tary cover; and if the basin is asymmetrical, in monoclines developed on the slope. Basin size is typically 20-60 km (12-37 mi) in width and 70-300 km (43-186 mi) in length.

An intracratonic rift of this type is part of the Central African rift system. This system trends east-west, from the Benue trough in Nigeria to the Lamu embayment in Kenya. It is the result of the propagation of rifting from the triple junction that separated South America from the western margin of Africa, and also from the triple junction on the eastern margin where Madagascar separated from Africa. The rift system was tectonically active during the Cretaceous and Tertiary (Paleogene), and ceased after the initial faulting and coincident igneous activity but before any new crust was formed. The rifting along this trend was superseded in the Miocene by the East African rift system, which is still active.

Several companies have made significant oil discoveries in different components of the Central African rift system. Average daily production for 1982 from the basins associated with the Benue trough was 107,928 BOPD. Conoco has drilled at least eight discovery wells in the Chari basin and Ngaoundere rift components, and zones tested flowed up to 1,900 BOPD. In the Abu Gabra rift component, where Marathon is currently exploring, Chevron has drilled approximately 60 wells. Nineteen of these were discoveries and tested an average rate per well of 3,500 BOPD. The oil in the Chari basin and Abu Gabra rift is found in multiple zones in the Upper Cretaceous and Tertiary continental sands, and is a typical derivative of lacustrine sediments. The Abu Gabra rift may contain up to 10 billion bbl of oil.

Research indicates that this type of rift system is present in other areas of the world. Ongoing worldwide exploration has shown that intracratonic rift basins have the potential to make a significant contribution to world oil reserves.

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Deep Mediterranean Basins and Their Oil Potential

Mediterranean deep basins are surrounded by oil and gas producing areas, either onshore or beneath the continental shelf. The main zones are the Ebro delta and the Valencia Gulf (Spain); the Pelagian Sea off Tunisia, western Libya; Sicily; the Adriatic Sea; the Prinou basin in the Greek Aegean Sea; and the Nile delta. In other areas, as in the Adana basin (Turkey), offshore Cyprus (DSDP Leg 42A), and west of Sardinia (DSDP Leg 13), oil and gas shows were present in boreholes.

In general, the Mediterranean basins have relatively flat and uniform bottoms with water depths of the order of 2,800-3,000 m (9,200-9,850 ft). Several major exceptions are the Tyrrhenian Sea and the Aegean Sea, which are internal parts of the Alpine orogenies with a stretched structure of a back-arc type. The Ionian Sea has gradual northward slopes. The Eastern basin occupies a typical external position with the front of the Hellenic and Tauric nappes and the external overthrust zone known as the "Mediterranean ridge."

In terms of the crust, the problem can be approached with the aid of geophysical studies (gravimetry, magnetism, and seismic) and variations in heat flow. The superposition of these varied data thus enables us to schematize the nature of crust of the Mediterranean basins.

The western Mediterranean has a high heat flow that is surpassed only at certain points in the Tyrrhenian Sea. In contrast, the eastern Mediterranean in general has a very low heat flow, even in the Ionian Sea where a very considerable positive gravimetric anomaly is known to exist. Without reaching the high Tyrrhenian levels, the Aegean Sea has relatively high heat values. This is normal because of the area's volcanic activity.

The main potential oil and gas objectives are the Oligocene and Miocene Series, deposited after and during the main orogenic phases, and covered by thick Messinian evaporites and Pliocene-Pleistocene marine sediments. Underlying the Ionian Sea, the Mediterranean ridge, and the eastern basins, Mesozoic and Paleogene rocks may be possible targets. The zone at the shelf limit of the African platform and the alpine chains resembles many of the productive areas around the globe.

In conclusion, the deep Mediterranean basins could hide large targets. The exploration effort will require various improvements (excluding that of the price of crude oil): a better comprehension of the deep structure, seismic techniques capable of obtaining reflection beneath the evaporites and in the overthrust sectors, and technology that allows drilling in 3,000-4,000 m (10,000-13,000 ft) of water with the requisite security safeguards.

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Giant Fields: Present and Future Petroleum Resources

By the end of 1982, 319 giant oil fields plus at least 159 giant gas fields had been discovered. Total ultimate recovery of these fields amounts to 847 billion bbl of oil and over 2,362 tcf of natural gas.

The numbers and reserve potentials of giant oil fields are considered reasonably accurate. It is most likely that many giant fields remain to be discovered worldwide.

Giant gas fields and reserves are certainly understated when costs of transportation to market are not considered. But, using an economic definition that requires demonstrated development activity, the giant gas data may be significantly overstated.

The rate of giant field discoveries has been declining, and has been low for the past decade; political restrictions and economic constraints have contributed more to this decline than have technical criteria. Less expensive energy sources may arrive before the remaining geologically favorable areas are thoroughly explored for oil and natural gas.

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African Oil—Past, Present, and Future

Nearly 50% of Africa's total area is comprised of sedimentary basins. These basins number more than 80 and contain an estimated proven hydrocarbon reserve of 89 billion bbl (oil equivalent), about 8% of the world's resources. Of these reserves, 68% occur in North Africa, 22% in Nigeria, and 7% in the Aptian Salt basin, which encompasses the coastal parts of Cameroon, Gabon, Congo, Zaire, and Angola. The first discovery of hydrocarbons in Africa was in Egypt in 1886, and the most recent discoveries are in the Gulf of Guinea and the interior rift basins of central Africa.

Africa's basins can be classified into six types. However, each type has modifiers and most basins have evolved through a polycyclic history from one type to another.

Giant hydrocarbon accumulations are related to marine source strata and large, non-giant pools to nonmarine source strata. All sizes of fields occur in areas with marine source rocks, but giant fields very rarely occur in areas where nonmarine source rocks are thought to predominate.

Estimates of future potential reserves for each basin have been established by conventional basin assessment, play assessment, and volumetric yield methods, where data were sufficient. The most intensely explored basins are those containing giant fields. However, basins such as the Taoudenni, Zaire, Okawango, and Kalahari are each as large as Texas or the North Sea, yet the number of wildcats in each can be counted on one hand. Furthermore, about 80% of Africa's sedimentary area is virtually unexplored.

Giant accumulations will be found in the future in Tunisia and Egypt, in east Africa (if a deeper Karroo-play is pursued), and in the interior sag basins of central Africa, which are remote and unexplored. Some chance of finding one or two giant fields exists in Algeria and Libya, the Aptian Salt basin, the Gulf of Guinea, and the interior rift basins of central Africa, but generally only large accumulations will be found. Also, northwest Africa may yield oil in commercial quantities.

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Southern Mozambique Basin: Most Promising Hydrocarbon Province Offshore East Africa

Recent offshore acquisition of 12,800 km (8,000 mi) of seismic reflection data, with gravity and magnetic profiles encompassing the southern half of the Mozambique basin, reveals new facets of the subsurface geology. Integrated interpretation of these new geophysical data with old well information results in the development of depositional and tectonic models that positively establish the hydrocarbon potential of the basin. Previous drilling was sparse and predated modern seismic technology and exploration philosophy, leaving the area classified as a frontier province.

Pessimistic views regarding the liquid hydrocarbon potential in the basin stem from the following common observations. (1) The only exploitable hydrocarbon discoveries to date have been gas. (2) The only known source rocks are of post-Jurassic age and predominantly contain land-derived organic carbon, and hence are considered as gas prone. (3) Today's inferred geothermal gradient is such that the oil window is at least 5,000 m (16,000 ft) deep, and below the "acoustic basement," implying that existing hydrocarbons result from biodegradational processes not conducive to oil generation. (4) Old seismic data did not reveal well-developed structural traps.

However, the recent comprehensive interpretation affords the following conclusions. (1) Significant oil shows accompanying wet gas discoveries suggest that the South Mozambique basin is a mature province, as the hydrocarbon associations imply thermogenic processes. Hence, the geothermal history must have been more favorable than is generally inferred from present-day gradients. (2) Super-Karroo marine Jurassic sequences have been encountered in the Nhamura-1 well onshore, and Triassic marine sequences have been interpreted offshore from the application of seismic stratigraphy and well correlation. Furthermore, extrapolation of the continental character of the older Karroo from intracratonic locations to paleocontinental margins may not be valid, as exemplified by the basinward increase in marine character of the Sakemena and Ecca formations in Madagascar and Natal, respectively. Accordingly, the local presence of oil-prone source rocks is likely. (3) Steeply dipping reflectors truncated by the pre-Cretaceous unconformity testify to significant tectonic activity preceding the breakup of Gondwanaland. Hence, preconceived ideas about the depth of the economic basement and the absence of mature source rocks of pre-Cretaceous age should be revised. (4) Wildcats in the vicinity of ample structural closures have not been, in retrospect, optimally positioned nor drilled to sufficient depth to test the viability of prospects mapped along a major offshore extension of the East African rift system delineated by this new survey.

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Thermo-Mechanical Properties and Evolution of Pull-Apart Basins

Pull-apart basins are generally characterized by two component subsidence; an initial essentially instantaneous isostatic subsidence ($S_1$) dependent on the ratio of crustal to lithospheric thickness ($C_z/l_z$) and the stretching factor $\beta$, followed by a slower exponentially decaying thermal subsidence ($S_t$) controlled by the thermo-elastic properties of the continental lithosphere which, in turn, can be characterized by a thermal time constant $\tau$. Rapid short-lived subsidence (Ridge basin) is indicative of either (1) inhomogeneous crustal stretching without major sublithospheric involvement, or (2) extremely small lithospheric diffusivities. The former implies a thin-skinned origin for pull-apart basins and suggests that the spatial and temporal distribution of bounding faults and splays typical of pull-apart basins result from inhomogeneous brittle failure of the upper crust. Crustal, extensional or shear-strength profiles for various geothermal gradients and degrees of wetness adequately explain two-layer extension with intra-crustal decollement. However, the effects of lateral heat flow decrease the thermal time constant by allowing a basin to subside more quickly because of both lateral and vertical cooling. The size of this effect is dependent on the width of the stretched lithosphere. The effective $\tau$ of a 100 km (60 mi) wide rift is 36 m.y. and for a 25 km (15 mi) rift is 6 m.y., whereas the actual thermal time constant in both cases is 62.8 m.y. Lateral heat flow amplified rift subsidence while producing complementary uplift in adjacent unstretched regions. However, the flexural rigidity of the lithosphere severely attenuates the deformation caused by the lateral flow of heat. Although the deformation is highly dependent on the mechanical properties of the lithosphere, $\tau$ is independent. Diachronous rift shoulders or peripheral uplifts may produce important hydrocarbon gradients and result from various combinations of lateral heat flow, flexural arching, and normal-fault decoupling.

Continental lithospheric rigidities appear to increase with age following an orogenic or thermal event, suggesting that the long-term mechanical behavior of the continental lithosphere is similar to that of the oceanic lithosphere. However, high rigidities ($10^{32}$ dyne-cm) associated with Archean or Proterozoic terranes and modeling of plate deformation suggest that the long-term thermal behavior of continental lithosphere is governed by a cooling plate model with a 200-250 km (124-155 mi) lithospheric thickness, nearly twice the 125 km (78 mi) estimated for the oldest oceanic lithosphere. This has important implications for the evolution of sedimentary basins. A doubling of the lithospheric thickness implies a quadrupling of $\tau$, yet basin subsidence models have assumed that $\tau$ for the oceanic and continental lithospheres are similar. A large $\tau$ allows basin subsidence to continue over significantly longer times, but lateral heat flow, in addition to vertical, must be included in basin models to obtain accurate subsidence and temperature estimates. In particular, $S_1$ is highly dependent on the age of the underlying basement.

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Deep Water (200-800 m) Hydrocarbon Potential of United States Gulf of Mexico

Recent active Outer Continental Shelf (OCS) lease sales in the offshore Texas and Louisiana portions of the United States Gulf Coast have emphasized that this will be an arena of vigorous exploration for at least the next decade. Much of the principal prospective acreage on the shelf area (water depth less than 200 m or 660 ft) has been awarded for exploration. As a consequence, there is now a well-established trend toward assessment of deeper water acreage (200-800 m or 660-2,625 ft). For example OCS sale 72, in May 1983, included the award of leases in water depths of over 1,000 m (3,280 ft). This trend is likely to make the United States portion of the Gulf of Mexico the first intensively explored deep-water area in the world.

Geophysical and geologic data have been acquired on a generally ad hoc basis by various research and governmental institutions over the last 15 years. More recently, individual oil companies and geophysical contractors have started more methodical data acquisition programs. This move toward a more systematic evaluation has culminated in extensive regional seismic programs being acquired to evaluate leases available in the April and July 1984 OCS sales 81 and 84.

Acquisition, processing, and interpretation problems can be expected by those attempting to evaluate prospects in the deep water portions of the Gulf of Mexico.

From the geophysical evidence available, broad conclusions can be made concerning the likely hydrocarbon potential of the area.

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Trapping Styles and Associated Hydrocarbon Potential in Norwegian North Sea

The exploration effort in the Norwegian North Sea is only 15-20 years old. The activity has resulted in several major oil and gas finds. Well data and significant amounts of seismic data have implied a thorough geologic understanding.

In the North Sea basin, the hydrocarbon discoveries to date can be assigned to four main forms of traps.

(1) The extensional structures are characterized by tilted fault blocks, or less commonly, rollover anticlines on the downthrown side of faults. The hydrocarbons occur in sub-unconformity, sandy reservoirs of Triassic to Late Jurassic age. (2) Salt-supported structures generally have fractured Upper Cretaceous–lower Tertiary chalk or Jurassic sandstones as a reservoir. (3) Stratigraphic traps are accentuated by drape, compaction, or late structural movements. Sands of Paleocene-Eocene age represent the main reservoir. (4) Anticlinal closures are related to a late phase of wrench movements. Discoveries of this type occur in the southern part of the basin and represent only a minor part of the proven reserves.

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Hydrocarbon Potential of East Coast of India

The east coast of India is considered to be a divergent margin formed during the fragmentation of Gondwanaland during the late Mesozoic. The four sedimentary basins located along this coast—Cauvery, Palar, Krishna-Godavari, and Mahanadi (from south to north)—have their seaward extensions into the Bay of Bengal where some of them have built a 5-6 km (16,000-20,000 ft) thick late Mesozoic to Holocene sedimentary section.