An examination of the continental shelf in the Ventura–Port Hueneme, California, area included the collection of can cores, box cores, and vibrocores to determine the primary physical and biogenic sedimentary structure to establish a depositional-facies model.

Core analysis permits recognition of three principal zones: (1) nearshore facies (backshore to 9 m water depth), made up primarily of parallel-laminated, ripple-laminated, and cross-bedded, clean sand; bioturbation is only locally significant; (2) transition facies (9 to 18 m water depth), zone of fine sand and silty sand, characterized by an increase in biogenic over physical sedimentary structures; wave-ripple bedding and parallel lamination are important structures in this facies; (3) offshore facies (>18 m water depth), sandy silt is the primary texture, and bioturbation is the dominant sedimentary structure; remnant parallel lamination is the only physical sedimentary structure present.

Comparison of the results of this study with a previous description of "low-energy" beach-to-offshore facies at Sapelo Island, Georgia, indicates that the two areas do not differ greatly in overall vertical sequence of sedimentary structures. The principal difference is in the thickness of the three facies: the California facies are significantly thicker than their Georgia counterparts. It is concluded that this difference is in direct response to the role of higher wave energy on the California coast.

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Mixed-Layer Clays in Eocene Interlaminated Shales and Sandstones

Kaolinite, illite, and mixed-layer montmorillonite-illite are present in interlaminated sandstones and shales from the Eocene Wilcox Formation of the Texas Gulf Coast at depths of 2,000 to 4,000 m. Ratios of kaolinite to discrete illite are higher in the sandstones than in the interlaminated shales. Mixed-layer clays in the sandstones are 5 to 20% more expansible and less ordered than those in interlaminated shales. These mineralogic differences are interpreted to reflect a significant difference in the solution chemistry of pore waters in the sandstones from that of pore waters in the interlaminated shales. At the relatively shallow depth of 2,000 m, mixed-layer montmorillonite-illite from the shales is roughly 30% expansible; this figure is significantly less than the 75% expansibility reported by J. Hower et al for Miocene age mixed-layer clays at similar depths. Assuming similar source and geothermal gradient for the two sets of samples, two explanations may account for these differences. The most plausible explanation is that the expansibility of the mixed-layer clay is controlled by the montmorillonite-to-illite transformation rate. Because the Eocene sediments have had an additional 25 m.y. to react, the montmorillonite-to-illite transformation is more complete in these samples. An alternative explanation is that the chemistry of pore waters in the Wilcox Formation is significantly different from that of pore waters in sediments studied by Hower.

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Carbonate Rocks of Montoya Group (Middle and Upper Ordovician) of Trans-Pecos Texas

In the petroliferous Permian basin of west Texas the subsurface Montoya Formation consists of a monotonous sequence of dolomitic limestones. However, 100 to 200 mi (160 to 320 km) west in the Franklin and Hueco Mountains of Texas and the Cooks Range and Sacramento Mountains of New Mexico, the Montoya is divided into three distinctive carbonate formations (in ascending order): the Upham Limestone, the Aleman Limestone, and the Cutter Limestone.

Study of microscopic sections shows several carbonate lithologies including: (1) crinoidal calcarenite with calcareous mud matrix (biomicrite); (2) crinoidal calcarenite with clear calcite cement (biosparite); (3) micrites with abundant cherty nodules and layers of interbedded chert; (4) laminated micrites without chert; (5) shelly limestones (mainly brachiopodal biomicrites); (6) autochthonous reef rock (coralline biolithite); and (7) partly or completely dolomitized equivalents of any of the former.

Crinoidal calcarenites with a calcareous mud matrix characterize the Upham Limestone except for the uppermost beds. There, shallow-water, high-energy conditions apparently winnowed out the calcareous mud, which is replaced by clear calcite cement. Cherty and chert-free micrites and biomicrites form the dominant lithologies of the overlying Aleman and Cutter Limestones.

At some localities, especially near faults, dolomitization is massive, cutting across all facies and rock layers. Dolomitization progresses from sporadic small crystals embedded in the original matrix to total replacement where original features are obscured or destroyed. Layered dolomites are most common in the Cutter Formation.

Montoya deposition is cratonic, averaging only 320 ft (96 m) over about 10 m.y. Individual rock units representing specific shallow-water epineritic environments may be traced widely (in some places more than 100 mi; 160 km).

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Strachan-Ricinus Gas Field, Alberta

Exploration for reef reservoirs in the "Deep Basin" of Alberta during the mid-60s resulted in the discovery of 1.9 Tcf of sales gas, 50 million bbl of condensate, and 24.5 million LT of sulfur in two reefs of Late Devonian age, at Strachan and Ricinus. The reefs were discovered in 1967 and 1969, respectively, by adapting the seismic CDP techniques of data acquisition and processing that were then being developed (particularly in the Rainbow area, in the shallower part of the Western Canada sedimentary basin).

The key well for these discoveries was the Gulf-Strachan well in Lsd. 12-31-37-9 W5M, which was drilled in 1955. This well encountered a partial buildup of Upper Devonian reef which yielded some gas and salt water from a depth of 13,900 ft (4,237 m). CDP seismic data were acquired and, after considerable experimentation in processing with orientation to the appropriate geologic model, showed that the key well was on the flank of what is now called the Strachan reef. In 1968, Banff and Aquitaine drilled a full reef buildup of 900 ft (27 m) in Lsd. 10-31-37-9 W5M with a pay section of 540 ft (165 m). A separate pool, the Ricinus reef, was discovered in 1969 by Banff and Aquitaine in Lsd. 6-25-36-10-W5M. The well showed a reef buildup of 800 ft (245 m) and a maximum pay of 690 ft (210 m). Remaining reserves of marketable natural gas at Strachan and Ricinus, after 6 years of production, are approximately 1 Tcf.

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Uranium Deposits of Texas Gulf Coastal Plain—Trend, Exploration, and Production

Uranium in the Texas Gulf coastal plain occurs primarily in two types of deposits: (1) in sandstone-type deposits of Goliad, Oakville, Catahoula, Frio, and upper Jackson, and (2) in Tertiary Wilcox, Yegua-Jackson, and upper Jackson lignite. Total potential resources of uranium in the coastal plain have been estimated to be about 0.25 million tons, ranking third in the United States.

Analyses of several thousand samples from the coastal plain show the following results.

1. In the sandstone-type deposits, uranium is both roll type and nonroll type. Most uranium concentrates are in reduced ores. Uranium is closely associated with (a) lignite or disseminated organic matter, (b) clays, particularly smectite, (c) zeolites, particularly with clinoptilolite, and (d) carbonate rocks and calcite. Uranium minerals present are uraninite, coffinite, carnotite. Adsorption of uranium by clays is largely dependent on pH.

2. In lignite, the concentration of uranium decreases with geologic age. Uranium is generally concentrated at the contacts of lignite seams with sandstones or shales rather than in the middle of the seam.

Recovery of uranium has been either by surface or in-situ mining. However, development of in-situ leaching has gained new impetus because of the unique situation of south Texas uranium deposits. Results of laboratory tests show that hydrochloric acid is the most effective solvent to recover uranium from either oxidized or reduced sandstone-type ore deposits, and from lignite without the addition of oxidant (e.g., H_2O_2).

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Twenty Years of United States Petroleum Estimates

In 1956, after 96 years of petroleum exploration and production, the United States had produced 52.4 billion bbl of crude oil. Industry opinion and all available evidence were in agreement that the ultimate amount of crude oil to be produced in the lower 48 states would probably fall between 150 and 200 billion bbl, with future production from two to three times that of the past. The high estimate for natural gas was about 850 Tcf. At that time, the writer showed that if the ultimate crude oil production should be between 150 and 200 billion bbl, and if the ultimate amount of natural gas to be produced should be about 850 Tcf, the peak of crude oil production should occur during the period 1966 to 1971, and the peak of natural gas production at about 1970.

That was the end of consistency in the estimates of the ultimate amounts of crude oil and natural gas to be produced in the United States. During the next 5 years petroleum-industry estimates escalated to 400 billion bbl for crude oil and about 1,500 Tcf for natural gas, while estimates by the U.S. Geological Survey reached 590 billion bbl for crude oil and 2,630 Tcf for natural gas. Furthermore, these higher estimates persisted until well into the 1970 decade.

In the meantime, successive estimates by the writer, based on analyses of publicly available petroleum-industry data, led consistently to about 165 to 175 billion bbl as the ultimate amount of crude oil, and 1,000 to 1,100 Tcf for natural gas, with the crude oil production peak due to occur during 1967-70, and that of natural gas in the mid-1970s. These estimates were predictions of the future, and that future has now elapsed. The peak of crude oil production was reached in 1970 and that of natural gas in 1973. By the end of 1972, the evidence was consistent with 170 billion bbl for the ultimate amount of crude oil and 1,000 to 1,100 Tcf for natural gas. However, since 1972 proved reserves and discovery and production rates of both oil and gas have been declining more rapidly than originally estimated. Should this continue, the ultimate quantities of oil and gas may be less than those estimated in 1972.

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Discovery and Development of Badak Field, East Kalimantan, Indonesia

The Badak field is located on the east coast of the Island of Kalimantan (Borneo), Indonesia, about 35 km south of the equator. The Badak 1 discovery well was spudded November 27, 1971, and completed on February 11, 1972. The well penetrated more than 900 ft (274 m) of net gas sand and about 300 ft (91.5 m) of oil sand.

Drilling of Badak 1 was preceded by an intensive exploration program, which started in December 1968 and which included aerial photographic and magnetic surveys, geologic field work, and reflection and refraction seismic surveys.

Geologically, the Badak field is a part of the Mahakam delta, a 6,000-m thick wedge of upper Tertiary clastic sediments, laid down in the major Kutai basin.

Badak reservoirs are coarse to very fine-grained quartz sandstones with an average porosity of 22% and average permeability of 200 md. The individual sand bodies are either channel-mouth or finger-bar sands deposited in a deltaic environment.

Structurally, Badak is one of several culminations formed on a long (60 km) north-trending structural axis, which also connects the Nilam and Handil fields on the south. The Badak culmination is a gentle anticlinal uplift with no known faults.