for hydrocarbon generation. However, temperatures in the past probably were high enough for hydrocarbon generation. Oil generated during this earlier, hotter period could have migrated into conventional stratigraphic and structural traps.

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Eocene Strike-Slip Faulting and Basin Formation in Washington

Eocene right-lateral displacements occurred on several fault zones in western and central Washington, including the Straight Creek fault (90-190 km or 56-118 mi of offset), the Entiat-Leavenworth fault system (amount of offset unknown), and possibly a major unnamed north-south trending fault through the Puget lowland. Within this framework, nonmarine sediments accumulated in several rapidly subsiding basins to form some of the thickest (more than 5,800 m or 19,000 ft) nonmarine sequences in North America. Two types of sedimentary basins are recognized. The Chiwaukum and Foss River grabens are small pull-apart basins that formed along the major faults. The Chuckanut, Swauk, and Puget(?) basins are much larger (up to 100 km or 62 mi wide) and formed between the major faults. To varying degree, these larger basins display the characteristics of idealized smaller pull-apart basins: (1) high sediment accumulation rates; (2) rapid facies changes; (3) abrupt stratigraphic thickening and thinning; (4) partly internal drainage patterns; (5) irregular basin margins characterized by dip-slip faults and unconformities; (6) predicted deformational patterns; (7) rapid changes between extensional and compressional tectonics; and (8) interbedded and intrusive relationships with extension-generated(?) volcanic rocks. The difference in size and mode of occurrence between these basin types emphasizes the regional as well as local control that strike-slip faulting has on basin formation.

This extensional-basin province formed in a forearc setting between an obliquely subducting oceanic plate to the west, and the broad, diffuse Challis volcanic arc to the east. Eocene nonmarine basins in Washington should therefore be considered as end-member types of forearc basins.

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Petrologic and Chemical Characteristics of Deep-Subsurface Wilcox (Eocene) Lignites from East and East-Central Texas

A recent drilling program has provided new petrographic and chemical data on deep-subsurface Wilcox Group lignites in east and east-central Texas. The seams occur in major lignite-bearing horizons of the Wilcox Group at depths of 240-1,040 ft (70-315 m).

The petrologic examination has been performed using white and blue light reflectance microscopy. The seams contain limited well-preserved plant material. Humodetrinite is the dominant maceral, and many of the huminites have undergone partial or complete gelification. The liptinite content is high and may exceed 30%, much of it occurring as a fine-grained matrix. Seams with less liptinite tend to contain more inertinite. Some of the huminites contain granular material which has a low reflectance and weak orange fluorescence. It is believed to represent an early stage in the formation of micrinite, with which it may be found in close association.

Chemical characterization includes proximate and ultimate analyses, forms of sulfur, ash oxides, plus minor and trace element concentrations. Most seams are low in sulfur, except for a seam underlying a marine unit at the top of the Wilcox, in which the dry sulfur content exceeds 5%. Ash contents are variable and largely determine calorific value. Sodium content increases from shallow to deeper seams, coincident with the evolution of ground-water chemistry from $Ca\text{-}HCO_3$ to $Na\text{-}HCO_3$ with increased depth. Comparison between petrographic and chemical data show that lignites with larger amounts of liptinite have higher hydrogen contents and calorific values.

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Reservoir Characterization of Mesaverde (Campanian) Bedload Fluvial Meanderbelt Sandstones, Northwestern Colorado

Reservoir characterization of Mesaverde meanderbelt sandstones is used to determine directional continuity of permeable zones. A 500-m (1,600-ft) wide fluvial meanderbelt in the Mesaverde Group is exposed as laterally continuous 3-10-m (10-33-ft) high sandstone cliffs north of Rangely, Colorado.

Forty-eight detailed measured sections through 3 point bar complexes oriented at right angles to the long axis of deposition and 1 complex oriented parallel to deposition were prepared. Sections were tied together by detailed sketches delineating and tracing major bounding surfaces such as scours and clay drapes. These complexes contain 3 to 8 multilateral sandstone packages separated by 5-20 cm (2-8 in.) interbedded siltstone and shale beds. Component facies are point bars, crevasse splays, chute bars, and floodplain/overbank deposits.

Two types of lateral accretion surfaces are recognized in the point bar facies. (1) Gently dipping lateral accretions containing fining-upward sandstone packages. Large scale trough cross-bedding at the base grades upward into ripples and plane beds. (2) Steeply dipping lateral accretion surfaces enclose beds characterized by climbing ripple cross laminations. Bounding surfaces draped by shale lags can seal vertically stacked point bars from reservoir communication. Scoured boundaries allow communication in some stacked point bars. Crevasse splays showing climbing ripples form tongues of very fine-grained sandstone which flank point bars.

Chute channels commonly cut upper point bar surfaces at their downstream end. Chute facies are upward-fining with small scale troughs and common dewatering structures. Siltstones and shales underlie the point bar complexes and completely encase the meanderbelt system. Bounding surfaces at the base of the complexes are erosional and contain large shale rip-up clasts.

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Hydrocarbons, Blind Thrusts, and Upper Detachments

Oil and gas occur in the foreland margins of deformed belts around the world, concealed beneath the mountain-facing flank of a foreland syncline. Such a syncline is formed by wedging of blind, foreland-directed thrusts against an upper detachment zone that extends out to the synclinal axis. Examples include mature exploration areas such as the Carpathian foothills of Rumania and the foothills of the Canadian Cordillera, and the foreland margins of the Appalachians, Ouachitas, and Brooks Range. Other examples have been reported from several sectors of the Alpine-Himalayan and Andean orogens. The upper detachment was originally horizontal, uplifted by the blind thrusts beneath it. While there is no way of measuring how far into a thrust belt an upper detachment extended before it was removed by erosion, computer modeling can reconstruct thrust belts within the constraints imposed by inclusion of an upper detachment. An example from Canada shows that the entire southern Alberta foothills belt can be modeled this way. This is consistent with the observed plunge of the Alberta thrust belt along strike beneath the fold belt of northeastern British Columbia, where wells spudded in folds penetrate blind subsurface thrusts. These data suggest that, like folded faults, blind thrusts and upper detachments are common features of deformed belts. Failure to recognize them can result in severely underestimating the extent of thrusting, and consequently downgrading the hydrocarbon potential of a deformed belt.

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Maturity Parameters of Woodford Shale, Anadarko Basin, Oklahoma

The Upper Devonian-Lower Mississippian Woodford Shale is an important source rock in the Anadarko basin. Because of its stratigraphic relationship to the Hunton Group and other productive reservoirs, it has been the subject of several recent studies attempting to evaluate hydrocarbon potential. Standard geochemical analyses were performed on a 5-well cross-section beginning in the northeastern shelf of the Anadarko basin at a depth of 5,700 ft (1,737 m) and ending in the southeastern part of the deep Anadarko basin at 22,000 ft (6,706 m). The data reveal systematic changes in geochemical parameters with increasing depth and maturity level. Such changes are consistent with maturation effects seen in other basins around the world.

Vitrinite reflectance data for progressively deeper wells yielded mean R_0 values of 0.60, 0.88, 1.23, 1.86, and 2.03%. These values are indicative of maturation levels ranging from the main zone of oil generation to the zone of dry gas generation. Bitumen ratios (expressed as milligrams of soluble organic matter per gram of total organic carbon) agree well with these maturation levels. Infrared spectroscopy, used to assess the changes in functional groups of the soluble organic matter and kerogen, shows a corresponding increase in the aromaticity of the organic compounds with increasing maturity level. Elemental analysis of kerogen (carbon, hydrogen, nitrogen, and oxygen) and gas chromatography of whole-rock bitumen extracts exhibit maturation effects similar to those noted in other basins.

In addition, organic matter (O.M.) isolated by conventional palynologic techniques was examined under white light and shows progressive changes from yellow-amber and translucent O.M. at $R_o = 0.60\%$, to dark brown, partially translucent and partially opaque O.M. at $R_o = 0.88\%$. Samples with R_o values of 1.23% and greater are completely opaque. Visual kerogen studies support the obtained geochemical parameters.

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Comparison of Carbonate and Shale Source Rocks

As with shales, the source potential of carbonate rocks depends primarily upon the organic facies rather than the mineral matrix. Where the depositional and early diagenetic environment is highly oxygenated, the total organic carbon (TOC) is low, with a negligible generative capacity for hydrocarbons, despite a relatively high hydrocarbon/TOC ratio in the immature state. An anoxic depositional and early diagenetic environment can result in the deposition of organic-rich, fine-grained carbonate rocks that are excellent potential source rocks.

Excellent oil-prone source rocks, whether with carbonate or clay mineral matrices, have many characteristics in common. Both form in anoxic environments, are generally laminated and heterogeneous, have moderate to high TOC, and contain high quality organic matter (OM).

Gas-prone organic facies are rare in carbonate rocks because such facies are usually dominated by terrestrial organic matter deposited in a dominantly clay matrix. Most carbonate rocks contain nongenerative organic facies as do most siliceous rocks. Oxygen-rich depositional environments for carbonates are found from sea level (reefs) to the ocean depths (*Globigerina* ooze).

Despite the basic commonality between organic-rich oil-prone carbonate and shale source rocks, some significant differences exist. Oils derived from carbonate rocks are often richer in cyclic hydrocarbons and sulfur compounds than oils derived from shales due to the dearth of terrestrial plant waxes in the OM and less iron in the pore water. In addition, the generally earlier decrease of porosity and permeability and the greater contrast between the physical properties of the OM and the rock matrix in carbonate source rocks often result in different primary migration characteristics.

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Regional Hydrogeochemical Exploration for Sandstone Uranium Deposits in South Texas—The Solution-Mineral Equilibria Approach

Because the chemical composition of groundwater in contact with a buried uranium deposit should be quite distinct from that of groundwater flowing through barren rock, analysis of the groundwater may provide 3-dimensional information useful to the explorationist. Because of the complex geochemistry of uranium, analysis for uranium only will not lead to an appropriate interpretation. The solution-mineral equilibria approach, using the computer program WATEQF, has shown to be useful for a regional exploration program in south Texas. The technique has outlined areas with known mineralization and with a high potential for mineralization.

Groundwater samples were collected and analyzed for a single aquifer in existing water wells on a 1-2-mi grid over an area of approximately 169 mi^2 (438 km^2). The WATEQF computer program uses the chemical analyses to calculate saturation indices, which describe the state of saturation of the groundwater with respect to a particular mineral. In the study area, saturation indices for the uranium minerals coffinite and uraninite were highest over the most prospective areas.

Hydrogeochemical information obtained in this study supports our geologic data that the known mineralization occurs as small reduced islands in oxidized ground. The solution-mineral equilibria approach suggests that larger deposits may exist downdip of the present-day redox front, which has moved updip since the main mineralizing event. Updip movement of the redox front may have resulted from leakage of H_2S from downdip faults.

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Organic Petrology of Selected Oil Shale Samples from Lower Carboniferous Albert Formation, New Brunswick, Canada

Incident light microscopy was used to describe maturation and composition of organic material in oil shale samples from the Lower Carboniferous Albert Formation of New Brunswick.

The maturation level was determined in normal (white) light by measuring vitrinite reflectance and in fluorescent light by measuring fluorescence spectra of alginite B. Results indicate low to intermediate maturation for all of the samples. Composition was determined by maceral analysis. Alginite B is the major organic component in all samples having significant oil potential. Oil yields obtained from the Fischer Assay process, and oil and gas potentials from Rock-Eval analyses correlate to the amounts of alginite B and bituminite determined in the samples.

In some of the samples characterized by similar high concentrations of alginite B, decrease in Fischer Assay yields and oil and gas potentials is related to an increase in maturation, as expressed by increase in the fluorescence parameter λ_{max} and red/green quotient of alginite B.

Incident light microscopy, particularly with fluorescent light, offers a valuable tool for the identification of the organic matter in oil shales and for the evaluation of their oil and gas potentials.

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Interpretation of Nonlinear Vitrinite Reflectance Profiles

Investigations have established that within basins that experience continuous sedimentation, maturation profiles are linear when vitrinite reflectance values are plotted on a logarithmic scale. Not unusual, however, are nonlinear profiles where discontinuities and/or reversals are present. Common geologic interpretations of discontinuities in such profiles include unconformities, faults, and intrusions. Faults and intrusions usually can be confirmed by paleontology, logging, and seismic techniques, and will not be considered further. Although unconformities can commonly be recognized by such techniques, their magnitude in terms of eroded section is usually difficult to measure or interpret. Time-temperature modeling presents an approach to quantifying the amount of erosion at unconformities.

Frequently, the estimate of the amount of erosion at an unconformity is determined using the graphical technique developed by Dow. However, modeling suggests that this graphical approach would be valid only when the vitrinite reflectance discontinuity is located at or near the surface, with no significant reburial after its development. Our models show that with reburial and time, the discontinuity in vitrinite reflectance values would diminish. The result is an apparent decrease in the estimate of eroded section as reburial continues.

Many nonlinear vitrinite reflectance profiles cannot be accurately modeled. This may result from the lack of sufficient data to correctly interpret the geology, stratigraphy, and/or thermal history of the basin being examined.