Cretaceous and Jurassic strata within the bombing range are more than 150 m higher than in the leased area to the east. Nine dry holes have been drilled in the vicinity, seven of them concentrated on a structural high in Upper Cretaceous strata on the eastern flank of the dome.

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Exploration History, North U.S. Atlantic Margin

The Baltimore Canyon Trough is the site of 26 exploration wells and two stratigraphic tests. As of November 1981, six dry holes had been drilled on the Great Stone Dome. This structure appeared to be the largest and most promising in the basin. Seventeen wells have been drilled along the edge of the continental shelf with significant hydrocarbon shows reported from five wells. Combined daily flow rate is 90 mmcf. This flow is approximately one-half the amount required to warrant construction of a production platform and pipeline.

Georges Bank basin is characterized by an older thick carbonate and evaporite sequence (0 to 8 km) of Late Triassic-Early Jurassic age; a middle sequence of interbedded limestone, sandstone, mudstone, and red shale of Middle Jurassic to Early Cretaceous age (0 to 2.5 km); and a thin sequence (middle Cretaceous and younger) of transgressive shelf limestone and regressive claystone and siltstone (0.5 to 2 km). Elevated patch reefs beneath the shelf and a massive reeflike carbonate buildup under the slope form potential hydrocarbon traps. The patch reefs, which are elongate to circular and as much as several kilometers across, have caused a broad arching of younger strata. They may be built on salt swells or elevated basement blocks. A two-dimensional, finite-difference simulation of the main basin's thermal history of crustal stretching and subsidence suggests that some of the oldest sedimentary sections over the seaward part of rift-stage crust and extending out to oceanic crust are thermally mature for oil generation.

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Stability of Natural Gas at High Temperatures, Deep Subsurface

The components of natural gas are reactive in the deep subsurface and may not survive under all conditions. The stability of natural gas in reservoirs of various lithologies is studied using a combined theoretical and experimental approach.

A computer program uses real gas data to calculate equilibrium in multicomponent (up to 50), multiphase (up to 30) systems simulating subsurface conditions to 12 km (40,000 ft). This program predicts the stability of hydrocarbons in sandstone reservoirs by first considering clean sands and then sequentially adding feldspars and clays, carbonate cements, and iron oxides. In all examples, equilibrium compositions have been computed for low, average, and high geothermal gradients; hydrostatic and lithostatic pressures; and with and without graphite. Graphite is present when deep gases are generated by the cracking of oil but is absent in reservoirs originally filled with dry gas. Similar calculations have also been made for limestone and dolomite reservoirs with various combinations of clays, iron minerals, anhydrite, and sulfur, again with and without graphite. Natural gas shows considerable stability in sandstone reservoirs under most conditions, but its concentration in deep carbonates is more variable and tends to a hydrogen sulfide-carbon dioxide (H_2S-CO_2) mixture except when an appreciable concentration of iron is present. Hydrogen is present at the 1 to 2% level for most lithologies.

A multicolumn gas chromatograph is used to analyze inorganic and organic gases released by crushing rock samples in a Teflon ball-mill. Gas samples from deep wells in the Anadarko basin and southern Louisiana have been analyzed and the compositions compared with those predicted from the computer program.

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Problems Facing Geophysical Industry Today with Suggested Solutions to These Challenges

No abstract.

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Phayles Sandstone (Upper Cretaceous) Deltaic and Shelf-Bar Complex, Central Wyoming

Outcrop and subsurface studies of Phayles Sandstone (basal Mesaverde Group), southeastern Wind River basin, indicate rapid deltaic progradation and subsequent formation of a shelf-bar complex. Net sand distribution determined from 175 well logs indicates a major deltaic lobe with maximum thickness of 45 m prograded at least 20 km basinward from exposures of deltaic and shoreface deposits. The West Poison Spider field is located approximately 8 km southeast and downdrift from this deltaic lobe. Study of 33 logs and 13 cores from this field indicates the reservoir is associated with elongate shelf sandbars. The bar complex is at least 10 km long, 8 km wide, and 15 m thick; bar-axes are oriented N40°W. Study of shoreface sandstones in outcrop suggests the paleoshoreline trended N50°W. Several distinct sandstone bodies are stacked within the complex. Three component facies are recognized: (1) cross-stratified medium-grained sandstone; (2) parallel-bedded (hummocky cross-bedded?) fine-grained sandstone; and (3) bioturbated fine-grained sandstone. These sandstones occur in repetitive successions with facies 1 capping the sequence and facies 3 forming the basal member. Log-response compares favorably with core descriptions permitting detailed facies correlations. Within the field, individual bars range from 3 to 8 m in thickness and pinch out both seaward and landward interfingering with bioturbated and rippled shelf siltstones. Sedimentary structures, stratigraphic relations, and petrography suggest the bar complex was derived from sands reworked from the deltaic lobe. The shelf bars migrated shoreward and stacked during a major transgression resulting in the deposition of the Wallace Creek Tongue of the Cody Shale. This shale overlies and forms an updip seal for the reservoir facies.

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Carapebus Member (Eocene), Campos Basin, Brazilian Offshore: An Example of Deep-Sea Fan Turbidites Winnowed by Bottom Currents

The Carapebus Member (Eocene), Campos basin, offshore

Brazil, consists of coarse-grained turbidite sand bodies enclosed by pelitic deposits. The turbidite sands represent a major oil reservoir in the Brazilian offshore. On the basis of core analysis, E-log correlation patterns, and seismic data, these sand bodies are interpreted as original deep-sea fan sediments that were extensively winnowed by bottom currents. Indirect evidence for such an interpretation is given by the complete absence of thin-bedded and fine-grained turbidite sediments. Direct evidence is the highly burrowed, fine-grained, and irregularly stratified bottom-current deposits. This complex depositional system was formed on a passive continental margin setting, concurrently with an overall seaward progradation of clastics. The correct understanding of such depositional models seems to be of primary importance for the oil exploration of the Atlantic margins.

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Utility of Computerized Data Bases of Drill-Stem Test Information in Hydrogeologic Studies

The Palo Duro basin, a subbasin of the Permian basin, is being investigated by the Bureau of Economic Geology at The University of Texas at Austin as a potential site for the location of a nuclear waste repository. As the program changes from a regional to a site-specific investigation, it becomes necessary to optimize the expenditure of funds for drilling and testing. Hydrogeologic information is of critical importance in evaluating the long-term stability of a potential repository; consequently, deep multipurpose wells should be drilled in locations that maximize the opportunity to obtain both hydraulic and geochemical data.

Prior to our own borehole testing, the only hydrogeologic data available came from petroleum exploration activities, namely, drill-stem test (DST) pressure measurements and brine samples collected with the test. Computer data files of DST information were purchased from commercial sources or obtained directly from operators who had worked in the basin, and the data were merged into a master file. Approximately one thousand tests have been sorted according to geologic formation and lithology. The DST data were then screened and ranked according to their level of confidence based on shut-in pressure characteristics, fluid recoveries, and flowing times.

Automatic computer contouring of the selected data produced an unsatisfactory map because of the varied quality of the tests. An objective geostatistical method was subsequently employed to map the regional pressure or hydraulic head distribution in the basin. Geostatistical analysis of the data revealed that a spatial dependency existed which could be modeled by a two-dimensional spherical variogram. The method of kriging was then applied to the data to estimate the regional hydraulic head surface.

A chemical equilibrium computer program was used to determine the reaction state of the deep basin flow system, using as input data the chemical composition of the brines collected during drill-stem testing. The program then incrementally added the CO_2 lost during collection back into the initial brine composition until it reached the calcite phase boundary. This mass transfer approach results in the computation of the most likely mineral constraints on the brine at measured formation temperatures, pressures, and computed pH conditions.

The results of these studies provide interpretations of the regional hydrogeologic processes. Consequently, exploration decisions can be made concerning the location of future test wells to further define the geologic, hydrologic, and geochemical characteristics in this sedimentary basin.

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An Alternative to Reservoir Simulation Using Critical Parameter Analysis of Reservoir Data Bases

Conventional methods of statistical analysis often break down in the study of reservoirs because exclusionary processes reduce the number of elements studied until they are statistically meaningless.

Using an Enhanced Oil Recovery (EOR) Field Test Data Base which was developed for 187 field tests, methods of multivariate analysis, particularly cluster techniques, were used to look for similarities and differences in the data. Each field test was treated as a key element with the following nine reservoir parameters considered as independent variables: porosity, permeability, oil saturation, API gravity, initial water saturation, age, depth, net pay, and viscosity.

A 187×12 unweighted data matrix was constructed. Then a 187×187 diagonal matrix of similarity coefficients was calculated using a moment based equation. The similarity matrix was ordered and plotted in the form of a dendrogram using a pair-wise grouping technique.

Clustering effects were found correlated to the five different enhanced oil recovery processes used in the field tests. The processes involved are in situ-combustion, carbon dioxide injection, improved waterflood, surfactant-polymer injection, and steam flooding.

The application of these methods to critical parameter analysis of a field test data base for enhanced oil recovery are discussed and illustrated by an assortment of computer and display techniques. The methodology appears to have significant potential in evaluations involving selection and application of reservoir screening criteria, the identification of minimum data requirements for decision making, audit methods for the examination of data bases, and comparative analysis of large numbers of reservoirs simultaneously.

An exploratory approach to prediction of performance of EOR Field Tests using an interactive stochastic model will also be described.

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Mississippian Conodonts from Well Cores, Crossfield, Alberta

Cores from three wells drilled into the Elkton Member of the Turner Valley Formation at Crossfield, Alberta, yielded numerous conodonts. These conodonts permit interregional and intraregional correlation to other sections in western Canada, to strata in the upper Mississippian Valley region, and to sections in Europe. This material came from 300 to 500 g samples taken at 5 ft (1.52 m) intervals from 0.5 in (1.26 cm) slabs of well cores.

Eotaphrus burlingtonensis and *Polygnathus mehli* are common and allow recognition of the *Eotaphrus* Subzone of the *Eotaphrus-Bactrognathus* Zone. This subzone can be recognized within the Turner Valley Formation at Cadomin and Moose Mountain and the lower Livingstone Formation in Bow Valley sections. This subzone also occurs in the upper part of the Burlington Formation within the type region of the Mississippian System and in the upper Tournaisian (Tn3c) of Belgium, Britain, and Germany.

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