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GEOSCIENCE FOR THE 21ST CENTURY

edited by

D.F. Merriam

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History

Occurrence and Development of Petroleum in Nebraska

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ABSTRACT

Nebraska's first documented exploratory test was in 1889 near Dannebrog (Howard County). Approximately 75 dryholes were drilled from 1903 to 1939. Forest City Basin discoveries focused attention on southeastern Nebraska. In November 1939, the Pawnee Royalty Company No. 1 Boice (Richardson County) was completed in Hunton (Devonian) carbonates. Deeper reservoirs (Viola–Ordovician) were discovered but activity declined. The Ohio Oil No. 1 Mary Egging was completed in Dakota (Cretaceous) sandstones in June 1949 in the Nebraska Panhandle—the discovery well for the multistate Denver Basin.

In 1960, the Murfin No. 1 Barth (Red Willow County) was completed in the Lansing–Kansas City (Pennsylvanian) limestone and the basal Pennsylvanian sand to open the Sleepy Hollow field in southwestern Nebraska. Activity reached an all-time high in 1961; 1,022 tests yielded 351 oil wells, 239 of these in southwestern Nebraska. Economics in the 1970's allowed several multiwell programs across the state—unfortunately no significant discoveries resulted. Older Paleozoic reservoirs in siltstone and dolomite (Pennsylvanian and Permian) under the Cretaceous Denver Basin were discovered in 1980 by the Diamond Shamrock No. 1 McMillan (Cheyenne County). Gas was discovered but undeveloped in the Niobrara chalky shale (Cretaceous) east of the Panhandle. As of January 1, 1999, 18,735 wells have been drilled in Nebraska and cumulative production to that date was 481,306,353 bbls of oil and 163,476,799,000 cubic feet of gas. Creative exploration, technology, and economics again could put the industry in Nebraska into a growth pattern.

3 November 1939, Lincoln *Journal* (dateline-Falls City, Nebraska): "It took some of us Texas rookies to show you there was oil in Nebraska," was the soft-voiced drawling comment by W. A. Gunn, Odessa, Texas, "wildcatter." Gunn and his Pawnee Royalty Company had successfully completed the No. 1 Boice in the Hunton (Devonian) carbonate in Richardson County, extreme southeastern Nebraska. Finally, Nebraska had joined the ranks of oil-producing states. However, as is usual in the oil business, the first well was not good enough. A second well, the No. 1 Bucholz, produced the required 50 bbls of oil per day (BOPD) for 60 days and received the state bonus of $15,000.

The search for oil in Nebraska had begun in the late 1800's with more enthusiasm than science (Fig. 1). Only seven of Nebraska's 93 counties have not had an oil-test well (Fig. 2).

The oldest documented test was drilled in 1889 near Dannebrog (Howard County) in central Nebraska (Fig. 3A). Total depth of the well was 1,011 feet in rocks of Cretaceous age. No shows of oil were noted. Drilling activity continued but was sporadic and usually highly speculative. Records show that only 35 bona fide deep tests for oil and gas were drilled from 1903 to 1929. An additional 39 tests were drilled from 1930 to 1939. Although all were dryholes, many of them were located and drilled by reputable companies.

Because of the success in eastern Kansas, attention became focused on the Forest City Basin in extreme southeastern Nebraska—and finally the Richardson County discovery occurred (Fig. 3B). Development was hampered by lack of equipment and water problems resulting from production. However, several additional fields were discovered and oil production in 1941 totaled

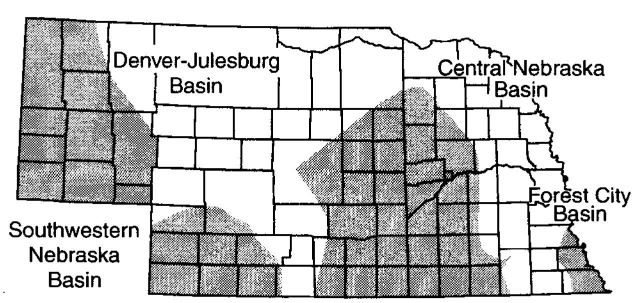

FIGURE 1—Location of major basins in Nebraska.

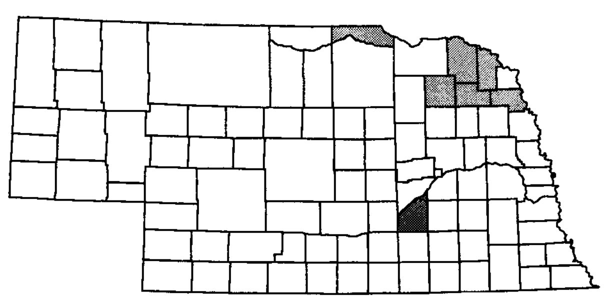

FIGURE 2—Location of seven untested counties in Nebraska.

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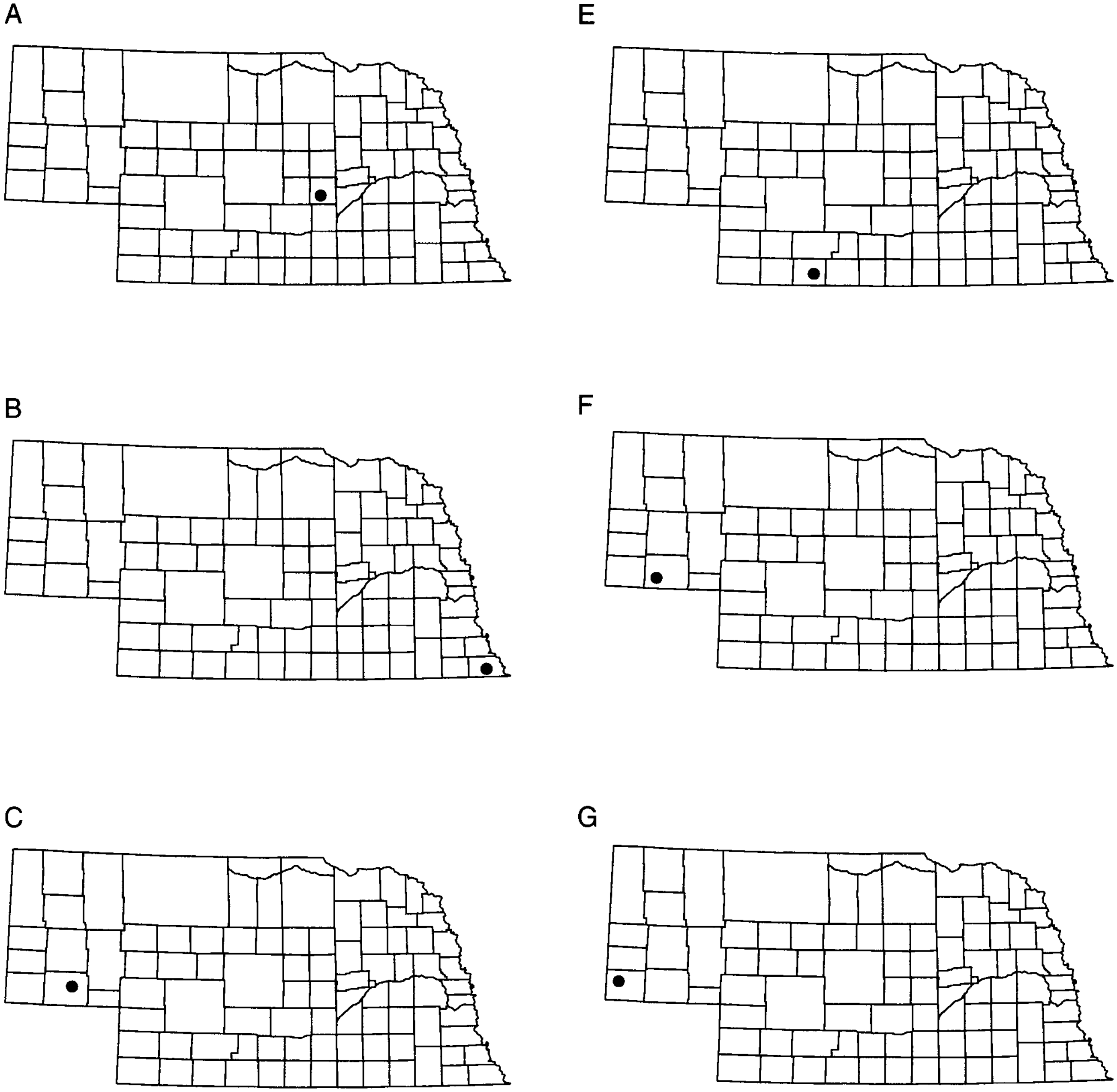

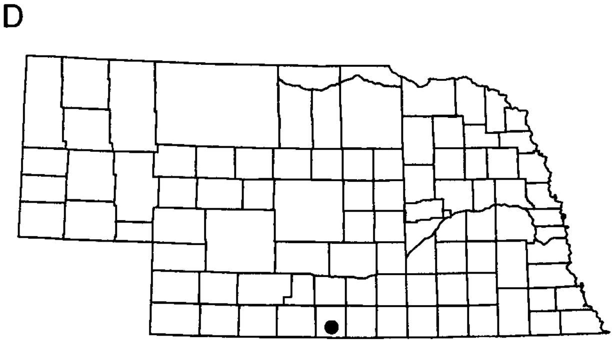

FIGURE 3—Location of new major discoveries by time in Nebraska. A, 1889 test near Dannebrog (Howard County); B, First decade (1940's): No. 1 Boice test (Richardson County); C, Second decade (1950's): No. 1 Egging/No. 1 Cruise (Cheyenne County); D, Location of No. 1 Fisher (Harlan County); E, Third decade (1960's): No. 1 Barth (Red Willow County); Fourth decade (1970's): no discoveries of note; F, Fifth decade (1980's): No. 1 McMillan (Cheyenne County); and G, Current activity (1990's): No. 1 Compton (Kimball County).

1,836,920 bbls, all from Hunton (Devonian) carbonate reservoirs. Although the discovery of deeper oil in the Viola (Ordovician) carbonate created some interest, the boom was over by the late 1940's. Low gravity and produced water continues to limit modern exploration.

Nebraska's second decade as an oil state was focused on the western end of the state. On 9 June 1949, the Ohio Oil Company completed the No. 1 Mary Egging in Cheyenne County in the Nebraska Panhandle (Fig. 3C). This well produced from the "D" zone (Dakota sandstone, Cretaceous) and opened the Gurley field. The well produced 230 BOPD from a depth of 4,402 feet. Not only was this discovery important to Nebraska, this well was the initial discovery in the multistate Denver Basin. Shortly thereafter (1950), natural gas in commercial quantities was discovered in the No. 1 Cruise, which had an initial production rate of 12,000,000 cubic feet per day. The producing zone also was the Cretaceous Dakota sandstone from 4,742 feet and opened the Huntsman field. The Cruise well qualified for the $10,000 bonus from the state for the first commercial gas production.

Exploration quickly expanded across the Denver Basin and, in 1950, 196 wells were drilled in Nebraska, yielding 87 oil, 12 gas, and 97 dryholes. Also in 1950, the South Alma field was discovered in Harlan County and was the first production in the Central Nebraska Basin. The No. 1 Fisher was completed for 50 BOPD from limestone of the Lansing–Kansas City Group (Pennsylvanian) at a depth of 3,366 feet (Fig. 3D).

Development continued through the 1950's. In 1959, 946 wells were drilled and production for the year reached a new high of more than 23 million bbls of oil. More attention was given to southwestern Nebraska because of the discovery by the No. 1 Barger in Red Willow County. This well produced 240 BOPD from the Lansing–Kansas City (Pennsylvanian) limestone at a depth of 3,856 feet. Additional drilling followed on the Cambridge Arch area of Nebraska and the Central Kansas Uplift to the south.

Following our discovery pattern, the third decade of "oil in Nebraska" opened with the discovery of the No. 1 Barth in Red Willow County in July of 1960 (Fig. 3E). This well opened the Sleepy Hollow field with an initial production of 144 BOPD from the "basal sand" of the Pennsylvanian at a depth of 3,418 feet. This sand zone, overlying the Precambrian, seems to have been derived from the Reagan (Cambrian) Sandstone and reworked by the advancing Pennsylvanian seas. The production rates, the widespread potential of the Lansing–Kansas City limestones, and the relatively shallow drilling focused drilling activity on southwestern Nebraska.

The basal sands and carbonates in the Sleepy Hollow field in Red Willow County made this the State's largest producing field. During an 18-month period, more than 200 producing wells were completed in this field. Drilling activity reached an all-time high in 1961. A total of 1,022 tests were drilled in Nebraska yielding 351 oil wells—239 of these in southwestern Nebraska. Enhanced-recovery techniques, particularly in the Panhandle Cretaceous, stabilized production. The largest producing year, 1962, yielded nearly 25,000,000 bbls, an average of 68,493 BOPD for the state. However, drilling and development generally declined after the initial boom of the early 1960's.

The fourth decade, the 1970's, was a period of expanded exploration prompted by the change in economics—price per barrel increased tenfold. In addition to development drilling, several multiwell programs tested large areas of the state. Unfortunately no significant wildcat areas were discovered. Nebraska's pattern of "discovery decades" was broken. Perhaps there is a dryhole out there that was not properly tested. Much of the drilling activity was focused on southwestern Nebraska. The Pennsylvanian production expanded across eight counties and enhanced-recovery processes helped to maintain production levels.

We were back on schedule for our fifth decade. In 1980, the No. 1 McMillan discovered production in the deeper Permian and Pennsylvanian rocks under the Denver Basin (Fig. 3F). This Amazon field discovery produced 115 BOPD from the Virgilian Series (Pennsylvanian) at a depth at which dolomites also have been productive (7,062 feet). The Admire (Permian) dolomites also have been productive in the southern Panhandle. Additional wells, zones, and fields have been discovered in the pre-Cretaceous rocks under the southern Panhandle of Nebraska. Farther to the north, encouraging tests have suggested that the Paleozoic production may be more extensive. Exploration continues. Natural-gas production has been developed from the Niobrara chalky shale (Cretaceous) in Deuel County in the southern Panhandle. Another series of wells in the Niobrara have been completed just east of the Panhandle, but production has yet to be developed.

In parallel with national patterns, drilling and production continued a slow decline into the 1990's. Although no new areas of discovery were initiated in our sixth decade, several plays have been made utilizing newer technologies. The Admire reservoir in the southern Panhandle was tested with the state's first horizontal wells that were drilled and completed in 1997. During late 1998, horizontal-drilling technology was applied in the Pennsylvanian section in the northern Panhandle. Exploration continues statewide, in part because of the favorable economics of exploration in Nebraska. The total vertical depth of the deepest test so far drilled in Nebraska was 9,971 feet in the Compton No. 1 (Fig. 3G). Currently the deepest production is at 8,450 feet from the Prairie State No. 2–A well in Kimball County.

The record as of January 1, 1999, shows that 18,735 wells have been drilled in Nebraska (Fig. 4A). Cumulative gas production to that date was 163,476,799,000 cubic feet (Fig. 4B). Cumulative oil production was 481,306,353 bbls of oil (Fig. 4C). Average daily production during 1998 was 8,700 bbls from 1,160 wells (Fig. 5). There are 113

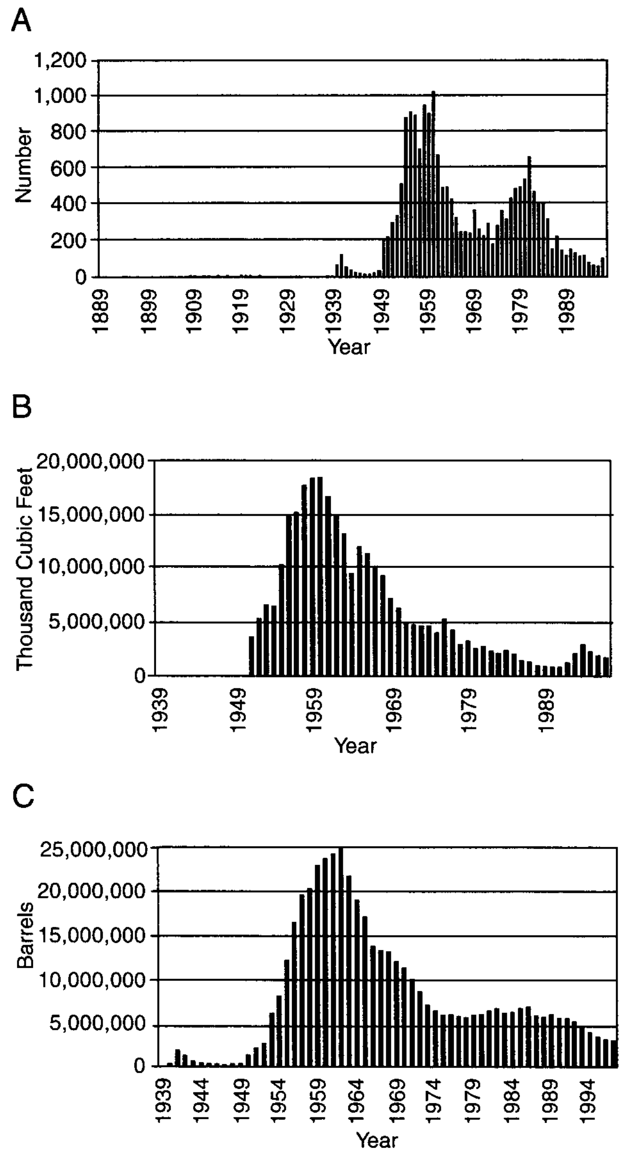

FIGURE 4—A, Total wells drilled in Nebraska by year; B, Natural-gas production in Nebraska by year; and C, Oil production in Nebraska by year.

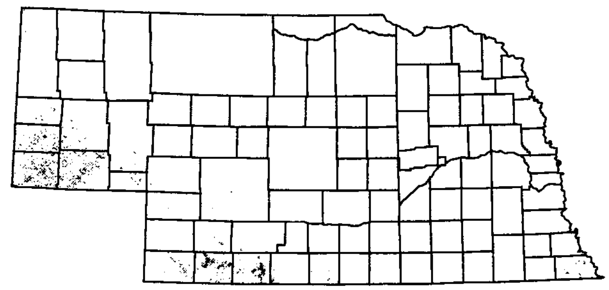

FIGURE 5—Location of active fields.

secondary-recovery projects. It is estimated that about 57% of the oil production is attributable to enhanced-recovery techniques.

Relatively shallow oil and cheap drilling have maintained minimal activity in Nebraska. This activity, however, forms the basis for potential new discoveries. Current bright spots are the Paleozoic fields in the Panhandle, the widespread distribution of the presence of Cretaceous gas, and the unusual high productivity of several wells in southwestern Nebraska. All of these are considered as short-term objectives for development.

Longer term goals might include linking across northwestern Nebraska the productive trends of the Powder River Basin of Wyoming with the Paleozoic trends in the Panhandle.

Concerns have been expressed that interpretations of the needed windows to mobilize oil are difficult to apply in parts of Nebraska; this is open to discussion. In addition, new theories of long-distance migration of oil suggest that the abundant stratigraphic traps of central Nebraska may be hosting Kansas or even Oklahoma oil. Another potential reservoir is the Midcontinent Rift System that crosses southeastern Nebraska and contains hundreds of feet of permeable clastic rocks. There is additional potential for expanded production in the Forest City Basin, both stratigraphic and structural. The unique history of Nebraska's largest field, the Sleepy Hollow field in Red Willow County, can be replicated in several counties. Many have looked but unexplored space remains for "Sleeping Hollows." Enhanced-recovery techniques are extending the life of many of the current fields. Technology promises to provide new tools for exploration and production.

If the cycles of activity of the first 60 years are any indication, the right combination of creative exploration, technology, and economics could again put the oil and gas industry in Nebraska back into a growth pattern. The next wildcat could create a new cycle of activity. Nebraska will continue to develop its natural resources contributing both barrels and bushels to the economy of the state.

Additional information on the petroleum resources of Nebraska is given on the Conservation and Survey Division Home Page, in Nebraska Geological Survey (NGS) *Geonotes* "Oil and Gas Facts for Nebraska," in NGS *Geonotes* "Nebraska Oil and Gas Production and Value for 1996 and 1997," and in NGS Resource Report No. 11 "Oil in Nebraska."

First Integrated Petroleum Production and Refining West of the Mississippi River

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E. M. Cassaday is credited with completing the first sustained petroleum production from a drilled well west of the Mississippi River in 1862. This initial shallow well located near oil seeps 6 miles north of Canon City, Colorado, eventually led to the development of the Florence field. Cassaday's operation included a crude distillation unit built by James Murphy to produce wagon grease and lamp fuel (Barb, 1942). Thus started the first major petroleum-production and refining center in the west that lasted until the 1936 shut-down of the last refinery in Florence, Colorado. Recent research by Kupfer (1998) indicates that the first "offset" well near Florence Colorado, was drilled in 1881 rather than in 1876, the date widely quoted. This well started a major exploration effort that eventually defined the limits of the field. Early drilling was accomplished with standard wood derricks and cable-tool methods. Wooden walking beams used for drilling were retained to serve as pumpjacks. Some attempts were made to group wells close together so that a single boiler could supply several steam-pumping engines used on successful production wells. More than 15 million barrels of oil have been produced from a total of more than 1,200 wells. Stripper production continues from wells that include several original wood-beam pumpjacks (Fig. 1).

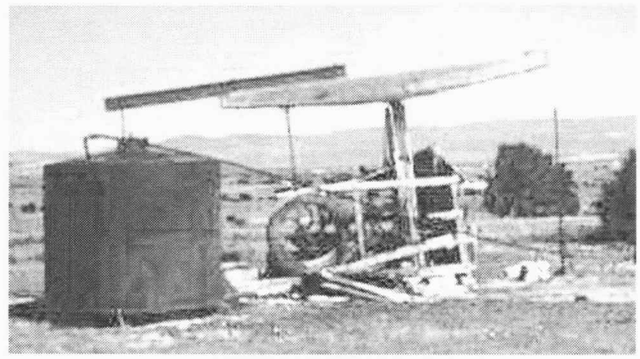

FIGURE 1—Wood-beam pumpjack.

Geologically the field is noteworthy because (1) the oil is produced from a syncline rather than the traditional anticline, and (2) the oil is produced from fractures in the Pierre Shale (Upper Cretaceous) rather than the typical high-permeability reservoir rock of the early oil fields.

Geochemical evidence indicates that the source rock is the Sharon Springs Member of the Pierre Shale (Gauthier and others, 1984). The oil moves into the fractures by gravity with subsequent drainage into well bores where it is pumped to the surface. The crude oil produced averages about 30° gravity (Be) with small amounts of associated gas and virtually no water. During the early period of the field, the associated gas was used to illuminate the well sites, fire boilers, and later to fuel gas engines for pumping. Aside from minor use in home heating in Florence, no commercial us of the gas took place.

The discovery of major reserves lead to many investment schemes involving land, oil, and refining. The first refinery was built by Arkansas Valley Oil and Land Company near Florence. Eventually major refineries were built by United Oil Company, Standard Oil Company, and Continental Oil Company. The Rocky Mountain Oil Company began construction of a large refinery north of Pueblo, Colorado, in 1891. This was connected to the Florence field by approximately 30 miles of 4-inch pipeline. This represented the first effort in the region to locate refineries away from the producing fields to obtain better transportation rates and marketing capability. The refinery closed in 1895 because of financial difficulties caused by a price war and flood damage.

Shortly after the turn of the century, the refined fuel products consisted of naphtha, gasoline, kerosene, gas oil, and residual fuel oils. In addition, signal oil, paraffin wax, and various lubricating oils were produced. Most products were marketed through the Continental Oil Company subsidiary of Standard Oil before the breakup of Standard Oil. The entire production of wax was purchased by the Dupont Powder Company for use in dynamite manufacture. As local production dwindled and refineries suffered major fires and explosions, the refining plants successively were closed.

The recent technological development of horizontal drilling techniques has been applied to the Florence field, which may lead to another cycle of development in a field whose history ranges from primitive drilling and refining to the latest in fractured reservoir production methods.

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Exploration and Exploitation

Kansas Oil and Gas Exploration, a 10-year History and Future Strategies

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The Kansas Geological Survey has a long history of reporting on oil and gas exploration and production. Starting with "Kansas Oil and Gas during 1936" by W. A. Ver Wiebe, these reports have been considered indispensable for petroleum geologists working in Kansas. This report summarizes drilling activity and hydrocarbon production between 1987 and 1996, analyzes the performance of leading operators, examines which counties and formations are the largest contributors to new reserves, and offers multiple strategies for future exploration.

Kansas drilling activity has declined from a high of 3,661 new wells drilled in 1987 to 1,513 new wells in 1996. These 25,909 well completions have resulted in the discovery of 122 million bbls of oil reserves and 2.2 TCF of gas reserves. Statewide oil production remained stable from 1987 to 1992 at approximately 5 MM bbls per month, then declined to 3.5 MM bbls per month in 1997. Statewide gas production has risen consistently from 35 BCF per month to 60 BCF per month during this 10-year period. This increase is primarily a result of infill drilling in the Hugoton gas field.

Many factors affect the selection of a strategy for future exploration. Rapidly changing product prices can render today's excellent strategy uneconomic or worse. Historical trends of oil and gas reserve-replacement rates yield valuable information in determining a suitable strategy. Analysis of companies' finding costs can provide guidelines for corporate strategies. Knowing which counties produce the greatest estimated ultimate recovery per foot drilled can focus the choice of a geographical strategy. Scrutinizing those formations that currently are yielding the biggest reserves allows an exploration staff to concentrate its talents.

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Detailed Reservoir Modeling on a Basinwide Scale and Implications on the Decision-Making Process

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More than 3,500 wells producing from the sandstones belonging to the Morrow Group (Pennsylvanian) and underlying Springer Group (Mississippian–Pennsylvanian) were the subject of detailed reservoir analysis within portions of the Anadarko Basin (USA). Within the study area, these reservoirs ultimately will produce more than 8 TCF gas, with individual completions >25 BCF gas. Because the area has been drilled by many companies, a large variation in the drilling and completion techniques has been observed; consequently, large variation in the results exists. Detailed stratigraphic correlation resulted in accurate reservoir nomenclature throughout the study area, which allowed the examination by specific reservoir and within subsets of wells with similar parameters.

The results were unexpected and should have significant impact on the decision-making processes in both exploration and development efforts. For example, mud balance influences how much invasion into a zone occurs. When it is combined with pH of the water, the mud pH demonstrates more impact on ultimate recovery than any single drilling of completion factor examined. Interestingly, mud-water loss (typically below 8 ml) did not seem to have much impact upon this observation. Another observation suggests that the practice of perforating selected intervals of a reservoir has a direct relationship to ultimate recovery—usually not favorable. Extensive stratigraphic correlations, detailed geologic analysis, and the findings presented demonstrate that changes in the decision-making process should result in opportunities for significant infield development, trend extensions, and the further exploration in what may be considered a "drilled out" play.

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Upper Pennsylvanian and Lower Permian of Southeastern New Mexico—Rejuvenation of Underdeveloped Fields Yields Major Reserves

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Carbonate reservoirs in the Cisco and Canyon (Upper Pennsylvanian) and lower Wolfcamp (Permian) sections in the Permian Basin of southeastern New Mexico are significant reservoirs for oil and gas. The 400 fields that produce from the reservoirs have yielded a cumulative 508 million bbls of oil and 3.2 TCF of gas. Sixteen of these fields have been identified that were underdeveloped at some stage in their history.

Although initially underdeveloped, subsequent redevelopment added significantly to reserves and production. For the 16 fields studied, redevelopment accounted for 65% of developed reserves. Redevelopment in the late 1980's and 1990's accounted for more than 95% of total reserves at Dagger Draw, and turned this seemingly insignificant field into the most productive field in New Mexico. Redevelopment of Dagger Draw has reversed the production decline in southeast New Mexico.

Redevelopment in these fields was generally in undrilled portions of the fields and not in overlooked pay zones. Most of these fields are formed by stratigraphic traps, but initially were thought to be structural traps and were developed as such. Because initial development was on structure and off-structure areas were undrilled, most reserves remained unproduced until redevelopment. Because 91% of the Upper Pennsylvanian and lower Wolfcampian fields have less than 10 producing wells and have been developed primarily on structures, significant reserves may remain undeveloped in existing fields.

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Blind-Thrust Spiro Play—
a Case History, Western Arkoma Basin, Oklahoma

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This paper presents a case history of the in-fill development of a portion of the Hartshorne South gas field (100+ BCF), located in the western Arkoma Basin of southeastern Oklahoma, USA. Development primarily targets the basal Atoka "Spiro" sandstone where thrust faulting compartmentalized the Spiro into separate, gas-charged reservoirs at 12,000 feet to 15,000 feet. Having no surface expression, the "blind thrusted" Spiro fault blocks require detailed, subsurface imaging to identify and define drilling targets. Although the Hartshorne South gas field was developed successfully during the mid 1980's to early 1990's using 2D seismic for structural imaging, the increased subsurface illumination of a 50-sq-mi 3D seismic survey was required to locate the undrilled and potentially undrained structures targeted by our in-fill development program.

Interpretation of the 3D volume, integrated with well control and production performance data, identified a previously untested structure that, because of its structural orientation, was mostly invisible to the existing, predominately north-south-oriented, 2D seismic data. Amplitude analysis of reservoir continuity aided in the selection of a drill site at the optimum structural location. The Barrett Resources Watts Ranch No. 1–25 wellbore successfully encountered a productive and originally pressured "blind-thrust" Spiro reservoir.

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Morrow Incised Paleovalley Production, Stateline Trend, Northern Anadarko Basin

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Detailed sedimentological and petrophysical analyses of cores from producing Morrow Sandstone fields along the Colorado–Kansas Stateline Trend indicates that reservoir production properties differ greatly between the two major paleovalley-fill producing facies, fluvial and tidal (estuarine) sandstones. The suite of sedimentary structures observable in cores also differs greatly between fluvial and tidal deposits, in fields such as Moore–Johnson, Arapahoe, and SW Stockholm. These fields are complex internally, contain geographically and vertically limited reservoirs, and only can be drained effectively and economically if the detailed internal architecture of the reservoirs is understood. Where tidal sandstones interfinger with fluvial sandstones, vertical permeability is diminished and flow units are fragmented. Tidally deposited (estuarine) sandstones are finer grained and more clay prone than the sandstones deposited by fluvial processes, and as a result have poorer reservoir properties. Thin, mm-thick, clay drapes, abundant in tidal channel accretion point bars, may reduce vertical permeabilities significantly .

Paleovalley-fill deposits in the Morrow Stateline Trend fields differ significantly from deltaic deposits with which they usually are confused. They differ depositionally, geometrically, and in the characteristics and distribution of flow units.

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South Eubank Field—Successful Development of Deeper Reserves Using 3D Seismic

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A portion of recent field development efforts in the Hugoton Embayment of western Kansas have focused on deeper Mississippian sandstone reservoirs of the Chester Series. Such efforts yielded particular success in the South Eubank field, Haskell County, Kansas. Subsurface mapping and 3D seismic information led to approximatelly 30 new producers being drilled in this field. Reservoirs are best developed in fine-grained, well-sorted Chester sandstones filling a narrow incised paleovalley system that extends north-south through the field. 3D seismic data were required to delineate the paleovalley system accurately and to locate specific drill sites. Success at South Eubank suggests that other portions of the same valley system might be similarly developed.

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History and Development of the Stewart Field, Finney County, Kansas

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The Stewart field produces from a Morrow valley-fill system at depths of 4,700–4,800 feet. The productive valley-fill trend is 5 miles long and 1/4 to 1/2 mile wide. The Morrow Sandstone is 30 to 40 feet thick within the valley and absent in adjacent areas. Productive sandstones are interpreted to be estuarine in origin based on core descriptions. The valley is incised into Mississippian Saint Genevieve and Saint Louis units. Trapping is regarded as stratigraphic with regional structure playing an important role. Average porosity and permeability in the reservoir are 16% and 138 md, respectively. The produced oil has a gravity of 280 and low gas oil ratio of 37 SCF/STB.

The development history of Stewart covers a time span from 1952 to the present with significant time gaps. Much of the development occurred from 1985 to 1989. Reasons for the time gaps involve change of operators, geologic concepts, and technology. Development of the field was aided significantly by 2D and 3D seismic data.

The field was unitized in 1995 and waterflooding began with six injectors in October 1995. Currently, 12 injectors are in operation and monthly production is in excess of 100,000 BO. The production in the field has been increased significantly with the secondary-recovery process. Estimated ultimate primary plus secondary recovery is greater than 7 million BO.

The success story of Stewart field illustrates that significant reserves of oil and gas remain to be discovered in the Morrow sandstones of Kansas and adjacent areas.

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Basin
Analysis

Subtle and Not-So-Subtle Anticlinal Structures and Their Geothermal Overprint in the Salina Basin, North-Central Kansas

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ABSTRACT

The Salina Basin in north-central Kansas is not a prolific oil-producing basin as are other similar basins in the Midcontinent. However, long-known subtle structures —*plains-type folds*—in the southern part have produced oil for almost 70 years. The northwest-southeast basin axis extends northward into Nebraska, and the basin is asymmetrical with a steeper southwestern flank bounded by the Central Kansas Uplift and a gentle northeastern flank extending eastward to the Nemaha Anticline. The southern limit of the basin is ill-defined with no major limiting feature between it and the Sedgwick Basin to the south. Rocks range in age from Precambrian to Quaternary, but it is mainly a Paleozoic basin with the stratigraphic section truncated to the east, so that the maximum thickness of sediment in the basin is about 4,500 feet. The structural history of the basin is similar to that of the adjacent Forest City, Sedgwick, and Cherokee Basins. A major change occurred in the structural regimen in the Late Mississippian/Early Pennsylvanian when the present-day structural features were formed. Minor folds, as elsewhere in the Midcontinent, were formed by differential compaction of sediments over tilted, rigid Precambrian fault blocks. Minor, but important, structural adjustments continued during the late Paleozoic and Mesozoic, and continue yet today. Several of the plains-type folds which occur along northeast-trending anticlines were analyzed as to time of origin, development, and relation to geothermal conditions of the region.

INTRODUCTION

The Salina Basin, located in north-central Kansas, is a typical shallow, asymmetric, cratonic basin (Fig. 1). It has a sediment fill of about 4,500 feet, and the sediments range in age from Precambrian to Quaternary. The structure was formed in the Late Mississippian/Early Pennsylvanian during the Ouachita Orogeny. Subsequent regional movement has been mostly tilting and readjustment of minor structures in response to external stresses.

Why the Salina Basin seemingly is nonproductive has been speculated on for many years. The oil and gas production is primarily in the southern part of the basin adjacent to the more prolific Central Kansas Uplift and Sedgwick Basin to the west and south (with a small amount present on the western flank to the east of the gap between the Cambridge Arch and Central Kansas Uplift). The absence of petroleum could be explained by the

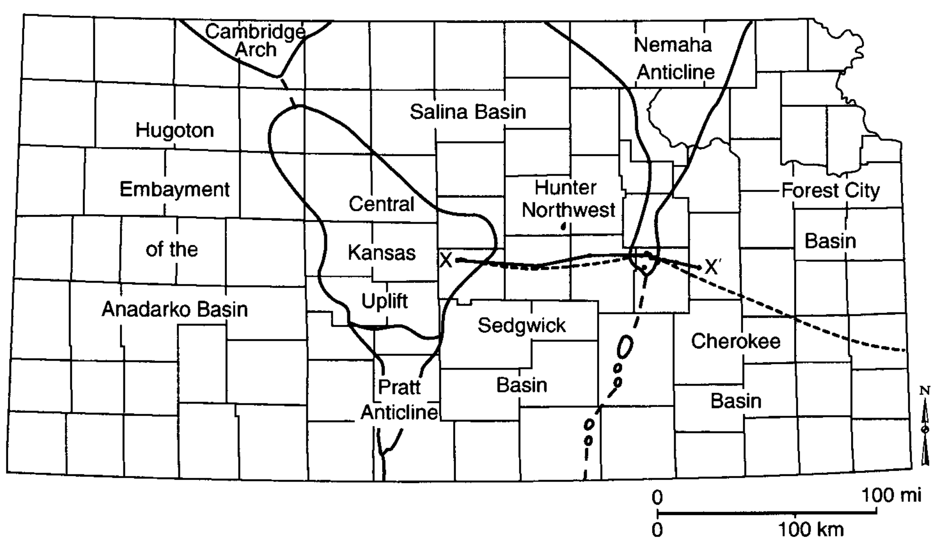

FIGURE 1—Location of major post-Mississippian/early Pennsylvanian structural features in Kansas (from Merriam, 1963). Location of cross section and Hunter Northwest anticline also are shown.

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Walters (1958) model, where northward-migrating fluids out of the Arkoma/Anadarko Basins were trapped prior to reaching the Salina Basin. This model assumes that no petroleum was generated in place. However, Newell and others (1987) have shown that there is potential for petroleum generation in the Forest City Basin under similar stratigraphic and structural conditions as in the Cherokee Basin (Förster, Merriam, and Hoth, 1998).

Because of the perceived notion of the absence of petroleum in the basin, fewer wells have been drilled and it has not received the same attention as its more productive counterparts. In addition, recent exploration has been minimal, so that much of the available data are older and not so complete. We investigated structural and temperature data from the database to search for relations that could point to conditions of fluid flow in the subsurface.

These subtle and not-so-subtle anticlines in the Salina Basin have an overprint of higher temperatures, as do similar structures in adjacent basins. We document this relation of 'warm' anticlines in Saline County, which is located in the southern part of the basin.

STRATIGRAPHY

The Precambrian basement in the basin consists of a crystalline granite (1600–2500 Ma) that was intruded by small high-magnetite-bearing granitic bodies (1380–1480 Ma). Slightly metamorphosed sediments (1600–1800 Ma) also occur apparently in downfaulted grabens in the crystallines. Cutting across the basement is the younger northeast-trending Midcontinent Rift System (MRS) containing metasediments and basalts (900–1600 Ma) (see Van Schmus and others, 1993, for a more complete summary of the Precambrian in the Midcontinent).

The sediment fill (about 4,500 feet) is mainly Paleozoic in age and consists of the (from oldest to youngest): Reagan (Lamotte) Sandstone noncomformably overlying the crystalline Precambrian rocks followed by the Arbuckle Group (mainly carbonates), Simpson Group (mainly sandstone), Viola Limestone, Siluro–Devonian carbonates, Kinderhook shale (=Chattanooga Shale), Mississippian carbonates, and a substantial succession of Pennsylvanian and Permian alternating thin clastics and carbonates in a cyclic sequence (Fig. 2). Some Cretaceous strata, mostly clastics, unconformably overly the Paleozoic, and the Cretaceous, in turn, is overlain unconformably by the Tertiary clastic veneer of the Ogallala Formation. Background stratigraphic and structural data are contained in publications by Lee, Leatherock, and Botinelly (1948), Lee (1956), Lee and Merriam (1954), and Merriam (1963).

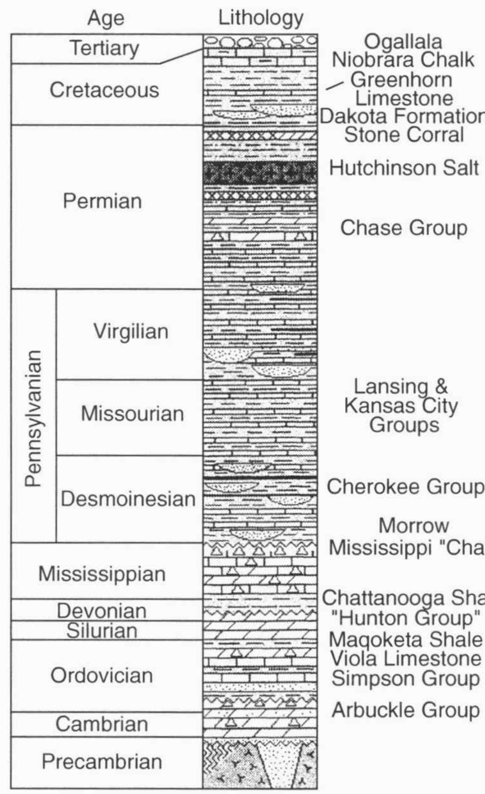

FIGURE 2—Generalized stratigraphic section of rock units in Salina Basin (total thickness is approximately 4,500 feet).

SUBTLE STRUCTURES

Merriam and Förster (1996) developed the concept of *structural gradient* and *structural interval gradient* to analyze the subtle structural features (plains-type folds). The structural gradient, the amount of vertical closure crossplotted against depth (or geologic age) gives evidence of change in structural conditions, and the structural interval gradient gives evidence of readjustment of features by noting the amount of thickness change plotted as a percent on and off structure (Merriam and Förster, 1996, 1997). These features have closure only in the tens of feet at depth and may be reflected in the shallow beds as structural noses.

All of the minor structural features seemingly were formed in the Late Mississippian/Early Pennsylvanian at the time of major change in the Midcontinent (Fig. 3). As van der Pluijm and others (1997) have shown, stress can be transferred for great distances through the rigid basement rocks of the 'stable' interior. This substantiates the concept that the minor folds (plains-type folds) were formed mainly by vertical movement as was noted 80 years ago by Gardner (1917).

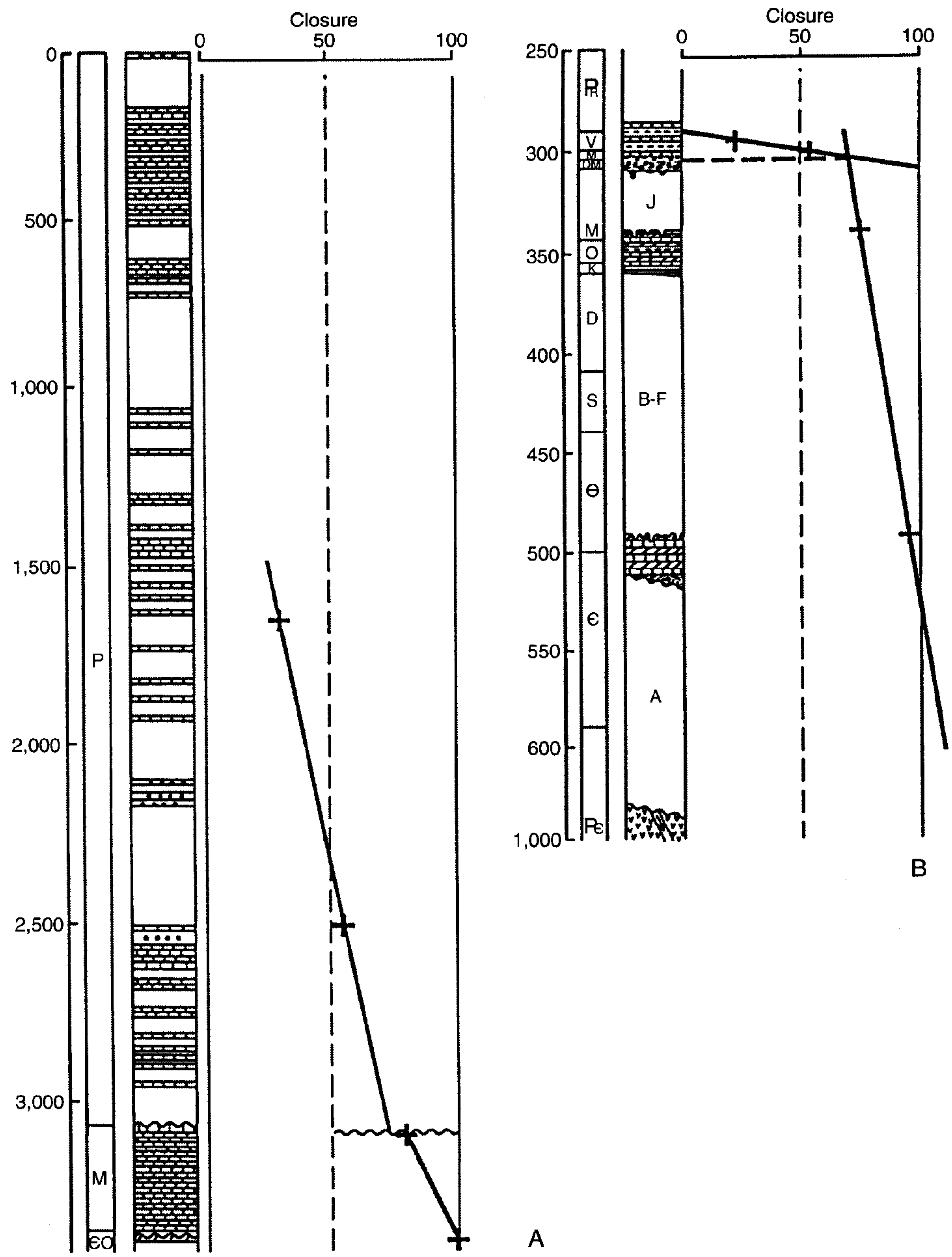

FIGURE 3—Structural gradient of Slick–Carson anticline: A, showing major time of development near end of Mississippian (plot of depth vs. closure), and B, different representation of structural gradient by crossplot of geologic time vs. closure showing time of major movement during late Paleozoic (from Merriam and Förster, 1996). Crossplot B is more effective in showing change in structural regime. Symbols A, B–F, and J show time intervals with missing stratigraphic record.

NOT-SO-SUBTLE STRUCTURES

Several prominent structures occur in the Salina Basin including the Voshell anticline that extends northward into the Salina Basin from the Sedgwick Basin and the Halstead–Graber trend. Several local anticlines that are located along these features are larger in extent and closure than the more abundant subtle anticlines (see Newell and Hatch, this volume, for a discussion of the McPherson anticline). These features are sharper and more pronounced with closures in the scores up to a couple of hundred feet.

GEOTHERMAL FRAMEWORK

Only one well in the basin is known to have been logged with high-precision temperature equipment. The well, Smokyhill borehole in Saline County (sec. 32, T. 13 S., R. 2 W.), is an observation well drilled by the USGS/KGS in the late 1980's for a geothermal study (Blackwell and Steele, 1989). Förster and Merriam (1993, 1994) constructed an east-west cross section including this well though the southern part of the basin as part of a geothermal study in eastern Kansas. A heat-flow value of 59 mWm^{-2} ±6 was calculated by Blackwell and Steele (1989) from data for this well.

Figure 4 shows the modeled temperatures for the east-west cross section across the southern part of the Salina Basin (see Fig. 1 for location). In general, the isotherms are deeper to the east, reflecting the overall thinning of the sedimentary section toward the Nemaha Anticline. Isotherms increase downward sharply over the crest of this major structure where the Precambrian crystalline basement is close to the surface. The temperature is on the order of 50°C in the deepest part of the basin, which is comparable with conditions in the Cherokee Basin. The cross section reflects the general structure in the basin, but not the more subtle features.

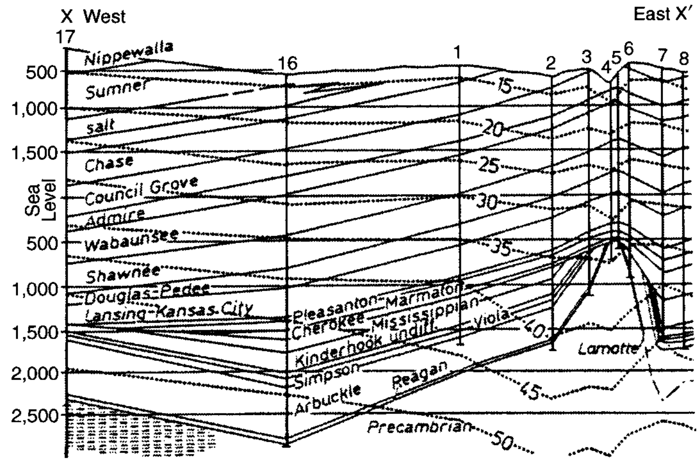

FIGURE 4—Cross section through southern part of Salina Basin showing relation of isothermal pattern to structure (from Förster and Merriam, 1993). Data used for thermal modeling are extrapolated from Smokyhill borehole (Saline County).

CONDITIONS IN SALINE COUNTY—AN EXAMPLE

The regional structural map on top of the Mississippian (see Merriam, 1960) in Saline County in the southeastern part of the Salina Basin shows a gently dipping surface to the southwest on which are located several major northeast-southwest-trending structures (Fig. 5). Part of the southwest-plunging Abilene anticline (Jewett, 1951) is present in the southeastern part of the county and several oil fields are located on local structural highs along the crest of a parallel feature just to the west, including Gypsum Creek (secs. 28, 32, 33, T. 16 S., R. 1 W.), Hunter (secs. 17, 20, T. 16 S., R. 1 W.), Hunter Northwest (sec. 18, T. 16 S., R. 1 W.), Hunter North (secs. 5, 8, T. 16 S., R. 1 W.), and Mortimer (sec. 33, T. 15 S., R. 1 W. and sec. 4, T. 16 S., R. 1 W.). To the west and semiparalleling the Abilene anticline is the Asseria anticline (here named) for the major feature extending through central Dickinson County through Salina and Asseria connecting to the Lindsborg anticline in south-central Saline and north-central McPherson counties. This feature also has several local oil fields located on anticlinal features including Salina, Smolan, Olsson, and Lindsborg. The vague Brookfield anticline (here named) is the next major northeast-trending, southwesterly plunging anticline subparalleling the Asseria anticline to the west.

Single temperature values are available from several wells in the county, where bottom-hole temperatures (BHTs) were recorded in the Mississippian in the Gypsum Creek and Hunter fields; along the Asseria anticline in the Viola Limestone and Maquoketa Formation, and in the Salina, Smolan, and Lindsborg fields; a few scattered measurements were made in the Simpson and Arbuckle. In general, the temperature increases with increasing depth so that in the southwestern part of Saline County, the temperatures are higher than in the eastern part for the same stratigraphic unit. The statistics for the temperatures in Saline County are given in Table 1.

TABLE 1—Statistical data on BHTs in Saline County.

Strat Unit	Temp. Range (° F)	Average Temp. (° F)	No. Points
Mississippian	89–114	98.6	20
Maquoketa	98—115	105.5	17
Viola	97–113	106.4	16
Simpson	101–111	108.1	15
Arbuckle	90–119	106.3	35

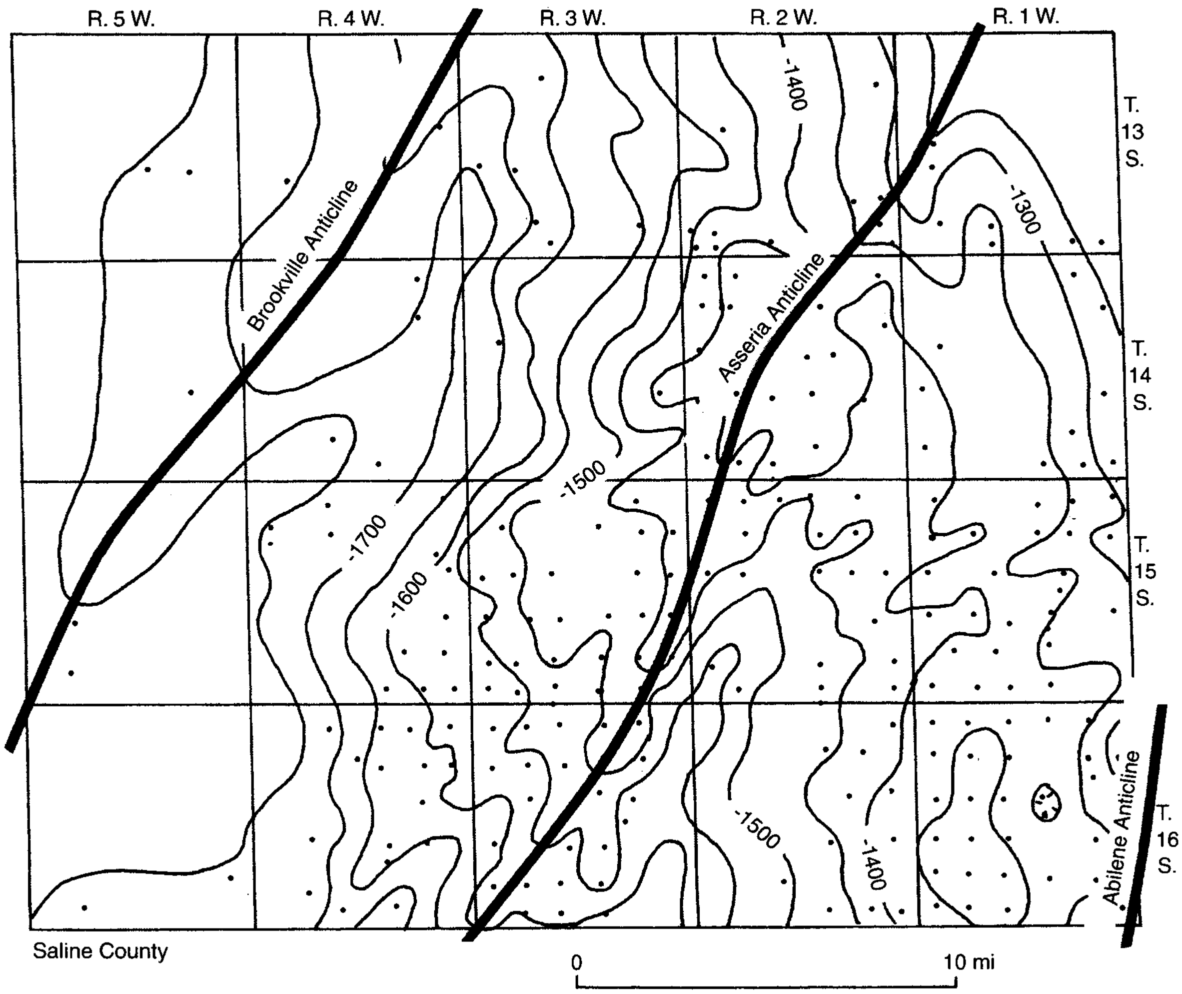

FIGURE 5—Regional structure map on top of Mississippian for Saline County, Kansas. Contour interval (subsea): 50 ft; location of data points (well locations) indicated by dots. Location of major anticlines outlined.

A detailed study of structure and subsurface temperature was made of four producing anticlines: Hunter Northwest, Gypsum, Hunter, and Hunter North, but only one—the Hunter Northwest—is presented here as representative. The structural closure on the respective features is 25 feet, 30 feet, 40 feet, and 40 feet; temperature difference on and off structure is 17°F, 10°F, 8°F, and 3°F. BHTs in the Hunter Northwest field were plotted over a structural cross section of the subtle anticline (Fig. 6), and they show a good coincidence of higher temperature with the apex of the structure as expected. This relationship of higher temperature on anticlinal folds in the Midcontinent was demonstrated by Förster and Merriam (1996; Fig. 7) in the Cherokee and Forest City Basins. Temperature anomalies in association with these subtle features have been recognized for about 70 years (see Thom, 1925) but only demonstrated in detail in the past few years.

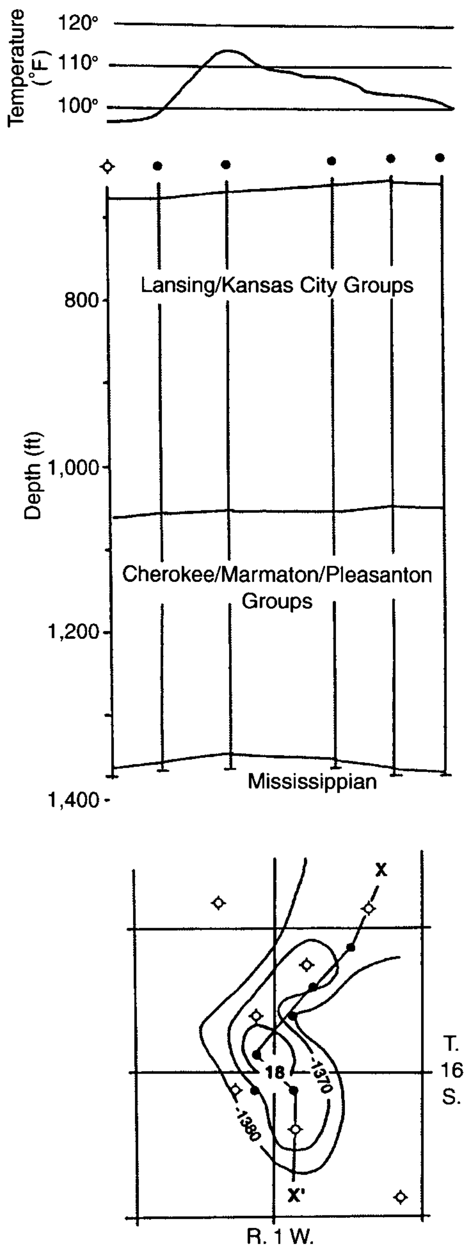

FIGURE 6—Cross section of Hunter Northwest anticline, typical plains-type fold, showing relation of BHT profile to structural cross section (for location see Fig. 1).

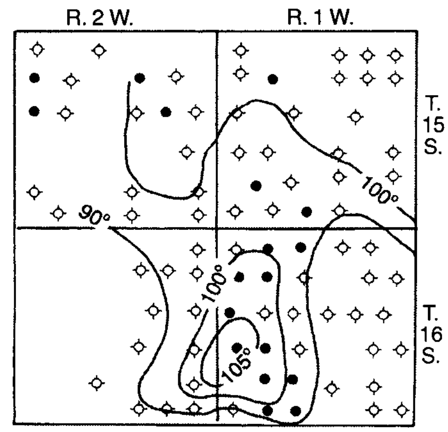

FIGURE 7—Contour map of uncorrected BHTs from top of Mississippian in southeastern Saline County for Gypsum Creek–Hunter trend showing higher temperature over structure. Symbols standard; temperature in °F; scale: township is 6 × 6 miles.

CONCLUSIONS

Origin and development of subtle anticlinal features in the Salina Basin of north-central Kansas were analogous to similar features in other Midcontinent sedimentary basins. The minor features developed by differential compaction over tilted, Precambrian fault blocks in the Late Mississippian/Early Pennsylvanian and continued to develop intermittently through the late Paleozoic, Mesozoic, and Tertiary to the present.

These subtle anticlines are 3–17°F warmer than the immediate surrounding area. It is unlikely that the observed temperature pattern is a relic of temperature disturbance during drilling. We interpret the coincidence of temperature and structural anomalies as a result of fluid movement along features developed in the sediments over the faulted basement blocks.

By careful and detailed study of the geothermal field, we believe from our studies that temperature could be used as an exploration guide to locate undiscovered petroleum deposits in the Salina Basin.

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Petroleum Geology and Geochemistry of a Production Trend Along the McPherson Anticline in Central Kansas, with Implications for Long- and Short-Distance Oil Migration

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ABSTRACT

The McPherson Anticline trends north-northeast–south-southwest and traverses the arch between the Salina and Sedgwick Basins in Kansas. This anticline extends 50 miles (80 km) and contains nine multipay oil and gas fields that produce from Paleozoic reservoirs. Subtle structural movement occurred throughout Paleozoic time, but the anticline is primarily a Late Mississippian–Early Pennsylvanian feature. It has a steeply dipping down-to-the-west fault on its western flank that has up to 400 feet (120 m) of throw. Culminations (and greater vertical offsets along the flanking fault) generally are adjacent to north-south-trending fault segments. Lesser vertical offsets along the flanking fault and structural sags are associated with north-northeast–south-southwest-trending fault segments. Reverse faulting is indicated by repeated stratigraphic sections encountered in wells, thus an overall right-lateral north-northeast–south-southwest wrench-fault regime can account for the distribution of structural traps.

The cross-fault juxtaposition of the Devonian–Mississippian Chattanooga Shale against a given pay zone may affect the chemical characteristics of the produced oils. Oils produced from Mississippian strata, relatively high in the section, have chemistries that suggest a mature Chattanooga Shale source rock and south-to-north migration up the crest of the anticline. Similarly, oils produced from pay zones in Ordovician rocks, where the Chattanooga Shale across the fault is shallower than the pay zone, are typical "Ordovician" oils of low relative maturity. If, however, because of faulting, an Ordovician pay zone is located above or directly against the Chattanooga Shale, then oils produced from the Ordovician pay zone may have compositions indicating mixing of Chattanooga Shale oils with "Ordovician" oils.

INTRODUCTION

The McPherson Anticline (Koester, 1934) in central Kansas is a north-northeast–south-southwest-trending anticline, which is situated on a broad unnamed east-west-trending arch that separates the Salina Basin from the Sedgwick Embayment of the Anadarko Basin. The anticline extends for approximately 50 miles (80 km) and contains a production trend of nine multipay oil and gas fields. From south to north, these fields are the Burrton, Hollow–Nikkel, Voshell, Elyria, Johnson, Chindberg, McPherson, Reuben, and Bonaville fields. The fields are named the Voshell trend after the most prominent field in the trend, and they are aligned along the anticline like pearls on a string. Generally, each of these fields is located on a structural culmination, but individual pay zones also may have stratigraphic components of entrapment.

Most of the fields along the McPherson Anticline were discovered in the late 1920's and early 1930's. As of 1998, these fields cumulatively have produced 132 million barrels of oil and 7.6 million cubic feet of gas. API gravities for the oils range from 35 to 42° API.

STRATIGRAPHY

The local Paleozoic strata are mainly a product of shallow-marine epicontinental seas and can be characterized as a series of vertical alternations of siliciclastic and carbonate strata. Disconformities and low-angle angular unconformities generally bound the upper and lower surfaces of each formation (Merriam, 1963).

Pennsylvanian units, which are not differentiated for this report, consist of thin shales, sands, and carbonate

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units that are the product of marine–nonmarine cyclothemic deposition (Heckel, 1986). Prolific petroleum reservoirs are widespread in Pennsylvanian rocks in Kansas, but only minor widely separated pays in this geologic system produce along the McPherson Anticline.

The most widespread pay zone occurs in porous, karsted Mississippian carbonate strata situated directly beneath the regional angular unconformity present at the base of the Pennsylvanian System. Most of the gas from the Voshell trend is associated gas (i.e., gas produced in association with oil, or from a field with an oil leg) produced from the Mississippian.

The apparent thickness of the Mississippian section ranges considerably. This primarily is an artifact of erosion of this unit beneath a major angular unconformity present at the base of the overlying Pennsylvanian strata. Off-structure wells have more Mississippian strata preserved in them than on-structure wells. The dominant producing zone is at the top of the Mississippian, but porous zones within the Mississippian also can be reservoirs.

The Chattanooga Shale, which conformably underlies the Mississippian carbonates, can be up to 200 feet (60 m) thick. An unconformity at the base of this unit is situated on top of the Silurian–Devonian "Hunton," but it locally cuts down to the Ordovician Viola. The Devonian–Mississippian Misener Sandstone is the basal transgressive sand beneath the Chattanooga Shale. It is distributed erratically and generally less than 10 feet (3 m) thick, but it can be a locally important pay zone, particularly at the Voshell field.

Silurian–Middle Devonian carbonate strata are identified as "Hunton" formation by drillers in Kansas, but in the strictest sense, the rocks in Kansas are not entirely equivalent to the true Hunton Group in Oklahoma, which is a Lower Devonian unit (Goebel, 1968).

The Upper and Middle Ordovician units are composed, from base to top, of the Simpson Group, Viola Limestone, and Maquoketa Shale. The Maquoketa is dominantly a dolomitic shale and it is not a reservoir in the Voshell trend. The Viola is generally a nonporous limestone within the study area, but its reservoir facies is a porous dolomite that is present at the top of the Viola in fields along the northern part of the McPherson Anticline. The Simpson Group is composed of marine shale and sandstone with minor dolomite. About 500 to 700 feet (150–210 m) of Upper Cambrian–Lower Ordovician Arbuckle Group carbonates are present between the base of the Simpson Group and the Precambrian basement.

GEOLOGIC STRUCTURE

A structure map of the top of the Middle Ordovician Simpson Group depicts the regional structure at depth of the McPherson Anticline and surrounding region (Fig. 1). Although the tectonic movement responsible for the present-day structural configuration of the McPherson Anticline is long-lived—probably spanning much of Paleozoic time—the main structural movement responsible for this feature occurred in Late Mississippian–Early Pennsylvanian time (Merriam, 1963).

The McPherson Anticline has a steeply dipping down-to-the-west fault on its western flank that has up to 400 feet (120 m) of throw (Figs. 1 and 2). Structural closures associated with individual fields along the length of the anticline (and greater vertical offsets along the flanking fault) generally are adjacent to north-south-trending fault segments. Lesser vertical offsets on the flanking fault correspond to north-northeast–south-southwest-trending fault segments. These fault segments are adjacent to structural sags, which form the north and south closures for the oil and gas fields along the McPherson Anticline.

Kinematically, the structural closures along the McPherson trend are compatible with a component of right-lateral strike-slip movement along the bounding fault on the western flank of the McPherson Anticline (Fig. 1). Structural adjustment of basement blocks and attendant deformation at the margins of the blocks can account for the structural traps along the anticline. Slight north-northeast–south-southwest strike-slip movement of two basement blocks will cause compression and folding along north-south segments of the fault. Mechanically, these north-south segments will behave as restraining bends in the overall strike-slip system, whereas north-northeast–south-southwest segments will accommodate more easily the lateral movement by simple lateral tearing; hence, these latter fault segments have lesser offsets associated with them.

The compression at the restraining bends would have to be accommodated by a component of folding and reverse faulting. Reports on the oil fields along the McPherson Anticline cite examples of repeated stratigraphic sections on the western flank of the anticline, such as at the Voshell field (Hiestand, 1933) and at the Hollow–Nikkel field (Bunte and Fortier, 1941).

RELATIONSHIP OF STRUCTURE IN PRODUCTION

A regional structural cross section (Fig. 2) along the fault plane west of the McPherson Anticline shows all the oil fields and enables an integrative look at their geometry and the relationship of the many pay zones. The cross section is drawn along the flanking fault instead of the crestal trace of the McPherson Anticline. Strata both on the upthrown and downthrown sides of the fault therefore can be displayed on the cross section, and thus the juxtaposition of strata across the fault and in relationship to producing horizons can be investigated. The cross

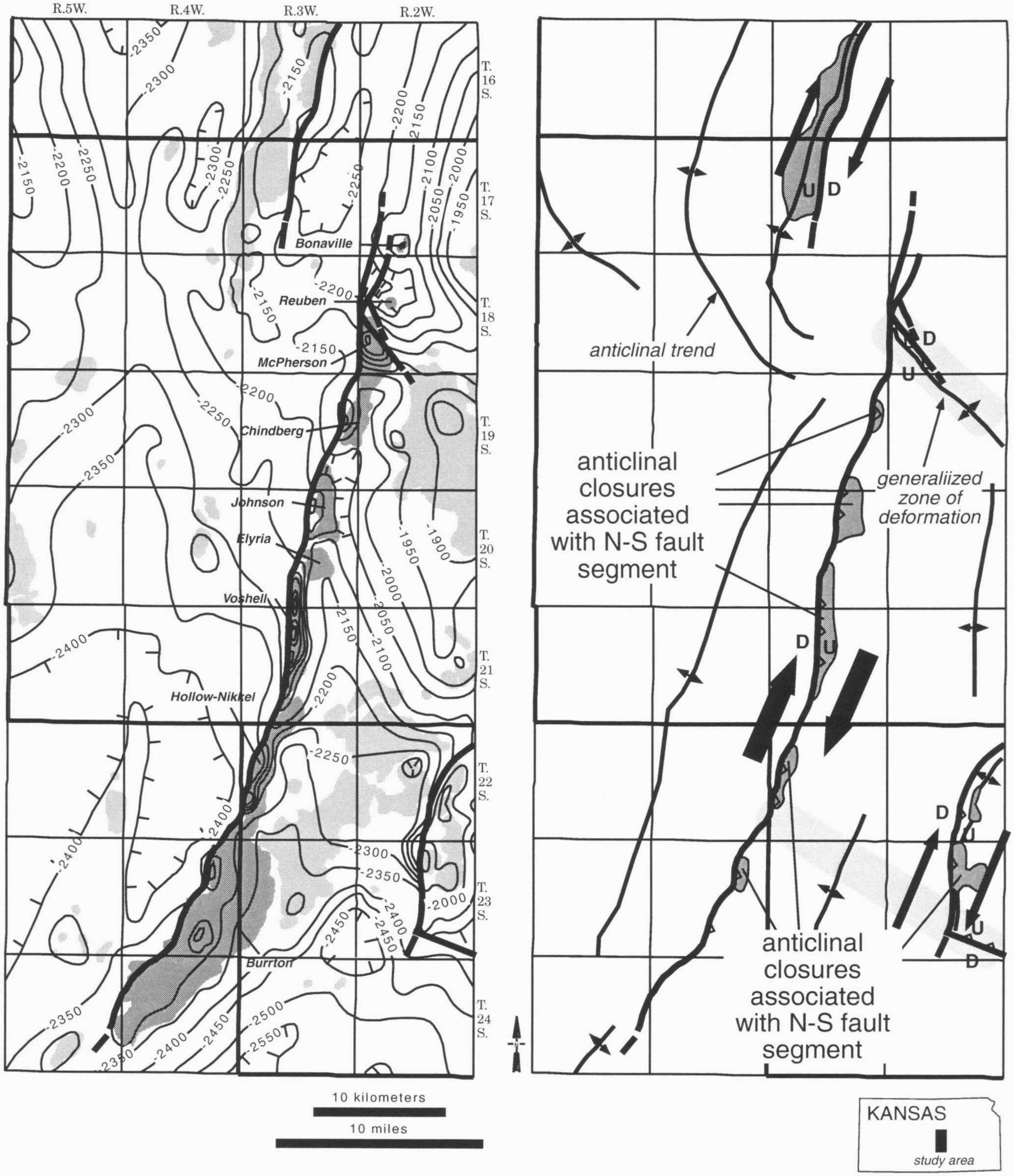

FIGURE 1—Structure map for top of Ordovician Simpson Group in area of McPherson Anticline, obtained from well records. Structural features are interpreted in right-hand figure. North-south fault segments are associated with anticlinal closures and reverse faulting, whereas north-northeast–south-southwest fault segments have relatively smaller vertical offsets and form structural sags. These sags correspond to spill points between oil fields. Slight north-northeast–south-southwest dextral movement of basement blocks may account for structural pattern observed along McPherson anticline (contour interval=50 ft.; relative to sea level datum; petroleum fields shaded; darker fields are along McPherson anticline).

section indicates that the Mississippian pay zones along the McPherson Anticline evidently have a component of stratigraphic entrapment in that the oil-water contacts for many of the fields are below their structural spill-points. Although not proving northward migration of the Mississippian oils per se, the general southward plunge of the McPherson Anticline at Mississippian level is at least compatible with it. The oil-water contacts of the "Hunton" carbonates and Misener Sandstone in the Burrton and Hollow–Nikkel fields are close to their northern spill-points at this stratigraphic level. Oil in the "Hunton" and Misener therefore may have migrated northward up the anticlines as far as the southern part of the Voshell field. Alternatively, and inasmuch as the Hunton and Misener are overlain immediately by Chattanooga Shale, their oil also could be derived from downward expulsion directly into the reservoirs, or by cross-fault migration from downthrown Chattanooga on the western side of the fault.

The oil-water contacts for the deeper pay zones (i.e., the Viola, Simpson, and Arbuckle horizons) between the Burrton and Hollow–Nikkel fields, and between the Hollow–Nikkel and Voshell fields (Fig. 2) are significantly above their respective spill points, hence either significant leakage may have occurred to raise the oil-water contacts in these fields, or perhaps local generation and migration may have incompletely filled the traps at these stratigraphic levels.

It is not evident why the Johnson and Chindberg fields do not produce from strata deeper than the Mississippian. One possible clue is the geometric relationship that these reservoirs have to the Chattanooga Shale on the downthrown side of the fault. The Chattanooga Shale, which is a potential source rock, is juxtaposed on the western side of the fault in a structural position significantly below the Arbuckle, Simpson, Viola, and Hunton pay zones in the Burrton, Hollow–Nikkel, and Voshell fields. If the Chattanooga Shale is generating oil locally, this geometry may permit this oil to migrate across and possibly up the fault into these older reservoirs on the upthrown side of the fault.

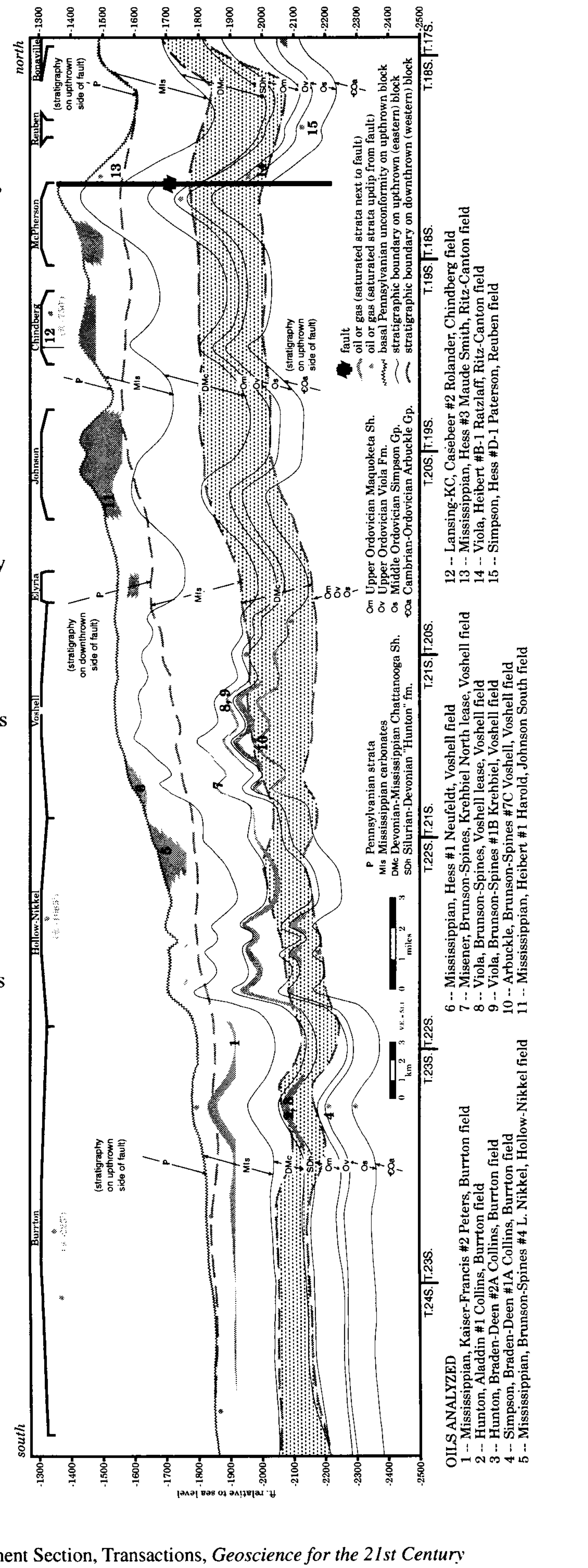

FIGURE 2 (right)—Structural cross section drawn along trace of fault on western flank of McPherson Anticline. Stratigraphy and structure on upthrown (eastern) side of fault on this cross section, as well as stratigraphy on downthrown (western) side, is shown so that cross-fault juxtaposition of stratigraphic units can be understood. Only Chattanooga Shale and top of Mississippian strata are shown for downthrown side. Oil and gas pay zones, some of which are directly adjacent to flanking fault, also are shown. Oil/water contacts for various pay zones are inferred from inspection of scout cards for producing wells. Locations of 15 oil samples taken from fields on or near this anticline are shown.

The Arbuckle pay zone at the Burrton field produces oil well below any Chattanooga Shale across the flanking fault, thus the source for this oil probably is not the Chattanooga Shale. Wells producing from this horizon have been abandoned and unfortunately no sample of this oil could be obtained. The Simpson reservoir at the Burrton field also is below the base of the Chattanooga; nevertheless, sufficient uncertainty in the structure on the downthrown side of the fault makes it possible that some Chattanooga-derived oil could have charged this reservoir.

GEOCHEMISTRY OF CRUDE OILS

Fifteen crude oils were collected along the fields on the McPherson Anticline (Fig. 2) and were analyzed geochemically. Previous studies listing geochemical analyses of oils from the McPherson Anticline and adjacent areas in central and eastern Kansas include Reed, Illich, and Horsfield (1986), Hatch and others (1987), Longman and Palmer (1987), Burruss and Hatch (1989), Hatch, King, and Daws (1989), and Hatch and Newell (1999). These studies clearly document the presence of at least two different major oil groups. Gas chromatographic charac-teristics of the first of these groups, the "Ordovician" oils (e.g., Fig. 3A) include a relatively high abundance of *n*-alkanes with carbon numbers less than 20, a strong predominance of odd-numbered *n*-alkanes between C_{10} and C_{20}, and relatively small amounts of branched and cyclic alkanes (Reed, Illich, and Horsfield, 1986; Hatch and others, 1987; Longman and Palmer, 1987; Burruss and Hatch, 1989; and Hatch and Newell, 1999). Gas chromatographic characteristics of the second oil group, the "Devonian" oils (e.g., Fig. 3B) include regularly decreasing amounts of *n*-alkanes with increasing carbon number, no odd-carbon predominance, and relatively abundant branched and cyclic compounds (Burruss and Hatch, 1989; Hatch, King, and Daws, 1989; Hatch and Newell, 1999).

Hydrocarbon source rocks for the first oil group are Middle Ordovician shales from the Simpson Group and equivalent rocks, whereas hydrocarbon source rocks for the second oil group are in the Chattanooga Shale and equivalents (Reed, Illich, and Horsfield, 1986; Hatch and others, 1987; Longman and Palmer, 1987; Burruss and Hatch, 1989; Hatch, King, and Daws, 1989; and Hatch and Newell, 1999).

For the 15 oil samples collected for this study, two oils (#14 and #15, Fig. 2) produced from Middle and Upper Ordovician sandstones and limestones are geochemically similar to the "Ordovician" oils described here. Four oils (#1, #11, #12, and #13, Fig. 2) produced from Mississippian and Pennsylvanian reservoirs have characteristics similar to the "Devonian" oil group. The other nine oil samples (#2 through #10, Fig. 2) produced from Upper Ordovician through Mississippian reservoirs share a range of geochemical characteristics that seem to result from mixtures of both major oil groups (Fig. 3C). For the example shown in Figure 3C (sample #10, Arbuckle Group, Voshell field), the saturated hydrocarbon distribution has both a strong predominance of odd-numbered *n*-alkanes between C_{10} and C_{20}, and relatively abundant branched and cyclic compounds. These "mixed" oils occur primarily where, because of faulting and folding, their reservoir intervals are in across-the-fault contact with hydrocarbon source rocks from both the Simpson and Chattanooga Shale. Stratigraphic contact of an Ordovician reservoir at the base of the Chattanooga also may produce a similar "mixed" oil.

CONCLUSIONS

Structurally controlled closures along the McPherson Anticline can be explained by deformation along two basement blocks that are separated by a fault. The eastern block has been uplifted in relationship to the western block, but a component of north-northeast–south-southwest right-lateral strike-slip movement controls where structural closures occur along the anticline adjacent to the fault. North-south fault segments act as restraining bends and have the greatest amount of fault offset. Reverse faulting dominates, and structural closures are adjacent to these north-south fault segments. North-northeast–south-southwest fault segments, which are parallel to the movement of the crustal blocks, have lesser offsets. Structural sags that separate the anticlinal closures form adjacent to the north-northeast–south-southwest fault segments.

The amount of vertical offset on the flanking fault has a relation to the type of crude oil in a reservoir. In Ordovician reservoirs where there is no contact with Chattanooga Shale, crude oils usually are "Ordovician" crudes derived from source rocks within the Ordovician section. Mississippian reservoirs generally contain "Devonian" crude oils. A mixture of "Ordovician" and "Devonian" oil types occur in reservoirs older than the Chattanooga Shale where the reservoir is in contact with Chattanooga Shale. The nature of this contact either can be stratigraphic, in which the Chattanooga unconformably overlies the reservoir rock, or structural, in which the reservoir rock is upthrown against the younger Chattanooga Shale. Both types of circumstances occur for the various oil fields along the McPherson Anticline.

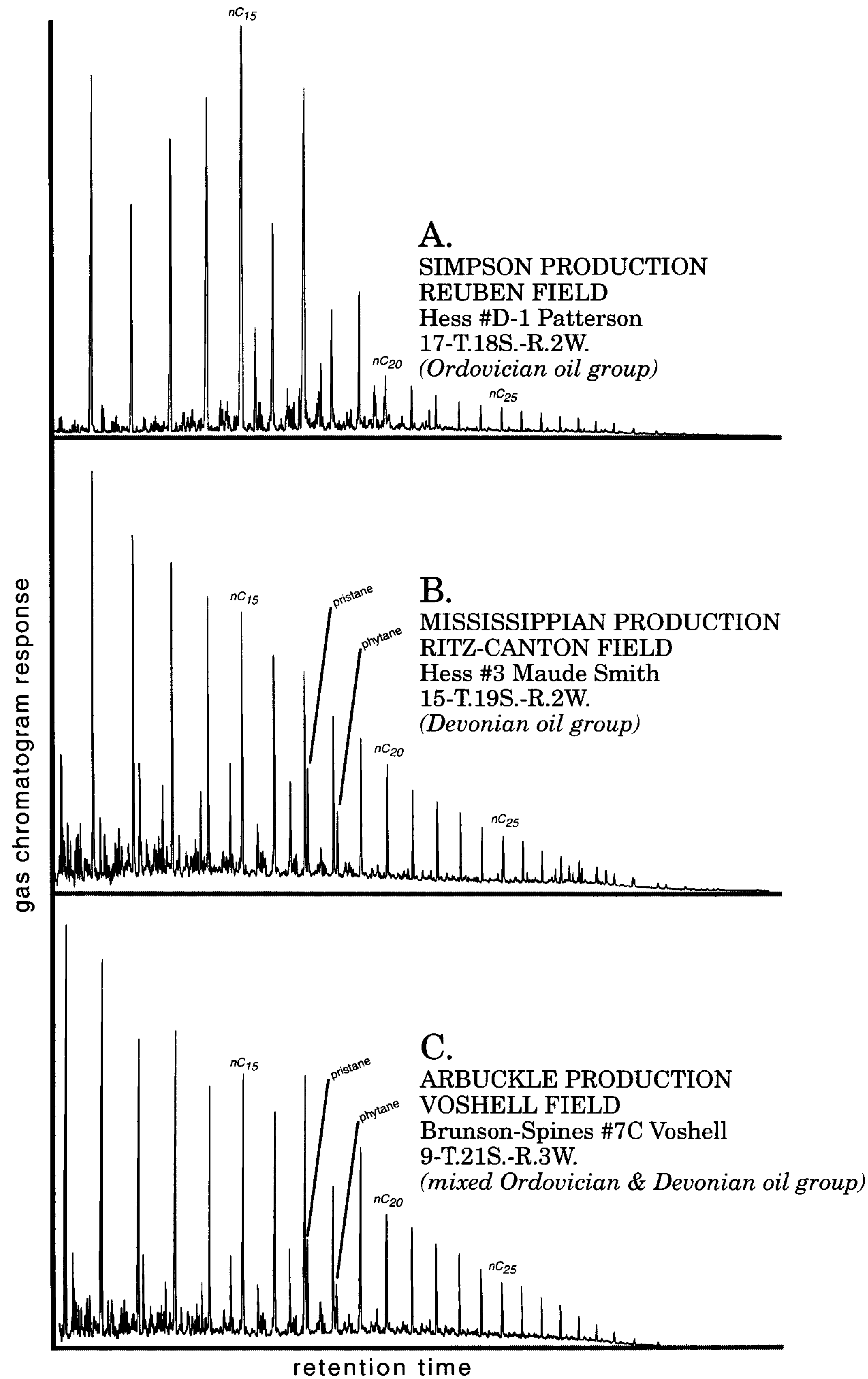

FIGURE 3—Three examples of crude oils that are produced from Voshell trend. A, "Ordovician" crude oil; B, "Devonian" crude oil; and C, Example showing characteristics of both "Ordovician" and "Devonian" crudes, and is mixture of two types.

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Contributions from Migrating Oil-Field Brines to Carboniferous Beds in the U.S. Midwest

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ABSTRACT

Paleozoic strata of the Midwest host (1) Mississippi Valley-type (MVT) ore deposits and fossil-fuel resources, which are localized in ore deposits, coal seams, and hydrocarbon fields; (2) widespread country-rock occurrences of ~60–200°C fluid inclusions containing brines and hydrocarbons; and (3) extremely metal-rich black shales. The metalliferous shales occur in Mississippian strata but are especially prevalent in overlying Pennsylvanian cyclothems throughout the Midwest.

The paucity of petrographic information and absolute dates for MVT ores has hampered the development of a coherent hypothesis relating these phenomena. The discovery of additional occurrences of hydrothermal minerals and new dates have set the stage for refinement of a genetic model that begins with introduction of metals from migrating basinal brines to shales and surrounding rocks during sedimentation and early diagenesis. Substantial augmentation of metal values in permeable beds, including thin-jointed black shales, took place at a later time. Consequent plugging of numerous minor fluid passageways in carbonate and shale beds may have been a major factor in confining the subsequent development of major ore and hydrocarbon deposits within discrete locations.

INTRODUCTION

As noted by Heyl (1968), minor occurrences of typical Mississippi Valley-type (MVT) ore minerals including sphalerite, barite, and galena, and typical MVT gangue minerals, such as dolomite and quartz, are widespread in the American Midwest. For example, barite usually is associated with dolomite, calcite, and sphalerite in lower Paleozoic strata of central Missouri (Leach, 1979) and in clam burrows and other tubes in Pennsylvanian beds of Missouri and Kansas (Gentile, 1979). Hydrothermal (MVT) sphalerite, dolomite, and calcite occur in cleats that fill joints in Pennsylvanian coal far removed from known ore deposits in Illinois, Kansas, and Missouri (Hatch, Gluskoter, and Lindahl, 1976; Cobb, 1981). Similar cleat fillings, ranging up to 1.0 cm thick, occur in Pennsylvanian carbonates and shales in the Kansas City area (Figs. 1 and 2). MVT minerals also occur in tubes and solution cavities of various secondary origins and fill pores in fossils in Pennsylvanian limestones between Kansas City and the Tri-State lead-zinc mining district located about 100–150 km to the south, where zinc-lead ores are hosted primarily by Mississippian strata (Coveney, Goebel, and Ragan, 1987; Ragan, 1994). The metalliferous black shales in the area probably accumulated metals throughout their history, beginning at the time of sedimentation (Coveney and Glascock, 1989; Coveney, 1992). This paper focuses on the later stages of mineralization.

FLUID INCLUSIONS

Available temperatures of homogenization (Th) for primary brine inclusions in sphalerite from minor occurrences of the Midwest typically lie between 60 and 130°C—coinciding with temperatures for MVT ores occurring in the Midwest (U.S.A.) (Leach, 1979; Cobb 1981; Coveney and Goebel, 1983; Coveney, Goebel, and Ragan, 1987; Ragan, 1994, 1996; Ragan, Coveney, and Brannon, 1996). For example, even in Kansas City far from any zinc mines, primary fluid inclusions contained by sphalerite register Th values of 60–110°C (Fig. 1). Moreover, some occurrences, mainly in lower Paleozoic strata or in Pennsylvanian beds located in the midst of major hydrocarbon fields, yield homogenization temperatures as high as 194° C (Goebel, Coveney, and Ragan, 1988). It also should be noted that equivalent salinities for fluid inclusions in the minor MVT occurrences are comparable to those of ores (~18–22 equiv. % NaCl). Some inclusions are petroliferous (e.g., Blasch and Coveney, 1988; Ragan, Coveney, and Brannon, 1996). Two fluid-inclusion determinations, indicating temperatures in excess of 70°C, were derived directly from black shale-hosted sphalerite (Coveney, Goebel, and Ragan, 1987).

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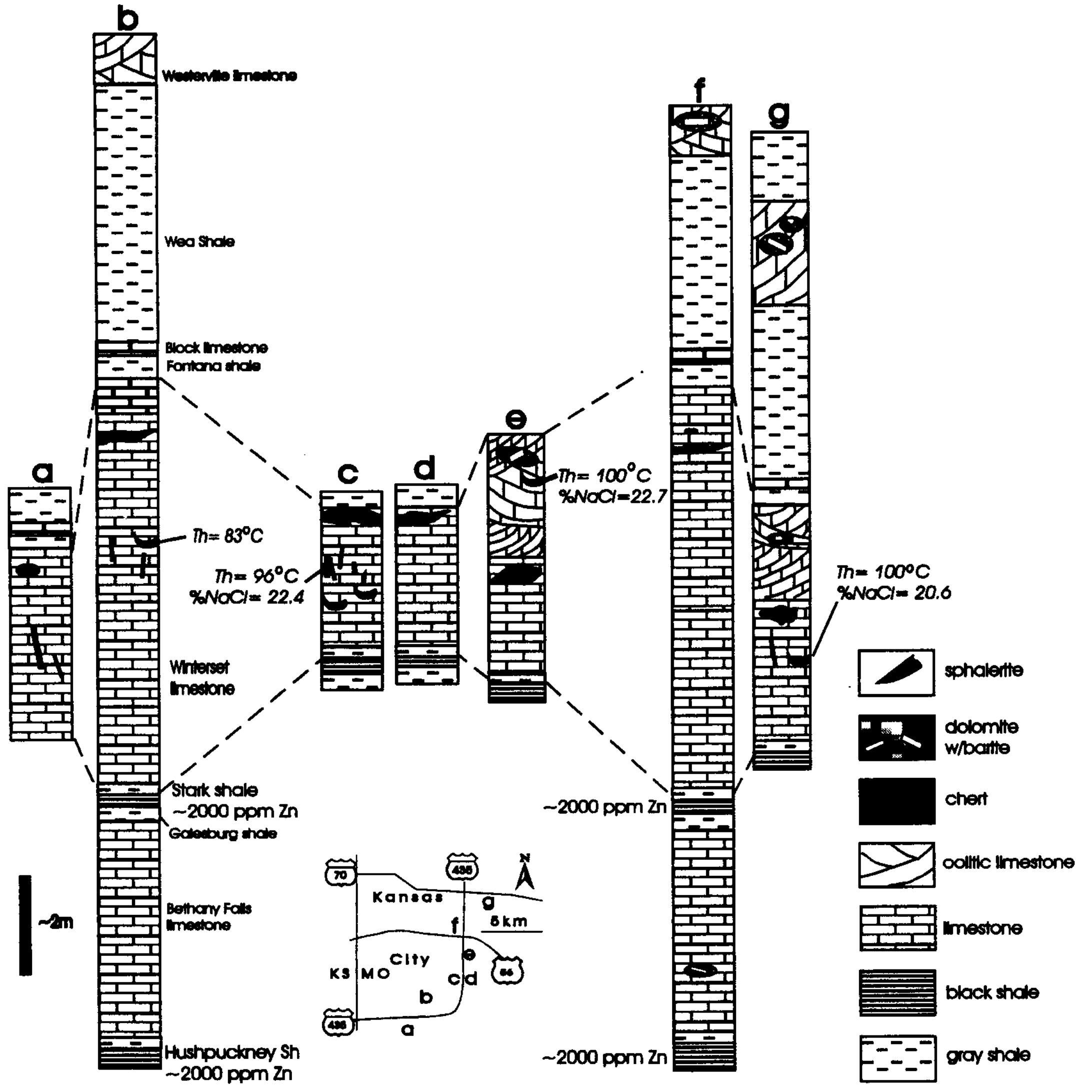

FIGURE 1—Relationships between occurrences of sphalerite, dolomite, barite, and other MVT minerals with respect to predominantly marine Middle Pennsylvanian stratigraphic units of Kansas City, Missouri. Homogenization temperatures (Th) and salinity values shown in diagram are taken from Coveney, Goebel, and Ragan (1987). Th values of 80–110°and salinities exceeding 20 wt % NaCl overlap values that have been recorded for world-class zinc-lead deposits of Joplin area located more than 150 km to south of Kansas City. Assay data for Zn, indicating about 2,000 ppm Zn (0.2 wt. %) in thin black shales in area are taken from Coveney (1979). Illustrated stratigraphic sections are centered on Winterset Limestone Member, which occurs at about same elevation throughout area shown, striking ~N45°E and dipping 1–2° to northwest.

Although attempts have been made by several groups of investigators, it is impossible to document regional paleothermal gradients with any degree of certainty from fluid-inclusion data because (1) in the absence of reliable independent estimates of confining pressures, fluid inclusions can be used only to establish minimum temperatures; (2) ranges of measured Th values at any one location are typically as large as the regional variations (ca. 10–40°C); and (3) the precise timing for deposition of each minor occurrence is not established. Nevertheless, existing data suggest the *possibility* of declining temperatures to the north, consistent with inferences of a role for Alleghanian tectonic events in mineralization as discussed by many workers (e.g. Leach, 1979; Leach and Sangster, 1993). Conodont color alteration index values generally are consistent with homogenization temperatures for fluid inclusions hosted by sphalerite in and near the Tri-State district (Goebel, 1997). Furthermore Sangster, Nowlan, and McCracken's (1994) results suggest that the ores of the Tri-State district were in thermal equilibrium with the host rocks during deposition at temperatures within the range 80 and 140°C.

Recent studies of diagenetic and hydrothermal carbonate minerals by Wojcik, Goldstein, and Walton (1994) report Th values as high as 160°C for aqueous inclusions in carbonate cements in Pennsylvanian beds that are now exposed at the surface in southeastern Kansas, approximately 50 km west of the Tri-State mining district.

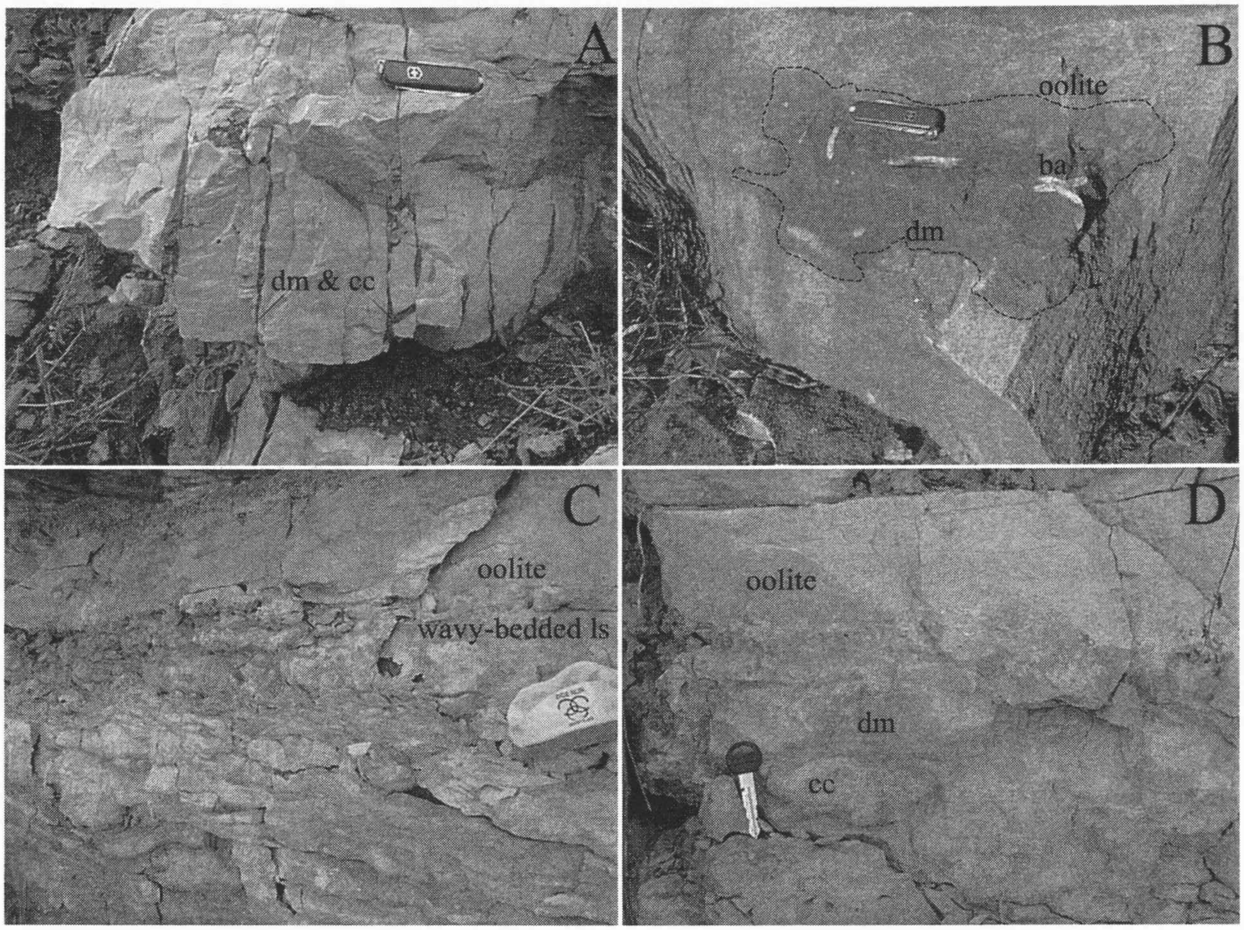

FIGURE 2—Hydrothermal dolomites, Kansas City area. A, Ferroan dolomite and calcite cleats filling joints formed in footwall of normal faults in Bethany Falls Limestone Member, Swope Formation, Raytown, Missouri; B, Early ferroan dolomite with barite in oolitic limestone, Kansas City, Missouri. Presence of such isolated pods of dolomite completely surrounded by undolomitized oolite and clear-cut feeder fracture system imply some dolomite and barite (and in some situations, ZnS) were introduced prior to complete lithification of host strata; C, Oolitic limestone with sparse ferroan dolomite underlain by wavy-bedded clayey limestone with abundant late dolomite, Beardsley Road and interstate highway I–70, Kansas City, Missouri; and D, Detail of contact between oolitic limestone, free of ferroan dolomite, and underlying wavy-bedded dolomite containing abundant dolomite, suggesting that this occurrence of dolomitization post-dated lithification of Kansas City area limestones.

Thus, it seems that the maximum temperatures experienced by country rocks occasionally exceeded the Th values previously reported for sphalerite from the country rocks and from the ores. Such findings further complicate modeling of the regional paleothermal gradients at any given stage in the history of the area.

AGE OF MVT MINERALIZATION

Wisniowiecki and others (1983) reported a Pennsylvanian magnetic paleopole for the Viburnum trend ores of southeastern Missouri, providing one of the first reliable absolute ages for MVT mineralization. Subsequently Pan, Symons, and Sangster (1990) determined that the Tri-State and Northern Arkansas districts had paleomagnetic properties consistent with a Kiaman age of mineralization. Brannon and others (1996) dated ore-stage gangue calcite from the Jumbo lead mine of Linn County, Kansas, at ~251 Ma ± 11. Mineralization in some other MVT districts located elsewhere in the southeastern and midwestern United States probably formed during the late Paleozoic, including the Pennsylvanian (Christensen, Halliday, and Kesler, 1996; Brannon, Podosek, and Cole, 1996). However, some districts, particularly to the east of the study area, may have been mineralized during the early and middle Paleozoic (see Symons, Sangster, and Pan, 1996, for a recent summary of absolute-age determinations). Mineralization generally is conceded to be a product of the migration of oil-field-type brines (e.g., Leach and Sangster 1993).

METAL-RICH CARBONIFEROUS BLACK SHALES

At least a dozen thin (<1 m) metalliferous Pennsylvanian black shales, which hold remarkable amounts of metals (e.g., up to 800 ppm U, 2500 ppm Mo, 10,000 ppm V, 15,000 ppm Zn), underlie the main coal basins of the Midwest, including the Illinois and Forest City Basins and also occur on the fringes of the Midwest, for example in the Minnelusa Formation of Wyoming and South Dakota (Vine and Tourtelot, 1970; Coveney and Glascock, 1989). The shales are enriched consistently in zinc (0.1–1.5 wt % Zn) in the form of sphalerite, a major component of MVT ores (e.g., Coveney, 1979). For example, in metropolitan Kansas City, throughout an area amounting to more than 4,000 sq km, the black fissile lower beds of both the Hushpuckney and the Stark Shale Members consistently carry an average of 2,000 ppm zinc (0.2% Zn). However, it should be noted that the metalliferous zone in the Stark and the Hushpuckney and other thin metalliferous black shales hold such values for their entire outcrop belts which extend from southern Iowa to southern Kansas (Coveney 1979; Coveney and Glascock 1989; Schultz and Coveney, 1992). Zinc-rich beds also occur within the Mississippian–Devonian Chattanooga Shale and its stratigraphic equivalents (e.g., see Ripley, Shaffer, and Gilstrap, 1990). The Midwest is the type region for Zn-rich MVT ore deposits which mainly formed during the late Paleozoic (e.g., Symons, Sangster, and Pan, 1996). Hence the timing of events and spatial relationships in the region suggest that the metals in the shales may have been derived from MVT hydrothermal systems (Coveney and Glascock, 1989; Sangster, 1993). If so, the shales, which extend over millions of hectares including most of Missouri, Illinois, and Iowa, and substantial portions of Indiana, Kansas, Kentucky, Oklahoma, and Nebraska, may be among the best indicators of the geographic breadth and stratigraphic extents of the MVT systems of the Midwest. Hydrothermal kaolinite and dickite are widespread in the country rocks of the central U.S.A. (Keller, 1988). Tourtelot and others (1986) have suggested that various features including refractory clay deposits of Missouri, previously interpreted by some as being of supergene origin, may have been formed by hydrothermal fluids. Rationales for migration of fluids have been the topic of numerous articles since the contribution of Sharp (1978). Garven, Person, and Sverjensky (1993), for example, note that the "...deposits of the Midcontinent provide a superb data set for quantifying the nature of ancient groundwater flow systems at the continental scale."

TIME OF METALLIZATION OF BLACK SHALES

Some of the occurrences of sphalerite in Carboniferous black shales of the Midwest may well have been emplaced during sedimentation as weakly developed sedex deposits with metal values around a tenth those of zinc ores (Coveney, 1979, 1992; Coveney and Glascock, 1989). However, petrographic relations clearly indicate that some sphalerite was deposited during lithification or even later, for example when the Pennsylvanian strata of the Kansas City area experienced dolomitization (Figs. 1 and 2). The same can be said about the timing of emplacement of barite (Fig. 2B; Gentile, 1979).

In all probability, a complete record of the history of emplacement of MVT minerals will be discernable only when a more comprehensive set of radiometric dates becomes available. Nevertheless there is abundant petrographic evidence that the trace occurrences of sphalerite and the MVT gangue minerals were emplaced at several stages in the history of the region ranging from the time of deposition of the beds (Coveney, 1979) to at least the end of the Permian.

HYDROCARON MIGRATION

The history of migration of hydrocarbons through Carboniferous strata of the Midwest comprises multiple stages. For example, the Pb deposit at the Jumbo mine in Linn County, Kansas, in which sphalerite, calcite, dolomite, and barite all contain abundant primary and secondary inclusions of oil-field brines, petroleum, and mixtures of brines and petroleum, formed at ~251 Ma judging from the Th–Pb date for ore-stage calcite (Brannon and others, 1996). Some of the calcite crystals collected near Joplin in the heart of the Tri-State zinc-lead mining district contain petroleum inclusions. However, 39 Ma-calcite samples from the same general area do not contain petroleum inclusions (Brannon, Podosek, and Cole, 1996). These crystals can be used to constrain speculations about the timing and duration of the migration of hydrocarbons in the region, but this topic will be expanded upon in a separate contribution (e.g., Coveney, Ragan, and Brannon, 1999).

GENETIC MODEL

Country-rock occurrences of hydrothermal sphalerite and carbonate minerals in the central U.S. imply that at one or more times in the past, moderate to hot (60–200°C) oil field brines were widespread in Paleozoic strata of the Midwest. The minor occurrences of MVT mineralization together with occurrences of hydrothermal clays and metalliferous shales that extend over millions of hectares of the American Midwest may be products of the regional hydrothermal event responsible for the main zinc-lead ore deposits of the Mississippi Valley. The duration of the hydrothermal event (or events) is uncertain, but textural and field relations in combination with fluid-inclusion data and radiometric dates leave open the possibility of periodic introduction of MVT ore and gangue minerals for an extended period of time ranging from shortly the time of sedimentation to the Mesozoic and possibly to the Cenozoic. Details of the occurrences of hydrothermal dolomites exposed in limestone quarries, construction sites, and roadcuts in and near Kansas City attest to the likelihood of an early introduction of some of the MVT mineralization. However, the existence of MVT mineralization in crosscutting veinlets that post-date the lithification of host rocks and available radiometric dates suggest that mineralization, which may well have been episodic, proceeded during a period of tens to hundreds of millions of years after the close of the Paleozoic. It is possible that the plugging of minor passageways in the country rocks by early hydrothermal minerals was essential in providing the necessary focus for ore-grade mineralization to occur in the region. The same process may have been important in forming hydrocarbon resources.

SUMMARY AND CONCLUSIONS

Carboniferous beds, including both Mississippian and Pennsylvanian black metalliferous shales, lead-zinc mining districts, coal deposits, and hydrocarbon fields have been affected by migrating oil-field/MVT hydrothermal brines as evidenced by field relationships, fluid-inclusion results, and geochemical data. The duration of migration of hydrothermal brines probably extended from the late Paleozoic to the Cenozoic, judging from age determinations on the mineral deposits and trace occurrences of MVT ore and gangue minerals in the country rocks. The distribution of elevated (e.g., >0.2 wt % Zn) metal values in certain black shales is more geographically widespread than ore districts into country rocks located hundreds of kilometers from known ore deposits. Thus, homogenization temperatures of briny fluid inclusions and elevated values from MVT ore metals indicate that the influence of hydrothermal mineralization was pervasive in the region and much more widespread than the limited geographic extent of the metal mining districts. Analogous statements can be applied to hydrocarbon resources in the region, although the extent of such systems has long been well established as a result of extensive exploration for hydrocarbons in eastern Kansas. Nevertheless, dated ore and trace MVT mineral occurrences may provide important clues about the timing of migration of oil-field brines in the area and the locations of ancient flow paths that are now plugged by mineralization.

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Relationships of MVT Mineralizations, Color-Altered Conodonts, Fluid Inclusions, "J"-Type Lead, and Migrating Oil-Field-Type Basinal Brines with Unconformity-Bounded Stratigraphic Sequences

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Ore and trace occurrences of MVT deposits, fluid inclusions in sphalerite, color alteration of condononts (CAI), and the genesis of "X"-type lead, reflect different effects of the heat present during migrations of hydrothermal fluids. In the Midwest, spatial-distribution patterns of these heating effects are localized in the porosity and permeability in strata along the boundaries of unconformity-bounded stratigraphic sequences (UBSS). These strata, where preserved, contain the relict pathways of ore fluids and possible hydrocarbon migrations.

When plotted stratigraphically within the UBSS framework, the highest CAI temperatures in the Tri-State district's Kaskaskia host strata, are the closest to the pre-Pennsylvanian unconformity, a reversal of the temperature sequence expected from burial heating alone. Fluid inclusion temperatures from Absaroka (Pennsylvanian) carbonate cements, also in the Cherokee Basin, exhibit an anomalous increase downward toward the pre-Pennsylvanian unconformity. Collectively, advective flow of hydrothermal fluids is indicated.

In the subsurface of southwestern Nebraska and northwestern Kansas, also plotted in the UBSS framework, trace amounts of "J"-type lead are more radiogenic toward Precambrian anorogenic granitic source rocks. This spatial pattern is evidence of a paleohydrothermal fluid pathway.

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Pennsylvanian History of the Chautauqua Arch, Oklahoma and Kansas

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The Chautauqua Arch experienced maximum uplift during Late Devonian Acadian movements, and again much later during the Pennsylvanian. The Chautauqua Arch was uplifted episodically and eroded during the Pennsylvanian, a phase usually omitted on many Pennsylvanian tectonic maps. This arch separates the northern ramp of the Arkoma Basin in southeastern Kansas and closely straddles the northeastern Oklahoma and Kansas border. These later uplifts coincide with tectonic movements of the evolving Ouachita Mountains and Ozark Uplift. Consequently, the Lower to Middle Pennsylvanian sedimentary pile along the Chautauqua Arch is about half the thickness of this interval in the Kansas Cherokee Basin and one-fifth or less of a similar chronological interval in the Oklahoma Arkoma Basin.

Numerous Lower Pennsylvanian beds of northeastern Oklahoma are missing over this arch. Middle Pennsylvanian unconformities in southern Montgomery and Labette counties result in complete absence of the Hepler Sandstone, Lost Branch Formation, Canville and Stark Shale Members of the Dennis Limestone, Cherryvale Shale, Corbin City Limestone of the Drum Limestone, and Dewey Limestone. In addition, much thinning of other stratigraphic units exists over the arch, including the Iola, Plattsburg, and Stanton Limestones. In contrast, thick silty to sandy sediments of the Bandera and Chanute Shales were deposited during brief periods of deltaic accumulation.

The Chautauqua Arch may be considered as a Pennsylvanian forebulge that separates the Arkoma foredeep basin and northward adjoining foreslope from the Cherokee backbulge basin.

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Significance of Accurate Carbonate Reservoir Definition and Delineation

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Reservoir definition may be vague or poor even in mature areas because of misidentified angular unconformities, facies changes, or poor understanding of the relationships existing in deep portions of a basin that was undrilled until late in the development history. Typically no mechanism exists to correct misnamed reservoirs, and the problem may be dismissed as being "purely academic," insignificant, or unnecessary. As a result of a recent Gas Research Institute project (GRI–96/0196), a classic example of the significance of accurate reservoir definition and delineation was identified. One thousand two-hundred and thirty-two (1,232) well completions had been reported as being from the Chester (Mississippian), when, after detailed correlations, it was demonstrated that only 221 completions could be attributed to the Chester within the study area. Consequently, the ultimate recovery of the Chester diminished from 1,781 BCF to 277 BCF gas. Most of the gas was being produced from carbonate reservoirs belonging to the overlying Springer Group and could be identified as such through regional stratigraphic correlations. Although occurring at comparable depths, the carbonate reservoirs belonging to the Springer Group typically produce 50 to 80% more gas per completion than completions in the Chester.

This paper will present the findings which explain the significance of the disparity between the misidentified reservoirs. These findings demonstrate that opportunities exist for significant infield development, trend extensions, and the further development of newly recognizable trends. Basinwide stratigraphic correlations and detailed geologic analysis will be presented.

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Basin Analysis
(continued)

Strike-Slip, Compressional Thrust-Fold Nature of the Nemaha System in Eastern Kansas and Oklahoma

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ABSTRACT

Much has been written about the Nemaha Ridge in Kansas and Oklahoma since geologists first became aware of it from oil-well drilling in the early years of this century. It has been described as extensional, compressional, and strike-slip. Data are presented to show that the Nemaha was formed in the usual manner of nonvolcanic, nonintrusive uplifts, that is, by compressional, or thrust, faulting that began deep within the Precambrian crust to the west and extended in listric fashion to the ground surface coincident with the Humboldt fault zone, or an east-bounding fault. Compressional effects observed from oil-well drilling and seismic surveys along its entire length are too numerous to ignore and to permit of an extensional origin, if it is even possible to consider an extensional origin for an uplift.

Two additional effects occurred simultaneously with the thrusting. A backthrust evidently formed in a manner similar to that mapped in many compressional environments, for example the Front Range of Colorado, Uinta Mountains in Utah, and Wichita Mountains in Oklahoma, essentially making the ridge a V-shaped "pop-up block," thus explaining the up-to-the-east fault or fold on the west. Additionally, the thrusting had a strong component of strike-slip motion which resulted in end closures of structures along it, that is, the formation of petroleum traps, plus additional complexities that have made the Nemaha system difficult to interpret and its origin controversial. Small, near-surface normal faults indicate that extension played a minor role in post-Permian time.

INTRODUCTION

Merriam (1963) said that the Nemaha Uplift in eastern Kansas is "probably the most famous of all Kansas structures." He gives a good overall description and states that it is ". . . faulted along the east side in several areas, and seemingly there are both high angle and reverse faults." Earlier descriptions of the Nemaha Uplift presented in the regional discussions of Lee (1943) and Jewett (1951) are similar. More recently, Luza and Lawson (1982), in discussing the Oklahoma part of the Nemaha, stress the "near-vertical faults on the east side that are downthrown to the east," implying only normal faulting. They were evidently unaware of a number of well-documented reverse faults in their study area. Serpa, Setzer, and Brown (1989) in their discussion of the Nemaha in northeastern Kansas likewise ignore many reverse faults in that area and state: ". . . the inferred geometry of the Humboldt fault zone. . . moderately east-dipping. . . is extensional." Berendsen and Blair (1995) take a new tack and attribute the uplift to wrench faulting and state that the "entire fold-fault system was subjected to a sinistral (left-lateral) strike-slip motion in the Pennsylvanian."

We thus are confronted with a potpourri of ideas on the origin of the Nemaha Uplift. For the present study I have researched extensively the occurrence of repeated section and reverse faulting along the Nemaha from the Kansas–Nebraska line to its southernmost limit south of the Oklahoma City oil field—a distance of 400 miles (650 km). This research has yielded 20+ separate localities of reverse faulting (so far) from both subsurface and seismic data and from published and unpublished sources. I will cite all these and show a few of the newer examples. Many of the examples are on structures parallel to the Nemaha Ridge proper, structures which had a similar structural history and are part of the Nemaha "*system*," both in Kansas and Oklahoma.

Because the reverse faulting that is so prevalent on the Nemaha system could not have occurred in an extensional environment, the inevitable conclusion is that the Nemaha system must have formed as a result of compression. To understand properly this compressional regime, I turn to the Rocky Mountains, where only in the last 10 to 15 years geologists finally have deciphered the nature of the faulting in a similar compressional environment. Many of the main stress-relieving, crustal-shortening faults there are listric thrust faults that have shallow dips deep within the basement, steeper dips near the basement-sedimentary section interface, and are vertical or near-vertical near the

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surface. This latter characteristic should alleviate the doubt in the minds of many Kansas and Oklahoma geologists who are *convinced* that the observed vertical or steeply dipping faults continue to be vertical or steeply dipping to great depths and are thus necessarily normal faults.

Also, confusion perhaps has resulted from the knowledge that some reverse faults in the Nemaha system dip the "wrong" way—the east-dipping one at Voshell field, McPherson County, Kansas, being a well-known example (Hiestand, 1933). From strain theory, we know that in a compressional system there is no preferred direction of thrusting. There are many examples of this in the Rockies. Both the Big Horn and Hoback Basins in Wyoming had major north-south thrusts converging on them contemporaneously from opposite directions.

Additional features of compressional systems in the Rockies that probably apply equally well to the Nemaha are "backthrusts," late "relaxation" normal faults, and crustal depression resulting from "tectonic loading," all of which I will discuss briefly. The concluding argument is that the Nemaha was uplifted mainly in Late Mississippian–Early Pennsylvanian time contemporaneously with the elevation of the Ancestral Rocky Mountains in Colorado (Ye and others, 1996) and thus would have been subjected to the same massive compressional forces. Earlier periods of lesser movement in the Nemaha have been noted, possibly coinciding with thrusting in the Appalachians to the east.

A large amount of strike-slip movement that occurred on the Nemaha system and has been discussed by others (e.g., Blair and Berendsen 1988; Berendsen and Blair, 1995; Davis, 1986; and Fenster and Trapp, 1982). The strike-slip movement is believed to be contemporaneous with the later stages of thrusting. It created, or accentuated, the cross folding that forms reservoirs in many oil fields.

OCCURRENCE OF REVERSE FAULTING ON THE NEMAHA SYSTEM

To foster the idea of a compressional origin for the Nemaha system I present examples of reverse faulting, from both published and unpublished sources, that occur along the system in Nebraska, Kansas and Oklahoma. Locations of these examples are shown in Figures 1 and 2, and they are summarized in Table 1.

A shallow high-resolution seismic line (Steeples, 1989) furnished a clear image of a reverse fault in northeastern Kansas, 13 miles south of the Nebraska line (Fig. 3), although the author stated that it was "...a reverse or vertical [normal] fault...." The east-bounding fault for the John Creek field in T. 15 S., R. 9 E., is shown in the 1960 Kansas Geol. Society Oil and Gas Fields (Vol. III, p. 101) as a normal fault (Fig. 4). However, a high-quality east-west seismic line run in 1982 showed this to be a reverse fault (R. Feige and T. Dillard, pers. comm., 1999), and a 1982 Applied Geophysics, Inc. magnetic survey shows a basement fault a few thousand feet to the west of the surface trace, indicating a west dip and hence a reverse sense of movement.

The east-bounding fault for the prolific El Dorado oil field in Butler County was penetrated by a "boom well" in 1982, 60 years after the field was developed. This modern well shows approximately 126 feet of reverse offset (Fig. 5). El Dorado is one of Kansas' largest fields (300 MMBO), and the fault probably was penetrated many times in the 1910's and 1920's when the field was being developed. However, at that time the stratigraphic succession was not well known, petroleum geology was in its infancy, and early workers evidently did not recognize repeated sections. Of the many articles on Kansas oil fields I have read, no reverse faults are mentioned prior to the 1940's.

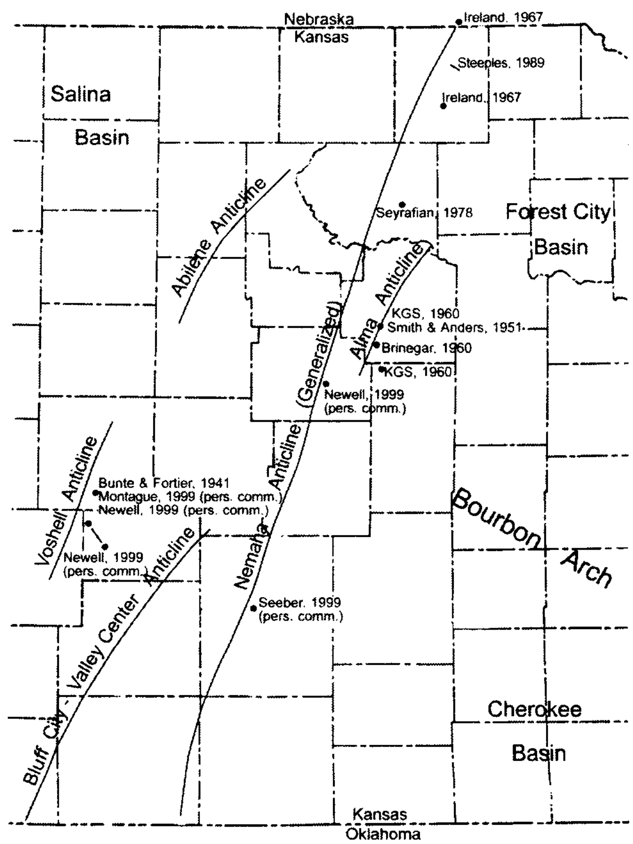

FIGURE 1—Principal anticlinal structures of eastern Kansas where reverse faulting has been demonstrated.

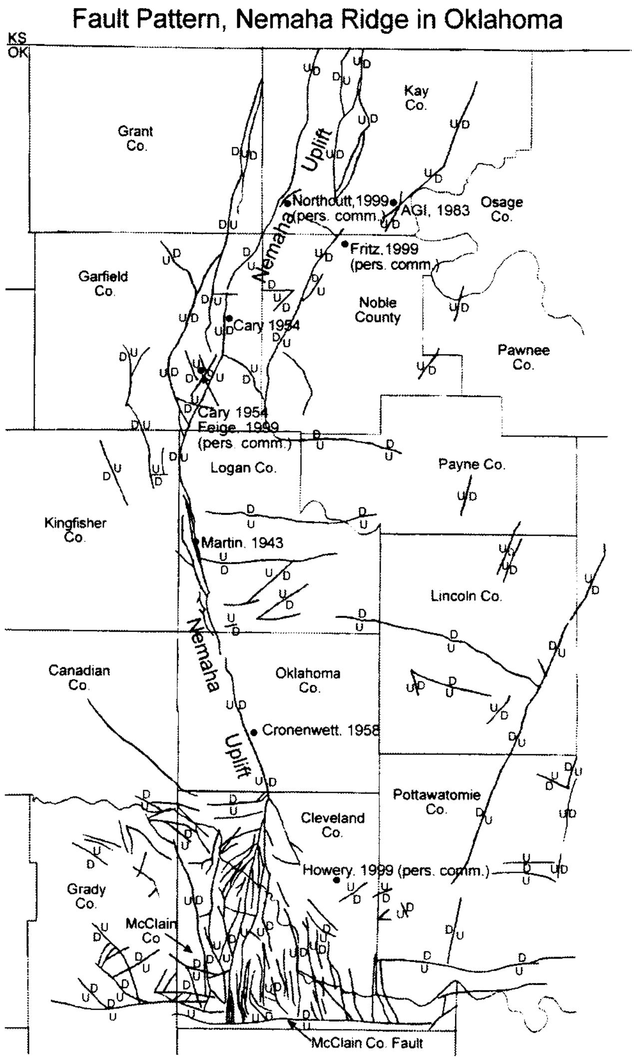

FIGURE 2—Detailed fault pattern, north-central Oklahoma, from proprietary mapping by Lloyd Gatewood (pers. comm., 1983) and places where reverse faulting has been demonstrated.

The Ponca City field in Kay County, Oklahoma (Fig. 6), is an anticlinal field with a steeply dipping eastern flank. Such asymmetric folds generally are the result of compression and have "blind" thrusts or reverse faults underneath them at depth. This field has a prominent basement fault mapped by magnetics lying a few thousand feet west of the steep eastern flank, which would be the basement location of the blind fault, thus making it a reverse fault.

The reverse nature of the east-bounding fault at Garber field in Garfield County, Oklahoma, was well documented by Cary in 1954 (Fig. 7). He also mentions a well (No. 1 Atkinson) south of Garber field that has repeated section. This well cuts a southwest-trending reverse fault that has been verified and traced for 9 miles with a recent 3D seismic survey (R. Feige, pers. comm., 1999).

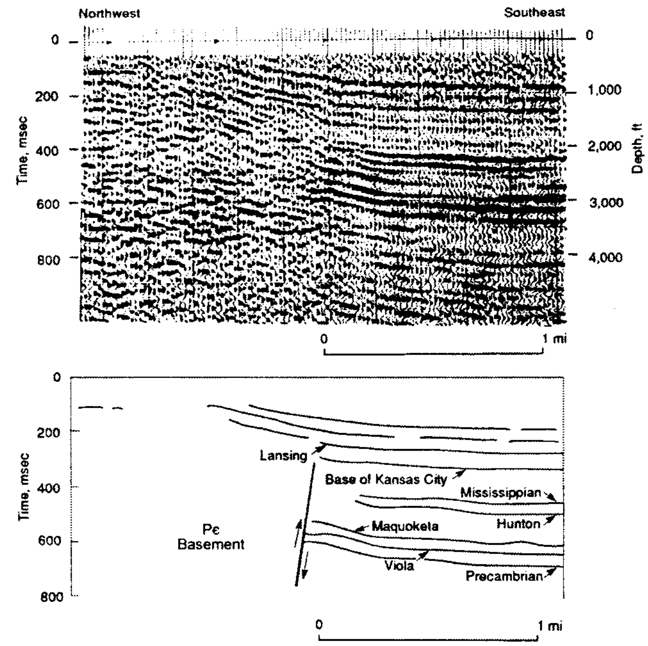

FIGURE 3—NW-SE high-resolution seismic line in T. 3 S., R.13–14 E., Nemaha County, Kansas, on eastern flank Nemaha Uplift (from Steeples, 1989, who termed this "...reverse or vertical fault....").

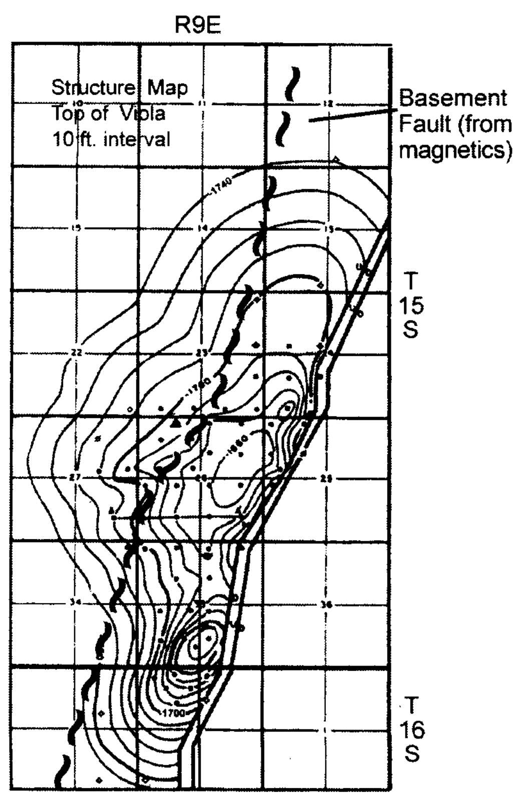

FIGURE 4—Structure map of John Creek field, Morris County, Kansas (Kansas Oil & Gas Fields, Vol. III, 1960, p.101, Kansas Geol. Soc.). 1982 east-west seismic line here showed east-bounding fault to be reverse (R. Feige, pers. comm., 1998). Westerly location of fault at basement level also indicates it is west-dipping, and hence reverse.

TABLE 1—Examples of reverse faulting along Nemaha System (north to south).

Source	Location	Comments
1. Ireland (1967)	sec.9, T. 1 N., R. 14 E. (Nebraska)	An early use of forams to decipher stratigraphy.
2. Steeples (1989)	R. 13–14 E., T. 3 S. (Kansas)	Seismic profile here shows reverse fault, but it was labeled "reverse or vertical."
3. Ireland (1967)	sec. 25, R. 13 E., T. 3 S. (Kansas)	See comment no.1.
4. Seyrafian (1978)	R. 10–11 E., T. 8 S. (Kansas)	Repeated section was discussed, but profile was redrafted to show this properly.
5. Smith and Anders (1951)	sec. 4, R. 10 E., T. 14 S. (Kansas)	Davis Ranch field—Two reverse faults mentioned in Smith and Anders.
6. Brinegar (1960)	Sec. 29, R. 10 E., R. 14 S. (Kansas)	Ashburn field—Reverse section was described and cross section was redrawn.
7. KGS (1960) (pers. comm.)	R. 9 E., T. 15–16 S. (Kansas)	John Creek field—1982 seismic showed reverse fault.
8. K. D. Newell (1999) (pers. comm.)	sec. 18, R. 8 E., T. 16 S. (Kansas)	Two wells show repeated section.
9. Bunte and Fortier(1941)	sec. 9, R. 3 W., T. 21 S. (Kansas)	Voshell field—Earliest cross section published of repeated section on Nemaha. Two additional wells mentioned in 1933, two more in 1999.
10. K. D. Newell (1999) (pers. comm.)	sec. 12, R. 3 W., T. 22 S. (Kansas)	Wildcat well.
11. K. D. Newell (1999) (pers. comm.)	sec. 18, R. 3 W., T. 22 S. (Kansas)	Five wells show repeated section.
12. D. Seeber (1999) (pers. comm.)	sec. 3, R. 3 E., T. 26 S. (Kansas)	1982 well in El Dorado field.
13. B. Northcutt (1999) (pers. comm.)	sec. 9, R. 2 W., T. 25 N. (Oklahoma)	Thomas field.
14. Gay (1995)	R. 2 E., T. 25 N. (Oklahoma)	Ponca City field—Magnetic data by Applied Geophysics, Inc. show west dip to fault, hence reverse throw.
15. R. Fritz (1999) (pers. comm.)	sec. 7, R. 1 E., T. 24 N. (Oklahoma)	Three Sands field.
16. Cary (1954)	sec. 6, R. 3 W., T. 22 N. (Oklahoma)	New Garber field (north of Garber).
17. Cary (1954)	sec. 12, R. 4 W., T. 21 N. (Oklahoma)	South of Garber field—Recent 3D seismic shows this reverse fault is *at least 9 miles* long. (R. Feige, pers. comm., 1999)
18. Martin (1943)	sec. 33, R. 4 W., T. 17 N. (Oklahoma)	Crescent field.
19. Cronenwett (1958)	sec. 23, R. 3 W., T. 12 N. (Oklahoma)	Oklahoma City field—Gatewood (1970) also mentions reverse faulting here.
20. S. Howery (1999) (pers. comm.)	R. 1 W., T. 8 N. (Oklahoma)	Two wells about 15 miles south of Oklahoma City field.

In a 1943 University of Oklahoma masters thesis, M. G. Martin made a thorough analysis of Crescent field, an asymmetric anticline in Logan County, Oklahoma. His study included five well sections and four structure maps for the field. He determined that one well (Texas No. 5 Denny) cut the west-bounding fault and repeated a portion of the lower Paleozoic section. He drew a flat thrust at this locality, but I have reinterpreted the data to show a pair of high-angle reverse faults here (Fig. 8).

Another masters project at the University of Oklahoma in 1978 attempted to explain the occurrence of historic earthquakes in the Oklahoma City–Mustang–El Reno area of Oklahoma (Koff, 1978). The author's conclusion was that a deep, listric, west-dipping fault or faults, probably was responsible for these quakes (Fig. 9). This possible fault, or faults (No.1), is precisely what I envision as the trace of the causative fault for the Nemaha system.

The underlying Nemaha thrust fault apparently was imaged by the COCORP line in northern Kansas shown in Serpa, Setzer, and Brown (1989) and also in Setzer and others (1983) but was not recognized. A listric, west-dipping reflector is shown clearly that could well be the fault in question (Fig. 10). Serpa, in her oral presentation in 1985, proposed the opposite—a listric, *east*-dipping normal fault here—a mirror image of the one I show in Figure 10.

One problem that has long cast doubt on the compressional origin of the Nemaha system is the vertical, or near-vertical, attitude of the Humboldt fault and the other major faults in this system. It has been reasoned that compressional systems are characterized by shallower dipping thrusts or reverse faults than those observed (L. Gatewood, pers. conv., 1999). However, I will show two examples from the Rocky Mountain region, well-documented by both seismic and drilling, where vertical, or near-vertical, faults become shallow with depth, that is, they have a typical listric configuration. Figure 11 shows a cross section of the Little Laramie anticline in the South Laramie basin, Wyoming (Stone, 1993a), where a vertical

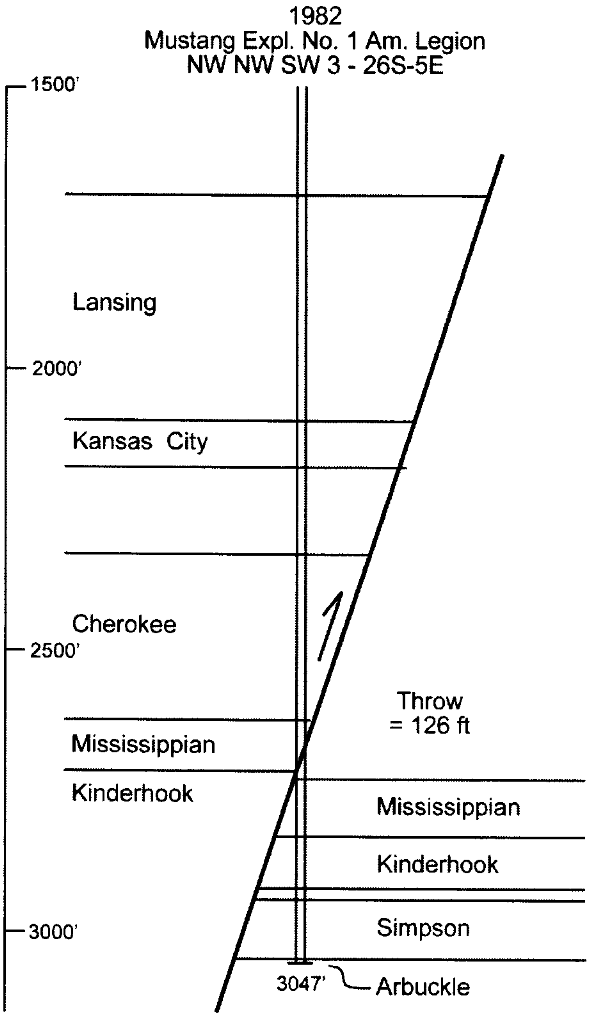

FIGURE 5—Reverse throw for east-bounding fault of prolific (300 MMBO) El Dorado field, Butler County, Kansas, is indicated in this 1982 "boom" well, logged with modern equipment (well data provided by D. Seeber, 1999). Original drilling was in 1910's and 1920's before faulting was accepted in Kansas.

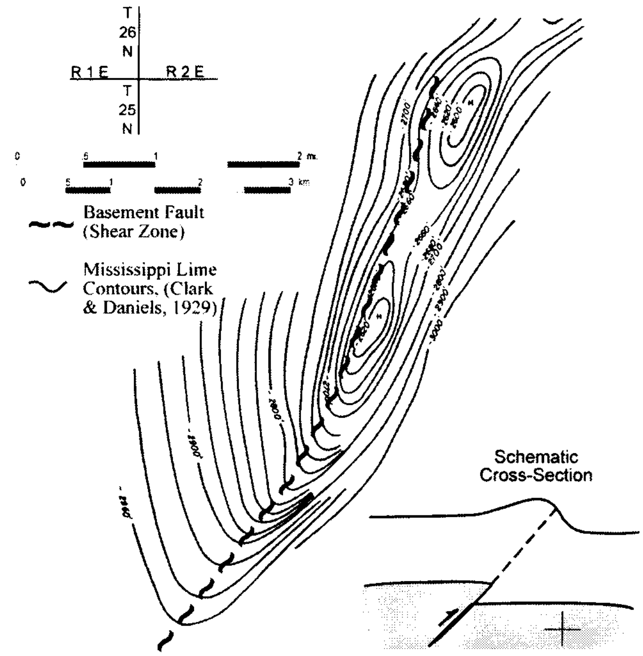

FIGURE 6—Ponca City field, Kay County, Oklahoma, showing typical asymmetric form of compressional fold. Close correspondence of basement fault with axis of fold proves causative relationship; westerly position of fault at basement level proves reverse dip (adapted from Clark and Daniels, 1929).

fault at the surface dips westerly, assuming a dip of less than 45° in about a mile. Figure 12 shows a similar situation in the Elk Basin field of the Big Horn Basin, Wyoming (Stone, 1983). In fact, if we are to believe totally the latter interpretation, a strand of the west-dipping listric thrust here assumes a steep *east* dip at the surface.

Note the "overhang" of the thrusts in Figures 11 and 12. Can the east-bounding fault of the Nemaha system have a similar overhang, perhaps in places where the throw is large? An exploration opportunity may exist if this is correct.

Five additional published cross sections of listric thrust structures with near-vertical dips near the surface are listed here for the interested reader. All are from Stone (1993a): Southern Wind River Basin (his Fig. 6), Grass Creek field (Fig. 10), Garland anticline (Fig. 14), South Elk Basin anticline (Fig. 14), and Sage Creek anticline (Fig.19).

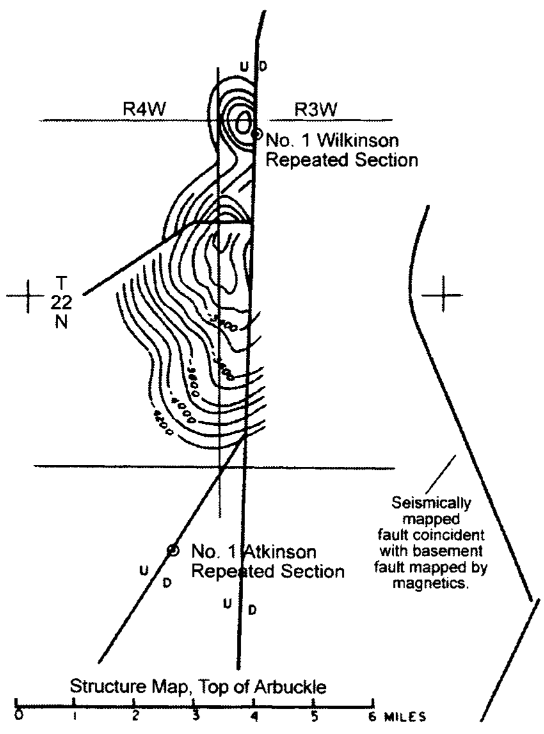

FIGURE 7—Structure map of Garber field, Garfield County, Oklahoma, showing location of two wells with repeated section (Cary, 1954). No. 1 Wilkinson well indicates reverse nature of main east-bounding fault in this field. No. 1 Atkinson well indicates reverse nature of southwest-trending fault south of Garber. This latter fault has been shown by recent 3D seismic survey to extend at least 9 more miles to southwest (R. Feige, pers. comm., 1999).

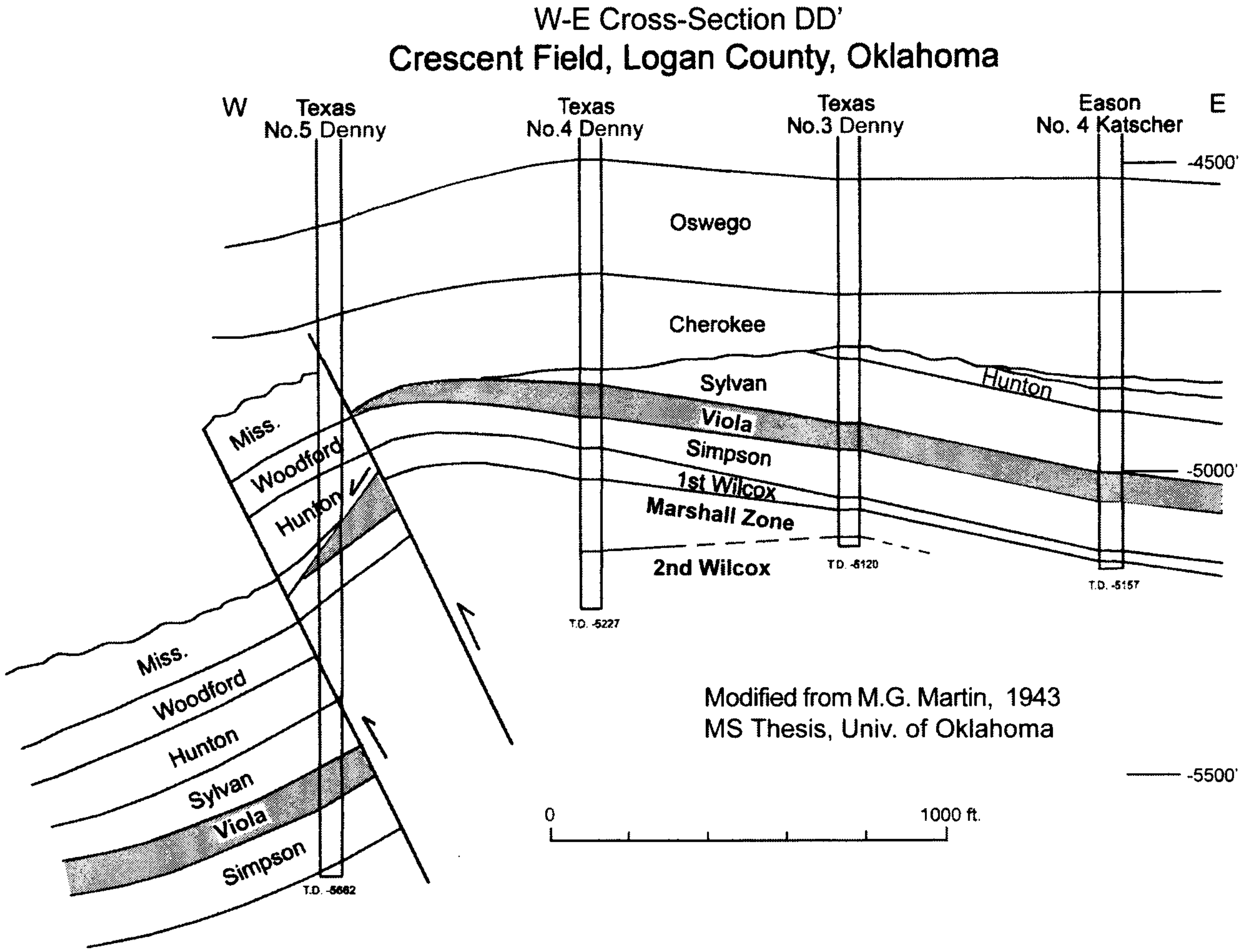

FIGURE 8—West-bounding, north-south-trending reverse fault of Crescent field in Logan County, Oklahoma. Section was redrawn from original 1943 thesis data that showed flat thrust in Texas No. 5 Denny well (Martin, 1943).

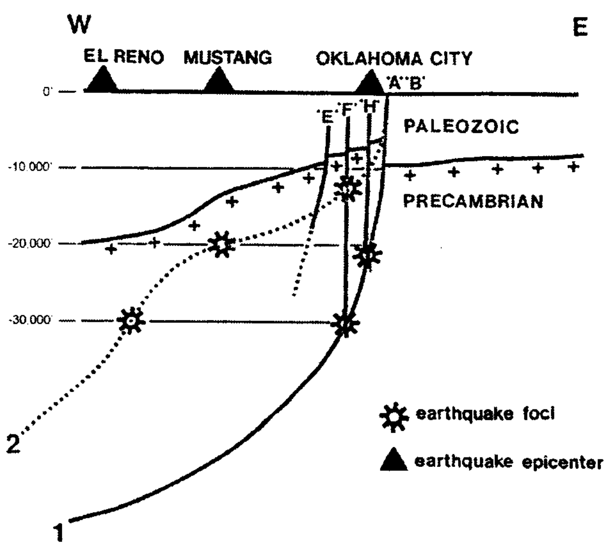

FIGURE 9—Fault trace (1) that satisfies earthquake data for Oklahoma City fault. Second trace (2) was considered less likely (Koff, 1978).

Another characteristic of thrust systems in the Rockies is the occurrence of sedimentary basins in front of the thrusts. This has been attributed to "tectonic loading" (Jordan, 1981), that is, the piling up of rock-on-rock, resulting in isostatic imbalance which depresses the Earth's crust in the thrusted region. This may have occurred on the Nemaha system as well. Dolton and Finn (1989, p.12) state that the deepest part of the Forest City Basin in northeastern Kansas occurs opposite the greatest throw on the Humboldt fault. On a lesser scale, accentuated depressions are located in front of the prominent thrusts at the Oklahoma City and Garber fields in Oklahoma and the El Dorado and Alma Anticlines in Kansas and perhaps other places.

An additional feature of compressional systems which are not documented yet for the Nemaha, but which may well exist, are "backthrusts." In Kay County, Oklahoma, the Nemaha Uplift is characterized by down-to-the-east east-bounding faults and down-to-the west west-bounding faults that may both be reverse faults. The separation between these faults is 8–10 miles and the uplift is 200–

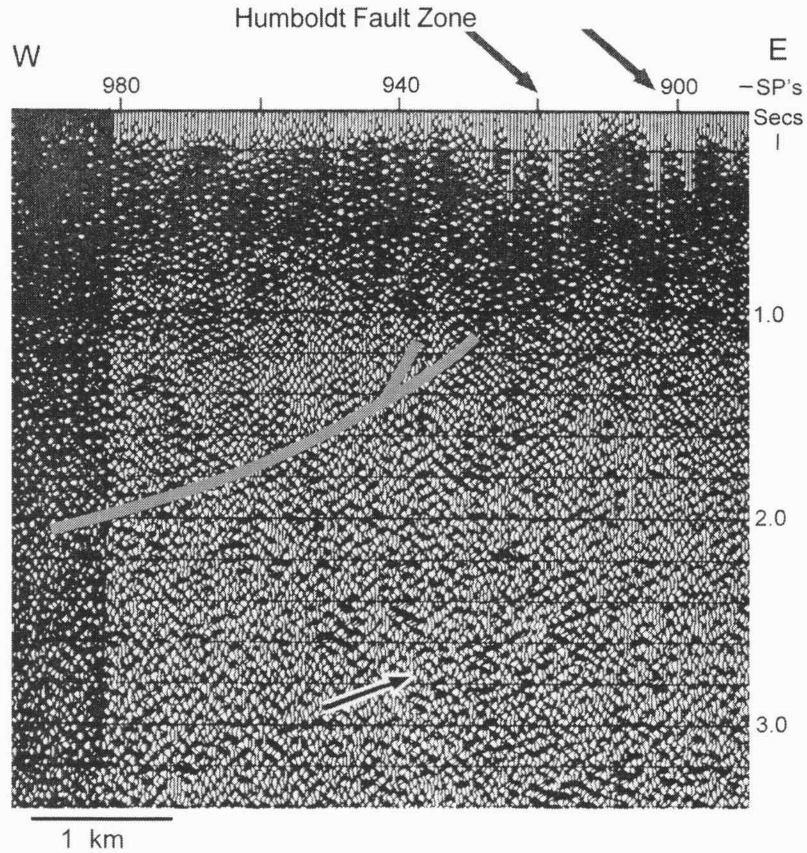

FIGURE 10—COCORP line across Humboldt fault zone in T. 5 S., R. 12 E., Nemaha County, Kansas. Indicated listric west-dipping reflector deep in basement possibly maps author's proposed causative fault for Nemaha Uplift at this locality (after Serpa, Setzer, and Brown, 1989, with help from Setzer and others, 1983).

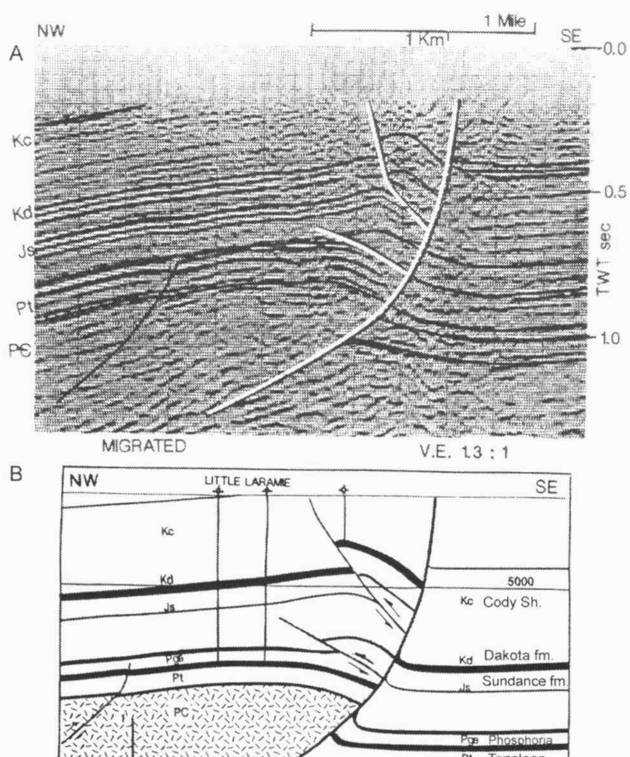

FIGURE 11 (left)—Seismic line across Little Laramie anticline in south Laramie Basin, Wyoming, A, with geological cross section constructed from it, B, Note near-vertical attitude of fault near ground surface and shallow dip at depth (Stone, 1993a, fig. 23).

300 feet at Viola level. At other places along the system, there are folds, but not faults, on east and west sides of the uplift. At depth these folds may also show fault offset, as I postulated earlier for the east flank of the Ponca City field, that is, "blind" faults may be present. Once again, by comparison to structures in the Rockies, Figure 13 shows a typical backthrust in the Owl Creek Mountains in Wyoming, that together with the main west-dipping thrust, creates a "pop-up block".

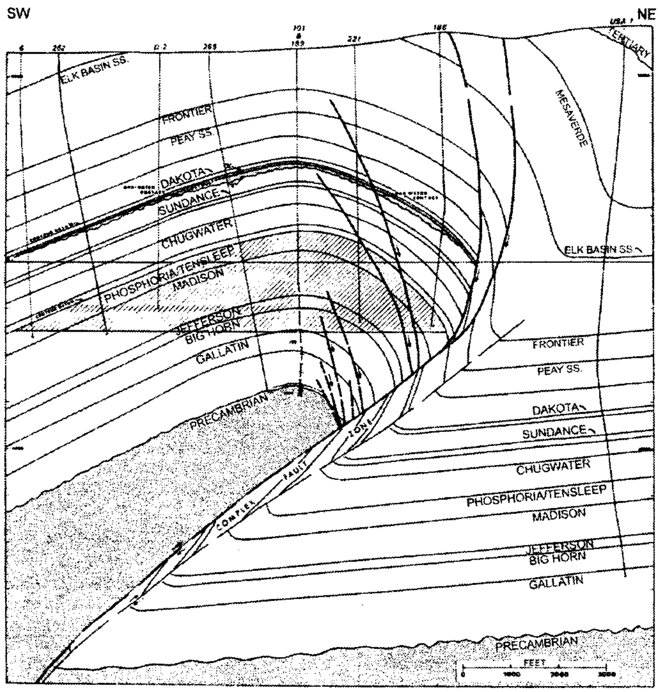

FIGURE 12—Geologic cross section constructed from seismic data and drilling across Elk Basin field in the Big Horn Basin, Park County, Wyoming. Note again near-vertical attitude of thrust faults near surface and shallow dip at depth (from Stone, 1983, fig. 4).

Figure 14 shows the pop-up block concept applied to the Wichita Mountains in southern Oklahoma. The Burch fault and Muenster–Waurika fault systems on the south side of the range would be "backthrusts" to the main south-dipping listric Mountain View fault on the north. Incidentally, it was only as recent as 1971 that the Mountain View fault was depicted as *vertical,* that is, a normal or strike-slip fault (Witt, 1971)—precisely the same concept believed to exist by many present-day geologists for the Nemaha system.

Other noted structural "pop-up" blocks, as shown by recent literature, are the Uinta Mountains in Utah (Stone, 1993b), the Front Range in Colorado (Jacob, 1983), and probably the buried Central Basin Platform in the Permian Basin (Applied Geophysics, Inc., 1996, unpublished).

An explanation for the origin of the Nemaha system by some Kansas Geological Survey staff in recent years has been normal faulting accompanied by left-lateral strike-slip movement (Blair and Berendsen, 1988; Berendsen and Blair, 1992; see also Fenster and Trapp, 1982; Davis, 1986). That there is abundant strike-slip

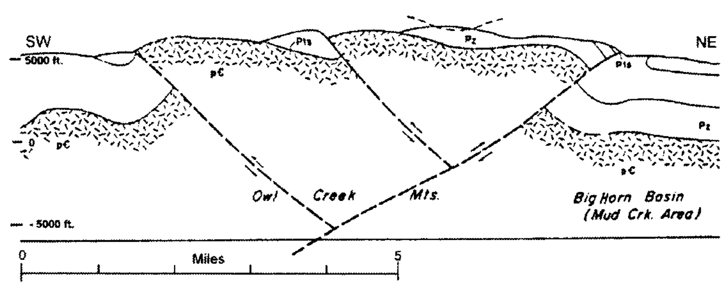

FIGURE 13—Geologic cross section of Owl Creek Mountain Uplift south of Big Horn Basin, Wyoming. Two east-dipping backthrusts branch off the main west-dipping North Owl Creek Thrust (from Blackstone, 1985).

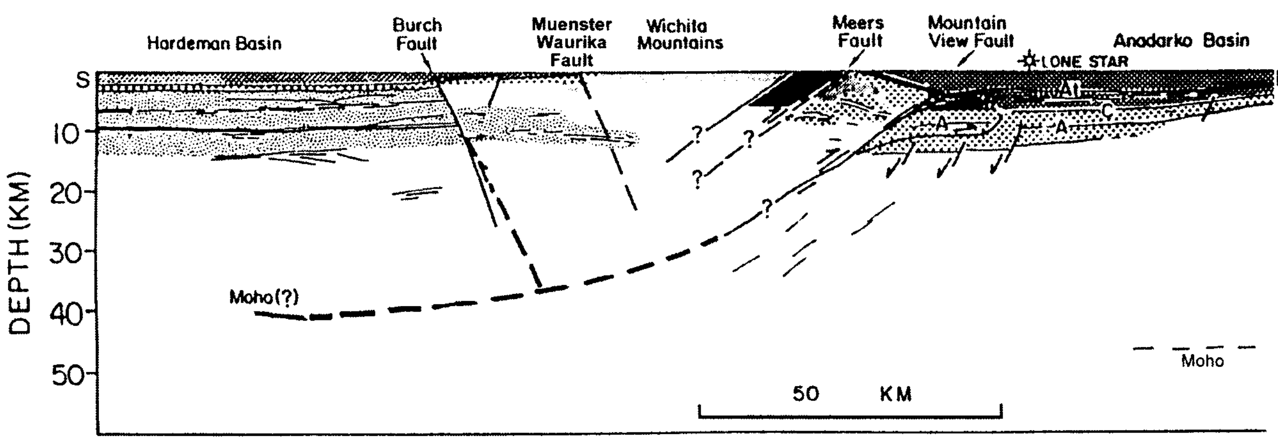

FIGURE 14—Interpretation of COCORP line across Wichita Mountain Uplift, southern Oklahoma. South-dipping Mountain View Thrust has been extended in listric fashion to south, and Burch fault and Muenster–Waurika faults are shown as backthrusts branching from Mountain View (COCORP line from Brewer and others, 1983).

movement on the Nemaha is undeniable, but this lateral movement probably is late, after much, or most, thrusting had occurred. Figures 15 and 16 show two oil fields where prominent *northwest-trending* anticlines occur because of shortening in the longitudinal direction at right angles to the thrusting: El Dorado in Kansas and Tonkawa in Oklahoma. Another place along the system where contemporaneous left-slip movement occurred is on the nearby Wichita Pluton (Gay, 1989) which was offset 6 kms (4 miles) by a fault (Fig.17). Of this fault, Shawver (1965) states: "After...Mississippian sediments were deposited...the faults on east and west sides of the Gillian pool were formed." Strike-slip movement is difficult to document with standard petroleum-exploration techniques, that is seismic and well data, but it is a straightforward solution with magnetics where a geologic marker is present, such as the intrusive boundary in this example.

The last subject discussed is post-compressional normal faulting on the Nemaha system. Stander (1989) shows a high-resolution seismic cross section of the east flank of the Nemaha anticline in northeastern Kansas (Fig. 18). A down-to-the-east normal fault that offsets the shallow Pennsylvanian and Permian beds is apparent. This situation probably occurs in other places along the Nemaha system. By way of comparison, a cross section from seismic and drilling near the tip of the granite wedge of the Owl Creek Thrust in Wyoming is shown in Figure 19. Sedimentary rocks may extend as far back as 10 to 20 miles to the north beneath this thrust. Two normal faults are shown just west of the granite. These may be termed "relaxation" faults, as they apparently result from isostatic adjustments that occurred after compression ceased—perhaps the same as the fault on the Nemaha mapped by Stander (Fig. 18). Similar normal faults, also in the Rockies, are well documented in front of the Wind River Thrust (Basham and Martin, 1985) and the Washakie Thrust (Winterfeld and Conard, 1983).

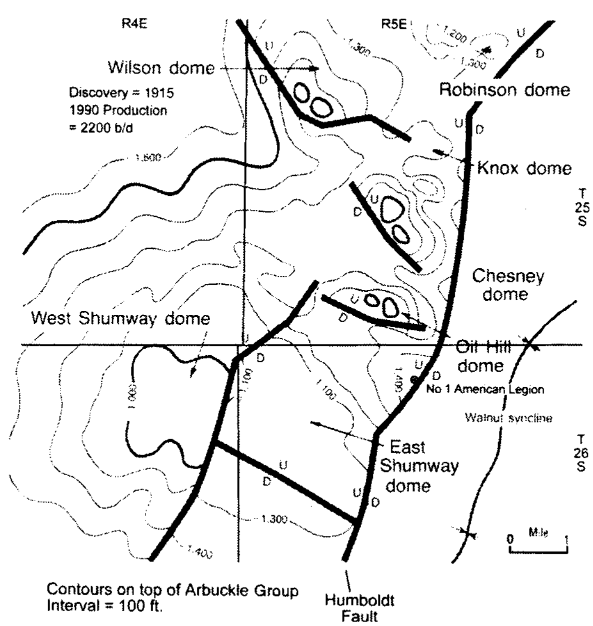

FIGURE 15—Schematic structure map of El Dorado field in Butler County, Kansas (from Ramondetta, 1990). Main east-bounding fault was shown by 1982 American Legion well to be reverse fault. Left-slip movement in later stages of compression is proposed as cause of northwest-trending domes on top of this large anticline.

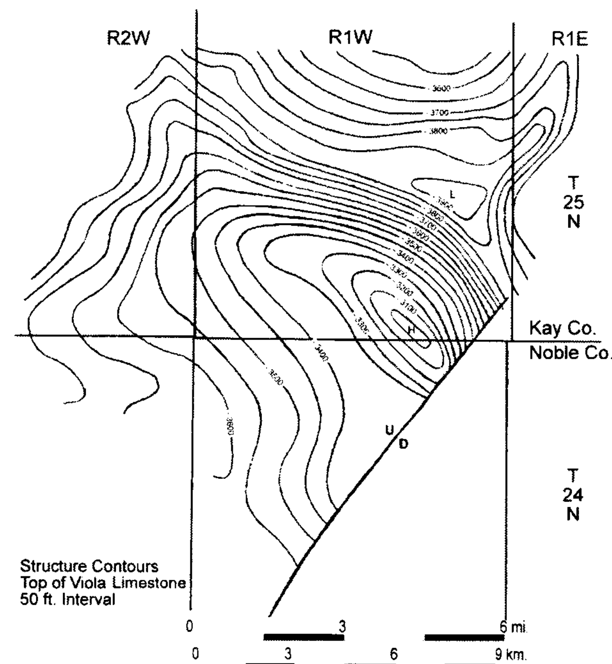

FIGURE 16—Structure map of Tonkawa field, Kay and Noble counties, Oklahoma. East-bounding, northeast-trending fault is part of Nemaha system. Structural shortening parallel to fault, as proven by northwest-trending fold, indicates left-slip (modified from proprietary map, courtesy L. Gatewood, 1983).

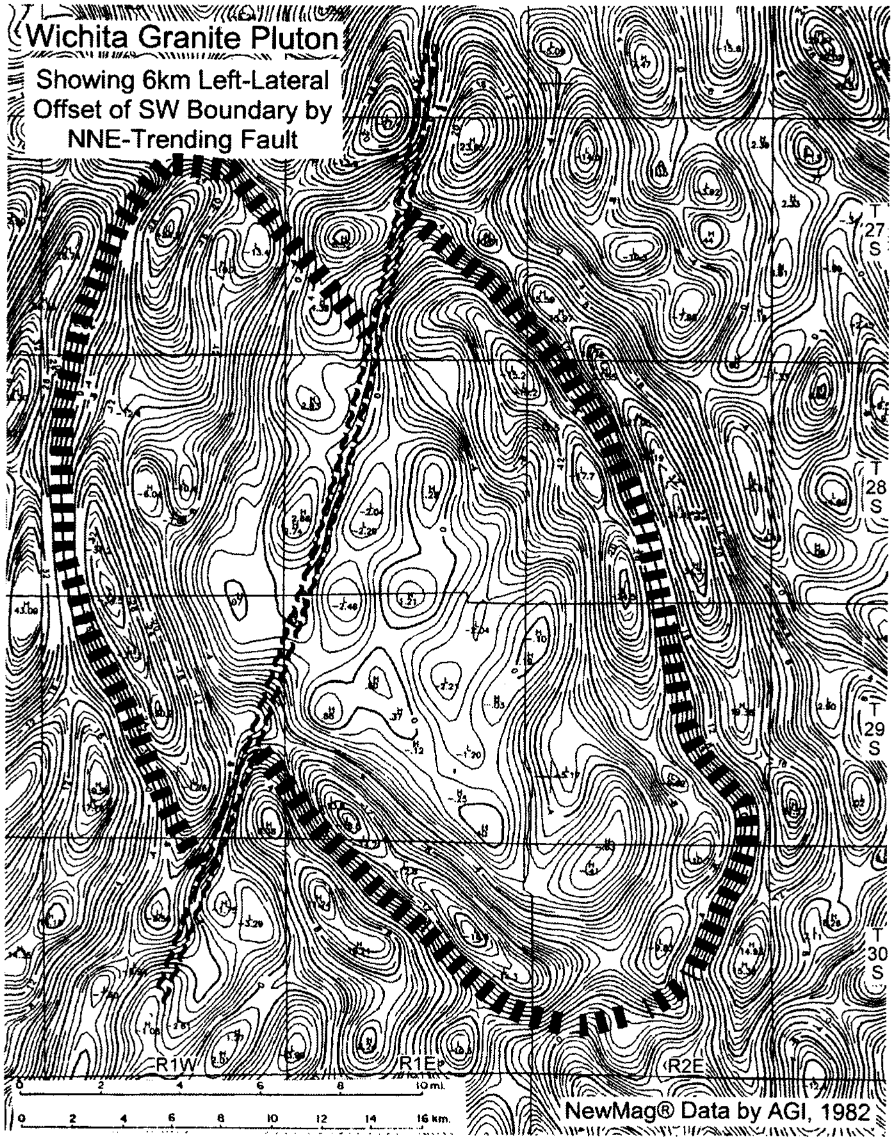

FIGURE 17—Detailed residual aeromagnetic data by Applied Geophysics, Inc., 1982, showing boundary of Wichita Granite Pluton. 6 km (4 mi) left-lateral offset occurred contemporaneously with uplift of Nemaha system.

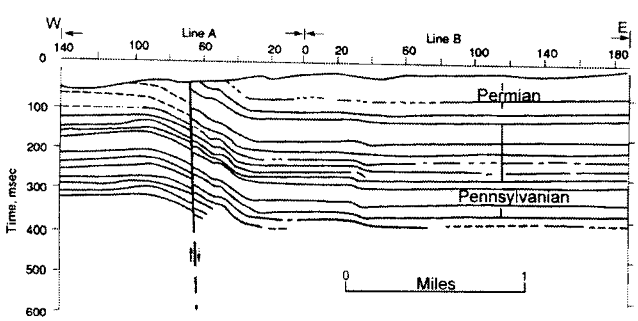

FIGURE 18—Shallow high-frequency, high-resolution seismic line on east flank of Nemaha Uplift, T. 1 S., R. 13 E., Kansas. Note down-to-east normal fault cutting Pennsylvanian–Permian beds (from Stander, 1989).

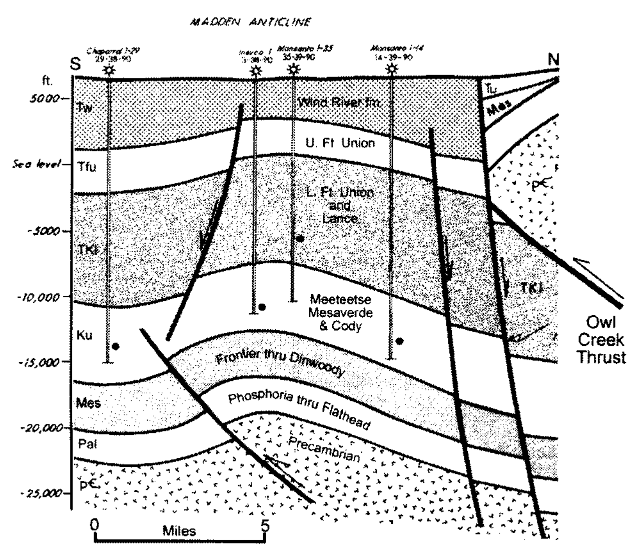

FIGURE 19—Interpretation of seismic and well data of area immediately in front of far traveled (>20 km?) Owl Creek Thrust. Three steeply dipping, post-thrusting "relaxation" faults occur here (from Ray and Keefer, 1985).

CONCLUSIONS

(1) The Nemaha Ridge/Uplift was raised by thrusting in a regional compressional event that was contemporaneous with the creation of the Ancestral Rocky Mountains.

(2) The main bounding thrust (generally on the east side) is steeply dipping or vertical and has been mistaken for a normal fault.

(3) In many places where this fault has been intersected in wells, it has reverse movement and dips steeply west. It is believed to decrease in dip with depth in the *basement,* becoming a typical listric thrust fault similar to dozens of thrusts mapped in the Rockies.

(4) Thrusting has piled rock upon rock (tectonic loading) resulting in crustal downwarping in front of the thrust.

(5) Considerable left-lateral strike-slip movement occurred on the Nemaha system, probably during the later phases of thrusting.

(6) "Relaxation" normal faulting occurred in response to isostatic adjustments after the compressive phase ceased in late-Permian or post-Permian time.

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I would like to thank the following geologists and geophysicists for providing me with cross sections, well logs, technical articles, theses, names of other people, etc., that I have used for demonstrating the compressive nature of the Nemaha system: Pieter Berendsen, Jock Campbell, Marvin Carlson, Jan Dodson, Roberto Feige, Rick Fritz, Lloyd Gatewood, Sherrill Howery, Fred James, Joseph Laravie, Dave Montague, David Newell, Bob Northcutt, Dean Seeber, John Shelton, Bob Slamal, and Jack Wilson.

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Use of Gravity and Magnetics for Low-Cost Exploration and Development in Mature Areas Such as Kansas

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New Geographic Information Systems (GIS) technology allows us to combine rapidly the traditional color gravity and magnetic maps with pseudo-sun shading and a variety of geologic and geographic overlays. This approach can be used to readily identify and characterize structural and stratigraphic features within the basement, and correlate these features with structural and stratigraphic features in the overlying strata, including the location of oil and gas fields. Interpretation of the color and sun-shaded gravity and magnetic maps shows major Precambrian tectonic features, as well as numerous but more subtle structures and lithologic trends associated with these features. On these maps, the important features for petroleum exploration and development are the boundaries between anomalies, and alignments of anomalies. These lineaments are indicated by steep gravity or magnetic gradients which cause increased shading on the maps, or by the regional alignment of gravity and magnetic gradients and the anomalies associated with them. The lineaments seem to correlate with numerous geologic features, including Precambrian lithologic boundaries and structures interpreted from well control, flexures or faults that cut various levels of overlying strata, variations in Paleozoic lithofacies and stratal geometries, and trends of numerous oil and gas fields. These lineaments are interpreted as simple lithologic boundaries or Precambrian structures, some of which may have influenced deposition, structural evolution, paths of fluid migration, and the location of oil and gas fields in overlying strata. In light of this interpretation, the gravity and magnetic maps could be used as a low-cost way of identifying structures and stratigraphic changes that affect oil and gas accumulations and, thus, continue trends of existing fields and plays.

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Regional Stratigraphic Analysis of a Pennsylvanian Carbonate Shelf and Margin in Kansas

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ABSTRACT

Gamma-ray logs representing Upper Pennsylvanian strata were correlated using computer-assisted techniques for distances of 220 mi (354 km) along a northwest-to-southeast line of section in western and south-central Kansas. The section crosses a carbonate-dominated shelf of the Virgilian and Missourian Stages that borders the Anadarko Basin. Correlations were based on log data sampled at 0.5-ft (15-cm) intervals. Manual correlation of cyclothemic-scale genetic units approximately 50 ft (15 m) in thickness provided initial constraints to the automated correlation using regionally extensive marine shales (maximum flooding surfaces and condensed sections). These marine-shale markers were correlated previously from a regional study of core, outcrops, and wireline logs. Correlations of natural gamma-ray response within these genetic units were derived using computer-assisted autocorrelation. Stratal units resolved include: (1) cyclothemic-scale genetic units (10's of meters in thickness); (2) longer term sets of cyclothemic-scale genetic units (10's to 100's of meters in thickness); and (3) meter-scale stratal elements including high-frequency cycles within genetic units. Classic onlap and offlap and forward- and backward-stepping stratal geometries are noted. Reliability of correlations was computed. Uncorrelated intervals result in triangular-shaped intervals of no correlation between wells. These are associated with onlap and offlap geometries. This is critical evidence to assess stratigraphic truncations, usually limited in manual correlation unless surfaces are described in core or outcrop or seen in seismic data.

Regional correlation of genetic units and coherent sets of genetic stratigraphic units strongly suggest important allogenic and basin controls on sedimentation. This computer-assisted method provides an opportunity to assist in development of consistent, finer scale correlations that augment traditional geologic analyses. Manual correlation of high-resolution genetic units using wireline logs has been limited by issues of consistency and subjectiveness. Computer-assisted correlation can minimize these issues, if properly calibrated (trained). Integration of manual and computer techniques will help place surface and subsurface studies on a more equal footing to help resolve controls on sedimentation.

Targeting stratigraphic traps is facilitated using digital well logs and computer techniques. Reservoir attributes including porosity and resistivity and computed variables such as bulk volume water, fluid saturations, and even hydrocarbon pay can be introduced into the correlated sections. Furthermore, false-color imaging of the petrophysical properties and computed information within the digital cross sections will help identify anomalies and potential drilling opportunities.

INTRODUCTION

The wealth of subsurface information in mature oil and gas provinces and availability of "off-the-shelf" computer techniques provides the potential to process more extensive three-dimensional control for more robust stratigraphic modeling. Wireline logs, a major subsurface data type, provide continuous, high-resolution records of physical and chemical properties. Enhanced analysis and display of log data can help improve understanding and provide new insights into the stratigraphic record.

A major barrier exists in fully utilizing well logs to establish consistent high-resolution stratigraphic correlations. Log data may be distributed widely and manual correlations can be biased by conceptual preferences of the user. Problems of reliability and resolution are a major impediment to the utilization of sequence stratigraphy in exploring for natural resources. More complete integration and access to surface and subsurface data may help constrain and quantify stratigraphic models. Traditional manual correlation of wireline logs is unlikely be sufficient to meet these needs.

Computer-assisted correlation of digital wireline-log data is able to provide reliable correlations that go beyond routine lithologic tops to isolate stratigraphic anomalies important in exploration. Such subtle, normally uncorrelated stratal elements permit new insights about potential stratigraphic traps. Fundamental problems in correlation of well logs that need to be addressed include:

(1) Can stratal geometries be resolved routinely within stratigraphic sequences dominated by one lithology?

(2) Can correlations of high-resolution stratigraphic units be established for distances of 10's and 100's of kilometers?

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(3) Can the reliability of correlations be established and quantified?

(4) Can correlation be linked more closely to analytical activity using computer-assisted methodology?

(5) Can large numbers of well logs be processed routinely for large stratigraphic intervals and wide areas to resolve long-term, small-scale changes in the stratigraphic record?

METHODOLOGY

Thickness and lithofacies of Upper Pennsylvanian genetic stratigraphic units (GSU's) were used to infer the detailed regional paleogeographic evolution of the Kansas shelf (Watney and others, 1995) (Fig. 1). Approximately 3,000 wells were used to map thicknesses of GSU's in the Kansas City Group, and cores and surface exposures were used to characterize lithofacies of these stratigraphic units and to verify wireline-log correlations. Log tops were correlated manually among these wells to establish a framework of structure, interval thicknesses, and porosity development in regressive carbonates, and gamma-ray responses in condensed sections. Resulting maps show shelf configuration changing in seeming response to differential subsidence, sediment supply, and eustacy (Watney and others, 1995).

Surface and near-surface studies in eastern Kansas provide details of depositional sequences and genetic units in Upper Pennsylvanian carbonated-dominated strata. Components include subaerial surfaces, flooding units, condensed sections (maximum flooding surfaces), and stratigraphic packages containing minor shallowing-upward cycles (Watney, French, and Franseen, 1989; Watney and others, 1995). Stratal geometries observed in closely spaced cores suggest onlap and downlap (Fig. 2). Bennison documented analogous stratal geometries and GSU's in concurrently deposited clastics shed from the Ouachitas and deposited in the Arkoma Basin in eastern Oklahoma (in Watney, French, and Franseen, 1989; Fig. 4). Regional controls explain this consistency between contrasting depositional settings.

A hierarchy in Middle and Upper Pennsylvanian cycles was recognized, consisting of five to seven successive GSU's that form genetic sets (GS's) bounded by marine shales (Youle, Watney, and Lambert, 1994;Watney and others, 1995). GSU's included in a set exhibit backstepping and forward-stepping stratal patterns.

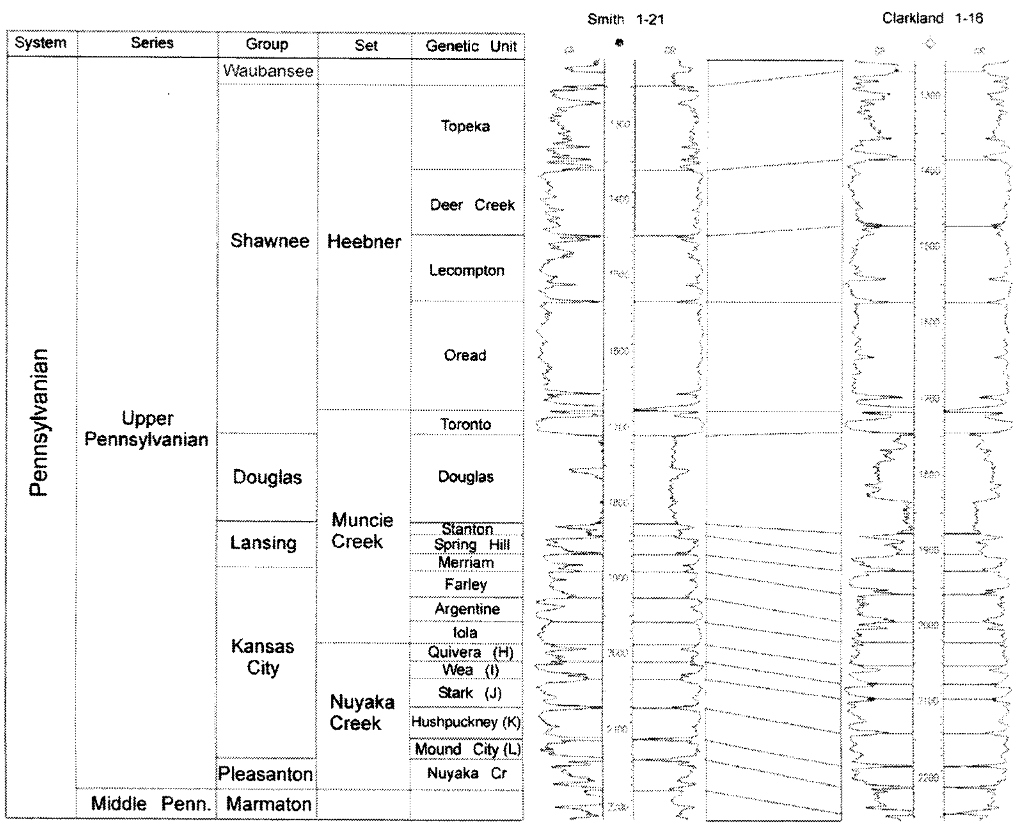

FIGURE 1—Two gamma-ray logs depict correlations of formal and genetic stratigraphic nomenclature and classification. Genetic stratigraphic units (GSU's) are bounded by marine condensed sections, usually thin, black, radioactive shales. Shales have been correlated through extensive log database and cores have been used as available to substantiate lithofacies. Unit names reflect prominent condensed section or marine formation encompassed by GSU. Genetic sets (GS's) are groups of five to seven GSU's distinguished by stratal organization within these packages. GSU's include documented regional subaerial exposure surfaces, but these are not correlated easily on regional basis in subsurface, thus GSU's are used for practical expediency.

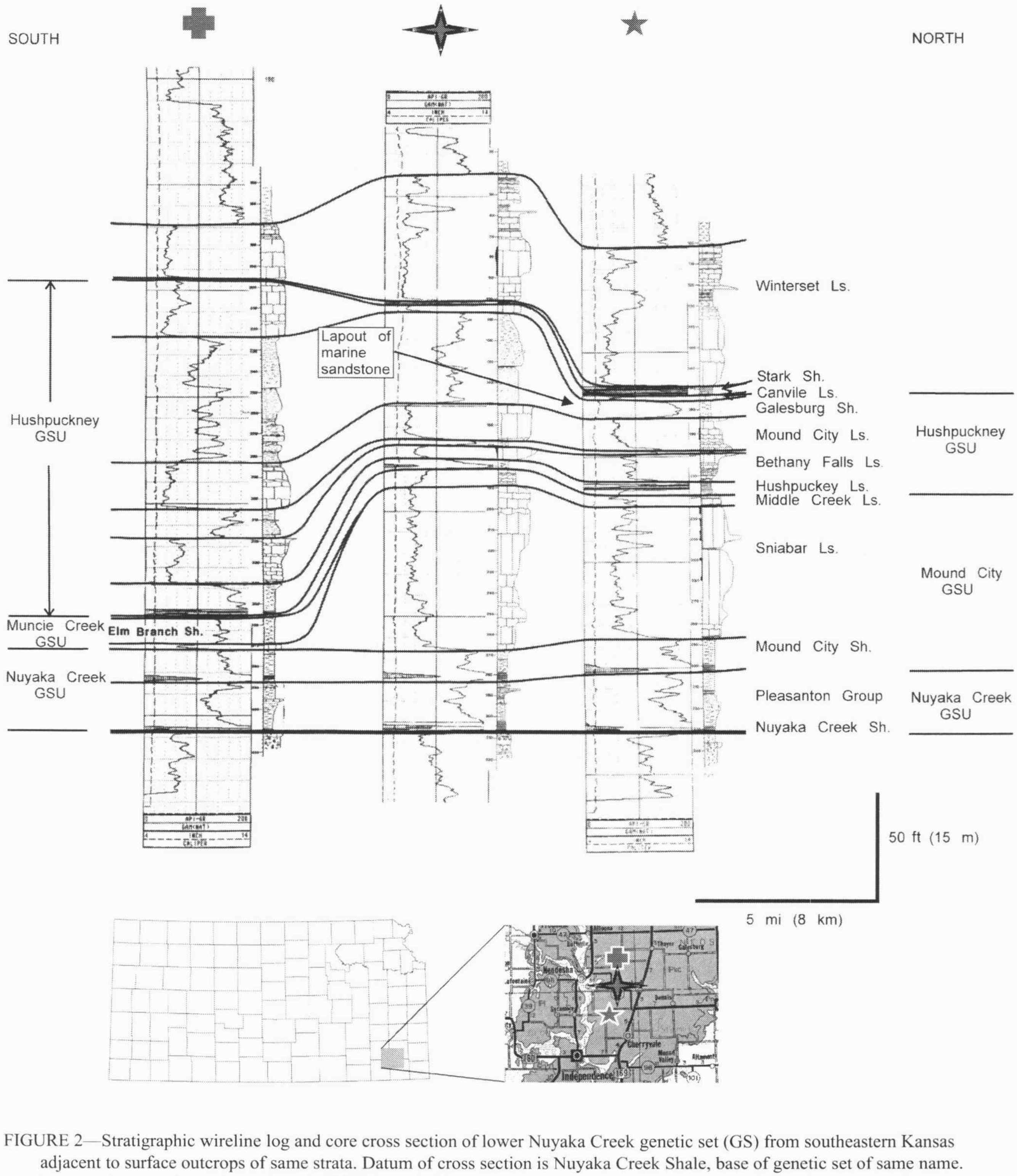

FIGURE 2—Stratigraphic wireline log and core cross section of lower Nuyaka Creek genetic set (GS) from southeastern Kansas adjacent to surface outcrops of same strata. Datum of cross section is Nuyaka Creek Shale, base of genetic set of same name. Mound City genetic stratigraphic unit (GSU) bounded by underlying Mound City Shale and overlying Huspuckney Shale contains carbonate bank in Sniabar Limestone developed along margin of broad carbonate-dominated shelf. Eighty feet (24 m) of limestone thin down to less than few feet for distance of less than 5 mi (8 km). Thinning is assumed to occur by downlap of carbonate unto its underlying condensed section. Overlying Hushpuckney GSU, whose boundaries extend from Hushpuckney Shale to Stark Shale, thickens basinward (south) filling in accommodation space in front of underlying carbonate bank. Index map for cross section is part of illustration (modified from J. French, written comm., 1999).

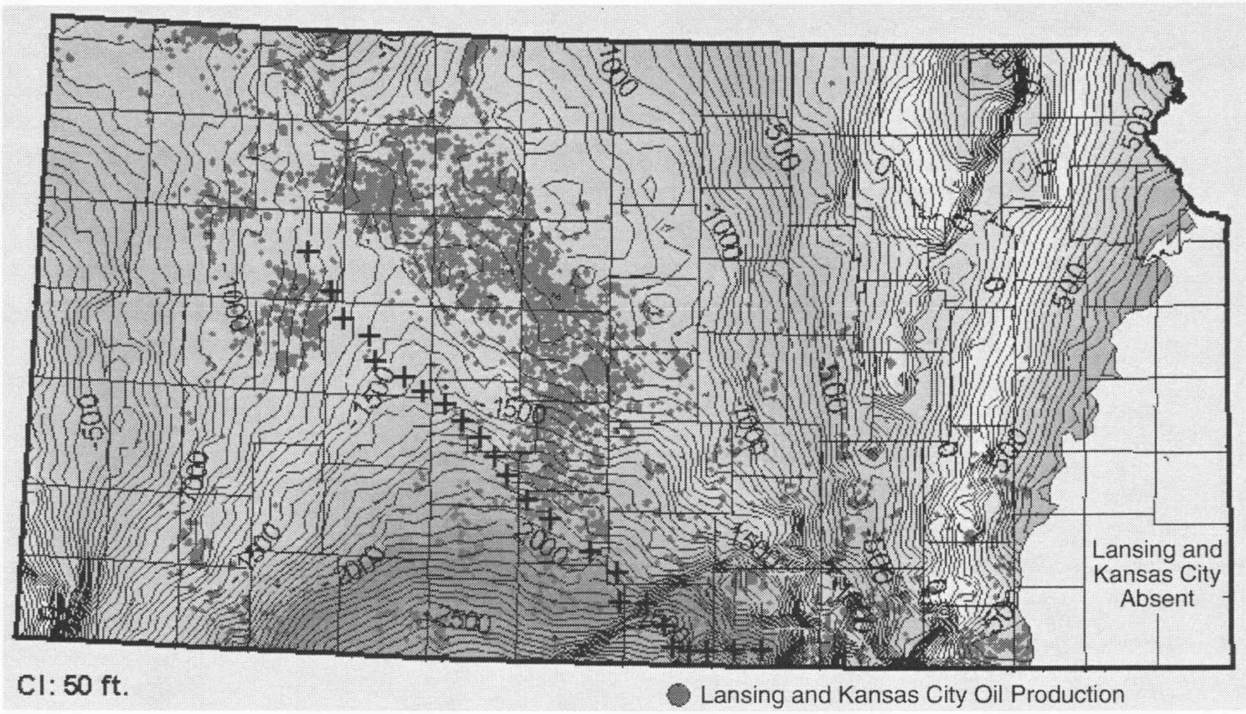

FIGURE 3—Index map of Kansas for cross section showing wells that produce oil from Lansing–Kansas City reservoirs. Section extends from Ness County in west-central Kansas to Sumner County in south-central Kansas (modified from P. Gerlach, written comm., 1999 http://crude2.kgs.ukans.edu/DPA/Plays/ProdMaps/lgkc_gas.html).

This trend also is shown by regional maps of successive GSU's where carbonate buildups are oriented along strike on the shelf and shelf margin. These buildups generally are rectilinear and closely follow basement lineaments (Watney and others, 1999). Map patterns and stratal organization of GS's suggest an interplay of regional eustacy and subsidence. GS's correspond to formal stratigraphic groups, including the Excello GS and Marmaton Group, Nuyaka Creek GS and Pleasanton and most of Kansas City Group, Muncie Creek GS and upper Kansas City, Lansing, and Douglas Groups, and Heebner GS and Shawnee Group (Fig. 1).

Previous studies recognized two types of carbonate-dominated shelf margins including a long-term sediment-starved carbonate margin of several GSU's (Watney and others, 1995), and reciprocal carbonate accumulation and episodic siliciclastic influx filling space in front of the carbonate margin during each GSU. Mixed clastics and carbonate strata of the Hushpuckney GSU fill the space in front of and override the carbonate bank of the underlying Mound City GSU (Fig. 2). Also, clastic units thicken basinward and overall thickness of the Hushpuckney GSU on the basinward side exceeds thickness on the landward side. This suggests greater subsidence on the basinward side or increase in elevation of the sediment surface. Decompaction of clastics would add additional thickness on the basinward side, if compaction of carbonates is less than in clastics. Stratigraphic traps associated with reciprocal sedimentation are a result of ephemeral events that can be identified efficiently by detailed correlation of well logs. Isopachous mapping of large intervals spanning multiple GSU's would miss the lapout of the sandstone and the carbonate-bank margin (Fig. 2).

Gamma-ray logs from 24 wells in a 220-mi (354 km) northwest-to-southeast cross section in western and south-central Kansas (Watney and others, 1999) were correlated by computer in this current study (Fig. 3). In comparison to manual correlations (Fig. 4), stratal elements within the GSU's are defined at higher resolution. The computer-correlated section of this current study was expanded to include the Shawnee Group, Heebner GS overlying the stratigraphic interval that was correlated manually in the earlier paper (Fig. 1).

The natural gamma-ray curve was digitized at a set interval of 0.5 ft (15 cm) and normalized to a shale baseline set to 1 and a clean, shale-free lithology set to 0. Normalizing resulted in a consistent log response between wells, but eliminated high gamma-ray spikes associated with condensed sections (black marine shales) of the GSU's. The methodology is described in Olea (1994). CORRELATOR cross sections are coded so the lighter the gray tone, the lower the rock-shale content. Intervals that are white represent no correlation between wells for that segment. These gaps serve to outline correlations between wells. Original illustrations in color are available on the internet website of the Kansas Geological Survey at http://www.kgs.ukans.edu.

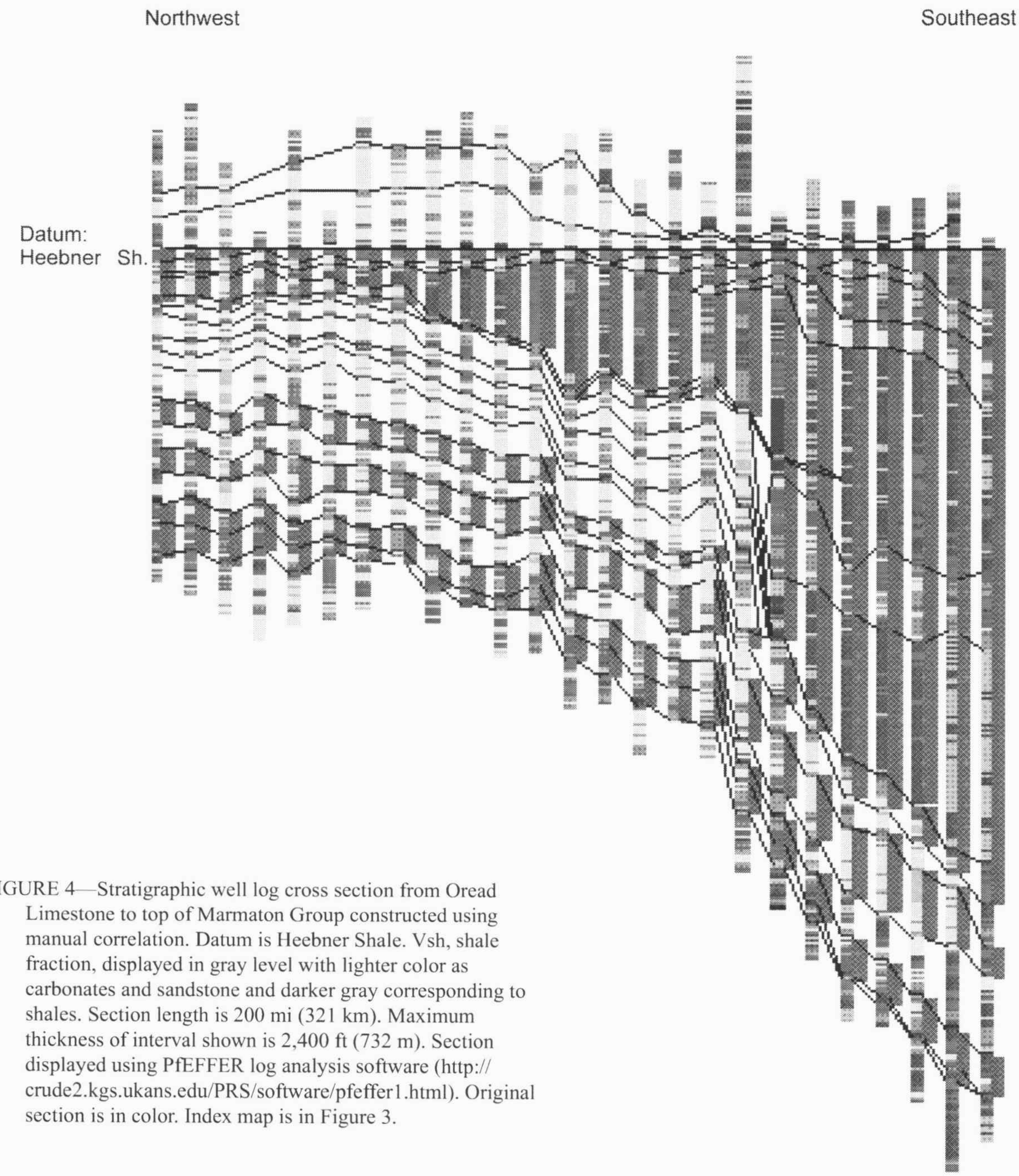

FIGURE 4—Stratigraphic well log cross section from Oread Limestone to top of Marmaton Group constructed using manual correlation. Datum is Heebner Shale. Vsh, shale fraction, displayed in gray level with lighter color as carbonates and sandstone and darker gray corresponding to shales. Section length is 200 mi (321 km). Maximum thickness of interval shown is 2,400 ft (732 m). Section displayed using PfEFFER log analysis software (http://crude2.kgs.ukans.edu/PRS/software/pfeffer1.html). Original section is in color. Index map is in Figure 3.

RESULTS

In the structural presentation of the cross section (Fig. 5), the Sedgwick Basin is clearly visible as the synclinal area corresponding to most clastic deposits. The west flank of the Nemaha Uplift, bordering the east of the Sedgwick Basin, affects the four rightmost wells of this cross section. During times of shale accumulation, such as during the Muncie Creek GS, the site was a basin and the Nemaha Uplift was not active. The carbonate bank deposited late in the Heebner GS suggests that the Nemaha Uplift again may have been active. Present configuration suggests additional periods of renewed uplift following Pennsylvanian deposition.

On stratigraphic cross section with a Heebner Shale datum (Fig. 6), genetic sets (GS's) are distinguished as group of carbonate-dominated shelf strata. The carbonate shelf associated with the Nuyaka Creek genetic set spans most of the cross section. The easternmost well is off the shelf and seemingly underwent reciprocal clastic sedimentation during a lowstand in sea level as clastics bypassed the shelf and crossed the Arkoma Basin to the south. The reciprocal sedimentation here resembles that observed near the surface exposures of this interval (Fig. 2). GSU's constituting the Nuyaka Creek GS show backstepping, then forward-stepping geometries as

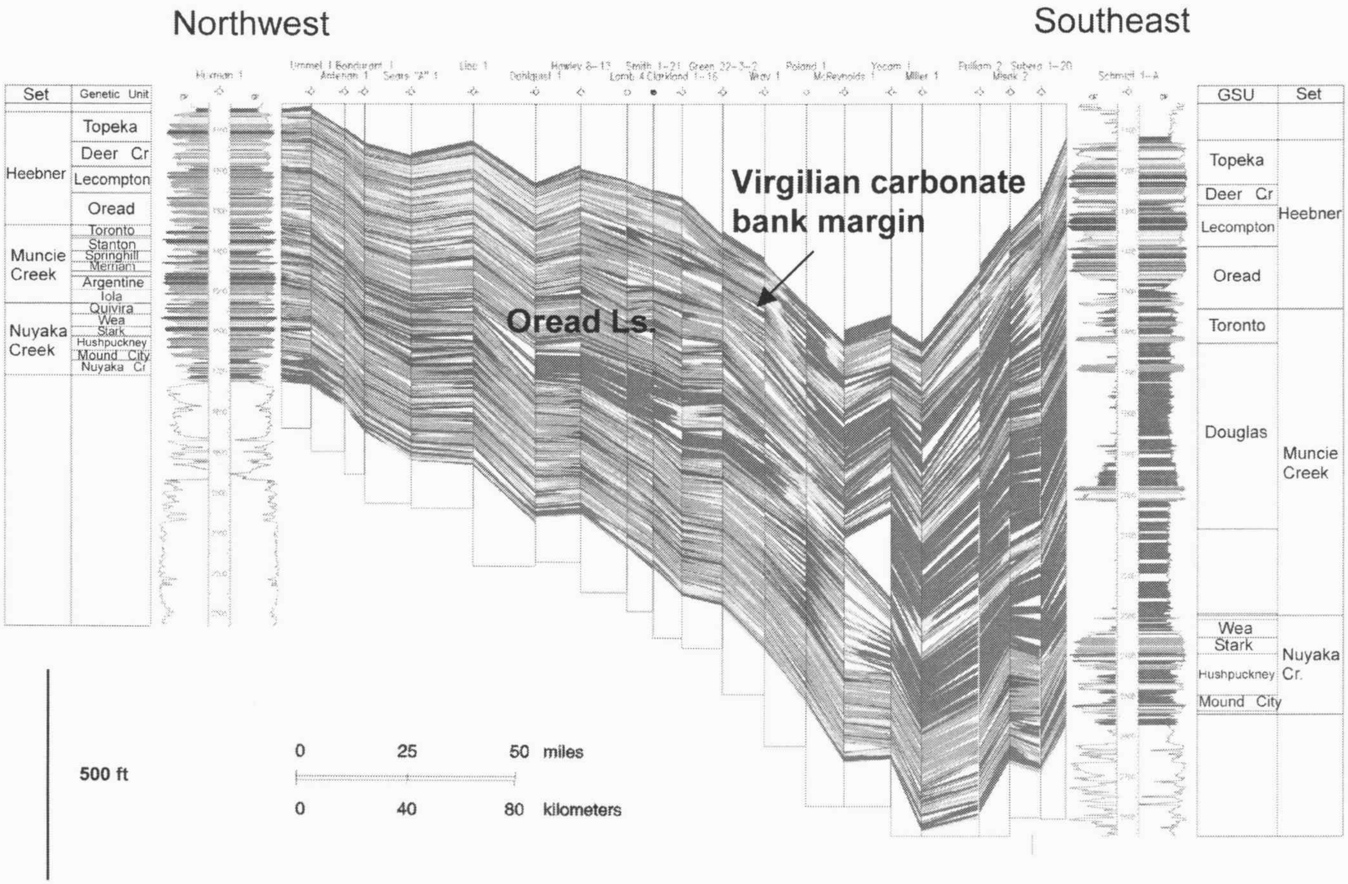

FIGURE 5—Structural well log cross section constructed with CORRELATOR software showing Vsh, shale fraction, in gray scale with darker gray shades depicting shale and lighter shades for sandstone and carbonate. Most lighter areas are carbonate units. Index map is in Figure 3.

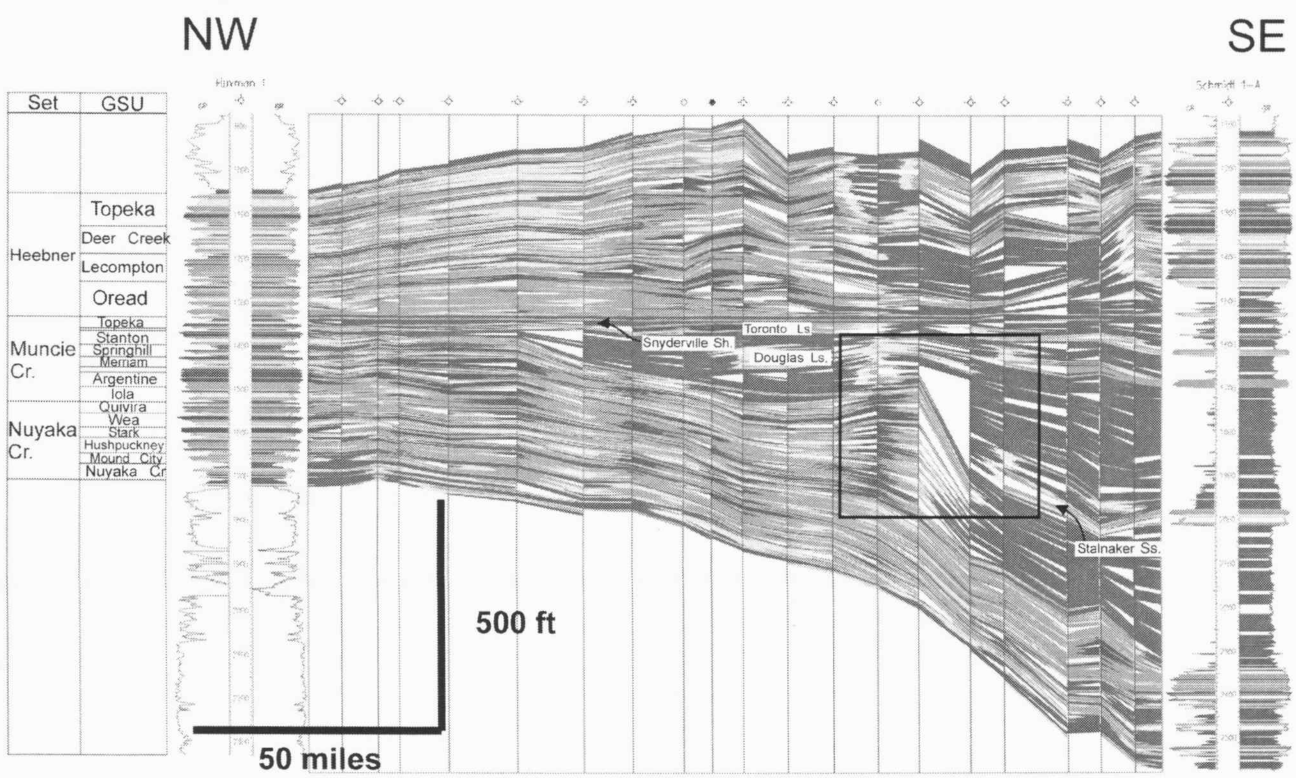

FIGURE 6—Stratigraphic cross section showing Vsh using same wells as in Figure 5. Datum is Heebner Shale. Box shown for close-up cross section in Figure 8. Index map is in Figure 3.

indicated by landward (westward) migration of more shaly GSU's through the mid portion of the set and then forward-stepping (lateral accretion) of the cleaner carbonate GSU's. This stratal succession suggests overall rise and fall in relative sea level during the Nuyaka Creek GS.

The carbonate shelf of the succeeding Muncie Creek GS occupies only the western two-thirds of the cross section. The carbonate shelf margin is more abrupt, suggesting prolonged reduced and sediment starved conditions in the shale-dominated basin adjoining this carbonate shelf. A small amount of backstepping of the carbonate shelf toward land was followed by a forward step prior to the close of carbonate-bank deposition. A more prominent pattern of backstepping and forward-stepping carbonate margin covering 100 mi (160 km) occurs along the eastern Kansas outcrop (Fig. 7). Maximum extent of backstepping is associated with the Argentine GSU (including the Wyandotte Formation) in both cross sections (Figs. 6 and 7), in spite of contrasts in the amount of the shift of the carbonate-bank margins. More clastics are interspersed with the GSU's in eastern Kansas, suggesting that reduced subsidence rates in the east kept the eastern shelf at higher elevations so carbonate shifted greater distances with similar shifts in eustacy. The triangles of no correlation (white) between wells located down the flanks of the bank margin between shelf carbonates and basin shales suggests that alternating segments of the carbonate-bank margin do not correlate with the shale, that is, have no resolvable shale counterparts and downlap into the basin. The "no correlation" wedges point basinward. Some of the shale in the basin was deposited as the bank developed, but the accumulation of shale did not keep up with the carbonate bank leading to topographic relief estimated to be at least 200 ft (61 m).

Stalnaker Sandstone was deposited in the basin above the shale interval correlated with the carbonate bank (Fig. 8). Neither the Stalnaker Sandstone nor the 150 ft (46 m) shale above (Fig. 6) correlate with any stratigraphic interval on the shelf. This suggests that the Stalnaker Sandstone is a lowstand deposit, perhaps representing bypassed sediment from the shelf, as suggested in previous work (Winchell, 1957; Walton and Griffith, 1985; Archer, Lanier, and Feldman, 1994; Feldman, Archer, and Heckel, 1994). The Tonganoxie and Ireland Sandstones in eastern Kansas occupy significant incised valleys up to 135 ft (41 m) deep in the Kansas City area, 100 mi (160 km) inboard from the shelf margin of the underlying Stanton GSU in southern Kansas. This clastic influx is coeval with a prominent conglomerate that advanced into the Arkoma Basin from the Ouachita Mountain front. It has been suggested that a major tectonic uplift may have been responsible for the prominent clastic influx (Visher, 1999). The uncorrelated wedge on the cross section in Figure 8 is 200 ft (61 m) thick and suggests that sea level fell to this position in front of the carbonate-shelf margin. Total change in sea level probably was greater as water rose to inundate the shelf and deposit black shales (condensed sections). The uncorrelated Stalnaker Sandstone and overlying shale is interpreted as a lowstand deposit. These lowstand conditions may have represented maximum fall in sea level associated with the Muncie Creek GS. The equivalent conglomerate toward the Ouachita Mountain front may have advanced basinward because of the relative lowstand. In both the northern carbonate-dominated shelf and southern clastics apron, clastics bypassed the higher reaches of the shelves through incised valleys to reach what were previously sediment-starved reaches of the basin.

The predominately clastic section above the Stalnaker Sandstone shows onlap and overstepping of the carbonate

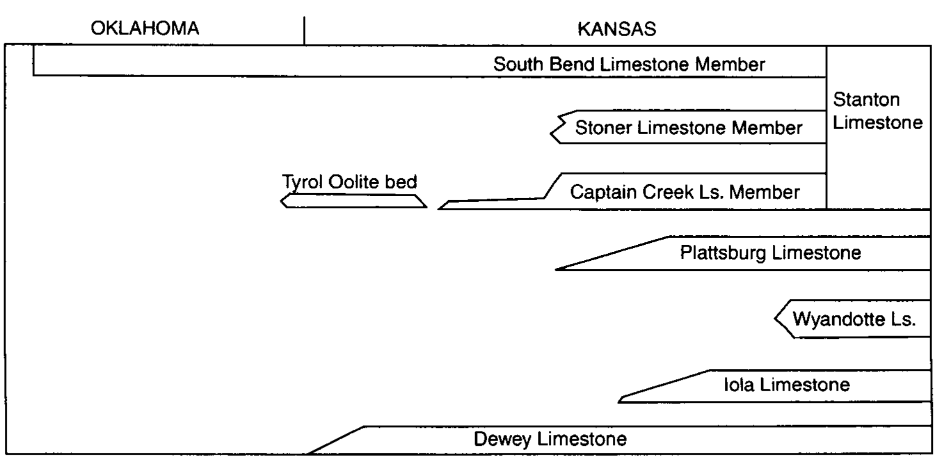

FIGURE 7—Schematic stratigraphic cross section for lower carbonate-dominated Muncie Creek GS extending along surface exposures between Oklahoma and northeastern Kansas. Iola bank margin backsteps from carbonate margin (Dewey Ls.) of underlying Nuyaka Creek GS located at Kansas–Oklahoma border. Backstepping of bank margin continues to maximum at Wyandotte Limestone (containing Argentine Limestone Member). Then carbonate margin steps forward (basinward) some 100 mi (160 km) to position of South Bend Limestone in northeastern Oklahoma (figure modified from Heckel, 1975).

bank with wedges of no correlation pointed landward indicating that sections of basinward deposits do not correlate with sediments on the landward, updip side. Limestone in the Douglas onlaps and the Toronto Limestone oversteps beyond the cross section. This implies continued relative rise in sea level (Fig. 6). Sea level however is inferred to have been at an intermediate level compared to the lower portion of the Muncie Creek GS when the carbonate shelf was developed. Differential subsidence is suggested by lowering and flexing of the southern portion of the lower Muncie Creek GS relative to the northwestern side. Subsidence may have contributed to this relative rise in sea level and created some of the renewed sediment accommodation space for the upper Muncie Creek GS.

The succeeding Heebner GS began with a marked marine inundation that crossed the entire cross section and initiates renewed development of a carbonate-dominated shelf and shelf margin (Fig. 6). An underlying paleosol below the flooding surface in the Synderville Shale, immediately overlying the Toronto Limestone (Fig. 1) has been recognized as a significant unconformity in the immediate interval (Joeckel, 1994, 1995). The carbonate-shelf margin of the Heebner GS thickened through aggradation slightly landward from the margin formed by the underlying Muncie Creek GS. Moreover, carbonate-dominated GSU's developed on the east side over the site of the Nemaha Uplift suggesting renewed uplift or less differential subsidence. In the region between the two carbonate-dominated areas, clastics were correlated with the carbonate-dominated shelf and indicate downlapping of carbonate units into the basin and shales onlapping the shelf.

High-resolution correlations within the Oread GSU, located at the base of the Heebner GS, indicate two distinct episodes of carbonate accumulation. A lower carbonate unit in the Plattmouth Limestone downlaps onto the underlying Heebner Shale (Fig. 9C, close-up of interval shown in Fig. 9A). The carbonate unit in turn was onlapped by a thin wedge of marine shale extending landward from the Heebner Shale onto the lower carbonate unit. Onlapping shale is probably a maximum flooding surface. Following deposition of the shale, the succeeding carbonate unit downlaps onto the Heebner Shale at a

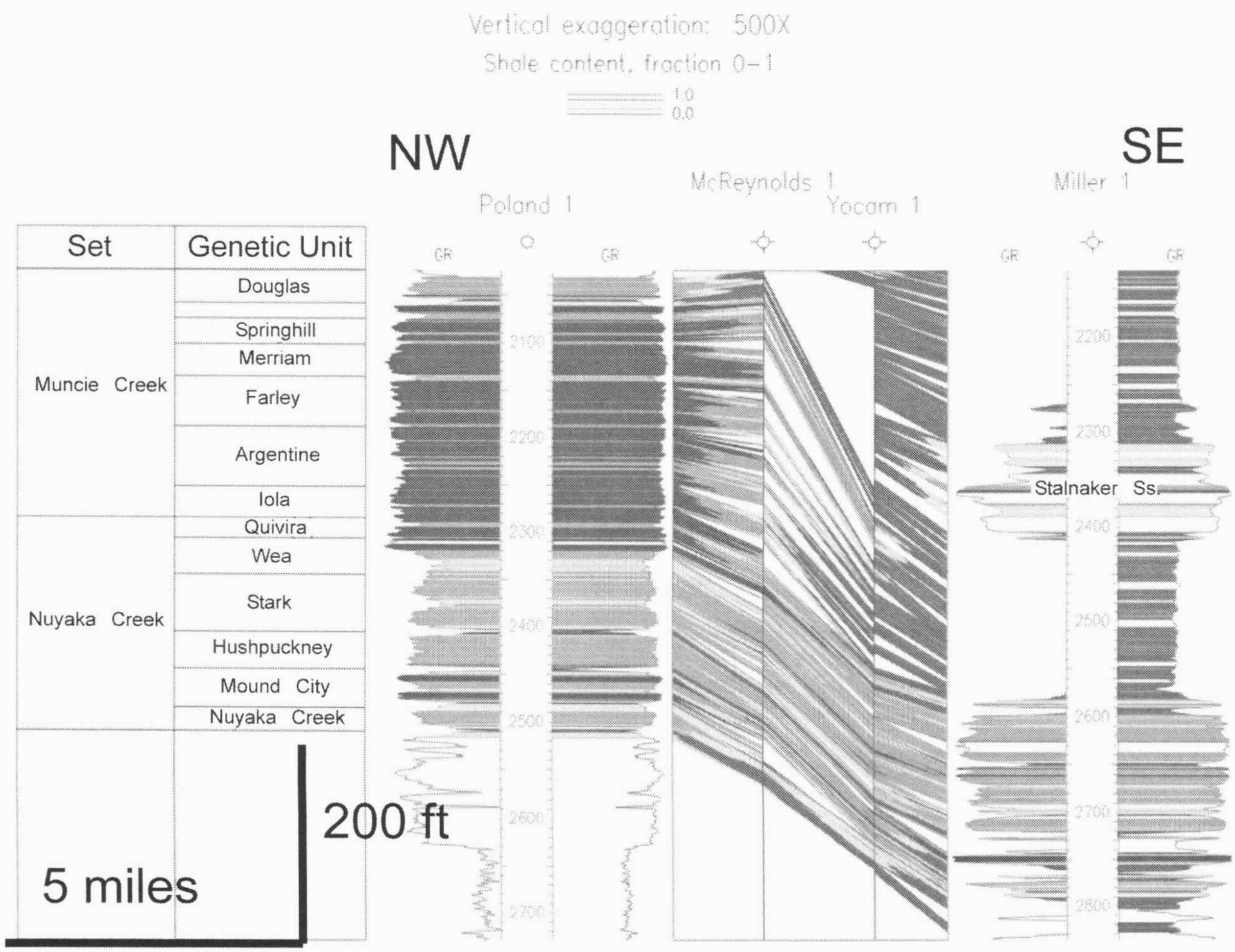

FIGURE 8—Close-up of stratigraphic cross section in Figure 6 showing four wells and stratigraphic interval between Nuyaka Creek GS and lower portion of Muncie Creek GS.

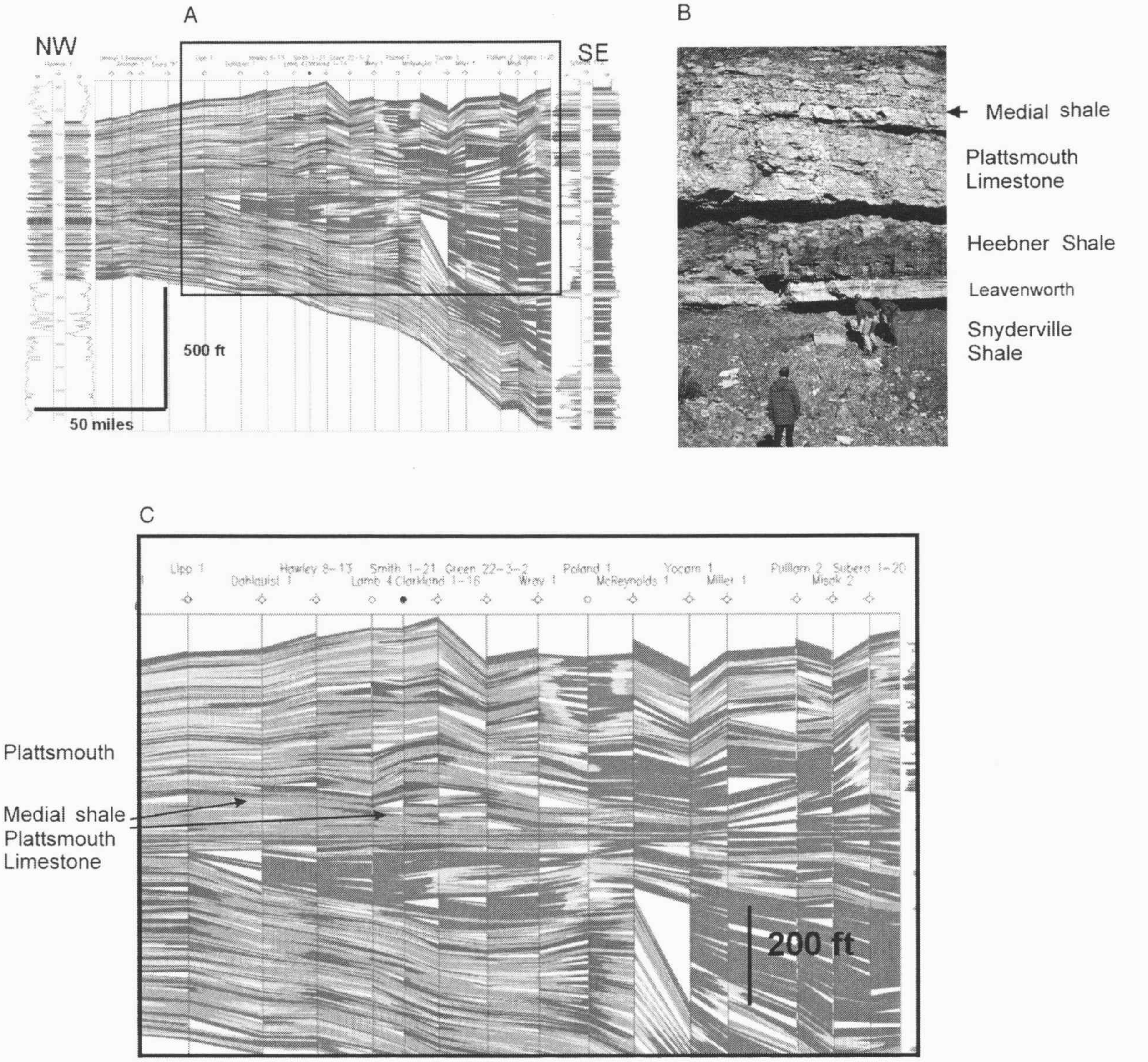

FIGURE 9—Small version of Figure 6 (upper left) showing portion of cross section enlarged in lower part of illustration. Photograph (upper right) of surface exposure of Plattsmouth Limestone, Heebner Shale, and Leavenworth Limestone showing medial shale discussed in text (thin shale bed overlying more resistant clean limestone bed). Location of photograph is near entrance to Hamm Quarry, 7 mi (11 km) north of Lawrence, Kansas. Close-up cross section covers horizontal distance of 140 mi (225 km) and 845 ft (258 km) of vertical section. Medial shale in Oread GSU dividing carbonate unit into lower backstepped unit overlain by forward-stepping succession downlaps on Heebner Shale into basin.

basinward position.This stratigraphic pattern suggests accumulation during a relative fall in sea level and probably represents the last phase of a high-frequency cycle. The cycle extended about 82 mi (132 km) from the point of lapout of its lower marine-flooding shale to where the carbonate unit extends over basinal shales.

Surface exposures of the Plattsmouth Limestone Member in the outcrop belt in eastern Kansas include a medial shale that separates two distinct cycles of carbonate sedimentation. Shelf setting in east-central Kansas is approximately the same as the northern half of cross section of this current study (Fig. 9A). A quarry exposure of the Plattsmouth Limestone near Lawrence, Kansas, 190 mi (300 km) to the northeast of the cross section, contains two distinctive shallowing-upward units separated by a prominent marine-shale marker developed midway through the Plattsmouth (Stephens and Watney, 1986, and Fig. 9B).

Mathews (1978) correlated this middle shale in the Plattsmouth Limestone for 100 mi (160 km) through his study area extending southward from Lawrence along the eastern Kansas outcrop. The middle shale separates a lower mixed skeletal wackestone (low energy, deeper water) from an upper section consisting of interbeds of phylloid algal, sponge, brachiopod-bryozoan-crinoid, and fusulinids (lower diversity and overall shallower water). A phylloid algal bed immediately underlies the middle shale that was interpreted by Mathews (1978) as abrupt shallowing prior to deposition of the shale. The shale is characterized by sharp contacts with adjacent strata and absence of marine macrofossils in the shale.

Stephens and Watney (1986) also recognize two distinct divisions of the Plattsmouth Limestone from the Skelly No. 1 Bartosovsky core (sec. 9, T. 1 S., R. 34 W.) taken in Rawlins County in northwestern Kansas. The core is 110 mi (177 km) northwest of the northern edge of the cross section of the current study (Fig. 9A). The lower Plattsmouth Limestone is a calcareous siltstone to argillaceous limestone with abundant microstylolitic shale seams and sparse brachiopod and crinoid fauna. Nodular chert is dispersed throughout lower unit. The lower unit is capped by a radioactive chert bed containing dark disseminated material, possibly phosphatic. The lower unit is interpreted to have been deposited in deeper water under conditions of reduced carbonate sedimentation. The upper division of the Plattsmouth Limestone is clean carbonate mudstones to packstones with diverse fossils capped by a subaerial exposure surface. The upper division indicates marked shallowing relative to the lower division.

Such stratal elements are nearly impossible to correlate regionally in limited cores and surface exposures unless events can be uniquely identified. Biostratigraphic correlations of conodonts in similar thin marine shales of the Upper Pennsylvanian Dennis Limestone from eastern Kansas to Iowa indicate that conodonts can be used to correlate marine shales (Felton and Heckel, 1996). Geochemical trace elements or isotopes or magnetic-susceptibilty signatures may aid in future correlation and substantiate high-frequency cycles, for example Carr, Hoth, and Bau (1999). Current interpretation suggests that lithofacies are displaced back and forth over significant distances between the shelf and the basin even within a single GSU, seemingly the result of abrupt shifts in relative sea level. Sites of changes in thickness and lithofacies composition are related closely to local structural conditions such as differential subsidence or local uplift.

CONCLUSIONS

The following geologic events and processes have been either confirmed, better understood, or discovered through computer-assisted lithostratigraphic correlation of gamma-ray logs of 24 wells through the Upper Pennsylvanian in an area from west-central to south-central Kansas:

(1) Correlations within individual GSU's, thick shales, and transitions between successions of carbonates to shales suggest temporal correlations and stratal patterns of backstepping, forward stepping, onlap, and downlap;

(2) Stratal geometries within GSU's are recognized, including high-frequency cycles of onlap, downlap and laterally accreting carbonate strata onto a maximum flooding surface/condensed section;

(3) Isolated stratigraphic intervals between wells that could not be correlated provide precise sites of probable onlap and downlap;

(4) Longer term genetic sets were confirmed utilizing a combination of detailed correlations and gamma-ray variation.

(5) High-resolution stratigraphy conducted using software to automate the process results in consistent and unbiased correlations at a regional scale not possible or practical manually. This technique offers the potential to better target subtle stratigraphic traps in a mature basin.

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Compartmentalization of the Overpressured Interval in the Anadarko Basin

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ABSTRACT

Reservoir pressures within the lithologic column in the Andarko Basin are a tiered system. The overpressured zone termed the Megacompartment Complex (MCC) is overlain and underlain by normally pressured intervals. Compartments are classified in three different groups or levels. The basinwide MCC is termed Level 1 compartment. Within the MCC, reservoirs that form fields or districts usually have similar pressure values. These fields or districts are termed Level 2 compartments. Detailed analyses of initial pressure, fluid types, and decline curves indicate that Level 1 and 2 compartments contain many smaller and isolated (sealed) compartments termed Level 3 type. The seals occur mainly in clay- or sand-rich rocks and may exhibit diagenetic banding patterns.

Banding patterns in clay-rich rocks seem to form independently of sedimentary textures or result from the enhancement or modification of sedimentary features. Diagenetic bands in sandstones typically consist of silica- and carbonate-cemented layers that are separated by clay-coated porous layers. Styloites and other pressure-solution features such as penetrating grain boundaries suggest a mechanism for the source of silica cements. The integration of tectonic history, stratigraphic relationships, facies distribution, thermal history, and diagenetic patterns of seal zones suggests that seals and compartments evoloved primarily during the Pennsylvanian orogenic episode. This occurred during the rapid subsidence phase of the orogeny during a period of approximately 30 million years.

INTRODUCTION

Basin compartmentalization, a concept introduced by Bradley (1975) and D. E. Powley (pers. comm., 1987), is important in the exploration and production of hydrocarbons in deep sedimentary basins. A compartment consists of a porous internal volume and a surrounding low-permeability seal. Compartmentalization occurs beyond a certain depth because of the interplay of a number of geological processes, in particular, subsidence and sedimentation rates, lithologies, and diagenetic modifications. Compartments within abnormally pressured zones exhibit distinctly different pressure as compared with their immediate surroundings. They are recognized most easily on pressure-depth profiles (PDP's) by their departure from the normal hydrostatic gradient. The Anadarko Basin provides an excellent example to study geometrical configuration and sealing processes of abnormally overpressured compartments. Integrated pore-pressure and subsurface geological data indicate the presence of an overpressured and completely sealed compartment of basinwide scale; the term *megacompartment complex* (MCC) thus was introduced by Al–Shaieb and others (1994a) to describe this feature (Fig. 1). The MCC encompasses sections in the Devonian, Mississippian, and Pennsylvanian Systems. It consists internally of a network of totally isolated smaller, nested compartments.

Isolation of the MCC has been maintained for a considerably long geological time (early Missourian to present) via encasement by top, basal, and lateral seals (Al–Shaieb and others, 1994c). Compartments nested within the MCC are isolated from each other by an intricately complex framework of seals. Seal rocks display unique diagenetic banding structures that formed as a result of the mechano-chemical processes of compaction, dissolution, and precipitation.

LEVELS OF COMPARTMENTALIZATION

Three distinct levels of compartmentalization were recognized (Al–Shaieb and others, 1994b). Level I is a regional feature that transects stratigraphic boundaries and includes most of the overpressured rocks in the basin. Level II is a field- or district-sized feature with relatively uniform pressure gradients that occurs within a

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stratigraphic interval. Level III is the smallest in size and consists of small field- to reservoir-size compartment within a particular stratigraphic unit. The size and geometry of these compartments are linked strongly to their depositional setting and facies.

Level I Compartments

The first level of compartmentalization is a basinwide overpressured volume termed the megacompartment complex (MCC). The MCC is an elongate body of overpressured rocks approximately 240 km (150 mi) long and 113 m (70 mi) wide that has a maximum thickness of about 4,880 m (16,000 ft) (Fig. 1). Pressure data indicate that the top of the MCC is located between 2,290 m (7,500 ft) and 3,050 m (10,000 ft) below the surface. The top is shallower in the proximity of the Nemaha Ridge in central Oklahoma, and dips gently westward toward the basin axis where it occurs about 3,050 m (10,000 ft) deep in western Oklahoma. The MCC contains strata from the upper Pennsylvanian at 2,290 m (7,500 ft), to the Woodford Shale at 3,050 m (10,000 ft). All reservoirs within this complex are overpressured (Fig. 1).

Level II Compartments

Level II compartments typically are restricted to a specific stratigraphic horizon. Pressure measurements within each horizon are relatively uniform and predictable across a trend. Examples, such as the Morrowan Watonga and the Chert Conglomerate trends, may be identified by their distinct pressure regimes. They also are delineated using pressure gradients and poteniometric surface maps. Figure 2 is a three-dimensional Morrowan potentiometric diagram showing the Watonga trend as a "ridge-like" feature along the eastern edge of the basin; whereas peaks of the Chert Conglomerate potentiometric values are identified as the "castle-like" feature in the southwestern corner of the basin. The individual peaks within these Level II compartments represent the third compartmentalization level.

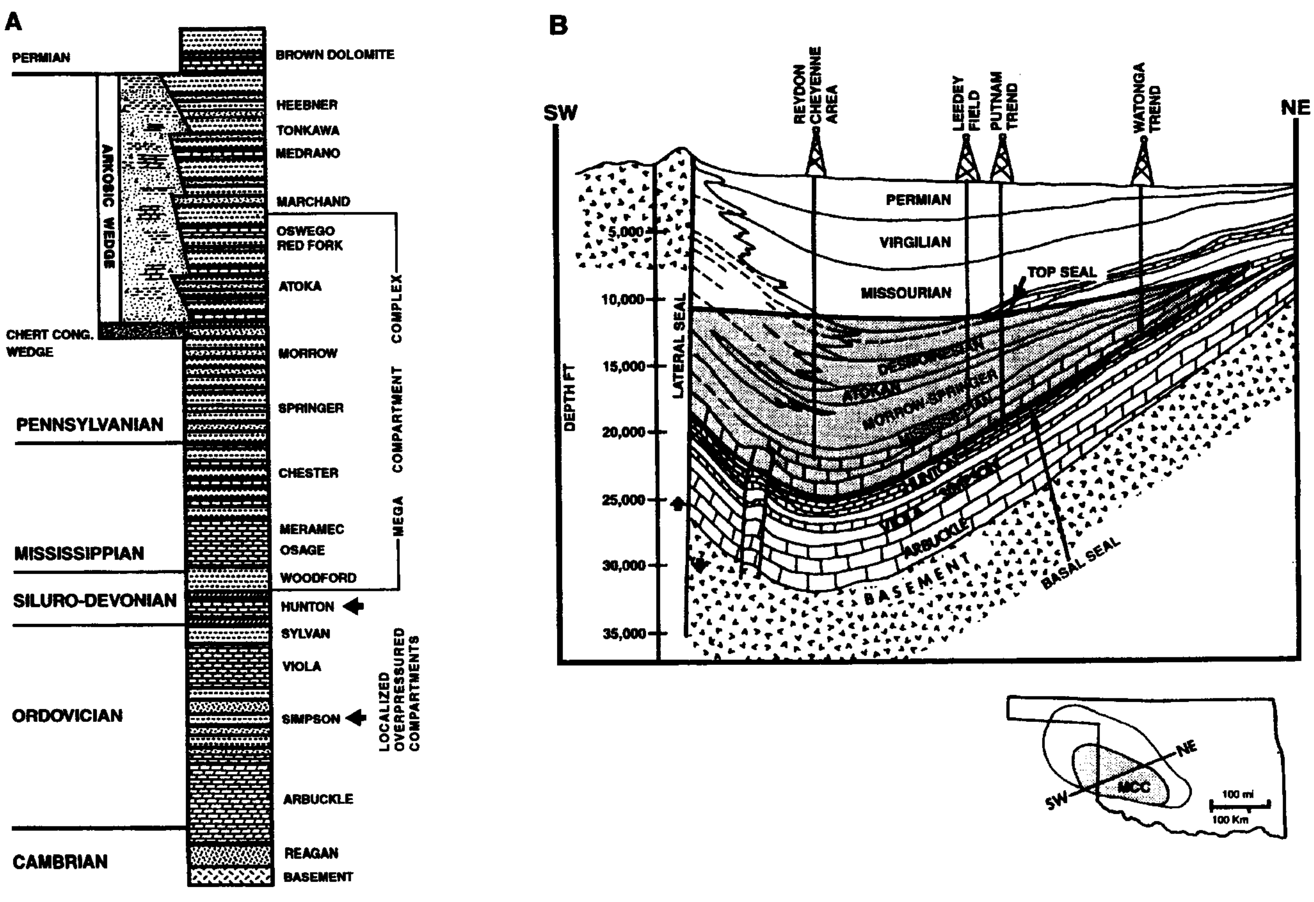

FIGURE 1—A, Generalized stratigraphic column of Anadarko Basin showing intervals contained within MCC; also stratigraphic position of two localized overpressured compartments (arrows) outside megacompartment complex (after Evans, 1979). B, Generalized cross section of Anadarko Basin showing spatial position of MCC within basin. Geopressures within MCC are maintained by top, lateral, and basal seals (reprinted by permission of the AAPG).

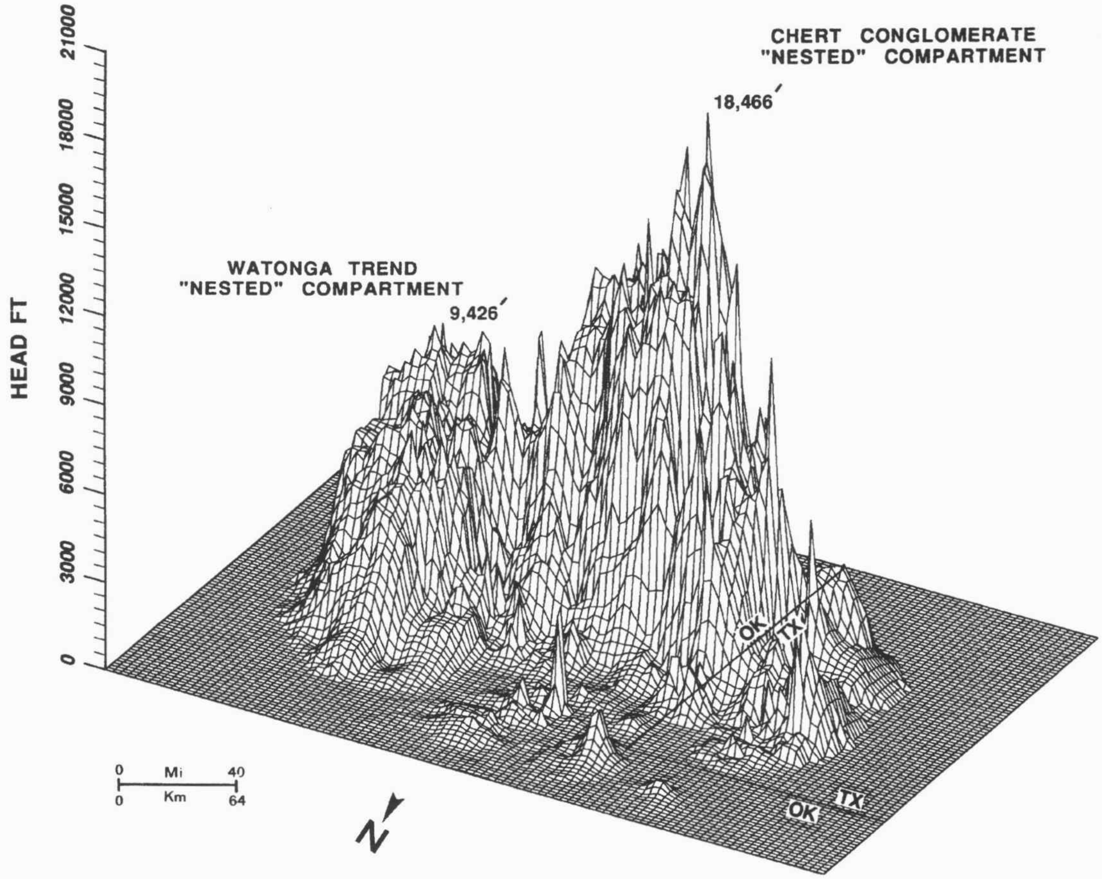

FIGURE 2—3D diagram of potentiometric surface values of Morrowan Series that constitute middle and part of lower portion of megacompartment complex. All peaks represent overpressured Morrowan rocks within MCC (plane of zero feet coincides with surface elevation of Anadarko Basin). (Reprinted by permission of AAPG.)

Level III Compartments

Level III compartments are single, small field- or reservoir-size subdivisions usually nested within Level II. Their geometry is related closely to the depositional facies of the associated reservoirs. Examples of this type include the Southwest Leedey Red Fork sandstone reservoir (Al-Shaieb and others, 1994b), the "Old Woman" channel-fill reservoir in the North Geary area of the Watonga Trend, and individual reservoirs within the Upper Morrowan Chert Conglomerate (Reydon–Cheyenne fields in western Oklahoma). These Level III compartments can be identified by their distinct pressure gradients, fluid types (gas/oil and water ratios), and pressure-decline curves that indicate isolation from nearby reservoirs. Figure 3 is a schematic diagram that depicts the relationship between the three levels of compartmentalization in the Anadarko basin. Figure 4 is a pressure-depth profile that graphically portrays the relationships among Level I, II, and III compartments.

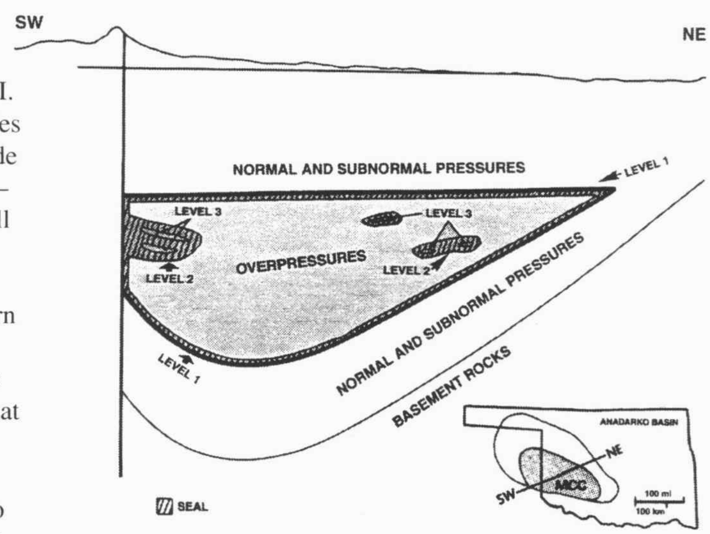

FIGURE 3—Schematic diagram illustrating spatial relationship of three levels of compartmentization in Anadarko Basin. Inset map shows areal extent of MCC within basin (reprinted by permission of AAPG).

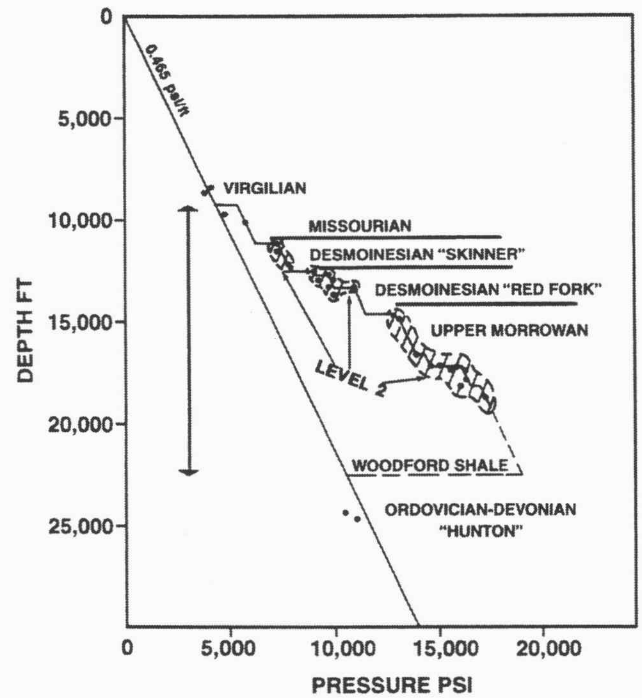

FIGURE 4—Graphical representation on pressure-depth profile illustrating relationship among Level 1, 2, and 3. Note Level 2 compartments are essentially clusters of isolated Level 3 compartments. Pressure-depth profile was constructed in Reydon–Cheyenne area in western Oklahoma (reprinted by permission of AAPG).

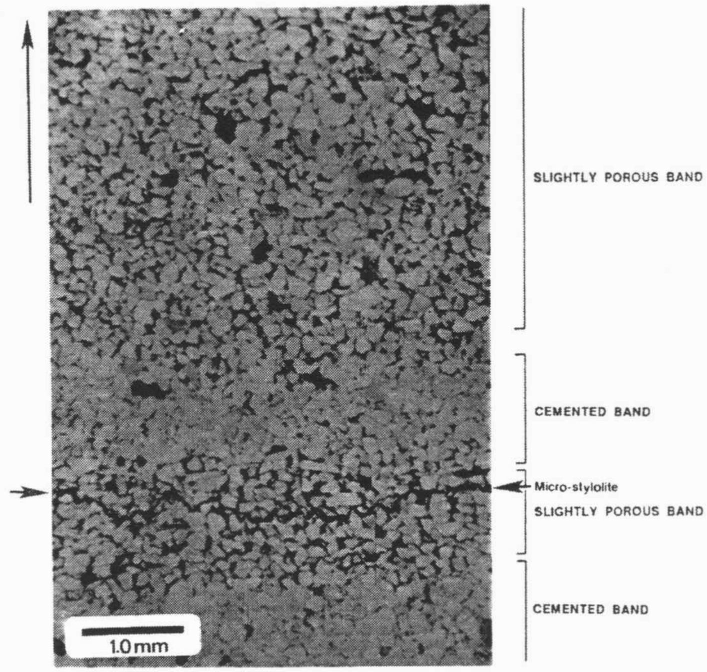

FIGURE 5—Alternating porous and silica-cemented bands in Springer Lower Cunningham Sandstone. Microstyolite is manifestation of pressure solution. Silica liberated by dissolution seemingly was precipitated in adjacent cemented bands. Gulf No. 1 Miller, Caddo County, Oklahoma. Depth, 5,022 m (16,475 ft) (reprinted by permission of AAPG).

BANDING FEATURES WITHIN MCC

Many seal rocks display unique diagenetic banding that formed as a result of the interplay of stress-induced mineral reactions, pore-fluid interactions, mass transport, and precipitation. This banding is observed in rocks that were buried deep enough to enter the "seal window." In the Anadarko Basin the seal window occurs between 1,829–3,000 m (6,000–9,843 ft). Rocks from shallower intervals clearly lack such banding features. The origin of such features has been simulated using reaction-transport developed by Dewers and Ortoleva, (1988, 1990).

Banding in Sandstones

Silica cement bands (Fig. 5) occur in sandstones and consist of zones of enhanced quartz overgrowths alternating with bands of preserved interparticle porosity. The silica seemingly was derived from pressure solution of quartz grains in the adjacent band. Porous regions usually contain thicker clay coatings on grains, suggesting clay-inhibition of quartz cementation in these areas. Silica bands may occur relatively early in the diagenetic history of the rocks (≈6,500 ft, 2,000 m at 65°C) and reflect the mechano-chemical processes associated with burial compaction, dissolution, and precipitation as described by Ortoleva, Dewers, and Sauer (1993).

The alternation of permeable and cemented sandstones within the diagenetically banded pressure seal in the Ordovician Simpson Group in Oklahoma is a manifestation of these processes. The compositionally homogeneous First Bromide Sandstone Member contains silica bands that seemingly were generated by local dissolution and precipitation. Sandstone with thin nonpervasive clay-grain coatings had undergone compaction and became a likely silica source. Adjacent intervals received imported silica and evolved into silica-cemented bands. On the other hand, clay coatings inhibited silica precipitation and preserved primary porosity.

A second type of banding observed in sandstones is composed of carbonate that postdated the silica bands. Carbonate-cementation bands may consist of calcite or dolomite that alternate with porous bands of silica-cemented sandstones (Fig. 6). Carbonate bands occur on scales similar to those observed for silica bands. They may form a collection of millimeter-scale bands within a thin (4-in, 10-cm) interval, or they maybe composed of thicker (2–4-in, 5–10-cm) bands.

In the Bromide sandstone interval, the earliest diagenetic calcite cements seemingly were derived from compactional dissolution of carbonates within or adjacent to the sandstones. Potential sources include limestone beds and fossil-rich zones within the sandstone, and maybe the overlying Bromide and Viola carbonates.

In the Simpson sandstone seal, $\delta^{13}C$ and $\delta^{18}O$ values of several carbonate cements range from –5 to –9 ‰ PDB and from –7 to –11‰ PDB, respectively. These isotopic compositions indicate that the carbon was derived partially from an organic source; whereas, oxygen isotope ratios indicate relatively higher temperature fluids. On the other hand, $\delta^{13}C$ values of most carbonate cements (0–4‰ PDB) suggest a marine source for the carbon. A crossplot of carbon and oxygen isotopic compositions is shown in Figure 7.

Fluid inclusions within the silica and carbonate cements in the Ordovician Simpson Group sandstone seal interval were examined to determine the timing, temperature, and nature of fluids that resulted in the generation of the diagenetic cements. The analysis was performed under the supervision of David I. Norman at New Mexico Tech. A burial-history curve, modified after Schmoker (1986), was constructed for the southeasteren part of the Andarko Basin. The homogenization temperatures of fluid inclusions from various cement phases (Fig. 8) were plotted on the curve (Fig. 9) to depict the timing relationships of cementation phases. Inclusion homogenization temperatures (T_h) of four cementation episodes (Q–1, C–1, C–2, and Q–2) are shown in Figure 8. The first episode consists of two-phase aqueous fluid inclusions from silica cement (Q–1) with (T_h) values ranging from 70 to 100°C. The second episode consists of two-phase aqueous fluid inclusions from calcite cement (C–1) with (T_h) values concentrated between 80 and 110°C. The third episode consists of petroleum-bearing and aqueous inclusions from a second calcite (C–2) cement. The (T_h) values for the hydrocarbon-bearing inclusions range from 95 to 140°C. The fourth episode is a later silica (Q–2) cement that contains hydrocarbon inclusion. The (T_h) values of the second silica cement range from 110 to 120°C. The genesis of petroleum-free, higher temperature calcite (C–1) inclusions (T_h> 120°C) may be related to hot, basinal fluids. The relationships of the cement stratigraphy thus is important in the interpretation of seal evolution.

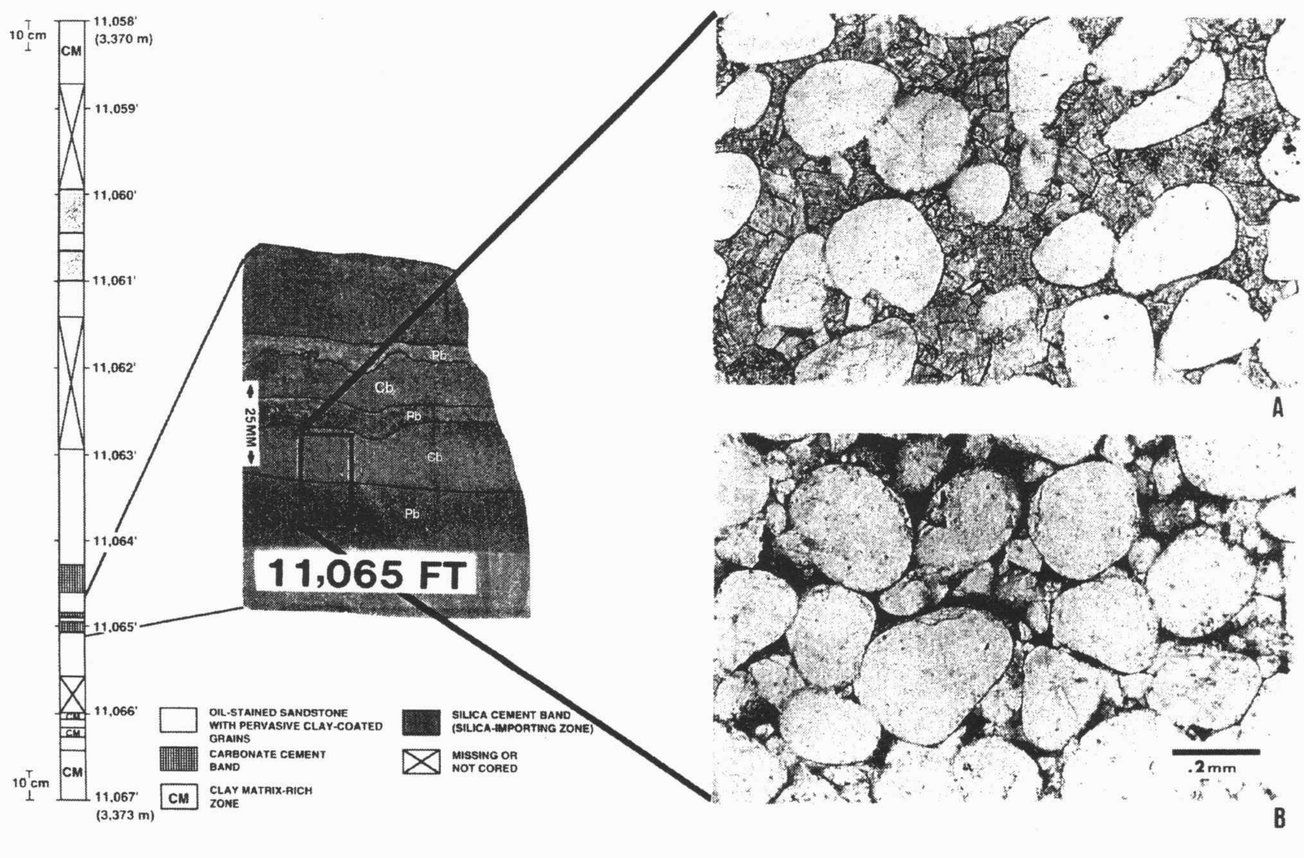

FIGURE 6—Calcite-cemented bands (Cb) alternation with porous bands (Pb). Photomicrographs in plane polarized light: A, Carbonate band; B, porous band. Gulf No. 1 Weaver. Depth, 3,372 m (11, 065 ft) (reprinted by permission of AAPG).

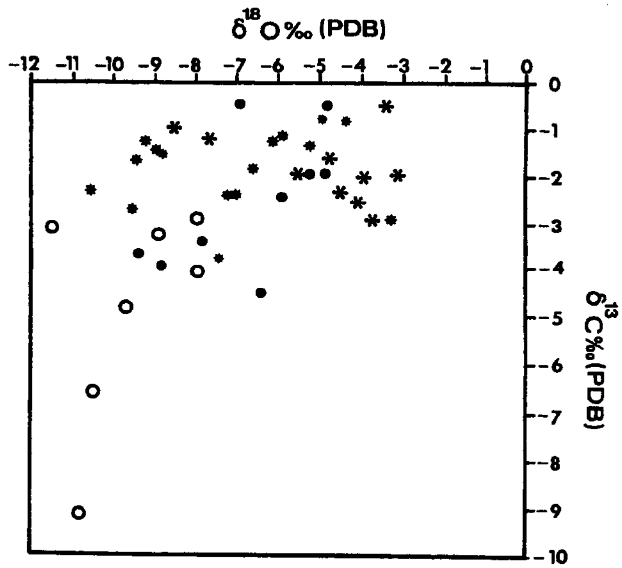

FIGURE 7—Crossplot of carbon and oxygen isotope composition for carbonate cements in Simpson sandstone seal interval. Data are from Al-Shaieb and others (1982), Mitcheltree (1991), and Pitman and Burrus (1989). o = calcite, Weaver Unit No. 1; * = dolomite, Weaver Unit No. 1; • = calcite, Costello No. 1 and Mazur No. 1; * = dolomite/ankerite, Costello No. 1 and Mazur No. 1 (reprinted by permission of AAPG).

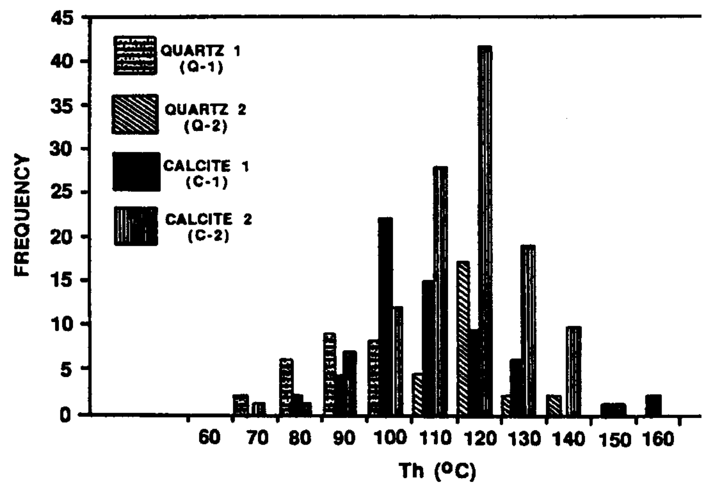

FIGURE 8—Homogenization temperatures (T_h) of various cementation episodes within Simpson sandstone seal, Gulf No. 1 Weaver (reprinted by permission of AAPG).

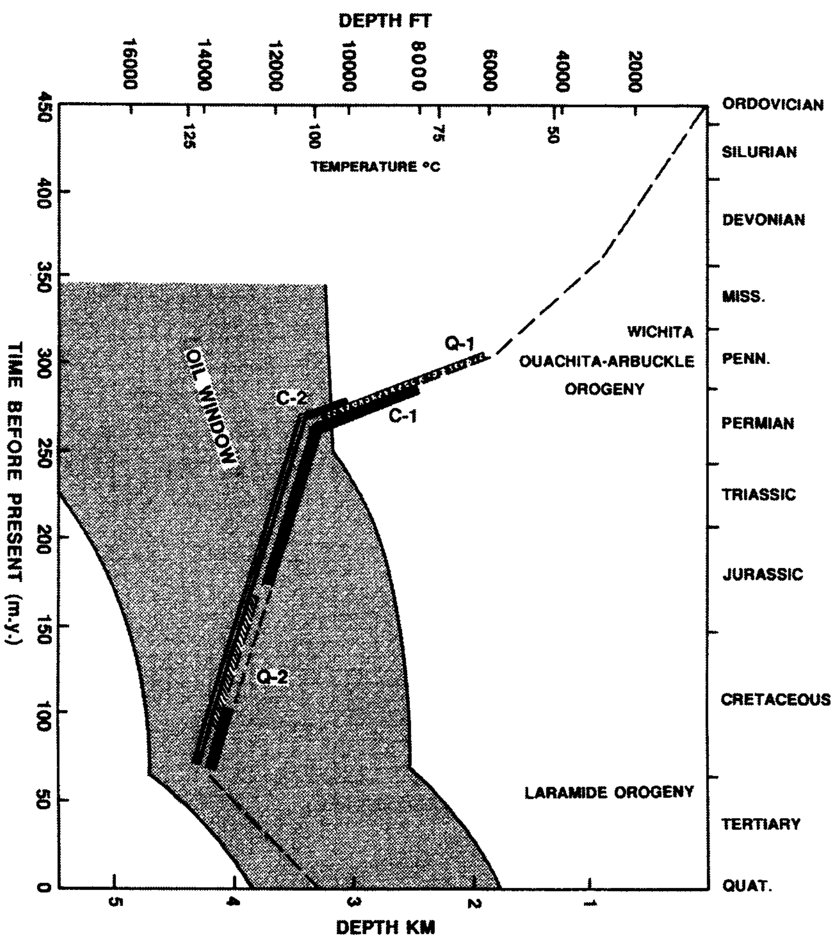

FIGURE 9—Timing of top seal cementation phases in relation to burial history of Simpson interval, Gulf No. 1 Weaver well (reprinted by permission of AAPG).

Banding in Clay-Rich Rocks

Shales and siltstones of the seal intervals contain distinct diagenetic bands. Comparative analyses of cores and outcrops of shales and siltstones reveal this banding is noticeably absent in rocks that were never buried deeply enough to become overpressured. In the Pennsylvanian Pink Limestone/Red Fork Sandstone interval, diagenetic bands seemingly developed independently of any depositional facies. On the other hand, banding in the Devonian Woodford Shale usually occurs as an enhancement or modification of existing sedimentary features.

The Pink Limestone/Red Fork Sandstone seal interval consists of calcareous black shales and thinly laminated siltstones and shales. The frequency of diagenetic bands and the lateral extent of the banded interval suggest that this is an effective seal for the underlying overpressured Red Fork reservoirs (Al–Shaieb and others, 1994c). The core data indicate that the seal interval consists of at least 6 m (20 ft) of black shale that contains repetitive diagenetic bands. These bands have specific morphological characteristics. One group has sharp boundaries between the band and the surrounding shale (Fig. 10). These bands generally are (1) uniform in thickness and flat, or (2) irregular in thickness and hummocky or concretionary in appearance. The bands are typically chlorite rich. They generally range from 3 to 10 cm (1.25 to 4 in) in thickness and are separated by finely laminated, illitic black shale. Some of the bands are crosscut by fractures that are calcite cemented.

Mercury-injection tests indicate that the chlorite bands have lower porosity and smaller pore throats than the surrounding shales (Powers, 1991). Band porosity is approximately 0.6% compared to 6.6% for the host shale.

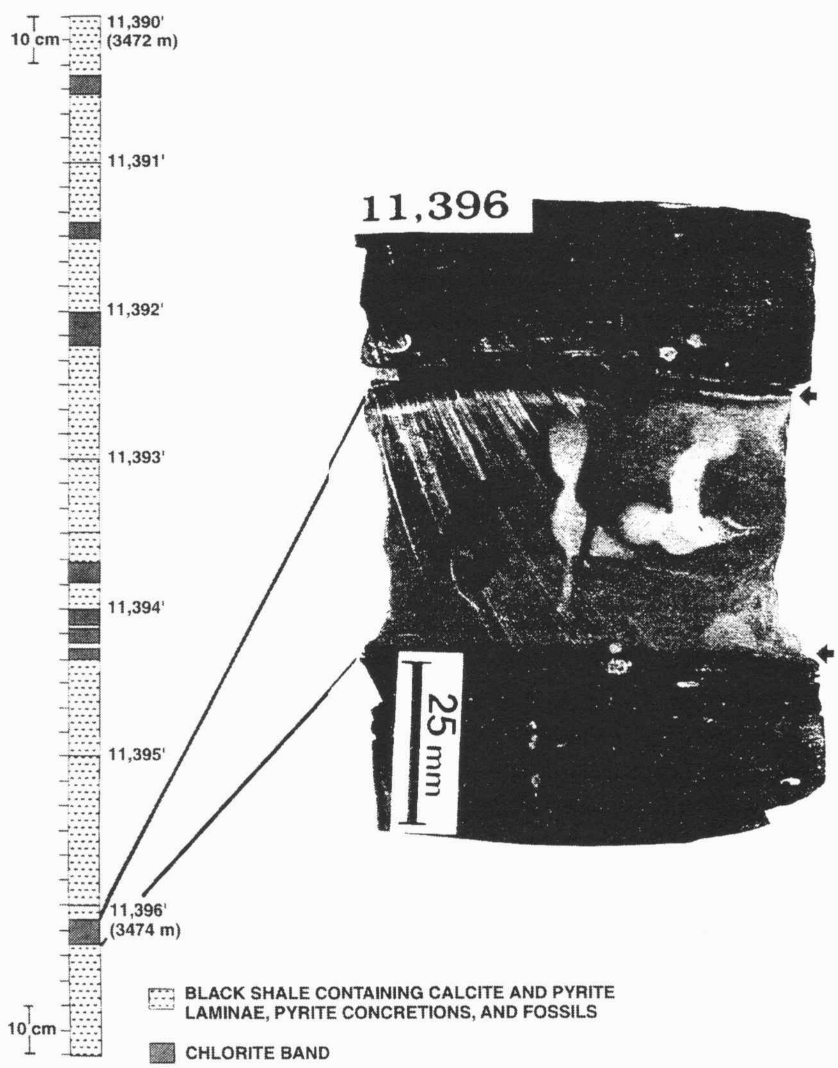

FIGURE 10—Diagenetic band exhibiting sharp boundaries (arrows) with shale host rock. Fractures are calcite cemented. Schematic diagram indicates location of described feature within seal zone. Wood No. 1 Switzer, Roger Mills County, Oklahoma. Depth, 3,474 m (11,396 ft) (reprinted by permission of AAPG).

Most pore-throat radii in the bands are less than 0.004 microns whereas those in the shale are between 0.011 and 0.004 microns (Powers, 1991). These measurements suggest that repetitive bands restrict fluid flow much more effectively than unaltered shale and are critical to seal competence.

CONCLUSIONS

- Integrated pore pressure and potentiometric and geologic data in the Anadarko basin demonstrate the existence of a basinwide, completely sealed, overpressured compartment, termed a megacompartment complex.
- Megacompartment complex is enclosed by top, basal, and lateral seals.
- Interior of the complex is subdivided into a myriad of smaller compartments with distinct pressure gradients. Three levels of compartmentalization were recognized.
- The top seal is located between 8,500 to 10,000 feet deep and exhibits distinct banding.
- The basal seal is basically the Woodford Shale and possibly the Caney Shale.
- Lateral seals are either associated with fault zones or formed by convergence of the top and lateral seals.

ACKNOWLEDGMENTS

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Reservoir Systems
(Session A)

Reservoir Characterization of the Council Grove Group, Texas County, Oklahoma

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ABSTRACT

Production from Permian Council Grove Group carbonates in the Hugoton Embayment was established on a regional basis in the mid 1950's. Panoma field extending from Kearny County, Kansas, to Texas County, Oklahoma, currently has 2,482 active wells that have produced over 2.4 trillion cubic feet (TCF). Historically wells generally were fracture stimulated and brought on production with a substantial amount of water production. Operators involved in recent exploration plays in Texas County have discovered new reserves in the Beattie, Neva, and Howe Limestones. A revised completion technique of limiting the perforations to only a specific reservoir and then using an acid stimulation or small frac has reduced the amount of associated water production.

Depositional cycles interpreted as fourth-order parasequence sets in the Council Grove Group are characterized by coarsening-upward carbonate shoals overlain by terrestrial redbeds. Shoal and shoal-flank lithofacies generally consist of skeletal grainstones, packstones, and wackestones respectively. Dissolution of carbonate allochems and matrix by meteoric diagenesis created porosity that averages 15%. Pore types range from intergranular to touching vugs with permeability ranging from 0.01 to 200 millidarcies.

A more accurate prediction of hydrocarbon and water productive reservoirs can be achieved if each reservoir is evaluated by lithofacies. A case history of constructing Pickett plots and bulk volume water plots on the basis of lithofacies in the Beattie Limestone illustrates how a silty carbonate matrix can result in high water-saturation calculations. A cementation exponent (m) of 1.8 in the standard Archie water saturation equation is more appropriate for the skeletal wackestones.

INTRODUCTION

Permian Council Grove Group sediments have been economically significant reservoirs in the Hugoton Embayment since the mid 1950's. Panoma field is located on the western shelf of the Anadarko Basin, stretching from Kearney County, Kansas, to Texas County, Oklahoma. As of January 1999, there were 2,482 producing wells. The average production per well is 974 MMCF with an estimated average ultimate recovery of 1.2 BCF (Fig. 1). Total field production is 2.4 TCF. The perforated interval has been the upper 150 feet of interbedded shales and carbonates. Only 1.5% of the Panoma completions have been to reservoirs deeper than the Bader Limestone (Fig. 2). A hydraulic fracture treatment using 20,000 pounds of proppant and 10,000 gallons of fluid was the traditional completion technique.

Recent exploration wells in Texas County, Oklahoma, have discovered economic reservoirs deeper than the traditional Panoma field pay. Completions in T. 2 N., R. 15 E. CM correlate to the Neva Limestone of the Grenola Formation with completions in T. 6 N., R. 17 E. CM correlating to the Beattie Limestone and the Howe and Glenrock Limestones of the Red Eagle Formation. In these reservoirs, the completion strategy has been adjusted to 2,500 gallons of acid or small hydraulic-fracture treatments to minimize vertical communication between reservoirs. This stratigraphic study is based on examination of seven cores from various wells borrowed from the Kansas Geological Survey and two cores from Cross Timbers Oil Company-operated wells in Texas County, Oklahoma. The outcrop terminology correlated to stratigraphic intervals observed in core in this study is after Puckette, Boardman, and Al-Shaieb (1995). The core interval studied generally extends from the Spieser Shale at the top to the Beattie Limestone at the bottom. One core of the underlying Red Eagle Formation was described and is included in this study (Table 1).

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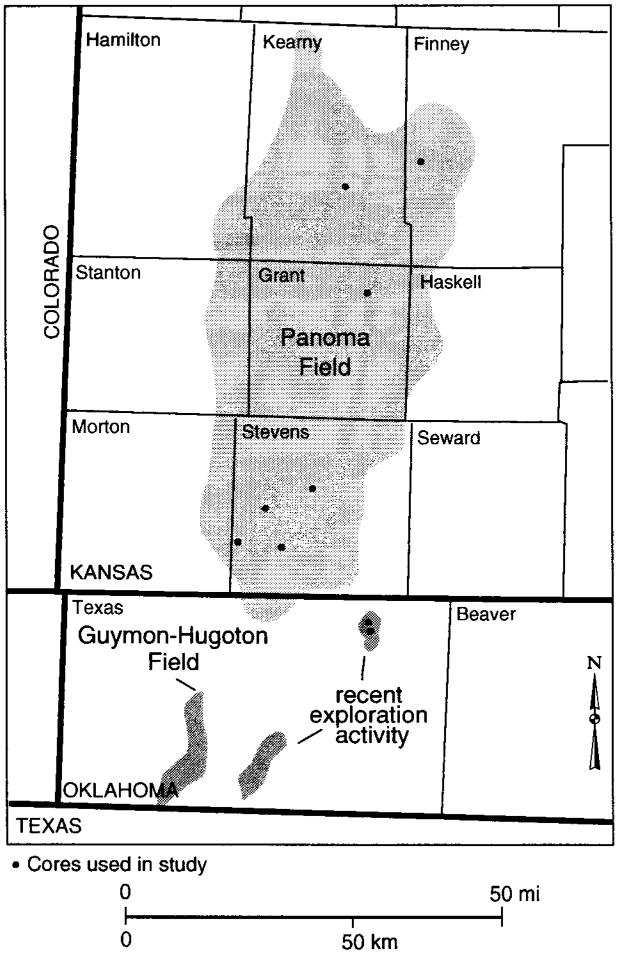

FIGURE 1—Locator map illustrating Panoma field (2,482 producing wells), Guymon–Hugoton field (45 producing wells; Council Grove), cores used in study, and recent exploration activity.

STRATIGRAPHY

In the Hugoton Embayment, Middle to Late Wolfcampian sediments were deposited as cyclical shelf carbonates that laterally grade into nonmarine siliciclastics at the basin margin (Fig. 3). Maximum thickness of the Late Wolfcampian-age sediments is approximately 1,500 feet, located along the axis of the Anadarko Basin. A previous investigation into the sequence stratigraphy of the Council Grove Group by Puckette, Boardman, and Al–Shaieb (1995) described the Council Grove Group as a third-order composite sequence with a transgressive systems tract, a highstand systems tract, and a regressive systems tract. A modification to that model is proposed in this study. The regressive systems tract of Puckette, Boardman, and Al–Shaieb (1995) is thought to be the late phase of the highstand-systems tract of the Exxon model. Fourth-order depositional cycles of the late phase of the highstand-systems tract prograde into the basin in response

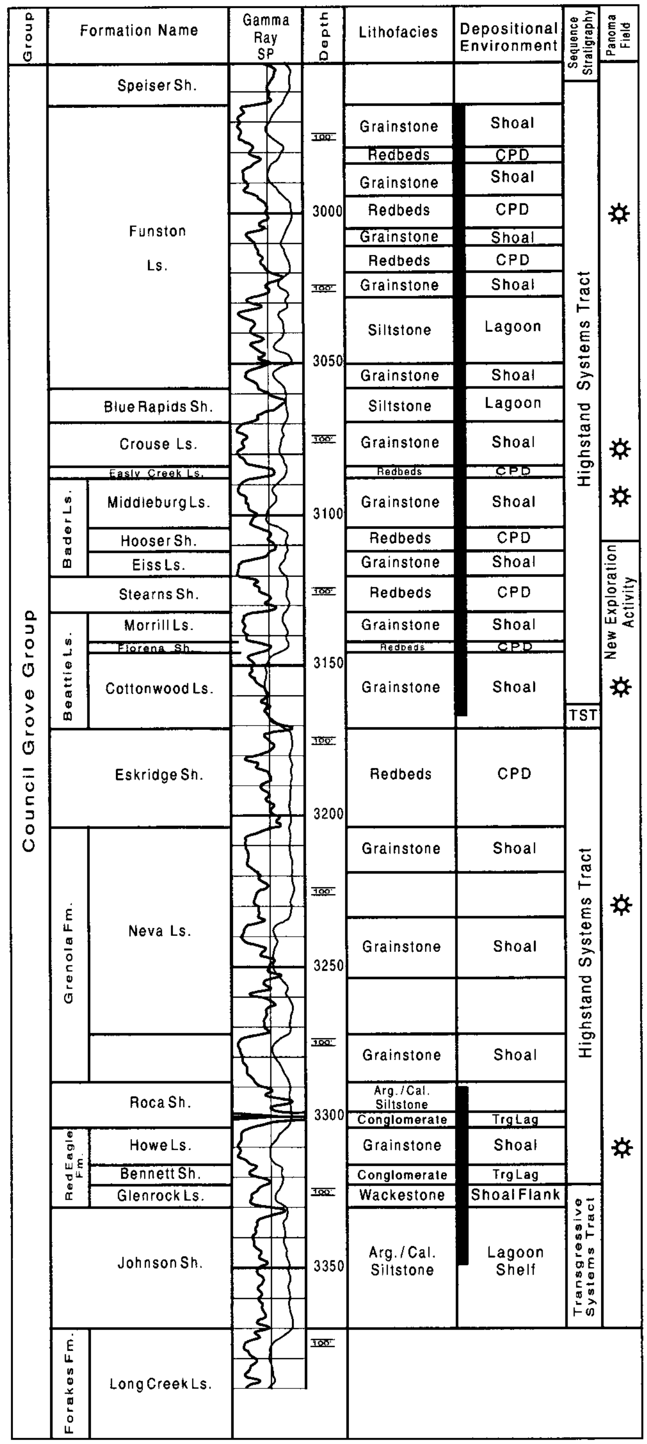

FIGURE 2—Formation names from outcrop (Puckette, Boardman, and Al–Shaieb, 1995) applied to subsurface for Hill No. 1–3, sec. 3, T. 5 N., R. 17 E. CM, Texas County Oklahoma. Cored interval is shown by black bar to right of lithofacies tract. Coastal-plain deposits (CPD) partially consist of terrestrial redbeds (paleosols), which record sea-level fall on carbonate platform.

TABLE 1—Well name, location, and samples.

Operator	Lease Name	State and County	Section	TWP	RGE	Cored Interval	Feet of Core	Porosity Permeability Samples	Thin-section Samples
Cross Timbers Oil Co.	Hill #1–3	OK Texas	3	5N	17ECM	Roca Sh. to Johnson Sh.	60	60	21
Cross Timbers Oil Co.	Hoeme #3–27	OK Texas	27	6N	17ECM	Speiser Sh. to Funston Ls.	55	53	15
Anadarko Prod. Co.	Kimsey "A"#1	KS Stevens	1	34S	38W	Funston Ls. to Neva Ls.	238	98	62
Anadarko Prod. Co.	Light "D" #1	KS Stevens	34	33S	38W	Funston Ls.	71	0	0
Anadarko Prod. Co.	Neer "A" #1	KS Stevens	7	33S	38W	Funston Ls. to Bader Ls.	116	10	10
Anadarko Prod. Co.	Rinehart Estate #C–10	KS Stevens	22	32S	30W	Wreford Ls. to Beattie Ls.	240	57	0
Champlin Petroleum	Garden #C–10	KS Finney	16	23S	34W	Funston Ls. to Beattie Ls.	137	5	5
Gulf Energy & Minerals	Stinchcomb #1–20	KS Kearny	20	24S	36W	Funston Ls. to Beattie Ls.	158	6	6
Cities Service Oil Co.	Alexander "D" #2	KS Grant	29	27S	35W	Funston Ls. to Beattie Ls.	241	28	28

to a falling sea level and decreasing amount of accommodation space. Lowstand-systems tract sediments would be expected in a more basinal position to the south and east, away from the Middle to Late Wolfcampian-age carbonate platform (Sarg, Weber, and Markello, 1995).

The Hill No. 1–3 core recorded three fourth-order parasequence sets in the transgressive-systems tract from the Johnson Shale to the Glenrock Limestone (Fig. 2). The early phase of the highstand-systems tract is a carbonate-rich interval with a high percentage of skeletal grainstones (Fig. 4). A depositional model for this sequence of rocks is one of increasing energy from shoal flank to shoal crest followed by subareal exposure (Fig. 5). Meteoric diagenesis of the grainstone shoal has enhanced the original pore network. Each grainstone is capped by an exposure surface, followed by a lime lithoclast conglomerate (transgressive lag) which marks the onset of the next sea-level rise. Fourth-order parasequence sets in the regressive phase of the highstand-systems tract will have a vertical distribution of lithofacies that begins with skeletal wackestones overlain by peloid/skeletal packstones followed by skeletal grainstones. Each shoaling-upwards fourth-order parasequence set is capped by terrestrial red beds. Many of the fourth-order parasequence sets observed in core were not complete or had thin wackestone/packstone lithofacies. Reservoir development in the regressive phase of the highstand-systems tract is good low in the interval but degrades vertically. A decreasing amount of accommodation space during the regressive phase coupled with an increasing amount of meteoric diagenesis result in an areally limited pore network. The Beattie Limestone from the Kimzey No. 1, is the thickest most complete fourth-order parasequence set observed in core (Fig. 6).

RESERVOIR CHARACTERIZATION

Reservoirs capable of trapping hydrocarbons can develop within any of the lithofacies in a fourth-order parasequence set in the Council Grove Group except for the terrestrial red beds and the argillaceous siltstones. The vertical distribution of lithofacies and their respective pore types exhibit unique wireline log signatures that can be used to identify various lithofacies.

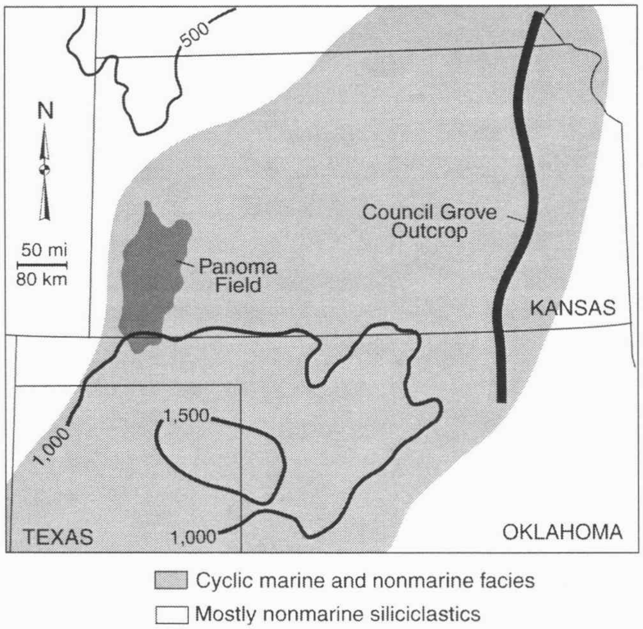

FIGURE 3—Paleogeographic map of Kansas and Oklahoma during Middle to Late Wolfcampian. Cyclical shelf carbonates grade laterally into continental clastics that rim basin (modified from Rascoe and Adler, 1983).

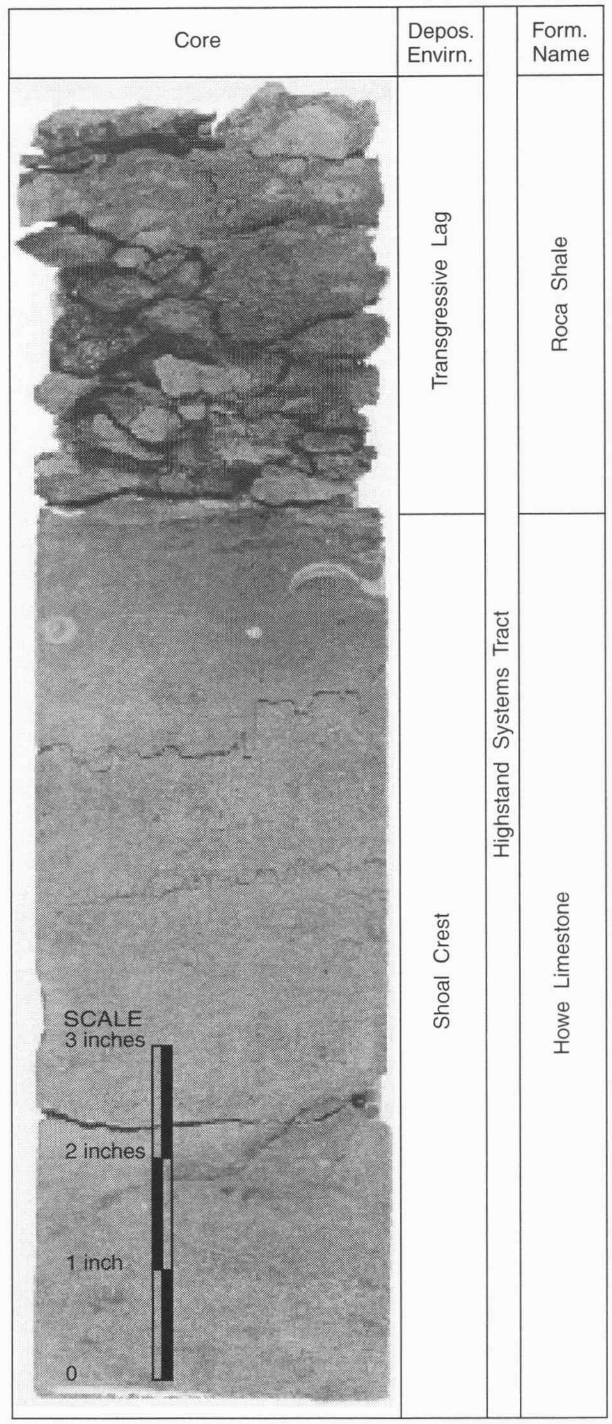

FIGURE 4—Core photograph of Howe Limestone in Red Eagle Formation and overlying Roca Shale, at depth of 3,302 feet in Hill No. 1–3, sec. 3, T. 5 N., R. 17 E. CM. Howe Limestone is described as a light-gray skeletal grainstone with moldic and vuggy pores. Roca Shale consists of irregular-shaped lime lithoclasts in calcareous shale.

Wackestone Lithofacies

Typically the wackestone facies consists of skeletal fragments that are floating in a limestone matrix. The skeletal wackestone lithofacies has an intergranular micropore system that ranges from little porosity to 25% porosity. Secondary diagenesis in the form of leached skeletal debris created the porosity and enhanced permeability (Fig. 7A). Crossplots of porosity and permeability indicate a porosity cutoff of 10% is the economic limit (Fig. 7). Reservoirs with porosities of less than 10% porosity and permeabilities of less than 0.1 millidarcies have production tested uneconomic quantities of gas. Because of the limestone matrix, this lithofacies typically will have low resistivity values (1 to 5 ohm-m) and will calculate water productive using the standard Archie water-saturation equation. A blocky SP response; a caliper that is in gauge at the base of the parasequence set; and a gamma-ray reading of 40 to 120 API units gives this lithofacies a distinct petrophysical character. Distinguishing redbeds/siltstones from wackestones can be done only with a complete log suite that includes SP and resistivity. Core studies have shown that if the fourth-order parasequence set has a shoaling-upwards profile on the gamma-ray log and an SP deflection throughout, then the interval with the shaly gamma ray profile can be interpreted as the wackestone lithofacies.

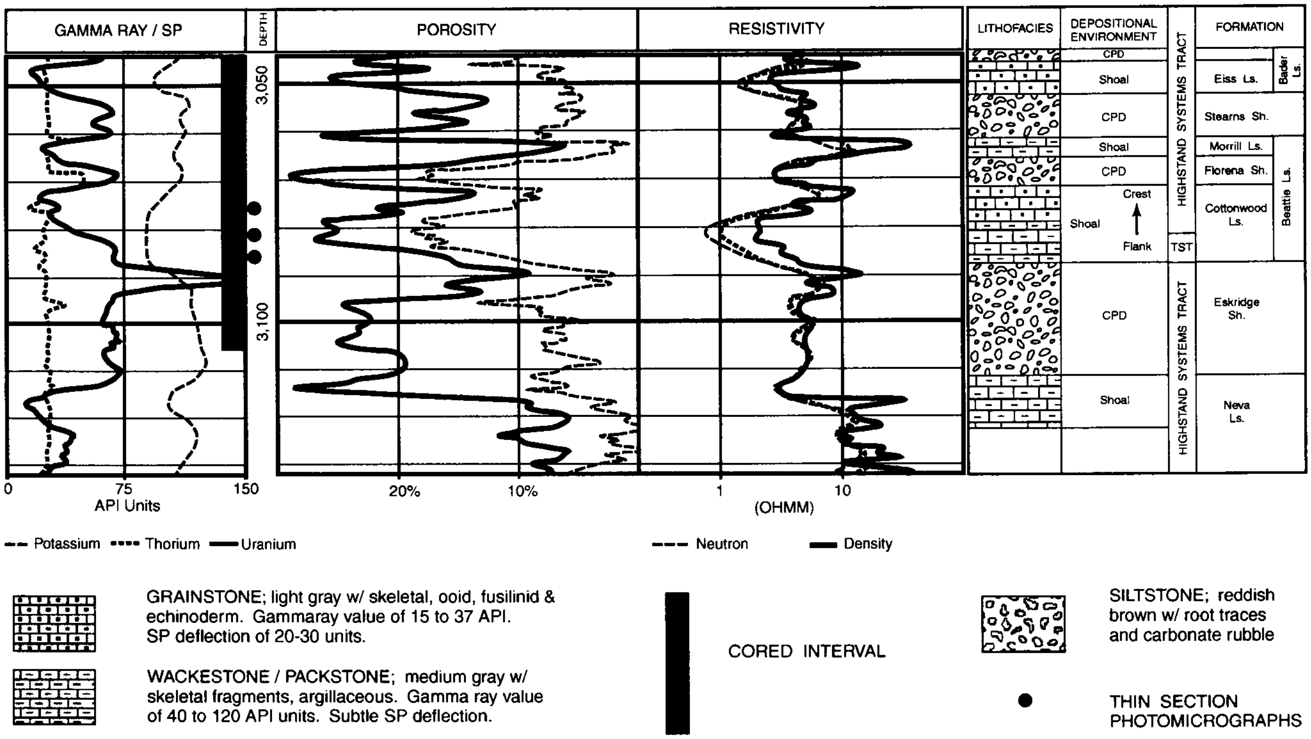

FIGURE 5—Core description and log suite for transgressive-systems tract and highstand-systems tract. Carbonate shoals in highstand-systems tract are characterized by thick grainstones overlying thin wackestones. Trend of increasing shoal thickness from base of highstand-systems tract also is present.

Packstone Lithofacies

In the packstone lithofacies the amount of carbonate allochems such as skeletal grains and forams, echinoderms, bryozoans, and ostracodes increases with a decreasing amount of limestone matrix. Dissolution of the various carbonate allochems has created a pore system with pore types ranging from moldic to vuggy. The average core porosity of packstone samples is 13.5%. In some samples the leaching is so extensive, it created a reservoir with 24% porosity and 200 millidarcies of permeability (Fig. 7B). Porosity /permeability crossplots indicate that 10% porosity is an economic cutoff. The packstone lithofacies has gamma-ray values that range from 35 to 55 API units.

Grainstone Lithofacies

Grainstones lithofacies are the most recognizable facies on wireline logs. The API value of the gamma ray always is less than 37 units. In thin section, grainstones consist of all the carbonate allochems present in packstones only in a greater frequency. Grain-to-grain touching is visible with a very minor amount of matrix material (Fig. 7C). Pore types range from interparticle to dissolution-enhanced molds and vugs. Porosity averages 12%, however permeability differs greatly, ranging from 0.001 to 235 millidarcies.

A porosity/permeability crossplot based on pore type illustrates that wackestones, packstones, and grainstones can all be reservoir-quality rock (Fig. 8). Depending on the dominant lithofacies in each reservoir, the flow characteristics of individual wells could be dramatically different. Reservoirs having a high percentage of grainstones and packstones may only require acidizing to establish economic flow rates. If the wackestone lithofacies is predominant, reservoir stimulation may require a small hydraulic fracture treatment.

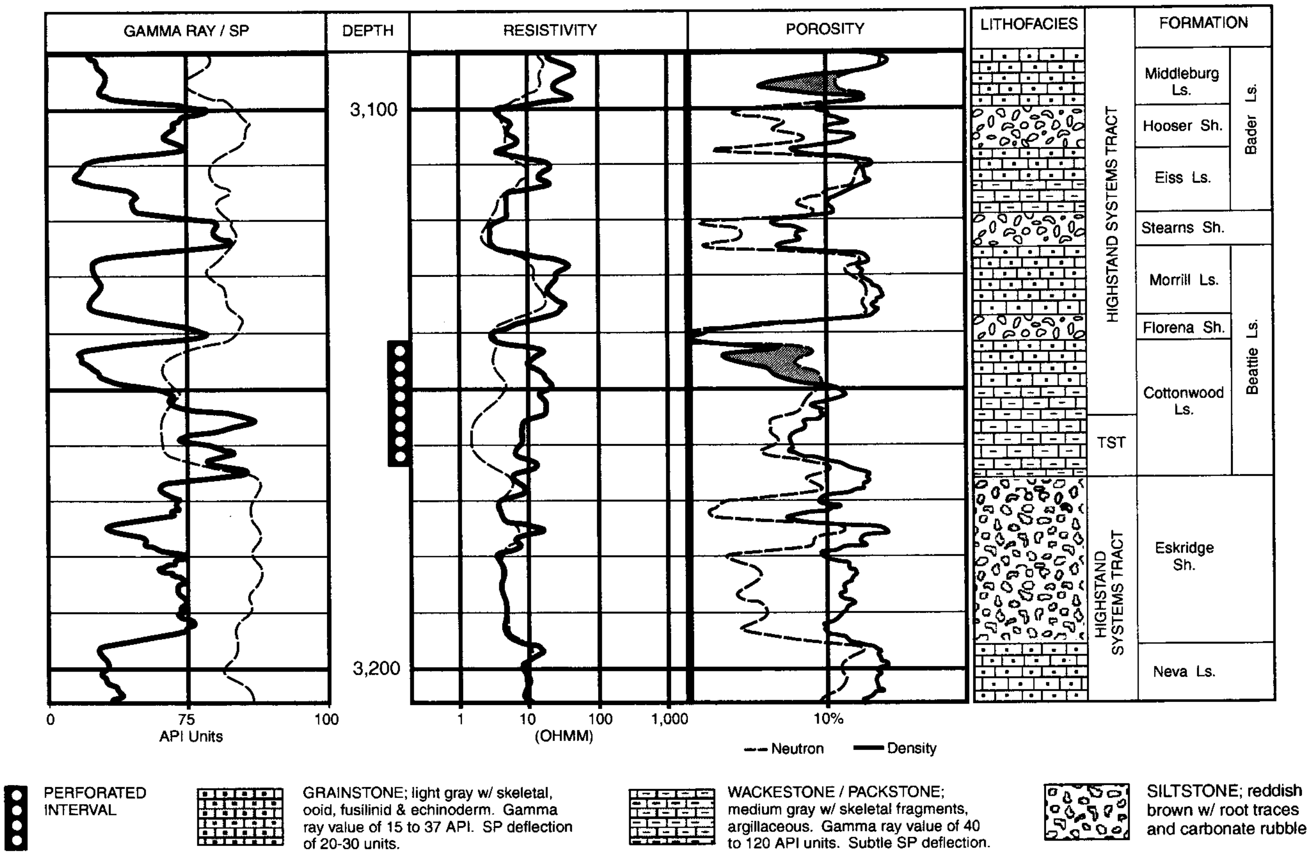

FIGURE 6—Core description and log suite for three fourth-order parasequence sets in highstand-systems tract. In this well, Cottonwood Limestone illustrates coarsening-upwards profile typical of transition from wackestone to grainstone textures. Other fourth-order parasequence sets are thinner and do not have variety of textures present in Cottonwood Limestone. Coastal-plain deposits (CPD) partially consist of terrestrial redbeds (paleosols).

PETROPHYSICAL EVALUATION—A CASE HISTORY

Pickett plots and bulk volume water plots traditionally have been used to evaluate the productivity of a well targeting the Council Grove Group. Pickett (1966) recognized that the cementation exponent used in the Archie equation for water saturation can differ dramatically in carbonate reservoirs depending on pore type. By cross plotting resistivity with porosity, the slope of the line denoting 100% wet resistivity can be calculated. This value is m, the cementation exponent in the Archie equation. Plots of the bulk volume water, which is the porosity times water saturation, also are used to determine the irreducible water saturation for a reservoir. Irreducible water saturation is defined as the water saturation at which water free hydrocarbons are produced. Points which plot along a line of constant value are considered to be at irreducible water saturation. In theory even if a carbonate rock has a high-water saturation, if it plots along a line of constant-bulk-volume water the well should produce water-free hydrocarbons. The diversion of points away from a line of constant-bulk-volume water (BVW) indicates a greater probability of water production. Figures 7 and 8 illustrate that the pore type can range from touching vugs (Lucia, 1995) to intergranular. The effect a silty limestone matrix has on resistivity values also is a variable which can complicate log analysis.

The Hill No. 34–A and No. 34–B were drilled in 1998 and both produce from Council Grove Group reservoirs. A Pickett plot of all potential reservoirs in the Hill No. 34–A indicates the Beattie Limestone and Funston Limestone are wet. The primary reservoirs are the limestones in the highstand-systems tract of the Red Eagle Formation (Figs. 9 and 10). The BVW plot for the Hill No. 34–A and the Hill No. 34–B illustrate an irreducible water saturation of 4% to 6% for the Red Eagle Formation. Previous investigations into the relationship between carbonate reservoirs and BVW plots suggest that even though the Red Eagle Limestones plot along a constant-bulk-volume water, the permeability is too low for economic production (Asquith, 1985). Contrary to the long-established trend of avoiding these reservoirs, the Red Eagle Formation was perforated in both wells and economic production was established from both wells.

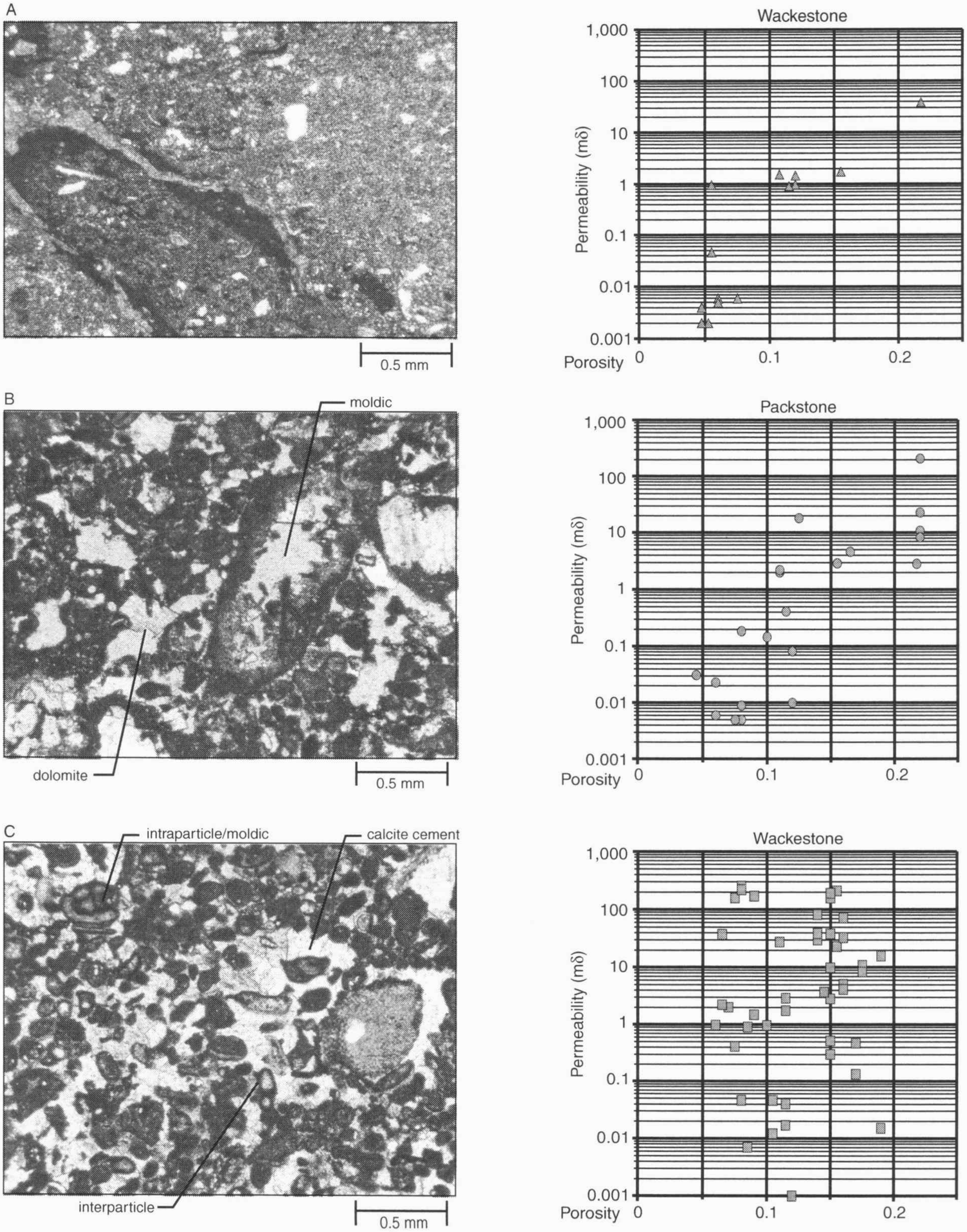

FIGURE 7—Thin-section photomicrographs and porosity-permeability crossplots for each lithofacies. A, Fine-grained skeletal-wackestone lithofacies with 25% porosity and 38 millidarcies permeability. Combination of moldic and interparticle pores creates reservoir capable of producing hydrocarbons. Pore-throat size can be less than 0.03 mm. In this photomicrograph, porosity is lighter pinpoint areas within gray matrix; B, Packstone lithofacies with intergranular and vuggy pores. Porosity in sample is 24% and permeability is 209 millidarcies. Effect that meteoric diagenesis has on original fabric is greatest in this sample. Calcite and dolomite fill only small portion of pores; C, Well-sorted, peloidal-foram grainstone lithofacies with 7% porosity and 0.015 millidarcies permeability. Peloids and forams are black/dark gray concentric to oval-shaped clasts. Patchy calcite cement (shown in white) occludes most of interparticle pores.

The scatter plot nature to the Beattie Limestone in the Hill No. 34–A and the high irreducible water saturation in the Hill No. 34–B would indicate that the Beattie Limestone is water productive in both wells. Considering the variability of the lithofacies present in the cores, a more detailed evaluation was conducted. Reservoirs with thick wackestone lithofacies would seem wet on a BVW plot when compared to reservoirs with predominantly skeletal grainstones. The need for a more-detailed evaluation was substantiated by gas shows in the Beattie Limestone from both wells (Figs. 11 and 12). Because core data were not available on either of the Hill wells, a correlation of the petrophysical characteristics recognized in the nine cores in this study was used to identify lithofacies in these wells. Plotting gamma-ray API values against the lithofacies identified in core was the primary correlation used to identify lithofacies in the uncored wells. Skeletal grainstones have an API value of less than 37 units; wackestones have API values greater than 40 units (Fig. 13). The two textural extremes are the most easily recognized lithofacies and became the basis for flow-unit description within a fourth-order parasequence set. Possibly with more data, a unique petrophysical characteristic for the packstone lithofacies will be recognized.

A Pickett plot of the wackestone lithofacies for the Hill No. 34–A and the Hill No. 34–B suggests a cementation exponent (*m*) of 1.8 is appropriate (Fig. 14A). Permeability/porosity cross plots indicate a pore network that is well interconnected. Low resistivity measurements are partially the result of a silty limestone matrix and a micropore network. Thin sections show that the pore-throat size in the wackestone lithofacies is 0.03 mm or smaller, in comparison to 0.1mm or larger in the grainstone facies. The silty limestone matrix, micropore network, and the smaller size pore throats typically present in the wackestone lithofacies affect the petrophysical response and the ultimate performance of the reservoir.

Higher water saturation values in the grainstone lithofacies of the Beattie Limestone possibly reflect a slight textural change when compared to the gainstones of the Red Eagle Formation (Fig. 14B). A bulk-volume-water plot which highlights the lithofacies differences in the Beattie Limestone also illustrates the complex nature of the pore system in Council Grove Group reservoirs (Fig. 14C). By applying the 1.8 cementation exponent to the standard Archie water-saturation equation in the wackestone lithofacies, the BVW values fit into a tighter grouping. Even though the values fit into a tighter grouping, the BVW plot is indicating that more than one pore network is present in the Hill No. 34–A. Grainstones and wackestones plotting along the 8.5% to 9% irreducible water-saturation line are probably more moldic to vuggy pore dominated whereas lithofacies plotting along the 10% to 11% irreducible water-saturation line are dominated by micropores (Fig. 14C). On the BVW plot, the Beattie Limestone in the Hill No. 34–B is identified as likely wet. In the Hill No. 34–A, the Beattie Limestone is identified as potentially productive if the 1.8 cementation exponent is applied to the wackestone lithofacies. Confirmation of these conclusions was obtained with the completion of the Beattie Limestone in the Hill No. 34–A, flowing at an initial rate of 1,000 MCFPD. Production tests of the Beattie Limestone in the Hill No. 34–B were predominately water with only a small amount of associated gas.

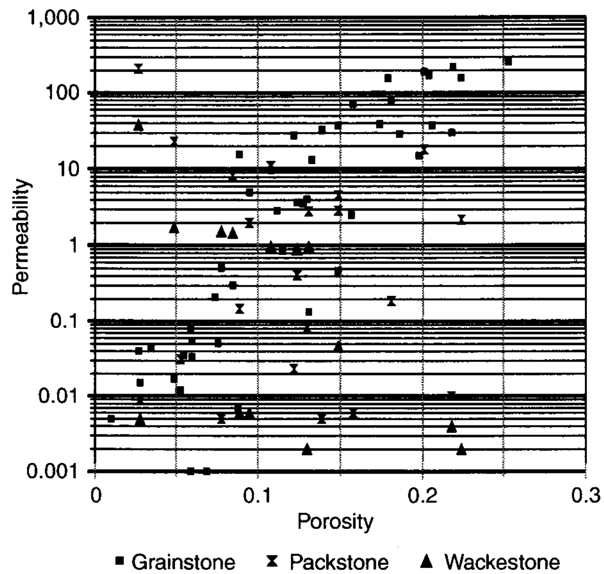

FIGURE 8—Council Grove Group reservoirs consist of predominantly four pore types. Crossplot of porosity and permeability illustrates 10% cutoff in porosity regardless of pore types. Pore-throat size ranges dramatically between pore types. In skeletal-wackestones lithofacies, 0.03–0.07-mm pore throats are one variable affecting water saturation and causing low resistivity values.

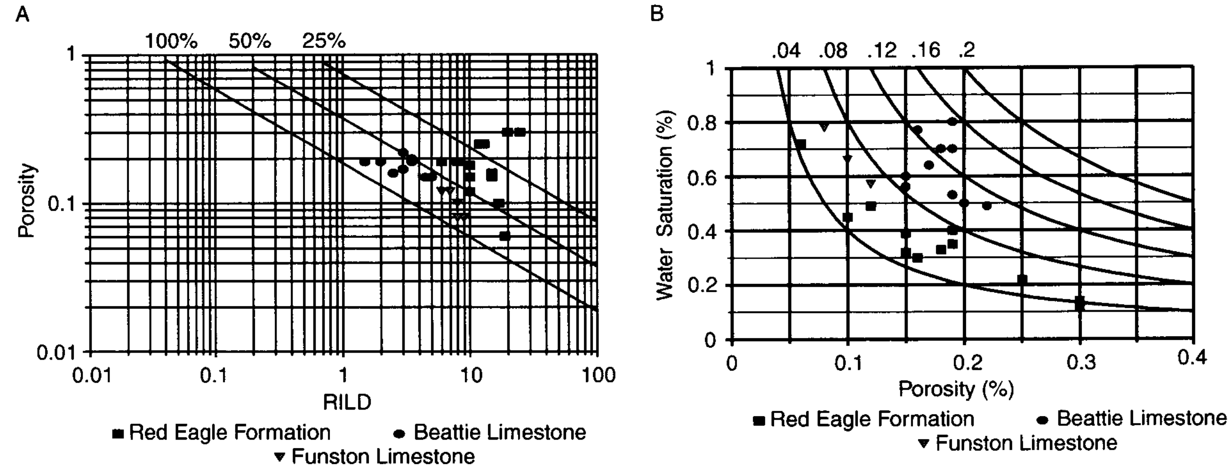

FIGURE 9—Pickett plot and bulk-volume-water plot for Hill No. 34–A. Limestones in Red Eagle Formation generally are well-sorted skeletal grainstones and have water saturations in 20%–40% range. Bulk-volume-water calculations illustrate 0.04–0.06 irreducible water saturation. In contrast, Beattie Limestone seems wet according to these plots. Water saturations are in 50%–75% range with wide variety of irreducible water saturations.

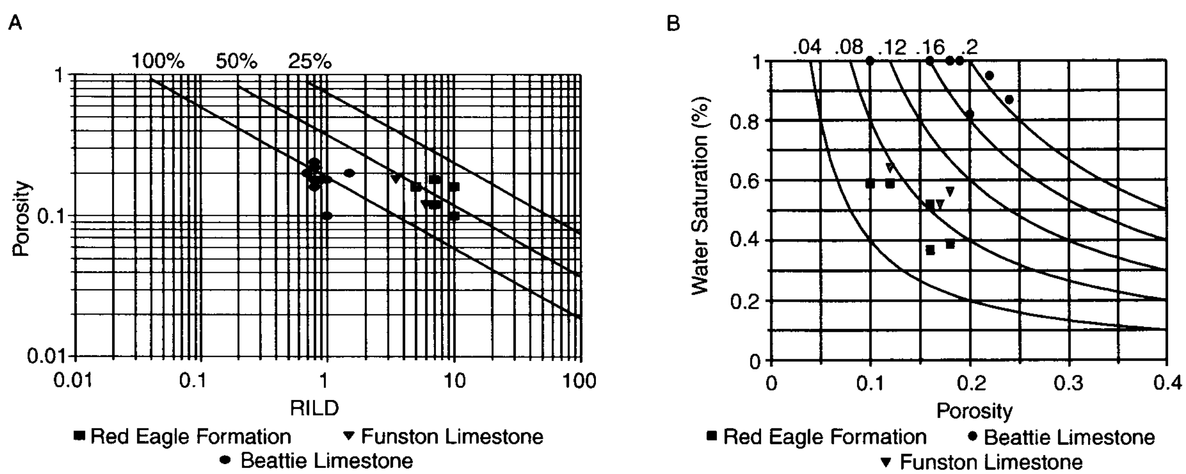

FIGURE 10—Pickett plot and bulk-volume-water plot for Hill No. 34–B. Red Eagle Limestone is productive in this well with water saturations in 40%–50% range. Notice Beattie Limestone values plotting below 100% water-saturation line on Pickett plot. This suggests that standard default cementation exponent (m) of 2 is inappropriate.

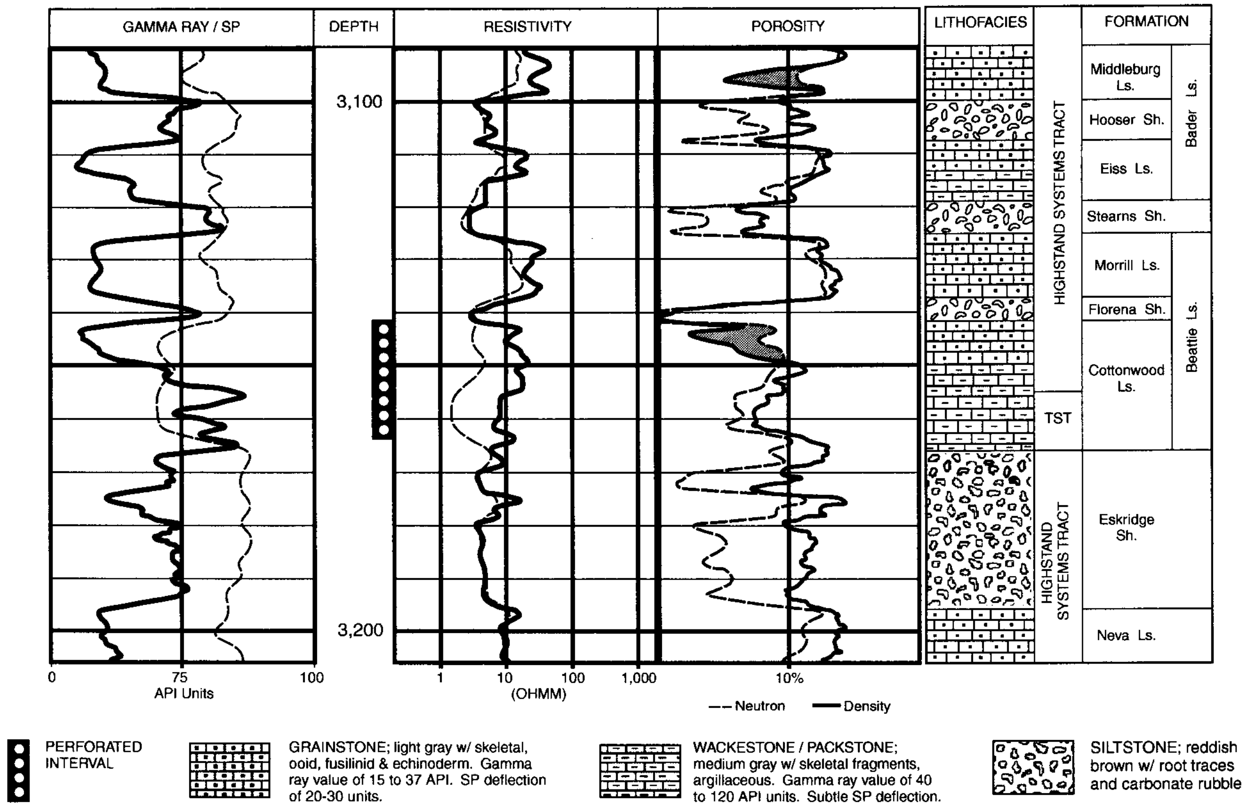

FIGURE 11—Wireline-log suite for Hill No. 34–A in Beattie Limestone. This well was perforated from 3,142 to 3,162 feet and had initial potential of 1,000 MCFPD. 14-feet-thick wackestone with low resistivity is overlain by 8-feet-thick grainstone. Resistivity profile suggests water contact at base of grainstone.

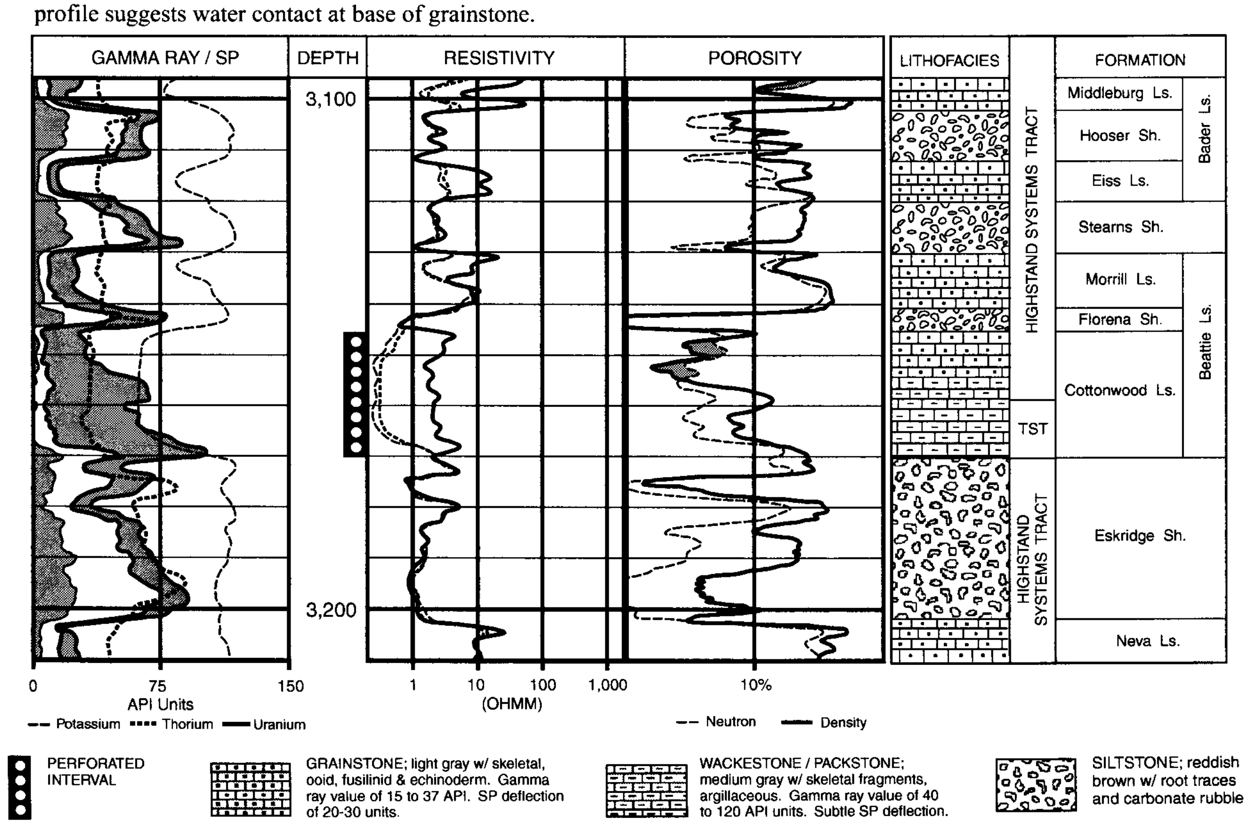

FIGURE 12—Log suite for Hill No. 34–B in Beattie Limestone. Gamma ray for this well has been separated into potassium, thorium, and uranium components. Note high content of uranium, giving wackestone lithofacies shaly appearance. Hill No. 34–B is 27 feet low to Hill No. 34–A, and produced mostly water with some gas.

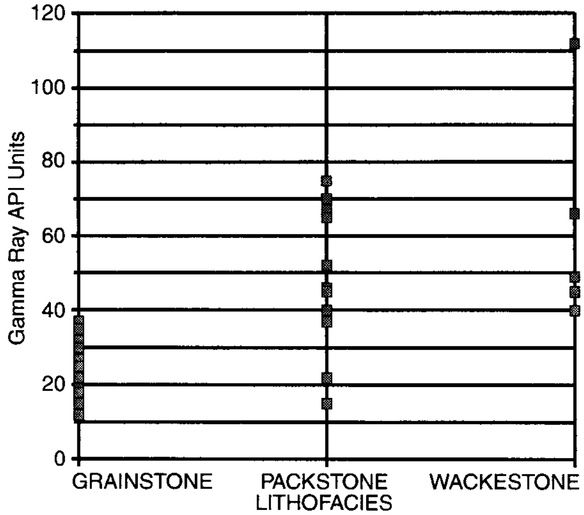

FIGURE 13—Crossplot of gamma ray and lithofacies. High uranium content in wackestone lithofacies as compared to packstone and grainstone lithofacies provides a strong correlation between lithofacies/rock texture and gamma ray.

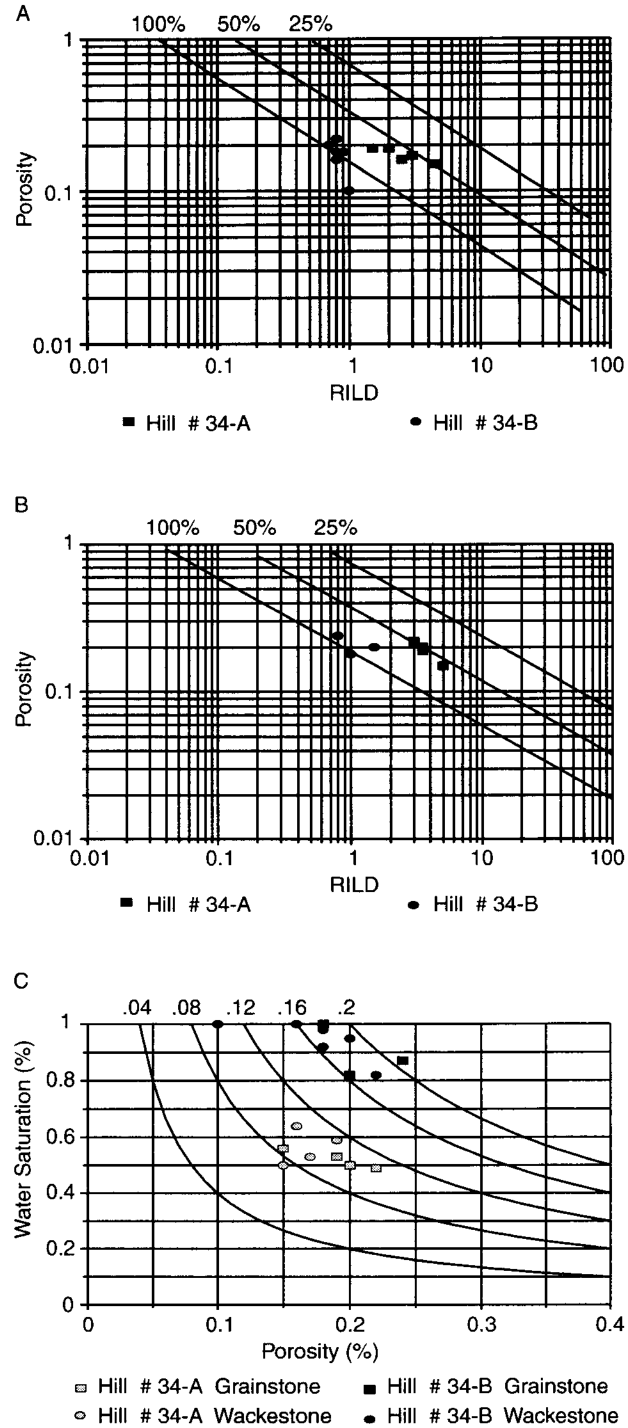

FIGURE 14—Pickett plots and bulk-volume-water plot based on lithofacies in Beattie Limestone. A, Water-saturation lines on wackestone-lithofacies Pickett plot are calculated using cementation exponent of 1.8. B, Pickett plot for grainstone lithofacies has water-saturation lines that calculate cementation exponent of 2 for use in standard Archie water-saturation calculation. Both plots predict Hill No. 34–A to be potentially productive of gas and water with Hill No. 34–B expected to be water producer. C, Plot of bulk-volume water based on lithofacies would predict gas/water completion in Hill No. 34–A and water completion in Hill No. 34–B.

CONCLUSIONS

(1) Understanding the sequence stratigraphic setting is of primary importance when describing the reservoirs of the Council Grove Group. Transgressive systems tracts will develop poor reservoirs because of the silty texture of the carbonate rock and because of the absence of exposure surfaces. Highstand-systems tracts have the greatest potential for yielding highly permeable reservoirs. The regressive phase of the highstand-systems tracts will develop economic reservoirs but these reservoirs will degrade vertically from the base of the systems tract.

(2) Reservoir characterization is defined easily from core and thin-section analysis. More importantly, when cores are unavailable, lithofacies can be recognized by various unique petrophysical responses.

(3) The complex nature of the pore systems present in the Council Grove Group can be isolated using a variety of petrophysical characteristics in combination with bulk-volume-water plots and Pickett plots. Productive grainstones will plot along the 0.04 to 0.06 irreducible water-saturation line while wackestones will plot along the 0.1 to 0.11 irreducible water-saturation line. Packstones or grainstones with multiple pore networks will plot along an irreducible water-saturation line that is between the two textural extremes.

(4) Completion strategy must be dependent upon where in the sequence stratigraphic framework the reservoir is placed. Predictions of flowing capacity of wells will be dependent upon the lithofacies present in each reservoir. Wells completed in reservoirs of the regressive phase of the highstand systems tract in the 1950's required a hydraulic fracture treatment to establish economic production. This same completion technique is inappropriate for the reservoirs in the early phase of the highstand-systems tract. Depending on the relative percentage of wackestone lithofacies present in a reservoir, acidization maybe insufficient to achieve reservoir stimulation. In reservoirs dominated by wackestone lithofacies a small hydraulic fracture treatment maybe required.

ACKNOWLEDGMENTS

I thank Steve Palko, President of Cross Timbers Oil Company, and the senior management of Cross Timbers Oil Company for allowing publication of this study. I also would like to thank Magell Candelaria for editing this manuscript; he made several contributions concerning the technical writing. Reservoirs Incorporated described the cores and provided the porosity/permeability data and the thin-section analysis. Christine Bradford and Larry Bruno at Reservoirs Incorporated are the primary geologists responsible for this work. Mary Jones at Cross Timbers Oil Company drafted the figures and coordinated the illustrations.

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Intravalley Cut-and-Fill Structures in Lower Cretaceous Fluvial Strata of Colorado and Kansas—a Cause for Compartmentalization in Fluvial Reservoirs

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The upper Muddy Sandstone in southeastern Colorado and the Terra Cotta Member of the Dakota Sandstone in central Kansas both represent mid-Cretaceous (Albian/Cenomanian) fluvial deposition in the U.S. Western Interior between marine deposition of the Kiowa–Skull Creek and Greenhorn cycles.

These units also are characterized by intravalley cut-and-fill structures. These structures are composed of amalgamated channel-fill, lateral accretion, and overbank-fine elements; and are channel shaped with width/depth ratios near 14:1, and thicknesses near 7–12 m. At least in the situation of the Muddy Sandstone examples, these structures are bound by larger scale channel-shaped surfaces that represent cut-and-fill of large-scale valleys. These intravalley cut-and-fills thus exist on a scale larger than channel scours and smaller than fluvial valley scours, and seem to result from primarily tectonic and climatic stimuli that result in temporary episodes of incision of channels into their own alluvium and subsequent filling.

Because these cut-and-fill structures may be filled with a wide variety of lithofacies, the potential to generate permeability contrasts across structure boundaries is high (as is exemplified in the Terra Cotta Member). Because of their linear nature, such structures may serve as narrow conduits for petroleum migration as well. As the processes that form these structures are widespread in most modern fluvial systems, these structures should be universal to fluvial deposits. They, however, are rarely reported from ancient strata.

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Latest Advances in Concepts and Technology

(Session A)

Computer Technology and the Petroleum Geologist, 1999

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Computer technology has evolved so rapidly that it has left some geologists overwhelmed and frustrated. To make matters worse, some of those geologists have horrible memories of early computer mapping (circa 1980) and therefore are reluctant to try the new computer tools. For those that already use a computer to help them conduct geologic work, knowledge of the latest technology is important to them if they want to stay at the cutting edge.

There are three compelling reasons for geologists to use computers in their work: (1) manipulate and process a large volume of data quickly and easily; (2) accommodate changes during the interpretation process; and (3) visualize three-dimensional features. A cost/benefit analysis of using a computer further emphasizes the importance of this new technology to petroleum geologists.

New technology does not necessarily indicate tremendous expense; today's powerful personal computers and dozens of sophisticated PC applications make it affordable for even the smallest company. It is useful to provide an overview of software applications such as mapping, digitizing, and log analysis in terms of capabilities versus cost. For example, geologic-mapping software ranges from \$0 to \$55,000; what is the reason for this vast difference in price?

Geologists interested in getting started in this technology require guidelines for buying or upgrading a computer, sources of software training, and knowledge of the Internet as a tool for accessing data, research, news, and networking.

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Changes in Patterns of Cyclicity in Upper Carboniferous through Lower Permian (Virgilian–Sakmarian) Depositional Sequences in the North American Midcontinent

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Analysis of Virgilian–Sakmarian North American Midcontinent depositional sequences cropping out reveals major changes in the nature of the cyclothermic-scale depositional sequences and patterns of cyclicity that are considered to result from allocyclic as well as autocyclic mechanisms.

Lower Middle Virgilian (Douglas, Shawnee, and basal Wabaunsee) strata are grouped into mixed composite carbonate-siliciclastic sequences with a regular pattern of minor to major depositional sequences that have the thickest sequence containing well-developed marine condensed sections represented by nonskeletal phosphatic black shales. Incised valley fills and laterally extensive paleosols are well developed during lowstands.

Upper Virgilian (Wabaunsee and Admire) strata are grouped into mixed composite carbonate sequences-siliciclastic sequences with a regular pattern of between two to three minor to intermediate sequences with no marine condensed sections but with updip maximum marine flooding surfaces that are either fossiliferous gray shales or phosphatic and glauconitic wackestones. Also, an upward trend towards more minor cycles is noted. Incised valley fills and laterally extensive paleosols are well developed during lowstands.

Lower Council Grove strata are grouped into mixed composite carbonate-siliciclastic sequences with a pattern of minor to major depositional sequences that have the thickest sequence containing well-developed marine condensed sections represented by black shales or laterally equivalent black shaly, phosphatic, and glauconitic wackestones. No nonskeletal phosphate is denoted in these sequences. Lowstands denoted by well-developed paleosols are represented in the majority of the outcrop belt with incised valley fills restricted to the Oklahoma part of the outcrop belt.

Upper Council Grove strata are grouped into mixed composite sequences with a pattern of minor to intermediate depositional sequences that have the thickest sequence containing no marine condensed sections but only minor condensation at the level that corresponds to maximum marine flooding.

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Evidence for Hierarchy of Stratigraphic Forcing in the Upper Carboniferous (Virgilian, Wabaunsee Group) in the Anadarko Basin

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Analysis of Upper Carboniferous (Virgilian, Wabaunsee Group) strata cropping out in the North American Midcontinent suggests a hierarchy of stratigraphic forcing. Fourth-order depositional sequences from the Wabaunsee Group represent the latest highstand sequence sets of a composite third-order sequence (1–10 m.y.) that encompasses strata from the Douglas, Shawnee, Wabaunsee, and Admire Groups.

The composite third-order sequence (110 m.y.) is composed of 15 composite fourth-order depositional sequences (0.1–1 m.y.). The composite fourth-order depositional sequences of the Wabaunsee Group contain between two and three fifth-order cycles (0.01–0.1 m.y.). These fifth-order cycles form retrogradational transgressive system tracks and aggradational to progradational highstand-system tracks.

Lowstand units are composed of incised valley-fill deposits or laterally extensive paleosols. The fifth-order cycles are separated by poorly developed, laterally discontinuous paleosols or marginal-marine units. These poorly developed paleosols are expressed as coals, coaly shales, or underclays.

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Seismic Sequence Stratigraphy of the Upper Morrow Formation—a Regional Study in the Western Anadarko Basin

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The upper Morrow Formation in the western Anadarko Basin, northeastern Texas Panhandle, was studied using 360 km of seismic-inversion data integrated with data from 80 wells. The goals were to use seismic data to interpret the lithologies, depositional environments, evolving paleogeography, and changing sea level represented by this stratigraphic interval.

Seismic-interval velocity contouring, based upon wavelet character, and correlation with borehole data provided the basis for the interpretations. Characteristic seismic signatures of three lithologies, sandstone, shale, and clayey siltstone, were recognized.

Sandstone anomalies, concentrated at three seismic horizons, were mapped. The highest and lowest horizons are interpreted to represent deltaic distributary channel systems, whereas the middle horizon is interpreted to represent a meandering fluvial system. These seismic horizons also are interpreted to represent three minor progradational pulses of fourth- to fifth-order global stratigraphic cycles produced by repeated glaciation in the southern hemisphere, with possible tectonically generated pulses superimposed.

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Characterizing a Morrow Sandstone Reservoir through Stratigraphic Interpretation of 3-D Seismic Data, Sorrento Field, Colorado

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Sorrento field, southeastern Colorado, contains an estimated 21 million bbls of original oil in place in the Pennsylvanian Morrow sandstone. The reservoir consists of a complex of stacked channel sequences within an incised valley. Interpretation of 3-D compressional seismic data has outlined the configuration of the incised valley and provided essential information about the characteristics of the rocks that fill it. This seismic interpretation provides stratigraphic details on the compartmentalization of the four flow units which explain the multiple fluid contacts and variable performance of wells in this field.

The petroleum industry has been challenged to characterize Morrow reservoirs because the sandstone reservoir is encased in marine mudstone; normal compressional seismic data are not capable of imaging reservoir rock because the acoustic impedance is not sufficient to distinguish the two lithologies. Rather, seismic modeling shows that the compressional seismic character of the Morrow interval is the result primarily of high-velocity/high-density nonreservoir rocks. The distribution of these nonreservoir rocks is critical in delineating the reservoir because the channel sandstone is bordered by reflective rocks such as floodplain deposits or high-density facies which lie outside of the valley wall. Nonreservoir rocks that are barriers to flow within the reservoir, such as carbonate-cemented zones, define the compartmentalization.

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Subsurface Structure and Sequence Stratigraphy of the Western Margin of the Hugoton Embayment, Morton County, Kansas

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In low-relief basins mapping the subtle structural and stratigraphic features required for effective exploration and production of hydrocarbons can be difficult. The Hugoton Embayment, containing the giant Hugoton and Panoma gas fields, is an example of such a basin. We have used digital wireline logs and a new approach, termed pseudoseismic, to map subtle structural and stratigraphic features on the western edge of the Hugoton Embayment in Morton County, Kansas. Mapped were four previously poorly constrained faults and low-relief structural noses plunging into basin.

Eight Wolfcampian sequences also were defined and mapped. The extreme landward position of these sequences has influenced their geometries and results in a modified sequence-stratigraphic model for the Wolfcampian rocks of southwestern Kansas. The sequence model places nonmarine-dominated strata in the late-highstand systems tract. Pinchouts of marine-dominated reservoir-prone lithologies within the Wolfcampian sequences, coupled with structural features, seem to be controlling factors on production from the Hugoton and Panoma gas fields.

These stratigraphic and structure problems are not unique to the Hugoton Embayment. The approaches and results could have widespread application in other basins and mature exploration provinces.

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Integrated Petrophysical Methods for the Analysis of Reservoir Microarchitecture—a Kansas Chester Sandstone Case Study

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ABSTRACT

Traditional log analysis is an inverse procedure in which an interpretation of reservoir fluid and pore volumetrics is made from indirect physical measurements of a logging tool. When logged zones from a well-reservoir interval are plotted on a Pickett resistivity-porosity crossplot, they form a trajectory whose trace is dictated by petrofacies and relative height in the hydrocarbon column. The trajectory graphs the log response "effect" to the reservoir variables "cause," for which multiple interpretations can be possible when attempting the inverse path from log response to reservoir properties. The microarchitecture of the reservoir pore system and its contained fluids determine the resistivity-porosity trajectory and can be modeled using hypothetical parameters or, preferably, from core measurements of porosity, permeability, and capillary pressure. Capillary pressure curves simultaneously describe the size distribution of pore-throats and their aggregate determination of the hydrocarbon column saturation profile. When integrated directly with log measurements of porosity and resistivity, pore-throat sizes and their estimated height above free-water level provide a more comprehensive formulation of petrofacies zonation and fluid producibility that reach beyond the basic volumetric estimations of standard log analysis.

INTRODUCTION

The Archie equation remains the keystone of log analysis for the solution of water saturation of potential oil and gas zones (Archie, 1942):

$$S_w = \left(\frac{a}{\Phi^m} * \frac{R_w}{R_t}\right)^{\frac{1}{n}}$$

The equation links water saturation, S_w, to the zone porosity, Φ, formation resistivity, R_t, the formation water resistivity, R_w, a (a constant, usually given a value of one), m, the cementation factor, and n, the saturation exponent. The endurance of the Archie equation is adequate testimony to its great predictive power in the estimation of fluid saturation. However, in themselves, estimations of porosity and water saturation may be inadequate guides to hydrocarbon productivity. Many authors such as Hawkins (1994) have concluded that additional information on pore size and geometry is a crucial guide for consistent forecasts of water-cut and production rates. This view now is accepted widely by the energy industry and is the main reason for the recent great technical and commercial success of nuclear magnetic resonance (NMR) logging. NMR logging measurements are transformed to volumetric porosity and its subdivision into size fractions of pores (Hodgkins and Howard, 1999). The pore-size subdivision allows a distinction between free- and bound-water, as well as an improved estimate of permeability from internal surface area data.

In many regions NMR logs have not been run in older wells, although economic considerations encourage cost-effective use of existing data to improve reservoir analysis. Much of the necessary information already is contained implicitly in the log data, although measurements from core are needed to make the reservoir controls both explicit and quantitative. Logged zones are ordered in a stratified depth sequence so that their saturation profile is the result of the interaction of the hydrocarbon column with the microarchitecture of the formation pore system. Buoyancy and capillary pressure are the driving forces controlling saturation and these conform to simple physical laws. Capillary pressure on core plugs have been used for many years to evaluate both pore-throat size distribution and hydrocarbon column height. These data can be integrated with logging measurements to improve reservoir characterization as demonstrated by authors such as Alger, Luffel, and Truman (1989), Smith (1991), Beck (1995), and Skelt and Harrison (1995). Even where laboratory measurements of capillary pressure are unavailable, reservoir profiles can be modeled to match

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hypothetical capillary-pressure curves and pore-throat size distributions with water-saturation logs (Raymer and Freeman, 1984). Otherwise, capillary-pressure curves can be estimated from conventional core measurements of porosity and permeability (Smith, 1991; Pittman, 1991; Hawkins, 1994; Skelt and Harrison, 1995). In this paper, I describe the analysis of the microarchitecture of a Chester sandstone section from southwestern Kansas, using log analysis combined with capillary-pressure modeling as a demonstration of integrated log analysis.

LOG ANALYSIS OF A CHESTER SANDSTONE SECTION

The Hugoton MLP Koenig No. 1–28 well was drilled in 1997 in the South Eubank field, Haskell County, Kansas, with oil production from the sandstones of the Mississippian Chesterian Series. The sandstones are fine grained, generally well sorted, and occupy a north-south-oriented incised paleovalley that was delineated by 3-D seismic data (Montgomery and Morrison, 1999). The Chesterian section contains two sandstones that are referred to here informally as the "Upper sandstone" and the "Lower sandstone" (Fig. 1).

The gamma-ray log indicates the sandstones to be relatively free of shale, so that the Archie equation can be applied to volumetric estimations of water- and oil-saturation in most of the zones. The Pickett plot (Pickett, 1973) usually is used as a graphical pattern recognition aid to establish the values of the Archie equation parameters (Fig. 2) from crossplotted resistivity and porosity values on logarithmically scaled axes. The Archie equation and the Pickett plot are interchangeable: one is an algebraic relationship written to solve for water saturation as the unknown; the other is a geometric mapping which transforms axes of porosity and resistivity to water-saturation contours. Each has its major advantage. The Pickett plot allows pattern recognition of complex clouds and trends in data that are difficult to see in numerical processing. The Archie equation provides the numbers necessary for quantitative reservoir analysis. Pickett plot analysis of the MLP Koenig No. 1–28 fitted a "Water line" to zones in the basal part of the Lower sandstone, whose slope gives a cementation factor, m, value of 1.8 and intercept value for formation water resistivity, R_w of 0.05 ohm-m. These values are consistent with those of a moderately cemented sandstone and with an R_w estimated from the spontaneous potential. Application of the Archie equation to the Chester sandstones (Fig. 3) shows high oil saturations in the Upper sandstone that may be at "irreducible" water saturation at the top, but seem to grade downward into a transition zone. By contrast, the Lower sandstone probably never reaches "irreducible" water saturation but is marked by a transition zone above a fully water-saturated section. In fact, the conclusions concerning reservoir structure and fluid production are a matter for interpretation because the results of the Archie equation are purely volumetric. However, the saturation-porosity depth profile contains the implicit information for reasonable qualitative judgments and the incorporation of additional petrophysical data can make the reservoir description both explicit and quantitative.

INTEGRATED RESERVOIR MICROARCHITECTURE LOG INTERPRETATION

Although the Pickett plot provides a geometrical realization of the Archie equation, the important variable of depth is suppressed on the plane of the plot. This deficiency may be remedied in commercial log-analysis computer packages through the assignation of intelligent color to the plotted points as an implied depth scale. Depth also can be added directly as a third variable in the "Pickett chimney plot" (Fig. 4). The clouds of points from the Upper and Lower sandstones now become trajectories whose path in "log-depth space" is dictated by the hydrocarbon column and its interaction with the reservoir microarchitecture. It should be noticed that the projections of the trajectories on the chimney walls sketch out the resistivity and porosity logs. If the trajectories were projected on an oblique plane perpendicular to the water saturation contours, then the projected trace would be the depth profile of water saturation.

The primary axes of the Pickett plot are resistivity and porosity, but the addition of water saturation contours marks a remapping from "log space" into "pore volume-fluid saturation space." The trajectory of plotted points then is simultaneously a multiple log curve and a pore/fluid trace whose primary trend reflects relative height above free-water level (FWL) in the interplay between buoyancy pressure and capillary forces. Local deviations from the trend correspond to changes in aggregate pore volume as well as pore-body and pore-throat sizes that cause changes in hydrocarbon charging of the pores.

The reservoir-engineering aspects behind the trajectory (Fig. 4) are shown diagramatically in the schematic representation of a simple, homogeneous reservoir (Fig. 5), based on Arps (1964). Notice that the FWL does not coincide with the oil-water contact (OWC), regardless of whether the OWC is defined as the deepest zone that will flow oil (as well as water) or the maximum depth at which the formation will produce oil with no water-cut. Any rock has a distribution of pore-throat sizes that will be penetrated selectively at higher levels above

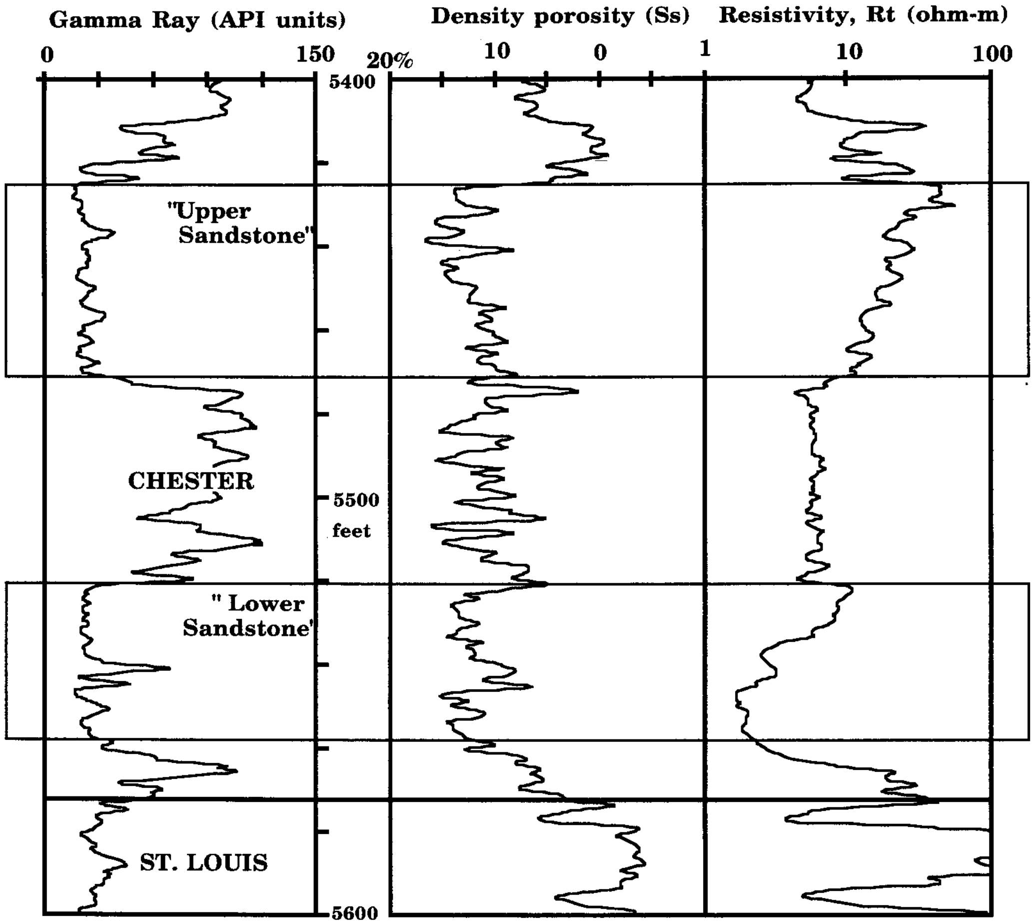

FIGURE 1—Gamma-ray, density porosity, and deep induction resistivity logs of part of Mississippian section from Hugoton MLP Koenig No. 1–28 well in South Eubank field, Haskell County, Kansas. "Upper" and "Lower" Chester sandstones are subject of case study.

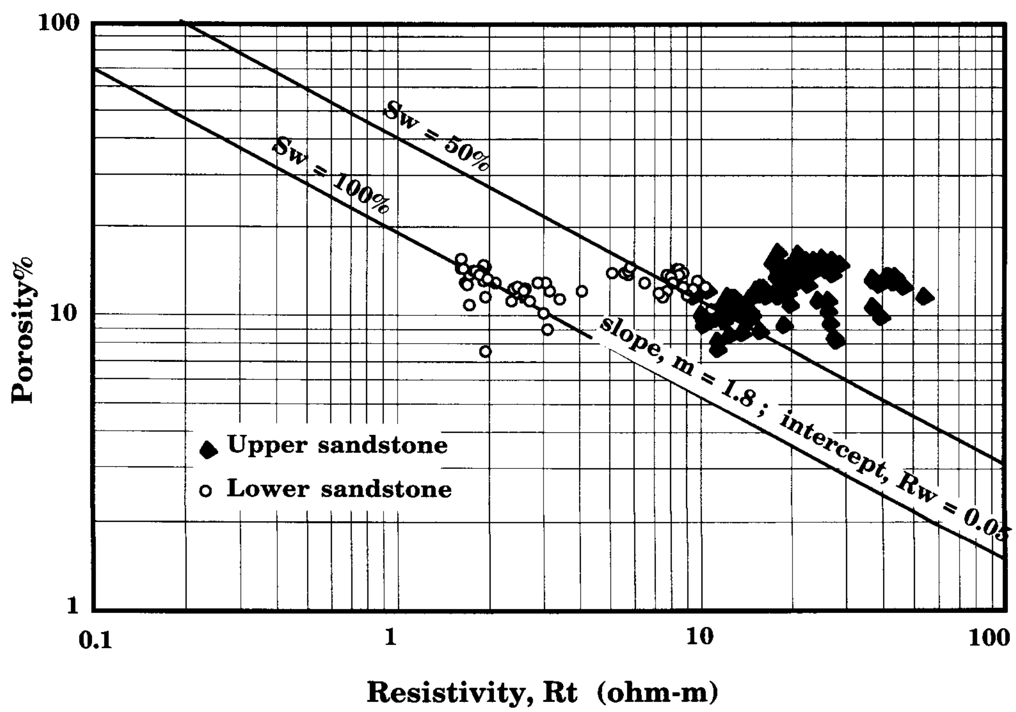

FIGURE 2—Pickett plot of resistivity and porosity log values from Upper (black diamonds) and Lower (open circles) Chester sandstones.

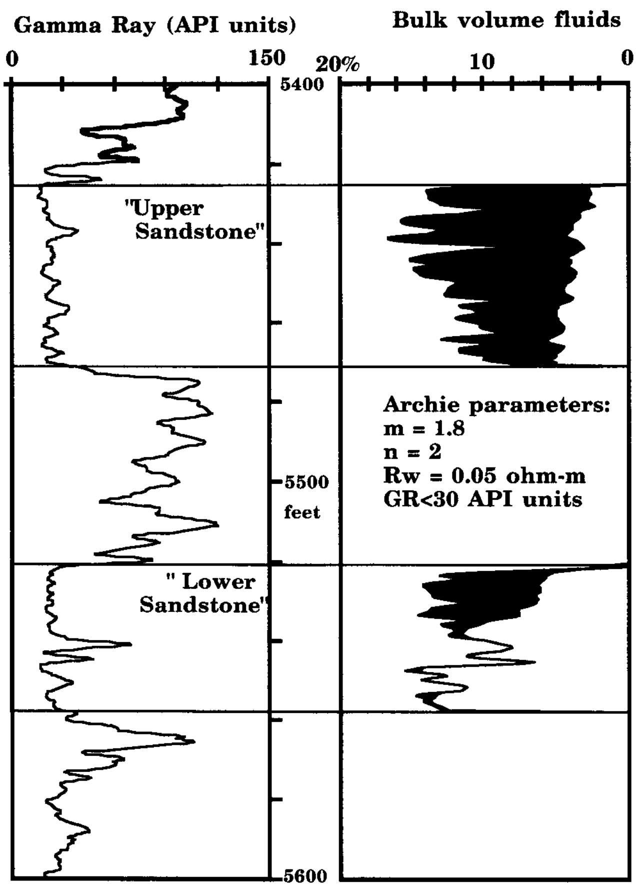

FIGURE 3—Reservoir log analysis of porosity and oil and water contents within Upper and Lower Chester sandstones from application of Archie equation to resistivity and porosity logs.

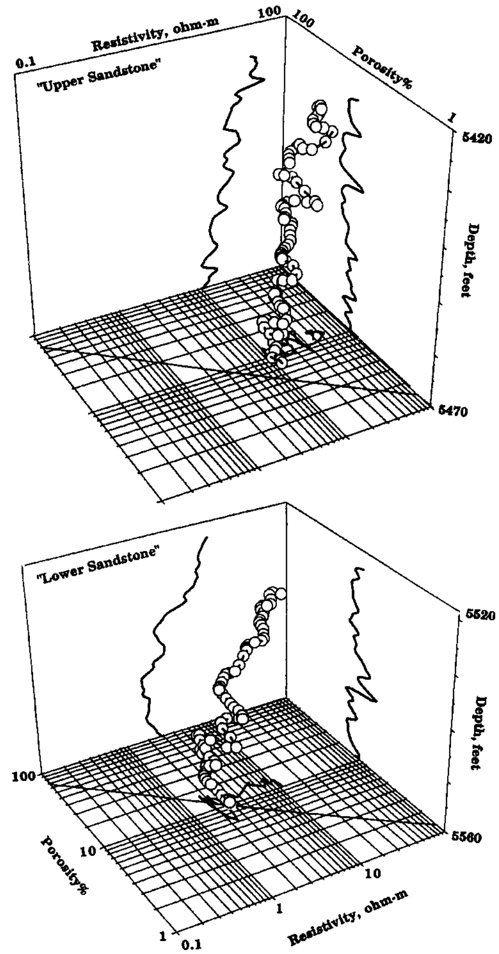

FIGURE 4—Pickett "chimney plots" of Upper and Lower Chester sandstones, showing crossplotted log trajectory on basal Pickett plots and resistivity and porosity logs projected on chimney walls.

the FWL as the buoyancy pressure increases and penetrates progressively smaller pore throats. Immediately above the FWL, the buoyancy pressure is low, so that only the largest pore throats are breached. The majority of pores are filled completely with water. At this level, the well-site geologist might well notice some minor oil-stain in the sample. Core samples also would show low oil saturations. However, if a test were made the produced sample might be entirely water. The oil occurs as isolated globules because there is insufficient oil saturation to establish a connective flow path through the interval. This critical oil saturation below which oil will not flow is known informally as "residual oil saturation," S_{or}. At this point the complementary water saturation is the residual oil-water saturation, S_{wor}.

At some height above the FWL, the produced fluid would change from water to water with a small oil-cut. This point marks the lower portion of the transition zone and occurs when the increased buoyancy pressure causes a more pervasive penetration through pore throats to a saturation where oil globules have started to form continuous filaments through the pore network. The continuity of the oil phase now allows it to flow together with the water. At shallower depths, the oil cut becomes greater until fluid production shifts to recoveries of water-cut oil. Finally, a depth is reached when water-free oil is produced and marks the lower boundary of what some would define as the reservoir zone. At shallower depths, remaining water is immobile for Darcian fluid flow and occurs as thin films on pore surfaces, within micropores, and, possibly, finer macropores. At higher levels, all the macropores are filled and the remaining water is contained within the micropores as "irreducible" water.

The fluid-production performance of this reservoir profile is captured by the relative permeabilities of the reservoir rock with respect to oil and water as a function of fluid saturations. Between the FWL and the critical ("residual") oil saturation at the base of the transition zone,

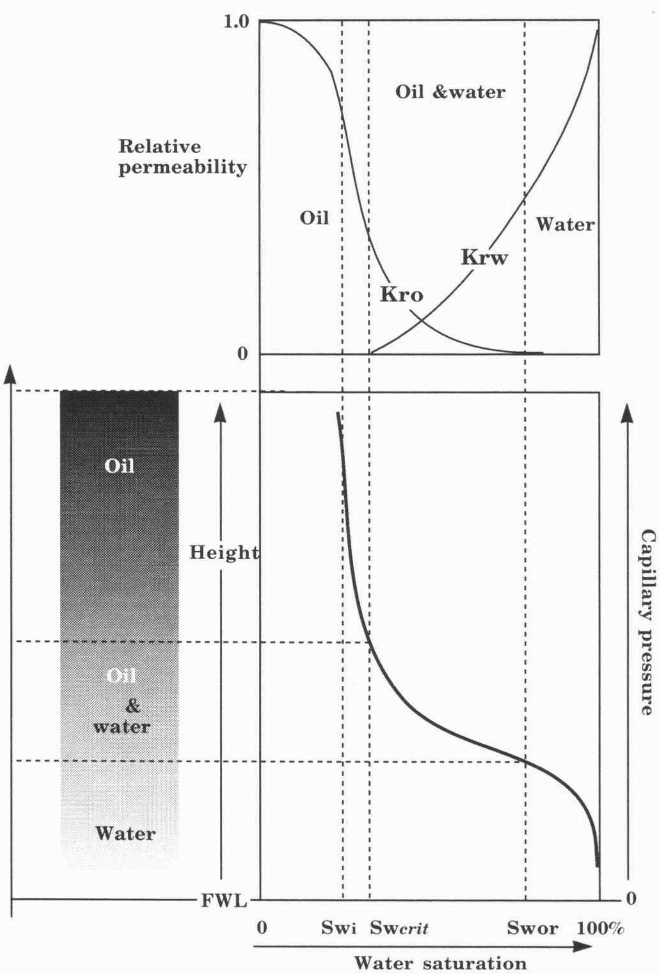

FIGURE 5—Schematic oil column graphed against generalized capillary pressure curve and relative permeabilities (modified after Arps, 1964). See text for explanation of terms.

oil is not produced and the relative permeability to oil, $K_{ro.}$ is essentially zero. Above this region of the transition zone, K_{ro} increases progressively and moves asymptotically to unit value (equivalent to the absolute permeability) where the water phase becomes immobile and confined to progressively smaller pores. The relative permeability to water, $K_{rw,}$ clearly is equal to unity at the free-water level where the rock contains water as its only phase. Above the FWL, K_{rw} declines as the oil saturation increases until a "critical water saturation," $S_{wcrit,}$ is reached, when K_{rw} is effectively zero. This saturation marks the oil-water contact above which no water production occurs. Notice that S_{wcrit} differs from S_{wi} (although they can be coincident in some rocks). The irreducible water saturation, $S_{wi,}$ marks immobile water held in micropores. S_{wi} is usually approximately constant over moderate heights of hydrocarbon column in uniform reservoir rocks, basically because many rocks (particularly clastics) have a distinctly bimodal macropore/micropore system. The relatively lower frequencies of pore-throat sizes between the two categories causes a relatively stable value of water saturation until sufficient height of hydrocarbon column is attained to penetrate the larger micropores. However, S_{wcrit} takes a larger value than S_{wi} when some proportion of the smaller macropores fail to contribute any permeability for their contained water when all the larger pores are filled with oil.

In summary, the fluid saturations and production are determined by the buoyancy pressure exerted by the hydrocarbon column as it increases above the free-water level and the pore-throat sizes and their distributions within the formation rock. The schematic reservoir used to illustrate points so far has a basic limitation in that this simple reservoir is composed of a single rock type with both a constant porosity and pore-throat size distribution. In the vertical dimension, there will be an overall trend to decreasing water saturation moving upwards, but the trend will be broken by excursions to lower or higher saturations that reflect changes to larger or smaller pore-throat sizes. The exact pattern will be determined by the structure of the reservoir; whether it is relatively homogeneous or whether it consists of layers of rock with distinctly different pore size distribution. Although the water-saturation profile may be choppy, there will be many instances where the bulk volume water will be smoother, because higher water saturations will tend to be associated with lower porosities and vice versa. At "irreducible" water saturations, the bulk-volume water (BVW) becomes "irreducible"(BVWi) If the reservoir consists of several petrofacies, then the BVW will show significant fluctuations within the main reservoir.

These mechanisms account for the patterns seen on a Pickett plot and a simple schematic map is shown in Figure 6 of a hypothetical reservoir. Zones high in the reservoir plot on a steep trend that seem to be at "irreducible water saturation," a characteristic recognized by Pickett (1973) who also related the trend position to the formation grain or pore size. This observation reflects the fact that BVWi takes a hyperbolic form when graphed in porosity-water saturation space, described by the relationship:

$$\Phi \bullet Sw_i = c$$

which is linear on a Pickett plot as pointed out by Greengold (1986). A general inverse hyperbolic relationship between irreducible water saturation and porosity was noted by several early authors, including Archie (1952). They correctly attributed differences in the curvilinear trends to differences in reservoir-pore sizes. This is because irreducible water saturation is controlled by surface tension at the internal surfaces and capillary pressure. Although zones at irreducible water saturation in a moderately homogeneous reservoir should lie on a

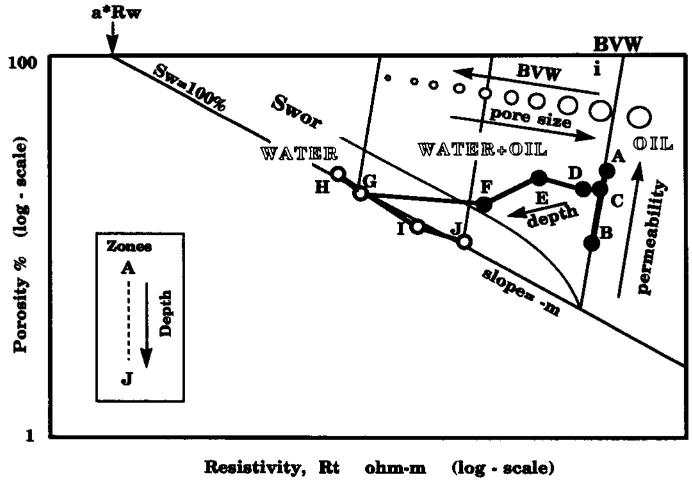

FIGURE 6—Schematic Pickett plot of simple reservoir marked by trajectory of crossplotted zones A–J and indexed with trends of bulk-volume water (BVW), pore size, permeability, and water-cut.

common curve, transition zones will be displaced to higher values of bulk water volume ($\Phi * S_w$). The distinction is important, because it determines which zones should produce water-free oil or gas, and which should produce water or water-cut hydrocarbon. Computations of bulk volume water therefore are a critical additional step in log analysis for the assessment of producibility, as pointed out by Morris and Biggs (1967), Asquith (1985), and others. Information on pore size can be related to contour lines of BVW (bulk-volume water) on the Pickett plot. Zones that contain coarse pores will tend to be associated with lower BVW numbers; those that have fine pores with higher BVW numbers. Interpretation of productivity therefore is based on a combination of porosity, water saturation, and BVW.

An upper section of reservoir zones seems to be at "irreducible" water saturation and grades downward in a ragged trend of less resistive points in a transition zone which terminates in a water leg located along a fully water saturated "water line." Zones that are marked by residual hydrocarbon saturations form a broad trend parallel to the water line with water saturations typically of the order of 35% (Schowalter and Hess, 1982; Fig. 3). Trends of permeability on the Pickett plot generally are subparallel to the porosity axis, reflecting both the primary control of pore volume and the secondary control of pore size/ internal surface area that is partly picked up by changes in water saturation.

QUANTITATIVE INTEGRATION OF CAPILLARY PRESSURE DATA WITHIN LOG ANALYSIS

Capillary pressure data have been obtained from core samples by the oil industry for about 50 years, but their primary users have been petroleum engineers. Fortunately, several excellent review papers have been written for geologists that relate capillary pressure to rock type and reservoir structure, as well as applications to both reservoir analysis and exploration (Arps, 1964; Stout, 1964; Berg, 1975; Jennings, 1987; Vavra, Kaldi, and Sneider, 1992). Capillary-pressure measurements are made on standard core plugs by injecting a nonwetting phase (typically mercury) at increasing pressures and recording the nonwetting saturation of the core at different pressure levels. The laboratory process simulates the intrusion of hydrocarbons into a water-wet rock under increasing buoyancy pressure that would be experienced by the rock at successively higher levels in a hydrocarbon column. The obstacle to the introduction of the nonwetting phase into the core is provided by the capillary forces within the pore system. In a hydrocarbon system, the wetting fluid (conventionally thought to be water) adheres to the internal surfaces and resists the introduction of the hydrocarbon nonwetting phase. The equation of the capillary forces is given by:

$$P_c = \frac{2\sigma\cos\theta}{r}$$

where P_c is the capillary pressure, σ is the surface tension of the wetting fluid, θ is the contact angle between the wetting fluid and the solid surface, and r is the pore-throat radius. Because the term $2\sigma\cos\theta$ is a constant for any given nonwetting/wetting phase couplet, the capillary pressure is controlled by the pore-throat radius of the rock pores. If the pore throats had a unique radius, then the pore network would be impenetrable up to a threshold pressure, when the entire pore system would be breached. In reality, rock-pore systems have a range of pore-throat sizes, so that the capillary-pressure curve records the saturation of pore throats and associated pore bodies at successively smaller sizes with increasing pressure. The curve is a rendition of a cumulative frequency curve of pore-throat sizes.

In addition to characterizing the key features of the capillary-pressure curve, the pressure units can be converted into either the radius of the pore throat that is entered by the nonwetting fluid or the equivalent column of hydrocarbon that will provide the equivalent buoyancy pressure. The buoyancy pressure necessary to provide these entry pressures is generated by the height of the hydrocarbon column and the difference between the hydrocarbon density and that of the formation water. The relationship is:

$$P_b = (\rho_w - \rho_{hc})gh$$

where P_b is the buoyancy pressure, r_w and r_{hc} are the densities of the formation water and hydrocarbon, g is the gravitational constant, and h is the height above free-water level (FWL).

The integration of capillary-pressure data with standard log-analysis measurements requires some type of averaging of the curves to generalize the pore-throat properties as representative formation descriptors. The most used procedures are either to compound individual curves into a composite Leverett J-function or to develop statistical regression functions that relate capillary pressure or height above FWL to porosity, water saturation, and permeability (Hawkins, 1984; Alger, Luffel, and Truman, 1989; Skelt and Harrison, 1995). The entry of hydrocarbons into the pore system is controlled by the size of the pore throats, so that the capillary pressure curve is linked primarily with permeability. However, capillary pressure data are expensive and usually not available, as is the situation with the Chester sandstones in the South Eubank field. For these reasons, Pittman (1992) published empirical equations for estimating pore-throat sizes in sandstones based on their porosity (Φ) and permeability (k). The equation coefficients were established from regression analysis of 202 sandstone samples and took the form of:

$$\log(r_x) = A + B \bullet \log k + C \bullet \log\Phi$$

where r_x is the predicted radius of the smallest pore throat penetrated when the sandstone is saturated by x% of mercury, ranging in value from 10 to 75%. Estimates of pore-throat radius then are transformed easily into equivalent entry capillary pressures.

Core measurements of porosity and permeability were made in two South Eubank field wells close to Koenig No. 1–28, so that the Pittman equations can be applied in estimating capillary-pressure curves in the Chester sandstone. Because permeability measurements are not available in the Koenig well, it is necessary to establish first whether there is a satisfactory relationship between porosity and permeability so that porosity can be used as a credible permeability-trend predictor. A regression trend line fitted to the core data (Fig. 7) has a coefficient of determination of 0.76, which was judged to be sufficient to allow the Chester sandstone to be modeled viably by a single transfer function. Deviations from the trend are caused by variability in pore sizes that are relatively localized. A transfer function with a coefficient of determination of 1.0 would signify absolute colinearity

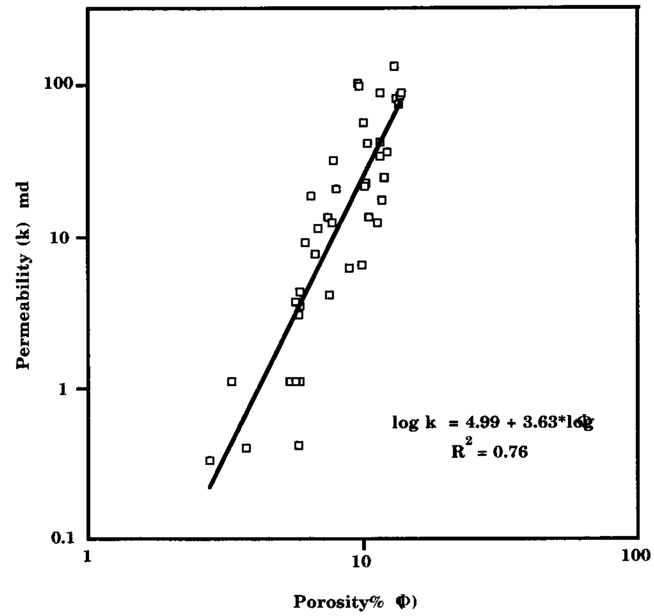

FIGURE 7—Double-logarithmic crossplot of permeability and porosity measured from Chester cores in South Eubank field and fitted with linear regression function.

between the porosity transform and measured permeability, so that porosities could be used as ideal proxy variables. The ability to predict permeabilities to a satisfactory degree is important, because permeability is linked more closely with capillary pressure than porosity as determined both by simple physical considerations and statistical analysis (Pittman, 1992). Higher overall deviations from the permeability-porosity trend or the development of secondary trends would require subdivision into several petrofacies with separate porosity-permeability relationships.

The application of the porosity and predicted permeabilities within the Pittman equations generated empirical predictions of capillary pressure curves for the Chester sandstones shown in Figure 8. These represent average relationships whose reliability is greater at the higher range of water saturation, because Pittman (1992) noted a systematic decline in predictive power of his empirical equations at higher levels of mercury saturation. The fact that the capillary curves are cumulative expressions of pore-throat size distribution is useful for the geologist, in that the first derivative can be used to graph the pore-throat sizes in microns. The Pittman equations suggest the Chester sandstone pore-throats to be primarily macrosized which is the general expectation for a sandstone intergranular pore system.

Capillary pressure also can be mapped onto a Pickett plot using the porosity and water saturation axes as reference coordinates (Fig. 9). The capillary-pressure contours are average expectations for the Chester sandstone because they are based on a regression-trend

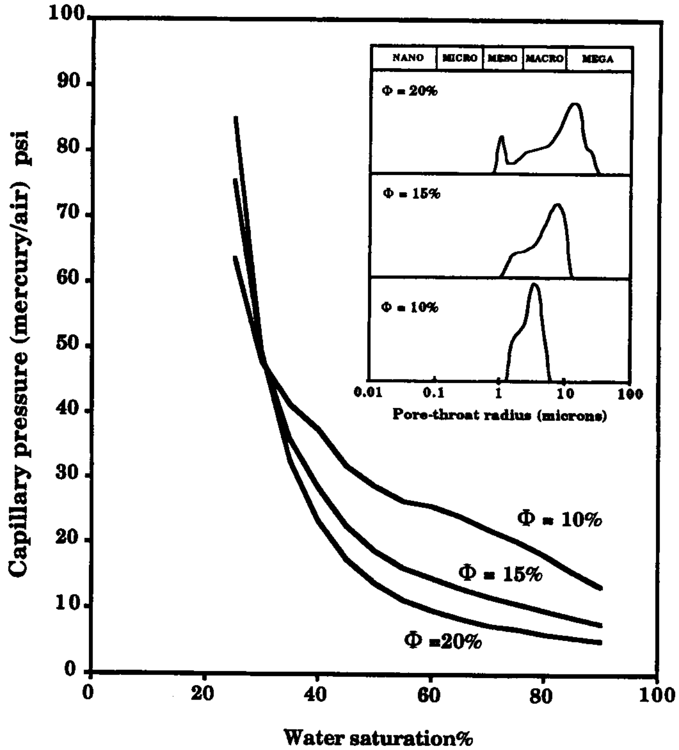

FIGURE 8—Estimated mercury/air capillary pressure curves and pore-throat size distributions for Chester sandstone, generated from application of Pittman (1992) equations to porosity-permeability function computed from regression analysis of South Eubank field core measurements.

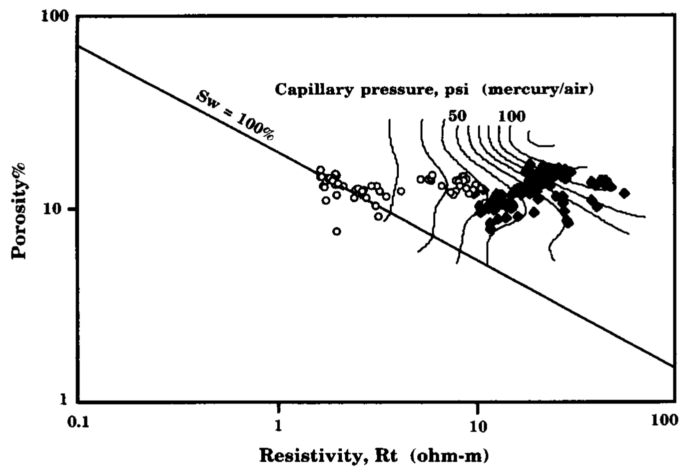

FIGURE 9—Projection onto Pickett plot of expectation of Chester sandstone mercury/air capillary pressure surface generated by Pittman equations.

estimate of permeability used within the Pittman equations which themselves are generalized predictors for sandstones. Notice how the contours become progressively more constricted at higher values as the surface approaches "irreducible" water-saturation values. The trend also loses coherence at higher pressures, partly because of the poorer performance of the Pittman equations at higher levels of equivalent mercury saturation.

Capillary pressure is expressed more usefully as its equivalent of height of column of hydrocarbon. The necessary conversion requires first a transformation from laboratory nonwetting/wetting units to capillary pressure under reservoir conditions in a system of formation water and hydrocarbon, with oil or gas properties representative of the field fluid. The second conversion then translates the reservoir-capillary pressure to the equivalent buoyancy pressure exerted by the column of oil or gas. Although the contact angle and interfacial tension are well-known for laboratory conditions, these quantities are variable and poorly characterized in hydrocarbon reservoirs, even though some general guidelines are outlined by Vavra, Kaldi, and Sneider (1992). Usually, the parameters are compounded collectively into a conversion factor (C) that transforms capillary pressure directly from nonwetting/wetting psi units (P_c) to equivalent heights of oil or gas (H) measured in feet: $H = C \cdot Pc$. Rule-of-thumb values of C for converting mercury/air values are about 0.7 for a typical oil and 0.35 for a typical gas under typical reservoir conditions. However, the value for the conversion also can be calibrated directly from field measurements, as is the situation in this Chester sandstone study.

The log analysis provided a saturation profile of the two Chester sandstones for which any depth has an associated estimate of the porosity and water saturation. If the Chester sandstone permeability-porosity relationship is applied to estimate permeability, then the Pittman equations can be used to estimate the equivalent mercury/air capillary pressure at all depths. Each of these estimates is only an average expectation of capillary pressure because it is based on the averaging of both the permeability-porosity relationship and that of the Pittman equations. However, taken collectively, the trends of capillary pressure with depth can be used both to establish the pressure-height conversion coefficient, C, and the intercept at zero capillary pressure, which is the free-water level (Fig. 10). A regression line matched with the Lower sandstone data has a fit of 90% yielding a FWL at a depth of 5,550 feet (1692 m) and a conversion coefficient of 0.71. Not surprisingly, the trend matched with the Upper sandstone had a lower fit of 60%, where zones are approaching irreducible water saturation in the higher part and the Pittman equation predictions perform progressively worse. Even in the Upper sandstone, the trend estimate of the conversion coefficient of 0.74 is fairly acceptable, but the Lower sandstone figure of 0.71 was substituted as better, and used in locating the FWL at a depth of 5,493 feet (1674 m). The relatively small oil columns in these two sandstones is consistent with hydrocarbon columns in Kansas reservoirs which generally are less than 50 feet (15 m).

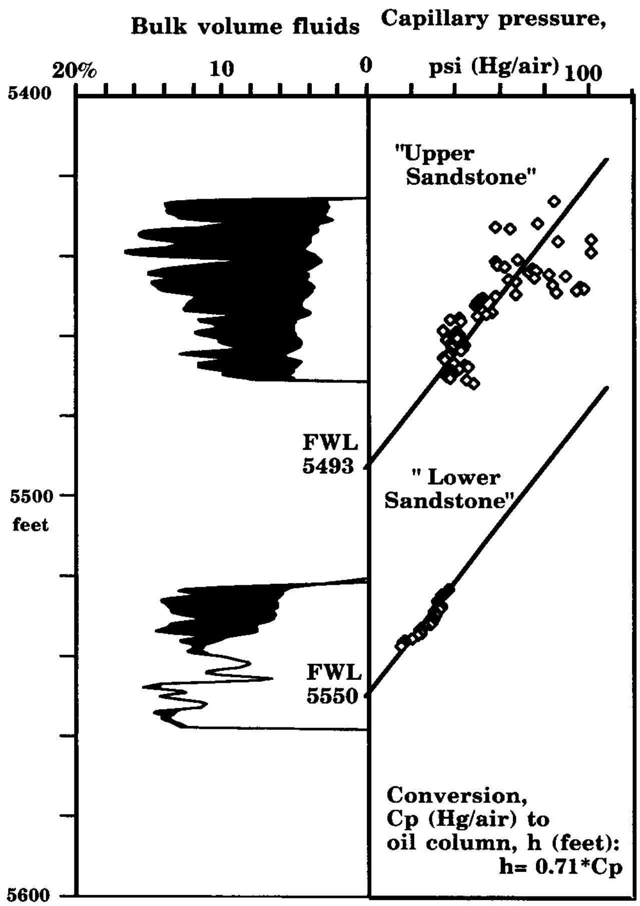

FIGURE 10—Depth plot of predicted mercury/air capillary pressures from application of Pittman equations in Chester sandstones to establish locations of free-water level and coefficient to convert capillary pressure to equivalent height of oil column.

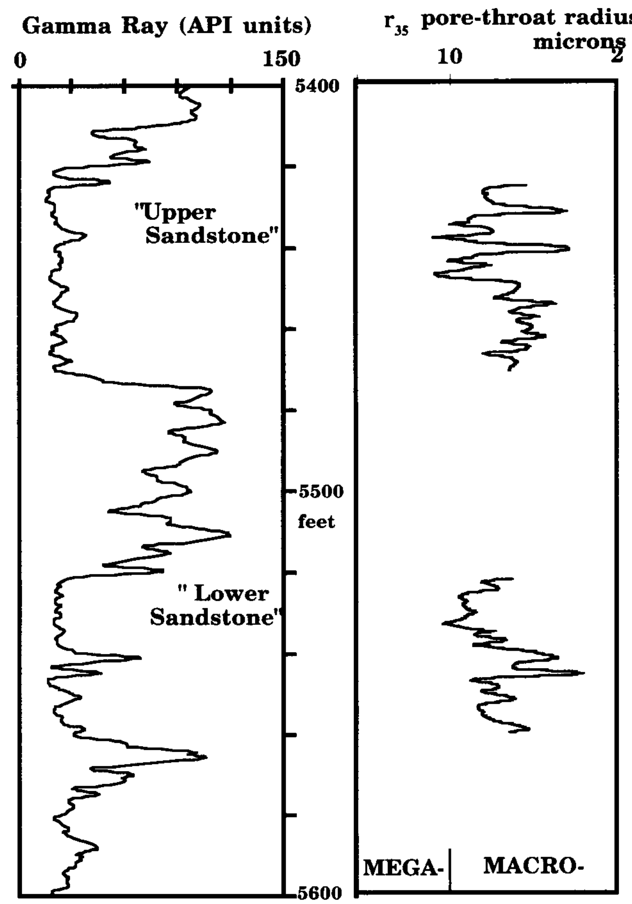

FIGURE 11—Profile of r_{35} pore-throat radius estimated from Winland equation in Upper and Lower Chester sandstones.

The capillary pressure- oil column fitting procedure provides internal checks on the relative validity of the application of generalized numerical predictions through its estimation of conversion coefficients and FWL's, which must simultaneously conform with physics and local geology. In this case study, the match is good, probably because the reservoir formation is not markedly heterogeneous, but can be modeled successfully by a single petrofacies whose sandstone properties are fairly typical. The end-result is a matching of depth in these sandstones to either an equivalent height of oil column or capillary pressure in the mercury-air system which is tailored specifically for this well. The duality of capillary pressure as a measure of entry pore-throat radius indicates that the reservoir sandstones also can be characterized in terms of their pore-throat stratigraphy. The r_{35} measure of pore-throat radius may be a useful summary measure of size that simultaneously marks the approximate position on the capillary-pressure curve that corresponds with a nonwetting phase occupation of a continuous, well-connected pore system and matches the modal pore-throat of the intergranular pore network. Predictions are based on the Winland equation:

$$\log r_{35} = 0.732 + 0.588 \bullet \log k_{air} - 0.864 \bullet \log \Phi$$

where r_{35} is the pore-throat radius in microns (μ) at 35% mercury saturation, k is the permeability (md), and Φ is porosity (%) and the coefficients are based on statistical analysis of core-sample data by Winland and reported by Kolodzie (1980).

Estimates of r_{35} pore-throat radii were computed in the Chester sandstones by back-substituting the capillary pressure trend into the Pittman equations to solve for local estimates of permeability, then using this value in conjunction with log porosity in the Winland equation. More general estimates of permeability were used from the core permeability-porosity correlation in zones outside the range of Pittman equation estimation such as below the free-water level in the Lower sandstone and below 25% water saturation in the Upper sandstone. The r_{35} pore radius profile of the Chester sandstones (Fig. 11) seems to show some similarities between the two Chester sandstones. Each sandstone consists of a lower unit with a weak upward trend of diminishing pore-throat size which is capped by an upper unit with coarser pore throats.

Sedimentological analysis of a cored section in a nearby well (Hugoton MLP Black No. 4–3) showed a fine- to very fine-grained, moderately to well-sorted Chester sandstone with stacked fining-upwards grain-size sequences representing tidal flat/estuarine facies overlain successively by a convoluted siltstone interpreted as a storm deposit and fine-grained clayey sandstones from an intertidal flat facies (Montgomery and Morrison, 1999). The gamma-ray log of this well is distinctively different from that studied in this paper (Koenig No. 1–28), with its more serrated trace and implied higher clay contents within the sandstones. However, the overall sand petrography, estuarine setting of the sandstones, and other broad features probably are applicable to both wells. Therefore, the vertical pattern of pore-throat sizes suggests that the lower unit in each sandstone may be estuarine channel in origin whereas the upper unit represents sand-wave or tidal bar facies, identified in core from the Hugoton Clawson 2–9 well (Montgomery and Morrison, 1999). From an engineering perspective, the pore-throat sizes indicate two major flow units, both with good reservoir quality, but with the best character developed in the upper unit.

One method to show the estimated r_{35} pore-throat sizes in conjunction with log data is to map them onto a Pickett plot (Fig. 12). As discussed before, the primary axes of the plot provide the resistivity and porosity coordinates for the logged data. The water-saturation grid generated by application of the Archie equation provides the secondary axis that allows other petrophysical variables to be mapped. The capillary pressure surface generated by the Pittman equation estimates is replotted, but now shown as equivalent oil column height as a result of calibration by the Chester sandstone saturations. The bubble-plot convention gives an immediate impression of modal pore-throat size and an appreciation of the trend and twists in the log trajectory that result from the interaction between height in the oil column and pore-throat size.

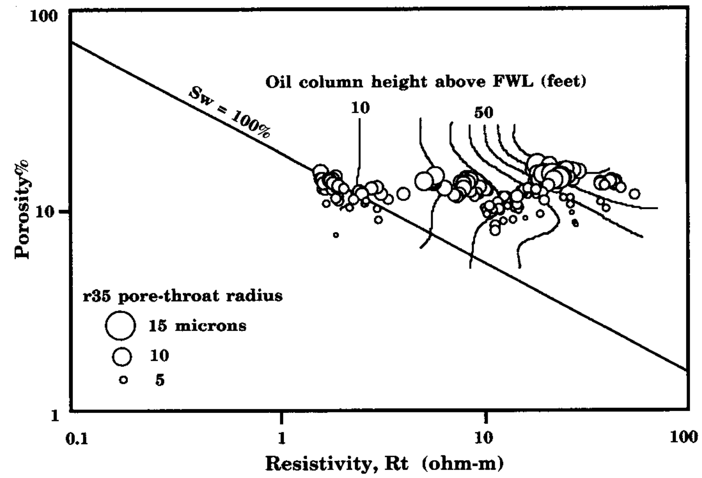

FIGURE 12—Projection onto Pickett plot of expectation of Chester sandstone oil column surface and r_{35} pore-throat radii generated by Winland equation.

CONCLUSIONS

The integration of pore network measures within standard log analysis mingles causal process variables with log responses in a synthesis that provides key insights into reservoir microarchitecture. Capillary-pressure measurements usually are not available, but published relationships enable useful predictions to be made, based on core measurements of porosity and permeability. These first-order models can be fine-tuned for field application using local knowledge of reservoir engineering and geology in conjunction with simple laws of physics. The necessary computations and graphic displays are generated easily by a PC spreadsheet program. The results mark an extension of standard log analysis beyond quantitative volumetrics and interpretative generalizations to numerical modeling with quantitative conclusions that have immediate implications for both petroleum geology and reservoir engineering.

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Resistivity Modeling and Neural Network Synthetics—Powerful New Exploration and Development Tools

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[1]Goolsby Brothers, Inc., Denver, Colorado, and [2]Petroleum Software Technologies, Denver, Colorado

The most fundamental application of wireline-log analysis always has been the calculation of formation fluid saturation. The calculation requires accurate resistivity and porosity information.

Historically, although slow and somewhat cumbersome, forward modeling and inversion processing methods have been used successfully to overcome the limitations of resistivity tools used to measure true formation resistivity (Rt). Inexpensive, high-speed PC hardware and vastly reduced processing-time requirements on available software recently have transformed this technique into a practical solution for multiwell applications.

If porosity and permeability information is inaccurate, incomplete, or simply not available, neural networks can provide high-quality synthetic information using data from available wireline logs, cores, or cuttings from nearby wells.

These two new methods represent powerful exploration and development tools. Applications include accurate reserve prediction, completion strategies, reservoir modeling, and the identification and evaluation of bypassed pay zones. Successful applications of these techniques are discussed.

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Prediction of Effective Porosity and Permeability in Mississippian Carbonates, Kansas

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The integration of saturated and desaturated NMR responses and air-mercury and air-brine capillary pressure analyses with more conventional petrophysical techniques allows the exploration and development geologist to predict better the effective porosity and permeability of producing reservoirs. The Schaben field in western Kansas, which has produced about 9 million bbls of oil primarily from the Mississippian Osage carbonate, has been studied extensively as a Class 2 USDOE project.

The primary reservoir is a coarsening-upward spicule-rich dolomite wackestone-packstone-grainstone deposited on a shallow southwestward dipping ramp. The dominant grain type is sponge spicules and their molds intermixed with a dolomite mudstone. The porosity primarily is moldic, intercrystalline, and intergranular, but may contain a significant number of vugs. Grain or crystal sizes are fine (<100 μm to <2 μm) resulting in very fine microcrystal line pores. Determination of effective porosity requires additional data than that available through typical well log suites.

The oil column in the Schaben field is between 35–50 feet and is discontinuous because of a heterogeneous reservoir. The integration of NMR responses, which predominantly measures the size of the pores, and the capillary pressure data (which predominantly measures the size of the pore throats), allows an excellent evaluation of the pore geometry of the reservoir. The critical component of the NMR evaluation is the T2 relaxation-time cutoff, which divides the effective and ineffective pore sizes. The T2 cutoff within the Schaben field is typically about 20–25 ms as defined by the point of divergence of the desaturated and saturated cumulative porosity curves. As the T2 values increase, there is an increase in pore size and permeability.

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An Innovative Horizontal Drilling Program Opens a New Exploration Play in Admire (Permian) Reservoirs of the Northern Denver Basin, Nebraska

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[1]Goolsby Brothers and Associates, Inc., [2]Pepco, Inc., and [3]Evertson Oil Company, Denver, Colorado

An innovative approach to oil and gas exploration may result in unexpected but beneficial results. Such is the situation with a recent horizontal drilling program initiated in the Nebraska Panhandle to exploit the hydrocarbon potential of the lower Wolfcampian Admire "C" of the northern Denver Basin.

The zone exhibits relatively uniform thickness and continuity over a large portion of the Alliance Basin, reflecting baselevel rise and fall symmetrical brining cycles in an intermittently restricted basin affected by glacial-eustatic sea-level changes. Reservoir development is variable, with the best reservoirs developed in dolomitized packstones associated with shoaling cycles. The reservoir consists of intercrystalline and separate-vug pore types that exhibit permeabilities of less than 25 md. An engineering review of the completion practices in the zone determined that it is a depletion-drive reservoir, and that structural position does not affect water influx. A horizontal program therefore was initiated to increase wellbore permeability height without regard for structural position.

Although the horizontal drilling venture did not result in economically viable hydrocarbon production, it did demonstrate that a large continuous hydrocarbon accumulation covering an area of up to 5,400 square miles (13,986 sq km) is present in the Admire "C". With relatively shallow drilling depths of 7,500–8,500 feet (2,286–2,592 m), this low-permeability, pervasively oil-saturated reservoir currently is poised for the development of an innovative technology to recover its extensive oil resources.

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State-of-the-Art of 3-D Seismic Technology—Integrated Multicomponent Characterization of Carbonate and Clastic Reservoirs

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Three-dimensional multicomponent (3-D, 3-C) reflection seismology is the technology of the future for reservoir characterization. Applications of this emerging technology provide quantitative solutions for porosity and permeability determinations within both clastic and carbonate reservoirs that are unattainable from compressional-wave seismic data alone. A 3-D, 3-C seismic survey over a clastic valley-fill reservoir in the Pennsylvanian Morrow Formation at Sorrento field, southeastern Colorado, U.S.A., demonstrates the application of this technology to identify and characterize a sandstone reservoir. At Joffre field, Alberta, Canada, multicomponent 3-D seismic data characterize carbonate intervals in the Devonian Nisku and Leduc Formations. Those two recent studies mark a major turning point in the use of seismic technology for reservoir characterization. Today, time-lapse monitoring of petroleum reservoirs, using new 3-D multicomponent technology, emerges as the next seismic frontier.

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Coalbed Methane

(Session B)

Small Closed Structural Lows—Unconventional Gas Exploration Targets in Northern Missouri

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Colonial Limestone Incorporated operates a quarry in alternating limestones and shales that comprise the lower two-thirds of the Kansas City Group (Pennsylvanian System) west of Milan in Sullivan County, Missouri. These rocks dip from 9° to 16° inward toward a central low. A vertical clay-filled pipe about 125 feet in diameter occupies the center of this structure. Radial and tangential fractures, some containing calcite, goethite, and pyrite, are present in several limestone beds.

The structure covers about 40 acres centered in the NW SW sec. 4, T. 62 N., R. 20 W. It is developed along the strike of the Northeast Missouri tectonic zone, which may represent a major zone of weakness in Proterozoic continental crust. The Milan area is underlain by 600 to 700 feet of Pennsylvanian strata, which were deposited upon Mississippian carbonates. Samples from the H. V. Elwell No. 1 Taylor, NW NE sec. 12, T. 62 N., R. 21 W., suggest extensive leaching occurred in the upper 185 feet of Mississippian strata.

One interpretation of this structure is that the pipe was a hydrothermal discharge point. Solution of underlying Mississippian limestones allowed Pennsylvanian rocks to subside in the immediate vicinity of the pipe to form a small closed structural low. If hydrothermal fluids of sufficient temperature permeated the surrounding Pennsylvanian rocks, then the vicinity of this structure is a potential exploration target for unconventional gas derived from coal beds and carbonaceous shales.

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Oklahoma Coalbed Methane—From Mine Explosion to Gas Resource

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ABSTRACT

Methane emissions have been a hazard in underground coal mines in Oklahoma since before statehood. The development of coalbed methane (CBM) as a natural-gas resource began in Oklahoma in 1988, with methane production from the Hartshorne coalbeds (Hartshorne, Lower Hartshorne, and Upper Hartshorne; Middle Pennsylvanian) in the Arkoma Basin. Completions in the Mulky and Rowe coalbeds (Middle Pennsylvanian) on the Northeast Oklahoma Shelf began in 1994. By the end of April 1999, there were 691 CBM completions reported in Oklahoma, 282 in the basin and 409 on the shelf. The CBM completions, separated into the Northeast Oklahoma Shelf and the Arkoma Basin, are evaluated by coalbed, depth, initial potential gas rate, and initial produced water rate.

INTRODUCTION

Mine explosions from gas and dust caused more than 500 deaths in 19 major mining disasters in Oklahoma from 1885 to 1945 (Oklahoma Department of Mines, 1999). The U.S. Bureau of Mines conducted a series of studies from 1964 to 1980 to reduce underground coal-mine hazards and explosions (Deul and Kim, 1988). The knowledge gained from those studies has been applied to coalbed methane (CBM) development as an economic resource.

Commercial production of CBM in Oklahoma began in 1988 with methane production from the Hartshorne coal (depth range of 611–716 feet [186–218 m]; initial-potential gas rate per well of 41–45 thousand cubic feet of gas per day, MCFGPD) from seven wells in the Kinta anticline (sec. 27, T. 8 N., R. 20 E.) in Haskell County by Bear Production. Bear Production was the only CBM operator in Oklahoma until 1991.

The following discussion of Oklahoma CBM completions is based on information reported to the Oklahoma Corporation Commission and Osage Indian Agency. The names of coalbeds are as reported by the operator and may not conform to usage accepted by the Oklahoma Geological Survey. Because not all of the wells are reported as CBM gas wells, some interpretation was necessary. Dual completions, including coalbeds, were perforated in some wells. Therefore, not all of the wells are exclusively CBM completions. This summary is incomplete because some wells may not have been known to be CBM wells or were not reported by the time of this compilation. This evaluation is based on reported CBM completions, which may or may not have been connected to a gas pipeline. Likewise, some completions may have produced gas but since have been plugged.

The data for this report were compiled in the coalbed-methane completions table of the Oklahoma Coal Data Base. Each record (well completion) in the table includes the operator, well name, completion date, location information (township grid system and latitude-longitude), county, coalbed, producing-depth interval, initial potential gas and produced water rates, initial pressure rates, and comments. The database is available at the Oklahoma Geological Survey (OGS). A searchable version of the coalbed-methane completions table is available on the internet as a link from the OGS web site:

http://www.ou.edu/special/ogs-pttc/.

The coal field in eastern Oklahoma is divided into the Northeast Oklahoma Shelf and the Arkoma Basin (Fig. 1). The commercial coal belt contains coalbeds of mineable thickness (≥ 10 inches [25 cm] thick and < 100 feet [30 m] deep for surface mining); coalbeds in the noncommercial coal-bearing region are too thin, of low quality, or too deep for mining. CBM exploration has occurred in both areas. Coal rank ranges from high volatile bituminous on the shelf and western part of the Arkoma Basin to medium and low volatile bituminous in the eastern part of the Arkoma Basin in Oklahoma.

Through April 1999, there were 691 CBM completions reported in Oklahoma, 282 in the basin and 409 on the shelf (Fig. 2). The CBM play began in the basin in 1988, with a peak of 68 completions in 1992. There were three CBM completions on the shelf in 1994. In 1995, there were 21 completions in the basin and 41 completions on the shelf, signaling increased activity on the shelf. As of April 1999, there were 28 completions in the basin and 167 completions on the shelf reported in 1998.

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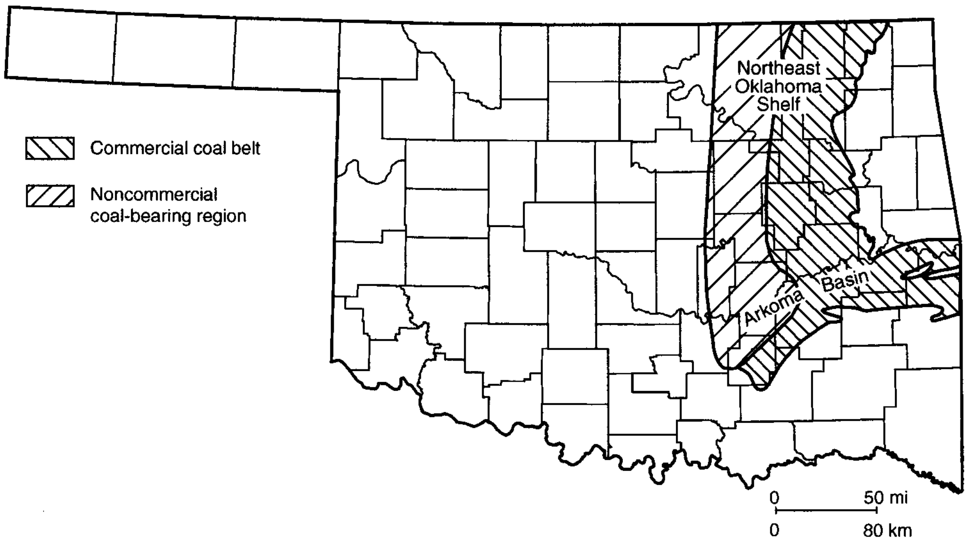

FIGURE 1—Map of Oklahoma coal field (modified from Friedman, 1974).

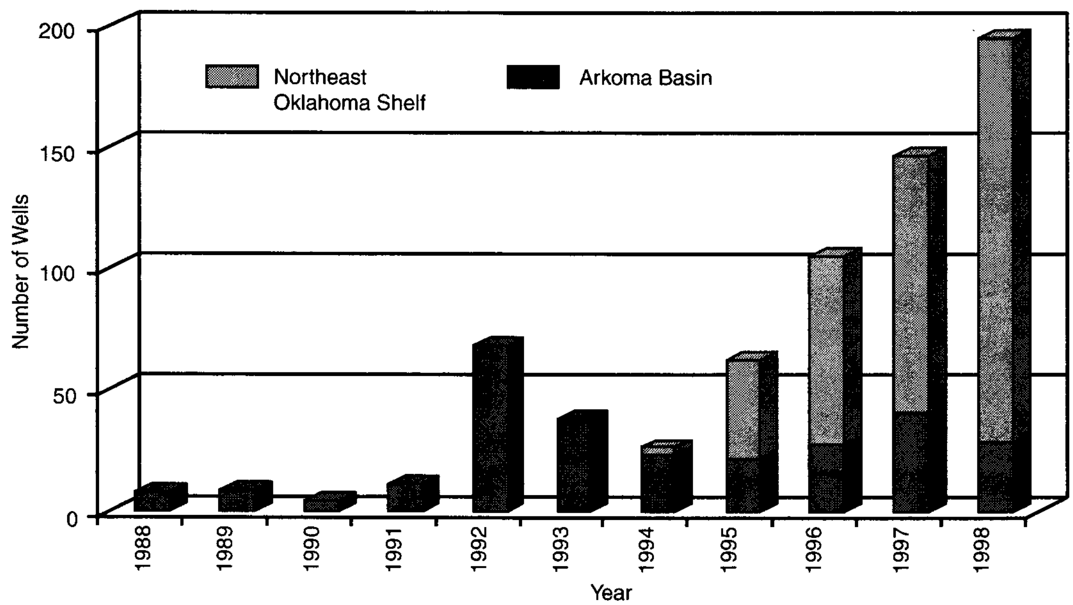

FIGURE 2—History of Oklahoma coalbed-methane completions.

NORTHEAST OKLAHOMA SHELF

Figure 3 shows the locations of 409 CBM completions on the shelf reported by 30 operators through April 1999. CBM completions on the shelf have been reported in Craig, Nowata, Osage, Rogers, Tulsa, and Washington counties. In ascending order, the coalbeds producing methane on the shelf are the Riverton (McAlester Formation), Rowe and Drywood (Savanna Formation), Bluejacket (Boggy Formation), and Weir–Pittsburg, Croweburg, Bevier, Iron Post, and Mulky (Senora Formation) in the Krebs Group of Desmoinesian (Middle Pennsylvanian) age (see Hemish, 1987, for nomenclature). The commercial coalbeds on the shelf are 0.8–5.0 feet (0.2–1.5 m) thick, average 2.0 feet (0.6 m) thick, and dip westward 1/2° to 2° (Friedman, 1999).

Figure 4 shows the depth range of CBM completions on the shelf. Coalbeds were perforated at depths-to-top of coal of 216–2,428 feet ([66–740 m]; average of 918 feet [280 m] from 408 wells). Most of the wells on the shelf are in the Mulky coal (217 wells, depth range of 216–1,430 feet [66–436 m]). The Mulky coal is the uppermost coalbed in the Senora Formation and occurs at the base of the Excello Shale Member (Hemish, 1987). The Mulky

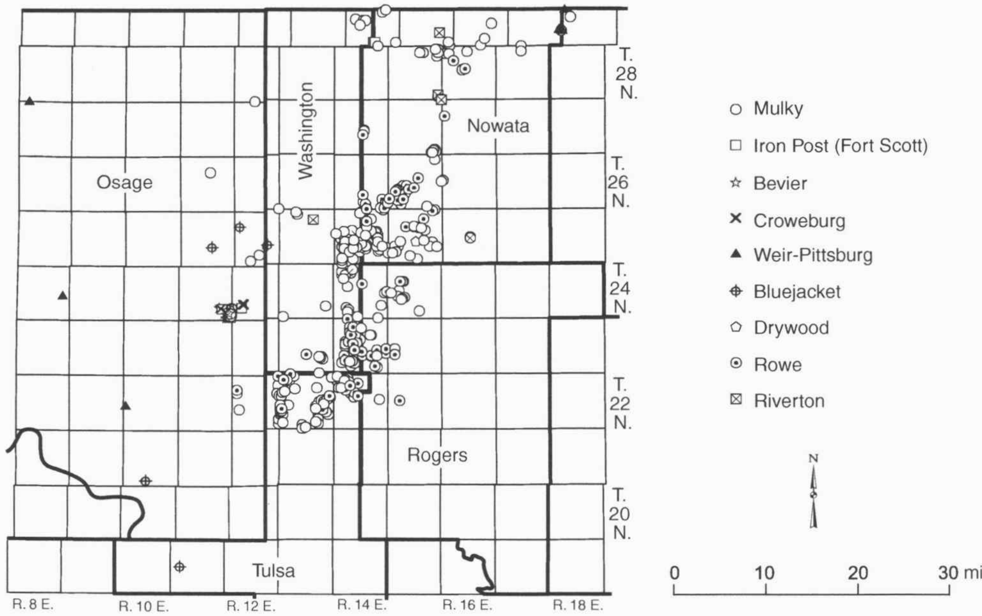

FIGURE 3—Map showing coalbed-methane completions on Northeast Oklahoma Shelf.

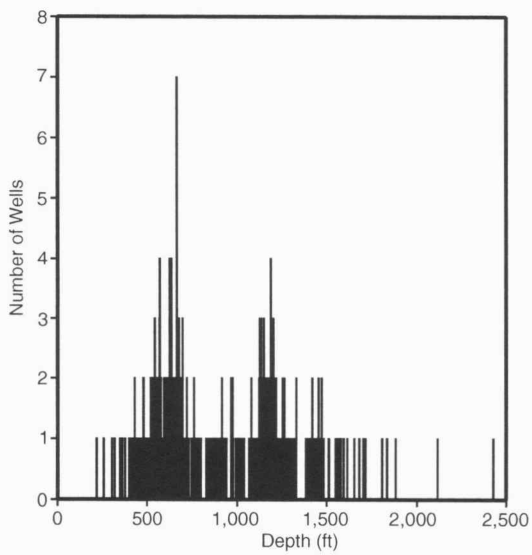

FIGURE 4—Histogram of coalbed-methane completions by depth on Northeast Oklahoma Shelf.

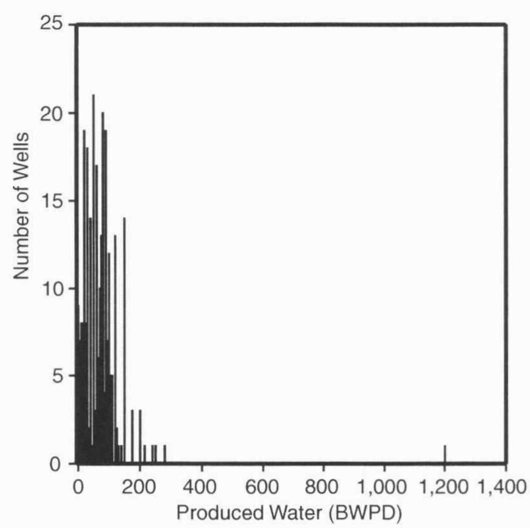

FIGURE 5—Histogram of coalbed-methane completions by initial potential gas rate on Northeast Oklahoma Shelf.

coal ranges from bituminous coal to carbonaceous shale with increasing amounts of mineral matter. The next most important CBM reservoir on the shelf is the Rowe coal (142 wells, depth range of 801–1,810 feet [244–552 m]). The deepest CBM completion on the shelf is in the Weir–Pittsburg coal in Osage County. There were 22 completions on the shelf that perforated more than one coalbed.

Initial-potential CBM rates for individual wells on the shelf range from a trace to 260 MCFGPD (average of 29 MCFGPD from 359 wells; Fig. 5). The Mulky coal ranges from a trace to 125 MCFGPD, and the Rowe coal ranges from 2 to 260 MCFGPD. The four wells on the shelf having the highest initial potential gas rates were from the Rowe coal in T. 25 N., R. 14 E. These four wells initially produced 130–260 MCFGPD and 30–90 barrels of water per day (BWPD) from depths of 1,136–1,190 feet (346–363 m). Typical production decline curves of eight wells in Nowata, Rogers, Tulsa, and Washington counties illustrate production histories for wells with initial potential rates of 7–60 MCFGPD and 12–120 BWPD. Following a period of three to twelve months of erratic production in some wells, production can stabilize at more than 1 million cubic feet of gas per month. The maximum monthly production for the eight wells selected is 4,664 MCFG, an average of 155 MCFGPD, attained 12 months after completion.

Initial produced water on the shelf ranged from 0 to 1,201 BWPD (average of 66 BWPD from 337 wells; Fig. 6). Most of the water is believed to be formation water and not water from fracture stimulation.

ARKOMA BASIN

Figure 7 shows the locations of 282 CBM completions in the basin reported by 27 operators through April 1999. CBM completions in the basin have been reported in Coal, Haskell, Hughes, Latimer, Le Flore, McIntosh, and Pittsburg counties. In ascending order, the coalbeds producing methane in the basin are the Hartshorne (undivided), Lower Hartshorne, and Upper Hartshorne (Hartshorne Formation), McAlester (McAlester Formation; a CBM completion in Coal County reported to be in the "Lehigh" coal is equivalent to the McAlester coal), "Savanna" (Cavanal coal?; Savanna Formation), and unnamed in the Krebs Group of Desmoinesian (Middle Pennsylvanian) age. Most (93%) of the CBM completions in the Arkoma Basin are from the Hartshorne coalbeds. The commercial coalbeds in the basin are 1–10 ft (0.3–3 m) thick and dip 3° to nearly vertical in eroded, narrow anticlines and broad synclines that trend northeastward (Friedman, 1999).

Figure 8 shows the depth range of CBM completions in the basin. Coalbeds were perforated at depths-to-top of coal of 598–3,726 ft ([182–1,136 m], average of 1,335 ft [407 m] from 277 wells). The deepest CBM completion in the basin is in the Hartshorne coal in Hughes County.

Initial-potential CBM rates for individual wells in the basin range from a trace to 595 MCFGPD (average of 72 MCFGPD from 234 wells; Fig. 9). Most (82%) of the wells produced 10–120 MCFGPD. The highest initial-

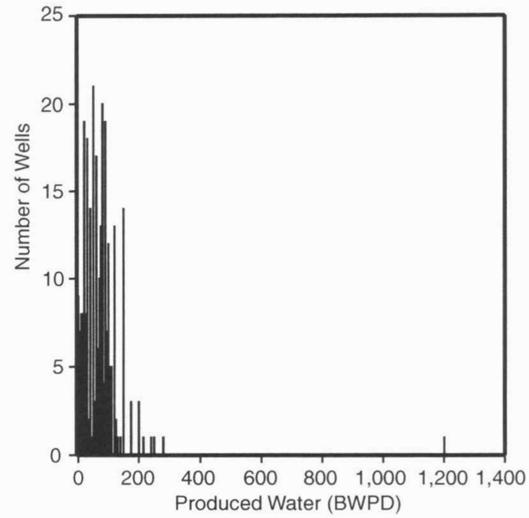

FIGURE 6—Histogram of coalbed-methane completions by produced water on Northeast Oklahoma Shelf.

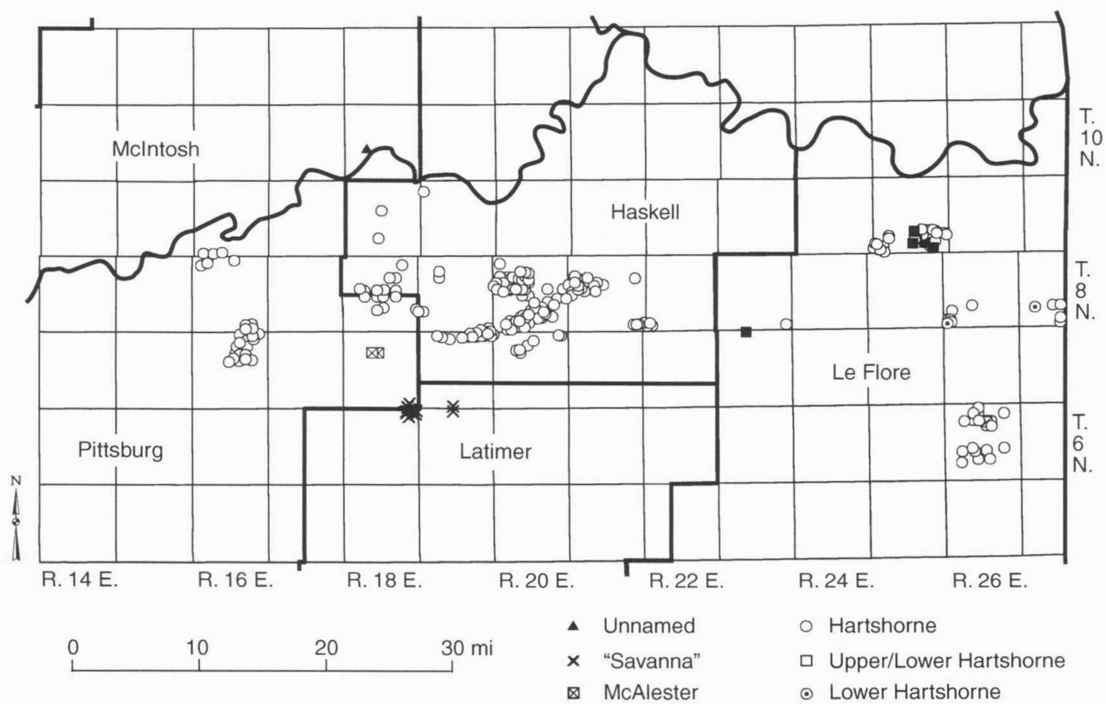

FIGURE 7—Map showing coalbed-methane completions in Arkoma Basin.

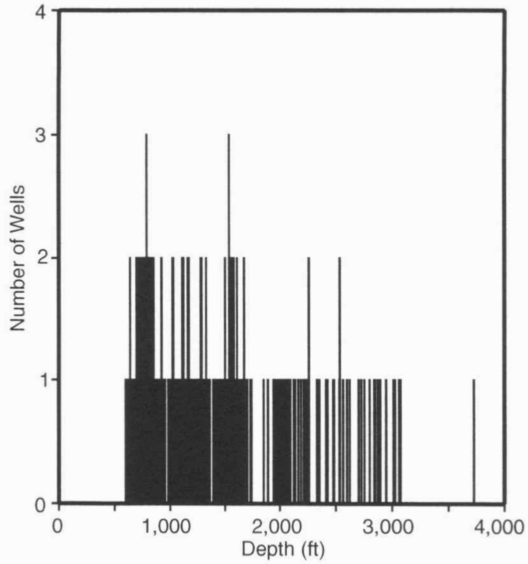

FIGURE 8—Histogram of coalbed-methane completions by depth in Arkoma Basin.

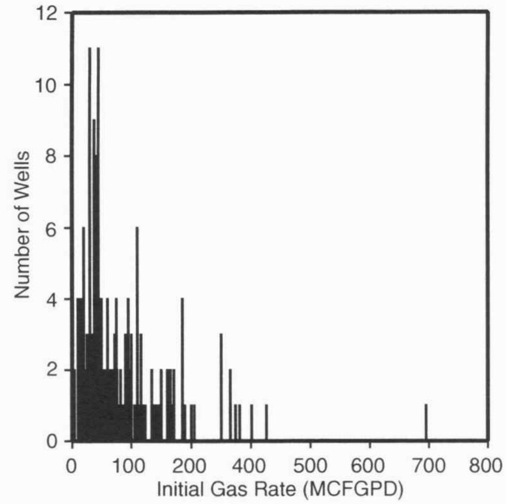

FIGURE 9—Histogram of coalbed-methane completions by initial potential gas rate in Arkoma Basin.

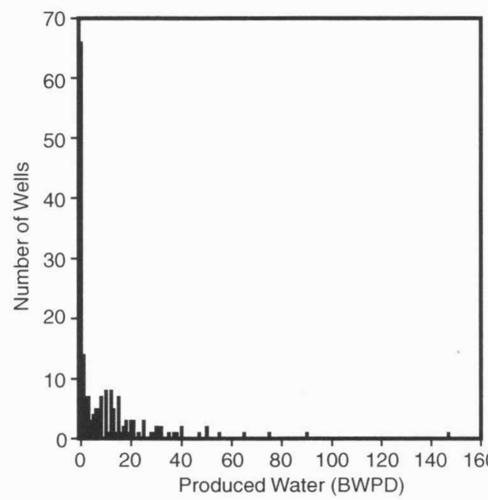

FIGURE 10—Histogram of coalbed-methane completions by produced water in Arkoma Basin.

potential gas rates are from the Hartshorne coal. The first horizontal CBM completion in Oklahoma was by Bear Production in August 1998. By the end of April 1999, there were nine horizontal CBM completions in Haskell, Le Flore, and Pittsburg counties reported by four operators. Initial-potential CBM rates were 80–595 MCFGPD.

Initial produced water in the basin ranged from 0 to 147 BWPD (average of 10 BWPD from 186 wells; Fig. 10). Most (83%) of the wells produced less than 20 BWPD. Most Arkoma Basin CBM completions are on the flanks of anticlines and have relatively little produced water. An undisclosed amount of initial water production is frac water (introduced during fracture stimulation).

A Hartshorne CBM field study in the Spiro Southeast gas field (T. 9 N., R. 25 E.) indicated "The average daily gas production per well ranged from 6 to 127 MCFGPD, with an average of 50 MCFGPD. Gas production from all 28 wells was about 1,400 MCFGPD...Cumulative gas production from September 1994 through March 1998 was 1,178,372 MCF." (Andrews, Cardott, and Storm, 1998, p. 62). Production-decline curves for six wells showed the effects of restimulation (using freshwater and sand) and servicing the water pump. The best well had a peak of 6,631 MCFG in the fifth month of production.

CONCLUSIONS

The Oklahoma CBM play began in the Arkoma Basin in 1988. The play spread to the Northeast Oklahoma Shelf in 1994. Through April 1999, there were 691 CBM completions reported in Oklahoma, 282 in the basin and 409 on the shelf. There were nearly 50% more completions on the shelf than in the basin. The primary CBM objectives were the Hartshorne coals in the basin and the Mulky and Rowe coals on the shelf. There were nearly 50% more completions in the Mulky coal than in the Rowe coal.

The range in depth of the CBM completions was 216–2,428 feet ([66–740 m], average of 918 feet [280 m] from 408 wells) on the shelf, and 598–3,726 feet ([182–1,136 m], average of 1,335 feet [407 m] from 277 wells) in the basin.

Initial-potential gas rates range from a trace to 260 MCFGPD (average of 29 MCFGPD from 359 wells) on the shelf, and a trace to 595 MCFGPD (average of 72 MCFGPD from 234 wells) in the basin. The maximum initial gas rate was from a horizontal well in the Hartshorne coal in Haskell County at a true vertical depth of 824 feet (251 m).

Produced water ranged from 0 to 1,201 BWPD (average of 66 BWPD from 337 wells) on the shelf, and from 0 to 147 BWPD (average of 10 BWPD from 186 wells) in the basin.

Low initial gas rates and minimal initial increase in gas production during dewatering may be attributed to formation damage caused by well stimulation, including the generation of coal fines that plug permeability. Present industry emphasis is on matching the completion technique to the specific coalbed.

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Coal Geology and Underground-Mine Degasification Applied to Horizontal Drilling for Coalbed Methane

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In eastern Oklahoma's Arkoma Basin in 1998 at least three energy companies drilled coalbed methane wells 700–2,000 feet deep that eventually penetrated 700–800 feet horizontally into the 4–6-foot-thick Hartshorne coal, but also drilled through shale, mudstone, and interlaminated shale and sandstone. Those well segments in shale and mudstone may collapse, leading to well abandonment. Obviously coal will not be penetrated if the bit drifts into strata overlying or underlying the coalbed. Coal may be missing if the bit intersects a normal fault, a thick noncoal parting, or a channel-fill sandstone.

Coal geology studies, including coal characterization before drilling begins, should help in lease selection and to hold down costs. Also data should be tabulated and maps constructed showing net coalbed thickness, cleat frequency and orientation, coalbed structural contours, faults and secondary coal fractures, cleat-filling minerals, coal-rank isocarbs, inherent moisture, vitrinite reflectance, and lithology of strata overlying or underlying the coalbed. Most of these items, in addition to the laws of gas movement, affect or control the permeability and porosity of the coalbed methane reservoir and the flow of gas to the well.

Twenty-three horizontal, openhole, experimental boreholes, 300–2,200 feet long, were drilled by a coal company into the 4-ft-thick Hartshorne coal in an underground mine in Oklahoma in the middle 1970's, removing great quantities of 97% methane gas without hydraulic fracturing.

Therefore, detailed geological evaluation, combined with information from the history of horizontal drilling to drain gas from coal beds in underground mines, should be applied to maximize success in coalbed methane drilling, production, and profit.

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An Economic Evaluation of the Hartshorne Coalbed Methane Play in Oklahoma

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The effort to produce coalbed methane (CBM) from the Hartshorne coal in the Arkoma Basin of Oklahoma may or may not make economic sense. Geologic, technical, and serendipitous factors must be matched to have a profitable CBM well.

CBM production in Oklahoma began in 1926 with documented production in Pittsburgh and Haskell counties. Modern CBM production as a result of concerted efforts began in 1988 at the Kinta anticline in Haskell County. Since then, more than 250 wells have tested the profitability of Hartshorne CBM production. Some of the best wells have produced at rates in excess of 200 MCFGPD for more than a year. Rates of 25 to 75 MCFGPD are more usual. The effort at the Kinta anticline has been a commercial success; however, certain unique attributes of the coal and the operator, Bear Productions, Inc., were present. Since 1988, Bear Productions has produced in excess of 4 BCFG from 54 wells with current production in excess of 1,000 MCFGPD. The more recent CBM projects probably are in the process of "paying out" with a distinction drawn between projects (multisection, multiwells) and "hit and miss" efforts (perforating the coal when a good show is observed). In 1998 for the first time in Oklahoma, a few horizontal holes have been drilled into the Hartshorne coal with some good and some poor results. Horizontal drilling may be the future of Oklahoma CBM.

The Arkoma Basin's ample endowment of CBM resources has attracted an initial investment. Has "scratching the surface" determined it is wise to "plunge in?"

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Coal Resources and Coalbed Methane Potential in the Kansas Portion of the Forest City Basin

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Within the Kansas portion of the Forest City Basin is an estimated 16.4 billion tons (14.9 billion metric tons) of coal that is present deeper than 100 feet (30 m) below the surface. Of this amount, 14.3 billion tons (13.0 billion metric tons) is from coals within the Cherokee Group (Middle Pennsylvanian). These resource quantities were determined from 27 coalbeds with 23 of the coals within the Cherokee Group. Resource amounts were determined for coals 14 inches (35 cm) or greater in thickness. Apparent rank of the coals is generally high-volatile B bituminous. Of primary concern for methane development is the thin [<2 feet (0.6 m)] occurrence of most coalbeds in the basin.

A continuous core taken in east-central Leavenworth County (sec. 35, T. 9 S., R. 22 E.) penetrated 13 coalbeds within the depth interval from 721 to 1,164 feet (220–355 m) for a total thickness of 11.5 feet (3.5 m) of coal. Within the Cherokee Group interval of 721–1,130 feet (220–344 m), there are 11 coals present with a total coal thickness of 10.9 feet (3.3 m). The Riverton coal at 2.1 feet (64 cm) thick is the thickest coal in that core. Apparent rank of the Riverton coal is high-volatile B bituminous, and two samples show vitrinite-reflectance values of R_o max = 0.53 and 0.56.

Review of geophysical logs from areas of the Forest City Basin in Kansas indicate that multiple coalbeds are widespread throughout the basin, but generally are thin. Preliminary investigations indicate there are a few areas in the basin where the coalbed thickness exceeds 42 inches (107 cm). Additional study and exploration effort is needed to determine if economic quantities of coalbed methane exist in the basin.

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Environmental Geology
(Session B)

Evaporite Karst in the Southern Midcontinent

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Evaporites are the most soluble of sedimentary rocks; they are dissolved readily to form the same karst features that typically occur in limestones and dolomites. Evaporites, including gypsum (or anhydrite) and salt, are present in 32 of the 48 contiguous states, and they underlie 35–40% of the land area. They underlie western Kansas, western Oklahoma, the Texas Panhandle, and eastern New Mexico and Colorado, and locally can be a serious problem to petroleum exploration and development. In areas where gypsum crops out (or is less than 30 m deep), or where rock salt is less than 250 m deep, evaporites may be dissolved partly or wholly by unsaturated water. Evaporite outcrops typically contain sinkholes, caves, disappearing streams, and springs. Other evidence of evaporite karst includes surface-collapse features, saline springs, and saline plumes as a result of salt dissolution. Many evaporites in the deep subsurface also contain remains of paleokarst; such as dissolution breccias, breccia pipes, slumped beds, and collapse structures.

Human activities also have caused development of evaporite karst, primarily in salt deposits. Boreholes or underground mines may enable (either intentionally or inadvertently) unsaturated water to flow through or against salt deposits, thus allowing development of small to large dissolution cavities. If the dissolution cavity is large enough and shallow enough, successive roof failures can cause land subsidence or catastrophic collapse. At least 30 sites in the United States have reported land subsidence or collapse because of human-induced salt karst. Among these sites are Cargill and Panning sinks in Kansas, Wink sink in West Texas, and other sites in the southern Midcontinent. Evaporite karst, both natural and human-induced, is far more prevalent than generally believed.

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Compliance with Oil and Gas Environmental Regulations During Periods of Low Oil Prices

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ABSTRACT

Compliance with production related environmental regulations is required regardless of the quantity of production or the price and represents a constant cost to the operator. Many operators include the cost of complying with environmental regulations as an increment of operating and maintenance. This method, although practical, does not set out the cost of environmental regulatory compliance. Regulations which require submission of applications for obtaining permits or reports for monitoring operator compliance can be budgeted as a part of the annual operations plan or drilling program. Unexpected events such as spills, uncontrolled formation pressures, and well failures during production represent unplanned costs which may devastate the financial resources of the operator, particularly if the operator has not set aside contingency funds to address the "average special situation."

Fines and penalties for noncompliance with State and Federal environmental regulations are unnecessary costs and provide no benefit to the operator in correcting an environmental situation. In most situations, a strong line of communication between the operator and the State regulatory agency limits the cost of environmental compliance to necessary activities. Regulatory agencies usually are willing to work with operators to solve environmental situations which are complex technically and costly to rectify. These situations are less costly if the regulatory agency becomes aware of the situation through notification by the operator rather than through routine inspection. Regulators have basis for the assumption that environmental problems increase with a prolonged period of low oil prices.

INTRODUCTION

Lawmakers in several oil- and gas-producing states currently are considering legislation that is directed toward easing the economic plight of the U.S. oil and gas operator during periods of low oil prices. Some of these legislative initiatives have come in the form of tax credits for gas or oil production; others have been directed toward reducing, in some instances, repealing statutes authorizing State severance and ad valorem taxes. At the Federal level, the Department of Interior (DOI) recently has instituted a program to allow operators of marginal wells on public lands to suspend operations for up to two years without losing their leases or until the price of West Texas intermediate crude oil reaches or exceeds $15 per barrel for 90 consecutive days. The 1998 depression in oil prices coupled with the ever-present uncertainty for the length of time before a substantial recovery period might occur, if, in fact, it ever occurs before a majority of independent operators with marginal oil production become insolvent, is a question which will be answered only by time.

Operators are expected to comply with State and Federal oil-field-related environmental-protection regulations regardless of the economic status of the lease or the industry in general. In 1999, the Oklahoma legislature, at the request of the Governor, passed a moratorium on plugging wells unless such wells are deemed to be an imminent cause of environmental or water-quality degradation. Kansas, by Kansas Corporation Commission order, has instituted a similar program for reporting temporarily abandoned wells, providing certain predetermined conditions have been met. Although these random acts of sensitivity to a serious industry situation may provide relief to some operators, the general body of environmental State and Federal strictures remain intact. They represent a consistent cost to the operator and influence both exploration and production decisions. The Environmental Protection Agency (EPA) has shown no signs of relaxing or waiving lesser important environmental regulations solely because the operators of marginal production may be financially unable to fulfill some compliance obligations. EPA, in fact, continues to "refine" longstanding regulations toward a stricter mode and, in spite of the Paper Reduction Act and the economic situation, is looking at new Toxic Release Reporting requirements.

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EVOLUTION AND DISPOSITION OF ENVIRONMENTAL REGULATIONS

Congress has shown little interest in repealing or amending stricter Federal environmental laws when they come up for reauthorization to accommodate the economic status of any industry, including the petroleum industry, both upstream and downstream. The primary reason for this lack of interest is because a dichotomy of philosophy exists between those Congressional members genuinely concerned about the decline of environmental resources and those concerned with the economy of any business and industry. Beginning with the 1972 Federal Water Pollution Control Act (FWPCA) and continuing through the 1990 Oil Pollution Prevention Act (OPPA), Congressional sponsors of environmental legislation were either from states with little or no oil or gas production, or in the situation of California, from areas having an acute overriding sense of environmental awareness. With the exception of California, Texas, Ohio, and Louisiana, most oil and gas is produced in lesser populated states and in the rural areas of those states with a greater population.

Congress passed most environmental laws as a result of constituent concerns over a particular national or international environmental or human-resource disaster such as the Exxon Valdez or Love Canal. In all examples, legislation was thought to be a panacea to thwart a recurrence of the disaster. Congress knew there would be some financial effect on other industries which had not the caused the specific disaster providing the impetus for the legislation. However, no guarantee was made that these industries might not be involved in future environmental insults if their operations remained unregulated. A prime example of Congressional overreaction is the Oil Pollution Prevention Act of 1990 which was crafted to prevent another Exxon Valdez but established onerous liability-insurance requirements for every producing lease in the United States which was located in the drainage of any intermittent tributary to a flowing stream, including road ditches. The producers of inland leases were drawn into the web because OPPA used the definition of "navigable stream" from the Clean Water Act Amendments of 1977 to define the scope of compliance. Of particular interest was that OPPA '90 passed the Senate 100–0 which meant that not even senators from oil-producing states understood how the EPA and Coast Guard regulators would interpret the law during implementation. This flaw was somewhat corrected in amending legislation in 1996, but represents a concern to the portion of the environmental community which been involved in oil and gas environmental issues.

Another example is the 1986 amendments to Superfund (SARA) which established the Community Right-to-Know Act (EPCRA) under Title III. This measure started out to prevent an occurrence of the Bhopal chemical disaster in the United States and was drafted under the premise that local communities have a right to know the nature and quantities of toxic substances transported and stored within their jurisdiction so they could develop appropriate emergency evacuation plans and proper training exercises to provide first-line response to the release of hazardous substances. EPA and State agencies administering regulations under this law have interpreted "toxic and hazardous substances" to include stored crude oil and saltwater. Operators now have to report how much crude oil is stored in tanks on the lease and subsequently are required to report any spillage of crude oil from the facility to both the State regulatory agency and the National Response Center (NRC) in Washington, D.C.

A detailed litany of how oil-field related environmental laws are passed in the United States is not the purpose of this paper. The complex nature of the laws, however, which collectively exact compliance and liability for past and present pollution from an oil and gas operator is part of the conundrum faced by each operator during normal economic times and is amplified when depression occurs. Financial resources and industry infrastructure both reach a point where proper and timely response to environmental compliance is not always possible.

OIL PRICES VERSUS ENVIRONMENTAL COMPLIANCE

The philosophy behind most environmental regulations, particularly those which address spill cleanup and remediation of pollution to environmental or water resources, is that the polluter pays. In reference to the cost of plugging abandoned wells, past operators, at the election of the Federal or State administrative body, may be drawn into the web of responsibility along with the current operator of the lease. Regulatory agencies, with some historical basis, assume that as oil prices go down, the operator's remaining financial resources will be directed toward loan payments, debt obligations, and keeping the wells in operation rather than providing the level of lease maintenance necessary to detect early signs of equipment or facility design failure which could magnify and result in a major environmental problem (i.e., line seeps, pump leaks or corrosion, or erosion of emergency collection facilities). Historical evidence dating back to the 1960's supports this contention because every low oil-price period has added abandoned wells and unfilled pits to the state heritage. One of the primary tenets of oil-lease management is that the cost of compliance with environmental regulations is basically a constant and is not guided by the price of oil. Kansas, for example, has a working inventory of approximately 10,000 abandoned wells for the last several years. Even though the 1996 Kansas Legislature authorized increasing the plugging fund four times, the number of wells discovered to be abandoned equals or exceed the number plugged by the Commission (State).

Operators of marginal oil properties can take several actions to maintain reasonable compliance with regulations and to avoid escalation of noncompliance conditions into the more expensive, less productive enforcement arena where penalties, fines, lease shut down orders, license suspension or revocation, and felony charges are options available to the regulatory agency to address noncompliance. Few of these actions have any geologic or technical facets which would require the operator to utilize the services of professional personnel; most are based on good common sense.

(1) Make an inventory of permits on record in the operator's office and determine if these permits have been transferred from a previous operator with the knowledge and approval of the regulatory agency. For the last 20 years, almost every environmental protection facility used on the lease has required a permit or some type of approval from the regulatory body. The best practice is to assume a permit is needed unless the regulatory agency informs otherwise. It is not an expensive proposition to contact the regulatory body's office to determine if these permits have been transferred by the previous lease operator or whether the transfer is the new operator's responsibility. An operator who does not know what is under his or her control is asking for noncompliance determinations by the regulatory agency.

(2) Maintaining *extremely* positive communication levels with the landowner (lessee) and the resident tenant at all times is an effort which pays off in times of low oil prices. The latter may have nothing to gain from the presence of oil reserves under the property because he or she derives no royalty income. In many instances, all routine operator payments for land damage, road use, or disposal-well use, goes to the landowner and are not shared subsequently with the tenant whose income is dependent on the crops or soil resources which were damaged. Landowners and tenants both use the complaint process to force an operator of a marginal producing lease to plug the wells and abandon the lease. This behavior, unfortunately, is becoming more frequent with each passing year and usually occurs after communication between the operator's field representative and the landowner or, in some situations, the tenant, ceased to exist or reached uncivil levels. The operator may have allowed an accumulation of little problems to become big ones for the duration of the lease and these problems did not prove nettlesome enough to take action until the production and associated royalty payments declined to the point where the worth of the land exceeds the worth of the royalty income from oil.

(3) Each operator must know the conditions of the lease agreement and how long production may be shut down before the landowner can declare the lease no longer valid because the wells are not producing "in paying quantities." In times of low oil prices, most marginal leases are not producing in paying quantities even when in active production. The operator should seek written agreement from the lessee (landowner) to allow wells to be shut down for periods exceeding sixty (60) days (old standard lease agreements) or for periods acceptable to the State regulatory agency without threat of lease forfeiture so long as all facilities on the lease are maintained in an environmentally safe manner. Under many of the older lease agreements, lease forfeiture may be caused even though the operator has filed all necessary paperwork with the regulatory agency and received approval to place the wells in temporarily abandoned status for a year. The operator also is responsible for resolving any environmental problems which occur during the shut-down period and may be held liable by the State for cleanup of pollution which occurs or is discovered even after the landowner has elected to exercise forfeiture action.

(4) Maintaining a credible relationship with the State oil and gas regulatory agency is extremely important. During periods of low oil prices, the operators cannot afford to lose allies. The regulators can be either cooperative or adversarial depending upon their past dealings with the operator. Regulators are not allowed to waive rules derived from statutory mandates which would favor one operator to another, even in times of industry depression. This would create unfairness and an "unlevel playing field." The regulators, however, may be able to allow time extensions for an operator to fix a potential environmental problem if they are comfortable with the operator's past performance. Actions that erode this level of trust and reduce options available include:

- *Historically falsifying lease conditions to field inspectors*. Field inspectors have to be able to explain to both superiors and landowners what conditions are problems and which are not. When the operator's representatives try to cover up conditions that could lead to environmental damage, the regulator has little sympathy to offer when that problem becomes more serious and is reported by the landowner or by a legislator. This particularly applies for downhole conditions where the evidence of an incipient problem or the quality of a repair job is not apparent to the State inspector.
- *Responding to all written notices from the regulators within the time indicated in the correspondence.* Failure to respond may escalate to the point where a penalty or fine is assessed. When the operator is operating on a marginal financial situation, payment of fines for noncompliance and nonresponsiveness or

attorney fees to appeal the sanctions through the hearing process is more expensive than a phone call or a letter to the regulator explaining the situation.

When an agreement is reached with the regulators to address an environmental problem or perform a well-plugging program in accordance with a schedule geared to the financial situation, the operator must carry out the prescibed work in accordance with the schedule. If extenuating circumstances develop which make it impossible to complete the task, the operator should notify the regulators to negotiate a new agreement to remain in compliance. The worst-possible option is to do nothing and fail to inform the regulatory body of any changing situation.

GEOLOGIC APPLICATIONS IN ENVIRONMENTAL REGULATIONS

Until the last few years, petroleum geologists employed by independent oil companies primarily directed their pursuits to finding oil and gas reservoirs. Hydrogeologists and hydrologists from State environmental regulatory bodies, geological surveys, and water-planning agencies generally were responsible for developing the groundwater protection standards for the drilling and completion of exploratory holes and producing wells. This separation of duties created a situation whereby the petroleum geologists and hydrogeologists both studied and evaluated an interval of the stratigraphic regime penetrated by a drilled hole; however, the twain seldom met and neither had the opportunity to develop a holistic understanding of the hole. One of the few benefits of periodic low oil prices, other than the economic euphoria experienced by the consumer at the pump, was that some petroleum geologists who had worked previously for independent oil operators and had not determined it necessary to become familiar with the nonproductive water-bearing upper intervals, discovered a new stratigraphic and hydrogeologic environment if they went to work for the State oil and gas regulatory agency or a geological survey.

In a similar sense, hydrologists who knew little or perhaps were not concerned about the economics of the oil- and gas-producing business were forced to consider principles of oil and gas conservation so that water-protection standards were established realistically and did not become so restrictive as to create an unnecessary economic burden to the exploration and production of oil and gas. The environmental community always has held the philosophical view that redundant layers of protection are needed to avoid singular catastrophic events (casing collapse, upward migration of saline waters, etc.) and the incurred expense of extra protection and the health of the industry is a secondary consideration.

The developers of oil and gas regulations in the 1940's and 1950's recognized the need to isolate producing intervals from being flooded by the downward migration of both saline and fresh groundwater. Geologic standards were and are used to establish the base of fresh and usable water resources for each geographical and geological area of a state or regional area. Casing and cementing programs designed under these standards serve both the need for petroleum conservation and water protection. In this sense, the petroleum industry has been technologically far ahead of other industries in the proper use of geologic criteria to form standards.

Since the 1970's, the use of geologic and engineering methods and practices has been secondary in the development of environmental policy at both the Federal and State level. After the environmental community became actively involved in the enactment of environmental laws during the 1970–1980 period, scientific parameters were replaced somewhat by legal and administrative procedures and measurements as the primary tests for achieving operator compliance. For example, the evidence that an application for an oil-field brine-injection well had been offered for public hearing by proper notification became more important than the actual technical merits of the proposal. This philosophy now has been institutionalized to the extent that except for a scaling back of certain unnecessary monitoring and reporting requirements, the body of environmental law and regulation will not be changed in response to either general regulatory reform or devastating economic downturns of the "upstream" petroleum industry. Operators who have instituted computerization into their business and reporting procedures will benefit because regulatory agencies are increasingly more receptive to automated or electronically transferred documents for proof of compliance.

CONCLUSIONS

The observations included in this paper represent the author's 36 years of experience as both a staff person and director of Kansas oil and gas regulatory programs. Between 1935 and 1986, Kansas had a unique sharing of regulatory responsibility between the environmental and oil and gas conservation agencies. These observations, therefore, are presented from the point of view of having had to deal with at least four major economic declines while administering oil and gas programs. One frustration experienced by regulators who are trying to achieve operator compliance at times when industry financing is marginal is the inability of the petroleum producers to provide valid data on how much a particular major environmental regulation costs. Such activities such as testing injection wells for mechanical integrity, maintaining emergency spill-containment facilities, and routine spill cleanup are generally included within the operating-expense budget and are not easily broken out into costs of individual requirements. Consequently, when petroleum associations and individual operators claim that the high cost of environmental regulation is forcing them to shut down production or prematurely plug wells or abandon leases, the regulators have little information to verify or contradict those claims when faced with having to legislatively address the concerns.

Any operator who intends to continue producing into the 21st century will learn the environmental costs to be a constant part of business which primarily is independent of oil price. As a routine procedure, the prudent operator should take advantage of the upswings to set aside dedicated contingency funding for addressing major environmental problems should they occur. Oil-spill cleanup, downhole corrective action where casing collapse has occurred, and remediation of ground water where saltwater contamination has resulted from an unexpected line leak are examples of costly situations for which compliance is expected.

Halophyte Remediation of Brine-Impacted Oil and Gas Sites in Kansas

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In the Midcontinent, historical oil-producing practices have been responsible for patches of bare, sterile soil that cannot support crops or indigenous weeds. Such land may be severely eroded. Usual practice has involved excavation of impacted soil and removal to a public landfill site. "Dig and haul" activity is expensive and is not sustainable in the long run; there are too many brine-impacted sites.

Brine-impacted soil can be remediated in situ by calcium substitution for sodium in the clay mineral matrix. Gypsum is applied to the surface, causing sodium to leach into deeper strata below the root zone. However, brine-impacted soils also have low permeability. Remediation can be enhanced by planting salt-tolerant species (halophytes) that increase vertical permeability by rooting action and actually draw salt out of the root zone and fix it in their leaves and stems.

CH2M HILL is teaming with the Kansas Corporation Commission and the Kansas Biological Survey to remediate an orphan water-flood site. The Leon oil field covered approximately 400 acres in southwestern Butler County and operated for many years under primary production and water flood. The field has approximately 8 acres sterilized by spills of brine as well as tank bottoms. The impacted areas are being treated with several halophyte cultivars and soil additives. By the end of the growing season, the Kansas Corporation Commission will have determined which halophytes are best suited to conditions in Kansas and will distribute a handbook for best management practices in remediating brine-impacted soil.

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ZOEI, a Computer Model to Calculate the Zone of Endangering Influence of Class 11 Injection Wells

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Abandoned or improperly plugged oil and gas wells can constitute an endangerment to underground sources of drinking water by acting as conduits for injected or formation fluids to enter shallow groundwater aquifers. Area of Review is the collation of plugging and well construction details for all boreholes within a specific radius of an injection well. Typically the required radius is one-quarter mile around the injection well, but it can be calculated from site specific data as the "zone of endangering influence" with a modified Theis equation defined in US EPA regulations.

CH2MHILL developed the ZOEI computer model for the Underground Injection Control Department of the Kansas Corporation Commission, which calculates and graphically plots the pressure and head differences between groundwater aquifers and the injection zone after a predicted period of injection. The ZOEI program was constructed to address requirements of Federal regulation through the calculation of the zone of endangering influence.

The Kansas Corporation Commission utilizes the ZOEI program for the protection of the State's groundwater resources as part of its Class 11 injection well approval process. Data elements, model limitations, conclusions, and recommended use of zone of endangering influence in the Kansas Class 11 injection program demonstrate the usefulness of the model and its ability to save operators and the KCC time and money.

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Interdisciplinary Studies

Kansas Geological Survey's New Initiative in the Manhattan 1° × 2° Quadrangle, Northeastern Kansas

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ABSTRACT

Because of its geologic association with the 1.1 billion-year-old Midcontinent Rift, the area encompassing the largely unexplored Manhattan 1° x 2° Quadrangle, has the potential to host major ore deposits and possible hydrocarbon accumulations. Depth to the Precambrian basement ranges from about 700 feet in the northeast on top of the Nemaha Uplift, the shallowest in all of Kansas, to more than 4,000 feet in the southwest in the deeper parts of the Salina Basin.

The aim of the 4-year-long multidisciplinary study is to map the geology and assess the resources of the area. New geologic maps, reevaluation of existing maps, and digital compilation of geologic information for all parts of the 17 counties located within the quadrangle is a major component. Surface and subsurface structural studies, paying particular attention to neotectonism in the large area underlain by younger glacial materials is another important aspect. Reevaluation of existing and new aeromagnetic and gravity data as well as geochemistry of available Precambrian rock samples is an integral part of this study. The results of these studies will be used to evaluate the mineral and resource potential and to identify areas that may be favorable for future exploration of new resources.

All digital information obtained or developed during the course of this project will be available on the Internet as well as in project reports and publications.

INTRODUCTION

The Manhattan 1° × 2° Quadrangle, located between 96° and 98° west longitude and 39° and 40° north latitude, in north-central Kansas (Fig. 1) adjoins the Nebraska border to the north. Seven entire counties, including Republic, Washington, Marshall, Pottawatomie, Riley, Clay, and Cloud, and parts of 10 other counties make up the quadrangle's 18,740 square kilometers (7,236 square miles).

This project was conceived first about 17 years ago when the CUSMAP (Conterminous United States Mineral-Resource Assessment) program was an important and successful interdisciplinary effort between the U.S. Geological Survey and the state geological surveys to assess the mineral potential of 1° × 2° quadrangles. At that time the Joplin quadrangle, situated in southwestern Missouri and southeastern Kansas, was selected for two primary reasons. One was that it provided for continuity with assessments going on in the Rolla and Springfield quadrangles to the east. Secondly, in our quest to better understand the genesis of Mississippi Valley lead-zinc deposits in both the Rolla and Joplin quadrangles, in which there was a lot of interest in those days, new data for that area were deemed important.

This initiative is a major new, four-year program, entitled: "Geology and Resource Studies in the Manhattan 1° × 2° Quadrangle." Utilizing existing data and initiating new studies where needed, the main purposes of the multidisciplinary study are (1) to produce geologic maps at a common scale for all counties in the area; (2) to assess the potential mineral and energy resources; and (3) to put all the information in digital format for easy access for anyone needing information about the quadrangle.

Two counties presently have no geologic map coverage. Geologic maps for most of the other counties are either out-of-print or have not been mapped in sufficient detail. As part of the mapping effort, structural and lineament studies will be conducted with particular attention being paid to those areas where major known subsurface faults occur. Neotectonic studies in the large area underlain by younger glacial materials are an important aspect of the structural investigations. In addition the study will address issues related to slope stability and subsidence.

Information about certain industrial mineral resources in the quadrangle are given in publications of the Kansas Department of Transportation, Material Inventory Reports (construction materials), and other publications cited in Table 1. This information will be updated and augmented with new information on resources not covered in the publications.

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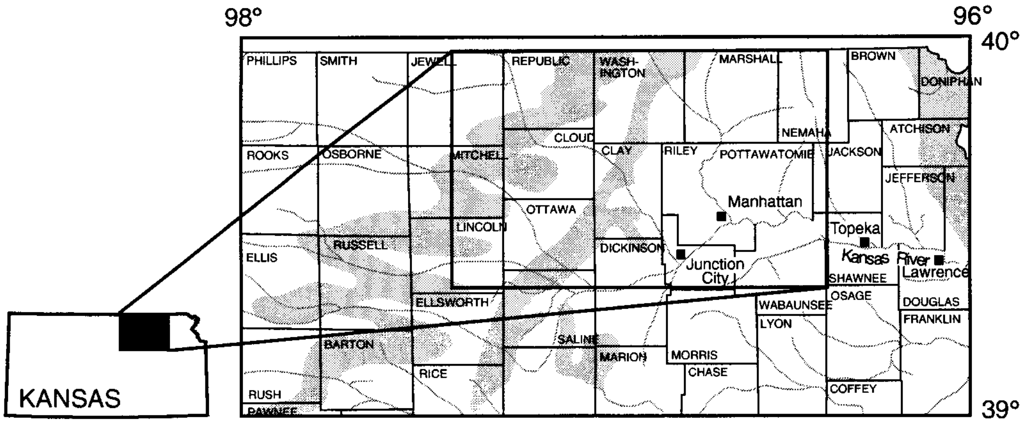

FIGURE 1—Index map showing location of Manhattan Quadrangle. Landslide risk is moderate in shaded areas

New and existing aeromagnetic and gravity data, together with data that will be collected as part of this study, will allow us to study the known kimberlites as well as evaluate other potential kimberlite intrusives and deeper buried potential resources.

Geochemical studies on available Precambrian rock samples is another aspect of work planned to evaluate deeply buried resources.

All maps will be digitized and other data will be stored in computer databases available to the public. Results obtained during the course of various phases of this project will become available as formal publications, open-file reports, and on the Kansas Geological Survey web site.

Rationale

Reasons to study the geology and resources of the Manhattan Quadrangle are manifold.

•The quadrangle mainly is unexplored and because of its geology potentially can host major ore deposits and possibly hydrocarbon accumulations.
•Depth to the Precambrian basement in the quadrangle is the shallowest in all of Kansas, at 700 feet below the surface in Nemaha County on top of the Nemaha Uplift.
•The geology is associated with the 1.1-billion-year-old Midcontinent Rift System, a major continental rift extending from the Canadian border near Thunder Bay, through Minnesota, Michigan, Wisconsin, Iowa, and Nebraska into southern Kansas.
•In the United States and elsewhere in the world, major metallic ore deposits are associated with rifts.
•Thick packages of Precambrian sedimentary rocks deposited in the rift may contain significant accumulations of hydrocarbons.
•Ten kimberlite bodies are known to occur in the quadrangle, some of which have been evaluated for their diamond-bearing potential. Other kimberlites are believed to be present. Kimberlites ascended from the mantle along deep-seated faults that also can serve as conduits for other ore-forming fluids.
•Large gypsum resources occur in the quadrangle. One major gypsum mine has been operating for many years a few miles north of the town of Blue Rapids.
•Other resources in the Paleozoic and younger near-surface rocks should be better evaluated. They include such commodities as coal, sand and gravel, volcanic ash, limestone, and building stone.
•Earthquakes with intensities of V to VIII have occurred in historic times in the area.
•Known landslide-prone areas occur in the western portion of the quadrangle, presenting geological-engineering hazards which should be better understood.
Hydrogen gas occurs in large quantities scattered throughout the quadrangle, but no estimate as to the size of this resource is available.

Mapping

The status of mapping in the seven full and 10 partial counties in the Manhattan Quadrangle is shown in Table 1. Of the seven counties that make up most of the project area, only Riley County has a recently completed digital geologic map database developed at a scale of 1:24,000. Washington and Dickinson counties have been mapped only on a reconnaissance scale of 1:500,000. They are in the process of being mapped on a 1:24,000 scale as part of this project. Table 1 also shows that most of the mapping was done prior to 1960 at scales ranging from 1:63,360 to 1:84,480 or smaller. Much of the information was published in Kansas Geological Survey bulletins. These bulletins dealt primarily with the groundwater resources of the counties, but included geologic maps based on aerial photographs augmented with field observations. Other useful information about surface geology and construction materials in several counties are included in eight United States Geological Survey publications. During the 1960's

TABLE 1—Status of geologic maps in Manhattan quadrangle.

County	Publication	Date	Scale factor	Out-of-Print	Digital	Whole County in Quadrangle	Part of County in Quadrangle
Clay	KGS B-136	1959	82300			X	
Cloud	KGS B-139	1959	84480			X	
	KDOT IR-30	1978	63360	X			
	USGS Cir-88	1951	63360	X			
	KGS B-073	1948	72411	X			
	KGS B-015	1930	184320	X			
Dickinson	KGS M-23	1991	500000				X
Geary	KGS B-039	1941	126720	X			X
Jackson	KGS B-101	1953	84480				X
Jewell	KGS B-115	1955	126720				X
	USGS Cir-38	1950	63360	X			
Lincoln	KGS B-095	1952	84480				X
Marshall	KGS B-106	1954	84480			X	
	KDOT IR-7	1965	63360	X			
Mitchell	KGS B-140	1959	84480				X
	KDOT IR-3	1965	63360	X			
	KGS B-98	1952	84480	X			
	USGS Cir-106	1951	63360	X			
	KGS B-16	1930	184320	X			
Nemaha	KGS GW-2	1974	125000				X
	KDOT IR-19	1970	63360	X			
	USGS B-1060D	1959	63360	X			
Ottawa	KGS B-154	1962	90000				X
	KDOT IR-31	1977	63360	X			
Pottawatomie	USGS B-1060C	1959	63360	X		X	
Republic	KDOT IR-29	1976	64000	X		X	
	USGS Cir-79	1950	63360	X			
	KGS B-073	1948	126720	X			
	KGS B-015	1930	184320	X			
Riley	KGS M-36	1995	50000		X	X	
	KGS B-039	1941	126720	X			
	KDOT IR-35	1978	63360	X			
Shawnee (2 sheets)	USGS B-1215	1967	48000	X			X
	KDOT IR-26	1974	63360	X			
Wabaunsee	USGS B-1068	1959	63360	X			X
Washington	KGS M-23	1991	500000			X	

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and 1970's, the Kansas Department of Transportation published Materials Inventory Reports for eight of the counties in the quadrangle. These reports have generalized maps showing the geographic location of construction materials and include site-specific information detailing the geologic units involved.

As is shown in Table 1, practically all the maps are out of print and thus are not readily available to the public. In addition, differences in scale further complicate integrated use of existing documents. Geological data contained in the mentioned publications provide enough information to compile reasonably good geologic maps for most of the counties.

In combination with new field mapping, such compilation will be used to produce a digital geologic-map database for all the counties in the quadrangle. The database will be compatible with the existing geologic map database for Riley County, which was developed at a scale of 1:24,000.

Geologic maps will be prepared for Washington, Republic, and Marshall counties, and for the northern part of Dickinson County from new field mapping. Digital geologic maps will be prepared for the other areas using information obtained from out-of-print publications and field checking where necessary. A technique to produce digital geologic maps through interpretation of information available in published material has been developed and tested at the Kansas Geological Survey (Ross and Collins, 1997).

POTENTIAL RESOURCES

Industrial and Energy Minerals

Consolidated rocks of the Permian and Cretaceous Systems make up most of the bedrock in the Manhattan quadrangle. A few small areas underlain by rocks belonging to the Pennsylvanian System occur in the easternmost counties along the crest of the Nemaha Uplift. The rocks generally dip at a slight angle (about 2°) to the west and strike north-northeast to south-southwest. Unconsolidated clastic deposits of the Neogene System consisting of glacial, fluvial, and windblown materials cover large portions in the northeastern part of the quadrangle and are present along the larger rivers traversing the area.

Rocks of the Permian and Pennsylvanian Systems consist of a succession of varicolored shales, siltstones, limestones, and dolomites, some of which contain large amounts of chert either dispersed throughout the rock or occurring as distinct, laterally persistent layers or bands.

Permian strata are known for their evaporite deposits. In southwestern Marshall County, an 8–9-ft-thick gypsum bed occurs at the base of the Easly Creek Shale. The gypsum bed is exploited in an underground mine located about 2 miles north of the town of Blue Rapids. Evaporite deposits must have been present in several other shale units. This is evidenced by disturbed bedding; laterally persistent, hard, carbonate-cemented layers up to a 1/2 foot thick characterized by boxwork structures indicative of extensive dissolution and reprecipitation; small intraformational, normal and reverse faults showing maximum offsets of up to a few feet; and solution collapses are recognized regionally in outcrops of several shale units in Riley and Marshall counties. These shale units include the Holmesville Shale Member of the Doyle Shale Formation, the Blue Springs Shale Member of the Matfield Shale Formation, Easly Creek Shale Formation, and Hooser Shale Member of the Bader Shale Formation. It is not clear what process or combination of processes gave rise to this deformation or when it occurred.

Historically, most of the building stone quarried in Kansas is from Permian limestone ledges. Today, thin (0.3–1.0 m.;1–3 feet) ledges of the Americus Limestone Member of the Foraker Limestone Formation and the Five Point Limestone Formation are the principal sources. Other limestones that have been used extensively in the past for building stone include the basal ledge of the Fort Riley Limestone Member (the so-called "Rim Rock") of the Barneston Limestone Formation, Cottonwood Limestone Member of the Beattie Limestone Formation, and Neva Limestone Member of the Grenola Limestone Formation. The Cottonwood and the Fort Riley limestones today are quarried in areas outside the Manhattan quadrangle.

Ample supplies of limestone and dolomite that can be used by producers of crushed stone are present. Because of the chert's abrasive nature, carbonate units devoid of chert are preferred.

Sand and gravel are another major resource. Sand in sufficient quantities is present in the Kansas River and to a lesser extent in the Republican, Little Blue, and Big Blue rivers. A number of pits produce gravel from glacial-outwash deposits. This material is poorly sorted and the mineral composition is variable.

Clay and shale formations are abundant in the eastern portion of the quadrangle. The shale is mainly of the illite type and probably suitable for red brick, aggregate, and related uses.

Other minerals have been reported to occur, but they seem not to be present in large enough volumes or have no demonstrated uses at this time. They include include shallow Cretaceous coals and deep Pennsylvanian coals that may have the potential to produce methane gas. Hydrogen gas has been reported to occur in a number of drill holes in the area. The distribution, origin, and abundance of the gas was discussed in a paper by Angino and others (1984). Plio–Pleistocene age, wind-borne volcanic ash deposits derived from sources to the west have been reported to occur in Nemaha, Marshall, Washington, and Ottawa counties (Carey and others, 1952).

Metallic Minerals and Diamonds

In contrast to the resources discussed in the previous section, all of which must occur at or near the surface if they are to be exploited, other more deeply buried potential resources include the base metals (copper, zinc, lead, nickel, gold, silver, etc.), rare earth minerals, and diamonds.

The Manhattan Quadrangle is situated over a unique geologic structure referred to as the Midcontinent Rift System. In a paper describing the tectonic evolution of the rift in Kansas (Berendsen, 1997), numerous references pertaining to the rift are cited. The 1,500-km (930-mi)-long, 1,100-million-years-old rift extends from the Lake Superior region near the Canadian border southwestward into Kansas and is characterized by voluminous outpourings of basalts which show pronounced linear gravity and magnetic anomalies along the trend of the rift (Lyons, 1959; King and Zietz, 1971; Yarger and others, 1981). In the Manhattan Quadrangle, the rift cuts across older, 1,800–1,630-million-years, high-grade metamorphic and granitoid rocks of the Central Plains Orogen (Sims and Peterman, 1986; Van Schmus and others, 1993). Deep-seated, north-northeast and northwest-trending faults break the area into orthogonal blocks (Fg. 2). Faults have been reactivated periodically throughout geologic time. The last major movement recorded on north-northeast-trending faults occurred towards the end of Mississippian time and resulted in compound vertical displacements along a set of anastomosing stepped-down-to-the-east faults (Humboldt fault) up to 915 m (3,000 feet) (Fig. 2).

Throughout the world, rift environments offer good potential to host major ore deposits. The Keweenaw Peninsula of Upper Michigan was one of the great copper districts of the world. Copper was mined by the Indians as early as 3,000 B.C., and large-scale mining began in the second half of the 19th century and continued into the first half of the 20th century. Copper was mined from the amygdaloidal flow tops and associated conglomerate beds of the Portage Lake Lava Series (White, 1968). Copper also occurs in the overlying shale and siltstone beds of the Nonesuch Shale (Ensign and others, 1968), and mining of this resource began in earnest in 1915 at the White Pine mine. Mining operations continued for most of the century until the mine closed down only a few years ago. The troctolite basal part of the Duluth gabbro complex contains considerable reserves of Cu-Ni, as well as minor concentrations of Co, Au, Ag, Pt, and Ti (Ojakangas and Matsch, 1982). Also in the Lake Superior region, alkaline and carbonatite complexes are related closely to rifting (Norman, 1978; Weiblen, 1982).

The Elk Creek carbonatite, located in southeastern Nebraska, just a few miles north of the Manhattan Quadrangle, was analyzed and contains P_2O_5 and the rare earth element Nb_2O_5 in concentrations typical of average carbonatite values (Brookins, Treves, and Bolivar, 1975). Within the Manhattan Quadrangle, 10 Cretaceous kimberlites occur in Riley County (Brookins and Naeser, 1971; Cullers and others, 1982) in close association with the Abilene anticline (Fig. 2). Four of these were discovered in the early 1980's by geophysical, remote sensing, and geochemical techniques.

In support of this study, we have acquired detailed, closely spaced aeromagnetic data covering large portions of Riley and Marshall counties. Less-detailed aeromagnetic data for the whole quadrangle were previously collected by the Kansas Geological Survey (Yarger and others, 1981). The plan is to analyze the data and use them to arrive at a regional interpretation of the Precambrian bedrock geology including regional bedrock structures. A number of magnetic anomalies have been identified. These may be attributed to kimberlite bodies or other intrusives. Detailed ground magnetic studies will be conducted over the anomalies and will allow modeling to determine the shape, size, and burial depth of the feature. This may be followed by drilling to positively identify the body causing the anomaly.

TECTONICS AND LANDSLIDES

As a result of episodic tectonic activity, renewed movement on the dominant north-northeast- and northwest-trending structures resulted in anastomosing faults and complicated fault slices, for which the term "Tectonic Zone" is used. Two well-defined north-northeast-trending, rift-related tectonic zones are the Humboldt fault and the Abilene anticline (Fig. 2). Structures associated with the Abilene Anticline (Jewett, 1951), stretching from the Nebraska border through Marshall and Riley counties into Dickinson County, are recognizable in surface rocks. In the subsurface the anticline is a zone of complex faulting more or less centered atop the axis of the Midcontinent Rift. The Humboldt fault, bounding the rift to the east, traverses the quadrangle in south-central Nemaha County through Pottawatomie County and into southeastern Riley and northwestern Wabaunsee counties. A more deeply buried and less-understood tectonic zone bounding the Midcontinent Rift to the west passes through Washington and Cloud counties. Surface folds and faults are known to occur, but no detailed structural mapping has been done in Manhattan Quadrangle.

FIGURE 2—Map shows major structures associated with Midcontinent Rift System and configuration of Precambrian basement surface in feet below sea level.

This project will reexamine structures recognized during previous studies and augment existing data with new information gathered as a result of more field mapping. Special attention will be paid to surface structures in the area. Periodic tectonic activity affected structures throughout the Paleozoic with the last major movement taking place in Late Mississippian to Early Pennsylvanian time.

No record or physical evidence exists for more recent movement on known structures. In recent years careful structural studies in southeastern Missouri identified sand blows, dikes, and numerous faults in unconsolidated Late Quaternary sediments (Palmer and others, 1996), caused by multiple prehistoric earthquakes.

The bedrock in the northeastern part of the Manhattan Quadrangle is covered by unconsolidated Quaternary sediments. In historic times three earthquakes, assigned intensities of V–VIII on the modified Mercalli scale, have been reported to occur in and near the Manhattan Quadrangle (Dubois and Wilson, 1978; Merriam, 1956). Undoubtedly, an unknown number of earthquakes must have occurred in Prehistoric time. A thorough study will be conducted for possible evidence of earthquake activity in the northeastern part of the Manhattan Quadrangle covered by Quaternary sediments.

Landslides of differing size are an abundant and natural occurrence in Kansas. Shales and their weathered products are associated with landslides (Ohlmacher, 1999). On a landslide map of the United States published by the U. S. Geological Survey (Radbruch–Hall and others, 1982) two northeast-trending belts traversing the quadrangle were identified as having a moderate risk (1.5% to 15% of the area is landslide prone). They involve Lower Cretaceous rocks of the Kiowa Formation in Washington, Clay, and Ottawa counties, and Upper Cretaceous rocks of the Graneros Shale and Greenhorn Limestone in Washington, Republic, and Cloud counties (Fig.1). Landslides involving rocks of other ages are known to have occurred throughout the quadrangle. Landslide sites will be mapped and inventoried as part of our study's geologic data base for the quadrangle.

CONCLUSIONS

Some of the more important reasons for studying the Manhattan quadrangle have been outlined and the type of studies that will be conducted are discussed in the sections concerned with the various aspects of the program.

A four-year interdisciplinary study is described to present, in a common database, our knowledge concerning the surface and subsurface geology and the resources of the quadrangle. The information will be accessible easily on the web and in accompanying reports and publications. Presently, information on any one aspect of the geology and resources is spotty. We plan to gather all available information and conduct more studies where additional data are needed to present an up-to-date account of the geology and resources in the Manhattan Quadrangle

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Even though the project idea has been around for some time, discussions with many persons in the Kansas Geological Survey have helped greatly to initiate this project. I would like to extend thanks to the following persons for their advice: David Collins and Gina Ross, digital mapping efforts; Dana Adkins–Heljeson, web site; and Greg Ohlmacher, Jim McCauley, and David Newell, field mapping, tectonic, and stratigraphic studies; David Grisafe and Lawrence Brady, industrial and energy minerals; and Tom Weis geophysical studies.

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Big Basin Impact Craters of Western Kansas

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A sharply defined basin, 1,300 m in diameter, 35 m deep, and with internal drainage, is located 45 km south of Dodge City, Kansas. This feature is named Big Basin on topographic maps of the region. It has been considered to be of solution origin.

Remote-sensing investigations of the area revealed that the feature had two small satellite pits approximately 300 m in diameter. This cluster of holes is an isolated phenomenon in this area. However, the cluster of one large crater and two nearby smaller ones is similar to numerous primary impact crater clusters that occur on other planets. This type of clustering does not occur in areas of karst. The remote-sensing data further showed prominent radial fracture sets and a polygonal shape that reflects the regional fractures.

Subsequent field work revealed that the strata on the rim of the larger hole dip radially away from the center of the feature. The rim and wall materials are intensely fractured. These observations are indicative of impact features and not solution features.

When the Big Basin Crater is compared physically with Meteor Crater, Arizona, and Upheaval Dome, Utah, it shows a close similarity to Meteor Crater, Arizona. This similarity is indicated by polygonal shape, size, and radial features. Big Basin seems to be filled partially with wall and rim materials. It is more eroded than Meteor Crater, Arizona. The walls of the Big Basin Crater contain cherts that seem to have been extracted partially by early man for tools. Tektites and magnetic material occur beyond the rim area.

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Monday, August 30
Poster Sessions

Sequence Stratigraphy of the Lower Morrow in the Arroyo and Gentzler Fields of Southwestern Kansas

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Wireline logs and cores from two fields in southwestern Kansas were used to construct a sequence-stratigraphic framework for the lower Morrow successions in the Hugoton Embayment. Twenty-one lithofacies, representing upper estuarine to offshore depositional environments, were defined. Core data and wireline-log responses were integrated to construct an electrofacies model. Distinctive wireline-log responses define five electrofacies, related to depositional environment. Crossplots, RHOmaa-Umaa and Nphi-Dphi versus photoelectric index, were used to determine lithology and distinguish facies.

An upper estuarine electrofacies is confined to valleys incised in the pre-Pennsylvanian unconformity. Laterally, the incised valley fill is bounded by an electrofacies interpreted as interfluve deposits. Lower estuarine and upper shoreface facies and lower shoreface to offshore facies comprise the remaining lower Morrow facies. At Arroyo field, a simple incised valley-fill deposit constitutes the transgressive systems tract separated by a maximum flooding surface from the overlying offshore to lower shoreface facies of the highstand system tract. The overlying sequence of the middle Morrow limestone is separated by a transgressive surface of erosion. The facies interpretations developed at Arroyo field were applied to the lower Morrow at Gentzler field. The lower Morrow at Gentzler field represents more open-marine environments arranged into three sequences composed of lower estuarine and upper shoreface and offshore to lower shoreface facies.

The proposed sequence stratigraphic framework better represents the complex stratigraphy of the lower Morrow in the Hugoton Embayment.

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Conglomerates Associated with Pennsylvanian Incised Valley-Fill Sequences of Eastern Kansas

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ABSTRACT

A variety of sizes of incised paleovalley fills (IVF's) occur in Pennsylvanian strata of the Midcontinent. The basal fill of these IVF's usually is conglomeratic and consists of intrabasinal materials. Within the study area, smaller scale IVF's contain well-rounded, limestone-clast conglomerates cemented with sparry calcite. Conversely, the larger scale IVF's include a greater variety of clast types, including limestone, seemingly reworked sideritic concretions, shale, and siltstone. The matrix in these more heterogeneous conglomerates is fine-grained, micaceous sandstone.

INTRODUCTION

Significant localized occurrences of Pennsylvanian conglomerates occur within the U.S. Midcontinent as portions of the basal facies developed at unconformities related to paleovalley formation. During sea-level lowstands, a series of paleovalleys were eroded into preexisting stratigraphic units. In eastern Kansas, both smaller and larger scale paleovalleys occur. At least seven sequences are present within the stratigraphic interval ranging from the Vilas Shale of the Missourian Series to the Oread Limestone of the Virgilian Series (Fig. 1). Smaller scale paleovalleys occur within the Rock Lake Shale Member of the Stanton Formation. Larger scale incised valley-fills (IVF's) are well developed within the Douglas Group (Sanders, 1959; Winchell, 1957).

In east-central Kansas, a smaller scale paleovalley is developed within the Rock Creek Shale near Garnett, Kansas. Although this is a small feature (about 10 m deep by 80 m wide), it contains a locally developed, thick conglomeratic fill. The conglomerates primarily are limestone clasts derived locally from the valley walls.

In northeastern Kansas, the incised valley-fill sequence developed within the largest of these paleovalleys includes the Tonganoxie Sandstone Member of the Stranger Formation (Lins, 1950). This paleovalley is greater than 10 km wide and was incised as much as 40 m into carbonate and shale units of the Missourian Series. Other paleovalley-forming episodes occurred during Douglas Group deposition (Griffith, 1981). Within the upper part of Lawrence Shale, the Ireland Sandstone Member seems to form an IVF sequence similar in scale, although less well documented, to the paleovalleys of the Tonganoxie Member. The conglomerates in the basal part of the large-scale IVF's primarily are derived locally materials within a matrix of fine-grained, micaceous sandstone.

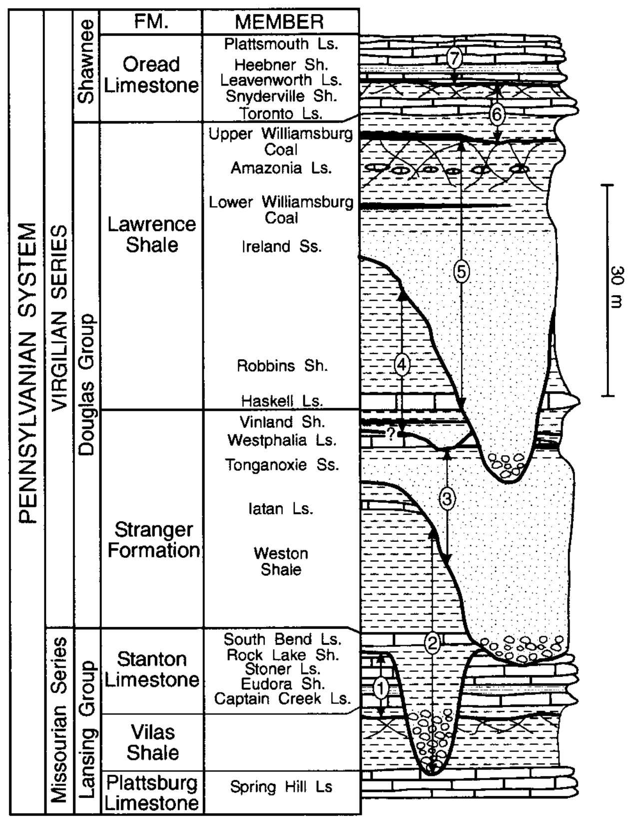

FIGURE 1—Generalized stratigraphic column of upper Missourian and lower Virgilian Series of eastern Kansas. At least seven unconformity-bounded sequences can be delineated within this interval and these sequences do not conform to traditional cyclothem model. Within smaller scale IVF's, conglomeratic facies are well developed in Rock Lake Shale ("Sequence 1"). In larger scale IVF's, conglomerates occur in Tonganoxie Sandstone ("Sequence 3") and Ireland Sandstone ("Sequence 5"). Lowstand surfaces of erosion (LSE) delineate sequences.

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STUDY AREA

Geologic Setting

The general stratigraphy and repetitive nature of Pennsylvanian sequences in Kansas consists of alternations of siliciclastic- and carbonate-rich units. This repetition led to the concept of "cyclothem" (Wanless and Weller, 1932) as applied originally to lithologic cycles in the Illinois Basin. Subsequently, derivatives of this model were applied to the Midcontinent (Moore, 1935; Heckel, 1994). Not only were single cyclothems recognized but also cycles of cyclothems, or megacyclothems, were recognized (Moore, 1935). The delineation of megacyclothems was based upon interpretations of changes in relative sea level that had occurred during deposition of the various facies. Within a megacyclothem the most marine parts, which included thickest limestones and black shales, were defined as the center or "core" of the cycle, whereas the most nonmarine, dominantly siliciclastic and coal-bearing parts were defined as the "outside" parts of the cycle (Heckel, 1977).

Biostratigraphic correlation and the establishment of an extremely detailed, formal lithostratigraphy long has been a fundamental component of Midcontinent geologic research, particularly in Kansas. "Core" facies usually exhibit a low degree of lateral variability and are relatively easy to correlate in areas typically having limited data. In addition, these "core" shales may contain radioactive, organic-rich units and are particularly easy to correlate in the subsurface using gamma-ray logs. Conversely, "outside" shales have been less extensively studied. Compared to carbonate-rich "core" facies, these units are less extensively exposed, biostratigraphically useful fossils are rare to absent, and a high degree of lateral variability makes even local correlations difficult.

Sequence Stratigraphy

Modern coastal analogs seem to provide useful information for the interpretation of conditions that occurred during the development of incised-valley systems during the Pennsylvanian Period. The large-scale eustatic changes that occurred during a single depositional cycle (cyclothem) resulted in dramatic paleogeographic changes. For example, during deposition of the Douglas Group of eastern Kansas, lowstand coastlines were considerably south of Kansas (Fig. 2). During sea-level rise, large-scale river valleys were converted to tidal estuaries and in some instances, significant inland amplification of tides probably occurred. Finally, during sea-level highstands, a shallow, cratonic seaway inundated much of eastern North America.

Conglomerate-bearing, incised-valley fills (IVF's) and laterally correlative paleosols can be used to define

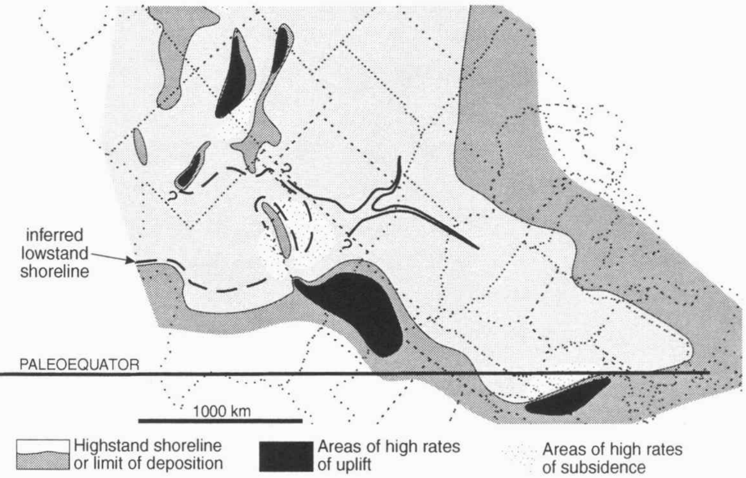

FIGURE 2—Paleogeographic reconstruction for interval comprising Douglas Group of Kansas and lateral equivalents (adapted from Archer and others, 1994; Feldman and others, 1995).

unconformity-bounded sequences. In some situations coals associated with the laterally correlative paleosols provide useful local and regional markers. The correlative surface of erosion generally includes the upper surfaces of paleosols and base of paleovalley incision.

By applying these types of criteria to a 100-m-thick sequence, seven distinct sequence stratigraphic units are evident (Fig. 1). The conglomerate-bearing components of specific IVF's will be discussed here. The second sequence in this interval includes a smaller scale paleovalley, termed the Garnett paleovalley that contains a locally thickened interval of the Rock Lake Shale. This paleovalley was formed by the erosional incision of older members of the Stanton Limestone (Feldman and others., 1993).

The Douglas Group contains large-scale IVF's, which include the Tonganoxie Sandstone ("Sequence 3") and overlying Ireland Sandstone ("Sequence 5"). Smaller scale sequences within the Douglas Group interval include a small-scale paleovalley ("Sequence 4") and a nonincised sequence delineated by a widely correlative paleosol ("Sequence 6").

It is important to note that sequence stratigraphic units do not conform to the traditional lithostratigraphic units. For example, both the Vilas Shale and upper parts of the Lawrence Shale include laterally extensive and well-developed paleosols. These would have required considerable time to develop. The depth of valley incision also indicates a significant duration of erosion. This nonconformance of lithostratigraphic and sequence-stratigraphy units points out some of the problems that occur when using lithostratigraphic nomenclature for designating depositional cycles

Overview of Occurrences

In eastern Kansas there is a continuum of IVF sizes. This range can be characterized by discussing the conglomerate-bearing, smaller and larger scale IVF's. The smaller IVF's have paleovalleys less than 1 km in width that are incised less than 10 m deep. These smaller scale paleovalleys contain a significant amount (>30%) of carbonate sediments. Conversely, larger scale IVF's are on the order of 10 km in width and exhibit 10's of m of incision into older strata. The fill is dominated by distal-source siliciclastics, contains thin coals, and has estuarine lithofacies containing sideritic concretions with well-preserved fossils.

The localities discussed here include smaller scale paleovalleys exposed near Garnett, as well as exposures of the Douglas Group that extends throughout much of eastern Kansas (Fig. 3). Exposures near Garnett, Kansas, are unique because of the exquisite fossils, primarily articulated vertebrates, recovered from the site (Feldman and others, 1993). Exploratory coring revealed that the Garnett locality was developed within the upper, fine-grained facies of incised valley fills (IVF's). A similar, small-scale IVF occurs near Hamilton, Kansas (see Fig. 3) and has been described by Feldman and others (1993).

This small-scale paleovalley is different in scale compared to large-scale IVF's developed within the Douglas Group. The differences between the Garnett versus Douglas Group paleovalleys are attributable primarily to differences in climate and bedrock lithology.

Smaller Scale Paleovalleys

The Garnett paleovalley includes a diverse terrestrial assemblage of plants, arthropods, fishes, amphibians, and reptiles (Reisz, Heaton, and Pynn, 1982). This small-scale IVF is within the Rock Lake Shale Member of the Stanton Limestone ("Sequence 2"). The valley is approximately 11 m deep and 80 m wide. The paleovalley fill can be subdivided into a lower carbonate conglomerate and an overlying assortment of fine-grained facies.

In many parts of northeastern Kansas the sequence boundary is at an erosional surface, or at a paleosol in the Rock Lake Shale. At other localities in east-central Kansas, the top of the Stoner Limestone was eroded and exhibits as much as 1 m of local relief (Ball, 1964). The basal conglomeratic unit in the core is 5 m thick and includes coarse-grained conglomerate as well as thin siltstone and wackestone interbeds. The upper 4 m of the IVF includes laminated to thin-bedded siliciclastic mudstone and siltstone and thin conglomerate beds. Bioturbation is absent, and well-preserved plants, fish, terrestrial arthropods, large reptiles, and tetrapod trackways are abundant (Reisz, Heaton, and Pynn, 1982). The articulated preservation of the reptiles suggests that they were buried soon after death, which isolated them from extensive scavenging.

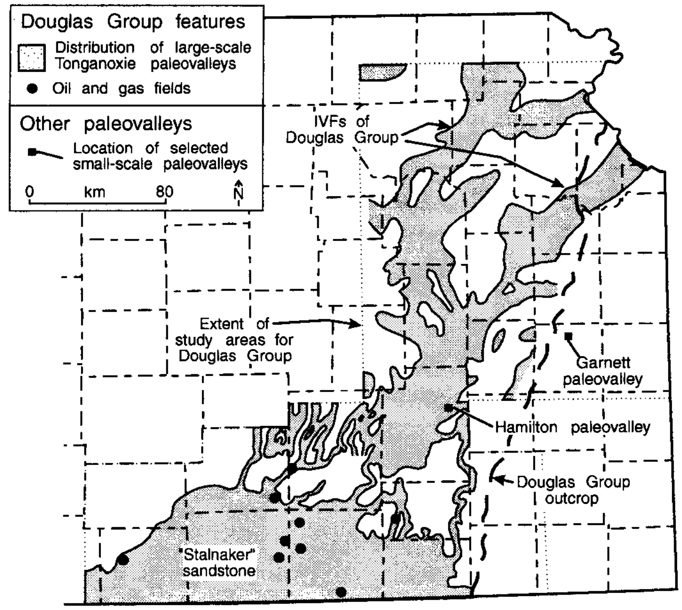

FIGURE 3—Map of eastern Kansas showing locations of IVF's containing conglomerates. Larger scale IVF's of Douglas Group are conglomeratic in northeastern part of Kansas. Smaller scale, conglomerate-bearing IVF's include Garnett paleovalley (discussed here) and Hamilton paleovalley (discussed by Feldman and others, 1993).

Within the Garnett IVF, the Rock Lake Shale includes a wide range of facies. The valley-fill facies at Garnett consist of a lower conglomerate and upper fine-grained facies composed of mudstone, carbonate mudstone, and siltstone. The conglomerate consists of well-rounded clasts of limestone, shale, and siltstone that are identical to facies exposed in valley walls. Evidence that clasts were lithified prior to deposition of the conglomerate includes truncation of internal grains at clast edges and cracking of the clasts. Clasts are rarely deformed without cracking.

Larger Scale Paleovalleys of the Douglas Group

The Douglas Group includes at least four unconformity-bounded depositional sequences (Fig. 3), which from bottom to top include: (1) a prominent valley-fill sequence containing the deeply incised Tonganoxie Sandstone; (2) a paleosol-based sequence within the Vinland Shale; (3) a deeply incised, valley-fill sequence based at the Ireland Sandstone; and (4) a paleosol-based sequence in the upper Lawrence Shale capped by paleosols in the Snyderville Shale Member of the Oread Limestone. The Douglas Group contains estuarine facies similar to those present throughout the Pennsylvanian siliciclastic rocks of the Midcontinent (Archer, 1994; Lanier, Feldman, and Archer, 1993; Archer and others, 1994; Archer, Lanier, and Feldman, 1994, Archer and Feldman, 1995; Feldman and others., 1995).

The Tonganoxie Sandstone is a large-scale IVF in eastern Kansas (see Fig. 3). The facies architecture of this IVF has been determined from analyses of outcrops, well logs, and cores (Feldman and others, 1995). The Ireland incised valley contains well-developed basal fluvial sandstone and conglomerate facies (Archer and others, 1994). This facies is overlain by more muddy estuarine facies. Few outcrops have sufficient stratigraphic control to allow detailed characterization of the Ireland IVF and there is little subsurface control.

CONCLUSIONS

The interval from the Missourian Vilas Shale to the Virgilian Oread Limestone can be subdivided into at least seven stratigraphic sequences. Several of these sequences contain IVF's with conglomeratic intervals. The valley fills differ in lateral and vertical dimensions including smaller scale Rock Lake Shale IVF's and larger scale Douglas Group IVF's. The types of conglomerates that occur within the smaller and larger scale paleovalleys are distinctly different although they all are composed almost exclusively of intrabasinally derived materials. In the small-scale Garnett IVF, the basal conglomerates are dominated by well-rounded clasts of a variety of limestone types. The matrix is crystalline spar and siliciclastics are not evident.

Within the larger scale IVFs, both Tonganoxie and Ireland conglomerates are characterized as consisting of intrabasinal clasts that occur within a matrix of fine-grained, micaceous quartz-rich sandstone. The clasts include fragments of limestone, sideritic concretions, shale, and siltstone. Limestone clasts are subrounded to angular and may attain diameters of 10 cm. These limestone clasts clearly indicate that the underlying bedrock was well lithified before it was erosionally incised.

Long periods of emergence and erosion are indicated by the deep incision of the paleovalleys, the occurrence of eroded, well-lithified bedrock clasts, and the laterally correlative paleosols. Some of the traditional interpretations of cyclothem durations and controls need to be reconsidered in light of this new and intriguing evidence of long durations of subaerial exposure within the stratigraphic record of the Midcontinent.

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Analysis of Structural Controls on the Development of the Upper Pennsylvanian Tonganoxie Incised Paleovalley System of Northeastern Kansas

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ABSTRACT

The paleotectonic setting of the Tonganoxie Sandstone (Upper Pennsylvanian, Virgilian) incised-valley system in the Forest City Basin of northeastern Kansas was analyzed using isopachous maps of the stratigraphic interval containing the paleovalley-fill and lineaments maps based on previous analyses of the configuration of the present-day Precambrian basement. Because structure maps of the present-day configuration of the Tonganoxie Sandstone reveal nothing about the structural framework that influenced paleovalley erosion and sedimentation during the Pennsylvanian, isopachous maps were used to detect subtle changes in local topography. These local topographic changes were the result in part of concurrent structural displacements.

Isopachous maps of intervals bounding and containing the Tonganoxie Sandstone were compared with lineaments interpreted from a map of the 2nd-order trend residuals of the basement gravity-field intensity and a map of the configuration of the present-day Precambrian surface. Previous studies along the eastern portion of the Tonganoxie paleovalley system used isopachous maps to identify a large trunk valley with smaller tributary valleys exhibiting a rectilinear or trellised drainage. Persistent linear thickness trends were recognized that coincide with the trends of interpreted lineaments. The coincidence of these trends suggests that Upper Pennsylvanian structures that influenced the location of paleovalley incisions were developed when preexisting basement faults were reactivated. The reactivation of these basement faults may have occurred in response to the Ouachita tectonic event far south of the Forest City Basin. Variations in thickness of these stratigraphic intervals are related, in part, to differential subsidence within distinct multi-km scale structural blocks with boundaries oriented predominately northwest-southeast and southwest-northeast. Movement along the structural blocks caused differential subsidence and influenced the subsequent drainage pattern of the Tonganoxie paleovalley. The results of this study suggest that exploration for incised valleys should focus on regional mapping of stratigraphic intervals that enclose the valleys and related basement information to delineate structural blocks that may have influenced the locations of valley incisions.

INTRODUCTION

The Tonganoxie Sandstone Member of the Stranger Formation (Douglas Group, Virgilian Series, Pennsylvanian System) was deposited in an incised-valley-fill (IVF) system in eastern Kansas (Fig. 1). The IVF system is up to 32 km wide and extends 140 km through the Forest City and Cherokee Basins (Feldman and others, 1995). Because of the regional westward dip of the strata of 6 m/km (20 ft/mi), the paleovalley extends southwestward, oblique to the outcrop belt, and then grades into the subsurface (Fig. 1). The paleovalley was formed in response to a fall in relative sea level during the early Virgilian and was incised up to 41 m (134.5 ft) deep through marine shales of the lower Douglas Group and limestones and marine shales of the Lansing Group (Fig. 2).

Archer, Lanier, and Feldman (1994) discussed the fluvial and estuarine facies and the sequence-stratigraphic subdivision of their "Tonganoxie Sequence." They provided a model for a tripartite subdivision of the Tonganoxie paleovalley during depositional phases. Similarities between the estuarine geometry of the Tonganoxie paleovalley and modern macrotidal estuary systems, and similarities between the types and scales of contained sedimentary structures, led Archer, Lanier, and Feldman (1994) to characterize the Tonganoxie IVF as a macrotidal system containing fluvial and estuarine strata. After valley incision, a rise in relative sea level caused the valley to be filled with a succession of fluvial, estuarine, and marine siliciclastic sediments (Archer, Lanier, and Feldman, 1994; Feldman and others, 1995). Siliciclastics

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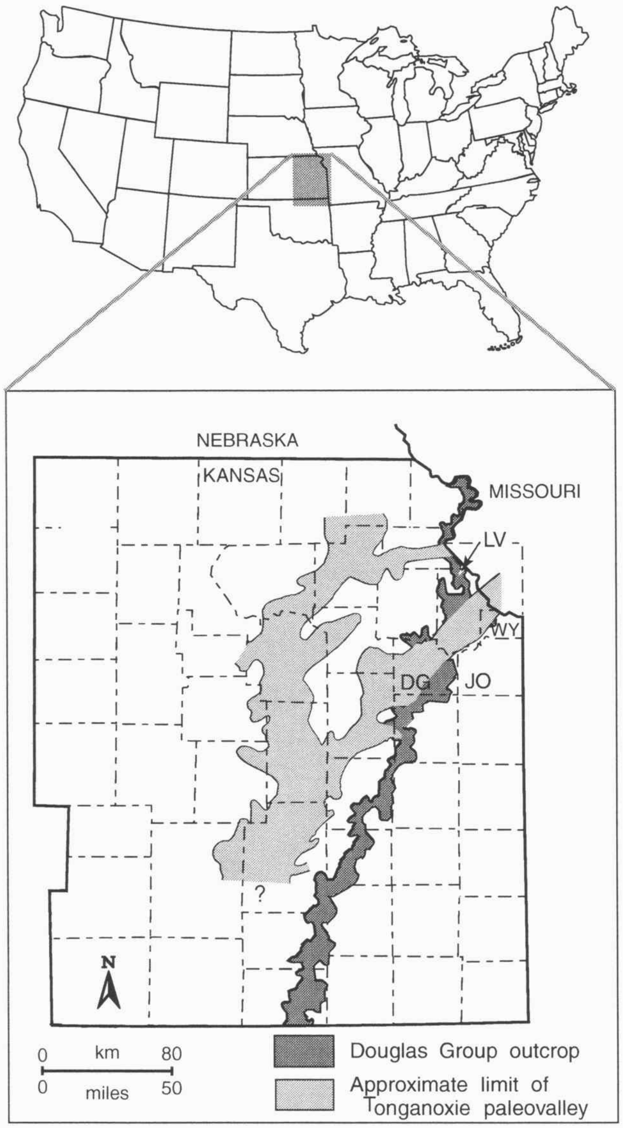


FIGURE 1—Map showing location of Tonganoxie paleovalley in northeastern Kansas.

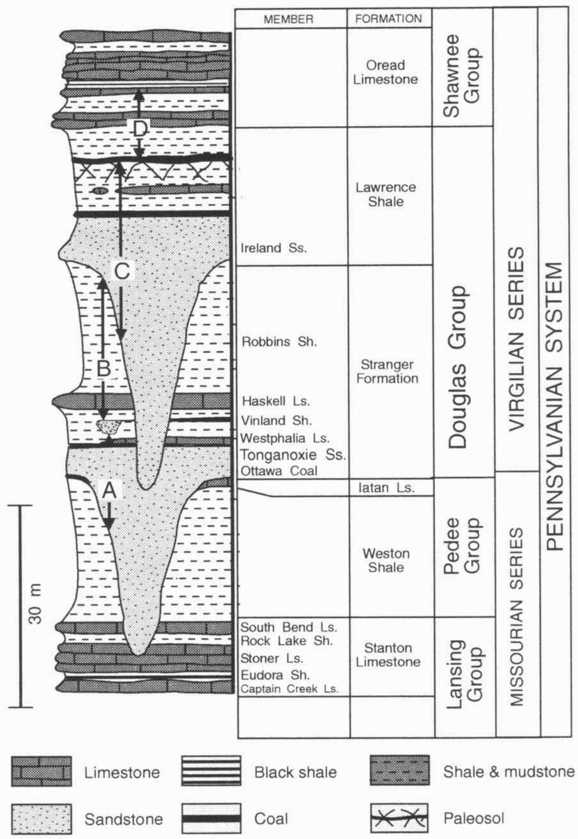


FIGURE 2—Stratigraphic column showing Tonganoxie Sandstone and other stratigraphic units in study interval. Sequences named for nonmarine units; A, Westphalia; B, Haskell; C, Amazonia; and D, Toronto and Feldman, 1995).

prograded through eastern Kansas and lapped onto the higher shelf of western Kansas roughly at the position of the Nemaha Uplift.

The Tonganoxie paleovalley contains fluvial and fluvially influenced, estuarine (FIE) sandstones that are potential reservoir analogs for numerous Pennsylvanian IVF oil and gas reservoirs in the Midcontinent. Previous work on incised valley fills focused on tectonic, climatic, and eustatic controls on deposition, but primarily concerned the types and amounts of siliciclastic input, rates of discharge, and amounts of landward erosion. However, evaluation of tectonic controls on initiation and development of incised valleys has been lacking. An exception among recent studies is the regional study of Quaternary incised valleys in Belize conducted by Esker, Eberli, and McNeill (1998). They demonstrate that subtle, contemporaneous structural deformation seems to control the location and development of incised valleys. In addition, structural deformation acts in concert with sediment supply and glacio-eustatic sea-level change to influence the manner in which the incised valleys are filled. This paper evaluates the role of structural deformation (in particular differential subsidence) in defining the location of the trunk and tributary valley system associated with the Tonganoxie Sandstone. Preexisting structure was an important control on the location of the large paleovalley. The results of this study suggest that topographic relief caused by subsidence within reactivated basement fault blocks controlled subsequent drainage when sea level fell.

Recognition and analysis of tectonic features that influenced the paleovalley development and sedimentary architecture of the Tonganoxie IVF system can serve as a guide to predict locations and trends of reservoir intervals in other IVF systems. Exploration for incised valleys should focus on regional mapping of the stratigraphic interval bounding the IVF system in order to glean valuable information concerning basement involvement in the shelf configuration during paleovalley development. Multi-km scale mapping projects that delineate trends in stratigraphic thickness and relate the trends to changes in basement slope and elevations can help to discern structural blocks and associated bounding faults that may have influenced valley incision and subsequent episodes of sediment filling.

TECTONIC SETTING

Major structural features developed in northeastern Kansas during the late Missourian and early Virgilian include the Forest City and Cherokee Basins (Fig. 3). The Arkoma Basin lies south of the Cherokee Basin, 300 km (186 mi) from the southern edge of the Forest City Basin (Fig. 3). The Arkoma Basin was an actively subsiding foreland basin responding to plate collision and thrusting farther south in the Ouachita Mountains (Watney and others, 1997). Because the Forest City Basin is on the edge of the craton lying adjacent to an active foreland basin, the north-directed Ouachita tectonic event provides a mechanism for the directed stress fields that may have led to basement-fault reactivation. Similar to the Arkoma and Cherokee Basins to the south, during the late Missourian and early Virgilian, the intracratonic Forest City Basin also was actively subsiding (Watney, 1994). The Forest City Basin was bounded by slowly subsiding structural features, such as the Nemaha Uplift in the west and the Bourbon Arch in the south.

Maps of sedimentary thickness (isopachous maps) are one way to determine the effects of concurrent structural controls on depositional systems (Esker, Eberli, and McNeill, 1998), but these maps rarely relate well with maps showing the present-day structural configuration of the depositional basin of interest. Present-day structure maps of the Precambrian and other stratigraphic intervals bounding the Tonganoxie IVF reflect every structural event that affected the craton since the intervals were developed. A map of the present-day structure of the top of the Haskell Limestone shows the current structural configuration of the Forest City Basin with a syncline exhibiting a north-northeast-trending axis along the western edge of the map and a broad, similarly trending anticline along the eastern edge (Fig. 4). The present-day structural configuration of the Haskell interval has little resemblance to the shelf configuration during the Upper Pennsylvanian when the limestone was deposited. This lack of correlation between present and past structure indicates that generalizations about the long-term structural setting from present-day structure maps alone may be irrelevant and even misleading.

During the Pennsylvanian, flexure along the southern edge of the craton was not uniform, but was interrupted by discontinuities across which subsidence (and sediment thickness) abruptly changed (Watney and others, 1997). Average subsidence rates calculated for western Kansas shelves were approximately 0.02 m per thousand years but, during some time intervals, may have been more (Watney, 1994). In the Forest City Basin, the thick siliciclastic-dominated interval that includes the Tonganoxie IVF (strata in the interval between the base of the Stanton Limestone and the base of the Oread Limestone) has a combined thickness five to six times the

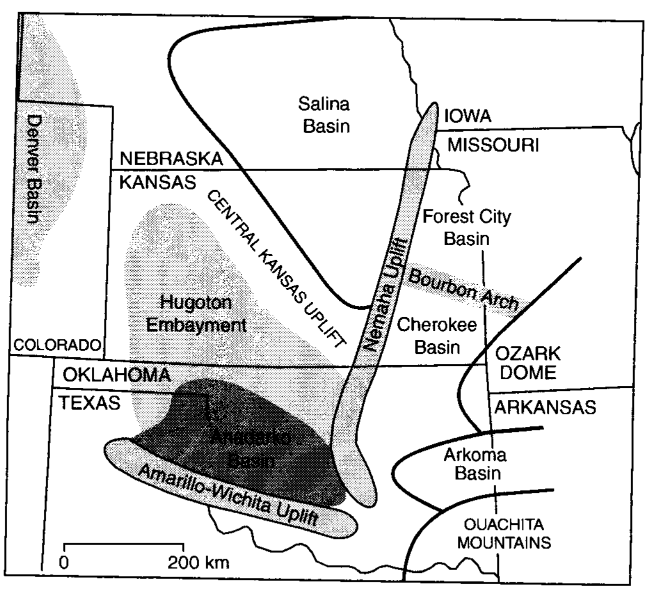


FIGURE 3—Map showing location of Forest City and Cherokee Basins in eastern Kansas and their relationship to other structural features of midcontinent (modified from Archer, Lanier, and Feldman, 1994).

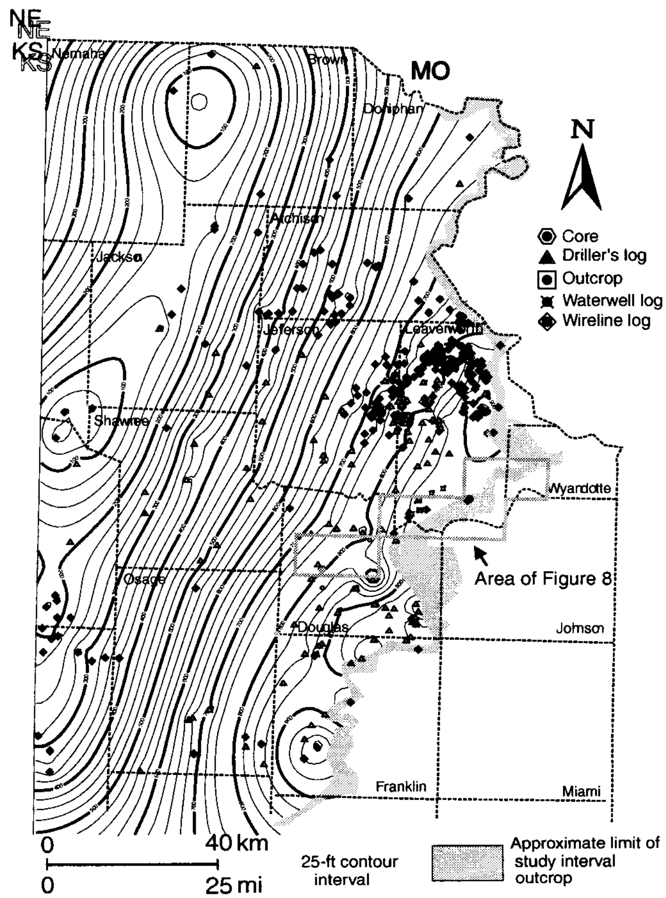


FIGURE 4—Structure map showing configuration of top of Haskell Limestone in Forest City Basin of northeastern Kansas.

thickness of the same stratigraphic interval in western Kansas (Watney, 1993). The difference in thickness in the east suggests that during the late Missourian and early Virgilian, subsidence was faster on the eastern Kansas shelf than on the western shelf.

Regional-scale isopachous maps that show the interval between the base of the Stanton Limestone and the base of the Oread Limestone in central and western Kansas indicate that differential structural movement produced sharply defined km-scale rectilinear areas of relatively uniform stratigraphic thickness (Watney, 1993). Subsequent mapping and analysis have confirmed the presence of these rectilinear blocks in this interval and in underlying Missourian strata (Watney and others, 1997; Watney and others, 1999). Movement along different lineaments and interpreted structural blocks was recurrent and episodic (Watney and others, 1997). The example described in this paper is more subtle, but distinctive.

Structural Controls on Late Missourian and Early Virgilian Sedimentation

Structural discontinuities are sites of anisotropy of basement rocks as revealed by studies of lithology, geochronology, and potential field (i.e., gravity) geophysical data (Watney and others, 1999). The gravity and basement configuration maps utilized in this study were used to determine whether basement faults were the key structures that influenced the development of stratigraphic intervals in the Forest City Basin during the late Missourian and early Virgilian. Lineaments that are thought to correspond to the edges of basement blocks were interpreted using a map of the 2nd-order trend residuals of the basement Bouguer gravity field intensity (J. M. Kruger, written comm., 1996) and a map of the configuration of the present-day Precambrian surface (Cole, 1976). The 2nd-order residual gravity map (Fig. 5A) contains a dominant northwesterly structural grain and a secondary northeasterly grain (Fig. 5B). Similarly, a map of the Precambrian surface (Cole, 1976) contains pronounced northwesterly plunging synclines and anticlines. Mapping of the present-day basement configuration helps to interpret the trends of lineaments that may be associated with zones of crustal weakness in the basement. Such interpreted lineaments may be caused by abrupt changes in basement composition (such as igneous intrusions) or, with this study, may correspond to changes in elevation that are attributed to crustal movement along basement faults reactivated during

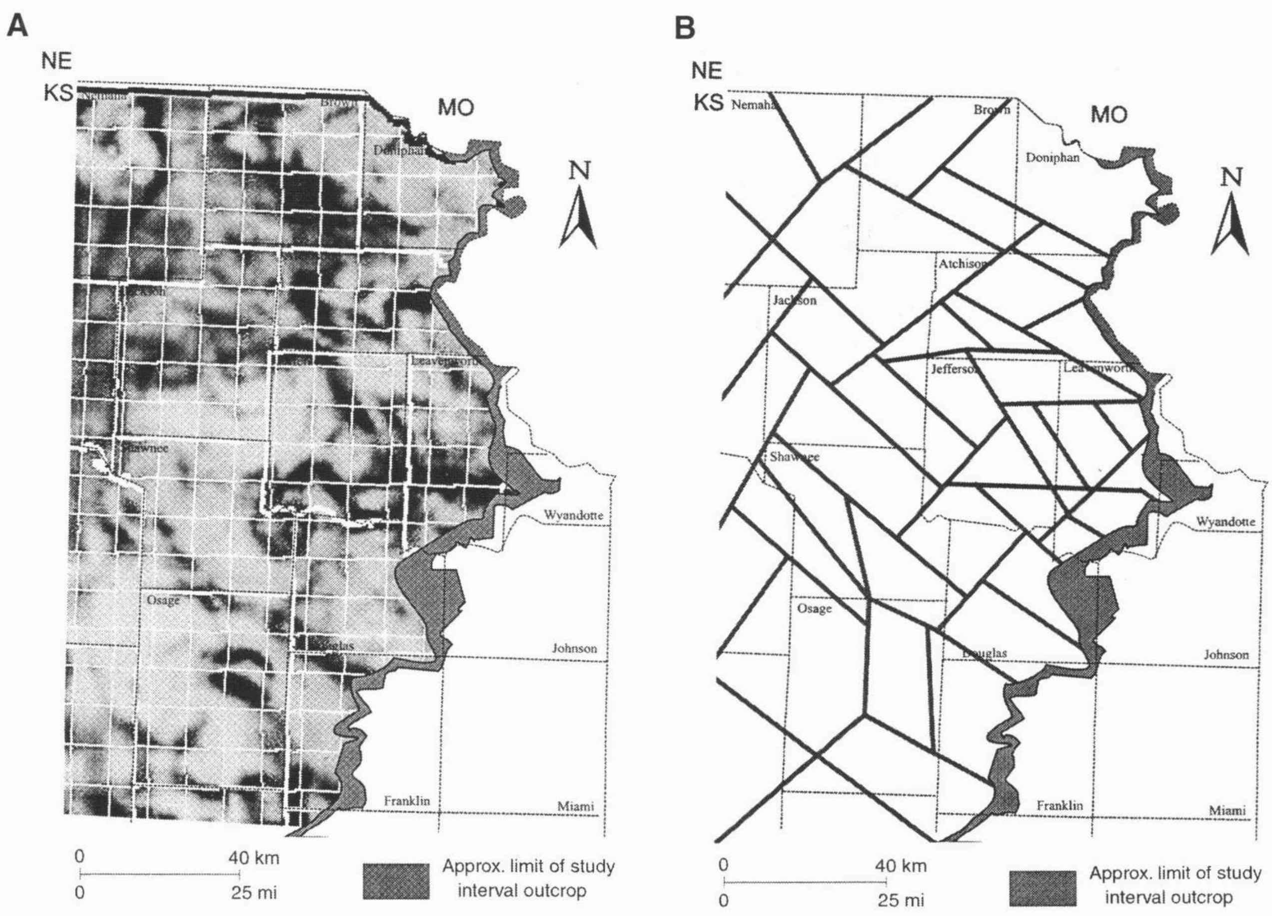


FIGURE 5—A, Map of 2nd-order residual gravity in northeastern Kansas. B, Lineament map interpreted from 2nd-order residual gravity map. These lineaments define dominant northwesterly structural grain and secondary northeasterly grain.

different phases of basinal development. The effects of basement reactivation of fractures and faults on later topography need to be analyzed by documenting changes in stratigraphic thickness. Structural lineaments interpreted from these maps were compared to patterns or thickness trends established from analysis of regional isopachous maps of the stratigraphic interval below and containing the Tonganoxie IVF.

Persistent linear thickness trends were recognized that correspond closely to the trends of the interpreted structural lineaments in Figure 5B. The similarity of trends between the two types of maps was identifiable even though continuous proportional contouring was used to create isopachous maps and well control was limited in some portions of the study area. The apparent link between interpreted basement lineaments and present-day structure suggests that reactivation may have occurred along preexisting deep-seated faults during the development of the Forest City Basin. The movement of structural basement blocks may have caused stratigraphic thickness to differ across the depositional basin in response to differential subsidence. Uplift or flexure of the land surface may have resulted in localized modification of surface elevations and in the subsequent development of a knick point during the initial stages of valley incision (Schumm and Ethridge, 1994). Throughout the rest of the text, groups of prominent lineaments interpreted from maps of basement data are labeled with the letters "a" through "e" on isopachous maps. These lineaments are thought to be related to orthogonal fault sets and fractures at the edges of basement blocks.

Structural Controls on Valley Incision

Feldman and others (1995) mapped the Tonganoxie paleovalley system in Douglas, Leavenworth, and Wyandotte counties. They used an isopachous map of the interval from the base of the Eudora Shale of the Lansing Group to the lower sequence boundary of the Tonganoxie IVF to approximate the configuration of the erosional surface prior to valley filling (Fig. 6A). The base of the Eudora Shale was selected as the lower horizon for the isopachous map in Figure 6A because its depositional thickness has been preserved and because it has a distinctive signature that is easily discernable during wireline-log evaluations. In rocks underlying the Tonganoxie Sandstone, the Eudora Shale Member of the Lansing Group is the youngest stratigraphic horizon not incised by the developing paleovalley (Feldman and others, 1995). In Figure 6A, thick intervals correspond to areas in the valley system that underwent little incision whereas the thinnest intervals correspond to the location of the valley floor. Tributary valleys along the length of the main Tonganoxie paleovalley (the trunk valley) branch at nearly right angles to the valley axis in a trellis pattern.

The paleovalley configuration map from Feldman and others (1995) was compared to maps showing the locations of interpreted lineaments (Fig. 6B). The lowest

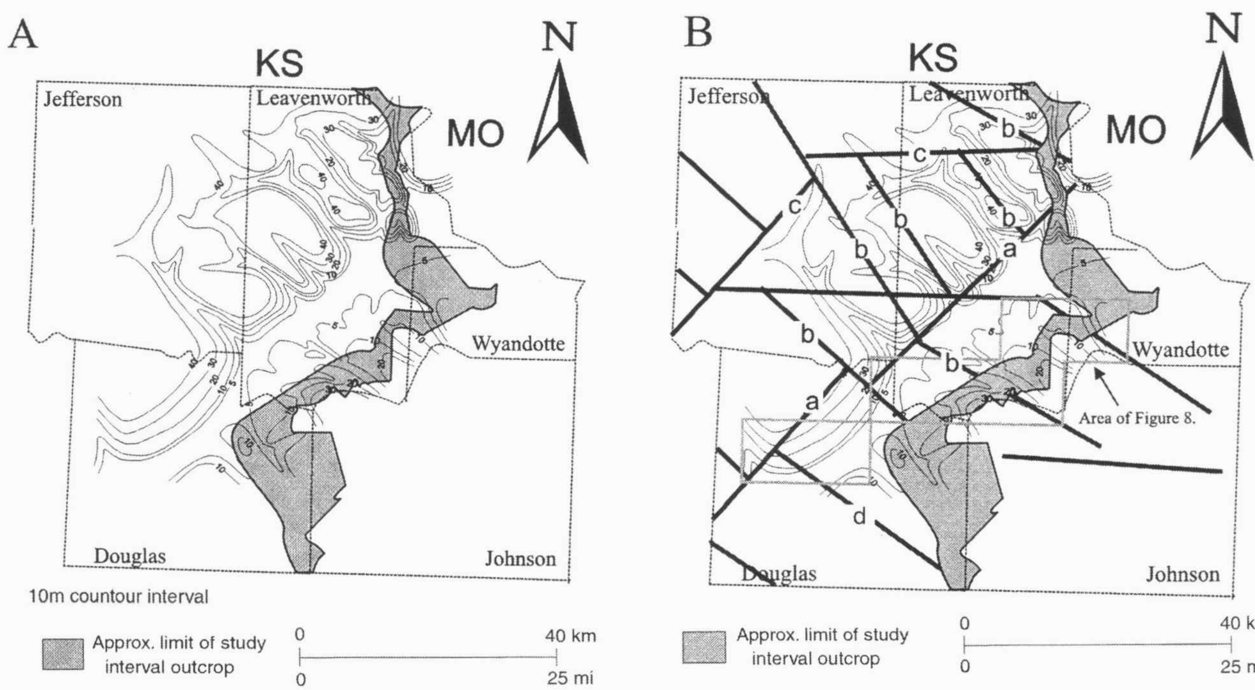


FIGURE 6—A, Isopachous map of interval from base of Eudora Shale to lower sequence boundary of Tonganoxie IVF. Map approximates configuration of erosional surface prior to valley filling. B, Lineaments interpreted from basement data (Fig. 5B) superimposed on map in Figure 6A. Rectilinear drainage pattern during incision resulted from orthogonal fault sets that bounded basement blocks (modified from Archer and Feldman, 1995).

portions of the paleovalley (forming the trunk valley) correspond to long, persistent southwest-trending lineaments (labeled "a" in Fig. 6B) that parallel the trend of the main Tonganoxie trunk valley axis, whereas southeast-trending lineaments (labeled "b" in Fig. 6B) trend subparallel to the trends of tributary valleys. Two additional southwest- and west-trending lineaments ("c") are located along the northern edge of the mapped area. These lineaments delineate the headward limits of the incised portions of the tributary valleys (Fig. 6B).

Feldman and others (1995) noted that tributary valleys along the southeastern edge of the main Tonganoxie trunk valley are wider than tributary valleys along the northwestern edge. Subsidence-related tilting of strata probably influenced the pattern of trunk and tributary valleys (Fig. 6B). During incision, the sloping surfaces of the basement blocks seem to have influenced the locations of tributary valleys and led to the development of the rectilinear drainage pattern. Differential subsidence of blocks bounding the main trunk valley resulted in contrasts in the types of substrate that were incised by the trunk and tributary valleys. Tributary valleys that entered the main trunk valley from the southeast drained upland areas in present-day Missouri. Basement blocks southeast of the trunk valley were high relative to the blocks northwest of the trunk valley, and downcutting and headward erosion in southeastern tributary valleys were constrained by more resistant substrate presented by limestone beds of the Stanton Formation. Because of the support imposed by the underlying, more resistant beds in the southeast, a broad, high terrace remained adjacent to the main trunk valley after valley incision. This seemingly is not the situation on the northwestern side of the main trunk valley where tributary valleys form a prominent rectilinear drainage pattern. In areas northwest of the trunk valley, incising streams were forced to flow within narrow flexures formed by draping of underlying Missourian strata above downdropped basement blocks. These northwestern tributary valleys were incised primarily through thick deposits of Weston Shale. Although the amount of discharge was limited by the small size of the upland area, tributary valleys northwest of the main trunk valley were narrow with steep sides because of the relative ease of downcutting through Weston Shale. The Weston Shale is composed of shaly sandstone, silty shale, and shale and represents the initial episode of siliciclastic accumulation above the Stanton Formation. In contrast, in areas southeast of the main trunk valley, the Weston Shale interval is thought to have been relatively thin prior to paleovalley incision.

REGIONAL MAPPING

Regional (multi-kilometer) scale isopachous and structure maps were created for an Upper Pennsylvanian interval that includes the stratigraphic succession from the base of the Eudora Shale to the top of the Haskell Limestone (Fig. 2). Drillers logs, water-well logs, and wireline logs, including SP, gamma-ray, neutron, density, and sonic logs, were examined from 438 wells. The mapped area is centered on the paleovalley and encompasses an area of 193 km (120 mi) by 155 km (96 mi).

Isopachous maps were used to compare the depositional framework of the stratigraphic interval bounding and including the Tonganoxie IVF system with the concurrent structural framework. The approach used to create the isopachous maps (continuous proportional contouring) was not biased and is consistent between maps, but the patterns defined may not reflect clearly the true anisotopy of the system. Computer mapping as conducted here assumes that stratal-thickness changes are isotropic and range continuously across the mapped interval. Such a contouring system stresses continuity between data points when, in fact, conditions may be discontinuous (e.g. stratigraphic changes between structural blocks). The succession of Upper Pennsylvanian isopachous maps described in this paper reflect a combination of events that include: (1) differential subsidence and local structural deformation throughout the northeast Kansas region, (2) regional marine sedimentation of carbonates and siliciclastics associated with changes in sea level, (3) erosional development of an incised-valley system, and (4) sediment accumulation within the incised-valley system.

Eudora Shale to Haskell Limestone Interval Isopachous Map

Widespread marine units that show minor lateral variation bound the isopachous map of the interval from the base of Eudora Shale to the base of the Haskell Limestone. Assuming that the Haskell Limestone was deposited across northeastern Kansas as a relatively flat, continuous horizon, the isopachous map shown in Figure 7A is thought to indicate the structural configuration of northeastern Kansas during the early Virgilian. A regional southwestward thickening of the interval from the base of the Eudora to the base of the Haskell Limestone is interpreted as a general trend during the Virgilian from a structurally high area in the northeast to a structurally low area in the southwest. Large, broad variations in thickness of this interval probably are related to differential subsidence on the northeastern Kansas shelf that occurred during late Missourian and early Virgilian time. Prior to Tonganoxie paleovalley incision, local variations in marine sedimentation were influenced by preexisting and concurrent structural deformations. Local thickening of the interval from the base of the Eudora Shale to the base of

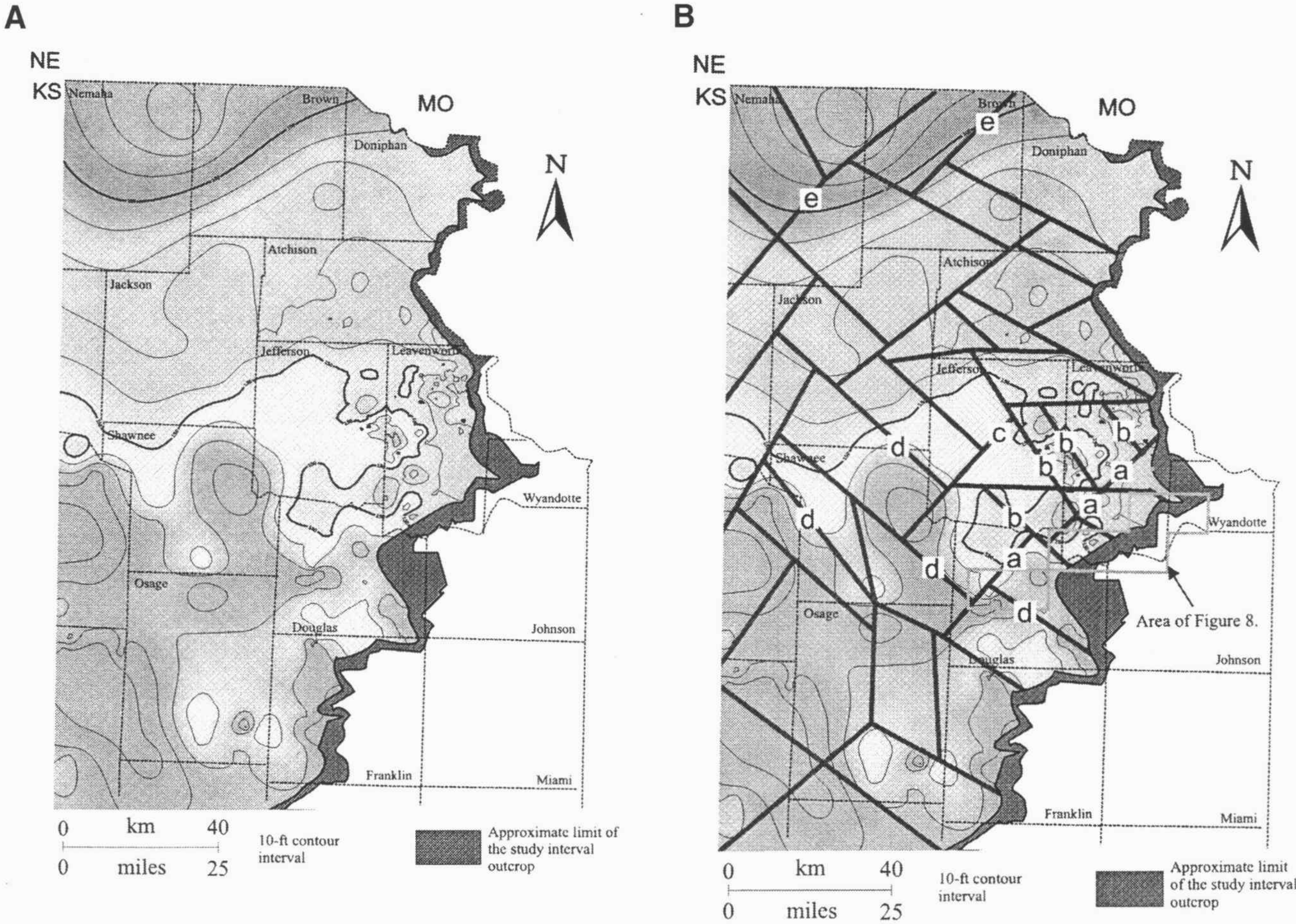


FIGURE 7—A, Isopachous map of interval from base of Eudora Shale to base of Haskell Limestone. Assuming that Haskell limestone was deposited as relatively flat, continuous horizon, map is thought to indicate structural configuration of northeastern Kansas during early Virgilian. B, Lineaments interpreted from basement data (Fig. 5B) superimposed on isopachous map in Figure 7A. Northwest-trending flexure in Miami, Johnson, and Douglas counties divides northern from southern structural terrain.

the Haskell Limestone may reflect development of an embayment or flexure along the southwest-trending lineament "a" (Fig. 7B).

The south and southwest regions of the map in Figure 7A are notably thicker than the central region. The divide between the thinner, central region and thicker, southwestern region again is linear, trending diagonally through the map area at about the 49-m (160-ft) thickness contour. The persistent 160-km (100-mi) linear trend strongly suggests a structural flexure associated with differential subsidence. The flexure line that divides the southwestern and central regions coincides with the flank of a prominent northwesterly plunging basement anticline mapped by Cole (1976). The flexure line also coincides with the northern edge of a large, elevated gravity terrain shown on the map in Figure 5A as a light-gray pattern extending northwest through Miami, Johnson, and Douglas counties. In addition, the flexure line roughly parallels the trends of several northwest-trending lineaments "d" in Figure 7B. Increased thickness of the isopachous interval is consistent with a regional increase of basinward subsidence to the south and suggests that directed compressive stress imposed by the Ouachita Orogeny caused the basement to fragment into blocks along preexisting zones of weakness.

The structural configuration of the northeastern Kansas shelf seems to have affected the location of the Tonganoxie paleovalley. Lineament "a" (Fig. 7B) corresponds with the location of the incised trunk valley and is parallel to the trend of thick sandstone accumulations. In the isopachous map in Figure 7B, a thin northern region, centered in T. 2 S., R. 14 E. in the northeastern corner of Nemaha County, is bounded on the southeastern edge by two northeast-trending lineaments (lineaments "e"). The area northwest of lineaments "e" was the topographically high, southwest-to-northeast-trending Nemaha Uplift, which seemingly acted as a barrier to constrain the location of these Virgilian fluvial systems (Fig. 7A). Differential subsidence along lineament "a" acted in concert with the interpreted higher block north of lineament "e" to create an embayment and consequently constrain the location of the superimposed drainage system. The structurally low region may have served to focus fluvial runoff during Tonganoxie paleovalley incision when sea level lowered to expose the shelf. Movement along the smaller scale lineaments trending subperpendicular to lineament "a" influenced the location, depth, and elevation of tributary-valley incisions.

Figure 8 is a 50-km-long stratigraphic cross section that extends southwest to northeast across the central portion of the study area. The cross section includes gamma-ray profiles and surface and core descriptions of the interval from the Haskell Limestone (datum) to the base of the Captain Creek Limestone. Three lineaments, shown on the map in Figure 7B, intersect the cross section in Figure 8. These lineaments are labeled with the same designations on the cross sections as on the map. The lineaments labeled "b" on the cross section are northwesterly trending and correspond most closely with the location of tributary valleys adjacent to the trunk valley. Lineament "d" corresponds to the flexure zone across which the trunk valley widens and across which the interval from the base of Eudora Shale to the base of Haskell Limestone thickens to the southwest.

The five westernmost wells in the cross section (Fig. 8) are located in the main Tonganoxie trunk valley. The eastern wells are located on the broad terrace southeast of the main trunk valley. Wells within the trunk valley contain a thicker base of Eudora Shale to the base of the Haskell Limestone interval than wells along the southeastern terrace. Where the interval contains large proportions of sandstone (>67%), localized areas probably did not compact as much as areas where the interval was predominately composed of shale and shaly sandstone. However, it is not possible to attribute all of the relative increases in interval thickness in Figure 7 to the effects of differential compaction. Although more sandstone generally is present in the western wells, differential structural subsidence seems to be the main cause of the increase in interval thickness. A core on the eastern side of the cross section contains an interval of sandstone with a thickness similar to the westernmost well on the cross section, yet the Eudora Shale to Haskell Limestone interval in this eastern well is thin relative to the western well. Thus, the isopachous map in Figure 7 incorporates thickness variations that are the result of regional subsidence, leading to the creation of greater accommodation space, and to a lesser degree, in areas where the paleovalley contained relatively high amounts of sandstone, local interval-thickness increases also may be caused by the effects of differential compaction.

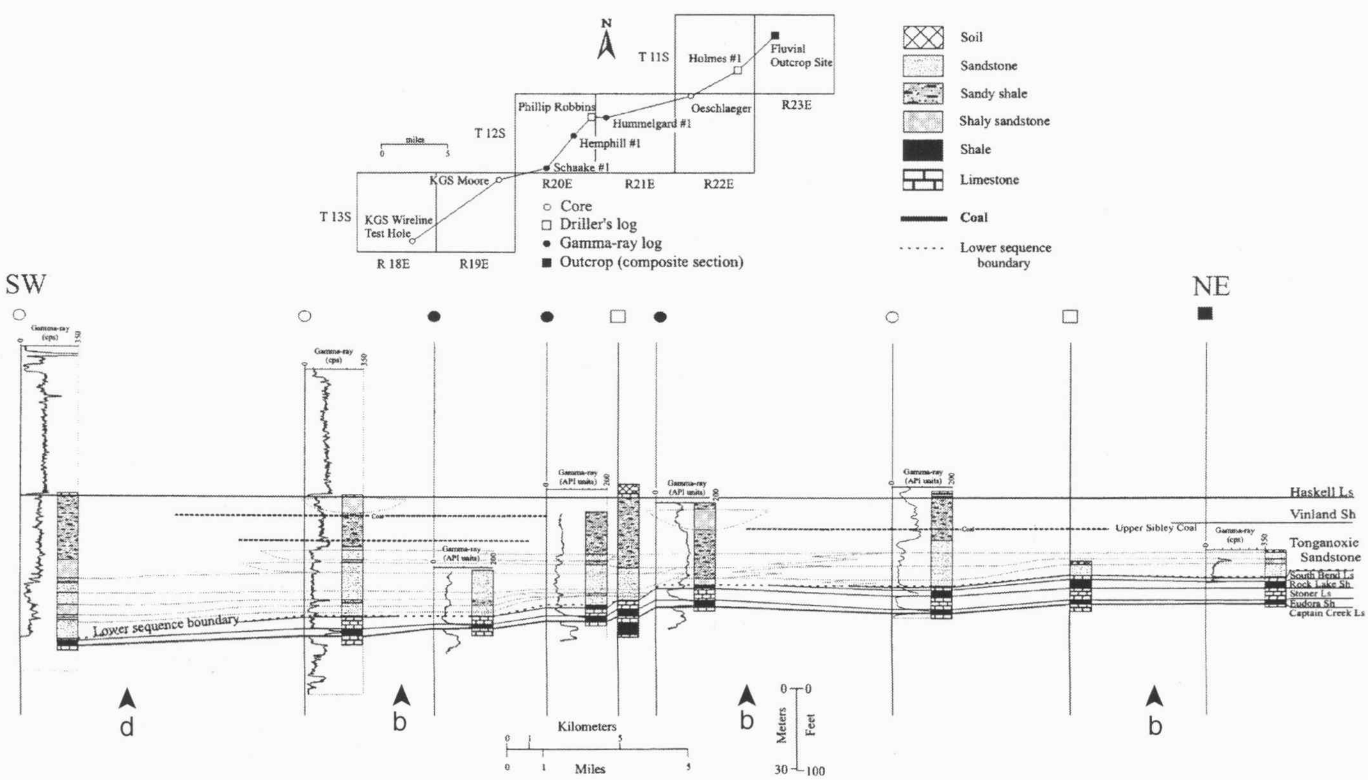


FIGURE 8—Fifty-km-long stratigraphic cross section extending southwest to northeast across central portion of study area. Cross section includes gamma-ray profiles and surface and core descriptions of interval from Haskell Limestone to base of Captain Creek Limestone. Datum is base of Haskell Limestone. Area of cross section is shown on Figures 4, 6, and 7. Intersections with lineaments "b" and "d" shown below cross section.

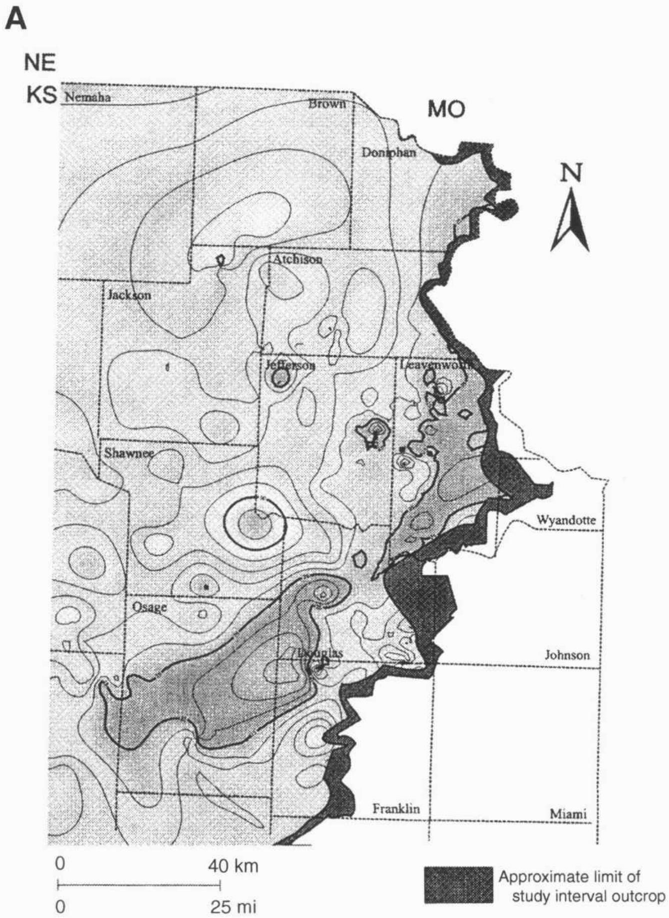
Eudora Shale to Stanton Limestone Interval Isopachous Map

The isopachous map of the base of the Eudora Shale to top of the Stanton Limestone interval best delimits the location of the deepest portions of the Tonganoxie paleovalley. On the map, thin elongate areas indicate the locations where the Tonganoxie paleovalley has been incised into the top of the Stanton Limestone (Fig. 9A). The thinnest areas of the Eudora to Stanton interval are elongated southwest-northeast. Boundaries of these elongate thin areas are distinctively linear and coincide with the location of lineaments labeled "a." For the isopachous interval from the base of the Eudora to the top of the Stanton Limestone, the pattern of thick and thin areas seemingly corresponds to the rectilinear pattern of lineaments interpreted from basement data (Fig. 9B). Adjacent to lineament "a" are slightly thicker areas that flare out, resembling narrow shelves or benches. These secondary features are oriented northwest-southeast with boundaries that are linear and well defined, corresponding closely with lineaments "b." Movement along several lineaments in eastern Osage County may have led to the broadening of the valley. The northwest-trending flexure zone also follows similarly trending lineaments "d" and delineates a shallower valley incision separating two valley segments.

The large-scale, regional correspondence of thickness trends to mapped patterns of interpreted lineaments (Fig. 9B) suggests that the development of the base of the Eudora to the top of the Stanton Limestone interval, including depositional and erosional phases, was tempered by the preexisting structural configuration of the northeast Kansas shelf. During deposition of these marine sediments in the late Missourian, the northeast Kansas region was already experiencing subsidence controlled by the reactivation of multi-km-scale basement fault blocks. The fault blocks are similar in size and shape to fault blocks previously identified in western Kansas (Watney, 1993).

Tonganoxie–Vinland Sandstone Isopachous Map

Sanders (1959) mapped the subsurface distribution of sandstone below the Haskell Limestone in northeastern Kansas (Fig. 10). This isopachous map includes both



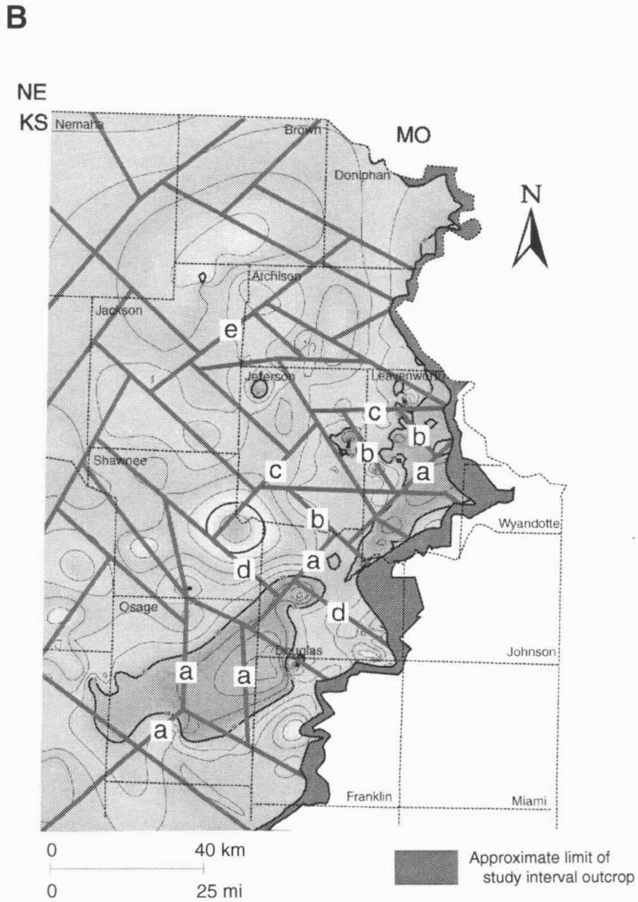


FIGURE 9—A, Isopachous map of interval from base of Eudora Shale to base of Stanton Limestone. Thin elongate, southwest- and northwest-trending areas indicate locations where Tonganoxie paleovalley was incised into top of Stanton Limestone. B, Lineaments interpreted from basement data (Fig. 5B) superimposed on isopachous map in Figure 8A. Correspondence of rectilinear pattern of thickness trends to lineaments suggests that deposition in interval was tempered by preexisting regional structural control.

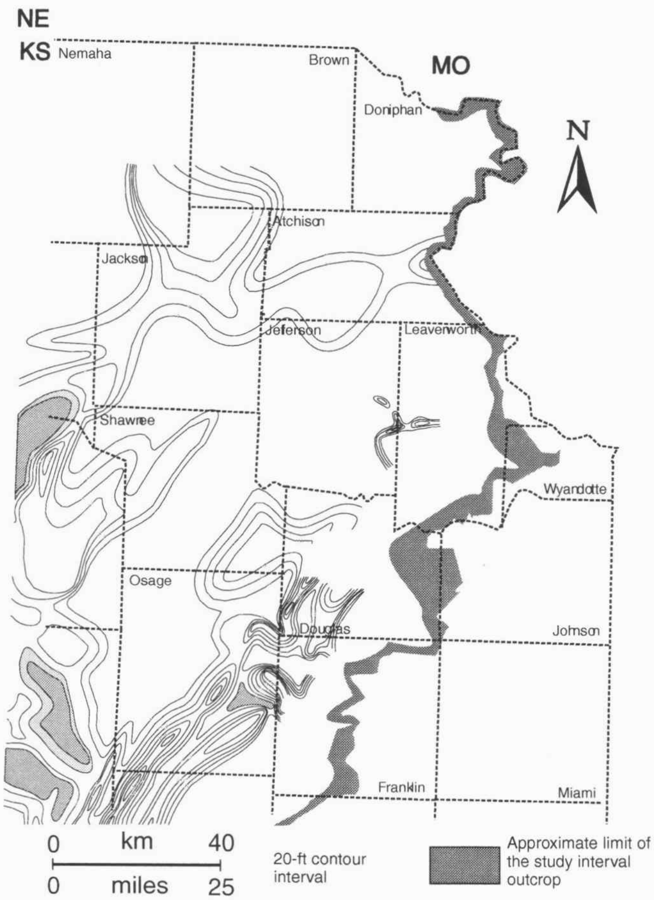


FIGURE 10—Isopachous map of subsurface distribution of sandstone below Haskell Limestone in northeastern Kansas, including both Tonganoxie and Vinland sandstones. In northeastern Kansas, sandstone exhibits two dominant northeast-to-southwest trends of thickening that are here referred to western and eastern branches of valley system (modified from Sanders, 1959).

Tonganoxie and Vinland sandstones, as Sanders did not distinguish between the two sandstone horizons. Superposition of the isopachous map of sandstone thickness on a map showing interpreted basement-related lineaments reveals that, similar to the earlier isopachous map showing the configuration of the Tonganoxie paleovalley (Fig. 6), general thickness trends are bounded by the lineaments. However, the sandstone isopachous map provides a more regional basis for analyzing the effects of structural changes on paleovalley development than the previous map.

In northeastern Kansas, the sandstone exhibits two dominant northeast-to-southwest trends of thickening. Within the trends, distinct areas of thick sandstone are evident (Fig. 10). The western valley extension exhibits a depth of incision that is not as great as the eastern valley incision. The valley segments join in Lyon County (Fig. 9), where the western extension bends southward to meet the eastern segment. The eastern branch of the Tonganoxie paleovalley system is subparallel to the outcrop belt and contains sandstone bodies with elongate thicknesses that generally trend along the trunk-valley axis (northeast-to-southwest) along lineaments labeled "a" (Fig. 9). This eastern branch also contains thick sandstone accumulations that trend from west to east. Many of these sandstone bodies were deposited in tributary valleys near the junction with the main trunk valley.

The deep, eastern incised-valley system was eroded into Weston Shale in areas northwest of the main-trunk valley but in areas southeast of the main-trunk valley, tributary valleys were instead eroded into the top of the more erosion-resistant Stanton Limestone. The sandstones accumulated in separate segments, possibly isolated and temporally distinct, in response to variations in valley-floor elevation and relative sea level. In the mapped area, elevation and location along the valley seem to be important factors that control the distribution of the Tonganoxie Sandstone. Different rates of subsidence in the blocks caused contrasting elevations within valley and upland surfaces. Because of their closer proximity to the photic zone, it is likely that sedimentation over structurally higher blocks favored active carbonate precipitation and buildup. In combination with the structural downwarping, the locations of these buildups also may have influenced the directions of local valley incision, especially in areas southwest of the main trunk valley where branching tributary valleys may have been diverted by localized carbonate buildups (Esker, Eberli, and McNeill, 1998).

The northwest-to-southeast line of flexure (along lineament "d") separating the southwestern and central regions of the mapping area seems to have acted as a knick point that led to segmentation of the Tonganoxie paleovalley and influenced sandstone accumulation. Thick accumulations of Tonganoxie Sandstone were deposited along this flexure zone in southwestern Douglas County. This location is coincident with the site of the Worden fault in southern Douglas County. Other work has indicated that this fault was active during the interval of time between deposition of the Toronto and Leavenworth limestones and may actually be a series of en echelon faults and flexure zones (O'Conner, 1960). Segments along the valley systems include sandstone deposited in deeply incised portions of the valley to the south and on higher elevations (terrace) to the north.

SUMMARY AND CONCLUSIONS

Present-day structure shows no evidence of the structural framework that influenced Pennsylvanian erosion and sedimentation. Detecting changes in local paleotopography resulting from structural controls requires isopachous mapping of stratigraphic intervals and integration with available basement data. These analyses necessitate information about the regional tectonic setting during valley development in order to substantiate reactivation mechanisms and sense of structural movement of basement blocks. Differential subsidence of basement blocks in the Forest City Basin prior to development of the Tonganoxie paleovalley controlled the location and depth of the later fluvial incision and influenced the development of tributaries to the main-trunk valley. Continued subsidence and a gradual rise in eustatic sea level led to the development of a coastal estuary (Feldman and others, 1995) and resulted in deposition of a transgressive succession of facies within the valley.

The locations of basement heterogeneities and structure interpreted from the configuration map of the Precambrian surface and 2nd-order trend residuals of the magnetic- and gravity-field intensity are consistent with locations of multi-km-scale structural blocks. Similarity between isopachous thickness patterns, mapped using unbiased isotropic algorithms, and patterns of interpreted lineaments suggest that concurrent structural deformation contributed to the development of the Tonganoxie paleovalley system. Rectilinear drainage (the consequent drainage pattern) is interpreted to be associated with early structural movement along basement faults (i.e. faulting and the subsequent subsidence and tilting of strata above fault blocks). Draping of underlying Missourian strata into deep-seated basement blocks influenced the location of trunk- and tributary-valley incisions and the thickness of accumulated sediments. Changes in elevation and direction of the valley led to segmentation of the valley fill and influenced associated sedimentation. Structural blocks exhibiting higher rates of subsidence contained multi-km-long sandstone compartments.

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Is the Mississippian of Kansas a Viable Petroleum Target After a Century of Exploration?

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The Mississippian rocks in Kansas have produced about 16% of the oil and 11% of the gas of the total in the past 100 years. The Mississippian units are predominately uniform carbonates (mostly limestone), but are missing on the higher positive structures such as the Central Kansas Uplift and Nemaha Anticline. Production of petroleum is from both structural and stratigraphic traps. The present configuration of structures, formed near the end of the Mississippian when the North and South American plates collided, overprinted the previous structures and caused a change in the previous structural and sedimentary regimes in the region. An influx of upper Paleozoic clastics alternating rhythmically with carbonates signaled the onset of the Quachita Orogeny and major changes and provided the seal for the reservoirs. Mississippian units (up to 1,700 feet thick) include (from oldest to youngest): Kinderhookian, Osagean, Meramacian, and Chesteran; unconformably overlie the Siluro–Devonian or Ordovician units and are unconformably overlain by rocks of Pennsylvanian age - (from oldest to youngest) Morrowan, Atokan, or Desmoinesian.

Since discovery of oil in the Mississippian in 1916 in the Virgil field (Greenwood County), production from Mississippian rocks has accounted for slightly more than 13% of the state's total oil and gas production. Although historically most of the Mississippian oil has been produced from the Salina and Sedgwick Basins, the increasing contribution of Mississippian oil to total production is primarily the result of exploration in the Hugoton Embayment in western Kansas.

Information from 16,000 qualified wells was used to quality check formation data from 43,000 operator reported wells. Separating these new discoveries by date and comparing their spatial distribution to historical production provides a better understanding of emerging trends and new areas for exploration.

Geoscience for the 21st Century
Edited by D. F. Merriam: Transactions of the Am. Assoc. Petroleum Geologists Midcontinent Section Meeting (Wichita, KS), 1999

Bedrock Geology of Woodson County, Kansas

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Woodson County (503 sq mi) is located in southeastern Kansas in the Osage Cuesta physiographic province. The bedrock is Pennsylvanian in age and the units crop out roughly north-south and dip gently to the west at about 30 feet/mile so that the rock units range from the Lansing Group (oldest) through the Douglas Group to the top of the Shawnee Group (youngest) and consist of alternating units of bench-forming limestones and softer clastics, mostly shale and siltstone with some sandstone. Most of the surface drainage in the county is through the Neosho River and its tributaries, but the Verdigris and its tributaries drain the southwesternmost corner forming a scalloped outcrop belt. Two notable igneous intrusions occur at Rose Dome and Silver City where basic igneous rocks were intruded into the Pennsylvanian sediments in the late Cretaceous and formed oval-shaped domes. Some surface faulting is associated with the Silver City Dome. A third intrusive probably is present near Neosho Falls, but there is no surface expression. This county is the fourth mapped by the senior author—the others being Chautauqua, Elk, and Greenwood (Coffey County is currently being mapped). The surface geology is mapped in the field on 7 1/2-minute quadrangles (1:24,000), which then are digitized, coded, and overlain on topographic and cultural bases to produce a final, full-colored map. The map, or any portion of it, can be reproduced at any desired scale depending on the need and use; normal scale for the final map is 1:50,000. These county maps are just four of the 34 counties that have been or are being mapped or remapped to produce a new geological map of the State of Kansas.

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Progress in Development of Digital Geologic Maps Databases in Kansas

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Several new geologic maps of individual counties in Kansas have been published recently with progress in development of the Kansas Digital Geologic Map Database. In coordination with the National Geologic Map Database Project of the U. S. Geological Survey, programs at the Kansas Geological Survey, have focused on new field mapping in areas where published geologic maps were unavailable or deemed inadequate. This effort is combined with innovations in database development from previously published paper maps (usually out-of-print) in those counties where maps of reasonably good quality already exist. The Kansas mapping program has established large-scale (1:24,000) base maps as the standard for field mapping and database development, a significantly larger target base-map scale than the 1:100,000 scale set for the national project.

This presentation demonstrates recent geologic database development efforts and derived products. Techniques used by the Kansas Survey for database development from previously published maps are compared to the more usual practice of direct digital imaging (e.g., scanning). The Survey's techniques provide for integration of resulting data with geologic data from new field work or with Federal topographic map databases such as the USGS digital raster graphic map images. Recently published maps, including Labette, Leavenworth, Wilson, Greenwood, Wyandotte, and Chase counties are presented. Methods used by the Kansas Survey to provide access, via the Internet, to these maps and associated geologic data also are explained.

Geoscience for the 21st Century
Edited by D. F. Merriam: Transactions of the Am. Assoc. Petroleum Geologists Midcontinent Section Meeting (Wichita, KS), 1999

Mississippian Stratigraphy of Southwestern Kansas—Some Correlations Resolved, Many Mysteries

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Joe Clair noted in a 1948 Kansas Geological Society report, that the Mississippian was "for many years, to the majority of Kansas Geologists ... a top and base with varying thickness of very hard rock between." Ed Goebel's study of cores, samples, and microfossils in 1966 was a major contribution to Mississippian stratigraphy in western Kansas. The Kansas Sample Log Service (primarily J. D. Davies) lithologic strip logs also provide a wealth of rock descriptions and subdivisions of the Mississippian. Many geologists and companies, following the 50-year-old remark of Clair, may drill only the top portion of the Mississippian and report "Miss." (literally period, with no reference to subdivisions).

Continued petroleum exploration in the Hugoton Embayment has provided a wealth of new geophysical logs. Regretfully, Mississippian rotary drilling samples may be of poor quality from severe caving of overlying units. Up to date, preliminary research of all wells penetrating the complete Mississippian section has been made. Log sections and maps prepared from this study give a scattered sample of Mississippian subdivisions and correlations.

The distinct massive, "clean" oolitic limestone of the Gilmore City Formation is one of the best correlation markers. Reservoir development related to Salem (Spergen) anhydrite dissolution is illustrated. Various unresolved stratigraphic problems, such as the distribution of Chesterian rocks, Ste. Genevieve–St. Louis boundary, and St. Louis oolite reservoir zones also are illustrated. As the exploration history of this area has proven, resolution of difficult Mississippian geology correlations will result in new hydrocarbon discoveries for many more years.

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Tar Mat Formation within the Hitch Oil Field, Seward County, Kansas

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ABSTRACT

Hitch field (T. 33 S., R. 34 W., Seward County, Kansas) produces from Upper Mississippian Chester sandstone, deposited in a narrow valley incised into Mississippian Ste. Genevieve and St. Louis limestones. The Hitch reservoir originally had a small gas cap, a 98-foot oil column, and two minor water legs. Midway within the oil column, 20–30 feet of otherwise porous sandstone is filled completely with solid bitumen. The tar mat composition is similar to produced oil but with concentrated heavy components, and probably formed by precipitation, rather than biodegradation.

Although historical core descriptions reported "dead oil stain," and a low-permeability layer was well known from routine core analyses and well tests, the complete occlusion of the pore system was not originally recognized. Core-cleaning procedures removed most of the bitumen, resulting in acceptable porosity and grain-density values, and conventional wireline-log calculations indicated porous sandstone at irreducible water saturation, as expected. The tar mat is readily apparent with UV fluorescence core photography, thin section and SEM petrography, and NMR wireline logs, but these techniques were not incorporated into early field studies.

The Hitch tar mat went unrecognized for 20 years, despite multiple cores and standard wireline-log suites. Many producing reservoirs in the Hugoton Embayment contain similar oils, at similar pressures and temperatures, implying that in situ precipitation of heavy organic material should not have been unique to Hitch. It is likely that other tar mats, probably in reservoirs with disappointing production performance, are waiting to be recognized.

INTRODUCTION

The Anadarko Basin and shelf in general, and the Hugoton Embayment in particular, are known for gas and light (30–45°API) oils. Heavy, low-maturity or biodegraded oils are essentially unknown, except along limited areas of the basin's southern and eastern structural margins. The discovery of an extensive tar mat, containing significant volumes of immovable oil, in an area where none had been reported previously, was unexpected and not welcomed. The economic impact of this deposit has been substantial, and similar, as yet unrecognized deposits, probably have been responsible for disappointing production performance at other fields in the general area.

For purposes of this paper, the solid to extremely viscous pore-filling organic matter will be referred to as reservoir bitumen, without genetic connotation, following the usage of Lomondo (1992). The gross portion of the reservoir body that contains the reservoir bitumen will be referred to as a tar mat, again without implying a genetic origin. A definitive determination of the causal mechanism for the accumulation, or even the technically correct nomenclature (Cornelius, 1987), will require laboratory geochemistry that has not been performed.

HITCH OIL FIELD

The Hitch field usually is considered as part of the larger, multipay Shuck field, and is located in secs. 3, 10, 11, 14, and 15, T. 33 S., R. 34 W., Seward County, Kansas (Figs. 1 and 2). The reservoir was discovered in 1979 by the Anadarko No. 1 Hitch G, NW SE sec. 3, T. 33 S., R. 34 W., and initially flowed 254 BOPD and 1,519 MCFD from the basal Chester sandstone. This was preceded in 1978 by the Anadarko No. 1 Cosgrove A, the discovery well for the adjacent Etzold field, in secs. 22 and 27, T. 33 S., R. 34 W. Hitch and Etzold fields are in pressure communication and now are believed to be one common reservoir. Hitch by itself is 3 miles (4.8 km) long, and the total reservoir,

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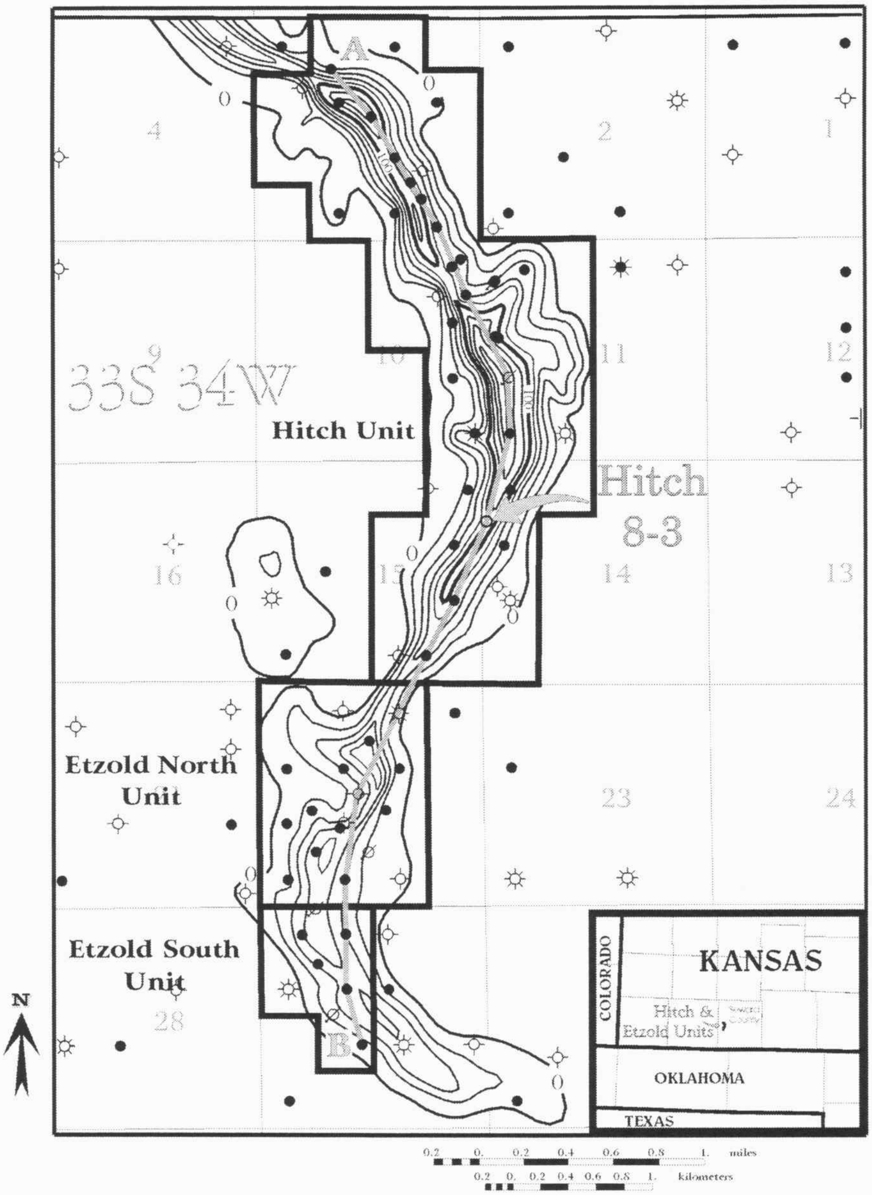

FIGURE 1—Net basal Chester sandstone, >8% porosity. Contour interval: 20 feet (6.1 m).

including Etzold, is 5 miles (8 km) in length and and less than 0.5 miles (0.8 km) in width (Figs. 1 and 2). Hitch had an initial gas/oil contact at -3,252 ft (-991 m) and two localized water legs, with oil/water contacts at -3,329 ft (-1,015 m) and -3,350 ft (-1,021 m). A third oil/water contact at –3,400 ft (-1,037 m) occurs at Etzold (Fig. 3).

The basal Chester sandstone reservoir, originally described by Severy (1975), was deposited in a narrow incised valley cut into Mississippian Ste. Genevieve and St. Louis limestones. This sandstone averages 46 ft (14 m) in thickness but can exceed 100 ft (31 m). The depositional setting is fluvial to estuarine, similar, but with somewhat more marine influence, to the South Eubank field, located 20 miles to the north and depositionally updip within the same valley system (Montgomery and Morrison, 1998, 1999; Morrison, 1999).

Within the oil column, porosity averaged 11.6% and permeability averaged 40 md. Fieldwide, within the oil column, a 30-foot (9.1-m) layer of lower core porosity (<8%) and permeability (average 2 md) was recognized from both core analyses and test results. This layer was subparallel to structure, extended over most or all of the Hitch field area, and did not have an equivalent within the Etzold reservoir (Fig. 3). Core porosity generally matched the neutron-density crossplot porosity, but was lower than crossplot porosity within the low-permeability layer. Resistivity and neutron-density porosity measurements were similar in both the normal and low-permeability sections.

Waterflooding at Hitch and Etzold commenced in 1990 and 1989, respectively, utilizing low-salinity treated water from the Liberal, Kansas, sewage-treatment plant.

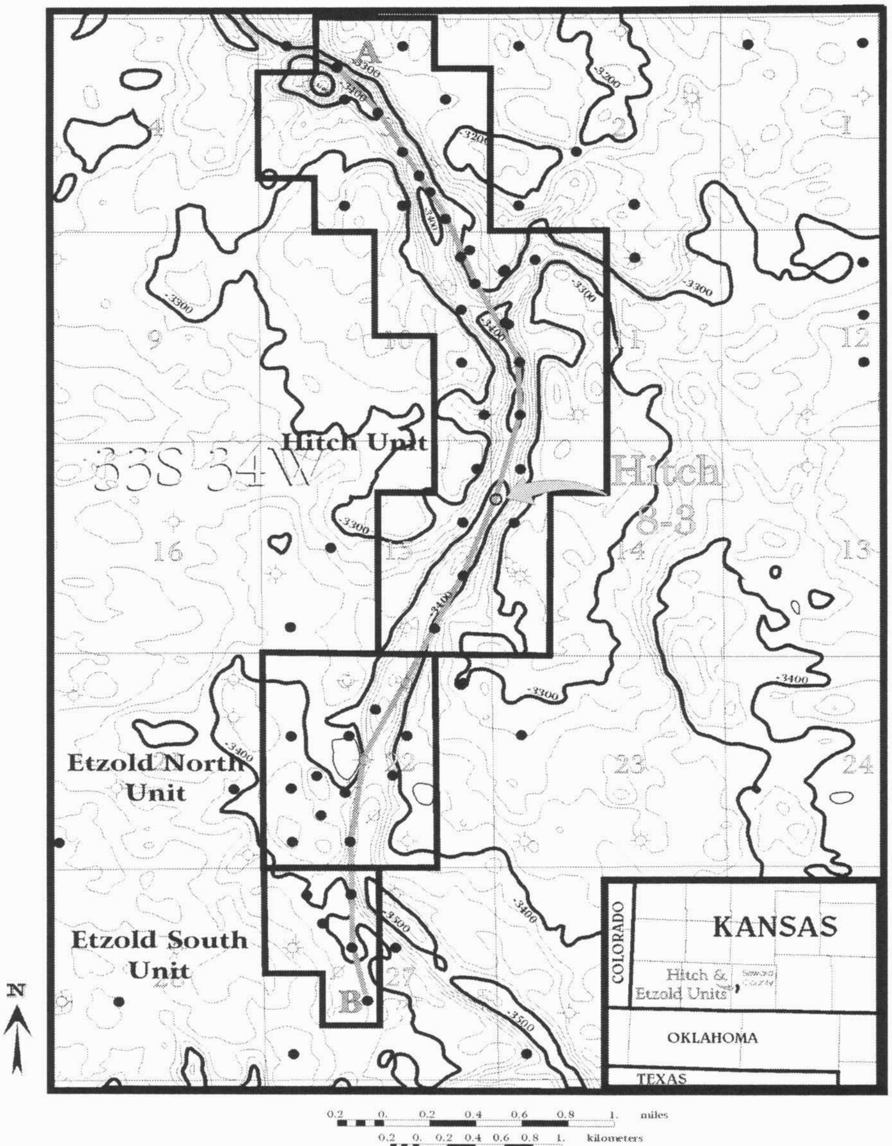

FIGURE 2—Structure, base of Chester unconformity. Contour interval: 20 feet (6.1 m).

The cumulative primary and secondary production at Hitch is 5,071 MMBO and 9,271 MMCF. Hitch has an EUR of approximately 31% of the original oil in place, based on volumetric calculations that include the low-permeability layer. This compares with 48% recovery anticipated from primary and secondary operations at Etzold, which has similar reservoir properties but lacks the low-permeability layer.

HITCH 8–3 FORMATION EVALUATION

In mid-1997, 111 feet (33.8 m) of core, representing all of the reservoir sandstone, was cut in the Hitch No. 8–3 well. The core was brown in color under visible light and exhibited bright yellow fluorescence under UV light throughout most of the sandstone. Porosity ranged from 10 to 17%, permeability ranged from 8 to 790 md, and grain density was a consistent 2.64–2.65 gm/cc. Within the oil column, a 27-foot (8.2-m) interval, correlating to the low-permeability layer known from earlier wells, was dark gray and displayed negligible fluorescence (Fig. 4). Core measurements within the nonfluorescent interval showed that porosity was less than 10%, permeability was less than 1 md, and grain density ranged from 2.54 to 2.60 gm/cc. Closer inspection revealed that bitumen was plugging the pore system in this zone.

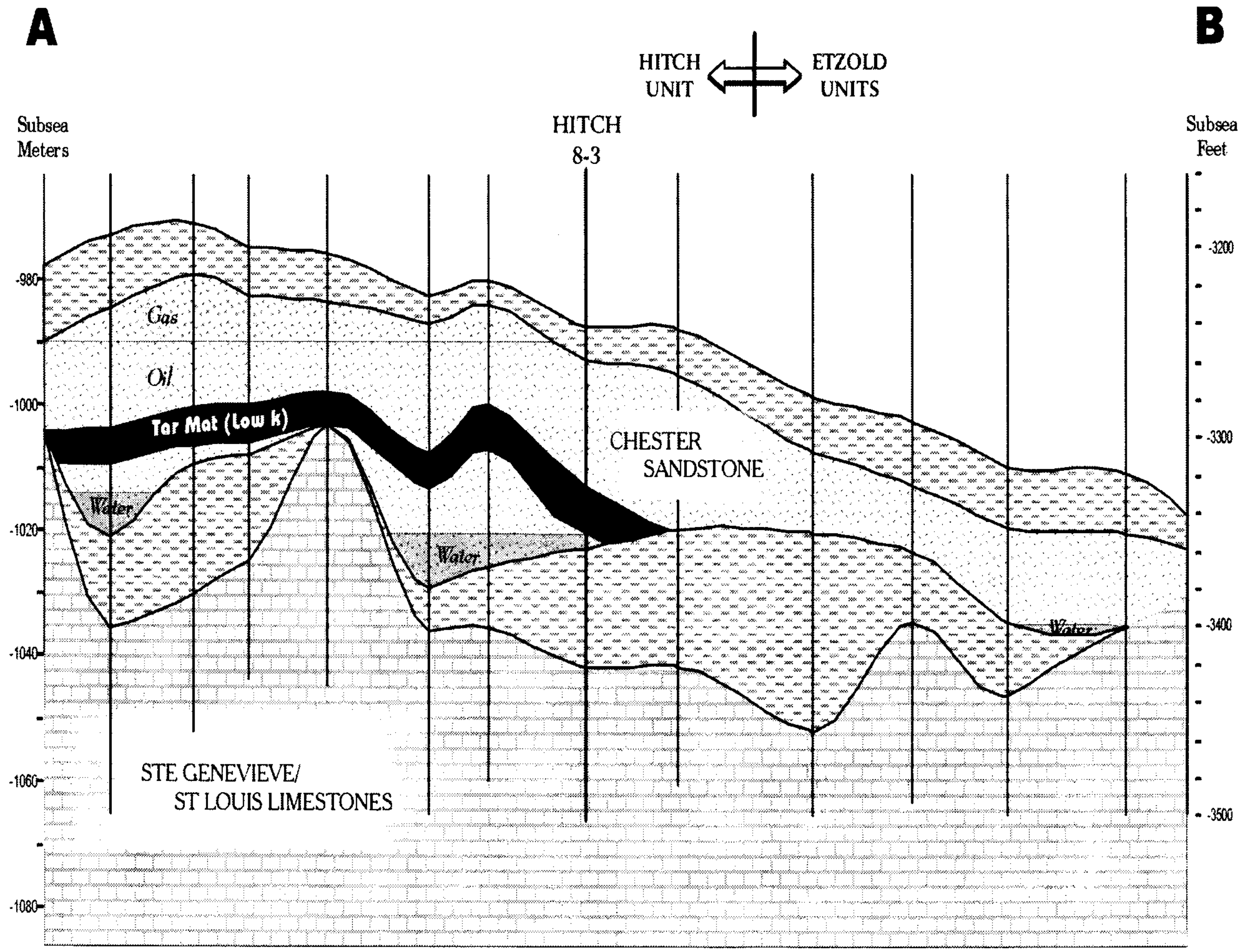

FIGURE 3—Structural cross section along axis of basal Chester valley. Vertical exaggeration approximately 33:1.

Grain composition and mineral cementation were similar for both sandstone types, indicating that the low grain-density values were the result of residual, lightweight bitumen. Whereas blue epoxy indicated good porosity and permeability in thin section for most of the reservoir, the corresponding interparticle space in the low-permeability interval was filled with black bitumen, with little or no penetration of blue epoxy. SEM photomicrographs of the bitumen had the appearance of "mudcracks," caused by shrinkage of the bitumen in the vacuum chamber.

The wireline-log suite in the Hitch 8–3 well consisted of the Schlumberger AIT–CNL–LDL, supplemented by a Numar MRIL. NMR porosity matched reasonably well with the neutron-density crossplot porosity for most of the reservoir, but deviated significantly for the interval that had bitumen plugging. Within this tar mat, the NMR porosity was "too low" by 2–5 porosity units relative to the neutron-density crossplot, because much of the bitumen was responding as a "solid." The NMR T2 distribution had low amplitudes and fast decay times, an observation that would typically be interpreted as capillary-bound fluid, but in this situation was the result of high oil viscosity. The low apparent porosity and fast decay times resulted in the calculation of low permeability for the tar mat interval (Fig. 4).

Hitch 8–3 resistivity curves within the tar mat interval indicated negligible invasion and irreducible water saturation. Although calculated oil saturations were high, the oil was not mobile. The Chester sandstone porosity above the tar mat interval, which was originally oil-bearing, tested water with only a trace of oil cut in the Hitch 8–3, a consequence of several years of prior waterflooding. The high formation resistivity in the watered-out zones was because of the high resistivity of water utilized in waterflood operations (Fig. 4).

In the absence of core or the MRIL log, this well would have been interpreted as having been partially watered-out by the waterflood, with bypassed pay in the middle of the reservoir. In the absence of obvious shale barriers or faults, the mechanism by which the reservoir was compartmentalized would have remained problematical.

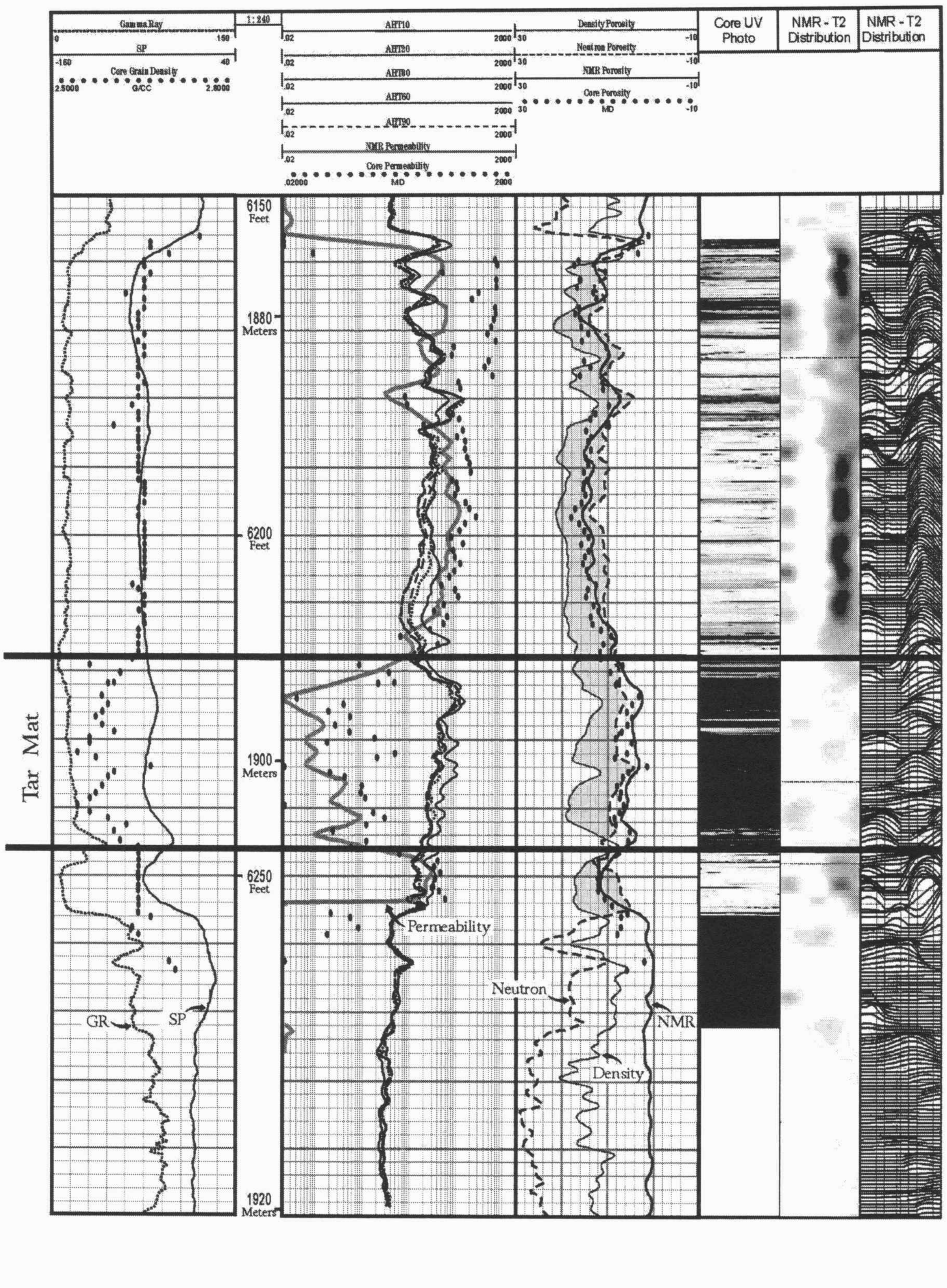

FIGURE 4—Hitch 8–3 composite log of basal Chester sandstone.

HISTORICAL FORMATION EVALUATION

Wells in the Hitch field have been logged routinely with a minimum suite consisting of a dual induction log and a neutron-density log. The tar mat would have been barely detectable with this log suite, even with prior knowledge of its existence. The differences in fluid density or hydrogen index between movable oil and bitumen were too small to cause obvious changes in the total porosity or in the separation of the neutron-density porosity curves. Log calculations indicated that the tar mat portion of the reservoir was at irreducible water saturation.

Several cores, which were examined routinely at the time for the purpose of determining the sandstone depositional environment, were cut during the initial field development in Hitch and Etzold. There were numerous anecdotal comments such as "dead oil stain," "gilsonite," etc., for cores which had the low-permeability layer, but the studies neither report the complete occlusion of the pore space by bitumen, nor establish a correlation between the presence of bitumen and the low permeability in this interval.

With one exception, the routine core analysis of bitumen-plugged intervals yielded porosity values similar to, but slightly less than, the porosity logs, indicating that the core cleaning process had removed significant quantities of the bitumen prior to the measurements. Permeabilities in the tar mat averaged 2 md, rather than the expected average of 40 md, and this knowledge about the low-permeability interval was incorporated into the later waterflood design. There was no mention of the bitumen plugging in the laboratory core reports, which came from at least five different laboratories. The core analysis report from one well recorded grain-density values of 2.54 to 2.57 gm/cc within the low-permeability interval, clearly indicating the presence of lightweight material such as bitumen or halite, but it seems to have gone unnoticed.

Routine laboratory practice calls for thorough cleaning of core plugs prior to the measurement of porosity, permeability, and grain density. Organic material can be removed by heating in a vacuum retort, or by cycling a solvent such as toluene through the plugs until the exiting solvent is found to be "clean." More aggressive solvents, such as chloroform, might be used to assure that no hydrocarbon residue remains in the plug. Although these steps are proper for the optimum measurement of reservoir rock properties, they can create artificial porosity by removing bitumen that is part of the solid matrix under in situ conditions. Much of the bitumen was removed from the core plugs prior to analysis, but the procedures employed did not remove all of the organic material within the tar mat interval. The slightly low core porosities relative to the neutron-density crossplot values and the significantly reduced permeability values reflect the presence of residual bitumen and partially blocked pore throats.

Simulated cuttings, derived from 1.5-year-old bitumen-plugged core, were examined using routine wellsite procedures. These samples have obvious bitumen plugging of the pores and no visible fluorescence in a UV box. When contacted by solvent (lighter fluid), the samples immediately display bright-white to light-blue fluorescence, colors which usually are associated with condensate or light crude oils. A slow streaming cut follows, with pale-yellow-green fluorescence, which could prompt a wellsite geologist to conclude that some of the oil in the tar mat interval is movable.

GEOCHEMISTRY

The Hitch reservoir, at discovery, had a reservoir pressure of 1,920 psig, a temperature of 145°F (63°C), and it produced 40°API oil with a viscosity of 0.75 cp. The composition of the produced oil, based on gas chromatography (Fig. 5A), is similar to oils from other Mississippian reservoirs in the Hugoton Embayment. The primary source rock for Hitch oil is believed to be Woodford Shale, implying long-distance migration from the Texas Panhandle (Burruss and Hatch, 1989; Hester and Schmoker, 1993; Johnson and Cardott, 1992). Some oil samples from Hitch, Etzold, and nearby fields have a modest odd-even predominance for n-alkanes in the C13–C20 range, suggesting that there could be a contribution from Ordovician *G. prisca* source rocks as well (Longman and Palmer, 1987; Wang and Philp, 1997).

Gas chromatography of a thermal extract of bitumen from the Hitch 8–3 core yields a similar distribution of alkanes heavier than C15 (Fig. 5B), suggesting that the bitumen may have precipitated from a genetically related oil. The bitumen extract has a low abundance of alkanes lighter than C15, relative to the produced oil. Evaporation during a year of core storage under ambient surface conditions is a contributing factor for the low concentrations of n-alkanes lighter than C10. The results from liquid chromatography (Fig. 5) indicate that the bitumen extract is enriched significantly in asphaltenes relative to produced oil, but the sample is dominated yet by saturated hydrocarbons. Aromatics and resins have similar concentrations in both samples.

The exact composition of the reservoir bitumen is somewhat uncertain. Simple extraction methods always leave minor quantities of organic residue behind in the pore space, which may differ from the mobilized material. The products of thermal extraction are dependent on

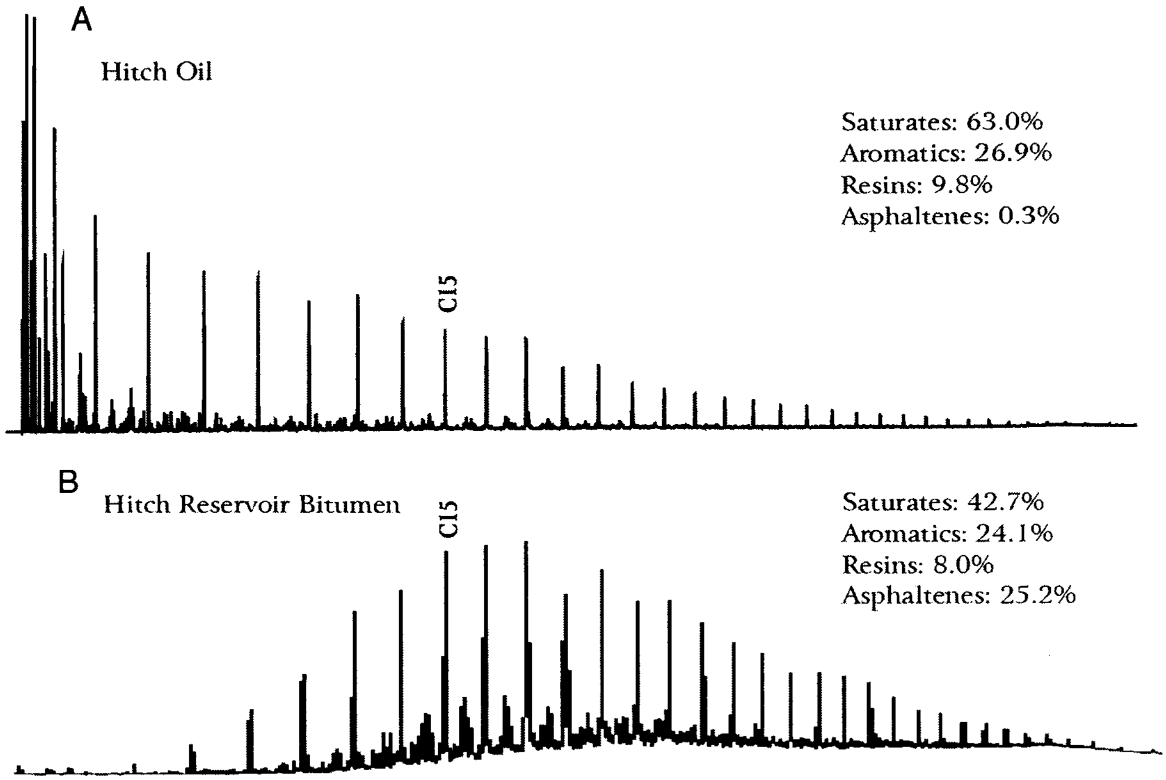

FIGURE 5—Whole oil gas chromatography and SARA analysis (liquid chromatography) of A, produced oil from Hitch Chester reservoir, and B, thermal extract of reservoir bitumen from Hitch 8–3 core.

heating rates and maximum temperatures employed, and these can result in thermal cracking if the heating is too aggressive. Solvent extraction techniques can result in significant variability in the end product, depending on the choice of solvent (Hwang, Teerman, and Carlson, 1998). Even if the extraction has been thorough, paraffins heavier than C40 can be difficult to remove from the asphaltene fraction (Thanh, Hsieh, and Philp, 1999). More laboratory study will be required to address these questions.

TAR MAT ORIGIN

Solid organic deposits can form within a reservoir by several processes (Wilhelms and Larter, 1994a, 1994b, 1995; Hunt, 1996). Theories regarding the origin of the Hitch tar mat must honor local and regional geological relationships, the low thermal maturity of southwestern Kansas, and the composition of the bitumen. The detailed geochemistry required to define the process has not yet been performed. The layered nature of the tar mat suggests that it might have formed at an oil-water contact, followed by accumulation of additional oil in what formerly had been the water column.

Asphaltene precipitation within tubing or surface production equipment has been a problem in Hitch and other nearby reservoirs, and can occur within a reservoir as a result of production operations (Hwang and Ortiz, 1998). The Hitch tar mat, however, is not a humanmade phenomenon. Core analyses indicative of the tar mat are available from some of the early wells in the field, demonstrating a preexisting condition. The asphaltene concentration in produced oil (Fig. 5) is inadequate to generate the asphaltene component of the known volume of reservoir bitumen. Material balance considerations demand that reservoir precipitation must have occurred with a different, more asphaltene-rich oil in the reservoir, or be the product of the migration of multiple reservoir volumes of oil through the Hitch system.

Thermal cracking of oil to gas and pyrobitumen can occur at elevated temperatures (Hunt, 1996), yielding carbonaceous residues that are commonplace in the thermally mature reservoirs of the Arkoma Basin (Gross and others, 1995). This mechanism is not viable in Hitch, where the reservoir is at best marginally mature for oil generation (Cardott, 1989; Schmoker, 1989).

Biodegradation and water washing lead to a predictable, sequential loss of organic compounds, beginning with light paraffins, and continuing until only the insoluble and indigestible large molecules such as asphaltenes are left (Hunt, 1996; Miller, Holba, and Hughes, 1987). This would be plausible in southwestern Kansas if oil accumulations formed prior to significant burial during the Pennsylvanian, when the reservoirs might have been in communication with outcrops by fresh groundwater flow, a scenario used to explain bitumen deposits in the Oklahoma City field (Webb, 1976). Reports of significant biodegradation within the Anadarko Basin are limited to its south and east margins, where oil accumulations have been exposed to near-surface conditions within the Arbuckle and Wichita Mountains (Harrison and Burchfield, 1987; Miller, Holba, and Hughes, 1987). Limited geochemistry indicates that biodegradation is not significant at Hitch. The alkane disdribution of the produced oil exhibits no signs of biodegradation (Fig. 5A), and the abundance of saturated hydrocarbons (42.7%) in the bitumen extract (Fig. 5B) is inconsistent with a biodegradation origin.

Plugging of reservoirs by paraffin precipitation at low reservoir temperature, as suggested by Bolyard (1995) for Morrow sandstones in the Las Animas Arch area, is not considered likely at Hitch, even though the bitumen contains a substantial quantity of paraffin. Hitch oil does not have the high pour point and concentration of heavy paraffins typical of Upper Morrow oils in the Hugoton Embayment, and the Hitch reservoir temperature of 63°C (145°F) is sufficiently high to make paraffin crystallization under in situ conditions unlikely.

Gas deasphalting, widely used as an early step in refining, can cause precipitation of heavy compounds when large concentrations of hydrocarbon gases are introduced into crude oil. This can occur in reservoirs when migration of oil is followed by gas, as source rocks become more thermally mature (Hunt, 1996). This mechanism is plausible for the Chester, because downdip source rocks have been buried into the gas window in the deep Anadarko Basin. The areal distribution of the tar mat and the gas cap are roughly the same in the Hitch reservoir, whereas both are lacking at Etzold (Fig. 3). Whether this reflects a causal mechanism or is merely coincidental is not known.

Heavy oils, generated from low-maturity source rocks, typically have a high asphaltene content but are not highly prone to asphaltene precipitation. Asphaltenes tend to be less stable in solution in light oils or high GOR oils, which typically come from source rocks of greater thermal maturity. Consequently, episodic migration from source rocks at increasing levels of thermal maturity can lead to mixed oils with an unstable composition (Khavari–Khorasani, Dolson, and Michelsen, 1998; Khavari–Khorasani, Michelsen, and Dolson, 1998; Hwang, Teerman, and Carlson, 1998; Thanh, Hsieh, and Philp, 1999). Multiple waves of increasingly mature Woodford-sourced hydrocarbons probably migrated through this part of Kansas, as the Woodford Shale underwent progressively deeper burial in the Texas Panhandle. Ordovician *G. prisca*-sourced oils, which typically have low concentrations of heavy (>C20) alkanes regardless of thermal maturity (Longman and Palmer, 1987), also might have caused asphaltene precipitation when mixed with low maturity, asphaltene-rich, Woodford-sourced oils.

ECONOMIC CONSIDERATIONS

The Hitch field oil is similar in composition to oils from numerous other fields within southwestern Kansas and the Oklahoma Panhandle, and occurs at similar depths, pressures, and temperatures. If a tar mat 30 feet (9.1 m) thick could remain hidden at Hitch for two decades, despite multiple cores and modern wireline-log suites, unrecognized solid bitumen deposits could be present in many other fields, where the database usually is of lower quality. The primary clues should be the references to dead oil stain in cuttings and the disappointing completion and production results, as operators tried to develop reservoirs where the hydrocarbons had little or no ability to flow.

Conventional wireline-log interpretations, within the tar mat interval, indicate 30 feet (9.1 m) of reservoir-quality sandstone at irreducible water saturation. Volumetric estimates, based on routine log calculations, caused approximately 5 MMBO of immovable bitumen to be included as part of the original oil in place. The horizontal permeability barrier created by the tar mat also caused a complete separation of the reservoir into two compartments, complicating the waterflood operations. The end result was lower than expected oil recovery under both primary and secondary operations.

Reservoir bitumen does not have to fill pores completely to cause significant problems. A substantial loss of permeability can occur with minor amounts of bitumen, depending on its distribution, which usually is within the intervals of highest reservoir quality (Lomondo, 1992). The surfaces of precipitated bitumen have a tendency to be strongly oil-wet, which can seriously impact wireline-log interpretation, and alter the fluid-flow characteristics and oil recovery in waterflood operations.

The extension of a CO_2 pipeline into the Hugoton Embayment, with initiation of a CO_2 flood in Morrow reservoirs at the Mobil-operated Postle field in Texas County, Oklahoma, has caused additional reservoirs to be evaluated as potential EOR projects. The solubility of the bitumen in laboratory solvents, as demonstrated in the historical core analyses, suggests that mobilization of the tar mat under CO_2 flood conditions is a possibility. Bitumen mobilization could add to potential reserves but with the attendant risk that asphaltene-precipitation problems in production equipment will increase. Alternatively, the introduction of CO_2 could cause additional precipitation within the reservoir, resulting in reservoir plugging, a decline in water and gas injectivity, and a change toward oil-wettability, as has been observed in CO_2 floods elsewhere (Hwang and Ortiz, 1998; Monger and Fu, 1987; Monger and Trujillo, 1991). The stability in solution of the heavy components of the crude oil should be a critical part of the EOR evaluation process for any reservoirs in the Hugoton Embayment that contain this type of oil.

CONCLUSIONS

The nature of the Hitch tar mat remained unrecognized for two decades, despite a better than average formation evaluation database, extensive production and test information, and the work of numerous geologists and engineers. Although it is the first to be reported from the Hugoton Embayment, it is unlikely to be a unique phenomenon. A search of other fields will probably turn up additional overlooked examples, most of which will have had disappointing, but poorly explained, production characteristics.

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Tuesday, August 31
Poster Sessions

Significance of Accurate Carbonate-Reservoir Definition and Delineation

Paul W. Smith, Walter J. Hendrickson, and Ronald J. Woods
IHS Energy Group, Oklahoma City, Oklahoma

See abstract on p. 37 in presentations.

Geoscience for the 21st Century
Edited by D. F. Merriam: Transactions of the Am. Assoc. Petroleum Geologists Midcontinent Section Meeting (Wichita, KS), 1999

Detailed Reservoir Modeling on a Basinwide Scale and Implications on the Decision-Making Process

Paul W. Smith, Walter J. Hendrickson, Ronald J. Woods, John V. Hogan, and Charles E. Willey
HIS Energy Group, Oklahoma City, OK

See abstract on p. 8 in presentations.

Geoscience for the 21st Century
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High-Resolution Sequence Stratigraphy of the Mississippian of the Appalachian and Illinois Basins

A. Al–Tawil, L. B. Smith, A. B. Khetani, T. Wynn, and J. F. Read
Department of Geological Sciences, Virginia Tech, Blacksburg, Virginia

Logging of outcrop sections and shallow cores from the Appalachian and Illinois Basins has generated a high-resolution sequence stratigraphy that we are taking into the subsurface of the Appalachian Basin using well cuttings and gamma-ray logs calibrated to outcrops. The Mississippian carbonates developed on and in front of the Borden siliciclastic deltaic/marine shelf. The Osagean–Meramecian Ft. Payne–Salem units built out from the abandoned delta as six to eight prograding, clinoformal depositional sequences of siliceous carbonate slope and ramp margin banks, and low-stand lobate sands. Chesterian Ste. Genevieve units are oolitic carbonates with numerous disconformities whereas post-Ste. Genevieve Chesterian units mainly are interlayered carbonate and siliciclastic units with some karstic disconformities and paleosols. These are capped by prograding dominantly siliciclastic units (Pennington and equivalent units). Between nine and eleven fourth-order Chesterian sequences can be traced between the Illinois and Appalachian Basins. Ste. Genevieve to Paoli sequences generally are carbonate-dominated except in the western Illinois Basin where they contain major clastic units. Carbonate-dominated units contain relatively regional parasequences composed of ooid grainstone tidal-ridge facies, capped by extensive lagoonal mudstones and updip by disconformities. Younger Chesterian sequences are mixed carbonate-clastic sequences with incision on sequence boundaries. These contain parasequences with a basal sandstone valley fill and tidal sand-ridge units, overlain by skeletal limestone and shale-dominated siliciclastics. The sequences seem to be bundled into third-order composite sequences bounded by major erosional disconformities. The upsection changes in sequence stratigraphy may reflect buildup of Gondwana ice sheets and increased amplitude glacio-eustasy.

Geoscience for the 21st Century
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Constraining Permeability Field to Engineering Data: an Innovative Approach in Reservoir Characterization

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ABSTRACT

Reservoir characterization can yield major improvements in reservoir management and hence in reservoir forecasting. The use of engineering data in reservoir characterization has become increasingly important particularly when it comes to permeability modeling. This paper presents a new technique in integrating engineering data such as pressure-buildup tests and flow-meter surveys in conditioning core permeability data to capture high flow zones in stratified reservoirs.

Flow-meter data are used to allocate total permeability from pressure-buildup test. Through this technique a permeability log is produced that has the same vertical resolution as the flow meter. Series of cross validations are performed between core permeability and permeability derived from engineering data. Such validations provide statistical comparison between the two sources of permeability for each facies. A comparison of the porosity relationship also is made between both sources of permeability. Upon completetion of the cross validation phase, an integration phase is accomplished. Subsequently, the permeability obtained from engineering data is used to sample the cumulative density function of the core-permeability cloud transform.

Finally, the spatial correlation of permeability is obtained from the radial diameter of the pressure buildup test to construct a permeability model. Such a model then is compared with a conventionally built permeability model. This approach was applied to one of the Saudi Arabian oil fields. The results of this case study show that a model conditioned to engineering data produces better results of capturing the high flow zones in a highly stratified Saudi Arabian reservoir.

INTRODUCTION

Permeability is considered as the primary component in any fluid-flow simulation study as it defines the path of fluid flow. However, one of the most outstanding challenges in reservoir characterization is to build high-resolution permeability models that satisfactorily utilize observed production data for simulation purposes.

Because permeability can not be measured from conventional wireline logs, most conventional permeability models are based on permeability values measured from cores and correlated to rock porosities. The process generally leads to a large scattered cloud of core data. These data are the only source of permeability information, which is limited both vertically because of the nonrecovery nature of the core, as well as horizontally, because of the high cost of any coring program and limited sampling at well locations only.

The conventional permeability models based on scattered core plugs data do not describe the true complex heterogeneity within the reservoirs. On the other hand, the permeability measured in pressure-buildup tests (engineering data) provides a measure for a gross vertical interval instead of a foot-by-foot, and a gross drainage area (100's of feet). In this study, flow-meter profile is used to resolve the difference in scale between pressure buildup Kh and core permeability. A novel approach is used to integrate permeability from core data with the permeability from pressure buildups allocated by the flow-meter profile. Results are compared to permeability distribution out of conventional models in a clastic reservoir for accuracy and reliability.

CONVENTIONAL METHOD

Figure 1 shows how the current permeability models are built. A regression line is fitted through a cloud of core porosity and permeability values by averaging the distribution of permeability for a given porosity value. This linear relationship then is used to transform a constrained porosity model where porosity is present at each well

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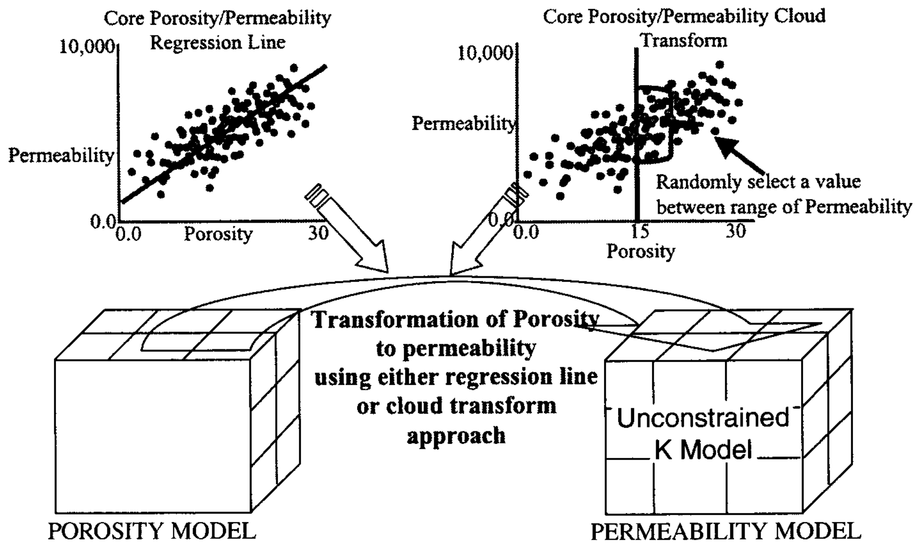


FIGURE 1—Schematic cartoon showing how current permeability models are built.

location from wireline logs to unconstrained permeability model that has no permeability information at well locations. However, because of averaging of permeability values, the permeability models show homogeneous results encased with poor values. Lately, this problem has been resolved by employing a new approach to capture all the possible values of permeability for a given porosity value by building a cloud transform to better represent the heterogeneity of the reservoir.

Both the regression line and the cloud transform approaches produce unconstrained permeability models that do not reproduce the real well information. These methods usually produce poor results that do not match the observed production data (such as pressure and water cut). As a result, permeability distribution is distorted significantly during the history-matching phase of a simulation process with no geological basis.

PROPOSED METHOD

To overcome the shortcomings of the conventional methods, the flow-meter profile is used in this study to allocate the total or gross measurement of pressure buildup to a higher resolution permeability log. Figure 2 illustrates how flow-meter data are used in allocating permeability from pressure buildup to produce a permeability log, so that a mirror image is created using the same scale and resolution of the flow meter. The newly produced permeability log from engineering data, however, lacks the information at nonperforated intervals as well as it is characterized by the blocky shape.

In order to resolve this problem, initially the high-resolution core data are integrated to produce a permeability log at each well location that matches the engineering data. This integration is accomplished by assigning permeability values from cloud transforms equal or close to engineering derived permeability as shown in Figure 3. At nonperforated intervals, however, facies-based cloud transforms are used to randomly sample possible permeability values from core data for a given porosity (Deutsch and Journel, 1992).

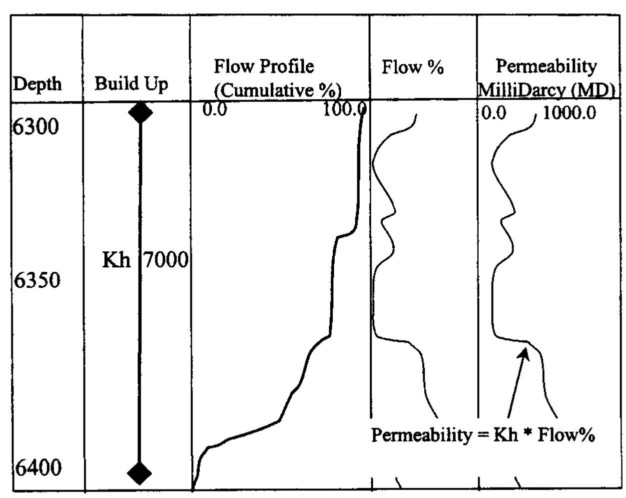


FIGURE 2—Illustration of how flow meter is used to allocate pressure buildup permeability.

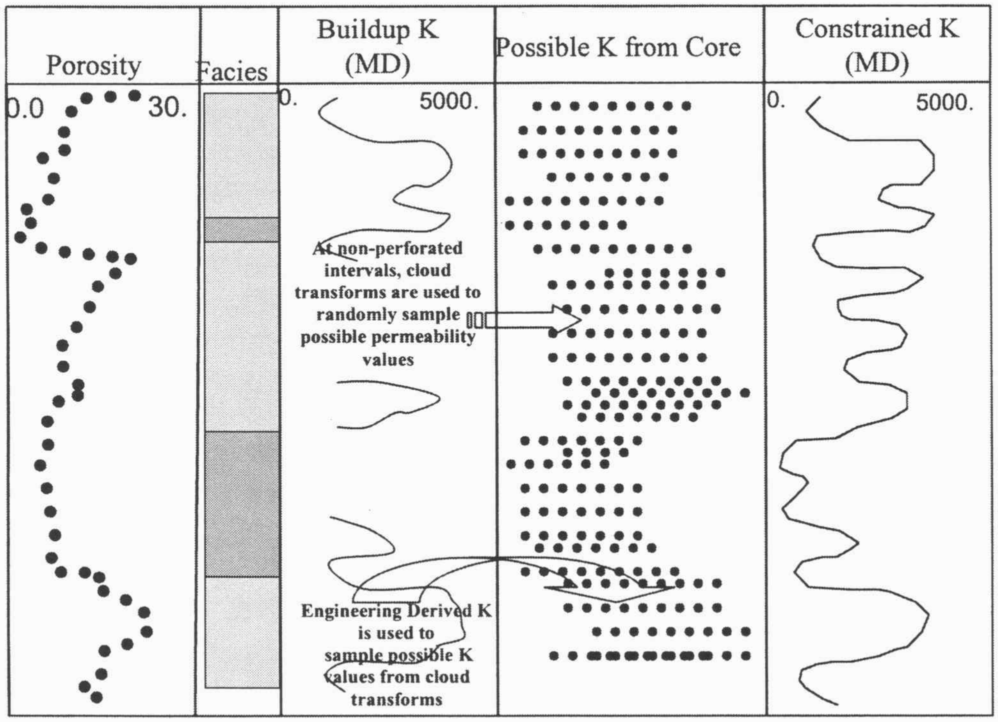


FIGURE 3—Integrating buildup permeability as selecting criteria in sampling range of permeability values from core.

CASE STUDY

Geological Background

The Hawtah field is located in the central part of Saudi Arabia (Fig. 4). The Unayzah Formation clastics form the principal reservoir rock. The Unayzah Formation in this field is sandwiched between two unconformities (Fig. 5); the large Hercynian Pre-Unayzah Unconformity (PUU) at the base and the Pre-Khuff Unconformity (PKU) at the top. The highly stratified clastic reservoir, Unayzah, has been selected to demonstrate the use of the application in integration of engineering data in building a permeability model.

Sedimentological studies of available cores and interpretation of borehole-image data indicate that the lower portion of the Unayzah Formation consists of locally derived alluvial fan and braided stream sediments. Borehole-image data through the lower Unayzah sandstones show sedimentary structures consistent with this interpretation. In contrast, the upper portion of the Unayzah Formation is dominantly eolian and associated lacustrine and sabkah facies. Both borehole images and core studies support this interpretation (AlQassab and Heini, 1998).

Data Set

The data set available in this study consists of core porosity and permeability from selected cored wells, as well as porosity from neutron and density logs. Lithologies interpreted from wireline logs also are utilized for all wells in this study. Using an in-house cluster analysis, eight electric-log curves were used to establish electric-log-based lithofacies for all wells. These lithofacies then were cross-referenced with the core. The result showed five distinct electric lithofacies that tied well to the core. The facies were identified as follows: (1) shale, (2) mudstone, (3) siltstone, (4) sandstone, and (5) clean sandstone (Table 1 shows a more detailed description). However, these facies have been categorized into three major groups for the 3D facies modeling: a dune facies that consists of clean sandstone; a mixed eolian/fluvial facies consisting of sandstone and siltstone; and last is an interdune lacustrine and sabkha facies that consists of siltstone, shale, and mudstone.

Permeability from Pressure Buildup and Flow Meter

Seventy-nine wells have been made available that have flow-meter profiles and permeability from pressure-buildup tests. However, only those wells that show dry oil production with no water have been selected in this study to reflect the obsolute permeability measured in the core. Figure 6 shows an example of permeability thickness (Kh) from a pressure-buildup test (Track 1) and flow-meter profile from one of the wells (Track 2) in Hawtah field. Within the Unayzah reservoir the permeability thickness is

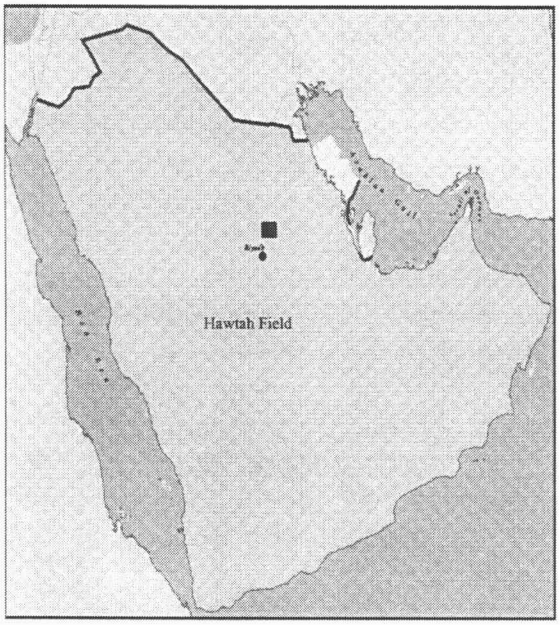


FIGURE 4—Location map of Saudi Arabia.

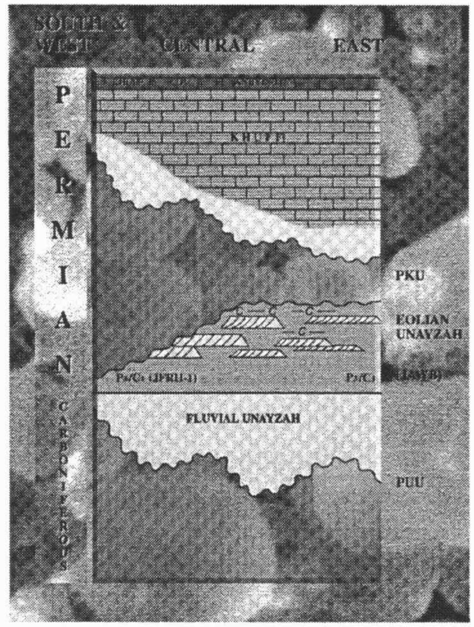


FIGURE 5—Stratigraphic column showing Unayzah Formation.

TABLE 1—Detail description of Unayzah facies (from Al–Qassab and Heine, 1998).

Electrofacies	Core Facies	Description
1	Shale	Black marine shale. Only occurs in the Qusaiba and Khuff Formations, none in the Unayzah.
2	Mudstone	Brick-red, brittle mudstone. Breaks out in wellbore.
3	Siltstone	Red, very fine-grained sand to siltstone, wave-ripple laminations, adhesion ripples. Characteristic of the interdune sabkah.
4	Sandstone	Well-sorted, well-rounded sandstone. Variable crossbedding dips mostly low-angle unidirectional. Porosity 18–24%. Permeability 50–350 md.
5	Hi P&K sandstone	Well-sorted, well-rounded sandstone. Planar tabular crossbedding 30° dipping bed sets (eolian facies) Porosity > 24%. Permeability > 500md.

measured to be about 27000 (Kh) across two perforated intervals. In the third track, the cumulative flow has been converted to percentage of flow to represent the flow from each perforated zone. The percentage of flow then is used to allocate the total permeability from pressure buildup. The newly created permeability log indicates that it has the same resolution as that of the flow meter.

This procedure is applied at each well that has both flow-meter and pressure-buildup tests in Hawtah field. However, this step requires the validation of both flow-meter surveys and pressure-buildup tests.

Cross-Validation

The cross-validation of the engineering-derived permeability logs with the core-permeability measurement is an essential step to ensure that both sources reflect the same measurements regardless of their origin. During this process the existence of faults and fractures that may not be detected by core could be identified from engineering-derived permeability log.

This study includes comparative analysis of those cored wells that have both pressure-buildup tests and flow-meter profiles. Figures 7 and 8 show two such wells that have both cored permeability and engineering-derived permeability data. In these examples the similarities are noticeable between core permeability and engineering-derived permeability. In fact, some wells show more continuous permeability from buildup and flow-meter data than from permeability obtained from the cores. Moreover, the permeability from engineering data can be used to correct core depths, as it is more accurate than the core, where depth shifting of core is illustrated in Figure 8. It is also worth mentioning from the previous two figures, similarities do exist between facies and the permeability-derived engineering data.

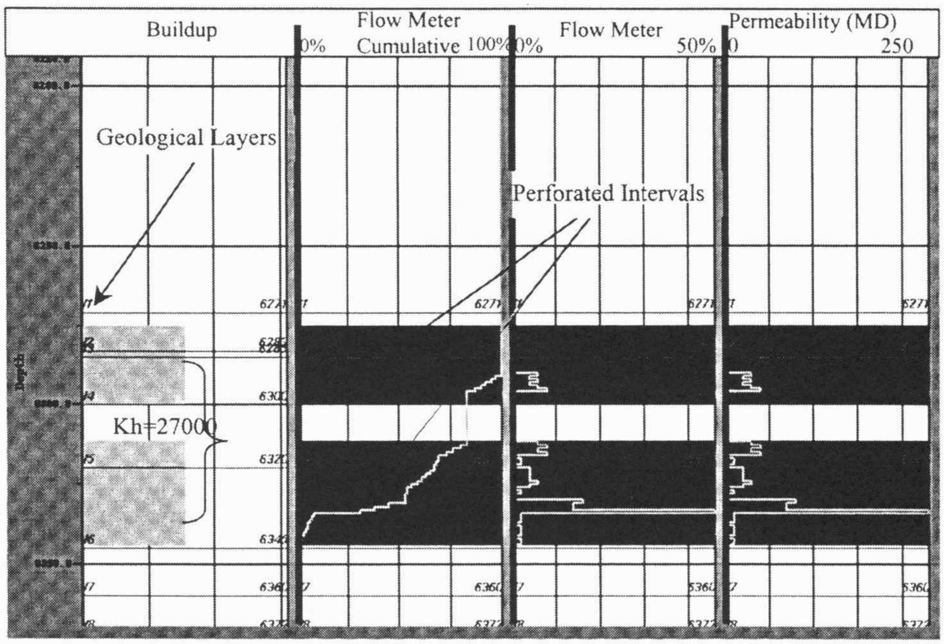


FIGURE 6—Example of permeability thickness allocated by flow meter in one of Hawtah field wells.

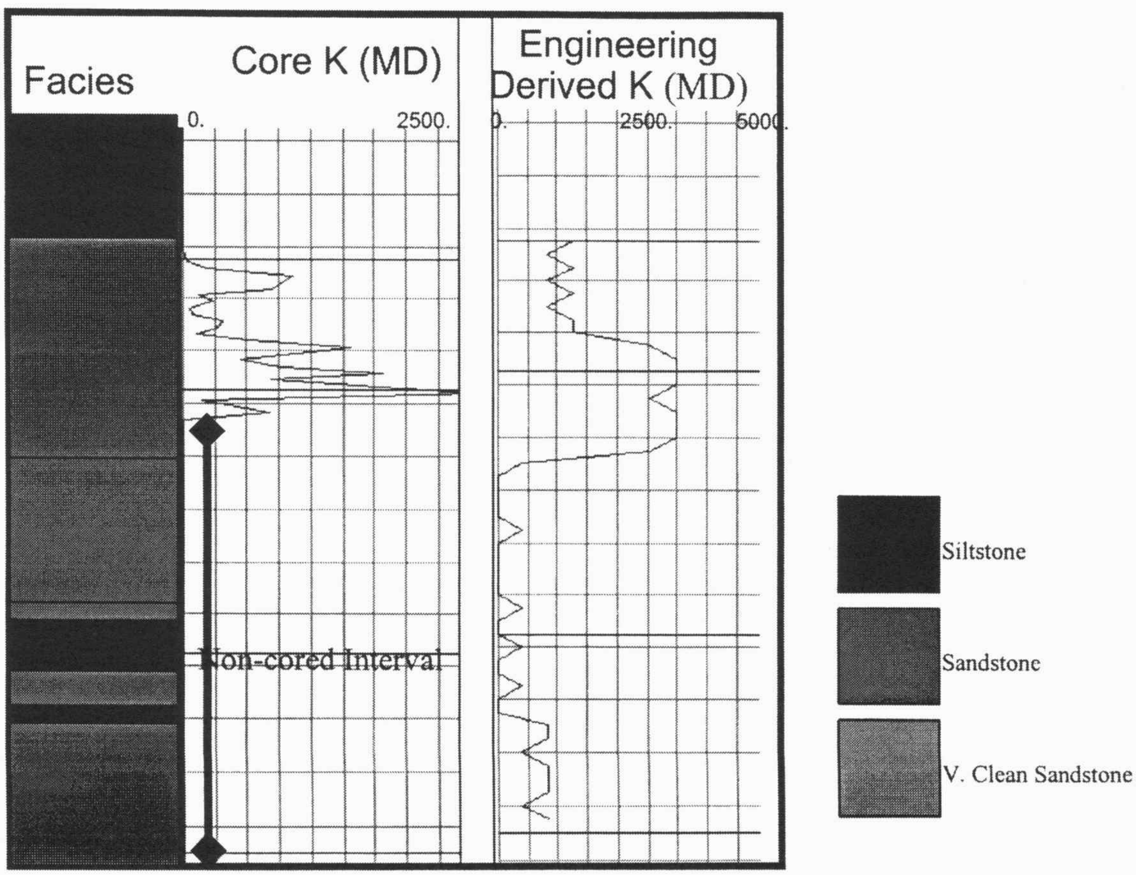


FIGURE 7—One of Hawtah wells showing comparison of permeability derived from engineering data and core permeability.

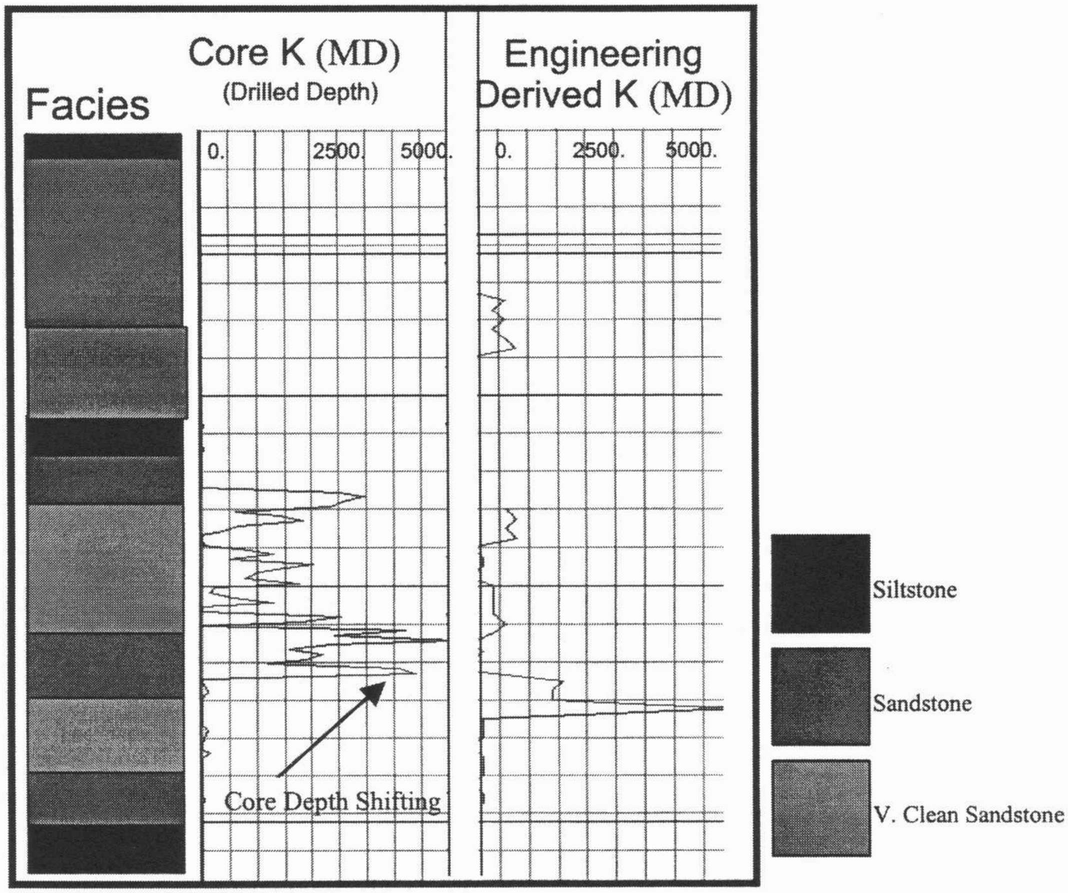


FIGURE 8—Example showing comparison of permeability derived from engineering data and core permeability.

As mentioned earlier, five facies have been defined in Unayzah reservoir based on wireline logs and core data. Permeability from core and buildup data shows separation where facies changes occur. This change is compared statistically in terms of their univariate and bivariate distribution. For example, Figure 9 shows two histograms of permeability from both sources for the "very clean sandstone" that is considered as high-quality reservoir facies. Similar distributions are indicated between both sources of permeability to typify the facies. Equal mean and standard deviation suggests that both sources of permeability are measuring the same system. Hence, the permeability from engineering data can be used in a similar fashion to core permeability or integrated with core data.

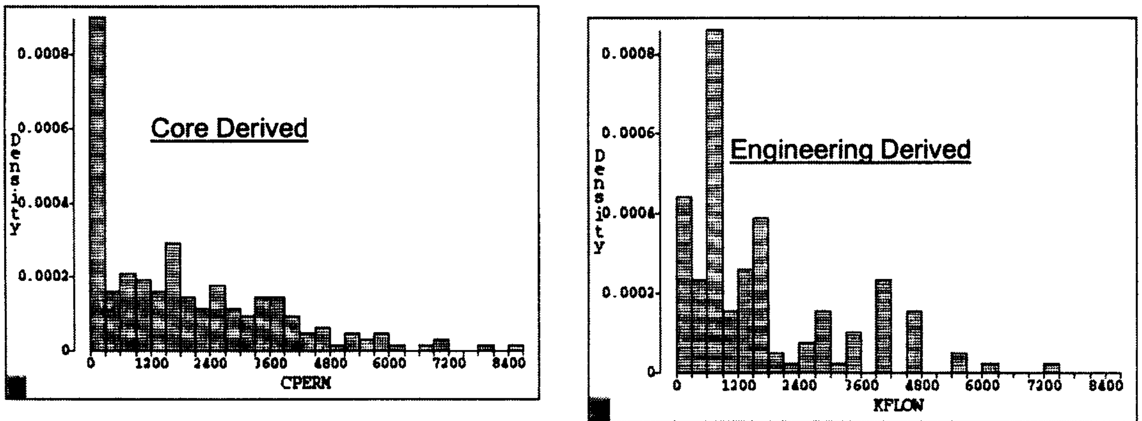
Univariate statistics also are shown in Figure 10 for the sandstone facies. Both core permeability and engineering-derived permeability have a similar distribution with nearly the same mean and standard deviation. Similar conclusions can be drawn from the statistics of the low-med reservoir-quality siltstone facies as shown in Figure 11.

The last cross-validation in this study is made to examine the relationship between porosity and permeability from different sources of core and engineering data. Figure 12 shows bivariate statistics of permeability from different sources. A similar relationship of porosity with the two types of permeability is observed. Noticeable are the fewer numbers of points in the low ranges of porosity and permeability in the engineering-derived data as shown in Figure 12. This is attributed to the selective nature of perforated intervals where higher reservoir-quality intervals are favored for perforation.

Integration of Engineering and Core Permeability

It was determined earlier that the permeability from buildup is equivalent if not better than core data in some instances. Figure 13 shows results of permeability from buildup and flow meter in Hawtah field. However, the blocky nature of engineering-derived permeability logs represents a lack of resolution when compared to cored permeability data. Because the permeability information from engineering data is limited to perforated intervals, it produces incomplete permeability information for the remaining portion of the reservoir interval where there are no perforations. However, if these data are integrated with core data, the result is a better representation of permeability in terms of completeness, reliability, and accuracy.

One way of integrating engineering permeability with core data is to treat it as prior knowledge on sampling the



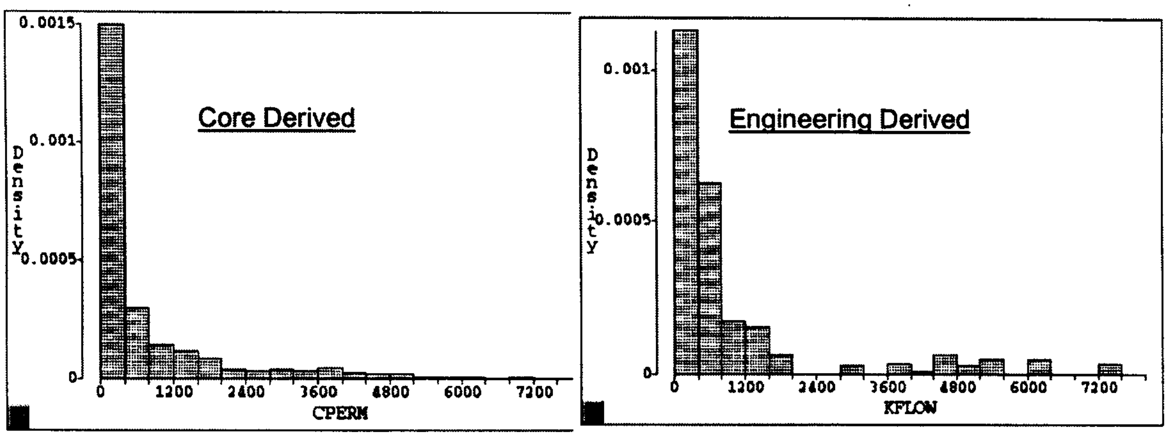
Moments

N	204.0000	Sum Wgts	204.0000
Mean	1891.8397	Sum	385935.300
Std Dev	1832.9642	Variance	3359757.75
Skewness	1.0521	Kurtosis	0.8073
USS	1.412E+09	CSS	682030823
CV	96.8879	Std Mean	128.3332

Moments

N	128.0000	Sum Wgts	128.0000
Mean	1819.9044	Sum	232947.766
Std Dev	1882.6841	Variance	3544499.25
Skewness	2.0517	Kurtosis	5.5615
USS	874094076	CSS	450151405
CV	103.4496	Std Mean	166.4073

FIGURE 9—Comparison of univarite statistics for Very Clean Sandstone Facies between core permeability (left) and engineering-derived permeability (right).



Moments

N	906.0000	Sum Wgts	906.0000
Mean	871.3663	Sum	789457.900
Std Dev	1606.0246	Variance	2579315.00
Skewness	4.0543	Kurtosis	28.9289
USS	3.022E+09	CSS	2.334E+09
CV	184.3111	Std Mean	53.3566

Moments

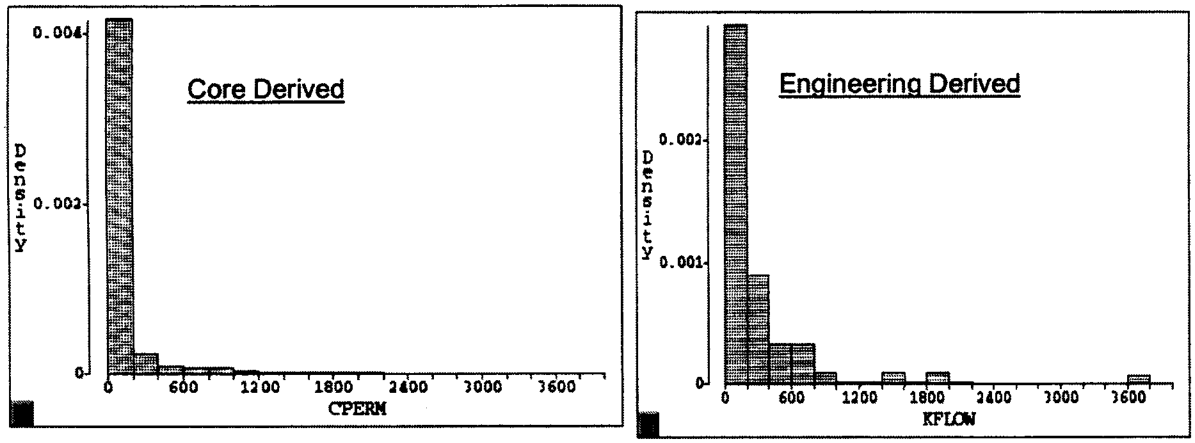
N	382.0000	Sum Wgts	382.0000
Mean	1159.7872	Sum	443038.700
Std Dev	1773.9224	Variance	3146800.65
Skewness	2.3046	Kurtosis	4.7118
USS	1.713E+09	CSS	1.199E+09
CV	152.9524	Std Mean	90.7618

FIGURE 10—Comparison of univarite statistics for Sandstone Facies between core permeability (left) and engineering-derived permeability (right).

cumulative density function (CDF) of possible permeability values from cloud transforms (Isaaks and Srivastava, 1989). This is accomplished by assigning permeability values from cloud transforms that are equal or close in values to those of engineering-derived permeability. Figure 14 shows how a porosity log is transformed into a permeability log using cloud transforms conditioned to permeability from engineering data. Each porosity value is examined regarding which facies it belongs to, in order to select the facies-based cloud transforms of core porosity and permeability. For a given porosity value, several possibilities of permeability can occur. If permeability from engineering data is present, then it is used to influence the selection of the final permeability value from the cloud transform. At nonperforated intervals, however, conventional facies-based cloud transforms are applied to produce permeability. Moreover, intervals with core-permeability data are honored at well locations.

Facies-Based Permeability Modeling

A 3D facies model was built utilizing an indicator-kriging approach (Journel and Huijbregts, 1978; Yarus,



Moments			
N	1464.0000	Sum Wgts	1464.0000
Mean	247.5417	Sum	362401.000
Std Dev	852.5467	Variance	726835.958
Skewness	5.9446	Kurtosis	43.3322
USS	1.153E+09	CSS	1.063E+09
CV	344.4054	Std Mean	22.2817

Moments			
N	200.0000	Sum Wgts	200.0000
Mean	386.4663	Sum	77293.2549
Std Dev	762.3971	Variance	581249.408
Skewness	5.4737	Kurtosis	40.2619
USS	145539868	CSS	115668632
CV	197.2739	Std Mean	53.9096

FIGURE 11—Comparison of univarite statistics for Siltstone Facies between core permeability (left) and engineering-derived permeability (right).

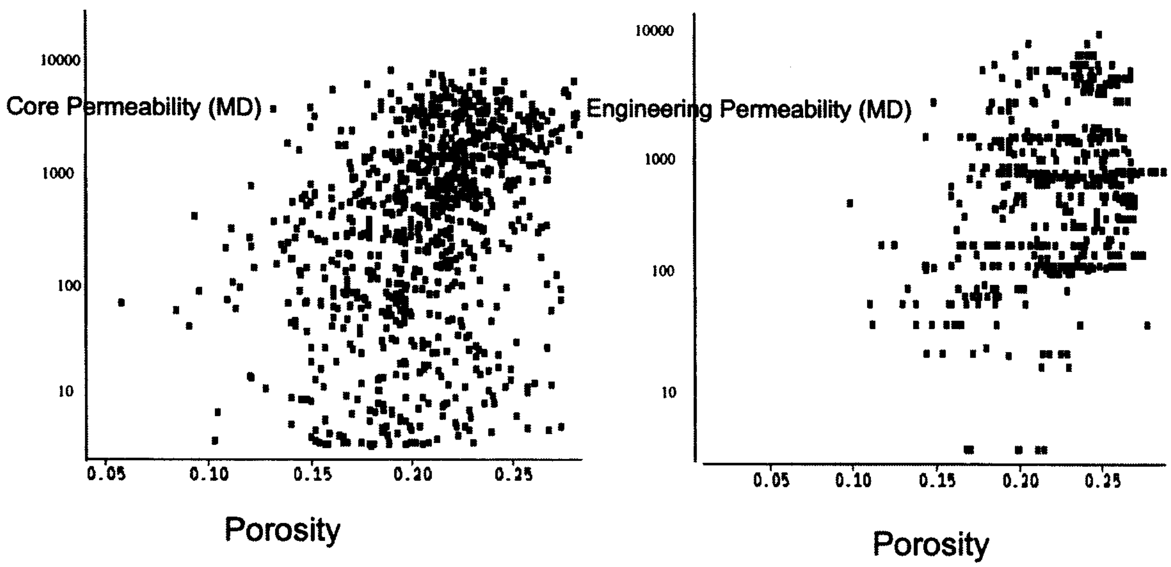


FIGURE 12—Porosity relationship with core permeability (left) and engineering-derived permeability (right).

1994) and then was sampled by a correlated-probability field (Haldorsen and Damsleth, 1990). This model defines the spatial connectivity among three grouped facies as explained earlier (*Case Study*) namely Dune, Mixed Eolian/Fluvial, and Interdune facies. Porosity then was distributed within each facies from the facies model producing a 3D-facies-based porosity model (refer to Al–Qassab and Heine, 1998, for details).

Permeability at each well in Hawtah field has been constructed that honors both buildup and core-data values using the approach explained in the previous section. Areal and vertical variograms of permeability are constructed to define the spatial continuity of permeability and then confirmed with the radial diameter of the pressure-buildup tests. The variograms (Journel, 1989) then are used to construct a 3D-correlated probability field from the existing conditioned permeability logs at each well location. This correlated probability field is used to basically sample the cloud transforms for each facies for a given porosity value corresponding to the existing facies-based porosity model and assigns permeability values. The result is a permeability model that honors both engineering data at each well location (*Permeability from Pressure Buildup and Flow Meter*) as well as retains core porosity

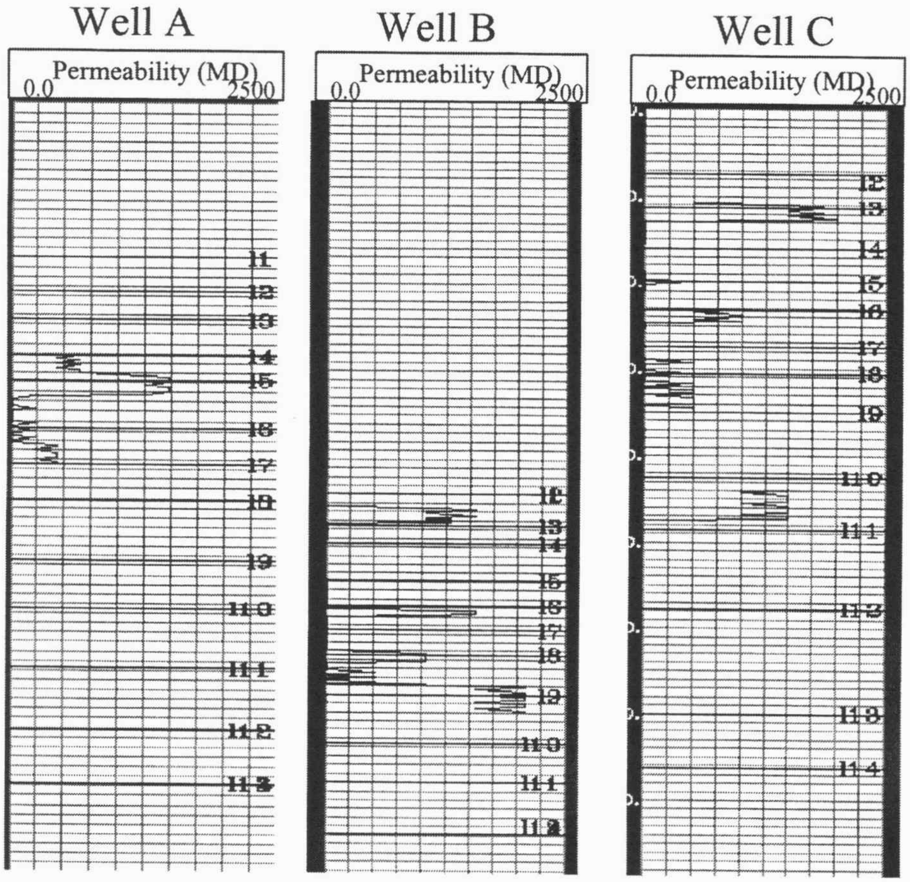


FIGURE 13—Examples of engineering-derived permeability logs. Note blocky character as well as missing information at nonperforated intervals.

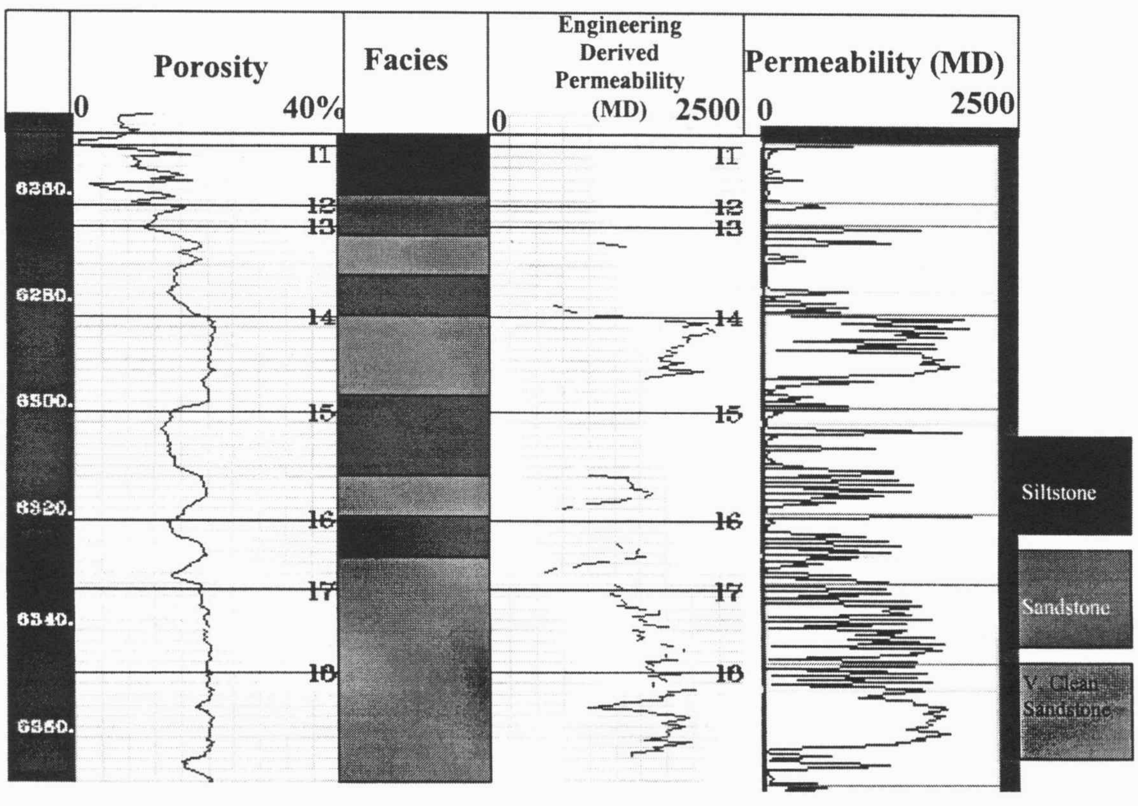


FIGURE 14—Integrated permeability log from engineering- and core-derived permeability.

and permeability character for each facies. Stratification of Unayzah reservoir is captured better in this model as illustrated in Figure 15, where thin zones of high permeability are captured by honoring the flow meter and the pressure-buildup test.

Another permeability model is built by transforming the facies-based porosity model to permeability model using cloud transforms without honoring engineering-derived permeability. Figure 16 shows the difference between a conventionally built permeability model and a conditioned permeability model. Noticeable in this figure are the high permeability zones that are captured in the conditioned-permeability model and are missing in the conventionally built permeability model.

CONCLUSION

Conditioning the permeability models to observed engineering data is necessary for any fluid-flow simulation study. By employing geostatistical methods, a new way of integrating engineering-derived permeability with that of core origin has become possible. The proposed method is essential and unique to condition permeability models to engineering data. Results fully honor the input engineering-derived permeability, core data, and geological facies. Finally, high-permeability zones from a stratified reservoir are more vividly highlighted as compared to the conventionally built permeability model.

ACKNOWLEDGMENTS

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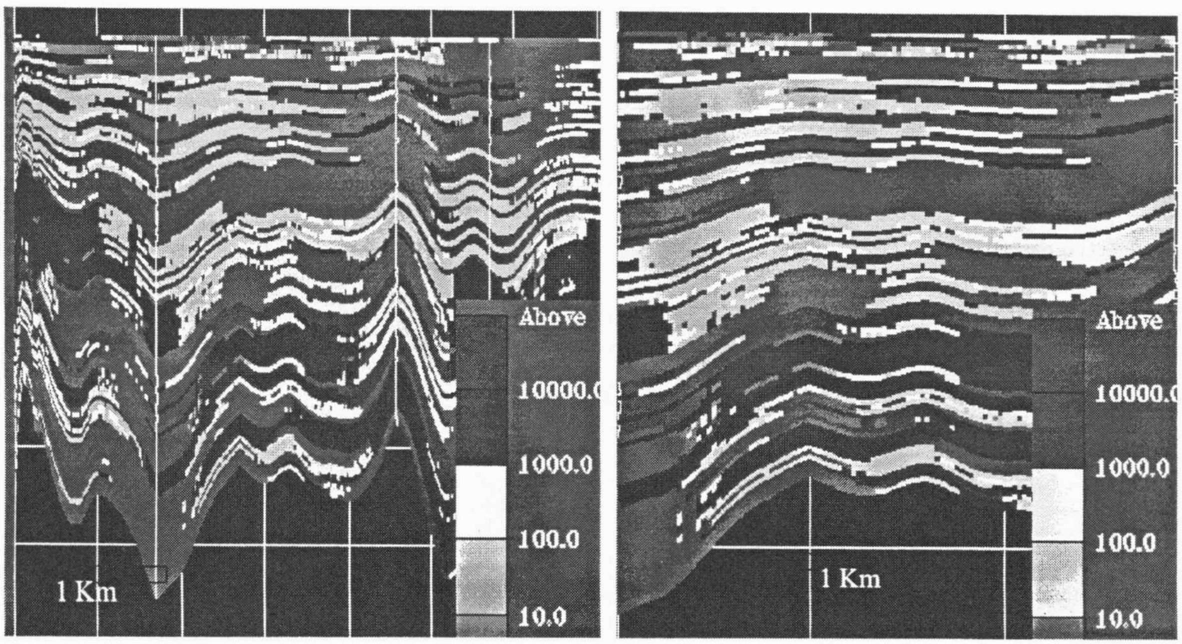

FIGURE 15—East-west (left) and north-south (right) cross sections from conditioned-permeability model. Note thin zones of high permeability.

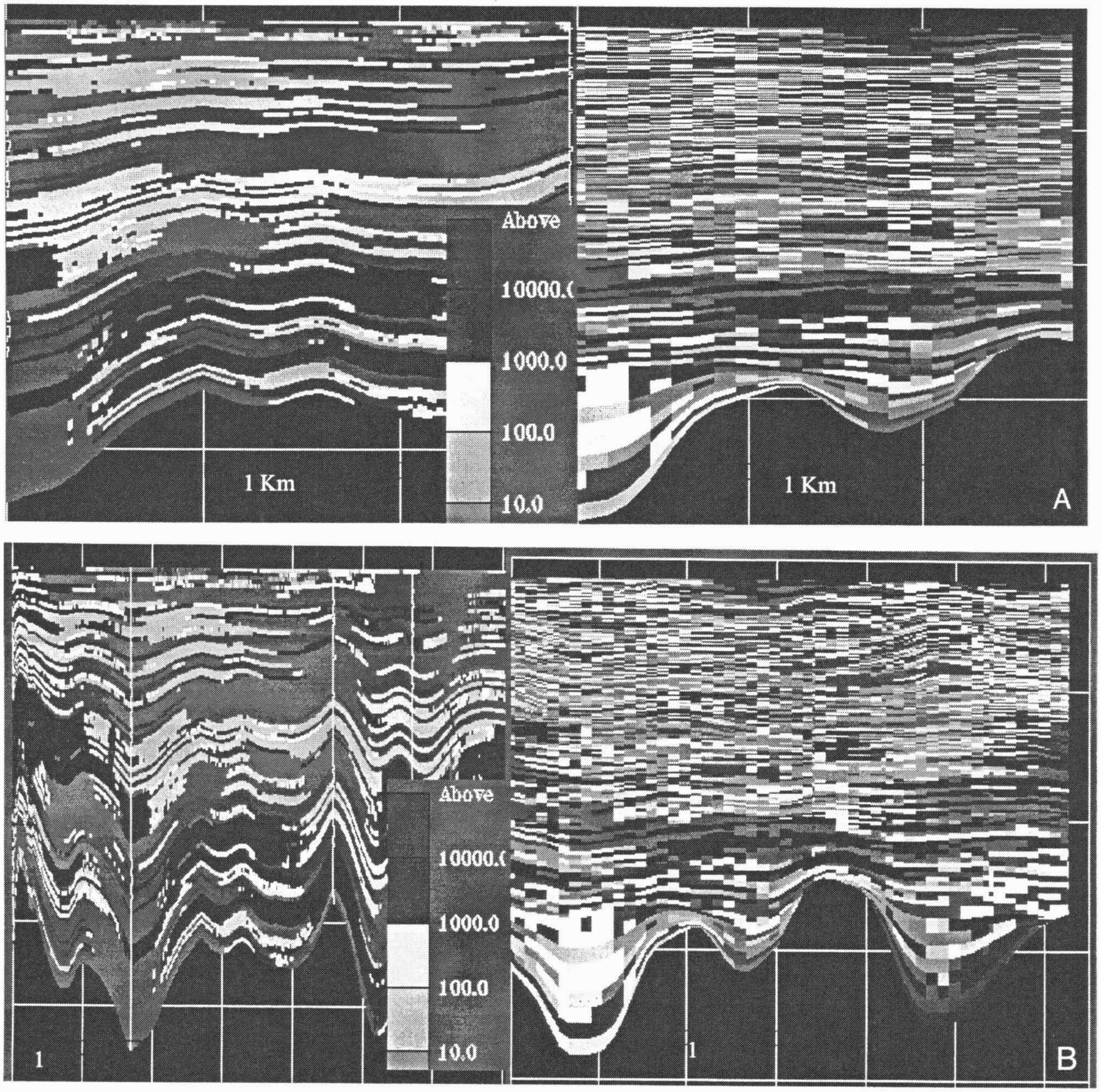

FIGURE 16—A, North-south cross section showing comparison between conditioned-permeability model (left) and conventionally built permeability model (right). B, East-west cross section showing comparison between conditioned-permeability model (left) and conventionally built permeability model (right).

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Petroleum Potential of the Middle Proterozoic Midcontinent Rift System (MRS) in Iowa

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The Midcontinent Rift System (MRS), a billion-year-old failed rift that extends from Lake Superior to Kansas, is characterized in Iowa by a central horst, dominated by mafic volcanics and deep, clastic-filled flanking basins. These basins, which reach a maximum model depth in excess of 12,000 m, include a basal clastic stratigraphic sequence that is roughly correlative with the Oronto Group of northern Wisconsin. Unit C, the middle unit of this basal clastic sequence, is a dark shale equivalent to the Nonesuch Shale, and 586 m of this unit were penetrated by the Amoco No. 1 M.G. Eischied well at a depth of 5,400 m. Similar dark shales also were encountered in cores from the Manson Impact Structure and although an intact sequence was not penetrated, the abundance of this lithology suggests that a relatively thick sequence of Unit C rocks originally existed at that location. The presence of thick Unit C shales in the Eischeid well, 7 km outside of the original axial rift graben, and a similar thick sequence at the Manson Structure, 25 km from the graben, implies a widespread original distribution of this unit, deposited in a waterbody at least 150 km wide and probably wending along most of the 1,450 km length of the feature.

Unit C in the Eischeid well now is over-mature and is only a marginal source rock (T_{max} 497°–508°C, TOC avg. 0.13–0.6%, generic potential avg. 0.22 mg HC/g rock) that reached peak oil generation about 800 Ma. However, the Eischeid rocks originally lay in an area of high heat flow from the voluminous volcanic and plutonic rocks in the active rift graben. Rocks in more distal locations would not have been subjected to these high heat conditions and likely would have released their petroleum much later. The most likely place to recover MRS petroleum would be in the Keweenawan fluvioclastics that overlie Unit C and at some distance from the over-mature rock near the axis of the rift.

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Microfabric Analysis of Cyclic Rhythmites—a Comparison of Modern and Ancient Samples

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A cyclic rhythmite is represented by alternating silt-rich and clay-rich laminae, which can be used to interpret original depositional environments. This research on cyclic rhythmites compares fabric features of sediment from modern tidal environments with possible ancient analogs in order to determine the depositional conditions of the ancient samples. Samples from both modern and ancient cyclic rhythmites were collected and prepared for study at the macroscopic and microscopic level. Layer thickness, components of layers, and fabric features were studied using hand samples, thin-section analyses, and the scanning electron microscope.

The study of the samples helped in the determination of depositional processes and the variations that operated within the environments. A number of factors, other than tides, such as climate, season, or varying influx of material through time from river systems, have been considered to be influential in the formation of these rhythmites. This research has helped determine how these may have played roles in the rhythmite formation. Examining the rhythmite laminae at different scales allows the layering observed megascopically in hand samples to be related to microscopic clay fabric that was sensitive to environmental depositional controls. This study characterizes the features of fabric representative of rhythmite sediments and rocks and uses these features in identifying sedimentary processes operative in the original depositional environment.

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Depositional Facies and Petrophysical Properties of the Pennsylvanian Cottage Grove Sandstone Member (Osage–Layton Sand), Chanute Formation—East Newkirk Field, Cherokee Platform, Oklahoma

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Core and e-log interpretations indicate that the Cottage Grove Sandstone Member (Osage–Layton Sand) of the Pennsylvanian Chanute Shale Formation, at least in this geographic setting, consists primarily of a heterogeneous (120-ft [37-m])-thick succession of delta-front deposits. The delta-front deposits can be subdivided into a proximal delta-front facies (distributary mouth-bar subfacies) and a distal delta-front facies. The delta-front facies grades seaward into prodelta deposits and is capped by a marine-transgressive black shale facies.

Compositionally, the sandstones are primarily lithic subarkoses. Quartz is the dominant framework grain with lesser amounts of feldspars, rock fragments, and clays. Clay content consists primarily of illite + smectite and ranges from 1% to 39%, averaging 18%, and is correlated inversely with grain size.

The sandstone succession shows significant degrees of internal heterogeneity, including carbonaceous-lined laminae, comminuted plant material, shaly coal and coal spars, clay rip-up clasts, shale laminae and interbeds, and secondarily matrix-clay content and locally cemented zones.

Measured core porosities range from 2% to 20%, averaging 16%. Porosity is limited primarily by compaction of ductile rock fragments and muddy matrix. Measured core permeabilities range from 0.01 to 97 md, averaging 15.3 md. Illite + smectite is the main permeability-reducing component and is followed in decreasing order of importance by compaction, ferroan dolomite, and quartz overgrowths. Core porosities and permeabilities are consistently higher and more uniform in the proximal delta-front facies (distributary mouthbar subfacies) and lowest in the distal delta-front, prodelta, and marine transgressive shale facies.

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Springeran/Chesterian Relationships within the Anadarko Basin and Shelf of Northwestern Oklahoma and the Texas Panhandle

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ABSTRACT

An extensive regional study covering the Anadarko Basin and shelf of Oklahoma and Texas has been conducted with the generation of regional cross sections, production allocation, and reservoir characterization. It has long been apparent to those working the Anadarko Basin and shelf area of Oklahoma and Texas that the nomenclature used typically is erratic and the resulting production allocation less than precise. A correlative and equivalent formation may be termed by various names and there are all too many instances of nomenclature being vague, too broad, or incorrect. As part of a regional study, the logs from every producing well within the majority of the Anadarko Basin and shelf were reviewed to verify the actual producing reservoir. Approximately 35,000 wells in northwestern Oklahoma and the Panhandles of Oklahoma and Texas were examined. Regional cross sections were constructed and used to determine the stratigraphic relationships and to develop a stratigraphic nomenclature system that could be used across the area with accuracy, detail, and consistency. Although the entire stratigraphic section has been subjected to elements of this study, the Springer Group, Upper Mississippian, and Lower Pennsylvanian, are the most demonstrative of a carbonate platform and slope system with its stratigraphically equivalent basinal clastic system.

The Springer Group may be misnamed as the overlying Pennsylvanian Morrow sandstone or underlying Mississippian Chester limestone. Historically, the first carbonate encountered below the Morrow/Springer clastic section has been termed Chester limestone. Generally, the Springer Group consists of the Boatwright, Britt, and Cunningham, in ascending order. Whereas in Oklahoma, the Cunningham was a sandstone, extensive correlations indicated that the Boatwright or Britt in certain areas developed a carbonate facies that generally was referred to as Chester limestone. Regional correlations in both Oklahoma and Texas from the deep Anadarko Basin, through the slope and onto the shelf, indicate that the Springer clastics of the deep basin are equivalent stratigraphically to Springer carbonate facies on the slope and shelf. As a result of these correlations, Britt and Boatwright carbonates have been identified which heretofore have been identified generally as Chester limestone. A highly conductive Boatwright shale directly above the true Chester limestone provides a reliable regional marker as the base of the Springer Group. In Texas, the Cunningham was observed to develop a carbonate facies that was rare and nonproductive.

Regional cross sections will be presented showing these facies changes and indicating trapping mechanisms along with production maps delineating trends and lithofacies maps.

PURPOSE

The purpose of this study is to ensure that the production within the study area was allocated accurately to a common and consistent stratigraphic nomenclature. This nomenclature was developed through regional correlations and substantiated by a dense framework of contiguous and detailed cross sections.

Hendrickson, Smith, and Williams (1996), Williams, Hendrickson, and Smith (1996), Smith (1996), and Smith, Hendrickson, and Williams (1996) previously have discussed correlation and allocation projects with specific results. Smith, Hendrickson, and Williams (1996) reported that certain Springer sandstones were observed to undergo facies changes into carbonates. In the areas of Springer carbonate deposition, these carbonates had been identified as Mississippian Chester. This paper provides condensed cross sections previously presented as a poster session at the *Silurian, Devonian, and Mississippian Geology and Petroleum Geology in the Southern Midcontinent* Workshop held in Oklahoma City, Oklahoma, in March 1999 (Smith and others, 1999). These cross sections demonstrate the relationships of the Springer sandstones, Springer carbonates, and Mississippian Chester. These

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correlations have resulted in notable reserves being reallocated from what originally was indicated as Mississippian Chester to what more specifically is herein identified as Boatwright and Britt carbonates. The included production maps indicate the areas of Boatwright and Britt production (specific as to sandstone and carbonate areas) as well as the areas of true Chester production.

STUDY AREA

Figure 1 presents a map of the Anadarko Basin and shelf area and indicates the study area. It encompasses the vast majority of the Anadarko Basin and shelf area of Oklahoma and Texas.

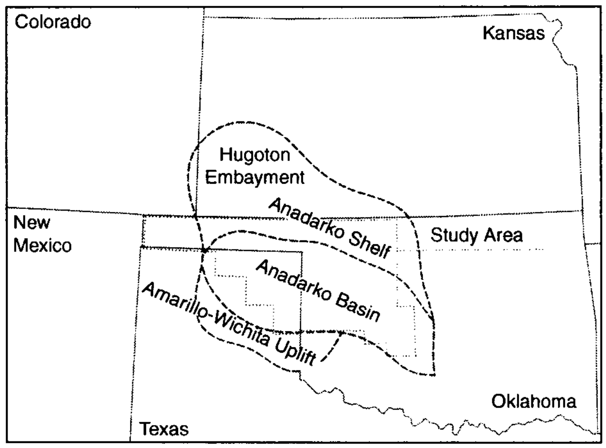

FIGURE 1—Anadarko Basin study area.

METHODOLOGY

The producing formation(s) in a well is defined originally by way of the completion report (Form 1002A) filed with the Oklahoma Corporation Commission (OCC) where both the perforated interval(s) and the producing formation(s) are listed. It is a responsibility that the producing formation be identified as fully and correctly as possible, but there are no exacting standards in his process, nor are there any mechanisms in place to ensure that the producing formation has been correctly and fully defined. As a result, the nomenclature in the basin and shelf area is at times erratic and less than precise. During a recent effort at IHS Energy Group to standardize reservoir nomenclature, the authors generated more than 15,000 miles of geologic cross sections to demonstrate the stratigraphic sequences and relationships throughout the Anadarko Basin and shelf area. Figure 2 presents the stratigraphic section used in this study to designate reservoir and formation names. Figure 3 is a base map of the study area indicating the network of nearly 3,000 miles of drafted cross sections which are a small part of the total used in this project. Also indicated are the traces of the cross sections included in this paper (A–A′, B–B′, C–C′, and D–D′) which demonstrate the facies change that has resulted in certain formations within the Springer Group, as herein defined, being identified as Mississippian Chester. To ensure nomenclature consistency and accuracy, the electric logs of approximately 35,000 wells were reviewed for this study.

Regarding the perforated interval (as indicated by the completion card or Form 1002A), a comparison was made between the producing formation as indicated by the IHS regional cross sections and the operator defined producing formation. If there was a difference between the two, the nomenclature as indicated by the regional cross sections was used. Almost 40% of the producing formations as defined originally on completion cards were either too vague, too broad, or incorrect, and were consequently reassigned a reservoir name to conform with the cross sections. Furthermore, approximately 15% of the perforated intervals required correction because of reporting errors, typographical errors, or the perforated interval was simply absent from the production records.

SYS	SERIES	GROUP	UNIT	SANDSTONE	CARBONATE	EQUIVALENT
PENNSYLVANIAN	VIRGILIAN	Shawnee/Cisco	Topeka Ls Pawhuska Ls Hoover Ss Elgin Sd Oread Ls Heebner Sh Endicott Ss	Hoover Endicott	Pawhuska Oread Ls	
		Douglas/Cisco	Lovell Ls Haskell Ls Tonkawa Ss	Tonkawa	Douglas Group	
	MISSOURIAN	Lansing/Hoxbar	Avant Ls Cottage Grove Ss	Cottage Grove	Lansing Group	
		Kansas City/Hoxbar	Dewey Ls Hogshooter Ls Layton Ss Checkerboard Ls Cleveland Ss	Layton Cleveland Culp	Kansas City Group Melton	Marchand Upper Marchand Lower
	DES MOINESIAN	Marmaton	Big Lime Oswego		Big Lime Oswego	Marmaton Wash
		Cherokee	Cherokee Marker Prue Ss Verdigris Ls Skinner Ss Pink Ls Red Fork Ss Inola Ls Mona	Prue Skinner Red Fork Cherokee Wash Middle Cherokee Wâsh Lower/ Mona	Verdigris Inola	Prue Wash Skinner Wash Red Fork Wash Bartlesville, Tussy
	ATOKAN	Atoka	Atoka 13 Finger Ls	Atoka	Atoka 13 Finger	
	MORROWAN	Morrow	Morrow Primrose	Upper Morrow Morrow Lower Morrow Primrose		
MISSISSIPPIAN	SPRINGERAN	Springer	Cunningham Britt Boatwright	Cunningham Britt Boatwright	Britt Boatwright	
	CHESTERIAN	Chester	Chester Ls		Chester	
		Manning	Manning Ls		Manning	
	MERAMECIAN	Meramec	Meramec Chat Meramec Ls		Meramec Chat Meramec	
	OSAGEAN	Osage	Osage Ls			
	KINDERHOOKIAN	Kinderhook	Kinderhook Sh			
SIL./DEV.	CHATTANOOGIAN		Woodford Sh Misener Ss	Misener		
	ULSTERIAN	Hunton	Hunton Group		Hunton (Frisco) Hunton (Bois d'Arc) Hunton (Haragan) Hunton (Henryhouse) Hunton (Chimney Hill)	
	NIAGARAN ALEXANDRIAN					
ORDOVICIAN	CINCINNATIAN	Sylvan	Sylvan Sh Maquoketa		Maquoketa	
	CHAMPLANIAN	Viola	Viola Group		Viola (Fernvale) Viola (Trenton)	
		Simpson	Simpson Dense Bromide Ss Tulip Creek Ss McLish Ss Oil Creek Ss Joins	Bromide Tulip Creek McLish Oil Creek Joins		
	CANADIAN	Arbuckle	Arbuckle Group		Arbuckle	
CAMB	CROIXAN					

FIGURE 2—Stratigraphic section.

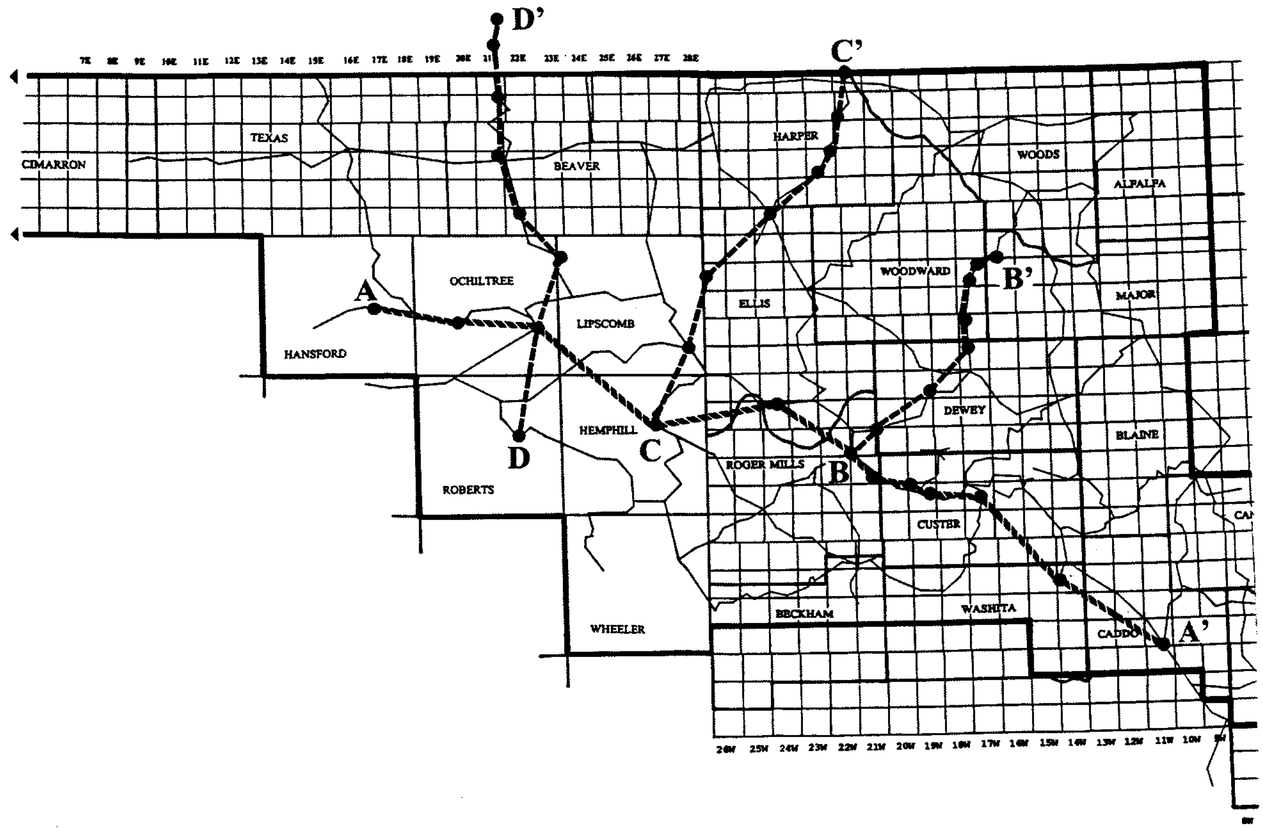

FIGURE 3—Study area with lines of cross section; A, cross section A–A′; B, cross section B–B′; C, cross section C–C′; D, cross section D–D′.

RESULTS

The overall results of this study have been two-fold. First has been the development of a dense framework of regional cross sections that demonstrate the stratigraphic sequences and relationships within the Anadarko Basin and shelf area. Second has been an improvement in the accuracy, detail, and consistency in the allocation of production as reflected in the IHS Production Database, which should be of great and varied benefit of anyone using production data within the study area.

Additionally, and to be discussed in some detail herein, the relationships and facies of the Springer and Chester Groups have been clarified. Regional correlations from the deep portion of the Anadarko Basin northwestward demonstrate that the Boatwright and Britt undergo a facies change from sandstones to carbonates. Previously, these carbonates have been identified as Mississippian Chester. However, they are distinct from the true Chester in that the intervening Boatwright shale always is present and correlative, lying on top of the true Chester and separating it from the overlying Boatwright and Britt. The Boatwright shale is present independently of the facies (sandstone or carbonate) of the Boatwright and Britt. Cunningham sandstone deposition took place over the south half of the study area, and no carbonate facies has yet been observed for this unit.

Cross Section A–A′ is an approximate strike section over the southeastern two-thirds of its extent. The northwestern one-third of Cross Section A–A′ develops into a dip section as the beds are coming out of the Anadarko Basin at its most western extent. The southeastern well of the cross section, the Arkla/Clancey Estate No. 1–21, is located in the Eakley–Weatherford Trend (an area of notable Boatwright and Britt sandstone production) and produces from Boatwright sandstone between 16,115 feet and 16,220 feet. The massive Boatwright shale in this well occurs from 16,220 feet to 16,550 feet at which depth the true Chester was encountered. For the extent of Cross Section A–A′, the Boatwright shale thins from 330 feet in the southeast to 225 feet in the northwest but always is present and situated on top of the true Chester. From the Clancey No. 1–21, the cross section extends northwestward where the Boatwright sandstone first thins and then experiences a facies change into thin carbonates. Northwestwardly, these thin carbonates coalesce into a massive carbonate section of more than 200 feet (T. 15 N., R. 21 W.), which in turn thins into a regionally persistent Boatwright carbonate bed approximately 40 feet in thickness at the northwestern end of the cross section. Similarly, the Britt sandstone, present in the southeastern portion of the cross section, experiences a facies change into a massive carbonate section (T. 16 N., R. 21 W.). This lithologic change takes place farther to the northwest than was observed in the Boatwright. The Boatwright and Britt carbonates are shown to be continuous through northwestern Oklahoma and across the northeastern portion of the Texas Panhandle until they are truncated as evident on Cross Section A–A′.

Cross Section B–B′ is a dip section which intersects the strike section A–A′ in T. 16 N., R. 21 W. From the southwestern end of Cross Section B–B′, the Boatwright and Britt carbonates can be correlated to the northeast until they are truncated systematically, first the Britt and then the Boatwright. These units are carbonates on this cross section as its trace lies to the northwest of where both units undergo a facies change from sandstone to carbonate. The Boatwright shale thins from 215 feet in the southwest to 60 feet towards the northeast, where an intervening limestone member that developed within the Boatwright Shale unit accounts for 20 feet of the 60-feet gross thickness. As with the overlying Boatwright, Britt, and Cunningham Members, the Boatwright shale is ultimately truncated prior to the last log of the cross section. However, in the absence of truncation, the Boatwright Shale is a regionally continuous and correlative marker bed between the underlying true Chester and the overlying Boatwright and Britt, being carbonates or sandstones.

Cross Section C–C′ is another dip section that intersects A–A′ in section 163, block 43, H&TC Survey, Hemphill County, Texas, and traces the Boatwright shale, Boatwright carbonate, Britt carbonate, and Cunningham sandstone to the northeast until they are truncated successively in a manner identical to that observed on A–A′ and B–B′.

Cross Section D–D′ is the other dip section and ties to Cross Section A–A′ in section 475, block 43, H&TC Survey, Ochiltree County, Texas. The cross section's most southwestern log is located in Roberts County, Texas, and shows the Cunningham sandstone and Britt carbonate truncated and the Boatwright carbonate coming out of the Anadarko Basin towards its southwestern extent. The tie log shows the Cunningham sandstone truncated but a full section of Boatwright and Britt carbonate near the thickest part of the Anadarko Basin represented on this cross section. The cross section progresses northeastward across Lipscomb County, Texas, and the Panhandle of Oklahoma and ultimately ends in Seward County, Texas, where the Boatwright and Britt carbonates as well as the Boatwright shale are successively truncated.

Because of the constraints of space, the cross sections presented here have no horizontal scale and the wells represented are widely spaced. The presented cross sections are a distillation of literally thousands of miles of cross sections that have been constructed at IHS Energy Group. Logs included on the presented cross sections were selected to clearly demonstrate specific points. Although in certain circumstances correlations may not seem irrefutable; obviously, many additional logs between any two represented were used in the correlation process. The well-to-well correlation of individual sandstone members is not intended to be taken literally but is only graphic in nature and intended to illustrate lithology.

The reallocated production database has been completed for the northwestern part of Oklahoma, including the Oklahoma Panhandle. The Oklahoma Panhandle and Texas Panhandle portions of the database will be completed shortly. Therefore, Figure 4 presents a map of the northwestern portion of Oklahoma indicating wells that have produced from the Springer Group, as herein defined. In general, the Springer sandstone production, being Boatwright, Britt, and Cunningham, is limited to the southeastern quarter of the study area with the exception of the Cunningham which produces in the south half, having never developed a carbonate facies. Two northeast-southwest trend lines delineating the approximate location of the facies change from sandstone to carbonate observed in both the Boatwright and Britt are indicated with sandstone deposition to the southeast of the respective line and carbonate deposition to the northwest. As the Britt and Boatwright carbonates are truncated successively, the productive trends of these two units are indicated as they occur in subcrop.

Figure 5, covering the same area as Figure 4, presents the true Mississippian Chester production map. In the southeastern portion of the indicated Chester production, a full section of Chester is approximately 300 feet in thickness immediately prior to the beginning of its subcrop whereas to the northwest of the study area, a full section is usually 150 feet thick. The Chester production occurs predominately downdip from the ultimate truncation of the Chester. Hydrocarbon trapping occurs slightly downdip of where the Chester first subcrops. This position is the result of the fact that Chester production is limited generally to the upper portions of the Chester. At a point where a well encounters the Chester near its ultimate truncation, the upper, potentially productive portions have been truncated and the remaining lower portions are typically not productive.

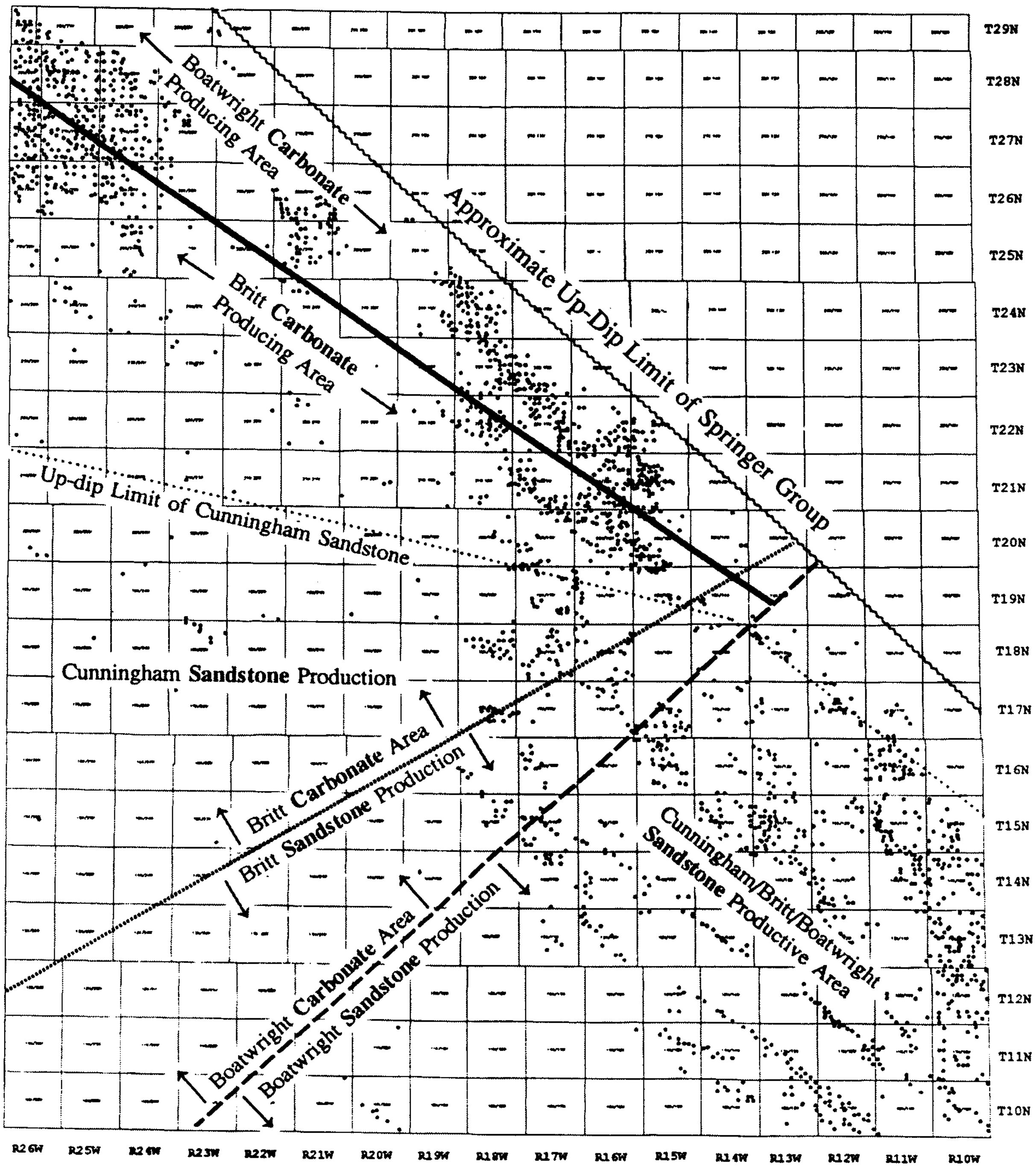

FIGURE 4—Generalized Springer production map.

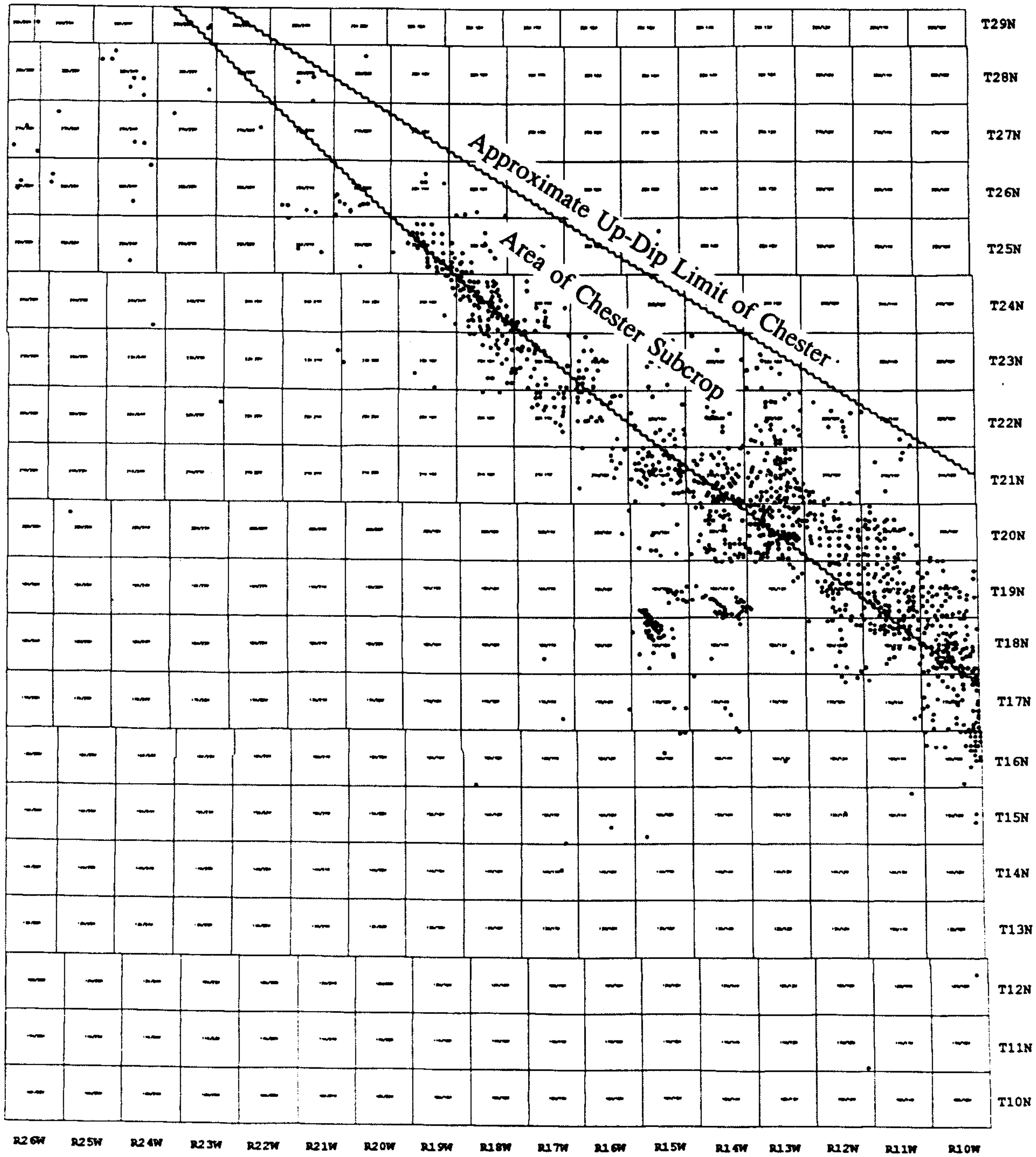

FIGURE 5—Mississippian Chester production map.

CONCLUSIONS

Production within the study area has been allocated by IHS Energy Group to conform to a standardized nomenclature system in the study area and has been used to generate a new database, the "Intelligent Reservoirs" database. For this effort an extensive network of cross sections was generated to enhance the accuracy, detail, and consistency of the allocation process, and nearly 3,000 miles of cross sections have been drafted to support the database.

The stratigraphic and facies relationships of the Springer and Chester Groups have been demonstrated and in the situation of the Boatwright and Britt carbonates, the definition of these individual units and their separation from the true Mississippian Chester limestone gives additional, and heretofore unavailable, detail and insight into the reservoir production data (note Fig. 6). Additionally, an understanding of these relationships is necessary in the proper mapping of these units within the study area.

It is anticipated that the increased accuracy, detail, and consistency of the allocated production as well as the stratigraphic and facies relationship developed by this study will aid in future exploration/exploitation endeavors.

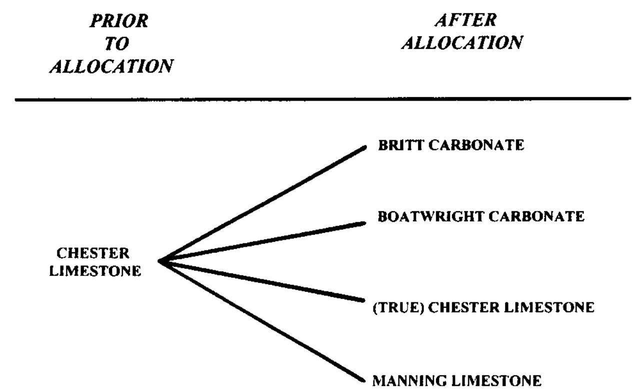

FIGURE 6—Nomenclature assignment.

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Lansing Reef and Stratigraphic Trapping on the Slope Front in the Douglas and "Tonkawa" at the Edge of the Hugoton Platform

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This paper is part of an extensive regional study covering the Anadarko Basin and shelf in Oklahoma and Texas which examined approximately 35,000 wells and generated about 15,000 miles of geological cross sections. The cross sections were used to determine stratigraphic relationships and to develop a consistent stratigraphic nomenclature system throughout the basin. Accuracy, detail, and consistency in production allocations were achieved by reviewing the majority of the producing wells of the Anadarko Basin and shelf, and correlating them to the cross sections. This process corrected a number of instances where correlative and equivalent formations were identified as vague, too broad, or with incorrect nomenclature.

The Lansing and Kansas City intervals in the Anadarko Basin belong to the Missourian Series, Hoxbar Group of the Pennsylvanian (Table 1). They are represented generally by a series of thin limestone beds (Avant, Hogshooter, and Checkerboard) separated by thin shales having high gamma-radiation readings. In the Oklahoma portion of the basin and the shelf, sandstones (Cottage Grove, Layton, and Cleveland) also are present between these carbonate markers. These areas are representative of high clastic input.

In the northern shelf of the Texas Panhandle, the sandstones are absent. The limestone markers thicken dramatically in short horizontal distances, generally becoming the massive carbonate banks of the Hugoton Platform. Facies change in the Lansing–Kansas City from the sand- and shale-dominated clastic sequences near the basin axis in Hemphill County in the southeast to the massive carbonate banks and reefs on the shelf edge in Hansford County in the northwest. Such rapid facies

<table>
<tr><th>System</th><th>Series</th><th colspan="2">Group</th><th>Unit</th></tr>
<tr><td rowspan="6">PENNSYLVANIAN</td><td rowspan="2">Virgilian</td><td colspan="2">WABAUNSEE</td><td>Wabaunsee Ls</td></tr>
<tr><td colspan="2">SHAWNEE</td><td>Topeka Ls
Hoover Ss
Elgin Ss
Oread Ls
Heebner Sh
Toronto Ls</td></tr>
<tr><td rowspan="3">Missourian</td><td colspan="2">DOUGLAS</td><td>Lovell Ss
Douglas Ss
Haskell Ls
Tonkawa Ss</td></tr>
<tr><td rowspan="2">HOXBAR</td><td>LANSING</td><td>Avant Ls
Cottage Grove Ss</td></tr>
<tr><td>KANSAS CITY</td><td>Hogshooter Ls
Layton Ss
Checkerboard Ss
Cleveland Ss</td></tr>
<tr><td>Des Moinesian</td><td colspan="2">MARMATON</td><td>Marmaton</td></tr>
</table>

TABLE 1—Nomenclature of Pennsylvanian units in Anadarko Basin and Anadarko Shelf, Hansford County, Texas.

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changes cause subsurface correlations to become difficult. These correlations become especially problematic as the clastics lap out against the reef structures.

In Hansford County, Texas, a Lansing carbonate bank is productive at the crest in stratigraphic traps in the Lansing itself. Production from stratigraphic traps also has come from the overlying Virgilian clastic formations (Douglas and "Tonkawa") which lap out on the reef structure. Detailed correlations derived from extensive cross section work indicate that many "Tonkawa" completions should be identified properly as Douglas completions.

Table 2 gives the nomenclature of producing reservoirs in a portion of Hansford County, comparing the reported formation names and reallocated names derived from this study. Proper identification of producing reservoirs enhances detailed, as well as regional, exploration and development.

State Reservoir Name		IHS Reservoir Name	
No reservoir name	16		
ATOKA	2	ATOKA	2
CHEROKEE	21	CHEROKEE CARBONATE	38
		CHRKC-MRMN	5
CLEVELAND	102	CLEVELAND	87
		CLVD-MRRWL	1
		CLVD-MRRWU	1
COLLIER LIME	2		
DES MOINES	57		
DOUGLAS	93	DOUGLAS	126
		DOUGLAS CARBONATE	31
HEPLER	13		
KANSAS CITY	7	KANSAS CITY	26
		KSSC-MRMN	2
KATHRYN	5		
LANSING	5	LANSING	60
		LNSG-MRMN	2
LANSING-KANSAS CITY	39		
MARMATON	58	MARMATON	102
MISSOURIAN LOWER	15		
MORROWAN UPPER	2	MORROW UPPER	1
OSWEGO	15		
		PINK LIMESTONE	1
		RED FORK	12
		SKINNER	10
		SKINNER CARBONATE	1
TONKAWA	57	TONKAWA	1

TABLE 2—Comparison of nomenclature.

Petrophysical Analysis of Shaly Sandstones Using Integrated Wireline Log Interpretation

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ABSTRACT

Low-contrast oil and gas reservoirs are becoming increasingly important exploration targets. These reservoirs contain significant reserves, but are difficult to evaluate petrophysically because their water-saturation (Sw) calculations seem high using conventional analyses. Recent technological advances in logging have improved interpretation and evaluation of these zones. High-resolution resistivity and porosity logs accurately represent rock properties in beds greater than 1-foot thick. Formation evaluation can be refined further in some situations using core-calibrated micro-imaging logs. These logs detect lithologic and diagenetic changes to the inch-scale and can be used to identify reservoir and seal zones.

A low resistivity/low contrast LR/LC gas reservoir was analyzed using an integrated approach involving detailed core analysis, production data, and various petrophysical methods. Wireline logs were correlated to other data to evaluate the effectiveness of various tools in determining lithology and measuring rock and pore fluid properties in shaly sandstones. A variety of methods were used to determine clay content. Water-saturation (Sw) calculations from core analyses were compared with those from several models designed to evaluate shaly sandstones. The models analyzed show high variability in predicting water saturation. This suggests successful Sw calculations in shaly LR/LC reservoirs may depend on modifying these equations so their components reflect rock constituents.

INTRODUCTION

Some shaly sandstone reservoirs exhibit distinct low-resistivity and low-contrast (LR/LC) characteristics. Although LR/LC reservoirs contain significant reserves of oil and gas, the evaluation of these reservoirs using only wireline logs has been a challenge for well-log analysts. The degree of shaliness is directly proportional to the volume of clay minerals within the reservoirs. Abundant clay minerals can cause a considerable decrease in resistivity and consequently higher apparent water saturation (Sw) values. In addition, the thin-bedded nature of these reservoirs also complicates the measurement of total porosity, resistivity and gamma-ray values. Consequently, conventional wireline-log analysis yields high water-saturation values and may not provide useful information and data regarding the characteristics and quantity of water and hydrocarbons occupying the pore space.

Lower Vicksburg shaly sandstones in the TCB field, Kleberg and Jim Wells counties, Texas Gulf Coast region were the focus of this investigation (Fig. 1). These LR/LC gas reservoirs are primarily interbedded, very fine-grained silty sandstones, siltstone, and shale. Bed thickness is typically less than 2 feet and the maximum single bed thickness in the cored intervals is 4 feet. Shales and sandstones usually are burrowed and contain Foraminfera.

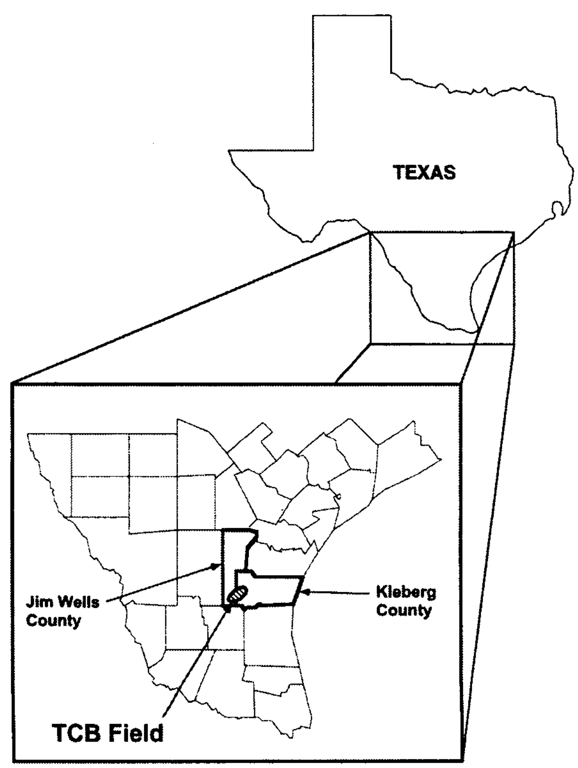

FIGURE 1—Location of TCB field in Kleberg and Jim Wells counties, Texas.

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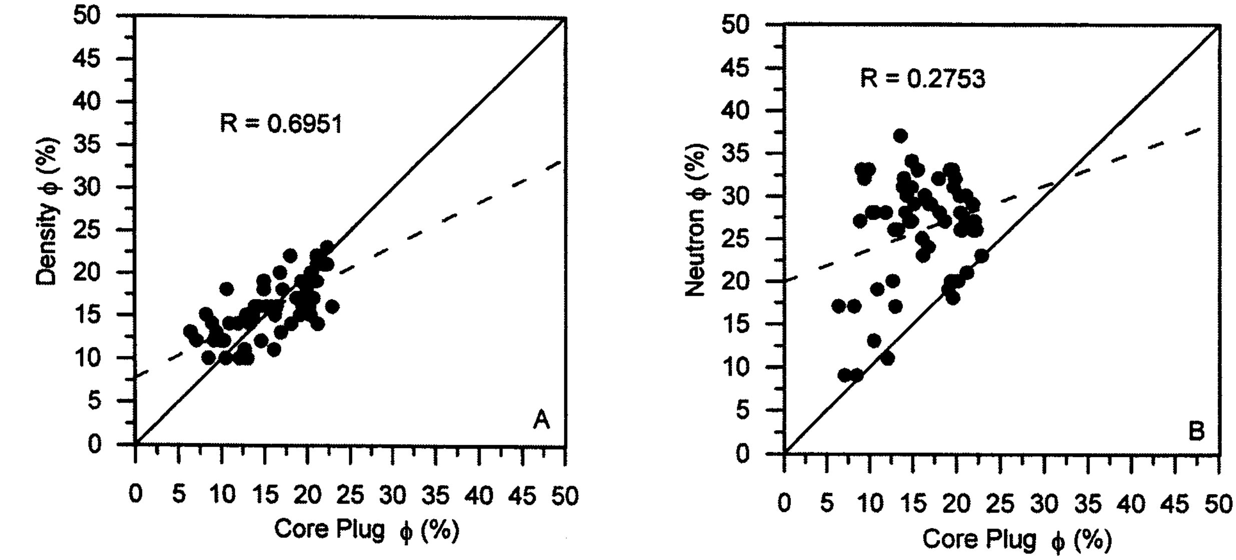
Ripple marks, horizontal laminae, planar crossbeds and soft-sediment deformation features are the more abundant sedimentary structures. These features suggest this thin-bedded interval formed in a low-energy, shallow marine setting that experienced episodic increases in energy and sand-rich sediment influx.

The LR/LC analysis used in this investigation was based on integration of the following: (a) detailed core analysis, (b) compilation of accurate production data, and (c) various petrophysical methods. In addition, this study examined the feasibility of various analysis methods in providing relatively accurate petrophysical data regarding LR/LC reservoirs.

CORE ANALYSIS

The cored-interval used in this study is representative of the Lower Vicksburg LR/LC reservoir. Wireline-log signatures, sedimentary structures, trace fossils, textures, mineralogical constituents, and genetic sequences were described and recorded in detail on a specially designed petrolog sheet. Detrital and diagenetic constituents were determined using thin-section microscopy, x-ray diffractometry, and scanning-electron microscopy. Approximately 60 core plugs were analyzed by Core Laboratories, Inc., to determine porosity, permeability, and grain density. The crossplot of porosity and permeability measurements is shown in Figure 2. Water and oil and gas saturations also were determined. These data were compiled and used for further petrophysical analysis.



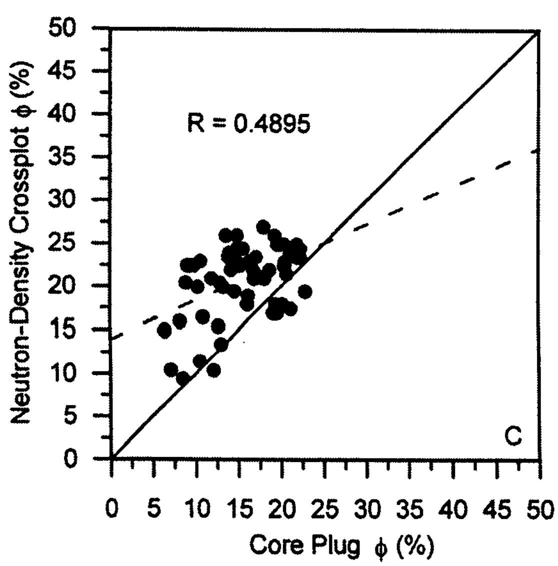


FIGURE 2—Wireline-log-derived porosity versus porosity measured from core plugs. Solid line (45° line) represents ideal prediction and dashed line is regression line. A, Density porosity; B, Neutron porosity; and C, Neutron-density crossplot porosity. Density porosity shows best correlation with core-plug porosity.

PRODUCTION DATA

Since its discovery in 1942, TCB field has produced over 104 billion cubic feet (BCF) and 2,197,000 barrel condensate (BC) from Lower Vicksburg reservoirs (Int. Oil Scouts Assoc., 1997 and Petroleum Info. /Dwights, 1998). The Lower Vicksburg LR/LC sandstone examined in this study produced in excess of 20.4 BCF gas and 451,000 BC from 19 completions prior to field consolidation in 1993 (Int. Oil Scouts Assoc., 1997). Since that date, most wells have been multiple completions and production for individual reservoirs has become difficult to ascertain.

Production data from single zone completions were used to establish the productivity of the LR/LC sandstone interval. Core analyses confirmed the presence of producible gas in these rocks.

PETROPHYSICAL METHODS

Wireline logs were correlated to core and production data to evaluate the effectiveness of various logging technologies in determining lithology and measuring rock and pore fluid properties. Micro-imaging, magnetic resonance, and high-resolution gamma-ray, resistivity, and porosity logs were evaluated. The following is a brief discussion of the accuracy and effectiveness of these tools in thinly bedded/laminated reservoirs:

(1) Micro-imaging tools normally are used to measure the resistivity in the flushed zone and generally are not affected by formation fluids. They generate synthetic color images of borehole, where color is keyed to resistivity ranging from black (low resistivity) to white (high resistivity). They may be used to investigate depositional, diagenetic, and biogenic features to the inch-scale. Core-calibrated micro-imaging logs can help in identifying reservoir and sealing facies (Al-Shaieb and others, written comm., 1999). Dark-gray-brown zones on the static micro-imager view represent silty claystone and shale. White zones represent highly cemented sandstones with low porosity and permeability. Yellow zones have the highest porosity and permeability and represent the best reservoirs. Orange zones have high porosity but can have low permeability because of their high clay content. In addition, micro-imaging logs allow the accurate calibration of core samples to the high-resolution logs.

(2) Magnetic-resonance logs can provide lithology-independent effective porosity, irreducible water volume and permeability measurements (Lomax and Howard, 1994). However, the vertical resolution of these tools (2–4 feet) limits their application in the thin-bedded Vickburg reservoirs.

(3) High-resolution gamma-ray logs generally can resolve beds thicker than 2–3 feet (Sneider and Kulha, 1995). In the LR/LC Vicksburg interval, gamma-ray responses defined sandstones greater then 3 feet thick and detected thinner shales (approximately 1.5 feet thick).

(4) Array-induction logs provide resistivity measurements of five different investigation depths: 10, 20, 30, 60, and 90 inches. These tools can resolve beds down to 1 foot in thickness (Sneider and Kulha, 1995). Shallow investigation curves (10 inches and 20 inches) effectively defined boundaries for beds greater than 1.5 feet thick, but the thin beds limited the effectiveness of the deeper curves in measuring resistivity in beds less than 3 feet thick.

(5) High-resolution density porosity correlates well with core-plug porosity for beds thicker than 1.5 feet. High-resolution neutron-porosity values are consistently higher than those from density logs. In cleaner sandstones (white and yellow zones on micro-imaging logs), density porosity increased slightly over adjacent shale-rich zones. Neutron porosity decreased significantly to cause convergence of the curves and occasionally generate neutron-density crossover. Density and neutron-porosity values for clay-rich sandstones (orange zones on micro-imaging views) are similar to those for adjacent sandy shales.

LOG INTERPRETATION OF LOW-CONTRAST ZONES

The major source of error in petrophysical evaluation of thinly bedded LR/LC reservoirs is related directly to the amount, type, and distribution patterns of clay minerals. The differentiation between detrital and authigenic clays and their distribution patterns may have a significant impact on estimating parameters such as clay conductivity, effective porosity, and cation-exchange capacity (CEC).

Clay volume is an essential parameter in calculating effective porosity (fe) and water saturation (Sw). Eight methods were used to determine the volume of clay (Vcl) from wireline logs. These methods include consolidated and unconsolidated gamma-ray methods, Stieber method, spontaneou-potential method, gamma-ray–bulk-density method, resistivity method, neutron method, and neutron-density method. The results were compared to petrographic data obtained from x-ray diffraction and modal thin-section analysis.

Cation-exchange capacity (CEC) is an important component in water-saturation calculation methods such as the Waxman–Smits analysis. CEC is dependent on volumes, types, and distribution patterns of clays. CEC was calculated using the composition and percentage of each clay mineral present. In reservoir rock (yellow and orange zones identified from FMI logs), total clay content generally ranges from 25% to 35% with smectite/illite mixed-layer clays and illite being the predominant clay minerals. A CEC value of 0.13 (meq/gm) was estimated for these zones, which have deep resistivity readings of generally less than 2 ohm-m in. In white zones, total clay content ranges from 5% to 15% with kaolinite as the dominant clay. A CEC value of 0.013 (meq/gm) was estimated for white zones. These zones, which represent seals, are characterized by resistivity readings higher than 2 ohm-m.

High-resolution neutron- and density-log porosity was compared to core-plug porosity (Fig. 2). Density porosity shows the best correlation with core porosity. Point scattering in this figure primarily is generated from the thin-bed effect. If density porosity is used to represent core porosity, the standard error is 3.3%. By comparison, the standard error is 12% and 6.6% for neutron and neutron-density crossplot porosity, respectively. Core porosity was considered the most accurate measurement of total porosity. Therefore, density porosity may be used to represent total porosity (ϕt). Effective porosity (ϕe) was calculated by subtracting the volume of clay bound water (Vb) from total porosity.

A variety of models were used for the calculation of water saturation. Models that used total porosity include the Archie (Archie, 1942), Waxman–Smits (Waxman and Thomas, 1974), and Dual–Water (Clavier, Coates, and Dumanoir, 1977, 1984). Effective porosity was used in the Modified Simandoux (Schlumberger, 1972), Indonesia (Poupon, and Leveaux, 1971), and Dual–Water model. Model-calculated water-saturation values were compared to the 47 values from routine core analyses that were assumed to represent true total-water saturation. The effective water saturations calculated from Modified Simandoux and Indonesia models were converted into total-water saturations (Sw_T) to ensure a consistent comparison of all models.

Track 3 in Figure 3 shows the calculated water-saturation (Sw) curve from the Waxman–Smits model and also Sw data from core analysis. Arrows A, B, and C point to yellow, orange, and white zones, respectively. Calculated water saturations of yellow and orange zones are similar to core saturations (Figs. 3 and 4). In the white zone, calculated values tend to deviate from the core saturations. Figures 3 and 4 show that the Waxman–Smits model performed well in high-porosity intervals such as the yellow zones, but calculated saturations generally are higher than core saturations in highly cemented and low-clay-content seal zones (white zones).

Figure 5 shows the relationship between core Sw and those calculated from all models. Core-water saturations are lower than calculated ones for all models except the Waxman–Smits model in reservoir intervals. The poor correlation may be the result of ignoring the importance of the volume and type of clay minerals and thin-bed effect. Archie's laws were established specifically for clean sands (Worthington, 1985). Modified Simandoux and Indonesia equations only attribute the additional conductance to the amount of clay. The high-water saturations yielded by the Dual–Water equation may be caused by the lack of effective consideration of the type of clays.

The models examined show high variability in predicting Sw. Although high-resolution resistivity, porosity, and micro-imaging tools have improved the rock characterization, successful Sw calculations may depend on modifying these equations and changing their components to match rock constituents.

CONCLUSIONS

(1) The volume, type, and distribution of clay minerals are essential elements in evaluating LR/LC sandstone reservoirs.
(2) Chromatic variation on FMI logs differentiated between reservoir and seal zones. White zones represent seals whereas yellow and orange zones represent reservoir rocks.
(3) Porosities derived from high-resolution density logs correlate best with those obtained from core-plug measurements (correlation coefficient R = 0.6951) and are used to represent total porosity. In contrast, the neutron to core porosity R = 0.2753, whereas the density-neutron crossplot R = 0.4895.
(4) The Waxman–Smits model yielded water saturations that correlate best to those from core analyses (R = 0.6645 for yellow and orange zones). This method seems to work satisfactorally in some sandstones.
(5) Accurate Sw calculations in thin-bedded LR/LC rocks may depend on reevaluating the accepted models and modifying them to reflect rock constituents.

ACKNOWLEDGMENTS

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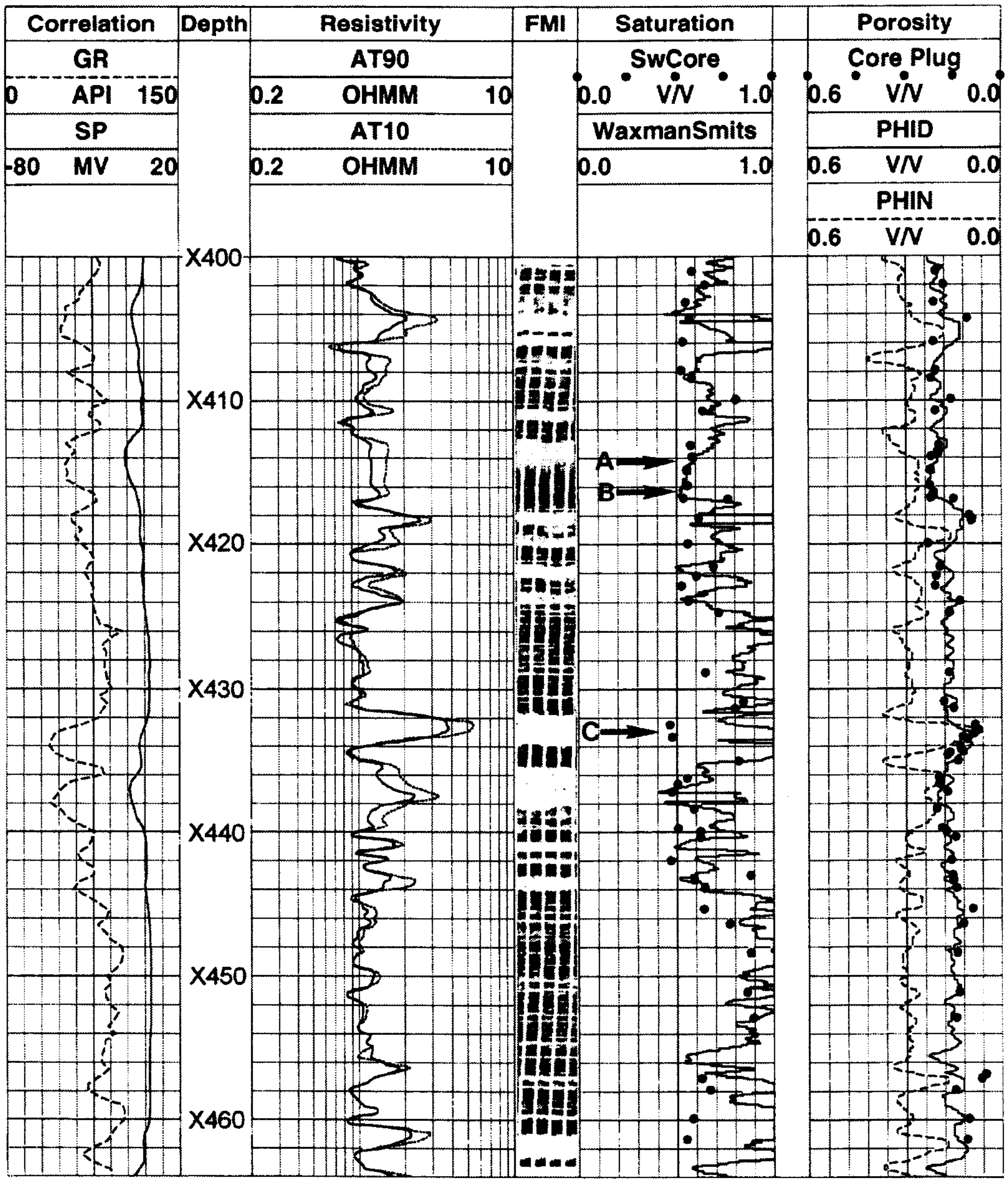


FIGURE 3—Water-saturation (Sw) curve derived from Waxman–Smits model. Solid dots in Sw track are measured-core values. Arrows A, B, and C point to yellow, orange, and white zones, respectively.

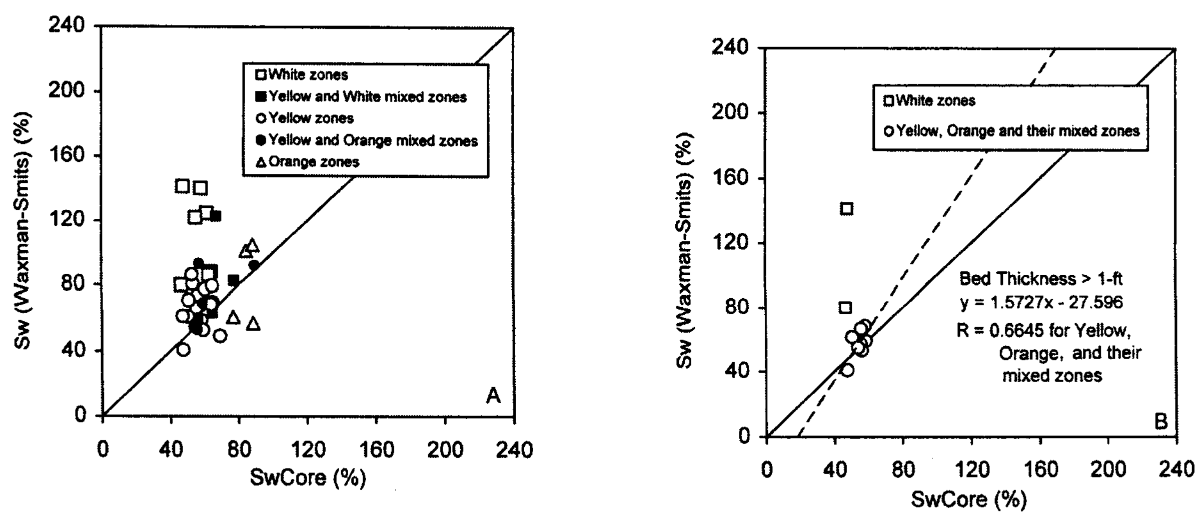
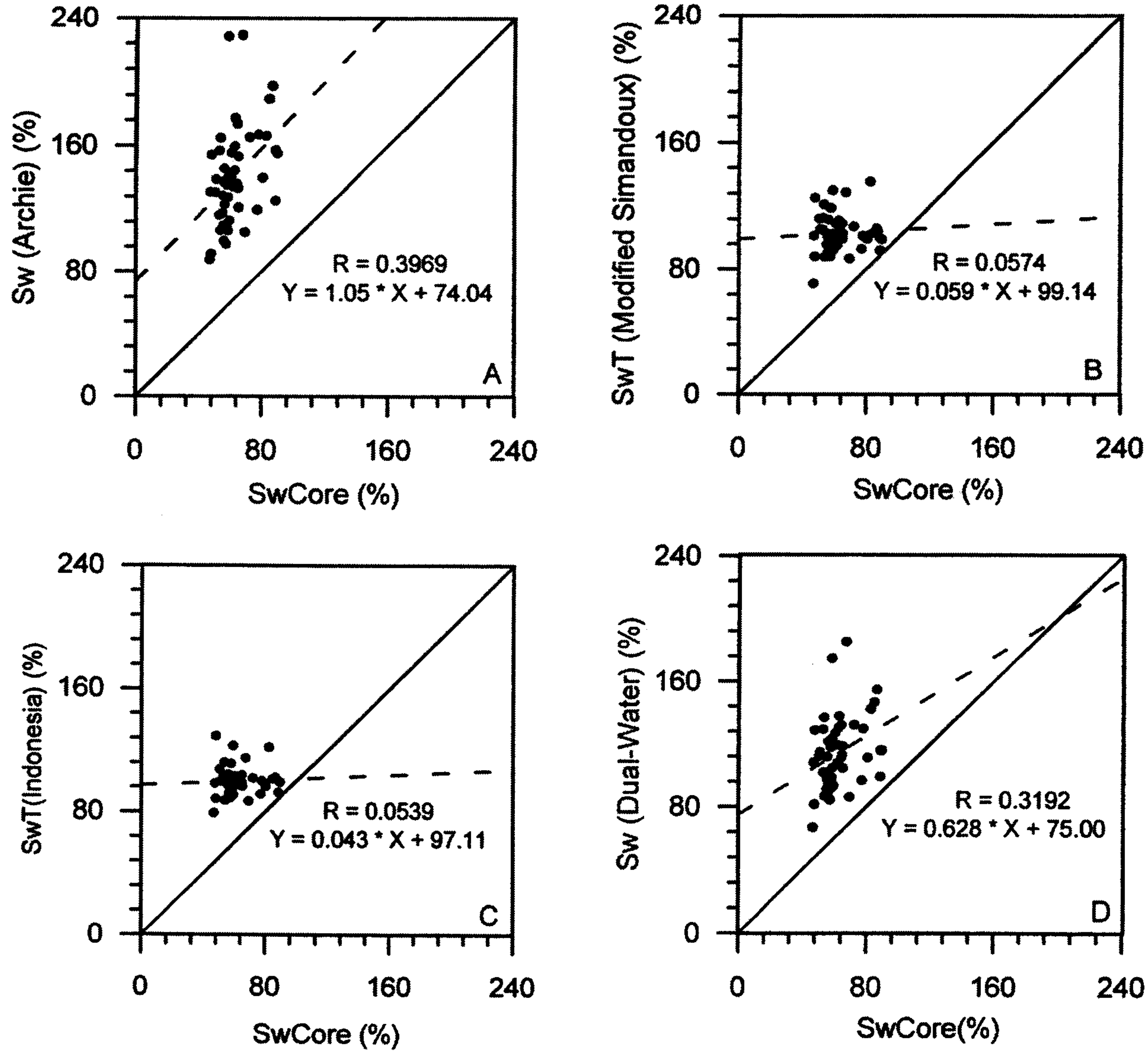


FIGURE 4—Calculated water saturations from Waxman–Smits model versus measured-core values. A, All sandstones; and B, Sandstones greater than 1 foot thick.



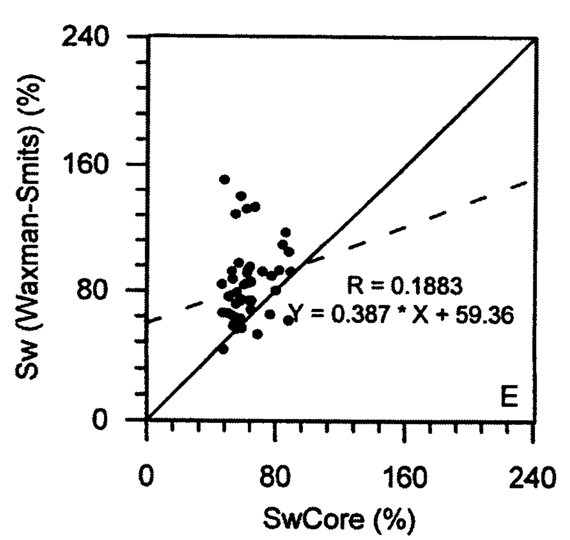


FIGURE 5—Calculated water saturations from various models versus measured core values. A, Archie equation; B, Modified Simandoux model; C, Indonesia model; D, Dual-Water model; and E, Waxman–Smits model.

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Syndepositional Dolomitization of Shallow Marine Deposits, Cangrejo Shoals, Northern Belize

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Dolomite cement comprises an average of ~12% of Holocene, subtidal carbonate sediments in an areally extensive, nearshore mudbank in northern Belize. It is present in sediments along the margins of tidal channels and within the interiors of broad banks between channels, throughout the maximum 7.6-m-thick section of subtidal deposits. Salinity of surface seawater here is 38‰, and that of pore fluids in dolomitic sediments is 38–40‰. Mean dolomite $\delta^{18}O$ composition is $2.1‰_{PDB}$, and is enriched by 0.7‰ relative to that of seawater and pore fluids. There is no change in dolomite $\delta^{18}O$ composition or of pore fluids with depth or location on the mudbank; therefore, dolomitization may take place in normal-salinity pore fluids. Three subpopulations of dolomite are recognized based on $\delta^{13}C$ compositions: (a) those with a mean of $-1.0‰_{PDB}$, which overlaps that of pore fluids and which is depleted relative to that of nondolomitic sediments and surface seawater; (b) those with mean $\delta^{13}C$ of $\sim 3.0‰_{PDB}$, which is close to that of nondolomitic sediments and unaltered pore fluids; and (c) those with anomalously enriched compositions (up to $+11.6‰_{PDB}$). There is no correlation of dolomite $\delta^{13}C$ composition with depth, location, sediment texture, or amount of organic matter in the sediment. Thus it is suggested that dolomitization is facilitated by both microbial sulfate reduction and methanogenesis, and that dolomitization has attended reversible organodiagenetic reactions in the sediment through time.

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Origin of Missourian and Virgilian Stratigraphic Sequences—Southern Midcontinent

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ABSTRACT

A revolution is underway in understanding the causality of depositional patterns and sequences. The areal distribution of accommodation space is a primary control interrelating the depositional setting, the deposition theme, and the genetic sequence. Accommodation space is related to changes in sea level, rates of sediment supply, and patterns of subsidence. These attributes can be interrelated in space and time on scales of a few hundred km^2, and time periods of thousands of years.

Depocenters are related to patterns of lithospheric stress distribution associated with wrench faulting related to interregional northwest-southeast lineaments. Gravity maps provide data on major areal and vertical variations in lithospheric thickness, density, and thermal conductivity.

Determining the origin of stratigraphic patterns requires the development of a time-rock correlation framework at a scale sufficient to determine the geometry of stratigraphic sequences. Depositional patterns may reflect vertical stacking, progradation, or onlapping and backstepping stratal packages. These patterns are related complexly to rates of change in accommodation space, rates of sediment supply, and sedimentary dispersive forces. The correlation and mapping of the geometry and pattern of terminations of bedding planes and disconformities is required in order to determine the depositional history.

The depositional history of Missourian and Virgilian (Pennsylvanian) strata in Oklahoma and Kansas reflect changes in the patterns of basinal subsidence, progradation, and onlap. These are associated with wrench faulting, the history of sea-level changes, and patterns of basinal subsidence. These can be related causally to the subsidence of deltaic depocenters, the development of carbonate banks, and onlapping black shales associated with maximum flooding surfaces.

INTRODUCTION

The recognition of stratigraphic units at scales of hundreds of thousands of years, or less, has produced a paradigmal change in stratigraphic analysis. Two-dimensional measured sections, well-log and outcrop cross sections, and lithostratigraphic maps only are descriptive. The determination of the origin of time-rock stratigraphic units requires a four-dimensional framework in order to delineate time-equivalent strata.

What is required is the determination of subsidence, depositional, and sea-level histories. The distribution and preservation of a stratigraphic interval is the product of lithospheric processes, changes in sea level, and depositional patterns. The synthesis of these histories and depositional patterns is required in order to determine the origin and paleogeography of a stratigraphic unit.

The construction of paleogeographic maps of stratigraphic units requires the determination of depositional history at a scale of thousands of years. Tectonic, sea-level, and depositional rates need to be interpreted. Time-rock surfaces ranging from bedding planes to sequence unconformities reflecting durations from a few thousand to hundreds of thousands of years are present in the stratigraphic record. The recognition of these surfaces, and the determination of their areal and vertical distribution, provides the basis for reconstructing depositional history.

TECTONIC FRAMEWORK

In a previous paper the author (Visher, 1996), documented a southern Oklahoma sequence stratigraphic framework for the deposition of Lower Carboniferous strata including strata ranging in age from Chesterian to the Upper Carboniferous Desmoinesian Series. These series reflected stacking of mostly siliciclastic stratigraphic sequences. Deposition ranged from shelf marginal basins to deposition at bathyal depths on oceanic crust.

Deposition in foreland basins resulting from coastal margin uplift has been modeled by Posamentier and Allen

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(1993). They described progradation of stratigraphic units from foreland uplifts onto the cratonic margin. Associated with the Ouachita Orogen, submarine canyon-fan deposition was reflected by Chesterian, Morrowan, and Atokan Series (Visher, 1996). In excess of 5 km of foreland basinal fill was documented. Plate covergence produced uplift of the cratonic margin, wrench faulting, and the development of thrust sheets. Depocenters migrated toward and across the craton, resulting in the development of marginal cratonic basins.

This paper provides a sequence analysis of the Missourian and Virgilian Series deposited in cratonic basins developed subsequent to the uplift of the cratonic margin foredeep. Tectonic patterns, as illustrated by the Decade of North American Geology gravity map (Fig. 1), indicate basement tectonic controls for the development of

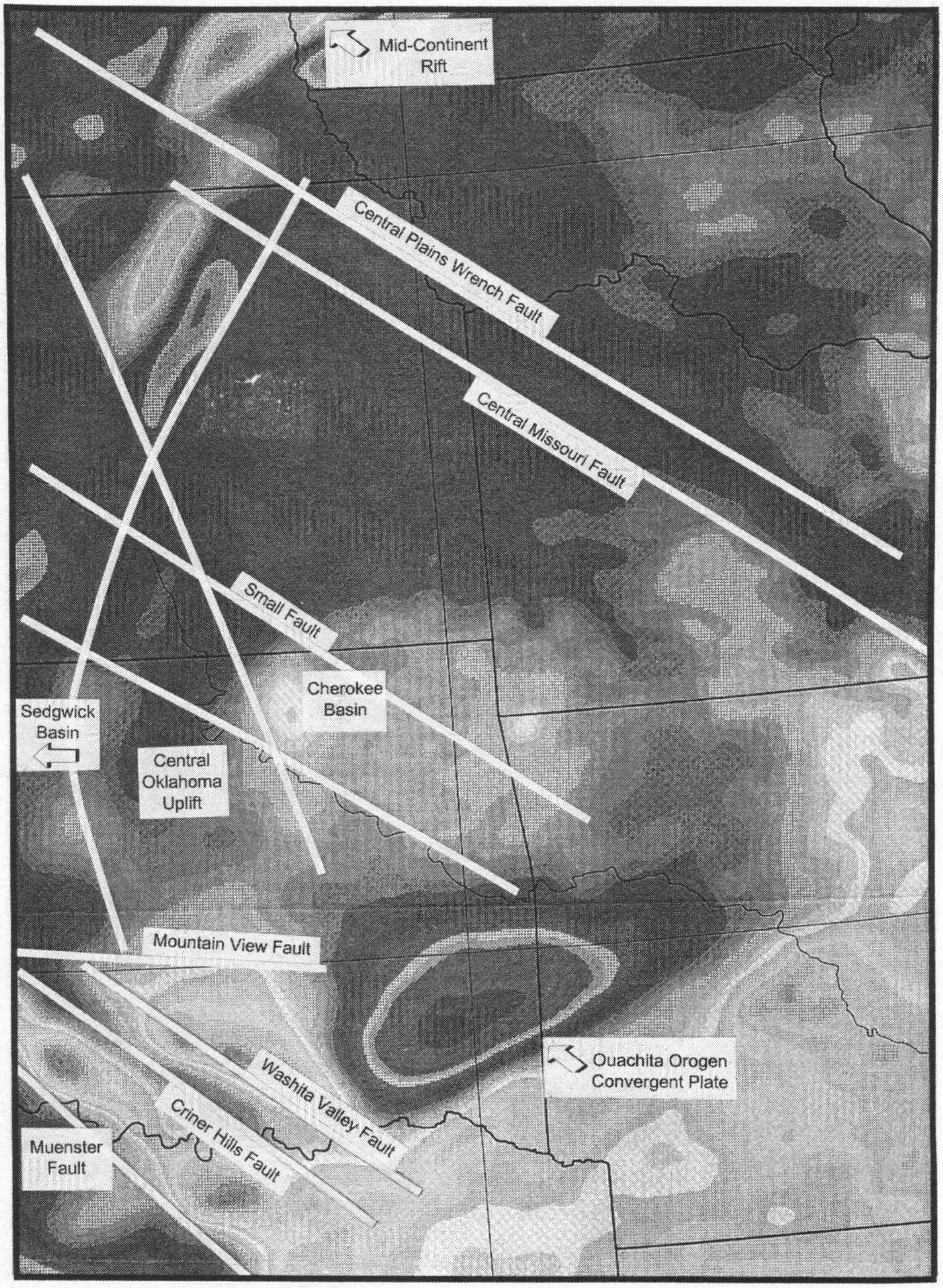

FIGURE 1—Regional gravity map including eastern Oklahoma and Kansas, western Missouri, and northwestern Arkansas (lighter areas are positive gravity anomalies). Structural elements have been identified by William McBee (pers. comm., 1999). Note position of Cherokee and Sedgwick Basins and Nemaha fault zone (from Gravity Anomaly Map Committee, 1987).

shelf basins. Wrench faults extending from the Rocky Mountains to the southern cratonic margin were activated and were partly responsible for the geometry and the history of cratonic foreland basin development (McBee, 1995). Uplift of the Ouachita orogen resulted from convergent plate-tectonic forces and produced foreland basins which migrated from the shelf margin onto the craton during the Carboniferous (Visher, 1996).

The northwest-southeast basement wrench fault system resulted in reactivation of the Precambrian Midcontinent Rift, the Nemaha fault zone, and the Central Missouri and Central Plains wrench fault zones (Baars, 1992). In central Kansas these structural elements reflect this complex wrench-fault assemblage (Fig. 2; Baars and Watney, 1991). During deposition of the Desmoinesian Series, the foreland McAlester cratonic basin developed containing nearly 3 km of siliciclastic fill. Similar thicknesses of basinal fill developed during the Desmoinesian in the Anadarko Basin and Arkoma Basin in central Arkansas (Visher, 1971).

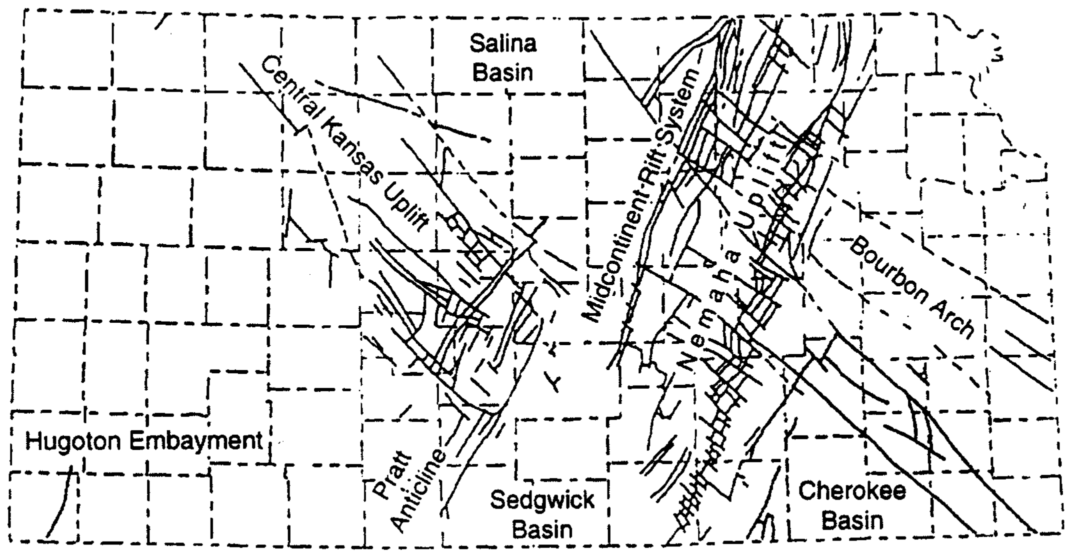

FIGURE 2—Major structural elements and basins in Kansas (from Baars and Watney, 1991).

SEQUENCE MODEL

The Cherokee, Sedgwick, and Anadarko foreland basins were produced during the Late Carboniferous in response to these forces. The clastic source for the sedimentary fill was derived from the uplift of the cratonic margin in southern Oklahoma. Nearly 2 km of Missourian and Virgilian strata filled the Anadarko, Sedgwick, and Cherokee Basins in southern Kansas and northern Oklahoma. These basins became depocenters.

Accommodation space for Missourian and lower Virgilian progradational stratigraphic intervals resulted from wrench faulting and lithospheric flow resulting in the development of topographic basins. The subsidence pattern was documented by the Missourian, Layton, Perry, and Cottage Grove progradational sandstone units filling the Cherokee topographic basin (Watney and others, 1995; Fig. 3).

A modification of the Posamentier and Allen model (1993) is required to account for the development of these basins and the topographic trough that resulted from continued subsidence of these cratonic basins. A seaway developed during the deposition of the Missourian and Virgilian Series. Paleodrainage was to the south from the central Kansas craton, and to the north and west from the rising Wichita–Ouachita orogen.

Both type 1 and 2 sequence boundaries were identified resulting in both transgressive and highstand sequences. Because these are intracratonic basins, no shelf-margin sequence boundaries (SMST) or deep-water lowstand sequences are developed (Van Wagoner and others, 1988). Basinal subsidence was continuous and did not reflect sedimentary fill (Visher, 1990). Water depth continued to increase, and condensed black shale units were deposited in the sediment-starved basins. Progradational sequences ranging from 100 to 200 m in thickness filled these basins. Continued subsidence contributed to the accommodation space for the deposition and preservation of regressive highstand 3rd-order parasequences, deposited in time intervals of from 1 to 3 Ma. Stratigraphic units reflected an equilibrium between subsidence; sediment supply; and wave, tidal, and fluvial transportational processes (Table 1).

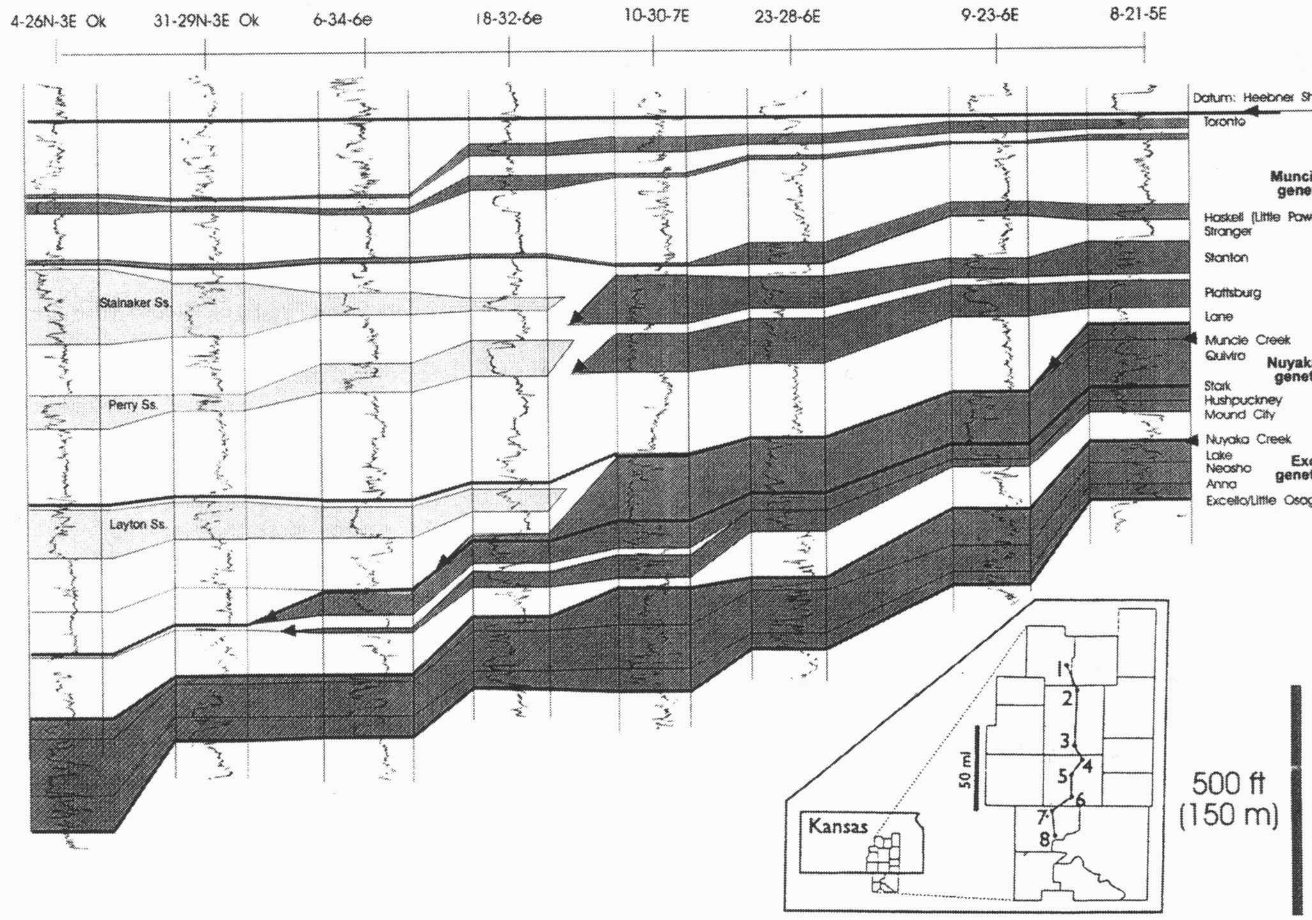

FIGURE 3—Subsidence pattern of Upper Missourian strata from Cherokee Basin of eastern Kansas and northern Oklahoma. Note carbonate shelf to basinal siliciclastic transitions (from Watney and others, 1997).

The subdivision of stratigraphic intervals was based upon criteria following Haq, Hardenbol, and Vail (1987), Ross and Ross (1988), Boardman, Nestell, and Knox (1995); and Puckette, Boardman, and Al–Shaieb (1995). Sequences ranging in periodicity from 100 Ka to 1–3 Ma were established. Level 1 sequence boundaries reflect major plate-tectonic forces on a scale of 30 Ma. Level 2 sequences reflect 10-Ma secondary cycles separating time-rock series. Level 3 sequences range from 1 to 3 Ma and reflect significant minor worldwide falls in sea level (Visher, 1990). Depositional sequences reflecting 800, 400, and 100 Ka (4th- and 5th-order) depositional cycles differ in response to local cratonic tectonic and climatic events. These cycles reflect one or more Milankovitch cycles with magnitudes of sea-level fall ranging from a few to as much as 10 meters (Fischer and Bottjer, 1991).

The levels of sequence boundaries are selected based upon physical stratigraphic evidence. Level 2, 10-Ma sequence boundaries (SB 2) mostly reflect faunal-based time-rock stages and ages. They are delineated by condensed sections, environmental changes, and possibly worldwide events such as periods of flood basalts, extra-terrestrial impact, rifting events, and subsidence of oceanic trenches (Visher, 1990).

Level 3 sequence boundaries (SB 3) reflect minor worldwide responses to depositional histories. Intraplate tectonic responses are indicated by paleogeographic patterns, provenance patterns, and especially local environmental controls. Cycles, ranging from 400 and 100 Ka (SB 4), mostly reflect local depositional controls such as climate changes, changing patterns of oceanic currents, and migration of depocenters reflecting changing areal patterns of sediment-accommodation space and dispersive energy.

Major sequence unconformities (SB 2) are characterized by nearshore black-shale units, valley-fill units, and discontinuous carbonate and/or siliciclastic shelf units. The Missourian–Virgilian unconformity surface is marked by deposition of the Tonganoxie and Ireland valley-fill sandstone units in Kansas and the Boley conglomerate and Cheshewalla sandstone units derived from rising foreland uplifts to the south.

TABLE 1—Synthesis of sequence stratigraphic intervals from Upper Desmoinesian to lowermost Wolfcampian Series.

Pawnee and Kay Counties, T. 29 N., R. 3–4 E.

	PERMIAN–WOLFCAMPIAN SERIES		
			Ma288.3
	Council Grove Group		SB_3
	Neva ls. (Grenola ls., KS)	HST	.2
	Sallyards, KS - **Black Shale**	TST	.1
			Ma289.6
	TOP OF PENNSYLVANIAN–BURSUMIAN SERIES		SB_4
	Roca paleosol., KS		.1
(0.4Ma)	Red Eagle ls. Bank	TST	.2
	Bennett (worldwide) - **Black shale**	TST	.1
			Ma290.0
	Council Grove Group (Foraker Sequence)		SB_3
	Johnson sh.	HST	.4
(1.0Ma)	Hughes Cr. sh. (Longs Creek ls., KS)	HST	.2
	(Unnamed) - **Black shale**	TST	.1
	Americus ls., (Stonebreaker ls., KS)	TST	.2
	(Unnamed) - **Black shale**	TST	.1
			Ma291.0
	Admire Group (Richardson Sequence)		SB_4
	Janesville sh.	HST	.2
	Admire undif. (Onaga sh., KS)	HST	.4
	Richardson Sub-Group		
	(Wood Siding Fm., KS)	HST	.2
(2.0Ma)	(Root sh., KS)	HST	.4
	(Stotler ls., KS)	HST	.2
	Pillsbury sh.. KS	TST	.2
	Wakaurusa ss., KS	TST	.4
			Ma293.0
	VIRGIL SERIES		
	Wabanusee Group (Wabanusee Sequence)		SB_2
	Brownville Bank (Zeandale ls., KS)	HST	.2
	Wamego sh., KS - **Black shale**	TST	.1
	Perry Creek sh., (Willard sh., KS)	HST	.2
(1.6Ma)	Emporia ls. - Reading ls.	HST	.2
	Garber ss. (Auburn sh., KS)	HST	.2
	Burlingame ls. Bank	HST	.2
	Shanghi Creek - **Black shale**	TST	.1
	Mervine ss. (Howard-Topeka ss., KS)	HST	.4
			Ma294.6
	Shawnee Group (Pawhuska Sequence)		SB_4
	Pawhuska Bank	HST	.2
	Pawhuska ss. (Little Hominy ss., KS)	HST	.2
	Deer Creek ls.		.1
	(Larsh-Burr Oak) - **Black shale**	TST	
(1.6Ma)	Lecompton ls. Bank	TST	.2
	Queen Hill - **Black shale**	TST	.2
	Vamoosa Fm.,		
	Elgin - 2 ss's. (Hoover ss.)	HST	.4
	Oread ls. Bank (Plattsmouth ls., KS)	TST	.2
	Heebner - **Black shale**	TST	.1
			Ma296.2
	Douglas Group (Douglas Sequence)		SB_3
	Wynona ss.	HST	.4
	Lovell ls. Bank (Amazonia ls., KS)	HST	.2
(l.6Ma)	Little Pawnee - **Black shale**	TST	.2
	Kiheki ss., (Lawrence Fm., KS)	TST	.4
	Cheshewalla ss. (Boley conglomerate)	TST	.4
	(Stalnaker - Tonganoxie ss., KS)		
			Ma297.8
	MISSOURIAN SERIES		
	Ochelata Group (Lansing-Kansas City Sequence)		SB_2
	Stanton ls. Bank (Plattsburg ls.)	HST	.2
	Eudora - **Black Shale**	TST	.2
	Tallant Fm.		
(2.4Ma)	Bigheart ss. (Revard ss.)		.4
	Barnsdall ss. (Okesa ss.)	HST	.4
	Wann Fm.		
	Clem Creek ss.	HST	.4
	Washington Irving - 2 ss's.	HST	.4
	Avant ls. Bank (Iola ls., KS)	TST	.2
	Muncie Creek - **Black shale**	TST	.2
			Ma300.2
	Cottage Grove Group (Cottage Grove Sequence)		SB_3
	Cottage Grove ss., (Chanute, KS)	HST	.4
(1.4Ma)	Nellie Bly ss. (Shell Creek ss.)	HST	.4
	Dewey ls. Bank	HST	.2
	Cherryvale Fm.		
	Quivira - **Black shale**	TST	.2
			Ma301.4
	Skiatook Group (Skiatook Sequence)		SB_4
	Hogshooter ls. Bank	HST	.2
	Coffeyville Fm. (Coffeyville Group, KS)		
	Stark - **Black shale**		.2
	Lost City ls. Bank (Dennis ls.,KS)	HST	.2
(1.8Ma)	Layton - 2 ss's.	HST	.4
	Tacket - **Black shale**	TST	.2
	Checkerboard ls.	TST	.2
	Dawson coal	TST	.1
	Cleveland Fm. - 3 ss's.	TST	.6
			Ma303.4
	TOP OF DESMOINESIAN SERIES		
	Marmaton Group (Marmaton Sequence)		SB_2
	Lenapah ls. Bank	HST	.2
	Nuyaka Creek - **Black shale**	TST	.1
(1.6Ma)	Oologah ls. Bank (Big Lime)	HST	.2
	Oswego Bank (Ft. Scott) Wewoka 4 ss's	HST	.6
	Excello - **Black shale**	TST	.1
	Prue/Calvin - 2 ss's.	TST	.4
			Ma305.2
	Senora Group (Senora Sequence)		SB_4
	Breezy Hill ls.	HST	.2
(1.4Ma)	Verdigris ls.	HST	.2
	Skinner - 2 ss's.	HST	.4
	Stuart sh.	TST	.2
	Thurman ss.	SMST	.4
			Ma306.6
	Boggy Group		SB_3
	Red Fork - 2 ss's.		

(continued next column)

NOTES TO TABLE 1—
Following Vail, Haq, and Posamentier:

Sequence Boundaries:

Level 1; reflects 30 Ma Cycles
Level 2; reflects 10 Ma Cycles
Level 3; reflects 1-3 Ma Cycles
These reflect combinations of .4 and .8 Ma cycles
Level 4; reflects .4 Ma Cycles
Level 5; mostly reflects .1 Ma Cycles
Level 6; can reflect either .042 or .021 Ma Cycles, and reflect proximity to shorelines

Most 2nd order Sequences correlate with Time-rock Series boundaries, reflecting sea-level falls across continental shelves, producing faunal extinctions and pulsed evolutionary responses. They are mostly SB 2 boundaries.

Most 3rd order Sequences roughly correlate with Rock Stratigraphic Group boundaries, reflecting worldwide flooding surfaces due to sea-level rises, resulting in condensed intervals. They are mostly SB 3 boundaries.

Most 4th order Sequences reflect local depositional subsidence events and climate cycles. They are mostly SB 4 boundaries.

The levels of sequence boundaries are selected based upon physical stratigraphic evidence. They mostly reflect faunally based Time-rock Stages and Stratigraphic Ages. They reflect condensed sections, evironmental changes, and possibly world-wide events such as periods of flood basalts, extra-terrestrial impacts, rifting events, and subsidence of oceanic trenches.

With continued sea-level rise, transgressive nearshore coal and black shale units were deposited. Regionally these black shales reflected maximum flooding surfaces, and distal from shorelines they were dominated by phosphatic and pelagic sedimentary processes. Examination of a natural gamma-ray "spectralog" from T. 29 N., R. 4 W., indicates that these black-shale units reflect both nearshore and distal shoreline depositional environments as reflected by the Ur/Th ratio (Hallenburg, 1998, p. 206). Uranium is associated mostly with organic nearshore units, whereas thorium is associated with adsorption by clay minerals. Overlying these black shales, shelf-carbonate units developed. However, on the flanks of basins, continued subsidence resulted in continued bank deposition (Fig. 4). Within basins with limited clastic sedimentary supply, condensed black-shale intervals were

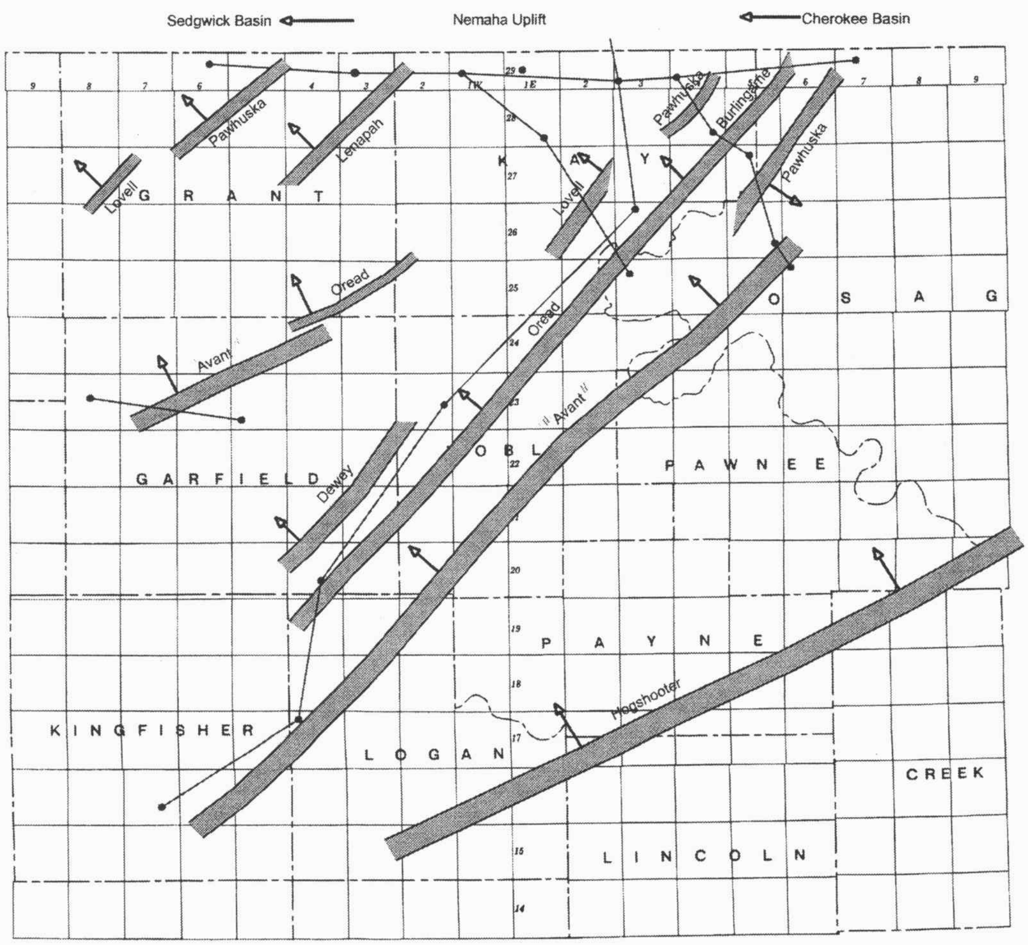

FIGURE 4—Distribution of carbonate banks in north-central Oklahoma. Trends reflect maximum bank thickness and direction of progradation. Data derived from indicated log cross sections.

deposited. Overlying these black-shale units, basins were filled with detrital carbonate and marine-shale sequences.

The balance between sea-level rise, sediment supply, and basinal subsidence determined whether siliciclastic deltaic or carbonate-bank intervals were developed. Banks continued to develop surrounding basins with low detrital siliciclastic sediment supply. Shoreline riverine, wave, and tidal deltaic deposits are present in areas of high siliciclastic provenance. Tidal shelf siliciclastic and carbonate sands have been documented in Virgilian sequences on the Kansas carbonate platform.

MISSOURIAN AND VIRGILIAN SEQUENCES

It has been recognized for a long time that the late Carboniferous contains many cycles (cyclothems). There has been speculation that these cycles are related to glaciation in the southern hemisphere (Gondwanaland). Boardman and Heckel (1989) correlated black shales associated with maximum flooding surfaces from Nebraska to Texas (Fig. 5). They did not attempt a specific time-rock sequence subdivision as suggested in Table 1, by

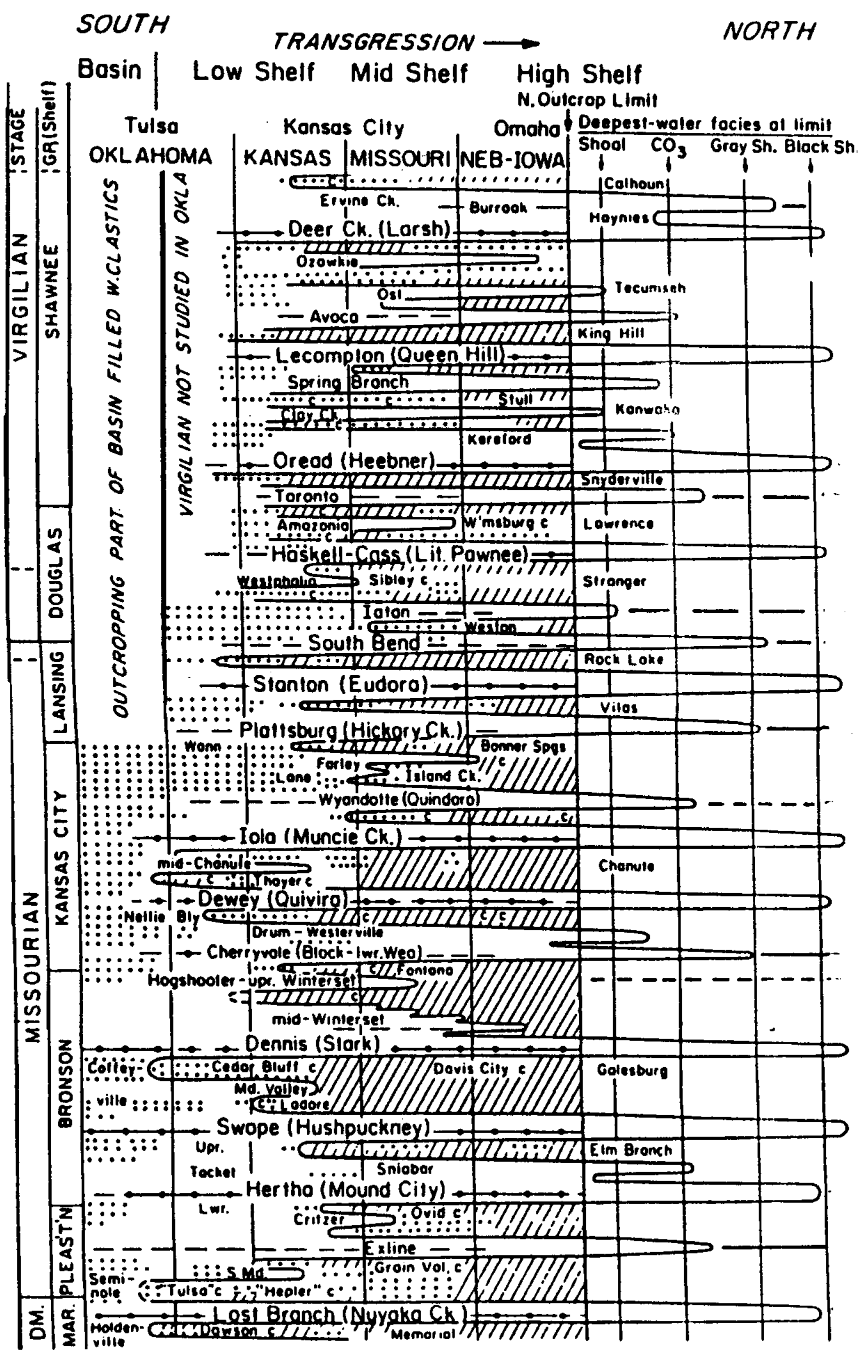

FIGURE 5—Regressive-transgressive depositional patterns for Missourian and Virgilian Series from Nebraska to Tulsa, Oklahoma (from Boardman and Heckel, 1989).

Haq and van Eysinga (1987), and by Ross and Ross (1988), but they did provide the framework for developing a detailed time-stratigraphic depositional history.

Application of this framework to a type log in northern Oklahoma (NW SE SE sec. 18, T. 29 N., R. 1 E.), has been developed based upon data from the Kansas Geological Society (1966), Boardman, Nestell, and Knox (1995), and the work of the Stratigraphic Committee of the Tulsa Geological Society (Fig. 6). A number of the black-shale units were not well developed in this type log, but a sufficient number could be identified to make it possible to subdivide the Missourian and Virgilian Series into

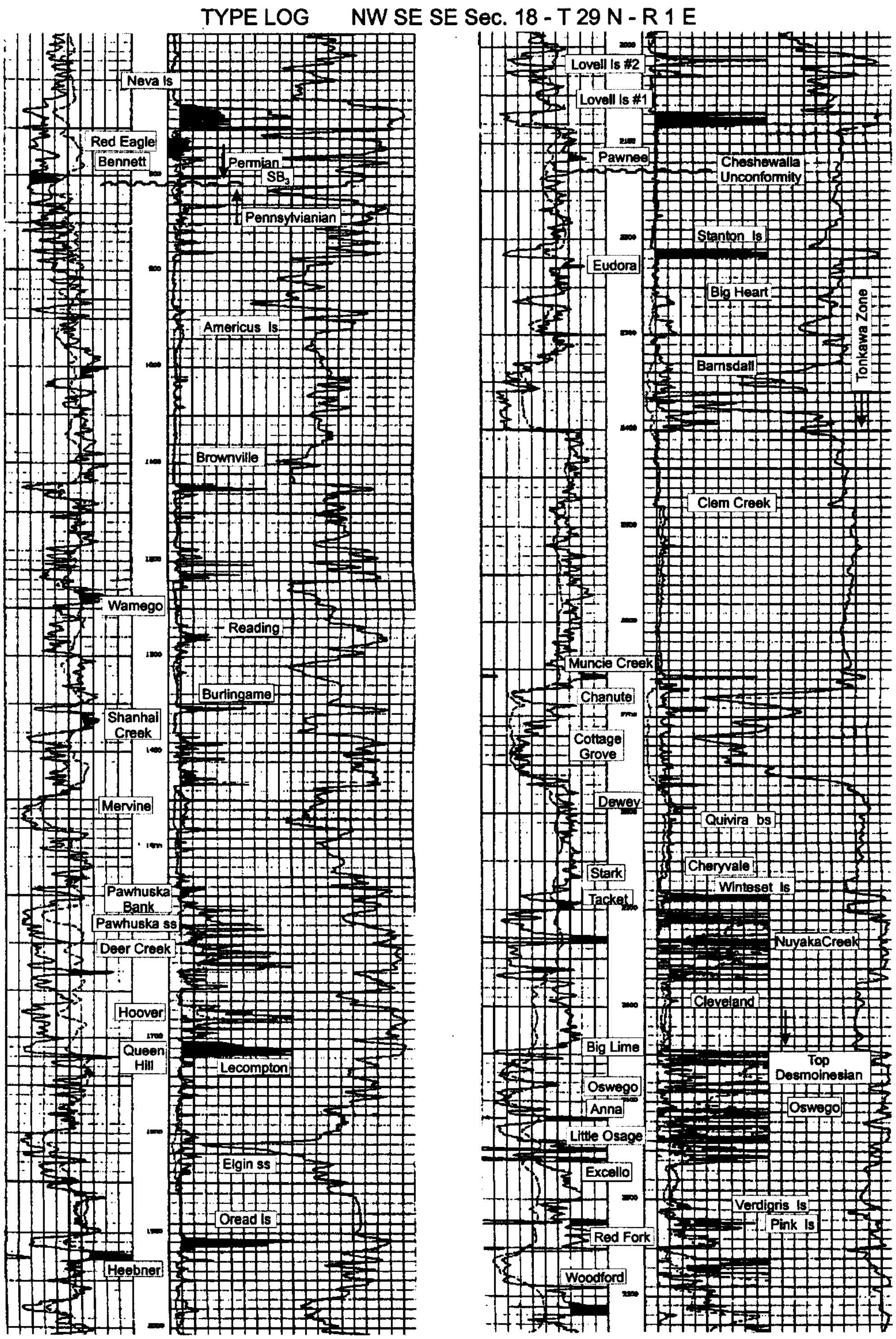

FIGURE 6—Type log showing principal black shale, carbonate bank, and lithologic units for Desmoinesian to basal Permian strata (compiled including data from Kansas Geological Survey; Boardman, Nestell, and Knox, 1995; and Tulsa Geological Society Stratigraphic Committee).

identifiable sequences. In northern Oklahoma, and most probably Kansas, each black-shale maximum-flood surface (MFS) usually was overlain by a limestone bank.

Log correlations of marker events indicate that the terminations of bedding units reflected progradation of carbonate banks towards the Andadarko and Sedgwick Basins (Fig. 4). Some bank intervals attained a thickness of more that 75 m. Major sea-level falls of possibly tens of meters (SB_2), exposed carbonate banks on the margins of basins, and subaerial exposure produced leached porosity that may contain hydrocarbon accumulations; omission surfaces developed within basins.

Paleogeographic reconstruction of individual 1–3 Ma (SB_3) sequences emerged with basinal black shales reflecting condensed sections associated with maximum flooding surfaces (MFS) that separated sequence boundaries. Condensed basinal black-shale units usually were overlain by progradational basinal clastic units. Basinal topography was such that accommodation space was available for stacked deltaic sequences up to 100 m in thickness. Detailed correlation usually allowed subdivision of stratigraphic units at time scales of 400 Ka or less (Fig. 7).

Detailed time-rock correlations have been constructed by Caylor (1958) and Fambrough (1965), which proved useful for reconstructing the paleogeographic pattern of individual sequences. The 1–3 Ma intervals reflect parasequences as described by Van Wagoner and others (1988). The geometry of carbonate banks and deltaic depositional sequences were useful for predicting the distribution of stratigraphic traps across basinal margins as reflected by Lansing–Kansas City carbonate build-ups.

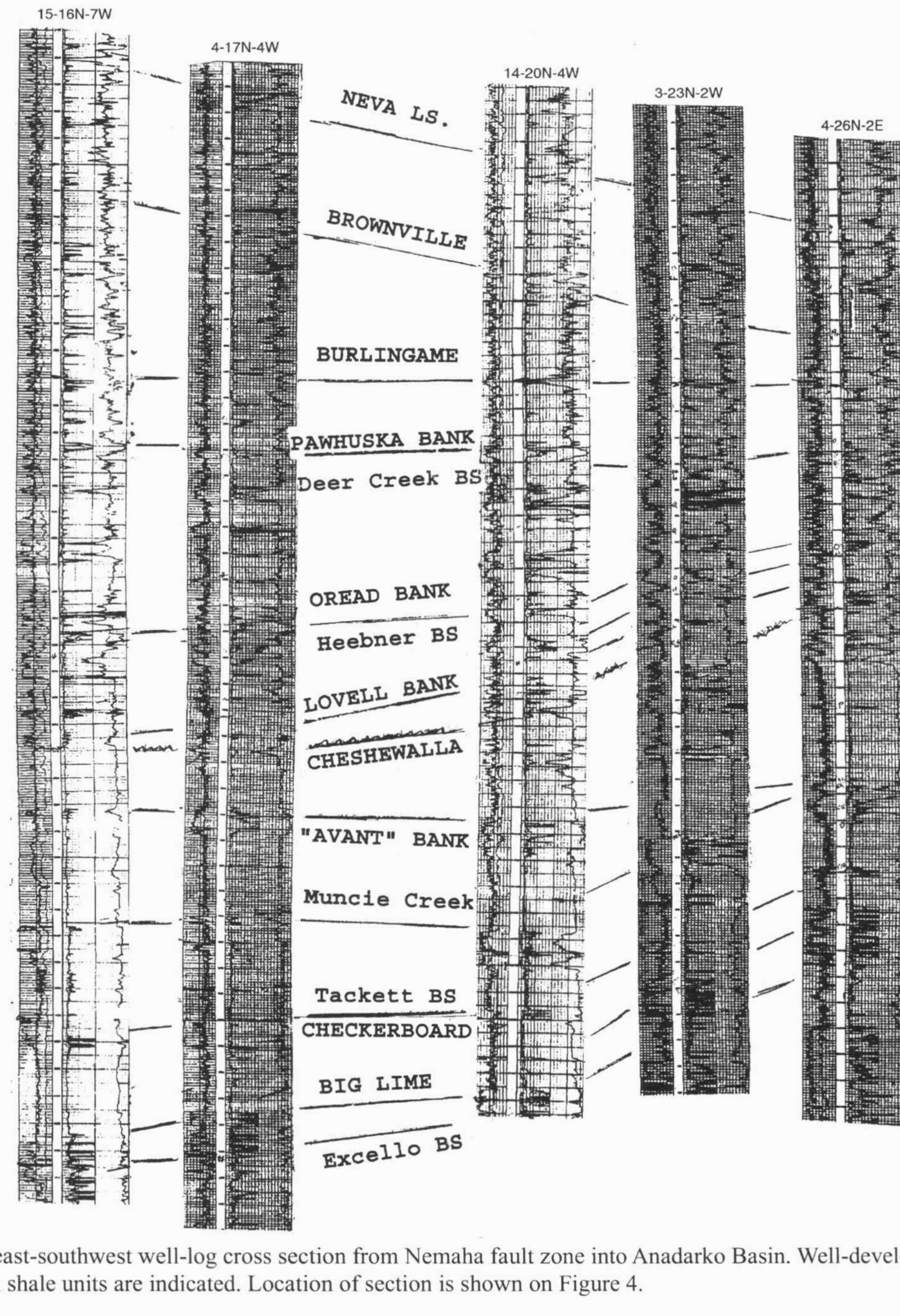

FIGURE 7—Northeast-southwest well-log cross section from Nemaha fault zone into Anadarko Basin. Well-developed carbonate bank and black shale units are indicated. Location of section is shown on Figure 4.

CONCLUSIONS

What has been demonstrated is that if bedding planes, and stratigraphic markers or unconformity surfaces, can be identified at sequence scales of hundreds of thousands of years, it is possible to reconstruct depositional history utilizing paleogeographic maps over large areas and for time-rock intervals from 1 to 3 Ma to more than 10 Ma. Sequence stratigraphic analysis does not have to be limited to cratonic margins; it can be reconstructed within cratonic plates.

Toplap, bottomlap, and seismic sections recording sigmoidal and oblique reflection surfaces are not required. What is needed is the identification of a cyclic stratigraphic theme. Ross and Ross (1988) and Boardman, Nestell, and Knox (1995) have determined that conodont, foraminiferal, and molluscan faunal zones can be plotted graphically to refine time-rock correlation in order to identify short time-rock increments.

The stratigraphic record provides the historical documentation of depositional events. The recognition and correlation of these events provides the framework for reconstructing and interpreting the origin of stratigraphic units, sequences, and intervals.

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A Regional Study of Sequences in the New Albany Shale of the Southeastern Illinois Basin (Indiana) with Gamma-Ray Logs and Well Cores

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The New Albany Shale of southern Indiana is a middle to late Devonian black shale unit that constitutes an important hydrocarbon source rock in the Illinois Basin. Going from east to west, the New Albany Shale thickens and changes its lithologic characteristics. These changes reflect the gradual deepening from the shallow water regions on the Cincinnati Arch to the deeper water regions of the Illinois Basin.

In outcrop studies from Tennessee and central Kentucky, recognition of widespread erosion surfaces allowed a sequence-stratigraphic subdivision of this black-shale succession. Gamma-ray logs from southern Indiana show that these subdivisions can be carried into the subsurface west of the New Albany outcrop belt. Systematic tracing of these sequences through the Illinois Basin may in the future allow substantial refinement in the understanding of the depositional history of these rocks.

The observed variability between adjacent gamma-ray logs is attributed to the erosional truncation at the top of individual shale packages. Additional variability is introduced because some shale packages that are present in western Indiana have been lost completely to erosion in eastern Indiana and Kentucky. The transgressive base of individual sequences typically coincides with an increase in gamma-ray intensity.

Future study of these shales will be the basis of making a better connection between the conformable sequences of the Illinois Basin interior and the discordant sequences of the Cincinnati Arch region.

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Revisiting Pennsylvanian Reservoir Architecture—Chitwood, Norge, and Northeast Verden Fields, Caddo and Grady Counties, Oklahoma

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ABSTRACT

Pennsylvanian Midcontinent reservoir sands historically have been interpreted to originate in fluvial channel to fluvially dominated deltaic settings. In recent years, reexamination of cored intervals and outcrop analogs of many of these reservoir units has modified the original depositional models to include incised valley fills and tidally influenced estuarine to tide-dominated deltaic and shallow marine shoal settings. Incorporating these modified reservoir architectures into field development strategies has led to improved secondary recovery and maximized daily production volumes and ultimate cumulation.

In particular, the original geologic models for the 30-year-old Chitwood, Norge, and Northeast Verden fields in Caddo and Grady counties, Oklahoma, have been modified substantially by reexamination of old field development cores and the recent acquisition of new cores and Formation Micro-Imaging (FMI) data sets. Stacked, fluvial channels within the Huddleston sand of Chitwood field have been recognized as early transgressive valley fill with pronounced tidal channel/shoal reworking. Similarly, initial fluvial deltaic models in the Missourian Marchand sand now reflect dramatic tidally influenced to tide-dominated shoal flow units. With no abrupt seaward shifting of facies present, a prograding highstand deltaic setting is envisioned for the Marchand sand in Norge and Northeast Verden fields.

By revisiting such fundamental geologic information, producers can better understand reservoir architecture for optimal well placement and more efficient design of secondary-recovery technologies. This is especially true where the geologic data are utilized in current, reservoir-engineering flow models.

PENNSYLVANIAN STRATIGRAPHY AND FIELD HISTORIES

Missourian sands comprise the reservoirs in several fields within Caddo and Grady counties, Oklahoma. Figure 1 shows the location of three of these fields, Northwest Chitwood, Norge, and Northeast Verden. Chitwood field produces from the Huddleston sand of the Lower Hoxbar Group as shown in Figure 2. The Marchand sand producing in both Norge and Northeast Verden fields is interpreted to be roughly equivalent stratigraphically to the Huddleston, although correlation across faults separating Chitwood and Norge fields remains subjective. Early regional correlations inferred the Huddleston as part of the basal Missourian Cleveland sand.

The Northwest Chitwood field is located 10 miles southeast of Chickasha, Oklahoma. Most of the development drilling in this field discovered in 1953 was completed in the 1960's, with peak preunitization production in 1972 reaching nearly 2,500 BOPD. Unitization was granted in 1991, with Oryx Energy (Sun Oil) Company appointed operator. At that time, the unit produced 350 BOPD. Present-day production is 3,300 BOPD and 2,000 MCFPD. Net pay averages nearly 40 feet within the field; measured sand permeabilities range from less than 1 millidarcy (mD) to more than 1,950 mD.

The Norge Marchand Unit (Norge field) incorporates several accumulations within west-central Grady County, Oklahoma, northwest of Northwest Chitwood field (Fig. 1). Marchand sands of the Lower Hoxbar Group produce from several stratigraphic horizons. The field was discovered in 1971 and rapidly developed on 160-acre spacing. Peak production of more than 28,000 BOPD occurred in February 1972. Unitization occurred in May 1973, with Oryx Energy (Sun Oil) serving as unit operator. Water injection began in April 1975 as documented in the summary review by Jowell and Haberthur (1976).

Northeast Verden field (Fig. 1) is located north-northwest of Norge and spans the Grady/Caddo county line. The discovery well was completed in February 1967 by Phillips Petroleum and produced 240 BOPD from the Marchand (Lower Hoxbar) sand. The field was developed on 160-acre spacing from 1967 to 1980, at which time a

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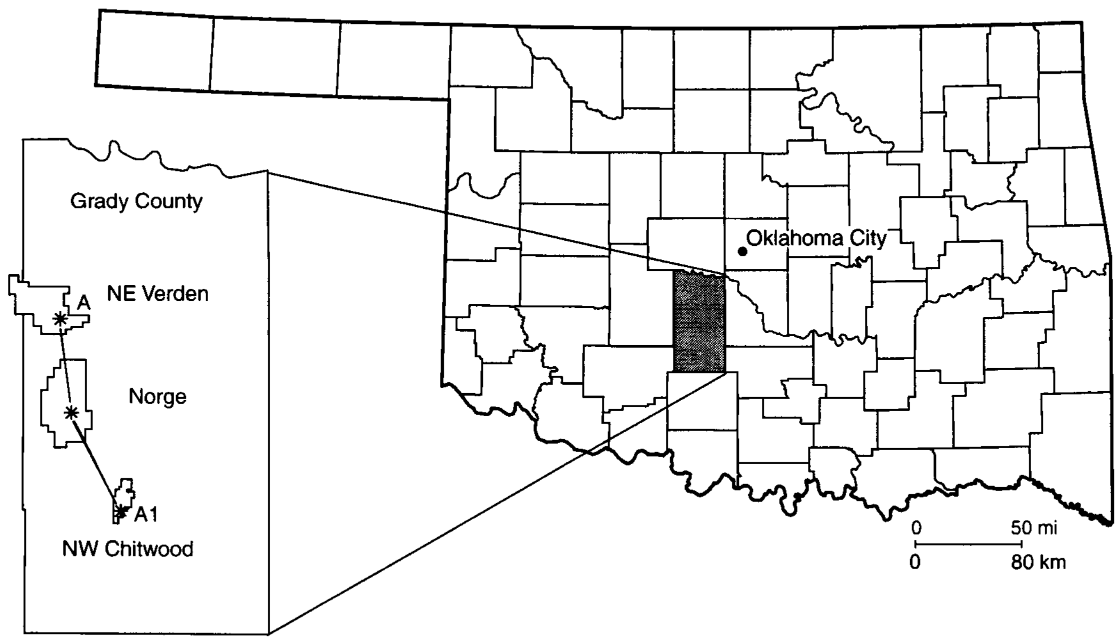

FIGURE 1—Pennsylvanian (Missourian) fields within Grady County, Oklahoma.

Lower Hoxbar Group	Lansing	Cottage Grove Sandstone
(Mississippian)	Kansas City	Layton sand --- Hot Shale Marchand sand (Huddleston ss) Cleveland sand

FIGURE 2—Pennsylvanian (Missourian) stratigraphy, central Oklahoma (modified from Northcutt and Johnson, 1996).

technical-advisory committee concluded that secondary waterflooding operations were economically feasible. The Northeast Verden Marchand unitization occurred in April 1984, with Oryx Energy (Sun Oil) as operator. Preunitization daily production was 700 BOPD; present daily production is 1,680 BOPD and 720 MCFPD.

CORE SEDIMENTOLOGY

A limited number of cored intervals have been acquired from the three producing fields. The more extensive of these cored intervals have been reexamined to determine productive depositional environments and the overall regional setting exhibited by the Marchand and Huddleston sands. The following paragraphs discuss the core sedimentology for the wells depicted in Figures 3, 4, 5, and 6. Representative core images in Figure 7 exhibit depositional environments of both the Marchand and Huddleston sands.

The annotated well log profile from the Chitwood 25-1 unit well within the Northwest Chitwood field is shown in Figure 3. From the top of the Huddleston sand at approximately 9,580 feet to the sand base at 9,706 feet, the Huddleston strata consist of sand-dominated beds abruptly overlying marine-shelf carbonates and shale units of the underlying (late Desmoinesian?) strata. The conglomeratic lag at the base of the Huddleston sand (Fig. 7A) consists of rounded clasts of carbonate mud to 10 centimeters length mixed with minor fossil debris. This basal lag abruptly overlies upward-shoaling carbonate mudstones to wackestones of marine-shelf origin. Above the lag, the 115 feet of Huddleston sand cored in the well (Fig. 3) exhibits no significant shale interbeds and can be subdivided into three gross genetic units of subequal thickness. Dominant sedimentary structures observed in the Huddleston sand of

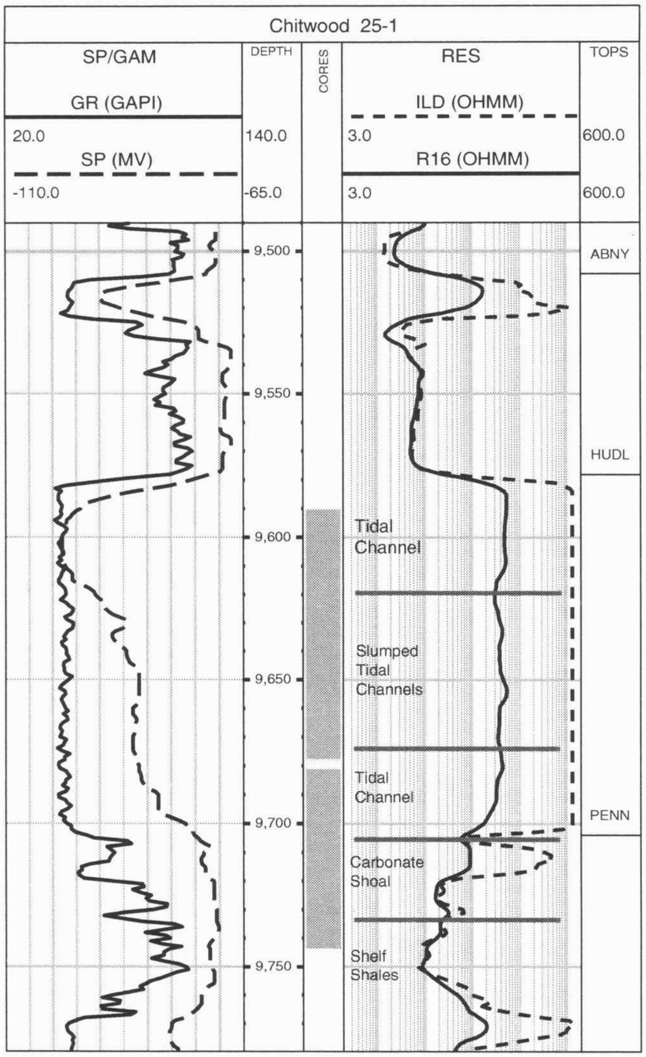

FIGURE 3—Representative Huddleston sand log profile (with shaded cored interval), Chitwood No. 25–1 well, Northwest Chitwood field, Grady County, Oklahoma.

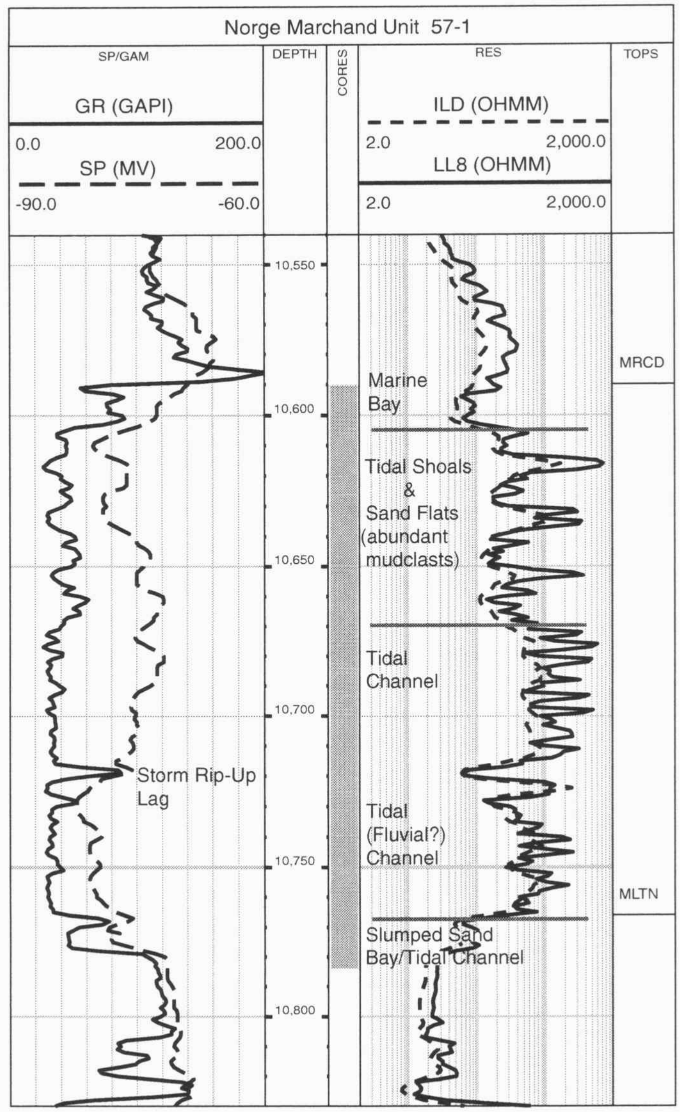

FIGURE 4—Norge Marchand Unit (Norge field) No. 57–1 well log through Marchand sand.

Chitwood field include thin crossbed sets of strongly oblique to near herringbone orientations as shown in the core photograph taken near the base of the Huddleston (Fig. 7B). Also present within the cored sands are numerous occurrences of soft-sediment deformation contorting the remnant sedimentary structures. The degree of slumping present within the central package of the cored Huddleston effectively separates the upper and basal sand units exhibiting less deformation and preservation of the bidirectional to sigmoidal crossbedding. Depositionally, each of the genetic sand units comprising the cored interval exhibits features attributable to a tide-dominated depositional setting. Each of these intervals was described originally by the senior author as originating within a tidal channel (shoreline) setting. Descriptions by Tillman (1996) closely match those observed in the Huddleston core and have been attributed to estuarine tidal-accretion bar facies. Whichever of these facies interpretations is correct, both are inferred to have been part of an estuarine setting fed by sands delivered either from bayhead deltas entering the estuary or from reworking of sand migrating into the estuary from the seaward side. It is our opinion that the Huddleston sand producing within Chitwood field represents a tide-dominated incised valley fill cut into older Pennsylvanian marine-shelf sediments eroded during sea-level drop at the beginning of Missourian time. In this setting, the base of the Huddleston is considered a sequence boundary, and the resulting sand is early transgressive fill of the estuary (valley). The top of the Huddleston sand in the well was not cored but appears as a sharp, rapid abandonment surface covered by marine (?) shales of the overlying (or remaining) Marchand interval.

Two cored intervals of the Marchand sand within Norge field were examined and are identified on the well-log plots shown in Figures 4 and 5, respectively. In the

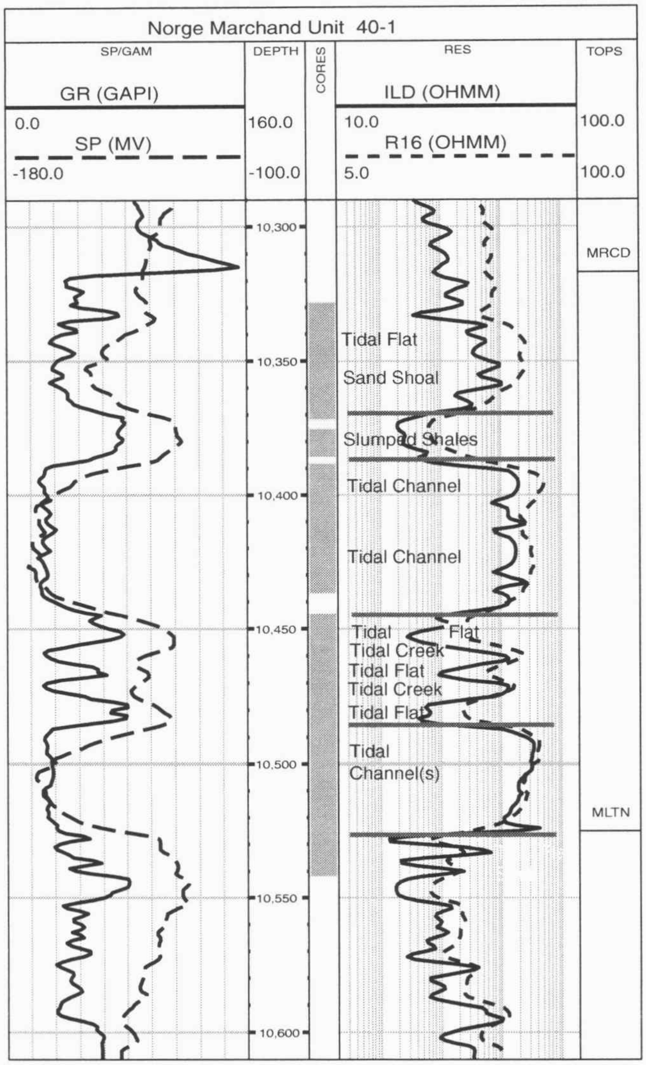

FIGURE 5—Norge Marchand Unit (Norge field) No. 40–1 log and cored interval.

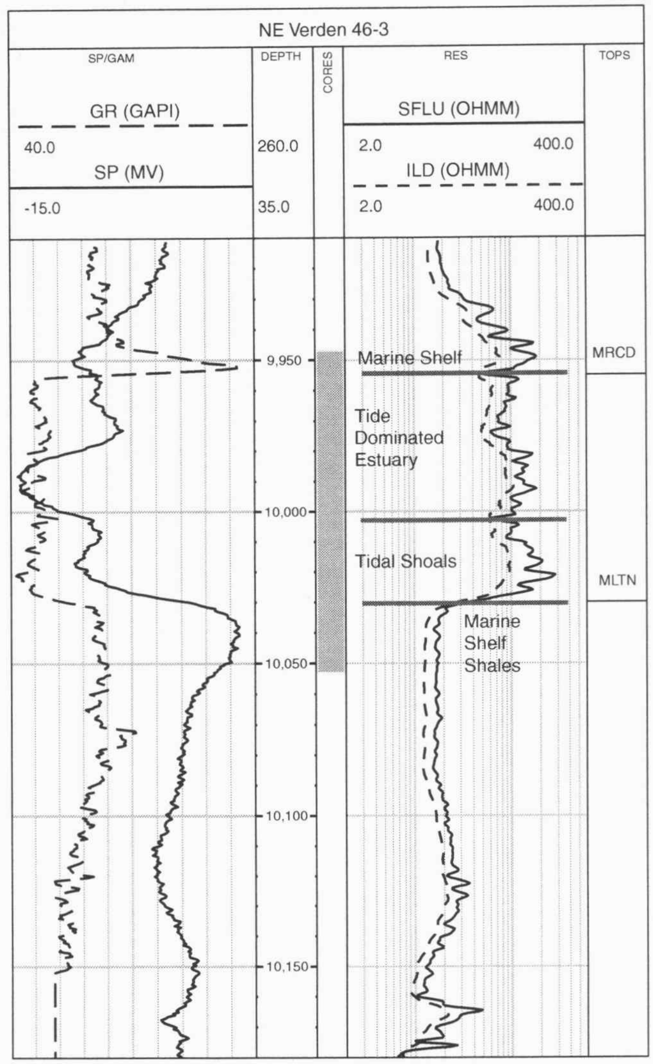

FIGURE 6—Northeast Verden No. 46–3 well log and cored interval, Marchand sand.

first of these (Fig. 4), the Norge Marchand Unit No. 57–1 core begins just below the top of the Marchand at 10,587 feet and is continuous through the base of the sand into underlying bay/tidal shales below 10,779 feet. From field correlations, the base of the Marchand interval in the well is below the cored interval (shoreline/bay shales overlying marine shelf shales). The Marchand interval cored (except for shaly interbeds at the top and base of the cored interval) is extremely sand-dominated with minor shale interbeds measuring individually less than 1 inch (2.5 cm) thick. The noisy gamma-ray and SP log responses historically have been interpreted to be indicative of abundant, thin shale interbeds thereby reducing inferred reservoir quality within these "shaly" intervals such as at the top of the core (10,605–10,670 feet). Core within this interval exhibits that the fine- to medium-grained sands locally contain abundant shale rip-up clasts up to 1-inch (2.5-cm) length (Fig. 7C). The relative abundance of these clasts gives the sands their "shaly" character whereas the sand-dominated beds retain significant reservoir quality. The sands themselves exhibit thin, oblique bidirectional crossbedding to indistinct low-angle lamination and occasionally massive sand (structureless) character. Depositionally, the repeated stacking of these sandstone beds is attributable to tidal-channel and accretion-bar facies similar to the Huddleston sand in Chitwood. The tide-dominated to tidal-influenced succession within the NMU 57–1 interval is divisible into at least five sand genetic units stacked on top of one other without significant shale breaks to separate flow units. The stacked Marchand sand architecture within the well is considered a tide-dominated, embayed shoreline setting. This tidal architecture also is identified within the NMU 40–1 (Norge) cored interval with the exception of several significant (though subordinate) shale/sand interbeds isolating the tidal-channel/shoal units. Figure 5 illustrates this interbedded succession—note that the shaly interbeds show more pronounced gamma-ray and SP log response.

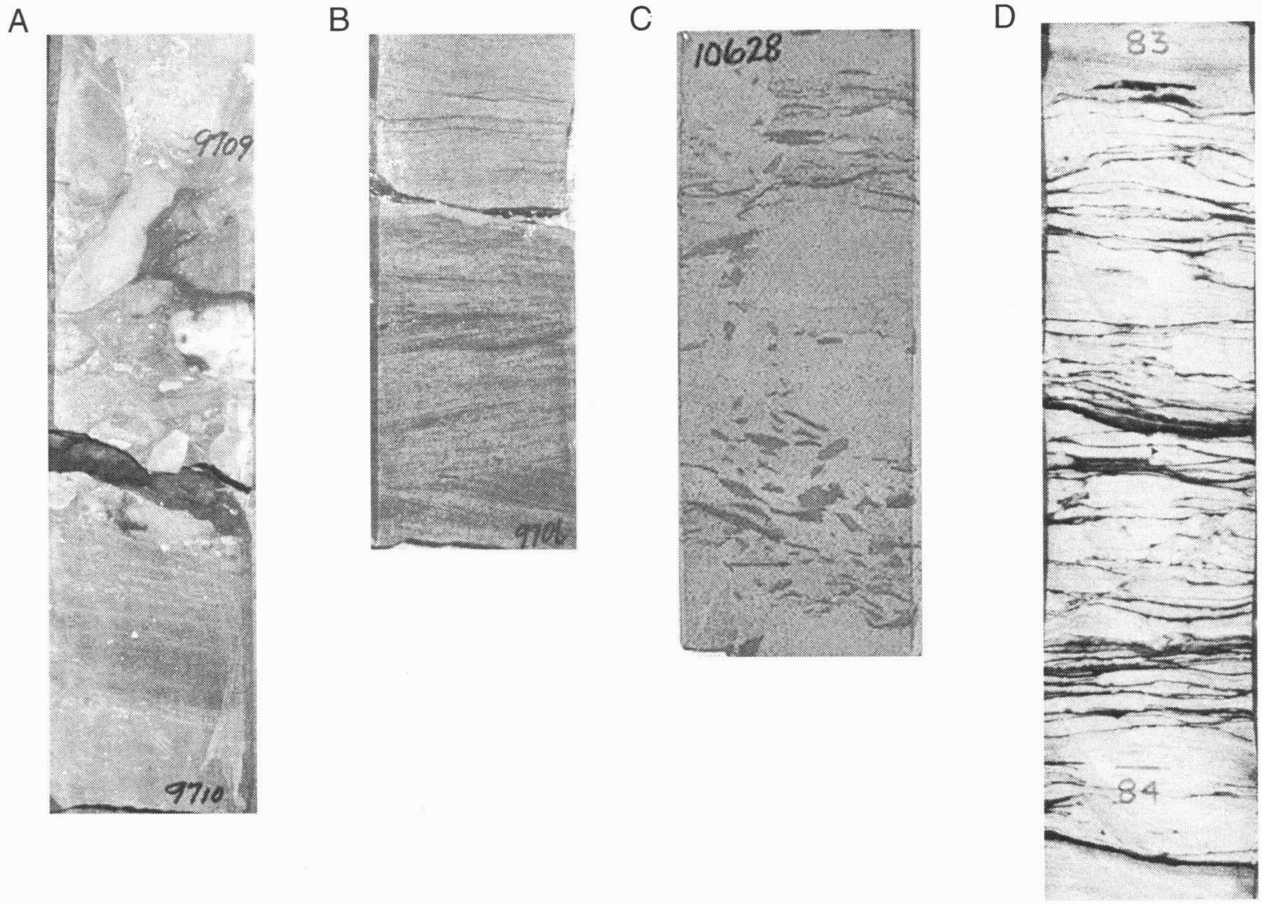

FIGURE 7—Representative core photographs: A, basal lag of Huddleston sand interval consisting of transported carbonate mud clasts (Chitwood No. 25–1—9,709 feet); B, bidirectional crossbedding, Huddleston sand (Chitwood No. 25–1—9,706 feet); C, tidally influenced Marchand sand with mud rip-up clasts (Norge Marchand Unit No. 57–1—10,628 feet); and D, very fine-grained Marchand sand with clay drapes and mud couplets (Northeast Verden Unit No. 46–3—10,084 feet, core depths).

Sedimentary structures noted within the sands include massive (structureless) bedding, low-angle crossbedding, and ripple lamination (in the finer grained sand beds). Mudstone rip-up clasts are present within the uppermost tidal shoal/accretion bar facies and yield a similar, ratty gamma-ray response. The shaly interbeds observed in the cored interval are part of intermittent mud-rich tidal flats occurring within this part of the irregular shoreline/estuary setting. Scattered fossil debris is present within the cored interval, especially near the base of the Marchand sand. The strata underlying the Marchand within the 40–1 interval exhibits interbedded greenish mud to very fine sand, tidal-flat sediments, which are different from the overlying Marchand strata. Although coarse sand-sized to granular mud rip-ups and fossil pelecypod, bryzoan, and crinoid debris occur within the basal-most beds of the Marchand, the contact is not demonstrably a regional unconformity or sequence boundary compared to that at the base of the Huddleston sand within nearby Chitwood field.

A thinner and finer grained Marchand sand succession is present within the Northeast Verden field (Fig. 6). The Northeast Verden No. 46–3 interval spans the productive sand and demonstrates that the shales below and above are of marine-shelf origin. The capping "hot" shale beds are laminated claystones devoid of burrows or fossil debris save for a lone, thin-walled pelecypod fragment near the top of the cored interval. Marchand sands in the Northeast Verden field are demonstrably finer grained than those present in Norge. The dominant, very fine sand exhibits ripple lamination (to flaser bedding) associated with abundant clay drapes and couplets (Fig. 7D). Occasional mudstone rip-ups and burrows are noted, but the sand interval is oil-stained throughout save for thin, isolated calcite-cemented zones. Overall, the Marchand sand within Northeast Verden is inferred to have originated in tidal channels or shoals either within an estuary or embayed shoreline setting. Greb and Archer (1998) documents several Carboniferous examples of tidal-channel rhythmites in the central United States. Distinguishing depositional units within the Verden No. 46–3 very fine-grained succession is difficult; however, nearby wells exhibit more stratigraphic heterogeneity within the Marchand sand of Northeast Verden field.

SEQUENCE STRATIGRAPHY

Previous authors have interpreted variably the Marchand sand within Norge, Northeast Verden, and other nearby fields to range from fluvial deltaic to tidal to offshore bar to deepwater turbidite origin (Baker, 1979; Graff, 1971; Sawyerr, 1972; Seale, 1981; Wilson, 1973). The recognition by Baker (1979) of tidal-influenced, upper Marchand sand deposits in the Binger fields (Caddo County) to the northwest of Verden agrees with the interpretations reported here. Although further regional evaluation needs to be accomplished to place the Marchand and Huddleston sand intervals into a basinal depositional understanding, what can be concluded from the core sedimentology is that the Marchand and Huddleston sands in Grady County originated as tide-dominated shoreline systems. Shoreline physiography was controlled by relative sea-level change, sediment supply, and possibly local tectonics.

The character of the Huddleston sand in Northwest Chitwood field has been interpreted to be an incised valley-fill succession overlying a sequence boundary. No biostratigraphic evidence exists at present to conclusively demonstrate that relative sea-level lowering and subsequent valley erosion occurred at the end of Pennsylvanian Desmoinesian and the beginning of Missourian time. However, it has been demonstrated that cyclic Pennsylvanian sediments were influenced by large shifts of shoreline during deposition of each cycle. It is reasonable to infer that a relative sea-level drop across a nearly flat marine shelf would have exposed significant distances of the old shelf and subjected the area to dendritic erosion whose river density depended upon the amount of rainfall (runoff), sediment supply, and lithology of the older shelf strata. The north-south linear trend of the Huddleston sand within Chitwood field supports the inference that the ancestral depositional trends for Missourian strata in central Oklahoma were generally south to north.

This northerly trend also is supported within the Marchand sand in Norge and Northeast Verden fields. Formation Micro-Imaging (FMI) analysis of the Marchand sand in Norge field reveals a significant variation in current bed dips with an overall northerly transport direction indicated. The tide-dominated sands in Norge field also show an appreciable increase in average grain size compared with Northeast Verden. Intuitively, the very fine-grained sands of Northeast Verden suggest a more distal (from shoreline) tidal setting than that present at Norge. It is possible that the finer Northeast Verden sands represent down-depositional dip equivalents to the coarser sands in Norge or that Northeast Verden is a stratigraphically younger, shoreline progradation farther shelfward from the Norge setting.

Several possible correlations between the three fields have been proposed. In the depiction shown in Figure 8, the Huddleston sand of Chitwood field (on the right side of Fig. 8) is correlated as stratigraphically equivalent to the Marchand within Norge and Northeast Verden. Even in this correlation, the Huddleston may be equivalent to the older Marchand sands present within the fields to the north-northwest. Other conceivable correlations could isolate stratigraphically the Huddleston below the Marchand in Norge and Northeast Verden, making it an early incised valley fill which is succeeded downdip (to the north-northwest) by transgressive to highstand tidal shorelines (Marchand sands). What is certain is that the implementation of sequence-stratigraphic concepts has resulted in heretofore-unpublished correlations between the reservoir sands within Pennsylvanian strata of central Oklahoma. These revised correlations warrant further consideration with respect to field extensions and new pool exploration potential.

RESERVOIR CHARACTERIZATION

The core sedimentology has comprised the bulk of the geologic data revisited within these old producing fields of Grady and Caddo counties. Foremost has been the documentation of the strong tidal influence on sand-body geometry and internal heterogeneity. Stacked tidal channel to accretion bar units within the Huddleston sand in Chitwood field are believed to occupy a linear, incised valley, which is limited along strike by valley margins consisting of older marine sediments and influenced along depositional dip by sediment supply and estuarine physiography.

Sandbody geometries within the Marchand sands of Norge and Northeast Verden differ from being similar to those of Chitwood (very sand rich) to stratigraphically isolated sand bars/channels separated laterally and vertically by mud-rich tidal-flat and bay shale successions. Such variation has influenced significantly recent engineering practices for secondary recovery including waterflood strategies, infill locations, and recompletion options in existing wellbores. Reservoir-engineering studies also need to be updated to take advantage of revised reservoir compartmentalization. A better understanding of reservoir continuity is beneficial during any phase of a field's producing life. Even in the final phase of infill drilling, recompletions, or waterflood recalibration, the incremental production realized from such seemingly simple tasks as revisiting reservoir sedimentology provides substantial insight for optimal reservoir management.

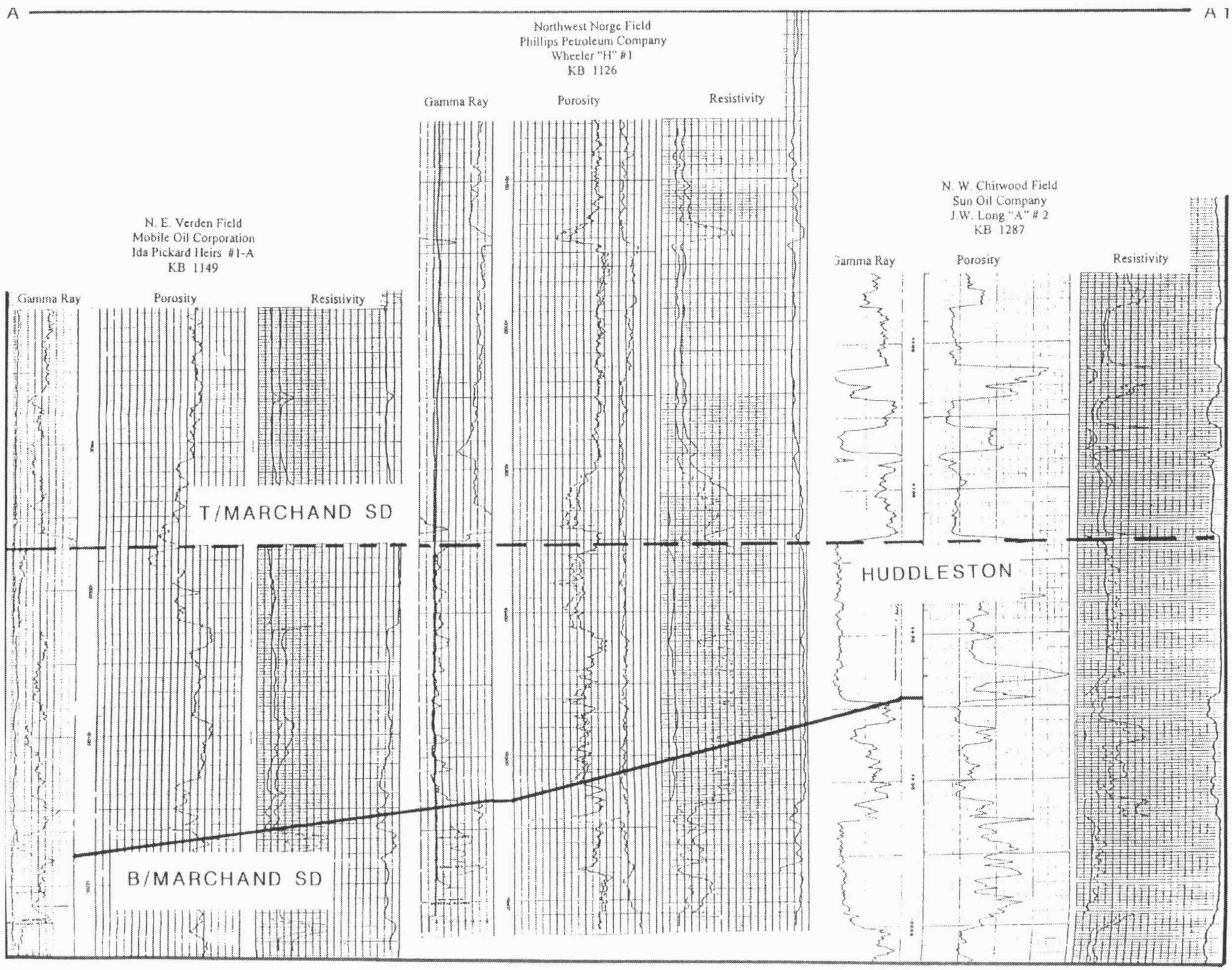

FIGURE 8—Stratigraphic cross section, Chitwood–Norge–Verden fields. See Figure 1 for location of section.

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Sedimentary Architecture and Diagenesis of Modern Carbonate Sands in a Low-Energy Shelf Lagoon, Northern Belize—Modern Analog to Some Ancient Hydrocarbon Reservoirs

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A widespread sheet of modern carbonate sands and muddy sands, deposited unconformably on buried soil and karsted Pleistocene limestone, is present in the shallow, low-energy lagoon (Chetumal Bay) behind Ambergris Caye in northern Belize. Sediment transport and deposition, and overall spatial distribution, are controlled mainly by wind-induced currents in this protected environment. As such, these sediments are a modern analog of some ancient inner-shelf carbonate sands that compose hydrocarbon reservoirs in the Midcontinent. As indicated by ^{14}C dates of buried mangrove peats, deposition was coincident with Holocene transgression in the study area, which began about 6,000 years ago. Surface and inferred buried bedforms include dunes and stacked ripple-forms, overwash lobes, and spits generated as the sands migrate in a southwesterly direction in response to dominant easterly trade winds. Maximum thickness of the sand sheet is 4 inches, and there is control of antecedent bedrock topography and cryptic faulting on facies distribution and thickness variations. Internal facies architecture shallows and coarsens upward in response to decrease in rate of sea-level rise, and has resulted in vertical and lateral heterogeneity in sediment texture and porosity.

Primary porosity in these transgressive-systems-tract deposits includes intraparticle pores within skeletal grains and interparticle pores in sands and muds; effective porosity increases upward in the section. Dolomite cement is present over a wide area in these wholly subtidal deposits, and has precipitated in pore fluids as a likely consequence of bacterial-sulfate reduction or methanogenesis. Partial dolomitization, and secondary pores, similarly are typical in analogous deposits in some upper Paleozoic hydrocarbon reservoirs.

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An Application of High-Resolution Marine Chemostratigraphy as a Chronostratigraphic Control for "Mid" Cretaceous Oxygen-Isotope Records in Amalgamated Nonmarine Paleosols

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Ongoing sequence-stratigraphic reconstructions have led to correlation of Albian–Turonian nonmarine-marine strata in a transect perpendicular to the eastern-margin paleoshoreline of the Western Interior Seaway. In the nonmarine strata, we have developed a high-resolution palynostratigraphy and oxygen-isotope chemostratigraphy from amalgamated Albian–Cenomanian kaolinitic mudrock paleosols in Iowa and Nebraska. Our results suggest that meteorological conditions were stable in the late Albian/early Cenomanian of the midwestern U.S. However, an enrichment in $\delta^{18}O$ values from -4.5 to -3.5 ‰ occurred in the late Albian, followed by a return to more depleted values of -4.5 ‰.

The sequence stratigraphy was used to tie detailed mid-basin geochemical profiles of %$CaCO_3$, %TOC, HI, and OI to nearshore geochemical profiles. Correlation of these profiles uses a model for the development of geochemically defined parasequences which provides ~100,000-year resolution. In Kansas, these parasequences interfinger with nonmarine paleosols. Here, oxygen-isotopic profiles generated from the paleosol sphaerosiderites allow us to tie the nonmarine oxygen-isotope chemostratigraphy to the geochemically defined marine parasequence. This approach allow us to better define the amalgamated nonmarine chronostratigraphy and therefore better interpret the paleoclimatological record.

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Acorn Field—a Plum in the Lansing–Kansas City Pudding

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Production was established in Dundy County, extreme southwestern Nebraska, in 1957 in the Jones field. The primary reservoirs in the area include carbonate zones in the Upper Pennsylvanian Lansing–Kansas City, Douglas, and Shawnee Groups. Forty-two fields have produced nearly 4,000,000 stock tank barrels of oil (STBO). During 1998, 74 wells produced 344,000 STBO. The Acorn field township has produced 2,467,171 STBO, nearly 62% of the county's production.

The Acorn field was discovered in September 1995 by the Advantage Resources No. 3–33 Ham in sec. 33, T. 2 N., R. 37 W. This well was completed for 113 barrels of oil per day (BOPD) from the Lansing–Kansas City D zone. After three apparently unsuccessful offset wells were drilled, BEREXCO completed the Howard–Ham No. 15–28 from the Lansing–Kansas City E zone, in October 1997 for 494 BOPD and 5BWPD. By March 1998, the field contained an additional four producers, the E zone is the major reservoir. Field production peaked in 1998 at about 1,000 BOPD and averaged 614 BOPD from six wells—the highest daily oil-production rate in the state.

Structural trends in the Acorn field area on the Lansing–Kansas City A zone are interpreted as being generally northwest-southeast, parallel to the strike of the Cambridge Arch. This trend differs from the northeast-southwest structural trends usually presented in Dundy and adjacent Hitchcock County. Analysis of original bottom-hole pressures, production tests, and stratigraphy indicate that the E zone locally is complex and consist of multiple carbonate buildups. Additional drilling is needed to verify these interpretations. With only about 400 wells, Dundy County is under-explored for an area that contains numerous subtle, complex reservoirs.

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