10:15 **T. SUND:** Tectonic Development and Hydrocarbon Potential Offshore Troms, Northern Norway

10:40 **F. SURLYK*, J. M. HURST, S. PIASECKI, F. ROLLE, L. STEMMERIK, E. THOMSEN, P. WRANG:** Permian of Norwegian-Greenland Sea Margins—Future Exploration Target

11:05 **F. RIIS, J. VOLLSET*:** Barents Sea Oil and Gas

Abstracts

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California and Saudi Arabia—Geologic Contrasts

Assessing hydrocarbon futures in unexplored basins involves geology by analogy. These assessments are needed to help quantify the amount of oil and gas postulated. It is important for the geology and geologic history of known producing basins to be defined in some systematic way, so that their favorable or unfavorable attributes may be recognized, and subsequently looked for in untested basins. The California and Arabian analogs are important.

Through 1978, approximately 265 fields were discovered in California, containing 22 billion bbl of oil, 53% being in the 10 largest fields, ranging in size from 0.6 to 2.4 billion bbl. These fields occur in several different sedimentary basins. Through 1978, about 50 fields were found in Saudi Arabia containing 206 billion bbl of oil, 78% in the 10 largest fields, ranging in size from 7 to 83 billion bbl. All these fields occur in one part of a single very large basin. The contrasts in field size distribution and in the total amount of oil present are explained by the dramatically different geology and geologic histories.

California's surface geology is characterized by rare Precambrian, isolated Paleozoic, and widespread Mesozoic accreted terranes and intrusions, and by highly uplifted and depressed Tertiary sedimentary prisms bounded by widespread high-angle thrusting and strike-slip and normal faulting. Numerous families of medium to small anticlines and fault traps, commonly involving moderately dipping to overturned beds, have resulted from Tertiary tectonism, which segmented California dramatically. The sediments associated with the oil and gas are largely local fine to coarse-grained clastics, shed from nearby highlands, but with one important regional chert-limestone-dolomite sequence.

Saudi Arabia is characterized by a broad Precambrian shield area, flanked on the east by very long, gently dipping cuestas of Paleozoic and Mesozoic sediments, with an upper thin veneer of nearly flat Tertiary strata. Most structures involving the Mesozoic and Cenozoic are large, but gentle and unfaulted, representing a passive reaction of the sediments to underlying mild basement distortion and/or movement of Cambrian salt, all occurring while the Arabian plate continued to subside and "tip" to the northeast. The sediments associated with the oil are largely widespread carbonates of uniform thickness, with one interbedded sandstone wedge, and some shale.

The contrasts between California and Saudi Arabia oil fields and geology result from contrasting plate-tectonic settings and history.

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Paleozoic Oil and Gas Potential of Arabian Basin

The central and northwestern region of the greater Arabian basin contains more than 5,000 m (16,400 ft) of oil- and gas-prospective clastic and carbonate Paleozoic sediments. The Hail-Rutbah arch divides the region into two Paleozoic basins, the western Tabuk basin on the west and the Widyan basin on the east. The Tabuk basin is filled with Cambrian to Devonian sediments, whereas the Widyan basin contains sediments ranging in age from Cambrian through Late Permian. A north-south-trending Precambrian platform separates these basins from the eastern sector of the greater Arabian basin.

The Cambrian-Ordovician Saq Sandstone, composed of fluvial and marginal-marine sandstones and minor shales, overlies Precambrian basement.

The Ordovician-Silurian Tabuk Formation consists of cyclically deposited marine and marginally marine clastic sediments. Three shale members, the Hanadir, Ra'an, and Quasaiba, are separated by siltstones and sandstones that pinch out basinward where shale becomes dominant. These shale members are covered by regressive sandstones of the Sharawra Member. Uplift and erosion followed deposition of the Sharawra.

Unconformably overlying the Tabuk Formation is the coarse and pebbly continental sandstone of the Tawil Member of the Devonian Jauf Formation. Alternating marine and nonmarine conditions followed deposition of the Tawil Member, producing interbedded carbonates and clastics. A major regional uplift accompanied by erosion followed deposition of the Jauf Formation. The uplift affected the entire central and northwestern basin region and it is believed the Hail-Rutbah arch came into being at this time, creating the two basins.

No post-Devonian Paleozoic deposition is recorded in the rocks of the western Tabuk basin; however, thick Carboniferous-Upper Permian sediments occur in the Widyan basin. The Carboniferous to middle Permian Berwath Formation was deposited in the center of the Widyan basin and was covered by the Unayzah Formation, which transgressed the area and overlapped older rocks and paleohighs. The middle to Upper Permian is represented by carbonates of the Khuff Formation, laid down by the transgressive sea.

Precambrian structural features significantly influenced structural trends and sedimentary deposition during the Paleozoic. Major stratigraphic breaks or unconformities are believed associated with the Caledonian and Hercynian orogenies.

The most significant factor relating to the oil and gas prospectiveness of the Tabuk and Widyan basins is the presence of thick alternating source and reservoir sections. The facies vary laterally, with sandstone grading to shale basinward. The facies changes combined with several unconformities and structural folding and faulting enhance the hydrocarbon potential of the two basins. Also, known shows and recoveries of oil and gas from the Paleozoic section in the eastern Arabian basin further support the possibility of the presence of commercial quantities of hydrocarbons in these basins.

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Hydrocarbon Potential of Intracratonic Rift Basins

Significant world oil reserves have been added in recent years from rift systems. Examples of petroliferous rift basins may be found on nearly every major continent. As our understanding of the mechanisms of sedimentation and structure in rift basins grows, more rift systems will be found. With a few notable exceptions, rifts that have been explored in the past are those that formed along continental margins. These contain marine sediments, and the conditions of source rock, sediment type, depositional environment, and structural style are well-known exploration concepts.

Intracratonic rift systems containing continental sediments have received little exploration effort because few have been recognized, and also because of the problems perceived to accompany continental sedimentation. A good modern analog is the East African rift system. The source rock is lacustrine shale with an organic content that ranges from 5 to 20%. The organic materials are preserved by anoxic conditions of deep lake waters. Heat flow, as in continental-margin rifts, is moderate to high. Combined with a commonly thick section and depth of burial, the sediments can be well within the oil generation window for lacustrine shales. The volume of oil generated may be very large for a basin of limited areal extent. The oil is generally waxy, has an API range from the 20s to 30s, and has a low sulfur content. The reservoir quality is highly dependent on the type of sediments deposited, because there is little energy available for sorting or winnowing. Possibilities include first-cycle arkoses derived from crystalline basement rock and second-cycle or multicycle sands derived from earlier pre-rift depositional episodes. Eolian sands are also possible reservoirs. There may also be sharp facies variations across the rift, and aspect ratios of these facies may approach 1:1. Seals for the reservoirs are either lacustrine shales or evaporites deposited under hypersaline, closed drainage conditions. Structures are genetically similar to those found in continental margin rift valleys. Accumulation zones are found in series of tilted blocks controlled by listric, down-to-the-basin faults; in reverse drag anticlinal features on the downthrown side of growth faults; in basement "high" blocks with a sedimentary 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.