TRAP BARRIERS—HYDRODYNAMIC, STRATIGRAPHIC, WETTABILITY

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The field mapping of formation-water pressures and salinities, together with theoretical and experimental research, has demonstrated that strong hydrodynamic gradients can be caused by difference in (a) water salinity, (b) oxidation-reduction potential, (c) temperature, and (d) topographic elevation. Significant differences in one or more of these parameters occur in almost every geologic province. Regional hydrodynamic maps constructed from accurate bottom-hole pressure data must be prepared in each area to determine if significant hydrodynamic or nearly hydrostatic conditions exist. Many areas having an essentially flat topography are found to have very strong hydrodynamic gradients.

The ability of a trap barrier to hold a substantial oil column is often primarily dependent upon the hydrodynamic pressure gradient. Reservoir pinchouts or terminations by facies change, cementation, unconformity, or faulting often have the capacity to trap, under hydrostatic conditions, only 5 to 50 feet of oil column before the capillary pressure exceeds the barrier entry pressure and causes oil to leak through the barrier. Under hydrodynamic conditions, this oil-holding capacity of a trap barrier may be (1) decreased almost to zero if the water flow is updip, or (2) increased to several hundred or a few thousand feet of oil column if the water flow is downdip.

For example, every 10-psi drop in pressure across the stratigraphic oil accumulation can increase (or decrease) the oil-holding capacity of the barrier by about 100 feet for a medium-gravity oil in brackish formation water. The velocity of water flow through typical stratigraphic-trap pinchouts necessary to cause this hydrodynamic control of stratigraphic oil entrapment is only about 1.0 to 0.01 inch per year. Fluid-flow models projected on the screen are used to demonstrate these hydrostatic and hydrodynamic-trapping capacities for stratigraphic-, unconformity-, and fault-trap barriers.

Most shales and other fine-grained sediments are normally water wet, and consequently any oil or gas from the adjacent reservoir rocks will not enter until the capillary pressure exceeds the entry pressure of these sediments. However, some shales are found to be preferentially oil wettable and will imbibe oil from adajacent reservoirs until either (a) the shales are nearly oil saturated. or (b) the reservoirs are barren of oil. Some gas provinces devoid of liquid hydrocarbons and other oil-lean areas may be the result of preferentially oil-wettable shales. Some research suggests that the clay-mineral exchangeable cations, which are in equilibrium with the formation waters, may substantially affect this wettability relationship. Calcium-magnesium-dominant waters would tend to make a shale oil wettable, and sodium-dominant waters would tend to make it water wet. The preferential wettability may vary throughout geologic history and thereby substantially affect the migration, accumulation, and preservation of oil.

The practical applications of these hydrodynamic and wettability factors to guide oil-exploration programs and to evaluate specific prospects are emphasized.