Drilling on the continental shelf of the Central Beaufort Sea has led to significant oil and gas discoveries. There is considerable optimism that the region may encompass a new oil basin. Hydrocarbons are present in Eocene and Oligocene strata. The environment of deposition, established by paleontology and seismic facies analysis, is deep marine. Reservoirs are considered to be sand, transported by turbidity currents and deposited as deep-sea fans. The resulting accumulations are constructional in that they form large mounds and are readily identified on seismic sections taken parallel with the sedimentary strike of the deposits. Traps are stratigraphic where closure is the result of deposition, and structural where shale swells have arched the sand layers. Timing of the latter may play a significant role in the migration and final concentration of hydrocarbons. Marine shales form an effective seal.

The first conventional cores of the reservoirs were cut during the 1981 drilling season. At Koakoak O-22, several oil-bearing sands were recovered. Porosities averaged 29% and permeabilities ranged from 61 to 2,500 md with an average of 1,000 md. The fine to medium-grained sands are friable with very little clay matrix.

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Evidence of Cross-Formational Flow Above Healdton Oil Field, Carter County, Oklahoma

An anticlinal trap is the locus of deep-water discharge with hydrocarbons being retained while the water is transmitted vertically through the sediments. The change in the sense of water movement from lateral to vertical at the apex of the anticline is accompanied by temperature- and salinity-gradient changes. Because of this, it might be possible to outline an oil field by an analysis of these gradients over an anticline.

To test this hypothesis, Healdton anticline, Carter County, Oklahoma, a textbook example of an anticline, was selected for study. This paper examines by an analysis of the salinity and geothermal gradients in the shallow beds the probability of cross-formational flow through the anticline. A large amount of data is available from electric logs of wells drilled in Carter County. Using the spontaneous potential curve and a modified computer program, formation-water resistivities were calculated and these resistivities were converted into total dissolved solids (salinity) based on empirical data from the study area. It is anticipated that contour maps of salinity and geothermal gradients will show the outline of the Healdton oil field.

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Tectonics and Sedimentation Along Continental Margin of Western India, Pakistan, and Adjacent Arabian Sea

The Chagos-Laccadive Ridge and its northern extension, the Lakshmi Ridge (CLLR), trending parallel with the coastline in the deep eastern Arabian Sea, is a continental fragment (with crustal thickness >20 km). Sea-floor spreading-type magnetic anomalies are absent and crustal thickness is about 16 km in the region east of CLLR. West of the ridge, magnetic anomalies, from 5 to 28 on the magnetic time scale, are present and the crustal thickness is 11.5 km. The magnetic anomalies, crustal thickness, and considerations of land geology suggest that most of the sedimentary basins in the region east of the ridge were initiated during the rifting stage in the Late Cretaceous, whereas those in the western region evolved during sea-floor spreading since 64 m.y. ago. The NNW-SSE and to some extent northeast-southwest and ENE-WSW basement trends, as well as associated horsts, grabens, and growth faults in the eastern region, formed as a result of reactivation of the ancient Precambrian trends observed on the Indian shield during and after rifting, and have determined the shapes, extents, and tectonic styles of the sedimentary basins there. The acoustic structure of sediments suggests that a basal sedimentary layer with a velocity of 4.0 to 4.3 km/sec is present in the region east of CLLR, but is absent west of it. This sediment layer, believed to be composed of clastics, volcaniclastics, and limestone, was probably deposited during the rifting stage. The seismic layers and the velocity structure (1.9 to 3.5 km/sec) of the overlying sediments are similar both east and west of the CLLR and suggest similar influences on sedimentary evolution in both the eastern and western regions during sea-floor spreading. However, sea-level changes during the Cenozoic in conjunction with tectonics resulted in several unconformities in the shelf sedimentary sequences. By about Oligocene and Miocene times, with the closure of Tethys Sea and the uplift of Himalayas, terrigenous sediments from the Himalayas became important for the northern margin and initiated the Indus deep-sea fan.

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Estimation of Paleo-Pore Pressure and Time of Hydrocarbon Expulsion—Computerized Simulation Model

A geological simulation model of generation and expulsion of hydrocarbon can be a useful tool in hydrocarbon exploration. The advantage of the model is to realize different environments in which hydrocarbon accumulations form under various geologic conditions.

A geologic cross section of an area is divided into a series of vertical columns, which are sectioned into rectangular cells. The model simulates the various geologic processes during basin development: (1) burial compaction of sediments, (2) history of temperature estimated from thermal conductivity and heat flow, (3) R_O (vitrinite reflectance) value calculated by Lopatin's method, and (4) the amount of generated hydrocarbon as a function of generation potential and of transformation ratio represented by R_O. Increase of pore pressure is assumed to be caused by (1) increase of overburden, (2) increase of volume of free water resulted by clay dehydration, (3) aquathermal expansion of water, and (4) expansion of fluid phase by hydrocarbon generation. Residual pore pressure in each step of geologic time in the model is calculated by Rubey-Hubbert's equation:

$$P_A = kT + (P_O - kT) \cdot e^{-t/T}$$

where P_A = residual abnormal pressure, P_O = initial abnormal pressure, k = ratio of pressure increase, t = duration, and T = relaxation constant. T is a function of permeability that is derived from porosity and grain size. The amount of hydrocarbon expelled is calculated from residual abnormal pore pressure as a function of relative permeability and viscosity of fluids. Direction and time of hydrocarbon migration can be interpreted from spatial distributions of paleo-pore pressure and of hydrocarbon expelled from source rocks for each geologic time.

The model is applied to the Niigata sedimentary basin of the coastal region of the Sea of Japan. Regional differentiation of time of hydrocarbon accumulation in the basin is observed. Upward hydrocarbon migration across the strata is also implied at culminations of the trapping structures.

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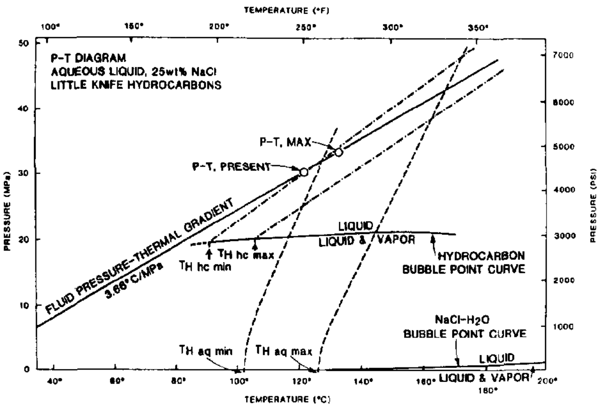
Origin of Reservoir Fractures in Little Knife Field, North Dakota

Thin, vertical, planar fractures in the Mission Canyon Formation of the Little Knife field, in west-central North Dakota, appear to be naturally occurring extension fractures. The fractures are restricted to carbonate units, but are not lithology dependent within the carbonate rocks. Fracture density averages 1 ft (0.3 m) of fracture per 2.3 ft (0.7 m) of core. The predominant east-west trend of the fractures, measured in oriented core from six wells, parallels the estimated maximum horizontal compressive stress in the Williston basin.



Formation and mineralization of these fractures were the most recent diagenetic events in the Little Knife carbonates. Heating- and cooling-stage observations of fluid inclusions in crystals bridging the fractures yield homogenization temperature ranges of 90 to 106°C and 102 to 126°C for hydrocarbon and aqueous inclusions, respectively. Correlation of these observations with the PVT properties of Little Knife reservoir fluids leads to the following conclusions: (1) the fractures formed after the strata were buried to at least their present depth of 9,800 ft (3,000 m), which indicates their age is post-Mesozoic; (2) the pore-fluid pressure gradient was normal hydrostatic immediately after, if not during, fracture system development; (3) formation-water salinity has remained fairly constant since fracture initiation; (4) migration of hydrocarbons into the reservoir probably preceded or accompanied fracture genesis; and (5) methane concentration may have decreased since fracture initiation.

The geologic mechanism specifically responsible for creating the fractures remains unknown. The potential for using fluid inclusions to document changing methane concentration within a reservoir could be significant to studies of hydrocarbon migration.

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Aracas Field—Reservoir Heterogeneities and Secondary Recovery Performance

In the Aracas field (Reconcavo basin, Brazil), the Sergi Formation held about 30% of the $60 \times 10^6 m^3$ of the field's original oil in place. Its contribution for the field cumulative production is, however, less than 11%.

The Sergi Formation (Upper Jurassic) is a braided-stream sequence of conglomeratic and coarse to very fine-grained sandstones and minor siltstone and shale layers (<5%) with an average thickness of 215 m. The pool has an area of 7.5 km^2 and the reservoir average depth is 2,750 m.

Primary recovery started in 1967 and 37 wells were drilled for exploitation of the pool (29 for production and 8 for peripheral water injection). The water injection was initiated in 1973 and neither improved the production nor repressured the reservoir to the expected levels. Today an average production of 23 m^3/day/well is obtained from 12 wells, far below the initial rates of 100 m^3/day/well. To date, only 8% of the estimated original oil in place has been recovered from this pool.

The Sergi Formation was cored in two new wells and the measured petrophysical parameters (such as porosity, permeability and water saturation) served to establish a model for the log analysis of the remaining wells. A good correlation of log-derived permeabilities and core permeabilities was obtained by the method known as multidimensional histogram. Standard computerized log analysis in conjunction with estimation of permeability made possible a description of each of the 12 reservoir zones in the form of contour maps depicting mean porosity, water saturation, and permeability and development of a suite of structural and isopach maps.

Pressure data from new wells and geologic analysis derived from log and core interpretation strongly suggest that the present peripheral injection-well pattern is insufficient and that an infill drilling program could contribute to a more effective pressure maintenance.

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Camorim Field, Brazil—Facies and Oil Qualities Controlling Reservoir Behavior and Well Performances

Camorim field is located offshore Sergipe State, Brazil. The producing section includes 150 m of Cretaceous conglomerates and coarse to very fine-grained sandstones, interbedded with siltstones and shales. Within this interval, six pools are recognized based on log correlation and facies analysis. The field has an area of 25 km^2 and the reservoir average depth is 1,900 m.

Twenty-eight development wells were drilled to exploit the pools and the productivity ranges from 100 to 1 m^3/day/well. Reservoir geology and performance were analyzed by a multidisciplinary group composed of development geologists, sedimentologists, production engineers, and log analysts.

The reservoirs were fully cored in five wells and the correlation between rock and log responses allowed facies mapping throughout the field. The depositional model is interpreted as an alluvial-fan complex prograding toward a lacustrine environment. Log analysis and correlation between lithofacies and permeability allow the estimation of reservoir quality at any point of the pools.

Together with reservoir quality, the oil properties are recognized as controlling the productivity of the wells. At reservoir conditions, oil viscosity ranges from 1 to 5 cp (centipoises). Data at tank conditions show that density (18 to 37° API) and viscosity (10 to 200 cp) increase eastward throughout the field and from the upper to the lower part of the blocks.

To support reservoir simulation, permeability is calculated for each well as a weighted geometric mean based on the thickness of each of the three reservoir facies: conglomerates (200 md), coarse to medium-grained sandstones (23 md) and fine to very fine-grained sandstones (1 md). This model explains the initial and long-term well performances and the pressure behavior of the reservoirs.

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Development of Publicly Owned Oil Shale Lands of United