especially useful in studying dolomites and magnesian calcites. The capability for simultaneous electron diffraction from regions less than 1 μm allows for identification of phases and evaluation of short-range ordering.

In addition, many modern TEMs have scanning devices allowing scanning-transmission images (STEM) as well as the more conventional secondary-electron images to be formed. The use of energy-dispersive X-ray spectrometers is optimized with such STEM instruments as spatial resolution of roughly 150 A is possible.

Recent studies of carbonate minerals using these techniques have revealed a wide variety of defect microstructures characteristic of different growth and diagenetic conditions. In many places, the microstructures are present in such high densities as to significantly influence the stability and reactivity of the mineral.

Notable examples include the calcium-rich dolomites, both from ancient rocks and Holocene sediments. The ancient calcian dolomites exhibit a complex modulated structure with growth and possibly transformation-induced defects. Holocene dolomites are structurally distinct, characterized by a high-density domain structure associated with growth faults. Pervasive, complex microstructures have also been found in saddle dolomites, magnesian calcites, and low-Mg calcites. In the latter, the defect structure is thought to be associated with local CO_3 group disorder.

Since the microstructures are characteristic of different diagenetic growth conditions, their proper characterization and interpretation represents a potential tool for hydrocarbon exploration in carbonate terrains.

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Depositional History and Petroleum Potential of Permian Tannehill Sand, King and Knox Counties, Texas

Channel deposits of the lower Wolfcampian Tannehill sand are a major oil-producing interval in west-central Texas. These sand bodies represent a fluvial meander belt that was part of an extensive depositional system which shifted laterally along paleoslope toward the slowly subsiding Midland basin.

Within the producing zone, stratigraphic traps commonly are formed by structural closure caused by differential compaction and updip pinch-outs against clay plugs of former channel thalwegs. Porosities range from 20 to 30%, with permeabilities of 300 to 700 md. Oil columns of approximately 5 to 30 ft (1.5 to 9 m) are reported. The abrupt erosional contacts of the channel deposits with the regionally persistent Stockwether Limestone clearly delineate the lower boundaries of the Tannehill sand. The typical Tannehill E-log signature shows a sharp basal contact, a decrease in SP amplitude upward, and a more serrate curve upward—all characteristic of point-bar sequences. However, an abnormally low resistivity value (2 ohms) is observed in the oil-saturated portions of the sand. Core analysis shows that this abnormal value does not result from high water-saturation levels. Instead, this anomalous feature is probably due to the retention of water in clay lenses found within the sand bodies.

Ultimate recoverable oil in the Tannehill is estimated to average 400 bbl per acre-foot. The relatively shallow depth, 2,600 to 2,700 ft (792 to 823 m), of the Tannehill and the low cost of drilling to reach it create favorable exploration prospects. Recognition and understanding of the resistivity anomaly in the Tannehill sand could be of major economic importance.

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Hydrocarbon Assessment of the Chattanooga (Devonian) Shale in North Alabama, Northwest Georgia, and South Tennessee

Devonian oil-bearing shale (Chattanooga Shale) occurs over a wide area of north-central Alabama and south-central Tennessee. Four counties, Limestone and Madison Counties, Alabama, and Giles and Lincoln Counties, Tennessee, appear to have the best potential for future development in the region. In this area, the shale ranges from 0 to 15 ft (4.5 m) thick and has less than 100 ft (30 m) of overburden. The shale is typically dark gray to black with pyrite laminae and nodules. Very small lenses and interbeds of sandstone and siltstone, calcite streaks, phosphate nodules, and cherty layers occur locally. The unit is correlative with the Gassaway Member of the Chattanooga Shale as recognized in Tennessee. Shale samples of high oil content are typically very dark gray to black, slightly pyritic, and some have a petroliferous odor. Sandy and silty shale samples show a sharp decrease in oil yield values. In this region, the shale appears to have accumulated in a shallow (less than 100 ft, 30 m) marine reducing environment with a highly irregular shoreline and some scattered islands. If this depositional hypothesis is correct, it may account for the sporadic occurrence, variable thicknesses of the formation, and vertical variations of chemical data for the shale unit.

Reconnaissance sampling throughout the four-county area, augmented by widely spaced core holes in Alabama, indicate that the shale has an average oil yield potential of 13 gal/ton by modified Fischer Assay. Maximum oil yield obtained was 23 gal/ton from a sample in Lincoln County, Tennessee. For samples having more than 7 gal/ton oil, whole rock and trace metals (Co, Cr, Mo, Ni, V, Ti, Zn, and U) analyses were made. Uranium values range from 0.0 to 70 parts per million (ppm) (av. 20 ppm). Values for other trace metals are as follows: Co 4 to 300 ppm (av. 91 ppm); Cr 5 to 200 ppm (av. 81 ppm); Mo 0 to 845 ppm (av. 230 ppm); Ni 10 to 600 ppm (av. 234 ppm); V 12 to 540 ppm (av. 257 ppm); Ti 3,000 to 11,500 ppm (av. 7,439 ppm); Zn 30 to 910 ppm (av. 228 ppm). Fixed carbon ranges from 0.60 to 12.97%, with an average of 9.58%. Total organic carbon averages 16.93 wt. % with a hydrocarbon index of 305 mg/g. The predominant clay mineral is illite, but mixed layered clays are common. The kerogen and organic content appears to coat and be interstitial to the quartz grains and clay particles. Coaly fragments were noted in some samples, but amorphous material suggestive of algal origin was noted in many samples. The components of the kerogen fraction are 29% aromatics, 65% resin and asphaltenes, and 6% saturates. Analyses of the extracted oil indicate 11% paraffins-naphthenes, 45.7% aromatics, 4.2% sulfur, 25.9% eluted NSOs, 1.5% non-eluted NSOs, and 11.7% precipated asphaltine. Solid-state ^{13}C NMR spectra suggest a poor conversion of organic carbon to oil.

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Distinction Between In-Situ Biogenic Gas and Migrated Thermogenic Gas in Ground Water, Denver Basin, Colorado

Methane-rich gas commonly occurs in ground water in the Denver basin, southern Weld County, Colorado. The gas generally is in solution in the ground water of the aquifer. However, exsolution resulting from reduction to hydrostatic pressure during water production may create free gas, which can accumulate in wells and buildings and pose an explosion and fire hazard.

The ground water is found in siltstones and sandstones that make up the Upper Cretaceous Laramie–Fox Hills aquifer at