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FRONTIERS OF WORLD EXPLORATION

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ABSTRACT

There are about 600 sedimentary basins in the world excluding the deep oceans. Of these some 160 are currently productive. Another 240 have been explored to some degree and have greater or less continuing interest. This leaves some 200 basins which can be truly called frontier areas. Most of the interest is in the 170 or so frontier basins located in the non-Communist world.

Most frontiers have producing geologic analogs. To better illustrate these analogs all basins, productive, non-productive, and frontier are divided into 5 basic types: 1. Divergent margins (including transform); 2. Deltas and fans; 3. Rifts and grabens; 4. Convergent margins (strike-slip, fore arc, and back arc); and 5. Cratons and forelands. Frontier examples of each are compared with appropriate producing areas.

In terms of numbers divergent margin basins are the most significant and have a number of productive analogs. Convergent margin basins have more variety and productive analogs, while common, are less well defined. Both complex and simple rifts and grabens, while fewer in number, appear to be significant. Stratigraphic frontiers characterize cratonic and foreland basins. Frontier deltas and fans are least well defined at this time.

The frontier basins, at present state of knowledge, have a high degree of risk. Categorically, not all will produce, even some of the most attractive. By and large the frontiers are located in harsh, high-cost settings: deepwater, polar, or otherwise remote. In addition to capital, sophisticated technology will be required to find and develop the frontier resources.

RESUME

Il y a environ 600 bassins sédimentaires dans le monde sans compter les océans profonds. 160 d'entre eux actuellement sont producteurs; 240 autres sont l'objet d'exploration à quelque degré et gardent un intérêt plus or moins grand. Cela laisse quelque 240 bassins qu'on peut vraiment appeler des zones frontières. Le plus grand intérêt concerne les 170 bassins frontières situés dans le monde non communiste.

La plupart des "frontières" ont des analogies géologiques. Pour mieux illustrer les analogies, on a divisé tous les bassins producteurs ou non frontières en 5 bassins-types: 1. de bordures divergentes (y compris les bassins de faille de transformation); 2. de deltas et d'éventails de pied de Talus; 3. de bassins d'ouverture et grabens; 4. de bordures convergentes (avec cisaillement, bassins en avant et en arrière d'arcs insulaires); 5. de cratons et avancées.

Les examples de bassins frontières de chaque catégorie sont à comparer avec les régions productives correspondantes. Les bassins de bordure divergente sont les plus nombreux et il y a beaucoup de bassins analogues productifs. Les bassins de bordure convergente sont plus variés et la comparaison avec des bassins productifs est plus délicate bien que banale. Les grabens et les bassins d'ouverture à la fois complexes et simples, bien que moins nombreux, paraissent significatifs. Les bassins frontières stratigraphiques caractérisent les cratons et bassins avancés; Les bassins frontières deltaiques ou d'éventail de pied de Talus sont encore mal connus.

Au stade actuel de connaissance, le risque d'exploration des bassins frontière est élevé. Sûrement, tous ne produiront pas, même parmi ceux qui paraissent les plus séduisants. Près ou loin, les bassins frontières se placent dans des endroits difficiles, a coût élevé; eaux profondes, régions polaires ou éloignées. En plus de l'argent le développement des ressources en pays frontières imposera une technologie sophistiquée.

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Introduction

The purpose of this paper is to discuss the principal controls on hydrocarbon occurrence within the frontier basins of the Free World. The subject is vast and diverse. Each frontier is a subject in its own right. Accordingly, this paper attempts to synthesize the principal controls on oil and gas occurrence in certain common basin types, well recognizing that any such synthesis is somewhat simplistic. This approach of necessity results in a generalized overview, rather than a specific basin-by-basin review.

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 currently 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. For the purposes of this paper, interest will be restricted to the 170 or so frontier basins located in the non-Communist world.

The importance of these frontiers as a potential source of new hydrocarbon reserves is substantial. To put this importance in perspective, it is appropriate to review the Free World's oil discovery history.

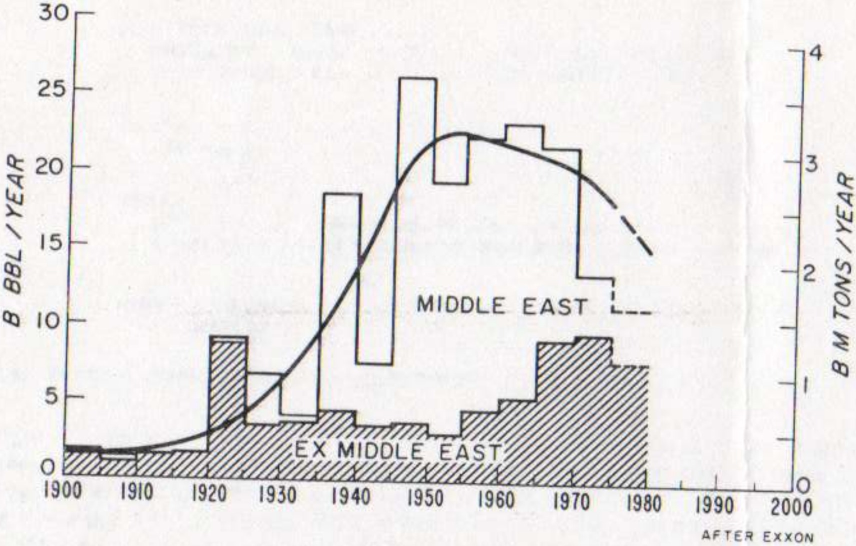

Fig. 1. Free world oil discovery history; annual rate averaged over 5 year periods.

Figure 1 illustrates the annual discovery of oil in the Free World averaged over 5-year periods. Shown are the roughly 133 billion metric tons (960 billion barrels) found to date. The Middle East discoveries are separated from the remainder of the Free World. The smooth curve depicts the Free World's discovery history as a typical discovery megacycle, asymmetric in shape with a steep buildup and gradual decline. It is obvious that discovery has been in decline for the last couple of decades. The decline in 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.

So much for the past. What does the future hold? One could speculate at great length as to the probable extrapolation of the finding rate curve. What is significant, however, is that the frontiers will contribute a sizable 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 sufficiently mature to permit at least qualitative judgement as to future expectations since most, if not all, frontiers have producing geologic analogs or look-alikes.

BASIN TYPES

Figure 2 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 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

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

Fig. 2. Generalized basin classification.

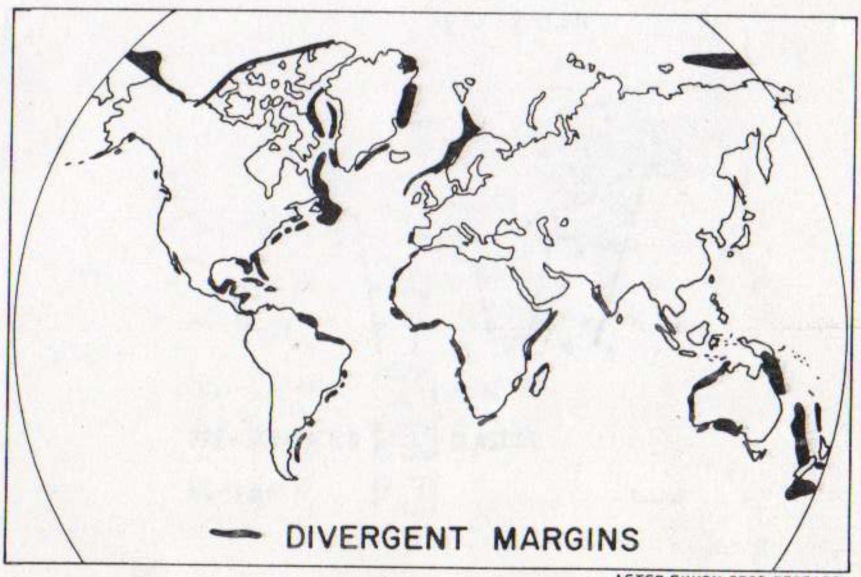

Fig. 3. Distribution of principal divergent margin basins.

the basis for subdivision. 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 Margins

In terms of numbers, divergent margin basins are the most important frontiers. Figure 3 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.

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

Fig. 4. Principal characteristics of divergent margin basins.

Figure 4 highlights the principal characteristics common to most divergent margin basins. Divergent margin basins, sometimes referred to as pull-apart basins, form with pure divergence with little or no strike-slip component. Development of the basin occurs in two stages — a pre-separation stage and a post-separation stage. Plays may occur in both stages. The pre-separation stage consists of an initial rift which is usually filled with non-marine to brackish sediments. These may contain both source and reservoir rocks. This sequence is often followed by a more marine clastic series and, given the proper paleoclimate, evaporites and carbonates. The post-separation stage contains deposits of open marine conditions. Deltaic sediments prograde over the underlying blocks and carbonate banks, and reefs may also occur overlying the high or more stable blocks. Structural traps are provided by horsts, draping over the horsts, tilted fault blocks, down-to-basin fault closures, and diapirs, either shale or evaporite. Stratigraphic traps may include lenticular sands, sub-unconformity truncation, or carbonate lenses and reefs. Major risks in the pre-separation stage include the absence of source rock in the initial non-marine rift sediments, and the absence of reservoirs in the overlying more marine sequence. In the post-separation stage the main risks are excessive tilt and lack of adequate burial.

In total, some 3.6 billion metric tons (26 billion barrels) of oil and gas equivalent have been discovered in these basins. On average, pool sizes tend to be modest. Of those fields discovered to date, most are less than 28 to 42 million metric tons (200 to 300 million barrels).

transform margin basins exhibit a somewhat different style. These basins develop with a strongly oblique separation, including strike-slip movements. Bounding faults are usually very steep and have a large throw. The facies generally changes rapidly from a shallow-shelf environment to a deepwater environment. Rapid facies changes and complicated lateral offsets should be common, making it difficult to explore in these basins. As of now, one would presume that transform margin basins are not particularly significant.

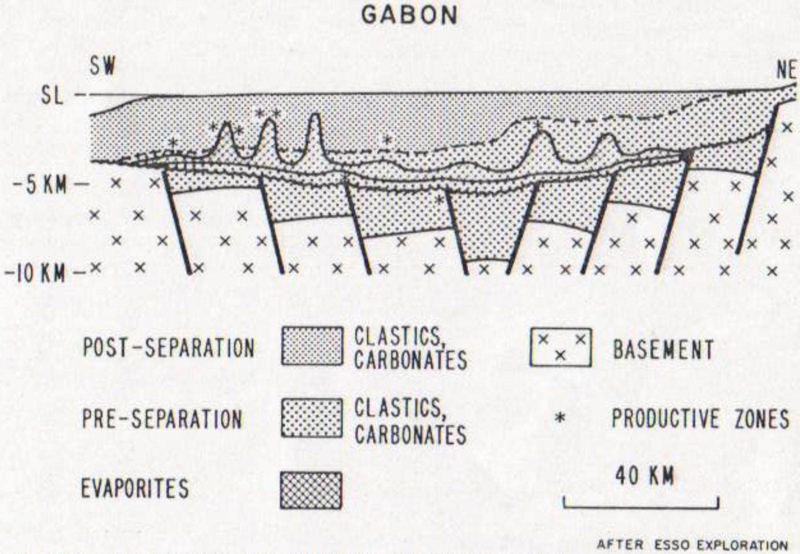

Fig. 5. Cross section of Gabon Coastal Basin (divergent margin).

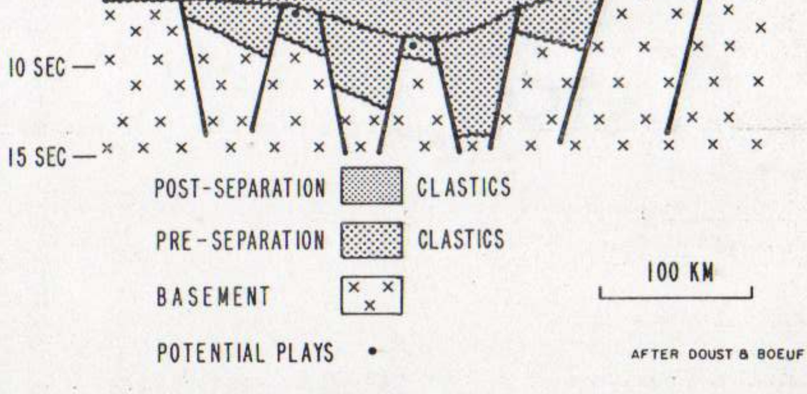

Fig. 6. Cross section of offshore South Australia (divergent margin), after Boeuf and Doust (1975).

Figure 5 is a generalized cross section 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 non-marine initial rifting phase are productive in traps related to basement movement. Basal sands and carbonates of the overlying shallow marine sequence are productive where drape over underlying high blocks provides the principal trapping mechanism. However, most of the production occurs in sands and carbonates in the progradational wedge of the post-separation stage. Traps are related to various styles of salt tectonics such as diapirs, pillows, and turtle structures.

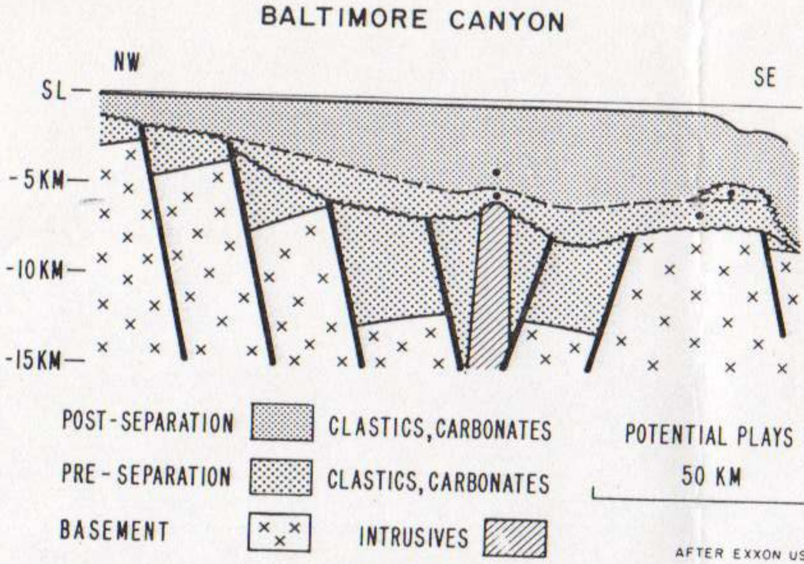

Fig. 7. Cross section of western Atlantic margin Baltimore Canyon area (divergent margin).

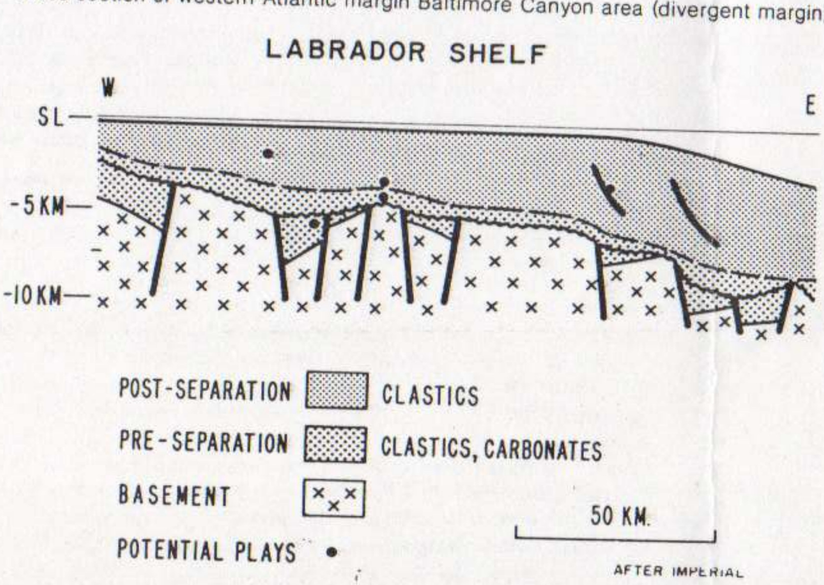

Fig. 8. Cross section of Eastern Canadian Shelf (divergent margin).

Figures 6, 7, and 8 illustrate a few of the non-producing frontier divergent margin basins. Figure 6 in the Bight of Australia shows the two stages of development mentioned earlier. Possible plays in the pre-separation stage would include sub-unconformity and fault traps in the initial rift sediments and lenticular sands and anticlinal traps over high blocks in the more marine sequence. Plays in the post-separation wedge would include lenticular sands or down-to-basin fault closures. Lack of burial diminishes the potential of this unit, however.

Figure 7, the U.S. Mid-Atlantic Baltimore Canyon area, also illustrates a typical divergent margin basin. The pre-separation stage is represented by the initial rifting during Triassic time, followed by a more marine sequence during Jurassic. The post-separation stage or open marine sedimentation occurred basically during the 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.

Figure 8 across the Labrador Shelf of eastern Canada is another example of a divergent margin basin. The pre-separation stage is represented by the initial rift sediments of probable Lower Mesozoic age, followed by a presumably more marine Upper Cretaceous section. The post-separation stage is represented by a thick, prograding Tertiary section. Potential plays should be present in both stages. In the pre-separation stage, the most likely plays are truncation of reservoirs by unconformity and drape over high blocks. In the post-separation stage, the most likely plays are discrete traps in lenticular sand lenses, rollover closures associated with down-to-basin faults and possibly drape over high blocks in the lowermost progradational units. The discovery of gas in several wells drilled on the Labrador Shelf is encouraging.

Deltas and Fans

These are a special category of divergent basins. Fans are thick depositional units forming in the pro-delta realm. They are built up by turbidites that reach the fan via channels. Fans can also be fed by submarine canyons to form thick turbidite deposits in deep water. The main risks in fans concern the presence and adequacy of reservoir and degree of structuring.

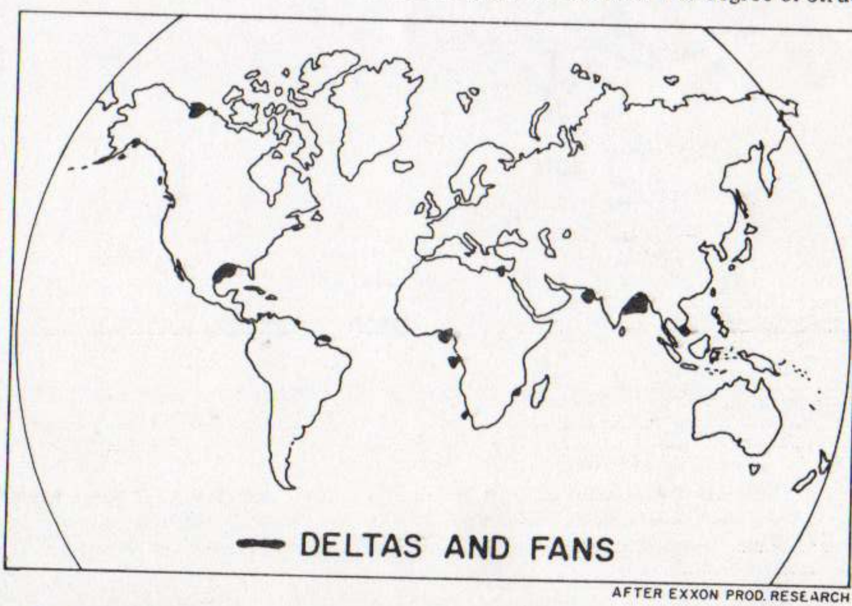

Fig. 9. Distribution of principal deltas and fans.

Figure 9 indicates the location of the principal deltas and fans as presently known. 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 discovered to date in the deltaic regime. Fans are generally unexplored because of the water depths involved.

DELTAS AND FANS

COMMON DIVERGENT MARGINS

INCLUDING TRANSFORM MARGINS

UNCOMMON OTHER MARGINS

CLASTICS PREDOMINATE

TRAPS - LENSES, DIAPIRS, ROLLOVER
ANTITHETIC FAULTS

RISKS - STRUCTURE, SEALS, GAS PRONE

Fig. 10. Principal characteristics of deltas and fans.

Figure 10 highlights the principal characteristics common to most deltas and fans. They are common along divergent margins, including transform margins, where large drainage systems are involved either present day or in earlier geologic time. They occur, but are much less common around other continental margin types.

Clastic sedimentation predominates throughout the deltaic sequence, generally grading upward from fine to coarse. The principal traps are either discrete sand lenses or reservoirs associated with detached structures, such as shale and/or salt diapirs and rollover into down-to-basin faults, and associated antithetic faults. Seals are provided by the interfingering of marine shale tongues into the coarse sequence. Good seals are required, or much of the potential may be lost through upward migration. Young deltas also have a tendency to be somewhat gas prone. Because of the complex nature of both the stratigraphy and structure, most deltas, if adequately structured, require a large number of wells to test and evaluate. The principal risks in exploring deltas are adequacy of structure and seals as well as a tendency for deltaic deposits to be gas prone. This latter risk is, of course, only a concern in very remote areas or harsh environments.

Approximately 15.5 billion metric tons (112 billion barrels) 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 (one billion barrels) are rare.

The Niger Delta is a good example of a productive deltaic basin. Figure 11 is a simplified cross section through the delta. 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.

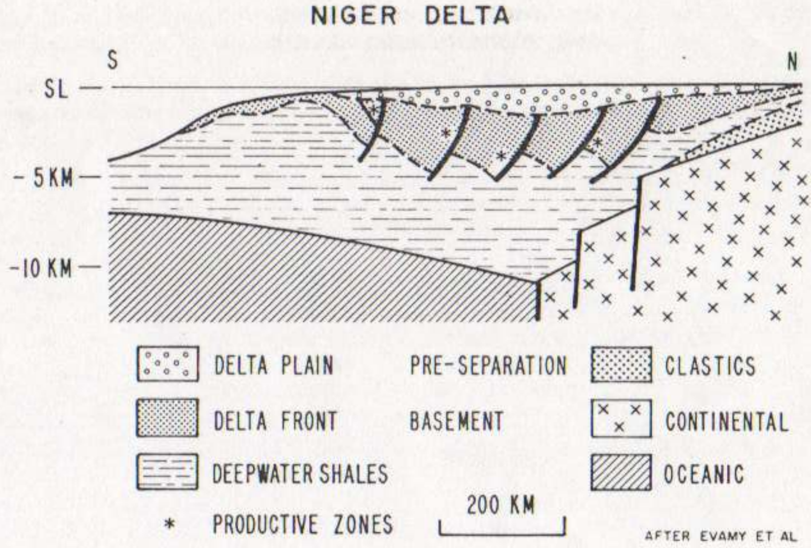

Fig. 11. Cross section of Niger Delta (deltas and fans); after Evamy *et al.* (1978).

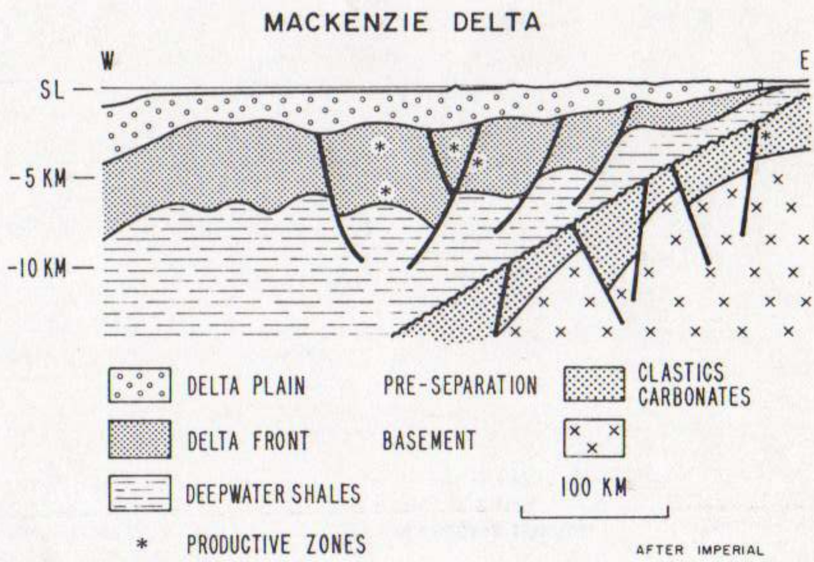

Fig. 12. Cross section of Mackenzie Delta, Canadian Arctic Beaufort Shelf (deltas and fans).

Figure 12 depicts another productive analog, namely 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 principal traps. However, stratigraphic traps in sand lenses may also be expected. Underlying the Mackenzie Delta, fault blocks in the older divergent margin regime are capable of production, as well.

The Amazon fan is perhaps a good example of fan deposition along a transform margin. This is illustrated somewhat schematically in Figure 13. The fan is largely unexplored due to the substantial water depths involved. Some gas has been discovered at the shelf edge. Both diapirism and growth faults are indicated on the section. Potential plays in the fan proper would most likely involve clastic reservoirs together with structural closures associated with down-to-basin growth faults and diapirs, as well as discrete sand lenses.

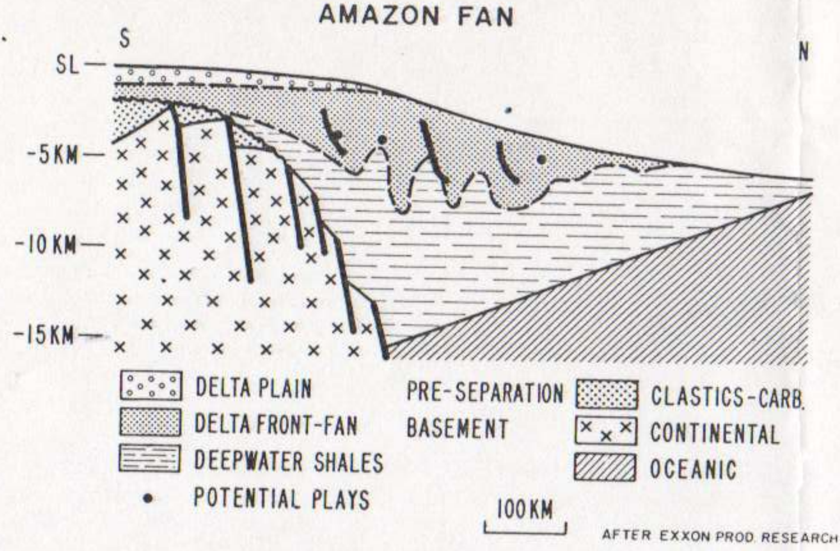

Fig. 13. Cross section of offshore Northeast Brazil (deltas and fans).

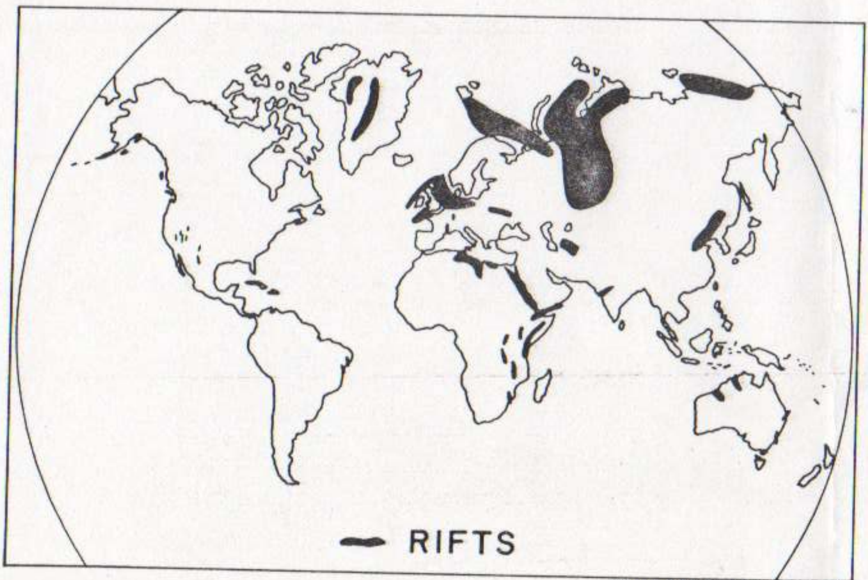

Fig. 14. Distribution of principal rifts and grabens.

Rifts and Grabens

Another type of basin is that formed when continental plates are stretched but do not separate. These basins are rather simplistically called rift and/or graben basins.

The principal rift basins in the world are shown on Figure 14. Most rift basins are structurally complex and consist of a series of grabens and intervening horsts which often have strike-slip displacement as well.

Figure 15 highlights the principal characteristics common to most rifts and grabens. The formation of rifts and grabens usually begins with broad uplift followed by downdrop of a block or blocks with intervening horsts. This initial uplift results in an unconformity between the pre-rift and post-rift sediments. Initial sediment fill is nearly always non-marine clastics with red beds common. Swamp and lake deposits which may provide good source rocks are often found as well. Subsequent fill may be marine; and in addition to sandstones and shales, carbonates and evaporites may be present. If the tectonics associated with the rift are sufficiently complex, fault blocks may be rotated, structures induced by strike-slip movements may occur, and unconformities may develop. These events can certainly complicate the geology but at the same time they can also improve the chances for hydrocarbon entrapment. A good seal, such as an evaporite section blanketing the basin, can also enhance the potential.

RIFTS AND GRABENS

ARCHING, DOWNDROP, HORSTS	COMPLEX TECTONICS MAY ENHANCE
UNCONFORMITY	SANDSTONE, PRE-RIFT, REEFS
INITIAL FILL NON-MARINE	TRAPS — HORSTS, STRIKE-SLIP, SUB-UNCONFOMITY, LENSES, REEFS
SUBSEQUENT FILL MARINE, SANDSTONES, SHALES, CARBONATES, EVAPORITES	RISKS — SOURCE, TEMPERATURE

Fig. 15. Principal characteristics of rifts and grabens.

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, sub-unconformity pre-rift reservoirs on high blocks, discrete sands in the graben, 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 structure 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, approximately 38 billion metric tons (275 billion barrels) of oil and equivalent gas have been found in rifts and grabens — some in giant fields in the 275 to 420 million metric tons (two to three billion barrel) range, or larger.

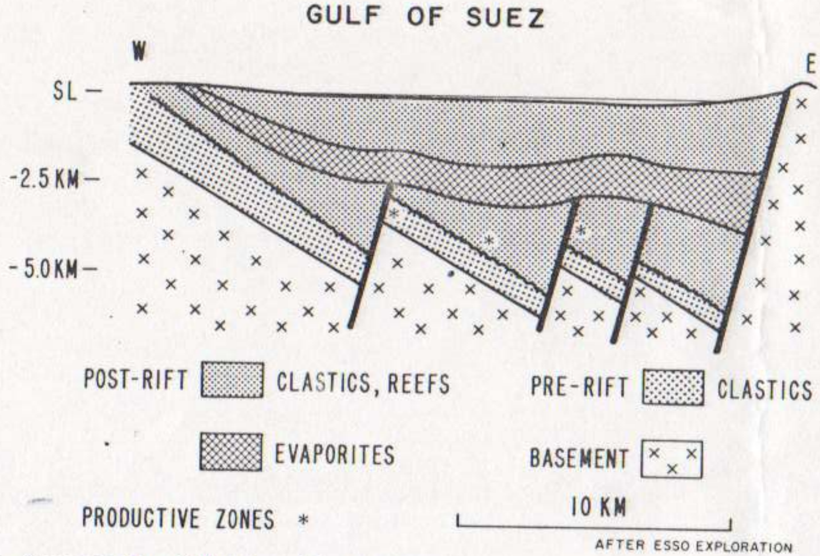

Fig. 16. Cross section, Gulf of Suez (rifts and grabens).

Figure 16, 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 sandstone 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, principally 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 pre-rift 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.

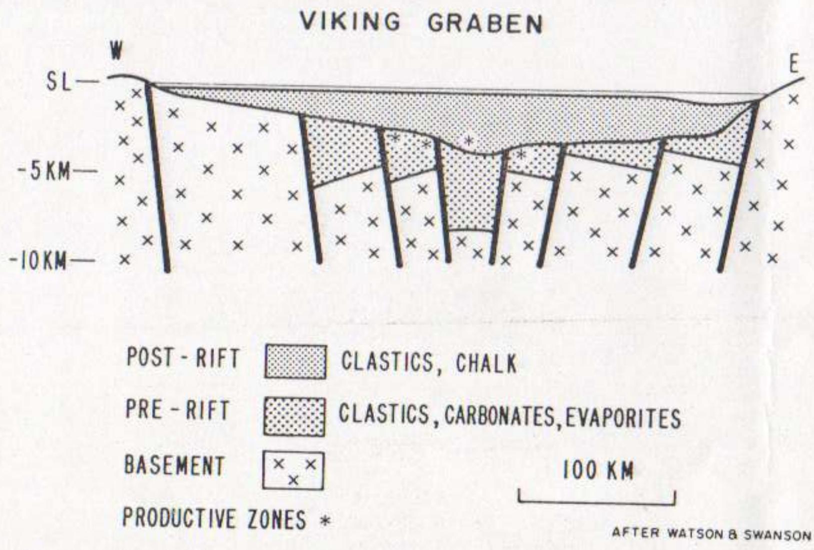

Fig. 17. Cross section, Viking Graben, northern North Sea (rifts and grabens); after Watson and Swanson (1975).

Figure 17, 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 commenced in Late Jurassic to Mid-Lower Cretaceous. Pre-rift sediments range from Carboniferous to Mid-Jurassic, although older sediments may occur in isolatd areas. In the Viking Graben area itself, productive reservoirs occur in Triassic to Upper Jurassic sandstones. Further 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.

Figure 18 is a frontier cross section along the Atlantic margin west of Ireland across the Rockall Plateau into the Porcupine Basin. This area consists of a series of rifts, whose age relationships are not yet definite. The easternmost rift, the Porcupine Basin is believed to have a Permian to Tertiary sequence, with the Upper Cretaceous lying unconformably on the block-faulted rocks of the Permian to Lower Cretaceous. A possible play might exist in shallow-water Permian to Jurassic sediments. The Rockall rift probably formed in Early Cretaceous. The pre-rift section consists of probable Jurassic and possibly older sediments. A play possibility could be shallow water, sub-unconformity Jurassic reservoir sands overlain by Cretaceous shales, a situation somewhat analogous to the Viking Graben. The Hatton Rift formed simultaneously with the opening of the North Atlantic during the Paleocene. A possible play could be Tertiary deep water turbidite sands, perhaps analogous to the Frigg accumulation in the Viking Graben.

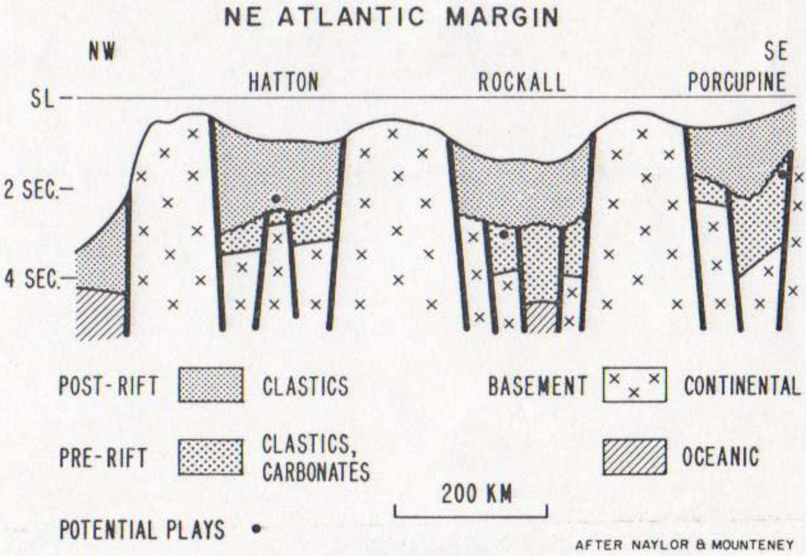

Fig. 18. Cross section of offshore Northwest British Isles (rifts and grabens); after Naylor and Mounteney (1975).

Convergent Margins

Figure 19 shows the distribution of most of the world's major convergent margin basins. Convergent margin basins are the most difficult margins to categorize and systematize. At the risk of oversimplification, these complex basins will be discussed under three categories, namely, fore-arc, back-arc, and strike-slip basins.

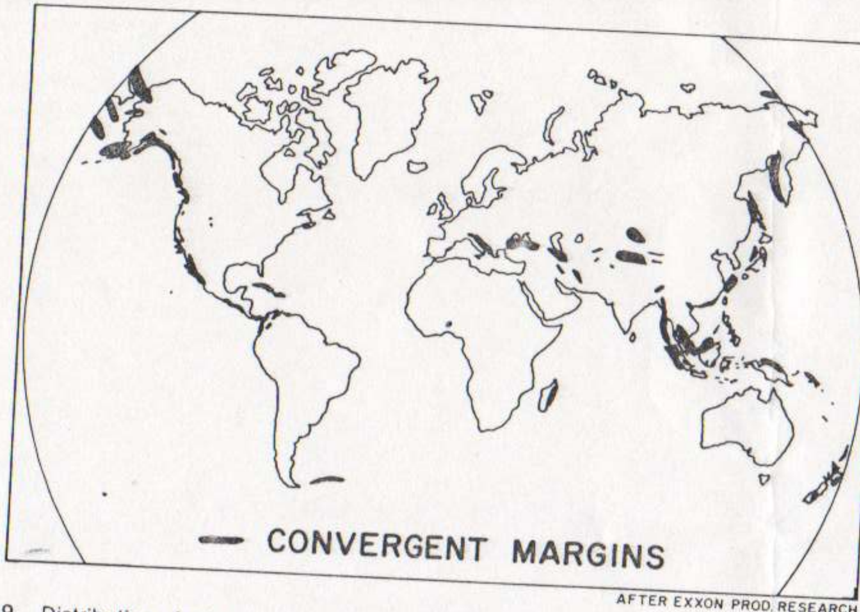

Fig. 19. Distribution of principal convergent margin basins.

Figure 20 highlights the principal characteristics common to most strike-slip basins. Strike-slip basins form as a result of transform movements on the converging plates, particularly where convergence is oblique. They can be in either the fore-arc or back-arc position. As convergence is rarely normal plate to plate, strike-slip components are very common. Where the transform movements are in convergence, compressional forces result in upthrust folds or mountain building. Where the transform movements are divergent, very deep basins form. The margins of the basins consist of either steep normal faults or high angle reverse faults. Extensive structuring can also occur in the basin center. Faulting proceeds during sedimentation, resulting in rapid facies changes from alluvial to submarine fans. Sedimentation is so rapid that reservoir quality is invariably mediocre at best. Large structures and thick producing intervals are required for significant fields.

STRIKE-SLIP BASINS

CONVERGING PLATES, OBLIQUE	EXTENSIVE STRUCTURING
FORE ARC, BACK ARC	RAPID FACIES CHANGES
TRANSFORM CONVERGENT UPTHRUSTING	TRAPS — WRENCH STRUCTURES
TRANSFORM DIVERGENT DEEP BASINS	RISK — LEAKAGE
BASIN MARGIN NORMAL, REVERSE FAULTS	

Fig. 20. Principal characteristics of strike-slip basins.

Plays in strike-slip basins are related to strike-slip faults, providing anticlinal closures. Reservoir rocks are mainly deep water 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 barrels) of oil or gas equivalent. Despite the generally mediocre quality of the reservoir sands these basins can be very prolific. The Los Angeles Basin, which for its size is one of the richest in the world, is a prime example. Fields in excess of 30 million metric tons are common in strike-slip basins.

The Los Angeles Basin is a good productive analog for strike-slip basins. Figure 21 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. Looking first at the Los Angeles Basin, the basin was formed by a right-lateral shear system. Faulting was active during sedimentation and resulted in an enormous amount of clastics being shed into the basin. Major production is from Pliocene-Pleistocene deep water sands. The richness of this basin is due entirely to the thickness of productive reservoir. There are several hundreds of metres of reservoir sands throughout the productive section. Structures are wrench-associated anticlines created by strike-slip faults.

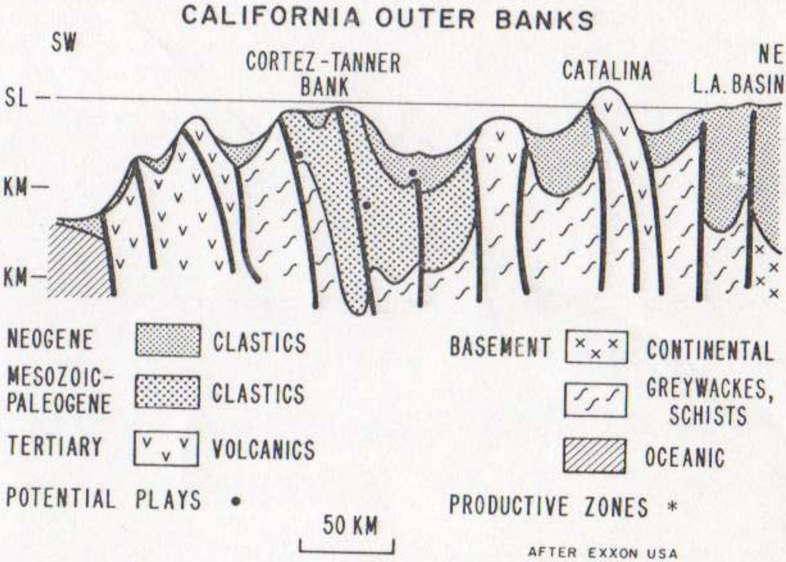

Fig. 21. Cross section of coastal Southern California (convergent margin).

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

Figure 22 highlights the principal characteristics common to most back-arc basins. Back-arc basins form by tension behind the magmatic arc. Shallow water facies provide the reservoirs. Sedimentation is frequently from the mainland, thereby decreasing the risk of volcaniclastic contamination of the reservoir sands. 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 barrels) of oil or gas equivalent. Pool sizes tend to be moderate — in the 14 to 40 million metric ton range. Giants are rare but they do exist — Minas in Sumatra, with about 590 million metric tons, being the prime example.

Figure 23, which is a cross section through the island of Sumatra, illustrates the occurrence of oil in a back-arc position. The Sumatra back-arc basins are located between the Sunda Shield to the north and the volcanic Barisan Mountains to the south. A series of basins formed in Early Tertiary time as a result of initial subduction. Sagging at the close of the Oligocene caused widespread transgression and linking of the various basin areas. Structural movement was intermittent throughout deposition. The Plio-Pleistocene uplift which formed the Barisan Mountains resulted in the formation of a series of wrench structures which contain most of the known fields.

BACK-ARC BASINS

TENSION, VOLCANIC ARC, PLATFORM

SHALLOW WATER FACIES

LESS VOLCANICLASTICS

TRAPS — NORMAL FAULTS, STRIKE-SLIP, REEFS

RISK — MATURATION

Fig. 22. Principal characteristics of back-arc basins.

Fig. 23. Cross section of Sumatra (convergent margin).

FORE-ARC BASINS

OCEANIC SIDE, CONVERGING PLATE

VOLCANIC ARC, SUBDUCTION

DEEP WATER SEDIMENTS HIGH ARC

VOLCANIC SEDIMENTS

THRUSTS, STRIKE-SLIP, REEFS

RISKS — VOLCANICLASTICS, MATURATION

Fig. 24. Principal characteristics of fore-arc basins.

This section also illustrates a younger fore-arc basin, the Mentawi Basin, which has been formed between the volcanic arc and the active subduction zone at the trench. To date, only minor dry gas has been found on crests of compressional folds associated with the overthrust taking place at the non-volcanic arc.

Figure 24 highlights the principal characteristics common to most fore-arc basins. Fore-arc basins form on the oceanic side and overlie the converging plate boundary between the outer high and the volcanic arc. Fill consists of deep water sediments within the outer high arc and prograding volcanic-rich sediments off the volcanic arc.

Clastic reservoirs in fore-arc basins are concentrated on the landward side of the basin. The petrographic composition is strongly influenced by the composition of the volcanic arc. Volcaniclastics in the reservoir, which destroy the permeability, are common. Closures in fore-arc basins are provided by thrusting and strike-slip displacements. Strike-slip faults can occur anywhere in the basin, and the oceanward side is strongly structured by thrusts. Given the proper paleo environment, reefs located on the side of the basin might also occur. Source rocks are not of primary concern, although these basins are invariably young, and maturity of potential source beds should be considered. Principal risks are contamination of reservoirs with volcaniclastics, and maturation.

So far, discoveries in fore-arc basins are fairly negligible, and pool sizes relatively small.

Figure 25, which is a cross section of a portion of southwestern Alaska, illustrates frontier basins in both the back-arc and fore-arc position. The Bristol Bay Basin is back-arc to the Aleutian chain. It is filled with Tertiary sediments. The Sanak extension of the Gulf of Alaska Basin is in the fore-arc position. This basin is part of an underthrust complex found adjacent to the trench. Structuring here is complex, principally compressional, but with elements of tension. Miocene and younger sediments fill the basin and drape over the outer high. Plays that might be anticipated would be primarily clastic reservoirs involved in structural closures related to thrusting and strike-slip displacement.

Cratons and Forelands

There is one category of basin that remains to be discussed, that is, the 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. Most of them are well known, so they will not be discussed in any detail. Figure 26 shows the distribution of the major cratonic and foreland basins.

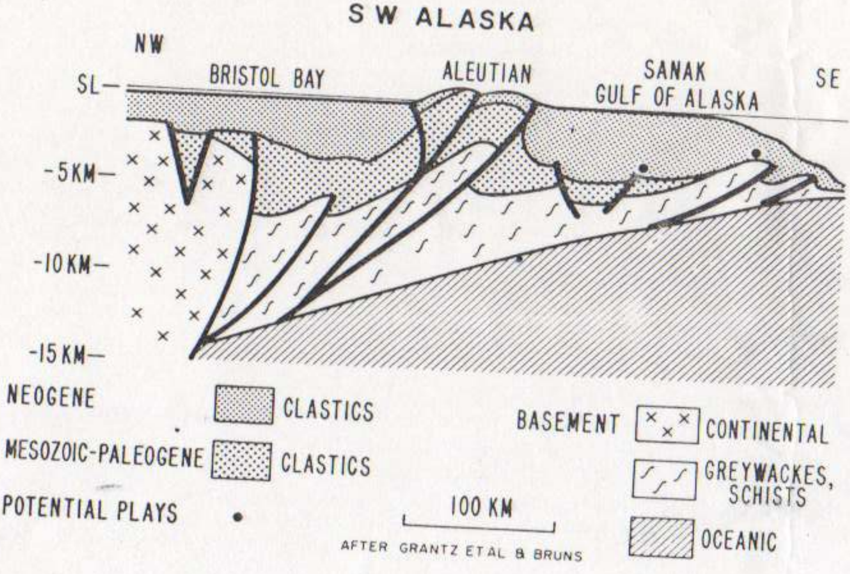

Fig. 25. Cross section, southwest Alaska (convergent margin); after Grantz *et al.* (1975) and Bruns (1977).

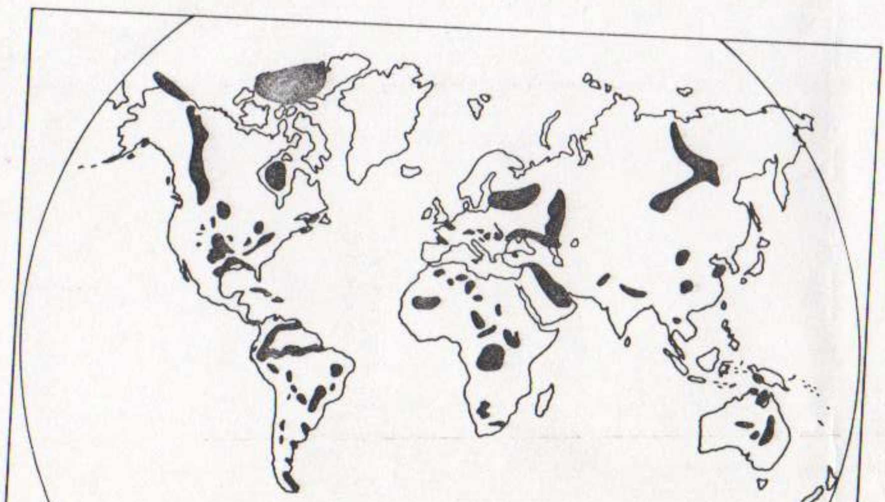

Fig. 26. Distribution of principal cratonic and foreland basins.

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 barrels) of oil and gas equivalent. They have also 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 in Canada.

As mentioned, most of these basins have been pretty well explored. There are very few true frontiers of this type. 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 large oil and gas accumulations. However, the potential for significant stratigraphic accumulation is always present in these basins whether they are in a mature stage of exploration or otherwise. 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.

Although not exactly a frontier basin in the strictest sense of the word, except climatically, the Sverdrup Basin in the Canadian Arctic Islands deserves at least passing comment. Figure 27 is a cross section through the basin. Although some divergence resulting in complex rifting took place in the Early Paleozoic, this basin appears to be basically a cratonic sag. It is fortunate that the Sverdrup Basin contains evaporites in the basin center, which are diapiric. Otherwise, this basin would suffer the fate of many cratonic sags and be relatively unstructured. Since the Sverdrup Basin is structured and has accumulated an alternating sequence of fine and coarse clastics, as well as carbonates, this basin has a reasonable chance of becoming a major hydrocarbon province.

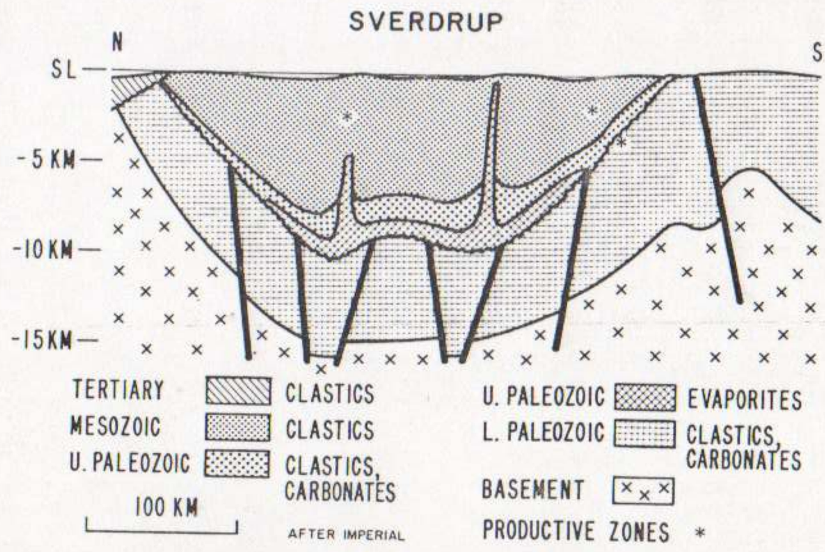

Fig. 27. Cross section, Sverdrup Basin, Canadian Arctic Islands (cratonic and foreland basins).

Conclusions

This concludes a somewhat gross overview of the "Frontiers of World Exploration." This paper has attempted to categorize the various frontier basin types and describe the principal plays and potential risks associated with each. This is obviously an oversimplification. However, within broad limits, it is possible to categorize basins and speculate on what the most likely plays might be. The main premise has been that 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, such as Arctic ice and/or deep water, many of the world's frontier basins will require technological innovation to enable them to produce. Because of 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. Canada has significant frontier areas such as the Beaufort Sea, the Arctic Islands, and the East Coast Offshore, which fall in this category. Thus, Canadians have all the challenges that go along with frontier exploration in extreme environments. The world industry will be keenly monitoring your efforts.

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AN ANALYSIS OF PETROLEUM DISCOVERY DATA AND A FORECAST OF THE DATE OF PEAK PRODUCTION

DAVID H. ROOT[1] AND E. D. ATTANASI[1]

ABSTRACT

Forecasts of the date of the maximum petroleum production for more than half of the world's productive area are derived from an analysis of the past discovery and production history in the non-Communist world outside the United States and Canada. World exploratory-drilling statistics are compiled by country and by year from the annual Foreign Developments Issue of the Bulletin of the American Association of Petroleum Geologists (1951-1976). A discovery-rate curve (L/well) is constructed by use of the drilling data and an estimate of past discoveries published by the Exxon Corporation. Extrapolations of past discovery rates and drilling rates are used to predict the future rate of additions to proved reserves. The extrapolation of past production rates is then used to estimate the date at which proved reserves become inadequate to maintain production. From the analysis, we predict that production for the non-Communist world outside the United States and Canada will probably peak during the 1990's.

RESUME

Des prévisions ont été tentées sur l'époque de culmination de la production, en ce qui concerne plus de la moitié des régions productrices du monde; les sources sont l'analyse des découvertes du passé et l'histoire de la production dans le monde non-Communiste, à l'exception des Etats-Unis et du Canada. Il y a eu compilation des statistiques de forages d'exploration par pays et par année, à partir de la livraison annuelle concernant l'étranger du "Bulletin of American Association of Petroleum Geologists" (1951-1976). Une courbe de productivité de découverte (en l./puits) était dessinée en utilisant les données de forage et une estimation des découvertes passées, éditée par Exxon. L'extrapolation de productivité des découvertes du passé et des rendements de forage permettait de prévoir