C. 899

GEOLOGICAL SURVEY CIRCULAR 899

Assessment of Undiscovered Conventionally Recoverable Petroleum Resources of Indonesia

Assessment of Undiscovered Conventionally Recoverable Petroleum Resources of Indonesia

By Joseph P. Riva, Jr.

GEOLOGICAL SURVEY CIRCULAR 899

Prepared in cooperation with
Congressional Research Service,
Library of Congress,
Washington, D.C.

A resource assessment and a brief description of the petroleum geology, including play distribution, that accounts for the petroleum accumulation in Indonesia

1983

United States Department of the Interior

JAMES G. WATT, *Secretary*

Geological Survey

Dallas L. Peck, *Director*

Library of Congress Cataloging in Publication Data

Riva, Joseph P.
Assessment of undiscovered conventionally recoverable petroleum resources of Indonesia.

(Geological Survey circular ; 899)
"Prepared in cooperation with Congressional Research Service, Library of Congress, Washington, D.C."
Bibliography: p.
1. Oil fields--Indonesia. 2. Petroleum--Geology--Indonesia. I. Library of Congress. Congressional Research Service. II. Title. III. Series.
QE75.C5 no. 899 [TN876.I55] 557.3's 83-600249
[553.2'82'09598]

Free on application to Distribution Branch, Text Products Section, U. S. Geological Survey, 604 South Pickett Street, Alexandria, VA 22304

ASSESSMENT OF ENERGY RESOURCES

The World Energy Resources Program of the U.S. Geological Survey intends to develop reliable and credible estimates of undiscovered petroleum resources throughout the world. Initial program efforts have focused on the major producing areas of the world in order to gain a broad geological understanding of the characteristics of petroleum occurrence for resource assessment as well as for analysis of production potential. Investigations of production potential are carried out in cooperation with other U.S. Government agencies; specifically, studies of the main exporting nations of the free world, of which this study is a part, are carried out in cooperation with the Foreign Energy Supply Assessment Program of the Department of Energy.

The program seeks to investigate resource potential at the basin level, primarily through analogy with other petroleum regions, and thus does not necessarily require current exploration information commonly held to be proprietary. In conducting the investigations, we intend to build a support base of publicly available data and geologic synthesis against which to measure the progress of exploration and thereby validate the assessment. Most of these investigations will lead directly to quantitative resource assessments; to be effective, resource assessment, like exploration, must be an ongoing process that takes advantage of changing ideas and data availability – the results produced are but progress reports reflecting on a state of knowledge at a point in time. Because the program is coordinated with the Geological Survey's domestic assessment program and uses similar assessment techniques, the user can be assured that a thread of consistency will permit comparisons between the various petroleum basins of the world, including those in the United States, that have been assessed in the overall Survey program.

In addition to resource estimates, the program provides a regional base of understanding for in-country exploration analysis and for analysis of media reports regarding the exploratory success or failure of ventures in studied areas.

Geological Survey publications relating to the assessment of undiscovered conventionally recoverable petroleum resources include the following:

Open-File Report 81-986 – Assessment of conventionally recoverable petroleum resources of Persian Gulf basin and Zagros Fold Belt (Arabian-Iranian basin)

Open-File Report 81-1027 – Assessment of conventionally recoverable petroleum resources, Volga-Urals basin, U.S.S.R.

Open-File Report 81-1142 – Assessment of conventionally recoverable petroleum resources of Indonesia

Open-File Report 81-1143 – Assessment of conventionally recoverable petroleum resources of northeastern Mexico

Open-File Report 81-1144 – Assessment of conventionally recoverable petroleum resources of southeastern Mexico, northern Guatemala, and Belize

Open-File Report 81-1145 – Assessment of conventionally recoverable petroleum resources of Trinidad

Open-File Report 81-1146 – Assessment of conventionally recoverable petroleum resources of Venezuela

Open-File Report 81-1147 – Assessment of conventionally recoverable petroleum resources of the West Siberian basin and Kara Sea basin, U.S.S.R.

These reports are available from Open-File Services Section, Branch of Distribution, U.S. Geological Survey, Box 25425, Federal Center, Denver, CO 80225.

CONTENTS

ILLUSTRATIONS

TABLES

ACKNOWLEDGMENTS

The resource assessment for this report was prepared in collaboration with the Resource Appraisal Group of the Branch of Oil and Gas Resources.

Assessment of Undiscovered Conventionally Recoverable Petroleum Resources of Indonesia

By Joseph P. Riva, Jr.[1]

ABSTRACT

The estimates of undiscovered conventionally recoverable petroleum in Indonesia at probability levels of 95 percent, 5 percent, and statistical mean are for oil (in billions of barrels): 5, 35, and 16; and for gas (in trillions of cubic feet): 13, 94, and 42.

In Indonesia, petroleum occurs in five types of basins: fore-arc, back-arc (foreland), median, inner-arc, and downwarp-into-small-ocean basins. The back-arc, median, and downwarp basins have significantly greater petroleum potential than do the fore-arc and inner-arc basins. The latter two types are expected to yield only small discoveries; also, significant portions of such basins lie in water depths in excess of 1,000 m. The back-arc basins have been the most petroleum productive, but they also have been the most extensively explored. The greatest undiscovered petroleum potential is estimated to lie in the downwarp and median basins.

In Indonesia, six general types of geological settings or plays have been identified as being favorable for petroleum accumulation. They are transgressive clastic sequences, regressive clastic sequences, deltas, carbonate platforms, pinnacle reefs, and fractured igneous and volcanic rocks. The multiple-pay transgressive clastic reservoirs in the back-arc basins have produced most of Indonesia's crude oil. In several basins, carbonate platform porosity has become a primary exploration target, but each reservoir (reef, bank, or bioclastic zone) tends to be restricted in size.

Typically, Indonesian oil is of medium gravity with a paraffin base and has a moderate to high pour point, a low sulfur content, and a relatively low gas to oil ratio.

INTRODUCTION

The history of Indonesian petroleum exploration and development can be divided into several phases (Bee, 1980). The pioneering phase began in the 1880's and lasted into the early 1930's. Such early work was confined to onshore areas mainly on the larger islands. The second phase, the modern onshore phase, took place from about 1930 to 1965. The first phase of exploration had been accomplished mostly by surface mapping, shallow-core drilling, and the drilling of oil seeps. The second phase was marked by the introduction of geophysical techniques, especially seismic surveys, which permitted the evaluation of deeper prospects. The fields that were discovered early were generally in shallow horizons, but in 5 of the 11 producing Tertiary basins, the largest field was discovered before 1930, in the preseismic phase. The third phase of exploration began in 1966 with the signing of the first offshore production sharing contract. This new phase was made possible by advances in offshore drilling and production technology. Although most of the work from mid-1960 to mid-1970 was done offshore, considerable onshore exploration was also going on, usually in remote areas made accessible by the use of helicopters. Exploration was mostly done by seismic surveys, but geological mapping continued to play a necessary part. This phase of accelerated exploration, which is sometimes called the "quiet boom," came to an end in 1974 with a significant downward trend in oil exploration. Throughout the mid-1970's, exploratory activity was low due to a general reorganization of the Indonesian state oil company, Pertamina, that resulted in the renegotiation of contracts with the international oil companies to provide an increased government share of the generated revenue. The latest exploration phase began in 1978 with governmental assurances of fiscal stability and conciliatory incentives. By the middle of 1980, Indonesia was experiencing an exploration boom that has continued into 1982 (Cowan and Parker, 1982).

[1]Congressional Research Service, Washington, DC 20540.

REGIONAL GEOLOGY

Indonesia comprises the central part of a great archipelago that extends between Southeast Asia and Australia (fig 1). Geologically, the East Indian Archipelago is one of the most intricate parts of the Earth's surface and has enormous crustal relief. The difference in altitude between the mountain ranges capped by perennial snow and the adjacent deep-sea troughs approaches 15,000 m. The largest of the Indonesian islands are Sumatra, Kalimantan (Borneo), Sulawesi (Celebes), Java, Timor, and Irian Jaya (New Guinea).

Zones of earthquake and volcanic activity can be used to divide Indonesia into four large regions that are parts of tectonic plates (fig. 2). The Eurasian cratonic plate contains the submerged Sunda Shelf in the northwest and most of the island system: Sumatra, Java, Kalimantan, and a part of Timor and Sulawesi. The Indian-Australian plate contains the remainder of the island system, Timor and Irian Jaya, as well as the bounding Java trench. To the northwest, the Caroline and Philippine Sea plates bound the Indonesian land areas.

Superimposed upon these plates are some 28 Tertiary basins, mostly initiated by tectonic movements at the end of Mesozoic time. Little is known about the Paleozoic and Mesozoic rock sequences that locally may underlie these basins. The oldest rocks in the region are Precambrian crystalline schists, which have been encountered in drill holes in Irian Jaya and crop out on the small island of Buru. The oldest fossiliferous deposits in the region are middle and late Paleozoic in age and have been found mainly on Sumatra and Kalimantan. During the Mesozoic Era, new sedimentary belts evolved in Indonesia. Triassic and Jurassic age rocks are known from many islands. In Timor and in many smaller islands, Triassic sediments have been described as "flysch-like" and have been observed to be "more or less oil-bearing" in some areas (Schuppli, 1946). Beds of Early Cretaceous age have been reported from only a few areas; beds of Late Cretaceous age, however, are widespread. The Tethys character of these beds and of the Mesozoic in general is very pronounced in certain areas: the association of radiolarian-bearing beds and ophiolites is typical of both the Mediterranean and the Indonesian areas. Remarkable similarities of other faunal and lithologic characteristics between the two regions indicate similar depositional environments.

Orogenic movements during the Cenozoic Era gave the region its present configuration. Considerable Tertiary volcanic activity occurred in most parts of the archipelago, producing intercalated tuffs, breccias, and lava flows. About 75 percent of the surface of the islands consists of sediments and volcanic deposits of Cenozoic age. The Tertiary sediments in the various basins in some cases were deposited under conditions of high rates of sedimentation and reach a composite thickness exceeding 15,000 m. The 28 Tertiary basins of Indonesia contain a total of 14.5 million km^3 (3.5 million mi^3) of Tertiary sediments (Fletcher and Soeparjadi, 1977). Of this total, about 20 percent is middle Miocene or older. The bulk of the rest is Pliocene and Pleistocene in age. Most of the oil and gas discoveries have occurred in early and middle Miocene age rocks.

Sedimentation in the Tertiary basins was cyclic, characterized by repetitions of marine transgressions, which commonly led to bathyal depositional conditions and finally terminated with a regression. However, local conditions have affected the stratigraphic sequences of each basin.

The Tertiary basins of Indonesia represent five general types (fig. 1): fore-arc, inner-arc, back-arc (foreland), median, and downwarp-into-small-ocean basins. Fore-arc basins are located on the oceanic side of active volcanic arcs and lie between the arcs and the subduction boundaries of the major crustal plates. Sediments in these basins consist primarily of outer shelf to neritic shale, marl, and limestone, which are often interbedded with volcanic rocks. Because of low heat flow, poor reservoir rock quality, and a lack of trapping structures, fore-arc basins are generally unfavorable habitats for petroleum.

Inner-arc basins are formed behind active arcs and are superimposed on the oceanic plate margins. They occur in the same relative position as a back-arc basin but without a proximal adjoining craton. Thus, they do not have a quality source for prograding sedimentary wedges likely to provide reservoir potential. Those inner-arc basins which commonly contain thin and geochemically immature sedimentary sections are likely to have only marginal petroleum potential. Several of the basins classed as inner arc, however, do have relatively thick sections of sedimentary rocks (e.g., Bone, Gorontalo, and Halmahera basins), and the deeper parts of these basins may have been subjected to sufficiently high temperatures to generate petroleum. For the most part, these basins are located in fairly deep waters and have not as yet been drilled.

Back-arc basins are located on the cratonic side of the volcanic arc and are formed by the relative subsidence of cratonic plates behind active arcs, and thus, are superimposed on continental plate margins. They contain indigenous carbonate sediments or prograding wedges of clastic sediments from the adjoining craton interbedded with abundant amounts of organic material. High geothermal gradients are common. Tectonic activity promotes good structural development. Prolific petroleum discoveries have been made in Indonesian back-arc basins, and good potential remains for future discoveries.

Median basins are small basins of irregular profile that are formed in the "median zone" between a subduction zone and the basins of the craton (Klemme, 1980). These basins commonly contain clastic sediments, the later cycles of which may be massive delta complexes. Interbedded shales provide both source and cap rock for the sandstone reservoirs, and the heat flow is sufficient to mature the source shales. Prolific petroleum discoveries have been made in Indonesian median basins, and good potential for future discoveries remains.

Downwarp basins occur on the continental margins and open into small ocean basins. They are asymmetric in profile and contain good potential source and reservoir rocks and high geothermal gradients.

The 28 Tertiary basins of Indonesia are classified as follows (see figure 1 for location):

Fore-arc: North Ceram, Sumatra fore-arc, Java fore-arc, Lombok, and Savu basins

Inner-arc: Bone, Flores, Bali, South Banda, Weber, North Banda, Gorontalo, Celebes, and Halmahera basins

Back-arc: North Sumatra, Central Sumatra, South Sumatra, Northwest Java, East Java, Salawati, and Waropen basins

Median: Kutei, Tarakan, Melawi, Barito, and South Makassar basins

Downwarp: Natuna and Arafura basins

PETROLEUM GEOLOGY

In Indonesia, six general types of geological environments or processes have been recognized as being favorable plays for petroleum exporation (Soeparjadi and others, 1975). These are transgressive clastic sequences, regressive clastic sequences, deltas, carbonate platforms, pinnacle reefs, and fractured igneous and volcanic rocks (fig. 3). These environments occur primarily in rocks of Tertiary age.

Transgressive clastic sequences contain coarse-grained, quartz-rich sandstones that were deposited by processes associated with a relative rise in sea level. These sand wedges, deposited in fluvial and nearshore environments and in deepwater environments by turbidity currents, generally require a nearby quartz-rich provenance for good reservoir development. When overlain by a seal of marine shales, with older nonmarine or time-equivalent marine shales as source rocks, and folded into large anticlines, multiple-pay transgressive reservoirs provide excellent habitats for petroleum and indeed are responsible for most of Indonesia's crude oil. Transgressive clastic reservoirs are common in back-arc basins having high geothermal gradients, which likely contributed to a more efficient generation of petroleum from the local source rocks. The high geothermal gradients presumably are associated with the generally high tectonic activity of the Indonesian area.

The oil produced from this environment ("typical Sumatran crude") is characteristically of medium gravity, with a paraffin base (waxy), and has a moderate to high pour point, a low sulfur content, and a relatively low gas to oil ratio (Soeparjadi and others, 1975).

Regressive clastic sequences are medium- to fine-grained, quartz-rich deposits that result from processes associated with a relative fall in sea level. The wedge-shaped sandstones are deposited in nearshore to open marine environments. Shoreline oscillation accompanying tectonic subsidence commonly results in multiple-pay sands; structural traps act as primary reservoirs for the petroleum. Much of the oil found in regressive clastic reservoirs is paraffin based, medium to high gravity, and has a low to moderate pour point, a low sulfur content, and a low gas to oil ratio. Some of the reservoirs, however, contain an overlying cap of asphalt base and low to medium gravity oil, having a slightly higher sulfur content, that has resulted from the biodegradation of the oil (Soeparjadi and others, 1975).

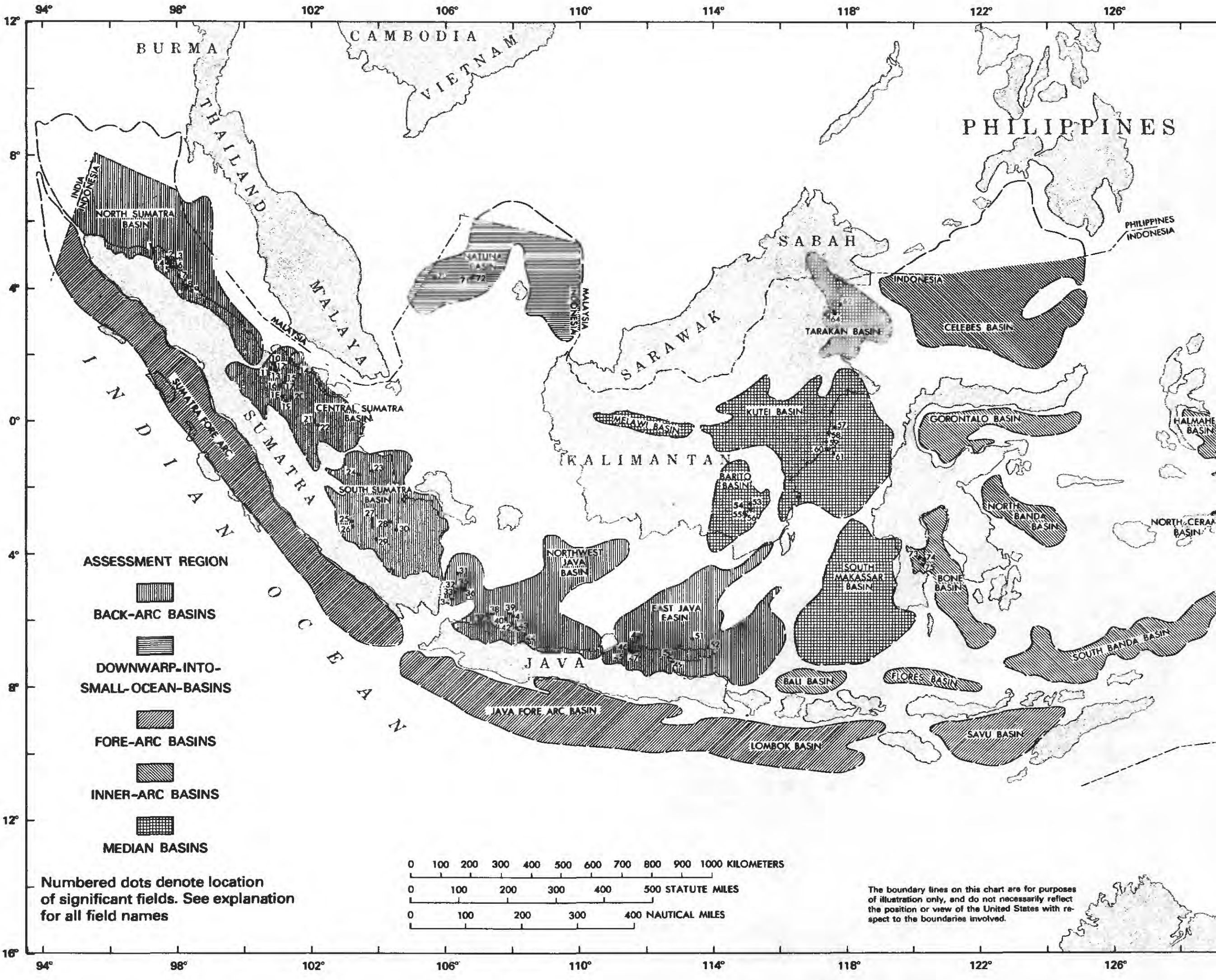
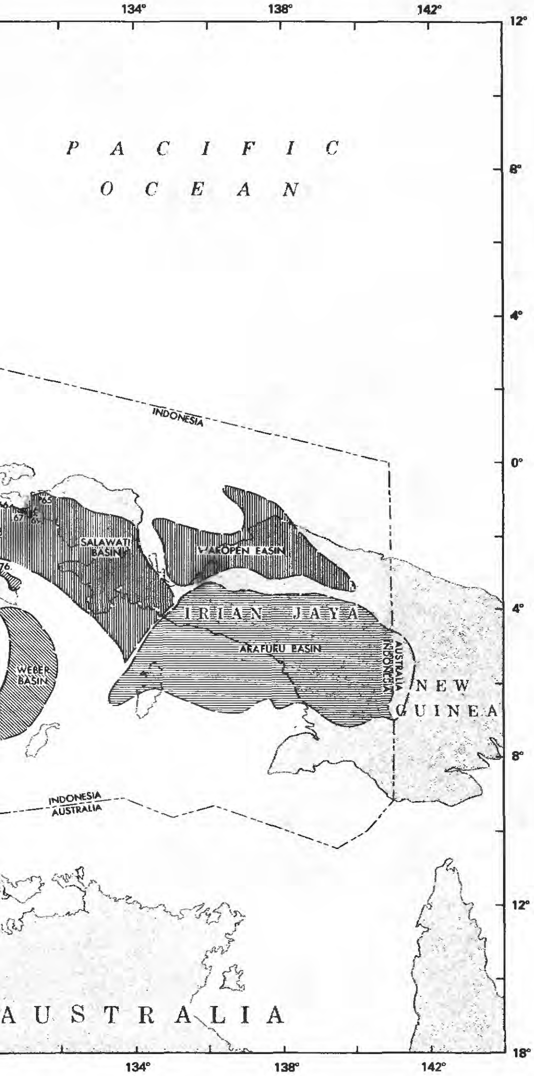


FIGURE 1.— Map of sedimentary basins and major oil and gas fields of the Indonesian assessment region.



EXPLANATION

NORTH SUMATRA BASIN FIELDS
1 Arun
2 Djulu Rajeu
3 Perkal
4 Guedongdong
5 Alur Tjimon
6 Tualong
7 Rantau
8 Telaga Said
9 Darat

CENTRAL SUMATRA BASIN FIELDS
10 Bangko
11 Balam
12 Sintong
13 Menggala
14 Pentani
15 Duri
16 Pematang
17 Bekasap
18 Petapahan
19 Kotabatak
20 Minas
21 Pulai
22 Sago

SOUTH SUMATRA BASIN FIELDS
23 Tempino
24 Bedjubang
25 Djirakt
26 Benakat
27 Talang Akar Pendopo
28 Abab
29 Limau
30 Djimar

NORTHWEST JAVA BASIN FIELDS
31 Krisna
32 Cinta
33 Kitty
34 Selatan
35 Rama
36 Nora
37 MX
38 MX
39 Arjuna Fields
40 Arjuna Fields
41 Arjuna Fields
42 Arjuna Fields
43 Arjuna Fields
44 Jatibarang

EAST JAVA BASIN FIELDS
45 Semanggi
46 Nglobo
47 Ledok
48 Kawengan
49 Kruka
50 Poleng
51 JS Well
52 JS Well

BARITO BASIN FIELDS
53 Kambitin
54 Tandjung
55 Tanta
56 Warukin South

KUTEI BASIN FIELDS
57 Attaka
58 Badak
59 Sanga Sanga
60 Handil
61 Bekapi

TARAKAN BASIN FIELDS
62 Bunyu
63 Mengatal
64 Pamusian

SALAWATI BASIN FIELDS
65 Klamono
66 Salawati
67 Kasim
68 Jaya
69 Walio

NATUNA BASIN FIELDS
70 Terubuk
71 East Udang
72 Udang

BONE BASIN FIELDS
73 Kampung Baru
74 Bonge
75 Walanga

NORTH CERAM BASIN FIELDS
76 Bula

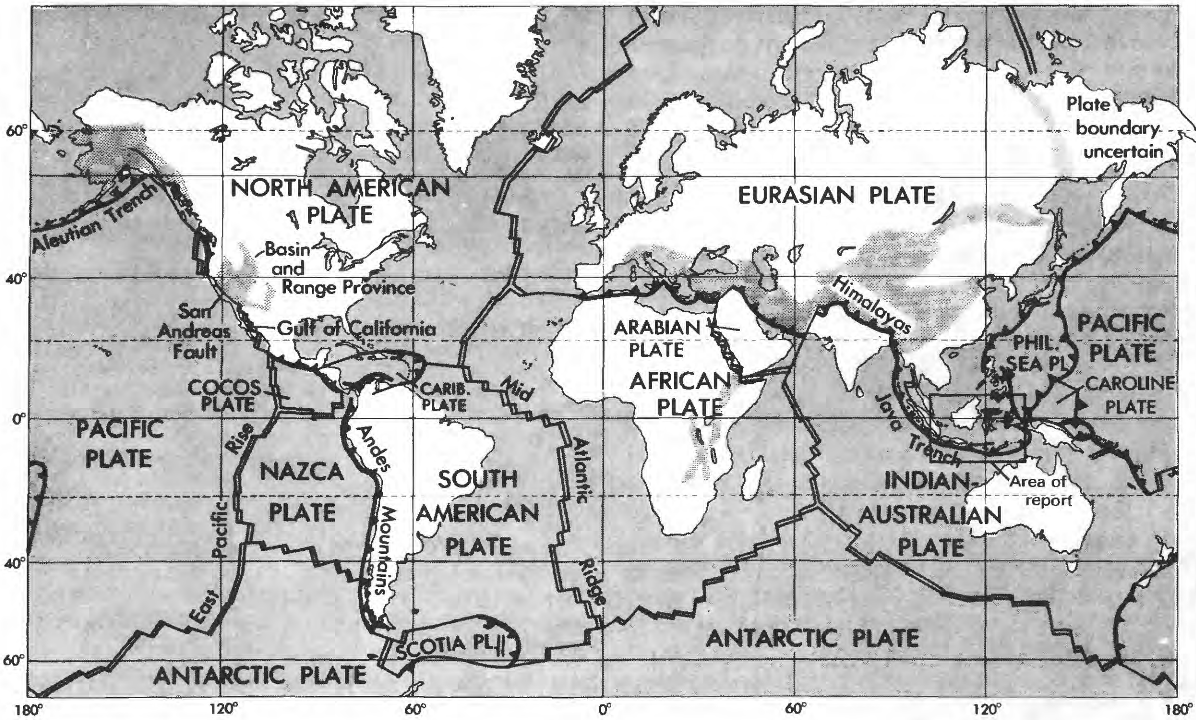


FIGURE 2.—**Lithospheric plates of the world showing boundaries that are presently active. Double line: zone of spreading, from which plates are moving apart. Line with barbs: zone of underthrusting (subduction) at which one plate is sliding beneath another; barbs on overriding plate. Single line: strike-slip fault, along which plates are sliding past one another. Stippled area: part of a continent, exclusive of that along a plate boundary, which is undergoing active extensional, compressional, or strike-slip faulting. Much simplified in complex areas.**

Deltas are vertically and laterally complicated, prograding sand-shale sequences concentrated in depocenters which, in this region, developed in response to the tectonic uplift of a river sediment supply area. These sequences comprise multiple-pay, medium- to thick-bedded quartz sandstones interbedded with shales that act as both cap rocks and source rocks. The petroleum occurs in both structural and stratigraphic traps; the rapid sedimentation, characteristic of a deltaic environment, attenuates the structural features and should enhance the potential for stratigraphic traps. Deltaic reservoirs often contain abundant methane gas reserves and high-gravity, low-sulfur crude oil. The gas may result from the large amounts of terrigenous organic matter in the source beds or it may result from increased temperatures due to deeper burial.

Carbonate platforms include a broad category of reefoid and bioclastic reservoirs that have developed upon a carbonate shelf. These reservoirs usually contain multiple-pay zones with vugular or intergranular porosity. Reservoir distribution is controlled by facies development and often modified by postdepositional tectonics. Seals are provided by shales or micritic limestones, while petroleum sources occur either within, laterally adjacent to, or underlying the porosity zones. Although carbonate platform porosity has become a primary exploration target in several of Indonesia's basins, each reservoir (reef, bank, or bioclastic zone) tends to be restricted in size. The oil discovered in this type of geologic environment is usually of medium gravity and paraffin based and has a low sulfur content and widely variable pour points and gas to oil ratios. Methane-rich gas is commonly found in these reservoirs, both associated with oil and as dry gas. (Soeparjadi and others, 1975).

Pinnacle reefs occur seaward of the carbonate platforms as isolated features. Their development is in response to a relative rise in sea level, which commonly results from active subsidence. Pinnacle reefs may also occur within the carbonate plat-

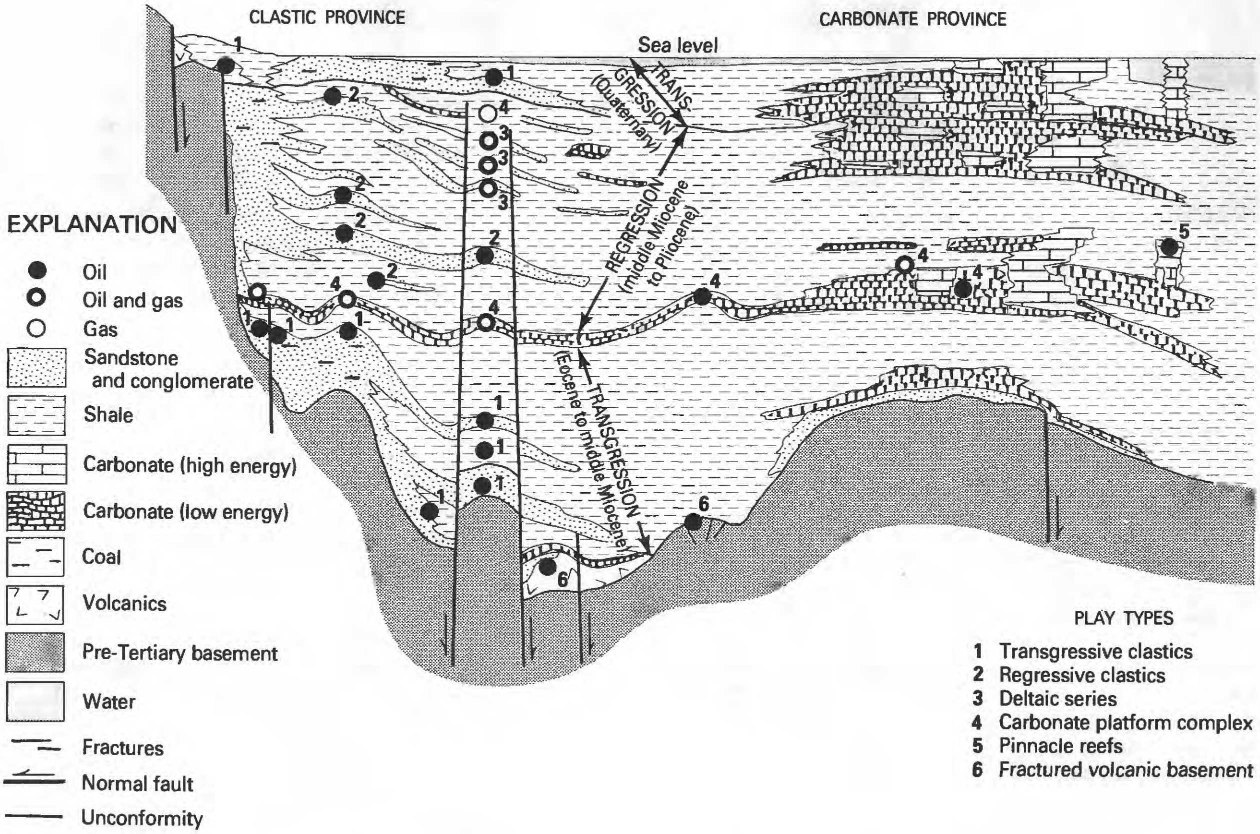


FIGURE 3.—Diagrammatic cross section of producing Tertiary plays in Indonesia.

form area in areas of local subsidence. The source rock is mainly adjacent organic-rich marine shales. Pinnacle reefs have excellent reservoir characteristics, high production rates, and thick productive sections, but reservoir area is commonly limiting. Subsequent tectonic activity has caused many pinnacle reefs to become uplifted, faulted, and tilted. The oil in pinnacle reefs is commonly paraffin based, of moderate to high gravity, and has a low pour point, a moderately low sulfur content, and a very low gas to oil ratio. Occasionally, shallow oil accumulations will have an asphalt base, a low gravity, and a higher sulfur content, probably as a result of the biodegradation of the original paraffinic crude (Soeparjadi and others, 1975).

Fractured igneous and volcanic reservoirs are capped by overlying finer clastics that also act as source rocks. They have been discovered by deep drilling on structural closures. The contained oil is low sulfur, paraffin based, moderate to high in gravity, and has a high pour point (Soeparjadi and others, 1975).

SIGNIFICANT PETROLEUM BASINS

The following discussion highlights the petroleum characteristics and prospectivity of the more significant petroleum basins in Indonesia. Certain basic data relevant to these basins is summarized in table 1.

NORTH SUMATRA BASIN

The North Sumatra basin is a medium-sized back-arc basin that produces from Miocene and Pliocene regressive clastic and carbonate platform-type reservoirs. The onshore portion of the basin is geologically well known from surveys and drilling. The first oil was produced in 1885. The Rantau field, discovered in 1929, is the dominant oil field of the basin. Although well into decline, it still produces almost half of the basin's oil and contains over half of the basin's oil reserves. A number of other fields that were discovered before 1940 are also in decline or have been abandoned. These fields were shallow structural features that

TABLE 1.—*Summary of petroleum information for Indonesia*

[Data source, Riva (1982)]

Basin Date of first discovery Plays	Annual production bbl oil/d (10^6ft^3 gas/d)	Cumulative production 10^6 bbl oil (10^6ft^3 gas)	Estimated reserves[1] 10^6 bbl oil (10^{12}ft^3 gas)	Largest Field % Annual prod. % Cumul. prod. % Reserves	Prospects (short-term production projection)[1]
North Sumatra 1885 Regressive clastic rocks Carbonate platforms	19,400 (600)	381	134 (13.7)	Rantau (1929) 48% 57% 51%	Oil production decline; gas production increase; small new fields expected onshore and offshore; moderate prospects.
Central Sumatra 1939 Transgressive clastic rocks	779,840	4,567	4,437	Minas (1944) 43% 53% 36%	Oil production decline; relatively small new fields expected; moderate prospects.
South Sumatra 1896 Transgressive clastic rocks Regressive clastic rocks Carbonate platforms	32,000	1,494	190	Talang Akar- Pendopo (1922) 2% 24% 4%	Oil production decline; small new fields expected; moderate prospects.
Northwest Java 1969 Transgressive clastic rocks Regressive clastic rocks Carbonate platforms Pinnacle reefs Fractured igneous rocks	225,506 (58.7)	498 (21.4)	1,432	Jatibarang (1969) 8% 11% 14%	Oil production increase; good prospects, especially offshore.
East Java 1888 Transgressive clastic rocks Regressive clastic rocks Carbonate platforms	561	165	4	Kawengan (1894) 51% of cumulative production	Oil production decline; most discoveries expected offshore; moderate prospects.
Kutei 1897 Regressive clastic rocks Carbonate platforms	359,653 (530)	920 (442)	1,100 (7)	Handil (1974) 46% 22% 54%	Oil production stable; gas production increasing; good prospects, especially offshore.
Barito 1937 Transgressive clastic rocks Regressive clastic rocks Carbonate platforms Fractured igneous rocks	5,121	112	30	Tandjung (1937) 100% 94% 100%	Oil production decline; poor prospects.
Tarakan 1900 Regressive clastic rocks Deltas	14,000	260	82	Pamusian (1905) 28% 72% reserves, ?	Oil production decline; prospects moderate onshore and offshore.
Salawati 1936 Carbonate platforms Pinnacle reefs	73,765	187	497	Walio (1973) 60% 38% 67%	Oil production stable; prospects moderate onshore and offshore.

TABLE 1.—*Summary of petroleum information for Indonesia—Continued*

Basin Date of first discovery Plays	Annual production bbl oil/d (10^6ft^3 gas/d)	Cumulative production 10^6 bbl oil (10^9ft^3 gas)	Estimated reserves[1] 10^6 bbl oil (10^{12}ft^3 gas)	Largest Field % Annual prod. % Cumul. prod. % Reserves	Prospects (short-term production projection)[1]
Waropen Little exploration thus far Transgressive clastic rocks Carbonate platforms					Prospects moderate.
Arafura Little exploration thus far Carbonate platforms					Prospects moderate.
North Ceram (Bula) 1897 Regressive clastic rocks Carbonate platforms	927	13	5	Bula (1897) 100% 99% 100%	Oil production decline; prospects poor.
Bone 1975 3 shut-in gas discoveries					Prospects poor to moderate.
Natuna 1974 Deltas (?) Pinnacle reefs	26,000	6	200	Udang (1974) 100% 100% 100%	Oil production increase; oil and gas prospects good.
Remaining basins					Oil prospects poor to moderate.

[1]Estimates by J. P. Riva, Jr., this paper.

were discovered by surface geologic mapping. Their reservoirs are upper Miocene Keutapang and, less commonly, Pliocene Seurula Formations. A major gas field, Arun, was discovered in the basin in 1971. The gas reservoir, middle Miocene Arun reef limestone, is deeper than the previously discovered oil reservoirs. This is the largest natural gas field in Asia.

In the 1960's and 1970's, exploration moved offshore and to the deeper portions of the basin where several discoveries have been made on the basis of gravity and seismic information. With many of the oil fields in decline, a continued decline in oil production from the North Sumatra basin is expected. However, exploration continues, particularly offshore, with moderate prospects for discovery. Gas production is expected to increase with continued development of the Arun field. Prospects for gas discoveries appear slightly better than for oil discoveries.

The North Sumatra basin produces only about 2 percent of Indonesia's oil and contains about 1 percent of the country's reserves. However, the basin contributes about half of Indonesia's marketed gas production and contains half of the nation's estimated gas reserves.

CENTRAL SUMATRA BASIN

The Central Sumatra basin is a small but very prolific back-arc basin that is well known geologically from outcrops and subsurface information. Its high density of wells and clustering of oil fields indicate an advanced stage of exploration maturity. The sedimentary area of the basin appears to be restricted to onshore. Relatively little geological work has been done offshore, which, apparently because of a rapidly thinning sedimentary section, offers poor petroleum prospects (Hamilton, 1979).

The oil fields are almost all anticlinal structures that were discovered by seismic surveys. Some of the larger shallow structures, including the giant and dominant Minas field, were discovered early in the exploration cycle on the basis of surface geologic mapping and shallow-core drilling. Reservoirs are in transgressive clastics of the Sihapas Group and the Telisa Formation of early and middle Miocene age. The major producing geologic unit is the Sihapas Group, which contains fairly massive, fine- to coarse-grained sandstones interbedded with shales. The transgressive deposit contains reworked older sediments and clastics derived from emergent areas. The interbedded marine shales have acted as both source and cap rock for the oil accumulations. The oil maturation process was aided by the generally high heat flow in the basin, and thus, a considerable amount of oil was generated from deposits of relatively small volume and moderate age at generally shallow depths.

The first oil discovery in the Central Sumatra basin was made in 1939, but then exploration was interrupted by World War II. The Minas field was actually discovered during the war by Japanese occupational forces drilling a site that had been selected previously and prepared by an international oil company. The Minas field is the largest known field in Southeast Asia and is Indonesia's greatest subsurface asset. The name "Minas crude" has become the term in world oil markets for waxy, low-sulfur crude oil. Minas production began at an initial rate of 15,000 barrels per day and increased steadily until it reached a rate of 400,000 barrels per day in late 1969. It has since declined to about 335,000 barrels per day. Peripheral water injection was initiated in early 1970 to arrest excessive pressure declines. Injection averages about 300,000 barrels of water per day into some 28 wells on the southwestern and western flanks of the field.

Minas accounts for about 43 percent of Central Sumatra basin oil production and contains 36 percent of the basin's estimated oil reserves. The Central Sumatra basin provides half of Indonesia's oil production; thus, Minas accounts for over 20 percent of the nation's oil production.

The basin may be dominated by Minas, but it also contains three other giant fields (Bangko, Bekasap, and Duri) and two possible giants (Pematang and Pentani). However, production from all six of these major fields is in decline. There are plans to steam flood Duri in an attempt to increase its production. About half the Indonesian oil reserves are in Central Sumatra basin fields.

With the major fields in decline, Central Sumatra basin oil production may continue to decline in spite of a number of new but smaller fields being put into production. The Beruk-Zamrud group of fields has substantial potential but will not rival the basin's six declining major fields in total ultimate production. The prospects of additional discoveries are moderate. Because exploration is in a mature stage, any new fields discovered should be expected to be smaller than the major fields found in the past.

SOUTH SUMATRA BASIN

The South Sumatra basin is a moderately sized back-arc basin that has a depositional history similar to that of the Central Sumatra basin. It is not, however, nearly as prolific in petroleum occurrence. Exploration in the basin began early with the discovery of at least two fields before 1900. The earliest discoveries were in shallow, regressive upper Miocene and Pliocene sandstones (lower and middle Palembang Formation). The larger fields, however, were found later in lower Miocene transgressive clastics (Talang Akar and Telisa Formations). There is also some production from carbonate platform rocks (Batu Radja Formation).

The Talang Akar Pendopo field is the dominant field in the basin, accounting for about one-quarter of the oil thus far discovered. However, this field was discovered in 1922 and is now well into decline, producing only about 2 percent of the basin's oil. Most of the fields in the South Sumatra basin produce oil and are in a state of advanced decline, with many already having been abandoned. The basin accounts for about 2 percent of Indonesian oil production and contains about 2 percent of the nation's estimated oil reserves. South Sumatra basin oil production is expected to continue to decline. Because of the maturity of exploration, the basin is considered to have only moderate prospects for additional discoveries of small fields.

NORTHWEST JAVA BASIN

The Northwest Java basin is a moderately sized back-arc basin that lies mostly offshore and includes the Sunda, Arjuna, and Jatibarang subbasins. A variety of petroleum plays occurs in the basin. These include Oligocene and Miocene transgressive and regressive clastic rocks, carbonate platforms, and pinnacle reefs. Perhaps the most unusual reservoir rock, however, is the Jatibarang, a fractured, volcanic sandy tuff of Eocene and Oligocene age. Fractures control the porosity of these reservoirs.

Successful petroleum exploration in the Northwest Java basin dates from the late 1960's, so the fields are relatively few and relatively young. Since they are mostly offshore, they had to await the development of the proper technology and favorable economic conditions before they could be exploited. The exception is the Jatibarang field, the largest yet found in the basin (containing 14 percent of the basin's reserves). There are a number of large offshore fields under production (Arjuna, Cinta, Rama, Selatan, and Kitty) and several new fields currently being developed. Thus, oil production from the Northwest Java basin will increase. At the present time, the basin produces about 14 percent of the nation's oil and contains about 15 percent of its total estimated oil reserves. A small amount of natural gas is also produced. The prospects of additional significant petroleum discoveries are good, especially offshore.

EAST JAVA BASIN

The East Java basin is of moderate size for an Indonesian back-arc basin, but it is not one of the region's better petroleum producers. The oil fields occur in two groups, one in the western portion of the basin and the other in the east, near Madura Island. Exploration in the basin began in the 1880's, and over half of the oil produced has come from the Kawengan field. It was discovered in 1894 and is now about depleted. Many of the older onshore fields have been abandoned, and a productive offshore field (Poleng) has been shut in to conserve associated gas. Current oil production (less than 1 percent of Indonesia's total) comes mainly from a few onshore fields, which are far past their prime. East Java basin oil reserves are also less than 1 percent of the nation's total.

The recent offshore exploration in the basin has taken place in the eastern portion near Madura Island. In this area, the carbonate platform complex is the preferred target, but the transgressive and regressive clastics may also yield discoveries. These three plays have proven productive in the older fields of the basin. Outside of any new discoveries, the East Java basin appears to be in the final stages of decline. The most prospective area is offshore from Madura Island, but even there prospects for commercial petroleum discovery are only moderate. Thus, the basin's current decline in oil production is expected to continue.

SALAWATI BASIN

The Salawati basin is geologically in a position similar to a back-arc basin, but, owing possibly to dislocations along the major Sarong fault zone to the north, no zone of active volcanism lies between the subduction zone and the basin. Conditions of high to normal heat flow characteristic of back-arc basins are, however, reported (Hayes, 1978). The basin is located west of the Vogelkop portion of Irian Jaya. Tertiary deposition in this region was characterized by a Late Cretaceous–Eocene transgression, an Oligocene regression, an early middle Miocene transgression, and a late Miocene regression. During the middle Miocene, the region was inundated and downwarped to form the Salawati basin (Pulunggono, 1976).

Beginning in the Miocene, basinal limestones interbedded with calcareous basinal shales were deposited. The shales are rich in organic material and may be the source rocks for much of the oil found in the basin. As the basin filled with sediments, shallower water depths allowed platform carbonates to form. The shallow-water environment provided favorable conditions for the growth of reef masses. When the region again subsided, some of the reefs were able to keep pace with the deepening waters and grew vertically upward, eventually reaching heights in excess of 500 m. These pinnacle reefs are middle and late Miocene in age. The off-reef areas were filled with a basinal shale, which provided excellent side and top seals to entrap the petroleum now found in some of the reefs (Vincelette and Soeparjadi, 1976).

The reef masses that contain the oil fields in the Salawati basin exhibit a wide variation in size and shape. The Walio reef, which contains a possible giant oil field, is about 6 by 20 km. The Walio field dominates Salawati basin oil production, some 60 percent of oil production coming from this field. It also contains 67 percent of estimated Salawati basin oil reserves. The basin accounts for about 5 percent of total Indonesian oil production and about 5 percent of estimated reserves.

With the exception of Klamono, which was discovered in 1936 and is now in prolonged decline, the Salawati fields were found in the 1970's. Many of the newer fields, however, have also recently declined. Regional tilting and local uplift of the eastern reef-belt platform area have exposed it at the surface and have thus provided a large area for surface water influx, which creates a strong water drive in most of the reefs. This drive, plus exceptional porosities, results in very high production rates for individual wells. The significant declines and, in some cases, the abandonments of some Salawati fields indicate that high production rates may have caused excessively rapid depletion of fields, which is a common occurrence in reef-field production.

There have been a number of recent petroleum discoveries in the basin, some of which are offshore. The accumulations were all in reef reservoirs and, in some instances, were of gas and gas condensate. These discoveries may stabilize Salawati basin production, at least for a time. At the current stage of exploration, the prospects for additional discoveries are judged to be moderate for both the offshore and onshore portions of the basin.

WAROPEN BASIN

The Waropen basin is a large basin located on the northern coast of Irian Jaya. It is tectonically positioned landward of the subduction zone in the New Guinea trench, but the intervening volcanic zone required for unequivocal characterization as a back-arc basin is absent. Otherwise the basin appears similar geologically to a back-arc basin but has undergone relatively little geological and petroleum exploration, which might confirm its classification of oil and gas potential (Fletcher and Soeparjadi, 1977). The basin has a thick sequence of Tertiary sediments composed of fine clastics interbedded with platform limestones that were deposited at the same time as the Miocene reefs of the Salawati basin. Any reefal buildups, therefore, would be age equivalents to those in the Salawati basin and could prove excellent exploration targets (Fletcher and Soeparjadi, 1977). In the onshore portion of the basin, a thick wedge of coarse clastics, which prograded northward during late Miocene to Pleistocene time, contains an assemblage of prospective reservoir rocks. Trap possibilities include anticlinal features and the onlap of the thick Miocene section onto large basement highs (Fletcher and Soeparjadi, 1977). The limited drilling that has been done, however, has encountered poor source rocks. Thus, in spite of the presence of oil and gas seeps, prospects for large accumulations of petroleum in the Waropen basin are only moderate.

KUTEI BASIN

The Kutei basin in eastern Kalimantan is a relatively large median basin with a superimposed deltaic complex. The combination of basin types resulted in a tectonically structured delta, a complex in which structural development has concentrated the occurrence of petroleum, uncharacteristically, into a few large fields. The basin initially formed in early Tertiary time and contains mostly clastic sediments. The maximum thickness of late Miocene and younger sediments is associated with the Mahakam delta and is located mostly offshore; these strata include the extensive shallow marine-shelf sediments and deeper outer shelf and bathyal deposits. A middle Miocene tectonic event that uplifted central Kalimantan initiated the deposition of the massive Mahakam delta, which prograded eastward and reached its greatest extent during late Miocene and early Pliocene time; deltaic deposition has, in general, continued to the present time (Beddoes, Jr., 1980).

In the Kutei basin, petroleum has been produced from lower Tertiary regressive clastic rocks and the later Tertiary deltaic complex. These depositional environments result in multiple-pay zones of medium- to thick-bedded, quartz-rich sandstones, which contain both oil and gas. The intercalated shale beds are both source and cap rocks.

The Kutei basin contains two giant fields (Attaka and Handil) and a possible giant (Sanga Sanga). Exploration began onshore along the coast almost 100 years ago. Sanga Sanga was discovered early and is now well into decline. Offshore seismic exploration began in the 1960's with a number of discoveries being made, among which were Attaka and Handil.

The Kutei basin provides about 23 percent of Indonesia's oil production and contains a similar proportion of the country's reserves. Handil produces about 46 percent of this total, and Attaka adds an additional 28 percent. Handil contains about 54 percent of the basin's estimated oil reserves. Associated gas is collected from some

Kutei basin fields. Delta basins do not show commonly a petroleum concentration in a few giant fields. However, when developed over a median basin, the underlying structure may affect the normal delta structuring and thereby influence the concentration of oil accumulation into a few large fields (Klemme, 1980).

A number of recent petroleum discoveries, which should help maintain current production levels, have been made in the Kutei basin (Petroconsultants). Commercial gas production should increase as gas reserves are further developed; the geology of a delta commonly is favorable for natural gas. The prospects for additional discoveries are good, especially offshore where exploration is relatively immature.

TARAKAN BASIN

The Tarakan basin is a median basin located to the north of the Kutei basin, which it resembles in sedimentary history. In the middle Miocene, the uplifting of Kalimantan initiated the deposition of thick, delta complexes in the Tarakan basin. One of these deltas is represented by the Meliat Formation, which was formed by the deltaic sedimentation of the ancestral Sesiap River. The progradation continued into Pliocene and Pleistocene time with the deposition of the deltaic deposits of the Tarakan Formation (Beddoes, Jr., 1980).

In the Tarakan basin, oil has been produced from regressive clastics and deltaic deposits. Exploration began early, with the discovery of some fields in 1900. The older fields are generally in decline and some have been abandoned. The Pamusian field, discovered in 1905, produces nearly one-third of Tarakan basin oil. The basin is, however, a very minor producer, accounting for about 1 percent of Indonesia's oil from about 1 percent of the country's oil reserves.

Recent exploration has included deeper drilling, and several discoveries have been made. The deeper finds have been mostly gas (Petroconsultants). Tarakan oil production is expected to decline. Overall, prospects for additional discoveries are moderate, and, in view of the relatively thick offshore sedimentary section, offshore prospects are somewhat more favorable than onshore prospects (Hamilton, 1979).

BARITO BASIN

The Barito basin, located to the south of the Kutei basin, is also a median basin but lacks the late Tertiary deltaic event described for the eastern Kalimantan basins previously discussed. In the Barito basin, oil has been produced from fractured pre-Tertiary volcanics and extrusive igneous rocks, transgressive Eocene sandstones, regressive Miocene sandstones, and from Miocene reef limestones. Exploratory drilling in the basin began in 1937. The Tandjung field, discovered during the first year of exploration, has completely dominated Barito basin production. This field has declined by 88 percent since 1964 and will continue to decline. The field currently produces all of Barito basin oil and contains all of the basin's estimated reserves; this amounts to less than 1 percent of total Indonesian oil production and oil reserves. Past exploration results suggest that the prospects for additional discoveries are poor.

NATUNA BASIN

The offshore Natuna basin, consisting of two parts divided by the Natuna arch, is an open downwarp basin located on the Sunda shield northwest of Kalimantan. The sediments in the West Natuna basin consist mostly of clastics deposited in shallow marine or lacustrine environments. Organic debris is abundant due to the proximity of land areas, and potential source rocks are common. Geothermal gradients range from normal to high. Successful wells appear to be related to the higher geothermal gradients. The Gabus Formation, considered to be of Oligocene age, is the oldest generally recognized Tertiary sedimentary unit. Thought to be deltaic in origin, it is the primary exploration objective in the Natuna basin. The structure of the basin includes strike-slip faults, thrust faults, and uplifts, all of which are thought to have influenced oil accumulation (DuBois, 1980). The Udang field, discovered in 1974, dominates Natuna basin petroleum production and reserves. Commercial production began from this field, which is beneath about 100 m of water, in April 1979. Although other discoveries of oil and gas have been made in the Natuna basin, Udang currently accounts for all of the basin's production and estimated reserves, each of which respectively composes about 2 percent of Indonesia's totals. Oil production is expected to increase with the further development of the Udang field and the probable development of some of the other newly discovered accumulations. Prospects for additional petroleum discoveries are good.

In the eastern part of the basin, a very large gas discovery recently has been reported (greater than 100 trillion cubic feet of gas) but with a very high proportion of carbon dioxide (possibly 70 to 80 percent) in the gas, which would result in economic problems in recovery (Aalund, 1981). The play appears to be related to carbonate reef development on the eastern edge of the Natuna arch platform. Additional reef development surely is present, but the carbon dioxide problem likely will remain, owing to the conditions of high heat flow in the area.

ARAFURA BASIN

The Arafura basin, which extends into the offshore region, is a closed downwarp basin on southern Irian Jaya. The basin is thought to contain carbonate rocks interbedded with shales as potential source rocks. Requisite structure and maturation of organic source material may be lacking, but Hayes (1978) does report conditions of high heat flow, favorable for maturation, in the southwest corner of the basin, and structuring associated with the impinging Banda arc may occur in the same area. There has been little exploration thus far in the Arafura basin. Prospects for petroleum discoveries are considered moderate.

NORTH CERAM (BULA) BASIN

The North Ceram basin is a fore-arc basin that stretches along the northern coast of the island of Ceram. Sedimentation began in the basin in early Pliocene and continued until Pleistocene time. Mainly, deepwater muds and silts were deposited, but sand and carbonate facies also occur. Pleistocene tectonic movement resulted in emergence and the deposition of regressive clastics (Crostella, 1977).

The Pliocene and Pleistocene sequence unconformably overlies beds thought to be of Triassic age. The oil has accumulated in shallow upper Tertiary sediments but may have been derived from the underlying Triassic beds, which are locally shaly with a petroliferous character; the low geothermal gradients in the region also suggest that the oil may not have been generated in the shallow, upper Tertiary sequence.

The North Ceram basin is very small and relatively shallow and contains three very shallow oil fields that were discovered by drilling-oil seeps. Two of the fields were extremely small and were abandoned by 1930. The third field, Bula, discovered in 1897, has accounted for almost all of North Ceram basin production. Currently Bula accounts for less than 1 percent of Indonesian oil production and reserves. In spite of a few recent exploration holes, North Ceram basin oil production is expected to continue its decline, and prospects for additional commercial petroleum discoveries are poor.

BONE BASIN

The Bone basin is an inner-arc basin that lies mostly offshore between the south and southeast arms of Sulawesi. The basin is fairly small and relatively young, with most of its sediments being of late Miocene age or younger. It is also a region of low geothermal gradients. Nonetheless, there have been three recent shallow gas discoveries onshore on the south arm of Sulawesi on the flank of the Bone basin. The discoveries are in anticlinal traps containing Miocene limestone reservoirs. The wells have been shut in for further development. The sediments in the central portion of the Bone basin reach 5 km in thickness. Thus, in spite of the low geothermal gradients and young sediments, it is possible that oil has matured in the basin. However, much of the basin lies beneath over 2,000 m of water, and in the near future, drilling can be attempted only around the basin margins. Current prospects for commercial petroleum discoveries in the basin are poor to moderate.

RESOURCE ASSESSMENT

INTRODUCTION

The location of the Indonesian Tertiary basins assessment region is shown in figure 1. Estimates by the U.S. Geological Survey of oil and gas resources in this region are given in table 2 and figures 4 and 5. Supplementary data of interest in analyzing these estimates are presented in table 3.

ASSESSMENT OF COMMODITIES

Assuming a continuation of present economic and technologic conditions, Dolton and others

TABLE 2.—*Assessment of undiscovered conventionally recoverable petroleum resources in Indonesia*

[Resource assessment by USGS as of June 25, 1981. F_n denotes the *n*th fractile; the probability that more than the amount F_n is present in *n* percent. Data source, Masters and Riva, 1981]

	Crude oil in billions of barrels			Natural gas in trillions of cubic feet		
	Low	High	Mean	Low	High	Mean
	F_{95}	F_5		F_{95}	F_5	
Estimate	5	35	16	13	94	42

TABLE 3.—*Supplementary and comparative data relative to the petroleum resource assessment of Indonesia*

[The term "identified reserves" follows usage of Dolton and others, 1981; a + denotes quantity positive but estimate not available; one billion barrels of oil equivalent (BBOE) = 6,000 $ft^3 \times 10^9$ of natural gas. Data source, Masters and Riva, 1981]

	Crude oil in billions of barrels	Natural gas in trillions of cubic feet
Cumulative production to Jan. 1, 1980	8.7	0.6
Identified reserves to Jan. 1, 1980		
Demonstrated	8.0	20.7
Inferred	+	+
Total	8.0	20.7
Original recoverable resources (ultimate)		
Cumulative	8.7	0.6
Identified reserves	8.0	20.7
Undiscovered resources (mean)	16.0	42.0
Total	32.7	63.3
		BBOE = 10.6
Total oil and gas	43.3 BBOE	

(1981) include in the assessment of undiscovered conventionally recoverable petroleum resources those resources that can be extracted by using conventional methods. The assessment does not include inferred resources that may yet be found in new pay zones or extensions of existing fields. Also excluded from the assessment, even if present, are unconventional resources such as heavy-oil deposits, tar deposits, and oil shales, as well as gas in low permeability (tight) reservoirs, gas occluded in coal, gas in geopressured reservoirs and brines, and natural gas hydrates.

COMMENTS ON ASSESSMENT

The potential petroleum basins of Indonesia can be divided into five types: fore arc, inner arc, back arc (foreland), median, and downwarp. The back-arc, median, and downwarp basins have significantly greater petroleum potential than do the fore-arc and inner-arc basins. The latter two basin types likely will yield only small discoveries, but isolated reefs might yield high flow rates; significant parts of these basins lie in water depths in excess of 1,000 m.

Although the back-arc basins are the most extensively explored, it is estimated that at least 60 percent of the undiscovered potential for oil lies in downwarp and median basins; in the case of gas, as much as 80 percent of the undiscovered potential is assigned to such basins. Since the assessment was made (June 25, 1981), there has been a report of a giant gas discovery in the Eastern Natuna basin; if this field exists, the estimate of undiscovered gas may require adjustment. The reported extremely high carbon dioxide content of

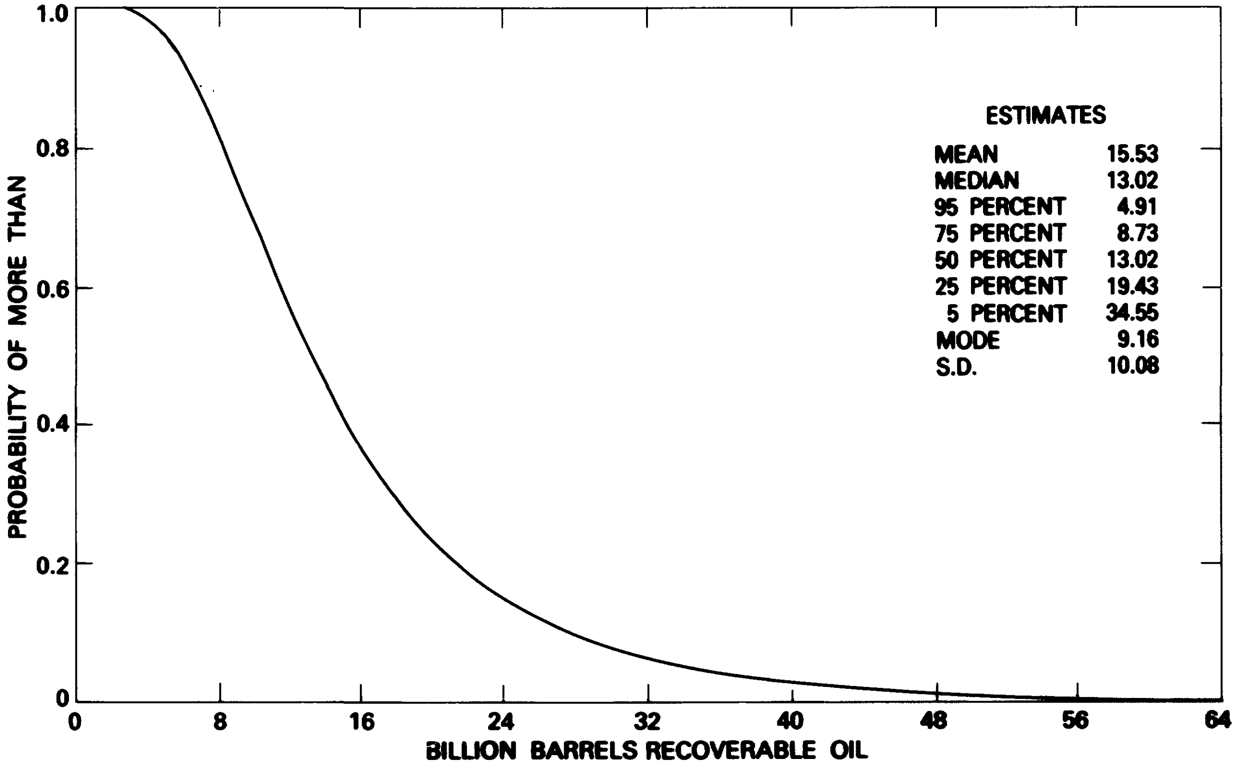


FIGURE 4.—Indonesian undiscovered recoverable oil as assessed June 25, 1981.

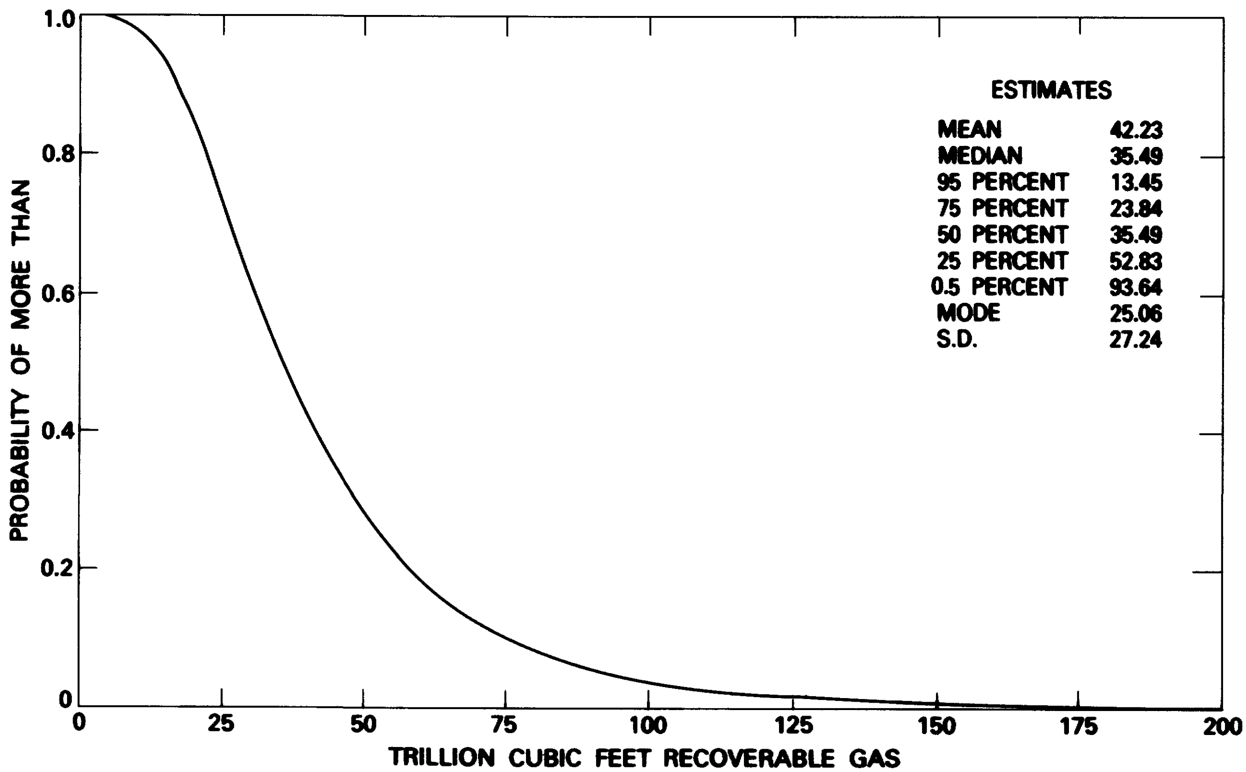


FIGURE 5.—Indonesian undiscovered recoverable total gas as assessed June 25, 1981.

the gas, however, may result in economic problems in recovery.

Of the basins actively being explored, the Kutei, Northwest Java, and Natuna hold the greatest potential. Owing to their size and geologic position, the Arafura and Waropen must be considered attractive frontier basins.

REFERENCES CITED

Aalund, L. R., 1981, Soaring refining capacity to spur oil development in Indonesia: Oil and Gas Journal, v. 79, no. 50, p. 99–102.

Beddoes, L. R., Jr., 1980, Hydrocarbon plays in Tertiary basins of Southeast Asia: Offshore Southeast Asia Conference, SEAPEX Session, p. 3.

Bee, Ooi Jin, 1980, Offshore oil in Indonesia: Ocean Management, June, p. 51–73.

Cowan, D., and Parker, M. A., 1982, Exploration/development pace picking up speed in Indonesia: Oil and Gas Journal, v. 80, no. 31, p. 47–51.

Crostella, A., 1977, Geosynclines and plate tectonics in Banda Arcs, Eastern Indonesia: American Association of Petroleum Geologists Bulletin, v. 61, no. 12, p. 2063–2081.

Dolton, G. L., Carlson, K. H., Charpentier, R. R., Coury, A. B., Crovelli, R. A., Frezon, S. E., Khan, A. S., Lister, J. H., McMullin, R. H., Pike, R. S., Powers, R. B., Scott, E. W., and Varnes, K. L., 1981, Estimates of undiscovered recoverable conventional resources of oil and gas in the United States, U.S. Geological Survey Circular 860, 87 p.

DuBois, E. P., Sr., 1980, Synoptic review of some hydrocarbon and potential hydrocarbon bearing basins of Southeast Asia: United National Development Programme (UNDP), Technical Support of Regional Offshore Prospecting in East Asia (RAS/80/003), ROPEA–R.093, p. 23–25.

Fletcher, G. L., and Soeparjadi, R. A., 1977, The land of plenty: Indonesia's 28 Tertiary basins hold 99 percent of production: Oil and Gas Journal, v. 75, no. 1, p. 150–156.

Hamilton, Warren, 1979, Tectonics of the Indonesian region: U.S. Geological Survey Professional Paper 1078, 345 p., 1 plate.

Hayes, D. E., 1978, A geophysical atlas of the east and southeast Asian seas: Geological Society of America, Map and Chart Series MC–25.

Klemme, H. D., 1980, Petroleum basins—classifications and characteristics: Journal of Petroleum Geology, v. 3, no. 2, p. 187–207.

Masters, C. D., and Riva, J. P., 1981, Assessment of conventionally recoverable petroleum resources of Indonesia: U.S. Geological Survey Open-File Report 81-1142. p. 3, 6.

Petroconsultants S. A., Geneva, Switzerland.

Pulunggono, A., 1976, Recent knowledge of hydrocarbon potentials in sedimentary basins of Indonesia: Circum-Pacific Energy and Mineral Resources, Memoir 25, American Association of Petroleum Geologists, Tulsa, Oklahoma, p. 248.

Riva, J. P., Jr., 1982, Petroleum prospects of Indonesia: Oil and Gas Journal, v. 80, no. 10, p. 314.

Schuppli, H. M., 1946, Geology of oil basins of East Indian Archipelago: American Association of Petroleum Geologists Bulletin, v. 30, no. 1, p. 2–4.

Soeparjadi, R. A., Noyoan, G. A. S., Beddoes, L. R., Jr., and James, W. V., 1975, Exploration play concepts in Indonesia: Ninth World Petroleum Congress, Proceedings, v. 3, Applied Science Publishers Ltd., London, p. 51–64.

Vincelette, R. R., and Soeparjadi, R. A., 1976, Oil-bearing reefs in Salawati basin of Irian Jaya, Indonesia, American Association of Petroleum Geologists Bulletin, v. 60, no. 9, p. 1448–1462.

☆U.S. GOVERNMENT PRINTING OFFICE:1983-421-614/590