Frontiers of world exploration

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THERE are about 600 sedimentary basins in the world, excluding the deep oceans, which appear to have at least some petroleum potential.

Of these some 160 are now productive. Another 240 or so have been explored to some degree and have varying degrees of continuing interest. This leaves some 200 basins which can be truly called frontier areas. The importance of these frontiers as a potential source of new hydrocarbon reserves is substantial.

Roughly 133 billion metric tons (960 billion bbl) of oil have been found in the free world to date. The decline in world oil discoveries since the early 1950's is highly weighted by the decline in the Middle East finds; not offset by the increasing discovery rate in the rest of the free world.

The frontier areas will contribute a large portion of the discovery volumes beneath any future projection, perhaps one-third or more. It is impossible, of course, to quantify this fraction in absolute terms. But industry's exploration experience worldwide is now mature enough to permit at least qualitative judgment as to future expectations since most, if not all, frontiers have producing geologic analogs or look-alikes.

Fig. 1 lists the basin types to be discussed. The assignment of the world's basins to the various categories listed is somewhat arbitrary and simplistic, and not everyone would necessarily classify all the basins in the same way. Many basins have a long and complicated history which modifies the basic basin form. The dominant basin-forming mechanism was used as the basis for subdivisions. Regions of plate divergence include divergent margin basins, most deltas and fans, and rifts and grabens. Regions of plate convergence include strike-slip, back-arc and fore-arc basins. Also noted are cratonic sags and foreland basins which are confined to continental plates.

Divergent margin basins are the most important frontiers. Fig. 2 shows the distribution of most of the world's divergent margin basins including transform margins. Many of these basins, particularly around Africa and Australia, have been explored to some degree in recent years, with many disappointments as well as some success. Exploration is in the initial stages along the east coast of North and South America, and the high Arctic basins have received little or no exploration to date.

Fig. 3 highlights the main characteristics common to most divergent margin basins. In total, some 3.6 billion metric tons (26 billion bbl) of oil and gas equivalent have been found in these basins. On average, pool sizes tend to be modest. Of fields discovered most are less than 28 to 42 million metric tons (200 to 300 million bbl).

Fig. 4 is a generalized cross section

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Fig. 1

Basin types

	REGIONS OF:
DIVERGENT MARGIN (INCLUDING TRANSFORM)	DIVERGENCE
DELTAS AND FANS	
RIFTS AND GRABENS	
STRIKE-SLIP (INCLUDING TRANSFORM)	CONVERGENCE
BACK ARC	
FORE ARC	
CRATONIC SAG	EXTENSION
FORELAND	COMPRESSION

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Fig. 2

Divergent margins

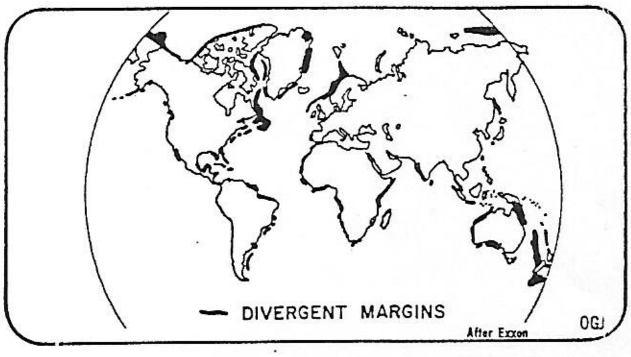

Fig. 3

Divergent margin basins

PRE- AND POST-SEPARATION STAGES

PLAYS IN EACH

PRE-SEPARATION STAGE
INITIAL RIFT - NON-MARINE, LACUSTRINE, SOURCE, RESERVOIR
MORE MARINE - CLASTICS, EVAPORITES, CARBONATES

POST-SEPARATION STAGE - OPEN MARINE
DELTAIC CLASTICS, CARBONATES

TRAPS -
STRUCTURAL - HORSTS, DRAPE, TILTED FAULT BLOCKS, DIAPIRS
STRATIGRAPHIC - LENTICULAR SANDS, SUB-UNCONFORMITY, REEFS

RISKS - SOURCE AND RESERVOIR ROCKS, EXCESSIVE TILT, MATURATION

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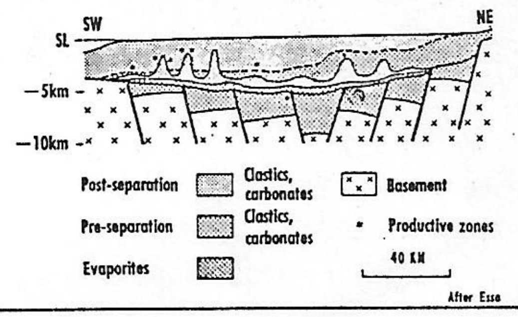
Fig. 4

Gabon



tiary, and are also complexly structured. These basins formed in Late Cretaceous and Tertiary time cover over a pre-Middle Cretaceous subduction zone. The main targets in the Outer Banks are the structural highs where the Paleogene and Cretaceous constitute the principal targets. Initial exploration results in the frontiers of the Outer Banks have not been particularly encouraging; the intervening basins remain to be explored, however.

• Back-arc basins. These basins form by tension behind the magmatic arc. Shallow water facies provide the reservoirs. Normal faults, which were active during basin formation as well as later strike-slip movements provide structuring in these basins. Also in the proper paleoclimate, carbonate reefs may have developed. Major risk is probably maturation as most of these basins are young and relatively shallow.

Discoveries to date amount to about 3.8 billion metric tons (27 billion bbl) of oil or gas equivalent. Pool sizes tend to be moderate—in the 14-40 million-metric ton range. Giants are rare, but they do exist, at Minas in Sumatra, with about 590 million metric tons.

Fig. 16 is a cross section through the island of Sumatra showing the occurrence of oil in a back-arc position.

• Fore-arc basins. These basins form on the oceanic side and overlie the converging plate boundary between the outer high and the volcanic arc. Fill consists of deepwater sediments within the outer high arc and prograding volcanic-rich sediments off the volcanic arc. So far, discoveries in fore-arc basins are fairly negligible and pools are small.

• Cratonic and related foreland basins. These are located primarily in the interior of present continental plates and they have for the most part been pretty well explored. Fig. 17 shows the distribution of the major cratonic and foreland basins. Cratonic basin plays are related to shallow water sediments, relatively gentle structures, and stratigraphic traps. Major risks are trapping, primarily due to lack of structure, and maturation. Foreland basins form on cratons in front of orogenic belts. Shallow-water sediments, old structures rejuvenated by orogenic events, and compressional structures define the plays in foreland basins. Major risk is probably the timing of trap formation.

These basins, of course, contributed a very large portion of the free world's reserves, in the order of 168 billion metric tons (1,200 billion bbl) of oil and gas equivalent. They also have yielded a substantial number of giant oil and gas fields.

Productive basins in the cratonic and foreland regime would include, among others, the Persian Gulf, the Touggourt and Ghadames basins of North Africa, the Oriente basin in South America, and several Mid-Continent basins in the U.S.A., and the Alberta and Williston basins of Canada.

There are very few true frontiers of this type basin. Those that do remain are located in the central portion of Africa, South America, and Australia. Most of these have had at least one round of exploratory effort and do not, as of now, seem particularly promising for big oil and gas. However, the potential for significant stratigraphic accumulation is always present in these basins whether they are in a mature stage of exploration or not. The recent West Pembina play in the mature area of West Central Alberta is a good example of this. Stratigraphic frontiers constitute the major plays of the cratonic and foreland basins.

The Sverdrup basin in the Canadian Arctic Islands deserves passing comment. Fig. 18 is a cross section of this basin. Although some divergence resulting in complex rifting took place in the early Paleozoic, this basin appears to be basically a cratonic sag. Since the basin is structured and has accumulated an alternating sequence of fine and coarse clastics, as well as carbonates, it has a reasonable chance of becoming a major hydrocarbon province.

Most of the frontier potential lies in continental margin basins of one kind or another. Obviously, all margin basins are not equal. Areas of divergence are the most important—rifts, margins, and deltas. Locally, convergent margin basins—strike-slip, back-arc, and fore-arc—will be significant, and the stratigraphic frontiers of the cratonic and foreland areas will be of continuing interest.

Because of harsh environments, many of the world's frontier basins will require technological innovation to enable them to produce. Because of the high costs associated with these frontiers, they will also require major reserves capable of sustained high producing rates to be economic.

Despite these constraints, the frontier basins have the potential to provide significant new reserves, and these areas will have a substantial impact.

END

OKLAHOMA

A REENTRY well in an old Oklahoma giant paid off with two zones producing.

Sohio Petroleum Co. went back into 1 Pease-C in NE NW NE 17-1n-2w, Eola-Robberson field, Garvin County. They tested oil and gas in the Hunton and Bromide. Dual completion was made first in the Bromide at 7,709-8,582 ft. Flow was 220 b/d and 616 Mcfd. Tubing pressure was 130 psi. Casing pressure was 1,110 psi. The Hunton zone was at 6,230-6,320 ft had 187 b/d and 1,220 Mcfd on 18/64-in. choke. The southern Oklahoma well was first completed back in 1955 in the McLish and the Bromide, both Ordovician zones, by Sohio.

Also in southern Oklahoma's Carter County, Gray Operating Co. pumped 104 b/d from the Viola Ordovician lime at 8,220-8,526 ft. The well is 1 Tadlock in C NW SE 26-5s-2w.

NEBRASKA

THE Cretaceous Niobrara play in the Denver basin continues to build up steam.

Hi Plains Petroleum and Exeter Drilling Northern have three more sites to drill in western Nebraska. One will drill in Deuel and two in Flah field, Cheyenne County. The 1 Carlson is in SE SE 11-14-44w with a 2,800-ft target. Location is 2 miles northwest of a discovery in SE NE 24-14n-44w. Voyageur Exploration Co.'s discovery flowed 225 Mcfd from Niobrara pay at 2,704-28 ft.

And, 17 miles northwest in Cheyenne County, Hi Plains et al. will drill 1 Wurtele in E½ NE 25-15n-47w. Target is 3,350 ft. The 1 Amsden is in NW SE 30-15n-46w. Goal is 3,400 ft. These wells are ½ mile northwest and ½ mile east of abandoned Flah field, a oil pool of 1966. This area is about 10 miles west of a discovery in NE SW 26-15n-45w drilled by Fremont Energy and Voyageur.

WYOMING

WYOMING's Am-Kirk field in Campbell County is still averaging good wells.

Phoenix Resources completed 32-1 Federal in NE SW 32-47n-70w. Flow was 638 b/d from the "B" zone of the Minnelusa at 10,154-64 ft. Location is on the northeast side of the field in the Powder River basin. Location is also 1½ miles northeast of the field's sole Minnelusa producer and 1 mile northeast of a Dakota oiler.

Fig. 15

California outer banks

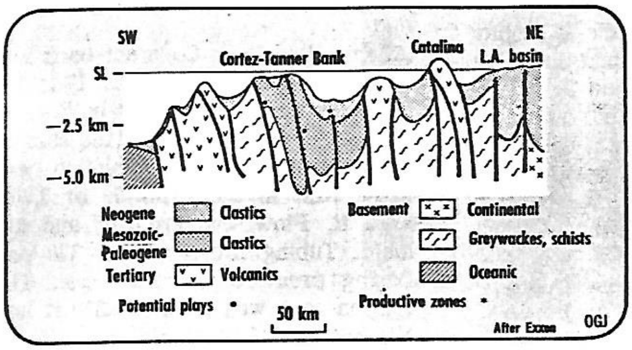


Fig. 16

Sumatra

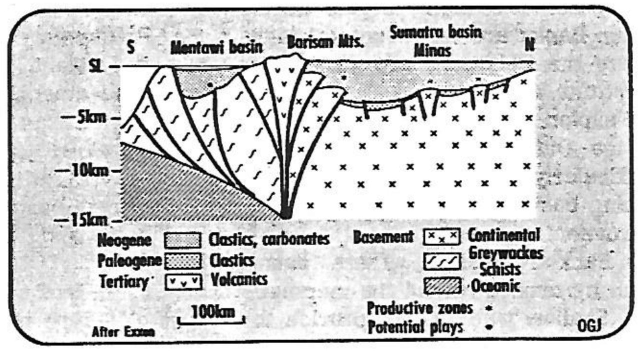


Fig. 17

Cratonic and foreland

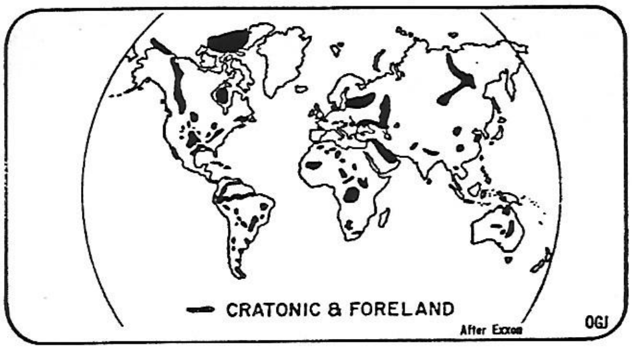
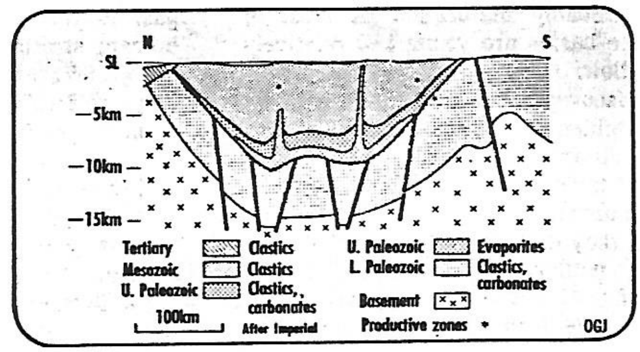


Fig. 18

Sverdrup basin



lion-bbl) range, or larger.

Fig. 11, the Suez graben, is a good example of a productive, relatively simple rift. The graben appears to have opened during the Miocene with a remnant of Cretaceous and older Nubian sandstones overlying basement. After opening, a complex of sandstone and interbedded organic rich shale was deposited, which in turn, is overlain by a thick evaporite sequence. Above the salt a fairly thin, mainly clastic, Pliocene-Recent section is present. Some Recent reef buildups also occur. Production is found on the upthrown side of fault blocks in both the Miocene sands and the underlying prerift Nubian sand. An excellent seal situation can occur with good reservoirs charged by the Miocene shales sealed both above and across faults by evaporites or the source shale itself.

Fig. 12, the Viking graben in the North Sea, is a good example of a more complex rift. This is a situation in which strike-slip components are present in addition to a fairly straightforward elongated graben. The opening of the Viking graben appears to have begun in Late Jurassic to Mid-Lower Cretaceous. Pre-rift sediments range from Carboniferous to mid-Jurassic, although older sediments may occur in isolated areas. In the Viking graben itself, productive reservoirs occur in Triassic to Upper Jurassic sandstones. Farther south, Cretaceous and Eocene carbonates and sands representing post-rift fill are also productive. Rich organic shales deposited during the opening of the graben, in this case Upper Jurassic Malm shales, provide the source rock. Traps are formed in high fault blocks, tilted away from the central graben. The source shales also provide an adequate seal.

Fig. 13 is a frontier cross section along the Atlantic margin west of Ireland across the Rockall Plateau into the Porcupine basin. A possible play might exist in shallow-water Permian to Jurassic sediments. A play possibility could be shallow water, subunconformity Jurassic reservoir sands overlain by Cretaceous shales, a situation somewhat analogous to the Viking graben. A possible play could be Tertiary deepwater turbidite sands, perhaps analogous to the Frigg accumulation in the Viking graben.

Convergent margin basins. Fig. 14 shows the distribution of most of the world's major convergent margin basins.

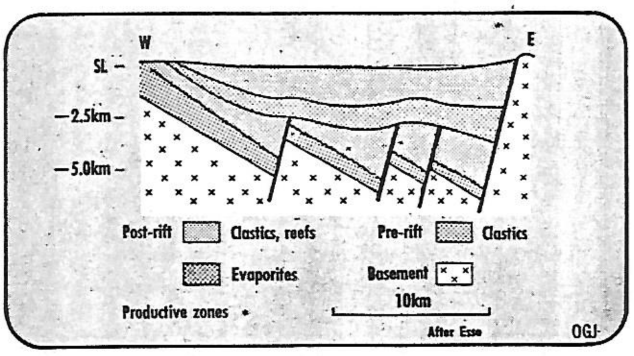
- Strike-slip basins. Plays in strike-slip basins are related to strike-slip faults providing anticlinal closures. Reservoir rocks are mainly deepwater sediments, but their shallow-water equivalents also occur. Because of intense faulting, the major risk is leakage. Reservoir quality may also be a problem.

Discoveries to date in strike-slip basins amount to about 18.5 billion metric tons (133 billion bbl) of oil or gas equivalent. Despite the generally mediocre quality of the reservoir sands these basins can be very prolific. The Los Angeles Basin is a prime example. Fields in excess of 30 million metric tons are common in strike-slip basins. Fig. 15 is a cross section which extends from the frontier basins of the Outer Banks of southern California, where exploration is just beginning, into the productive Los Angeles Basin. Major production in the basin is from Pliocene-Pleistocene deepwater sands. The richness of this basin is due entirely to the thickness of productive reservoirs. There are several hundreds of meters of reservoir sands throughout the productive section. Structures are wrench-associated anticlines created by strike-slip faults.

The frontier basins are indicated to have a relatively thin Upper Ter-

Fig. 12

Gulf of Suez



Viking graben

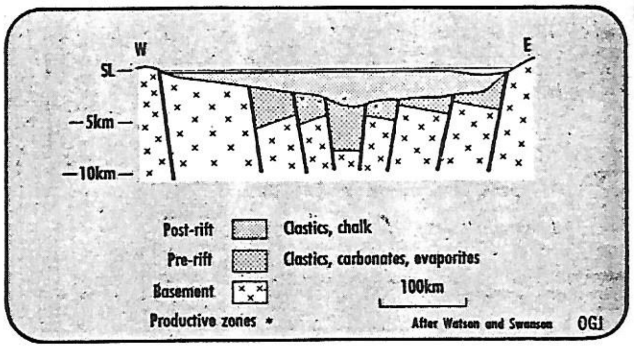


Fig. 13

NE Atlantic margin

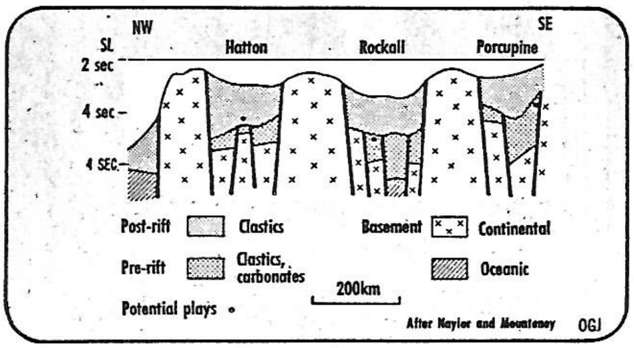
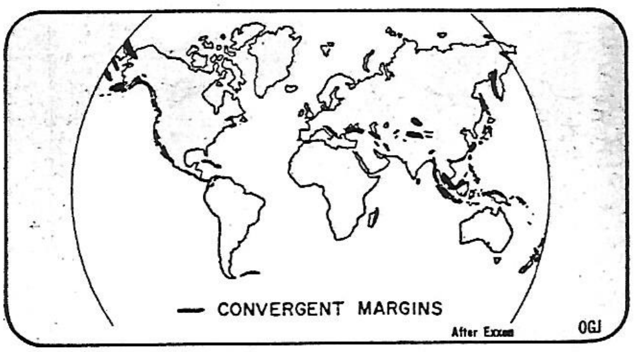


Fig. 14

Convergent margins



plays are discrete traps in lenticular sand lenses, rollover closures associated with down-to-basin faults, and possibly drape over high blocks in the lower most progradational units. The discovery of gas in several wells drilled on the Labrador shelf is encouraging.

Deltas and fans. The main risks in fans concern the presence and adequacy of reservoir and degree of structuring.

Fig. 7 shows the location of the principal deltas and fans of the world. Most of the world's deltas have received some exploration. The Mississippi and Niger deltas are the two with prolific production accounting for about 90% of the reserves found to date in deltaic areas. Fans are generally unexplored due to the water depths involved. About 15½ billion metric tons (112 billion bbl) of oil and equivalent gas have been found so far, all in deltas, where productive fields tend to be small-to-moderate in size. Giant fields in excess of 139 million metric tons (1 billion bbl) are rare.

The Niger delta is a good example of a productive deltaic basin (Fig. 8). Overlying the block faults of a divergent margin are relatively deepwater basinal shales of Late Cretaceous and Early Tertiary ages. This is in turn overlain by a sand-prone delta-front facies of Middle Tertiary age, which in turn is overlain by a relatively thin delta-plain facies. Principal traps are formed by rollover into down-to-basin growth faults and associated antithetic faults. The coincidence of source, sandstone reservoirs, and timely structures provide a multitude of productive reservoirs in over 140 fields found to date. Because of intense faulting, field reserves tend to be low. Oil columns on average are thin, with only a few fields with much better than average oil column thickness contributing the bulk of the reserves. Adequacy of seals is a critical parameter. In general, the same situation exists in much of the Mississippi and associated deltas of the Gulf Coast basin, the principal difference being the presence of an underlying Jurassic salt which contributes to additional diapirism.

Fig. 9 shows the Mackenzie Delta. This section illustrates the three major deltaic sequences, the underlying deepwater shales, the delta front sands, and overlying delta plain. Fault associated structures provide the main traps. However, stratigraphic traps in sand lenses may also be expected. Underlying the delta, fault blocks in the older divergent margin regime are capable of production as well.

Rift basins. Another type of basin is that formed when continental plates are stretched but do not separate.

These rift basins are shown on Fig. 10. Most rift basins are structurally complex and consist of a series of grabens and intervening horsts which often have strike-slip displacement as well. The main reservoirs are usually sandstones shed off the graben margins and high blocks. Principal traps are horst blocks, structures related to strike-slip movements, subunconformity prerift reservoirs on high blocks, discrete sands in the grabens, and reef and carbonate banks developed on high blocks.

The principal risk in exploring rifts or grabens is the presence of source rocks. Reservoir rocks and structures are almost always present. Many rift basins, although adequately structured, contain only coarse clastics and are barren. Another risk is the possibility of very high temperatures in the more deeply buried sediments.

To date, about 38 billion metric tons (275 billion bbl) of oil and equivalent gas have been found in rifts and grabens—some in giant fields in the 275 to 420 million metric tons (2-3-bil-

Fig. 5

Baltimore Canyon

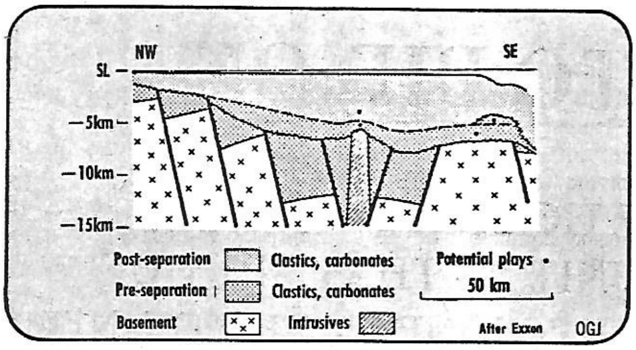


Fig. 6

Labrador Shelf

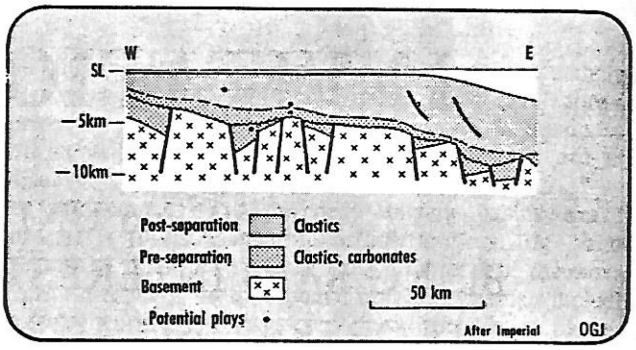


Fig. 7

Deltas and fans

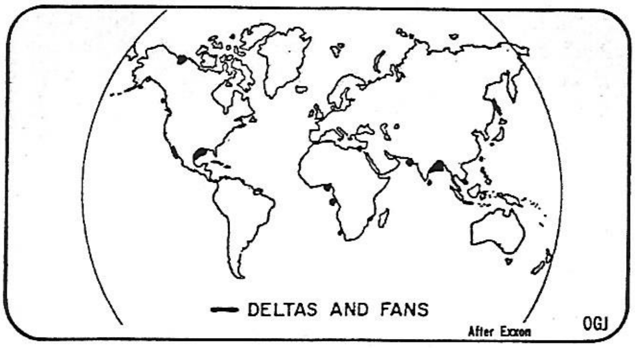


Fig. 8

Niger delta

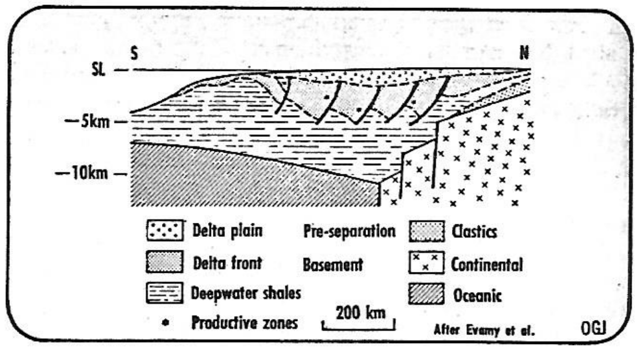


Fig. 9

Mackenzie delta

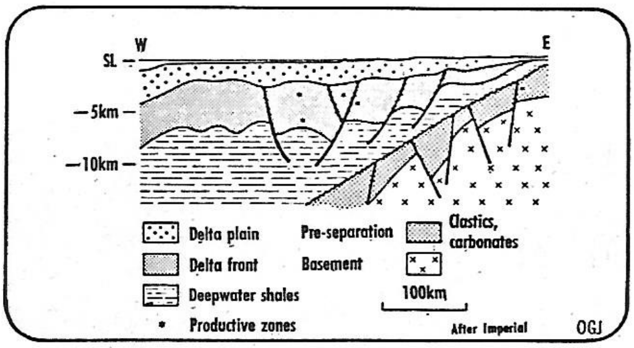
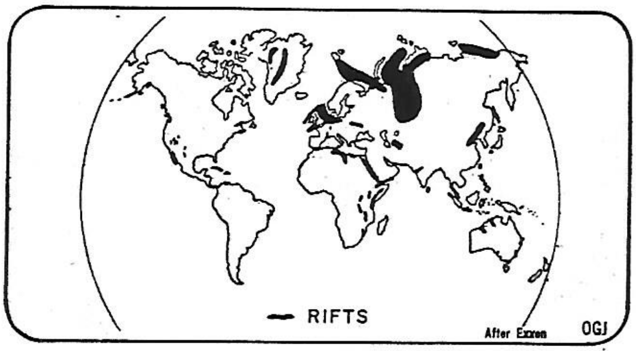


Fig. 10

Rifts



through the productive Gabon basin. This section illustrates the two evolutionary stages of basin development. Productive plays are associated with each. Source rocks are plentiful within the whole stratigraphic series. Clastics of the nonmarine initial rifting phase are productive in traps related to basement movement. Basal sands and carbonates of the overlying shallow marine sequences are productive where drape over underlying high blocks provides the principal trapping mechanism. Most of the production, however, occurs in sands and carbonates in the progradational wedge of the postseparation stage. Traps are related to various styles of salt tectonics such as diapirs, pillows, and turtle structures.

Fig. 5, the Baltimore Canyon area, shows another typical divergent margin basin. The preseparation stage is represented by the initial rifting during Triassic time, followed by a more marine sequence during Jurassic. The postseparation stage or open marine sedimentation occurred basically during Cretaceous and Tertiary. This section is complicated by the presence of magmatic intrusions which may provide additional structuring. Carbonate reefs are possible over the outer fault block high. Potential plays are similar to the other divergent margin basins.

Fig. 6 across the Labrador shelf is another example of a divergent margin basin. The preseparation stage is represented by the initial rift sediments of probable Lower Mesozoic age, followed by a presumably more marine Upper Cretaceous section. The postseparation stage is represented by a thick, prograding Tertiary section. Potential plays should be present in both stages. In the preseparation stage, the most likely plays are truncation of reservoirs by unconformity and drape over high blocks. In the postseparation stage, the most likely