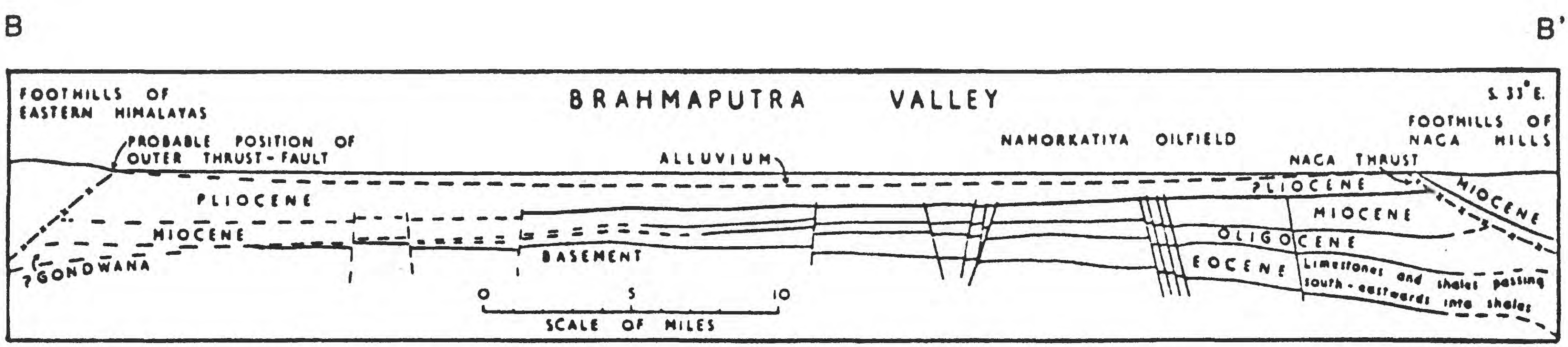
General stratigraphy

The general stratigraphy, including formation thicknesses and lithology, is shown in the stratigraphic correlation of the Assam Basin (fig. 49). Note that the formation and group names are the same as for the Bengal Basin, indicating their lithologic similarity. The Barail and Jaintia (Paleogene) Groups are derived largely from the Indian Continental Block, while the Surma, Tipam and Moran Groups (Neogene) are derived mainly from the Asian continental mass after its collision with the Indian Block. Except for the Sylhet Limestone near the base, the section is alternating sands and shales. The Jaintia Group is marine, the Barail largely deltaic, and the younger strata deltaic to fresh water.

Reservoirs

The principal hydrocarbon reservoirs are the deltaic sands of the Barail Group (fig. 49). A small amount of oil, and perhaps considerable gas, is found in the Tipam sands, but this is believed largely secondary, probably having leaked up through faults from the primary Barail reservoirs and source section; in the thrust and fold belt the Tipam sands are the main reservoirs (e.g.,

SECTION ACROSS UPPER ASSAM, NORTHEAST INDIA



(See fig. 46 for location)

ECAFE: MRDS, No. 10, 1959

Petroconsultants Ltd.

Figure 48.--Regional cross section B-B', Assam Basin.

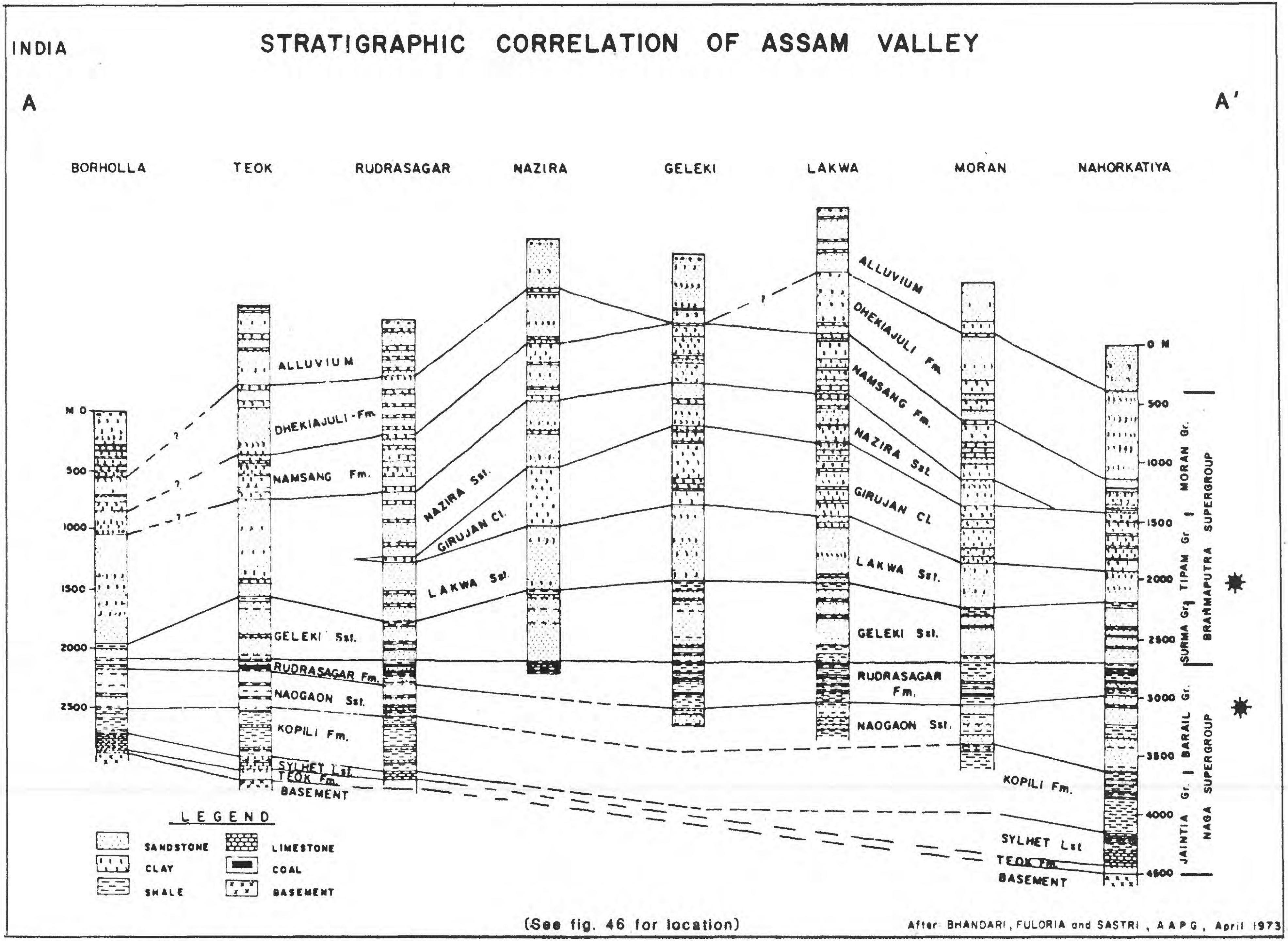


Figure 49.--Stratigraphic correlation of Assam Valley, A-A'.

Digboi Oil Field). Petroleum also has been found in Kopili sandstones (Eocene), Basal sandstone (Paleocene), and the basement. The Barail sands (and other minor reservoirs) are of irregular thickness and areal distribution, ranging in effective thickness from 100 to 700 ft, and probably averaging some 200 ft.

Seals

Since there is a large amount of shale in the upper part of the section and since the Barail-related faults do not appear to have cut the Pliocene formations (figs. 47 and 48), the seals should be good, we assume about 90 percent effective in the Foreland Play. In the mobile belt, however, this is not the case; numerous faults reach the surface, and seeps are prevalent.

Source rock section

The source rocks are undoubtedly the Paleogene strata, particularly the Barail deltaic shales and the Kopili marine shales, as is discussed below.

Generation and Migration

Richness of source

From the oil occurrence in often isolated Barail sands, it appears that the zone of sufficiently organically rich source rocks are principally the enclosing Barail deltaic shales. This conclusion is corroborated by the very waxy, low-sulphur type crude, which is generally taken to be derived from terrigenous (i.e., deltaic) kerogen. However, it has been established lately that the underlying marine Kopili shales (with largely terrestrial-derived kerogen) are also a primary source. Murty (1983) states that the Barail is a good to very good "potential source rock," while the Kopili Group is only "good" but favorable as a source in North Assam as it is more within the "oil window." The organic richness of the overlying Neogene strata is not known in the Assam Basin, but where the same formations were measured in the adjacent Bengal Basin, they were found to be organically lean to poor.

Depth and volume of mature sediments

The average thermal gradient of the Assam Basin is low, about 1.4°F per 100 ft of depth. This, together with the average rate of subsidence, puts the top of the thermally mature sediments at about 9,000 ft (2,750 m). As may be seen by a comparison to the depths on the stratigraphic columns (fig. 49), this depth very approximately coincides with the top of the Barail Group, further confirming it and the underlying Kopili shales as the principal source. We calculate about 13,500 mi^3 of mature rock in the basin, but there could be more if one considers the down-dip volume to the southeast under the thrusts (fig. 47).

Oil versus gas

No nonassociated gas is produced in the Assam Basin, but this may be because there is no available market. With the manifest terrigenous source and good sealing, one would expect gas. Gas reserves are reported to be 2.7 Tcf versus .708 BBO. Given the above, we assume for evaluation purposes that the hydrocarbon fill of the undiscovered trap area is 60 percent oil.

Migration timing versus trap formation

Assuming a constant thermal gradient and subsidence rate through the Tertiary, hydrocarbon generation and migration would begin when the source rocks were buried to a depth of about 9,000 ft. This would have occurred in late Miocene or early Pliocene. At this time the drape and fault closures were largely formed (the fault movements from Cretaceous-Paleocene to Miocene), the seals were largely in place (Neogene shales), and the reservoirs were intact but probably somewhat deteriorated since its deposition in the Paleogene.

Limiting Factors

The overall limiting factor concerning undiscovered petroleum is the advanced maturity of the exploration coupled with the relatively small size of the basin.

Indo-Gangetic Basin

Introduction

Location and size of area

The Indo-Gangetic Basin extends along the northern side of India at the foot of the Himalayas from Pakistan on the west (75° East) to Bangladesh on the east (80° East) (figs. 1 and 50). It has an area some 190,000 mi^2 and a sedimentary volume some 310,000 mi^3.

The basin may be divided into two subbasins, the Punjab Subbasin in the west and the much larger Ganga Subbasin in the east (fig. 50).

Exploration history

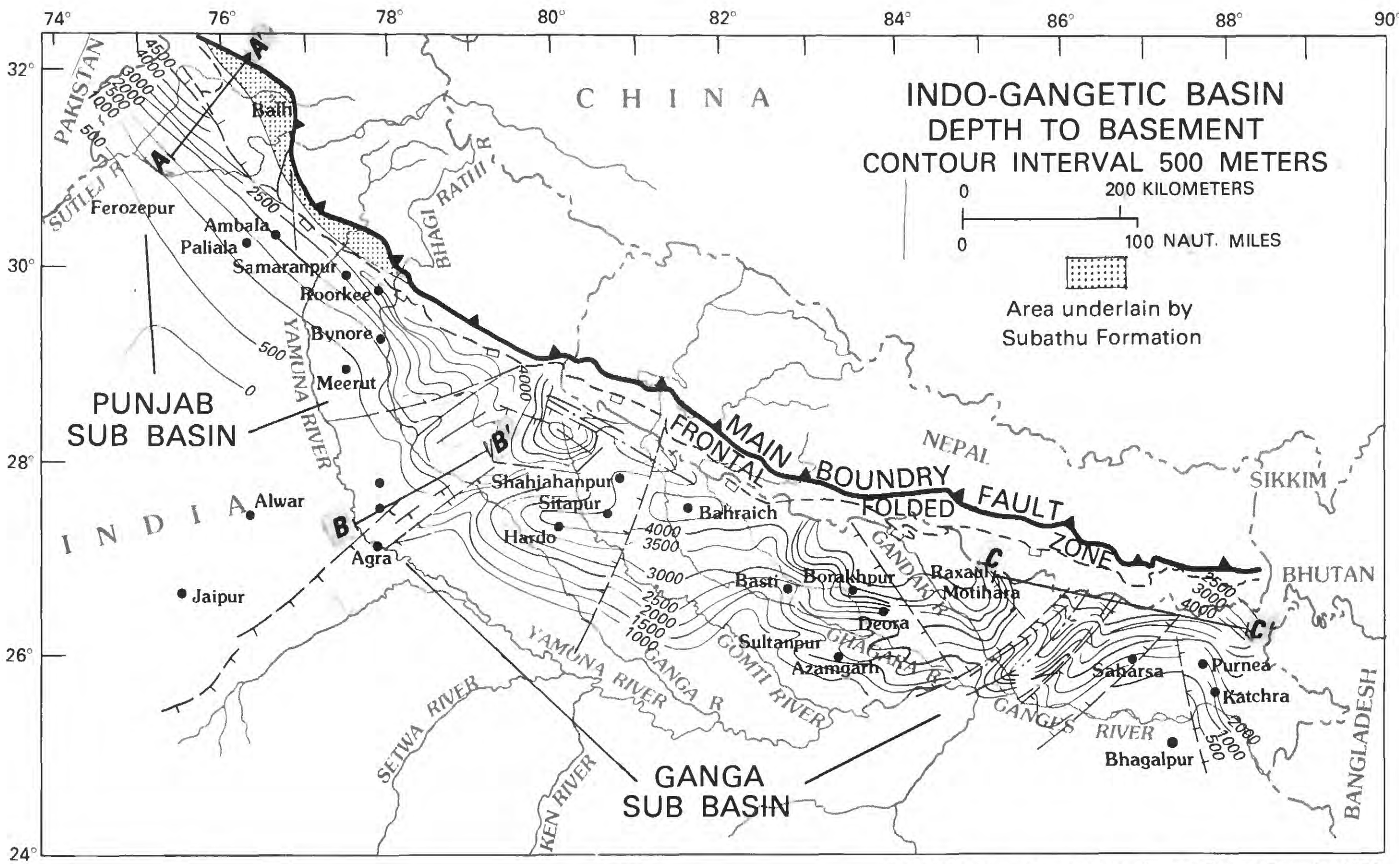
Through the sixties and seventies, the ONGC exploration consisted of the drilling of 12 wildcats and 10 stratigraphic holes, including the extensive geologic and geophysical surveys required to locate these holes. No oil or gas was found. Exploration is in an immature stage, about 20 percent complete, but because of the negative results, may never progress very far.

Structure

General tectonics

Prior to the Indian Continental Block's collision with the Asian continental mass in the Oligocene (?) to Miocene, the Indo-Gangetic area was part of an extensive pericratonic, or rifted continental margin, basin. There are some suggestions of west-northwest-bearing basement high trends (figs. 50, 51, and 52), which may be evidence of pre-Miocene horst and graben structure, developed during an ancient rifting along the north margin of the Indian Continental Block.

After the collision, which raised, particularly, the western part of the Indian Block causing a profound unconformity, subduction began. The Indian Block was depressed as the Himalayas rose, receiving a very thick, nonmarine,

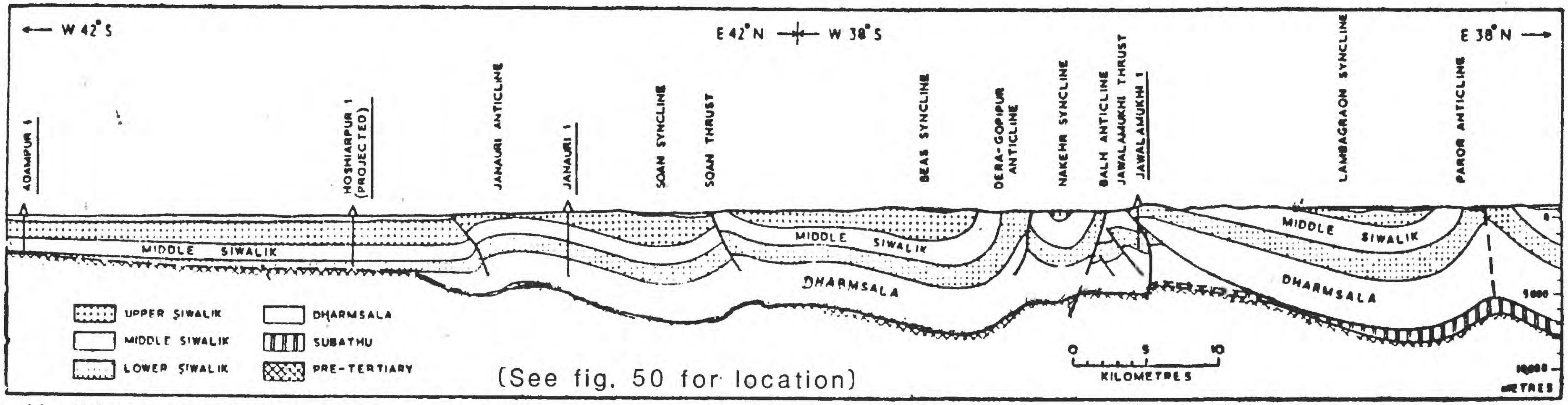


Modified from Karunakaran C. and Ranga Rav, A., 1976

Figure 50.--Depth to basement map, Indo-Gangetic Basin.

SOUTH NORTH

A **PUNJAB SUB-BASIN, INDO-GANGETIC BASIN** A'



(See fig. 50 for location)

Modified from Mathur L.P. and Evens P. 1964

FIGURE 51

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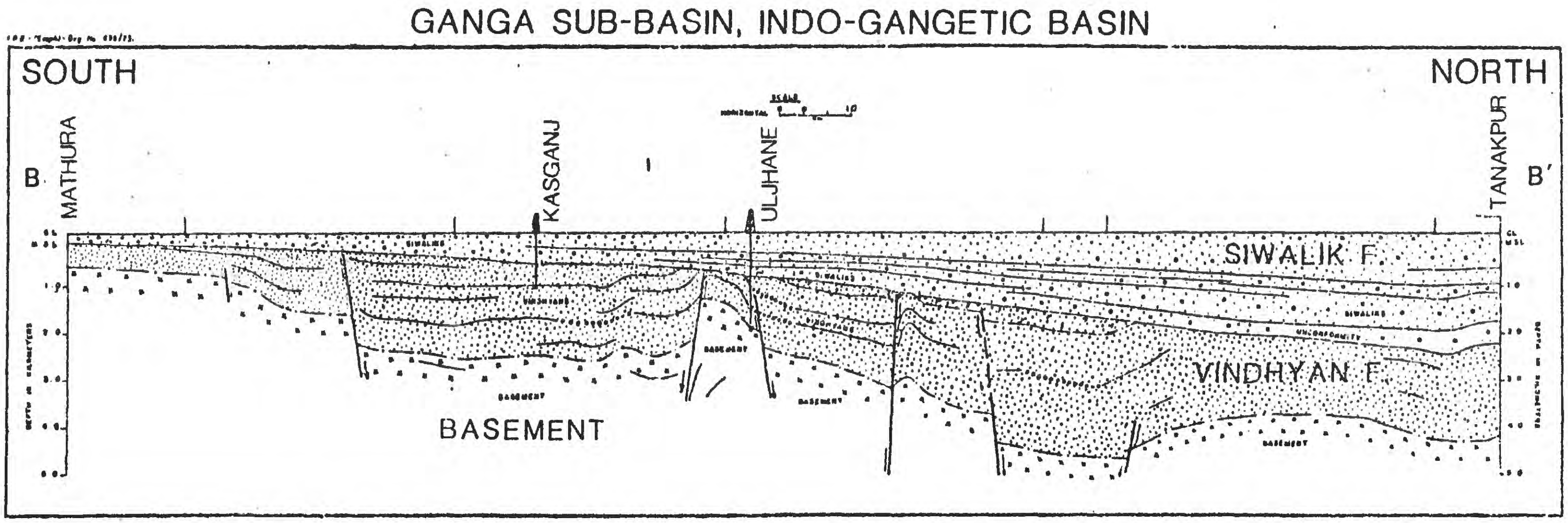


Figure 52 Schematic section across the West U. P. Plains. Based on Seismic data, By permission of Chairman, ONGC, (ONGC unofficial Report).

(See fig 50 for location) Modified from Rao, M.B.R., 1973 molasse into the resulting Indo-Gangetic trough. As subduction continued, there developed imbricate thrust structure in the older Himalayan rock and folds in the younger Tertiary rock in the southern foothills, and both are still developing at present. The relatively young compressional folds have been the principal objectives of exploration in this basin.

Untested trap area

Abundant structural traps are available in the folded Himalayan foothills with long anticlinal trends extending as long as 200 miles. Area of trap closure is not a factor limiting the amount of undiscovered hydrocarbon in this basin. There appears to be better trap formation than in the Indus Fold Belt, for instance, where the trap area appears to be 7.6 percent of the area. For assessment purposes, it is assumed that the closed trap area is 8 percent of the basin area or about 9.73 million acres.

Percentage trap area productive

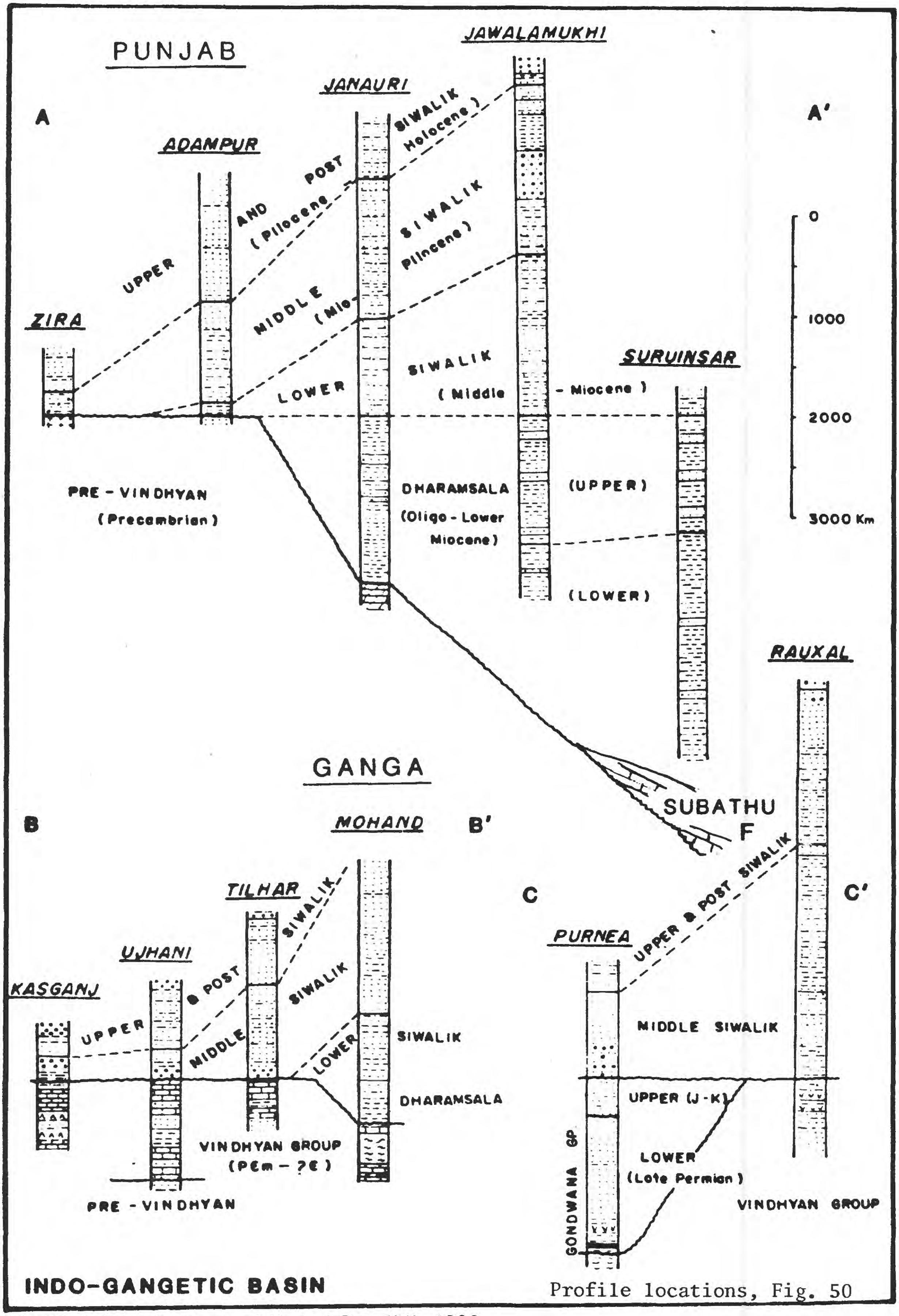
As is discussed under "Generation and Migration," the percentage of the traps that could have petroleum is curtailed by the apparently very limited part of the basin which is underlain by source rock, i.e., about 2 percent. Assuming one in 10 of the structures underlain by source rock would have oil or gas and that the average petroleum fill would be 30 percent, the productive portion of the trap area of the basin would be about .06 percent.

Stratigraphy

General stratigraphy

There is a thick pre-Tertiary sedimentary section under the eastern part of the basin, the Vindhyan Formation (pre-Cambrian to mid-Paleozoic) and the Gondwana Group (Permian to Cretaceous); these strata crop out over a large area of India and have no shows other than minor bitumen (dead oil) in Pakistan and methane largely associated with coal.

In general, the Tertiary strata are sandstones and shales in a molasse facies except for the lowest unit, the Paleocene-Eocene Subathu Formation of largely shale and limestone. The Tertiary strata lap progressively southward onto the Indian Shield (figs. 51, 52, and 53), the Subathu Formation extending only a short distance southward (cross-hatched area in fig. 50, vertical hatched in fig. 51, labelled in fig. 53), while successively younger beds extend further south. Sand-shale ratios in the Subathu Formation decrease northwards towards the Himalayas (Aditza and others, 1976), indicating that it derived from the Indian Shield to the south and that the depocenter of the Subathu deposition exists further to the north but is now under the southward-thrusting Himalayas. Sand-shale ratios in the overlying Dharamsala (Early Miocene-Late Oligocene) and younger formations increase toward the Himalayas showing that the derivation of detrital material has reversed, at that time coming from the Himalayan (Asian) side.



Modified from Acharyya, S.K. and Ray, K.K. 1982

Figure 53.--Stratigraphic sections, A-A', B-B', C-C', Indo-Gangetic basin.

Reservoirs

Reservoirs are plentiful in this molasse-dominated section. There are hundreds of feet of effective porosity. Since thickness is not the factor which limits the amount of hydrocarbon of the basin, a conservative 100 ft of thickness is assumed for basin evaluation purposes.

Seals

Seals should be fairly effective since there is considerable shale in the section.

Source rock section

The source section is limited to the Subathu Formation, as will be discussed in "Generation and Migration" below.

Generation and Migration

Richness of source

The pre-Tertiary sediments have been analysed by ONGC over an extensive area and over the complete stratigraphic section for organic richness and for ratios of naphtha-bitumen to organic carbon (a measurement of thermal maturity) (Bhatlacharza and Chandra, 1976). In general, it was found that these sediments are deficient in organic material. An exception is the Krols and Infra-Krols Formations (Permo-Carboniferous) of the Punjab Subbasin where the T.O.C. varies from 0.58 to 2.7 percent. The naphtha-bitumen to organic carbon ratios, however, indicate that, with minor exception, the pre-Tertiary section is overmature. It appears therefore that the pre-Tertiary is only capable of sourcing some gas in the Punjab Subbasin.

The Tertiary (except for the Subathu Formation), i.e., the Dharamsala, Sawalik and post-Sawalik Groups are uniformly poor in organic content.

The Subathu Formation does have adequate organic richness for hydrocarbon generation (T.O.C. of 0.52 to 36.5 percent), and this richness appears to increase in a westward direction towards the oil-bearing Potwar Basin (on trend less than 100 miles to the west). The Potwar Basin's principal oil reservoirs, and probably source, are Paleocene-Eocene shale and limestone formations, equivalent and lithologically similar to the Subathu Formation. The Subathu Formation, however, underlies only a small portion in the extreme northwest corner of the basin (2 percent of the basin, cross-hatched area in fig. 50).

Depth and volume of mature sediments

The thermal gradient averages about 1°F per 100 ft (.87 to 1.0°F/100 ft. in the Ganga Subbasin and 1.0 to 1.1°F/100 ft. in the Punjab Subbasin, i.e., becoming higher westward toward the Potwar Basin). This thermal gradient, along with the rate of subsidence, places the average top of the mature zone at 12,000 ft (3,700 m) and the base at 16,000 ft (5,000 m). This puts most of the source beds, i.e., the Subathu Formation, in the overmature zone.

The volume of once mature rock, including the pre-Tertiary, is incalculably large. The volume of the presently mature (or marginally over-mature) principal source rock (Subathu Formation), however, is now relatively small, perhaps 6,000 mi^3. However, in late Miocene when generation and migration began, a larger volume of source rock (Subathu Formation) was available before being thrust under the Himalayas.

Oil versus gas

As discussed under "Depth and volume of mature sediments," most of the probable source rock is now over-mature. It is therefore estimated that only about 30 percent of untested-trap petroleum fill area would be oil rather than gas.

Migration timing versus trap formation

Assuming that about the same thermal gradient and rate of subsidence continued through the Tertiary, the principal source rock, the Subathu Formation, subsided to depths of thermal maturity in about late Miocene and over-maturity in the Pliocene. Some of the petroleum generated and migrated during late Miocene could have escaped over-maturation. This was about the time the folds became well developed, but already a good portion of the Subathu basinal area had been thrust under the Himalayas.

Limiting Factors

The overriding factor limiting the undiscovered hydrocarbon is the absence of sufficiently rich source rock in all but 2.0 percent of the present basinal area. It is further limited for oil in that most of the source rock is now overmature.

Burma Basin

Introduction

Location and size of area

The Burma Basin extends southwards through the length of western Burma and onto the continental shelf to the south (fig. 1); it may be divided into four subbasins, Chindwin, Central (Minbu), Irrawaddy, and Eastern (fig. 54). It has an area some 120,000 mi^2 and an approximate sedimentary volume some 411,000 mi^3.

Exploration and production history

The Yenangyiang Oil Field (Lat. 20°20', fig. 55) was producing 200 to 400 barrels per day from about 100 wells prior to 1797; the first "modern discovery" well was drilled there in 1887. In 1902, the Chauk Oil Field (Lat. 20°50', fig. 55) was discovered. These two fields of the Central Subbasin (fig. 54) and smaller, on-trend satellite fields have essentially supplied the production of Burma up to 1962 when the government oil company, Myanma Oil Company (M.O.C.), took over the industry. This production peaked at 22,000 BOPD at

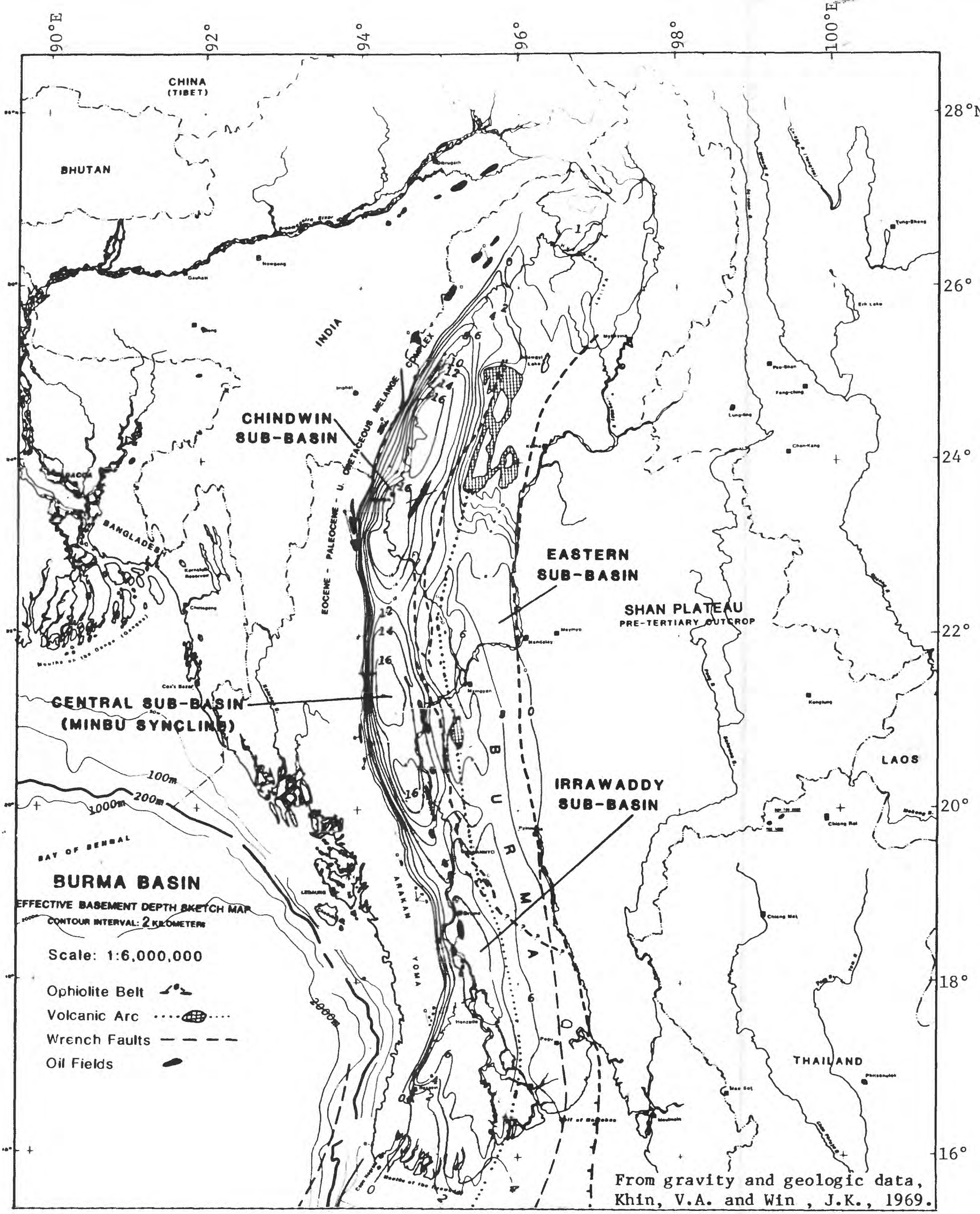


Figure 54.--Depth to effective basement, Burma basin.

the end of World War I, was virtually shut down during World War II, and did not again exceed the World War I peak until 1973. M.O.C.'s discoveries at Myanaung (Lat. 18°15', fig. 55) in 1964, at Prome (Lat. 18°35') in 1966, at Mann (Lat. 20°15') in 1971, and at Htaukshabin (Lat. 20°) in 1976 have steadily increased Burma's production, until it reportedly reached 30,000 BOPD in 1979, exceeding the 23,000 BOPD capacity of the country's refining capacity. Since then production has declined, levelling off at 23,200 in 1982, the main producers being the Mann/Htaukshabin fields with 18,500 BOPD. Gas production averages 65 MMCF/day. In 1981, three discoveries, Pagan-Tuyintuang, (Lat. 21°5', fig. 55), Kyontani (Lat. 17°45'), and Htantabin (Lat. 18°20') were announced as major discoveries with reserves of 200 MMBO, 17 MMBO, and 136 MMBO. The latter two were regarded as especially significant since they were from a new play (Miocene carbonate reefs in the Irrawaddy Subbasin). Appraisal drilling in 1982 and 1983 was discouraging; the Kyontoni and Htantab reef tests declined rapidly to the point of noncommerciality, and the Pegan-Tuyintuang appraisal wells were dry.

The above exploration was onshore; offshore exploration drilling began in the Gulf of Martaban after extensive seismic surveys. By 1974, 12 wells were drilled by the M.O.C., one of which was a gas well or blowout. By 1976, foreign contractors drilled an additional 19 wildcats, all of which were dry. As of late 1984, another 10 wells were drilled by M.O.C., two of which were discoveries, 3DA and 3CA structures (fig. 63), which, according to published figures, have estimated reserves of 5.3 Tcf (Hiller, unpublished communication).

The wildcat success rate appears to have been about 6 percent prior to World War II and 10 percent afterwards, perhaps averaging 8 percent. The overall exploration appears limited in scope and expenditure, so, in spite of the long history of exploration, it may be that the basin still has a potential for large petroleum production and that exploration may still be considered to be in a stage of early maturity, or about 65 percent explored.

Structure

General tectonics

The Burma Basin appears to be a classic fore-arc basin. On the east, between it and the craton (Shan Plateau), is a volcanic arc which trends southward to join the Indonesian volcanic arc and on the west is a line of ophiolites, melange, and thrusted flysch, which extends along strike into the well-defined accretionary wedge forming the outer arc of Indonesia (figs. 54 and 62). Figure 56 is a diagrammatic cross-section showing the relation of the basin to the continental margin, i.e., the oblique subduction of the Indian Plate beneath the Sunda Continental Block.

As may be seen (fig. 54), the Burma Basin, as termed here, includes a number of subbasins, which with more detailed information could be considered as separate plays.

Although not previously recognized (at least in available literature), it appears that the structure of the basin is profoundly affected by dextral wrench faulting. The abrupt and discordant changes in formation thicknesses across faults (fig. 58), narrow, straight alignment of structural closures

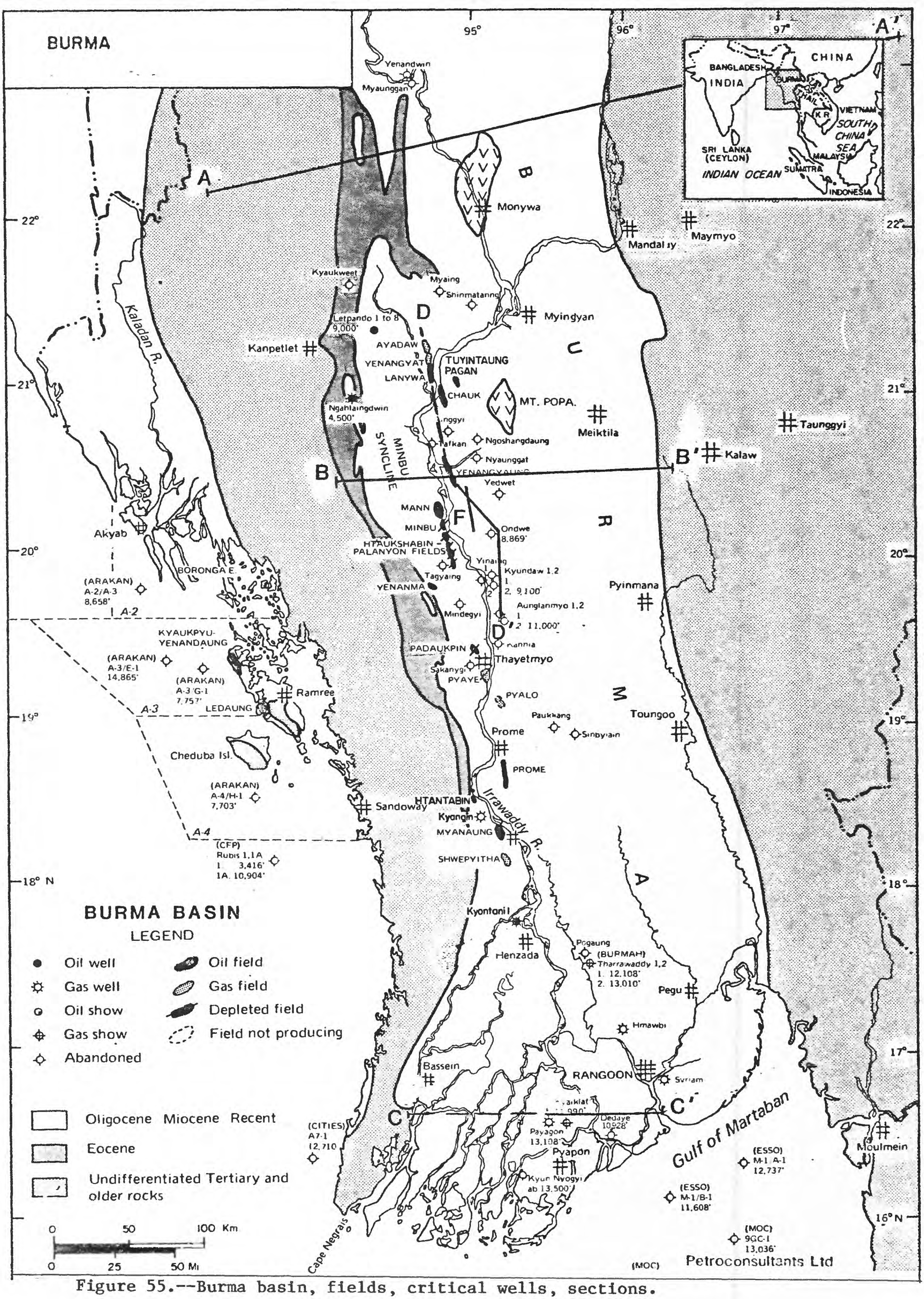
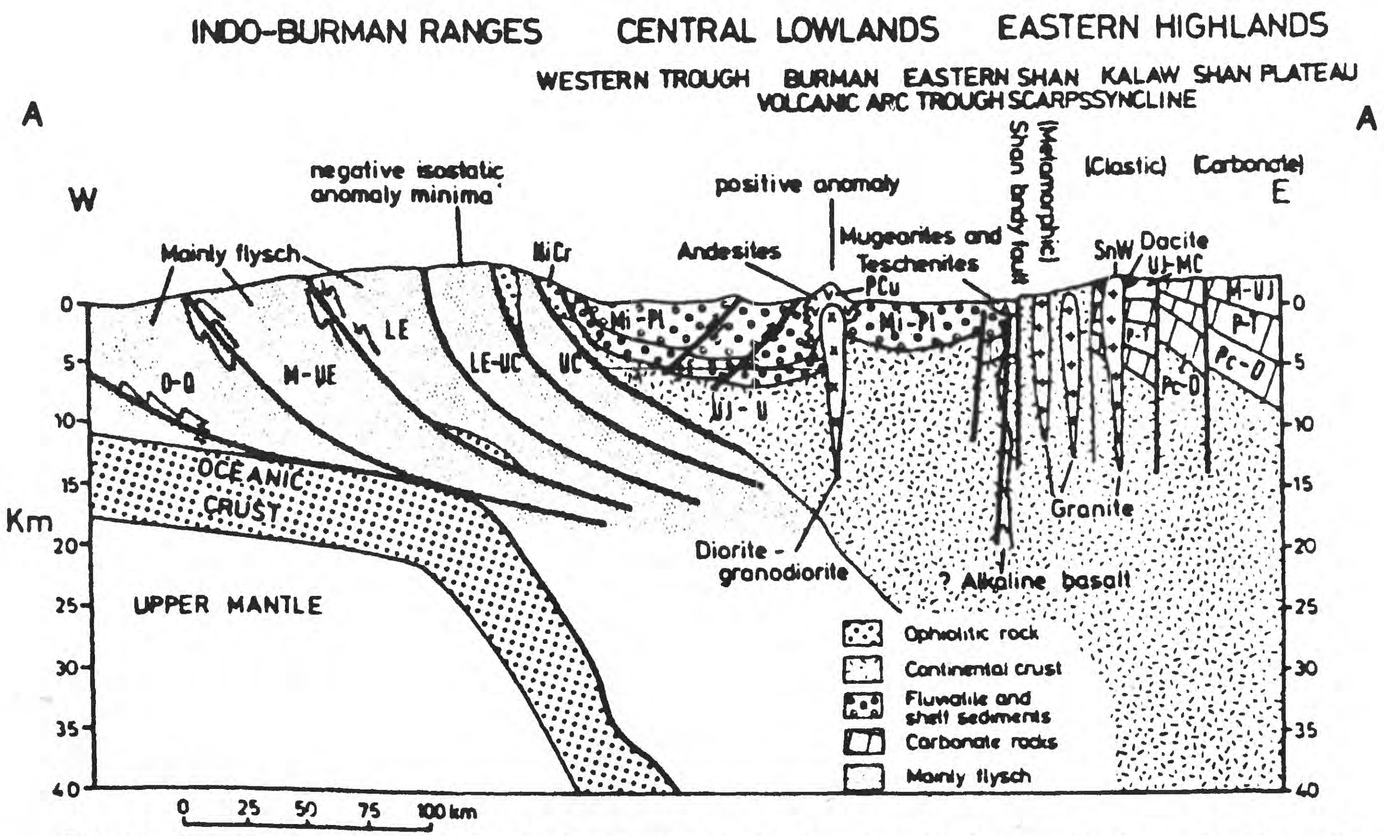


Figure 55.--Burma basin, fields, critical wells, sections.



Diagrammatic cross sections showing evolution of the Burma orogen. Pc = late Precambrian; D = Devonian; P = Permian; T = Triassic; J = Jurassic; C = Cretaceous; E = Paleocene and Eocene; Ol = Oligocene; Mi = Miocene; Pl = Pliocene; Q = Quaternary; L = Lower; M = Middle; U = Upper; PCu = porphyry copper; SnW = tin and tungsten; NiCr = lateritic nickel and chromite.

Mitchell, A.H.G and McKerrow, W.S. 1975 (See fig. 54 for location)

Figure 56.--Regional diagrammatic section, A-A', Burma basin.

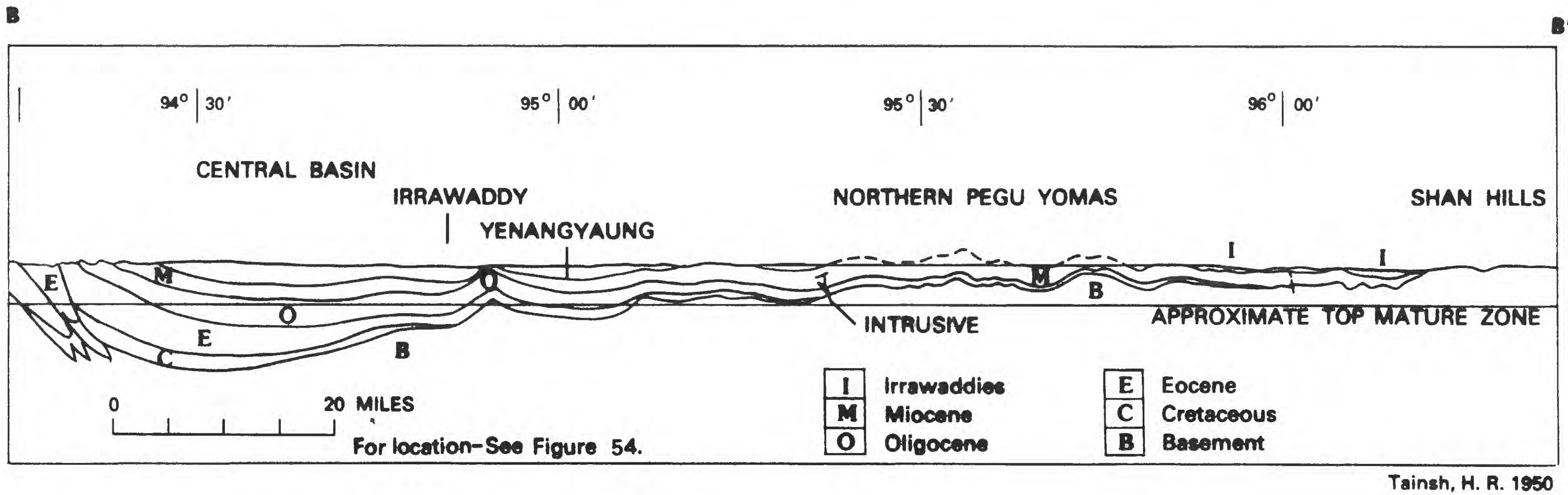
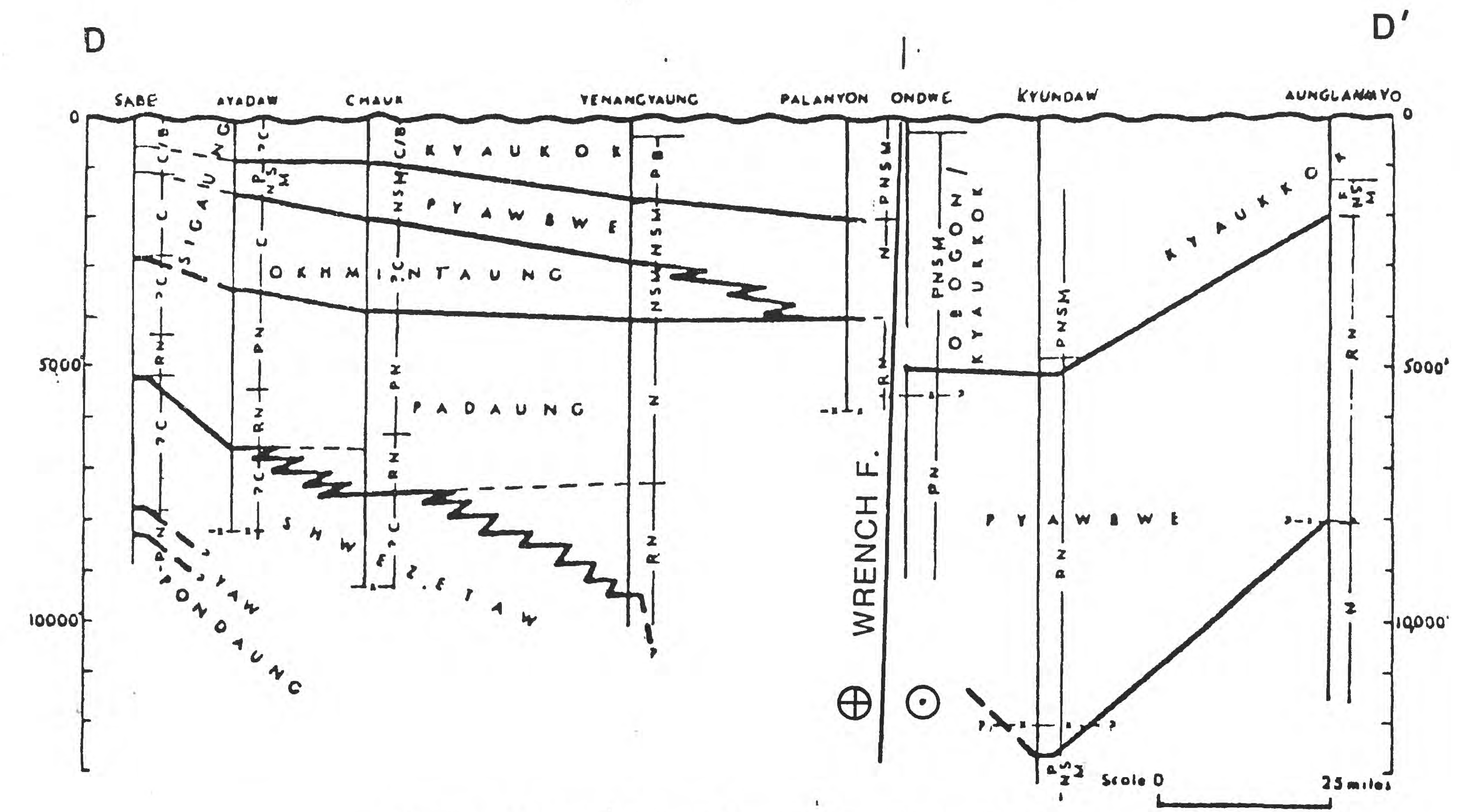


Figure 57.--Diagrammatic cross section B-B', central Burma.



Stratigraphical correlation in Central Burma (Irrawaddy river)

P. Poor **R.** Rich **N.** Neritic **C.** Continental **B.** Brackish **N.S.M.** Near shore marine

(See fig. 54 for location)

BASEMENT-42,000' BASEMENT-20,000'

modified from Bentham R. 1966

Figure 58.--Longitudinal stratigraphic correlation, D-D', central Burma.

(fig. 55), and widely-spaced anticlinal axes with intervening planes (figs. 57 and 59) indicate that a number of wrench faults trend northward through the basin. Given that the Indian Block is subducting beneath the Sunda Continental Block with a strong northward component, we assume that these wrench faults are dextral.

Untested trap area

No detailed structural map is available, and there is no analog for a productive forearc basin to aid in estimating the amount of trap area. It is believed, however, that the dominant closure-producer is drag on wrench faults, as it is in some other basins such as the Central Sumatra and Los Angeles Basins. By analogy to these basins, it is assumed that 5.5 percent of the basinal area is under closure (Central Sumatra Basin 3.3 to 7.7 percent, depending on assessor, and Los Angeles Basin 6.7 percent). Assuming 35 percent still untested (i.e., 65 percent exploration done) and adding 200,000 acres for Miocene reefs, the untested trap area is some 1.086 million acres.

Percentage trap area productive

From a partial structural map of Lanywa and Chauk, it is estimated that the closure area is 40 percent filled with petroleum, and this is assumed to be the average for the basin. Given a wildcat success ratio of 8 percent, 3.2 percent of the untested closure area will be productive.

Stratigraphy

General stratigraphy

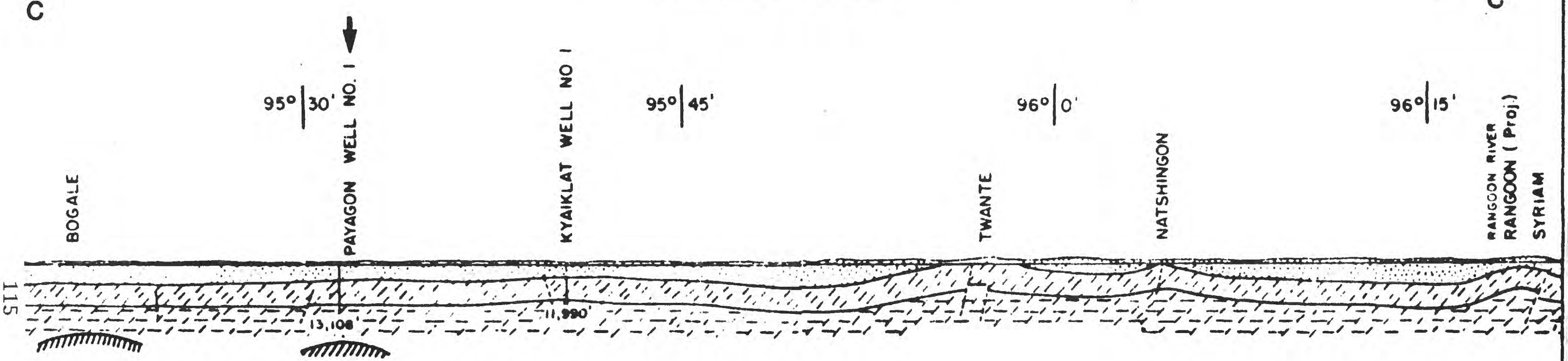
The Late Cretaceous, Paleocene, and Eocene is largely the India-Block derived flysch making up the Arakan Yoma on the western part of the basin, which is of great thickness and contains no appreciable reservoirs. It is greatly complicated by shuppen structure, including ophiolite slices, associated with the oblique subduction of the Indian Plate beneath the Sunda Continental Block. This melange is considered as effective basement in the sketch depth-to-basement map (fig. 54).

The Oligocene to Pliocene section is largely a shale and sandstone sequence (fig. 60), continental and coarser in the north becoming increasingly marine and finer-grained southward; the central part of the basin is largely deltaic and the southern part more marine, including some Miocene reefs. This is the more pertinent part of the section and is shown in more detail for the three principal subbasins in figure 61. The entire sedimentary section, exclusive of the melange, is very thick, over 50,000 feet in this relatively narrow (100-mile wide) basin.

Reservoirs

The productive reservoirs are largely concentrated in the Pegu Group of Oligocene to Miocene formations of deltaic sandstones and shales (fig. 60, and more detail, fig. 61).

CROSS SECTION THROUGH LOWER BURMA
(IRRAWADDY SUB-BASIN)
LATITUDE 16°30' N.



LEGEND

IRRAWADDIAN

LAYER 2+3 (UPPER MIOCENE)

LAYER 4 (LOWER MIOCENE / UPPER OLIGOCENE)

BASEMENT OR IGNEOUS

Geological subdivision based on lithology, salinity and fauna

(See fig. 54 for location)

After U AUNG KHIN and U KYAW WIN (1969)

STRATIGRAPHIC SEQUENCE OF THE TERTIARY BURMA BASIN.

AGE			ROCK UNITS			LITHOLOGY	THICKNESS	RESERVOIR	SOURCE ROCK
QUATERNARY			IRRAWADDY GROUP				3000 m+		
NEOGENE	PLIOCENE		IRRAWADDY GROUP						
NEOGENE	MIOCENE	Upper	IRRAWADDY GROUP						
NEOGENE	MIOCENE	Middle	PEGU GROUP	UPPER	Obogaon Formation		Up to 1000m		
NEOGENE	MIOCENE	Middle / Lower	PEGU GROUP	UPPER	Kyaukkok Sandstone		Up to 1500m	☼ ●	
NEOGENE	MIOCENE	Lower	PEGU GROUP	UPPER	Pyawbwe Clays and Sandstone		Up to 1000m	☼ ●	
PALEOGENE	OLIGOCENE	Upper Middle	PEGU GROUP	LOWER	Okhmintaung Sandstone		0 – 1500m	☼ ●	
PALEOGENE	OLIGOCENE	Lower	PEGU GROUP	LOWER	Padaung Clay		Up to 750m	☼ ●	
PALEOGENE	OLIGOCENE	Lower	PEGU GROUP	LOWER	Shwezetaw Formation		600 – 1200m	☼ ●	
PALEOGENE	EOCENE	Upper			Yaw Formation		300 – 600m		
PALEOGENE	EOCENE	Upper			Pondaung Sandstone		Up to 2000m		
PALEOGENE	EOCENE	Middle			Tabyin Clay		1500m		
PALEOGENE	EOCENE	Lower			Tilin Sandstone		Up to 1500m		
PALEOGENE	EOCENE	Lower			Laungshe Shale		2700 – 3600m		
PALEOGENE	PALEOCENE				Paunggyi Conglomerate		600 – 1200m		
PALEOGENE	PALEOCENE								
CRETACEOUS AND OLDER					Metamorphics rocks Schist, Phyllite, Quartzite				

Petroconsultants Ltd.

According to U N, 1975

FIGURE 60

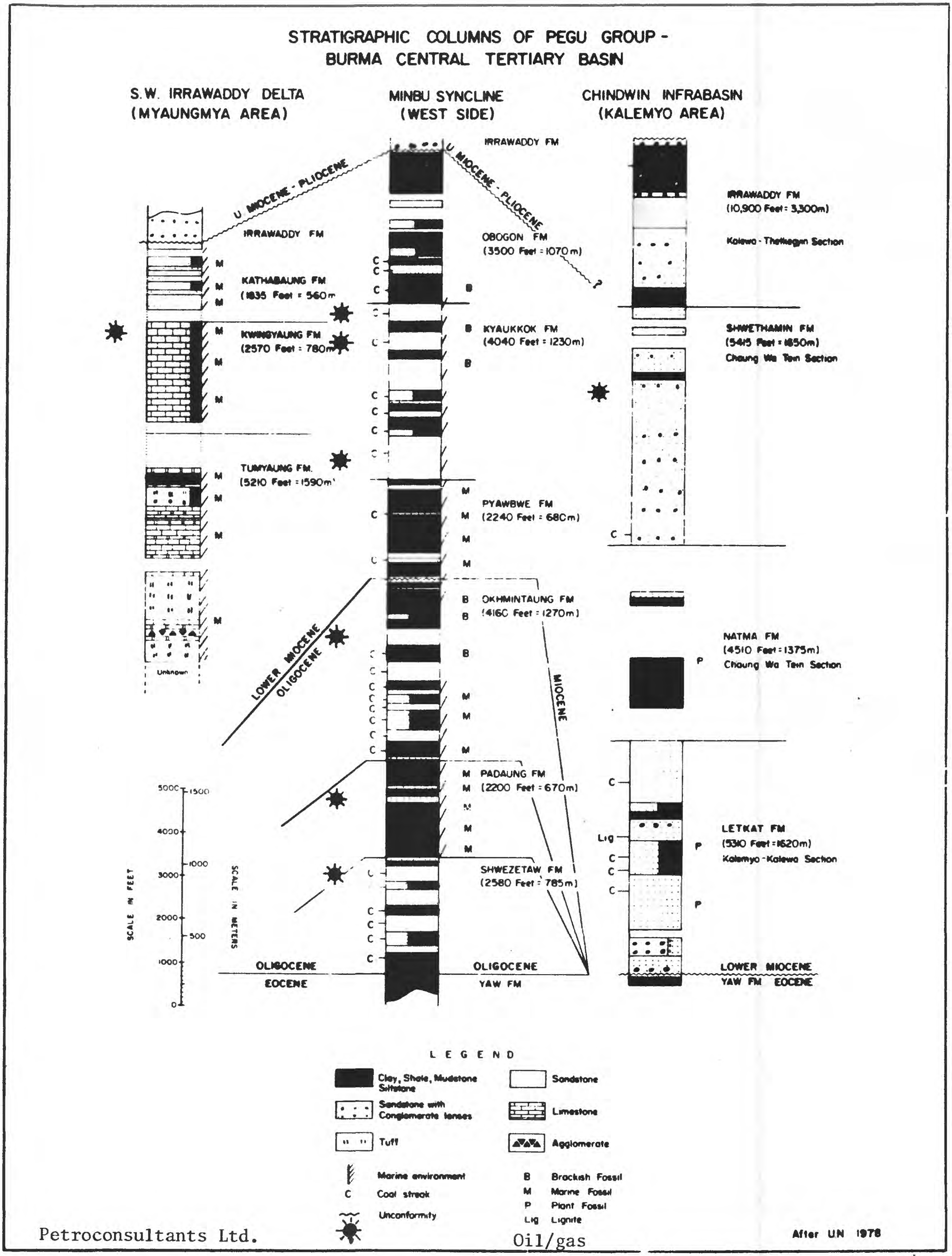


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Figure 61.

Reportedly, in the Yenangyaung Oil Field "there are more than 50 oil-bearing sands varying in thickness from 10 feet to 150 feet" (Tainsh, 1950), and in the Lanywa-Chauk Fields "there are about 35 oil-bearing sands, which vary in thickness from 10 feet to 50 feet" (Tainsh, 1950). From this description, net pays of more than 300 ft could be supposed, but in view of the relatively limited production from these fields, the average net pay probably is not more than 100 ft.

The Miocene reefs appear to be limited to the western side of the Irrawaddy Subbasin, i.e., the Htantabin-Kyontoni area (fig. 55). The gross thickness is some 2,570 ft, but how much of this thickness is net reservoir is unknown; 1982 appraisal drilling suggests it may be limited in thickness and extent. It is therefore assumed to have an effective thickness of 100 ft.

Seals

Seals appear to be poor since many seeps are reported, and the reservoir rock outcrops in areas around the subbasins. One field, Yenanma, produces from a wax-sealed seep. Most of the early discoveries were on the basis of oil seeps. It is estimated that seals are only 50 percent effective.

Source rock section

As discussed below, the source rocks appear to be the deltaic shales of the Pegu and older formations (figs. 60 and 61).

Generation and Migration

Richness of source

No specific data as to richness of organic content are available, but geologic evidence appears to limit the section of sufficient organic richness to the Oligocene-Miocene Pegu Group or older. The evidence is:

1. Oil seeps and thin, isolated oil sands are largely restricted to the Pegu Group part of the section and not higher (fig. 60).

2. The Pegu shales are dark and reportedly organically rich, and apparently of deltaic origin, with coal beds and marine fossil beds alternating in the section (fig. 61). Apparently some Eocene shales (Tabyin clay or equivalent, fig. 60) are of similar nature.

3. The high wax-content of Burmese oil is typical of crudes of terrigenous organic material, indicating deltaic shales as the source.

4. Hiller (unpublished communication) states that geochemical studies in the Central Subbasin indicate that pre-Oligocene claystones are "source rocks" and, somewhat in contradiction to the above observations, not the claystone/shales of the Oligocene or Miocene.

Depth and Volume of Mature Sediment

Only one thermal gradient (1°F per 100 ft) is available (Yenangyuang Oil Field, Tainish, 1950), and that is assumed to be the average of the basin. This low value is typical of fore-arc basins. On the basis of this gradient and the indicated rate of subsidence, the top of the mature zone appears to range to 15,000 ft. This depth not only limits the volume of mature rock (340,000 mi^3), but also limits the areas of the basin underlain by source rock to the central portion of the depocenters of the four subbasins, i.e., inside the 5-kilometer contour (fig. 54), the Chindwin, Central, Irrawaddy, and Eastern Subbasins. Allowing for some lateral migration, this reduces the area where accumulation may be expected to about 60 percent of the overall Burma Basin area. It will be noted that on this basis northern Burma as well as most of offshore Burma might be expected to have only little underlying thermally mature source rock. An exception to this might be the area of the recent offshore gas discoveries, which lies close to the higher-temperature volcanic line (fig. 63).

Oil versus gas

In 1971, Burma began producing gas from the Chauk/Ayadaw Field, in 1975 from the Shewpyetha Field (Lat. 18°, fig. 55), in 1976 from the Htankshabin Field, and in 1982 from the Htantabin Field, building production to 67.8 MMCFD by 1983. Gas caps are reportedly more prevalent in the deeper (3,000 feet) individual sands. Gas-oil ratios vary from 50:1 to 1000:1 CF/BO in deeper wells. The presumed terrigenous nature of the kerogen suggests that considerable gas was generated. Accordingly, it is assumed that 40 percent of the hydrocarbon filled area is gas and 60 percent oil.

Migration timing versus trap formation

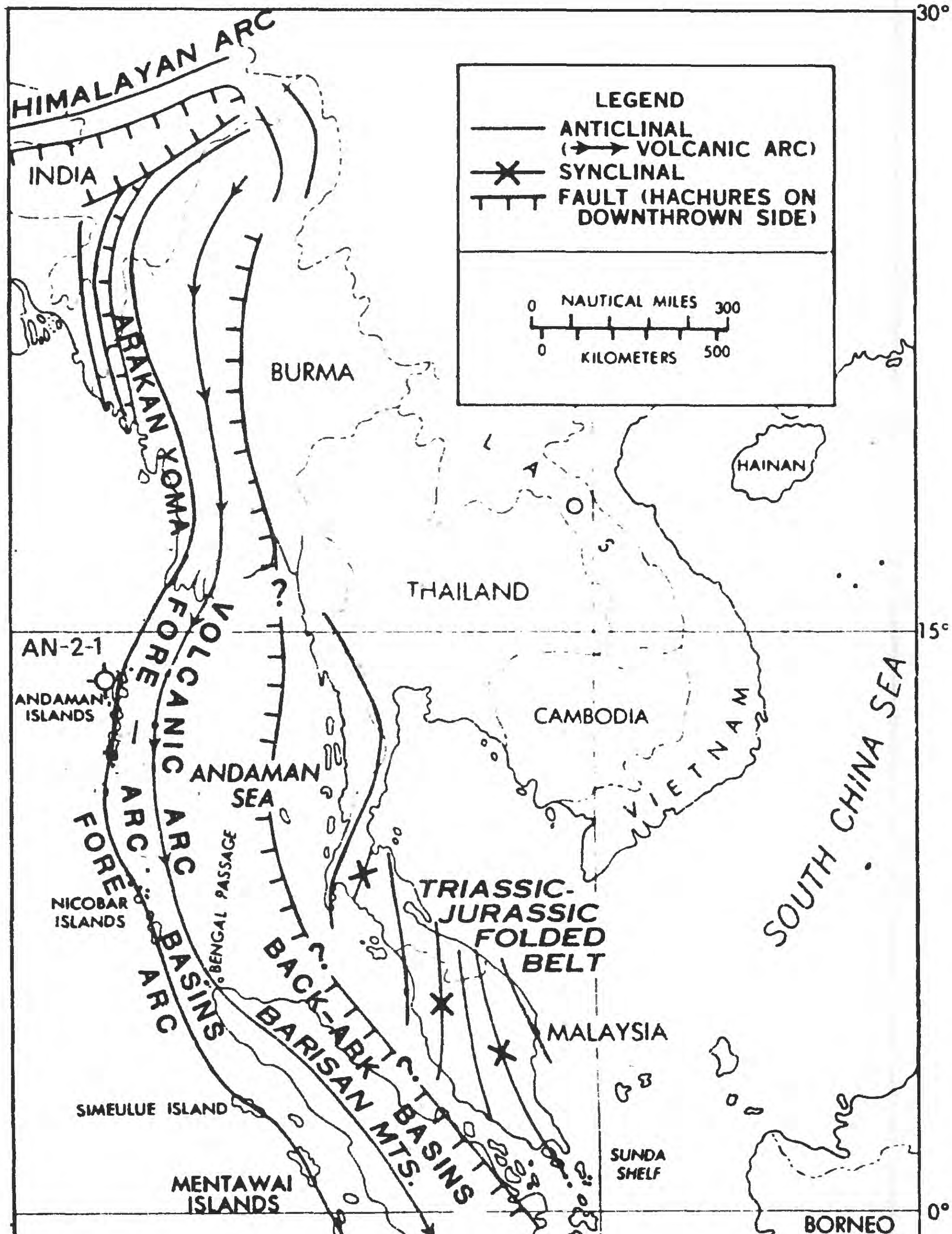
Assuming a constant thermal gradient and rate of subsidence through the Tertiary, hydrocarbon generation and migration must have begun in the Eocene when the sedimentary burial exceeded 15,000 ft (fig. 57). The migration flood probably did not start, however, until the rich upper Eocene or Oligocene began to reach a burial depth of 15,000 feet, which would be in the late Miocene.

There may be some drape traps associated with some ancient continental-margin rifting along the west side of the Sunda Continental Block and some compressional folds, but most of the structural closures are drag features associated with the wrench faults, which appear to have been active at least through the Neogene. It seems, therefore, that closures began forming in the Miocene and became more effective in the Pliocene. Although some older hydrocarbons may have escaped the trap, the migration flood appears to occur at a fairly optimum time, i.e., shortly before the traps were best developed and perhaps before much reservoir deterioration.

Limiting Factors

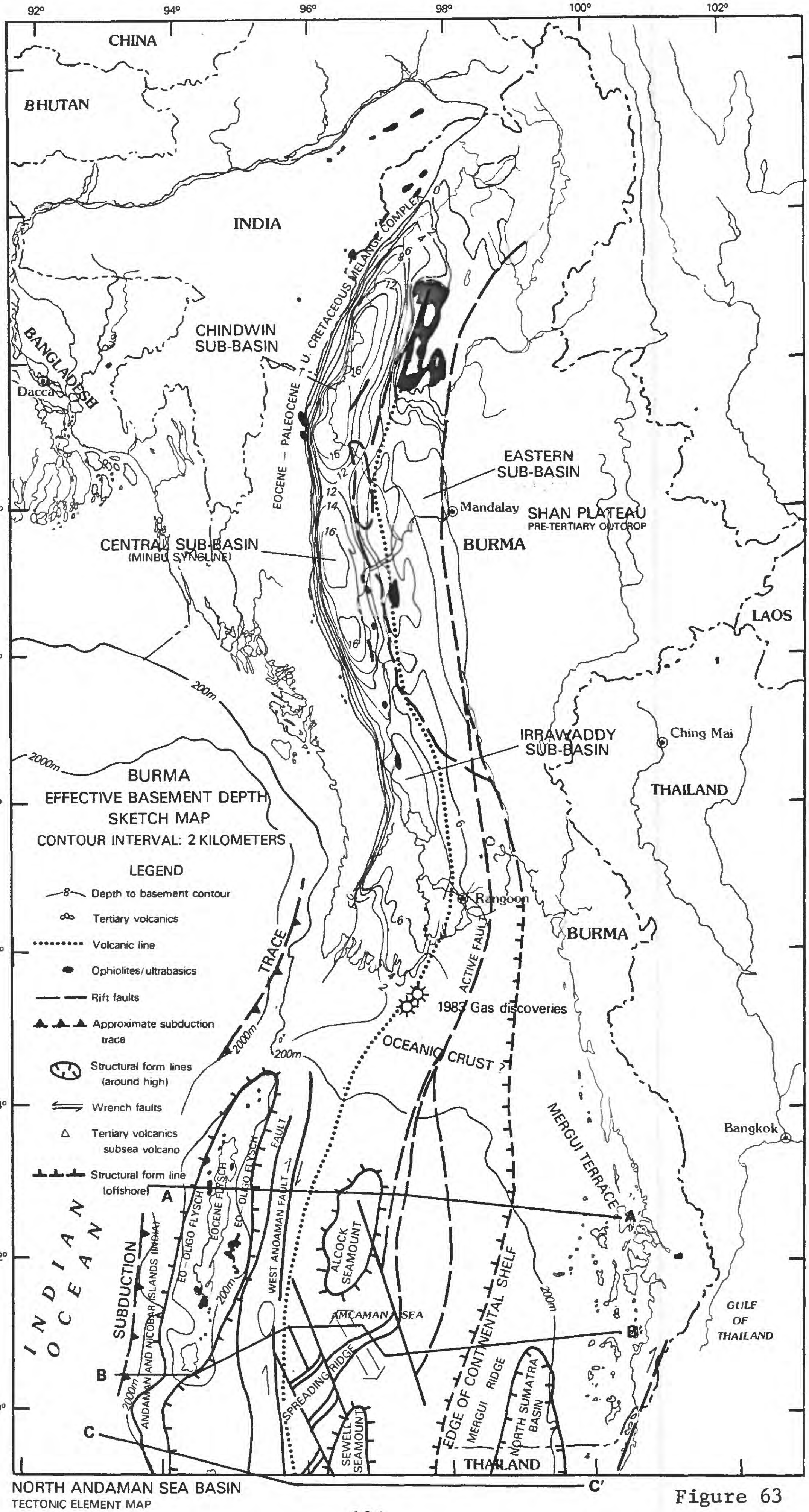
The overriding factor limiting the petroleum accumulation appears to be the low thermal gradient which limits the area and volume of source rock. A secondary factor limiting accumulation is the apparent lack of an efficient seal.

MAJOR STRUCTURAL TRENDS IN ANDAMAN SEA AREA, SOUTHEAST ASIA



Modified After L AUSTIN WEEKS, R N HARBISON and G PETER, AAPG Bulletin vol 51 no 9 1967

FIGURE 62



NORTH ANDAMAN SEA BASIN
TECTONIC ELEMENT MAP

Figure 63

Andaman Basin

Introduction

Location and size of area

The so-called Andaman Basin is a part of the Andaman Sea region, which is considered a petroleum province by the Indian ONGC largely because of its relative accessibility, being an area of shallow water (less than 600 ft) and islands (figs. 1, 62, and 63). It is the Indian territory between Burma to the north and Sumatra to the south. The area of the province, as defined by the current ONGC exploration block, is approximately 62,000 mi^2, containing some 190,000 mi^3 of sedimentary fill.

Exploration history

Exploration began in 1959. After extensive offshore seismic surveys, the first wildcat of the area, AN-1-1, was drilled in 1980 on the Beta structure (fig. 62). The well was a questionable discovery (6.4 MMCFGD). Subsequently, two appraisal wells and a test of a second, nearby structure, AN-2-1 (figs. 62 and 65), were all dry.

Since the discovery is questionable, the finding rate would be less than the indicated 50 percent; more likely it is 10 percent. The exploration is very immature, but the possibility of extensive exploration is low; it is assumed to be 10 percent complete.

Structure

General tectonics

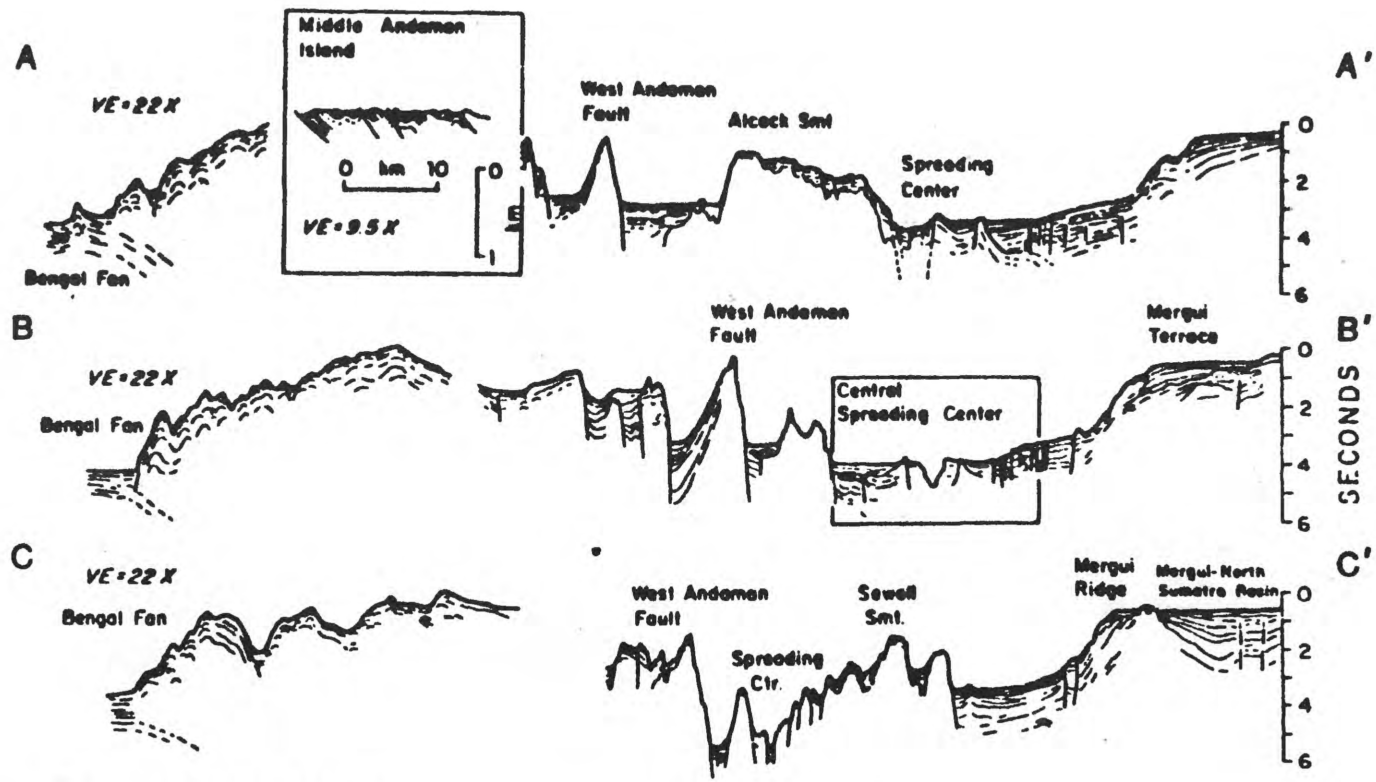
The province is on trend with and between the Arakan Yoma range of Burma-India and the Mentawi Islands of Indonesia, both of which have been recognized as outer arcs or Tertiary accretionary wedges (fig. 62). The province is confirmed as an accretionary wedge by the surface geology of the Andaman Islands, which consists of imbricated flysch and melange containing some ophiolites (figs. 63, 64, and 65).

Untested trap area

In such a structural complex, it would appear that there is little effective closure; for appraisal purposes it is estimated that only 2 percent of the province area is under structural closure, or 800,000 acres.

Percentage trap productive

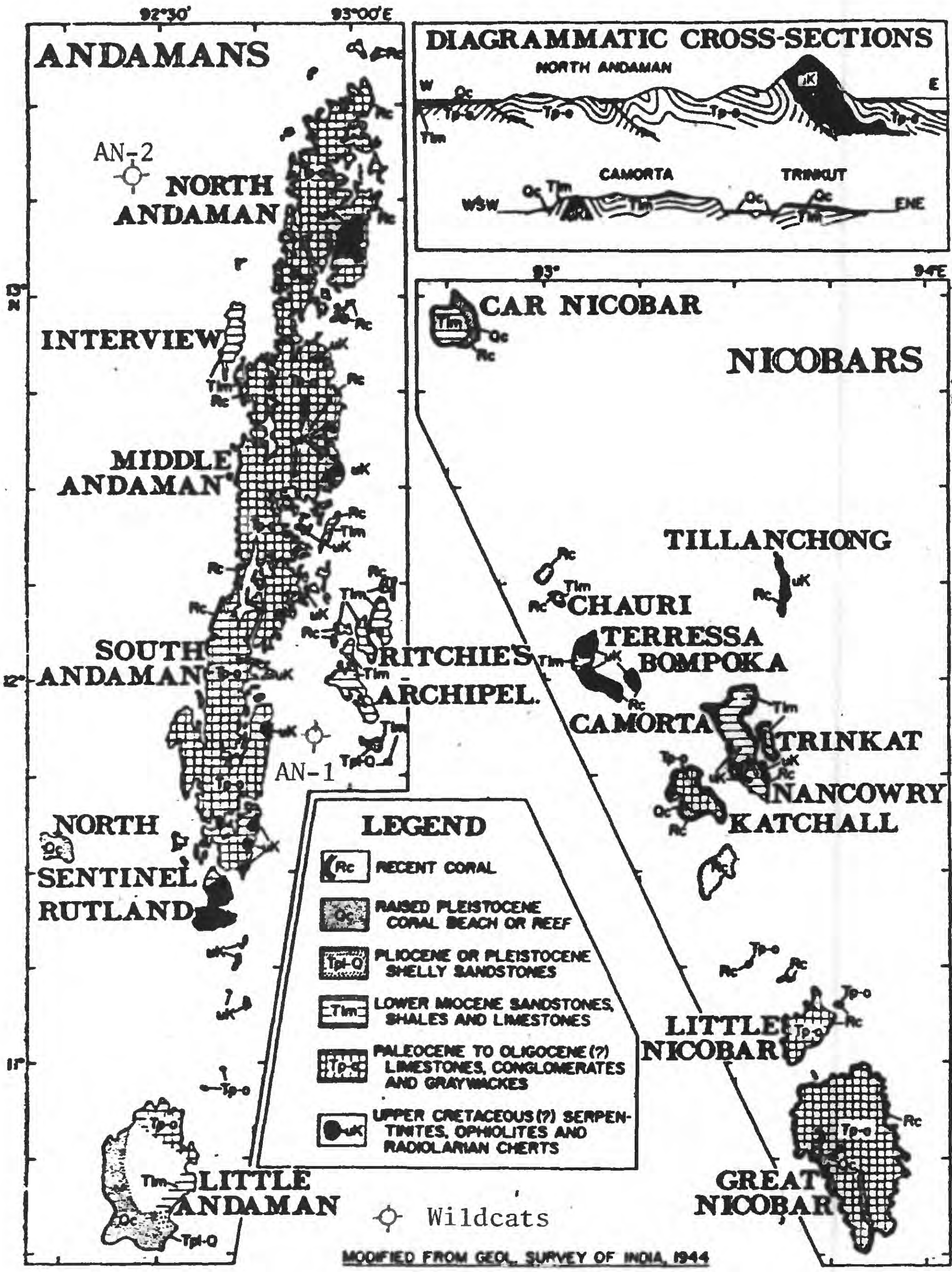
With the amount of structural complexity, particularly faulting, it is estimated that the percentage of petroleum fill in the trap area would average only 30 percent. This, with the estimated finding rate of 10 percent, indicates that 3 percent of the untested trap area might be occupied by petroleum.



(See fig. 63 for location)

After: Curray et al., 1979

Figure 64.--Geologic sections, Andaman Sea.



From Rodolfo, K. S., 1969

Figure 65.--Geology of the Andaman and Nicobar islands.

Stratigraphy

General stratigraphy

Although ONGC has attempted it, it does not seem possible to produce a meaningful stratigraphic column for the area. The bulk (10,000 ft plus) of the sedimentary column appears to be upper Cretaceous to Paleogene flysch, overlying, or mixed with, an ophiolite suite of rocks. The Neogene is represented by a relatively thin section of clastics and some limestone (1,000 ft plus). All are affected by relatively intense tectonics.

Reservoirs

In this generally flysch facies, reservoirs must be poorly developed. For appraisal purposes, it is estimated that the average net effective reservoir of the area is 50 ft. Porosities would likewise be poor, and 12 percent is assumed.

Seals

Seals would be poor in this complexly faulted area. Thirty percent effectiveness is assumed.

Source rock section

In the absence of any coherent stratigraphic frame, it can only be said that any petroleum generation would probably take place at a burial depth of some 15,000 ft (see below). This would probably largely involve Paleogene flysch.

Generation and Migration

Richness of source

No data are available on the organic richness of sediments. There are gas and minor oil seeps to attest the presence of some adequately rich source rocks. In general, rapidly deposited flysch is expected to have low organic content concentration and, therefore, poor source-rock quality, especially for oil.

Depth and volume of source rock

No data on thermal gradients are available, but on the basis of the regional tectonics of the area, i.e., outer arc, the province is deemed cool. It is estimated that the burial depth of thermally mature sediment is at least that of Burma, i.e., 15,000 ft. The volume of mature sediment is incalculable but more than 60,000 mi^3.

Oil versus gas

From the amount of reported gas seeps and from the test data of the one "discovery" well, i.e., 6.4 MMCFD, the area appears gas prone. It is estimated that the area of hydrocarbon fill of the untested traps would be only 15 percent oil.

Migration timing versus trap formation

Assuming conditions remained the same through the Tertiary, hydrocarbon generation and migration began when subsidence of the source rock reached a depth of 15,000 ft, which probably occurred in the Miocene. This would be about concurrent with structural trap formation and therefore favorable.

Limiting Factors

The overriding factor affecting the accumulation of undiscovered hydrocarbon is the lack of effective traps. The tectonics associated with an accretionary wedge, e.g., complex shuppen structure, do not allow for sufficiently large closures or satisfactory seals. The flysch nature of the source is also a limiting factor affecting organic content and therefore oil generation.

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Play Analysis

Play analysis forms for each basin or play follow in the order in which they are discussed in the text. Estimates of the five principal geologic factors, which have been discussed and quantified for each play or basin in the text of the report, are summarized. The estimates are given in ranges signifying the degree of uncertainty. These ranges include three values, a low number (95-percent chance the quantity will exceed this value), a modal number (most likely quantity), and a high number (a 5-percent chance the quantity will exceed this value). For the sake of conciseness, the rationale for only the estimates of the most likely quantities are noted.

The product of the most likely values for each of five key factors may indicate the quantity of undiscovered oil and gas resources. This product is shown at the bottom of each sheet. The overriding limiting factor or factors for each play are indicated as a judgment check on the product or aggregation of estimates.

These play analyses served as guides to the subjective consensus as to the amount of undiscovered petroleum in the basins of South Asia summarized in Appendix B.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Bombay Shelf, No. 1
AREA (mi^2) 56,000
VOLUME (Mi^3) 141,000
ORIG. RSVS. 2.70 BBO 13.35 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Tertiary Drapes, No. 1
AREA (MMA) 26.0
EST. ORIG. RSVS. 2.70 BBO 13.35 TCFG

DEFINITION AND LOCATION OF PLAY: The play is for Tertiary carbonate and sandstone reservoirs in drape or fault closures involved with horst-graben structure. The location of play is limited to the platform area of some 26 million acres.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	2.000	.420	.200
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	48	18	5
C.	AVERAGE EFFECTIVE PAY (feet)	120	60	30
D.	PERCENT OIL IN PETROLEUM MIX (%)	75	55	20
E.	OIL RECOVERY (BBLS/AF)	600	216	175
F.	GAS RECOVERY (MCF/AF)	840	680	500
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .539 BB, GAS 1.39 TCF, NGL .015 BB, OE, .784 BBOE*

A. Excluding Bombay High, an estimated .970 MMA of trap were mapped by 1984. We estimate this to be 70% of the ultimate trap area of 1.39 MMA, or 5% of play area. Assuming an area approximately equivalent to the already mapped trap area has been tested, .420 MMA of untested trap area remain.

B. Average fill estimated to be 60% mapped closure. Reported success ratio is 30%. 60 x 30 = 18% of closure would be productive.

C. Average pay thickness over the play area estimated at about 60 ft.

D. 55% oil, 45% gas estimated on basis reserves discovered to date.

E. Average (most likely) case on basis of 20% porosity (Bombay High), assumed 25% water saturation, and 25% primary recovery factor.

F. Assumed reservoir as above, average depth - 5,500 ft; press. grad. - .4333 psi/ft; therm. grad. - 3° F/100 ft; recovery factor - 80%.

G. Worldwide average.

LIMITING FACTOR - Thin pay

* Total Basin: .844 BBO, 3.171 TCFG, .036 BBNGL, 1.405 BBOE

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Bombay Shelf, No. 1
AREA (mi^2) 56,000
VOLUME (Mi^3) 141,000
ORIG. RSVS. 2.47 BBO 13.35 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Rollover/Growth Fault, No. 2
AREA (MMA) 5.0
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Petroleum accumulations in roll-over anticline associated with growth faults along outer (western) margin of Bombay Shelf. Assumed to be zone averaging 25 miles wide.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.500	.300	.100
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	21	9	5
C.	AVERAGE EFFECTIVE PAY (feet)	200	50	30
D.	PERCENT OIL IN PETROLEUM MIX (%)	60	40	10
E.	OIL RECOVERY (BBLS/AF)	320	270	210
F.	GAS RECOVERY (MCF/AF)	2,000	1,600	700
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .146 BB, GAS 1.30 TCF, NGL .014 BB, OE, .377 BBOE *

A. Mitra and others (1983) indicate some 80 leads. Published maps (Sahay, 1984, and Berger, 1983) indicate that 20 leads of some 300,000 acres of trap have been tested. Assuming these are the larger leads, we estimate half the trap area is tested, with 300,000 acres remaining to be tested.
B. Apparently testing to date has been unsuccessful. Play's position adjoining and over outer basinal shale area, which appears to be organically poor, may be negative factor; we estimate success rate half that of drape play, i.e. about 15%. Fill, as with other plays, estimated to be 60% indicating productive trap area of 9.0%.
C. Sands should be relatively thin on outer edge of shelf; we estimate average effective pay of about 50 ft.
D. In this play area of presumed over-pressure and greater depth, this play would appear to be gas-prone; we estimate 40% oil.
E. Primary recovery assuming average reservoir parameters.
F. Assuming average reservoir parameters, an average depth of 10,000 ft, a thermal gradient of 3°F/100 ft, and over-pressure below 7,000 ft.
G. World-wide average.

LIMITING FACTORS: Probable thinness of reservoirs and lack of source rock.

* Total Basin: .844 BBO, 3.171, TCFG, .036 BBNGL, 1.405 BBOE

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Bombay Shelf, No. 1
AREA (mi^2) 56,000
VOLUME (Mi^3) 141,000
ORIG. RSVS. 2.47 BBO 13.35 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Carbonate Buildups, No. 3
AREA (MMA) 18.0
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Petroleum accumulations in carbonate buildups including mud mounds. Play area is confined to carbonate areas of the basin or about 18 million acres.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.500	.250	.50
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	21	9	5
C.	AVERAGE EFFECTIVE PAY (feet)	250	50	30
D.	PERCENT OIL IN PETROLEUM MIX (%)	75	55	20
E.	OIL RECOVERY (BBLS/AF)	320	270	210
F.	GAS RECOVERY (MCF/AF)	1,600	950	700
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .167 BB, GAS .481 TCF, NGL .005 BB, OE, .252 BBOE *

A. Some 200 buildups have been mapped and others may exist, the size ranging from 185 to over 9,000 acres (Mitra and others, 1983). Some of these indicated features may not materialize but others may be found, especially along the carbonate shelf edge. We estimate trap area of Mitra's map to be 250,000 acres and take that as the most likely untested trap area of the play.
B. To our knowledge none of the indicated trap has yielded petroleum; so a low success rate is assumed, perhaps half that of drape play, or 15%. Fill, in conformity with the other plays, is estimated at 60% indicating 9% of trap area to be productive.
C. Although some of buildups have a relief of several hundred feet, we suspect that reservoirs would be thin as they are in the case of carbonate reservoirs of main play.
D. By analogy to the oil-gas mix in main play.
E. Assuming average reservoir parameters.
F. Assuming average reservoir parameters, average reservoir depth of 7,000 ft, and a thermal gradient of 3°F/100 ft.
G. World-wide average.

LIMITING FACTORS: Appears largely untested; critical and limiting factor may be existence of sufficient reservoir volume.

* Total Basin: .844 BBO, 3.171 TCFG, .036 BBNGL, 1.405 BBOE

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Cambay Graben, No. 2
AREA (mi^2) 20,000
VOLUME (Mi^3) 22,000
ORIG. RSVS. 1.17 BBO .90 TCFG
TECTONIC CLASSIFICATION: Graben, Rift

PLAY Eocene Sands, No. 1
AREA (MMA) 12.8
EST. ORIG. RSVS. 1.17 BBO .90 TCFG

DEFINITION AND LOCATION OF PLAY: There are a number of plays in the basin (drapes, drag folds, stratigraphic traps), but in absence of detailed information, they are treated as a single play, covering the entire basin.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.200	.161	.030
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	30	15	2
C.	AVERAGE EFFECTIVE PAY (feet)	90	60	20
D.	PERCENT OIL IN PETROLEUM MIX (%)	80	50	20
E.	OIL RECOVERY (BBLS/AF)	513	216	104
F.	GAS RECOVERY (MCF/AF)	1,463	502	145
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .156 BB, GAS .364 TCF, NGL .004 BB, OE, .221 BBOE

A. Extrapolation from a mapped part of basin indicates 6.3% of basin under closure. Possibly 80% of closure is tested, leaving .161 MMA.

B. Assuming Nawagam Field estimated fill of 60% is average, and current success rate of 38% diminishes to perhaps 25%, about 15% of untested trap area is productive.

C. Estimate Nawagam Field 82 ft, Ankleswar 62 ft, Cambay 38 ft; ave. possibly 60 ft.

D. On basis terrigenous source, good seals, and reservoir numbers, we estimate oil - 50%, gas - 50%.

E. Estimate average porosity 20%, assume water saturation 25%, and primary recovery factor of 25%.

F. Same reservoir factors, average depth 4,000 ft, average therm. grad. 3° F/100 ft; assume 80% recovery factor.

G. World-wide average.

LIMITING FACTORS - Small maturely explored basin. Thin pays.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Konkan No. 3
AREA (mi^2) 12,000
VOLUME (Mi^3) 18,000
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Eocene Drapes
AREA (MMA) 7.7
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: The play is for Tertiary reservoirs in drape and fault closures involved with horst-graben structure. Play-area limited by sufficient sedimentary thickness to outer Konkan Shelf of some 7.7 million acres.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.500	.385	.050
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	15	3	1
C.	AVERAGE EFFECTIVE PAY (feet)	60	40	20
D.	PERCENT OIL IN PETROLEUM MIX (%)	80	55	10
E.	OIL RECOVERY (BBLS/AF)	593	216	175
F.	GAS RECOVERY (MCF/AF)	613	500	370
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .055 BB, GAS .104 TCF, NGL .001 BB, OE, .073 BBOE

A. By analogy to the adjoining Bombay Shelf (exclusive of the Bombay High), traps would be 5.0% of play area or .385 MMA.

B. Assuming 10% discovery rate (versus 35% for Bombay Shelf) and 30% fill (half the fill of Bombay Shelf, on basis of much smaller volume of source rock), 3% trap area is productive.

C. Assumed analogous to Bombay Shelf discounted to two-thirds because of thinner section.

D. Analogous to Bombay Shelf.

E. Analogous to Bombay Shelf.

F. Analogous to Bombay Shelf but assuming somewhat shallower and cooler reservoirs.

G. World-wide average.

LIMITING FACTOR - Volume of mature source limited by thinness of section.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Kutch No. 4
AREA (mi^2) 35,000
VOLUME (Mi^3) 76,000
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Onshore No. 1
AREA (MMA) 15
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Largely Mesozoic reservoirs involved in drag (and perhaps some drape) folds. Generally limited to onshore area of basin but extending somewhat offshore encompassing some 15 million acres in all.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.800	.420	.200
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	4	2	1
C.	AVERAGE EFFECTIVE PAY (feet)	50	30	15
D.	PERCENT OIL IN PETROLEUM MIX (%)	90	30	5
E.	OIL RECOVERY (BBLS/AF)	593	215	175
F.	GAS RECOVERY (MCF/AF)	882	739	512
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .016 BB, GAS .130 TCF, NGL .001 BB, OE, .038 BBOE *

A. Trap area of the largely drag-fold closure area would be somewhat analogous to, but less than, the wrench and drag-fold dominated Burma Basin since the thin section is less prone to drag-folding. Estimate percent of closure area 1/2 that of Burma or 2.8 percent.
B. Thin section, intrusives, advanced induration, reduce the probability of the traps being productive to an estimated 1/10 of Bombay Shelf closures, or about 2%.
C. It is assumed that the reservoirs have half the effective thickness of the somewhat analogous Bombay Shelf, or an average of 30 ft.
D. Because of intrusives, advanced induration, analogy to adjoining gas-prone Indus Basin, it is estimated that oil averages only 30% of the petroleum mix.
E. Assumes 20% porosity, 25% water saturation, and primary recovery factor of 25% for average.
F. Assumes same reservoir parameters and estimates 6,000 ft depth, thermal gradient of 2.5° F/100 ft, and recovery factor of 80% for average.
G. World-wide average.

LIMITING FACTORS - Lack of sufficient reservoirs and small volume of source.

* Total Basin: .145 BBO; 1.081, TCFG; .011, BBNGL; .335 BBOE.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Kutch No. 4
AREA (mi^2) 35,000
VOLUME (Mi^3) 76,000
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Offshore No. 2
AREA (MMA) 7.4
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Tertiary and Mesozoic reservoirs in drape and fault closures involved with horst-graben structure. Play generally limited to offshore part of basin, an area of some 7.4 million acres.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.600	.370	.150
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	48	9	5
C.	AVERAGE EFFECTIVE PAY (feet)	120	60	30
D.	PERCENT OIL IN PETROLEUM MIX (%)	75	30	5
E.	OIL RECOVERY (BBLS/AF)	600	216	175
F.	GAS RECOVERY (MCF/AF)	840	680	500
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .129 BB, GAS .951 TCF, NGL .010 BB, OE, .297 BBOE *

A. Assumes that, analogous to drape play, Bombay Shelf, the trap area averages about 5.0% of the play area.

B. Analogous to the drape play of the Bombay Shelf but lacking the deltaic source rock so that the estimated productive area would perhaps be about half, indicating the productive area of trap at 9% for this play.

C. Assume analogy to the drape play, Bombay Shelf (i.e., 60 ft average).

D. Assume percentage oil intermediate to adjoining Bombay Shelf (55%) and Indus Basin (5%).

E. Analogous to Bombay Shelf.

F. Analogous to Bombay Shelf.

G. World-wide average.

LIMITING FACTOR - Reservoir thickness.

* Total Basin: .145, BBO; 1.081, TCFG; .011, BBNGL; .335 BBOE.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: PAKISTAN

BASIN Indus No. 5
AREA (mi^2) 125,000
VOLUME (Mi^3) 400,000
ORIG. RSVS. .05 BBO 22.0 TCFG
TECTONIC CLASSIFICATION: Rifted and Collided Continental Margin

PLAY Foreland No. 1
AREA (MMA) 51.2
EST. ORIG. RSVS. 0.05 BBO 4 TCFG

DEFINITION AND LOCATION OF PLAY: Play is for Tertiary reservoirs in drape and fault closures involved in horst-graben structure of a rifted continental margin on trend with west coast India. Play area is restricted to the eastern foreland part of the basin of some 51.2 million acres.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	3.8	2.0	1.0
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	8.0	5.4	1.9
C.	AVERAGE EFFECTIVE PAY (feet)	200	130	50
D.	PERCENT OIL IN PETROLEUM MIX (%)	40	5	2
E.	OIL RECOVERY (BBLS/AF)	269	183	151
F.	GAS RECOVERY (MCF/AF)	870	636	243
G.	NGL RECOVERY (BBLS/MMCF)	21	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .128 BB, GAS 8.50 TCF, NGL .093 BB, OE, 1.63 BBOE *

A. Percentage of trap area to play area is assumed to be analogous to the on-trend Bombay Shelf (exclusive Bombay High), i.e., 5%, giving about 2.5 MMA. Estimate .5 MMA tested leaving an average of 2 MMA.

B. Using Khairpur as the average case, the petroleum fill is 45 percent. The estimated wildcat success rate is 12%, indicating an average overall 5.4% of the untested trap area has petroleum.

C. Using Khairpur as the average case, the average pay thickness would be 130 ft.

D. Basin is gas prone with only some oil possibilities on the perimeter where Mesozoic not over-cooked.
E. Estimated average porosity is low (17%). Assumes water saturation of 25% and primary recovery of 25%.
F. With same resrvoir parameters, estimate average depth of 6,000 ft, thermal grad. of 2° F/100 ft, and recovery factor of 80% to give average.
G. World-wide average.

LIMITING FACTORS - Low organic content in oil window limits oil; porosities are low.

* Total Basin: .233, BBO; 16.55, TCFG; .181 BBNGL; 3.16 BBOE.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: PAKISTAN

BASIN Indus No. 5
AREA (mi^2) 125,000
VOLUME (Mi^3) 400,000
ORIG. RSVS. .05 BBO 22 TCFG
TECTONIC CLASSIFICATION: Rifted and Collided Continental Margin

PLAY Foldbelt No. 2
AREA (MMA) 28.8
EST. ORIG. RSVS. 0 BBO 18 TCFG

DEFINITION AND LOCATION OF PLAY: Play is Tertiary reservoirs involved in folds of the foldbelt formed in an oblique collision between Indian continental block and Afghanistan continental block + southern accreted melange. Play extends along the west side of the basin encompassing some 28.8 million acres.

		PROBABILITY DISTRIBUTION		
	MAJOR GEOLOGICAL/EXPLORATION FACTORS	5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	2.00	1.0	.50
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	15	4.5	3.2
C.	AVERAGE EFFECTIVE PAY (feet)	400	256	50
D.	PERCENT OIL IN PETROLEUM MIX (%)	40	5	2
E.	OIL RECOVERY (BBLS/AF)	400	183	100
F.	GAS RECOVERY (MCF/AF)	1,279	736	357
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .105 BB, GAS 8.05 TCF, NGL .088 BB, OE, 1.53 BBOE *

A. Estimate from outcrop map is that anticlinal traps make up 7.6% of area or 3,000 sq mi. Approximately half of this remains as viable untested trap.

B. Sui estimated gas fill of 37.5% is assumed to be average of play. The wildcat success rate is about 12 percent, indicating 4.5% of the untested trap area may be productive.

C. The pay thickness of Sui is taken to represent the play average.

D. Basin is gas prone with only some oil possibilities where Mesozoic not overcooked.

E. Estimate 17% porosity, 25% water saturation, 25% primary recovery factor, to give an average yield.

F. Same reservoir factors and estimate average depth of 4,500, thermal gradient of 2° F/100 ft, and recovery factor of 80%.

G. World-wide average.

LIMITING FACTORS - Low organic content in oil window limits oil; porosities are low.

* Total Basin: .233 BBO; 16.55 TCFG; .181 BBNGL; 3.16 BBOE.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: PAKISTAN

BASIN Potwar No. 6
AREA (mi^2) 8,500
VOLUME (Mi^3) 38,000
ORIG. RSVS. .200 BBO minor TCFG
TECTONIC CLASSIFICATION: Collision Foredeep

PLAY Mio-Pliocene Folds No. 1
AREA (MMA) 5.4
EST. ORIG. RSVS. .200 BBO minor TCFG

DEFINITION AND LOCATION OF PLAY: Tertiary and Mesozoic reservoirs involved in Neogene compression folds. Play extends over entire basin.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.333	.117	.030
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	25	6	2
C.	AVERAGE EFFECTIVE PAY (feet)	100	60	20
D.	PERCENT OIL IN PETROLEUM MIX (%)	95	90	70
E.	OIL RECOVERY (BBLS/AF)	300	120	100
F.	GAS RECOVERY (MCF/AF)	1,816	1,278	1,054
G.	NGL RECOVERY (BBLS/MMCF)	21	11	7

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .045 BB, GAS .054 TCF, NGL .001 BB, OE, .055 BBOE

A. Estimate area of tested map closures to be 470,000 acres (assuming 30% petroleum fill and 20% wildcat success). If exploration 80% completed, there are 117,000 acres of untested trap area remaining.

B. The above assumptions of about 30% fill and 20% wildcat success indicate that the untested trap area would be about 6% productive, in the most likely case.

C. Taking Dhulian as an average, 60 ft would be the overall average effective pay of basin.

D. No unassociated gas production and small associated gas production (50 MCFGD). May be gas in deep zones.

E. Estimate very low porosity of 11%, water saturation, 25%, and recovery factor, 25%.

F. Same reservoirs estimated depth 9,000 ft, thermal gradient 1.7° F/100 ft, and recovery factor of 80%.

G. World-wide average.

LIMITING FACTORS - Poor reservoirs; small maturely explored basin.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: PAKISTAN

BASIN Makran No. 7
AREA (mi^2) 60,000
VOLUME (Mi^3) 360,000
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Multiple - Forearc basins

PLAY Tertiary Sands No. 1
AREA (MMA) 38.4
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Tertiary sands involved in compression folds. Play is assumed to extend over the entire basin, but it is generally more prospective southward.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	1.536	.768	.192
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	5	3	.5
C.	AVERAGE EFFECTIVE PAY (feet)	100	50	25
D.	PERCENT OIL IN PETROLEUM MIX (%)	50	25	5
E.	OIL RECOVERY (BBLS/AF)	200	130	100
F.	GAS RECOVERY (MCF/AF)	1,021	739	337
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .037 BB, GAS .638 TCF, NGL .007 BB, OE, .150 BBOE

A. Very complex fore-arc melange-type structure, very few traps probably exist; 2 percent is estimated as the percentage of the play area under trap.

B. All six wildcats dry. Possible production appears remote, say 3 percent of untested trap area.

C. Reservoirs in this melange and flysch sedimentation would be poor; 50 ft of average net pay are estimated.

D. Based on the predominance of gas seeps, average productivity is judged to be 25 percent oil and 75 percent gas.

E. Porosity would be low, say 12 percent in average producible case; water saturation assumed to be 25 percent and primary recovery factor, 25 percent.

F. Assuming same reservoir factors, depths averaging 10,000 ft and a thermal gradient of 1.2° F/100 ft.

G. World-wide average.

LIMITING FACTORS - Poor traps and reservoirs.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Cauvery No. 8
AREA (mi^2) 30,200
VOLUME (Mi^3) 39,300
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Cretaceous Drapes No. 1
AREA (MMA) 19.3
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Cretaceous reservoirs in drape (and some fault) closures involved in horst-graben structures. Play extends over entire basin.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	1.500	.772	.300
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	9	6	3
C.	AVERAGE EFFECTIVE PAY (feet)	200	36	25
D.	PERCENT OIL IN PETROLEUM MIX (%)	75	40	30
E.	OIL RECOVERY (BBLS/AF)	440	270	103
F.	GAS RECOVERY (MCF/AF)	1,663	1,169	800
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .180 BB, GAS 1.170 TCF, NGL .013 BB, OE, .388 BBOE *

A. Based on Bombay Shelf and Upper Assam rifted continental margin analogs, untested trap area is estimated to average 5% of the play area, less 20% for already tested trap area.

B. The wildcat success rate has been estimated at 10%. By analogy to the Bombay Shelf, the petroleum fill is 60%, indicating an average 6% of remaining untested trap area has petroleum.

C. The only net thickness available, 36 ft at PH-9-1, is assumed average for basin.

D. On basis of tests to date and kerigen type, basin appears slightly gas prone. Estimate 40% oil.

E. Assuming 25% porosity, 25% water saturation, and 25% recovery.

F. Assuming same reservoir, 8,000 ft depth, 2° F/100 ft thermal gradient, and 80% recovery factor.

G. World-wide average.

LIMITING FACTORS - Lack of reservoirs, volume of source rock may be small.

* For both India and Sri Lanka, India would be 60% of these values.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Palar No. 9
AREA (mi^2) 4,100
VOLUME (Mi^3) 4,400
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Cretaceous Drapes No. 1
AREA (MMA) 2.6
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Cretaceous reservoirs in drape (and some fault) closures involved in horst-graben structures. Play extends over entire basin.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.300	.130	.025
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	5	3	1
C.	AVERAGE EFFECTIVE PAY (feet)	200	36	25
D.	PERCENT OIL IN PETROLEUM MIX (%)	75	40	30
E.	OIL RECOVERY (BBLS/AF)	440	270	103
F.	GAS RECOVERY (MCF/AF)	1,663	1,169	800
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .015 BB, GAS .098 TCF, NGL .001 BB, OE, .032 BBOE

A. Structurally analogous to the Cauvery Basin and probably the same percentage of play is under trap, i.e., 5.0%.

B. Although analogous to Cauvery Basin, Palar appears shallower and could have considerably less source rock. The percent of untested trap area productive is deemed to be only half that of Cauvery Basin, i.e., 3%.

C. By analogy to Cauvery Basin.

D. By analogy to Cauvery Basin.

E. By analogy to Cauvery Basin.

F. By analogy to Cauvery Basin.

G. World-wide average.

LIMITING FACTORS - Source rock volume, lack of reservoirs.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Krishna-Godavari No. 10
AREA (mi^2) 13,000
VOLUME (Mi^3) 18,000
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Cretaceous Drapes No. 1
AREA (MMA) 5.9
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Petroleum accumulations in drapes or fault closures associated with horst-graben structure involving largely Cretaceous and possibly early Tertiary sands and carbonates. Area restricted to approximately onshore area of basin of some 5.9 million acres.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.300	.240	.100
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	9	6	3
C.	AVERAGE EFFECTIVE PAY (feet)	200	36	25
D.	PERCENT OIL IN PETROLEUM MIX (%)	6	40	20
E.	OIL RECOVERY (BBLS/AF)	400	270	150
F.	GAS RECOVERY (MCF/AF)	1,600	1,169	500
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .056 BB, GAS .364 TCF, NGL .004 BB, OE, .120 BBOE *

A. By analogy to the Cauvery Basin, the drape traps make up 5.0% of the play area. Assuming 20% of the area has been tested, approximately 240,000 acres remain to be tested.

B. By analogy to the Cauvery Basin.

C. By analogy to the Cauvery Basin.

D. From discovery tests the play appears to be gas prone; we estimate the petroleum mix to be about 60% gas; analogous to the Cauvery Basin.

E. By analogy to the Cauvery Basin.

F. By analogy to the Cauvery Basin.

G. World-wide average.

LIMITING FACTORS: Lack of reservoirs, volume of source rock small.

* Total Basin: .370 BBO, 1.248 TCFG, .014 BBNGL, .591 BBOE.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Krishna-Godavari No. 10
AREA (mi^2) 13,000
VOLUME (Mi^3) 18,000
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin

PLAY Tertiary Deltaic Sands No. 2
AREA (MMA) 4.2
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Petroleum accumulations in Tertiary deltaic sands in growth-fault associated with rollovers and flow structures. Area of play is basinward of an early Tertiary shelf; occupies approximately present offshore area to a water depth of 3,000 ft, or some 4.2 million acres.

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A. UNTESTED TRAP AREA (MMA)	.300	.221	.070
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	30	10	4
C. AVERAGE EFFECTIVE PAY (feet)	250	100	30
D. PERCENT OIL IN PETROLEUM MIX (%)	90	60	30
E. OIL RECOVERY (BBLS/AF)	400	237	150
F. GAS RECOVERY (MCF/AF)	1,700	1,000	500
G. NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .314 BB, GAS .884 TCF, NGL .010 BB, OE, .471 BBOE *

A. Untested leads and prospects appear to make up some 193,000 acres or about 4.6% of play (fig. 37). Assuming this indicated trap area is 70% of what will eventually be found, there is a trap-area of some 276,000 acres. If 20% of this trap area has been tested, 221,000 acres remain.
B. Wildcat success rate estimated to be 16%. By analogy to deltaic sands of nearby Bengal Basin, the trap area is judged to be 60% full, indicating that about 10% of total trap area would be productive.
C. One wildcat well, G-1-1, reportedly found 197 ft of net pay, another, G-2-2, only 16 ft; we assume an average net pay for the play of 100 ft.
D. From tests to date and from the presence of growth-faults to allow primary migration of oil in this generally over-pressured shale, we assume play to be somewhat oil-prone, perhaps about 60% oil in petroleum mix.
E. By analogy to Neogene deltaic sands of the Bengal Basin.
F. Assuming average depth of 7,000 ft, a thermal gradient of 2.52°F/100 ft, and average reservoir parameters.
G. World-wide average.

LIMITING FACTOR: Relatively restricted area of water depths shallow enough for economic petroleum recovery on steeply sloping sea bottom.

* Total Basin: .370 BBO, 1.248 TCFG, .014 BBNGL, .591 BBOE

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRIES: Bangladesh 48%, India 38%, Burma 14%

BASIN Bengal No. 11
AREA (mi^2) 178,000
VOLUME (Mi^3) 700,000
ORIG. RSVS. 0 BBO 11.0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin (Cret.)
Trench + Forearc (Tert.)

PLAY Foreland No. 1
AREA (MMA) 41.6
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Foreland play is essentially for Mesozoic and Tertiary reservoirs in drape or fault closures involved in horst-graben structures of rifted continental margin tectonics. Play occupies the basin west of the hinge line, an area of 41.6 million acres.

MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A. UNTESTED TRAP AREA (MMA)	3.304	1.88	.827
B. PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	4	2	1
C. AVERAGE EFFECTIVE PAY (feet)	300	100	50
D. PERCENT OIL IN PETROLEUM MIX (%)	40	15	5
E. OIL RECOVERY (BBLS/AF)	440	270	103
F. GAS RECOVERY (MCF/AF)	2,497	2,315	1,500
G. NGL RECOVERY (BBLS/MMCF)	5	1.4	.5

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .152 BB, GAS 7.4 TCF, NGL .010 BB, OE, 1.40 BBOE *

A. Analogous to other rifted continental margin basins of east coast India, 5.0% of play area is assumed to be under closure. Of this, an estimated 200,000 acres have been tested, leaving 1,880,000 acres of untested traps.
B. All 20 wildcats drilled were dry but may have been too far up-dip. It is estimated that 7% of well-placed and sufficiently deep wildcats will succeed. These somewhat faulted traps are assumed to have a petroleum fill of 30%.
C. By analogy to Oligo-Miocene reservoirs of Assam, average reservoir thickness is estimated to be 100 ft (half as thick as Assam in this more basinal area).
D. Bengal Basin is gas prone, but the foreland, where migration-inhibiting overpressured shales are less, is deemed to have more oil--around 15%.
E. Assuming 25% porosity, 25% water saturation, and 25% recovery.
F. Assuming same reservoirs, 18,000 ft depth, 1.4° F/100 ft thermal gradient, and recovery factor of 80%.
G. Bakrabad Gas Field average.

LIMITING FACTORS - Limited availability to large source; inhibited oil migration.

*Total Basin: .254 BBO, 24.9 TCFG, .034 BBNGL, 4.44 BBOE.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRIES: Bangladesh 48%, India 38%, Burma 14%

BASIN Bengal No. 11
AREA (mi^2) 178,000
VOLUME (Mi^3) 700,000
ORIG. RSVS. 0 BBO 11.0 TCFG
TECTONIC CLASSIFICATION: Rifted Continental Margin (Cret.)
Trench + Forearc (Tert.)

PLAY Fold Belt No. 2
AREA (MMA) 72.3
EST. ORIG. RSVS. 0 BBO 11.0 TCFG

DEFINITION AND LOCATION OF PLAY: Fold Belt play is for Tertiary reservoirs in a thick trench-fill involved in compression folds of a forearc (outer arc) ridge.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	1.000	.360	.180
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	30	16	10
C.	AVERAGE EFFECTIVE PAY (feet)	600	250	100
D.	PERCENT OIL IN PETROLEUM MIX (%)	6	3	0
E.	OIL RECOVERY (BBLS/AF)	400	237	150
F.	GAS RECOVERY (MCF/AF)	1,872	1,251	619
G.	NGL RECOVERY (BBLS/MMCF)	5	1.4	.5

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .102 BB, GAS 17.5 TCF, NGL .024 BB, OE, 3.04 BBOE *

A. From observation of outcrop map of largely diapiric folds, there appears to be on the average only 360,000 acres of untested trap area.

B. The wildcat success rate (for gas) is about 27%. The petroleum fill is about 60%, as exemplified at Sylhet Gas Field, giving a productive area of about 16%.

C. Estimate for average of Sylhet and Bakrabad Fields, i.e., 250 ft.

D. Gas prone with thick overpressured shale inhibiting primary oil migration. Some oil found in Burma sector.

E. Estimate average porosity 22%, water saturation 25%, and primary recovery 25%.

F. Estimate same reservoirs with average depth at 9,000 ft (for gas), thermal gradient of 1.2° F/100 ft, and recovery factor of 80%. Effects of geopressure would increase recovery by perhaps 25% (conservative).

G. Bakrabad produces 1.4 barrels NGL per million cu ft gas--taken as basin average.

LIMITING FACTORS - Poor closures; lack of primary migration channels for oil.

*Total Basin: .254 BBO, 24.9 TCFG, .034 BBNGL, 4.44 BBOE.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Assam No. 12
AREA (mi^2) 8,000
VOLUME (Mi^3) 28,000
ORIG. RSVS. .708 BBO 2.7 TCFG

PLAY Miocene Deltaic Sands No. 1
AREA (MMA) 4.48
EST. ORIG. RSVS. 1.23 BBO 3.0 TCFG

TECTONIC CLASSIFICATION: Rifted Continental Margin + Collision Belt of Thrusts + Folds

DEFINITION AND LOCATION OF PLAY: Basin primarily two plays: drape and fault closures in a foreland of rifted continental margin tectonics, and a thrust and foldbelt associated with oblique collision of India and Sunda continental blocks. The area of the thrust and foldbelt has little potential and only the foreland of the Assam Basin is considered.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	.100	.042	.020
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	18	9	2.3
C.	AVERAGE EFFECTIVE PAY (feet)	400	200	50
D.	PERCENT OIL IN PETROLEUM MIX (%)	95	60	45
E.	OIL RECOVERY (BBLS/AF)	322	215	129
F.	GAS RECOVERY (MCF/AF)	1,436	1,006	682
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .098 BB, GAS .304 TCF, NGL .003 BB, OE, .152 BBOE

A. A very approximate estimate from a poor map indicates 168,000 acres of trap have been established. It is estimated that 80% of the eventually to-be-discovered trap area has been mapped and tested, leaving 42,000 acres.
B. The wildcat success rate is estimated to be about 20%. Petroleum fill at Nahorkatiya is taken as the basin average, i.e., 45%, indicating 9% of the untested closure area would be productive.
C. Average effective pay thickness appears to be around 200 ft.
D. Although never produced, terrigenous source and good sealing indicates gas. It is estimated that the oil-gas mix is 60-40%.
E. Estimating 20% porosity, assuming 25% water saturation, and 25% primary oil recovery.
F. Assuming same reservoirs, estimating average depth of 9,000 ft, a thermal gradient of 1.2° F/100 ft, and recovery factor of 80%.
G. Worldwide average.

LIMITING FACTORS - Small size and exploration maturity.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Indo-Gangetic No. 13
AREA (mi^2) 190,000
VOLUME (Mi^3) 310,000
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Trench and Collision Fold Belt

PLAY Fold Belt Sands
AREA (MMA) 121.6
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: The play is for Tertiary reservoirs involved in compressional Neogene folds; it covers the entire basin area.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	14.64	9.73	2.44
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	.20	.06	.01
C.	AVERAGE EFFECTIVE PAY (feet)	300	100	50
D.	PERCENT OIL IN PETROLEUM MIX (%)	70	30	10
E.	OIL RECOVERY (BBLS/AF)	440	269	103
F.	GAS RECOVERY (MCF/AF)	2,332	2,101	1,860
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .047 BB, GAS .859 TCF, NGL .009 BB, OE, .199 BBOE

A. Untested trap area is extensive. Trap formation appears more favorable than in the Indus Fold Belt (7.6% trap), and it is assumed that 8% of the play area is trap.

B. Trap area which might be productive is extremely curtailed by the limited amount of source rock (apparently limited to 2% of basin area). Assuming success rate of 10% and a petroleum fill of 30% in the area underlain by source rock, an overall average percent of untested trap area of .06 percent is obtained.

C. Reservoirs are abundant and thick but no explicit data are available. Since reservoir thickness is not a limiting factor, a conservative average of 100 ft is estimated.

D. Most of the source rock appears to be overmature.

E. Assuming 25% porosity, 25% water saturation, and 25% primary recovery.

F. Assuming same reservoirs, 14,000-foot depth, 1° F/100 ft thermal gradient, and a recovery factor of 80%.

G. World-wide average.

LIMITING FACTORS - Lack of sufficient source rock; source rock overmature.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: BURMA

BASIN Burma No. 14
AREA (mi^2) 120,000
VOLUME (Mi^3) 411,000
ORIG. RSVS. .914 BBO --? TCFG
TECTONIC CLASSIFICATION: Wrenched Forearc (Outer Arc) Basin

PLAY Oligo-Miocene Folds
AREA (MMA) 46
EST. ORIG. RSVS. .914 BBO --? TCFG

DEFINITION AND LOCATION OF PLAY: With more information, basin can be divided into 4 plays - 3 subdivisions, Chindwin, Central, and Irraddy Delta in which Tertiary sands are the objective, and a Miocene reef play. For now, the plays are lumped together. The thermally-mature source rock distribution in this cool basin limits accumulations to the deeper subbasins, i.e. 60% of overall basin area.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	2.070	1.086	.735
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	24.0	3.2	1.0
C.	AVERAGE EFFECTIVE PAY (feet)	300	100	30
D.	PERCENT OIL IN PETROLEUM MIX (%)	85	60	50
E.	OIL RECOVERY (BBLS/AF)	440	270	103
F.	GAS RECOVERY (MCF/AF)	1,985	1,280	724
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY
PROBABILITIES: OIL .563 BB, GAS 1.779 TCF, NGL .020 BB, OE, .879 BBOE

A. In absence of structural maps or fore-arc basin structural analogs, it is assumed that the dominant trap producer is drag folds on wrench faults and that analogs of Central Sumatra and Los Angeles Basins pertain. On this basis, a trap area 5.5% of the basin is estimated. Assuming 65% of trap tested and adding 200,000 acres for Miocene reefs, an untested trap area of 1.086 million acres is obtained.

B. 40% petroleum fill (Lanya and Chauk) is assumed average. Given a success rate of of 8%, the percent of untested closure to be productive averages 3.2%.

C. Although a great number of rather thick oil sands are referred to, limited production indicates a relatively low net pay, probably averaging 100 ft.

D. Terrigenous source plus gas caps at depth indicate appreciable gas, say 40%.

E. Estimate 25% porosity, assume 25% water saturation and 25% primary recovery factor.
F. Assume same reservoirs, estimate average depth of 8,500 ft, thermal gradient of 1.0° F/100 ft, and recovery factor of 80%.
G. World-wide average.

LIMITING FACTORS - Low thermal gradient limits area and volume of source rock.

PLAY ANALYSIS OF UNDISCOVERED PETROLEUM
COUNTRY: INDIA

BASIN Andaman No. 15
AREA (mi^2) 62,000
VOLUME (Mi^3) 190,000
ORIG. RSVS. 0 BBO 0 TCFG
TECTONIC CLASSIFICATION: Fore-Arc (Outer Arc) Ridge

PLAY Tertiary Sands No. 1
AREA (MMA) 40.0
EST. ORIG. RSVS. 0 BBO 0 TCFG

DEFINITION AND LOCATION OF PLAY: Play is for Tertiary reservoirs in fore-arc and possibly drag folds in a shallow-water area of a fore-arc ridge. Area assumed is approximately that of the ONGC exploration block.

	MAJOR GEOLOGICAL/EXPLORATION FACTORS	PROBABILITY DISTRIBUTION 5%	Most Likely	95%
A.	UNTESTED TRAP AREA (MMA)	2.500	.800	.300
B.	PERCENT UNTESTED TRAP AREA PRODUCTIVE (%)	10	3	2
C.	AVERAGE EFFECTIVE PAY (feet)	100	50	15
D.	PERCENT OIL IN PETROLEUM MIX (%)	40	15	5
E.	OIL RECOVERY (BBLS/AF)	200	130	100
F.	GAS RECOVERY (MCF/AF)	1,020	740	340
G.	NGL RECOVERY (BBLS/MMCF)	20	11	7

PRODUCT OF MOST LIKELY PROBABILITIES: OIL .023 BB, GAS .755 TCF, NGL .008 BB, OE, .157 BBOE

A. Extremely complex melange terrane; trap area guessed at only around 2%.

B. Assumed 30% petroleum fill and 10% wildcat success, indicating 3% of closure productive.

C. Reservoirs would be thin and sparse in flysch sediments; estimate atound 50 ft.

D. From seeps and tests, estimate petroleum fill mostly gas, say 85%.

E. Estimate porosity poor, 2%; water saturation, 25%; oil recovery, 25%.

F. Estimate same reservoirs, average reservoir depth, 10,000 ft; thermal gradient, 1.0° F/100 ft; and 80% gas recovery.

G. Worldwide average.

LIMITING FACTORS - Poor trap and reservoirs in melange/flysch terrane.

Appendix B

ILLUSTRATIONS

Figures:

TABLES

Summary of Assessments of Undiscovered Recoverable Petroleum Resources of South Asian Basins and Countries

On the basis of a geologic review of the South Asian hydrocarbon basins, including the Play Analyses, the following estimates of undiscovered oil and total gas in the basin of South Asia were made by consensus of The World Energy Resources Program (TWERP) group on June 20, 1983.

	Oil				Total Gas			
Province Name	MP	.95	.05	ML	MP	.95	.05	ML
Kutch Shelf (onshore and offshore) INDIA	.55	.3	2	.7	.55	1.8	12	4
Bombay Shelf (offshore), INDIA	1	.3	2.5	1	1	2	10	4
Cambay Graben, INDIA	1	.05	.5	.15	1	.25	3	.5
Konkan Shelf, INDIA	.2	.08	.3	.15	.2	.6	1	.4
Cauvery and Palar Basins, INDIA	.8	.1	1	.3	.8	.4	3	.8
Krishna-Godavari Basin, INDIA	.8	.1	.5	.2	.8	.5	2	1
Bengal Basin, BURMA, INDIA, BANGLADESH *	.4	.1	1	.4	1	10	80	30
North Assam and Indo-Gangetic Basins, INDIA	1	.05	.5	.1	1	.5	2	1
BURMA and Andaman Sea, INDIA	1	.3	3	1	1	1	6	2
Indus, Potwar, and Makran Basins, PAKISTAN	1	.05	.7	.3	1	15	60	30
* Burma = 14% India = 38% Bangladesh = 48%	Nos. 1-6, 38% of No. 7, and No. 8 are aggregated and called "INDIA." Note: MP = Marginal Probability, ML = most likely							

From these estimate ranges, probability distribution curves of the undiscovered oil and total gas were determined by a computer Monte Carlo technique. These curves are attached; figures are arranged in the same order as the estimates given above; table 1 summarizes the principal values from these curves. It is a summary of the estimates of undiscovered petroleum resources of these basins. Table 2 combines the estimated undiscovered petroleum resources (modal quantities) and estimated petroleum reserves to show the estimated total petroleum content of individual basins of South Asia.

The cumulative probability curves for the individual basins (or groups of basins) are shown in figures 1 through 30. The objective of the cumulative probability curve construction is to derive the mean quantity of undiscovered petroleum in each basin from a most likely (modal) quantity, a 5-percentile quantity, and a 95-percentile quantity obtained from a consensus group of geologists. Accordingly, the mean quantity embodies estimates of the most likely quantity, along with more remote probabilities for substantially larger quantities of undiscovered petroleum reserves.

The mean quantities from each basin are summarized in Table 1 and aggregated for each country. This is the principal result of this study and is summarized below:

	Oil (billions of barrels)	Gas (trillions of cubic feet)
Pakistan	.35	34.37
India	2.91	27.83
Bangladesh	.09	18.91
Burma	1.43	8.44

Assessment date: May 20, 1983

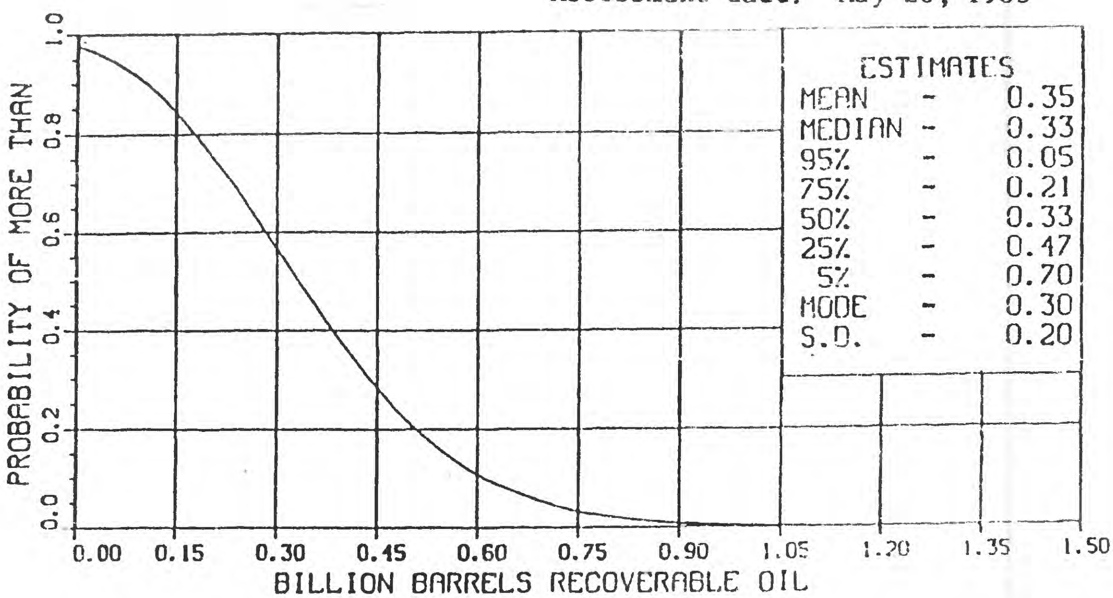

Figure 1.--Pakistan-Indus, Potwar, and Makran Basins, undiscovered recoverable oil.

Assessment date: May 20, 1983

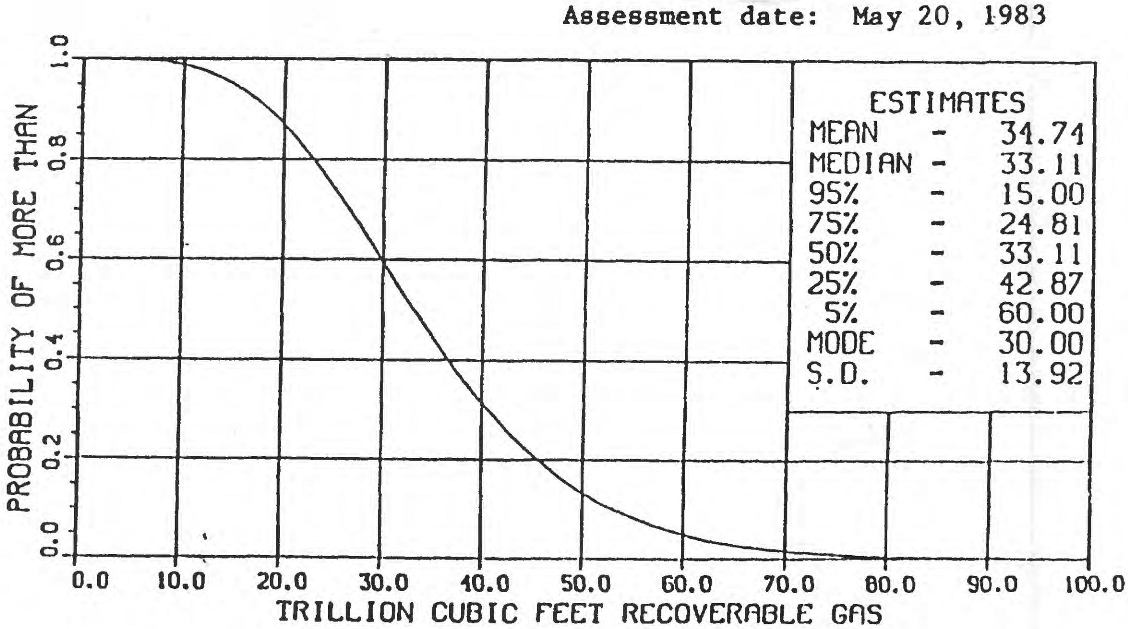

Figure 2.--Pakistan-Indus, Potwar, and Makran Basins, undiscovered recoverable total gas.

Assessment date: May 20, 1983

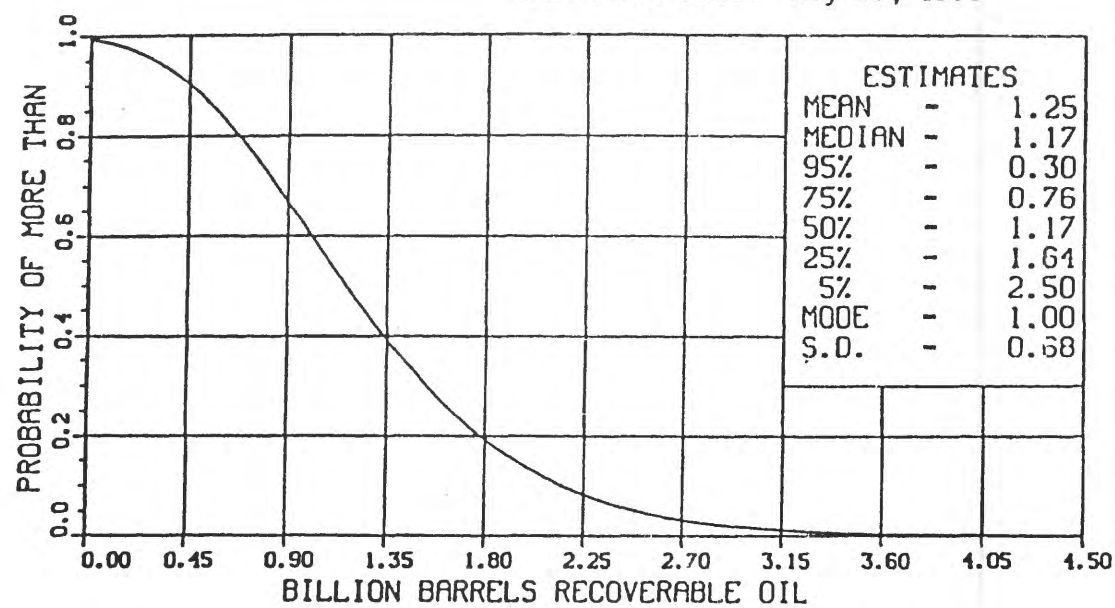

Figure 3.--India, Bombay Shelf, undiscovered recoverable oil.

Assessment date: May 20, 1983

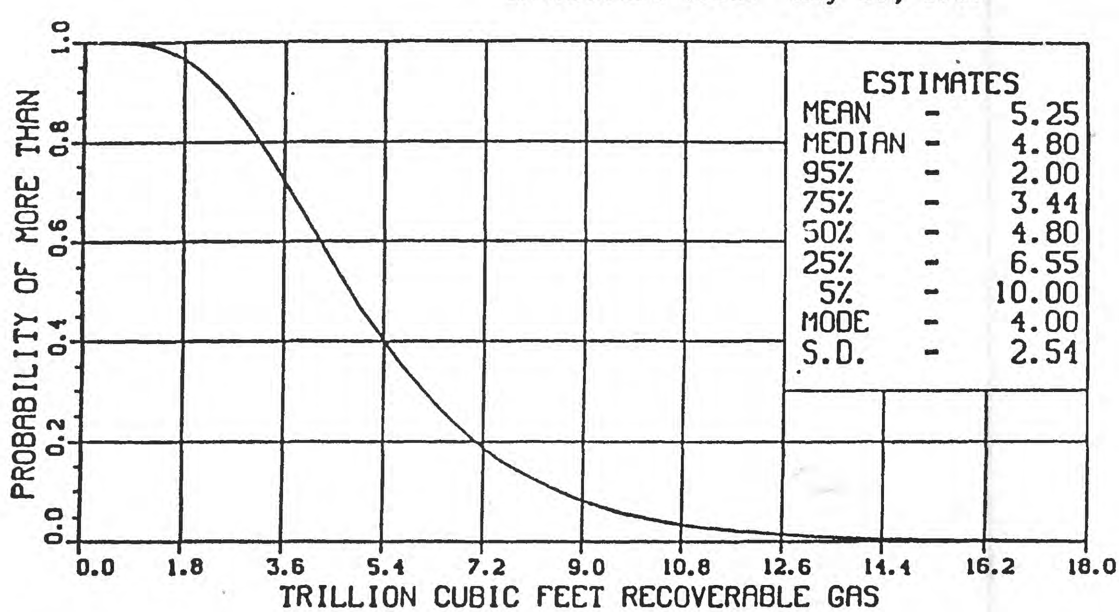

Figure 4.--India, Bombay Shelf, undiscovered recoverable total gas.

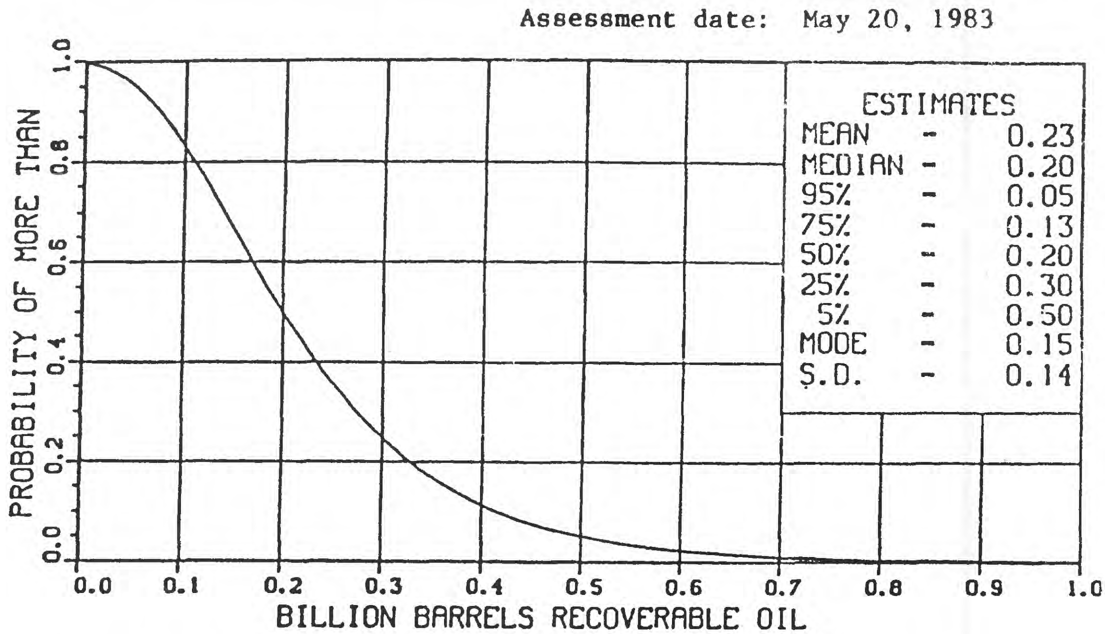

Figure 5.--India, Cambay Graben, undiscovered recoverable oil.

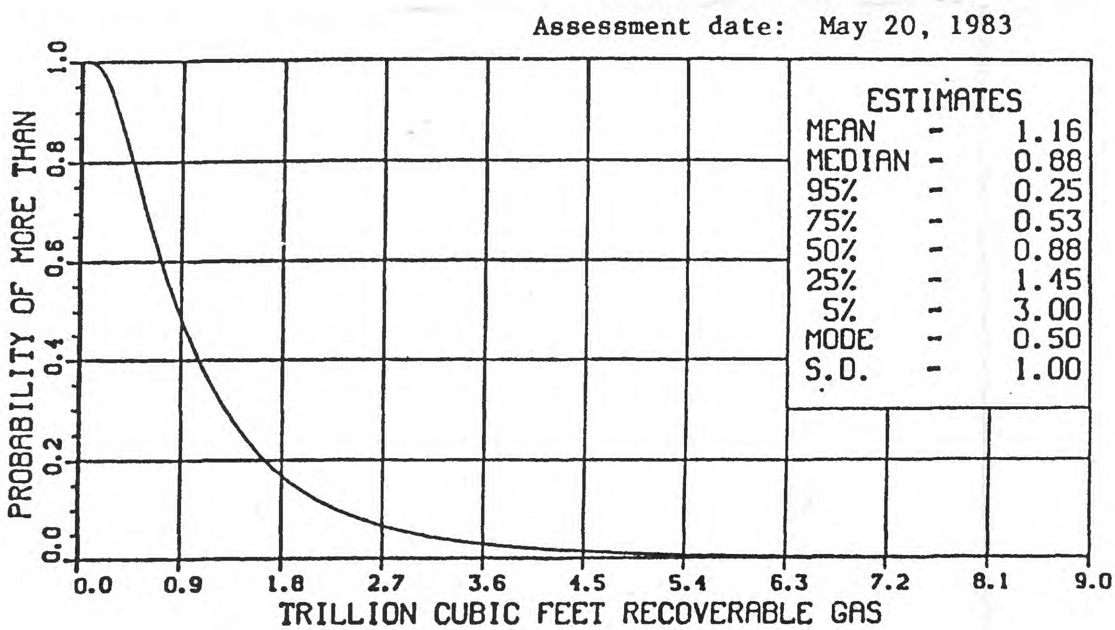

Figure 6.--India, Cambay Graben, undiscovered recoverable total gas.

Assessment date: May 20, 1983

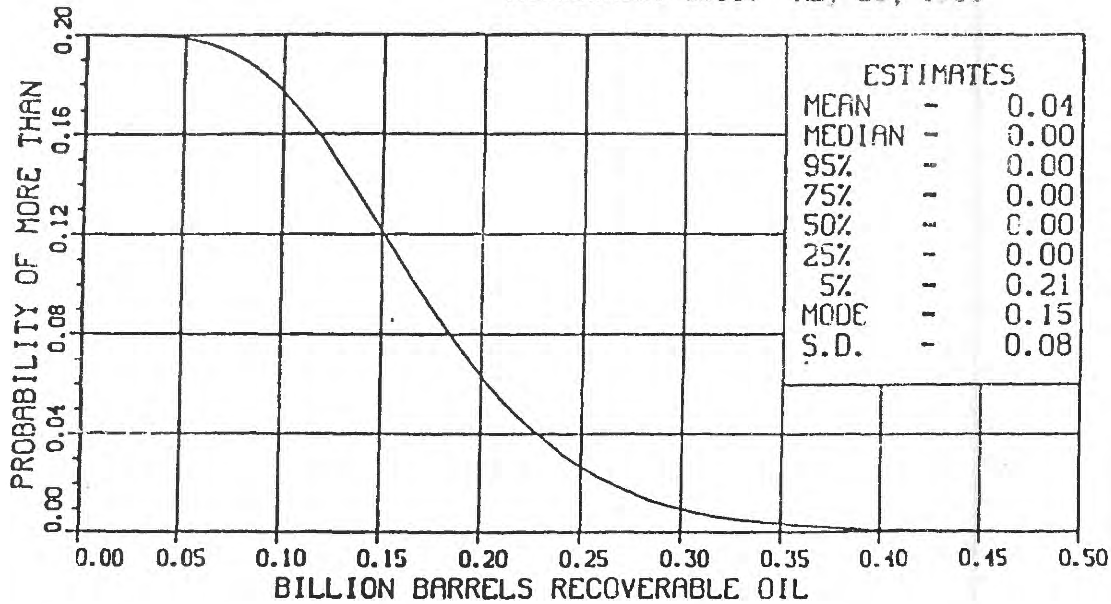

Figure 7.--India, Konkan Shelf, undiscovered recoverable oil.

Assessment date: May 20, 1983

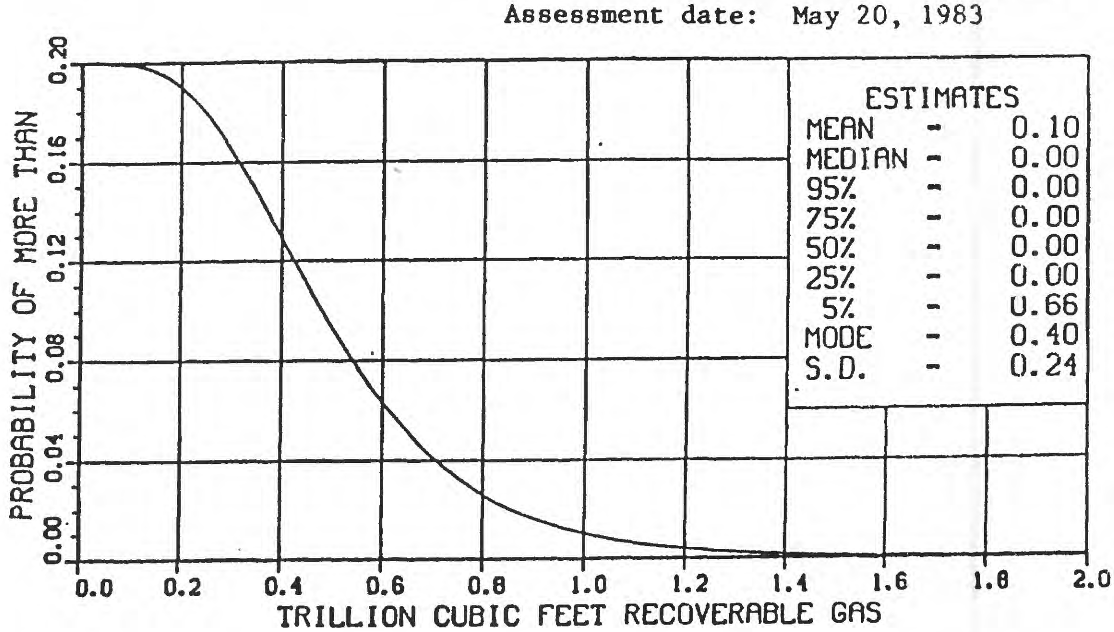

Figure 8.--India, Konkan Shelf, undiscovered recoverable total gas.

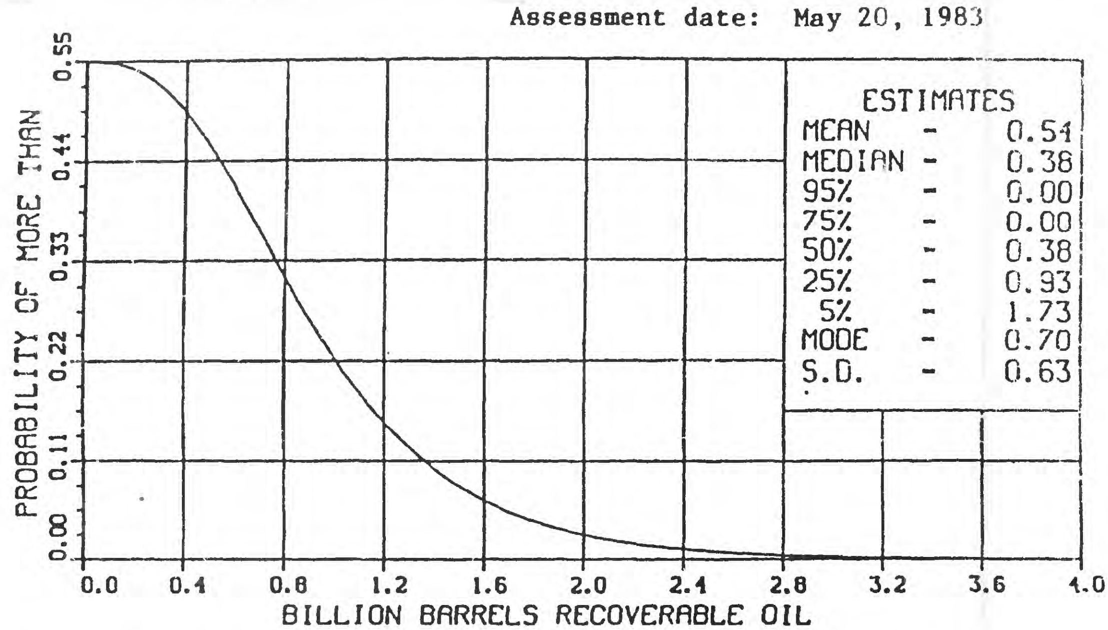

Figure 9.--India, Kutch Shelf, undiscovered recoverable oil.

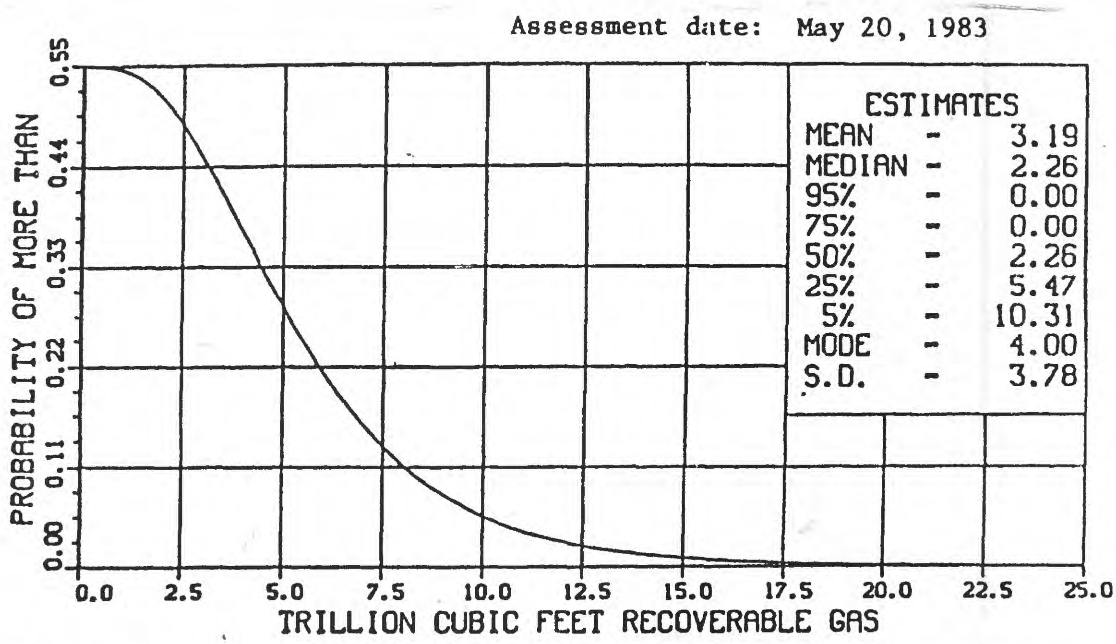

Figure 10.--India, Kutch Shelf, undiscovered recoverable total gas.

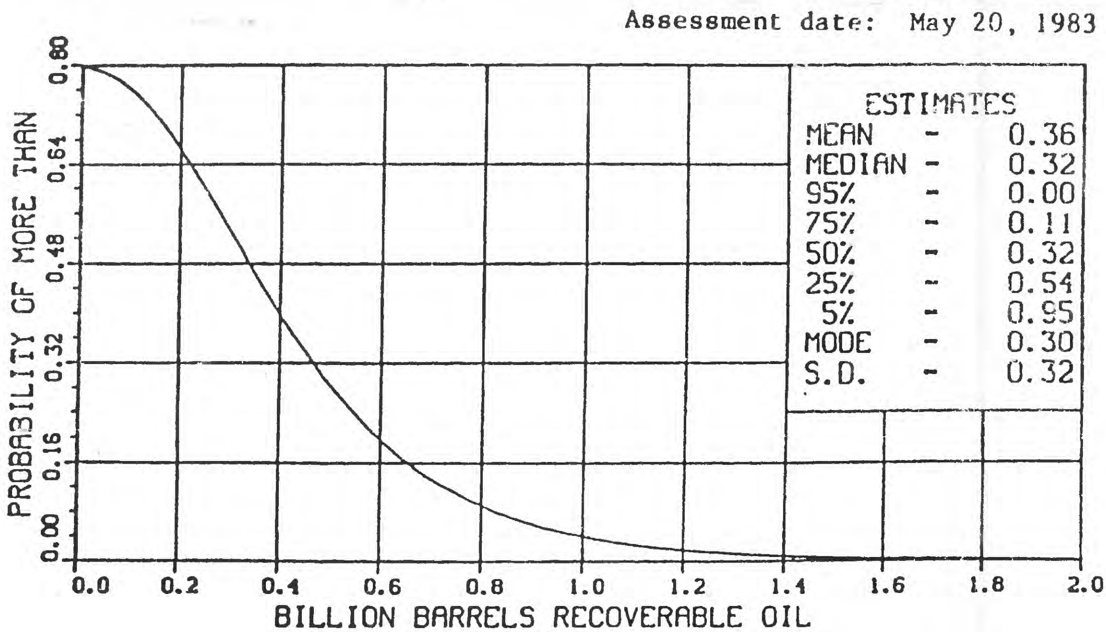

Figure 11.--India, Cauvery and Palar Basins, undiscovered recoverable oil.

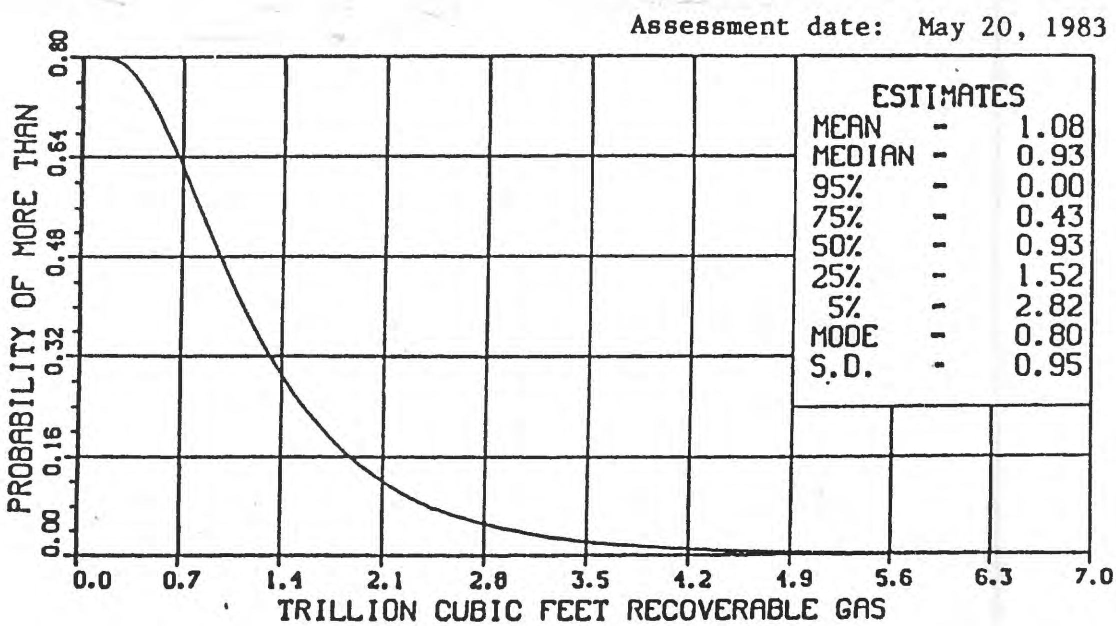

Figure 12.--India, Cauvery and Palar Basins, undiscovered recoverable total gas.

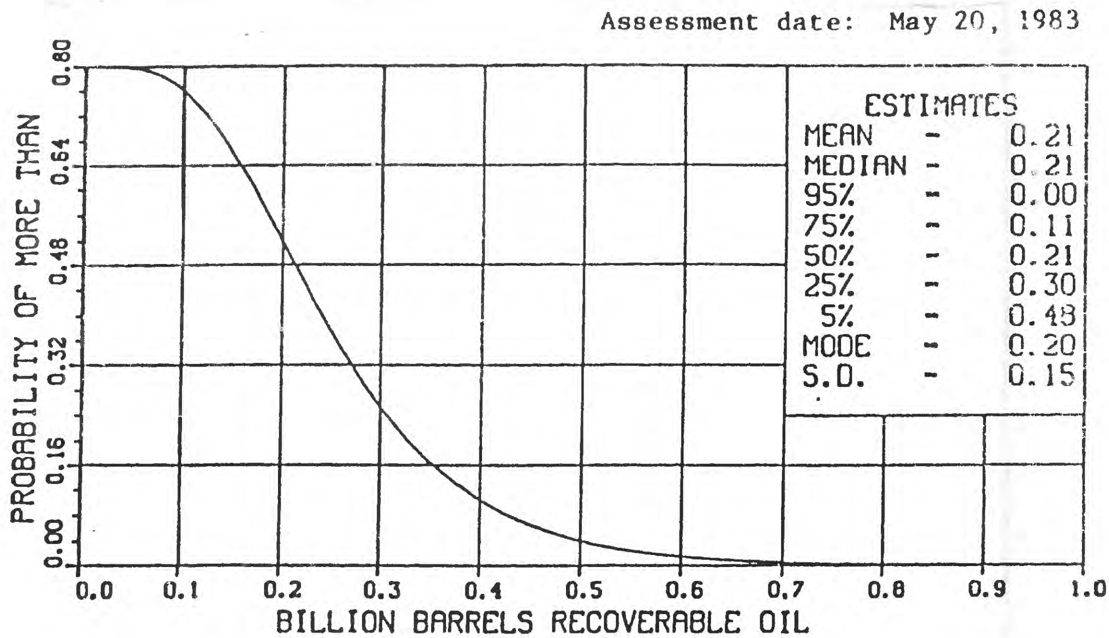

Figure 13.--India, Krishna-Godavari Basin, undiscovered recoverable oil.

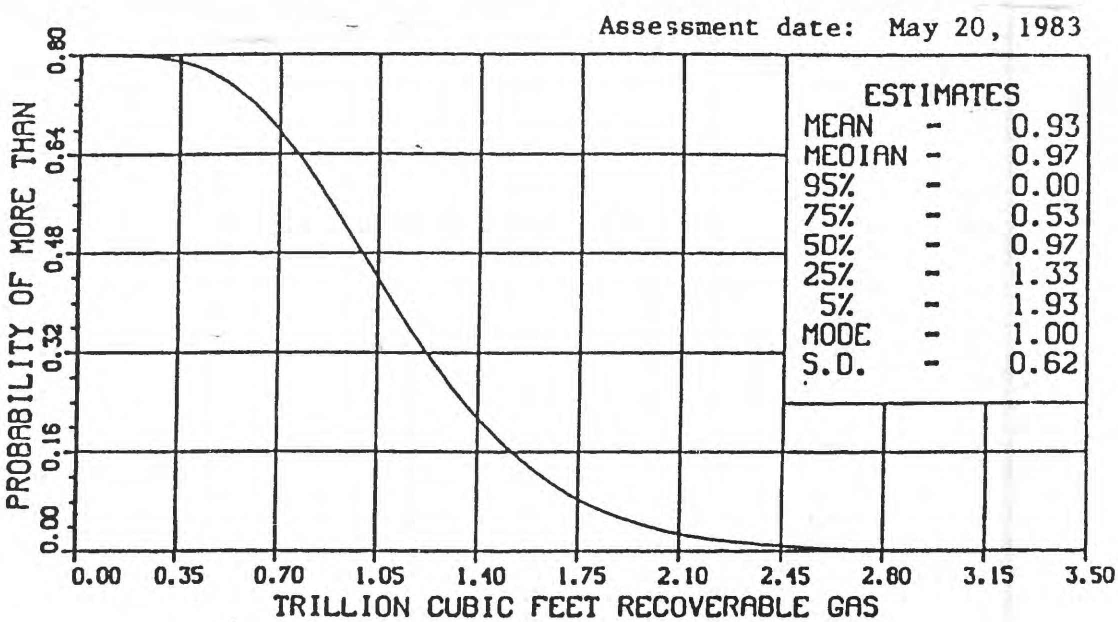

Figure 14.--India, Krishna-Godavari Basin, undiscovered recoverable total gas.

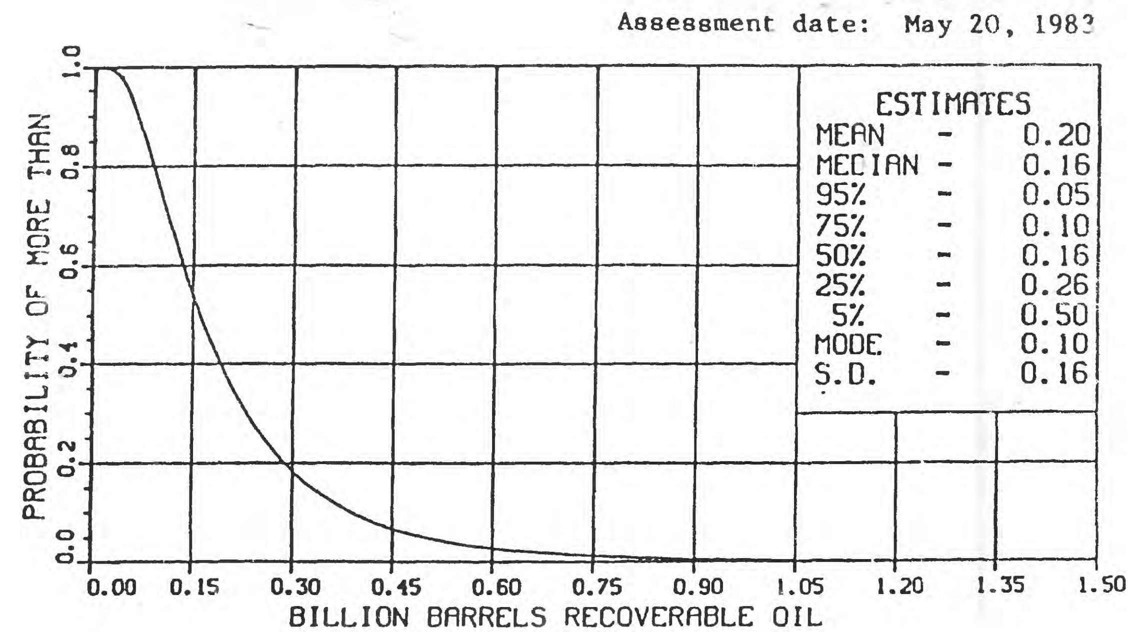

Figure 15.--India, North Assam and Indo-Gangetic Basins, undiscovered recoverable oil.

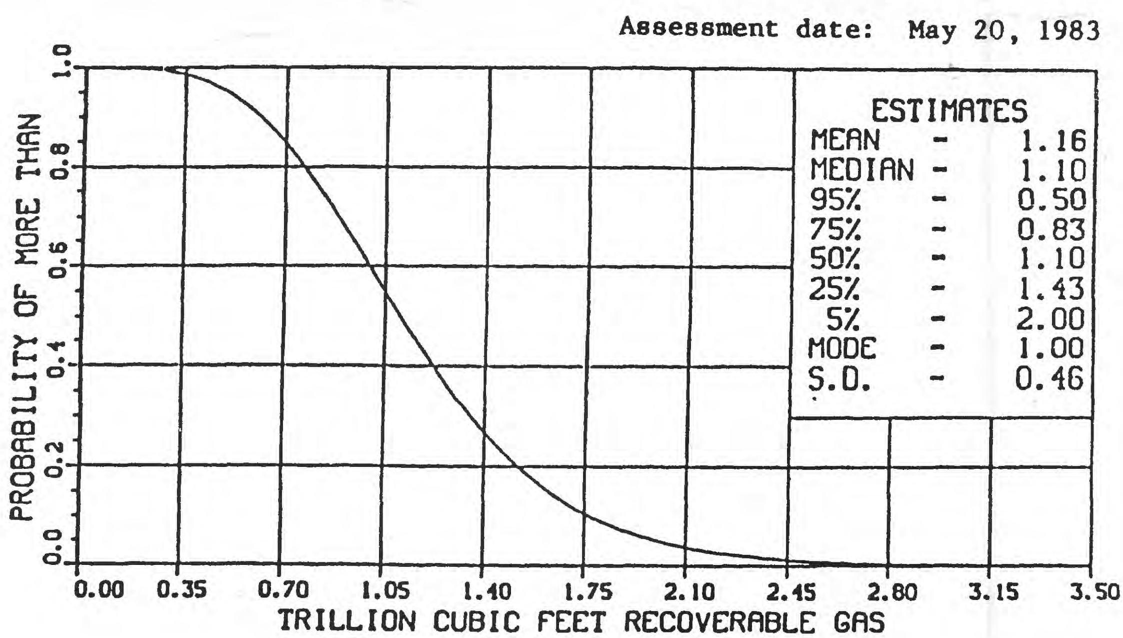

Figure 16.--India, North Assam and Indo-Gangetic Basins, undiscovered recoverable total gas.

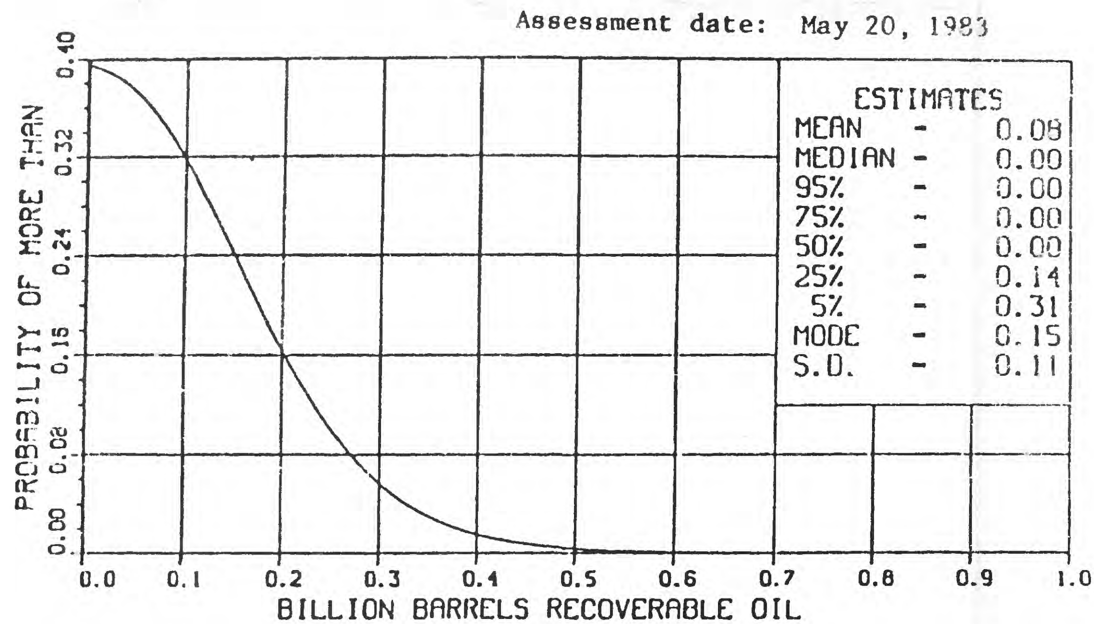

Figure 17.--India, Bengal Basin, undiscovered recoverable oil.

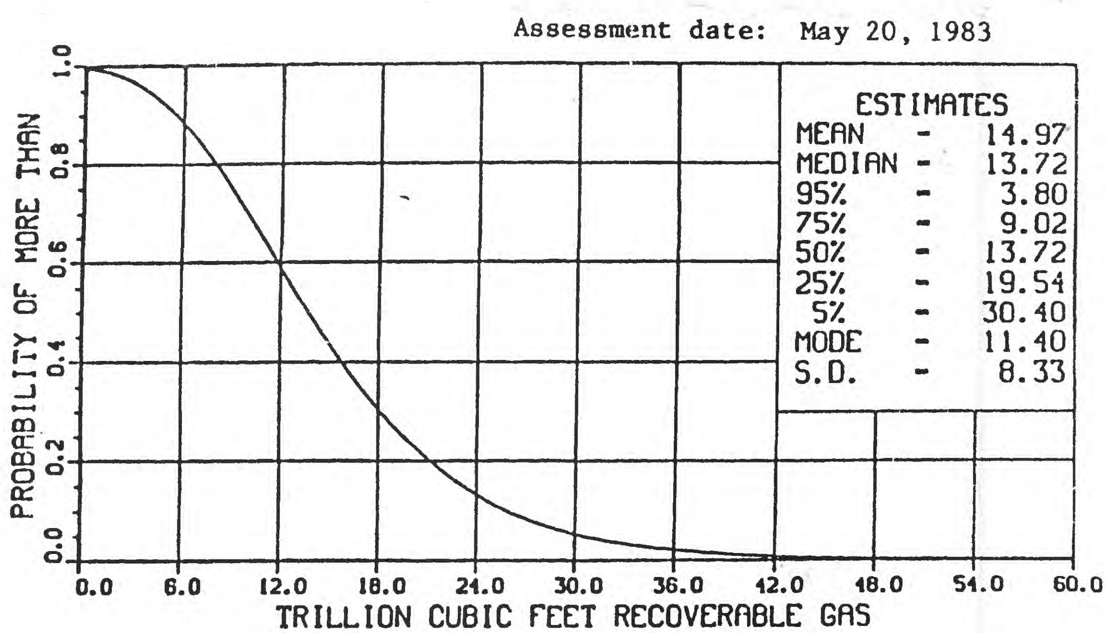

Figure 18.--India, Bengal Basin, undiscovered recoverable total gas.

Assessment date: May 20, 1983

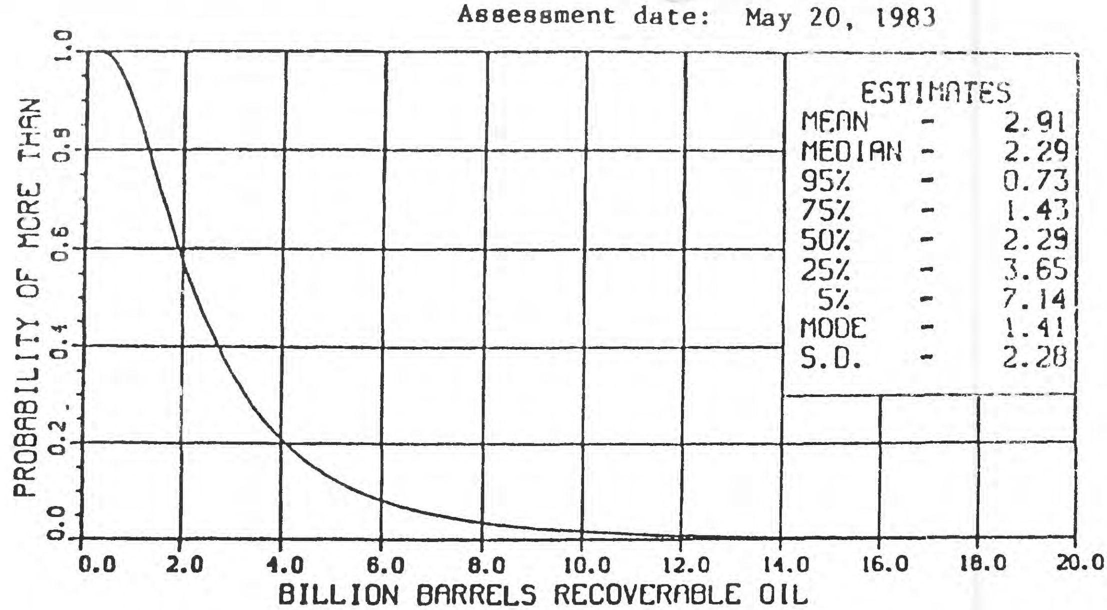

Figure 19.--India, aggregate undiscovered recoverable oil.

Assessment date: May 20, 1983

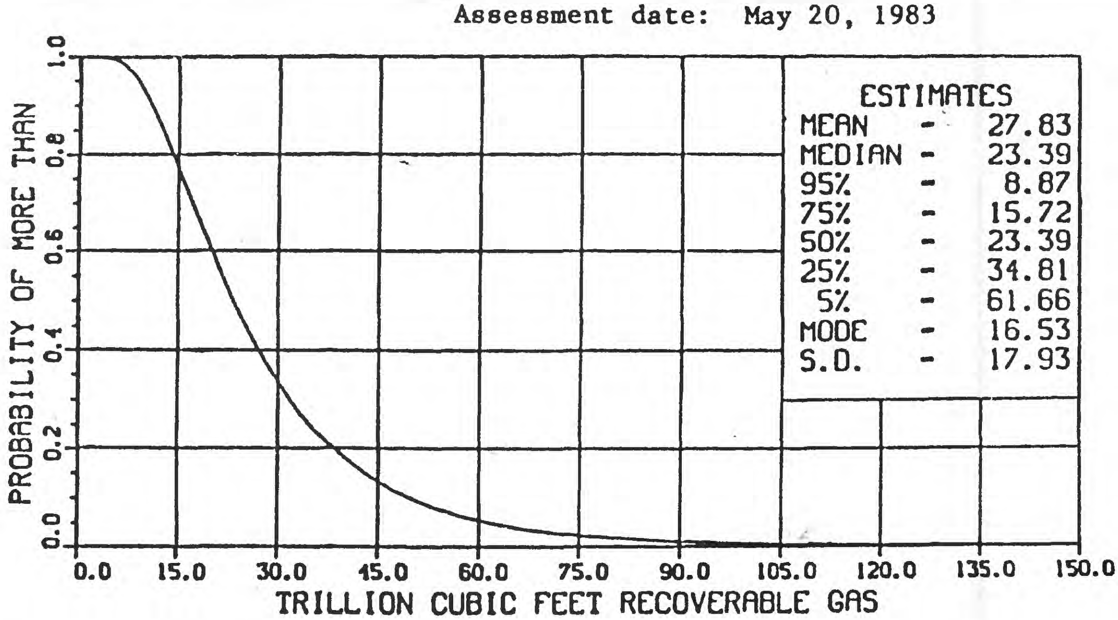

Figure 20.--India, aggregate undiscovered recoverable total gas.

Assessment date: May 20, 1983

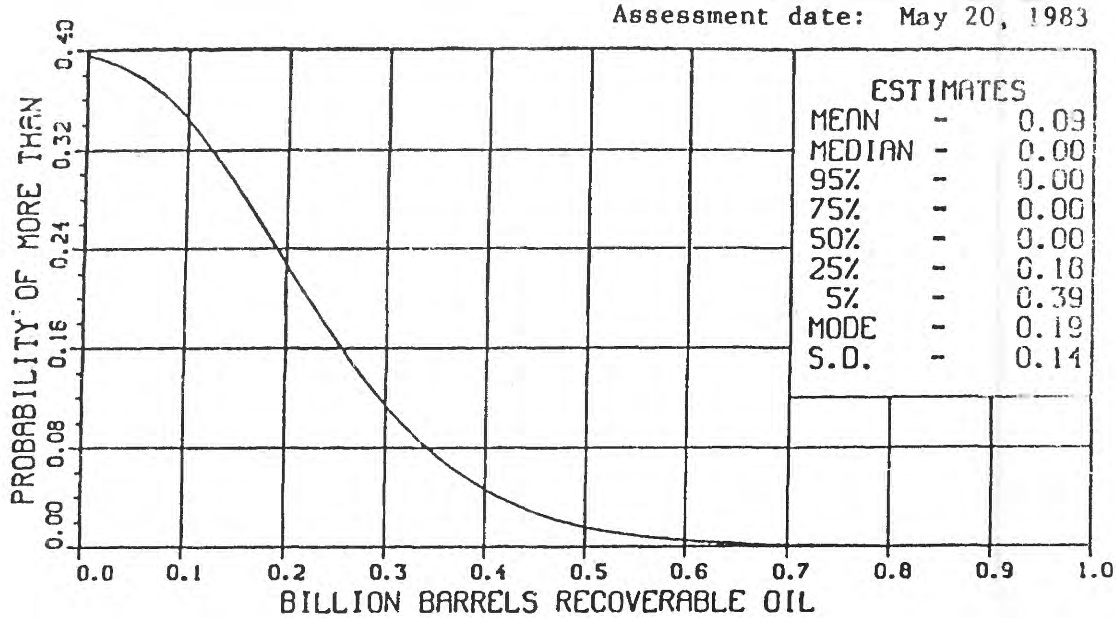

Figure 21.--Bangladesh, Bengal Basin, undiscovered recoverable oil.

Assessment date: May 20, 1983

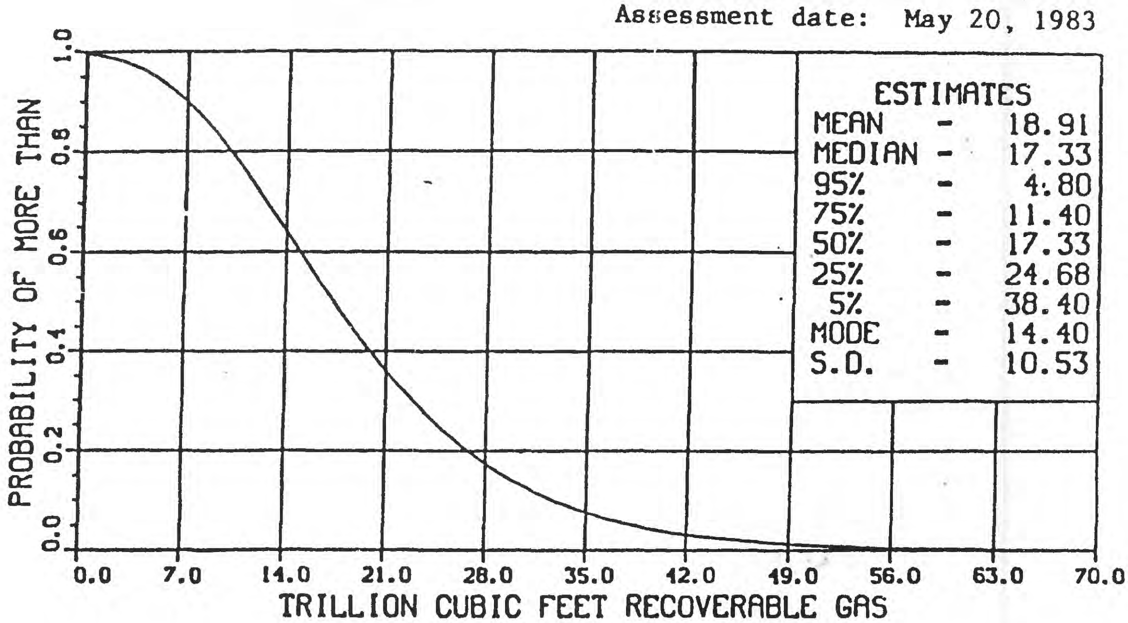

Figure 22.--Bangladesh, Bengal Basin, undiscovered recoverable total gas.

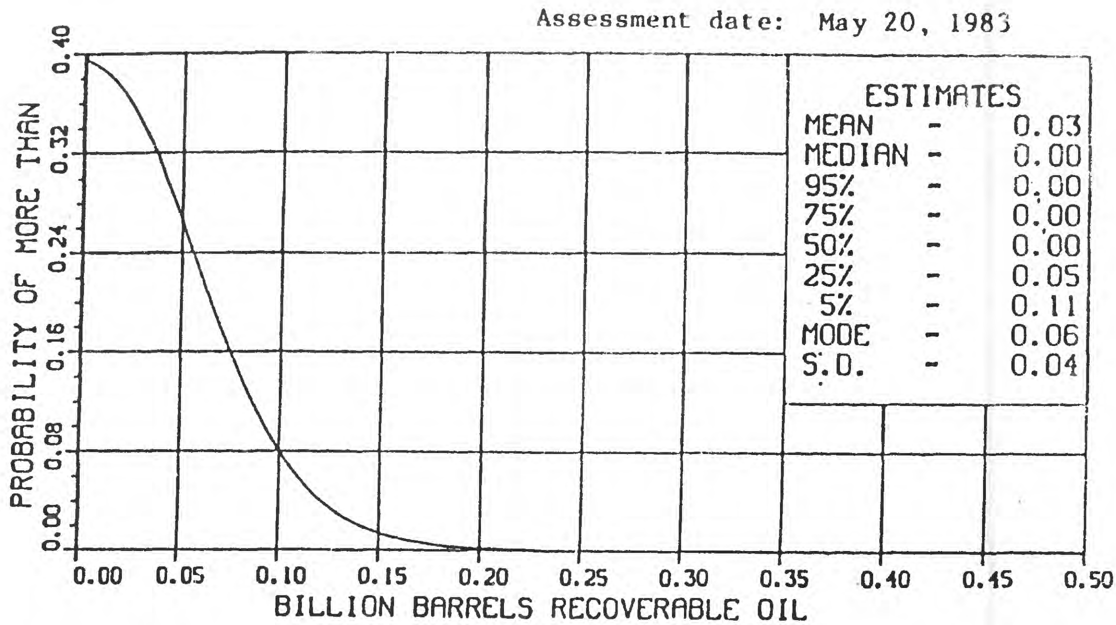

Figure 23.--Burma, Bengal Basin, undiscovered recoverable oi.

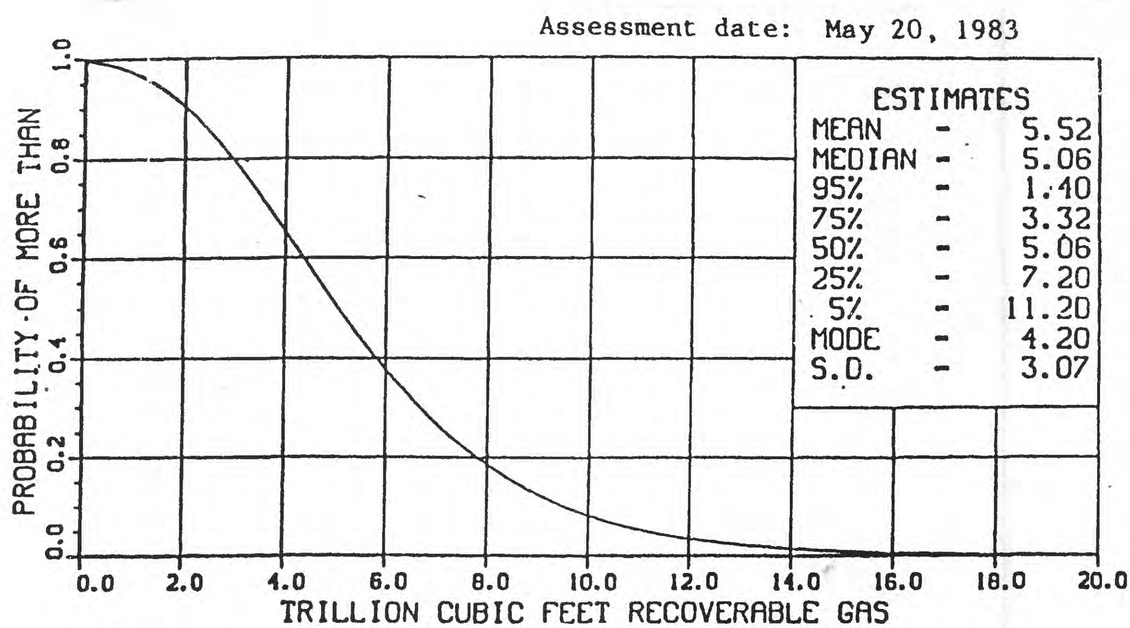

Figure 24.--Burma, Bengal Basin, undiscovered recoverable total gas.

Assessment date: May 20, 1983

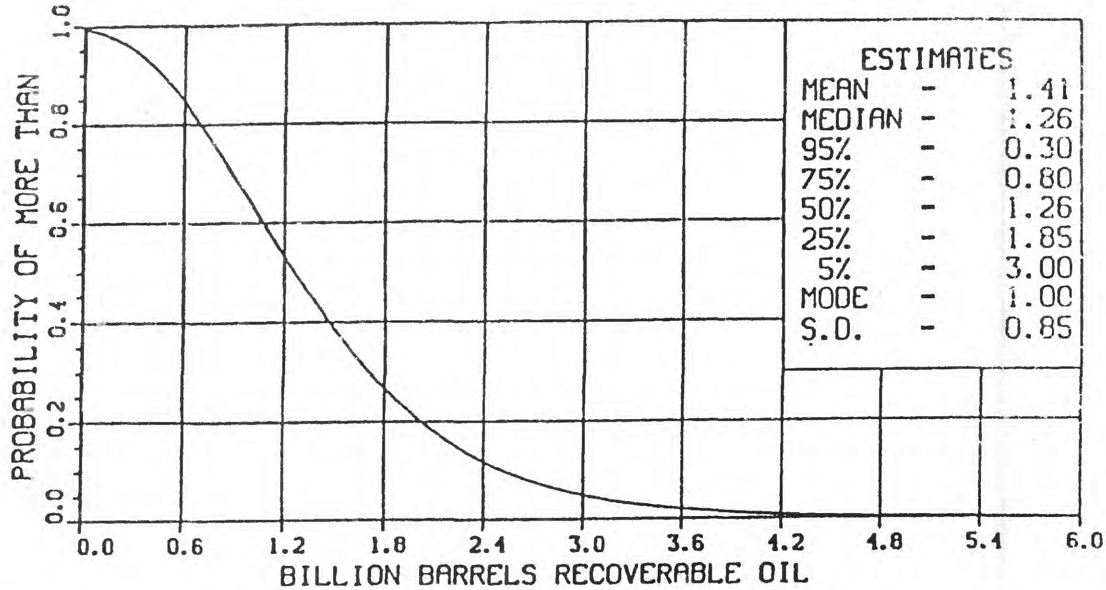

Figure 25.--Burma (4 plays) and Andaman (India) Basins, undiscovered recoverable oil

Assessment date: May 20, 1983

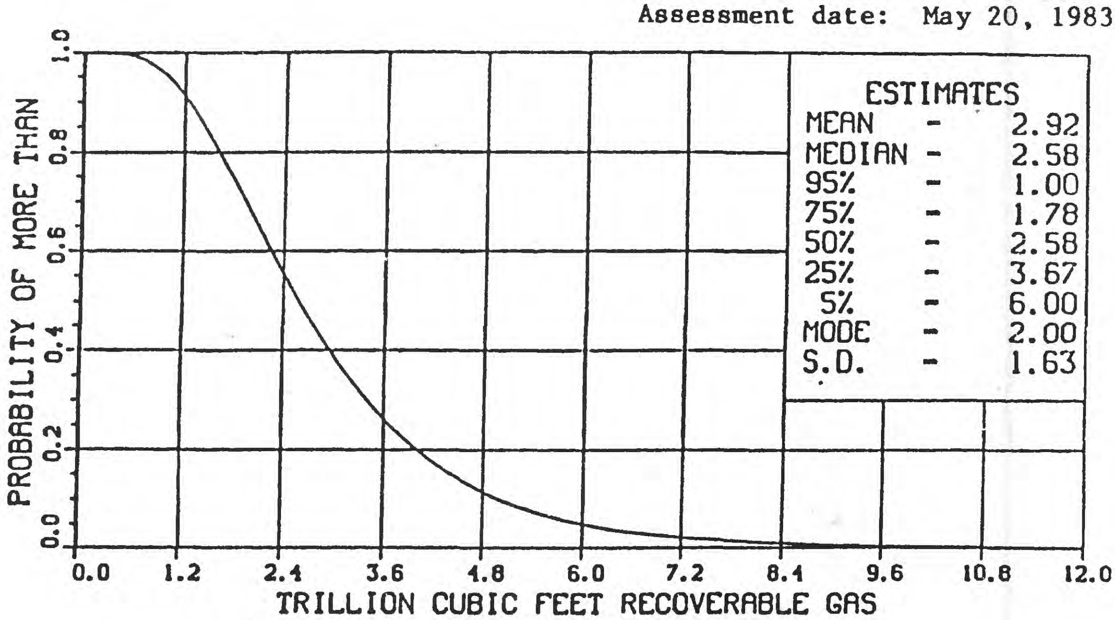

Figure 26.--Burma (4 plays) and Andaman (India) Basins, undiscovered recoverable total gas.

Assessment date: May 20, 1983

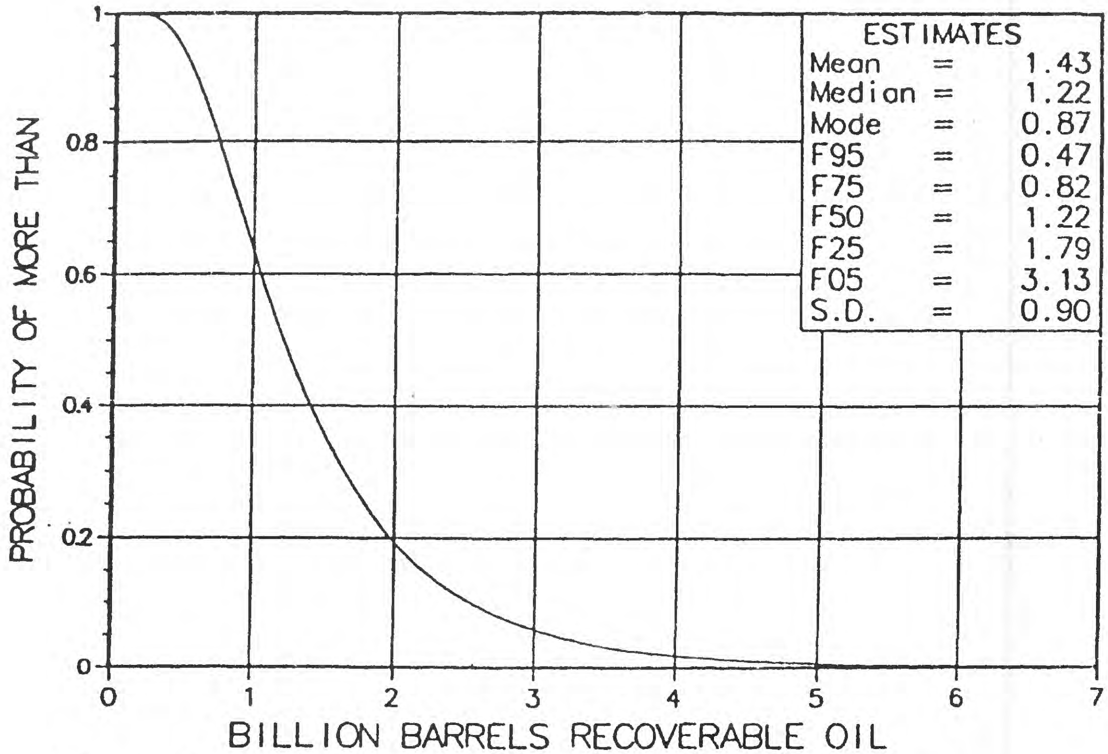

Figure 27.--Burma, aggregate undiscovered recoverable oil.

Assessment date: May 20, 1983

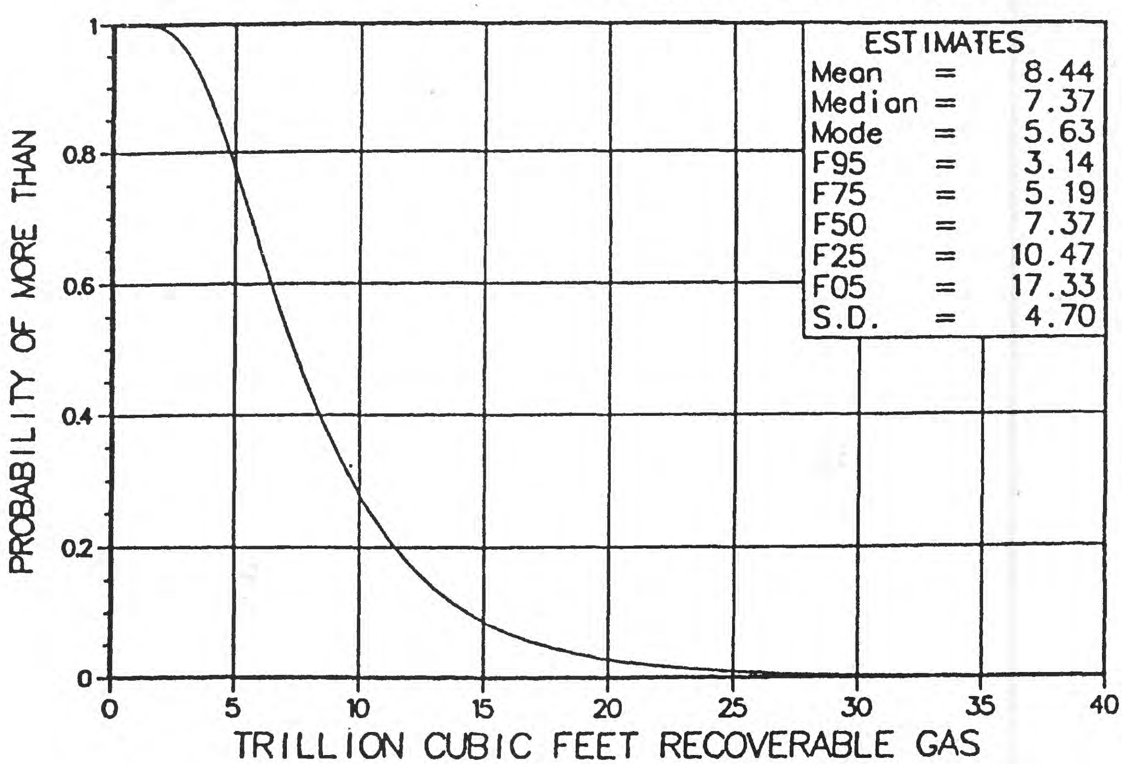

Figure 28.--Burma, aggregate undiscovered recoverable total gas.

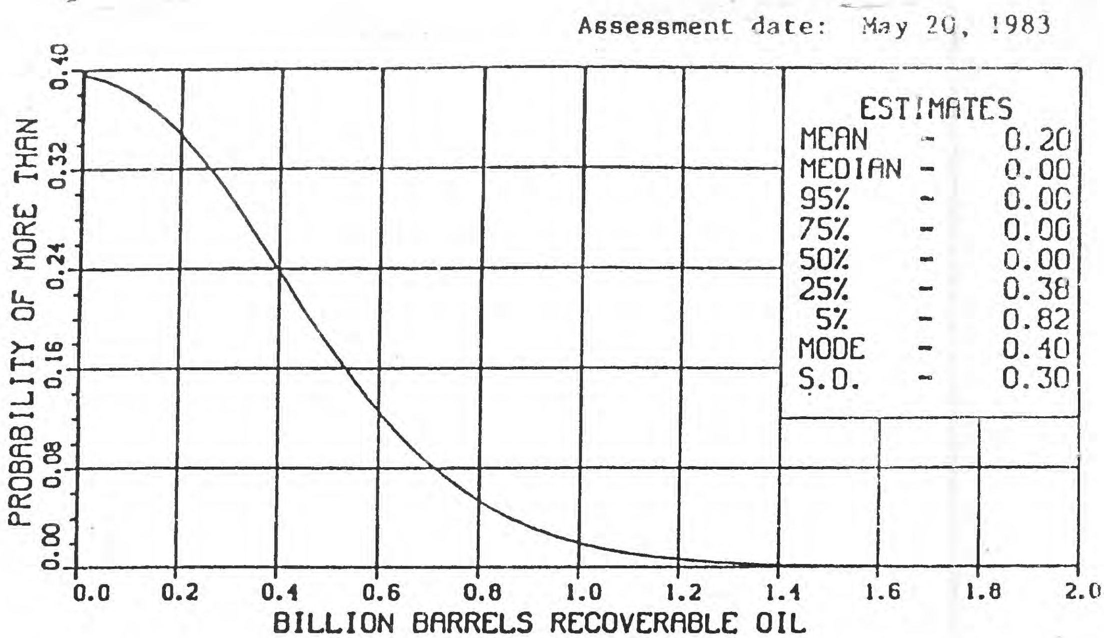

Figure 29.--Bengal Basin, Burma, India, Bangladesh, aggregate undiscovered recoverable oil.

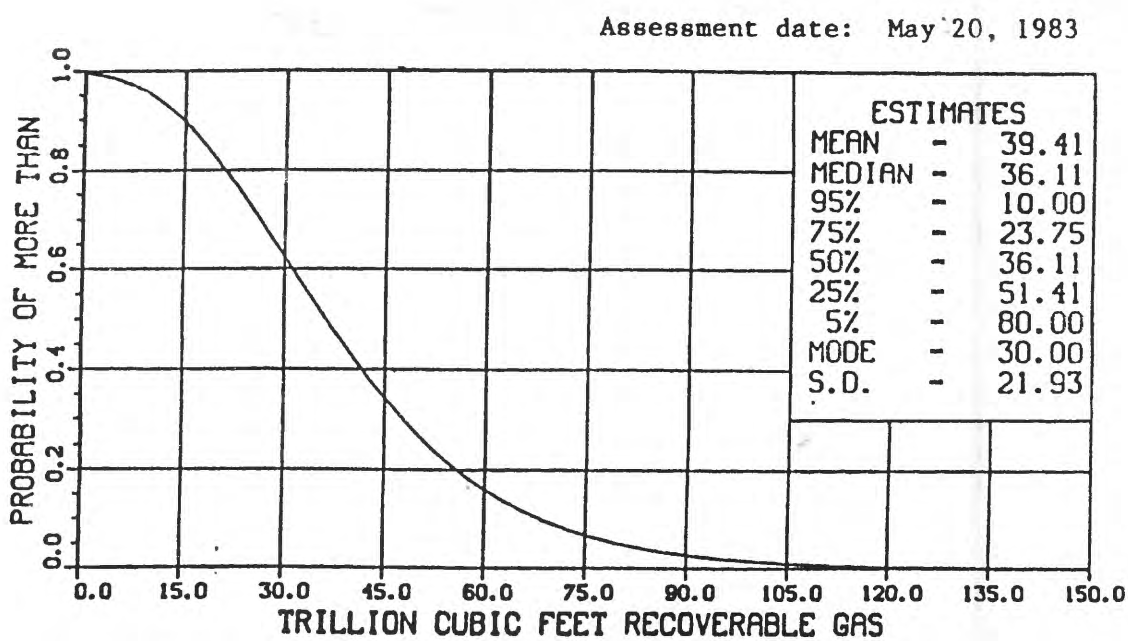

Figure 30.--Bengal Basin, Burma, India, Bangladesh, aggregate undiscovered recoverable total gas.

Table 1.--Assessment of undiscovered recoverable petroleum of South Asia. Unconditional resource assessment by USGS as of 4/20/83; see also figures 1 through 30.

	Oil in billions of barrels (BBb)				Gas in trillions of cubic feet (Tcf)			
Province / Probability	Low > 95%	High > 5%	Mean	Mode	Low > 95%	High > 5%	Mean	Mode
PAKISTAN								
Indus, Potwar, and Makran	0.05	0.70	0.35	0.30	15.00	60.00	34.74	30.00
INDIA								
Bombay	0.30	2.50	1.25	1.00	2.00	10.00	5.25	4.00
Cambay	0.05	0.50	0.23	0.15	0.25	3.00	1.16	0.50
Konkan	0.00	0.21	0.04	0.15	0.00	0.66	0.10	0.40
Kutch	0.00	1.73	0.54	0.70	0.00	10.31	3.19	4.00
Cauvary (+ Palar)[1]	6.00	0.95	0.36	0.30	0.00	2.82	1.08	0.80
Krishna-Godavari	0.00	0.48	0.21	0.20	0.00	1.93	0.93	1.00
N. Assam (+ Indo-Gangetic)[1]	0.05	0.50	0.16	0.10	0.50	2.00	1.16	1.00
Bengal (38%)[2]	0.00	0.31	0.08	0.15	3.80	30.40	14.97	11.40
India, aggregate	0.73	7.14	2.91	1.41	8.87	61.66	27.83	16.53
BANGLADESH								
Bengal (48%)[2]	0.00	0.39	0.09	0.19	4.80	38.40	18.91	14.40
BURMA								
Burma (+ Andaman)[1]	0.30	3.00	1.41	1.00	1.00	6.00	2.92	2.00
Bengal (14%)[2]	0.01	0.14	0.07	1.40	1.40	11.20	5.52	4.20
Burma aggregate	0.47	3.13	1.43	0.87	3.14	17.33	8.44	5.63

1. Basins of minor potential grouped with adjoining basins.

2. Bengal Basin aggregate: 0.00, 0.82, 0.20, 0.40 for oil; 10.00, 80.00, 39.41, 30.00 for gas.

Table 2.--Estimated petroleum content of South Asia sedimentary basins (in billions of barrels of oil and trillions of cubic feet of gas).

	Estimated Original Reserves[1]		Estimated undiscovered petroleum[2] (mode)		Estimated ultimate resources	
Province	OIL	GAS	OIL	GAS	OIL	GAS
PAKISTAN[3]						
Indus	<0.1	22.0	(0.2)[4]	(30.0)	0.2	52.0
Potwar	0.2	<0.1	(0.1)	(0.1)	0.3	0.1
Makran			(0.0)	(0.0)	0.0	0.0
Aggregate[5]	0.2	22.0	0.3	30.0	0.5	52.0
INDIA						
Bombay	2.7	13.3	1.0	4.0	3.7	17.3
Cambay	1.2	0.9	0.2	0.5	1.4	1.4
Konkan			0.2	0.4	0.2	0.4
Kutch			0.7	4.0	0.7	4.0
Cauvery			0.3	0.8	0.3	0.8
Palar[6]			<0.1	<0.1	<0.1	<0.1
Godavari-Krishna			0.2	1.0	0.2	1.0
North Assam	0.7	2.7	0.1	1.0	0.8	3.7
Indo-Gangetic[6]			<0.1	<0.1	<0.1	<0.1
Andaman[6]			(<0.1)[4]	(<0.1)	<0.1	<0.1
Bengal (38%)			0.2	11.4	0.1	11.4
Aggregate[5]	4.6	16.9	1.4	16.5	7.4	40.0
BANGLADESH						
Bengal (48%)	0.0	11.0	0.2	14.4	0.2	25.2
BURMA						
Bengal (14%)	<0.1	0.0	0.1	4.2	0.1	4.2
Burma (minus Bengal)	0.9	<0.1	(1.0)[4]	(2.0)	1.9	2.0
Aggregate[5]	1.0	<0.1	0.9	5.6	1.9	5.7

1. Original reserves include present reserves, plus cumulative production, plus an estimate of undeveloped discoveries.

2. Most likely (modal)values within a range of probabilities (figs. 2 through 30).

3. Pakistan basins grouped.

4. Bracketed values are estimates by another, outside assessment process to show approximate amounts of resources in individual basins comprising group assessments.

5. An aggregate of most likely (modal) values for estimated undiscovered petroleum is not a summation of the values for basins but a somewhat lesser number related to the degree of dependency between individual probability curves.

6. Minor basins grouped with related adjacent basins (see figs. 12, 13, 16, 17, 26, and 27).