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Charles J. Mankin, *Director*

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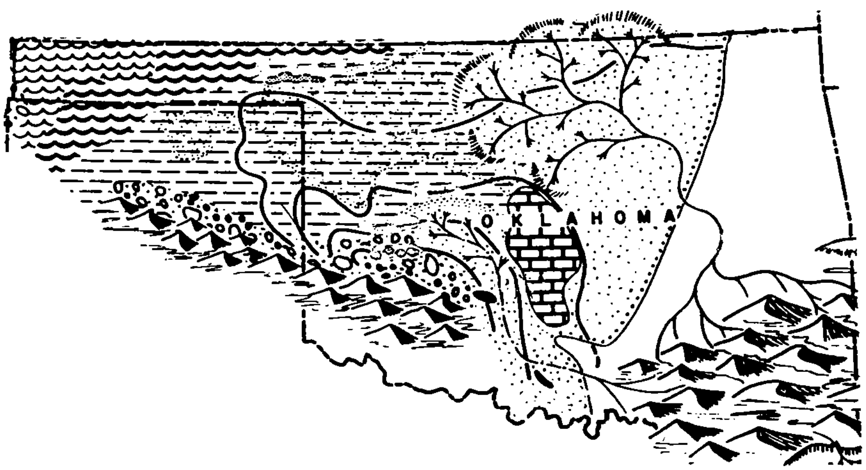
DELTAIC RESERVOIRS IN THE SOUTHERN MIDCONTINENT, 1993 SYMPOSIUM

KENNETH S. JOHNSON
Editor



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Title-Page Illustration

Paleogeography of the southern Midcontinent during the Missourian Epoch (from p. 44 of this volume).

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PREFACE

The transfer of technical information will aid in the search for, and production of, our oil and gas resources. To facilitate this technology transfer, the Oklahoma Geological Survey (OGS) and the Bartlesville Project Office of the U.S. Department of Energy (BPO-DOE) co-sponsored a symposium dealing with the petroleum geology and reservoir characterization of fluvial-dominated deltaic (FDD) reservoirs in the southern Midcontinent. The symposium was held on March 23–24, 1993, at the Oklahoma Center for Continuing Education, The University of Oklahoma, Norman. This volume contains the proceedings of that symposium.

Research reported upon at the symposium focused on the following: types of FDD reservoirs, depositional settings, diagenetic history, reservoir characterization, and enhanced oil recovery. In describing the various FDD petroleum reservoirs in the southern Midcontinent, the researchers have increased our understanding of how the geologic history of a river/delta complex can affect reservoir heterogeneity and our ability to efficiently recover the hydrocarbons they contain. We hope that the symposium and these proceedings will bring such research to the attention of the geoscience and energy-research community, and will help foster exchange of information and increased research interest among industry, university, and government workers.

Nineteen papers were presented orally at the symposium, and they are presented here as full papers or abstracts. An additional 13 reports were given as posters, and they are presented here as short reports or abstracts. About 250 persons attended the symposium. Stratigraphic nomenclature and age determinations used by the various authors in this volume do not necessarily agree with those of the OGS.

This is the sixth symposium in as many years dealing with topics of major interest to geologists and others involved in petroleum-resource development in Oklahoma and adjacent states. These symposia are intended to foster the exchange of information that will improve our ability to find and recover our nation's oil and gas resources. Earlier symposia subjects were: the Anadarko basin (published as OGS Circular 90); Late Cambrian–Ordovician geology of the southern Midcontinent (OGS Circular 92); Source rocks in the southern Midcontinent (OGS Circular 93); Petroleum-reservoir geology in the southern Midcontinent (OGS Circular 95); and Structural styles in the southern Midcontinent (OGS Circular 97).

Persons involved in the organization and planning of the FDD reservoirs symposium include: Kenneth Johnson, Jock Campbell, and Charles Mankin of the OGS; and Tom Wesson, Michael Ray, and Edith Allison of BPO-DOE. Other personnel who contributed include: Michelle Summers and Tammie Creel, Registration Co-Chairs; LeRoy Hemish, Poster-Session Chair; Connie Smith, Publicity Chair; and Gwen Williamson and Judy Schmidt, Exhibits Coordinators. Appreciation is expressed to each of them and to the many authors who worked toward a highly successful symposium.

KENNETH S. JOHNSON
General Chairman

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PART II—Abstracts and Short Reports Related to Poster Presentations

PART I

PAPERS PRESENTED ORALLY AT THE SYMPOSIUM

Distinction, or Indistinction, of Fluvial-Dominated Deltaic Reservoirs

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Masera Corporation
Tulsa, Oklahoma

ABSTRACT.—Fluvial-dominated deltas are characterized by elongate, lobate, and other shaped protuberances of the coastline and of associated shoreface and shallow-marine isobaths. The configuration of deltaic sandstone bodies, or reservoirs, varies widely, but commonly sandstone trends do not parallel regional interdeltaic depositional strike. Distinguishing subsurface deltaic reservoirs and estimating with a reasonable level of certainty the relative riverine input operating at the time the reservoirs were deposited commonly are formidable tasks—not just extrapolating features of Holocene deltas or invoking hierarchical terminology. The complexity of the task of distinguishing the general type of sandstone reservoirs (specifically, deltaic in this case—or, in even more detail, fluvial-dominated deltaic) is related in part to the changes of sea level that have characterized geologic history and the problems of detailed correlation required to interpret the depositional environment of individual sandstone reservoirs.

Nevertheless, fluvial-dominated reservoirs are thought to be commonly channelized in the upper part of the deltaic regime and to express some sort of downslope bulge of sand in the lower part. In the upper part they may be indistinguishable from alluvial (or fluvial) reservoirs, and in the lower part they may be indistinguishable from shoreface, shallow-marine, or even deep-marine deposits.

In the southern Midcontinent, Carboniferous (Upper Mississippian and Pennsylvanian) sandstones contain the most common representatives of fluvial-dominated reservoirs. In fact, older (middle and lower Paleozoic) sandstones in the region do not reflect deltaic deposition. Late Mississippian and Pennsylvanian times were characterized by frequent sea-level changes during a >100-m.y. period of overall relative highstand. Although fluvial-dominated Carboniferous reservoirs are commonly channelized, some significant channelized bodies are marine bodies (e.g., Spiro sandstone). A significant percentage of the fluvial-dominated reservoirs probably were deposited in fluvial, as opposed to deltaic, settings during lower or rising sea-level stands (e.g., Bartlesville sandstone in southeast Kansas and northeast Oklahoma). During sea-level lowstands, deltaic systems may have extended into "offshelf" areas; alternatively, reservoirs in those areas were deposited as distal units in deeper waters (e.g., Red Fork sandstone).

INTRODUCTION

Sandstone reservoirs are known to have developed in almost every depositional environment—from piedmont to deep marine. Volumetrically, deltaic reservoirs are most important because of (1) the dominance of streams in transportation of sediments to depositional sites with good to excellent chances for preservation (at or below sea level), (2) concomitant subsidence rates conducive to significant storage, (3) their dominant development during sea-level lowstands, and (4) spatial association with potential source rocks.

There is no shortage of literature on deltas and deltaic reservoirs—i.e., on both Holocene deposits and processes and their ancient counterparts. Even so, a number of interpretations concerning deltaic reservoirs are conjectural because of inadequate data and/or the equivocal nature of certain features generally available for study of ancient subsurface sands and sandstones. For example, geometry and distribution are not of themselves diagnostic criteria. In fact, the only unequivocal criteria for depositional environment are those features that are indigenous (e.g., paleosoils, certain fossils). Consequently, a reasonable interpretation of a deltaic reservoir, or more specifically a fluvial-dominated deltaic reservoir, generally requires the

Shelton, J.W., 1996, Distinction, or indistinction, of fluvial-dominated deltaic reservoirs, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 3–17.

convergence of various types of data, beginning with geologic setting, toward that conclusion.

TYPES OF DELTAS

Although modern deltas are present in a wide variety of geographic settings, one common feature in each is that the river provides clastic material to the coast, shoreface, and associated shallow-water environment more rapidly than it is removed by marine processes. Deltas (excluding fan deltas) may be classified according to the dominant process or group of processes at and near the river mouth (riverine and marine—tides, waves, and other currents) (Fisher and others, 1969; LeBlanc, 1972; Coleman, 1976). Correspondingly, deltas in general terms may be regarded as fluvial-dominated, wave-dominated, and tidal-dominated (Fig. 1). The fluvial-dominated type itself may be divided according to overall shape into various subtypes, such as elongate or lobate (Fisher and others, 1969). In numerous reservoir studies, the latter subdivisions are not applicable, because the area of study is too small to allow for determination of the overall shape of the inferred delta.

Internally, modern deltas have been subdivided by some workers into upper deltaic plain, lower deltaic plain, and subaqueous deltaic plain (Coleman, 1976; Coleman and Prior, 1982). Upper deltaic plain, as the transitional element to the alluvial valley, is dominated by riverine depositional processes (fluvial-dominated). In a number of reservoir studies, upper deltaic plain is indistinguishable from alluvial plain. Coleman (1976) has grouped the various modern deltaic deposits into six basic types of (deltaic) sand distribution, largely on the basis of the relative intensity of the major processes—river, tides, and waves, including longshore drift (Fig. 2).

DELTAS THROUGH TIME

Although significant deltaic deposition undoubtedly has occurred during the course of sedimentary history, it seemingly has not been uniform through time because of two major factors that may not be entirely independent—tectonism (time and intensity) and changes in sea level. Erosion, sediment transportation, and deposition are obviously stimulated as a result of significant tectonic events. Deltaic deposition is more likely to occur during lowstands, although there are a number of major Holocene deltas that have formed during this relative highstand.

FEATURES OF FLUVIAL-DOMINATED DELTAIC RESERVOIRS

Common features of fluvial-dominated deltaic reservoirs are markedly channelized (distributary) deposits closely associated with nonchannelized deposits (i.e., delta fringe—distributary-mouth bar, delta front and margin, and splay) that show an overall orientation at an high angle to the paleocoastline (or depositional strike). However, these features are not restricted to fluvial-dominated deltaic reservoirs. Additionally, common internal features include a coarsening-upward section overlain abruptly by a fining-upward or uniform grain-size section, abundant organic material, and turbid-water (relatively shallow-water) fauna. Yet these are not unique to fluvial-dominated deltaic reservoirs.

DELTAIC AND OTHER CHANNELIZED DEPOSITS IN THE SOUTHERN MIDCONTINENT

Excluding the fluvial-deltaic deposits in the Dakota Group, deltaic deposits of this region formed only in the late Paleozoic. The older sandstones of the Simpson Group and of the Misener Formation are marine. Even Cambrian sandstones are dominantly marine, with a lowermost fluvial unit. This chronostratigraphic distribution of sandstone types may reflect higher global sea levels during early and middle Paleozoic time than during late Paleozoic time, as shown by Vail and others (1977) (Fig. 3). A relatively long-term highstand existed for almost 200 m.y., beginning in the Late Mississippian and extending well into the Mesozoic. The unusually common occurrence of fluvial-deltaic sedimentation during the Pennsylvanian probably reflects favorable combinations of humid climate, high-frequency eustatic sea-level changes (Fig. 4), and geographic and chronologic linkage with orogenic belts. The prominence of channelized sandstones within the various deltaic packages is characteristic of much of the region, especially that part corresponding to the more stable parts of the craton. In many cases, the dominance of riverine processes is rather clear, but the depositional site may be in doubt. The options, for one set of conditions, are fluvial or fluvial-dominated deltaic; for another set, the options are fluvial-dominated deltaic or deeper-marine deposits. Selected examples are presented herein to illustrate reservoirs that are (1) channelized, but marine units; (2) channelized fluvial units; and (3) complexes of fluvial and fluvial-dominated deltaic sediments with and/or without offshelf marine units.

Channelized Marine Reservoirs

Misener Sandstone

The Upper Devonian Misener sandstone, deposited on an unconformable surface in parts of Kansas, Oklahoma, and northern Arkansas (Figs. 5,6), is a significant reservoir, especially where the underlying surface shows significant relief. Correspondingly, good Misener reservoirs are

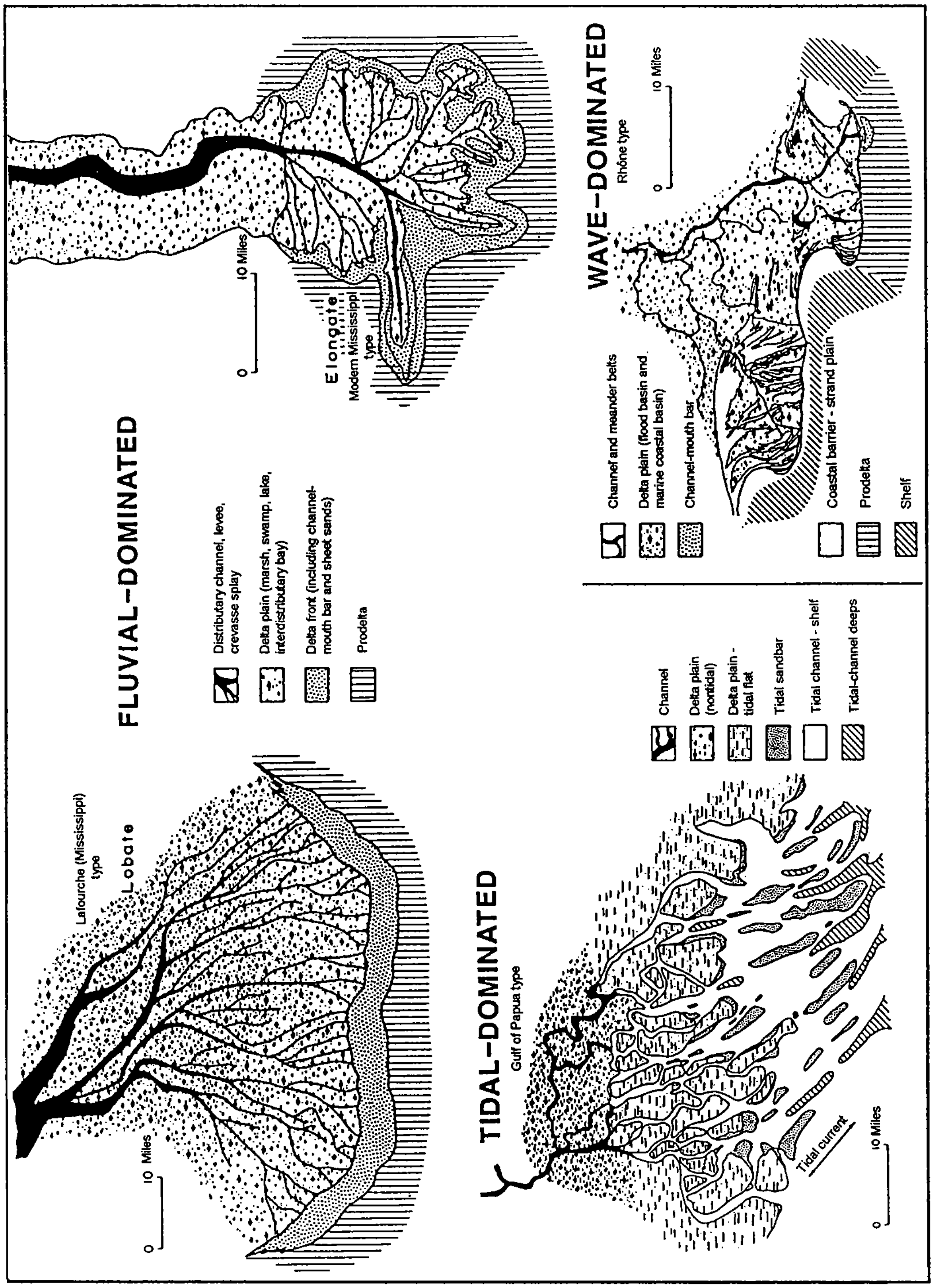

Figure 1. Delta types (after Fisher and others, 1969).

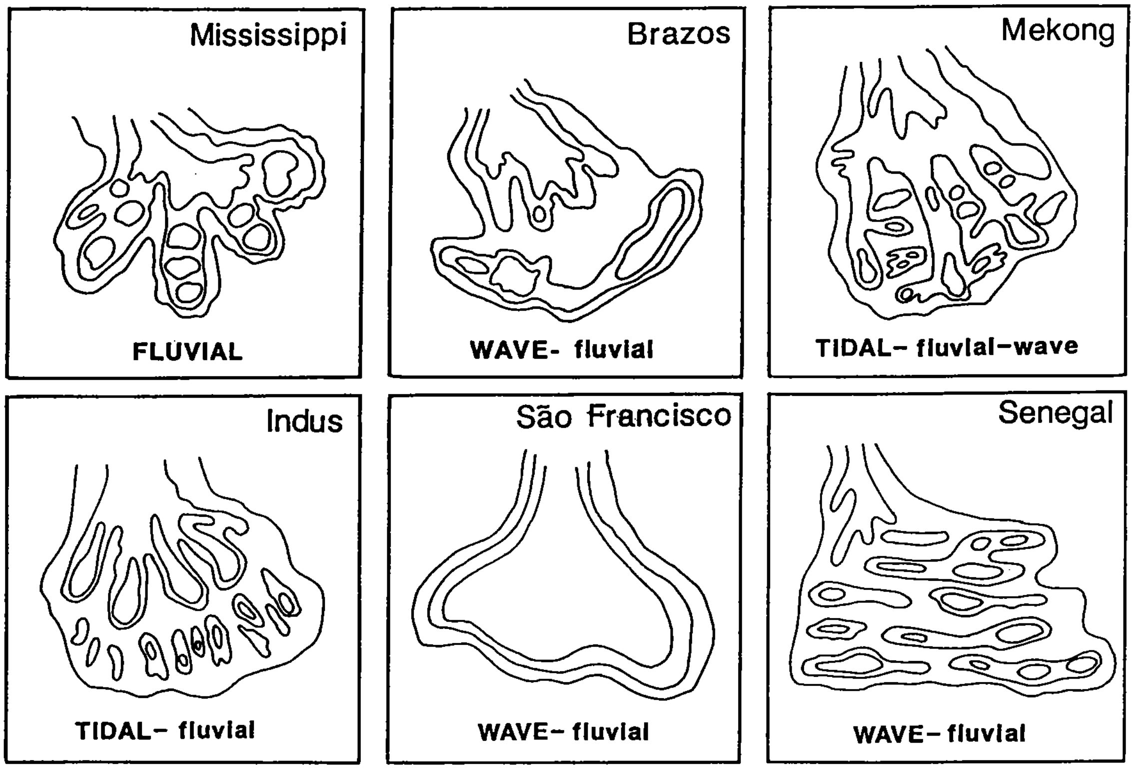

Figure 2. Sand distribution patterns in modern deltas (after Coleman and Wright, 1975; Coleman, 1977).

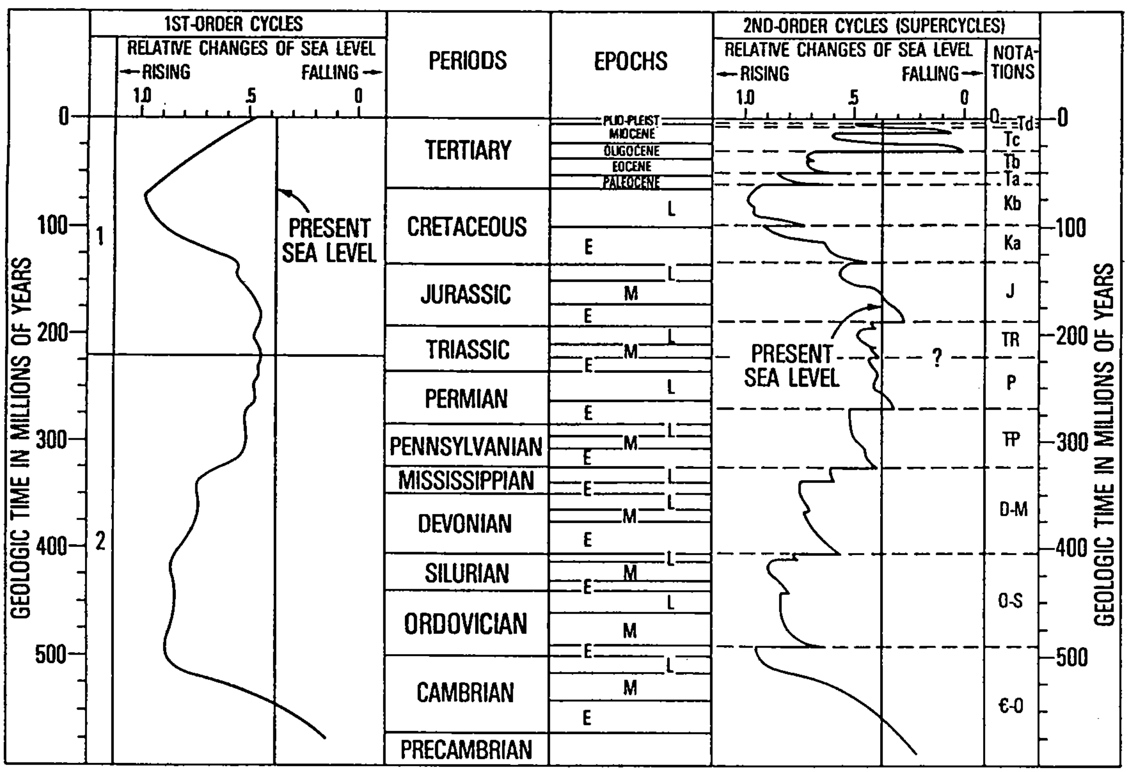

Figure 3. First- and second-order global cycles of change of sea level during the Phanerozoic (from Vail and others, 1977).

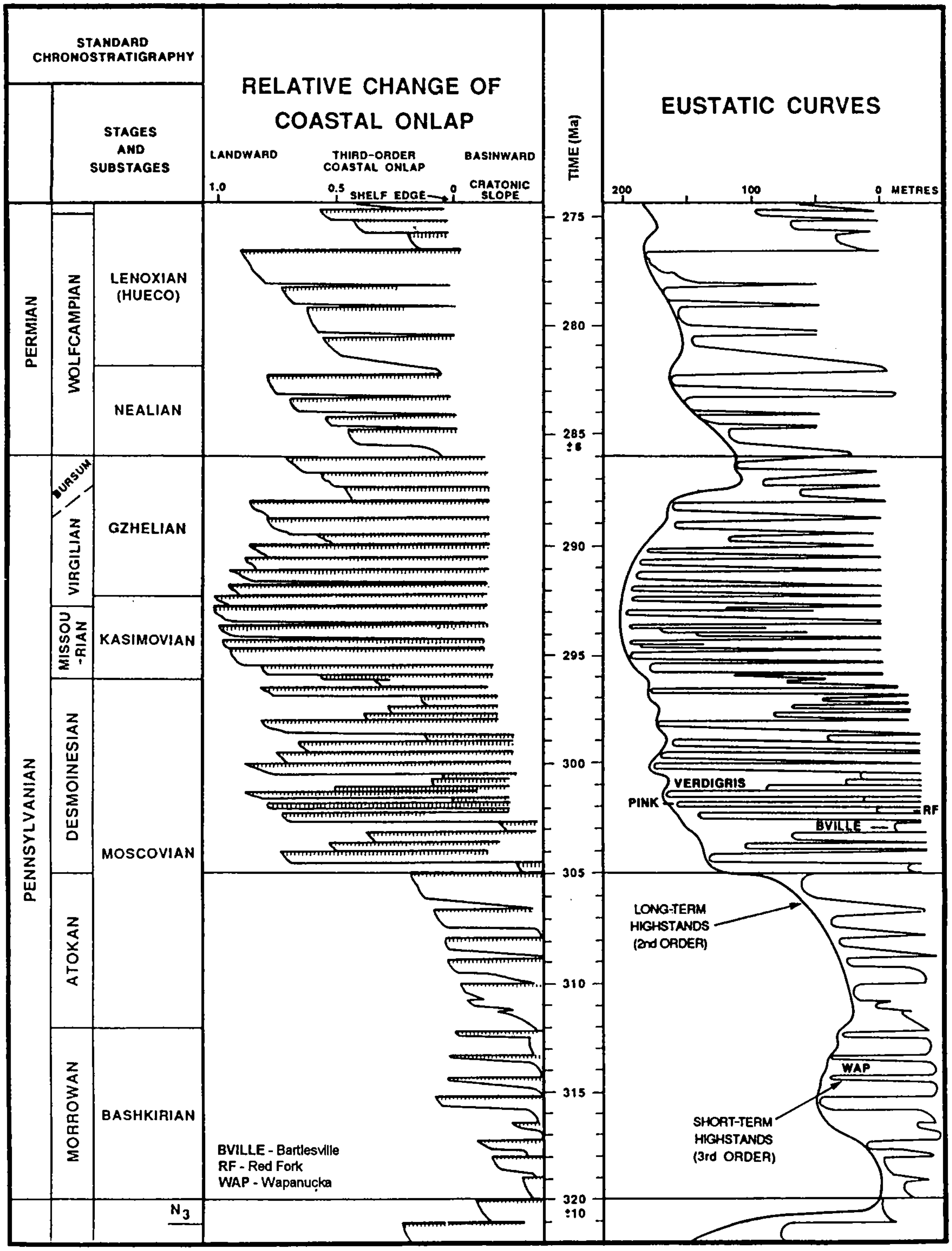

Figure 4. Cyclic chart of eustatic sea-level changes for the Pennsylvanian (after Ross and Ross, 1988).

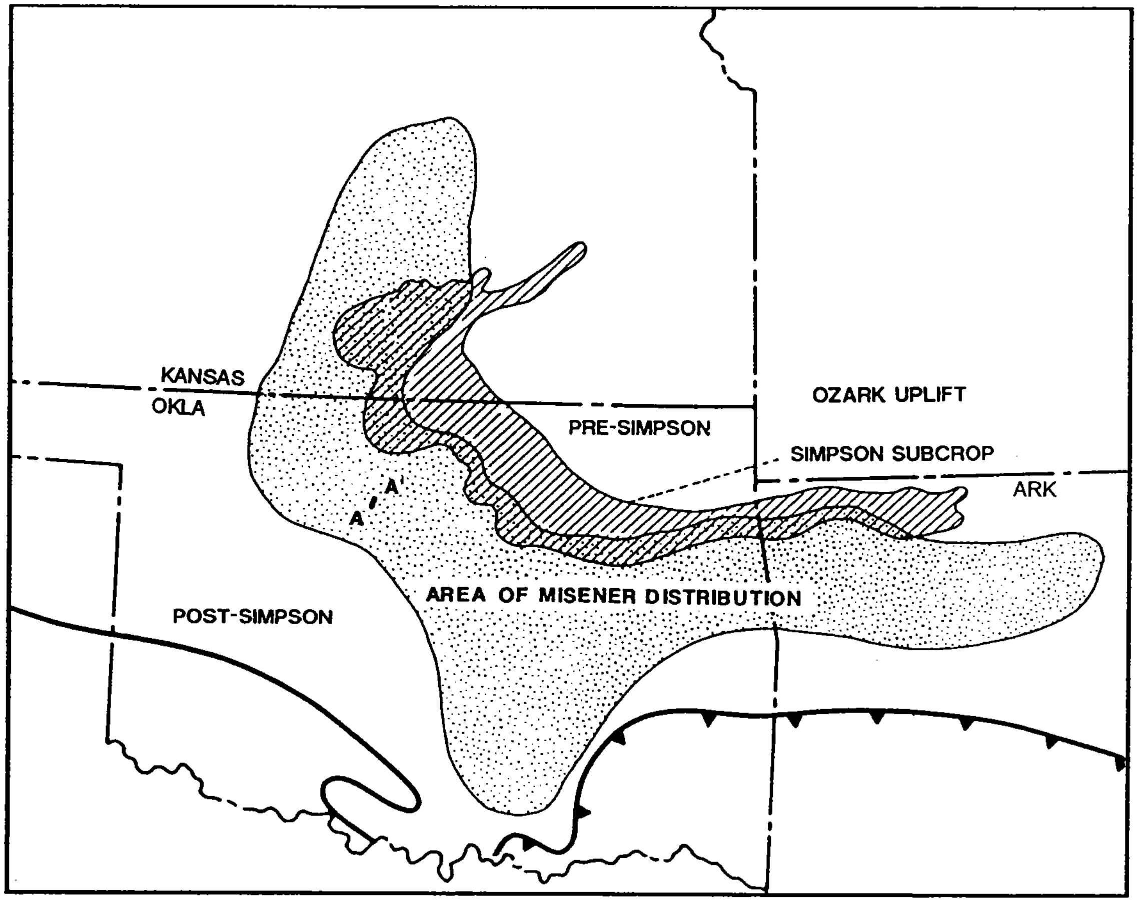

Figure 5. Generalized areal distribution of Devonian Misener sandstone (after R. D. Fritz and others, personal communication, 1988). Cross section A–A′ shown in Figure 6.

characterized by greater-than-average thicknesses and abrupt bases and lateral contacts. They contain fossil fragments—such as conodonts and fish scales, phosphate fragments, glauconite, and bioturbated structures (Mansfield and Breckon, 1985). Even though the channels in which Misener reservoirs were deposited may have been parts of valleys in an alluvial system, the depositional record is of marine units that formed in embayments, possibly by tidal action.

Spiro Sandstone

The Atokan Spiro sandstone, developed in the Arkoma basin (Fig. 7), contains a widespread nonchannelized unit, a limestone facies in the western part of its area of development, and localized lower channelized units with sharp bases and lateral contacts (Lumsden and others, 1971; Houseknecht, 1987; Al-Shaieb and others, 1989) (Figs. 8,9). The Spiro was deposited on an unconformable surface. The Spiro, in the relatively thick sections, consists of several units in which grain size decreases upward. These sections contain fossil fragments, glauconite, chamosite (as peloids and grain coatings), and collophane, pointing to an embayed marine environment (Porrenga, 1967; Al-Shaieb and others, 1989).

Fluvial Reservoirs

Bartlesville Sandstone

In northeastern Oklahoma, the Desmoinesian Bartlesville is generally considered to represent part of a deltaic complex (Visher and others, 1971; Mason, 1982; Kuykendall, 1983) (Figs. 10,11). Some linear thick trends of reservoir sandstone are >2 mi wide, and their thicknesses are >100 ft. These multistoried units commonly show upward fining and cross-bedding above a sharp base. The width and thickness suggest a fluvial setting (valley fill), rather than a deltaic-distributary setting. Thinner, more sheetlike sandstones, of limited reservoir quality, probably formed as delta-fringe units during an earlier relative

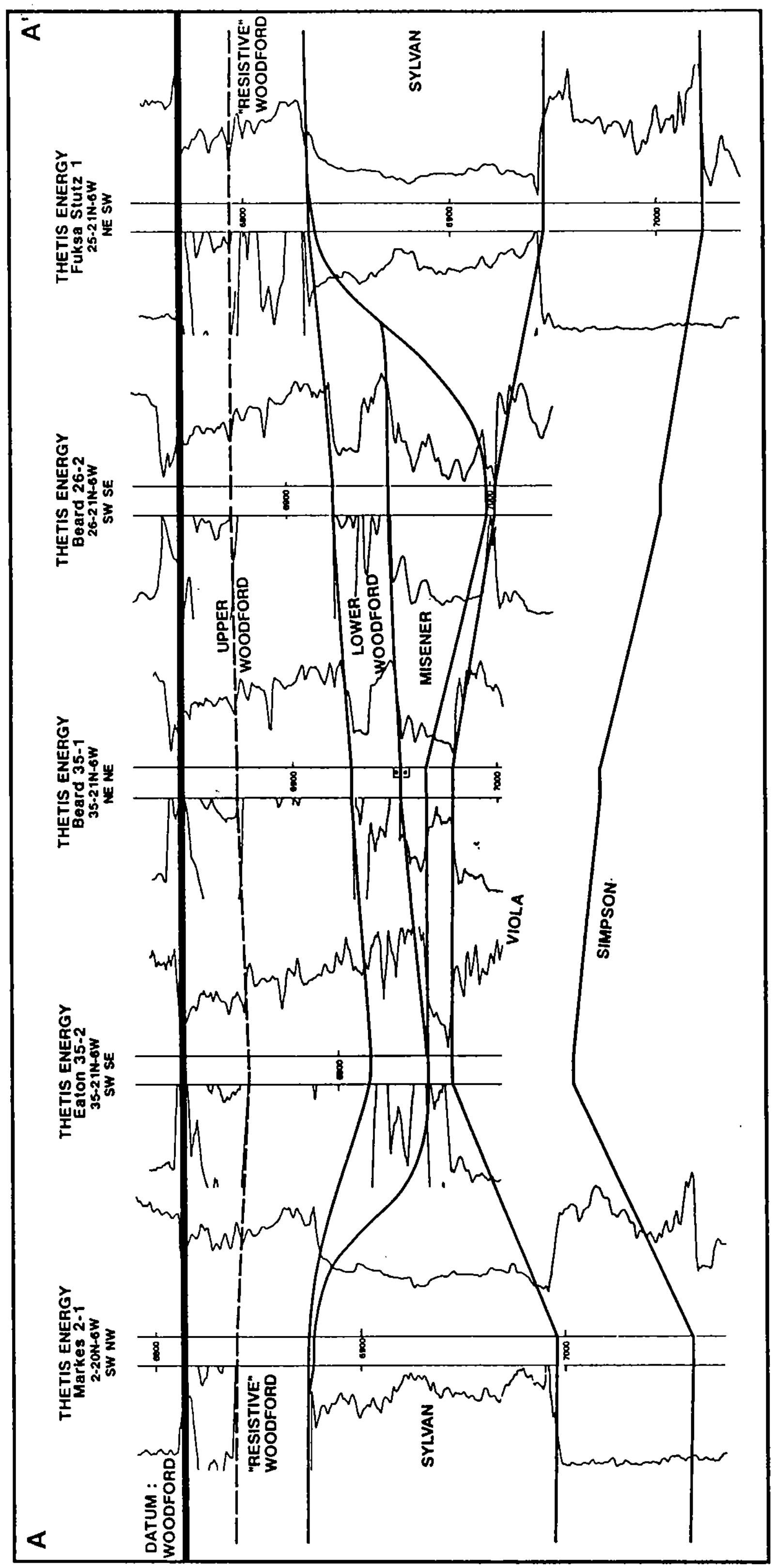

Figure 6. Cross section of channelized Misener sandstone, deposited on significantly unconformable surface, and associated strata in northern Oklahoma (location shown in Fig. 5) (after R. D. Fritz and others, personal communication, 1988).

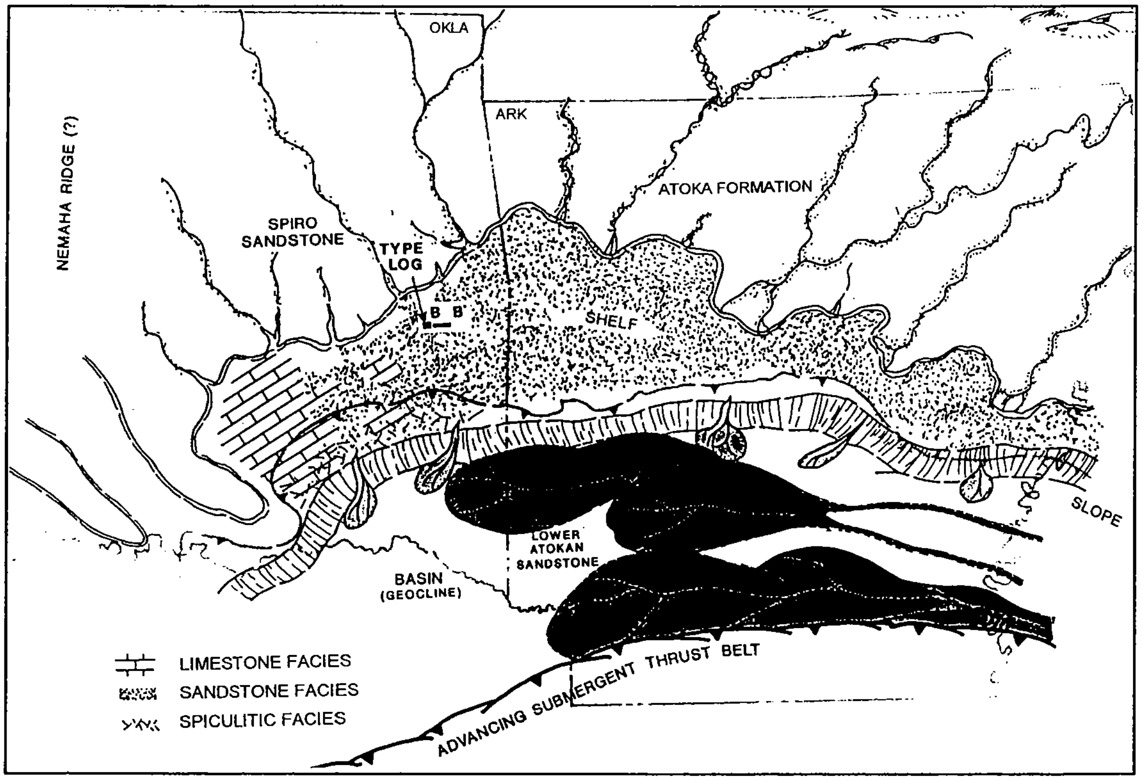

Figure 7. Paleogeographic map of Arkoma basin and environs during early Atokan, showing distribution of the Spiro sandstone (from R. D. Fritz and others, personal communication, 1990). Cross section B–B′ shown in Figure 8; type log shown in Figure 9.

highstand—earlier with respect to the sea-level stand during which the valleys were incised. Similar units may also have formed after development of the valleys.

Carter Sandstone, Muldon Clastic System

The Chesterian Carter sandstone in the Black Warrior basin (Figs. 12–14) consists of several sequences, each of which contains a thick sandstone interval along a linear trend. One interval is >200 ft thick. Linear trends are present within areas characterized by thinner, lenticular, and more sheetlike sandstones. The thicker intervals represent fluvial (valley-fill) deposits.

Fluvial-Dominated Deltaic Complexes

Bartlesville Sandstone

The Bartlesville sandstone—developed as an elongate, coarse-clastic complex between the Nemaha and Ozark uplifts—contains, in addition to the fluvial units noted above, various deltaic sandstone bodies representing distributaries as well as delta-front and marginal delta-fringe settings (Fig. 11).

Red Fork Sandstone

The Red Fork sandstone forms a lobate mass, extending from the craton into south-central Oklahoma and the inner part of the Anadarko basin (Fig. 15). Two basic types of sandstone units are present over much of the stable area of Red Fork development: (1) thick (>100 ft), multistoried, laterally restricted, and channelized sandstones; and (2) thin, relatively widespread sandstones (Tate, 1985). In the "deeper" part of the Anadarko basin, three thick sections (each >500 ft thick) are recognized. The channelized sandstones in the stable area include both fluvial and deltaic distributary units. The former developed as sea level rose after lowstands, whereas the latter were probably deposited both before and after lowstands. The thick sections in the deeper part of the Anadarko basin reflect (1) deltaic deposition during lowstands when sea level was lower than the shelf edge, thus separating areas of thinner and thicker Red Fork sections, or (2) off-shelf marine deposition (containing various sediment-flow units) when the shoreline was near or at the shelf edge (Johnson, 1984; Clement, 1991). Probably during lowstands, both types of deposits formed there. In either set-

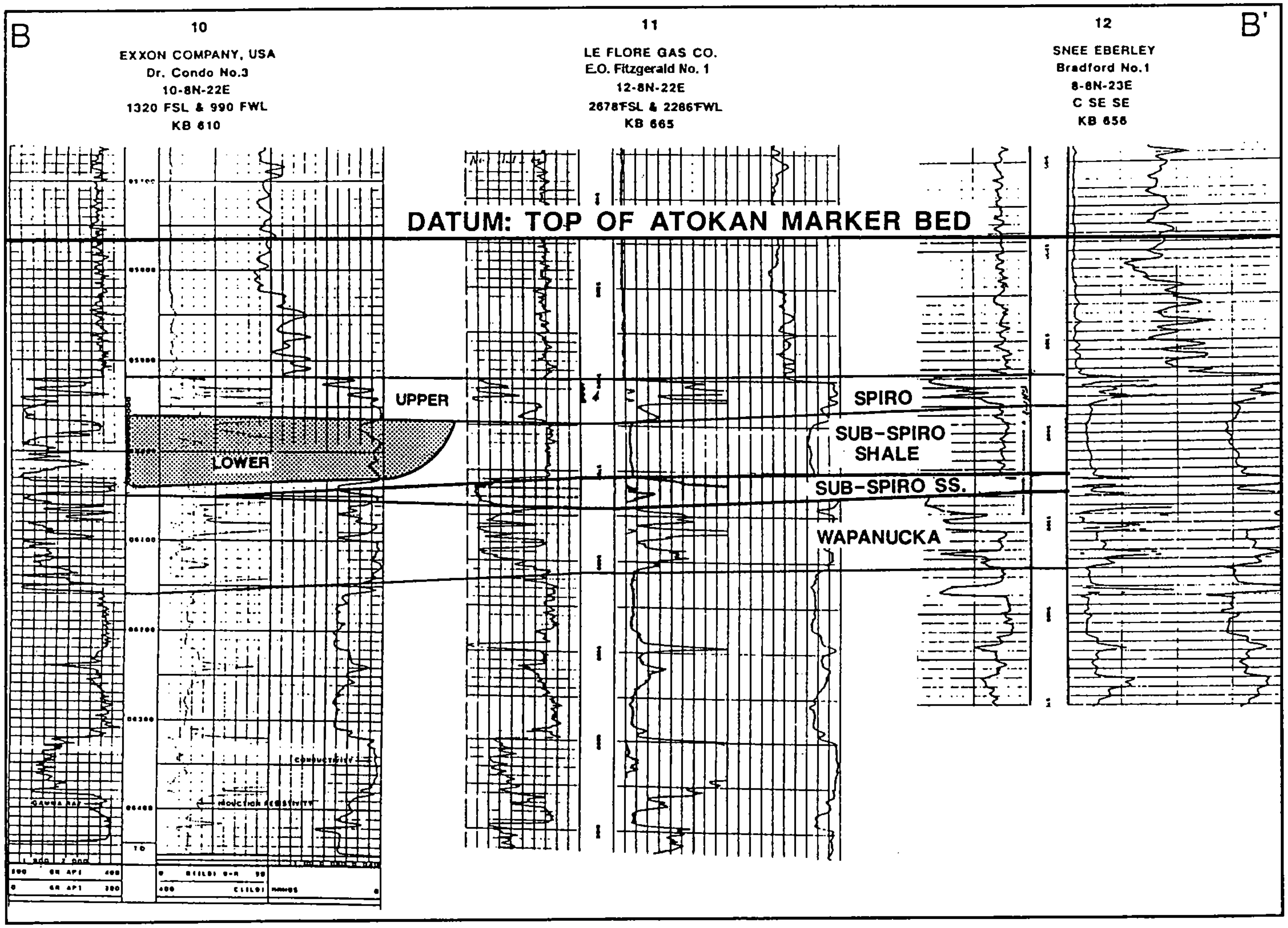

Figure 8. Spiro sandstone in schematic cross section, showing lower sandstone with sharp base and lateral contact (location shown in Fig. 7) (from R. D. Fritz and others, personal communication, 1990).

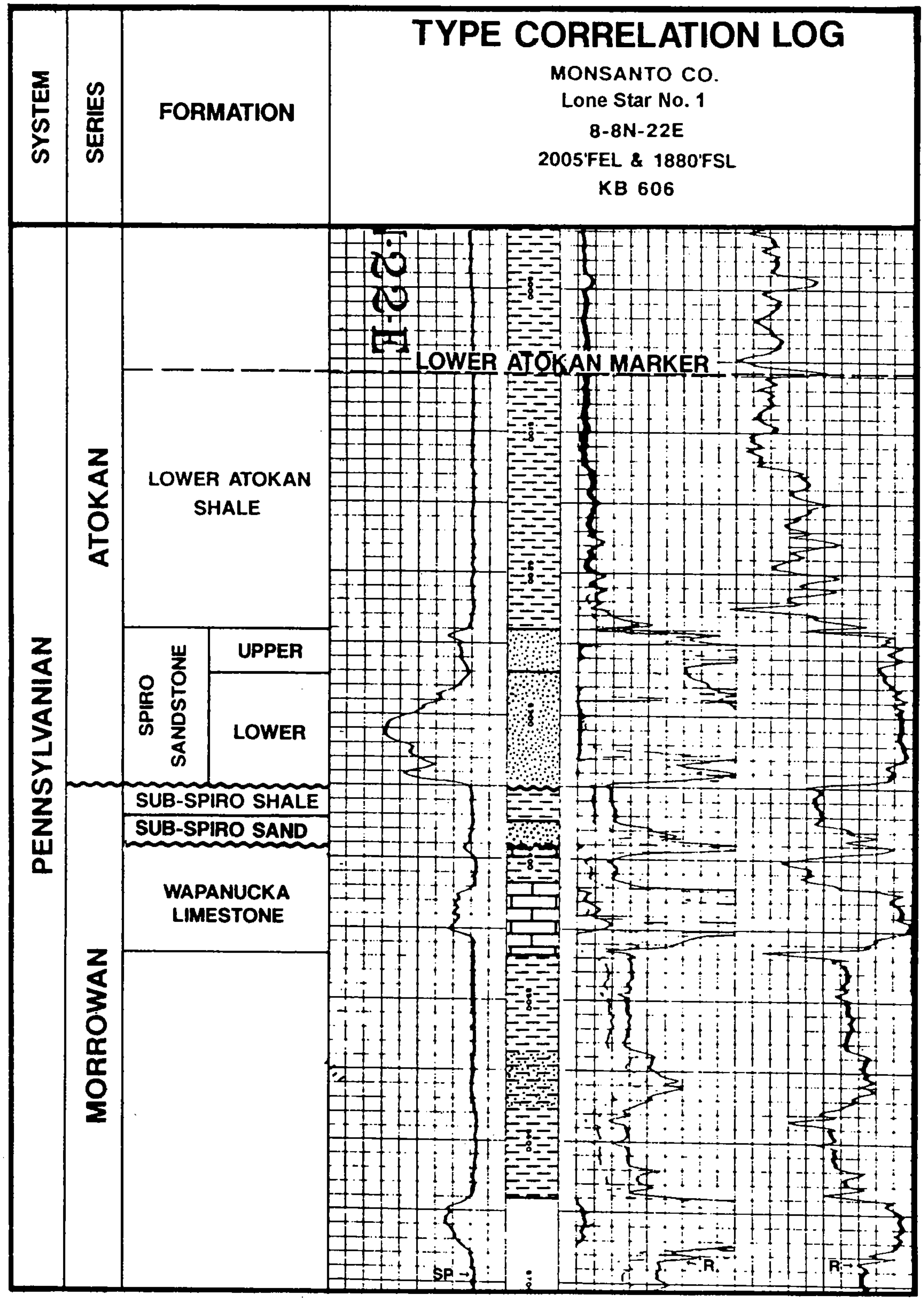

Figure 9. Representative stratigraphic section of Spiro sandstone in Monsanto no. 1, Lone Star, sec. 8, T. 8 N., R. 22 E. (location shown in Fig. 7) (from R. D. Fritz and others, personal communication, 1990).

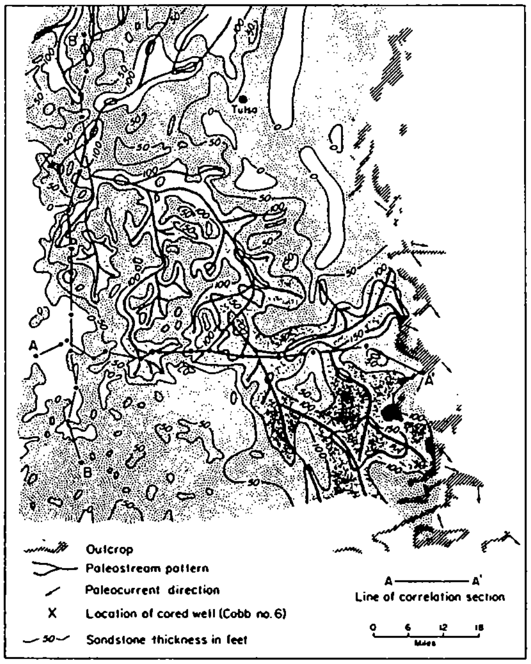

Figure 10. Gross-thickness map of Bartlesville sandstone in northeastern Oklahoma, showing width and thickness of channelized sandstone (after Visher and others, 1971; from Shelton, 1973). Correlation section A–A′ not shown in current report.

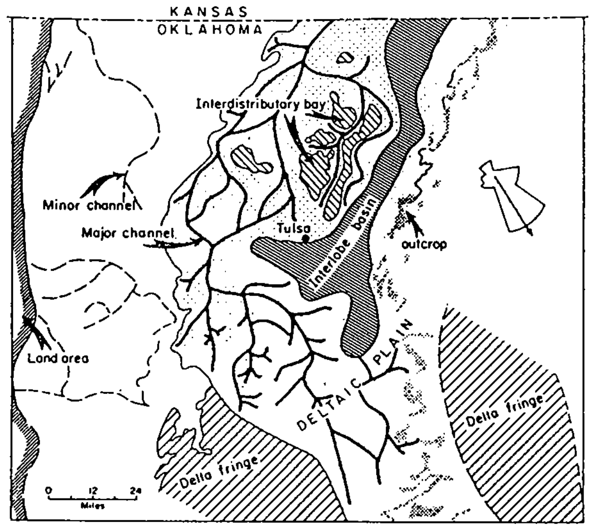

Figure 11. Paleogeographic map for Bartlesville sandstone in northeastern Oklahoma (after Visher, 1968; from Shelton, 1973).

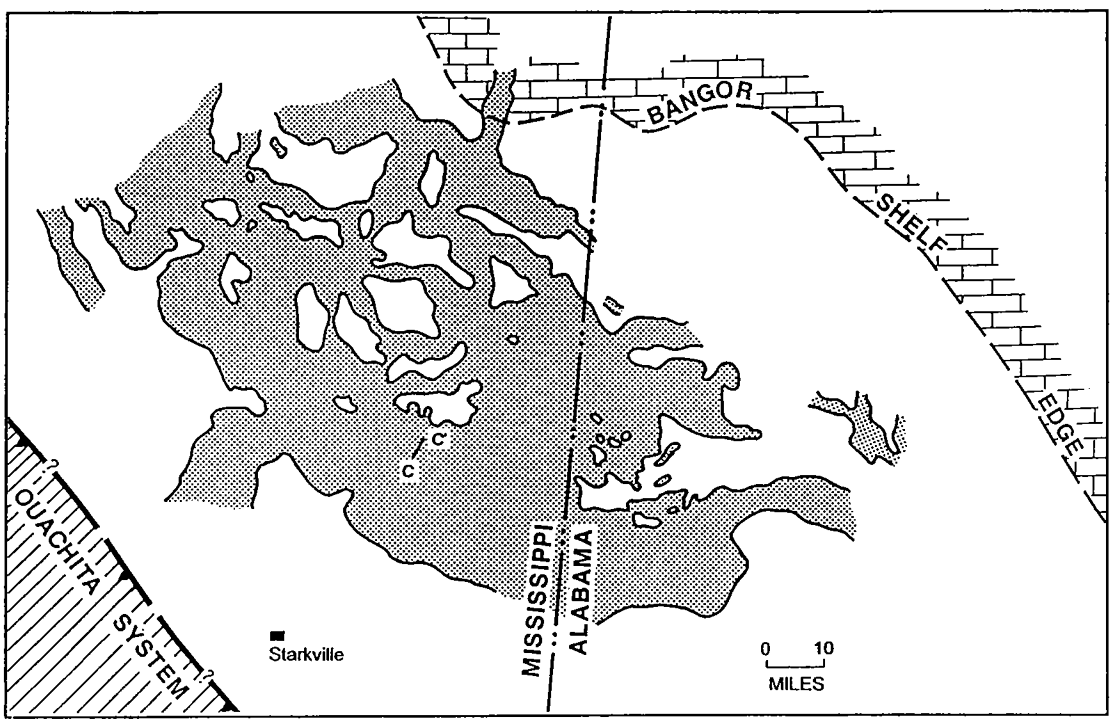

Figure 12. Generalized areal distribution of Chesterian Carter "B" sandstone, Black Warrior basin (after R. D. Fritz and others, personal communication, 1992). Cross section C–C′ shown in Figure 14.

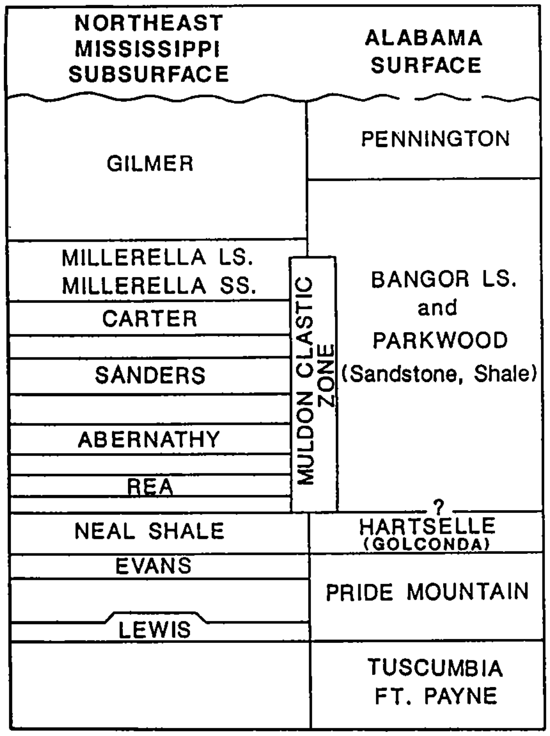

Figure 13. Stratigraphic nomenclature for Carboniferous sandstone-bearing rocks in the Black Warrior basin (after Cleaves, 1983).

ting, thick sandstone units were deposited distally (down depositional dip) before much of the updip channelized sandstone was deposited in this lobate deltaic complex. The shoreline shift was probably hundreds of miles, measured from its most landward position during deposition of either the underlying Inola Limestone (or equivalent shale) or the overlying Pink Limestone to its most seaward position during deposition of the Red Fork in the deeper part of the Anadarko basin.

Carter Sandstone, Muldon Clastic System

The Carter sandstone units form an elongate area of development in the Black Warrior basin (Fig. 12). In these units are various deltaic sandstones, representing distributaries, delta-front, and delta-fringe sands, in addition to the fluvial sandstone intervals noted above. Swann (1964) in his study of Chesterian sedimentary rocks of the Illinois basin suggested that during their deposition, the shoreline shifted >600 mi in the area north of the Black Warrior basin. Undoubtedly, the shift from lowstand to highstand during Chesterian deposition in the Midcontinent approached 1,000 mi.

CONCLUSION

Fluvial-dominated deltaic reservoirs commonly are high-quality reservoirs, largely because of their depositional fabric, but their recognition is dependent upon other factors—geologic setting, orientation and geometry, environmentally diagnostic indigenous constituents, and sedimentary structural sequences. Some fluvial-dominated deltaic reservoirs may be indistinguishable from fluvial (alluvial) units; others may be indistinguishable from shallow-marine or offshelf deposits.

Examples of channelized marine reservoirs in the southern Midcontinent include the Devonian Misener sandstone and Atokan Spiro sandstone. In some parts of its development, the Desmoinesian Bartlesville sandstone is fluvial. The most downdip part of the Red Fork sandstone may include offshelf units. Chesterian Carter sandstone in the Black Warrior basin contains both fluvial and fluvial-dominated deltaic reservoirs, as do most other deltaic complexes.

ACKNOWLEDGMENTS

My colleagues and former colleagues at Masera Corporation—Rick Fritz, Chris Johnson, Pat Medlock, and Mike Kuykendall—have contributed significantly to my understanding of Midcontinent stratigraphy, and my co-workers at Masera—Valerie Lindsey, Sandra PaskVan, and Rick Elliott—have prepared the text and illustrations for this manuscript. Also, former colleagues at Oklahoma State University—Zuhair Al-Shaieb, Gary Stewart, and Art Cleaves—have continued to contribute to my understanding of Midcontinent sandstones.

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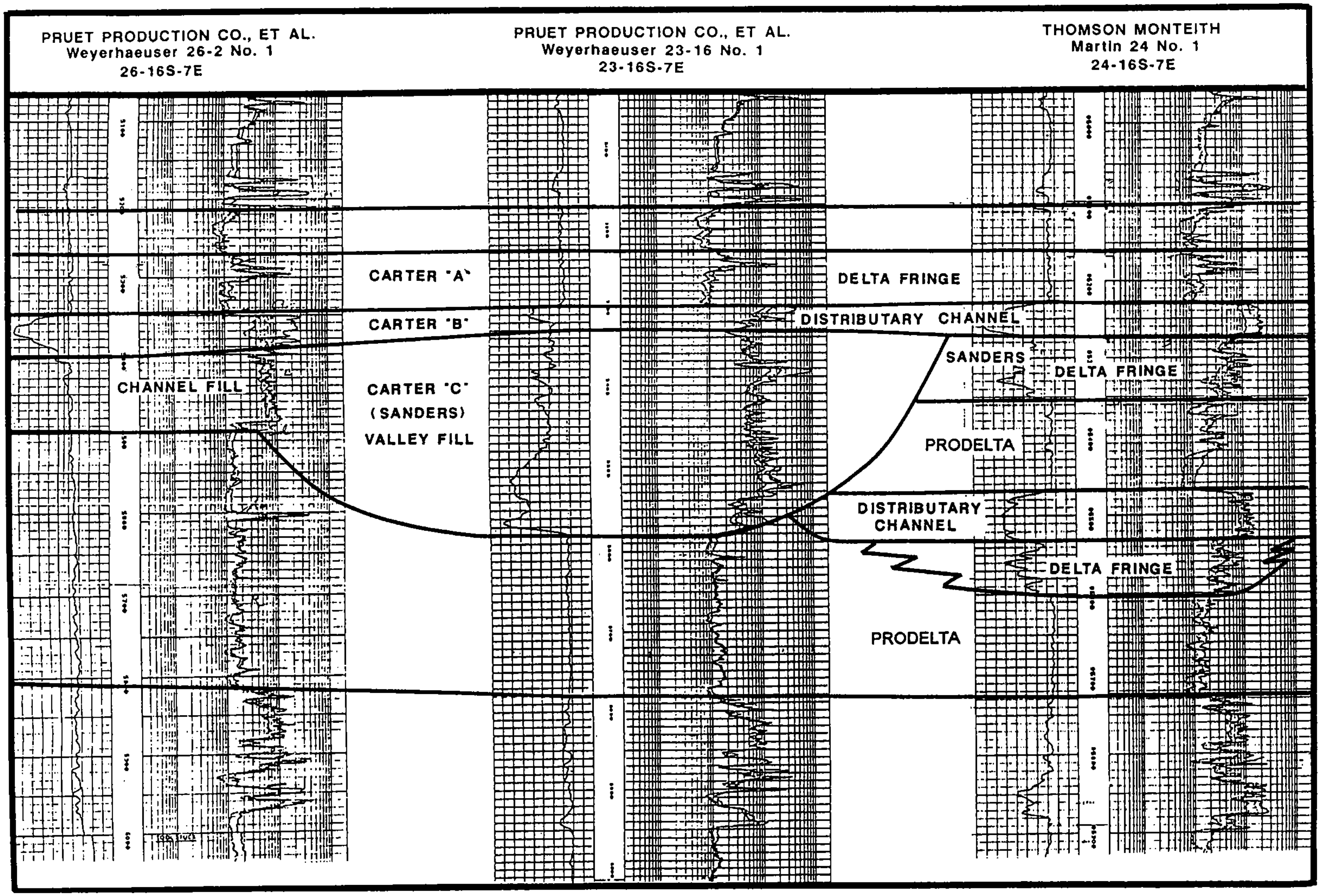

Figure 14. Schematic cross section of fluvial and deltaic reservoirs in Carter sandstone deltaic complex, Black Warrior basin (location shown in Fig. 12) (from R. D. Fritz and others, personal communication, 1992).

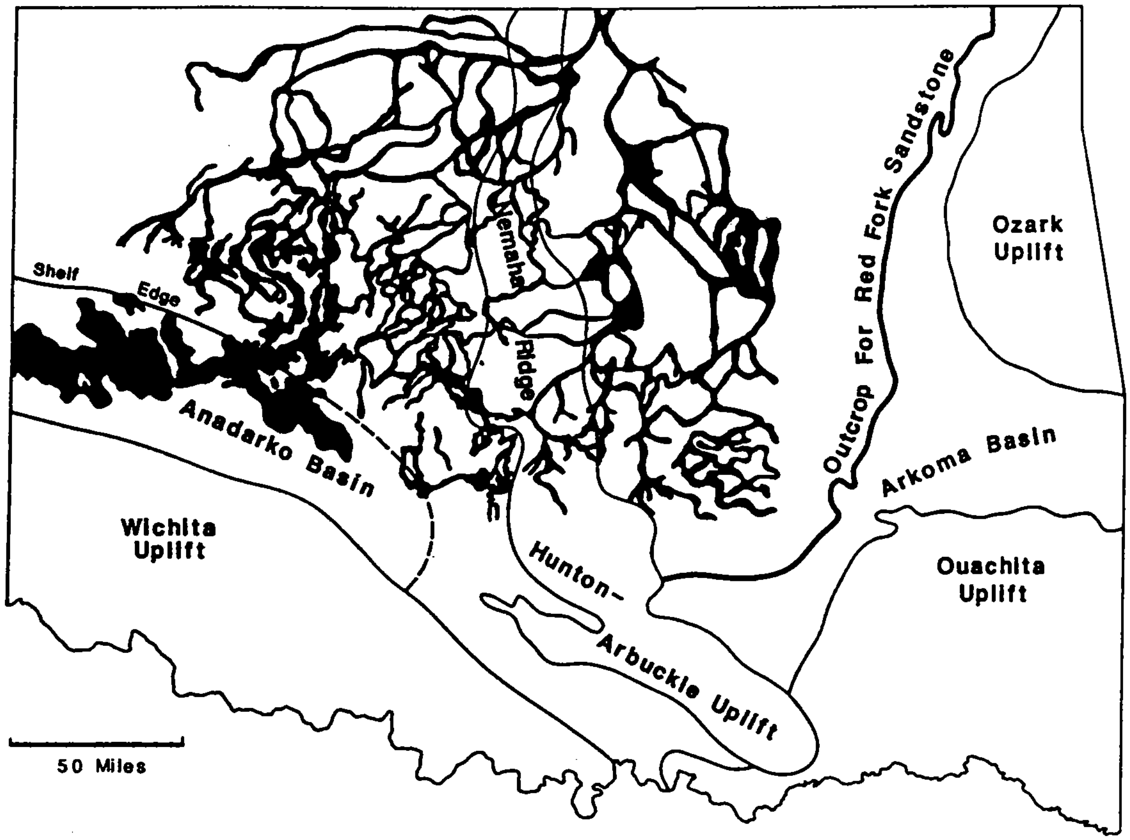

Figure 15. Generalized areal extent of Red Fork sandstone, showing distribution of major sandstone bodies (after Al-Shaieb and others, 1989).

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A History of Pennsylvanian Deltaic Sequences in Oklahoma

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ABSTRACT.—This paper describes the determination of the depositional origins of Pennsylvanian clastic, carbonate, and shale units that extended from the coastal plain into the deepest part of the continental-margin trench. Differing depositional environmental patterns are synthesized into depositional systems related to boundary conditions, depositional processes, and the tectonic and sea-level history for the Pennsylvanian rocks of Oklahoma and Arkansas.

INTRODUCTION

During the past 100 years, stratigraphy has undergone many fundamental changes in approach. With the recognition that time-stratigraphic and rock-stratigraphic units are separable, that biofacies and lithofacies patterns are four-dimensional, and that the first occurrence of a taxon could be based upon paleontological lineages rather than biozones, coupled with the merger of stratigraphy and sedimentation, it became possible to reconstruct paleogeographic history. This goal was mostly impossible until stratigraphic intervals could be subdivided into time units of sufficiently short duration to allow analogous comparisons to Holocene depositional processes and responses. Sequence stratigraphy provides the basis for the synthesis of stratigraphic attributes. Application of the sequence concept to depositional history has made it possible to causally interpret the origin of stratigraphic intervals (Vail, 1987; Visher, 1990).

For more than 30 years, my students and I have been studying clastic depositional intervals in Oklahoma. These studies have included outcrops, cores, well logs, and biostratigraphic zones. One of the goals of these studies was to map the areal distribution of individual clastic units. Interpretation of the origin of sandstone units was based upon comparisons of stratigraphic patterns and attributes to Holocene depositional-pattern responses. Comparisons were made by utilizing process and response depositional themes. These comparisons resulted in the identification of many scores of differing depositional environments. Environmental sequences and patterns provided the basis for recognizing differing depositional systems. Most of the stratigraphic intervals studied were associated with deltaic depositional processes and responses. These deltaic intervals included fluvial channels and valley fills, coastal shoreface and tidal estuaries and flats, shelf intervals, and submarine-fan channel and levee environments.

Clastic intervals contain differing patterns and sequences of these depositional environments. These differences are uniquely associated with differing Holocene depositional systems. From these comparisons, four principal delta types are identifiable: riverine, wave, tidal, and fan deltas. The areal distribution of a clastic interval and its relationship to unconformity surfaces, patterns of channel fill and progradation, and textural-response patterns are the result of the depositional boundary conditions. These include the geometry of the unconformity surface, water depths, proximity to shorelines and shelf margins, subsidence patterns and history, and rates of sea-level rise and/or subsidence. These boundary conditions are related to textural-response patterns, sediment by-passing, and the geometry of the depositional system.

These aspects are controlled in large measure by sequence stratigraphic themes. It is possible to synthesize depositional-response patterns and relate these patterns to lowstand, transgressive, shelf-margin, and highstand systems tracks (Figs. 1,2; Table 1) (Vail, 1987). Sequence and parasequence cycles are presented having scales of 10, 1–3, and 0.4 m.y. These patterns reflect sequences described by Haq for the Mesozoic Era and the Tertiary Period (Haq and others, 1987). In some instances it is possible to recognize stacked deltaic cycles consistent with Holocene depositional rates on the order of 100,000 years or less. These fifth-

Visher, G. S., 1996, A history of Pennsylvanian deltaic sequences in Oklahoma, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 18–31.

order cycles may also be identifiable. The method of sequence analysis has provided the theme for interpreting the depositional history of Pennsylvanian clastic rocks in Oklahoma. In addition, it provides the basis for determining the paleogeographic stratigraphic history. The results of this method are consistent with the vertical and areal patterns of deltaic intervals, unconformity patterns, regional time-stratigraphic correlation of stratigraphic units, and currently accepted biostratigraphic-age determinations (Huffman, 1958; Gordon and Henry, 1981; Sutherland and Manger, 1992).

CARBONIFEROUS STRATIGRAPHIC FRAMEWORK

Of principal importance to this analysis is the development of a correlation of time units, time-stratigraphic units, and lithologic units (Table 1). Table 1 includes the synthesis of stratigraphic information that has been obtained during nearly 100 years of study of Pennsylvanian strata in Oklahoma. Some of the relationships shown are well documented, but others are still equivocal. Some changes will of necessity be required as new information is obtained, but what is shown is internally consistent to the level of precision indicated. Most faunal biozones are readily arranged in sequence, but age determination based upon faunal zones may only be possible to a precision of 1–3 m.y. First-, second-, and third-order unconformity surfaces have been recognized by Haq and others (1987) worldwide and possibly reflect time-equivalent events. Identifying the time equivalence of unconformities requires careful worldwide correlation of faunal-lineage zones. Some confusion may arise because the time of first occurrence of a particular taxon may be different from place to place around the world.

Sequence-response patterns may also differ, depending upon the paleogeographic framework for deposition (Fig. 3) (Vail, 1987). The three patterns illustrated by Vail are all developed in Oklahoma. These include deposition on growth-faulted shelf margins, in shelf-foreland basins, and on depositional ramps. Posamentier and Allen (1993) later suggested the specialized sequence patterns associated with foreland basins.

Sequence cycles provide an event-based stratigraphic framework to understand "cyclothems," which have been the basis for interpreting repeating patterns of Pennsylvanian depositional cycles for more than 60 years (Wanless and Weller, 1932). However, little explanation was offered by Wanless and Weller for differing areal patterns of deposition. Such differences in areal depositional pattern are illustrated, for example, by the variations seen as one moves upward in the sequence that includes the lower Morrowan Cromwell and Hale sandstone units; the overlying Union Valley–Bloyd sandstone, carbonate, and shale intervals; and the capping, broadly distributed Wapanucka limestone and Limestone Gap shale highstand systems tract (HST) (Fig. 4; Table 1) (Sutherland, 1988). A similar pattern is reflected in the basal Atokan Foster valley-fill sandstone; the overlying, broadly distributed Spiro sandstone, carbonate, and shale interval; and the capping, transgressive shales that were deposited across the shelf (Fig. 5) (Sutherland, 1988). These interpretive themes are repeated throughout Pennsylvanian depositional intervals on the margins of the Arkoma basin. Depositional patterns reflect the boundary conditions outlined above. These conditions controlled the depositional patterns and can be deduced from the stratigraphic-response patterns.

The sequence theme allows depositional-response patterns to be causally understood and areal stratigraphic patterns to be predicted by using only limited information. From Table 1, it also appears that the nature of the depositional theme can be predicted. Valley-fill sequences occur either (1) in response to transgressive onlap across the shelf, following deposition of a lowstand systems tract (LST), or (2) on unconformities developed following a previous highstand depositional sequence. Similar, previously inexplicable patterns become sensible when this depositional framework is utilized.

PENNSYLVANIAN DEPOSITIONAL HISTORY UTILIZING SEQUENCES

Of principal importance to the application of sequences to the interpretation of depositional history is the need to obtain time-stratigraphic correlations of rock-stratigraphic units across the study area. Correlations of units deposited over hundreds of thousands of years require the identification of correlative events. These include unconformities, transgressive events, marker horizons resulting from depositional events, and evolutionary events. A shelf-to-foreland-basin time-stratigraphic correlation was developed by detailed analysis of all these aspects by Krumme (1981) (Fig. 6). His work was based upon outcrops, detailed subsurface well-log correlations, and detailed published information on biostratigraphic zonation developed from measured sections and stratigraphic relationships based upon field mapping.

Morrowan Strata

Controversy still exists as to the stratigraphic position of the boundary between the Upper Mississippian (Chesterian) and basal Pennsylvanian (Morrowan). Correlative shale units—including the Cane Hill limestone and shale units of Arkansas, the Caney shale unit of the Oklahoma platform, the Goddard shale unit in south-central Oklahoma, and the Springer sandstone and shale

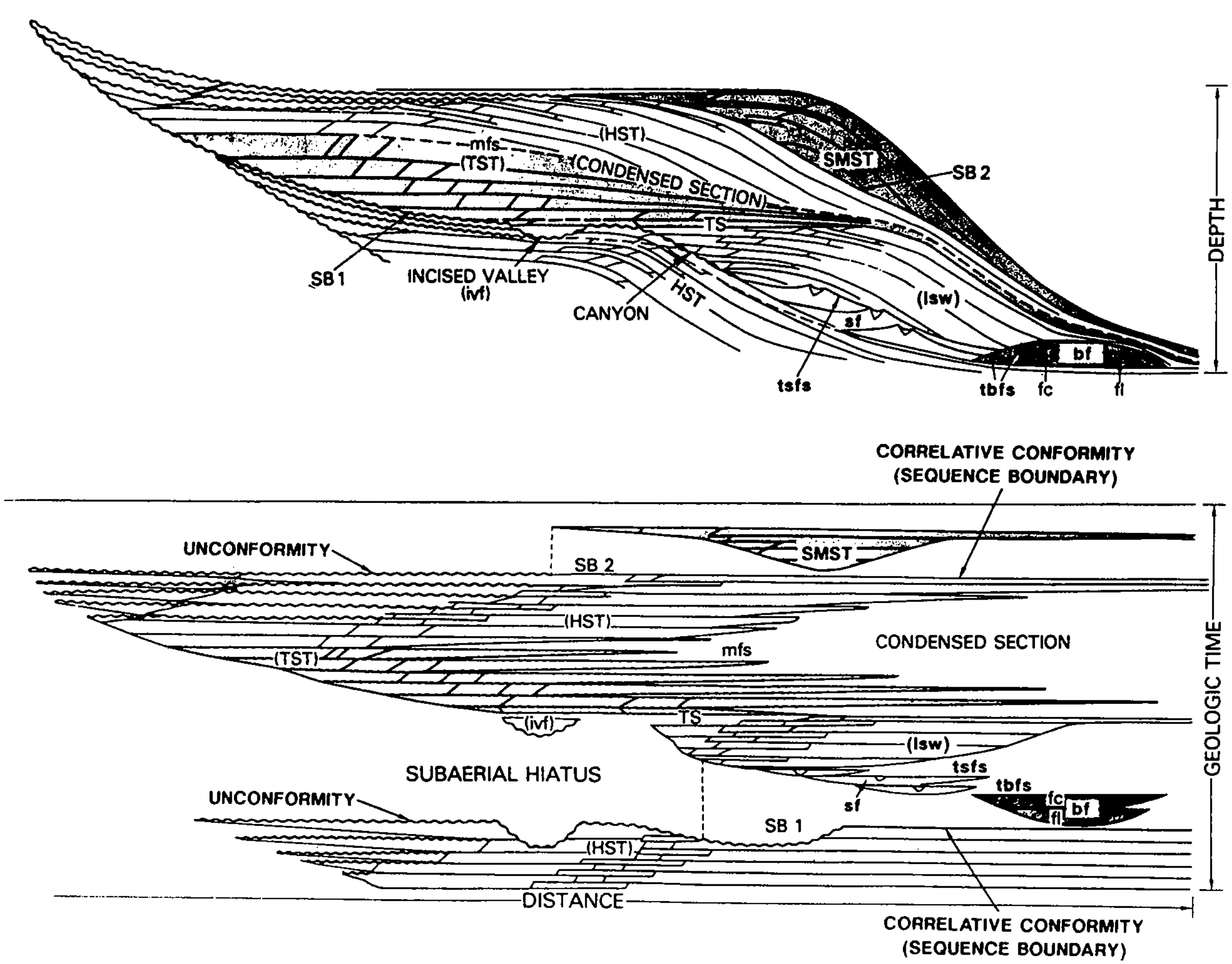
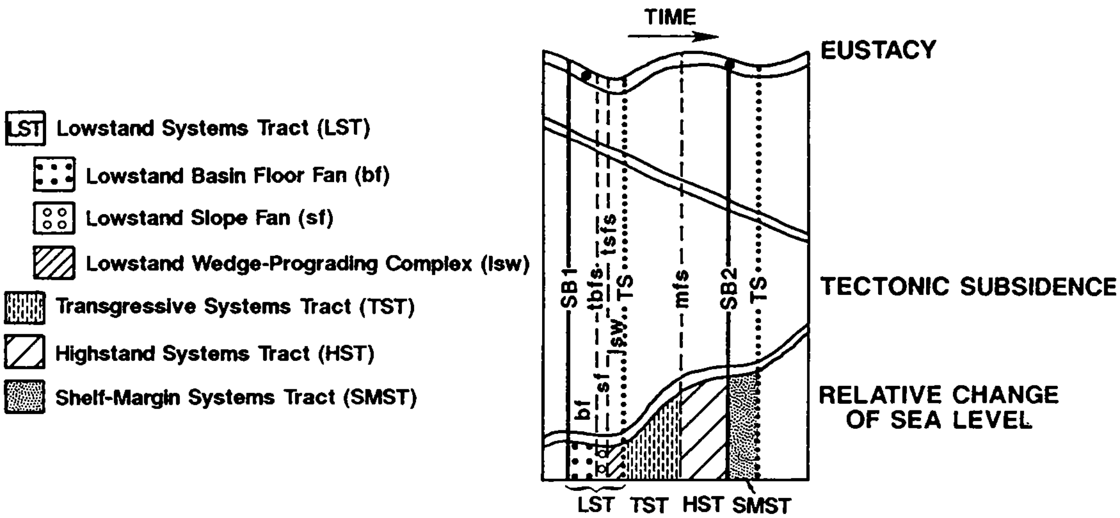


Figure 1. Sequence stratigraphy diagrammatic section, showing sequences and systems tracts in depth and geologic time (from Vail, 1987). For explanation of abbreviations, see Figure 2.



LEGEND

SURFACES

(SB) SEQUENCE BOUNDARIES
- (SB 1) = TYPE 1
- (SB 2) = TYPE 2

(DLS) DOWNLAP SURFACES
- (mfs) = maximum flooding surface
- (tbfs) = top basin floor fan surface
- (tsfs) = top slope fan surface

(TS) TRANSGRESSIVE SURFACE
- (First flooding surface above maximum progradation)

SYSTEMS TRACTS

HST = HIGHSTAND SYSTEMS TRACT
TST = TRANSGRESSIVE SYSTEMS TRACT
- ivf = incised valley fill

LST = LOWSTAND SYSTEMS TRACT
- ivf = incised valley fill
- lsw = lowstand wedge-prograding complex
- sf = lowstand slope fan
- bf = lowstand basin floor fan
  - fc = fan channels
  - fl = fan lobes

SMST = SHELF-MARGIN SYSTEMS TRACT

Figure 2. Diagrammatic analysis of the combination of eustasy and tectonic subsidence, reflected in the relative change of sea-level. Included is a legend of the terms and abbreviations used in the text (from Vail, 1987).

units in the Anadarko basin—contain both Mississippian and Morrowan faunas (Sutherland and Manger, 1992).

Stratigraphic mapping indicates that a major erosional unconformity surface is developed at the base of the Prairie Grove limestone unit of the Hale sandstone unit in Arkansas, the Cromwell sandstone in eastern Oklahoma, and the Squawbelly sandstone in the Anadarko basin. Transgressive systems tract (TST) channel-fill sandstones are deposited in erosional valleys, with >100 m of topographic relief (Huffman, 1958). Onlap across this erosional surface accounts for the varying ages of underlying stratigraphic units; ages range from the Chesterian Pitkin limestone unit, on the Arkansas shelf and Oklahoma platform, to the HST lowermost Pennsylvanian Caney, Cane Hill, Goddard, and Springer shales, deposited on the shelf margin and on the shelf between erosional valleys. These stratigraphic patterns can easily explain the reason for the difficulties encountered in determining the stratigraphic position of the Mississippian/Pennsylvanian boundary in different measured sections. Erosional backstripping of Mississippian/Pennsylvanian units also can explain the difficulties in determining ages of the LST Wesley shale, Jackfork sandstone, and Johns Valley shale units deposited on the Arkoma basin shelf margin.

This unconformity surface has been of primary importance both in the development of a channel system to bypass coarse clastic sediment into the marginal basin and as a migration route for fluids expelled from the compacting shales within the basin. This unconformity surface extends into Kansas; it possibly is the primary surface for migration of the tens of billions of barrels of oil that fill basal Pennsylvanian to lower Missourian reservoirs overlying the unconformity surface.

Subsequent Morrowan deposition on the shelf

Table 1. — Sequence of Time Units, Time-Stratigraphic Units, and Principal Carboniferous Formations Mapped in Oklahoma and Western Arkansas

Ages* (m.y.)	Sequences				
	2nd order (10 m.y.)	3rd order (1–3 m.y.)	4th order (0.4 m.y.)		
	Anadarko basin	Cherokee shelf	Ouachita shelf / basin†	Delta type‡	Sea-level stand‡
	Granite	Cottage Grove	Osage-Layton ss	fan	HST
Missourian	Wash ss		Layton ss	riverine	HST
300–305		Skiatook	Checkerboard ls		TST
	Marchand ss		Cleveland ss	riverine-fan	TST
			Oologah-Wewoka ss (4)	fan	HST
	Granite	Marmaton	Oswego ls		HST
	Wash ss		Prue-Calvin ss (2)	riverine-fan	TST
Desmoinesian			Skinner ss (2)	riverine	HST
305–311		Senora	Stuart sh		TST
			Thurman ss	valley-fill	SMST
	Red Fork ss	Boggy	Red Fork ss (2)	riverine	HST
	and sh		Bartlesville ss	riverine	HST
			Savanna ss and sh	riverine-fan	TST
		McAlester Fm	Booch and Warner ss	tidal	TST
			Hartshorne ss	fan	SMST
	Atoka ss	Gilcrease and	Carpenter ss	wave-tidal	HST
	and sh	Dutcher ss	Alma / Fanshawe ss	tidal	TST
Atokan			Areci / Red Oak ss	tidal	LST
311–314			Cecil / Brazil ss	tidal	LST
	Thirteen	Spiro ss	Spiro ss and chert	wave-tidal	HST
	Fingers ls		Foster ss	tidal	TST
	Morrow sh	Wapanucka ls	Limestone Gap sh		HST
		and sh	Union Valley ls		
Morrowan		and Bloyd ls	and sh		HST
314–325	Morrow ss	Hale ss	Cromwell ss	tidal	TST
		Prairie Grove ls	/ John's Valley sh		TST
	Squawbelly ss		/ Jackfork ss / Wesley sh	tidal	LST
Pennsylvanian/ Mississippian	Springer ss and sh	Cane Hill ls and sh	Caney sh / Jackfork ss	tidal	HST
Chesterian	Springer ss; sh	Caney sh	Pitkin ls		TST
325–335	Goddard sh	Goddard sh	/ Jackfork ss	tidal	TST
	Cunningham ss	Batesville ss	Fayetteville sh		TST
		Hindsville ls	/ Chickasaw chert		LST
Meramecian	Meramec ls	Moorefield	Mayes ls		HST
335–345		ls and sh	Stanley sh		HST
Osagean	Osage ls	Boone chert	Keokuk ls / Stanley ss	tidal	TST
345–356	and chert		Reeds Spr. / Stanley ss		LST
Kinderhookian–	Woodford sh	Chattanooga sh	/ Arkansas novaculite		HST
Middle Devonian			/ Arkansas novaculite		TST

*Ages from Haq and others (1987) and Haq and Van Eysinga (1987).
†Numbers in parentheses indicate the number of sandstone units; names of stratigraphic units following "/" are basinal equivalents.
‡Information indicates delta types and the nature of the depositional sequences, including lowstand systems tract (LST), transgressive systems tract (TST), shelf-margin systems tract (SMST), and highstand systems tract (HST).

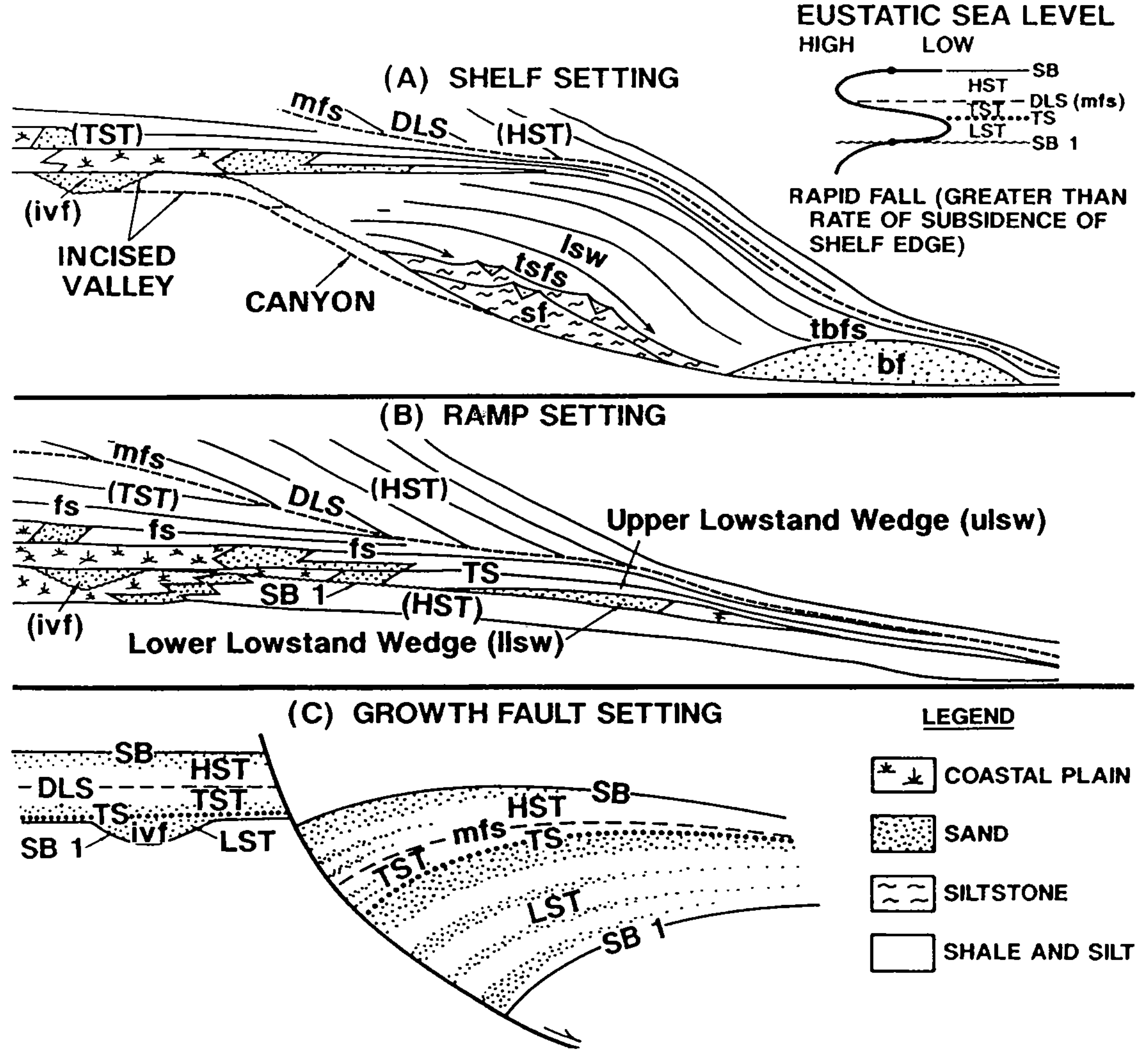


Figure 3. Sequence stratigraphy diagrammatic sections, showing systems tracts for shelf, ramp, and growth-fault depositional settings (from Vail, 1987). For explanation of abbreviations, see Figure 2.

included the HST Wapanucka and Brentwood limestones, Wapanucka and Morrow shales, and locally reworked and redeposited shelf sandstones. Basinal equivalents are reflected by deposition of a condensed interval of spiculitic limestones and organic-rich shales.

Atokan Strata

On the shelf margin, Atokan time commenced with the deposition of the Foster sandstone unit in an erosional valley-fill sequence. The overlying Spiro sandstone onlaps the Foster interval and is broadly distributed across the Arkoma basin marginal shelf. The Foster sandstone was deposited as a TST estuarine channel valley fill, and the overlying Spiro sandstone was deposited in response to continuing subsidence and/or sea-level rise, on a shelf with a high-energy wave- and tide-dominated environment of deposition (Lumsden and others, 1971). Clastic units reflect a depositional system similar to that of the Holocene Baram River Delta of northwest Borneo (James, 1984) (Fig. 7).

The shelf margin is cut by a number of well-developed growth faults, including the San Bois and Mulberry faults. Nearly 2,000 m of LST middle and lower Atokan submarine fans were deposited basinward of these growth faults (Vedros and Visher, 1978). This pattern indicates that lower Atokan strata are not present on the Oklahoma platform (Sutherland, 1988) (Fig. 8). On the Arkansas shelf, however, the shelf margin is incised by submarine-slope canyons, and the Atokan is represented by a series of stacked, tidally depos-

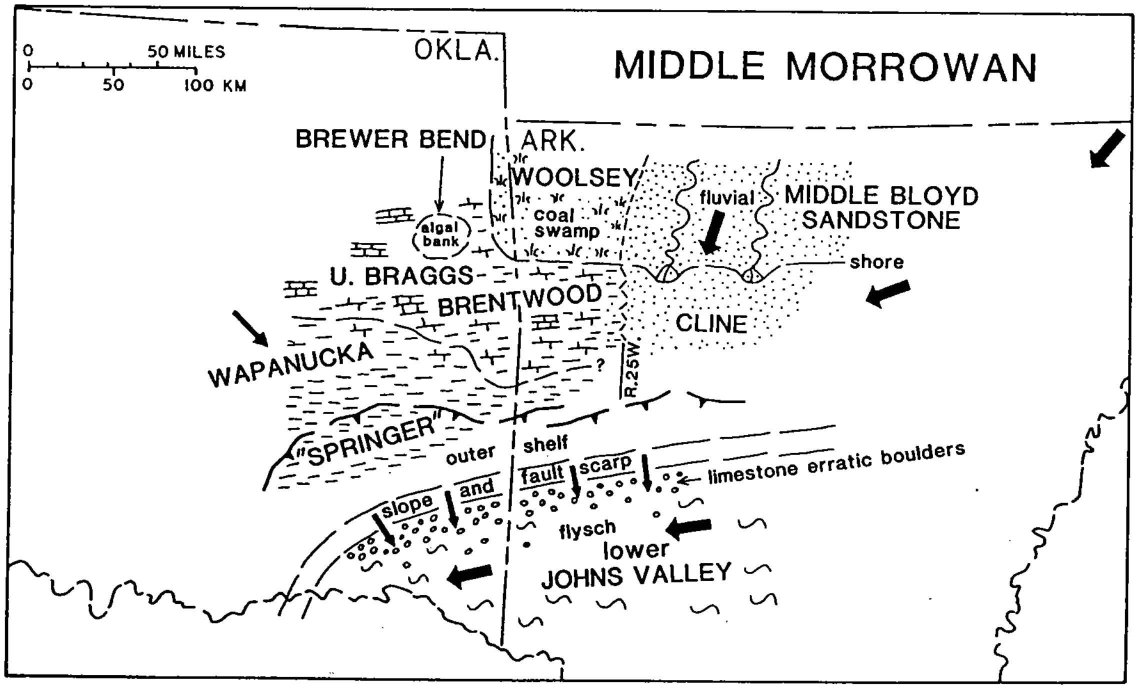


Figure 4. Areal distribution of middle Morrowan formations and depositional environments for eastern Oklahoma and northwestern Arkansas (from Sutherland, 1988).

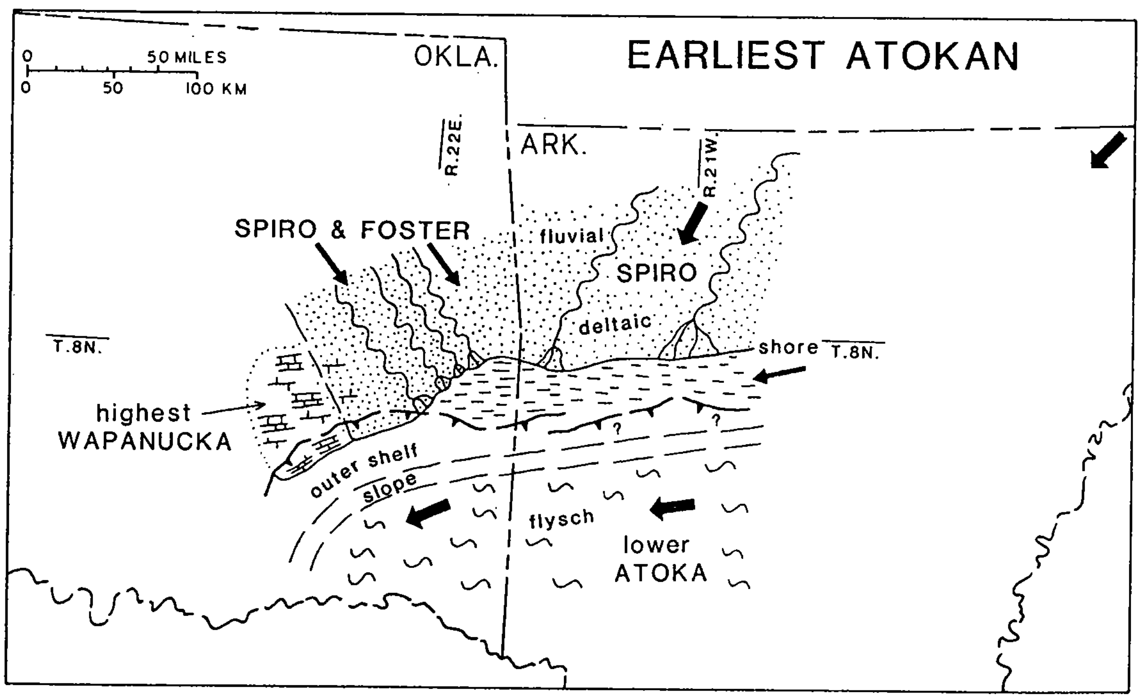


Figure 5. Areal distribution of earliest Atokan formations and depositional environments for eastern Oklahoma and northwestern Arkansas (from Sutherland, 1988).

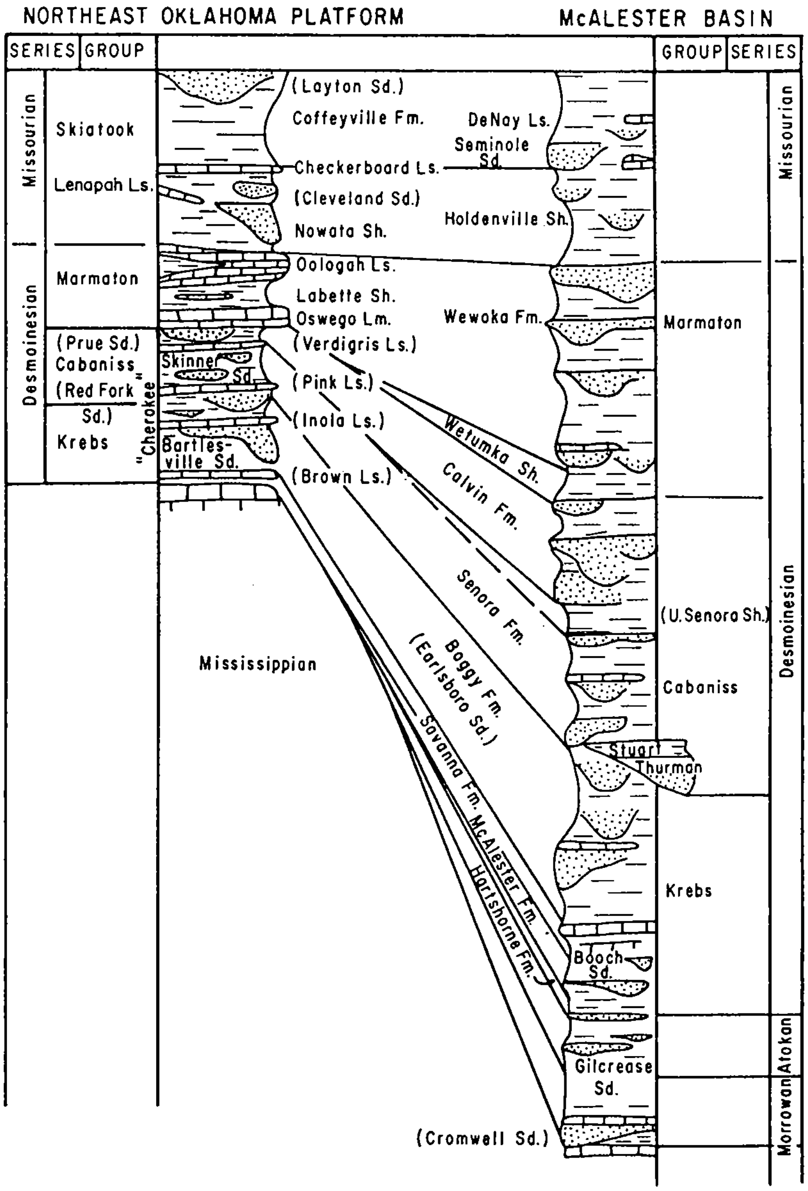


Figure 6. Shelf-to-basin time-stratigraphic correlations of some Pennsylvanian units from shelf to basin (from Krumme, 1981).

ited deltaic intervals, including the Cecil, Areci, Alma, and Carpenter sandstone units (Visher, 1990). Lower Atokan shelf intervals contain quartz-pebble conglomerates, possibly equivalent to the Pounds sandstone, of probable Atokan age, in the Illinois basin. Early Pennsylvanian erosional channels have been identified across Missouri and may be representative of a major fluvial system that transported detritus from the central part of the North American craton. More than 4,000 m of Atokan clastic sediments were deposited in deeper-water submarine fans. Lower Atokan basinal equivalents in the Oklahoma part of the Arkoma basin contain current structures suggesting a dominant westerly sediment transport within the Arkoma basin (Briggs and Cline, 1967).

Middle and upper Atokan Gilcrease and Dutcher sandstone depositional intervals are widespread across the Oklahoma Cherokee platform. Field mapping has demonstrated, as far north as Craig County in northeastern Oklahoma, the presence of sandstone-filled channels, 0.4–0.8 km wide, that were eroded as much as 30 m into the underlying Mississippian "chat" (regolith). Lower Burgess sandstone channel-fill units are of probable Atokan age, but other channel-fill units may also include lower Desmoinesian stratigraphic equivalents, i.e., the Hartshorne, Savanna, and Booch sandstones. Deposition is interpreted to reflect fluvial, estuarine, and deltaic channels. Examination of well logs and samples from wells penetrating channeled Atokan channel-fill intervals in Okmulgee County indicates the presence of a major channelized drainage system, identified by coarse bed-load sand ≤1 mm in diameter. Stratigraphic equivalents reflect onlap and include a range of depositional units such as shelf carbonates and glauconitic and bioturbated sandstone intervals.

Middle and upper Atokan shelf sequences are stacked and prograde across the shelf. This pattern indicates the development of a highstand sequence pattern, reflective of wave- and/or tide-dominated deltaic deposition. Detailed correlation of lower middle Atokan intervals suggests a maximum flooding surface (mfs) above the Spiro sandstone interval, which would reflect an internal third-order unconformity surface (J. G. Cole, per-

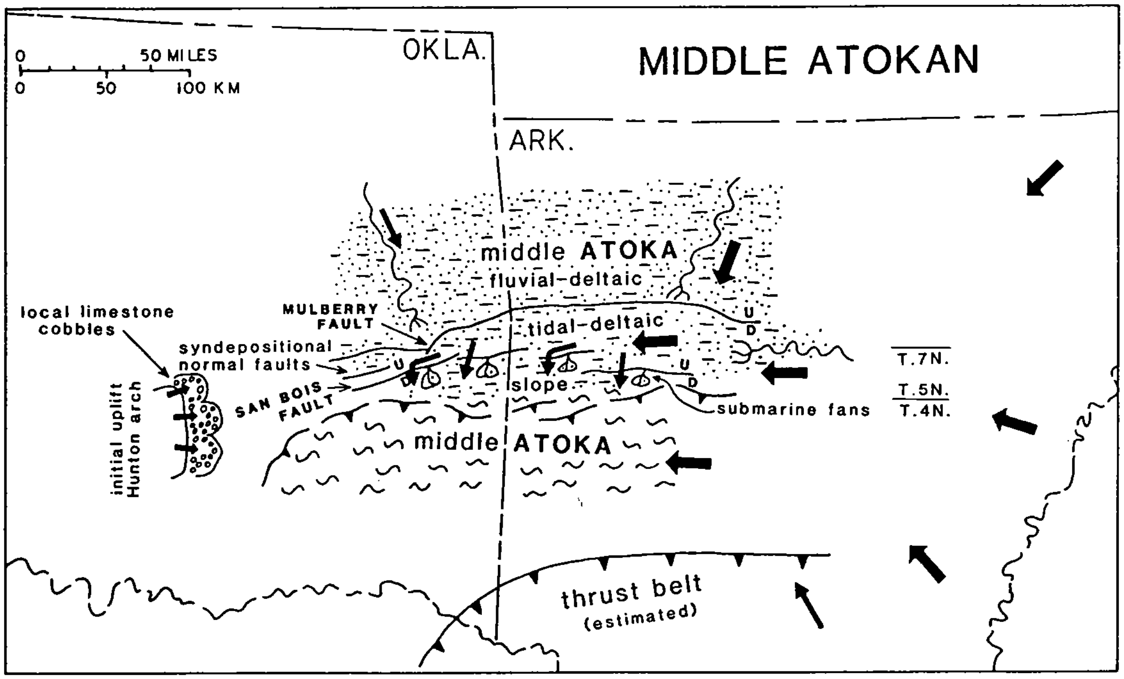


Figure 7. Areal distribution of middle Atokan formations and depositional environments for eastern Oklahoma and northwestern Arkansas (from Sutherland, 1988).

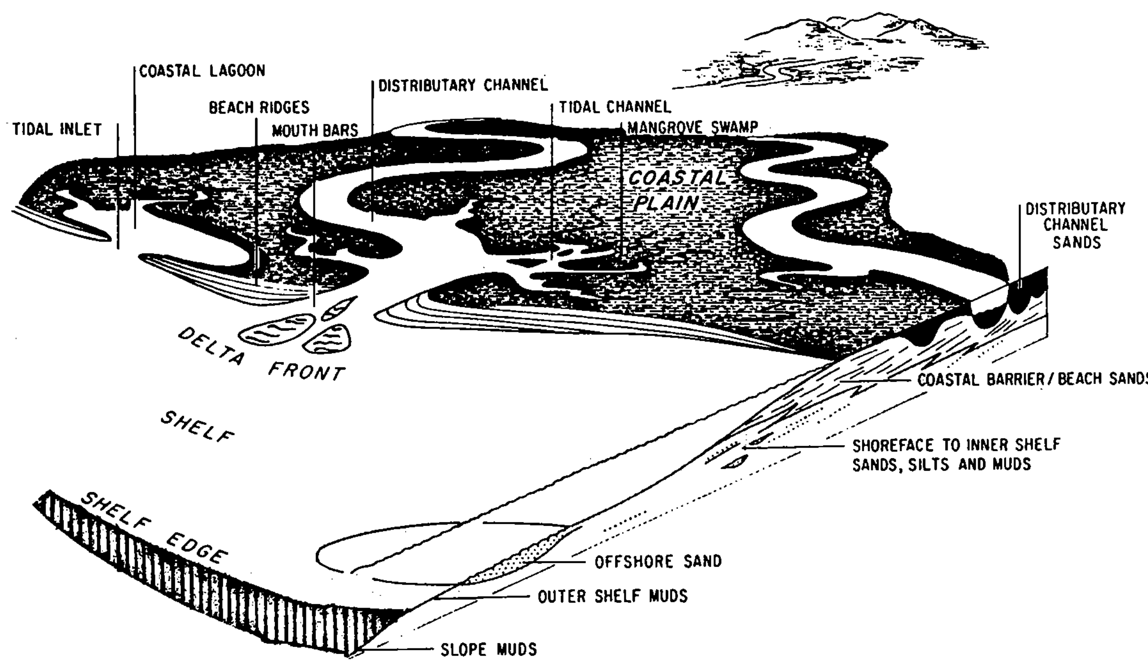


Figure 8. Pattern of depositional environments for the Baram delta, eastern Malaysia and Brunei (James, 1984).

sonal communication, 1993). The terminations of successively younger deltaic parasequences prograde across the shelf to the shelf edge, as sea-level rose (see Fig. 3, model A). These patterns can be seen for the Carpenter "A" sandstone near Ozark, Arkansas, and for the widespread distribution of Atokan deposition reflected by the Gilcrease and Dutcher sandstone interval on the Cherokee platform. These patterns provide the explanation for the bypassing of sediment through slope channels, producing continued deposition of the middle Atokan Red Oak and upper Atokan Fanshawe submarine fans. These aspects are consistent with those observed for the Holocene tide-dominated Mahakam Delta, as described by Allen and others (1979) (Fig. 9).

Desmoinesian Strata

After deposition of the Atokan Series, a foreland-basin and ramp depositional pattern was developed, similar to that described by Posamentier and Allen (1993). The basin was either filled, or the southern basinal margin was uplifted to near sea-level. The Atokan is unconformably overlain by the Hartshorne sandstone unit. To the north the unconformity surface is overlain by conglomerates, and channeling, with channel-fill deposition, is indicated. To the south the unconformity is marked by low-angle truncation, and minor channeling and little deposition reflect filling of a low-relief flood basin (Huffman, 1958; Visher, 1990).

The blanketlike character of the Hartshorne sandstone unit and the widespread occurrence of a "Hartshorne" time-stratigraphic marker reflect deposition on a maximum flooding surface (mfs). This surface is a low-relief ramp that extends across the Cherokee platform and into Kansas (see Fig. 3B). The McAlester-Hartshorne interval thickness (nearly 700 m) indicates continued subsidence near the former shelf margin, and a shelf-margin systems tract (SMST) is indicated.

The Hartshorne sandstone unit was deposited in a flood-basin depositional setting, typical of Holocene depositional patterns (e.g., the Colville delta of Alaska). This interpretation is supported by the presence of large-scale braid bars, ≤5 m thick; widespread coal layers, ≤2 m thick; and the presence of a broad floodplain and levee interval extending over an area of >5,000 km^2. These aspects are reflective of fan-delta deposition in a foreland basin. A similar Holocene coastal fan-delta pattern has been described by Galloway (1976) (Fig. 10). The McAlester sandstone, shale, and coal units contain multiple stacked deltaic parasequences. The Booch and Warner sandstone units, overlying the Hartshorne coal, were deposited on the northern flank of the foreland basin. These sandstone units represent valley-fill deposition in erosional estuarine channels (Busch, 1953; Visher, 1990). Similarly, the Savanna sandstone and shale units reflect deposition as multiple channel-fill units, but also reflect flood-basin depositional intervals characterized by the development of stacked, braided-channel, fan deltas. Erosional surfaces

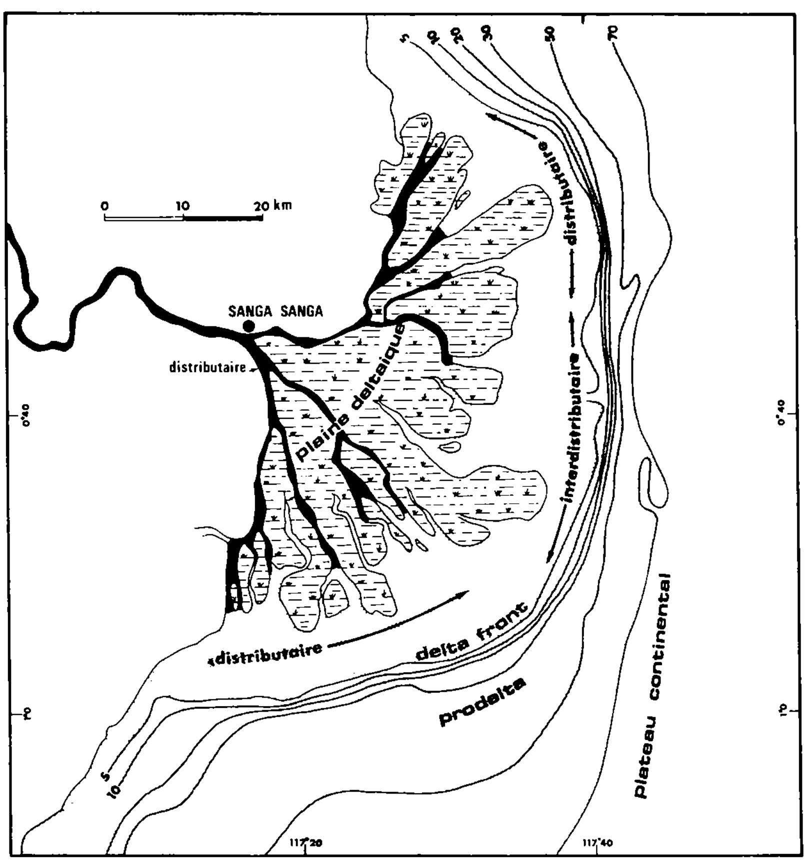


Figure 9. Pattern of deposition of environments for the Mahakam delta of eastern Kalimantan (from Allen and others, 1979).

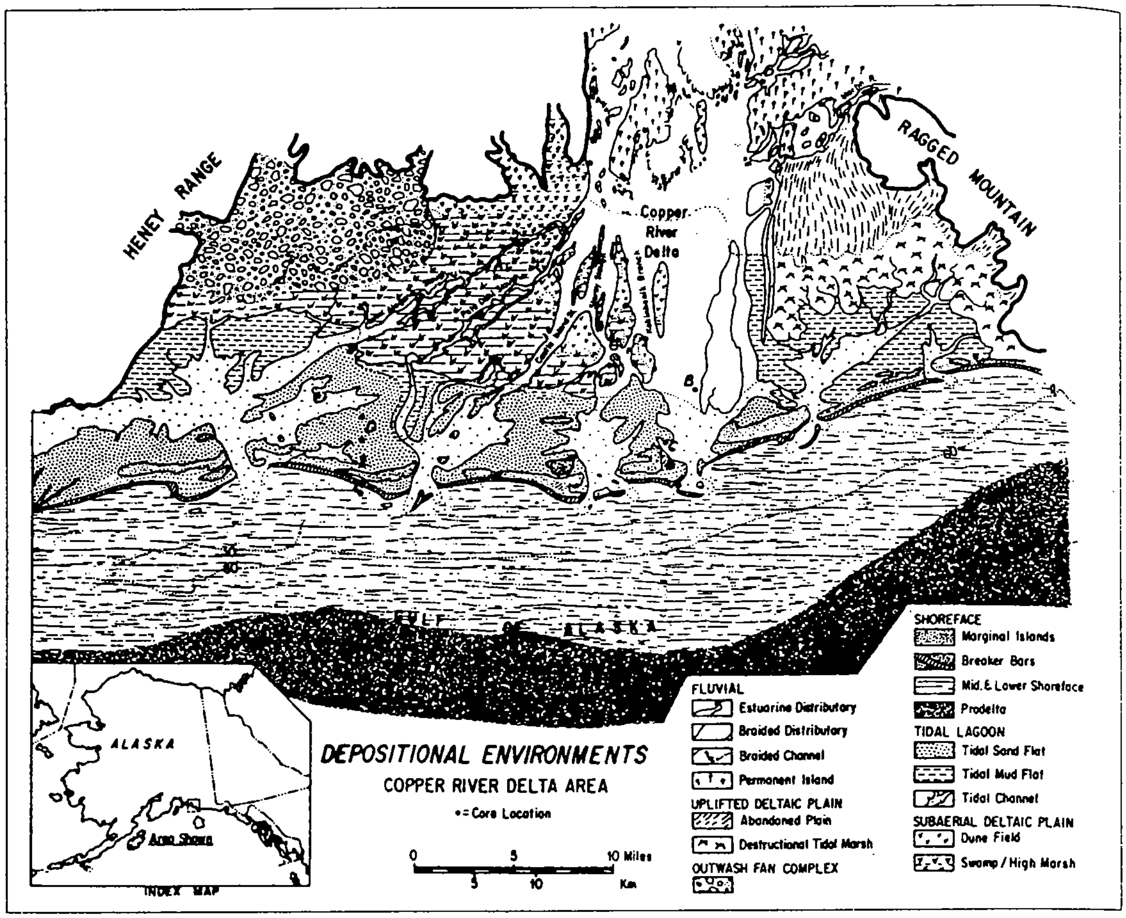


Figure 10. Pattern of depositional environments for the Copper River delta of Alaska (from Galloway, 1976).

were developed at the base of each parasequence on the Oklahoma Cherokee platform. The interval is transgressive, and successively younger parasequences are observed to the north, as suggested by Vail (1987) (Fig. 3B).

The overlying Bartlesville and Red Fork sandstone parasequences reflect a change in the depositional setting. They are progradational deltaic HST sequences overlying an upper Savanna flooding surface. The Bartlesville interval rarely fills erosional valleys in Oklahoma, but this pattern is common on the upper coastal plain in Kansas (Visher and others, 1971; Walton, 1993). Red Fork sandstone forms deltaic channels that occupy erosional valleys on the crests of structural and topographic highs and on the northern flank of the Cherokee platform, as developed in the Cherokee and Wakita hydrocarbon-producing trends. The Red Fork sandstone reflects continued sea-level rise and is widely distributed across most of Oklahoma and southern Kansas, an area of >50,000 km^2.

Each of these parasequences reflects deposition during a period estimated to be ~400,000 years (Table 1). Progradational clastic intervals are separated by nearshore limestone markers. They typically contain more than one depositional unit. Where stratigraphic intervals are thicker, as a result of a more rapid rate of subsidence (e.g., on the flanks of the Anadarko basin and on the southern margin of the Cherokee platform), several units deposited in 100,000-year cycles are developed. The Bartlesville sandstone parasequence contains indications of some tidal influence in outcrop on the southern margin of the platform (Visher and others, 1971). The Red Fork sandstone depositional interval may also have been partially tidally controlled on the flanks of the Anadarko basin, on the basis of rejoining channel depositional patterns. The principal depositional control for both parasequences reflects riverine deltaic processes, as illustrated by Holocene depositional-response patterns similar to those described by Gould (1970) for the Mississippi Delta (Fig. 11).

A major interruption in the continuity of the depositional history is represented by deposition of

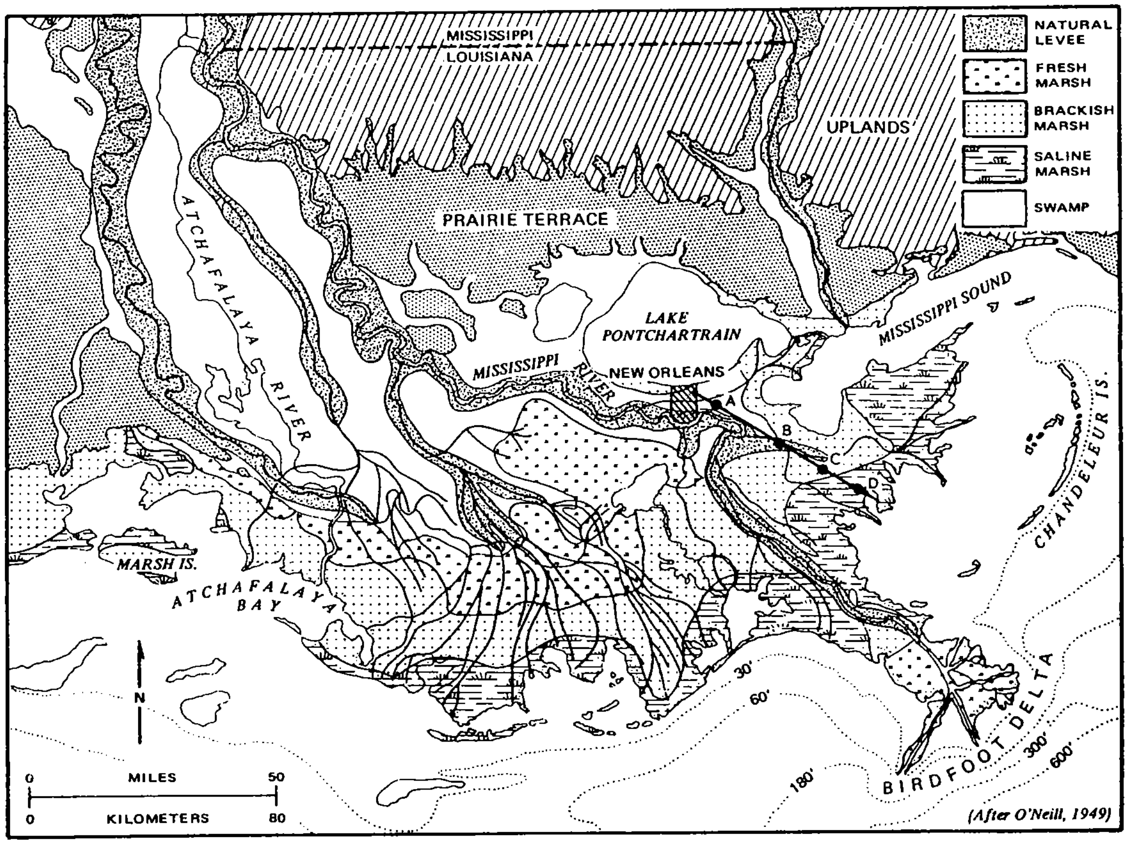


Figure 11. Distribution of environments and channels of the Mississippi River delta plain (from Gould, 1970).

the Thurman sandstone on the margin of the foreland basin. This unit is restricted to the basin margin, and it rests on (and fills) channels developed on a major erosional unconformity (Table 1). Those utilizing a tectonic framework for interpreting depositional history suggest that this interval may represent the development of a southern clastic source resulting from tectonic uplift of the Arkoma basin. This interpretation cannot be supported, however, since paleocurrent information indicates that late Atokan submarine fans had their source to the north and east, and Hartshorne and Savanna sandstone fan-delta patterns indicate an eastern source. A sea-level fall, after deposition of the HST Red Fork sandstone parasequence, is indicated by the erosional unconformity at the base of the Thurman sandstone. Also, the sediments involved in onlap deposition to form the Stuart shale, followed by the Skinner sandstone HST riverine deltaic parasequences, were derived from both northeasterly and southeasterly sources (Valderrama, 1974). These depositional patterns are in conflict with the tectonic interpretation.

The Skinner sandstone HST riverine deltaic sequences are unconformably overlain by restricted channelized Prue and Calvin sandstone depositional intervals. Previous depositional patterns are repeated, with an erosional unconformity overlying the Skinner HST parasequence, followed by the Calvin and Prue TST, valley-fill deposits (Krumme, 1981). These fan and riverine deltas were deposited in the foreland basin and then prograded to the north and west across the basin, in response to the rise in sea-level. On the margin of the foreland basin, the TST Oswego carbonate bank developed, and the Wetumka shale was deposited within the basin at the base of the Wewoka sandstone progradational fan-delta parasequences (Krumme, 1981). Continued subsidence of the foreland basin, flanked by Oologah carbonate-bank deposition, is documented by the deposition of Wewoka fan-delta sequences (Krumme, 1981).

Missourian Strata

During Missourian time, this pattern was repeated again, with deposition of clastic channel-fill sequences, unconformably overlying the HST Oologah carbonate-bank interval. Correlation of time-stratigraphic intervals is complicated by onlap, resulting in the filling of erosional valleys by Cleveland sandstone depositional units. In other localities, onlap was represented by deposition between erosional valleys, and this process produced stacking of TST depositional units (Vail, 1987) (Fig. 3B). This transgressive depositional history was capped by the maximum flooding surface represented by deposition of the Checkerboard limestone and the overlying deeper-water phosphatic-shale unit (Krumme, 1981).

Progradation of the overlying HST Layton and Cottage Grove riverine deltaic-sandstone parasequences, separated by the nearshore Hogshooter limestone transgressive interval, completed the cycle (Table 1). Of particular importance is the fact that the Layton sandstone riverine deltaic interval reflects deposition in deeper water, reflected by progradational deposition onto the underlying phosphatic shale (mfs), which, in turn, overlies the Checkerboard limestone that caps the Cleveland and Prue sandstone parasequence. This transgressive surface can be identified and correlated from Oklahoma to Iowa and from the Texas Panhandle to Missouri.

The areal depositional pattern of the Layton sandstone has been mapped and its environmental patterns have been interpreted on the basis of detailed outcrop studies by my students and me (Visher and others, 1975). A riverine deltaic depositional system is indicated, as reflected by areal depositional and process-response patterns that were observed both in core and outcrop sections.

The regional depositional pattern of the overlying Cottage Grove sandstone parasequence was mapped by Lalla (1975). The paleogeographic pattern, together with outcrop studies, indicates deposition in a blanketlike HST shelf environment. The thickness, the continuity of permeable-sandstone flow units, and the areal distribution of the parasequence all indicate deposition in a fan-delta framework. This pattern reflects HST deposition, with progradation from a rising source area on the shelf margin to the south. Shelf-fan deposition resulted from a decreased receptor capacity (decreased rate of subsidence) at the close of a highstand systems tract.

Subsequent Missourian and Virgilian sequences have been documented by Heckel (1986) in Oklahoma and Kansas. Regional sequence patterns have been reported by Ross and Ross (1988). The sequence stratigraphic theme documented by this paper can be utilized to interpret the origin of "cyclothemic" cycles in the Midcontinent.

CONCLUSIONS

The foregoing analysis illustrates that the sequence stratigraphic theme can be usefully applied to interpret the origin of depositional intervals. The value of this theme is both in the prediction of stratigraphic patterns and in the interpretation of previously poorly understood stratigraphic patterns. When all the depositional-response patterns are interrelated, confidence to predict and to interpret depositional patterns, and to understand the origin of single depositional units, is enhanced.

My students and I have often misinterpreted or debated the significance of a single observation. By using the sequence theme, the synthesis of unrelated observations often makes it possible to understand the causality and controls for the depositional origin of stratigraphic units and intervals.

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Pennsylvanian Deltaic-Channel Reservoirs in Oklahoma

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ABSTRACT.—Pre-Pennsylvanian strata in Oklahoma are a thick sequence of Upper Cambrian through Mississippian shallow-marine carbonates that were deposited in a broad epicontinental sea in an area called the Oklahoma basin. Major changes took place during Pennsylvanian time; the Oklahoma basin was divided by sharply uplifted crustal blocks into a series of well-defined basins. Pennsylvanian orogenic activity was limited to folding, faulting, and uplift and was not accompanied by igneous activity or metamorphism. Sedimentation in the rapidly subsiding basins was dominated by the coarse and fine clastic material shed from the nearby uplifts, and alluvial and/or deltaic sediments were deposited in the coastal areas.

Deltaic-channel petroleum reservoirs are present throughout the Pennsylvanian System in the Morrowan, Atokan, Desmoinesian, Missourian, and Virgilian Series rocks. These sandstone reservoirs were deposited in fluvial and fluvial-dominated deltaic environments, primarily located on the Cherokee platform and on the northern and eastern shelves of the Anadarko basin.

The sources of sediments for the Pennsylvanian delta systems in Oklahoma varied through time. A late Morrowan delta, located in the Oklahoma Panhandle, had a source of sediment from the northwest; the sediments that formed an oil-productive upper Morrow Group channel sandstone in the Postle field of Texas County were deposited in this southeast-trending delta system.

Desmoinesian strata include the deposits of the Booch delta in east-central Oklahoma that had its sediment supply coming from the north. Numerous oil pools have been discovered in these Booch channel sandstones. A large Bartlesville delta system on the Cherokee platform of northeast Oklahoma was supplied with sediment from the north; many oil pools are present in the resulting Bartlesville channel sandstones. The large fluvial and deltaic Red Fork system in northern Oklahoma and the Anadarko basin had its sediment source in the north. An extensive Red Fork channel in Kingfisher County crosses the Sooner Trend from east to west.

The large Missourian delta system had its source in the east and southeast; sands were transported across eastern Oklahoma into the Anadarko basin. The Marchand channel sandstone in the NE Binger field in Caddo County, on the eastern flank of the Anadarko basin, was derived from the northeast. The Endicott delta system, with a northern sediment source, is located in northwest Oklahoma.

INTRODUCTION

Oklahoma is one of the leading petroleum-producing states in the nation, and a significant amount of its production is derived from deltaic-channel reservoirs in Pennsylvanian strata. Deltaic channels are those sands or sandstone units deposited in main-stream or distributary channels that extended across deltas built up by rivers and streams that flowed into various depositional basins (Fig. 1).

This paper is intended to describe the geologic framework of Oklahoma leading up to, and during, the Pennsylvanian Period, and to discuss some of the major deltaic-channel reservoirs in the State. It also is intended to help set the stage for other, more detailed reports in this symposium volume.

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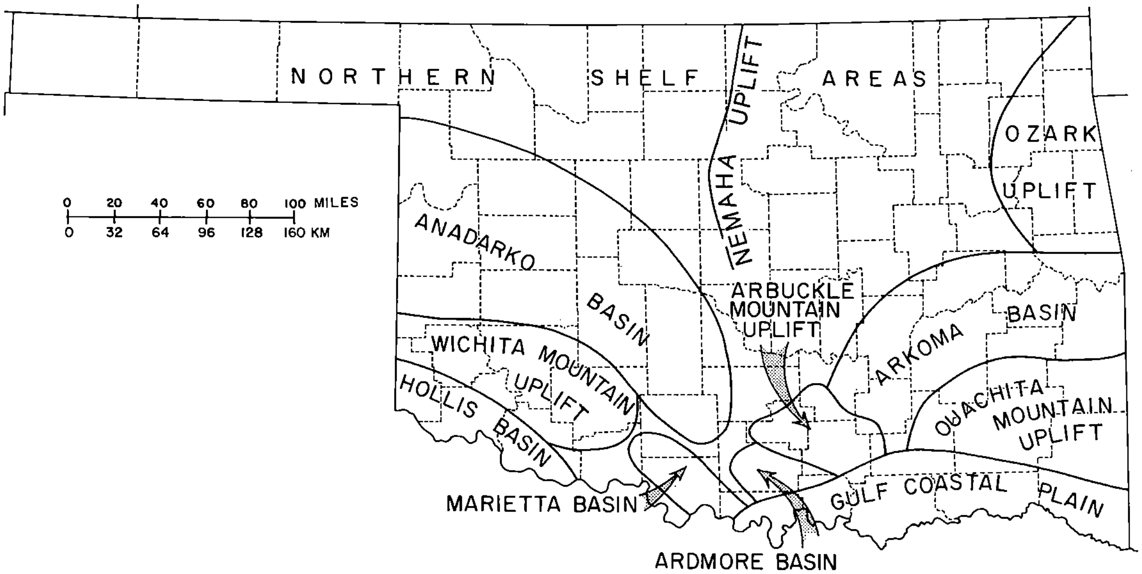

Figure 1. Major geologic provinces of Oklahoma (from Johnson, 1971).

GEOLOGIC FRAMEWORK

Late Cambrian through Mississippian conditions in Oklahoma are represented by marine sediments that were deposited in a broad epicontinental sea, the Oklahoma basin, that extended across almost all parts of the southern Midcontinent (Fig. 2). The Oklahoma basin was a shelflike area that received a sequence of remarkably thick and extensive sediments now represented by marine carbonates interbedded with thinner marine shales and sandstones. These strata are readily correlated throughout the basin. The sedimentary units thicken into protobasins (Anadarko, Ardmore, Arkoma, and others), which were accentuated later during Pennsylvanian orogenies, and they also were deposited upon and across the present-day major uplifts, from which they were subsequently stripped during Pennsylvanian uplift and erosion. The southern Oklahoma aulacogen was the depositional center for the Oklahoma basin.

Late Paleozoic geologic development in Oklahoma centered on orogenic activity during the Pennsylvanian Period. The broad, shallow-marine Oklahoma basin was divided by sharply uplifted crustal blocks into a series of well-defined marine basins. Orogenic activity was limited to folding, faulting, and uplift and was not accompanied by igneous activity or metamorphism. Pennsylvanian orogenic pulses caused, or contributed to, folding and thrusting of the Ouachita fold belt; raising of the Wichita, Criner, Arbuckle, and Nemaha uplifts; pronounced downwarping of the Anadarko, Ardmore, Arkoma, and Marietta basins; and moderate subsidence of the Hugoton embayment and the Hollis basin (Fig. 1).

Pennsylvanian strata of Oklahoma are sequences of marine and nonmarine shale, sandstone, conglomerate, and limestone that thicken markedly into the rapidly subsiding basins. Thick wedges of terrigenous clastic sediments were shed from nearby uplifts; thinner carbonate sequences were deposited on shallow-water shelf areas distal to the uplifts. Successively younger Pennsylvanian units commonly overlap older units at the margins of the basins and across some of the uplifts. Thin coal beds are abundant in Desmoinesian strata, mainly in the Arkoma basin and on the Cherokee platform. Total thickness of Pennsylvanian strata in the various basins is 10,000–15,000 ft in the Anadarko, Ardmore, Arkoma, and Marietta basins and about 4,000 ft in the Hollis basin. In most of the shelf or platform areas, Pennsylvanian strata typically are 1,500–4,000 ft thick.

SEDIMENTATION

Deposition of great amounts of clastic material in Oklahoma throughout Pennsylvanian time gave rise to the many deltas preserved in the geologic column. Sources of this clastic material surrounded the two primary depositional basins of Oklahoma, the Anadarko-Ardmore and Arkoma basins. In the southern part of Oklahoma, rapid uplift of the Wichita, Arbuckle, and Ouachita Mountains shed large volumes of clastic material directly into the marine environment from the rising terrain. Meanwhile, in northern Oklahoma, the clastic material being brought in and deposited was from sources on an emergent terrain located to the northwest, north, and northeast. This clastic material was transported across large drainage

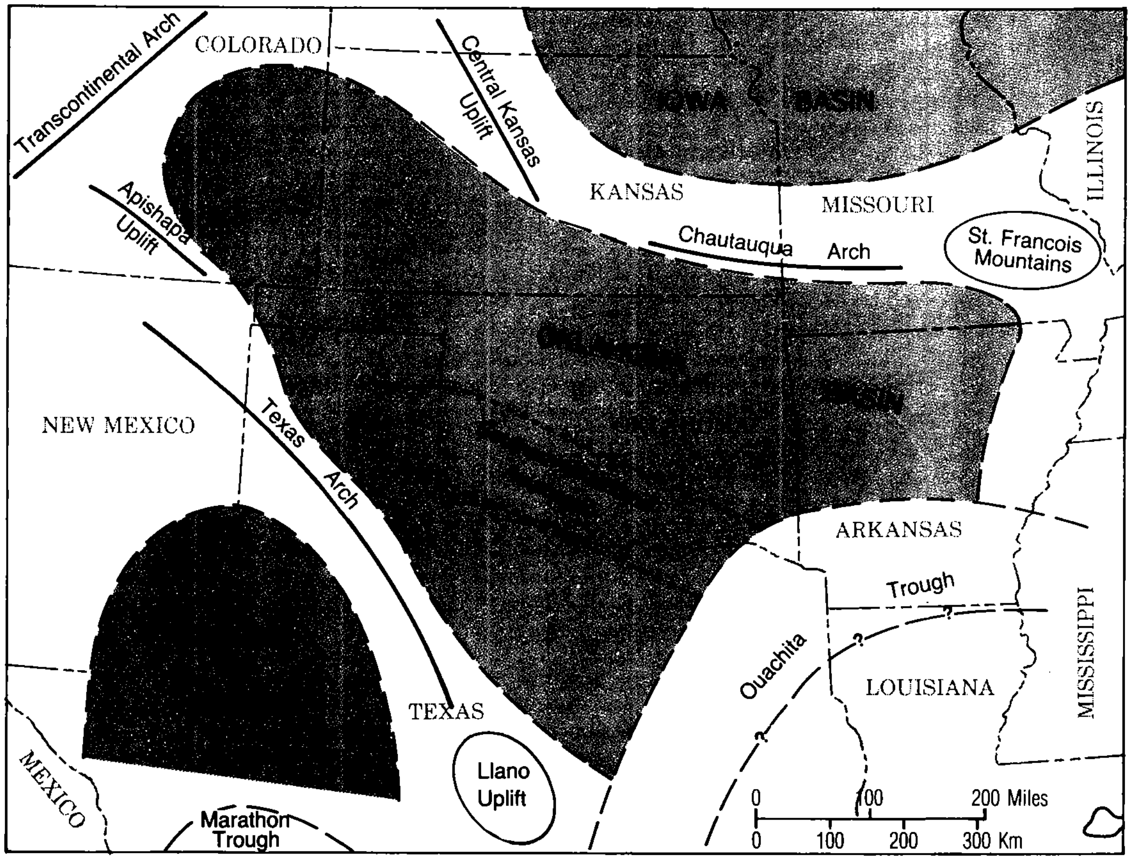

Figure 2. Map of south-central to southwestern United States, showing approximate outline of the Oklahoma basin and other major features that existed in early and middle Paleozoic time (from Johnson, 1991).

systems by fluvial processes. Deposition was at the coastal plain in deltaic environments that varied in type from tide dominated to wave dominated or to fluvial dominated, depending on the relative intensity of fluvial or marine processes.

STRATIGRAPHY

Except for parts of the Wichita, Arbuckle, Ouachita, and Ozark uplifts, Pennsylvanian strata crop out, or exist in the subsurface, in almost all parts of Oklahoma. Within the thick package of Pennsylvanian strata, which generally ranges from about 1,500 to 15,000 ft thick, are many sandstones. The deltaic-channel sandstones that are most significant (those that are major reservoirs for oil and/or gas) are shown in Figure 3.

DELTAIC RESERVOIRS

Fluvial processes dominated in most of the deltaic environments in northern Oklahoma, and that situation allowed the development and preservation of an abundance of channel sandstones. Many of these preserved channel sandstones now are oil and gas reservoirs.

Morrowan

The paleogeography of Oklahoma during Early Pennsylvanian time (Morrowan-Atokan) is shown schematically by Figure 4. During this period, sediments were being transported into the Anadarko basin of Oklahoma from emerging areas to the northwest, northeast, and south. Meanwhile, the Arkoma basin of eastern Oklahoma was receiving sediment from emerging areas to the northwest and from the Ozark uplift to the northeast.

In the Oklahoma Panhandle, the upper Morrow sandstones were interpreted by Swanson (1979) as having been deposited in a deltaic environment with preserved distributary channels occurring on the subsiding lower deltaic plain. The paleogeographic map of late Morrowan time (Fig. 5) illustrates the source areas, the postulated drainage system coalescing into a major stream on the upper deltaic plain, and the branching of the distributaries on the lower deltaic plain as they ap-

SYSTEM	SERIES	GROUP		DELTAIC-CHANNEL SANDSTONES
PENNSYLVANIAN	Virgilian	Wabunsee		
		Shawnee		Hoover Carmichael Endicott
		Douglas		Wade Tonkawa
	Missourian	Hoxbar	Lansing	Cottage Grove
			Kansas City	Layton Marchand Cleveland
	Desmoinesian	Marmaton		Peru
		Cherokee	Cabaniss	Prue (Calvin) Skinner (Allen)
			Krebs	Red Fork (Earlsboro) (Burbank) Bartlesville Booch
	Atokan	Atoka		
	Morrowan	Morrow		upper Morrow lower Morrow

Figure 3. Stratigraphic column showing age relationships of Pennsylvanian deltaic-channel sandstones in Oklahoma.

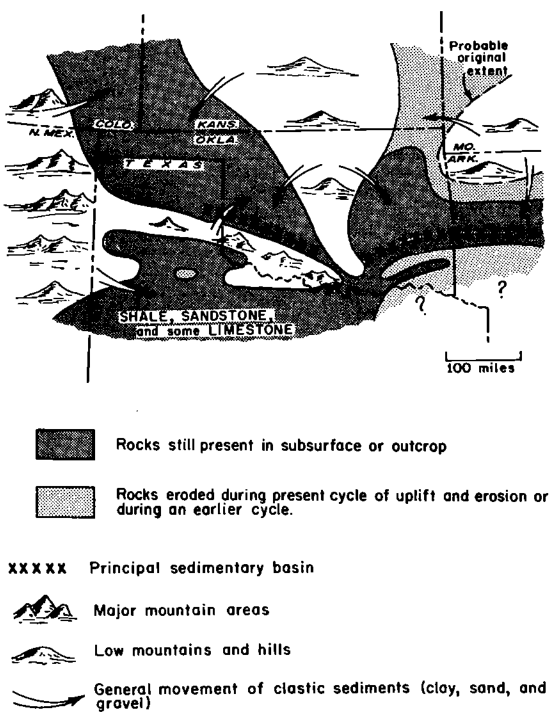

Figure 4. Early Pennsylvanian (Morrowan-Atokan) paleogeography of Oklahoma with explanation of map symbols (from Johnson, 1971). Light and dark shading shows known areas of sedimentation.

proached the sea. Subsidence on the lower deltaic plain resulted in the vertical stacking and preservation of the point-bar deposits at the delta front. Many of these channel sandstones are stratigraphic traps for oil and gas reservoirs.

Benton (1972) studied the upper Morrow sandstones in the Postle field area in Texas County, Oklahoma. One of the intervals studied included the "A-2" and "A-3" sandstones in the upper Morrow. An isopach map of the porous sandstone in this interval is shown in Figure 6. This large fluvial channel extends northwest to southeast across the study area, a distance of 21 mi. The width of this channel varies from 2 to 4 mi, and it reaches a thickness of >150 ft. Electric logs of two wells, which also were studied from core data, are shown in Figure 7. The upper Morrow "A-2" and "A-3" sandstones are identified on these logs, as are the Morrow "A" and "A-1" sandstones. The separation between these four sandstone layers is obvious in these logs; however, in other locations they do not show separation and are thought to represent continuous deposition (Benton, 1972). Where the sandstones are separated, they may have varying reservoir characteristics and trapping mechanisms resulting in inefficient recovery of the hydrocarbons. Thorough study of these sandstones is necessary to understand the architecture of the reservoirs.

Desmoinesian

During Middle Pennsylvanian (Desmoinesian) time, the paleogeography in Oklahoma shows rising highlands in the south and deposition of sediments that formed shale with sandstone, limestone, and coal in the north (Fig. 8). During early Desmoinesian time, deltaic deposition was prevalent in northern Oklahoma as clastic sediment was supplied from northern and northeastern sources. This deltaic deposition with northern source areas continued throughout deposition of sediments forming the Krebs Group. During deposition of sediments forming the Cabaniss Group, in middle Desmoinesian time, the source area changed to one in the east, and deltaic deposition expanded from northeastern Oklahoma across the Nemaha fault zone into the Anadarko basin. During deposition of sediments forming the Marmaton Group, in late Desmoinesian time, the supply of clastic material into the system diminished, and limestone deposition prevailed.

Booch Delta

Busch (1959) presented his study covering an area of >2,000 sq mi, which is part of the large deltaic system in the Booch sandstone, as part of his ongoing characterization of stratigraphic traps. From his work, the Booch delta has become a classic example of an elongate, fluvial-dominated delta. An isopach map of Booch sandstone (Fig. 9) shows a generalized deltaic distributary system extending toward the Arkoma basin in the south, beyond the indicated line of flexure. Major distributary channels have sandstone thicknesses of >120 ft. Many of the distributary-channel sandstones in this Booch delta system form the stratigraphic traps of oil and gas that abound on the distal part of the delta. Oil and gas production

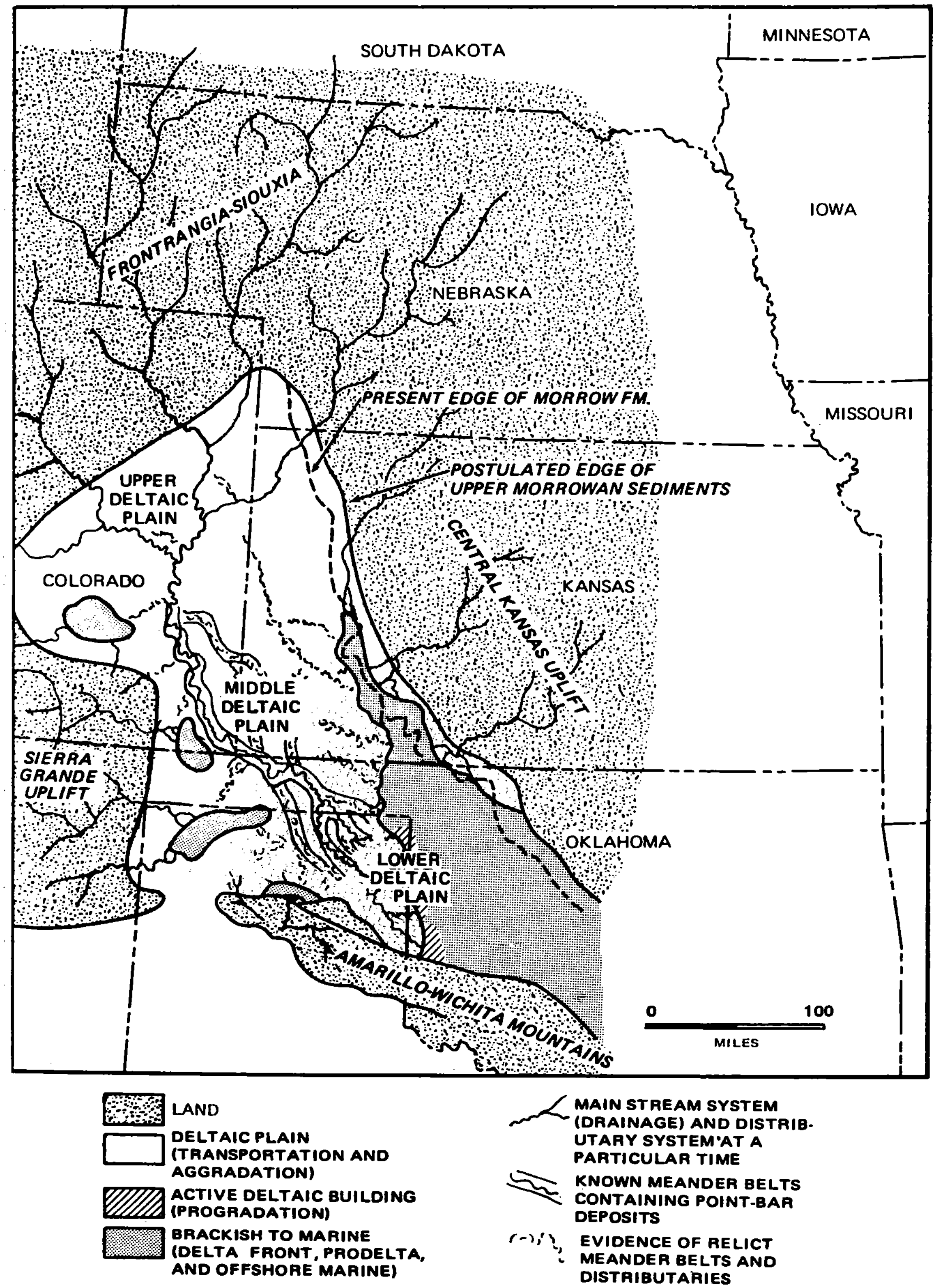

Figure 5. Paleogeographic map of the Midcontinent during late Morrowan time (from Swanson, 1979).

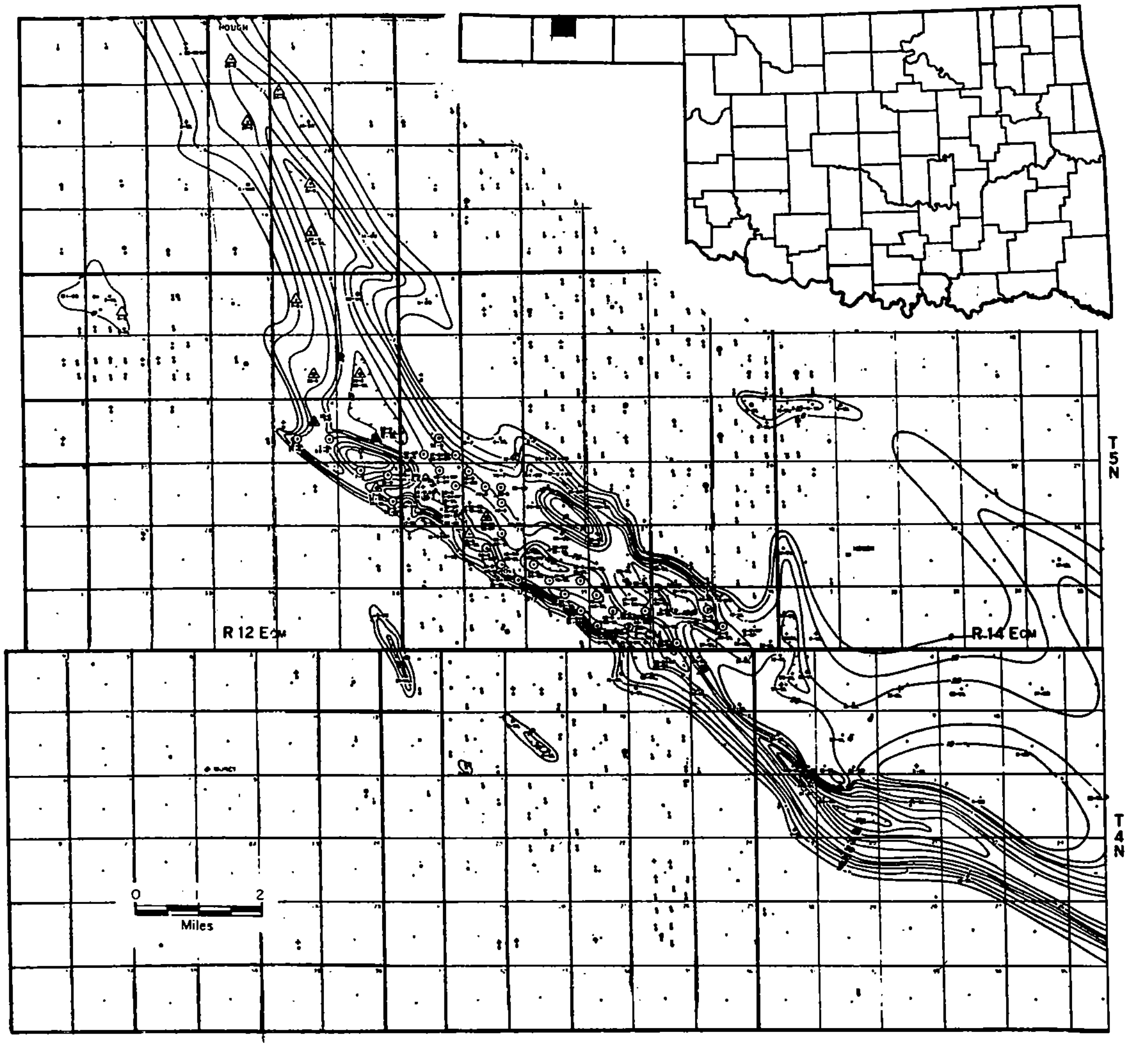

Figure 6. Isopach map of the porous "A-2" plus "A-3" Morrow Group sandstones in the Postle field area, Texas County, Oklahoma. Contour interval is 10 ft (up to 50 ft) and 25 ft (above 50 ft) (from Benton, 1972).

from the Booch sandstone was established as early as 1904 in the Okmulgee area. These oil and gas traps generally are found in sandstones that are <120 ft thick, but they do occur in the thick, major distributary channels. To characterize the Booch sandstone, Busch presented a structure map (Fig. 10) showing the oil pools and their postulated extensions in a 6 mi × 6 mi area. This map illustrates the sinuous character of the 20–60-ft-thick channel sandstones and the minor relationship to structural position in these stratigraphic traps.

Bartlesville Delta

Since the discovery of oil in the Bartlesville sandstone at Bartlesville, Oklahoma, in 1897, a large area (>9,000 mi^2) of these thick sandstones in northern Oklahoma has been studied for many years. A report on regional studies of this extensive, elongate, fluvial-dominated deltaic system was presented by Visher and others (1971). Figure 11 shows the distribution of the Bartlesville sandstone in northeastern Oklahoma, from the sandstone limit on the west to the outcrop area on the east. The map indicates the source area was in the north and shows the deposition of sandstone beds, up to 200 ft thick, in the major distributaries on the lower deltaic plain. Outcrop areas of Bluejacket Sandstone, equivalent to the subsurface Bartlesville sandstone, are shown on the east. The oil fields producing from the Bartlesville sandstone are shown in Figure 12. These oil fields are stratigraphic traps, with the oil trapped at the updip pinchout of sandstone. The structural dip, from northeast toward the south and southwest,

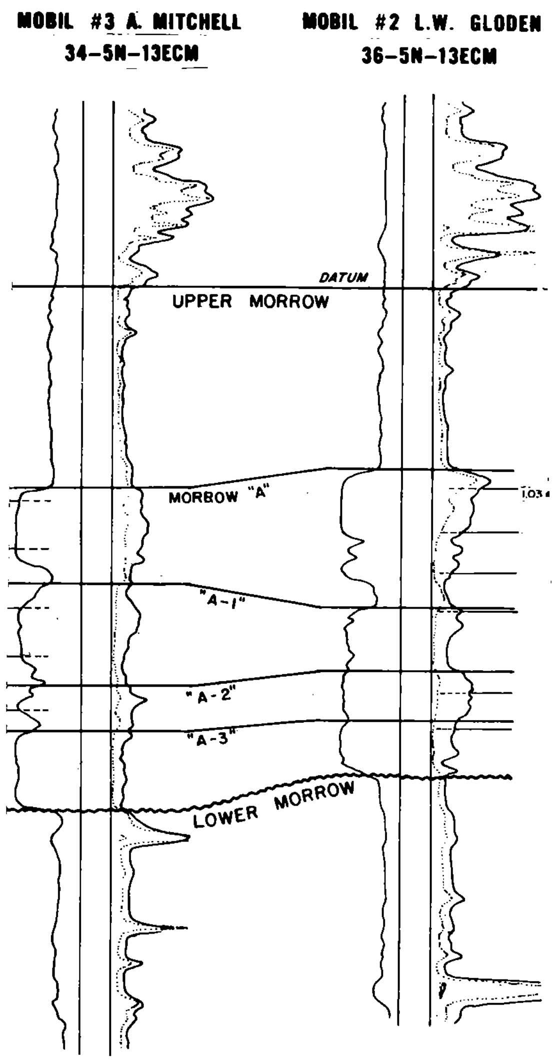

Figure 7. Electric logs of two wells showing intervals of upper Morrow Group sandstones (after Benton, 1972).

localizes the traps. Structural closure is not necessary to create these traps. The Bartlesville sandstone is a prolific oil producer, having yielded more than 1.5 billion barrels of oil through 1971 (Visher and others, 1971). The Bartlesville sandstone oil reservoirs also are desirable for secondary-recovery projects because of their shallow depth and high recoveries during water flooding.

Red Fork Delta

Fluvial and distributary-channel sandstones in the Krebs Group were extensively developed in early Desmoinesian time as part of the progradational sequences deposited in the large Red Fork delta system. This fluvial-dominated delta covered most of the northern shelf area of central Oklahoma, with deposition extending into the Arkoma and Anadarko basins. Marine processes tended to dominate the distal portion of the delta, with many of the delta-front sands being reworked during stillstand or transgressive phases. Figure 13 shows the general extent of the Red Fork sandstone formed in this delta system and submarine-fan basinal deposition in the Anadarko basin to the southwest.

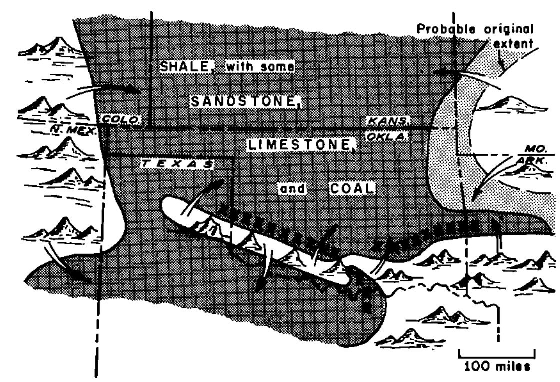

Figure 8. Middle Pennsylvanian (Desmoinesian) paleogeography of Oklahoma (from Johnson, 1971). See Figure 4 for map symbols.

Zeliff's (1976) study of the "Cherokee" sandstones in northern Kingfisher County, Oklahoma, gives an example of a fluvial channel cutting into earlier deposits on the upper portion of the Red Fork delta. The best depiction of this channel is the isopach map of the lower Red Fork genetic increment of strata (GIS) that shows the scour of the channel at its deepest part (Fig. 14). This channel is more than 43 mi long and is mostly located in the Sooner Trend; the channel is not completely filled with sandstone throughout this distance; but, where there is sandstone, it is an oil and gas reservoir. Thickness of this channel sandstone is up to 40 ft.

Delta systems also make up the Skinner and Prue sandstones of the Cabaniss Group (middle Desmoinesian). These deltaic sequences are located in northern and central Oklahoma and received most of their sediment from the east. Deposition of the sand that formed the Skinner sandstone spread across the Cherokee platform onto the Anadarko shelf to the west where channel sandstones are recognized (Zeliff, 1976). Deposition in northeasternmost Oklahoma formed a minor delta (Peru sandstone) in the Marmaton Group (late Desmoinesian).

Missourian

During the Missourian Epoch, clastic sediment was supplied from the east and southeast into the Anadarko basin (Figs. 15, 16). A sequence of deltas was formed across northeastern Oklahoma and in the southeastern Anadarko basin.

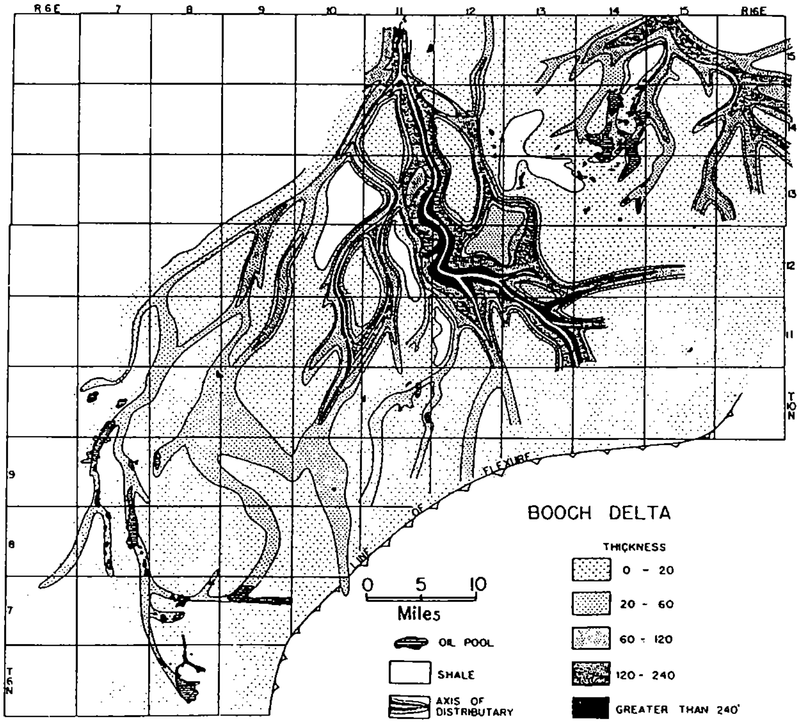

Figure 9. Isopach map of Booch sandstone in eastern Oklahoma; thickness in feet (from Busch, 1959).

Marchand Channel Sandstone

Baker (1979) recognized a Marchand channel sandstone in the NE Binger field in Caddo County, Oklahoma, with a course that trended south to north (Fig. 17). This channel extends over 6 mi long and is about 1 mi wide. Sandstone thickness is up to 25 ft. This stratigraphic trap is an oil reservoir sealed by lateral facies changes and permeability variations within the sandstone. Other deltaic systems with channel sandstones recognized in the Missourian rocks of Oklahoma are the Cleveland, Layton, "Osage" Layton, and Cottage Grove sandstones.

Virgilian

Endicott Delta

In Ellis and Woodward Counties of northwestern Oklahoma, a system of deltaic distributary channels illustrated by Busch (1971) is shown in Figure 18. These coalescing distributary channels, with their sediment source to the north, contain sandstones up to 200 ft thick. These channel sandstones have good reservoir characteristics, but because they have no apparent updip seal or structural trapping mechanism, they do not produce oil or gas.

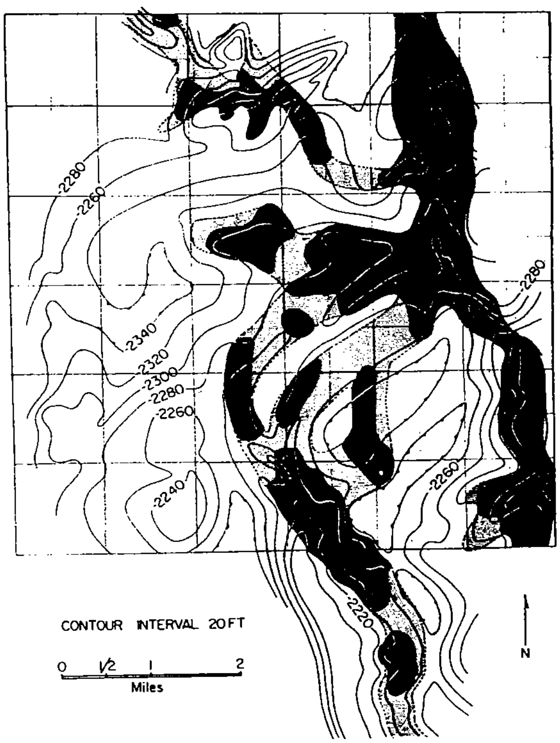

Figure 10. Structure map of Booch sandstone in T. 8 N., R. 7 E., showing oil pools (black) and postulated extensions of oil pools (gray) (from Busch, 1959).

CONCLUSIONS

Channel sandstones originating in deltaic environments occur throughout the Pennsylvanian System in Oklahoma. They have been, and still are, viable exploration targets. Many of them have not been sufficiently explored or developed and they merit additional study. Where lateral and updip seals exist, these reservoirs form stratigraphic traps that have been successfully water flooded. Undoubtedly, more opportunities are present to develop other water-flooding projects or to improve on those projects that have been attempted but were unsuccessful, perhaps because of a lack of understanding of the architecture of the reservoirs. The reader is encouraged to study other articles in this volume that present specific data on many of these reservoirs.

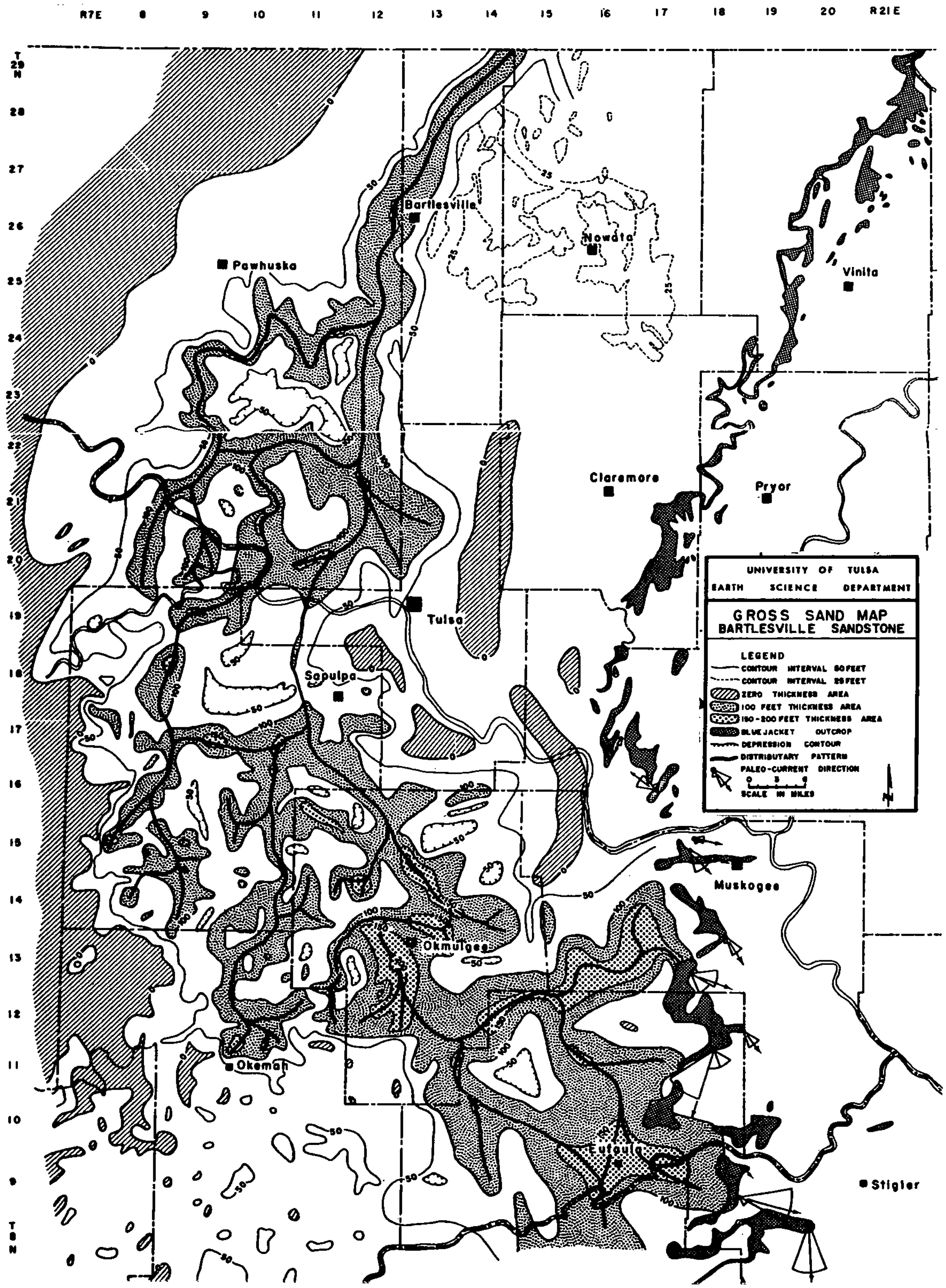

Figure 11. Map of gross sandstone thickness of the Bartlesville sandstone in northern Oklahoma showing the western limit, distributary patterns, sandstone thickness, and eastern outcrop area of the Bartlesville (Bluejacket Sandstone) in northeastern Oklahoma (from Visher and others, 1971).

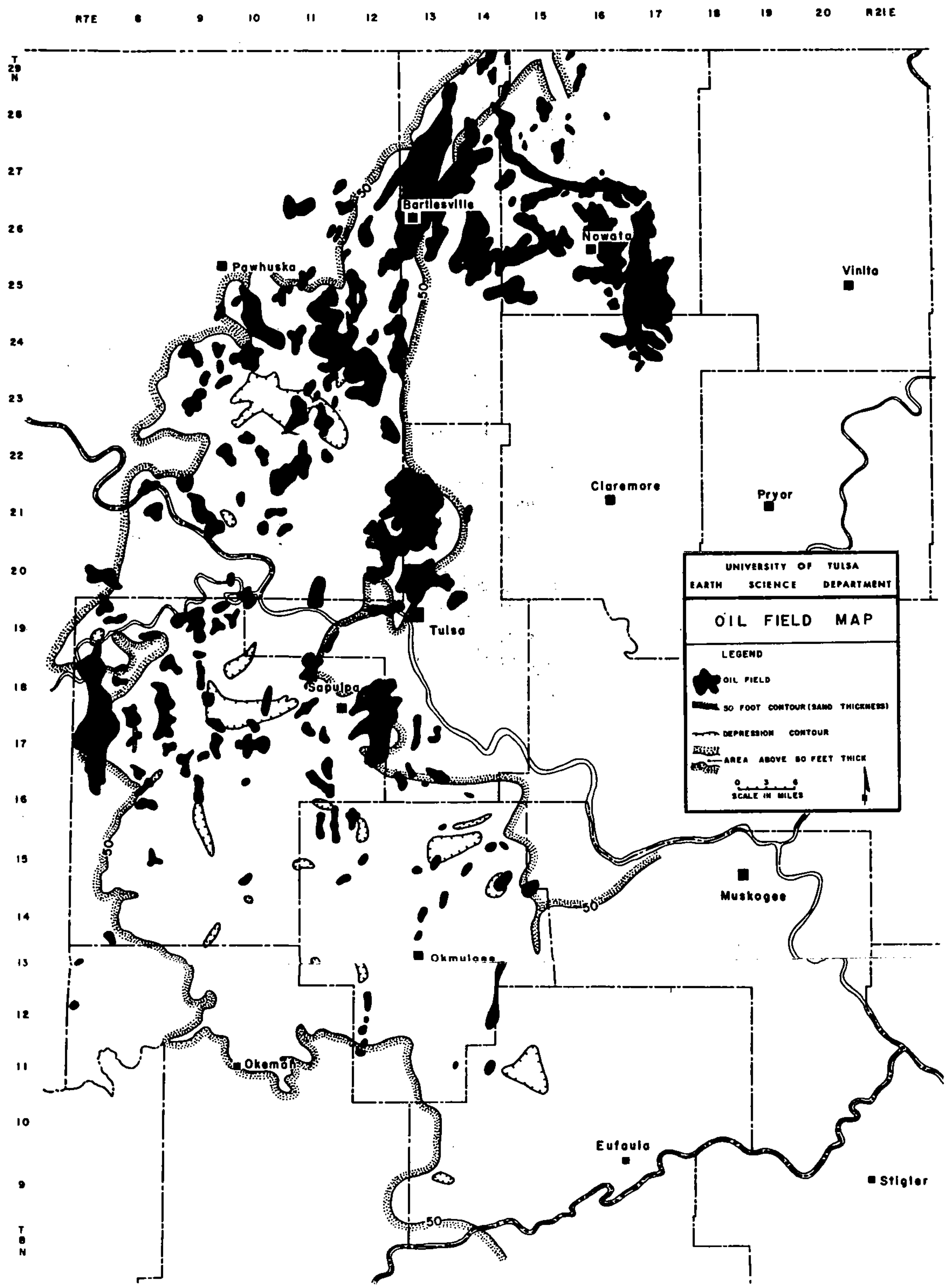

Figure 12. Distribution of oil fields producing from the Bartlesville sandstone. Pattern shows concentration of oil at updip pinchout of sandstone. Combination of structural dip and sandstone distribution is basis for individual accumulations (from Visher and others, 1971).

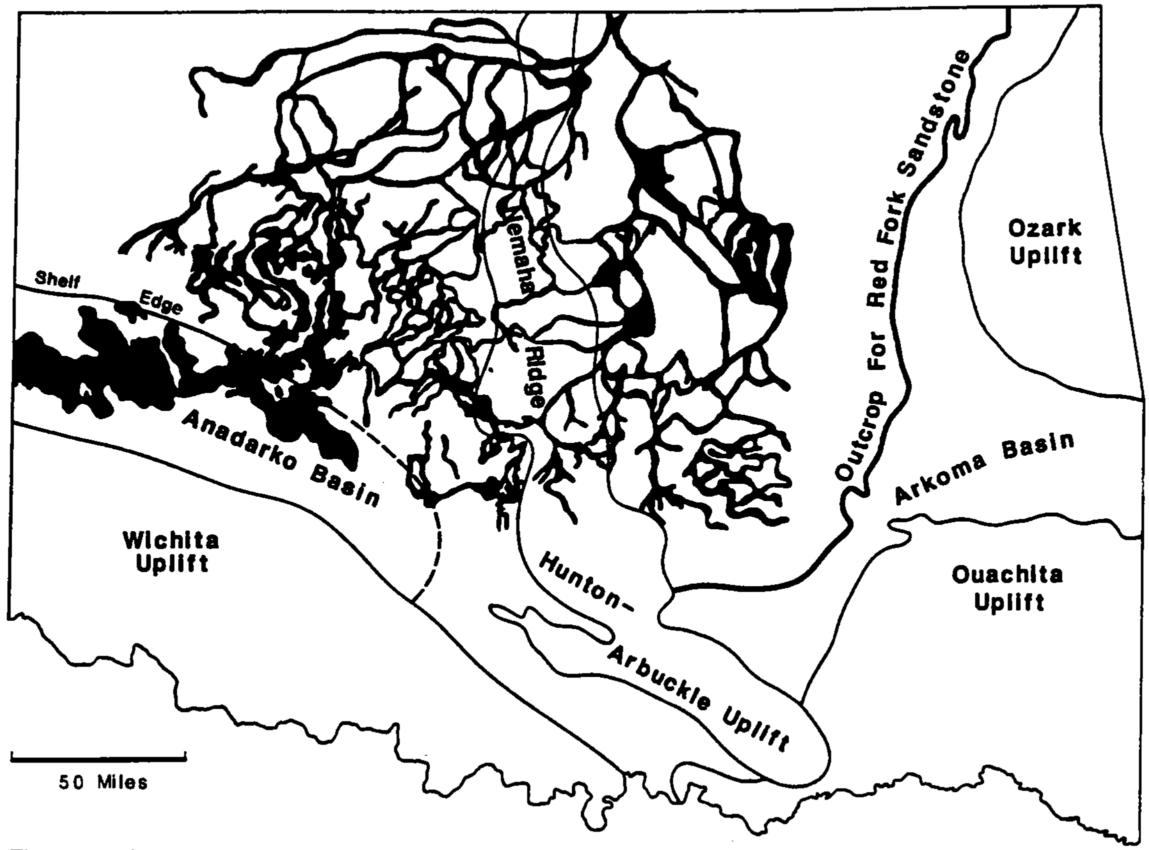

Figure 13. General extent of Red Fork sandstone, showing distribution of major sandstone bodies in northern Oklahoma (from Al Shaieb and others, 1989).

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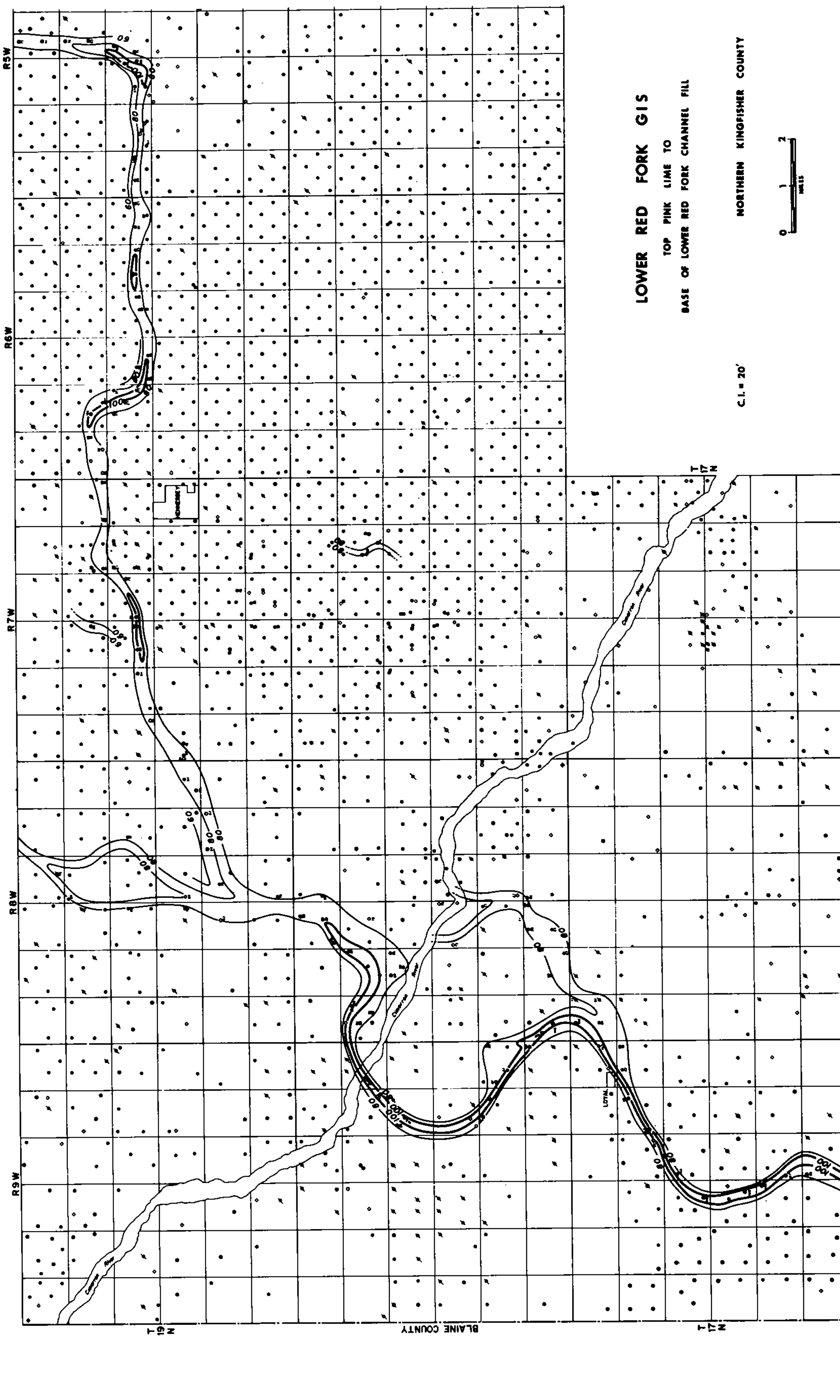

Figure 14. Isopach map of the lower Red Fork genetic increment of strata (GIS) in Kingfisher County, Oklahoma. Interval is from the top of the Pink lime to the base of the lower Red Fork channel fill. Contour interval is 20 ft (from Zeliff, 1976).

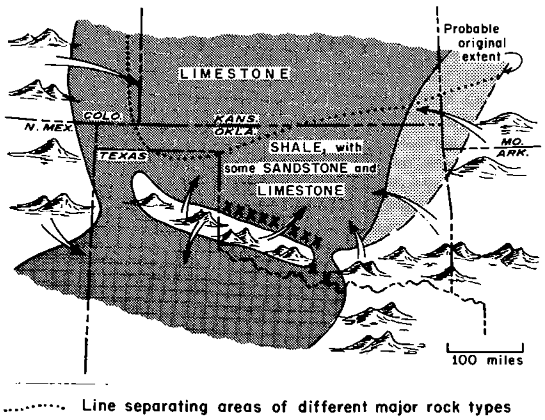

Figure 15. Late Pennsylvanian (Missourian-Virgilian) paleogeography of Oklahoma (from Johnson, 1971). See Figure 4 for map symbols.

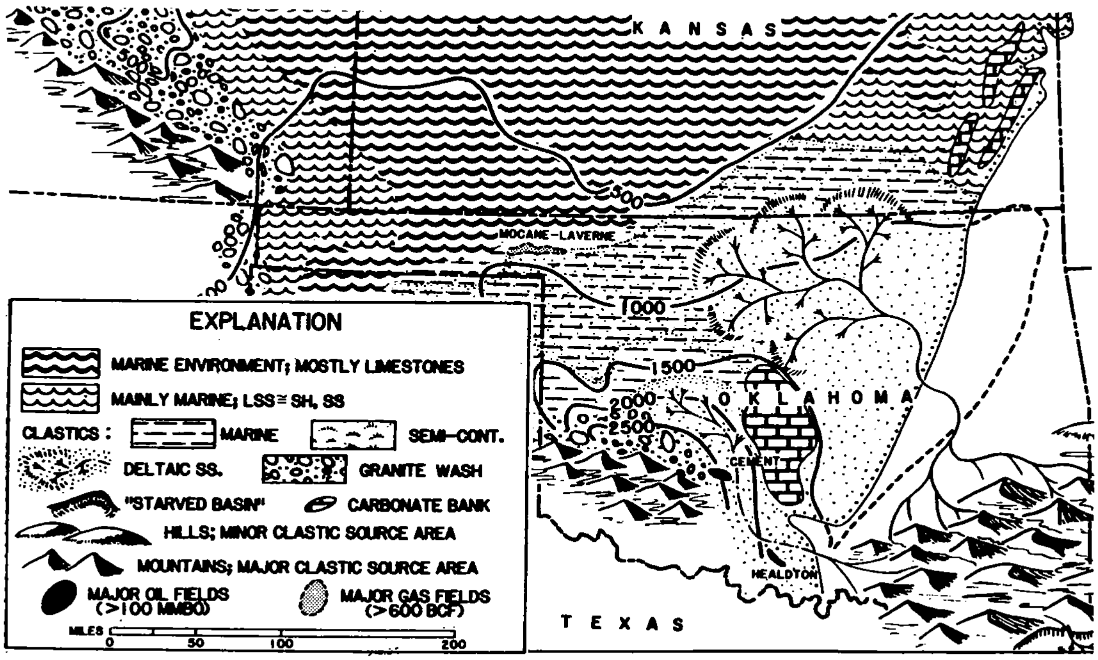

Figure 16. Paleogeography of the southern Midcontinent during the Missourian Epoch and isopachs of Missourian rocks (after Rascoe and Adler, 1983). Several major oil and gas fields are shown.

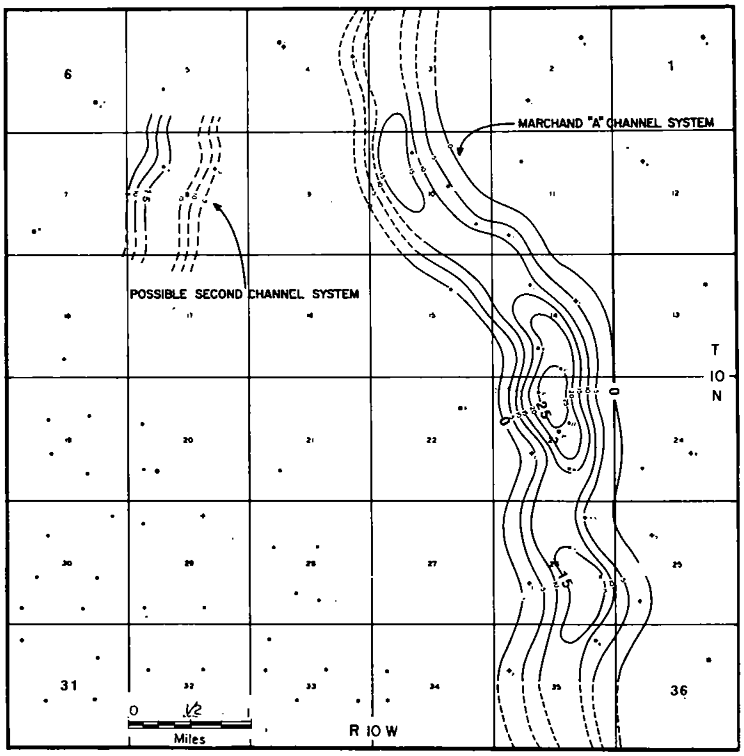

Figure 17. Isopach map of the Marchand "A" channel system, NE Binger field, Caddo County, Oklahoma. Contour interval is 5 ft (from Baker, 1979).

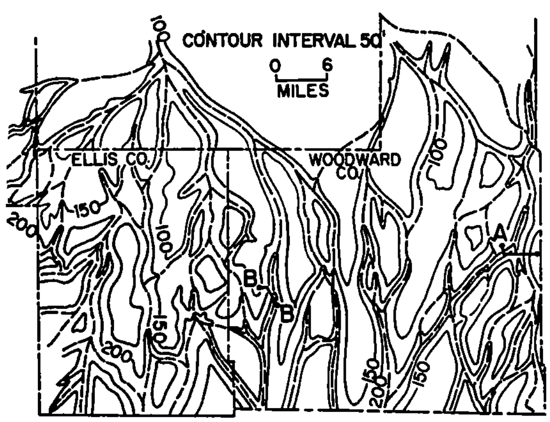

Figure 18. Isopach map of genetic increment of strata (GIS) between the top of the Oread limestone and base of the Endicott sandstone, northwestern Oklahoma. Contour interval is 50 ft (from Busch, 1971).

The Importance of Fluvial-Deltaic Processes and Their Role in Basin Filling

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Swanson and Associates
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ABSTRACT.—Thick intervals and large volumes of land-derived clastic deposits are evidence of the importance of fluvial-deltaic processes. For many years, fluvial deposits were ignored while geologists devoted much effort to "offshore bars" and "barrier islands." Now fluvial and "fluvial-deltaic" deposits are popular as geologists realize that even the strongest marine currents and tides in interdeltaic shallow-marine environments could not account for the large volume of clastic particles filling some basins.

Concentration of coarse clastic sediments into reservoir deposits further enhances the importance of the fluvial-deltaic continuum and contributes to the fact that fluvial-deltaic deposits are the Midcontinent's most important hydrocarbon reservoirs. The size, shape, lateral distribution, location, and internal character of these reservoirs depend upon processes about which much empirical data have accumulated. This information can be used to improve reservoir characterization and prediction.

Swanson, D. C., 1996, The importance of fluvial-deltaic processes and their role in basin filling, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 46.

The Upper Morrow Reserviors: Complex Fluvio-Deltaic Depositional Systems

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Oklahoma State University
Stillwater, Oklahoma

ABSTRACT.—Clastic reservoir rocks in the upper part of the Morrowan Series of the Anadarko basin were deposited within two distinct depositional settings: (1) a system of southward-flowing fluvial-dominated tracts on the northwestern part of the Anadarko shelf and (2) a system of northward-prograding fan-delta complexes adjacent to the Wichita-Amarillo uplift. Quartz arenite, sublitharenite, and subarkose are the dominant rock types that resulted from the northwestern shelf system. Sediments deposited in the Wichita system channels were derived primarily from sedimentary and igneous rocks exposed and eroded during the Wichita orogeny; chert litharenite is the dominant Wichita system rock type, but feldspathic litharenite and lithic arkose are also common.

Late Morrowan sea-level fluctuations strongly influenced the depositional facies of the northwestern shelf. Channels were incised into shelf muds during sea-level lowstands. These channels were filled with predominantly fluvial, estuarine, and flood-plain sediments during sea-level rises. Marine muds blanketed the valley-filling deposits during the major highstands. The complex depositional pattern and the resultant diverse lithologies are the main factors influencing the heterogeneity of the resulting reservoirs. Reservoir quality and preservation of primary porosity and/or evolution of secondary porosity may be attributed directly to the depositional style within these channels.

On the other hand, the chert-conglomerate reservoirs of the Wichita system are predominantly linear channel-fill deposits. Grain sizes, sedimentary structures, and the elongate geometry of most chert reservoirs suggest that they were deposited in northward-flowing braided streams.

INTRODUCTION

Sandstones and conglomerates of late Morrowan age are prominent oil and gas reservoirs in the Anadarko basin and the Hugoton embayment in Oklahoma, Texas, and Kansas. The late Morrowan depositional systems in the southern part of the Anadarko basin and the northwestern shelf (Hugoton embayment) are the major focus of this study (Fig. 1). In this area in late Morrowan time, sediments were deposited in two entirely different depositional settings: a southward-flowing fluvial system along the northwestern shelf—referred to as the shelf system—and a northward-prograding fluvial-deltaic complex adjacent to the Wichita uplift—referred to as the Wichita system (Fig. 2).

The northwestern shelf system yielded sequences of predominantly channel-fill reservoirs encased in shallow-marine shales. These channels were cut into the underlying rocks during sea-level lowstands. However, during sea-level rises, these channels were filled with fluvial and estuarine sediments. Periodic sea-level fluctuations were manifested by the formation of transgressive/regressive depositional sequences. Each sequence is bounded by erosional surfaces that reflect lowstand (regressive) conditions.

The Wichita depositional system yielded a complex of fluvial valley-fill and fan-deltaic deposits. The rocks are primarily chert and/or arkosic arenites and conglomerate. The erosion of sedimentary and igneous rocks from the Wichita uplift determined the types and volumes of coarse clastic sediments contributed to the northward-flowing braided-stream systems.

REGIONAL SETTING

The project area (Fig. 1) covers part of the deeper Anadarko basin in southwestern Oklahoma and most of the basin's northwestern shelf in the Texas and Oklahoma Panhandles. The basin is bounded to the south and west by the Wichita-Amarillo

Puckette, J.; Abdalla, A.; Rice, A.; and Al-Shaieb, Z., 1996, The Upper Morrow reservoirs: complex fluvio-deltaic depositional systems, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 47–84.

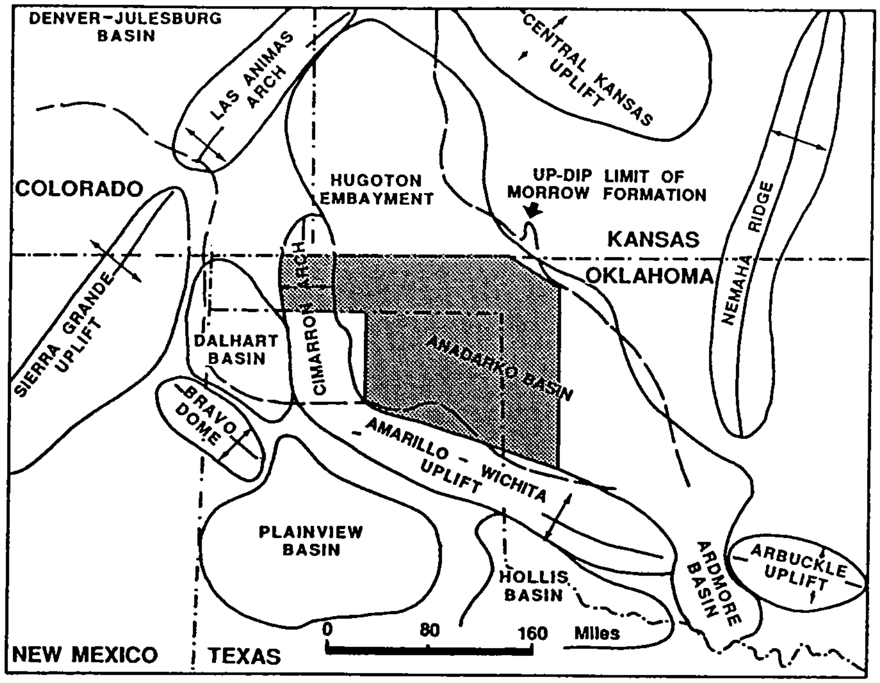


Figure 1. Study area in southwestern Anadarko basin and Hugoton embayment (after Khaiwka, 1968).

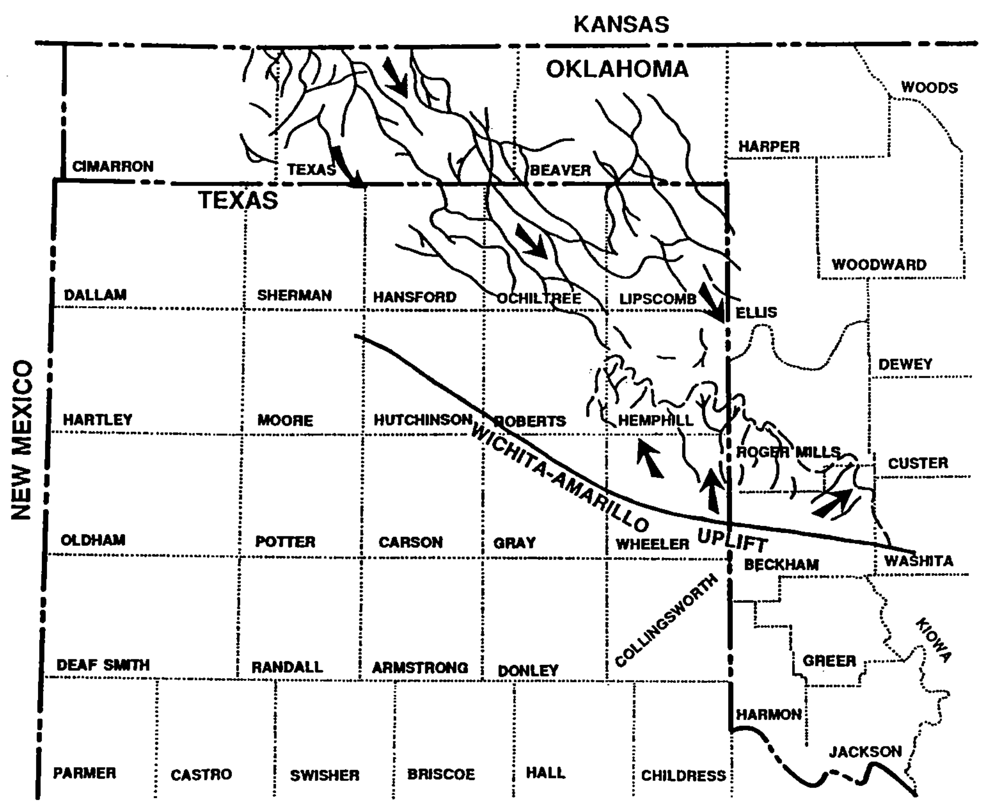


Figure 2. Trends of the major depositional systems during late Morrowan time. Arrows indicate paleodrainage flow directions.

uplift and the Cimarron arch. The northern boundaries of the basin (including the Hugoton embayment) are the Central Kansas uplift and the Las Animas arch. The eastern boundary of the basin is the Nemaha ridge. The basin is highly asymmetrical owing to periods of rapid subsidence and faulting associated with the Pennsylvanian orogeny.

Figure 3 shows the paleogeography during late Morrowan time. Positive elements include the Apishapa–Sierra Grande uplift to the west, Ancestral Front Range and Transcontinental arch to the north, and the Wichita-Amarillo uplift to the south. Central Kansas was a low-relief positive area northeast of the basin (Sonnenberg and others, 1990). These features influenced Morrowan depositional style and provided sources for sediments.

STRATIGRAPHY

The Morrowan Series is defined as the interval between the base of the Atokan "Thirteen Finger limestone" and the top of the pre-Pennsylvanian unconformity. The rocks of Morrowan age are divided into commonly accepted rock-stratigraphic units, the lower and upper Morrow. Within the deep basin, the "Squaw Belly limestone" is used as a marker bed to separate the upper and lower Morrow intervals. In the Oklahoma Panhandle, the division of rocks of Morrowan age into upper and lower intervals is commonly made at the top of the more resistant (calcareous) shale interval (Fig. 4).

The lower Morrow rocks of the northwestern shelf consist primarily of marine sandstones that were deposited on the eroded Mississippian topog-

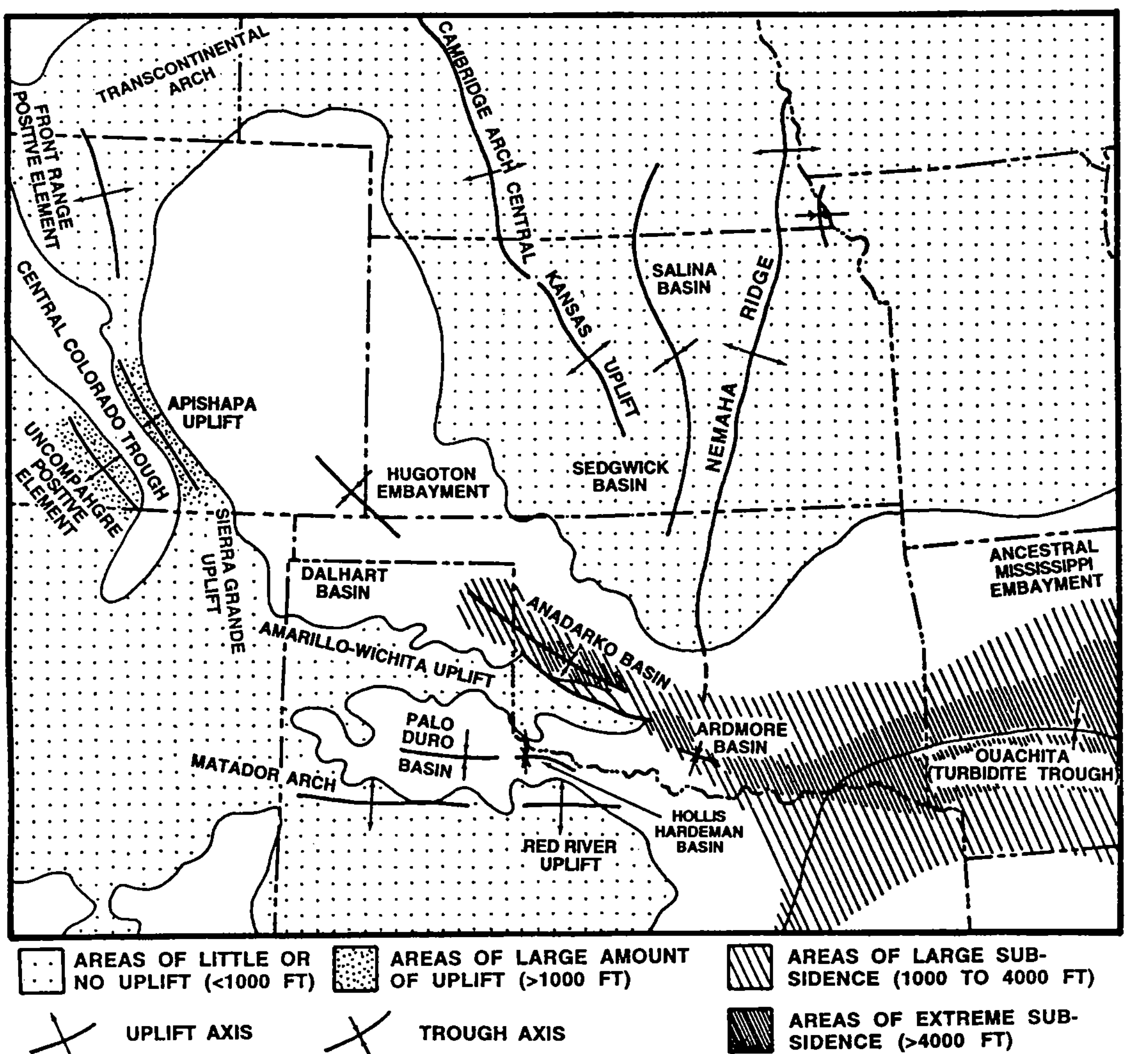


Figure 3. Paleogeography and structural features during Morrowan time (Sonnenberg and others, 1990).

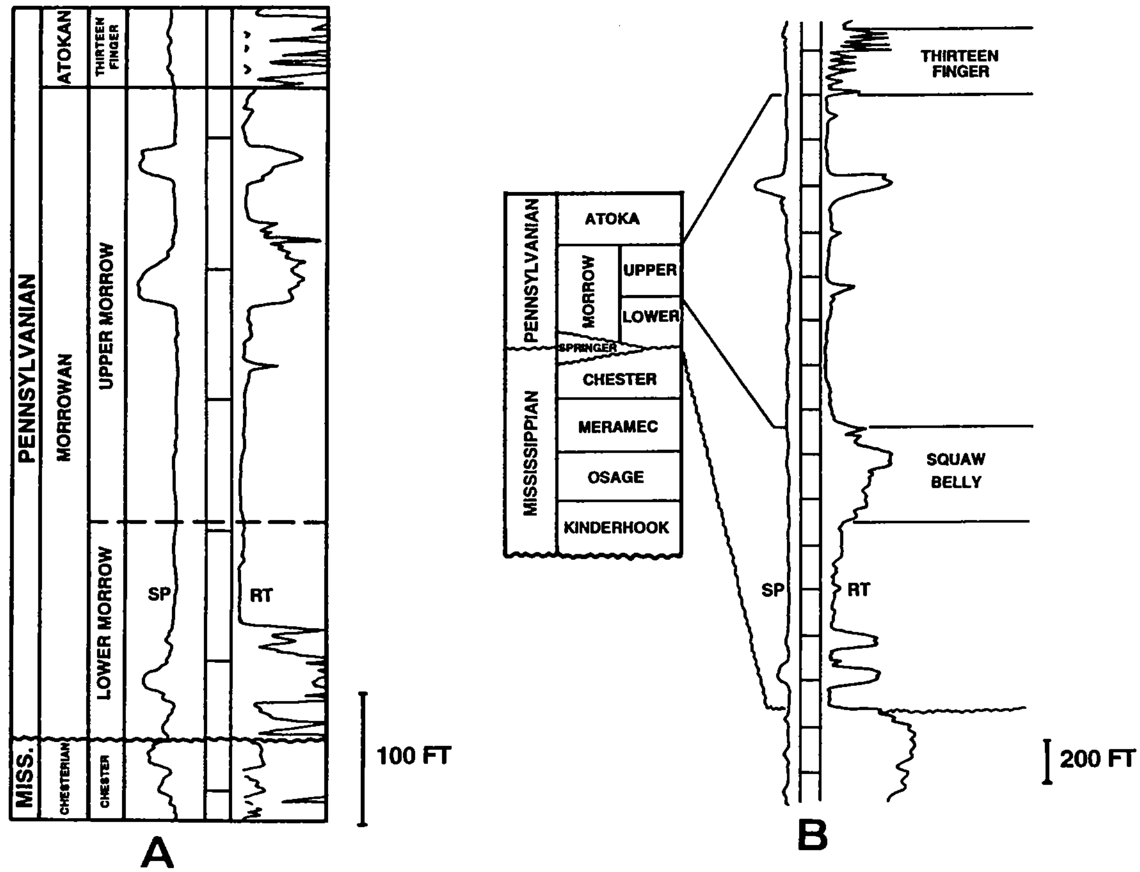


Figure 4. Morrowan stratigraphy showing informal stratigraphic divisions. (A) Panhandle region of Oklahoma (Cornish, 1984). (B) Deep basin (after Shelby, 1980). SP = spontaneous potential, RT = short normal resistivity.

raphy. The basal sandstones represent a variety of depositional facies including shoreface (Wheeler and others, 1990) and transgressive valley-fill sandstones (Gerken, 1992).

The upper Morrow facies were strongly influenced by the Pennsylvanian orogeny. Detritus shed from the Wichita-Amarillo uplift was deposited along the southern and western margins of the basin. Marine and fluvial rocks were the dominant deposits in the northwestern shelf system.

DEPOSITIONAL SETTING

The upper Morrow is a sequence of thick (marine) shales that encase sandstones. The shale-dominated interval thickens from ~200 ft in the Oklahoma Panhandle to ~3,000 ft close to the axis of the Anadarko basin (Figs. 5,6). The upper Morrow was deposited on a very low angle slope of ~1 ft/mi. Stream gradients determined from upper Morrow channel fills range from about 0.4 to 0.9 ft/mi (Cornish, 1984) to <2.5 ft/mi (Swanson, 1979). The flat-lying shelf topography was susceptible to inundation and subaerial exposure as sea level fluctuated.

The upper Morrow rocks along the southern margin of the basin are a clastic-dominated sequence that was derived from the Wichita uplift. These conglomerates and sandstones formed in response to rapid basin subsidence and mountain uplift associated with the Early Pennsylvanian orogeny. Tectonism was the major factor that influenced sedimentation rates and the spatial distribution of upper Morrow facies.

PREVIOUS INTERPRETATIONS

Regional studies that describe Morrowan paleotectonic settings, stratigraphy, and depositional history and facies have been published by Rascoe and Adler (1983), Forgotson and others (1966) Swanson (1979), Sonnenberg and others (1990), and Wheeler and others (1990). Numerous field studies are available in the literature including Arro (1965), Benton (1971), Munson (1989), Shelby

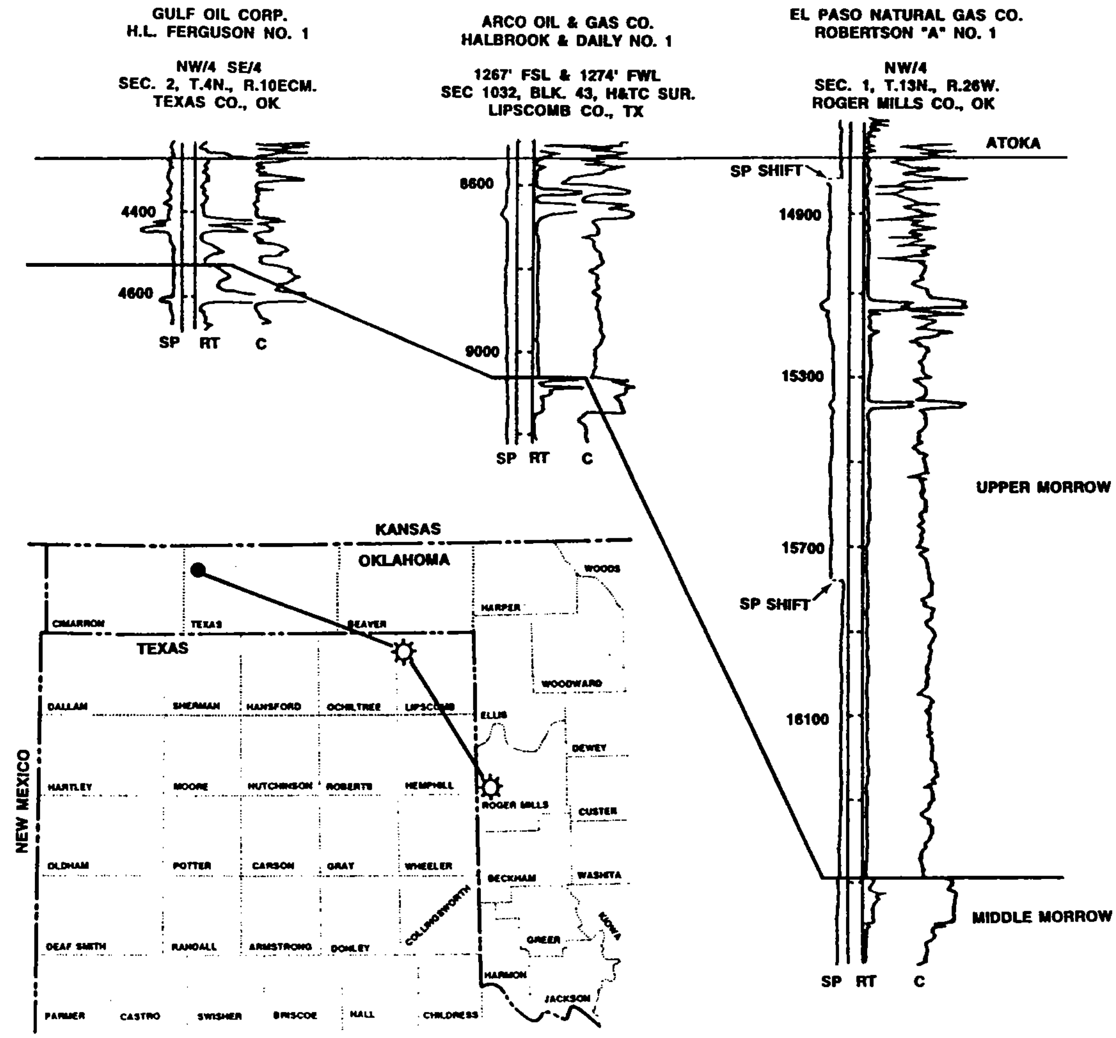


Figure 5. Cross section extending from Texas County, Oklahoma, to Roger Mills County, Oklahoma, depicting the basinward thickening of the upper Morrow interval.

(1980), Cornish (1984), Hawthorne (1984), Sonnenberg (1985), Alberta (1987), Harrison (1990), Bowen and others (1990), and Sonnenberg and others (1990).

Benton (1971) studied the rocks of the Morrowan Series in the Postle field (T. 5 N., R. 13 E. CM, Texas County, Oklahoma) and concluded that the upper Morrow sandstones were deposited within a fluvial system that eroded Morrowan paleotopography. Swanson (1979) conducted a comprehensive regional study of the upper Morrow rocks in the Anadarko basin and western Midcontinent. He proposed that deltaic processes controlled their deposition. Studies by Krystinik and Blakeney (1990), Sonnenberg (1990), and Wheeler and others (1990) in eastern Colorado and western Kansas concluded that the upper Morrow reservoirs are basically valley-fill deposits. Krystinik and Blakeney (1990) indicated that at least seven episodes of incision and valley-fill occurred. Sonnenberg and others (1990) showed that (1) Morrowan sedimentation was controlled by regional tectonism and eustatic sea-level changes and (2) most sandstone reservoirs are fluvial valley-fill deposits.

Shelby (1980), Alberta (1987), Johnson (1989), and Al-Shaieb and others (1989) characterized the chert-conglomerate reservoirs as alluvial-fan and fan-delta deposits. Al-Shaieb and others (1993) suggested that some reservoirs represented braid-delta and incised-valley-fill deposits and also indicated that sea-level fluctuation related to tectonism or eustasy had greatly influenced their deposition.

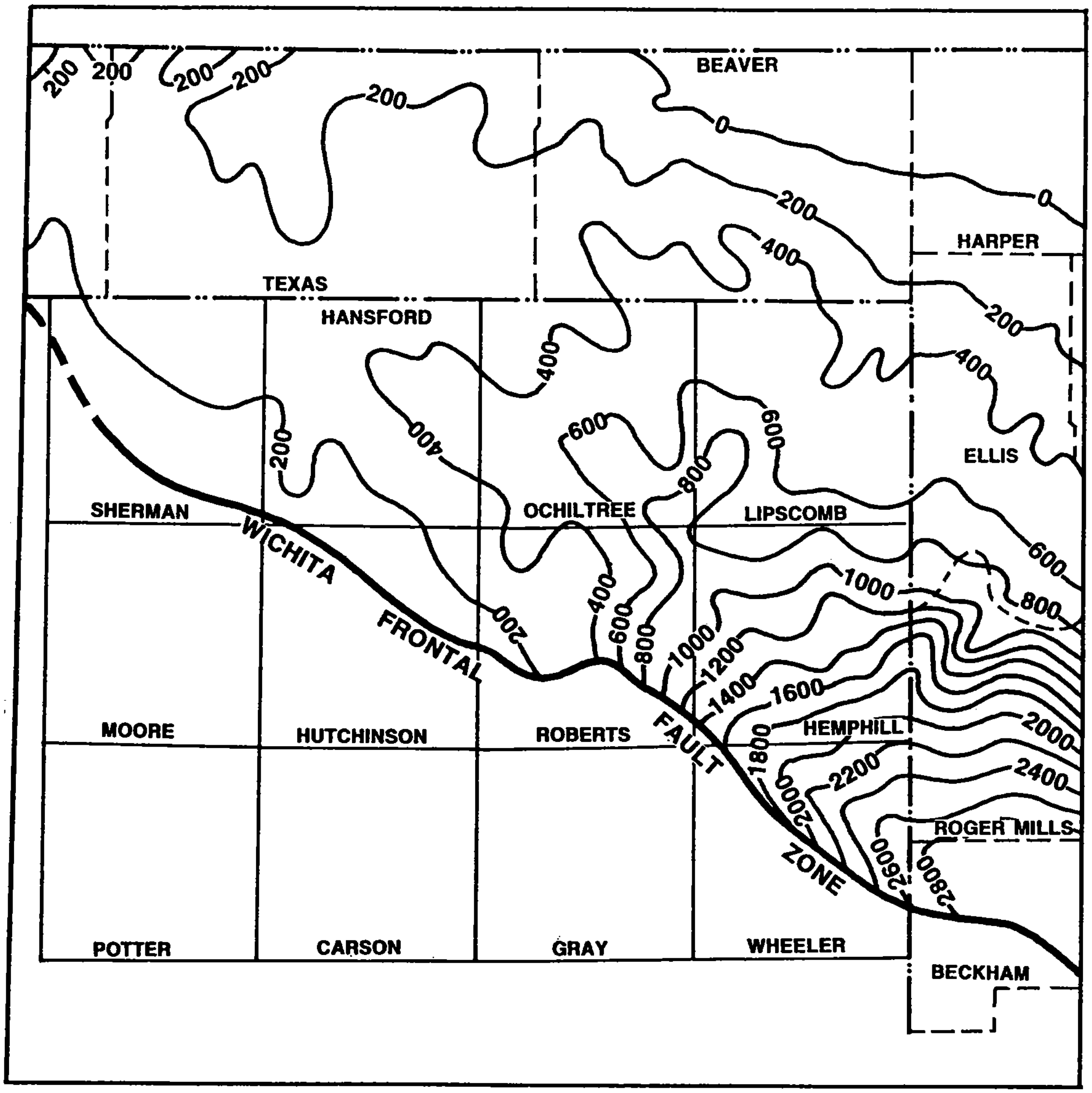


Figure 6. Thickness map of the upper Morrow interval in western Oklahoma and the Texas and Oklahoma Panhandles.

SEDIMENTOLOGY AND DEPOSITIONAL FACIES

Determination of depositional environments requires the integration of all types of available geologic data. Often, inferences are made solely on features such as geometry, log signatures, or grain size. Although diagnostic autochthonous features such as soils or fossils are solid and direct evidence, other features are less conclusive and require specific integration and interpretation within the geologic setting. Pennsylvanian sandstones of the Midcontinent have often been interpreted as analogues to modern depositional systems such as the Mississippi River delta. With the wide acceptance of sequence stratigraphy and eustatic sea-level changes, it is important that sandstones be interpreted by using an integrated approach that considers not only the geometry and internal features of the sandstone, but also addresses its context within surrounding genetically related strata.

Some of the past interpretations of upper Morrow rocks have been based on sparse, nonintegrated data. In other cases, the proposed interpretations were the best that were possible with the available data. As additional data became available, sedimentological models were improved.

Sedimentological Interpretations: Northwestern Shelf Example

Because the Hough area (T. 4–6 N., R. 12–14 E. CM, Texas County, Oklahoma) has been the focus of several investigations, it is used to illustrate the evolution of sedimentological interpretations. Arro (1965) suggested that the uppermost upper Morrow sandstones contain wave-sorted "bar" and "sheet" components. Benton (1971) examined 135 wire-line logs of the same sandstones and concluded that the upper Morrow sandstones were deposited in fluvial environments. Benton (1971) indicated that the linear sandstone trend of the lowermost upper Morrow sandstone (fig. 15 in Benton, 1971) was composed of fining-upward conglomerate-sandstone sequences of fluvial origin that filled a deeply cut channel (Fig. 7).

Swanson (1979) examined the Hough and Postle areas and indicated that the linear lowermost upper Morrow sandstone (fig. 25 in Swanson, 1979) was a prograding stream mouth-bar deposit. His interpretation was based on a variety of geologic data including sandstone geometry and spatial distribution, log signatures, and core data. However, it appears that his interpretation relied heavily on the use of spontaneous-potential (SP) log signatures to estimate textural (grain size) changes. Spontaneous-potential log signatures are a useful tool for interpreting relative porosity and permeability in reservoirs with fluid salinities that are distinctly different from drilling fluids. However, their susceptibility to suppression by porosity occlusion can diminish their usefulness in estimating textural changes.

The problems of interpreting grain-size changes and depositional environments from log shape are illustrated in Figure 8. In this

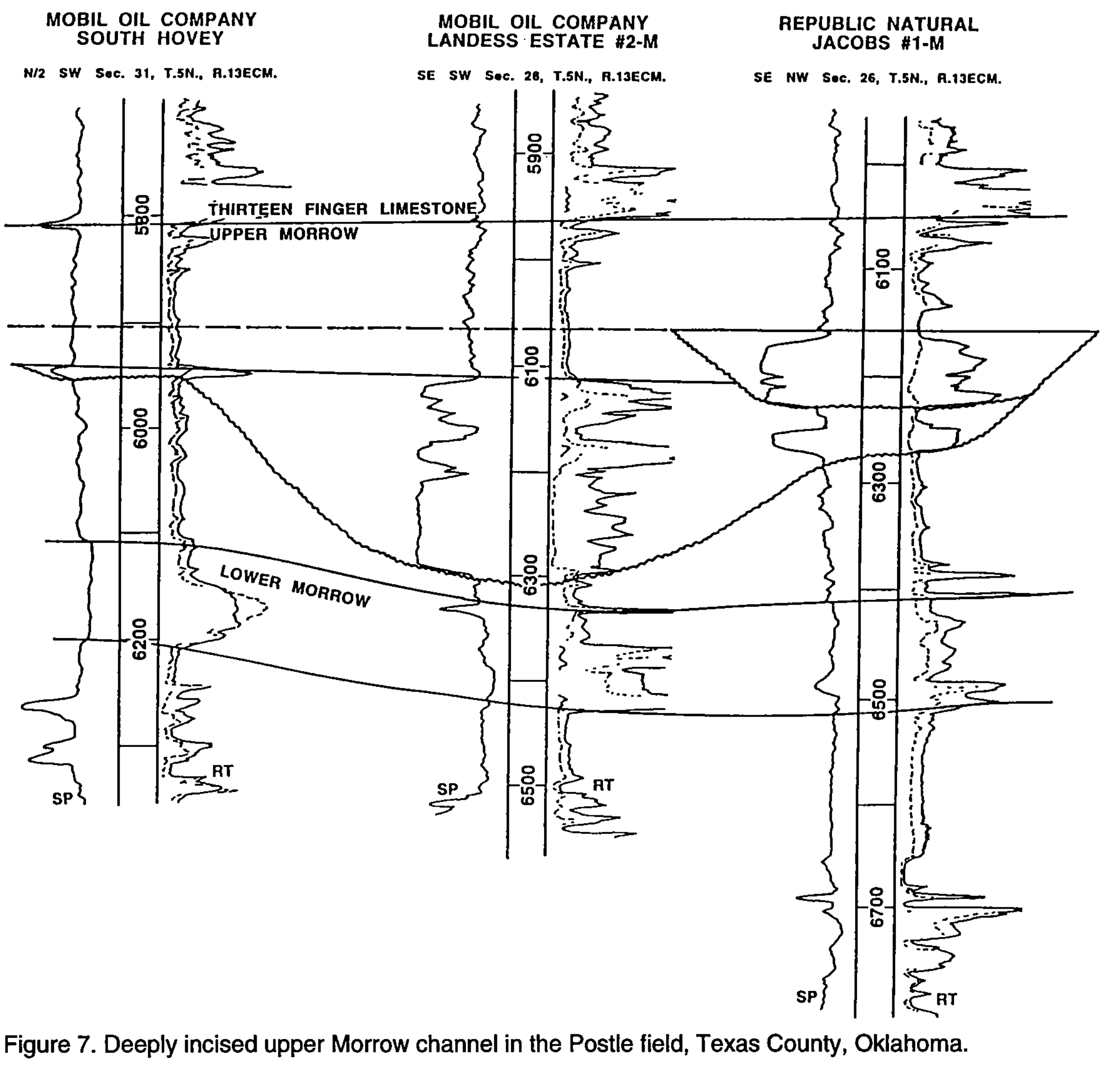


Figure 7. Deeply incised upper Morrow channel in the Postle field, Texas County, Oklahoma.

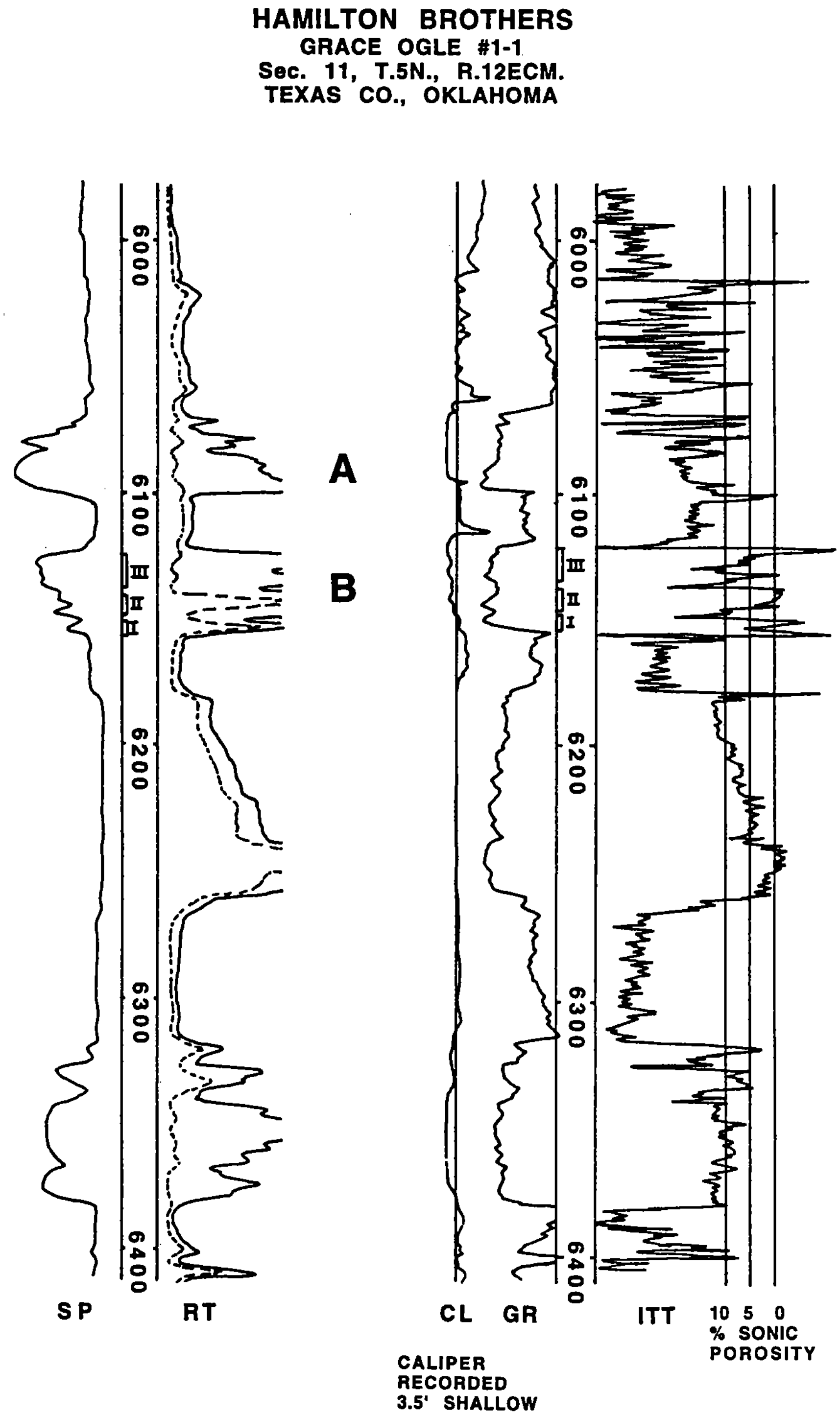


Figure 8. Log signatures and interpretations of sandstone grain sizes. On the basis of spontaneous-potential (SP) log shapes, sandstone A (6,070–6,100 ft) was interpreted as upward-fining, and sandstone B (6,124–6,154 ft) was interpreted as upward-coarsening. Note that the gamma-ray (GR) signatures indicate that both sandstones have very similar upward-fining profiles. Resistivity (RT), caliper (CL), and sonic porosity (ITT = interval travel time) curves suggest that the spontaneous-potential (SP) deflection is responding to porous and permeable intervals and not to textural trends across the zones.

case, spontaneous-potential curves were used to interpret depositional environments in the Hough area.

The funnel-shaped spontaneous-potential curve for sandstone B (6,124–6,154 ft; Fig. 8) was interpreted as a coarsening-upward channel-mouth bar. On the other hand, the bell-shaped spontaneous-potential curve for sandstone A (6,070–6,100 ft) was proposed to represent a fining-upward point-bar deposit (Swanson, 1979).

The gamma-ray signatures for both sandstones are very similar and suggest that the amount of fine material in both intervals increases upward. The difference in spontaneous-potential shapes for these sandstones can be deduced from the sonic, gamma-ray, and caliper logs. The gamma-ray curve suggests that sandstone B contains three separate fining-upward units (see Fig. 8). Unit I (6,154–6,148 ft) has relatively low porosity that peaks at ~6%, and its small accumulation of filter cake implies low permeability. Sandstone unit II (6,147–6,138 ft) has a thin porous layer at the base, but shows low porosity (<5%) over the remainder of the interval. Filter-cake build-up is present opposite the thin porous streak. The upper unit (III; 6,135–6,122 ft) averages ~8% porosity, but has consistent filter-cake build-up across the entire zone. The comparison of spontaneous-potential, gamma-ray, sonic, and caliper curves for these sandstones indicates that the spontaneous-potential signature is being suppressed in relatively clean sandstones with low porosity and permeability. In this case, the spontaneous-potential curve for the lower sandstone does not reflect apparent grain-size changes within the sandstone and inferences based on spontaneous-potential data may be misleading.

Analyses of upper Morrow cores indicate that the low porosity in coarse clastic units could be caused by a number of factors including carbonate cement and pseudomatrix. Pseudomatrix often forms in channel lag deposits from the ductile deformation of clay clasts. Carbonate cement is a common diagenetic constituent in the upper Morrow sandstones and occurs as calcite and thermal dolomite.

NORTHWESTERN SHELF CHANNEL-FILL RESERVOIRS

Integrated Upper Morrow Field Studies

Several upper Morrow fields in the Oklahoma and Texas Panhandles were examined in detail to determine the depositional environments of these reservoirs.

The Northwest Eva field in T. 4 N., R. 10 E. CM, Texas County, Oklahoma, was included in this study because of the availability of cores and a wide variety of data and information. Harrison (1990) studied the upper Morrow Purdy sandstone and was able to delineate the productive reservoir trend that extends northeast to southwest through the field (Fig. 9). Cross section A–A′ (Fig. 10) illustrates that the sandstone represents fill within a valley that was eroded into the underlying shale. Two cores were also examined in the sandstone trend: the Gulf Oil Corporation Ferguson no. 1 well in the NW¼SE¼ sec. 2, T. 4 N., R. 10 E. CM and the Gulf Oil Corporation Kelly no. 1 in the SW¼NW¼ sec. 1, T. 4 N., R. 10 E. CM.

The Gulf Ferguson core contains 47 ft of shale, siltstone, and sandstone. The basal part of the cored interval (4,453–4,466 ft) consists of 13 ft of fossiliferous marine shale; this interval is disconformably overlain by 16 ft of conglomeratic, fining-upward sandstone (4,435–4,451 ft) that contains small- to medium-scale cross-beds and several graded (fining-upward) intervals. This sandstone is overlain by 4 ft of dark-gray silty shale (4,431–4,435 ft). The upper 13 ft of core (4,418–4,431 ft) consists of a second conglomeratic channel-fill sandstone (4,424.6–4,431 ft) and abandoned-channel-fill siltstone, sandstone, and shale (4,418–4,424.6 ft). A petrologic log and parts of the cored interval are shown in Figure 11.

The second core in the Northwest Eva field is from the Gulf Oil Corporation Kelly no. 1 in the SW¼NW¼ sec. 1, T. 4 N., R. 10 E. CM. The basal part of the cored interval (4,434–4,455 ft) consists of 21 ft of dark-gray fossiliferous shale. This marine shale is disconformably overlain by 6 ft of medium- to coarse-grained sandstone (4,834–4,828 ft) that grades upward into carbonaceous shale and siltstone (4,428–4,422 ft) containing plant debris. The overlying carbonaceous shale extends from 4,422 to 4,416 ft where a disconformity separates it from a fossiliferous marine shale (4,416–4,415 ft). A petrologic log and photographs of this core are shown in Figure 12.

Subsurface mapping and lithologic data from the Northwest Eva field indicate that the upper Morrow is a sequence that includes shelf mudstones and shales, an incised valley-fill assemblage, and overlying transgressive marine shales. Deposition within the valley consisted of fluvial and estuarine sands and abandoned-channel-fill silts and muds. These sediments were covered by marine muds deposited during the subsequent transgression.

Another core examined in this study was from the Petroleum Inc. Hendrix no. 3 (sec. 25, T. 6 N., R. 10 E. CM), from the Carthage field in Texas County. The upper Morrow interval in this core is composed of sandstone and shale. The core contains at least four genetically distinct units. These are a basal, marine-influenced (estuarine) sandstone (4,558–4,568 ft), fluvial-dominated sandstone (4,537–4,558 ft), marine (estuarine) sandstone (4,527–4,537 ft), and marine shale (4,526–4,527 ft) (Fig. 13). The wire-line logs suggest that the basal estuarine sandstone is in sharp contact with an underlying (marine) shale that was not cored.

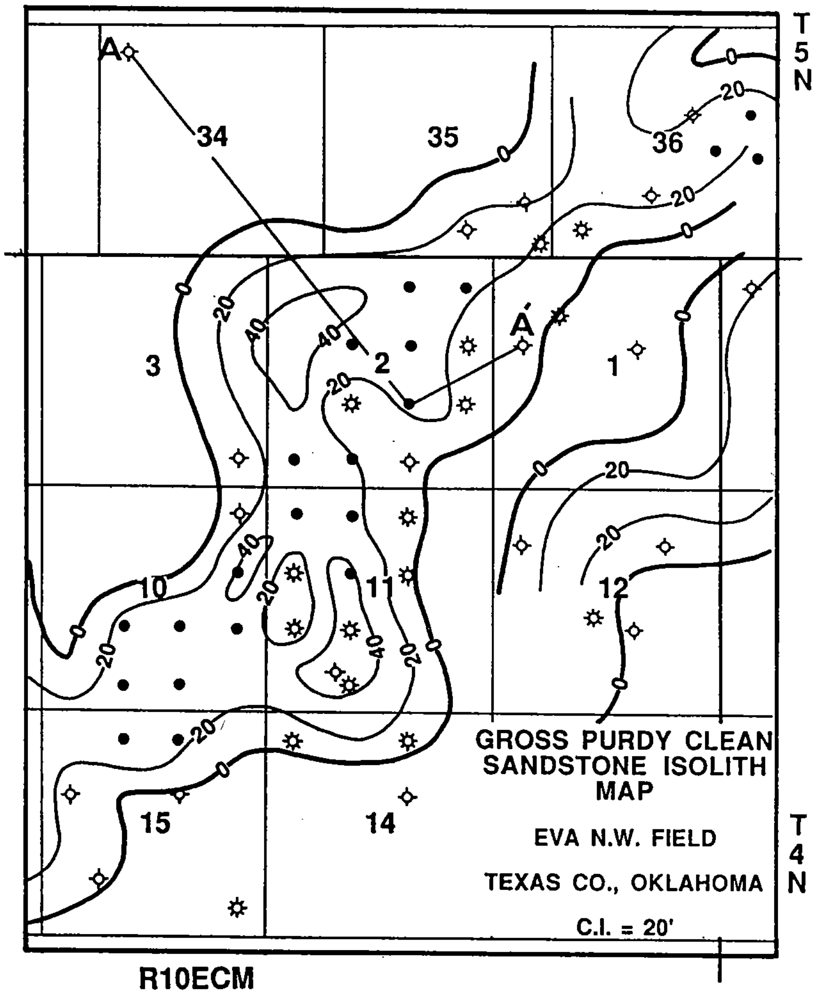


Figure 9. Thickness map of the upper Morrow Purdy sandstone, Northwest Eva field, Texas County, Oklahoma (Harrison, 1990).

Valley-Fill Profiles

Krystinik and Blakeney (1990) indicated that a typical vertical profile in a Morrow valley-fill deposit consists of five major parts: (1) background (preexisting) sediment, (2) a basal scour or unconformity surface, (3) braided-fluvial or meandering-fluvial sandstones, (4) flood-plain and/or estuarine sandstone, siltstones, and shales, and (5) marine mudstone (Fig. 14). Gamma-ray logs of the valley-fill deposits generally exhibit blocky and bell-shaped signatures.

The Petroleum Inc. Hendrix core contains three parts of the Krystinik and Blakeney profile. These are a fluvial sandstone (Fig. 15), estuarine sandstones (Fig. 16), and overlying marine mudstone. The marine mudstone is separated from the underlying strata by a fossil-hash deposit (Fig. 17) that typifies a transgressive surface of erosion (TSE) as described by Weimer (1984, 1988). The background sediment and the basal scour or unconformity were not cored in the Hendrix well, but can be inferred from log signatures.

The Gulf Kelly and Ferguson cored intervals show similar patterns to the Krystinik and Blakeney profile. The Ferguson contains fossiliferous marine shale (formed from the background sediment), a sharp erosional contact, coarse-grained fluvial sandstone, and flora-rich flood-plain shales and siltstones (Fig. 18). The Kelly core, on the other hand, contains marine shale (from the background sediment), estuarine sandstone, flood-plain siltstones and mudstones (Fig. 12), and capping marine mudstone.

The cores described above are a subset of 12 cores examined from the Oklahoma Panhandle region. In addition, more than 1,000 wire-line logs were analyzed. All of these data suggest that late Morrow deposition was dominated by fining-upward channel-fill sandstones and enclosing marine shales. Some of these sandstones represent point bars that developed along meanders in fluvial valleys. These deposits are well documented by Cornish (1984)a nd Swanson (1979).

Depositional Models

The linear upper Morrow sandstone trends examined from the northwestern shelf were deposited within incised-valley systems that downcut into existing shelf sediments during sea-level lowstands. Deposition during these lowstands was limited to thin, channel lag conglomerates composed primarily of background sediment (mud clasts). With sea-level rise and transgression, valley flooding produced estuaries where finer-grained sand, silt, and mud were deposited. Upstream, coarser-grained fluvial sediments were dominant. As sea level continued to rise, the fluvial sands were succeeded by additional estuarine

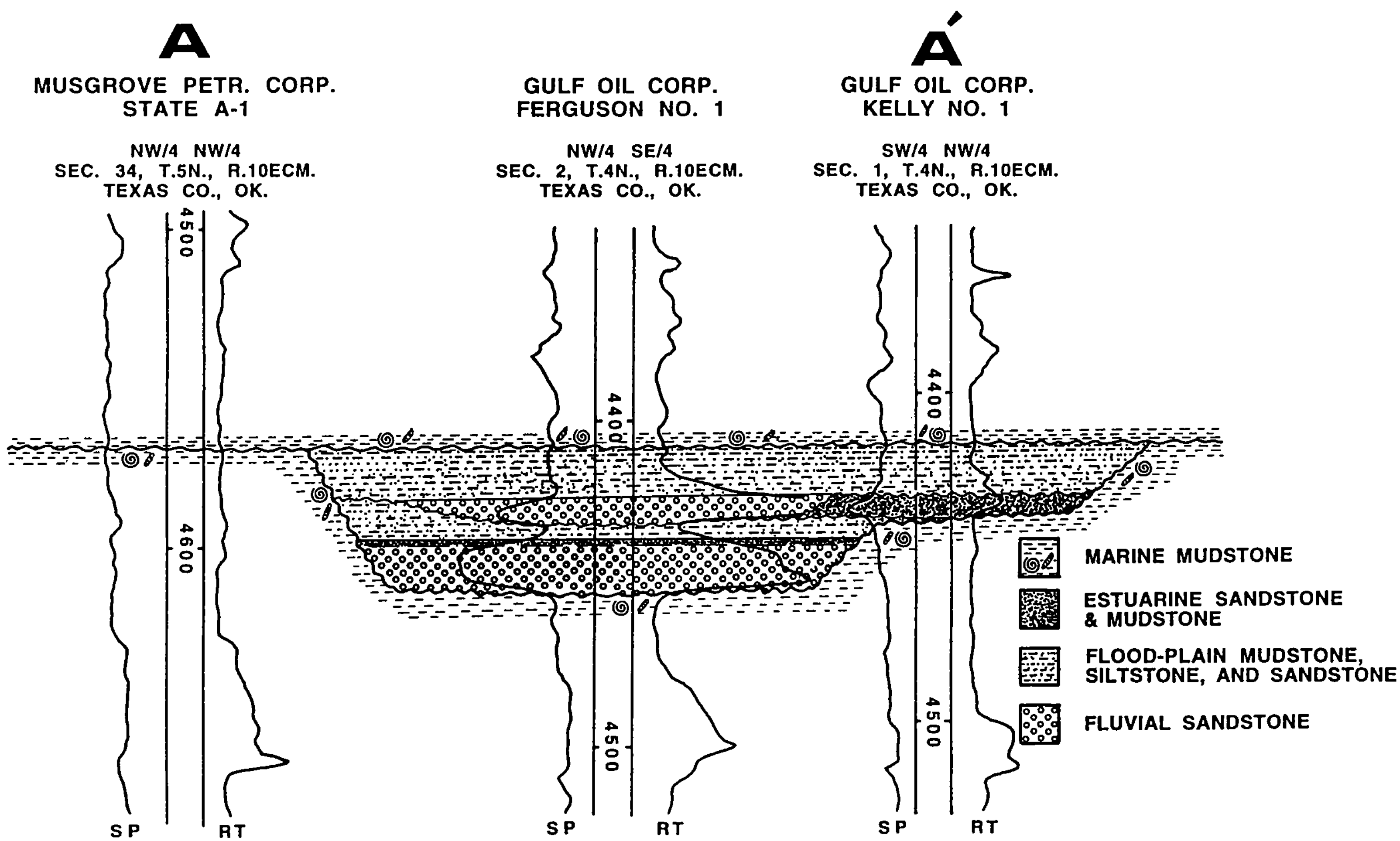


Figure 10. Schematic cross section A–A′ through the Northwest Eva field showing the apparent valley incision. The proposed valley-fill facies are identified (after Harrison, 1990). Location of cross section is shown in Figure 9.

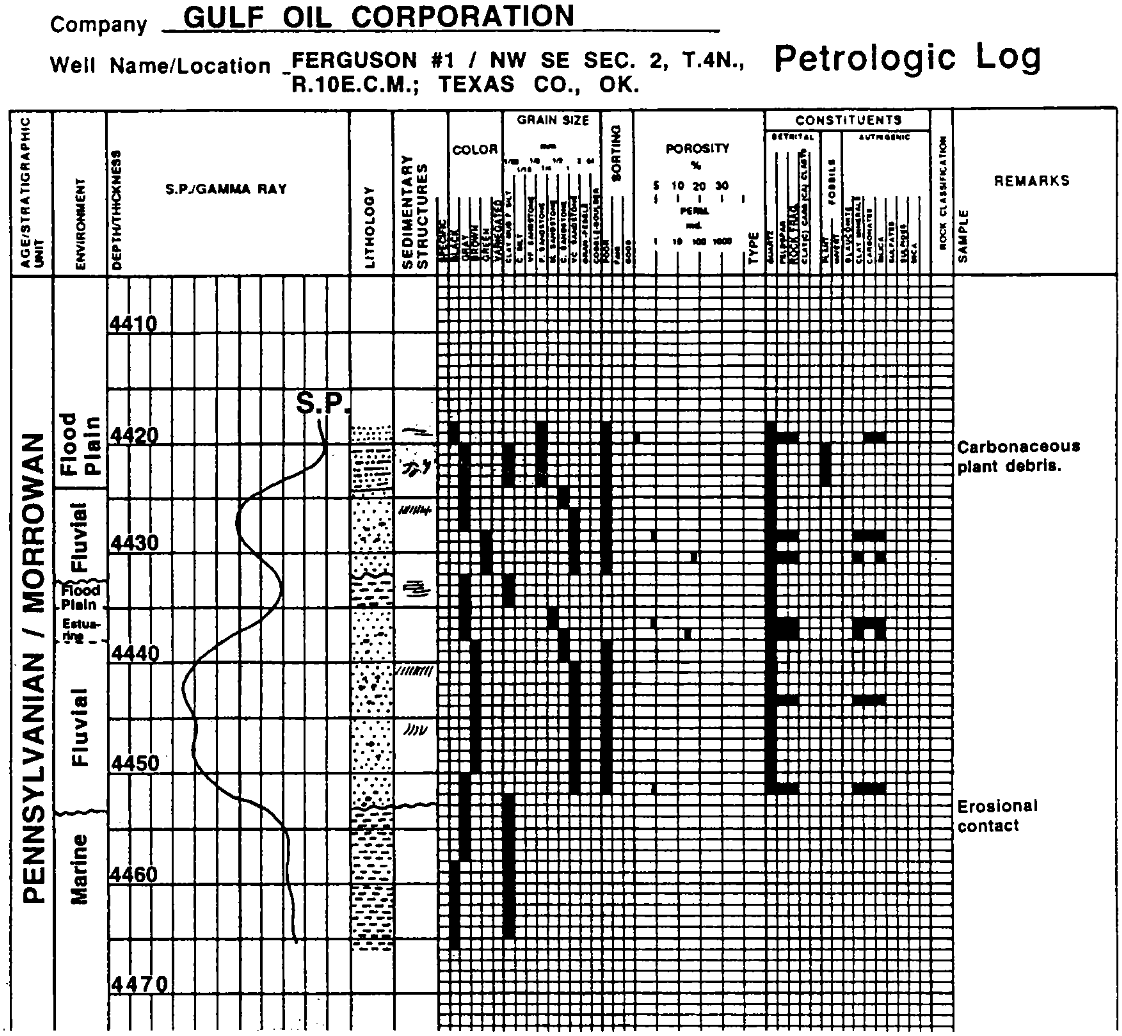
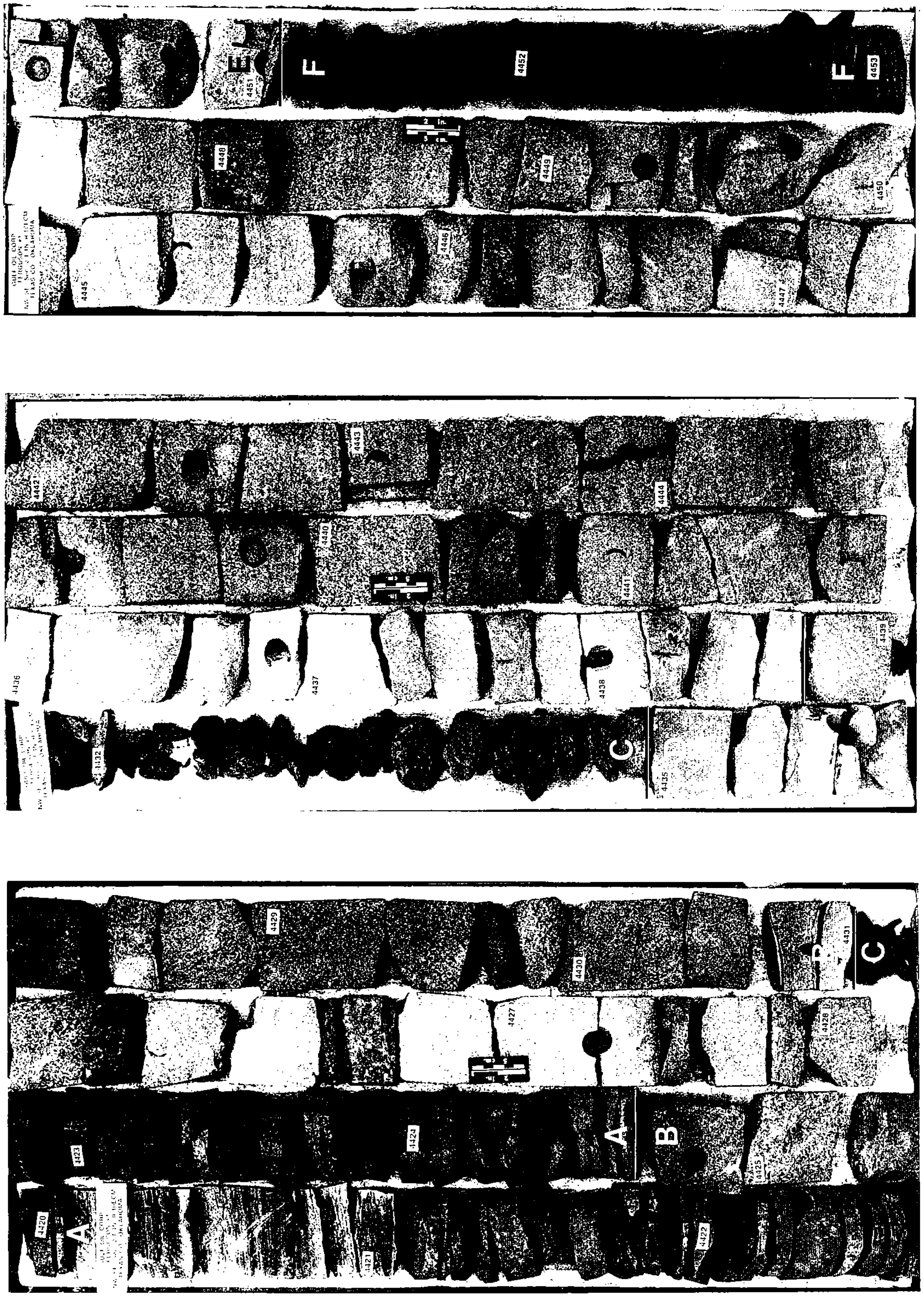


Figure 11. Gulf Oil Corporation Ferguson no. 1 petrologic log (above) and core (opposite page). (A) Abandoned-channel-fill siltstones and shales (4,420–4,424.6 ft) in sharp contact with (B) coarse-grained fluvial sandstone (4,424.6–4,431 ft). Note the erosional contact at 4,431 ft between sandstone and (C) underlying dark shale (4,431–4,435 ft). (D) Fine- to medium-grained sandstone (4,435–4,438.7 ft) and (E) coarse-grained sandstone (4,438.7–4,451 ft) unconformably overlie (F) dark-gray marine shale (4,451–4,453 ft).

sediments. Substantial variations in grain size and shale content within valley trends can be attributed to minor sea-level fluctuations during the transgression. Dropping sea level rejuvenated the system and generated incision of existing valley-fill sediments. Heterogeneities introduced by multiple episodes of incision as well as depositional variability have been described by Krystinik and Blakeney (1990).

Deltaic sedimentary units are apparently less abundant in the upper Morrow than once believed. Coarsening-upward delta-front sandstones and delta-margin sandstone and shale sequences that are common in Desmoinesian rocks such as the Skinner sandstone (Puckette, 1990) are not evident in the upper Morrow rocks of the northwestern shelf.

The regional model for upper Morrow valley-fill sedimentary assemblages, developed by Wheeler and others (1990), is shown in Figure 19. They have proposed that deltaic deposits may have been thin and difficult to distinguish from estuarine-influenced fluvial sandstones removed or reworked during transgression(s) or never deposited.



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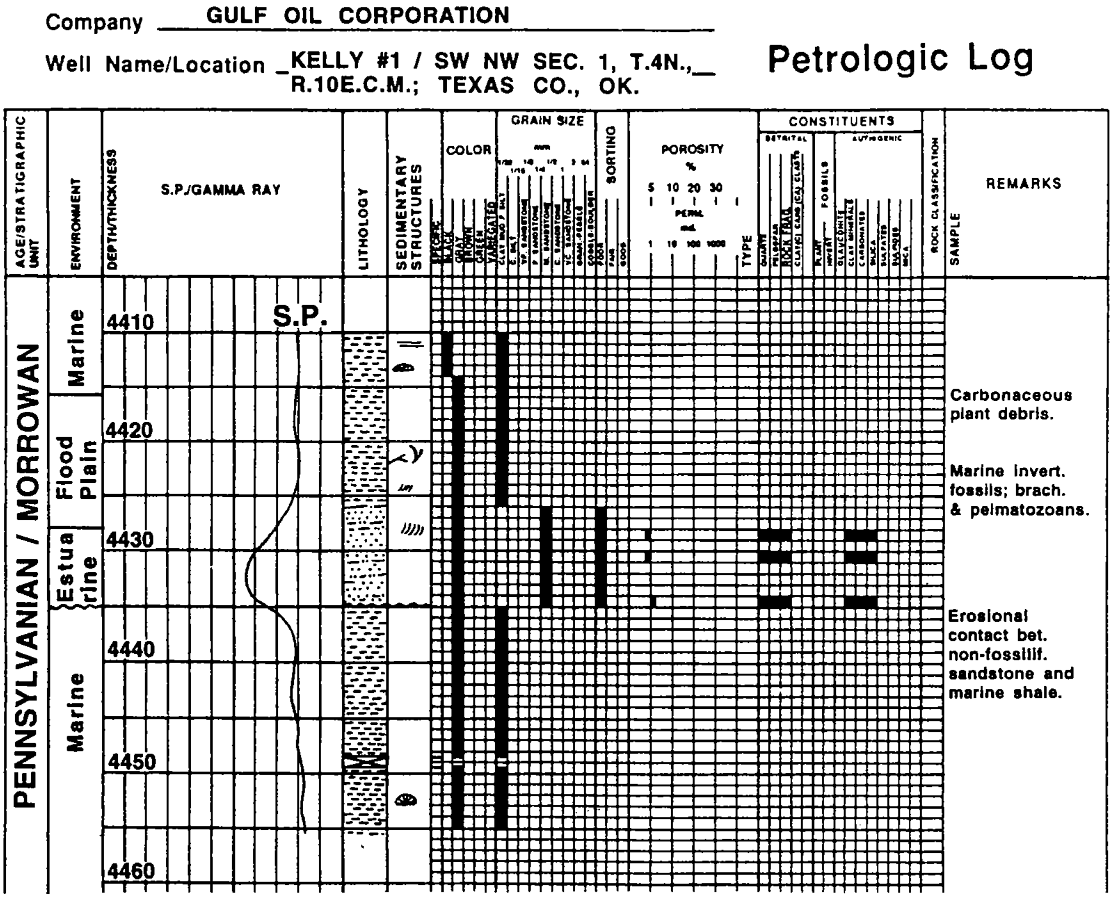


Figure 12. Gulf Oil Corporation Kelly no. 1 petrologic log (above) and core (opposite page). (A) Dark-gray fissile marine shale (4,415–4,416 ft) and (B) gray, silty flora-rich shale (4,416–4,422 ft). (C) Shaly siltstone and sandstone (4,422–4,428 ft). (D) Medium- to coarse-grained sandstone (4,428–4,434 ft) in sharp contact with underlying (E) dark-gray marine shale (4,434–4,442.5 ft).

WICHITA SYSTEM FAN- AND BRAID-DELTA RESERVOIRS

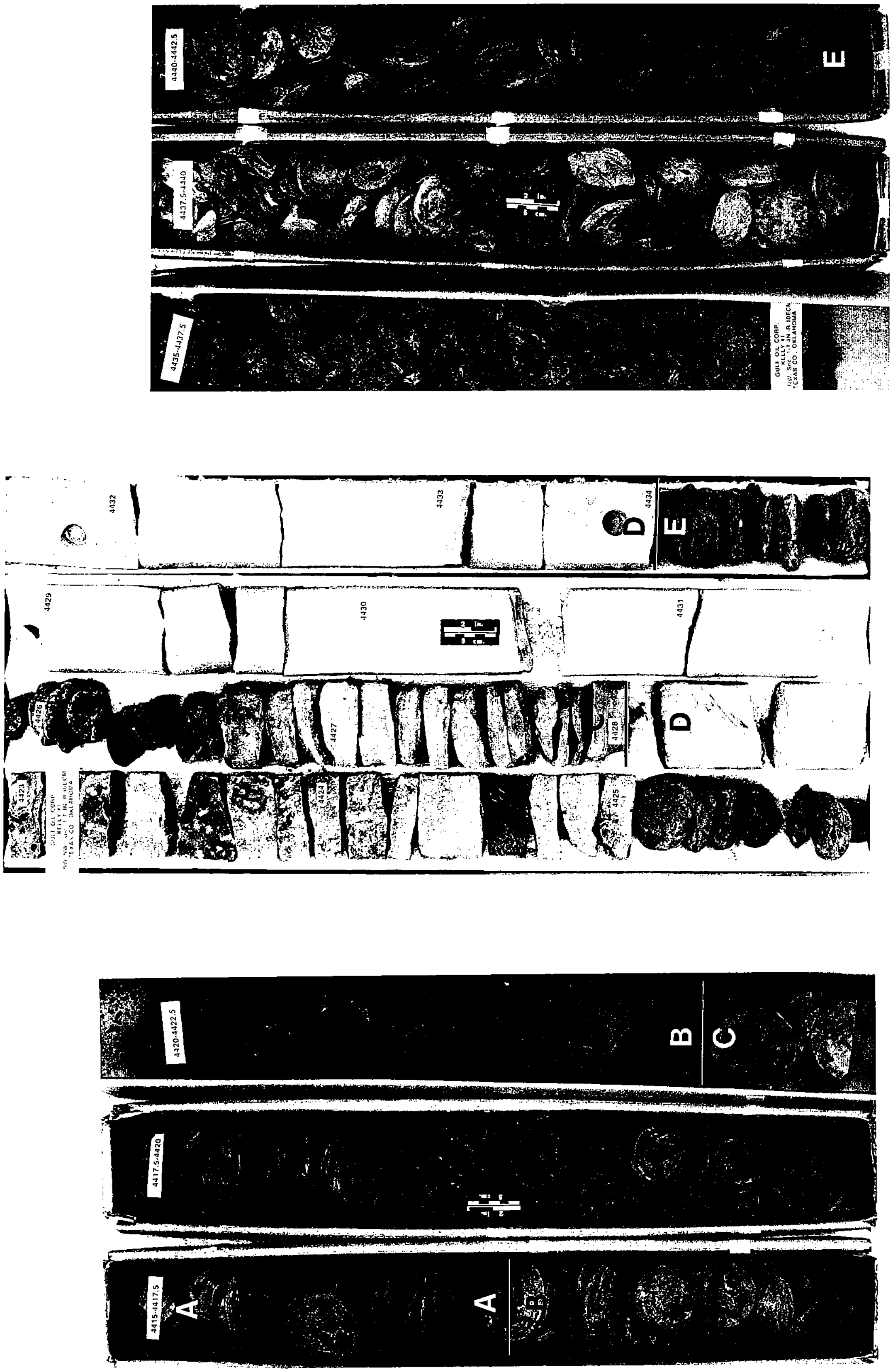
In the southwestern part of the Anadarko basin (Roger Mills and Wheeler Counties, Oklahoma and Texas, respectively), the upper part of the Morrowan Series is composed predominantly of conglomerates, sandstones, and shale. Within the northern edge of this system, the upper Morrow rocks form a shale-dominated sequence that contains thinner chert-conglomerate and chert-arenite reservoirs. The conglomerate-to-shale ratio increases southward, and the upper Morrow becomes a conglomerate-dominated sequence in the vicinity of the Wichita Mountain frontal fault zone.

Sediments deposited within this setting contain an abundance of detrital chert that ranges from sand-sized to cobble-sized fragments (Hawthorne, 1984; Shelby, 1980; Al-Shaieb and others, 1993). The source of these fragments was the chert-rich Mississippian rocks exposed on the rising Wichita Mountains to the south.

Depositional Environment

The conglomeratic upper Morrow rocks have been described as fan-delta complexes (Alberta, 1987; Al-Shaieb and others, 1989) and coastal alluvial fans (Johnson, 1989). Al-Shaieb and others (1989) examined cores from both the Purvis and Puryear intervals as part of an integrated study of sedimentary features, geometry, and wire-line log characteristics of the chert interval. These cores contain stacked, fining-upward, graded conglomerates and sandstones that typify braided-stream deposits of the mid- to distal-fan facies present in the fan-delta models described by McGowen and Groat (1971) and Dutton (1982). Deposits with similar characteristics have been classified as braid deltas by McPherson and others (1987) (Fig. 20).

These coarse-grained, multistoried channel de-



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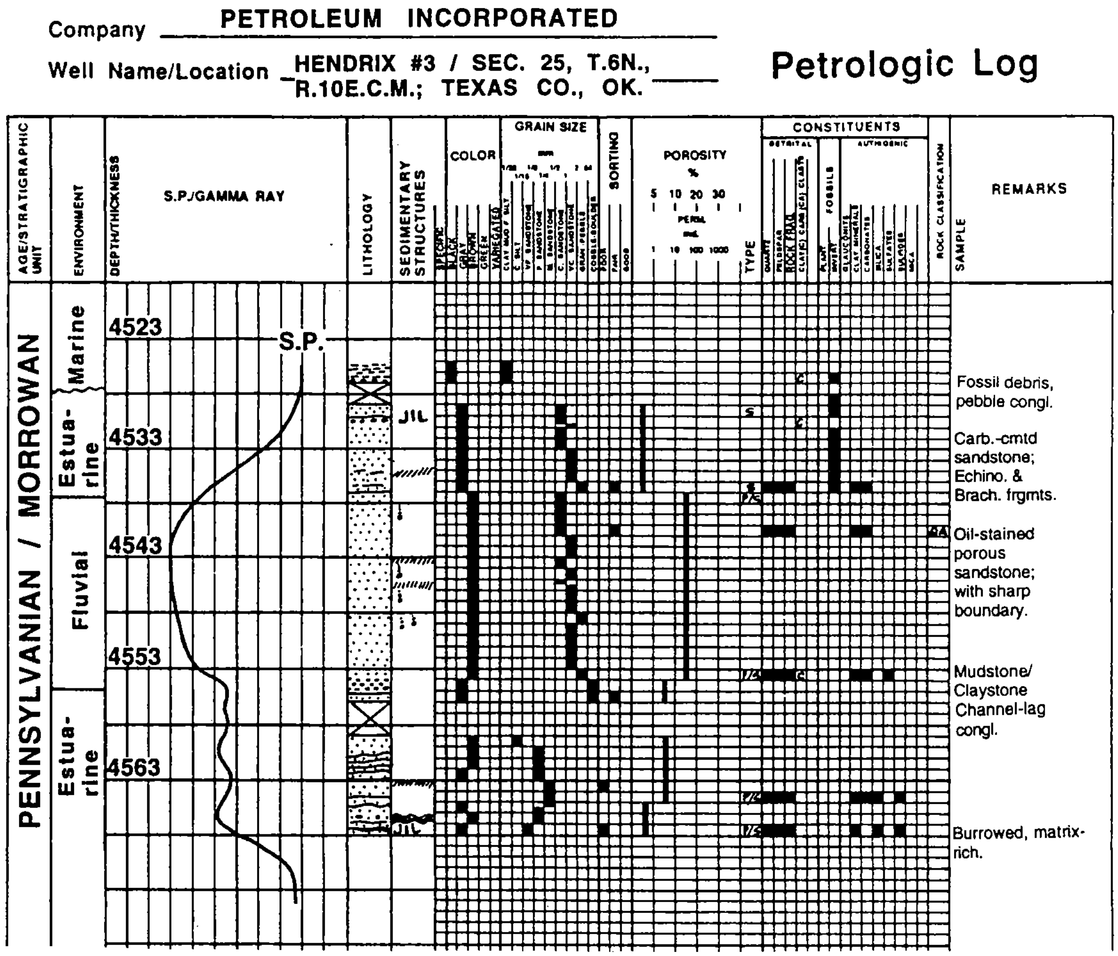


Figure 13. Petroleum Inc. Hendrix no. 3 petrologic log (above) and core (opposite page). (A) Dark-gray marine shale with fossil-hash zone at base (4,526–4,527.5 ft). (B) Medium- to coarse-grained sandstone with shale partings, burrowing, and abundant invertebrate fossils (4,527.5–4,538 ft). (C) Very coarse cross-bedded sandstone (4,538–4,559.5 ft) with basal clay-pebble conglomerate in sharp contact with underlying dark shale. (D) Mixed interval of dark shale, graded sandstones, and interbedded sandstone and shale (4,559.5–4,568 ft). Finer-grained sandstones are burrowed and contain clay-rich laminae.

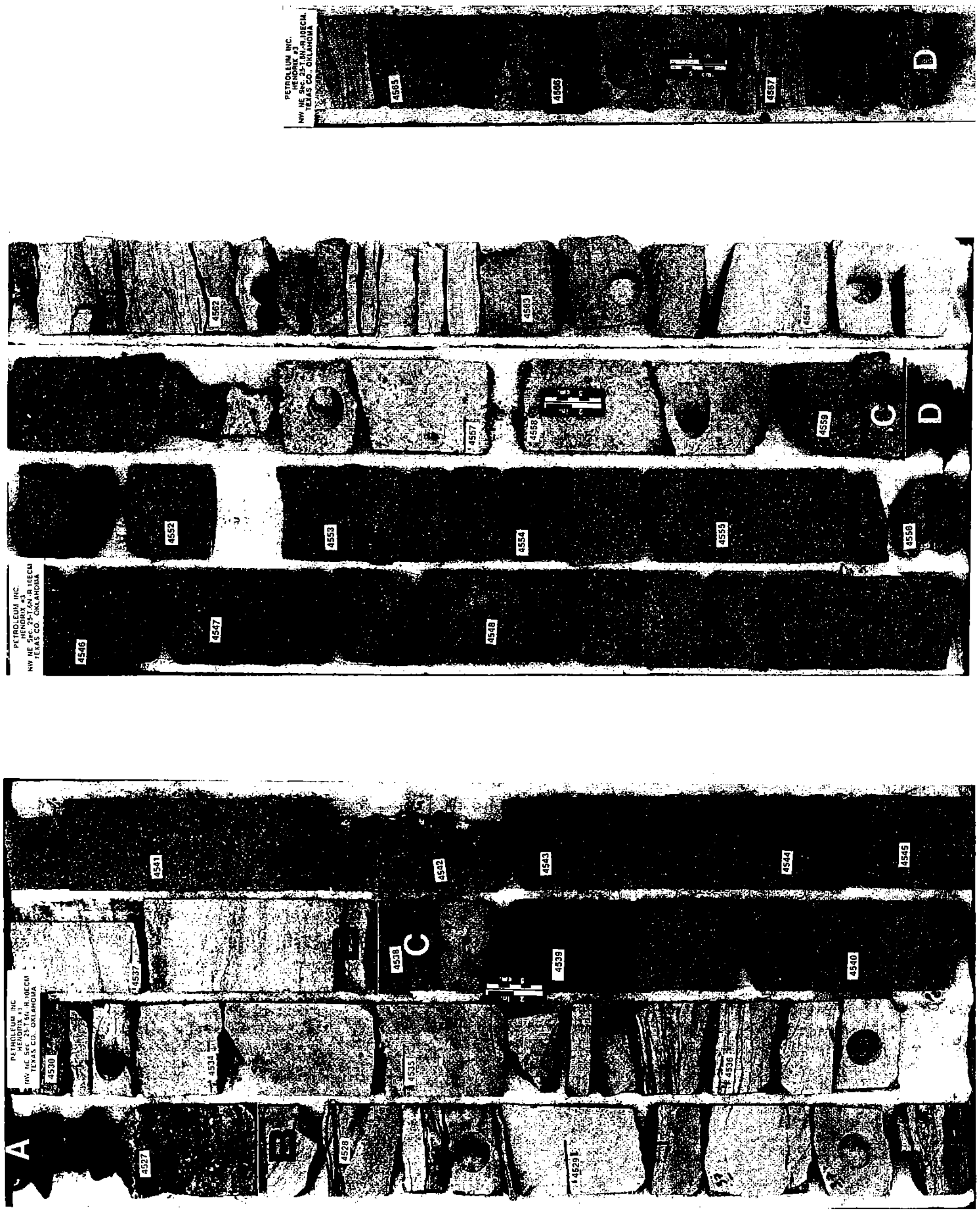
posits have sharp basal contacts with underlying mudstone-rich rocks such as fossiliferous shallow-marine and prodelta shales (Figs. 21,22). The basal sequences of the conglomerate and sandstone deposits consist of light-gray imbricated pebble conglomerates (Fig. 23) that fine upward to coarse-grained and then medium- and fine-grained chert-rich sandstone. The channel-filling conglomerates and sandstones are overlain by coal-bearing shales indicating a marsh or swamp or abandoned-channel environment (Fig. 21).

A Pierce conglomerate core described in Johnson (1989) and one from the stacked conglomerate interval adjacent to the frontal fault zone of the Wichita uplift (Al-Shaieb and others, 1993) also represent braided-stream deposits.

The Morrow chert-conglomerate cores contain depositional sequences that are interpreted as braided-stream deposits of the mid- to distal-fan facies. No proximal fan facies such as sheetfloods or debris flows (which are evident in the Desmoinesian arkosic "Granite Washes") have been recognized in the upper Morrow rocks. These facies were likely eroded during the later stages of the Pennsylvanian orogeny or have not been identified in the sparsely sampled region adjacent to the uplift.

Distribution of Chert-Conglomerate Reservoirs

The distribution patterns of the productive chert-conglomerate reservoirs illustrate several



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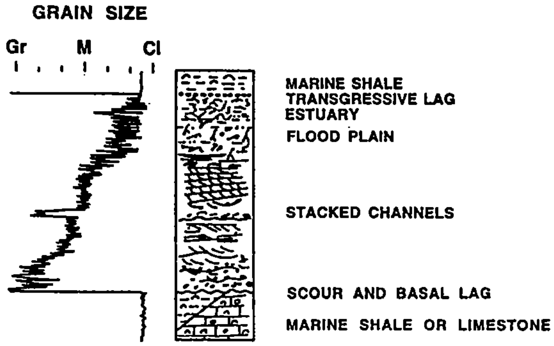

Figure 14. Typical vertical profile through valley-fill deposits (Krystinik and Blakeney, 1990). Grain-size scale: Gr = gravel, M = medium sand, Cl = clay.

types of depositional styles. The thickness map and cross section of the Pierce conglomerate (Figs. 24,25) suggest that this thinner conglomerate was not confined by channels and, instead, migrated laterally across the deltaic plain. This style is typical of braid deltas described by McPherson and others (1987). The Pierce conglomerate is enclosed by dark-gray shales and terminates without the development of any apparent shoreface deposits that reflect marine reworking.

The Puryear is the most widespread conglomerate and apparently reflects a major period of uplift and erosion of the Wichita highlands. It is an amalgamation of several northward-prograding deltaic lobes (Fig. 26).

The dominant Puryear lobes are shown in Figure 26. The western lobe trends northward along a pathway similar to the one for the underlying Pierce system. The main channel bifurcates to the northwest and northeast. The eastern lobe extends northwestward and also exhibits bifurcation and merging. Some thick channel-fill reservoirs suggest minor incision of the underlying deltaic muds and silts, but most Puryear channels appear to downcut very little (Fig. 25). Reworking of Puryear sediments by marine processes and the development of delta-margin facies are evidenced by the development of apparent cleaning- (coarsening) upward log signatures (Fig. 27) (fig. 12 in Shelby, 1980; fig. 20 in Hawthorne, 1984).

The Purvis conglomerate illustrates channel-confined deposition extending northward from thick conglomerate accumulations (Fig. 28). The Exxon Sayre Ranch core (Fig. 21) in the center channel trend (arrow shows core location in Fig. 28) contains braided-stream conglomerates that are enclosed in black shales. Alberta (1987) interpreted this core as representing a distributary channel that prograded over prodelta marine shales. Black shales with coaly material above the conglomerate represent final abandonment of the channel.

Figure 15. Coarse-grained, porous, and oil-stained fluvial sandstone with carbonate-cement, planar cross-beds, and fining-upward graded intervals. Core from Petroleum Inc. Hendrix no. 3. Depth, 4,544 ft.

Sediment-distribution patterns, core analyses, and wire-line log interpretations indicate that most chert-conglomerate reservoirs occur in what was a northward-prograding, coarse-grained delta system composed of main distributary channels, minor distributary channels, splays, marshes, and overbank deposits. These data suggest that late Morrowan deposition occurred primarily within braid- and fan-deltaic complexes that prograded northward from the Wichita uplift. This system became more channelized toward the north and developed similarly to fine-grained deltas.

Figure 16. Medium-grained, carbonate-cemented estuarine sandstone with invertebrate grains. Core from Petroleum Inc. Hendrix no. 3. Depth, 4,537 ft.

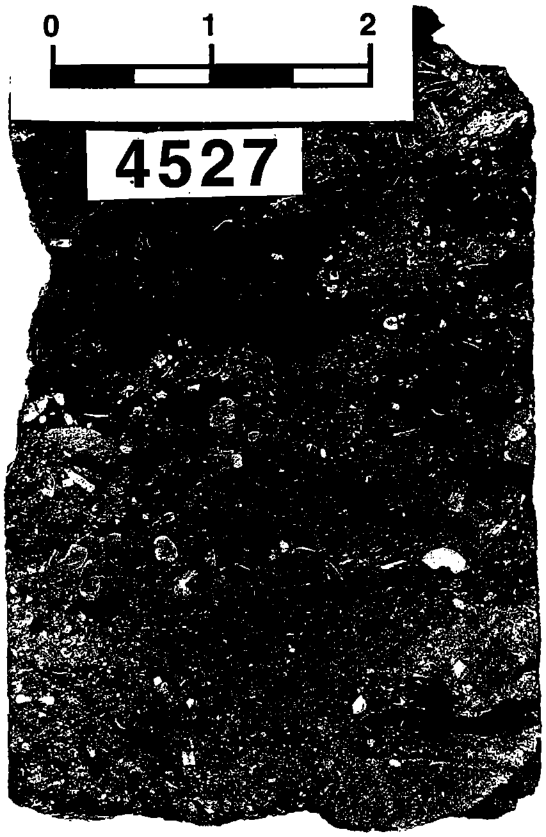

Figure 17 (top, right column). Marine mudstone with fossil-debris conglomerate at base. Fossil-hash zone is typical of the transgressive surface of erosion (TSE) (Weimer, 1984, 1988) developed by a regional marine transgression. Core from Petroleum Inc. Hendrix no. 3. Depth, 4,527 ft.

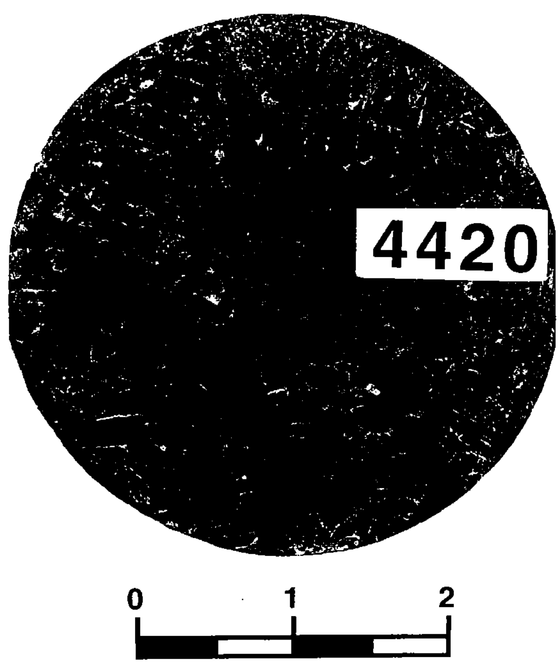

Figure 18 (bottom, right column). Plant fossils in flood-plain siltstone and shale. Core from Ferguson no. 1. Depth, 4,420 ft.

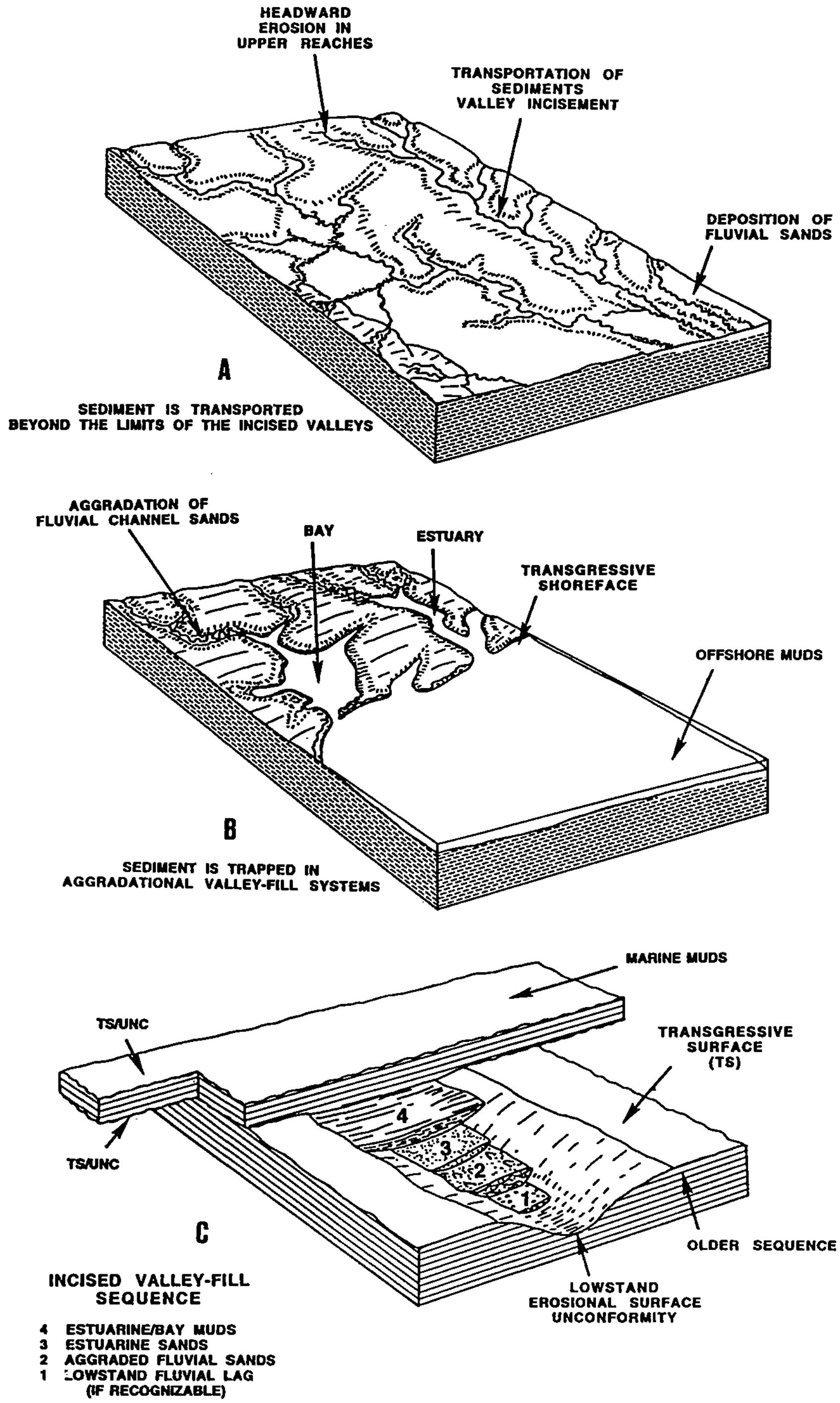

Figure 19. Paleogeographic models of Wheeler and others (1990) that illustrate the development of fluvial valley-fill deposits. (A) Sea-level lowstand; most sediment is transported beyond the limits of the incised valleys. (B) Sea-level rise that forms estuaries and bays and traps coarser sediments up-dip as aggradational valley fill. (C) Generalized schematic block diagram of a valley-fill depositional sequence that could form with a continuous sea-level rise following incision. Lowstand erosional surface and transgressive surface or unconformity (TS/UNC) correspond to the lowstand surface of erosion (LSE) and transgressive surface of erosion (TSE), respectively, of Weimer (1988). Sonnenberg and others (1990) and Wheeler and others (1990) have described the valley-fill model in the context of sequence stratigraphy.

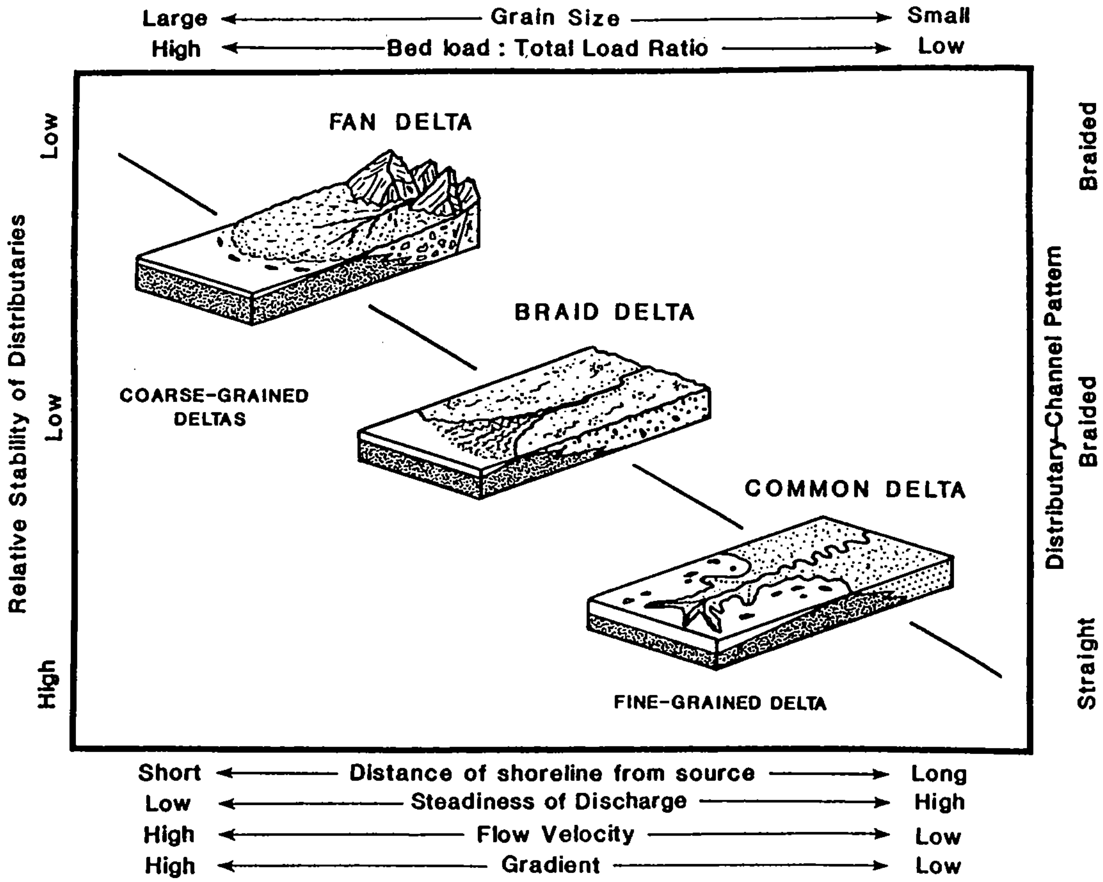

Figure 20. Schematic diagram comparing coarse-grained fan and braid deltas with fine-grained deltas (McPherson and others, 1987).

The most important chert reservoirs are found within the channel-fill deposits. These facies were recognized by blocky- to bell-shaped gamma-ray log signatures that reflect upward fining or an upward increase in clay content. The geometry of some channel-fill reservoirs suggests that the streams were rather confined and formed distributary-channel systems. Others exhibit channelization or incision of underlying deltaic sediments in response to sea-level lowstands (Fig. 29).

Overbank sandstone deposits are characterized by a thin (<10 ft thick) gamma-ray log signature that is spikelike in appearance. These deposits are located in interchannel areas between the more prominent delta lobes.

The limited data proximal to the uplift suggest that the chert-conglomerate interval adjacent to the fault is predominantly stacked braided-stream deposits. These thick accumulations are typically well cemented and regarded as very poor reservoirs.

GENESIS OF UPPER MORROW RESERVOIRS

The evolution of the upper Morrow reservoirs is closely related to depositional facies and detrital composition. The physical and chemical modifications of upper Morrow reservoir rocks that resulted in porosity occlusion or generation are strongly influenced by the detrital constituents. Porosity evolution in the chert conglomerate required dual processes of feldspar and chert diagenesis. The generation of secondary porosity in the northwestern shelf reservoirs depended on the presence of relatively metastable detrital grains and preserved primary porosity.

Detrital Constituents

The most abundant detrital constituents in the upper Morrow rocks of the northwestern shelf are monocrystalline quartz, composite quartz, micro-

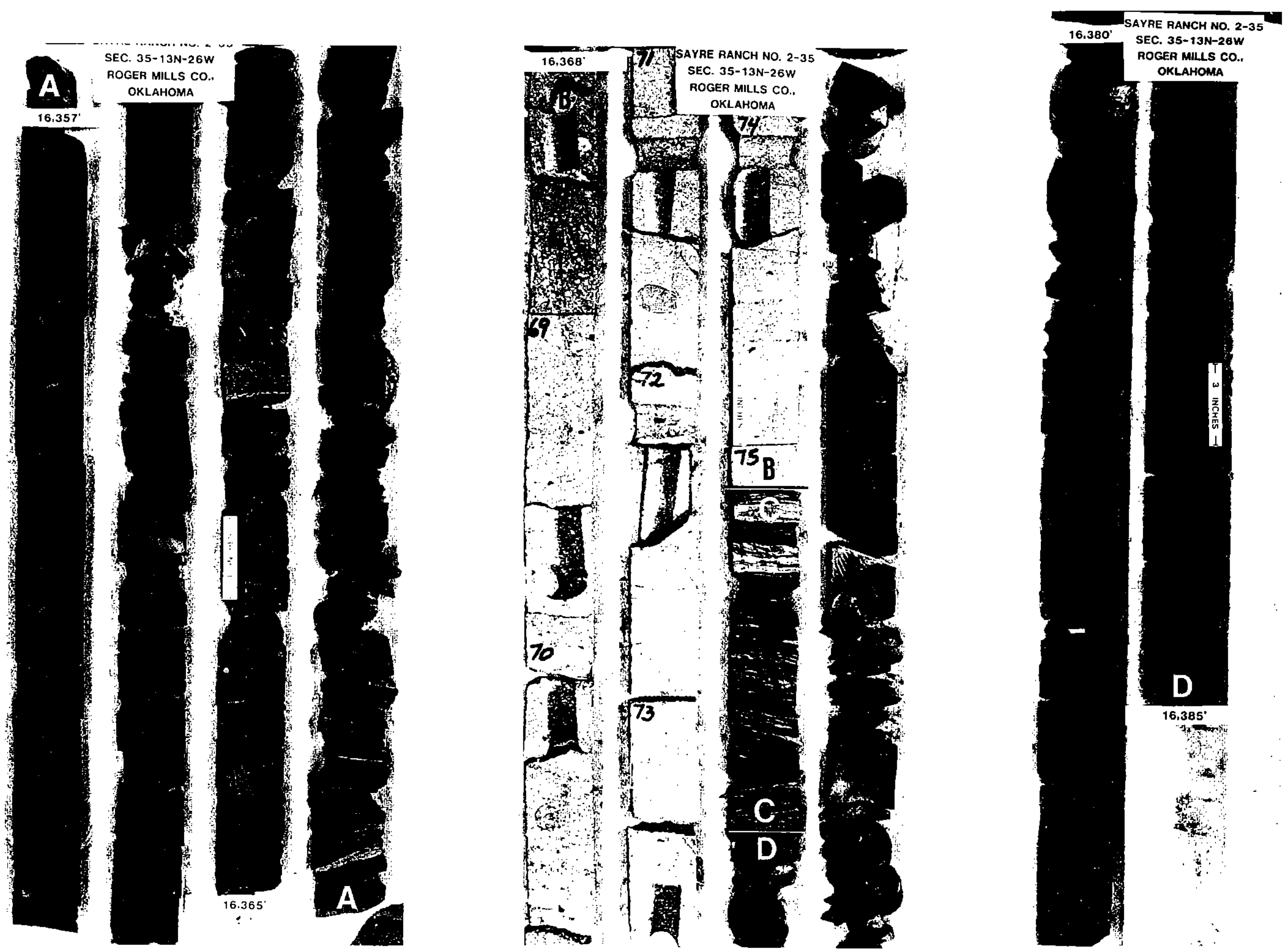

Figure 21. Core from Exxon Sayre Ranch no. 2-35. (A) Dark-gray to black shale with coal-rich material that increases in sand content at the base (16,357–16,368 ft). (B) Fine-pebble conglomerate with planar cross-beds, imbrication, and graded fining-upward intervals (16,368–16,375.2 ft) exhibiting sharp contact with underlying interbedded sandstone and shale. (C) Interbedded sandstone and shale interval with wavy bedding and sharp basal contact (16,375.2–16,376.3 ft). (D) Black marine shale (16,376.3–16,385 ft).

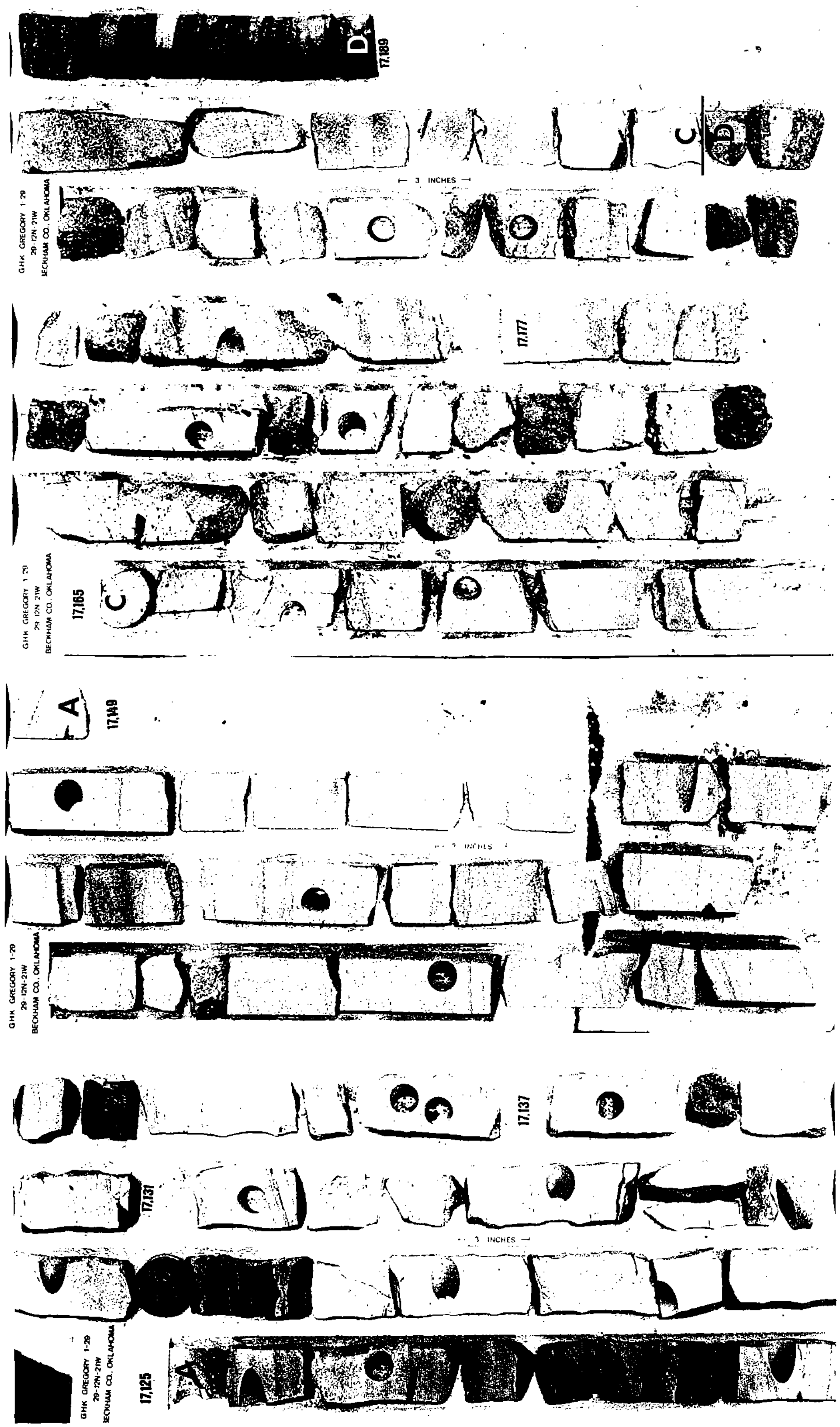

Figure 22. Core from GHK-Apache Gregory no. 1-29. (A) Fining-upward sequence consisting of fine-pebble conglomerate at base, very coarse grained to coarse-grained sandstone in the middle, and medium- to fine-grained sandstone and shale at the top (17,125–17,149 ft). Horizontal-bedded and planar cross-bedded intervals alternate with intervals displaying flowage features. Fining-upward grading is common. (B) Missing interval (17,149–17,165 ft). (C) Fine-pebble and granule conglomerate with planar cross-bedding, imbrication, and graded bedding (17,165–17,187 ft) in sharp contact with underlying black shale. (D) Dark-gray marine shale (17,187–17,189 ft).

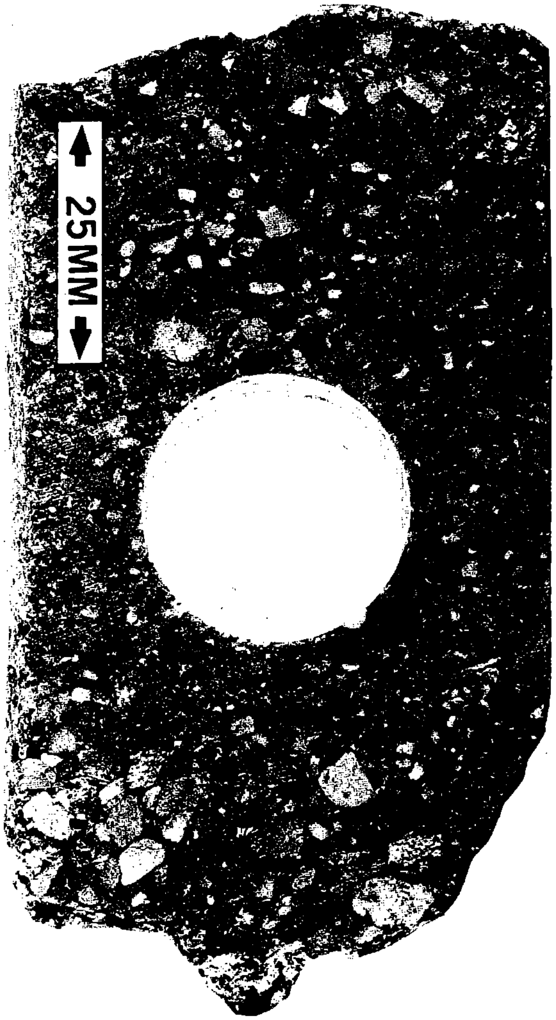

Figure 23. Fining-upward, imbricated, granule and pebble conglomerate interval of a braided-stream deposit. GHK-Apache Gregory no. 1-29. Depth, 17,180 ft.

cline, plagioclase feldspar, shale clasts, clay matrix, and igneous-rock fragments. Fossil fragments are an important framework component in the marine-influenced facies. Detrital constituents also include chert, metamorphic-rock fragments, phosphate minerals, micas, glauconite, and heavy minerals such as zircon and tourmaline. The relative percentages of the framework detrital constituents are reflected on the QRF ternary diagram (Fig. 30). As these rocks become more porous owing to the dissolution of feldspars, the rocks become richer in rock fragments and quartz and the composition changes from subarkose to sublitharenite (Fig. 30).

The composition of the upper Morrow chert conglomerates varies significantly. Conglomerates derived almost entirely from eroding Mississippian chert-rich rocks plot as litharenites on a ternary QRF diagram (Fig. 31). On the other hand, certain conglomerate facies were derived from the erosion of igneous rocks of the Wichita uplift. These facies are feldspar and quartz rich and composed of subarkose, lithic arkose, and feldspathic litharenite.

Northwestern Shelf Channel-Fill Reservoirs

In the shelf system, the filling of incised channels during sea-level rises contributed to reservoir heterogeneity and strongly influenced reservoir quality. The Hendrix no. 3 core illustrates this point.

Each of the four genetically distinct units in the Hendrix core has a unique set of textures, compositions, and diagenetic histories. A composite log schematic for the Hendrix (Fig. 32) indicates that the porous reservoir in the cored interval is the fluvial sandstone, whereas the basal and upper estuarine sandstones are tightly cemented. The development and preservation of porosity in the fluvial-dominated sandstone are primarily a function of the depositional history and composition of the sandstone facies.

Both primary porosity and secondary porosity are observed in the middle and top of the fluvial-dominated sandstone unit. Preserved primary pore spaces are recognized from the fact that they are bounded by euhedral crystal faces (Fig. 33). In Figure 33, primary porosity (pp) is framed by euhedral crystal faces of syntaxial quartz overgrowths (ov) that border inclusion-rich detrital grains (dg). Secondary porosity (sp) includes enlarged intergranular and intragranular porosity and microporosity. Enlarged intergranular porosity (Fig. 33) was generated by the dissolution of framework grains such as feldspars and granitic-rock fragments. Intragranular porosity developed within framework grains as the result of preferential dissolution (Fig. 34). Microporosity is present within some partially leached framework grains and more commonly between kaolinite books.

Porosity in the base of the fluvial-dominated unit is occluded by carbonate cement and pseudomatrix. Pseudomatrix formed from the ductile deformation of clay clasts in the channel lag. Carbonate cements in the base of the fluvial-dominated sandstone are dolomite and calcite. Calcite has a coarse equant morphology. The dolomite is baroque dolomite that apparently formed from calcite when hot fluids (>80 °C) (Radke and Mathis, 1980) moved through the reservoir.

No significant secondary porosity developed in the basal estuarine sandstone because it contained abundant clayey matrix (Fig. 35). The dispersal of matrix among the sand grains by burrowing animals occluded most primary porosity. As a result, fluid circulation through this homogenized rock was inhibited, and secondary porosity was not generated.

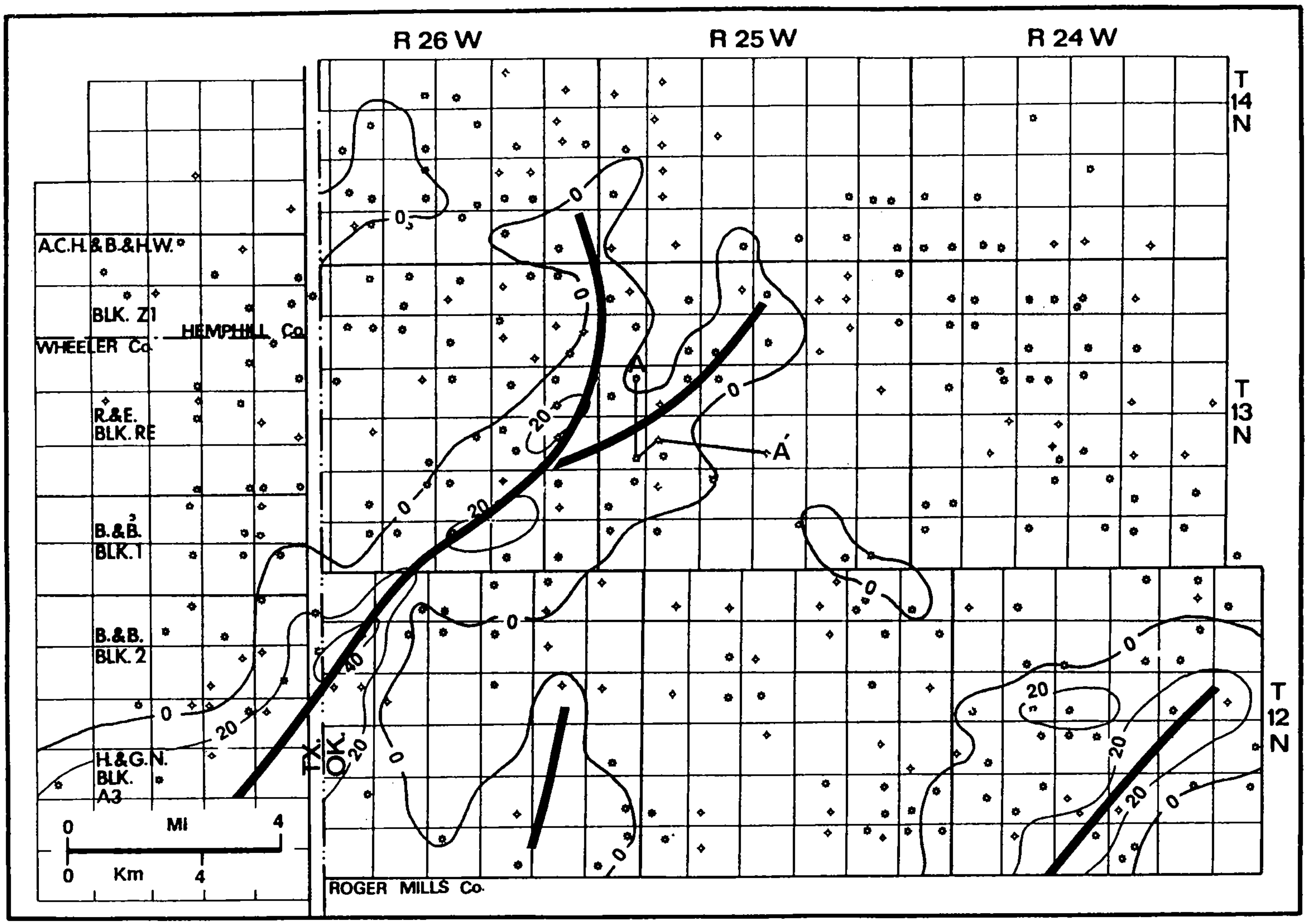

Figure 24. Thickness map of the Pierce chert conglomerate in western Roger Mills County, Oklahoma, and eastern Wheeler County, Texas. Thin, laterally extensive conglomerate deposition suggests braid-delta deposition. Contour interval = 20 ft.

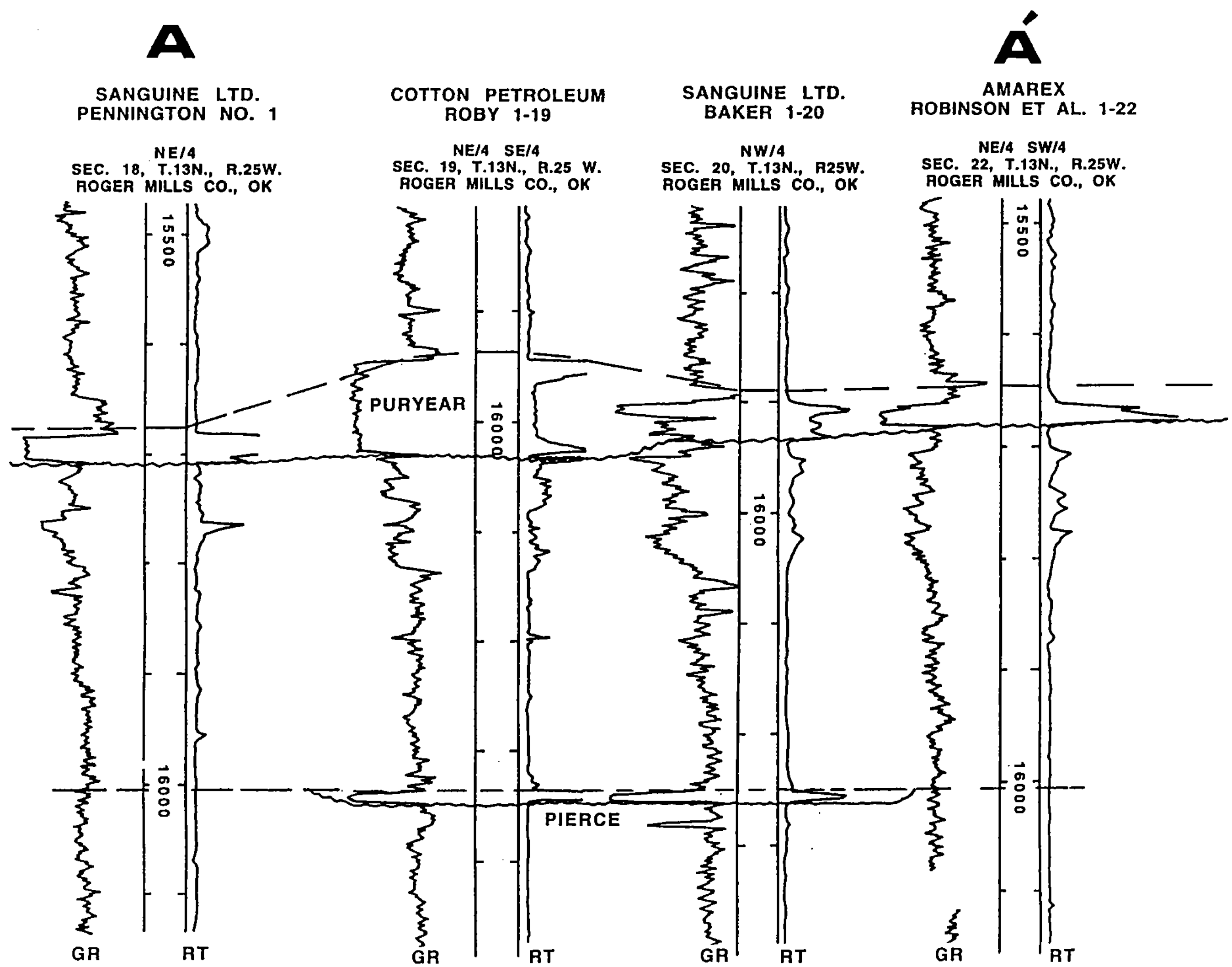

Figure 25. Cross section A–A′ illustrating the spatial relationship between the Pierce conglomerate and surrounding shales. Line of cross section shown in Figures 24 and 26.

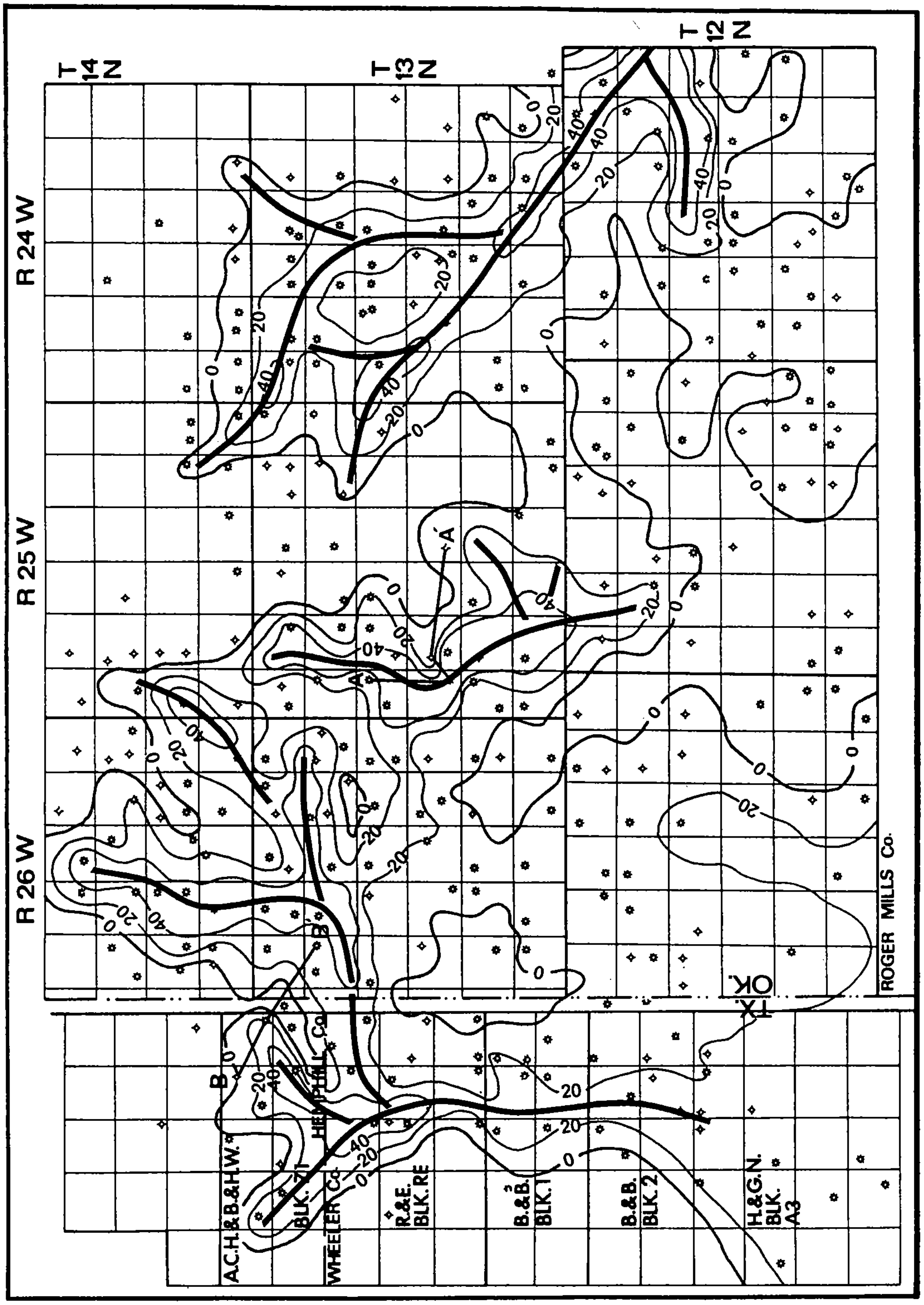

Figure 26. Thickness map of the Puryear conglomerate in western Roger Mills County, and eastern Wheeler County. Puryear geometry suggests northward-prograding distributary-channel systems. Contour interval = 20 ft.

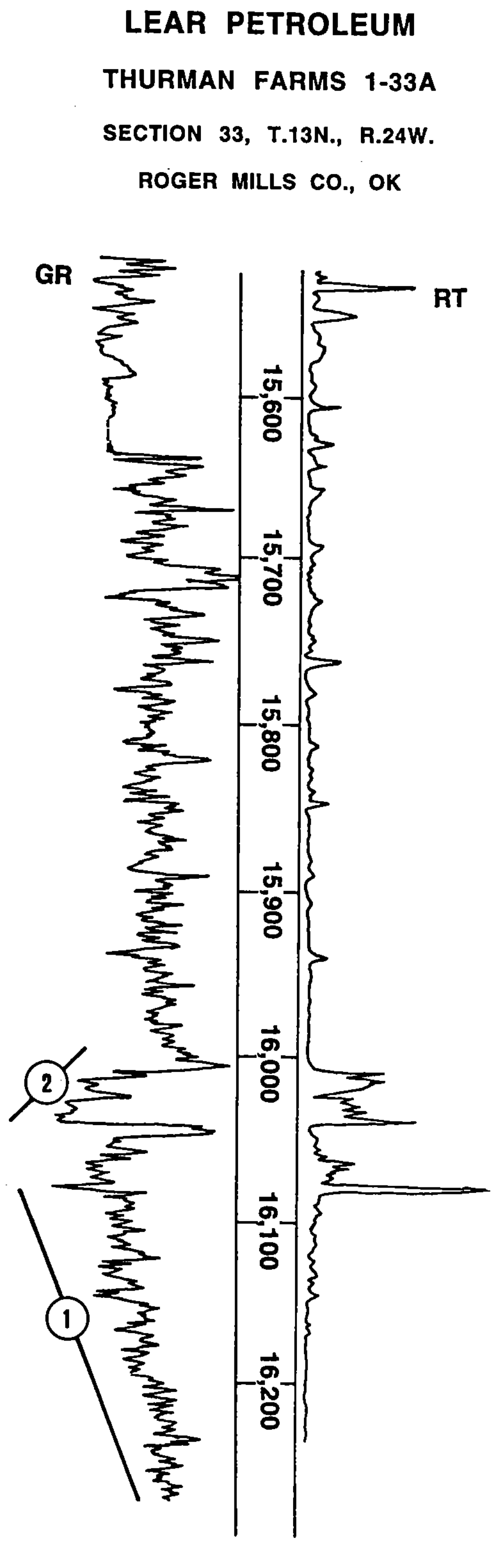

Figure 27. Log signatures that show (1) coarsening-upward sandstone and shale sequence (delta front) and (2) fining-upward sandstone (distributary-channel fill) in the Puryear interval.

The fossiliferous estuarine sandstone that immediately overlies the fluvial reservoir in the Hendrix core is tightly cemented by calcite cement (Fig. 36).

Paragenesis of the various diagenetic constituents in the upper Morrow channel-fill reservoirs is shown in Figure 37. Pseudomatrix in the fluvial unit formed very early in the burial history by the compaction and ductile deformation of shale clasts. Early sparry calcite precipitated in the estuarine sandstone prior to its isolation from the hydrodynamic flow regime. Calcite is especially abundant in the bioclastic estuarine unit, but occurs throughout the cored interval. The Morrow rocks were buried deep enough to initiate quartz overgrowths. With continued burial, kerogen matured and organic acids were generated. These acidic fluids leached relatively metastable grains such as plagioclase and microcline (Fig. 38). Dissolution of feldspars was followed by the partial leaching of granitic-rock fragments. The alkalinity of the pore fluids increased in response to H^+ consumption. These slightly alkaline fluids initiated dissolution of chert grains and the replacement of quartz grains by calcite.

The Morrow rocks on the northwestern shelf experienced a thermal event that converted some calcite to thermal (baroque) dolomite (Fig. 39). Afterward, the water chemistry became more acidic, and dolomite that bordered pores was corroded (Fig. 40). These acidic waters facilitated the precipitation of authigenic kaolinite (Fig. 40) and other clay minerals.

Wichita System Chert Conglomerates

The porous reservoirs in the upper Morrow chert conglomerates are the result of the extensive dissolution of grains, matrix, and cement. Four dominant dissolution features are recognized in the chert conglomerates. These are the dissolution detrital chert grains, detrital feldspars, detrital matrix, and carbonate cements.

Chert and feldspar were apparently components in dual geochemical processes. Detrital feldspars were initially leached to form honeycomb texture (Fig. 41). Subsequent dissolution completely removed grains and formed oversized pores. The dissolution of feldspar was likely driven by the generation of acidic fluids associated with source-rock maturation and hydrocarbon migration (Al-Shaieb and others, 1989). As feldspars were dissolved, H^+ ions were consumed and the pore fluids became more alkaline. These alkaline fluids attacked the relatively metastable matrix of chert grains and initiated chert dissolution.

Chert dissolution began with the selective removal of chert matrix between grains such as siliceous sponge spicules and fossils. This created initial microporosity (Fig. 42). With further dissolution, chert grains were completely removed, and

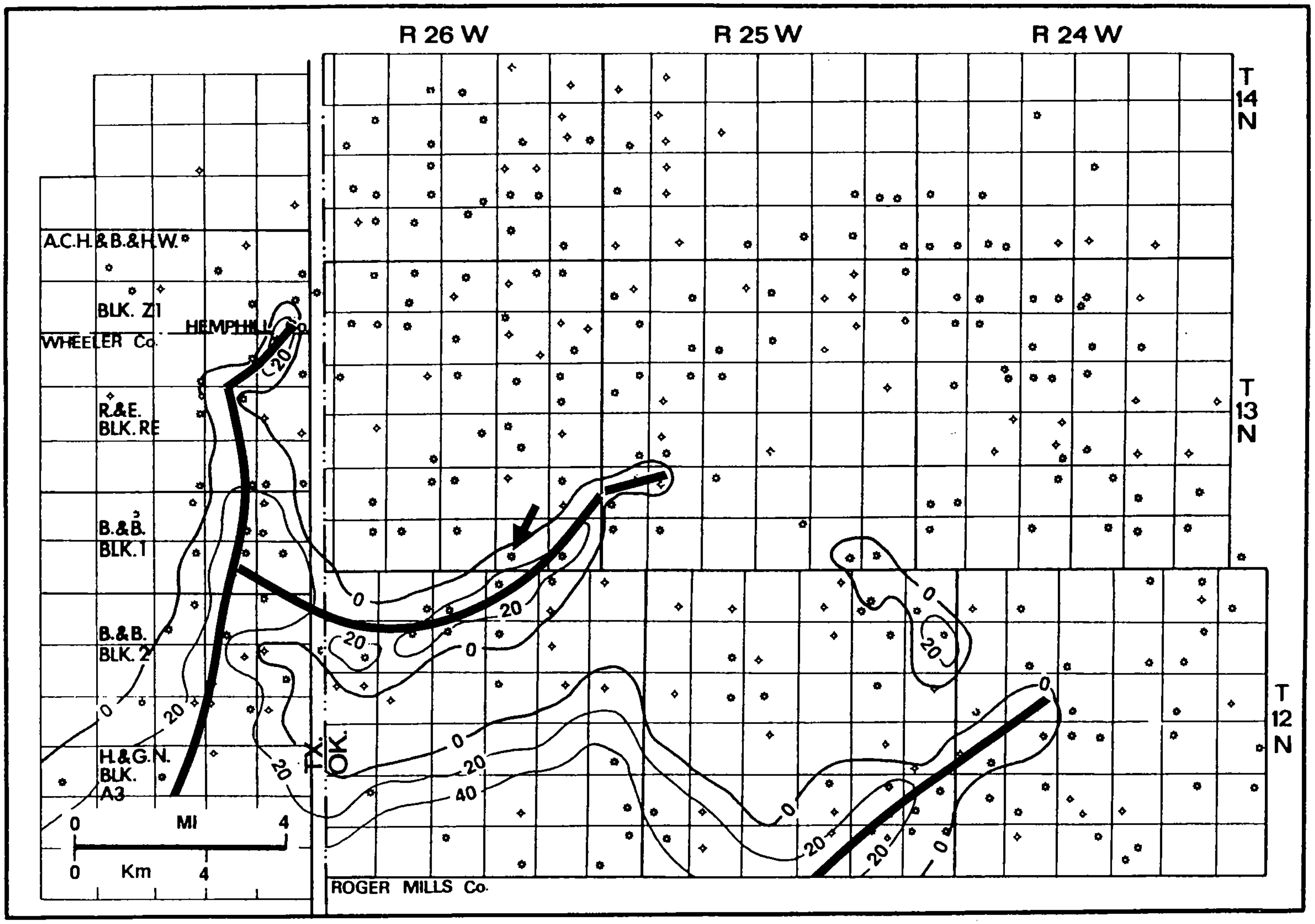

Figure 28. Thickness map of the Purvis conglomerate. Laterally continuous Purvis deposits occur along the southern margin of the map. Channelized braided distributaries extend northward from the area of sheet geometry. Contour interval = 20 ft.

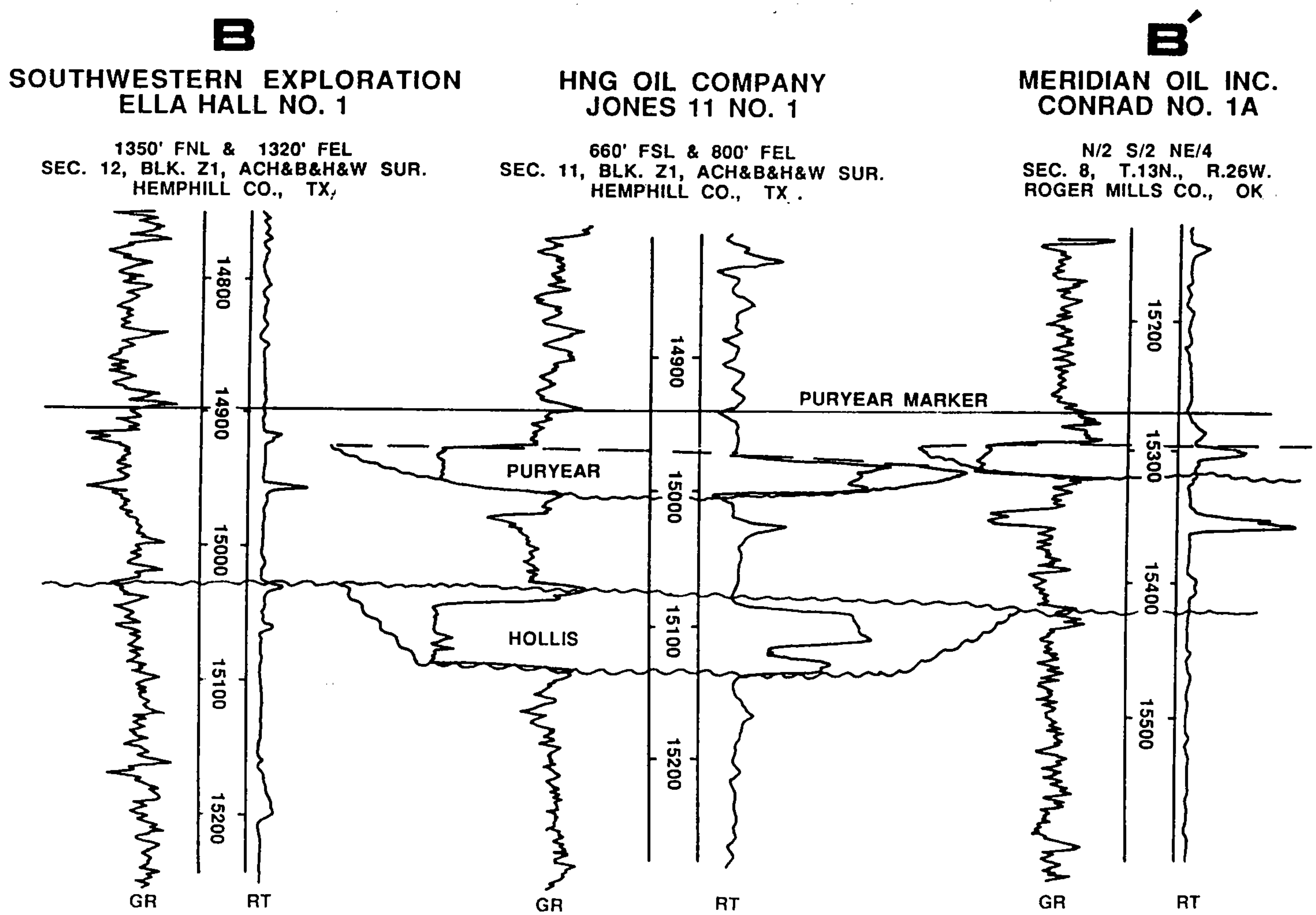

Figure 29. Cross section B–B′ illustrating the incision associated with the Hollis chert-conglomerate reservoir. Line of cross section is shown in Figure 26.

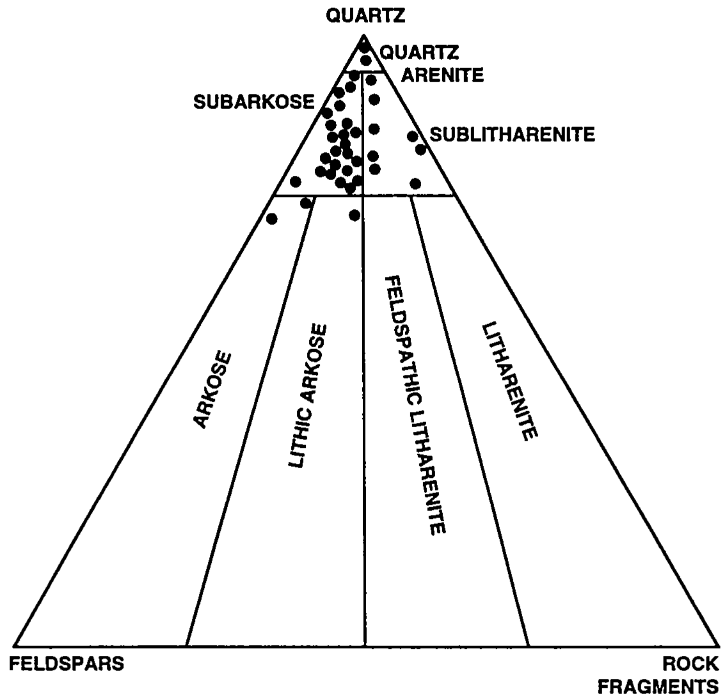

Figure 30. Classification of the upper Morrow sandstones of the northwestern shelf based on the method of Folk (1968; i.e., relative abundance of quartz, feldspar, and rock-fragment [QRF] detrital grains) (after Gerken, 1992; Harrison, 1990; and Munson, 1989).

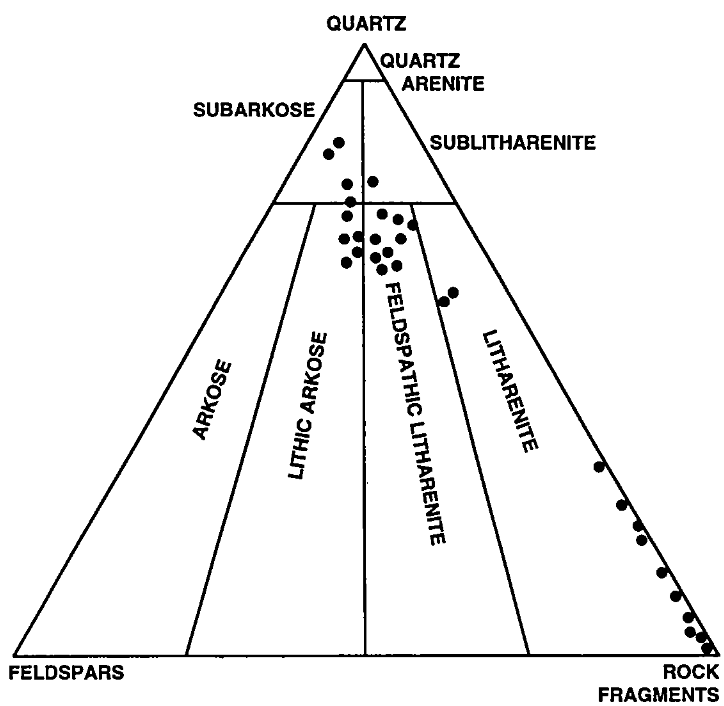

Figure 31. Classification of the chert conglomerates of the Wichita system based on the method of Folk (1968; see caption to Fig. 30) (after Alberta, 1987; Al-Shaieb and others, 1989).

oversized pores or vugs developed (Fig. 43). Dissolution of detrital matrix and carbonate cement also contributed to the chert-conglomerate reservoir genesis. Matrix and pseudomatrix (Fig. 44) dissolution occurred concurrently with feldspar dissolution (Alberta, 1987). Saddle dolomite precipitation may have accompanied chert dissolution. Dolomite corrosion (Fig. 45) and authigenic clay precipitation began when pore fluids became acidic again.

The complete paragenetic sequence of diagenetic events that have shaped the upper Morrow chert reservoirs is shown in Figure 46.

Chert conglomerates without an arkosic or early carbonate component became tightly cemented with silica. These chert-dominated rocks apparently make up much of the low-porosity, stacked conglomerate interval proximal to the Wichita-Amarillo uplift. These conglomerates may represent deposition by localized drainage systems. On the other hand, braided streams that drained larger areas, including those where igneous rocks were exposed, received larger amounts of sediments, including granitic-rock detritus. Over time, these braided streams repeatedly emanated from common locations along the uplift (Figs. 24,26,28) and flowed northward.

CONCLUSIONS

The upper Morrow rocks in the Anadarko basin were deposited within two distinct systems: (1) a southward-flowing, fluvial-dominated setting on the northwestern part of the Anadarko basin shelf (i.e., the shelf system) and (2) a northward-prograding braid- and fan-delta–dominated setting along the Wichita-Amarillo uplift (Wichita system).

1. The southward-flowing, fluvial-dominated system in the northwest deposited valley-fill

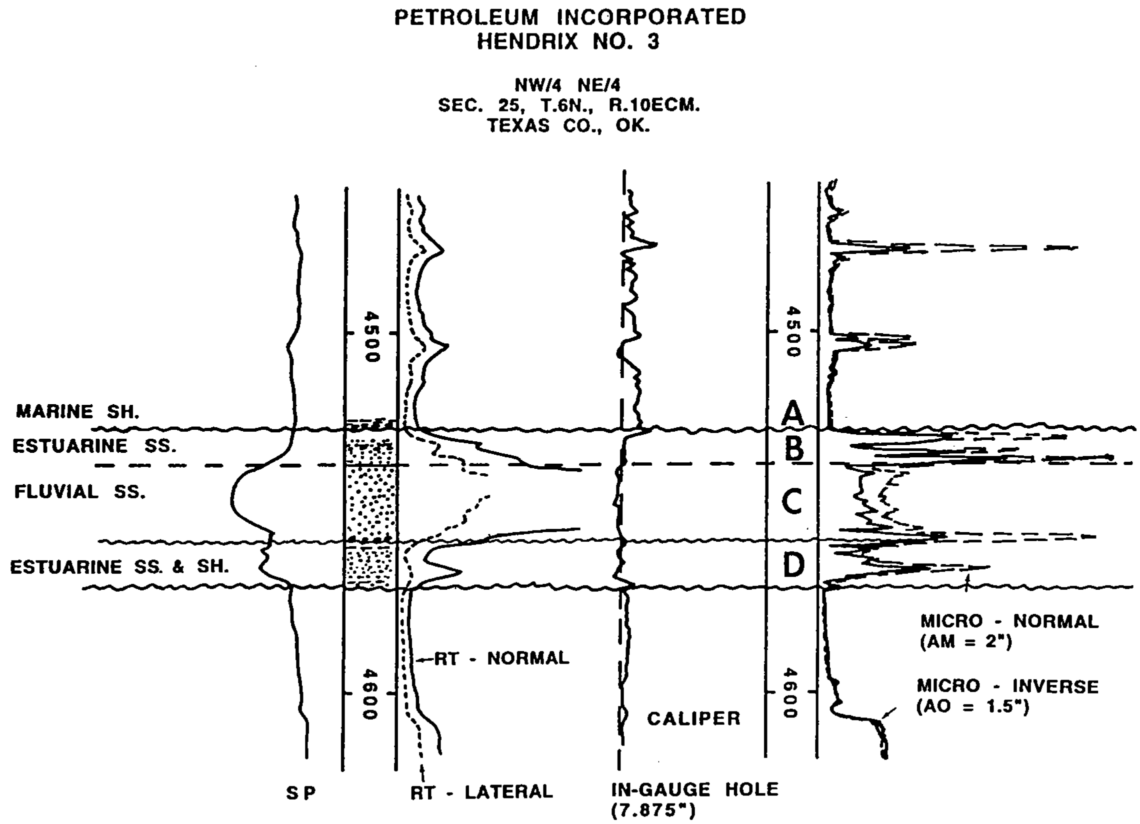

Figure 32. Composite wire-line log schematic diagram across the upper Morrow sandstone interval in the Petroleum Inc. Hendrix no. 3. Positive microresistivity separation identifies porous reservoir in the upper 11 ft of the fluvial sandstone (C). Estuarine sandstones B and D exhibit low porosity. (After Puckette, 1993.)

sequences within incised channels that cut into underlying shelf muds. This shelf system was characterized by fluvial, estuarine, and flood-plain environments that dominated channel deposition and that were succeeded by marine transgressions blanketing the shelf with mud. The shelf system was distinctly influenced by sea-level fluctuations that controlled deposition; channels were incised during sea-level lowstands and filled during sea-level rises. The subsequent channel-fill deposits are composed of quartz arenite, sublitharenite, and subarkosic rocks. They are characterized by variable reservoir quality that was influenced by depositional facies. Fluvial sandstones are coarser grained and have better porosity and permeability; estuarine sandstones, however, are typically finer grained and richer in detrital clay and bioclastic grains and therefore represent poorer reservoirs. Finally, the rocks of the shelf system exhibit both primary and secondary porosity. Secondary porosity was generated by the dissolution of metastable detrital grains and carbonate cement. Fluvial sandstones are typically more porous than estuarine sandstones in which detrital matrix and carbonate cements occluded much primary porosity.

2. The northward-prograding braid- and fan-delta system along the Wichita uplift (i.e., the Wichita system) is characterized by deposition of coarse clastic sediments within braided streams that prograded northward as braid- and fan-delta complexes or filled incised channels. The Wichita system was influenced by the rate of uplift to the south, which consequently controlled the style and rate of sediment deposition. Coarse sediment volume increased during periods of increased uplift. Braided streams incised underlying muds during tectonically (or eustatically) induced sea-level lowstands. The resulting deposits are composed of litharenites, feldspathic litharenites, and lithic arkosic rocks. Diagenesis in these deposits was dominated by the dual processes of dissolution of feldspar and chert, which controlled porosity development. Under acidic conditions, the granitic-rock fragments and feldspars were leached. When pore fluids became more alkaline owing to H^+ consumption, chert grains were dissolved. The porosity is almost entirely secondary.

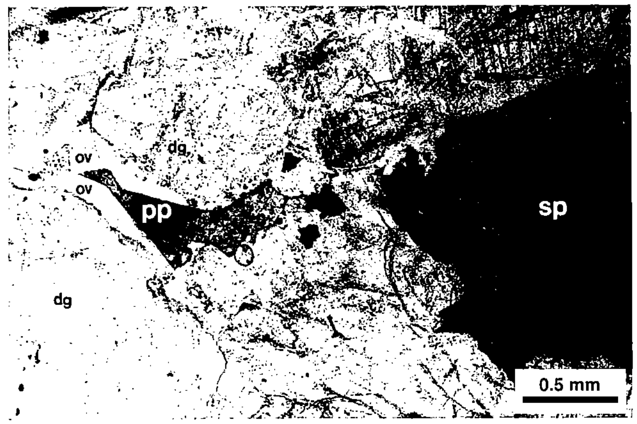

Figure 33. Photomicrograph illustrating primary and secondary porosity in the Petroleum Inc. Hendrix no. 3. Depth, 4,560 ft. Plane-polarized light.

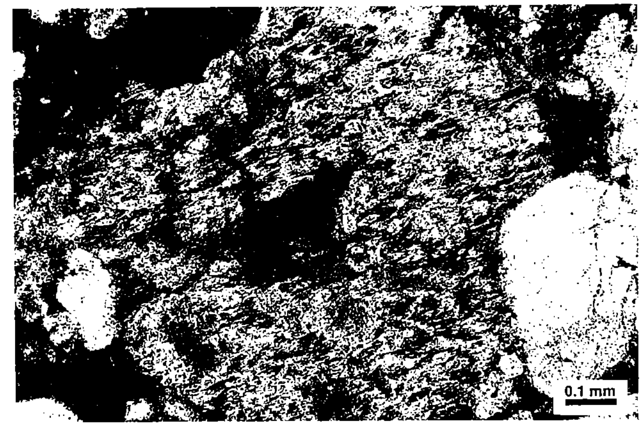

Figure 34. Photomicrograph of secondary intragranular porosity formed by the dissolution of feldspar. Petroleum Inc. Hendrix no. 3. Depth, 4,560 ft. Plane-polarized light.

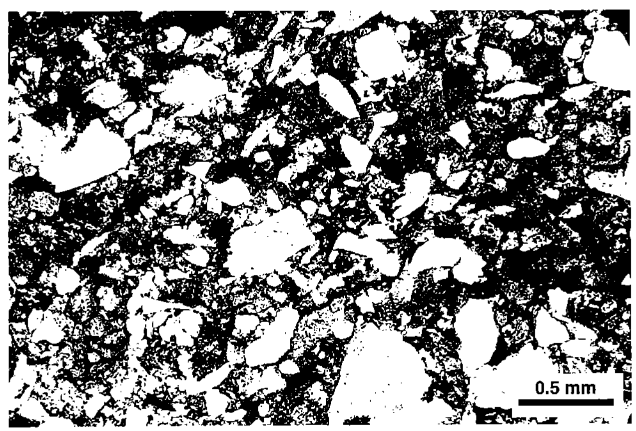

Figure 35. Photomicrograph of estuarine sandstone with abundant clay matrix and low porosity. Petroleum Inc. Hendrix no. 3. Depth, 4,573 ft. Plane-polarized light.

Figure 36. Photomicrograph of estuarine sandstone with abundant invertebrate grains and carbonate cement. Petroleum Inc. Hendrix no. 3. Depth, 4,543 ft. Plane-polarized light.

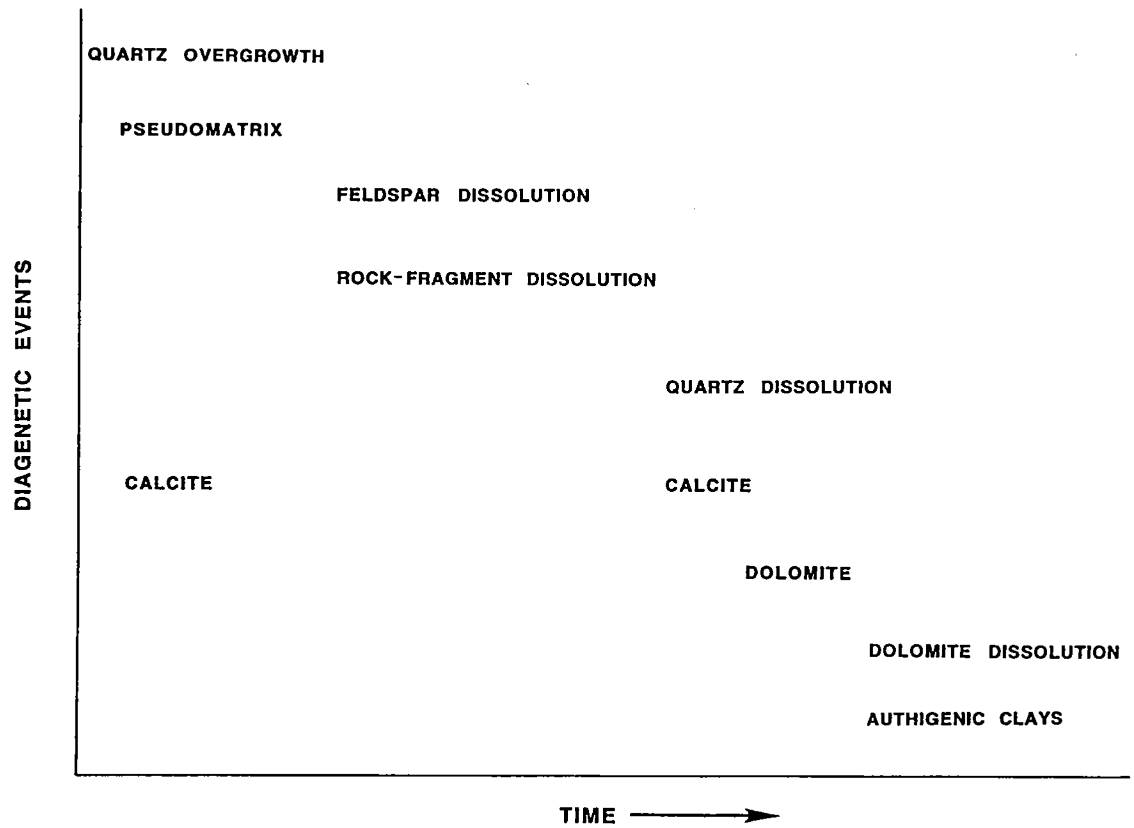

Figure 37. Generalized paragenetic sequence of diagenetic events for upper Morrow sandstones of the northwestern shelf.

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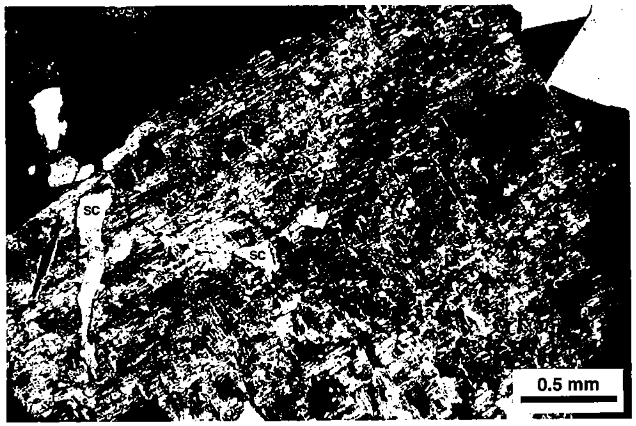

Figure 38. Photomicrograph of a leached microcline grain with infilling silica cement (sc). Petroleum Inc. Hendrix no. 3. Depth, 4,560 ft. Cross-polarized light.

Figure 39. Photomicrograph of baroque dolomite that replaced calcite cement. Petroleum Inc. Hendrix no. 3. Depth, 4,561 ft. Plane-polarized light.

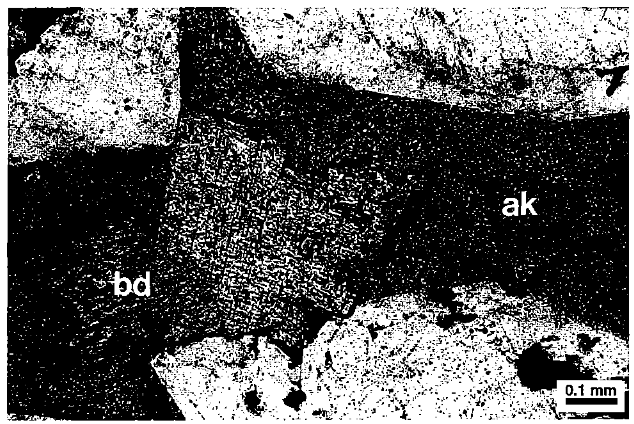

Figure 40. Photomicrograph of corroded baroque dolomite (bd) and pore-filling authigenic kaolinite (ak). Cox Carthage no. 7, sec. 20, T. 6 N., R. 20 E. CM. Depth, 4,536 ft. Plane-polarized light.

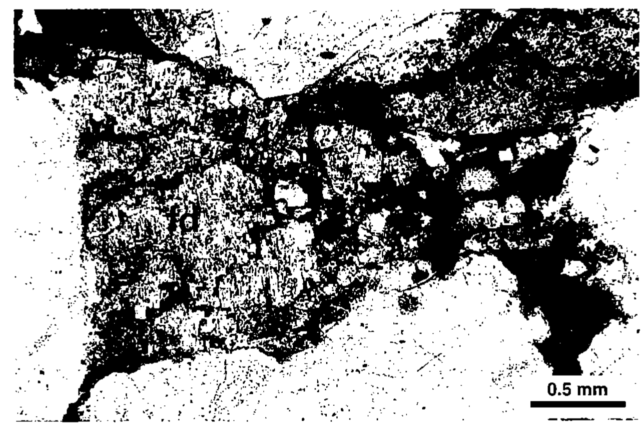

Figure 41. Photomicrograph of partially dissolved feldspar grain (fd) that was apparently crushed by postdissolution compaction. GHK-Apache Gregory no. 1-29. Depth, 17,167 ft. Plane-polarized light.

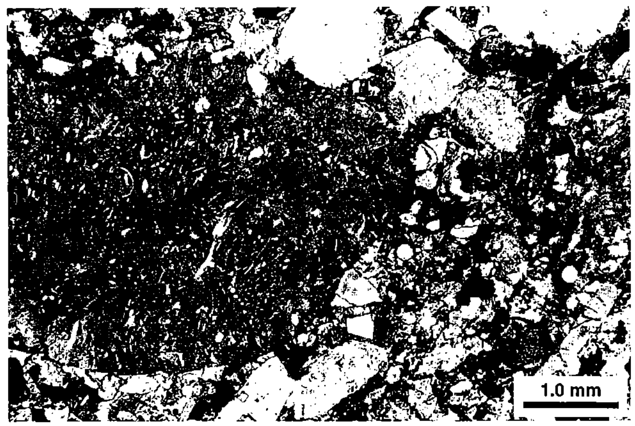

Figure 42. Photomicrograph of chert pebble where the grain matrix was selectively dissolved. Remaining light-colored material in grain is fossil debris. Exxon Sayre Ranch no. 1-35. Depth, 16,320 ft. Plane-polarized light.

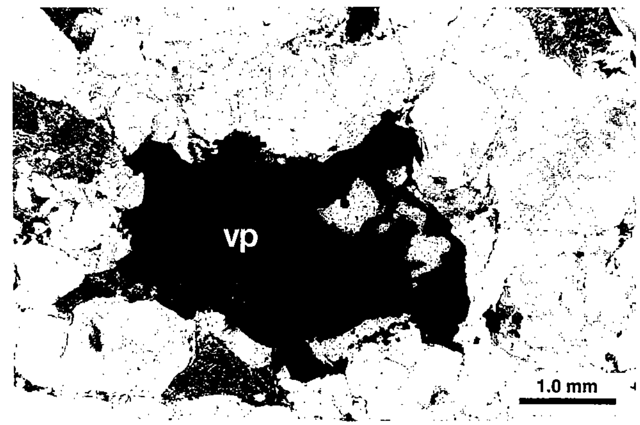

Figure 43. Photomicrograph of vuggy porosity (vp) formed by the dissolution of chert grain(s) and matrix. Apache Stiles no. 2-17, sec. 17, Block A-3, H&GN Survey, Wheeler County, Texas. Depth, 16,680 ft. Plane-polarized light.

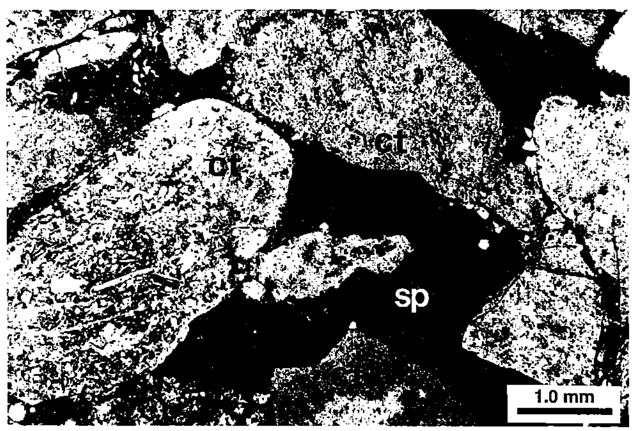

Figure 44. Photomicrograph showing secondary porosity (sp) formed by the dissolution of matrix between chert (ct) grains. Gulf Oil Company Osborne, sec. 37, Block M2, H&GN Survey, Roberts County, Texas. Depth, 10,840 ft. Plane-polarized light.

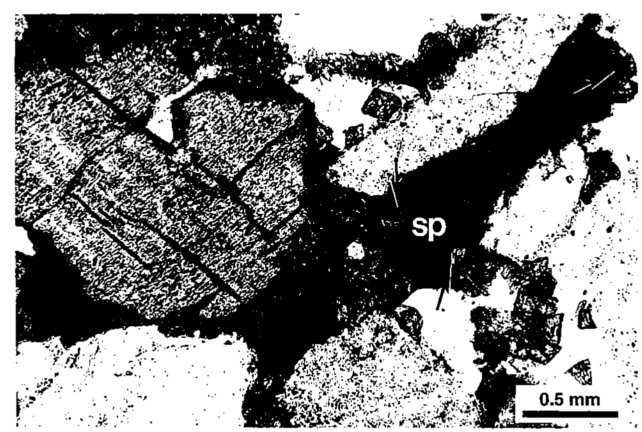

Figure 45. Photomicrograph of secondary porosity (sp) formed by the dissolution of dolomite (arrows). Shell Hobart Ranch no. 1-68, sec. 68, Block A-2, H&GN Survey, Hemphill County, Texas. Depth, 13,150 ft. Plane-polarized light.

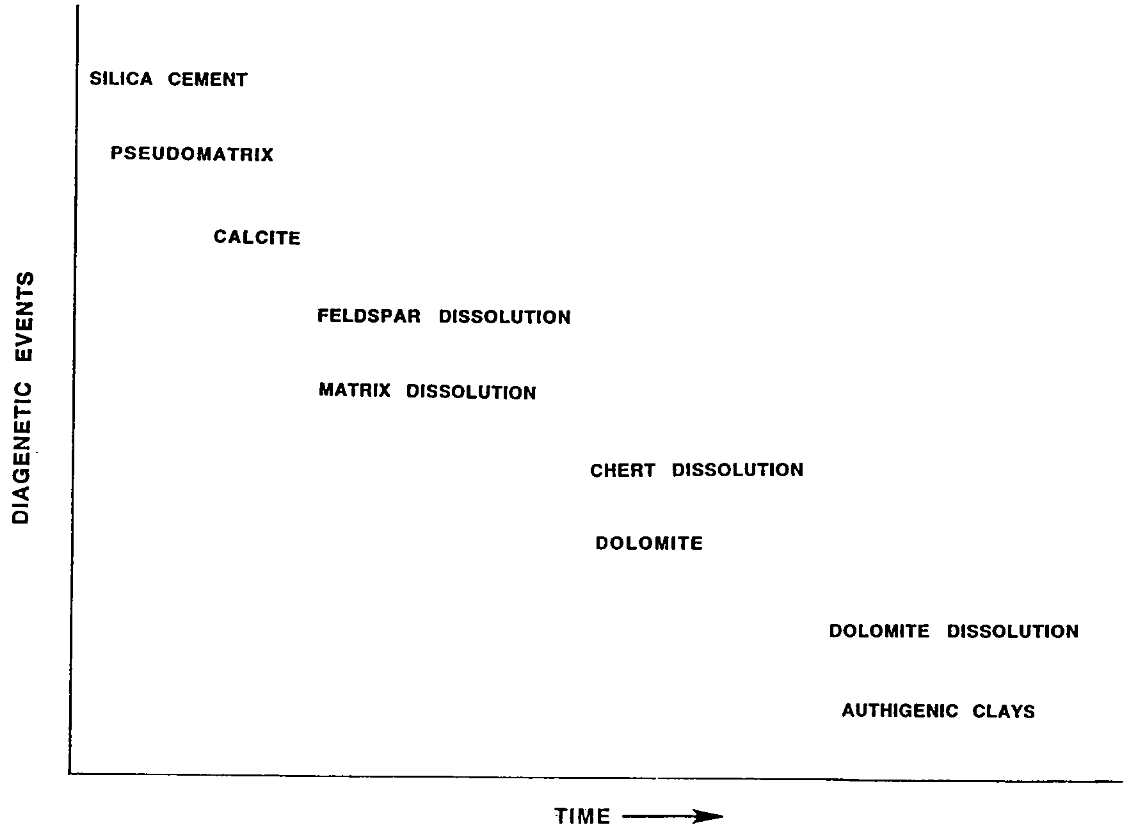

Figure 46. Paragenetic sequence of diagenetic events for chert-conglomerate reservoirs in the Wichita system (after Alberta, 1987).

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Three-Dimensional Modeling for Reservoir Characterization of the Gypsy Fluvial Sandstone Outcrop, Pawnee County, Oklahoma

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ABSTRACT.—BP Exploration spent more than $4,300,000 between 1989 and 1992 to establish a unique field laboratory and data set for the purpose of developing techniques for the characterization of fluvial reservoirs. The research facility, called "GYPSY," is located in northern Oklahoma, east of the town of Pawnee. The GYPSY data set consists of extensive geologic descriptions, cores and well logs, geophysical measurements (3-D seismic, cross well, and VSP), and well test data. In August 1992, this data set (including the test sites) was donated to the newly formed Center for Reservoir Characterization at the University of Oklahoma.

In preliminary studies of the GYPSY outcrop data set, the use of three-dimensional geologic modeling, combined with fluid-flow simulation, will be demonstrated for the purpose of reservoir characterization. In several flow simulations, an inverted geometric standard five-spot well pattern has been tested, versus an inverted nongeometric five-spot well pattern in which only the location of the injection well has been moved by ~250 ft. By moving the injection well, the total oil recovery during the simulated 2-yr period improved by 14.4%. In an attempt to optimize the recovery by using six wells, new locations for the producing wells have been established by building cross sections within the modeling capabilities of the software. As a result, the final simulation showed a much improved potential recovery.

INTRODUCTION

The verification of integrated methods of reservoir characterization requires data sets usually not provided by standard production operations. Between 1989 and 1992, BP Exploration sought to establish such a data set to bring focus to its integrated reservoir description program. In the three phases of data collection on its "GYPSY" field sites in northeastern Oklahoma, BP expended more than $4,300,000.

The GYPSY field laboratory consists of coupled outcrop and subsurface sites that have been characterized to a high degree of detail. The primary GYPSY outcrop site (strike view) is offered by the north face of a road cut along U.S. Highway 64, 25 mi from Tulsa. Secondary outcrops (strike and dip views) are located nearby. The subsurface site is located 19 mi downdip from the primary outcrop, where the Gypsy sandstone occurs at 1,000 ft depth (Fig. 1). Gypsy sandstone is an informal name for the lowermost interval of the Upper Pennsylvanian Vamoosa Formation (Fig. 2), and its name is derived from exposures at the GYPSY site.

The study area is located on the Cherokee platform, where the sediments that formed the Gypsy were deposited in a mixed-load meanderbelt system (after Galloway, 1985) whose dominant direction of sediment transport was to the west and northwest from source areas in the Ouachita and Arbuckle uplifts (Doyle and Sweet, 1992).

The GYPSY data set was gathered in three phases. The first phase developed detailed spatial distributions of reservoir properties (permeability, porosity, and lithology) from extensive sampling and mapping of the geologic units of the Gypsy sandstone as it is exposed by road cuts. To provide three-dimensional data, a grid of 22 shallow core holes were drilled behind the primary strike-oriented outcrop into the Gypsy interval.

The second phase characterized a subsurface pilot site containing depositional units with distributions of reservoir properties similar to those observed at the outcrop. Six wells were drilled and extensively cored and logged. Geophysical data were collected over a large frequency range, covering core, borehole (sonic-log, cross-well-seismic, and VSP—vertical seismic profiling), and surface

Seifert, D.; and O'Meara, D. J., Jr., 1996, Three-dimensional modeling for reservoir characterization of the Gypsy fluvial sandstone outcrop, Pawnee County, Oklahoma, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 85–92.

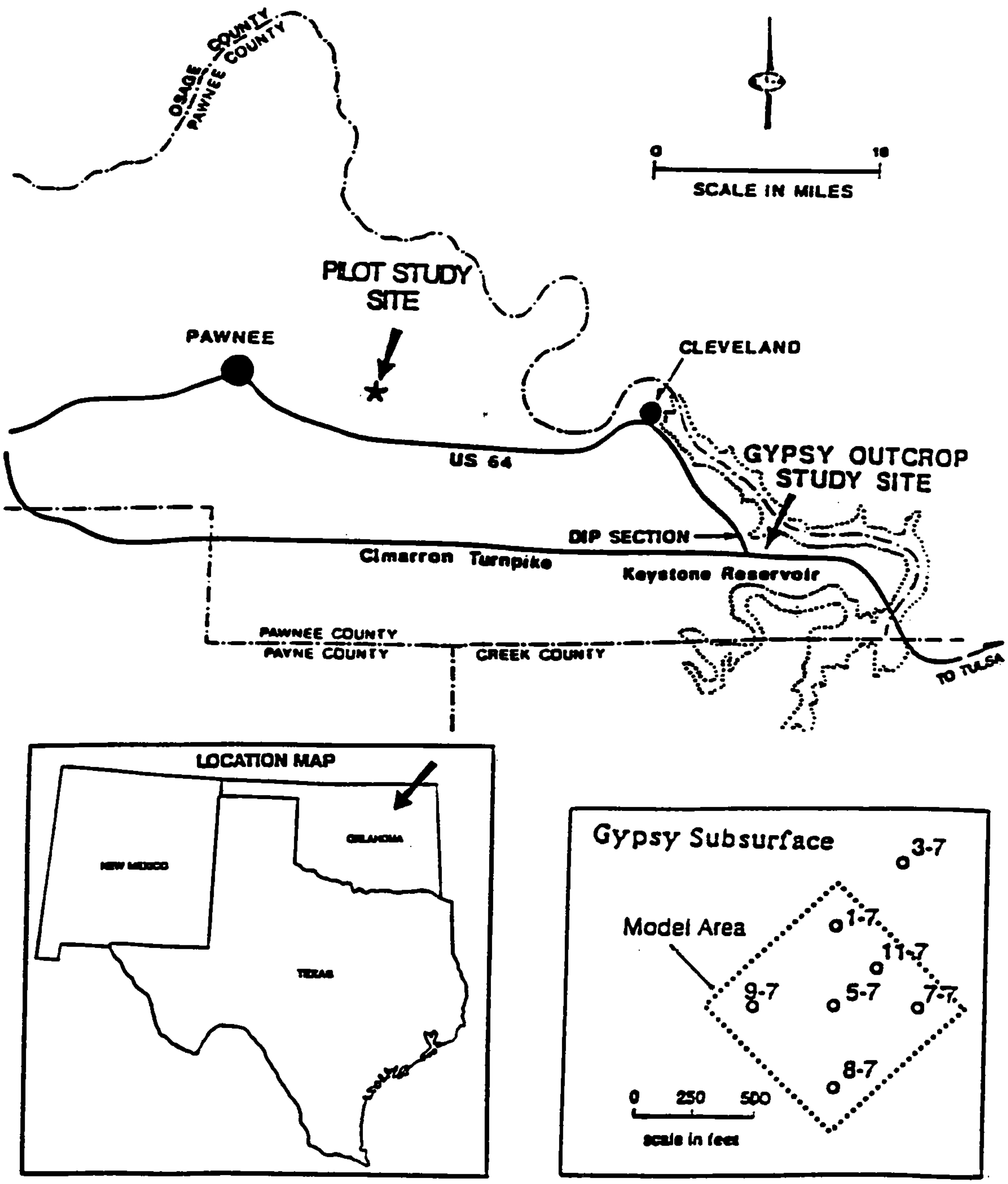

Figure 1. Location map showing the outcrop and subsurface study sites near Cleveland, Oklahoma.

(three-dimensional seismic-survey) measurements.

The third phase characterized reservoir flow performance. More than 125 pressure-transient well tests have already been completed in the six pilot wells. A proposed contrasting-salinity flood is designed to confront and verify descriptive and predictive tools with a detailed set of flow measurements that are capable of differentiating between equally plausible reservoir descriptions (Doyle and others, 1992).

An important part of designing the flood will entail investigating the range of possible flood responses, given the available data. In this prelimi-

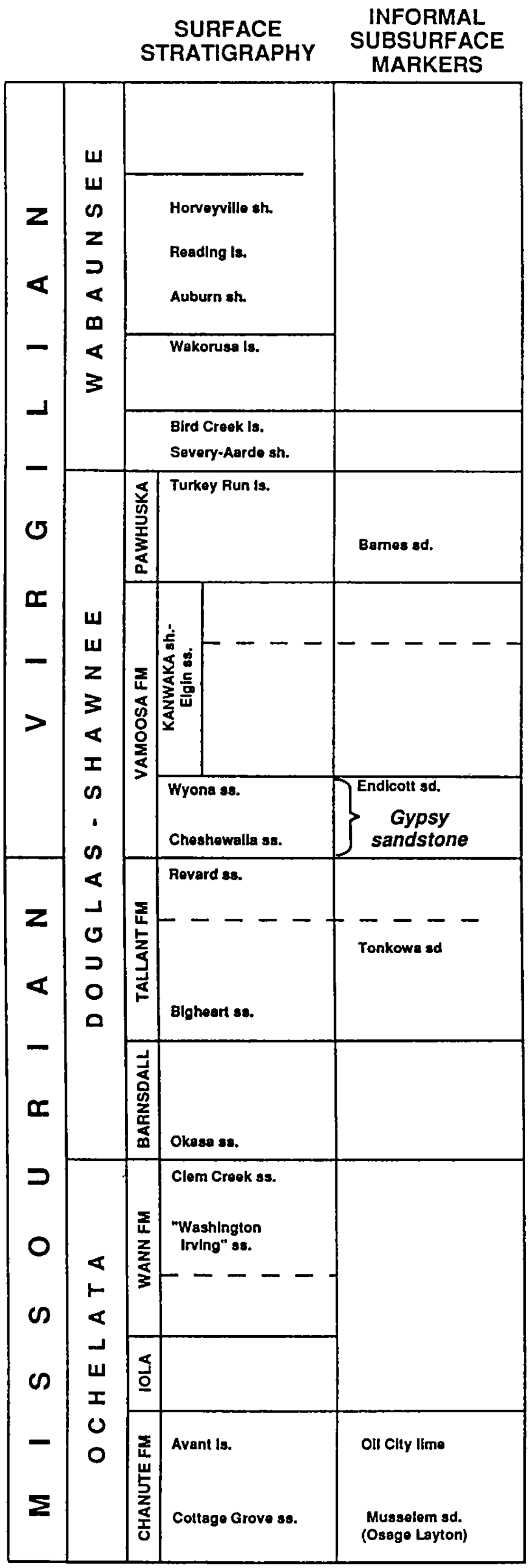

Figure 2 (left). Stratigraphic nomenclature of Pennsylvanian strata showing position of Gypsy sandstone (after Grieg, 1959; Ford, 1978).

nary study, detailed three-dimensional geologic models were constructed, fluvial-facies interpretations acquired from studies of the outcrops were incorporated, and reservoir fluid flow was simulated.

THE GEOLOGIC MODEL

Based on core descriptions, lithofacies mapping, and petrophysical measurements of the outcrop, a three-dimensional geologic model was established, as shown in Figure 3. The model was built by using a grid of 40 cells along the X-direction, 70 cells along the Y-direction, and 32 cells along the Z-direction. Therefore, the entire model consists of 89,600 cells, each of which has a size of $20 \times 20 \times 2$ ft in the X-, Y-, and Z-directions. The model was built by assigning a "channel number" value (based on core interpretation) to each X/Y location in a vertical sampling of 2-ft intervals in the Z direction.

In Figure 3, nine different depositional units can be identified (Doyle and Sweet, 1992), including seven channels (channel five includes crevasse-splay deposits), as well as the marine Tallant sandstone (lower boundary of the Gypsy interval), and the transgressive flood-plain deposits on top of the Gypsy interval. All channels are encased in shaly flood-plain deposits.

THE FLOW SIMULATIONS

Since it has been suggested in previous studies (Doyle and Sweet, 1992) that reservoir geometry—the trend of the channels—is far more important to fluid flow than the internal facies configuration within each channel, the reservoir properties, such as porosity and permeability, have been set as constant throughout the reservoir. The values for porosity (ϕ) and permeability (K) were derived from core descriptions and core-plug measurements, and the average values are $\phi = 20\%$, and $K(X,Y,Z) = 100$ millidarcies (md). The transmissibilities between the channels have been set at zero; therefore no flow communication exists between the channels. Each of the following simulations has been run for a simulated period of 2 yr (eight time steps), always by injecting a total of 2,000 standard barrels of water per day (STB/DAY) into one or both injection wells in the approximate center of the reservoir. The average simulation run was for 82 min, and the production data, as summarized in Table 1, were compared and analyzed after 365, 545, and 730 days.

TABLE 1. — OIL PHASE PRODUCTION DATA
Comparisons of Simulations 1–4 Showing Cumulative Oil Production and Percentage of the Total Recoverable Pore Volume

Total recoverable pore volume: 1,243,400 bbl

Simulations	Sim1	Sim2	Sim3	Sim4
365 days	516,700 bbl 41.6% of total	523,300 bbl 42.1% of total	598,400 bbl 48.1% of total	611,200 bbl 49.2% of total
545 days	555,800 bbl 44.7% of total	659,600 bbl 53.1% of total	701,200 bbl 56.4% of total	753,200 bbl 60.6% of total
730 days	573,200 bbl 46.1% of total	752,600 bbl 60.5% of total	762,200 bbl 61.3% of total	840,300 bbl 67.6% of total

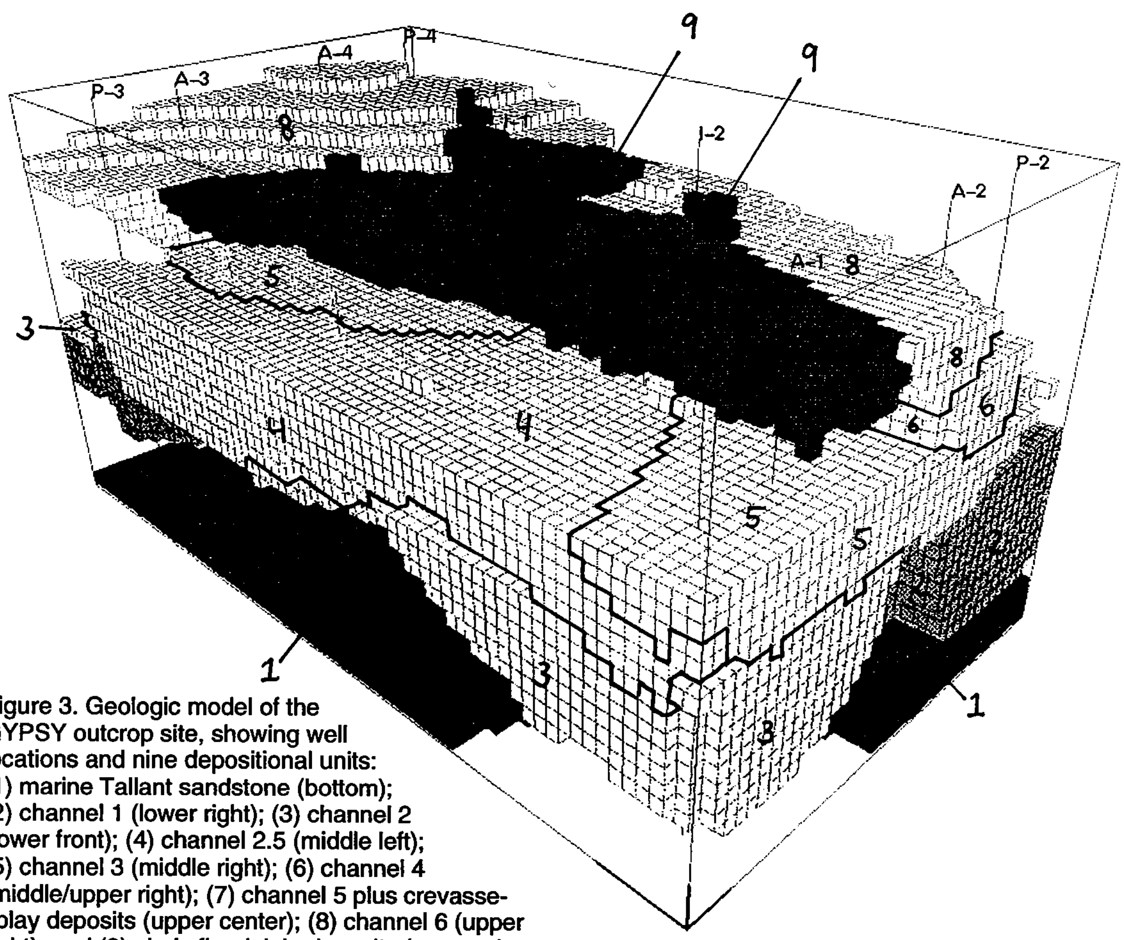

Figure 3. Geologic model of the GYPSY outcrop site, showing well locations and nine depositional units: (1) marine Tallant sandstone (bottom); (2) channel 1 (lower right); (3) channel 2 (lower front); (4) channel 2.5 (middle left); (5) channel 3 (middle right); (6) channel 4 (middle/upper right); (7) channel 5 plus crevasse-splay deposits (upper center); (8) channel 6 (upper right); and (9) shaly floodplain deposits (very top).

Simulation 1

For the purpose of simulation, a geometric standard five-spot well pattern was established. The water injection for the first simulation was performed at a rate of 2,000 STB/DAY through the geometric center, well I-1, toward the four producing wells (P-1 through P-4) in the four corners of the model (Fig. 3).

Figure 4 shows only the cells with a water saturation of >50% at the end of the simulation, after 2 yr; cells with such a high water saturation (S_W) are the ones in which the oil has been replaced by the injected water and produced. In addition, the gray shades of the cells represent the water saturation after 1 yr (365 days), and the black cells have a water saturation of 100% (complete production). Please note the sharp fluid front (saturation contrast), which is due to high and uniform porosity (ϕ = 20%). After 2 yr (730 days) of production, the thoroughly swept cells are well distributed laterally within the reservoir, but occur only below a certain vertical level, which includes only the lower channels. The explanation follows in Figure 5, which shows a traverse combining all the wells. It can be seen that the injector well I-1 (in the center of Fig. 5) does not penetrate many channels; in fact, it penetrates only channels two, three, and five (plus crevasse splay), and the other channels in the reservoir were not affected at all. It turns out that this well pattern contains only two productive geobodies, meaning channels that contain at least one injection and one production well (please note that the producing wells, P-1 through P-4, penetrate only two channels). Those are channels two and three, which were swept very well (98.9% of the total moveable pore volume of channels two and three), after 2 yr. However, the widespread distribution of black cells in the gray-shaded overlay (black cells equal 100% S_W) shows that these two channels were already thoroughly swept during the first year of simulated production (88.4%). Not surprisingly, total cumulative water production is very high and amounts to 886,100 bbl after 2 yr. Since production occurred only from two productive geobodies (out of seven potential geobodies), the total cumulative oil production after 2 yr amounted to only 46.1% (573,200 bbl) of the entire reservoir, resulting in a water/oil production ratio of 1.55.

The task of finding better well locations is often very difficult, since commonly there are not enough data available. Here, however, three-dimensional modeling can be put to work. By quickly building some arbitrary cross sections one

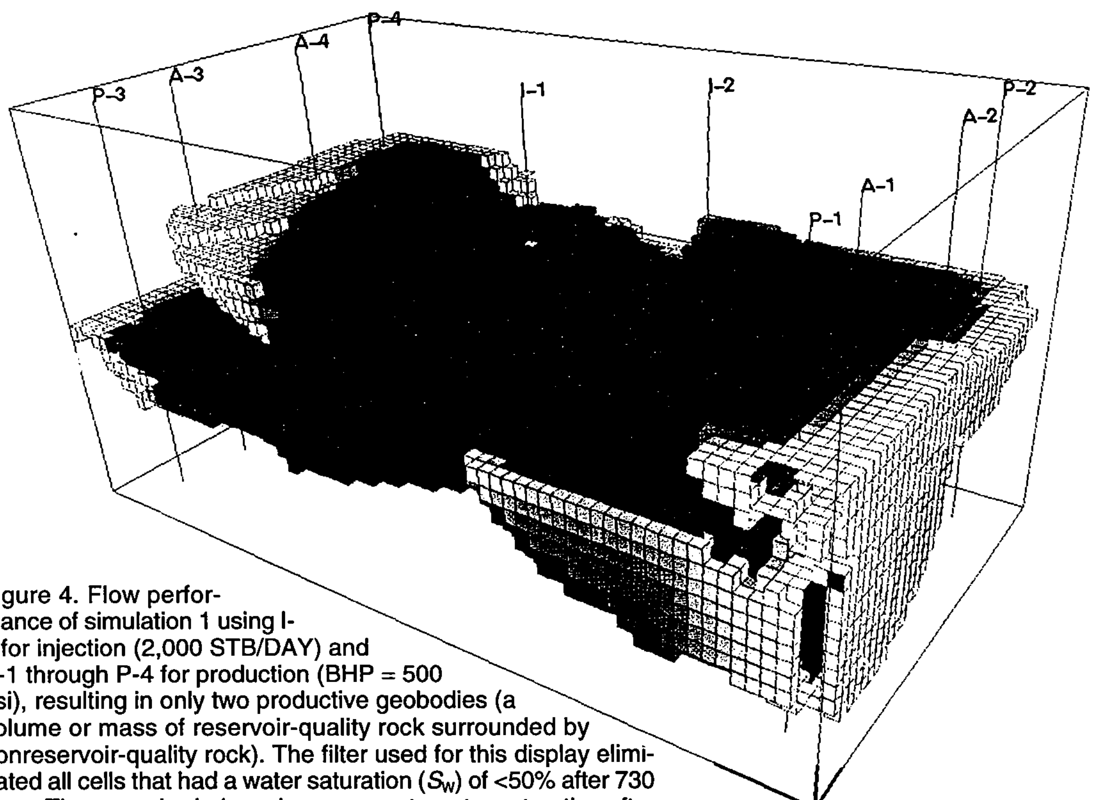

Figure 4. Flow performance of simulation 1 using I-1 for injection (2,000 STB/DAY) and P-1 through P-4 for production (BHP = 500 psi), resulting in only two productive geobodies (a volume or mass of reservoir-quality rock surrounded by nonreservoir-quality rock). The filter used for this display eliminated all cells that had a water saturation (S_W) of <50% after 730 days. The gray-shaded overlay represents water saturation after 365 days (in the black area, S_W = 100%), indicating the sweep efficiency at this time step. The total cumulative oil production equaled 46.1% of the total recoverable pore volume, after 2 yr.

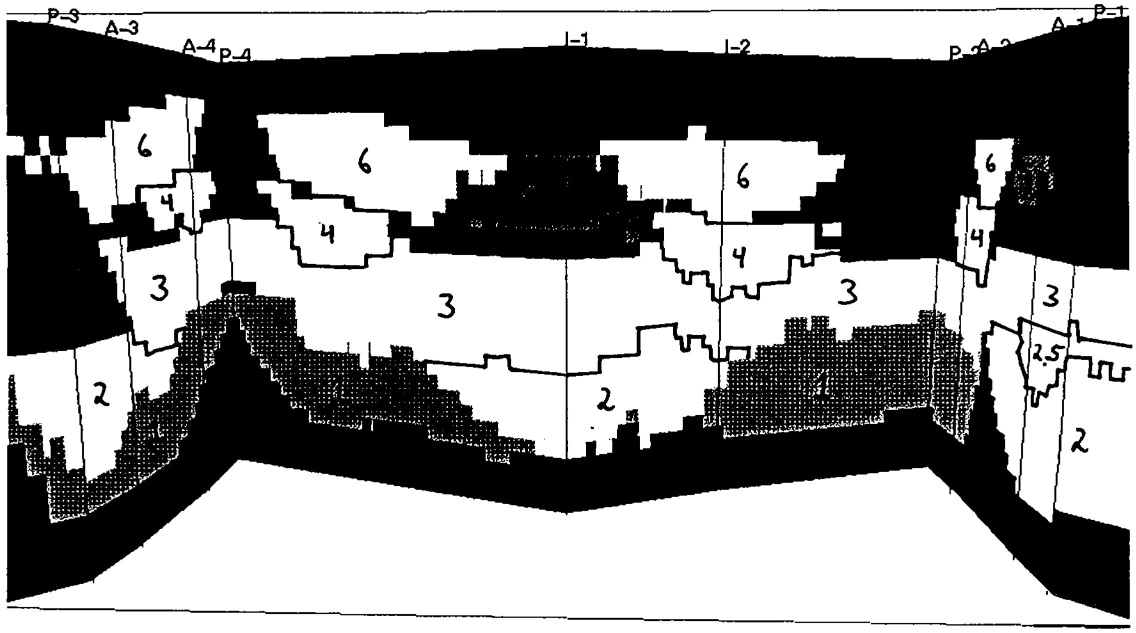

Figure 5. Northwest-southeast traverse through the GYPSY outcrop site, combining all wells. The numbers indicate the channel numbers; the black areas surrounding the channels are encasing shales. Wells P-1 through P-4 and I-1 are penetrating only two to three channels out of seven, resulting in only two productive geobodies. However, the wells A-1 through A-4 and I-2 are penetrating three to five channels, resulting in five productive geobodies. Only a combination of both injection wells and the production wells A-1 through A-4 will result in six productive geobodies.

can more clearly understand the reservoir geometry, and better well locations are then easily found and established. Based on such geologic modeling, another injection well (I-2)—which penetrates all channels except channel five (plus crevasse splay)—was established for the purpose of injection (Fig. 5).

Simulation 2

Again, a water injection over a 2-yr period was simulated, keeping the reservoir properties, time steps, and production-well locations the same as for simulation 1. However, this time the injection of water occurred only through the injector well I-2, at a rate of 2,000 STB/DAY.

At the end of the first year, simulation 2 shows only a 0.5% better total oil production than simulation 1. This result seems to be surprising at first, since simulation 2 utilized the injection well I-2, which penetrates more channels than I-1 and therefore accesses more of the reservoir (five productive geobodies). However, the low improvement of production during the first year is due to the fact that, since I-2 penetrates more channels, the total water input of 2,000 STB/DAY is also injected into more channels at the same time, and it therefore took longer to pass the threshold pressure within each channel to move the oil toward the producing wells (P-1 through P-4). In addition, channels two and three were swept very well during the first year in simulation 1. During the second year, the simulated production quickly out distanced that of simulation 1, and by the end of the simulated period, i.e., after 2 yr, simulation 2 had out-produced simulation 1 by 14.4% (179,400 bbl) (Table 1). This significant improvement of oil production clearly demonstrates the importance of a single well location, in this case that of the injection well I-2. Not surprisingly, the total cumulative water production in simulation 2 is much lower and amounts to 707,400 bbl after 2 yr, exhibiting a water/oil production ratio of 0.94.

Figure 6 shows the cells with a water saturation of >50% at the end of the simulation 2. Here, the flooded cells occur at all vertical levels and throughout the reservoir, and it is highly visible that the sweep efficiency in simulation 2 was much greater than in simulation 1.

Simulations 3 and 4

In order to test a different recovery strategy, the next simulation, simulation 3,was performed by injecting 1,000 STB/DAY into each of the two injection wells, I-1 and I-2. The producing wells, P-1 through P-4, were still located in the geometric corners of the reservoir. By using this production-well pattern, production occurred from five geobodies; after 1 and 2 yr, production during simula-

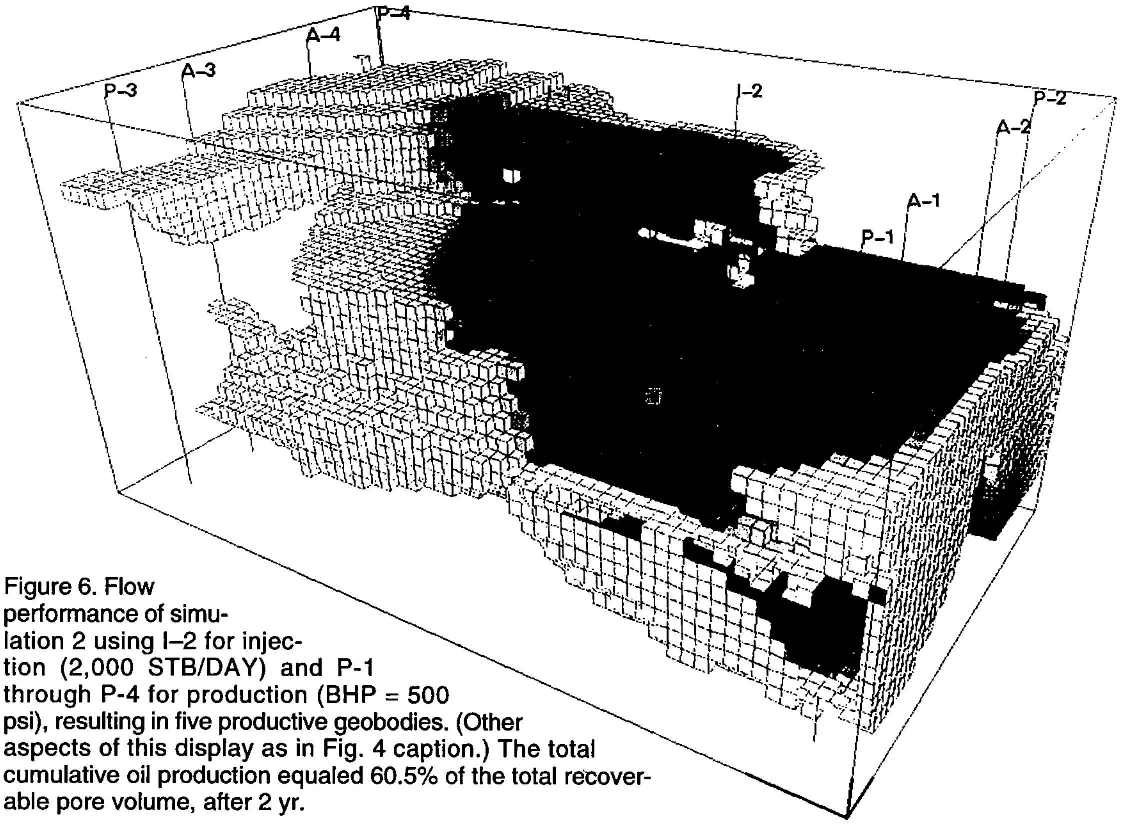

Figure 6. Flow performance of simulation 2 using I–2 for injection (2,000 STB/DAY) and P-1 through P-4 for production (BHP = 500 psi), resulting in five productive geobodies. (Other aspects of this display as in Fig. 4 caption.) The total cumulative oil production equaled 60.5% of the total recoverable pore volume, after 2 yr.

tion 3 was, respectively, 6.0% and 0.8% better than during simulation 2. The improvement of the total production decreased with time, suggesting that the unfortunate locations of the producing wells began to gain importance after 1 yr; thus the initially positive effect of spreading the injectant over two locations, rather than one, was equalized. The total production amounted to 61.3% of the total reservoir, or 76.0% of the total moveable pore volume of the five productive geobodies.

However, for the last simulation, simulation 4, new locations for the producing wells (A-1 through A-4) were chosen (keeping I-1 and I-2 at injection rates of 1,000 STB/DAY each), in an attempt to further improve the recovery. This well pattern utilizes six productive geobodies, but each of the production wells, A-1 through A-4, penetrates more channels (geobodies) than the wells P-1 through P-4 from previous simulations (Fig. 5), therefore improving the channel/production-well ratio. As can be seen in Figure 7, the distribution of the cells that have a water saturation of >50% is more evenly spread laterally and vertically over the entire reservoir, indicating a very good sweep efficiency. Again, the black cells indicate that sweep performance decreased through time (excellent sweep after 1 yr), but was still excellent at the end of the simulated production of 2 yr. Simulation 4 produced a total of 67.6% (840,300 bbl) of the total recoverable pore volume, which implies an additional increase of production of 6.3%, or 78,100 bbl, as against simulation 3 (Table 1).

CONCLUSIONS AND RECOMMENDATIONS

The GYPSY sites provide a well-calibrated field laboratory for testing new tools and methods. They offer a "real-world" environment for testing the effectiveness of reservoir-modeling tools, such as geophysical imaging, geostatistical methods, well-testing methods, tracer testing, and recovery simulation studies. The GYPSY Project provides a superb opportunity to focus interdisciplinary efforts. Moreover, it offers unique educational and training opportunities for industry, government, and university personnel.

By using specialized geologic-modeling software, a three-dimensional geologic model (consisting of 89,600 cells) of a potential fluvial reservoir of Pennsylvanian age was built, and four fluid-flow simulations were compared and analyzed. By utilizing six irregularly positioned wells, whose locations were chosen with respect to geology, instead

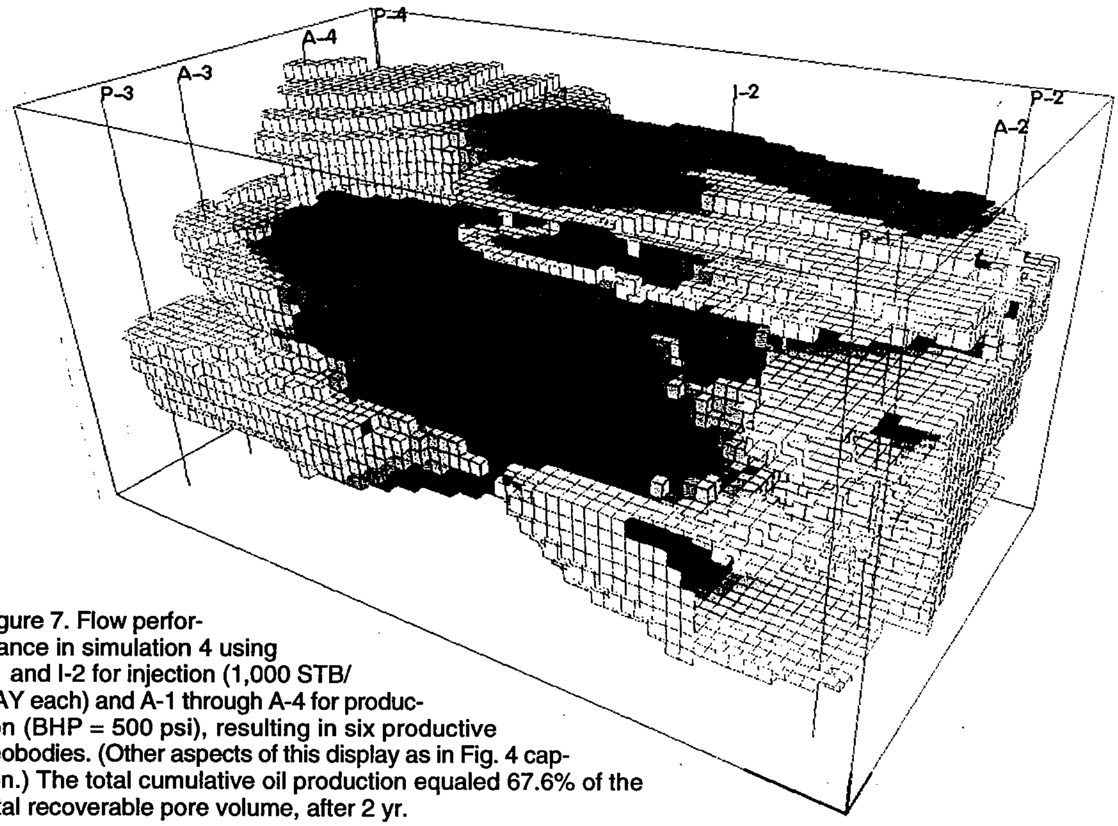

Figure 7. Flow performance in simulation 4 using I-1 and I-2 for injection (1,000 STB/DAY each) and A-1 through A-4 for production (BHP = 500 psi), resulting in six productive geobodies. (Other aspects of this display as in Fig. 4 caption.) The total cumulative oil production equaled 67.6% of the total recoverable pore volume, after 2 yr.

of the initially simulated geometric standard five-spot well pattern, the total cumulative oil production was improved by 21.5%.

This example clearly shows that a standard five-spot well pattern (presumably all standard well patterns) is not very well suited for exploitation of a fluvial reservoir in which the channels are not stacked vertically on top of each other. In such a reservoir, a well pattern would need to be chosen carefully, so that the wells penetrate as many channels as possible (e.g., using different well positions or deviated wells).

Three-dimensional modeling combined with fluid-flow simulation is found to be useful for the reservoir geoscientist in quickly testing, improving, and displaying a recovery strategy. Another very important advantage of three-dimensional modeling is the power of visualization, which would be very helpful in showing strategies and reservoir performances to the nongeoscientist, such as management boards of some oil companies.

ACKNOWLEDGMENTS

This study has been made possible by the enthusiastic support and generous donation of the software packages SGM/GTM (three-dimensional modeling and visualization) and StrataSim (reservoir simulation) from Stratamodel, Inc., in Houston. We also thank BP Exploration for providing such an extensive database and start-up funds to conduct this and further studies.

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Integrated Reservoir Description Using Outcrop Studies: Example from the Bartlesville Sandstone, Northeast Oklahoma

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ABSTRACT.—The study site consists of an east-west road cut, cleared of vegetation, along County Highway 20 between the communities of Claremore and Pryor, Oklahoma, and an array of 12 wells drilled north of the road cut. The exposure of Pennsylvanian Bartlesville sandstone in the road cut is 70 ft high and 350 ft long, and is approximately transverse to the regional channel-axis orientation. The road cut has been studied along 40-ft-spaced, and selected 20-ft-spaced, vertical transects. Wells drilled, cored, and logged (gamma ray, spontaneous potential, resistivity, and neutron density) into the Bartlesville are arranged in a 75-by-75-ft grid of ten wells with an extension of a single leg of two additional wells 780 ft northward from the road cut. A microresistivity log (FMS) was taken in the well located farthest from the road cut. Sedimentologic characteristics have been described and interpreted in detail from the road cut grid and slabbed cores. In addition, permeability values were measured with a minipermeameter on the surfaces of the outcrop and slabbed cores at 1-ft intervals and in selected areas at 0.5-ft intervals. Conventional methods were used to measure approximately 200 horizontal plus vertical core plugs for permeability and porosity. Core-plug and minipermeameter permeability values are closely correlated throughout the range of values (0.5 to 213 millidarcies).

At the study site, the Bartlesville sandstone is composed of multiple channel-fill storeys. Each channel-fill storey and its contiguous facies represent a discrete genetic interval. Erosion surfaces of variable relief separate 15- to 20-ft thick channel-fill facies with sand-on-sand contacts being common. The channel-fill facies is further divided into three subfacies, discussed here in ascending order. The *lower channel-fill subfacies* consists of a basal, medium- to thick-bedded, structureless, medium sandstone a few feet thick with abundant mudstone rip-up clasts and an overlying, medium to fine sandstone with medium-scale trough cross-stratification; intraclast lags are common at the base of cross-strata sets and within cross-strata foresets. The *middle channel-fill subfacies* is characterized by low-angle, parallel-stratified, and ripple-laminated, fine to very fine sandstone; however, rip-up clasts and mud drapes are common throughout, some of which are associated with lateral accretion surfaces. Isolated sets or cosets of low-angle medium-scale trough cross-stratification are also developed in the middle channel-fill subfacies and are thought to represent chute-channel cut and fill. The *upper channel-fill subfacies*, not well represented in core or outcrop because of the deep cutting of successive channels, is made up of very fine sandstone and mudstone with evidence of early diagenesis related to paleosol formation and plant bioturbation.

Geostatistical analysis has revealed some correlation between spatial variation in permeability and gamma-ray emission and sedimentologic character of the Bartlesville. Permeability within each discrete genetic interval can be represented by log-normal distribution; however, permeabilities among the discrete genetic intervals have different means. Vertical variograms of gamma ray and permeability consistently show a hole effect at 15–20 ft (channel-fill facies thickness); the hole effect for gamma ray, however, is more pronounced than that for permeability. Additional analysis is underway to evaluate the correlation, if any, between reservoir properties and sedimentologic units at finer scales.

Kerr, D. R.; Martinez, G.; Azof, I.; and Kelkar, M. G., 1996, Integrated reservoir description using outcrop studies: example from the Bartlesville sandstone, northeast Oklahoma, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 93.

Mine-Assisted Secondary Recovery of Oil in the Bartlesville Sandstone, Cushing Field, Northeastern Oklahoma

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ABSTRACT.—Sixteen different stratigraphic units have been oil and/or gas producers in the Cushing field. Of these, the most productive have been the informally named Layton sandstone, the Oswego limestone–Prue sandstone interval (or Wheeler sandstone), the Red Fork sandstone, and the Bartlesville sandstone (Middle and Late Pennsylvanian). Originally, the field was developed on 10-acre spacing, but, records show that production decreased rapidly as solution gas was dissipated.

Even though the present wells are widely spaced, field production has been relatively consistent since 1975. This record suggests that there is good horizontal permeability over a considerable area, at least in some stratigraphic horizons.

Mine-assisted development on 1-acre, or closer, spacing is likely to be a viable option. Such a system could provide controlled, gravity-drain access to each or all of the producing formations. Because of the extent of past development and the overlapping of producing areas, detailed examination of all available data will be required to determine a preferred shaft site and system of field development.

INTRODUCTION

As of December 1978 (Petroleum Information Corporation, 1978), the Cushing field had produced 471.3 million barrels of oil. The discovery well in the Cushing field was completed in March 1912 in the Wheeler sandstone, which now includes the Oswego limestone and Prue sandstone. The field is located in sec. 31, T. 18 N., R. 7 E. Until December 1913, production was confined to the Layton and Wheeler sandstones.

In December 1913, oil was discovered in the Bartlesville sandstone ; the discovery well is located in sec. 3, T. 17 N., R. 7 E. For the following year, most of the drilling was to the Bartlesville interval, with substantial production coming from that sandstone. The following quote from Buttram (1914) provides a good insight into early production:

> The Bartlesville pool is comparatively new and more time and development is necessary to give it a thorough test. The general behavior of the wells in the Bartlesville sand is shown by the following group of wells which have been selected from one of the principal leases in this area:
>
> No. 1, initial production 2,200 barrels, completed May 12, 1914
> No. 2, initial production 1,104 barrels, completed June 26, 1914
> No. 3, initial production 2,640 barrels, completed July 18, 1914
> No. 4, initial production 432 barrels, completed September 15, 1914
> No. 5, initial production 1,100 barrels, completed September 28, 1914
>
> The total initial production of these 5 Bartlesville wells was 7,476 barrels. On October 1, 1914, just 3 days after the last well was brought in with an initial production of 1,100 barrels, the 5 wells were making a total production of only 2,000 barrels per day, which is an extremely rapid decline on production.

It is interesting that the Dwight's Energydata (1992) curve for the Bartlesville in T. 17 N., R. 7 E., shows a production decline from 70,000 barrels per month in 1974 to 17,000 barrels per month in 1992 (Fig. 1). For T. 18 N., R. 7 E., the decline was from about 15,000 barrels per month in 1974 to 13,000 barrels per month in 1992 (Fig. 2).

Ayler, M. F., 1996, Mine-assisted secondary recovery of oil in the Bartlesville sandstone, Cushing field, northeastern Oklahoma, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 94–99.

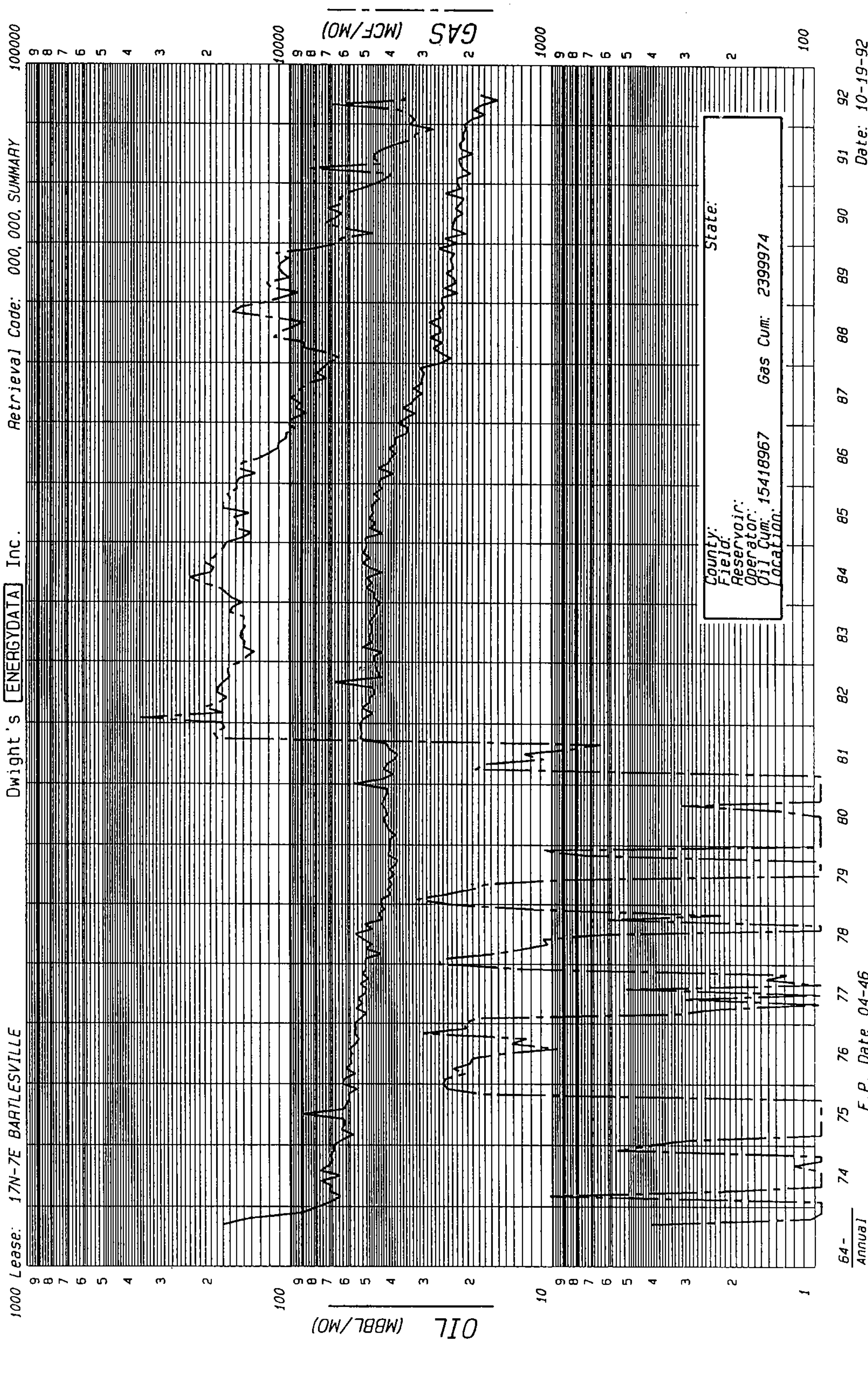

Figure 1. Production curve for Bartlesville sandstone in T. 17 N., R. 7 E. (Dwight's Energydata, 1992). Solid line shows decline curve for oil, in thousands of barrels.

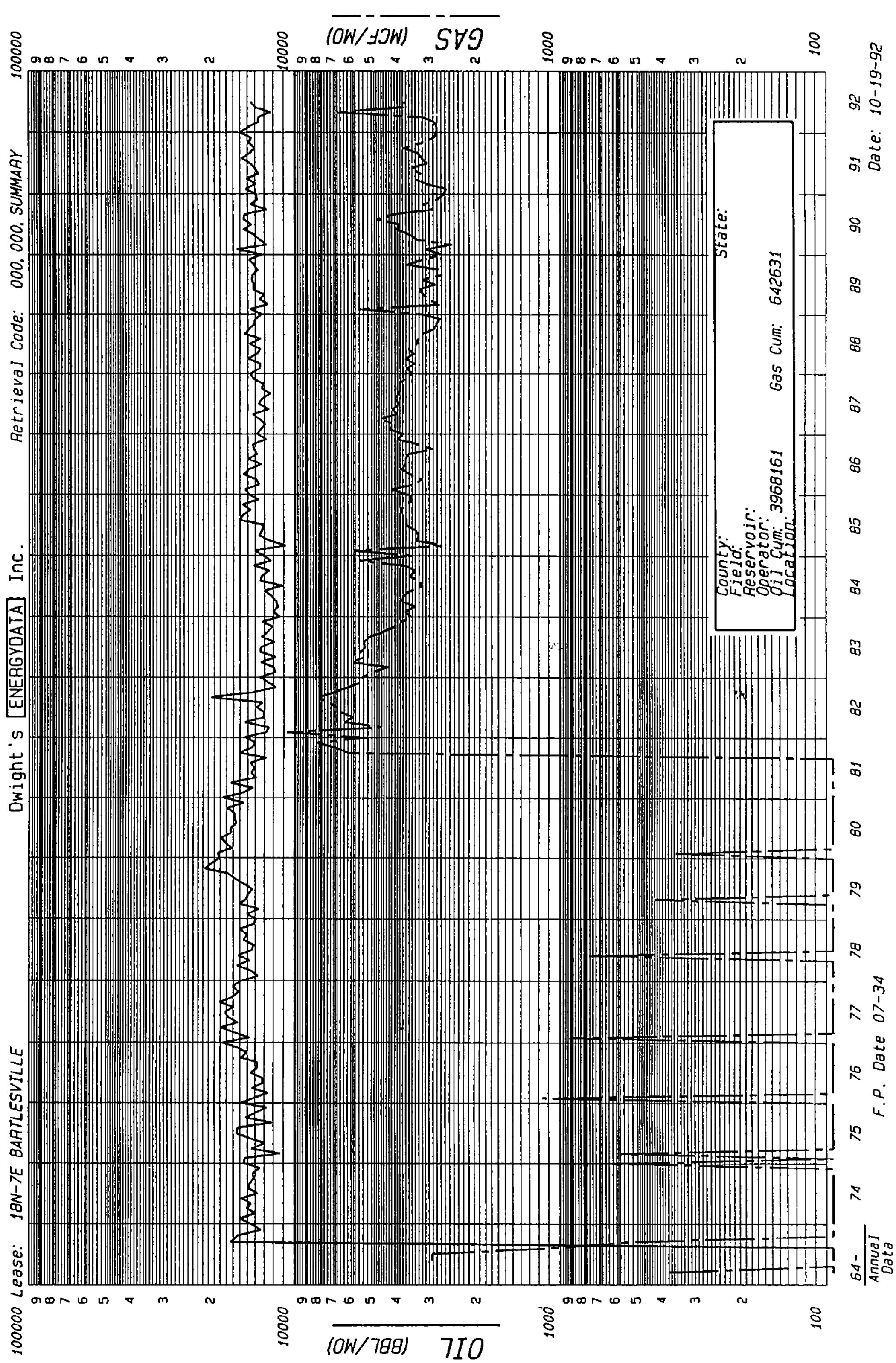

Figure 2. Production curve for Bartlesville sandstone in T. 18 N., R. 7 E. (Dwight's Energydata, 1992). Solid line shows decline curve for oil, in barrels.

At present, there are 39 wells producing from the Bartlesville sandstone in 15 sections within T. 17 N., R. 7 E. In addition, there are 24 other active wells in 17 sections that are listed as producing from the Bartlesville sandstone and one or more other stratigraphic units. There are five producing wells in secs. 3 and 5. All of the other sections have only one to four producing wells each. Although this field was originally developed on 10-acre spacing (*National Oil Well Index, Oklahoma Edition,* 1954, 1955, 1956, 1957, 1958), the average spacing is now about 130 acres, or more, per well.

These data clearly show a very rapid depletion of an original solution-gas drive, but there must be a reasonable continuity of permeability to sustain production for so long from so few wells. At present, wells are reported to be producing from 1 or more of 16 different reservoirs. The primary producers are the Layton sandstone, the Oswego limestone–Prue sandstone interval (or Wheeler sandstone), the Red Fork sandstone, and the Bartlesville sandstone reservoirs. Figure 3 illustrates the general lithology in the field. Figure 4 is a section of the electric log for the Sarah Deere No. 5 well, sec. 7, T. 17 N., R. 7 E.

POTENTIAL FOR MINE-ASSISTED DEVELOPMENT

In considering the Cushing field for mine-assisted development, several factors relating to economics must be considered. For this presentation, it is assumed that all of the basic requirements, such as mobile-residual-oil reserve, reservoir depth, and oil marketability, are satisfactory. The currently unanswered question is, What will be the optimum plan for mine-assisted development, and where should the initial mine shaft be located?

When choosing a shaft site, several factors must be considered. The early well data show that there were several "dry holes" across the field at locations where production should be expected. Do the dry holes represent areas of marked changes in the lithology of each of the otherwise-productive formations? Was the reservoir pressure so low that the drilling fluids invaded the reservoir? Was the initial production so low that the well was considered to be subeconomic? Were there other reasons for these dry holes? Answers to these questions are important because drilling the shaft is a major cost factor for oil-mine development. By using available technology, the shaft can be located within the producing area of the field.

Preliminary work suggests that extensive structure control and isopach maps of each producing formation will be necessary before selecting the optimum shaft sites and formulating a plan of mine development (Beal, 1917). The many reservoirs in this area present several options. It is pos-

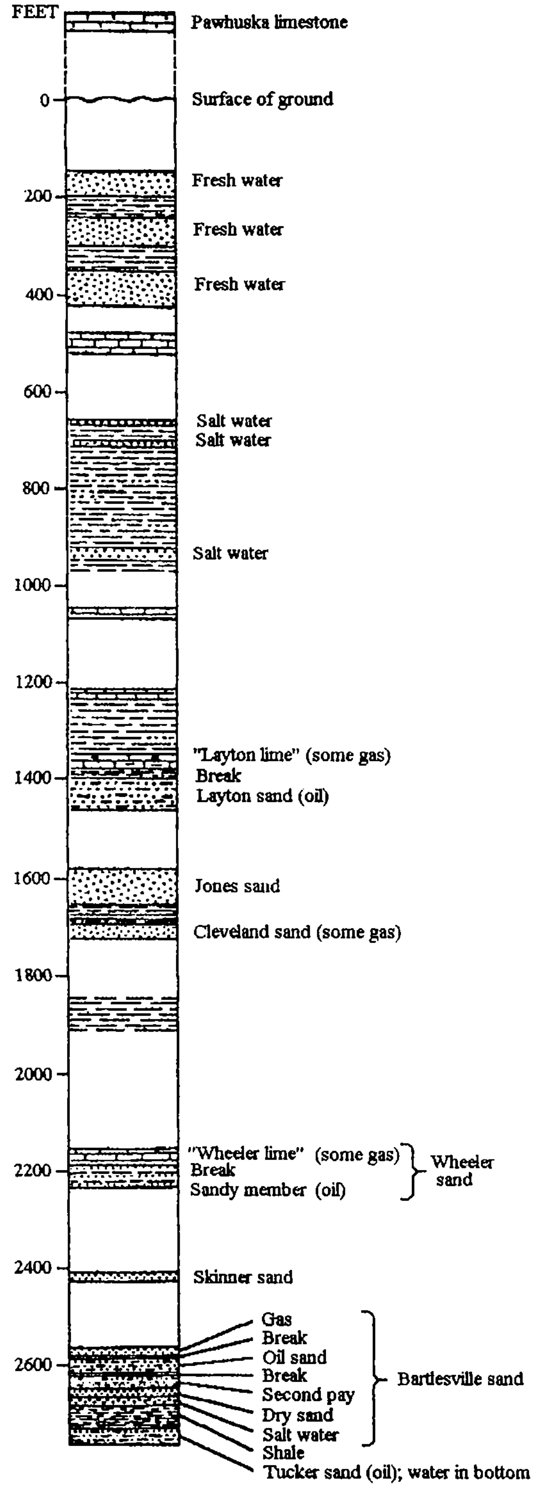

Figure 3. Generalized columnar section of Middle and Upper Pennsylvanian strata in the Cushing field, showing the positions of the principal oil- and gas-bearing sandstones.

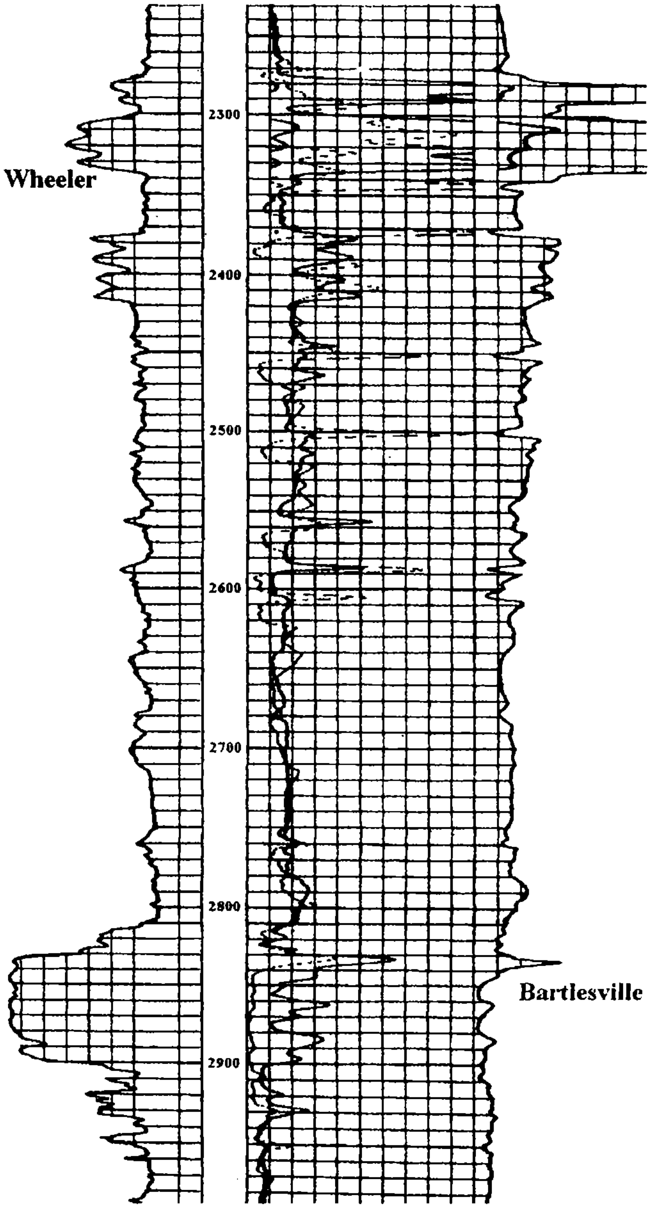

Figure 4. Electric log of Wheeler and Bartlesville sandstones in the Sarah Deere no. 5 well, sec. 7, T. 17 N., R. 7 E.

sible to develop mine workings under each of the reservoirs. It may be desirable to develop drains from below that extend up through each reservoir or to develop drains that produce from more than one reservoir. Determining the exact plan of mine development will require a detailed cost analysis, which should be possible by using available well data.

Another factor that must be considered in planning the mine is the location of all existing or past wells that have penetrated to the depth of the mine workings. Obviously, intersecting such wells would not be desirable.

In planning mine workings, it is desirable, but not essential, to have the shaft located at the lowest point, with the workings rising at ~0.5% up from the shaft. In this way, any produced water will flow (by gravity) back to the shaft sump for discharge at the surface. The shaft should extend ~100 ft below the workings level, to provide for a storage pocket for waste generated by the tunnel-driving process prior to removal by the mine hoist. The formations below the mine level should contribute little, or preferably no, water, oil, or gas to the shaft. The workings should be in the most stable, impermeable horizon available. To the extent possible, consideration should be given to any joints or fault patterns as potential problem factors.

Perhaps the greatest single consideration will be acceptable disposal of waste water that is produced during production. It should be possible to separate produced oil and waste water, either at the surface, as is currently done, or in rooms constructed at the mine level. Produced water could be returned to the production reservoir, or to whatever reservoir is now being used.

Solid waste produced through tunnel driving will likely be 600–700 cubic yards per day. If the mine workings are driven in a hard limestone, as one hopes would be the case, the mine waste could be screened for sale as crushed stone. The unscreened mine-run product would be marketable as road base.

The mine workings should be well insulated from the bottom of the nearest petroleum reservoir by ~100 ft of essentially impermeable shale or limestone. The tunnels, 880 ft apart, would be laid out much like streets in a city. Drains would be drilled up into, or through, the producing reservoir or reservoirs. Each completed drain would be connected into a central flow line to allow oil to be transported to the mine shaft and then pumped to the surface. Since all drains could be relatively short, spacing on 1 acre, or closer, would be possible and economic.

In selecting possible shaft sites, the effect of the surface installation on the surrounding area must be considered. During a preliminary reconnaissance, it was quite apparent there are extensive woods. Shaft facilities in wooded areas could be well screened, naturally. It was also apparent that, particularly to the south of Drumright, bedrock is very near the surface, a factor that would facilitate mine development.

CONCLUSIONS AND RECOMMENDATIONS

Available data on the Cushing field shows that development of mine-assisted oil recovery should be economically successful. On the basis of past history, the Bartlesville sandstone should be a primary target; for practical and economical reasons, however, other reservoir intervals, particularly the Layton sandstone and Wheeler sandstone (Oswego limestone and Prue sandstone), must be considered. It is possible that a well-located shaft will easily provide access to at least these three reservoirs.

Because of the possibility of multiple target intervals, detailed structure and isopach maps, and reserve analyses by the petroleum engineering staff, will all be needed as the first step. When a shaft site is selected, a test hole should be drilled. All potentially problematic horizons should be cored. The test hole should extend at least to the proposed depth of the shaft. Cores should be studied and sampled for their oil and water content and for rock-mechanics testing as needed.

All of the data mentioned above would be used first to evaluate the economic potential. When this has been demonstrated to be favorable, these data would provide the basis for mine planning.

The mine-assisted oil development proposed here will permit close infill drilling, with the potential for a much-better-controlled recovery from the Cushing field reservoirs.

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Red Fork Sandstone of Oklahoma: Depositional History and Reservoir Distribution

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ABSTRACT.—The Middle Pennsylvanian Red Fork sandstone formed as a result of progradation across eastern Kansas and most of Oklahoma. It is one of several transgressive-regressive sequences (cyclothems) developed within the Desmoinesian "Cherokee" Group. Sea-level changes together with varying subsidence were dominant factors controlling the general stratigraphic (correlative) characteristics of the Red Fork interval. Progradation was episodic with sand deposition in the more active part of the basin during lower sea-level stands and valley-fill deposition in the more stable areas during sea-level rises.

The Red Fork sandstone is essentially indivisible in the broad area of the stable platform (shelf) where it is relatively uniform in thickness. It is divisible into the lower, middle, and upper Red Fork in the deeper part of the Anadarko basin north of the equivalent Granite Wash.

A map of Red Fork sandstone trends reveals an alluvial-deltaic complex covering most of Oklahoma. The Red Fork consists primarily of alluvial-valley and alluvial-plain (fluvial) bodies in the northernmost part of northeastern Oklahoma and alluvial-deltaic bodies in most of the remaining parts of the shelf area. The orientation of these alluvial-deltaic sandstones is highly variable, and some sandstone bodies show local to subregional trends parallel to regional depositional strike.

The deltaic sandstones can be divided into two groups: distributary and delta fringe. The latter includes a wide range of specific types, such as delta front, delta margin, delta strand plain, and even distributary-mouth bar. Some sandstones, considered as representing distributaries, may include estuarine deposits, with the latter having formed during periods of quiescent river conditions, after stream abandonment or rise in sea level.

Distal deltaic sandstones and off-shelf submarine-fan and slope basinal-floor complexes dominate the deeper part of the Anadarko basin with each major Red Fork subdivision, showing distinctive depositional system tracts. The depocenter for the lower Red Fork was in the southeastern part of the Anadarko basin, and the depocenter for the middle Red Fork was in the central part. The upper Red Fork was deposited primarily in the western part of the Anadarko basin, and isopachs indicate a strong westward depositional dip.

The primary source area for the Red Fork was most likely to the north and northeast of Oklahoma. An extensive drainage system probably extended as far as the Canadian Shield and appears to have been subparallel to the Midcontinent rift. Secondary drainage systems that supplied sediment for the Red Fork were from the Wichita-Amarillo Mountains in the south and possibly from the northwest across the Texas and Oklahoma Panhandles.

Determination of reservoir trend and genesis requires integration of rock data and log data. Logs need to be calibrated to cores to estimate depositional environments accurately and to make a reasonable assessment of diagenetic overprints. Although both primary and secondary porosity are present, diagenesis has been responsible for most of the Red Fork reservoir capacity. Reservoirs can be developed at several stratigraphic levels even in shelf areas where the Red Fork cannot be divided into corresponding genetic units.

Much of the oil and gas has been trapped in stratigraphic traps, and a significant amount of oil is in channel sandstones and trends at high angles to the structural grain. The Cherokita-Wakita Trend, South Thomas Field, East Clinton Field, and Strong City Field represent excellent examples of facies and reservoir development controlled by facies distribution.

Fritz, R. D.; and Johnson, C. L., 1996, Red Fork sandstone of Oklahoma: depostional history and reservoir distribution, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 100.

Integrated Perspective of the Depositional Environment and Reservoir Geometry, Characterization, and Performance of the Upper Morrow Buckhaults Sandstone in the Farnsworth Unit, Ochiltree County, Texas

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Jesse T. Noah
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ABSTRACT.—The Farnsworth unit is the largest upper Morrow oil field in the western Anadarko basin. Of the 150 MMBO in place, 25% (38 MMBO) plus 30 BCFG have been recovered from the Lower Pennsylvanian upper Morrowan Buckhaults sandstone. The Buckhaults sandstone is a late-stage valley-fill unit deposited in a series of multiple-stacked, thin, upward-fining sequences in shallow, braided, fluvial channels. The sandstone layers are predominately well-indurated, conglomeratic to coarse-grained, light-gray to light-brown subarkose to sublitharenite. Distribution of the framework grains is heterogeneous. Grain size ranges from a pebble conglomerate to a medium-grained sandstone.

The following arithmetic averages were calculated from the cores of 52 wells in the field: porosity, 14.38%; permeability, 31.09 md; and hydrocarbon pore feet, 4.26 ft. The maximum core porosity is 22%. Porosity values are rarely <10%; however, where porosity is <10%, there is a corresponding decrease in permeability. Measured permeability ranges from <1 md to 740 md.

This study was designed to integrate geologic, geophysical, and reservoir data in an effort to refine the Buckhaults depositional-systems model. The goals were to (1) determine and predict sandstone distribution, (2) identify additional unrecovered primary banked-oil reserves, and (3) design an infill drilling program to improve the secondary water-flooding efficiency.

Methods used include (1) compilation of a database integrating thickness, porosity, permeability, and well-performance data; (2) interpretation of the Buckhaults environment of deposition from core data and geophysical well logs; (3) mapping the regional paleostructure to identify paleotopography and paleogradients; (4) mapping the Buckhaults paleovalley to identify the axis of maximum downcutting; (5) mapping the Buckhaults sandstone thickness, permeability, and performance trends; and (6) regional synthesis of seismic data for trend analysis and acquisition of detailed reservoir characterization through high-resolution seismic surveys.

The integration of geologic, geophysical, and reservoir-performance data resulted in (1) reinterpretation of the Buckhaults sandstone reservoir geometry and refinement of the depositional model, (2) identification of four possible field extensions, (3) the identification of 10 MMBO of proven unrecovered secondary reserves and probable banked-oil reserves, (4) the formulation of a 90-well infill or extension drilling program to increase the water-flooding efficiency, and (5) the formulation of a plan to prepare the Farnsworth unit for a tertiary enhanced-oil-recovery program.

McKay, R. H.; and Noah, J. T., 1996, Integrated perspective of the depositional environment and reservoir geometry, characterization, and performance of the upper Morrow Buckhaults sandstone in the Farnsworth unit, Ochiltree County, Texas, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 101–114.

INTRODUCTION

The Farnsworth unit is located in the west-central portion of Ochiltree County, 15 mi southwest of Perryton in the Texas Panhandle (Fig. 1). It is the largest upper Morrow oil field in the western Anadarko basin with >150 million bbl of original oil (MMBO) in place. Union Oil Company of California discovered the field in 1955 when production was established in the no. 1-32 Viva Buckhaults well from the Lower Pennsylvanian upper Morrow Buckhaults sandstone. This well had an initial-flow potential of 321 bbl of oil per day (BOPD) at a depth of 7,966–7,990 ft and an original formation pressure of 2,200 psi. The Buckhaults sandstone was originally produced under a solution-gas-depletion–type drive. By 1963 the Texas Railroad Commission had consolidated the Farnsworth field, the Waka field, and the West Waka field into the current Farnsworth unit. During primary recovery (i.e., prior to 1964), these fields with a total of 125 active wells produced 15 MMBO plus 13 billion cubic feet of gas (BCFG). This unitization allowed implementation of a water-flooding project in 1964. The Farnsworth unit's peak production during the water-flooding stage was 7,967 BOPD in 1972. An additional 22.7 MMBO has been recovered since unitization. Cumulative production has been 37.7 MMBO plus 29.3 BCFG as of December 1992. A total of 200 wells have penetrated the Morrow in the study area, which encompasses 45 mi^2. Within the Farnsworth unit, there are 145 Morrow penetrations with a historical success rate of 88%.

This study was designed to integrate geologic, geophysical, and reservoir data to (1) refine the Buckhaults sandstone interpretation, (2) identify additional unrecovered primary banked-oil reserves, and (3) design a drilling program to further develop secondary reserves in the Farnsworth unit.

GEOLOGIC SETTING

In the Midcontinent, the upper part of the Morrowan Provincial Series of Early Pennsylvanian age is an overall transgressive sequence. Numerous deltaic wedges extend from southeastern Colorado across the Oklahoma and Texas Panhandles and into the center of the deep Anadarko basin in southwestern Oklahoma (Fig. 1).

Regional channel systems trend subparallel to subtle preexisting paleotopographic lows created by normal faults in the older Paleozoic sedimentary section. This coincidence suggests that during deposition of the upper Morrow strata, recurrent minor syntectonic movements maintained the paleovalleys. Each successive progradational event may have been partially controlled by these recurrent fault movements that periodically lowered the paleoslope. The mechanism is thought to have been basin loading that caused movement along deep-seated normal faults extending northwest from the Amarillo-Wichita fault zone.

The typical upper Morrow meander valley in the region contains three types of fluvial sandstones: (1) point-bar deposits, (2) mixed-load low-sinuosity channel-fill deposits, and (3) overbank splay and sheet flood-plain deposits. The upper Morrow channel sandstones in southeastern Colorado, however, are predominantly channel-fill sediments deposited in incised valleys. To the south, in the Oklahoma Panhandle and the northern Texas Panhandle, the valleys are less incised, and point-bar deposition predominates.

In the Farnsworth area, both point-bar and mixed-load channel-fill sandstones are present. There are at least five main upper Morrow progradational sandstones. From bottom to top, these are locally referred to as the White, Jones, Pazoureck, Buckhaults, and Russell sandstones (Fig. 2). The upper Morrow interval, present over the entire study area, thickens to the south-southeast from 380 to 490 ft.

Southward across the Texas Panhandle, toward the basin axis, it is postulated that marine energy dominated the deltaic environment, as evidenced by the trend and shape of sandstones in Glazier field in southern Lipscomb County, Texas. The upper Morrow is unconformably overlain by the Atokan Thirteen Finger limestone.

The Morrow structure shows that the Farnsworth unit is positioned on a broad anticlinal nose dipping to the southeast at 2° to 3°. Regionally, the unit lies in a paleogeographic low between an east-trending intervalley high to the north and a low-relief anticlinal nose extending to the northeast on the southern side. Structural relief is 550 ft from northwest to southeast across the unit. The regional strike is N. 40° E.

The depth to the top of the Buckhaults sandstone ranges from 7,500 ft on the northwest to 8,050 ft on the southeast. The hydrocarbon trap is stratigraphic owing to an updip porosity pinch-out. The entire sandstone body was hydrocarbon charged and had an original hydrocarbon column 550 ft high. Since there is a downdip termination of the reservoir, there was no original reservoir water drive.

SEDIMENTOLOGY

Grain-Size Distribution and Sorting

The grain-size distribution is heterogeneous. The grain size ranges from a pebble conglomerate to a medium-grained sandstone with very fine grained quartz and feldspar fragments and clay matrix. The sandstones are predominantly coarse grained (Wood, 1956; Munson, 1989). Multiple fining-upward sequences are present throughout the section. A channel lag conglomerate with up to cobble-sized lithoclasts is present at the basal contact. There is a slight decrease in grain size from

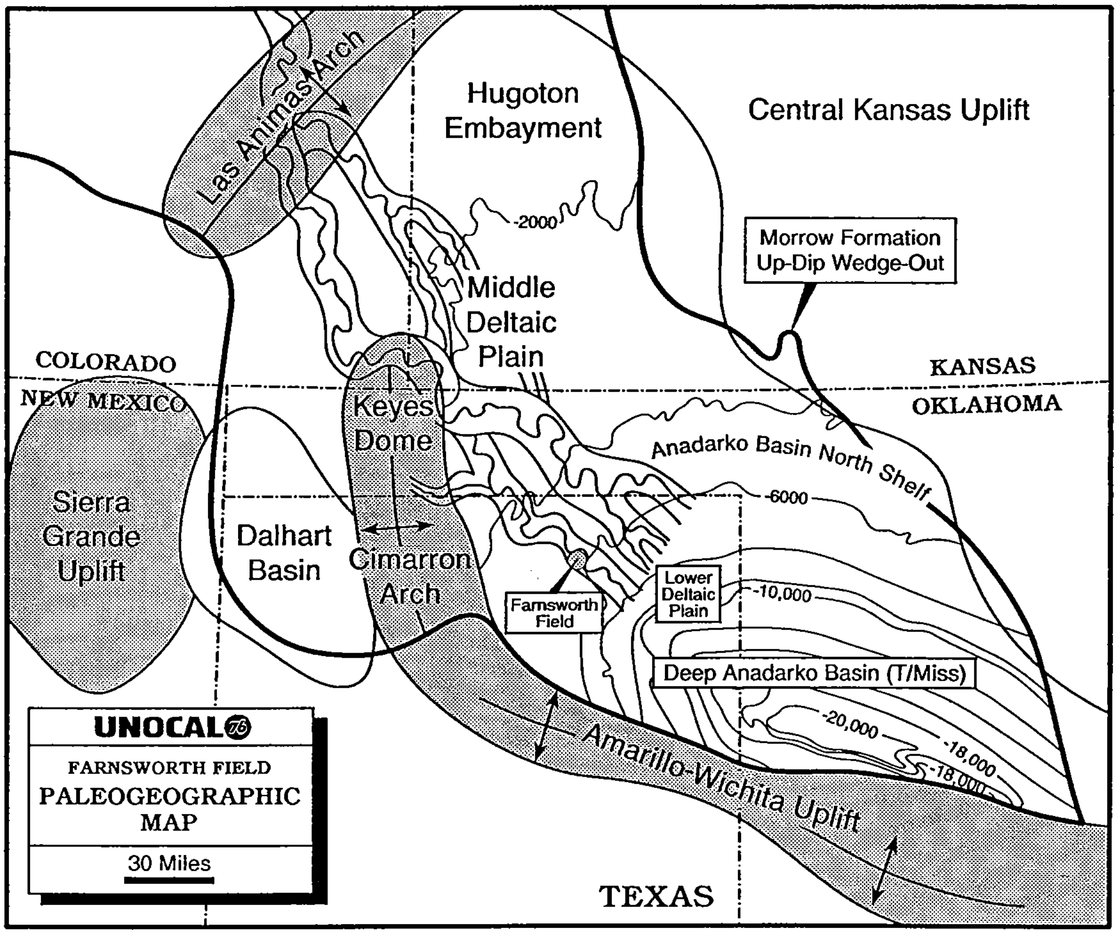

Figure 1. Regional paleogeographic map showing principal tectonic features, structure contours on top of the Mississippian, upper Morrow fluvial-deltaic channel fairways, and location of the Farnsworth field. Modified from Khaiwka (1968) and Swanson (1979). Contours are in feet.

west to east along with a slight increase in sorting (Munson, 1989). Sorting ranges from poorly to moderately well. A ten-well core study by Wood (1956) found that the majority of the sandstones are moderately sorted. The predominant cements are quartz and feldspar overgrowths with lesser amounts of clay, calcite, and pyrite.

A mean grain size vs. sorting statistical analysis was conducted on 68 samples from six wells by Munson (1989). He concluded that most of these sediments were deposited in a fluvial-deltaic environment. He also plotted weighted-percentage histograms of the grain-size distribution. This analysis showed that the predominant depositional environment was a delta distributary system (Munson, 1989).

Porosity and Permeability

Farnsworth unit porosity and permeability data were obtained from 52 wells with individual core analyses. Graphic plots show a heterogeneous vertical distribution of both the porosity and permeability in each core (Fig. 2). The average Buckhaults sandstone porosity in the unit is 14.38%. There is very little variance in the average porosity across the unit except near the sandstone limits where it decreases. The maximum measured core porosity is 22%. Porosity values are rarely <10%. Where the porosity is 10% or less, the permeability generally is <1 md (Fig. 3). The original porosity was reduced by pore-filling quartz and feldspar overgrowths and by authigenic clays.

The measured permeability ranges from <1 md to >750 md and averages 31.09 md for unit. Permeability decreases from west to east (i.e., an average of 90 md in the west and an average of 20 md in the east). It is thought that permeability is controlled by an increase in the clay matrix from west to east. Core data show that intervals with

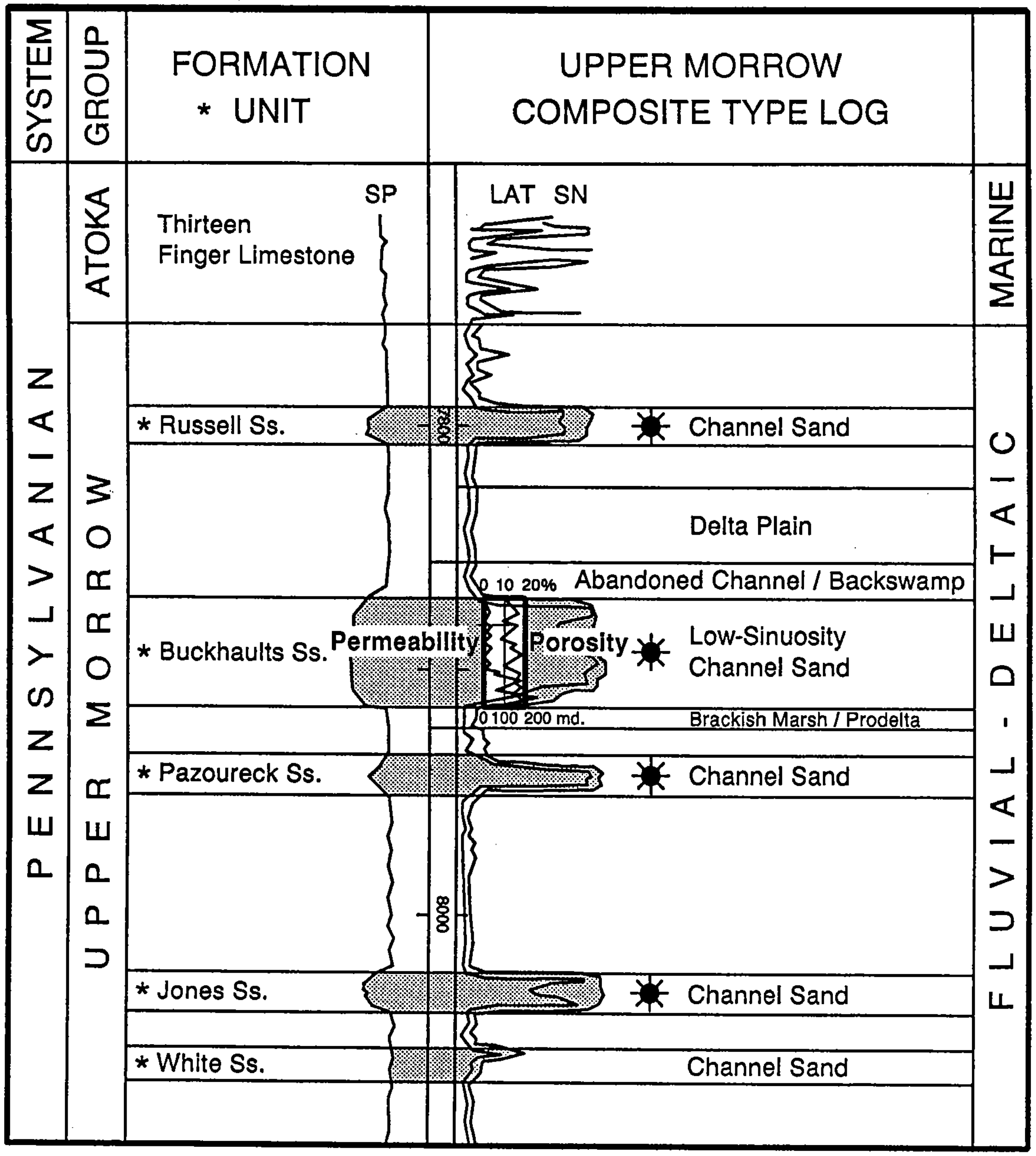

Figure 2. Composite log of upper Morrow strata in the Farnsworth field.

higher permeability are associated with the higher porosities (Fig. 3). There is no apparent relationship between grain size and permeability (Munson, 1989).

COMPOSITION

Framework Grains

The Buckhaults sandstone is a conglomeratic, light-gray to light-brown subarkose to sublitharenite (Munson, 1989; Davies, 1991,1992). It is well indurated with subangular to subrounded grains. The grains are close packed with point-to-point, edge-to-edge, and some sutured contacts (Fig. 4). The predominant framework grains are monocrystalline and polycrystalline quartz and granitic or other plutonic igneous-rock fragments, with lesser amounts of plagioclase feldspar (total feldspar is 4–20%), shale and siltstone lithoclasts, chert, muscovite, and volcanic-rock fragments (Munson, 1989; Davies, 1991,1992). Minor amounts of microcline (orthoclase feldspar),

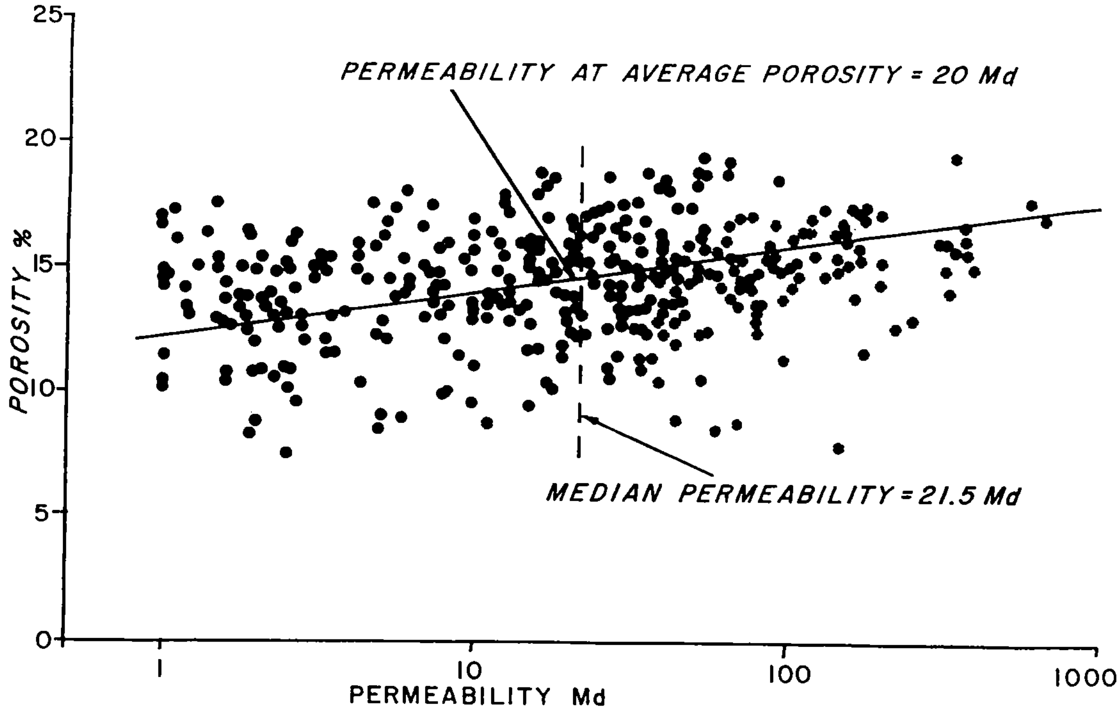

Figure 3. Plot of porosity vs. permeability for all Farnsworth unit Buckhaults sandstone cores.

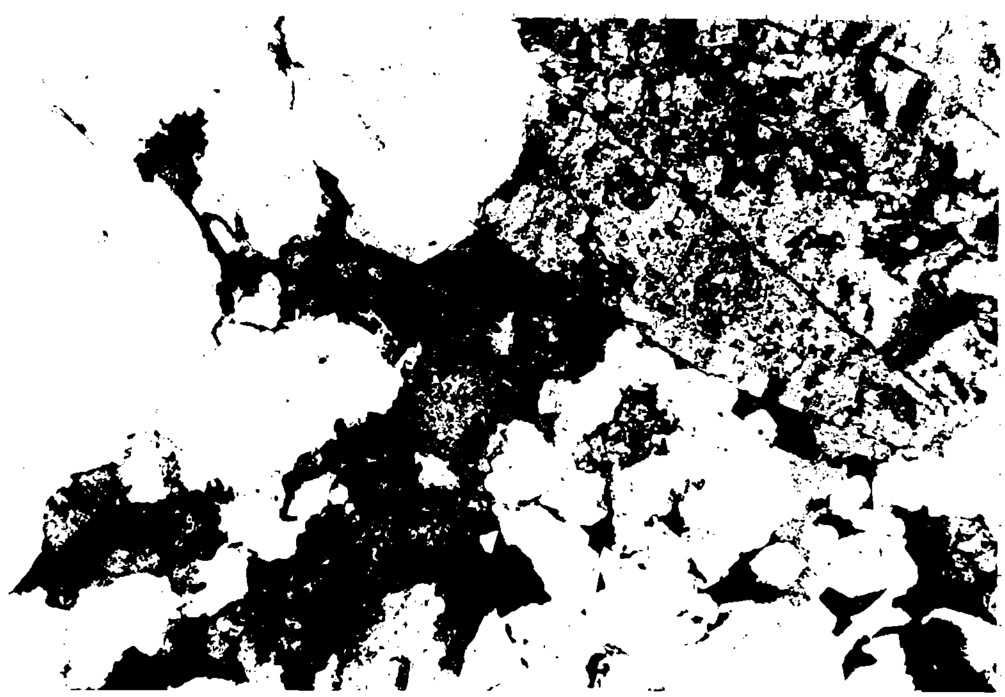

Figure 4. Thin-section photomicrograph (FWU no. 32-6) of the Buckhaults sandstone. Width of field of view is about 4.5 cm.

perthite, chlorite, chalcedony, and sericite were identified by Wood (1956).

The predominant heavy-mineral assemblage consists of zircon, tourmaline, garnet, mica, and magnetite with lesser amounts of rutile and leucoxene, indicative of a silicic igneous-rock provenance (Wood, 1956). The presence of euhedral crystals of blue, pink, and purple zircon and of smoky black tourmaline are indicative of mineralogically immature first-cycle sediments. The framework-grain immaturity also indicates a nearby source area, possibly in the Amarillo-Wichita uplift to the south (Munson, 1989). Other potential source areas include the Cimarron arch and Keyes dome to the west and northwest (Fig. 1). All three were nearby topographic highs in Early Pennsylvanian time. The presence of detrital chert in the Buckhaults sandstone indicates a nearby subaerial exposure of Meramecian and/or Osagean (Mississippian) rocks (Brown, 1979). The presence of well-worn zircon crystals and fragments, green tourmaline, rare rutile and leucoxene, and some frosted grains indicates that the sandstones consist partly of reworked older sedimentary deposits (Wood, 1956).

Clay Minerals

In general, the larger percentages of clay minerals are in the upper part of the Buckhaults sandstone, but in some cases, the concentration is reversed (Wood, 1956). Clays occur in several 1- to 3-in.-thick shale beds, shale laminations, and lithoclasts and as dispersed authigenic clays. The intergranular authigenic clays occur as particles, pore linings, and pore bridges (Fig. 5). Clay content ranges from 4 to 17.14% (Wood, 1956; Munson, 1989).

The predominant matrix clay is kaolinite with lesser amounts of chlorite, illite, and illite-smectite (Parker, 1956; Munson, 1989; Davies, 1991,1992). Our interpretation is that the authigenic kaolinite, illite, and chlorite were formed from diagenetically altered feldspars, lithoclasts, and volcanic fragments. Since these sediments are thought to have been deposited in a freshwater system, some of the kaolinite may be detrital (Selley, 1978).

Swelling clays are not a major cause of permeability reduction. The major reduction of permeability is caused by moved fines (i.e., kaolinite and illite) that were dislodged by high water-injection pressures and rates.

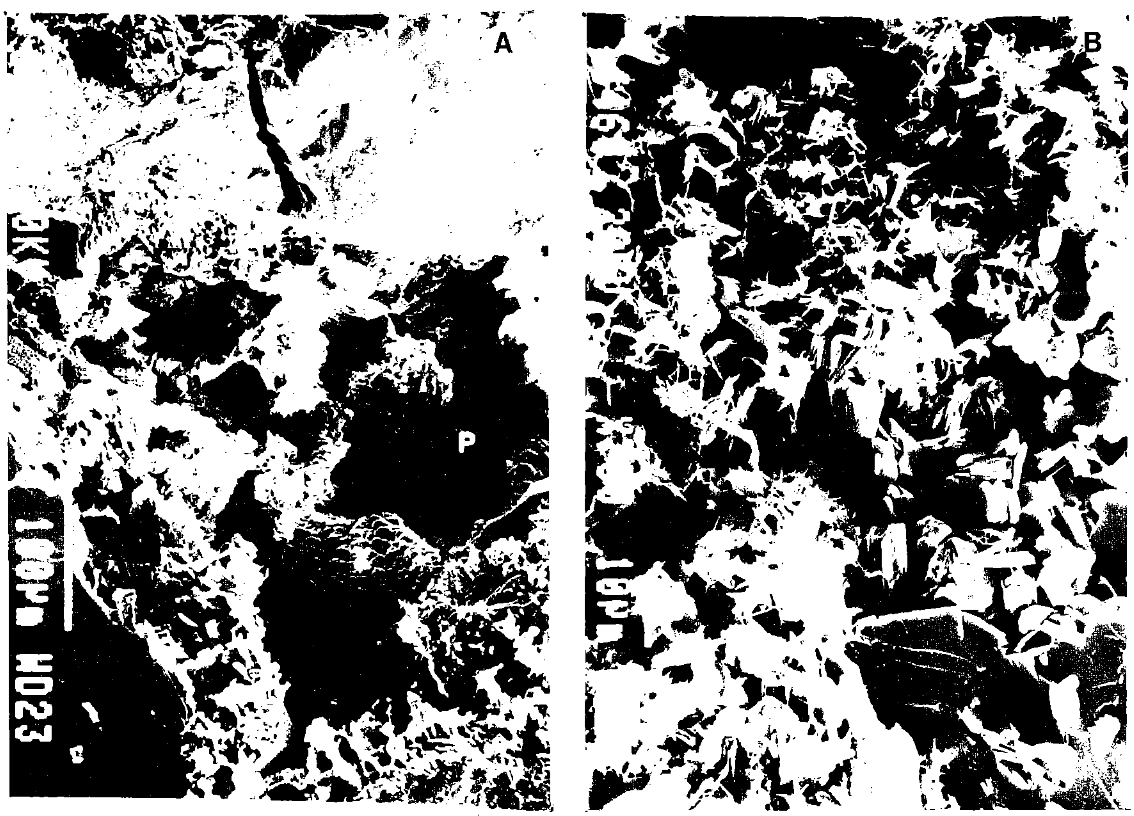

Figure 5. SEM photomicrographs of the Buckhaults sandstone (FWU no. 32-6). (A) Examples of porosity (P), chlorite (C), siderite (X), and illite-smectite (I). (B) Examples of kaolinite (K; the dominate clay type) and chlorite (C).

Figure 6. Photograph of core from the FWU no. 32-6 illustrating planar cross-bedding and channel scours. Depth range is 7,967 ft (upper left) to 7,977 ft.

Typically, bed forms and stratification are indistinct. The dominant bed forms include low- and high-angle planer-tabular cross-beds and trough cross-beds (Fig. 6). Soft-sediment-deformation structures are present locally.

Stratification is mostly indistinct. Some intervals, however, contain poorly developed, moderate- to small-scale cross-stratification, parallel stratification, and ripple laminae. Bar-top deposits consisting of small sets of planar-tabular cross-bedding and cross-laminated sandstones are locally present. Lower-angle cross-bedding is more dominant in the upper part of the section. Multiple scour surfaces are present throughout the interval with associated pebble to coarse-grained lag deposits. A well-developed channel-floor lag overlain by poorly defined parallel and trough cross-bedding is typically present.

Bed forms in the Farnsworth Unit no. 32-6 core showed an apparent preferred cross-bedding dip direction. A computer-processed directional analysis from a CIBL (stratigraphic dipmeter) bore-hole imaging log showed a well-developed southerly current vector over the entire Buckhaults sandstone interval. The majority of the cross-bedding has been destroyed by diagenetic alteration of the sandstone; thus most intervals are poorly stratified.

Bedded shales are locally present. Both the upper and lower contacts of the shale units are erosional. Shales of this type typically have a shoestring geometry and would not form lateral permeability barriers or compartments within the reservoir. Stylolites and siderite nodules are present over the entire section in some of the cores. Coalified root hairs are present in the upper part of many of the cores (Trevena, 1991).

Trevena (1991) examined eight Buckhaults sandstone cores. He interpreted that one of these cores, from the southwestern part of the unit, is composed of either mixed-load fluvial-channel-fill sediments or a coarse-grained point-bar deposit. He concluded that the multiple-stacked, thin, upward-fining sequences in the seven additional cores were deposited in shallow, braided, fluvial channels. Five of the cores are located in the southeast part of the unit and two in the northwest.

CORE ANALYSIS

About 60 cores of Buckhaults sandstone have been taken in the Farnsworth unit. There are 52 Buckhaults sandstone core analyses, and nine whole cores are available. The following arithmetic averages were calculated from the whole-core data: porosity = 14.38%, permeability = 31.09 md, sandstone recovered = 25.76 ft, sandstone with >10% porosity = 23.35 ft (9% of the recovered sandstone layers have >10% porosity), and hydrocarbon pore feet = 4.26 ft (the product of permeability [in millidarcies] and net sandstone thickness [in feet], expressed in feet). Hull (1956) calculated the original oil saturation to be 69% on the basis of a reservoir with 26.6 md permeability.

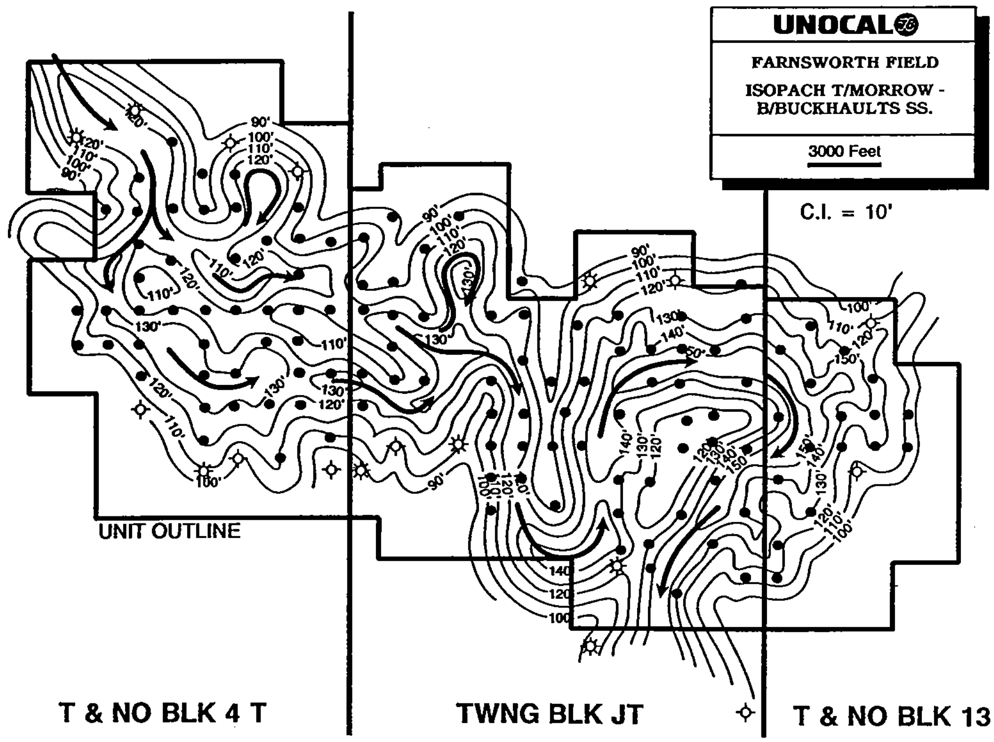

Figure 7. Isopach map of the interval from the top of the Morrow to the base of the Buckhaults sandstone; contour interval is 10 ft.

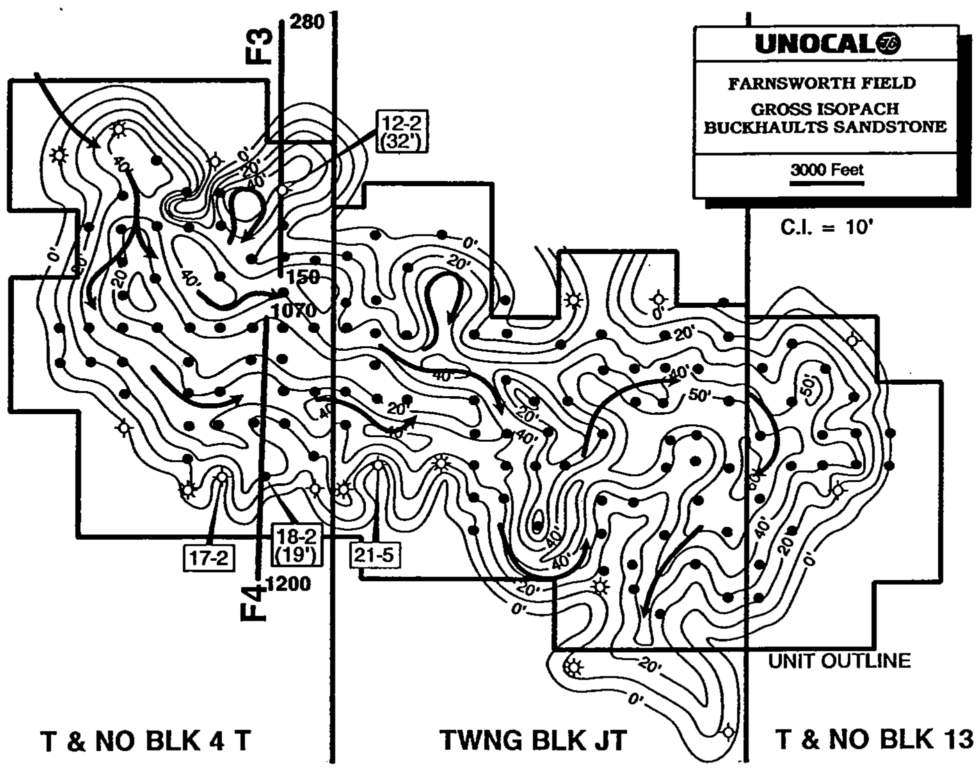

Figure 8. Isopach map of the Buckhaults sandstone; contour interval is 10 ft. Seismic sections F3 and F4 are shown in Figures 12 and 13.

MAPPING METHODS

Structural and stratigraphic cross sections and isopach maps were constructed to define the geometry of the Buckhaults sandstone. Isopach maps from the top of the Morrow to the top and base of the Buckhaults were constructed as the initial step. These isopach maps were used as the basis for the Buckhaults channel-system model. The isopach map of the interval from the top of the Morrow to the base of the Buckhaults (Fig. 7) best depicts the geometry of the Buckhaults paleovalley. From this map the paleogradient is estimated to have sloped at 10–15 ft/mi. The isopach map of the Buckhaults sandstone (Fig. 8) shows that the maximum thickness trends are coincident with the maximum downcutting trends in the paleovalley. Both well-log and seismic data were used to define the lateral limits of the sandstone channels.

The results of mapping additional parameters were closely correlated to this depositional model. Some of these maps include the permeability and thickness of the Buckhaults (Fig. 9), the daily-production potential (Fig. 10), and the cumulative production (Fig. 11). These maps demonstrate a very close coincidence of maximum thickness, permeability, and reservoir performance to the trend of the channel depositional axes.

SEISMIC METHODS

Between 1990 and 1991, Unocal shot ~40 mi of high-resolution vibroseis seismic lines to determine whether seismic data could successfully be incorporated into reservoir characterization of the upper Morrow Buckhaults sandstone in the Farnsworth unit.

The Buckhaults sandstone in the Farnsworth unit correlates to a high-amplitude peak located directly below the top of the Morrow (Figs. 12,13). The seismic data were not able to resolve the detailed stratigraphy or structure of the Buckhaults sandstone within the current productive limits of the unit. However, the seismic data were useful in expanding the previously interpreted Buckhaults sandstone limits. For example, Figures 12 and 13 are two north-south seismic lines (locations shown in Fig. 8) that were used to expand the unit limits. On Farnsworth line 4 (Fig. 13), the previous unit limit was located at shotpoint 1135. As a result of the seismic interpretation, the Buckhaults sandstone limit was expanded to shotpoint 1165. The Farnsworth Unit no. 18-2, drilled at shotpoint

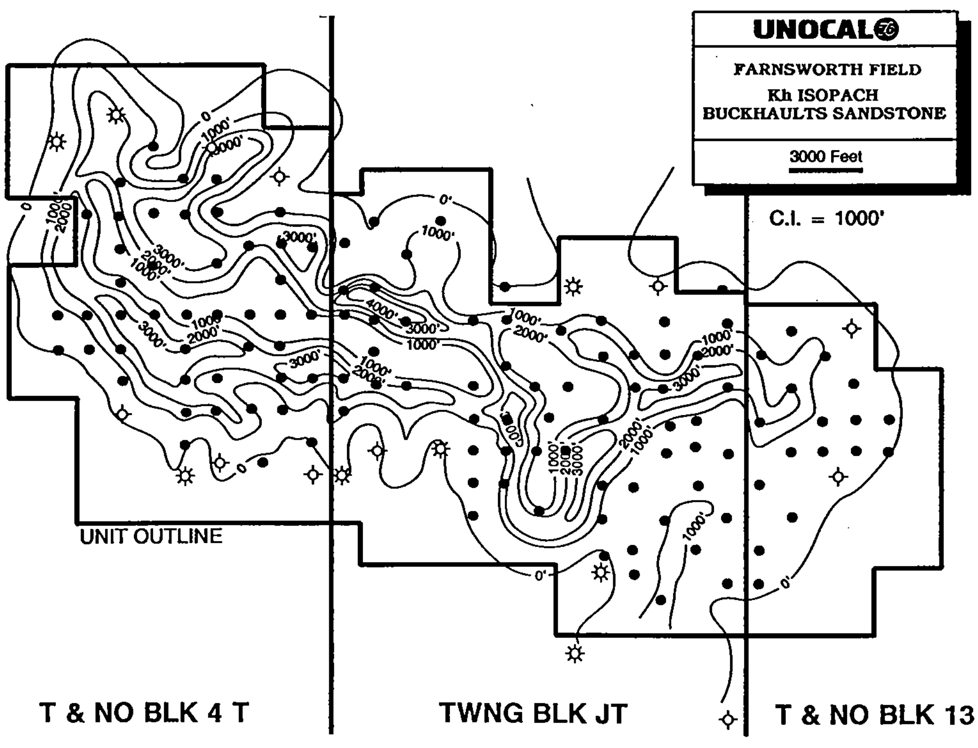

Figure 9. Contour map showing permeability (*K*) and thickness (*h*) of the Buckhaults sandstone. Values are the product of permeability (millidarcies) and net-sandstone thickness (feet), but are expressed here in feet; contour interval is 1,000 ft.

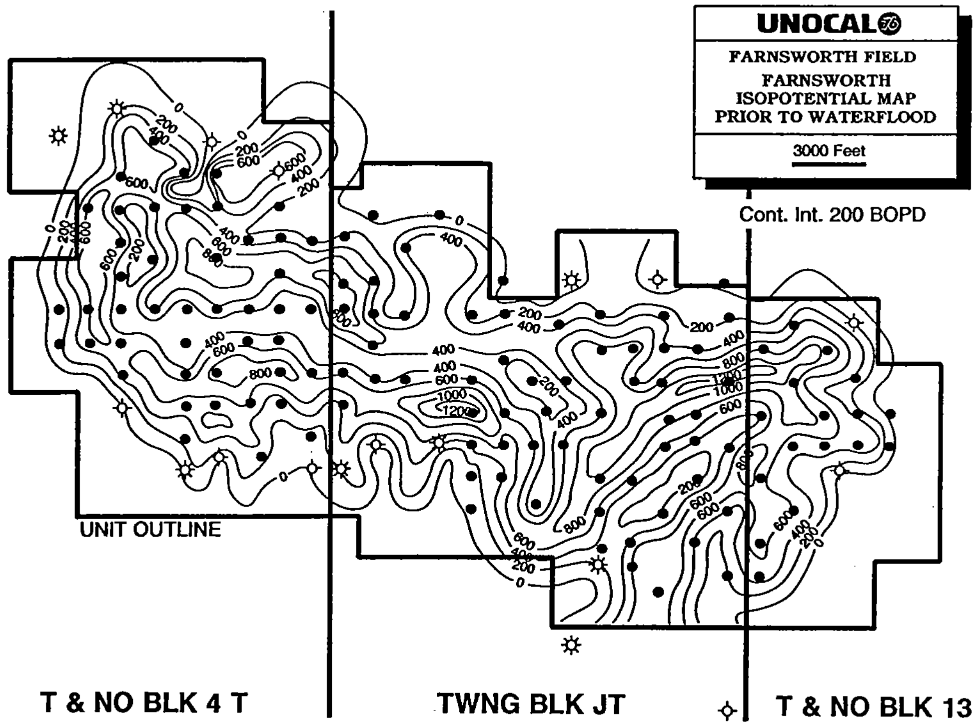

Figure 10. Contour map showing potential for daily production of oil from the Buckhaults sandstone prior to water-flooding operations; contour interval is 200 BOPD.

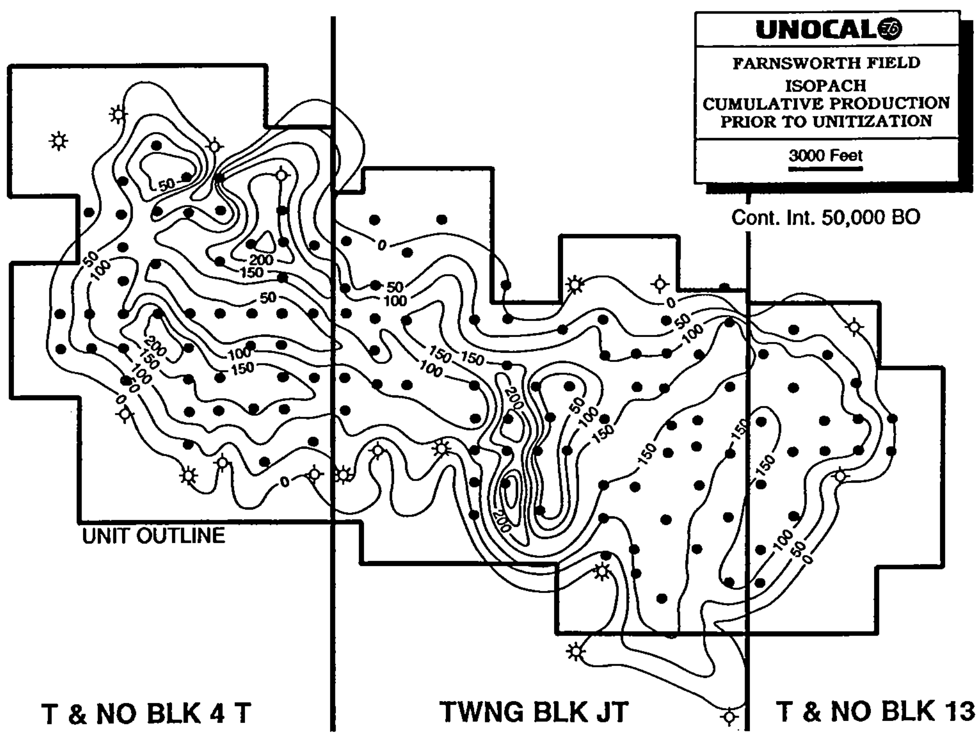

Figure 11. Contour map showing cumulative production of oil from the Buckhaults sandstone prior to unitization of the field; contour interval is 50,000 BO.

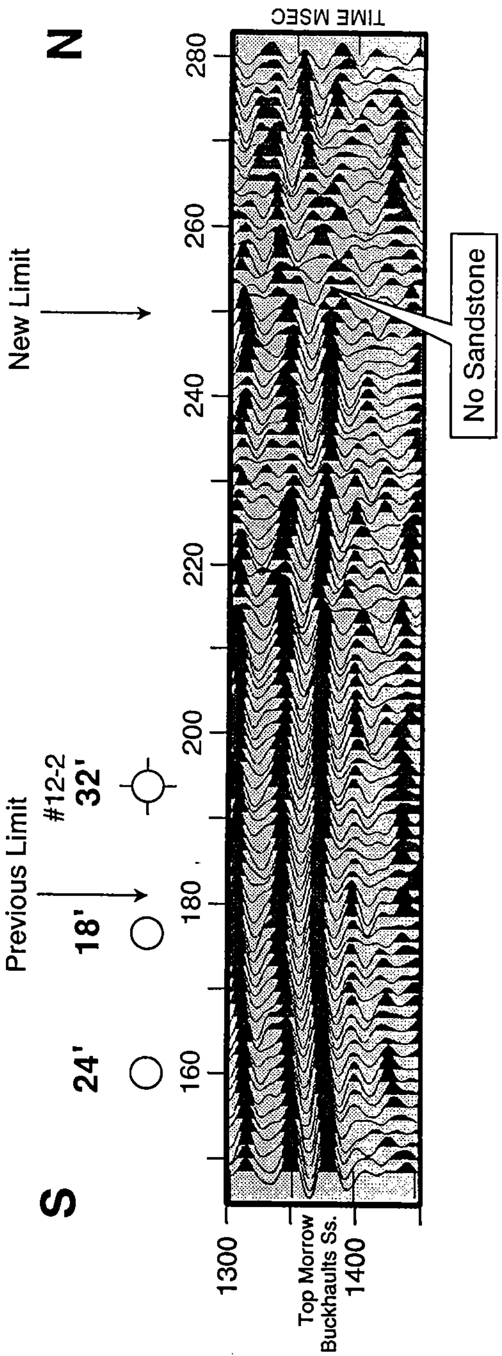

Figure 12. Farnsworth line 3 seismic section (F3); location shown in Figure 8.

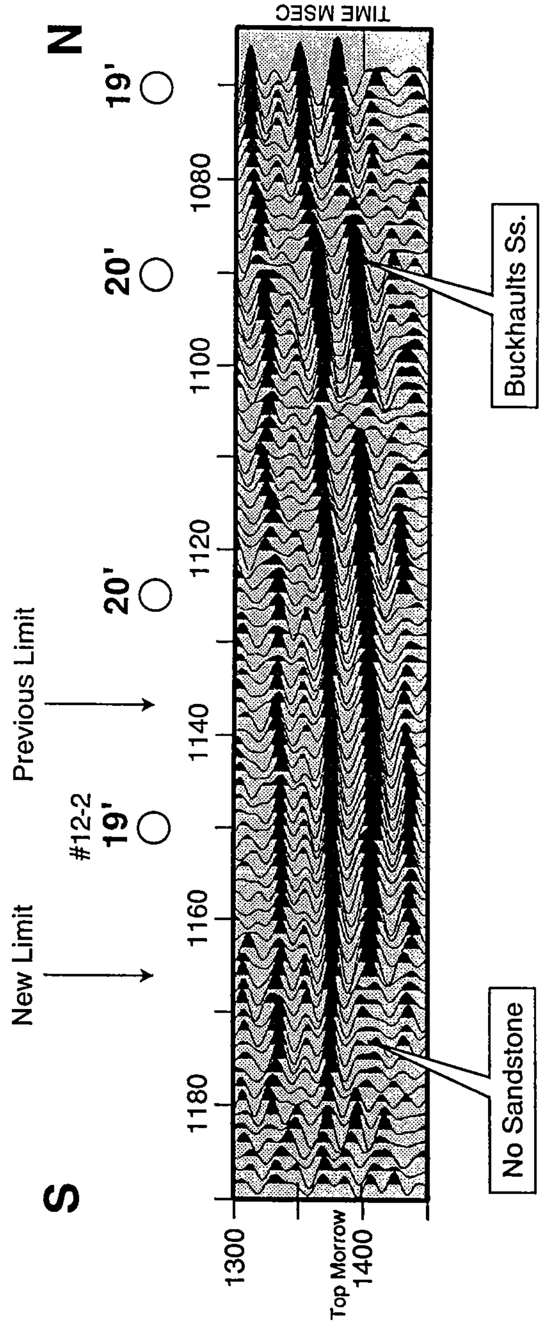

Figure 13. Farnsworth line 4 seismic section (F4); location shown in Figure 8.

1150, penetrated 19 ft of sandstone that had an initial potential flow (IPF) of 250 BOPD. Similarly, on Farnsworth line 3 (Fig. 12), the unit limit was extended from shotpoint 180 to 250. The Farnsworth Unit no. 12-2 was drilled on shotpoint 195 and encountered 32 ft of Buckhaults sandstone. Unfortunately, the water-flooding front had swept past the bore hole, and the well was wet.

ENVIRONMENT OF DEPOSITION

The upper Morrow sandstones in the Farnsworth area are interpreted to represent valley-fill sediments deposited by a fluvial-deltaic system. The following describes the characteristics of the Buckhaults sandstone that best categorize the deposit as a braided fluvial-deltaic deposit.

The Buckhaults sandstone has a laterally extensive sheetlike geometry, in this case, 2 mi wide and 7 mi long (Fig. 8). It is composed of thin, multiple-stacked, fining-upward channel sequences grading from pebble conglomerates to coarse- and medium-grained sandstones. The basal contact is erosional. Each successive channel has a well-developed channel-floor lag deposit.

The lateral and vertical continuity of the reservoir is good to excellent in most areas of the unit. The porosity and permeability are generally good, but vertical variability indicates multiple depositional cycles. These multiple-stacked channels are easily seen in each core.

Few shale partings or beds are present. The shale units have erosional upper and lower contacts characteristic of abandoned-channel sequences. These are diagnostic of braided fluvial deposits (Selley, 1978). Continual reworking by successive channels has removed entirely, or left only remnants of, the abandoned-channel segments. Abandoned-channel segments backfilled with organic-rich siltstone and shale have been documented seismically in sec. 13, Blk. 4T, T&NO Survey, by the Farnsworth Unit no. 21-5 (sec. 14, Blk. JT, TW&NG Survey), and the Farnsworth Unit no. 17-2 (sec. 47, Blk. 4T, T&NO Survey) well bores. These abandoned-channel reentrants have only been encountered along the channel edge.

Sedimentary structures include trough and tabular-planar cross-bedding with a few recumbent foreset beds, and soft-sediment-deformation structures. In seven Buckhaults sandstone cores, Trevena (1991) identified sedimentary structures associated with braided-stream sediments.

The apparent current direction in the core from the Farnsworth Unit no. 32-6 is dominantly to the south. This finding supports the interpretation that an entrenched, arcuate meander belt was present on the east side of the unit. Wood (1956) postulated that this arcuate-shaped sandstone body was a meander bend in the channel complex. Because of an anomalous increase of finer-grained sandstone, he also postulated that two channels merged in the southeast.

Transport direction is believed to have been from west to east. This is supported by the regional paleoslope, interpreted to be east-southeast. Munson (1989) documented that sorting increases, and grain size decreases, to the east, which also supports this interpretation. In addition, the Buckhaults sandstone isopach map shows a dramatic increase in thickness to the east.

In some areas of the Farnsworth unit, there is a high concentration of ferric oxide in the produced fluids. This may be indicative of an oxidizing condition at the time of deposition or may be a byproduct of acidizing treatments. In addition, only a small percentage of carbonaceous organic matter or coal clasts is present in the sandstone. These two characteristics are indicative of the oxidizing environment in which braided streams commonly occur.

No fossil assemblages have been documented in the sandstone units. The black shales and limestone beds below the Buckhaults contain a brackish-water fauna including brachiopods, fusulinids, crinoids, rugose corals, ostracods (Parker, 1956), and pelecypods (Trevena, 1991). The presence of wood fragments; a brackish-water fossil assemblage; black, pyritic shales; and brackish connate waters indicates that the Buckhaults prograded into a brackish marsh or lagoon. Wood (1956) interpreted from his core study that the Buckhaults channel complex was deposited shoreward of a lagoon or a bay environment.

On the basis of core data and electric-log signatures, three types of Buckhaults sandstone deposits were identified: mixed-load channel-fill sandstones, point bars, and distributary mouth bars. The channel sandstones are overlain by interbedded overbank siltstones and shales. They are underlain by dark-gray to black marine shales.

Schneider (1987) used log and core data to subdivide the Buckhaults sandstone into genetically and texturally distinct lower and upper units. The lower pebble-conglomerate unit was interpreted to have been deposited by a braided-channel system. This unit has a fairly uniform distribution across the entire channel. The upper unit lies unconformably on the lower unit. It eroded into, but not through, the lower unit. The upper unit has been interpreted to have been deposited by a laterally accreting fluvial channel in lobate point bars that thicken and thin within short distances. This unit is composed of finer-grained sandstone.

SUMMARY

It is our opinion that the Buckhaults sandstone represents one of at least five late Morrowan progradational pulses of a valley-fill sequence. The Buckhaults pulse was a late-stage valley-fill event just prior to the close of Morrowan time. The Buckhaults fluvial-valley flood plain contained both an active meander belt and an abandoned meander belt. Because of a local increase in slope in the

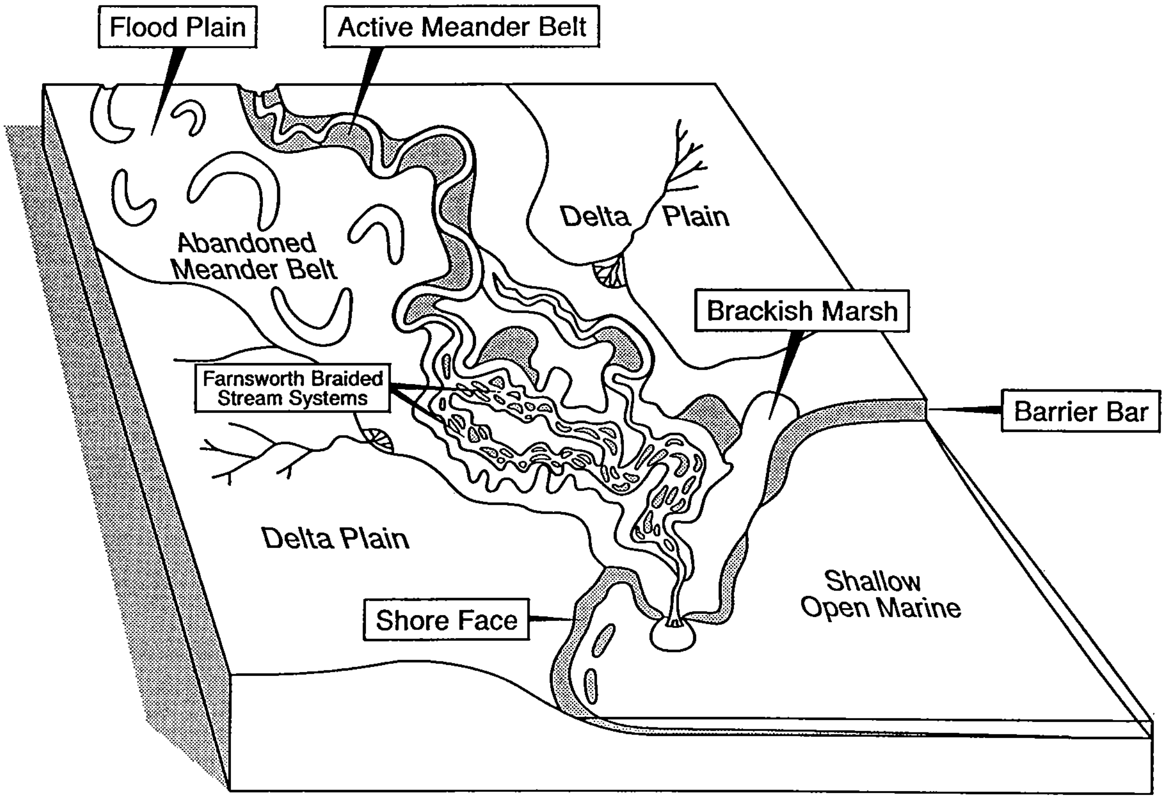

Figure 14. Depositional model showing the fluvial-deltaic environment of the upper Morrow Buckhaults sandstone.

Farnsworth area, a braided-stream segment formed. Sediments were transported to the coast where channel-mouth bars formed and were reworked into barrier bars. This fluvial-dominated sedimentary pulse moved rapidly into a marine basin, downcutting into brackish marsh or lagoon mud and silt deposits at the edge of an epicontinental sea (Fig. 14).

The mineral and textural immaturity of the Buckhaults sandstone is indicative of a short transport distance from a nearby sediment source, possibly located in the Cimarron arch or the Keyes dome area. The sandstone morphology, framework-grain texture, and sedimentary structures are most characteristic of fluvial-dominated low-sinuosity braided-stream sedimentation.

The following conclusions are drawn by integrating geologic, geophysical, and reservoir performance data and methods:

1. The Buckhaults sandstone reservoir geometry was reinterpreted, and a depositional model was made. The Buckhaults thickness, permeability, well performance, and recovery per well all trend parallel to the depositional model. The estimate of original oil in place was increased from 130 to 150 MMBO with the new interpretation.

2. Field extensions were identified with potential primary banked-oil reserves; two extensions were identified on the north and two on the south side of the unit.

3. An additional 10 million bbl of recoverable secondary-oil reserves were identified in areas with a wider well spacing, a lower average permeability, a lower amount of total fluid injected, and a lower recovery per acre-foot.

4. A 90-well infill and extension drilling program was designed to increase the water-flooding efficiency, to recover a higher percentage of the original oil in place, and to develop the field-extension banked-oil reserves.

5. Plans were made to prepare the Farnsworth unit for a tertiary enhanced-oil-recovery program. With the completion of the drilling program, the unit would be fully developed on a 40-acre well spacing, optimum for a CO_2 flood.

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Seismic Classification and Characterization of Deltas with Emphasis on Sand Quality and Geometry

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ABSTRACT.—In order to optimize the application of currently available seismic technology and seismic stratigraphic theory to the imaging of shallow-marine clastic wedges, an operational system of nomenclature (Pigott, 1995) has been developed that emphasizes sand quality and geometry by seismically characterizing and classifying deltas.

For a given shallow-marine clastic wedge isolated within a given sequence and imaged by seismic reflection, one may describe the clinoform internal-wavelet character (i.e., the relative amplitude and interreflector wavelength), the clinoform external-wavelet character (i.e., the maximum reflector dip and the reflector configuration in both depositional dip and strike views), and the static and dynamic aspects of the delta's vertical and horizontal position within the basin's accommodation space (a function of sea level). These seismic characters can then be appropriately plotted as a "seismic delta class" (Pigott, 1995) upon a composite seismic ternary diagram, fields corresponding to the fluvial-, wave-, and tide-dominated fields of the "Galloway" delta diagram. If the density and quality of the seismic coverage permit and if geologic information is available for lithologic calibration of seismic amplitudes, the sand-body (or sandstone-body) geometry can be defined through isochron and isopach mapping. The seismic delta class may then be modified to include a descriptive sand-system subclass.

A detailed seismic characterization can be a powerful tool for describing a delta's three-dimensional architecture and aspects of its paleoenvironmental setting. Moreover, such geophysically derived information, when systematically conducted and geologically constrained, also can provide an important predictive tool for reservoir sand-body definition and characterization. Selected modern delta examples are briefly inventoried as test cases for this seismic characterization and classification scheme. As an example applied to the ancient record, a Pennsylvanian clastic wedge of the eastern Anadarko shelf of Oklahoma is then examined.

INTRODUCTION: POSING THE PROBLEM

The "Galloway" or triangular delta classification (Galloway, 1975) currently in use is based upon a foundation that has been extraordinary in its geologic breadth and depth of research, but less extraordinary in its geophysical descriptive complement. However, with the post-1977 advent of seismic stratigraphic theory and the continually improving technology of geophysical imagery, deltas may now be additionally described in terms of the information revealed both by the geometric configurations of the reflections and by the characteristics of the reflection wavelet itself.

This paper applies a seismic characterization and classification scheme (Pigott, 1995) that is neither limited to a two-dimensional approach nor to a static classification based solely upon modern deltas. The scheme is descriptive, yet with purposeful genetic implications (e.g., philosophy eschewed by Folk in his classification methodology of sandstones, 1974). By drawing upon geophysical characterization and emphasizing sand-body geometries, the characterization and classification scheme represents a logical complement to borehole observations, further providing a necessary foundation for posing practical questions of reservoir quality and geometry.

BRIEF HISTORICAL REVIEW OF THE DELTA-CLASSIFICATION SCHEME

Rather than detail the extensive delta literature, the reader is suggested such reviews as those provided by Coleman (1981), LeBlanc (1975), Miall (1984), Reineck and Singh (1986), and Scruton (1960). In terms of the seminal works, the geologic study of deltas began with Lyell (1832), Credner (1878), and G. K. Gilbert (1885). The clinoform

Pigott, J. D., 1996, Seismic classification and characterization of deltas with emphasis on sand quality and geometry, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 115–132.

conceptual models of Rich (1951), the Mississippi delta contributions of Fisk (1954), and the Gulf of Mexico oceanographic research of Shepard (1960) were significant pioneering efforts. As industry-inspired attention and financial support for research grew, the studies of Coleman and others (1969) and Fisher and others (1969) led to delta investigations that were less parochial and more international and explicitly hydrocarbon oriented.

The paper of Fisher and others (1969) is particularly significant in that it proposed one of the first schemes to classify deltas. Their study suggested that these clastic depositional systems could be broken down into two categories: high-constructive and high-destructive systems. Such a categorization was based upon their early appreciation of the contrasting effect of marine and fluvial energies. Coleman and Wright (1975) attempted a statistical study that, though successful in differentiating many modern deltas, was less practical as a method of characterization for ancient environments (difficulties in quantifying paleo–wave energy, climate, sediment discharge rate, etc.).

In another seminal paper on the geologic description of deltas, Galloway (1975) compiled observations gleaned from an in-depth study of seven modern Holocene deltaic systems. From this process viewpoint, which was heavily influenced by Fisher and others (1969), he suggested that confined fluvial flow, wave flux, and tidal currents played the major roles in shaping the geomorphology of deltas. Galloway plotted these and other modern deltas on a ternary diagram (Fig. 1). This delta-classification system is fittingly "deltaic" or "triangular" in its ternary graphical representation, reflecting perhaps to some degree the similarity between the sand deposit at the mouth of the Nile River and the Greek letter Δ first noted by Herodotus (LeBlanc, 1975). In any case, Galloway's approach facilitates the differentiation between the effects of fluvial input processes and the contrasting effects of marine processes. Three idealized end members are identified: fluvial dominance, wave dominance, and tidal dominance. Many modern deltas throughout the world have been studied and placed within this context (Coleman and others, 1969), a few of which are plotted in the Galloway ternary classification system shown in Figure 1.

THE SAND-SYSTEM SUBCLASS

Sand-body geometries are important not only for geomorphic reasons that illustrate responses to fluvial-marine energies but also for definition of reservoir geometry and quality. Therefore, as a sand-body geometry can be delineated seismically (isochron maps) as well as geologically (isopach maps), the practicality of differentiating delta classes by sand distributions is ensured. In order for the triangular delta classification to better accommodate differing sandstone-body geometries, Figure 2 illustrates an expanded delta-classification scheme, based on modern-delta features, that

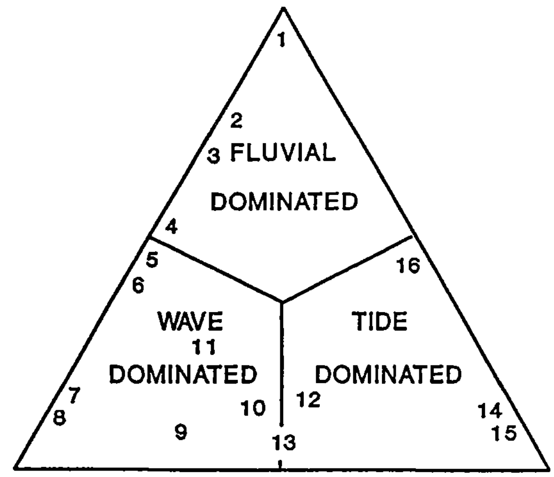


Figure 1. The triangular or Galloway (1975) delta classification, differentiating delta geomorphic type by contrasts in the degree of influence of fluvial, wave, and tide processes. The relative positions of Holocene deltas (after Elliot, 1986) are as follows: 1, Mississippi; 2, Po; 3, Danube; 4, Ebro; 5, Nile; 6, Rhone; 7, São Francisco; 8, Senegal; 9, Burdekin; 10, Niger; 11, Orinoco; 12, Mekong; 13, Copper; 14, Ganges-Brahmaputra; 15, Gulf of Papua; and 16, Mahakam.

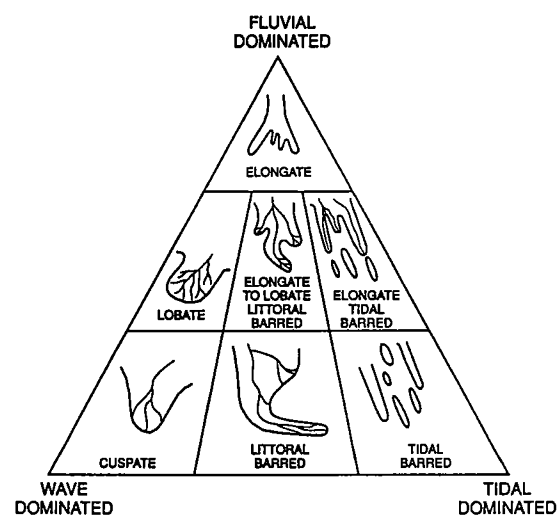


Figure 2. Sand-system subclass of the Galloway delta classification. The subclasses are based upon the geometry of the sand bodies, determined following sand isochron or isopach mapping. See text for details of the subclasses and examples of modern delta types. Within each polygon is a schematic sketch of the respective delta outline.

comprises seven "sand-system subclasses." These sand-system classifications are descriptive, detailing aspects of both the planar geometry and three-dimensional architecture of the sedimentary units. Yet, these subclasses also have genetic implications in terms of the interplay between marine and fluvial processes.

1. Elongate Deltas. Numerous seaward-bifurcating channels are a product of substantial discharge of sediment into a basin with low wave and tidal energies. Such conditions contribute to the wide dispersion of fine-grained sediment loads. Sand-body geometries are typically digitate. The modern-day Mississippi River delta with its bar-finger sand bodies is the classic example (Fisk and others, 1954).

2. Lobate Deltas. If the wave energies of the basin are high, such conditions lead to a prominent bulge in the bathymetric contours. Fine-grained materials are transported away, and this process leads to cleaner, coarser-grained sediment proximal to the mouth. Such a broad lobate geometry with deposition of the mechanical load proximal to the river mouth can also occur if the incoming sand/mud ratio is high. The Nile delta is an appropriate example (Coleman and others, 1981).

3. Elongate to Lobate, Littoral-Barred Deltas. Increasing littoral currents combined with moderate wave and fluvial energies cause sand deposition proximal to the river's mouth to form attached to detached lunate bars. Wave and littoral sorting processes lead to texturally clean sand. Sand-body geometries of this sand-system subclass are a combination of either lobate or short digitate ridges, leading to webbed fingers of sand accumulations terminating with a strike-system ridge. The Holocene Niger delta represents the features of this subclass (Allen, 1965).

4. Elongate, Tidal-Ridged Deltas. Moderate tidal energies with significant fluvial sediment input lead to the development of sandy tidal bars or ridges that can merge with the subaqueous levees. The geometries of the sand bodies of this system are principally stubby to radiating digitate. The Mahakam delta represents one such example (Allen and others, 1979).

5. Cuspate Deltas. High wave energies significantly restrict the seaward extension of the delta, efficiently transport the finer-grained sediment loads offshore, and lead to the nearshore deposition of coarser-grained sediment. Sand bodies exhibit a flattened, diamondlike geometry. A similar geometry can result if the source produced dominantly coarse clastic sediment. One example of this sand system subclass is the present-day Senegal delta (Coleman, 1981).

6. Littoral-Barred Deltas. High wave energies combined with a persistent longshore drift component allow the dispersion of sand into attached or detached strandline bars. Attached strandline bars tend to have sand flats behind them whereas, with increasing tidal or fluvial flushing, lagoons form behind detached bars (barrier islands). Consequently, this sand-system subclass is represented by strike-oriented linear thicknesses that occasionally exhibit lunate geometries. The Orinoco delta (Van Andel, 1967) is one such example.

7. Tidal-Ridged Deltas. Strong bidirectional tidal currents at the mouth of an estuary lead to the development of large linear bars that trend perpendicular to the shoreline; these tidal sand ridges may be separated by finer-grained silt and clay deposits. Geometrically, the sand bodies of this system subclass are represented by numerous, dip-oriented, detached linear fingers. A classic example exhibiting the characteristics of this sand-system subclass is the Fly delta of Papua New Guinea (Galloway, 1975).

SEISMIC CHARACTERISTICS OF DELTAS AND THE IMPORTANCE OF THE CLINOFORM

Neither the horizontal topset beds (undaform) of the fluvial or delta-plain facies nor the horizontal bottomset beds (fondaform) of the distal offshore-marine pelagic facies facilitate an easy definition of deltas exclusively by themselves. Fortunately, there is one particular geometric assemblage of facies peculiar to deltas that is usually easily identified on seismic sections. Just as the geomorphology of the delta lobe and the horizontal aspects of its sandstone bodies when mapped are chief parameters for a predominantly two-dimensional characterization of deltas, it is the delta clinoforms that provide important vertical information which can also be discriminatory. Rich (1951) pointed out that a dramatic, ubiquitous signature of progradational deltas is their inclining foresets of sediment, which he termed "clinoforms" and which separate the "undaform" from the "fondaform." In dip cross section, these sigmoidal deposits make up the delta front (as in the classic delta diagrammatic cross section of Scruton, 1960). Paleoenvironmentally, the shallowest part of the clinoforms represent the boundary between terrestrial and marine; at its deepest part, they represent the boundary between nearshore and offshore. Sedimentologically, the clinoforms represent a broad transition zone between mechanical and suspension processes, i.e., the transition from tractive deposition of sand at the distributary mouth bar, to the oscillating tractive-suspensional deposition of silt and clay in the delta-front facies, to the suspensional deposition of mud in the prodelta facies.

Mitchum and others (1977) early recognized the geophysical interpretive importance of clinoforms. They suggested that clinoforms viewed on seismic dip sections as sigmoid reflection configurations implied lower energies of deposition than those indicated by oblique configurations (the reader is referred to Mitchum, 1977, for definitions of various seismic stratigraphic terms used herein). Berg (1982) later capitalized upon this observation through his seismic examinations of the wave-dominated Woodbine Formation and the fluvial-dominated Tuscaloosa deltas. Berg proposed that wave-dominated deltas are represented by shingled to oblique clinoform reflections whereas fluvial-dominated deltas are typified by sigmoid clinoform reflections.

As the information from a single borehole is on the order of tenths of 1 m whereas the information obtained geophysically from a single common-midpoint gather can often be on the order of hundreds of meters (one Fresnel zone; see Sheriff, 1985), the advantages of integrating some three orders of magnitude worth of additional lateral information from the use of seismic data are underscored. Such an increased information content allows determination of local sandstone-geometries and integration with regionally delineated changes in tectonics, sea level, and other factors. The seismic information that can describe a delta is obtained either directly from observation of the reflected wavelet or from the groups of reflections. Although additional, geologically relevant data about the internal lithologic and fluid compositions of deltas can be determined from prestack information—e.g., velocity (Warwick and Pigott, 1990), elastic moduli (Pigott and others, 1989), porosity (Pigott and others, 1990), attenuation, and V_p/V_s ratios—this information is not so easily described as dependent upon delta types. Therefore, the characterization and classification scheme proposed by Pigott (1995) and detailed here focuses upon the poststack information, beginning with the internal-wavelet character and then progressing to the external-wavelet character. Such geophysical imagery allows the practical description and prediction of the changing reservoir–source rock quality of deltaic sedimentary units through time and space. Unless mentioned otherwise, seismic stratigraphic terminology follows the definitions of Mitchum (1977) and Van Wagoner and others (1987).

IMPORTANT SEISMIC CHARACTERISTICS FOR DESCRIBING CLASTIC WEDGES

Seismic Classification Scheme

Procedurally, the seismic characterization system proposed by Pigott (1995) is expressed by filling in the boxes shown in Figure 3. The numbers in the boxes refer to the following detailed descriptions of the seismically determined characteristics.

Clinoform Internal-Wavelet Character

1. Relative Amplitude (Optional)

In a perfect world where noise is absent, the greater the contrast in acoustic impedance between two layers, the greater the reflection coefficient and the resulting recorded and displayed relative amplitude (R.A.). Consequently, thick, high-impedance sandy tidal bars would tend to show pronounced separation from the finer-grained, underlying, siltier, low-impedance interbar deposits by exhibiting high reflection amplitudes. In contrast, the more homogeneous and sandier, wave-dominated deltas with no vertical changes in acoustic impedance would tend to exhibit packages of reflection-free internal configurations; acoustically homogeneous sand or mud bodies in fluvial-dominated deltas would be similarly reflection free.

However, one should note that discrimination between adjacent sand (or sandstone) and mud (or shale) is possible only if an impedance contrast exists between them. Indeed, with increasing depth, nonequivalent compaction rates of sand and mud can even lead to a crossover in their acoustic impedance with resultant transitional

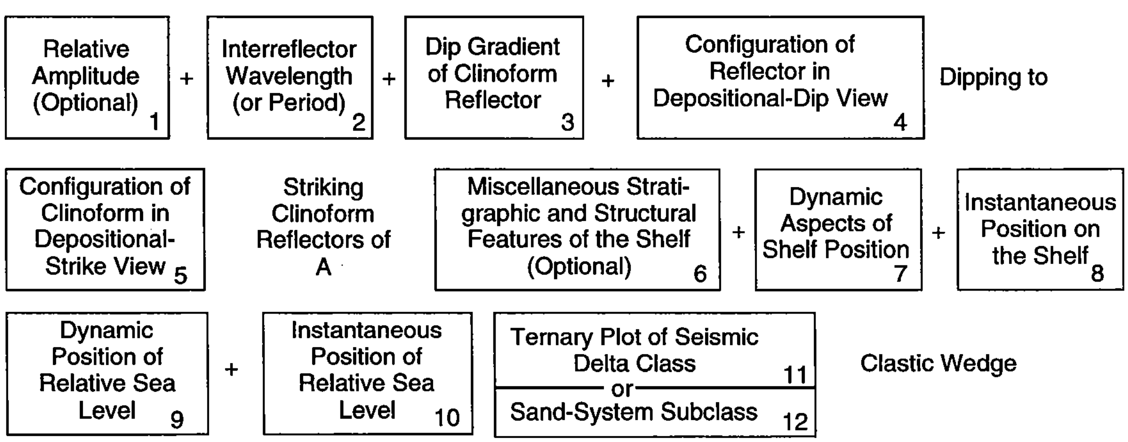


Figure 3. Chart for determining the seismic classification-characterization of a delta. The numbers refer to the pertinent text headings that detail the procedures to be followed.

zones that exhibit minimal impedance contrast (Neidell and Berry, 1989). Without the preservation of amplitude information during acquisition and processing (see Pigott and others, 1989) and unless the relative amplitudes are calibrated with borehole lithologic information, great caution should be exercised in interpreting the amplitude information. Moreover, if the relative-amplitude information is used for regional interwedge comparison of lithologies, it should be done qualitatively at the very least and with restraint at the very most. For these reasons, specification of the relative-amplitude information, though potentially useful, is considered optional. Terms for the relative amplitude that describe the wavelet character are qualitative, scaled with reference to an arbitrary reflection-free trace: *high* (>75%), *medium* (75% ≥ R.A. ≥ 25%), *low* (<25%), and *reflection-free* (≃0%).

2. Interreflector Wavelength (or Period)

For a given sedimentary package of intercalated sedimentary units of differing acoustic impedance, e.g., sandstones and siltstones, the thicker the units, the greater the interreflector wavelengths (or, if expressed in time, the longer the reflector period). Conversely, as the beds become more numerous and thinner, they acoustically exhibit shorter seismic interreflector wavelengths (and shorter reflector periods).

The composite stratigraphic data of Coleman and Wright (1975) for modern delta-front facies yield examples of each of the three geomorphic (i.e., Galloway, 1977) delta types: wave dominated, tide dominated, and fluvial dominated. Wave-dominated deltas tend to have the thickest sand packages (maximum of 66 m observed for the Holocene São Francisco delta) and consequently the longest potential interreflector wavelengths. Tide-dominated deltas have more moderate sand thicknesses (the Holocene Klang delta has 5–24-m-thick sand bodies) and more moderate potential wavelengths. Fluvial-dominated deltas have the most numerous and thinnest sand packages (the Holocene Mississippi delta has sand bodies as thin as 2 m and as thick as 21 m) and the shortest potential interreflector wavelengths. Incorporating these observations, one may characterize the interreflector wavelengths as predominantly *short* (wavelength < 5 m), *medium* (5 m ≤ wavelength ≤ 20 m), and *long* (wavelength > 20 m). The accurate discrimination of tops and bottoms of acoustic interfaces for the measurement of periods, which are then converted to wavelengths, is dependent on a sufficiently broad-frequency bandwidth (not just making the frequency higher!) for seismic resolving capacity, the prior application of proper deconvolution techniques (see section on Limits), and the availability of accurate interval-velocity information.

This internal-wavelet property may also be stated, though more cautiously, in terms of dominant frequencies. Although a function of the bandwidth of the input wavelet and contingent upon the attenuating properties of a particular sedimentary section (as described under Limits), with all other parameters held constant, generally the higher the number of acoustic interfaces or reflectors per arbitrary segment of vertical depth, the higher the observed dominant frequency per segment of equivalent two-way time segment. As a result, those ancient depositional systems such as fluvial-dominated deltas that feature clinoforms of delta-front sheet sandstones interspersed with finer siltstones and shales tend to show a higher-frequency content than both the more homogeneous wave-dominated deltas and the thicker-bedded, tide-dominated deltas. However, one should note that the observed frequency is not a simple linear function of sandstone and shale thickness. As acoustically contrasting beds become thinner, the peak-to-trough time separation shortens, the reflectors begin to constructively tune with a concomitant decrease in frequency (see classic treatment by Neidell and Poggiagliolmi, 1977). Inasmuch as these frequencies are mathematical reciprocals of the interreflector periods, and in view of the preceding discussion, use of the frequency in addition to the interreflector period is viewed as redundant and therefore is not included in the characterization scheme.

Clinoform External-Reflector (Reflection Group) Characteristics

3. Dip Gradient of Clinoform Reflectors

The greater the slope of the offlapping clinoform package (not necessarily equivalent with the shelf slope or shelf-edge slope), the less drag exerted by the underlying sediments upon the impinging wind-generated water waves. Consequently, coarse-grained, wave-dominated deltas that receive high incoming wave energies tend toward having steeper delta slopes at their river mouths. This relationship is supported by the data of Coleman (1981) that reveal fluvial-dominated deltas to exhibit low slopes with gradients as low as 0.003° and tide-dominated deltas to also have low slopes with gradients averaging 0.089°. In contrast, Coleman (1981) showed wave-dominated deltas to have the steepest slopes, as much as 0.48°. Operationally, in order to determine reflector dip angles on seismic sections, one must (a) delineate a reflector along the maximum sedimentary dip, (b) specify at least two arbitrary points on this reflector, (c) convert time to depth, and then (d) determine the gradient of the clinoform with respect to an arbitrary reflector that represents a near-horizontal syndepositional datum (e.g., water bottom or a delta-plain sequence boundary demonstrating toplap) by dividing the vertical depth differential of the clinoform reflector by its horizontal distance differential. Ideally, the seismic profile should be migrated, but if unmigrated, one can solve for the true angle β by using a derivation of a Huygens wave-front construction:

$$\beta = \arctan \sin \alpha,$$

where α is the unmigrated angle and β is the migrated angle. The terms, then, for characterizing these clinoform-reflector dip gradients in the seismic delta-classification scheme are *low gradient* ($<0.1°$), *medium gradient* ($0.1° \leq$ gradient $\leq 0.4°$), and *high gradient* ($>0.4°$).

One should note that differential postdepositional compaction of sediments will change gradients if the proximal and distal lithologies along a reflector compact following different rate laws. For example, compaction will increase gradients from the original values if the proximal lithologies (sand-rich systems) compress less than the distal lithologies (sand-poor systems). Although documented modern examples of deltaic sedimentation at shelf margins are less common than in the past (Winker and Edwards, 1983), as deltas prograde toward and finally reach the shelf edge, they tend to become increasingly wave dominated with their clinoform slopes eventually merging with that of the shelf break (can be in excess of 5°; see example 1, Mississippi delta, in the section Forward Seismic Models).

4. Configuration of Clinoform Reflectors in Dip View

Tangential Baselap (Sigmoidal; Oblique). Deltas deposited in environments of lower marine energies with attached, fine-grained, suspended loads tend to have elongate geometries that tangentially baselap seaward. If toplap occurs above, the complete form package is sigmoidal. If erosional truncation occurs, the clinoform dip geometry can appear oblique with the removal of the upper beds. However, independent of the degree of erosion in the upper beds, the downdip terminus of the clinoforms is preserved. Thus, one may consistently describe the baselap characteristic of these fluvial-dominated deltas as *tangential*.

Acute Baselap (Oblique). In wave-dominated deltas, owing in part to their disposition toward shelf slopes with high gradients and in part to waves removing and transporting away the finer loads, the mechanical loads dominate. Consequently, the clinoforms tend to less commonly exhibit the "settled-out" tangential seismic characteristics of the fluvial-dominated deltas. Instead, these deltas tend to be represented by *acute* or *oblique* to *shingled* baselap terminations. *Acute* is the preferred term as it focuses upon the relationship of the clinoform to the base.

Subparallel-Concordant Baselap. Owing to the numerous channels that characterize tide-dominated deltas, the sediment bedding planes in the dip view (as well as in strike views) are seldom consistent in their dipping intersection with the underlying beds, most commonly exhibiting *subparallel-concordant* baselap signatures.

5. Configuration of Clinoform in Depositional-Strike View

Continuity and Parallelism. Continuity and parallelism of reflectors within the strike perspective are separate and yet often related. *Continuity* refers to the lateral traceability of a reflector, whereas *parallelism* refers to the evenness of spacing between the reflectors. Strike views of the clinoforms of the fluvial-dominated and wave-dominated deltas, with the obvious exception of the distributary channel itself, can demonstrate remarkable reflector continuity and parallelism. Conversely, with growing tidal influence, in the clinoform packages of tide-dominated deltas, channeling and tidal-ridge development intensify, which increasingly reduces both continuity and parallelism of reflections. Indeed, the numerous, low-amplitude channel and mound-relief waveforms exhibited in cross section in tide-dominated deltas give rise to discontinuous to chaotic concave-convex clinoform reflector geometries. One must be aware, however, that chaotic reflectors also may occur accompanying structural deformation within the clinoforms owing to slumping, etc. Seismic character terms, in order of decreasing continuity, are *continuous, segmented,* and *discontinuous*; character terms for parallelism, in decreasing order, are *parallel, subparallel,* and *concave-convex.*

6. Miscellaneous Stratigraphic and Structural Features of the Shelf (Optional)

The shelf that both underlies and may itself be composed of the clastic wedges further can be described by seismically observable features of stratigraphic incision and structure. The following terms are used to characterize these miscellaneous shelf attributes.

Trough Incision and/or Unconformity Type for Sequence Package. Generally, the magnitude of trough incision is not correlated to any one type of delta system. Degradation by downcutting can be enhanced either extrinsically or intrinsically. For example, if degradation is extrinsic, or tectonically enhanced, such as may be caused by a rapid relative sea-level fall with respect to basin subsidence, deep incision can give rise to submarine canyons. If degradation is intrinsic, or depositionally enhanced, such as by stream avulsion and delta-lobe switching (slower relative sea-level fall with respect to basin subsidence), more gentle downcutting leads to smaller-magnitude incised channels and general peneplanation. The resultant unconformities may be termed "Type I" or "Type II," respectively (Van Wagoner and others, 1987) or, more consistent with the processes responsible, "Tectonically Enhanced" or "Depositionally Enhanced," respectively. With an accompanying global or relative sea-level rise, these channels can subsequently become filled with sand or mud that will acoustically contrast with the underlying units. Consequently, trough incision can be used as a descriptive though nonunique delta modifier when viewed from the perspective of depositional strike. Of course, if there is little contrast in acoustic impedance between the channel fill and the underlying beds, such as can occur in sand-prone wave-dominated deltas, the incised channels will be resolved with difficulty. However, in cases where trough incision can be seismically observed, the terms for incision are *shallow-trough-incised* (<10 m), *medium-trough-incised* (10 m ≤ incision ≤ 40 m), and *deep-trough-incised* (>40 m). Other miscellaneous stratigraphic terms (e.g., salt welded, condensed, etc.) may be added as appropriate.

Structures. Critical to the determination of the hydrocarbon potential of a delta are considerations of the syndepositional and postdepositional aspects of the structural evolution of the shelf. Though not unique to one delta type, such terms as *stable, reverse tilting, inverted, listric faulted, reverse faulted, wrench faulted, complex faulted, diapirically intruded,* etc. to describe structures that can be directly observed on reflection seismic sections communicate important information concerning the structural and tectonic setting of the delta and should be included in its characterization.

Accommodation Space

Though the principal geomorphic paradigm based upon Holocene studies for deltas is that of progradation (see Scruton, 1960), it would be inaccurate to assume that all deltas in the geologic past behaved similarly. A useful exercise to understand just how a clastic wedge is deposited is to consider the horizontal and vertical accommodation space that it must occupy. The instantaneous and dynamic aspects of how the clastic wedge responds to this accommodation space directly affect both the physical attributes of the wedge itself (geometry, sand content, etc.) and the local associated sedimentary environments. Conversely, reading the instantaneous and dynamic accommodation position from the seismic data reveals information about transgressions and regressions and sea-level rises and falls.

It is important to stress that both the horizontal and vertical position of the wedge and its vertical and horizontal motion within the accommodation space are independent descriptions. An analysis of both interdependent and independent relationships between sea level and transgressions and regressions has been theoretically detailed and schematically illustrated by Vail and others (1977) from considerations of coastal onlap. Therefore, as regressions and transgressions may occur coupled or noncoupled with sea-level changes, it is appropriate to describe these horizontal and vertical components separately.

Horizontal Accommodation Space (Regressions and Transgressions)

7. Dynamic Aspects of Shelf Position

The dynamic or time-transient features of the clastic wedge upon the shelf reveal whether the system is moving seaward, retreating, or standing relatively still. This motion is conventionally described as regressive (i.e., progradational offlapping clinoforms), transgressive (i.e., retrogradational or landward retreat of the coastal zone), or static (i.e., stationary). It must be emphasized that such a description of the dynamic aspects of filling the horizontal accommodation space makes no assumption, explicitly or implicitly, about the activity of the vertical sea-level datum, e.g., whether it is rising or falling (see following section on vertical accommodation).

8. Instantaneous Position on the Shelf

The instantaneous position of the apex of the clastic shelf wedge is an important feature that communicates information regarding geometrical relationships of associated sedimentary environments, reservoir continuity, juxtaposition of source rocks, and hydrocarbon migration pathways. One may refer to this position as *proximal shelf, medial shelf,* or *distal shelf.* Such a description is not identical to the bathymetric subdivisions of the shelf, which require paleontological calibration (e.g., the *inner shelf and outer shelf* of Johnson and Baldwin, 1986). Rather, this description should be viewed as a geometric concept of placement of the delta system (the delta plain, delta front, and prodelta) upon the shelf ramp. However, if particular shelf zones have been previously established by local convention, they should be used in lieu of these more general terms.

Vertical Accommodation Space (Changes in Relative Sea Level)

Changes in relative sea level, irrespective of whether caused by extrinsic (global) or intrinsic (local) processes, are best interpreted as changes in vertical accommodation space.

9. Dynamic (Time-transient) Position of Relative Sea Level

If the vertical space for delta accommodation is increasing, then the preserved clinoforms demonstrate aggradation; if the vertical accommodation space is decreasing, the upper portions of the clinoforms may exhibit erosional truncation, resulting in degradation. If, on the other hand, the vertical accommodation space remains approximately constant, the tops of the clinoforms tangentially merge, leading to toplap. With reference to an arbitrary relative sea-level datum, these respective relative sea-level positions may be described as a time of *rising sea level, falling sea level,* or *sea-level stillstand* (i.e., *sea-level highstand* or *sea-level lowstand*).

10. Instantaneous Position of Relative Sea Level

Deltas can be described as having been deposited during a time of relative high sea level as part of a highstand system tract, during a time of relative low sea level as part of a lowstand system tract, or during a time of intermediate relative sea level as an interstand (most usually a preserved transgressive) system tract. Such descriptions refer to instantaneous time snapshots, privileged interpretations viewed from the perspective of a dynamic synthesis.

Seismic Delta Classification

11. Ternary Plot of Seismic Delta Class

The preceding wavelet, dip-reflector, and strike-reflector characteristics can be combined into a seismic delta-class plot (Fig. 4; Pigott, 1995). The triangular approach is maintained, more from a conventional and aesthetic rationale than from any mathematical convenience. As such, the three divisions of these triangles should be viewed as "seismic delta-class tendencies," corresponding to the end members of the Galloway (1975) delta classification. The three divisions are (a) *fluvial-dominated tendency,* (b) *marine-dominated tendency,* and (c) *tide-dominated tendency.* When the qualifier *seismic* is inserted before *tendency,* this designation emphasizes that the interpreted class is based upon seismic criteria alone.

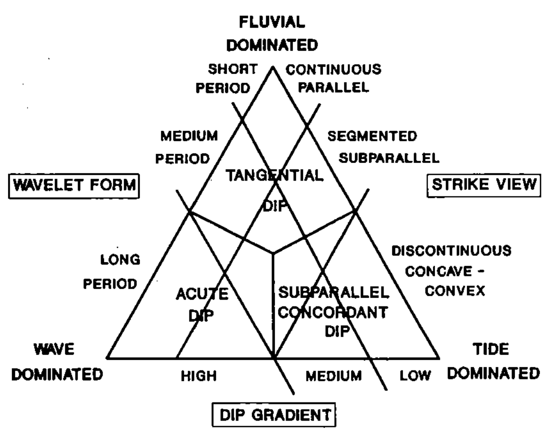


Figure 4. Ternary plot of seismic delta class. Following the determination from seismic data of a clastic wedge's internal-wavelet character, external dip and strike reflector configurations, and dip gradient, a delta-tendency type may be indicated. These delta tendencies correspond to the Galloway delta classes. See text for explanation.

The interpretation of the seismic characterization of a given clastic wedge as having a specific seismic delta-class tendency is necessarily not absolute, but relative. Of course, if sufficient borehole and regional information is available to geologically constrain the seismic delta end-member tendencies, and if the data permit, one may reduce the ambiguities from the seismic interpretation with the further quantification of some of these inferred parameters (sand content as a function of relative amplitude, etc.) and characterize the sand-system subclass.

12. Sand-System Subclass

Following detailed isochron and/or isopach mapping and comparison of the sand or sandstone geometry with Figure 2, the final sand-system subclass may be designated, augmenting or replacing the former delta-class tendency name.

LIMITS

Limits of seismic resolution (the determination of bed thicknesses, etc.) are an inherent function of nature of the particular sedimentary section's response to reflection seismic investigation (the reader is referred to a detailed review of the physics by Telford and others, 1990). In conventional reflection seismic studies, the strength of the input seismic signal necessary for accurate resolution decays from the spherical divergence of the wave front, transmission losses, and mode conversion. There is also the nonuniform attenuation of frequencies with increasing depth that is a function of, among other things, the transmission loss and absorption properties of different lithologies. If this nonuniformity of the input signal is compensated for by using appropriate gain-recovery techniques in processing, one can greatly enhance the signal-to-noise ratio of the imaged geology. With amplitude preservation and the broadening of the frequency bandwidth, the ability to image greater lithologic detail and smaller features of depositional structure (currently at the decameter level) is limited only by the technology (an extreme example is the nonconventional centimeter-scale sequence-stratigraphic application of high-resolution ground-penetrating radar described by Skinner and others [1989]).

The accuracy of the interpretation is also a function of proper processing. Seismic processing that is noncosmetic and is instead based upon physically appropriate methods that are problem dependent and geologically constrained introduces the fewest artifacts. Incomplete processing can also interfere with the interpretations. For example, if the seismic has not been deconvolved properly, artifacts related to the constructive interference of side lobes of the wavelet can mask, among many things, the proper determination of the period (as shown by the first two offshore examples in the section on Forward Seismic Models). Furthermore, there are the potential problems introduced during acquisition (e.g., aliasing and array effects) and processing (e.g., data-dependent gaining, certain migration techniques, etc.) that can corrupt the amplitude information. However, amplitude preservation is currently a standard industry concern and is almost routinely applied during processing. Indeed, there is hope that the data available from three-component and AVO (amplitude variation with offset) studies on rock-fluid elastic properties (see Pigott and others, 1989, 1990) could, after application to the clastic depositional system inventory, potentially yield additional discriminatory lithologic information. Then there are the problems of interpretation that occur with combining seismic data of different acquisition and processing vintages that have not consistently addressed in the same way the problems of amplitude preservation or the minimization of artifacts. With these concerns, one must realize that the preceding detailed seismic characterization parameters can yield geologically reasonable and accurate interpretation parameters only if the data are geophysically reasonable in their acquisition and processing.

Finally, it is always possible that, in the absence of geologic information (e.g., flanking sedimentary facies, paleo–water depths, shelf position), a clastic wedge may be something other than a delta, e.g., a carbonate prograding platform or a turbidite. Indeed, attempting to classify a clastic wedge from seismic data without any geologic constraint is as inappropriate as trying to interpret out of context sentences from the *Holy Bible, Holy Qur'an,* or *Tripitaka.* With this in mind, the wisdom and humility of using the words "seismic tendency" and "clastic wedge" in such purely seismic cases are emphasized.

EXAMPLES OF FORWARD SEISMIC MODELS OF HOLOCENE DELTAS AND THEIR CHARACTERIZATION

Published oceanographic bathymetric charts and lithologic data of several well-studied Holocene deltas allowed forward seismic models to be constructed from geologic models by convolving digitized stratigraphic sections with a zero-phase 8 16 60 90 Hz bandpass wavelet. Although these hypothetical seismic model products have much higher signal-to-noise ratios and significantly fewer structural complications than what is typically the case, these models from modern deltas serve as useful theoretical "high informational content" reference examples for the sand-system subclass (Fig. 2) and the seismic characterization and classification scheme. These models may be compared with "real life" examples from the ancient record described by Pigott (1986).

1. Mississippi Delta. Figure 5 illustrates a bathymetric surface plot and forward seismic model of the Mississippi delta (courtesy of the assistance of Rongjiao [Rita] Wang). Lithologic data were obtained from Fisk and others (1954), Frazier (1967), and Coleman and Wright (1975). The heavy lines on the surface plot represent dip gradients that vary between 0.12° and 0.57°. An important observation on the seismic model is that although the reflector clinoforms dip left to right, the interfaces between the sand, silt, and mud prograding units, as indicated by the fine lines, generally dip right to left. This phenomenon is caused by concurrent aggradation and progradation. A characterization of this model would be as follows: "medium amplitude; short period; medium gradient; tangentially dipping to continuous, parallel-striking clinoform reflectors; regressive distal shelf; rising sea level; highstand system tract; fluvial-dominated seismic tendency; elongate clastic wedge."

2. Nile Delta. Figure 6 illustrates a bathymetric surface plot and forward seismic model of the Nile delta (courtesy of the assistance of Abdelazim Ibrahim). Lithologic data were obtained from Coleman and others (1981), Rizzini and others (1976), and Said (1962). Although the dip gradient is a small 0.005°, on the compressed synthetic seismic model, the dip is easily observed, a common, but often unappreciated, property of most real seismic data. A characterization of this model would be as follows: "low to medium amplitude; medium period; low gradient; tangentially dipping to continuous, parallel-striking clinoform reflectors; regressive distal shelf; rising sea level; highstand system tract; fluvial-dominated seismic tendency; lobate clastic wedge."

3. Niger Delta. Figure 7 illustrates a bathymetric surface plot and forward seismic model of the Niger delta (courtesy of the assistance of Kwaku Feglo). Lithologic data were obtained from Allen (1965), Evamy and others (1978), and Avbovbo (1978). Because the progradational component substantially exceeded the aggradation component, internal lithofacies boundaries are more horizontal and less reverse dipping, as was produced by the Mississippi model shown in Figure 5. A characterization of this model would be as follows: "low amplitude; long period; low gradient; tangentially dipping to continuous, parallel-striking clinoform reflectors; regressive proximal shelf; rising sea level; highstand system tract; fluvial-dominated seismic tendency; elongate to lobate, littoral-barred clastic wedge."

4. Mahakam Delta. A characterization of the model of the Mahakam delta (not shown; lithologic data obtained from Allen and others, 1979; plots at position 16 in Fig. 1) would be as follows: "medium amplitude; medium period; low gradient; tangentially dipping to discontinuous, parallel-striking clinoform reflectors; regressive medial shelf; rising

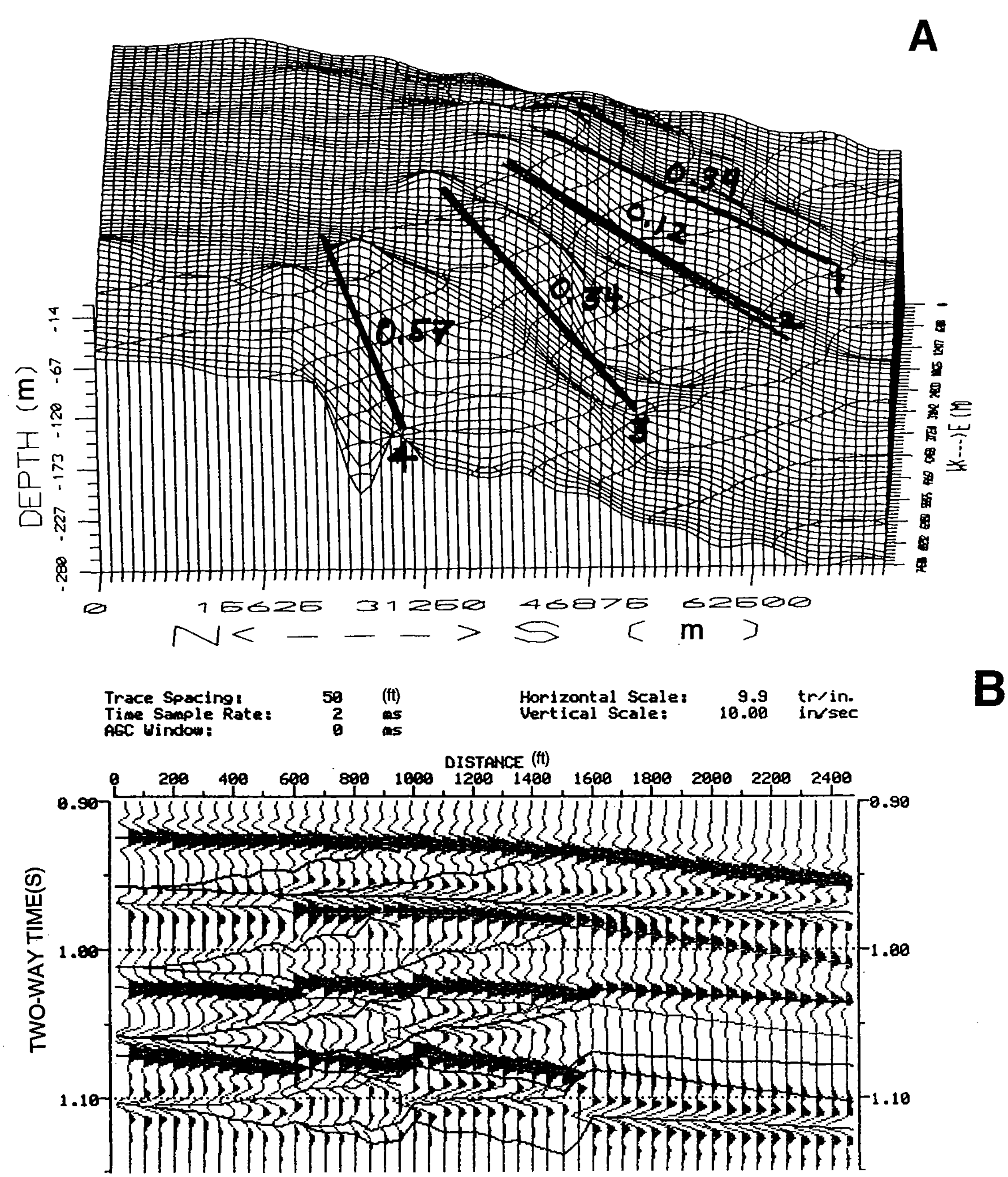


Figure 5. Holocene Mississippi delta (lat 29°15′–28°40′N, long 89°44′–88°63′W). (A) Bathymetric surface plot (contour interval, 25 m; vertical exaggeration, 100×; tilt, 20°). Heavy lines indicate dip-line transects with dips given in degrees. (B) Forward seismic dip-view model using a zero-phase 8 16 60 90 Hz wavelet. Note that although progradation is left to right as is indicated by the reflectors, right-to-left dips shown by the light lines indicate lithofacies boundaries.

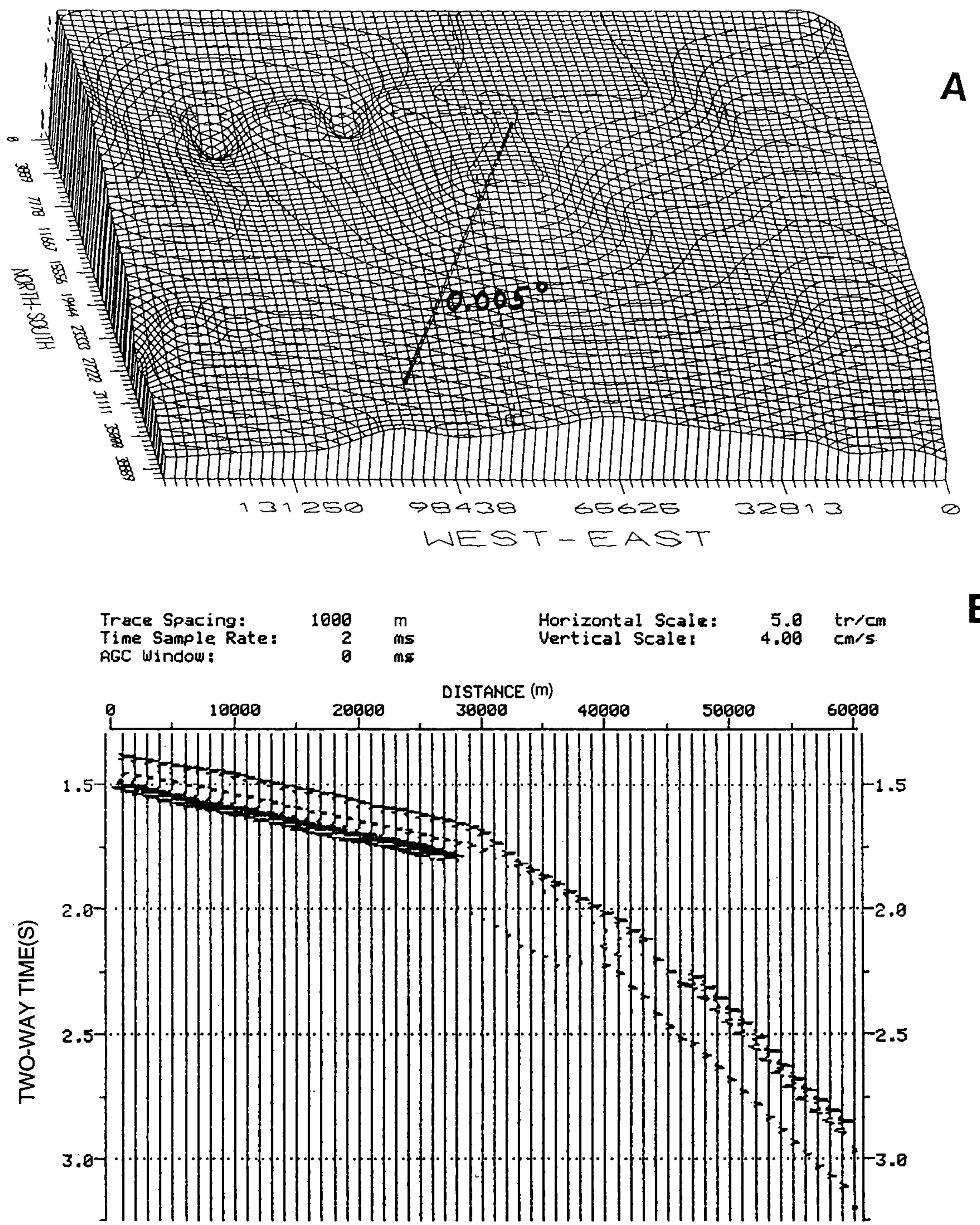


Figure 6. Holocene Nile delta. (A) Bathymetric surface plot (contour interval, 1 m; vertical exaggeration, 400×). The heavy line indicates the dip-angle transect. (B) Forward seismic dip-view model using a zero-phase 8 16 60 90 Hz wavelet. See text for complete seismic delta characterization.

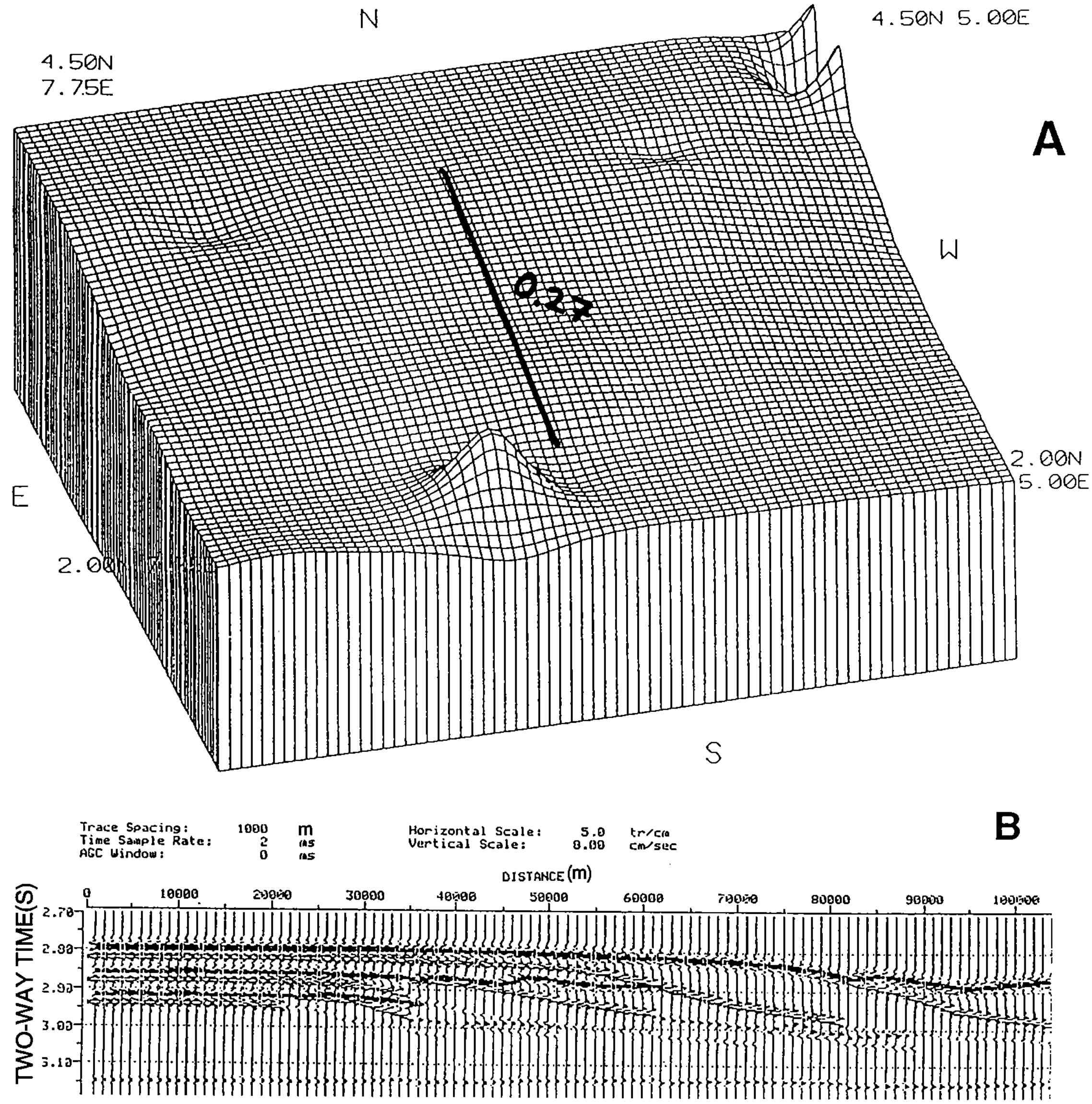


Figure 7. Holocene Niger delta. (A) Bathymetric surface plot. The heavy line indicates the dip-line transect with dip given in degrees. (B) Forward seismic dip-view model using a zero-phase 8 16 60 90 Hz wavelet. In contrast to the Mississippi model of Figure 5, lithofacies boundaries are generally horizontal. See text for complete seismic delta characterization.

sea level; highstand system tract; tide-dominated seismic tendency; elongate, tidal-ridged clastic wedge."

5. Senegal Delta. Figure 8 illustrates a bathymetric surface plot and forward seismic model of the Senegal delta (courtesy of the assistance of Carsten Geiger). Lithologic data were obtained from Coleman (1981). The heavy line on the model indicates a segmented dip gradient that varies between 0.23° and 1.11°, owing to the proximity to the shelf edge. The seismic model reveals gently inclining reflectors dipping left, which is basinward (reversed with respect to the preceding figures). A characterization of this model would be as follows: "low to medium amplitude; long period; medium to high gradient; acutely dipping to continuous, parallel-striking clinoform reflectors; medium-trough-incised, distal shelf;

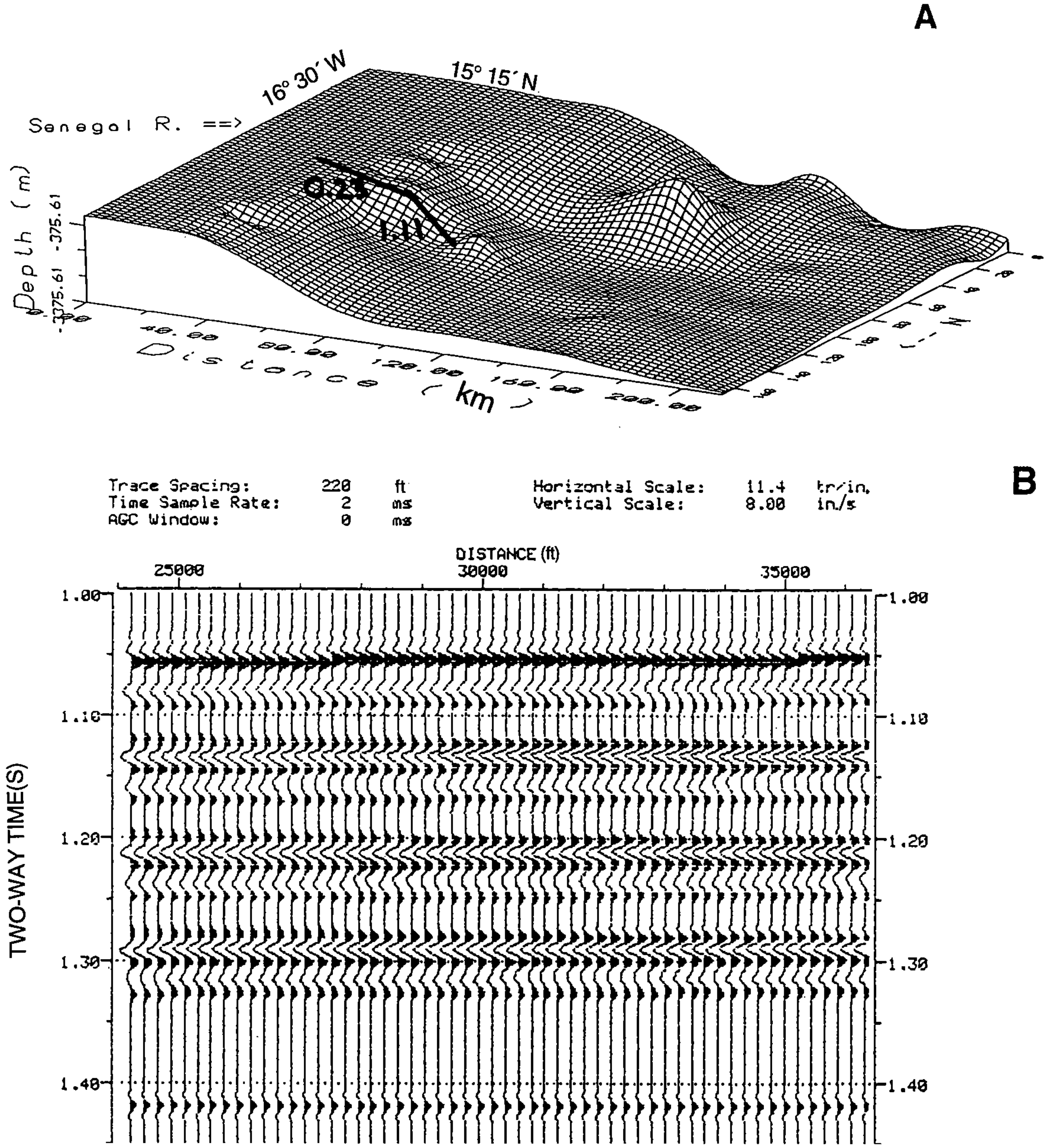
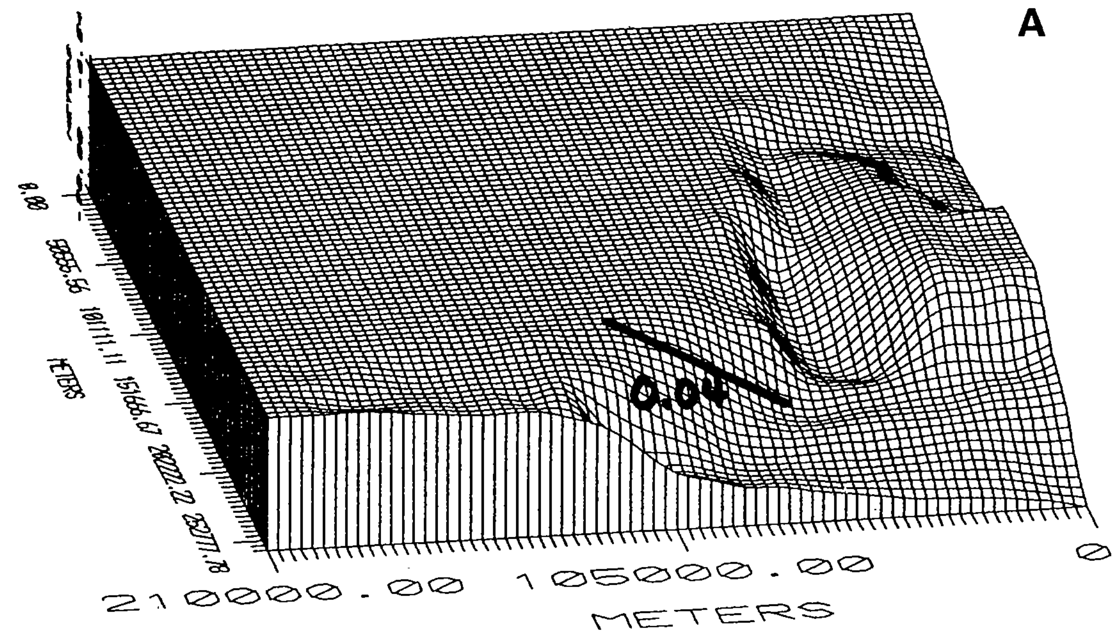


Figure 8. Holocene Senegal delta. (A) Bathymetric surface plot. Observe the segmented dip transect with two reported angles. (B) Forward seismic dip-view model using a zero-phase 8 16 60 90 Hz wavelet. Note that progradation is basinward to the left. See text for complete seismic delta characterization.

rising sea level; highstand system tract; wave-dominated seismic tendency; cuspate clastic wedge."

6. Orinoco Delta. Figure 9 illustrates a bathymetric surface plot and forward seismic model of the Orinoco delta (courtesy of the assistance of Alfredo Hosie). Lithologic data were obtained from Van Andel (1967) and Coleman and Wright (1975). Although the clinoform dips are low, approximately 0.04°, they are still visible as dips to the right on the compressed seismic model. A characterization of this model would be as follows: "low amplitude; long period; low gradient; acutely dipping to continuous, parallel-striking clinoform reflectors; medium-trough-incised; prograding; proximal shelf; rising sea level; highstand system



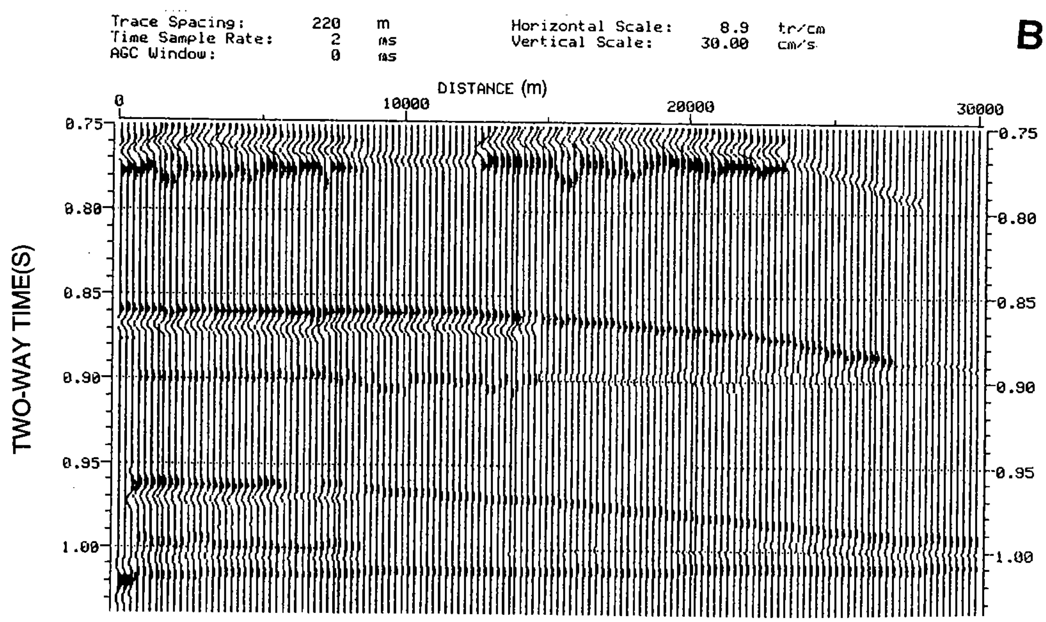
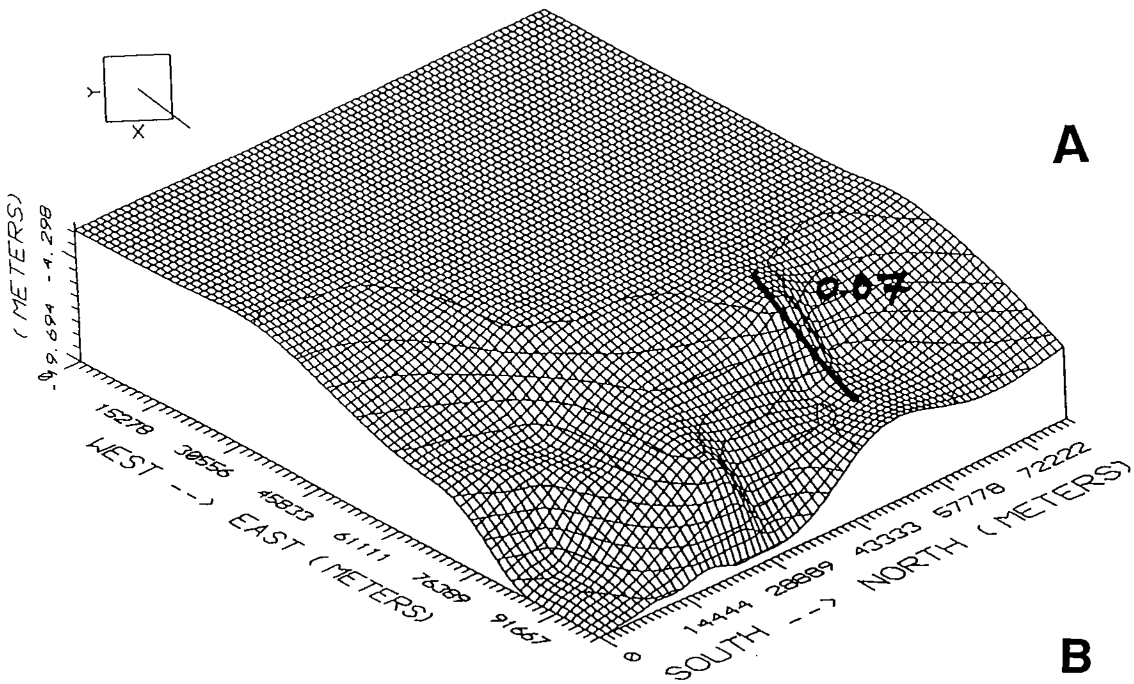


Figure 9. Holocene Orinoco delta. (A) Bathymetric surface plot. Heavy line indicates dip transect with the angle in degrees. (B) Forward seismic dip-view model using a zero-phase 8 16 60 90 Hz wavelet. See text for complete seismic delta characterization.

tract; wave-dominated seismic tendency; littoral-barred clastic wedge."

7. *Fly Delta.* Figure 10 illustrates a bathymetric surface plot and forward seismic model of the Fly delta of Papua New Guinea (courtesy of the assistance of Ye [Wiggy] Wang). Lithologic data were inferred from Galloway (1975). It should be observed that the clinoform dip gradient of 0.07° is taken parallel to a tidal ridge. The resulting forward seismic dip model reveals these dips. A



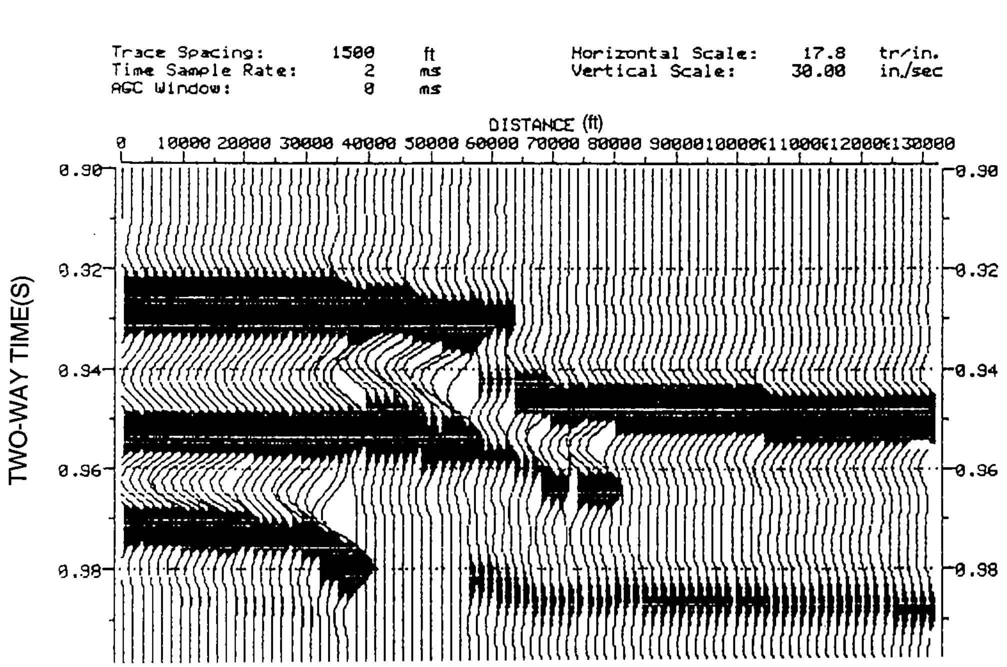


Figure 10. Holocene Fly delta (lat 8°13.3′–8°56.6′S, long 143°5.0′–144°0.3′E). (A) Bathymetric surface plot (contours: minimum = –18.1 m, maximum = –0.1 m, interval = 2 m). (B) Forward seismic dip-view model using a zero-phase 8 16 60 90 Hz wavelet. Thickness of seismic wavelet is caused by increased vertical exaggeration. See text for complete delta characterization.

strike view, not shown, would illustrate the mounds and troughs. A characterization of this model would be as follows: "high amplitude; short period; low gradient; tangentially dipping to discontinuous, concave-convex reflectors; shallow-trough-incised; prograding, proximal shelf; rising sea level; highstand system tract; tide-dominated seismic tendency; tidal-ridged clastic wedge."

WORKED EXAMPLE OF ONE ANCIENT DELTA

One example of the practical application of this scheme (see Pigott, 1995, for other examples) to ancient clastic wedges can be illustrated by the Pennsylvanian Pre–Belle City strata of the eastern Anadarko basin, Oklahoma. This example is based upon data directly extracted from the study of Galloway and others (1977). Figure 11A (from Galloway and others, 1977) illustrates a log section and a seismic dip section of equivalent horizontal scale for these strata. Figure 11B (also from Galloway and others, 1977) illustrates a sandstone isopach map constructed for the Pre–Belle City Sandstone. This sandstone wedge can be characterized as follows: "high amplitude; medium period; low gradient; tangentially dipping to continuous (?), parallel-striking reflectors; structurally stable platform; prograding, medial to distal shelf; lowstand system tract; fluvial-dominated seismic tendency; elongate clastic wedge." This characterization places the wedge within the seismic delta-tendency plot as the upper two left polygons (Fig. 11C).

CONCLUDING STATEMENT

This seismic characterization and classification scheme for clastic wedges proposed by Pigott (1995) provides an immediate, practical, systematic method for the differentiation of delta-type tendencies. By implementing this characterization, the scheme answers pertinent questions about a clastic wedge's setting upon the shelf, whether it is prograding or retrograding, whether it is a highstand or a lowstand deposit, its composition, and its sandstone-body geometries. These answers have immediate implications concerning the determination of reservoir and source-rock potential. Forward seismic modeling has been applied to analyze a spectrum of sand-body styles. One example from the ancient record is characterized.

ACKNOWLEDGMENTS

The characterization and classification scheme is an outgrowth of the insistence of my students from both university (University of Oklahoma, University of Dijon, and Sun Yat-sen University) and industry (International Human Resource Development Corporation [IHRDC] and Oil and Gas Consultants International [OGCI]) courses in seismic stratigraphy to write down my thoughts on a seismic delta-classification system. Indeed, the following students helped with the forward seismic modeling: Kwaku Feglo, Carsten Geiger, Alfredo Hosie, Abdelazim Ibrahim, Rongjiao (Rita) Wang, and Ye (Wiggy) Wang. Yet, I would be remiss if I did not acknowledge the inspirational effects while a student of some of my own "terri-genius" teachers: L. Frank Brown, Bill Fisher, R. L. Folk, Al Scott, and Larry Sloss.

I thank Carsten Geiger for his assistance with drafting and for being a classification "guinea pig." The text was significantly improved by the editorial comments of Mary Eberle. Harmonic inspiration was provided by my faithful feline companion, Smokey, and my dhamma partner, Kulwadee. An early version benefited from Bill Galloway's helpful comments regarding channel incision.

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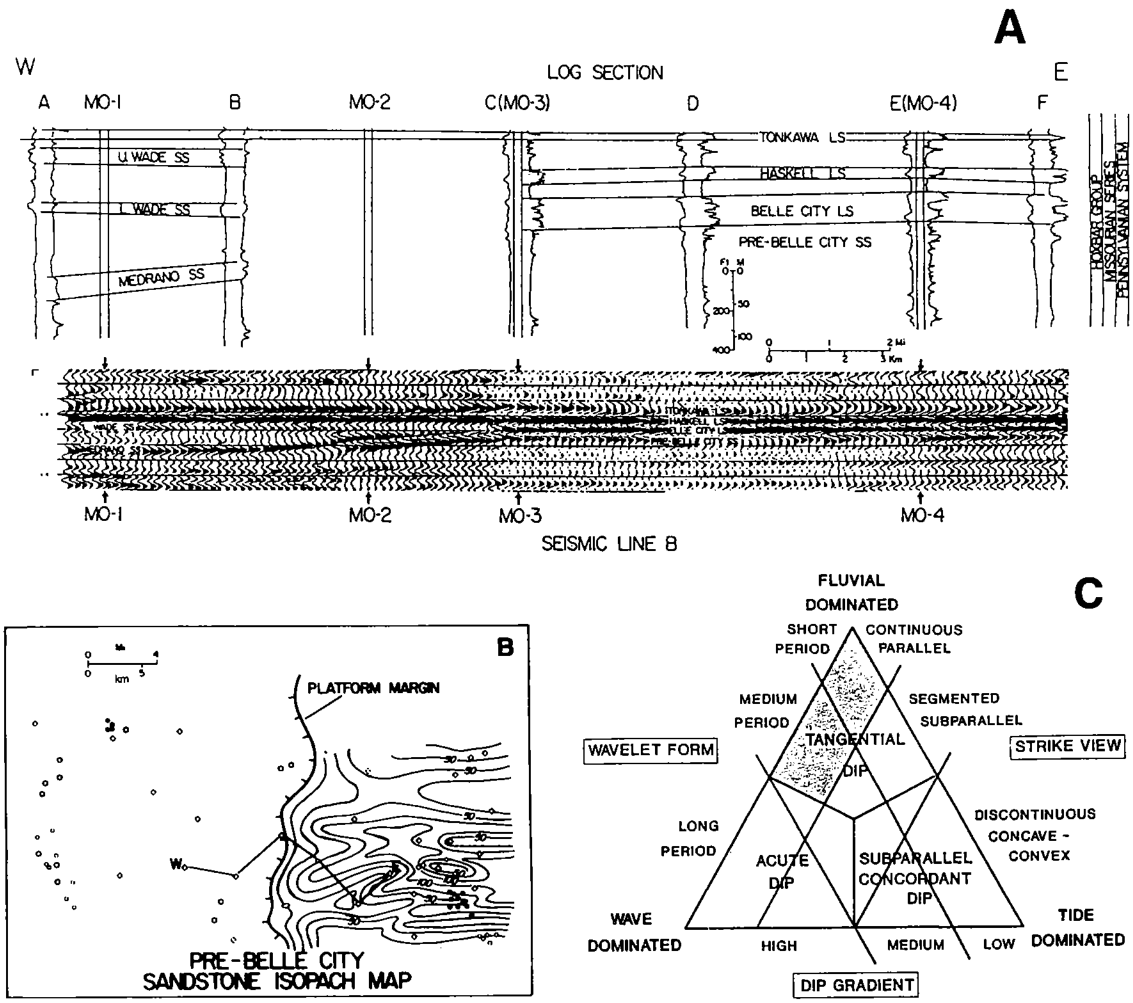

Figure 11. (A) East-west electric log (top) and equivalent seismic section (bottom) displaying the Pennsylvanian Pre–Belle City strata of the eastern Anadarko shelf, Oklahoma (after Galloway and others, 1977). (B) Pre–Belle City Sandstone isopach map (after Galloway and others, 1977). Note the east-west sandstone trends that are interpreted as elongate sandstone bodies of a clastic wedge. (C) Seismic delta-tendency plot of the Pre–Belle City clastic wedge described in text.

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Deltaic Facies: Problems, Practices, and Pitfalls

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ABSTRACT.—Fluvial-dominated deltaic reservoirs host significant volumes of hydrocarbons in the southern Midcontinent. Effective exploration to predict reservoir occurrence and quality and to develop and manage the reservoir requires detailed sedimentological and stratigraphic characterization because fluvial-dominated deltaic reservoirs, irrespective of age and geographic setting, are characterized by considerable variability in geometry and internal heterogeneity.

Some inherent problems, practices, and pitfalls include the following: (1) There is a lack of type well logs tied into subsurface reference sections and into updip reference surface sections. (2) Characterization of fluvial-deltaic sequences in the past traditionally has been concentrated on either limited exposures or geophysical logs from a few widely spaced wells supported by a paucity of core data. (3) Existing deltaic models do not provide adequate explanations for either the abundance of structureless sandstones or for the odd shoreline geometries often observed. (4) From a petroleum exploration standpoint, a general depositional model is not sufficient to predict reservoir distribution or quality within fluvial-dominated deltaic facies. (5) Earlier workers proposing depositional environments for ancient fluvial-deltaic systems had limited knowledge of modem analogues. (6) A "channel" or "offshore bar" origin for sandstone bodies is implicit in most earlier presentations and papers, but this assertion is without much significant documentation. (7) In selected stratigraphic and geographic settings, an estuarine valley-fill interpretation may provide a more viable alternative to the traditional channel-fill interpretation. (8) Sandstone isopach maps constructed in the past often combined sandstones of variable depositional origins; thus, the resulting thick sandstone trend may actually represent only a series of thin, poor-quality reservoirs. (9) There is a lack of dip-oriented stratigraphic cross sections across a field showing the timing relationships of different sandstone bodies and their en echelon stacking pattern. (10) There is a lack of regional chronostratigraphic correlations of fluvial-dominated deltaic sandstones demonstrating whether the different sandstone bodies or lobes within the fluvial-deltaic system are genetically and/or stratigraphically equivalent. (11) The best reservoirs in fluvial-deltaic facies may be the volumetrically less significant. (12) Different stratigraphic correlations yield different interpretations; correlations based on lithologies do not give the same sandstone-body geometries or interpretations as those based on boundary discontinuities—i.e., there is no unique correlation of sandstone bodies. (13) Major sandstone-producing reservoir units in the southern Midcontinent range from Morrowan through Virgilian and represent depositional environments ranging from fluvial-deltaic to submarine fans; few attempts have been made to place these variations within a rigorous sequence stratigraphic framework.

An understanding of these complex stratigraphic relationships is absolutely necessary in predicting reservoir occurrence and quality in fluvial-dominated deltaic facies, particularly in less explored parts of foreland basins.

Chaplin, J. R., 1996, Deltaic facies: problems, practices, and pitfalls, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 133.

Characterization of a Midcontinent Fluvial-Dominated Sandstone Reservoir by Routine and Advanced Analytical Methods

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ABSTRACT.— The Tucker sandstone in the Hepler field, Crawford County, Kansas, was characterized by using routine and advanced analytical methods. The characterization is part of a chemical-flooding pilot test to be conducted in the field, and the unit is classified as a DOE Class I (fluvial-dominated deltaic) reservoir. Routine and advanced methods of characterization were compared. Traditional wireline logs indicate that the reservoir is vertically compartmentalized on the foot scale. Routine core analysis, X-ray computed tomography (CT) scan, mini-permeameter measurement, and petrographic analysis indicate that compartmentalization and lamination extend to the microscale. There was good agreement among the several methods used for characterization.

Tracer tests were conducted in short core plugs while monitoring with CT to establish flow patterns under laboratory conditions. Results obtained from advanced characterization methods provided the best basis for an explanation of fluid-flow patterns in the core plugs. The small scale of compartmentalization indicated by characterization of plugs from the Tucker sandstone may actually help improve sweep between wells. This prediction was supported by comparison of core floods and tracer tests conducted with outcrop rock samples that have laminations similar to those of the Tucker sandstone.

INTRODUCTION

Hepler field is located in Crawford County, Kansas (Fig. 1), and is typical of many southeast Kansas oil fields. The field was discovered in 1917. Between 1948 and 1987, recorded production totaled 970,000 bbl of oil (Kansas Geological Survey, 1988). In 1980, 85 wells were present in the field (Paul and Bahnmaier, 1981); by 1988, annual production was 20,000 bbl from 52 active wells. Figure 2 shows the location of the pilot site, which is in northwestern Crawford County.

The geology of the Hepler site is typical of many Class I (fluvial-dominated deltaic) reservoirs (Tomes, 1986; Bradshaw, 1988). The Tucker sandstone (a local equivalent of the Bartlesville sandstone) has a net-sandstone thickness that ranges from 10 to 29 ft in the field, but is <16 ft in the pilot area (Fig. 3). The average permeability is ~80 millidarcies (md), and the percentage of sandstone with >100 md permeability is 10–14% in the pilot area (Fig. 4). Previous studies have concluded that depositional compartmentalization is a characteristic of many Midcontinent reservoirs (Willhite, 1986; Johnson and Olsen, 1993; Olsen and Johnson, 1993). Reservoir crude is a medium-gravity 26.2° API oil, with a relatively high viscosity of 69 centipoise (cP).

Earlier field projects have demonstrated that chemical (polymer) flooding can be successfully applied in fluvial-dominated deltaic reservoirs (Russell, 1988; Moritis, 1990,1992), and the pattern of wells shown in Figure 2 is expected to be used in the chemical-flooding pilot test. Reservoir core was obtained from wells J-4, H-4, and G-5. Wells were air-drilled to a depth slightly above the Tucker sandstone; then, after mudding-up, the entire sandstone interval was cored. Cores were placed in containers that are transparent to X-rays and were preserved with their formation brine.

French, T. R.; Schatzinger, R. A.; Johnson, W. I.; Tomutsa, L.; and Barnett, B., 1996, Characterization of a Midcontinent fluvial-dominated deltaic sandstone reservoir by routine and advanced analytical methods, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 134–142.

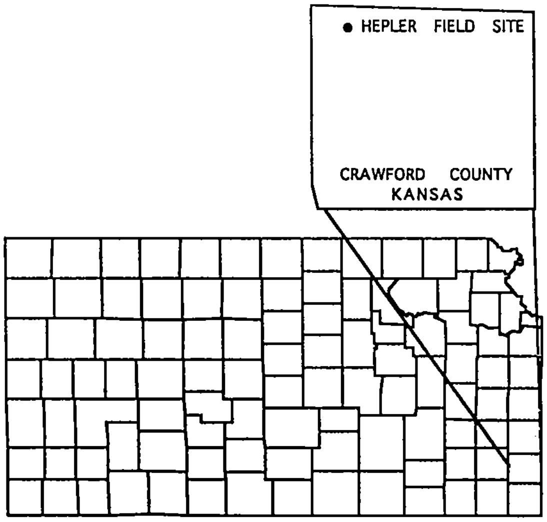

Figure 1. Location of the Hepler field site in Crawford County, Kansas.

RESERVOIR CHARACTERIZATION

Conventional Analytical Methods

Wireline logs for well H-4 are shown in Figure 5. The pay zone extends from depths of about 576–587 ft. Spontaneous-potential (SP) and gamma-ray (GR) logs indicate a general fining-upward over the entire interval. The GR log, in particular, indicates that the interval was deposited as multiple, stacked, point-bar sands, with a fining-upward nature for each sandstone body. The scale of resolution of the wireline logs is in feet. Overall, the sandstone appears to be vertically heterogeneous, with perhaps a few feet of homogeneous sandstone bodies. Logs from wells J-4 and G-5 are very similar to well H-4 logs, with a slight thinning of the pay zone from south to north.

Core plugs were cut from each whole core at 1-ft intervals, and each plug was analyzed for fluid saturation, permeability, and water-flooding susceptibility. A routine core analysis of well H-4 for permeability is shown in Figure 6. Routine core analysis indicates 1 ft of core with a permeability of <10 md, 8 ft of core with a permeability of 50–150 md, and 2 ft with a permeability of 250 md. The highest permeability is in the lower part of the sandstone, which is consistent with the upward-

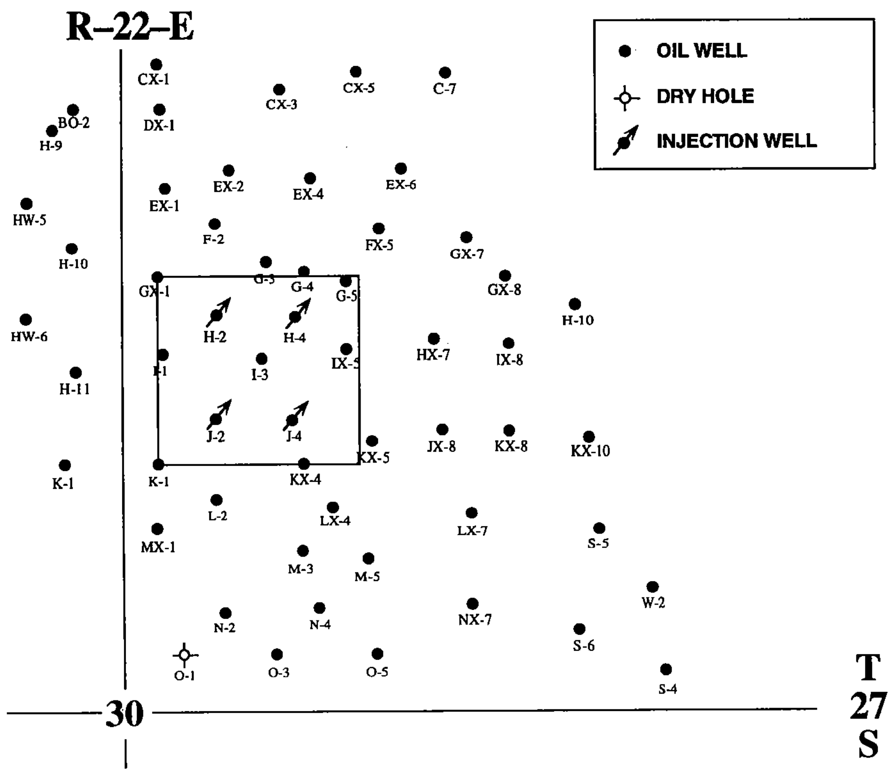

Figure 2. Detailed and outlined location of the pilot site in the Elmer C lease of the Hepler field, NE¼ sec. 30, T. 27 S., R. 22 E.

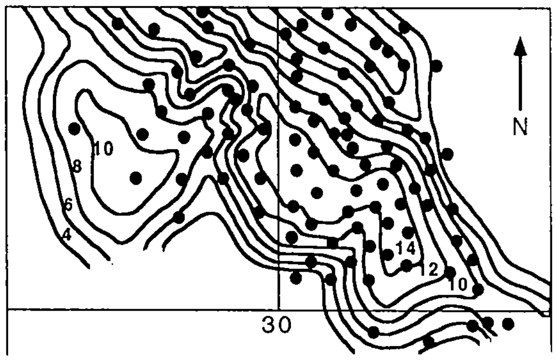

Figure 3. Net-sandstone thickness (in feet) of the Tucker sandstone in part of the Hepler field, N½ sec. 30, T. 27 S., R. 22 E.

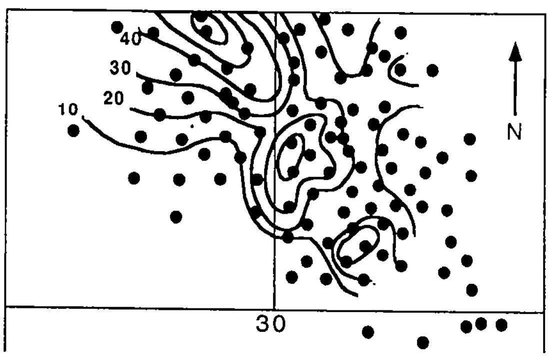

Figure 4. Percentage of sandstone with a permeability in excess of 100 md in part of the Hepler field, N½ sec. 30, T. 27 S., R. 22 E.

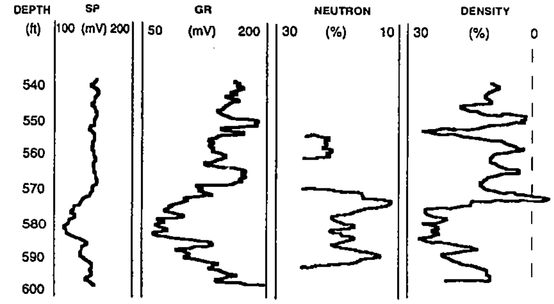

Figure 5. Wireline logs for well H-4 (see Fig. 2 for location of well).

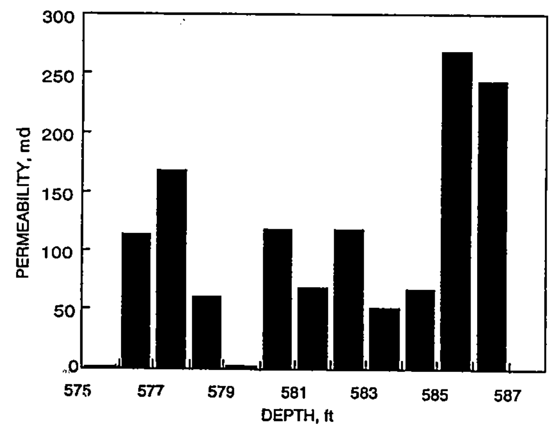

Figure 6. Permeability of well H-4, based on routine core analysis.

fining nature indicated by the well logs. Overall, the well logs and routine core analyses indicate ~10 ft of permeable sandstone in this area of the field.

Advanced Analytical Methods

The entire sandstone interval in each well was analyzed by X-ray computed tomography (CT), using third-generation equipment originally designed for medical applications and modified for rock analysis with special software and a high-accuracy positioning table. The mathematical relationships for correlation of CT density and rock and fluid properties have been described by Tomutsa and others (1990). The instrument resolution is 0.5 mm. CT-derived core permeability of the interval from 579.5 to 585.5 ft depth in well H-4 (Fig. 7) shows the lenticular, laminated nature of the sandstone. Laminations extend from the top of the interval to the bottom and across the entire width of the core (3 in.). Most of the laminations seem to be nonparallel, and from the apparent dip angles of individual laminations, it is concluded that the horizontal width of individual sandstone compartments is less than previous estimates (Olsen and Johnson, 1993). The horizontal width of individual compartments is probably on a scale of feet or tens of feet. Some high-energy foreset beds are visible in the lower parts of the interval, and these trough-bedded zones contain the most vertically homogeneous sandstone bodies.

Figure 8 directly compares CT as an analytical technique with wireline logs. The CT image shows the sandstone interval from 584.5 to 585.5 ft to be much more complex than indicated by wireline logging. CT shows that this 1-ft interval is the result of many cut-and-fill cycles. The interval from 585.0 to 585.5 ft is some of the most uniform sandstone in the core from well H-4, but CT imaging reveals the existence of permeability variations, on a fraction-of-an-inch (millimeter) scale, over this 0.5-ft interval.

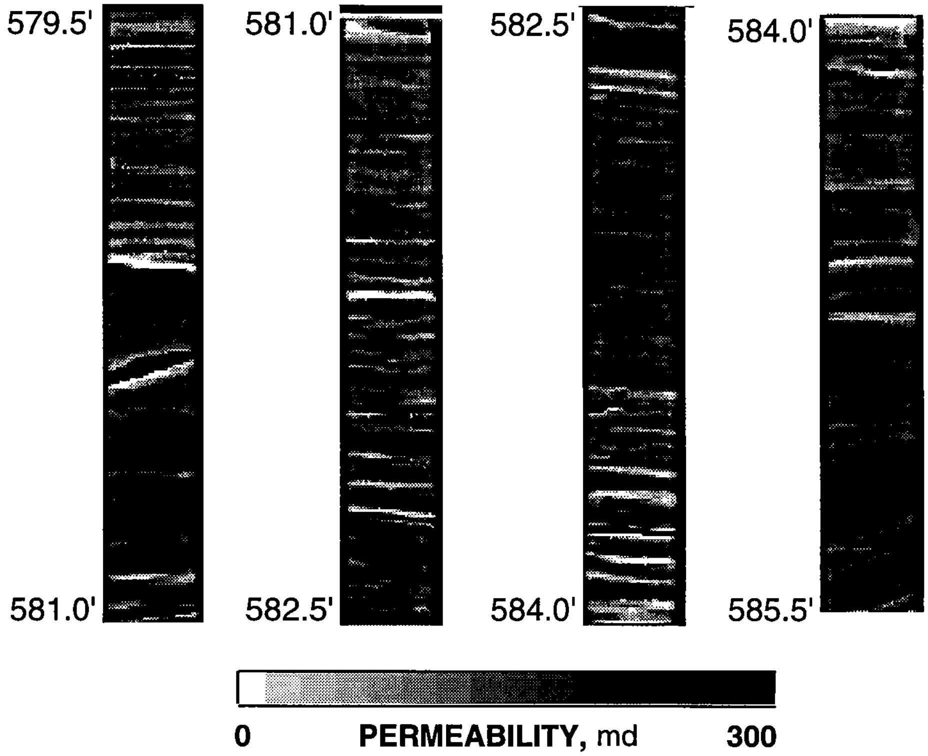

Figure 7. Permeability of core from well H-4, based on X-ray computed tomography (CT). High-permeability sandstone is shown in dark shades, and low-permeability sandstone is shown in light shades.

Petrographic image analysis (PIA) was used to determine if variations in rock properties extend to the micrometer scale and pore level. In a representative thin section of core (Fig. 9), individual sand grains and pores are identifiable. An area of low porosity extends from left to right across the thin section and is defined by areas of high compaction of interstitial clays, which appear as black bands. Zones of rock with similar porosities extend across the rock in a generally horizontal direction. Thin-section views show that vertical heterogeneities in the cores also occur at the pore and micrometer level.

The permeability of core plugs was also characterized with a mini-permeameter, which allows direct measurement of permeability across core faces. The mini-permeameter, shown schematically in Figure 10, is used to measure permeability a shallow distance into the core face. The degree of resolution of this instrument is the diameter of the o-ring seal, which is 3 mm. In Figure 11, the results of mini-permeability measurement correlate well with CT-derived porosity. Permeability varies greatly across the core face, and the areas of highest permeability correspond to the areas indicated by CT to have the highest porosity. Figure 12 shows permeability distribution from CT and mini-permeameter measurements across another core plug. Note that the mini-permeameter results correlate with the CT results at both core faces and verify that rock heterogeneities extend completely through the length of the 3-in. core plug.

An injectivity test was conducted with the core plug shown in Figure 12. Brine, tagged with potassium iodide, was injected while monitoring the flood with CT. Figure 13 shows that the tracer followed a path through the core plug that corresponds to invasion of the areas of high permeability. After only 0.08 pore volume (PV) of tracer injection, the potassium iodide was detected at the core outlet end. As tracer injection continued, the portion of the core swept by tracer increased; but after 3 PVs of injection, some areas of the core still had not been swept by the tracer. The results of this core flood could not have been predicted from wireline logs and conventional core analyses; however, these results seem reasonable on the basis of characterization of the core by advanced analytical techniques.

In other words, core heterogeneities can be detected with all of the analytical techniques described, including open-hole logs (foot scale), routine core analyses (foot scale), CT (millimeter

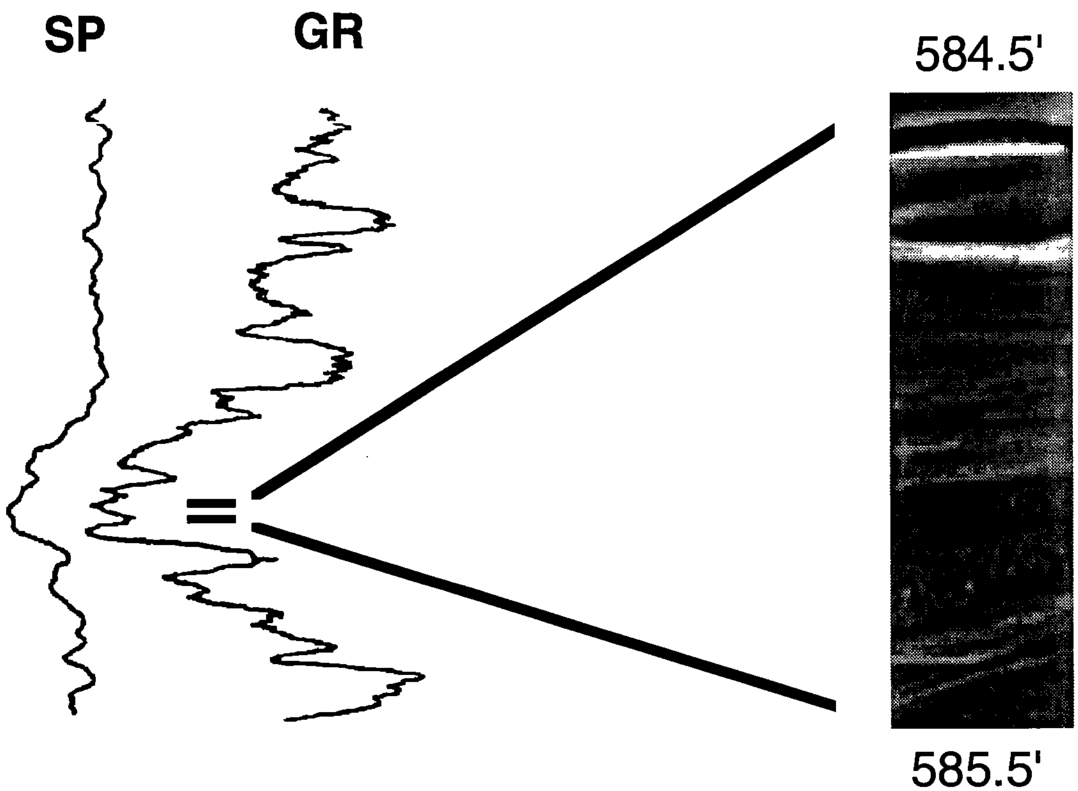

Figure 8. Comparison of wireline logs (left) from well H-4 with CT scan (right) for core from same interval in well.

scale), PIA (micrometer and pore scale), mini-permeameter tests (millimeter scale), and injectivity tests. Routine and advanced core-analysis techniques complement one another for characterization of reservoir heterogeneity from large scale to small scale.

SUMMARY AND CONCLUSIONS

Cores from the Tucker sandstone in the Hepler oil field were examined with routine and advanced analytical techniques. Routine core analyses and wireline logs indicated that sandstone properties vary with depth. Wireline logs indicate a general fining-upward sequence, with several point-bar sandstones being identifiable. Routine analyses of core plugs, taken at 1-ft intervals, demonstrated that 100%, and greater, changes in permeability occur over small vertical distances in the reservoir.

Cores also were evaluated with advanced analytical techniques: X-ray computed tomography (CT), petrographic image analysis (PIA), and a mini-permeameter. Advanced analytical techniques demonstrated that compartmentalization and lamination extend to the microscale. There was good agreement among all analytical methods, with advanced techniques allowing better resolution at smaller scales than could be achieved with the routine methods used for reservoir characterization.

Analytical information from three wells is hardly sufficient to characterize an entire reservoir. However, sufficient information is available to obtain a very good idea of the heterogeneities that exist vertically. The three cores had remarkably complex, yet similar structures. It was not possible to identify individual layers that extend from well to well. The complexity of the layering and the dip angles of individual layers, which are not exactly parallel, indicate that individual sandstone bodies probably extend horizontally for only a few feet or tens of feet. Figure 14 shows an idealized model of how the reservoir is probably structured: complex layering with small compartments.

Flow patterns during tracer tests in cores were adequately explained by characterization of core plugs with advanced analytical techniques. Channeling of injected fluids occurred in laboratory experiments because, on a core-plug scale, permeability streaks extended the full length of the core plug. However, flow patterns during reservoir flooding should be considerably different than the flow patterns observed with small core plugs. Previous laboratory experiments, conducted with out-

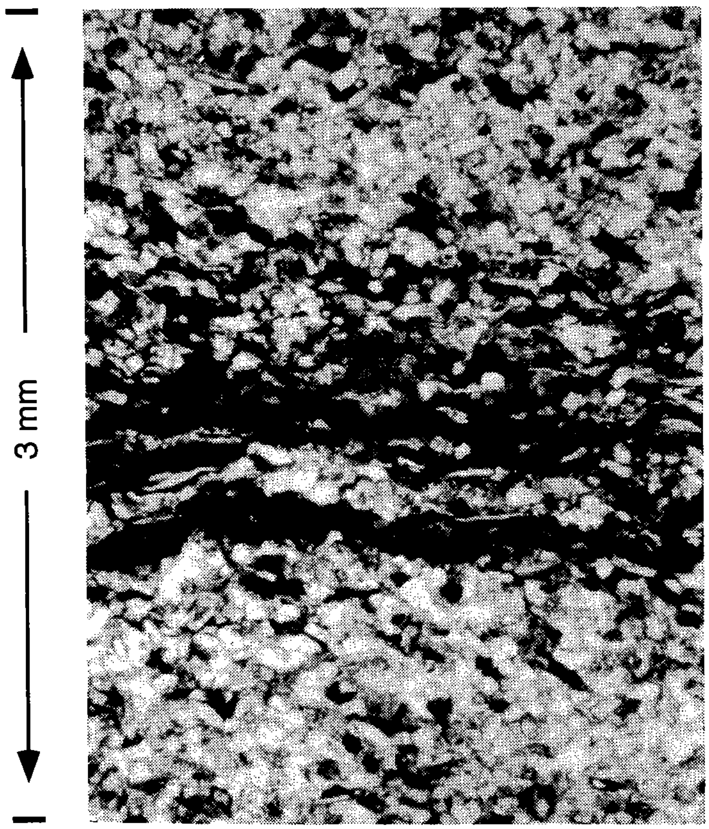

Figure 9. Thin section of core from a depth of 581.1 ft in well J-4. Dark shading corresponds to compacted, low-porosity areas, and light shading corresponds to mineral grains and porosity.

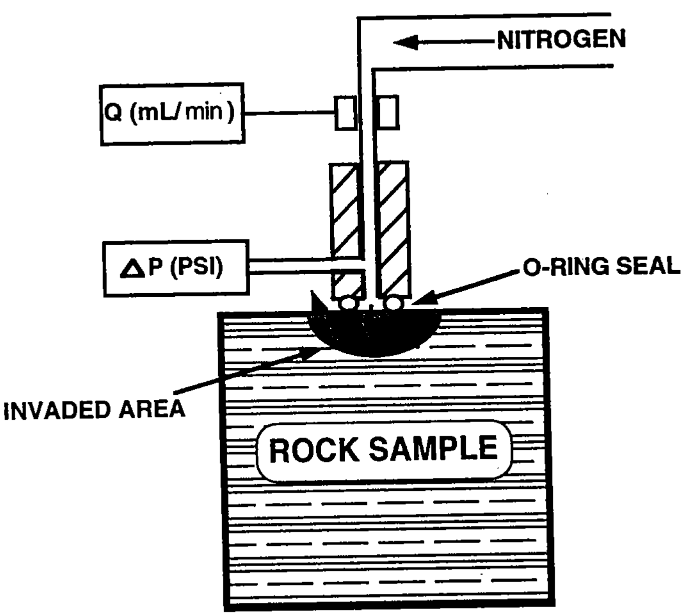

Figure 10. Schematic illustration of mini-permeameter used to measure permeability a short distance into the core.

crop samples of Tallant Formation, have shown much better sweep by injected fluids in situations where the fluids must traverse through many small compartments of variable permeability similar to those in the Tucker sandstone (Tomutsa and others, 1993), and several field-scale water-flooding projects conducted in the Tucker sandstone were reported as successful (Powell, 1959).

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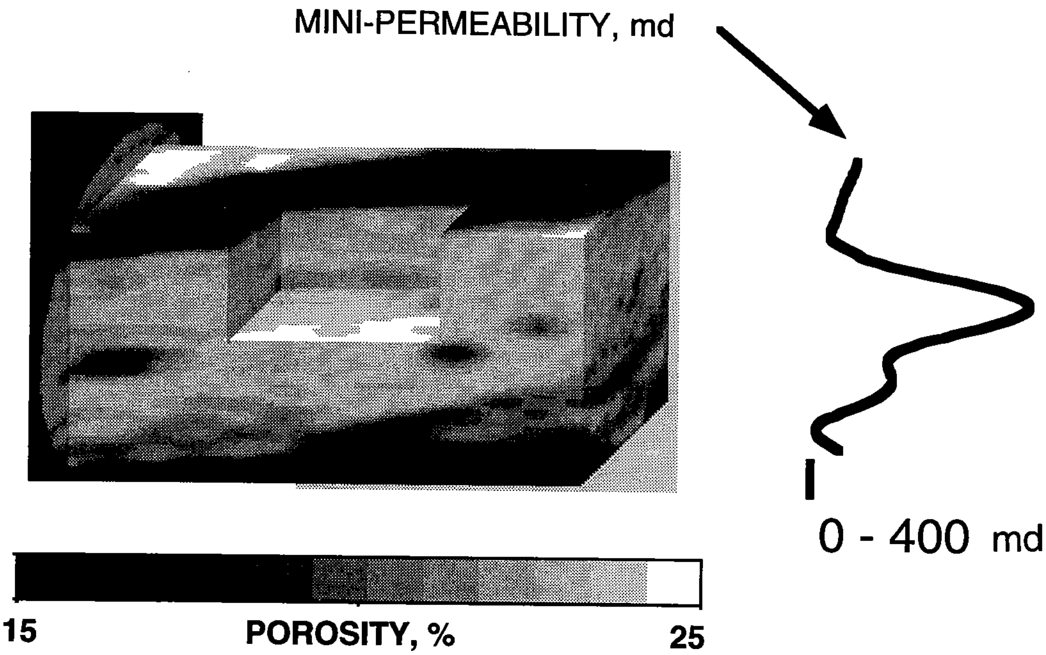

Figure 11. Comparison of CT-derived porosity with permeability as measured by the mini-permeameter; well J-4, at a depth of 581.1 ft.

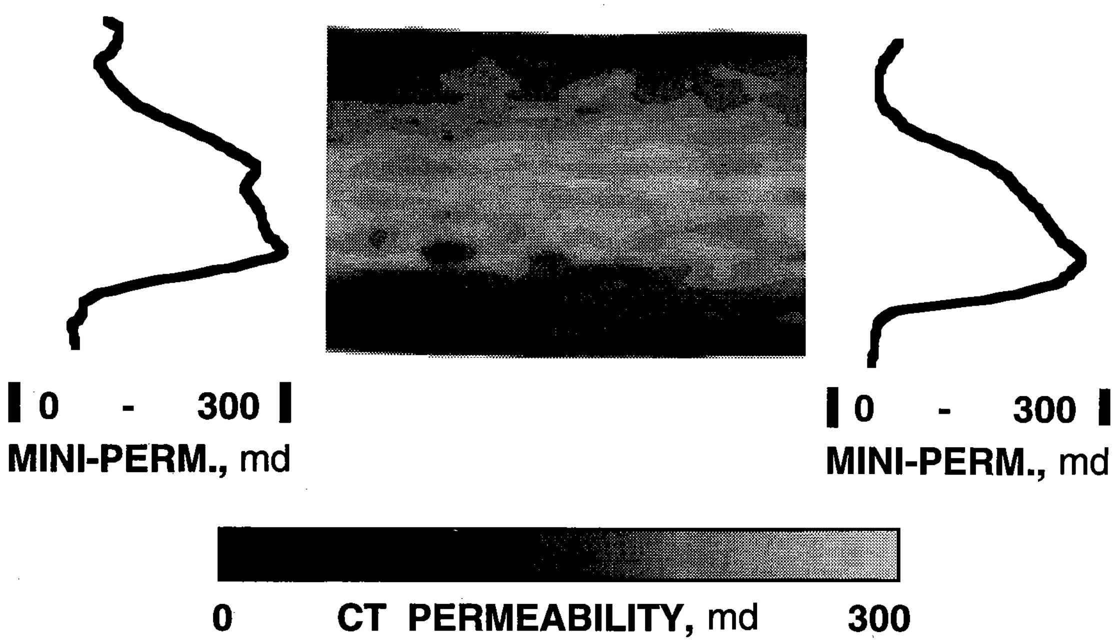

Figure 12. Comparison of permeability as derived by CT methods (center) and by use of the mini-permeameter at both core faces (left and right); well J-4, at a depth of 583.1 ft.

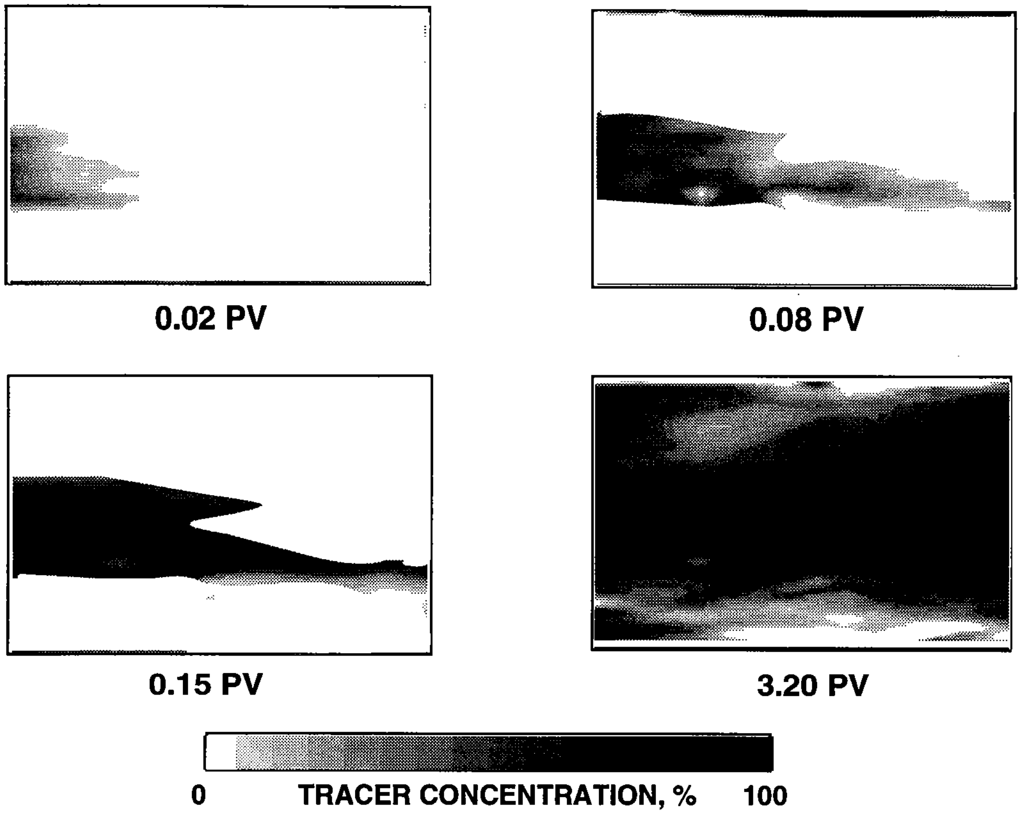

Figure 13. Brine, containing potassium iodide, was injected on the left and was monitored by CT methods; core sample from well J-4, at a depth of 583.1 ft.

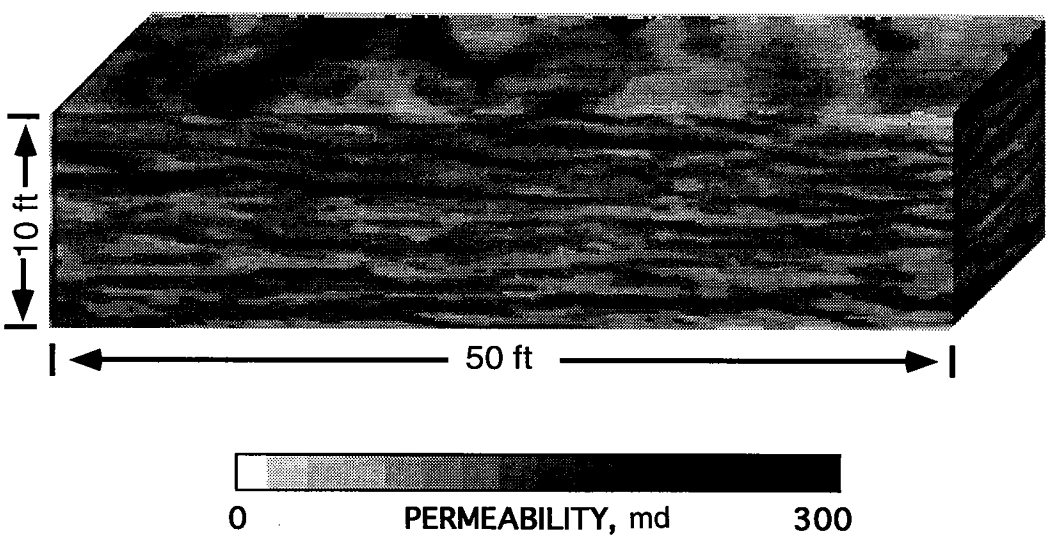

Figure 14. Idealized model showing probable distribution of permeability in the Tucker sandstone.

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Sequence Stratigraphy, Delta Models, and Fluvial-Deltaic Sediment-Dispersal Systems in the Pennsylvanian Cyclic Deposits of North-Central Texas

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ABSTRACT.—Late Atokan through Virgilian fluvial-deltaic sediment-dispersal systems of north-central Texas were developed in foreland-basin and stable-shelf settings subjected to high-frequency, large-scale oscillations of sea level. More than 40 cycles of glacially influenced transgression and regression were formed during this time period. Within the context of eustatic cyclic sedimentation, three important factors controlled the style of delta formation and distribution of reservoir facies associated with individual deltaic depocenters. These factors are (1) the length of the overall sediment-dispersal system from the source area to the distal terminus of coarse-grained, terrigenous clastic sedimentation, (2) the tectonic pattern of source-area uplift and shelf-margin subsidence, and (3) the sequence-stratigraphic systems tract in which the fluvial-deltaic systems were laid down.

In north-central Texas, both short-distance and long-distance sediment-dispersal systems were active during the Middle and Late Pennsylvanian. Short-distance sediment-dispersal systems involved fan-delta or braid-delta deposition emanating from localized, block-faulted uplifts (point sources). The Red River uplift and Muenster arch, as well as elements of the Wichita-Amarillo uplift, supplied arkosic conglomerate to adjacent, rapidly subsiding basins. By way of contrast, the long-distance sediment-dispersal systems mainly carried finer-grained sediment of river-dominated delta complexes, including fragments of chert and metamorphic rock that were derived from the Ouachita fold belt, a north-south elongate source resulting from a continent-continent collision.

Late Desmoinesian, Missourian, and Virgilian river-dominated deltaic systems prograded onto the relatively stable eastern shelf of the Midland basin, after decelerated subsidence in the Forth Worth basin allowed it to fill with Ouachita-sourced terrigenous clastic sediment. During the Desmoinesian, the western margin of the shelf was a poorly defined ramp. Only after the margin evolved into a rimmed platform at the beginning of the Missourian, as a consequence of increased subsidence to the west, did submarine fans become a significant component of the long-distance dispersal system. Each of the shelf-sequence boundaries involves an Exxon type-1 unconformity that was generated by lowstand, incised-valley formation. Lowstand deltas, which were laid down on the outer ramp or at the shelf edge, compose the principal reservoir systems of the eastern shelf. Vertically stacked sandstone facies representing channel-mouth bars and distributary channels furnished important stratigraphic traps. Alluviation of shelf-interior incised valleys during rising sea level (transgressive systems tract) also supplied important traps for hydrocarbons. On the other hand, highstand deltas contain very limited hydrocarbons. Early highstand bayhead deltas are thin and areally restricted; they lack sufficient volume of reservoir rock to merit serious exploration consideration. Late highstand river-dominated deltas of most cycles are present within or near the modern outcrop zone.

INTRODUCTION

During the past half-century, the mixed carbonate-siliciclastic sequence of the Concho platform and eastern shelf in north-central Texas has served as a testing ground for depositional models and hydrocarbon exploration concepts. Because these Middle and Late Pennsylvanian cyclic rock units are expressed on the surface (Fig. 1), as well as across easily identifiable subsurface sediment-dispersal systems from the eastern Ouachita source area to the deep basin (Fig. 2), models

Cleaves, A. W., 1996, Sequence stratigraphy, delta models, and fluvial-deltaic sediment-dispersal systems in the Pennsylvanian cyclic deposits of north-central Texas, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 143–167.

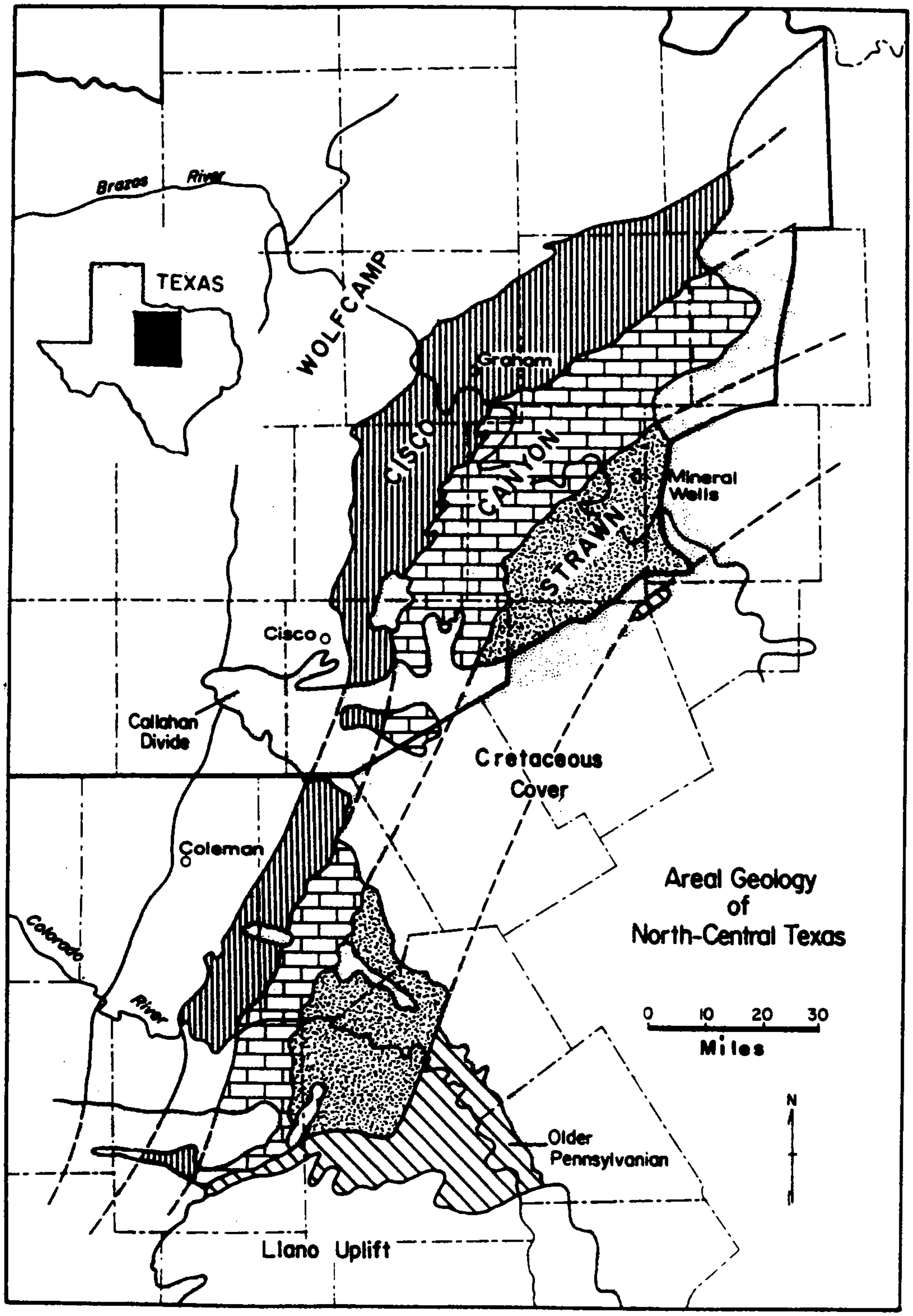

Figure 1. Outcrop zones (labeled patterns) of the Strawn, Canyon, and Cisco Groups in the Brazos and Colorado River valleys of north-central Texas (from Cleaves, 1982).

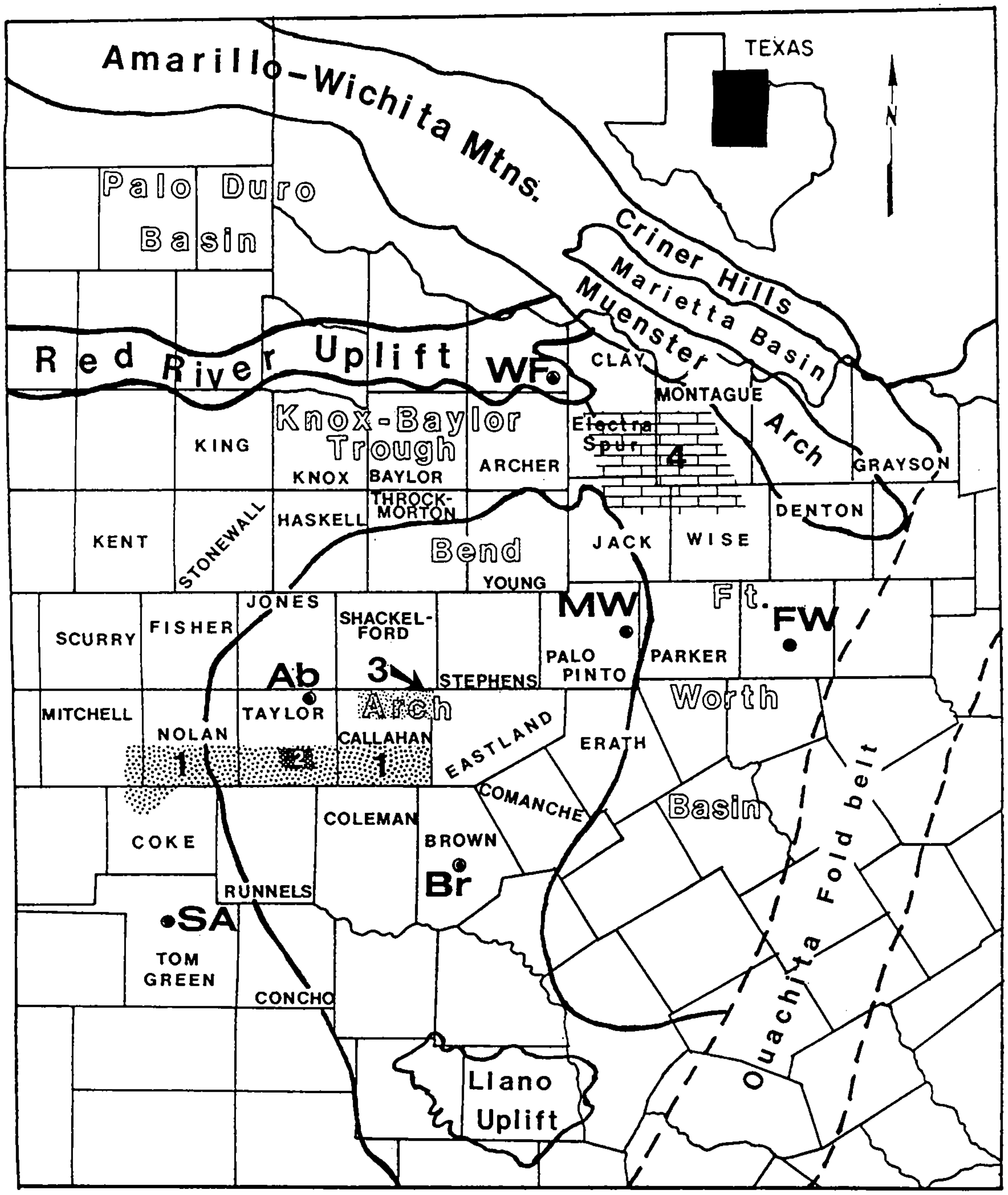

Figure 2. Pennsylvanian structural elements of north and north-central Texas. Patterned areas and numbers refer to examples of specific deltaic systems discussed in the text: (1) the Cook sandstone (Cisco Group) sediment-dispersal system described by Bloomer (1977,1991), (2) the West Tuscola field that produces from the Strawn "Gray" sandstone (Shannon and Dahl, 1971), (3) the area covered in Hamilton's (1990) discussion of the petroleum geology of the Moran and Cross Cut sandstones (Strawn Group), and (4) the distribution of the Atoka "Caddo" sandstone and conglomerate braid-delta system (Ammentorp and Cleaves, 1990). Cities: WF—Wichita Falls, Ab—Abilene, MW—Mineral Wells, FW—Fort Worth, SA—San Angelo, and Br—Brownwood, respectively. County names shown.

based on outcrop exposures are useful for subsurface exploration in age-equivalent rocks of the shelf. Careful, detailed surface and subsurface studies of the Cisco (Brown 1979), Canyon (Erxleben, 1975), and Strawn Groups (Cleaves, 1982) (Fig. 1) have demonstrated that deltas compose the dominant coarse-grained, terrigenous clastic system throughout the region. Hence, an understanding of the various types of delta models is a useful starting point for identifying subsurface reservoir facies.

This paper has two principal goals. The first of these is to discuss the applicability of specific delta models to Pennsylvanian deltaic systems of north-central Texas. The second involves identifying factors that control the overall style of delta formation and distribution of fluvial-deltaic reservoir facies across the eastern shelf. Three of these factors include (1) the length of the sediment-dispersal system, (2) the tectonic pattern of source-area uplift and shelf-margin subsidence, and (3) the sequence-stratigraphic systems tract in which the delta systems accumulated. Glacial-eustatic sea-level changes are considered to represent the dominant mechanism giving rise to cyclic sedimentation in this area.

DELTA MODELS

In 1968, Fisher proposed a set of four delta models that have been widely utilized to classify marine delta systems of all ages. Although the terminology was based on his study of Gulf Coast Tertiary deltas, it was also quickly applied to Cisco systems in north-central Texas (Brown, 1969a,b; Fisher and others, 1969). *High-constructive deltas,* involving extensive downdip progradation of delta-front facies, were singled out as the only delta type operating on the eastern shelf. The original Fisher subdivision for high-constructive deltas identified elongate and lobate subspecies, based on the coastal geomorphology of the delta plain for the Holocene models. These geometries were also reflected in the net-sandstone-isolith patterns of Tertiary Wilcox Group deltas. Unfortunately, such patterns were not replicated by isolith maps of Cisco or older Pennsylvanian delta systems on the eastern shelf. Brown (1973,1979) acknowledged that subsurface sandstone-isolith patterns were not usually very helpful for distinguishing the two types of high-constructive delta species and suggested several outcrop criteria (Fig. 3). *Elongate deltas* contain distal delta-front and channel-mouth-bar facies that are highly contorted because of prodelta mud diapirism. This soft-sediment deformation is directly related to the progradation of a delta lobe into abruptly deeper water; most of the accommodation space is filled with water-rich prodelta mud that moves when loaded. *Lobate*

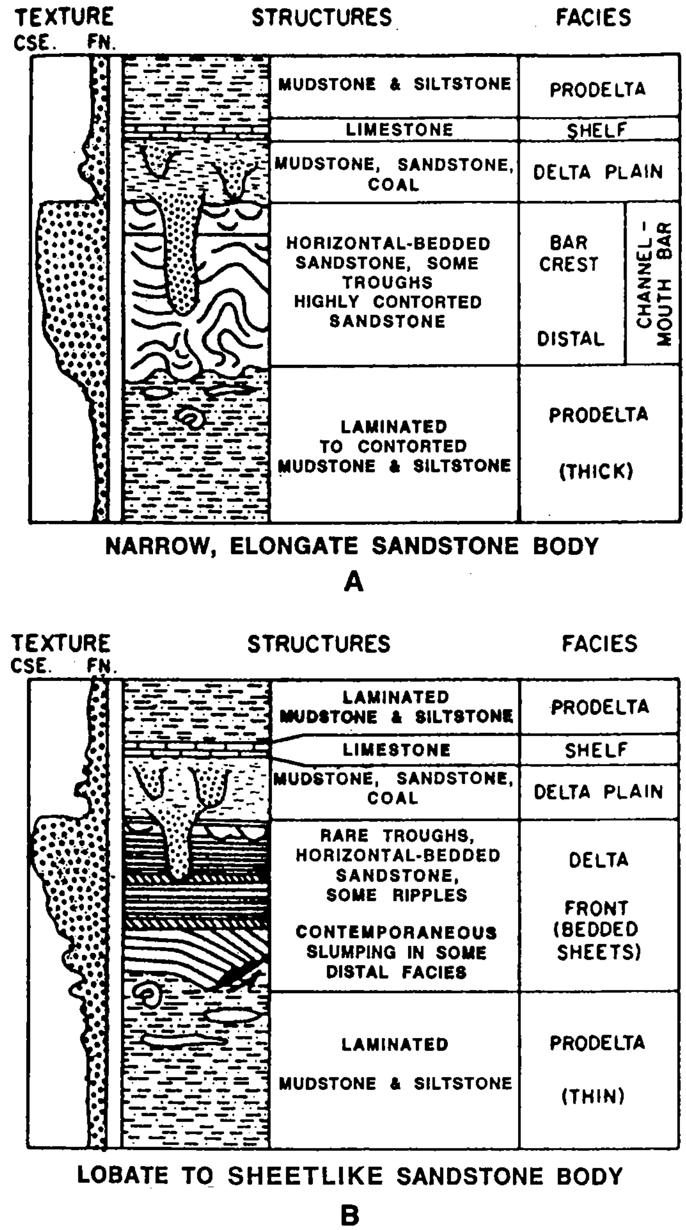

Figure 3. Outcrop criteria with which to identify marine, river-dominated (high-constructive) deltas based on lithology, texture, and sedimentary structures (from Brown, 1979): (A) river-dominated elongate (birdsfoot) delta; (B) river-dominated lobate delta.

deltas, in contrast, contain marine-reworked, flaggy-bedded, oscillation-rippled delta-front sandstone facies that lack thick intervals of deformed strata but may show growth faulting. Such "shoal water" delta lobes prograde onto shallow-marine platforms and lay down a much thinner prodelta. Compactional subsidence is less extensive, allowing for large-scale marine reworking of delta-front sands.

In addition to applying Fisher's high-constructive delta models to Pennsylvanian delta systems, Brown (1973,1979) also proposed a cratonic delta model. This model utilized the Holocene Guadalupe and Colorado deltas of the Texas Gulf Coast as sedimentologic analogues. Its distinctive features include a thin prodelta and delta-plain facies (Fig. 4, cross section A–B), as well as distributaries that downcut through the complete delta sequence into sediment laid down during a previous depositional cycle (Fig. 4, cross section C–D). Implicit in the model are the assumptions that distributary erosion was accomplished during a sea-level stillstand and that the deep downcutting represents typical distributary behavior on a stable cratonic

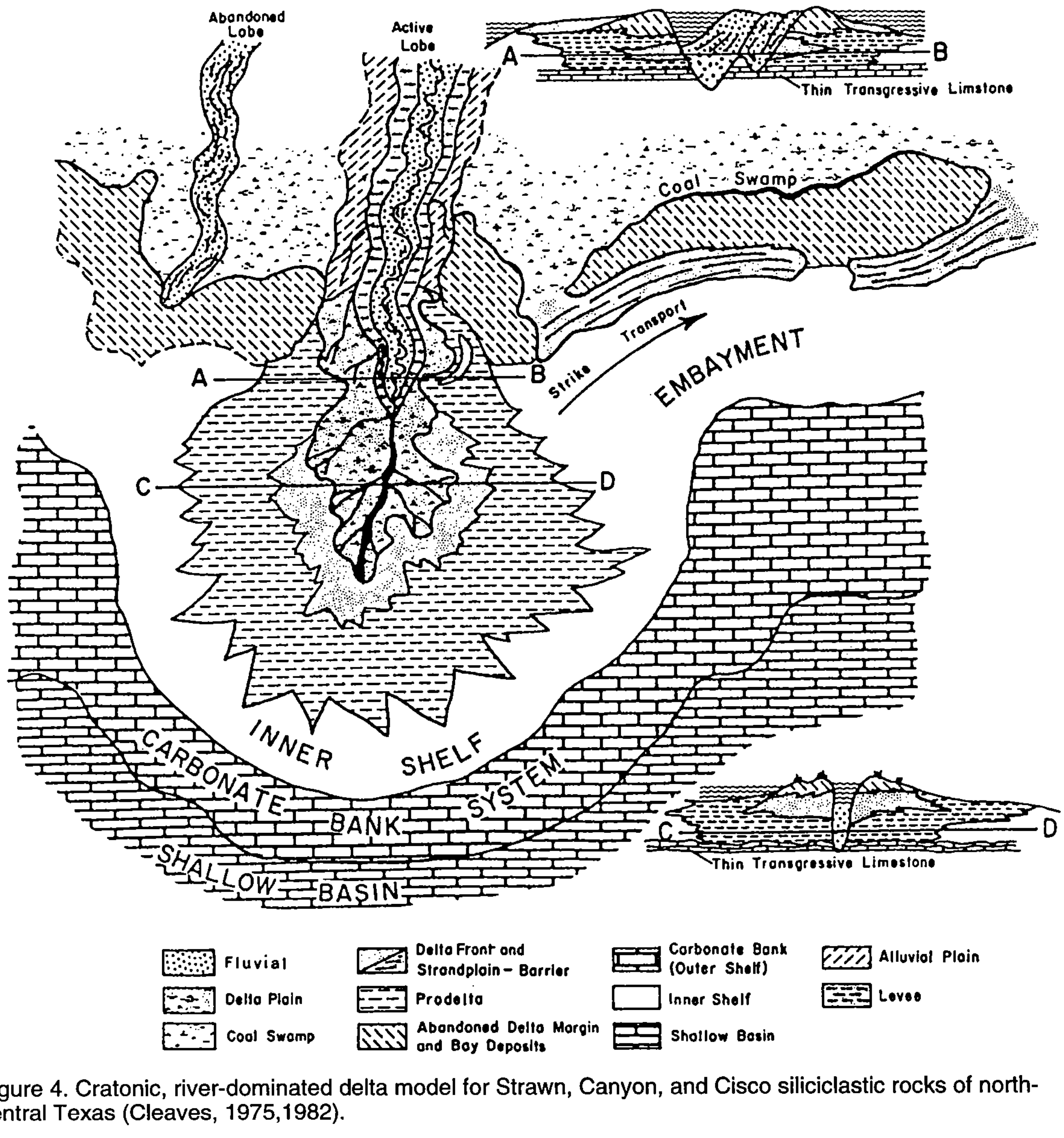

Figure 4. Cratonic, river-dominated delta model for Strawn, Canyon, and Cisco siliciclastic rocks of north-central Texas (Cleaves, 1975,1982).

TABLE 1.—DELTA CLASSIFICATION FOR PENNSYLVANIAN SILICICLASTIC UNITS IN NORTH-CENTRAL TEXAS

Lacustrine and Estuarine Delta Systems		Marine Delta Systems	
Lacustrine		Coarse-grained	Fan deltas
Coarse-grained	Fan deltas		Braid deltas
	Gilbert deltas		River-dominated
Fine-grained	Gilbert deltas		Wave-dominated
Estuarine			Tide-modified
Low-energy	Bayhead deltas	Fine-grained	River-dominated deltas
High-energy	Tide-dominated estuarine delta		Elongate (birdsfoot)
			Lobate (wave-modified)
			Wave-dominated deltas
			Tide-dominated deltas

shelf. Both of these conclusions, to some extent, are erroneous.

Brown's amalgamation of Fisher's Gulf Coast delta classification with a cratonic delta model for Pennsylvanian deltas has created some confusion in classifying the spectrum of surface and subsurface delta systems noted in north-central Texas. For example, are all cratonic deltas also high-constructive deltas? Were cratonic deltas restricted to the eastern shelf, or did they also accumulate in basins adjacent to the stable shelf? Under what conditions did high-constructive deltas develop where channel incision did not remove most or all of the underlying deltaic facies? A suggested delta classification that addresses some of these questions is provided in Table 1. Also, the issue of eustasy must be dealt with when considering incised channels.

In Table 1, the terms "fan delta" and "braid delta" (see McPherson and others, 1987) are included in the category of coarse-grained deltas. These systems contain abundant allochthonous conglomeratic debris derived from adjacent uplifted highlands (point sources).

True fan deltas are minor features that have a small subaerial surface area. The fan surface has a dip of 1° to 9° toward the standing body of water and the delta front shows only a small amount of progradation from a nearby, uplifted source terrain (Fig. 5A). These are, in truth, arid-area alluvial fans that comprise interbedded debris-flow, braided-channel, and sheet-flood deposits. Unconfined flow, not distributary-channel transport, occurs in the subaerial facies adjacent to the shoreline. Sediment is very poorly sorted, contains a mud matrix, and gives rise to low-quality reservoir rock.

Braid deltas, on the other hand, have large delta plains that accumulate at sea level and may evidence significant progradation into the standing body of water (Fig. 5B). Despite the coarse grain size, the source area may be far removed from the active site of deltaic deposition. The braided distributary channels represent the coarsest, most poorly sorted facies in the system, whereas the channel-mouth bar is sand-rich and may be reworked by marine waves to form coastal barriers. Debris flows, sheet-flood deposits, and overbank mud deposits are all largely absent from the delta plain. Marine braid deltas can be either river-dominated systems or wave-dominated systems, depending on the degree of progradation or marine reworking. McPherson and others (1987) asserted that most of the Pennsylvanian coarse-grained delta systems described in the literature on north-central Texas are, in reality, braid deltas.

TECTONIC AND DEPOSITIONAL HISTORY

The coastal morphology, total thickness, and overall distribution of reservoir facies in the deltaic systems of north-central Texas were all strongly influenced by both the regional tectonic settings and the effects of large-scale, eustatic sea-level changes during the Middle and Late Pennsylvanian. Although it would probably be futile to assign greater weight to one or the other of these two allocyclic mechanisms that influence delta formation, it is still useful to identify delta types and sedimentation patterns associated with specific phases (systems tracts) of a eustatic cycle. Similarly, the identification of specific source areas and tectonic settings where Pennsylvanian deltas were deposited can give valuable information regarding the mineral composition and reservoir geometry of coarse-grained facies. The strategy of presentation for this section of the paper will be first to review the Pennsylvanian tectonic history for the region and then to discuss the three main factors controlling style of delta formation on the eastern shelf and adjacent areas.

During the middle Paleozoic, a stable struc-

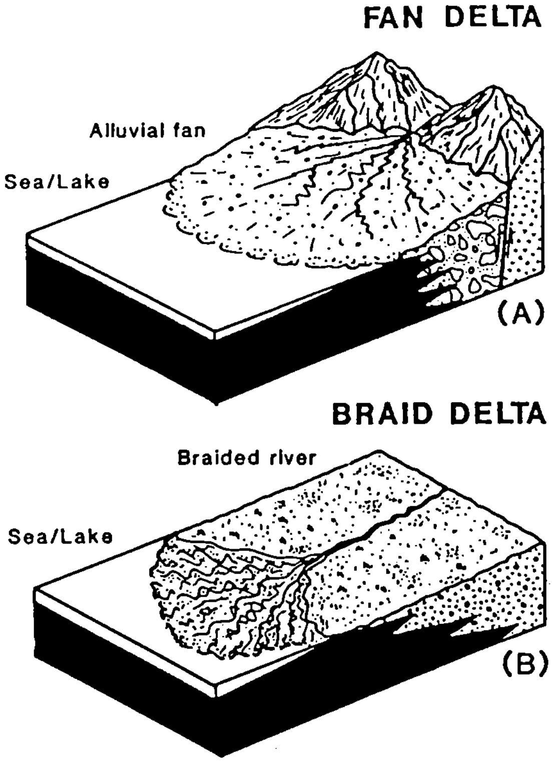

Figure 5. Block diagrams of marine, coarse-grained deltas. Modified from McPherson and others (1987).

tural element, the Concho arch, was present in central Texas. It acted as a broad, slightly positive feature that extended northwestward from the Llano uplift (Fig. 6). Prior to the Late Mississippian, the eastern periphery of Texas was tectonically quiescent. Beginning in the latest Mississippian, active subsidence began in the Fort Worth foreland basin. This subsidence established an eastern margin for the Concho structural element.

During the entire Early Pennsylvanian (Yancey and Cleaves, 1990), carbonate-shelf and -bank deposition predominated on the Concho structure, giving rise to the Concho carbonate platform. Terrigenous clastic sediment derived from the Ouachita fold belt to the east, as well as from the Muenster arch and Electra arch (Red River uplift) to the north, was largely trapped in the Knox-Baylor trough and in the foreland basin itself. The fold belt supplied recycled quartz and fragments of chert and metamorphic rock to the deltas for which it served as the source area. Localized block faulting uplifted the Muenster and Electra structures, exposed Precambrian basement, and supplied the deltas with K-feldspar grains and granite fragments (arkose). Farther to the west, the ancestral Midland basin was a shallow structural depression that lacked well-defined margins.

At the beginning of the Desmoinesian, the Concho platform evolved into a structural element with distinct boundaries that separated it from braid-delta and submarine-fan deposition in the Fort Worth basin and starved-basin (black-shale) sedimentation in the Midland basin. Accelerated subsidence around the northern perimeter of the platform during the earliest Desmoinesian formed a broad nose (Bend arch) that projected between areas of greater downwarping (Fig. 7). Subsidence in the southern and central Fort Worth basin lessened during the late Desmoinesian. This change allowed terrigenous clastic sediment, beginning with that which forms the Buck Creek Sandstone of the Strawn Group, to prograde from its Ouachita source area westward across the filled Fort Worth basin and onto the previously carbonate-dominated platform. Concurrently, a north-south–oriented hinge line developed along the platform's western margin. This hinge line served as the western boundary for the late Desmoinesian accumulation of carbonates on the Anson ramp. At the beginning of the Missourian Epoch, a new shelf-edge carbonate-bank system (outer Palo Pinto bank) accreted directly on top of the underlying ramp. This platform rim delimited the eastern side of the now actively subsiding Midland basin and established the boundary for the eastern shelf. Farther north, early Desmoinesian through Virgilian subsidence of eroded horst blocks associated with the Red River uplift provided a stable substrate for the accumulation of subtidal carbonates.

During the Middle and Late Pennsylvanian, the eastern shelf evolved through three stages (Cleaves, 1993). Its outer margin began as the poorly defined Anson ramp, which extended as a continuous trend from the Red River uplift southward to the vicinity of San Angelo (Fig. 8). The carbonates deposited on the ramp graded westward into nodular wackestone and basinal black shale (Marquis and Laury, 1989). Slightly later, during the Missourian Epoch, the second stage in the development of the eastern shelf involved the formation of a rimmed platform margin. Aggradation without basinward progradation characterized carbonate sedimentation on the shelf-edge bank system for the Palo Pinto, Winchell, and Home Creek Formations. A shelf-interior bank, ~25 mi east of the shelf edge, also accumulated during Palo Pinto and Winchell deposition (Fig. 9). The presence of two banks during the middle Missourian indicates eustatic, reciprocal sedimentation, as both banks could not have existed simultaneously without seriously impeding water circulation across the shelf and perhaps even causing evaporite precipitation. Active upbuilding of the shelf-margin bank complex occurred during sea-level lowstands. Growth of the inner bank took place during highstands, when the outer bank was submerged below the photic zone.

The second stage of shelf-margin development was associated with an extended episode of marine transgression and decreased deltaic sedimentation

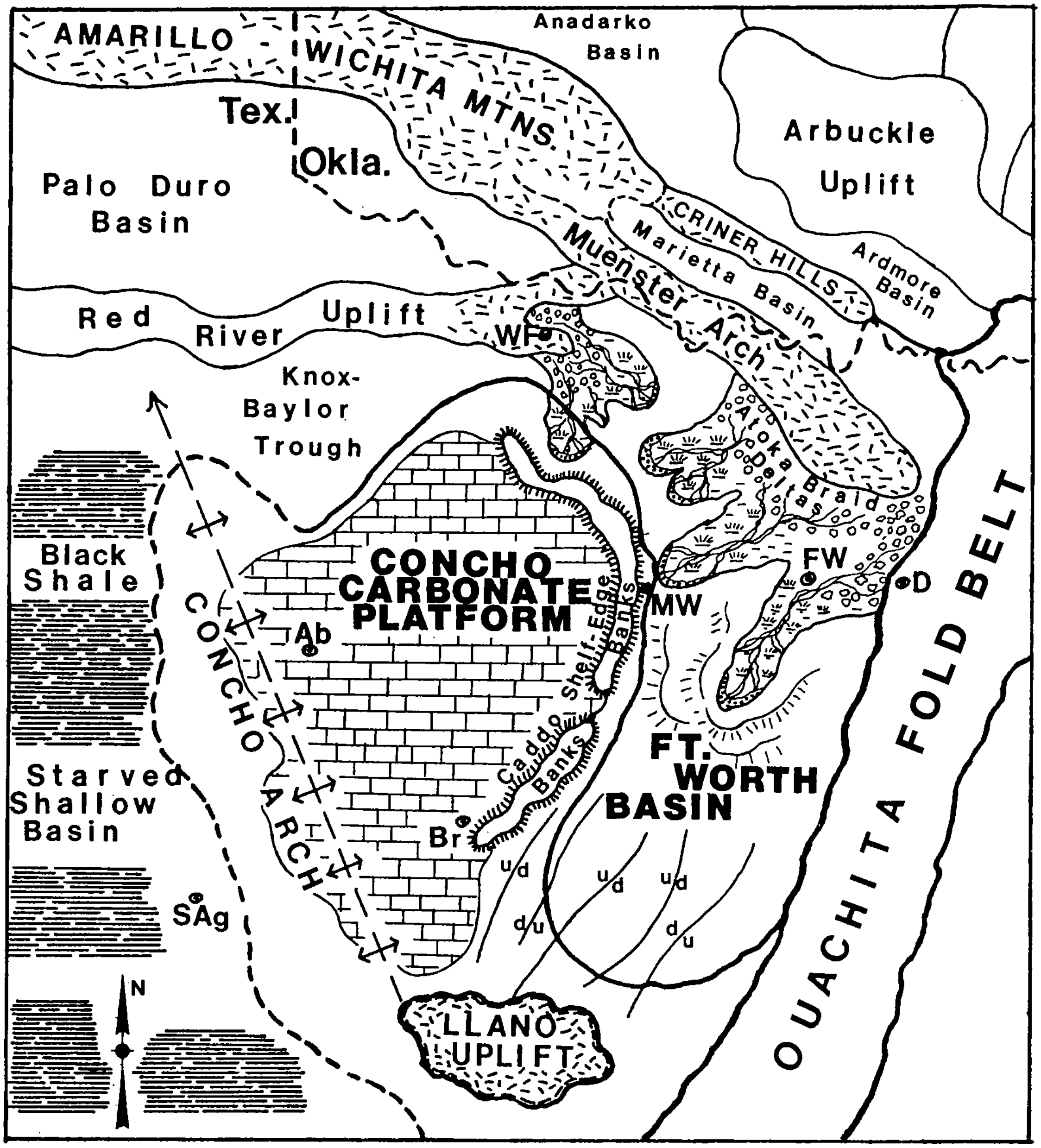

Figure 6. Atokan (Early Pennsylvanian) tectonic features and terrigenous-clastic-sediment dispersal systems of north and north-central Texas. Note that siliciclastic braid-delta sediment was trapped in the Fort Worth basin and failed to prograde onto the Concho carbonate platform. Cities: WF—Wichita Falls, Ab—Abilene, MW—Mineral Wells, FW—Fort Worth, D—Dallas, SA—San Angelo, and Br—Brownwood (Yancey and Cleaves, 1990).

throughout north-central Texas (Missourian Epoch). Coarse-grained siliciclastic deposits were largely restricted to the northeastern part of the shelf and involved the Perrin delta and Henrietta braid-delta systems. No Canyon Group fluvial-deltaic depocenters were active south of the Mineral Wells area. As a consequence, over the southern half of the eastern shelf, terrigenous clastic sediments did not reach the shelf edge in sufficient quantity to prograde the shelf margin westward. Farther to the north, the two active delta systems did prograde to the shelf edge and prevented the growth of a continuous bank trend in that area (Fig. 10). They also supplied coarse-grained sedi-

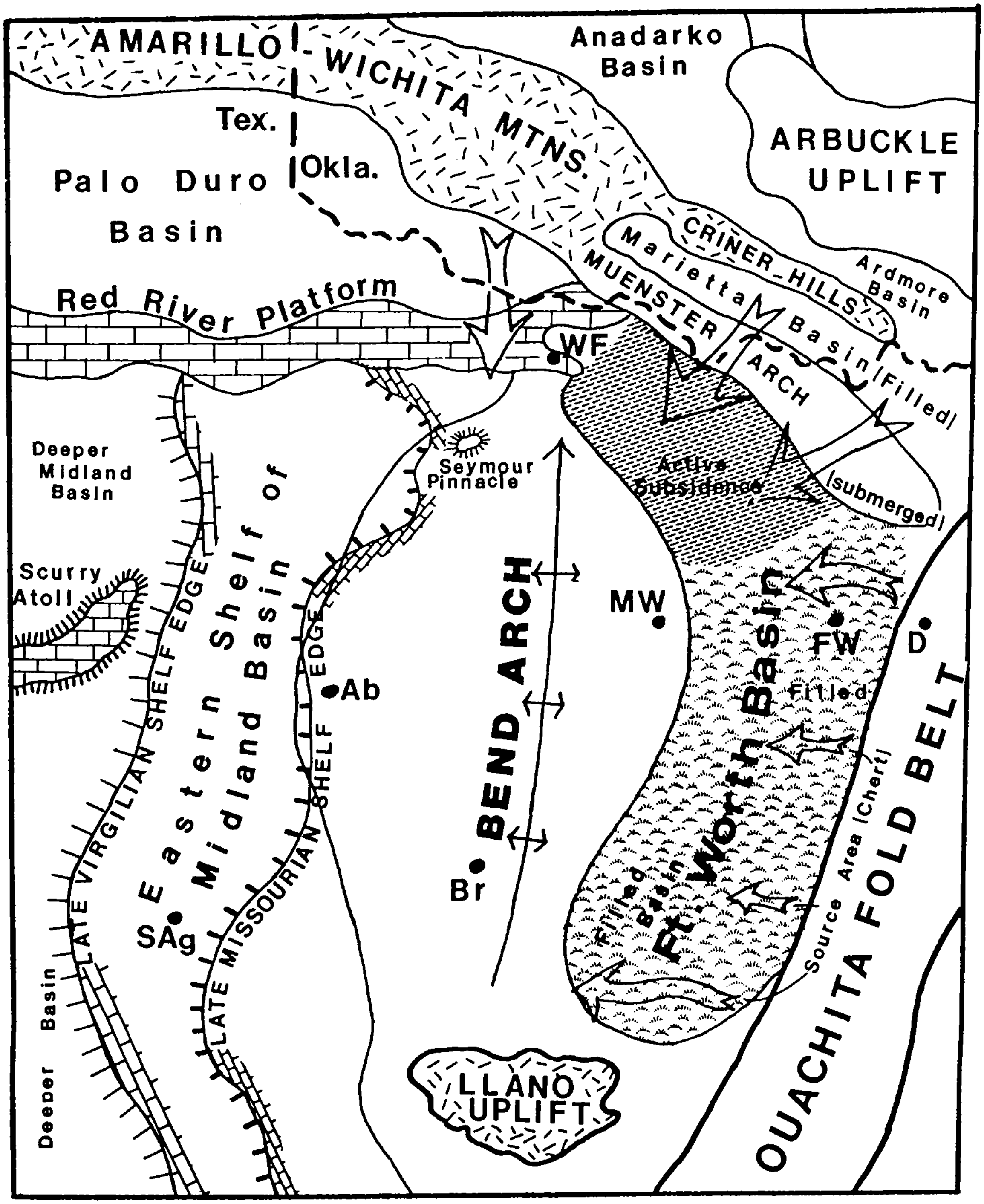

Figure 7. Middle and Late Pennsylvanian tectonic features and terrigenous-clastic-sediment dispersal systems of north and north-central Texas. The Bend arch is a residual structural high that was created by Late Mississippian and Early Pennsylvanian downwarping in the Fort Worth basin and Middle Pennsylvanian subsidence to form the Midland basin. The Desmoinesian Anson ramp formed before and directly underlay the late Missourian shelf-margin carbonate-bank system. Abbreviations for cities are shown in Figure 6. Modified from Yancey and Cleaves (1990).

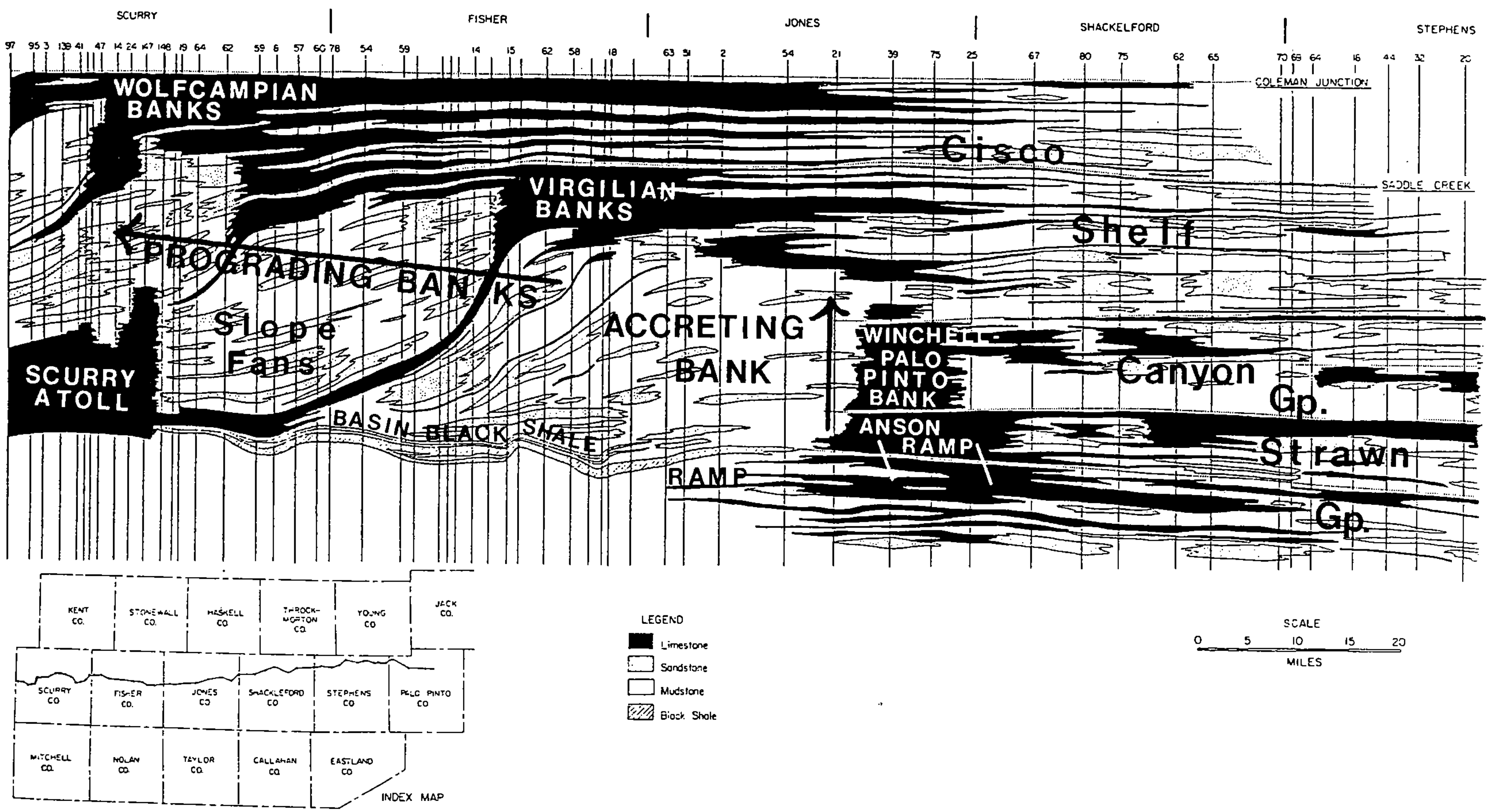

Figure 8. East-west lithologic cross section showing the Strawn, Canyon, and Cisco Groups of north-central Texas. Carbonate-bank and carbonate-ramp systems are shown in black; sandstone is indicated by the elongate pods with subdued dot pattern. Note the positions of the Anson ramp (Strawn Group), Winchell–Palo Pinto accretionary shelf-edge bank complex (Canyon Group), and the progradational shelf-edge banks (Cisco Group) of Virgilian and Wolfcampian age. Modified from Wermund (1975).

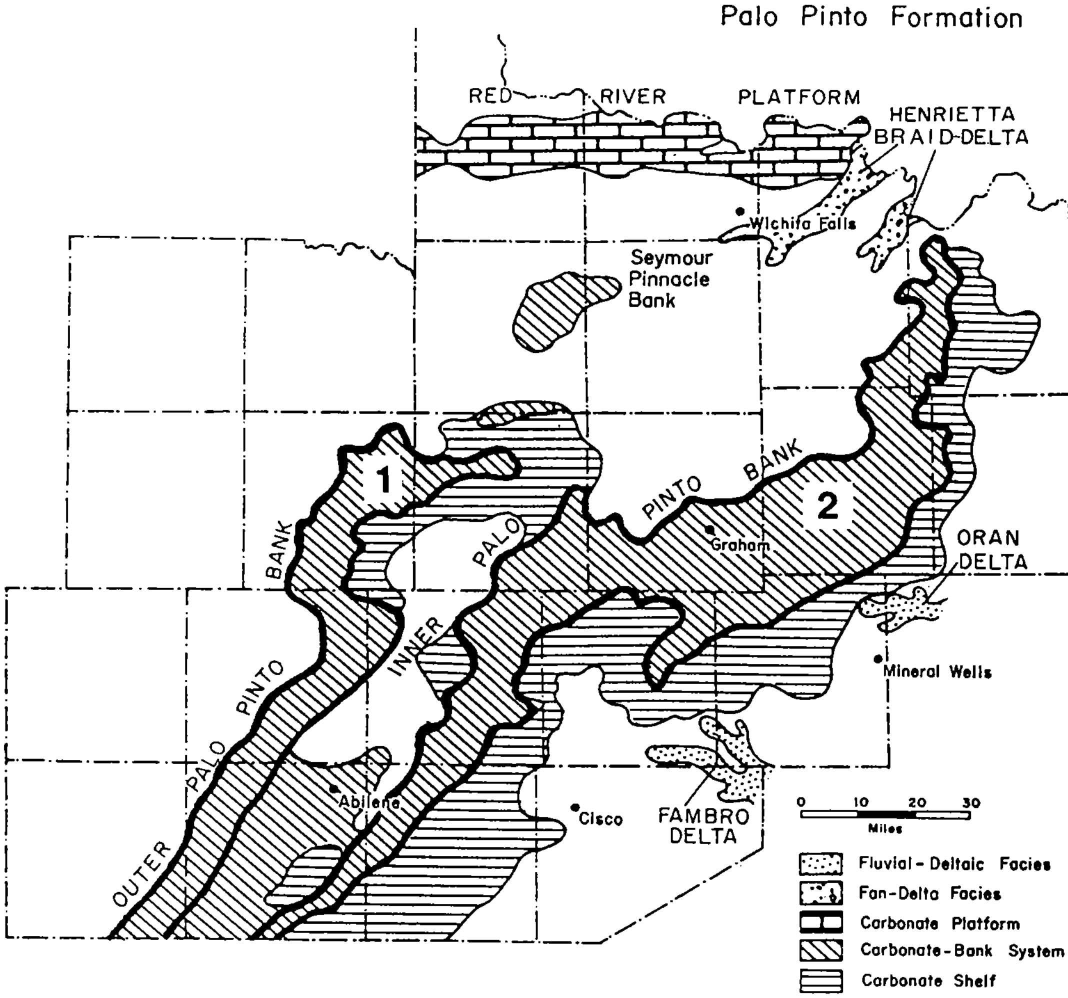

Figure 9. Distribution of carbonate-bank and carbonate-shelf systems with the subsurface Palo Pinto Formation of north-central Texas. The bank system is distinguished on the basis of the 80% carbonate isolith contour (carbonate rocks so defined are >200 ft thick), as indicated by the mapping of Wermund and Jenkins (1970) and Cleaves (1975). Bank 1 is developed at the eastern shelf edge of the Midland basin, whereas bank 2 is a shelf-interior carbonate buildup resulting from highstand reciprocal sedimentation that suppressed growth on the outer bank.

ment to submarine fans of the Knox slope system. Carbonate sedimentation across the shelf interior kept pace with subsidence and aggraded a shallow-water, nonevaporitic suite of subtidal wackestone facies.

The third stage in the evolution of the eastern shelf's western margin is illustrated by the formation of the Gunsight Limestone and younger Virgilian shelf-edge carbonate buildups of the Sylvester bank system (Galloway and Brown, 1973; Brown, 1990; Brown and others, 1990). No shelf-interior banks grew during this time, because Cisco fluvial-deltaic facies blanketed most of the shelf. A relatively continuous episode of uplift in the Ouachita fold belt brought about both upbuilding and a westward progradation of the shelf margin (Fig. 8). Fluvial-deltaic systems enlarged the shelf by covering the old carbonate bank during eustatic lowstands and by depositing siliciclastic sediment as a submarine-fan wedge that served as the substrate for younger sediment. Later, a new shelf-edge bank was established on the proximal submarine-fan facies, and the cycle was repeated with the next lowstand. In this manner, the shelf edge was displaced >80 mi to the west during deposition of the Cisco Group.

FACTORS CONTROLLING DELTA TYPE

Three important factors influenced the pattern of delta formation and the distribution of terrigenous clastic reservoir rock in the Pennsylvanian

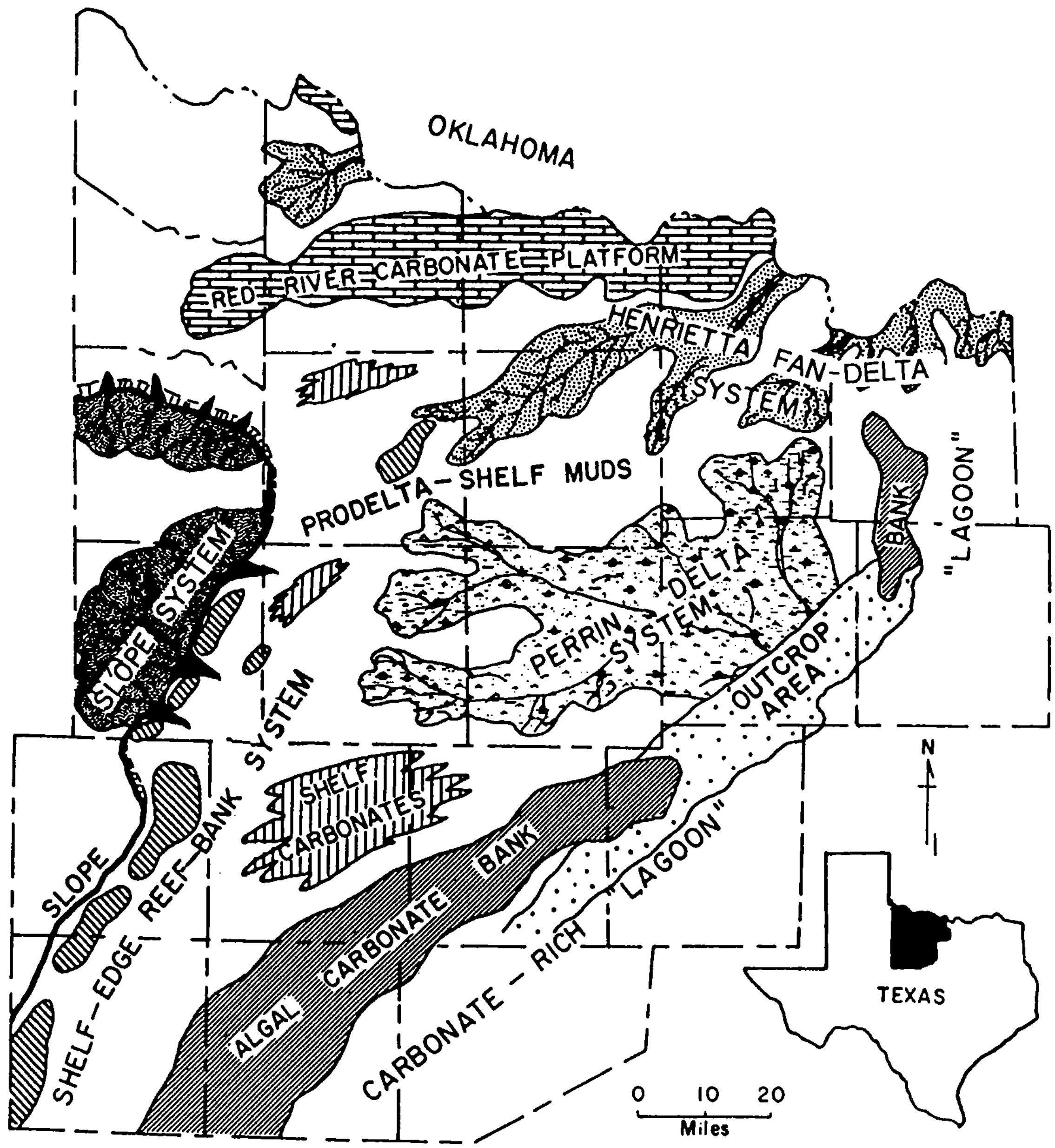

Figure 10. Principal depositional systems of the Canyon Group of north-central Texas (Erxleben, 1975).

rock units of north-central Texas. The first of these factors involves the length of the overall sediment-dispersal system from the source area to the distal delta front (or distal submarine fan); ultrashort-, short-, and long-distance sediment-dispersal systems can be identified for different delta systems. A second factor relates to the tectonic pattern of source-area uplift and shelf-margin subsidence. Were delta systems sourced by localized areas of block-faulted uplift or by an elongate mountain front generated by compressional orogeny? Also, how did subsidence patterns on the eastern shelf and in adjacent troughs influence reservoir geometry and delta-lobe stacking? The third factor is the delta's time of formation relative to eustatic sea-level changes. Sequence-stratigraphic analysis of cyclothemic deposits indicates that with Exxon type-1 sequences (the dominant type in north-central Texas), discrete highstand, lowstand, and transgressive systems tracts can be identified. What are the characteristics of deltaic systems associated with each systems tract? The length of the sediment-dispersal system (factor 1) and the nature of tectonism in the source areas, basins, and platforms (factor 2) are interrelated, whereas eustasy (factor 3) is an independent variable.

Length of Sediment-Dispersal System

Fluvial-deltaic sediment-dispersal systems in the Pennsylvanian siliciclastic deposits of north-central Texas can be described as being ultrashort, short, or long. Ultrashort dispersal systems involve sediment transport of generally <40 mi from the source area. Fan deltas that prograde from localized uplifts into adjacent, rapidly subsiding troughs best exemplify this type of deltaic dispersal system. These coarse-grained units commonly stack vertically to thicknesses of 2,300 ft. Handford and Fredericks (1980) and Dutton (1980) mapped numerous examples of such fan-delta systems in the Palo Duro basin of northwest Texas. Despite the fact that Thompson (1982) used the term "fan delta" for lower and upper Atokan coarse-grained deltas that accumulated in the northwest part of the Fort Worth basin, there is no clear indication that these units conform to the fan-delta definition as proposed by McPherson and others (1987). More likely, they are braid deltas, having delta plains formed at sea level and conglomeratic, braided distributaries. Most of the Pennsylvanian braid deltas, with the conspicuous exception of the Henrietta braid-delta system, have short dispersal systems, usually on the order of 50–100 mi.

One upper Atokan delta complex, the Atoka Group Caddo conglomerate, serves as an example of a coarse-grained braid-delta system that trapped moderate oil and gas reserves (Ammentorp and Cleaves, 1990). The unit had a short sediment-dispersal system (Fig. 11) and received conglomeratic, K-feldspar–bearing, arkosic sediment from a nearby point source, the easternmost horst blocks of the Red River uplift (Electra arch). Individual lobes prograded southeastward into the extreme northern end of the actively subsiding Fort Worth basin (Figs. 2,6). Regional dip into the basin is toward the northeast. The largest hydrocarbon fields accumulated in the dip-oriented, braid-distributary facies (Fig. 12). Delta-plain pinch-out into interdeltaic shale and limestone provided the stratigraphic traps. Marine reworking of delta-front facies into southwest-trending sheet-sandstone bodies also generated porous reservoir rock. Unfortunately these have the wrong geometry and orientation in relation to regional dip to trap a large volume of hydrocarbons. Ammentorp and Cleaves (1990) interpreted the Atoka Group Caddo conglomerate as being a "wave-modified" braid-delta system.

Tectonic Pattern of Uplift and Subsidence

Most of the gas production for north-central Texas is obtained from lower and upper Atokan braid deltas whose point-source areas were located east of the foreland basin (Thompson, 1982). The Muenster arch supplied abundant arkosic detritus for the braid-delta complex of the Boonesville Bend gas field (Wise and eastern Jack Counties). A separate point-source uplift within the Ouachita fold belt, near Denton, shed an orogenic suite of sediment, including recycled sedimentary quartz grains, white novaculite chert, and low-rank metamorphic-rock fragments. South of the Mineral Wells area, the high percentages of low-rank metamorphic-rock fragments in the deposits of delta lobes decreased the quality of reservoirs.

As noted above, braid deltas normally involve short-distance sediment-dispersal systems that begin at local uplifts. The Missourian Henrietta braid-delta system is a distinct exception to the general rule (Fig. 10). This arkosic system had its source area near the Criner Hills of southern Oklahoma (Fig. 7). The braid-delta complex was stacked vertically to a thickness in excess of 750 ft and prograded southwestward along a narrow, linear, 6- to 10-mi-wide trend (Erxleben, 1975). During deposition of the Colony Creek Formation (upper Canyon Group), distal deltaic facies of the braid delta reached the shelf edge, supplying coarse-grained sediment to the Knox slope system (submarine fans). Both the vertical stacking of deltaic facies through three separate depositional cycles, as well as the narrowness of the deltaic sandstone and conglomerate facies belt, resulted from subsidence in the Knox-Baylor trough. A similar stacking of fluvial-deltaic facies occurred in approximately the same position with the non-arkosic Bowie delta system of the upper Strawn Group (Fig. 13).

In north-central Texas, most of the long-distance sediment-dispersal systems were associated with uplift in the Ouachita fold belt. The overall pattern of uplift did not involve areally limited point sources, but rather a north-south–oriented front source generated by a collisional orogen. Strawn elements of the Perrin and Eastland river-dominated delta systems prograded westward across the sediment-filled Fort Worth basin onto the very gradually subsiding Concho platform. Rather than stacking vertically along narrow trends, delta lobes for individual cycles took on a multilateral pattern that blanketed most of the platform with siliciclastic sediment (Fig. 13). Discrete delta lobes, however, did not give rise to broad sheet sandstones, but instead formed narrow, dip-elongate, finger-shaped net-sandstone patterns. Delta-front and distributary-channel facies within the lobes are composed of fine-grained, well-sorted, mineralogically mature quartz arenite and sublitharenite sandstone. Feldspar is virtually absent, and other orogenic-provenance indicators, such as fragments of volcanic and metamorphic rocks, were largely removed over the course of the 75- to 200-mi-long travel distance of the sediment-dispersal pathway (Dutton, 1977). A major discontinuity with this petrographic scenario is

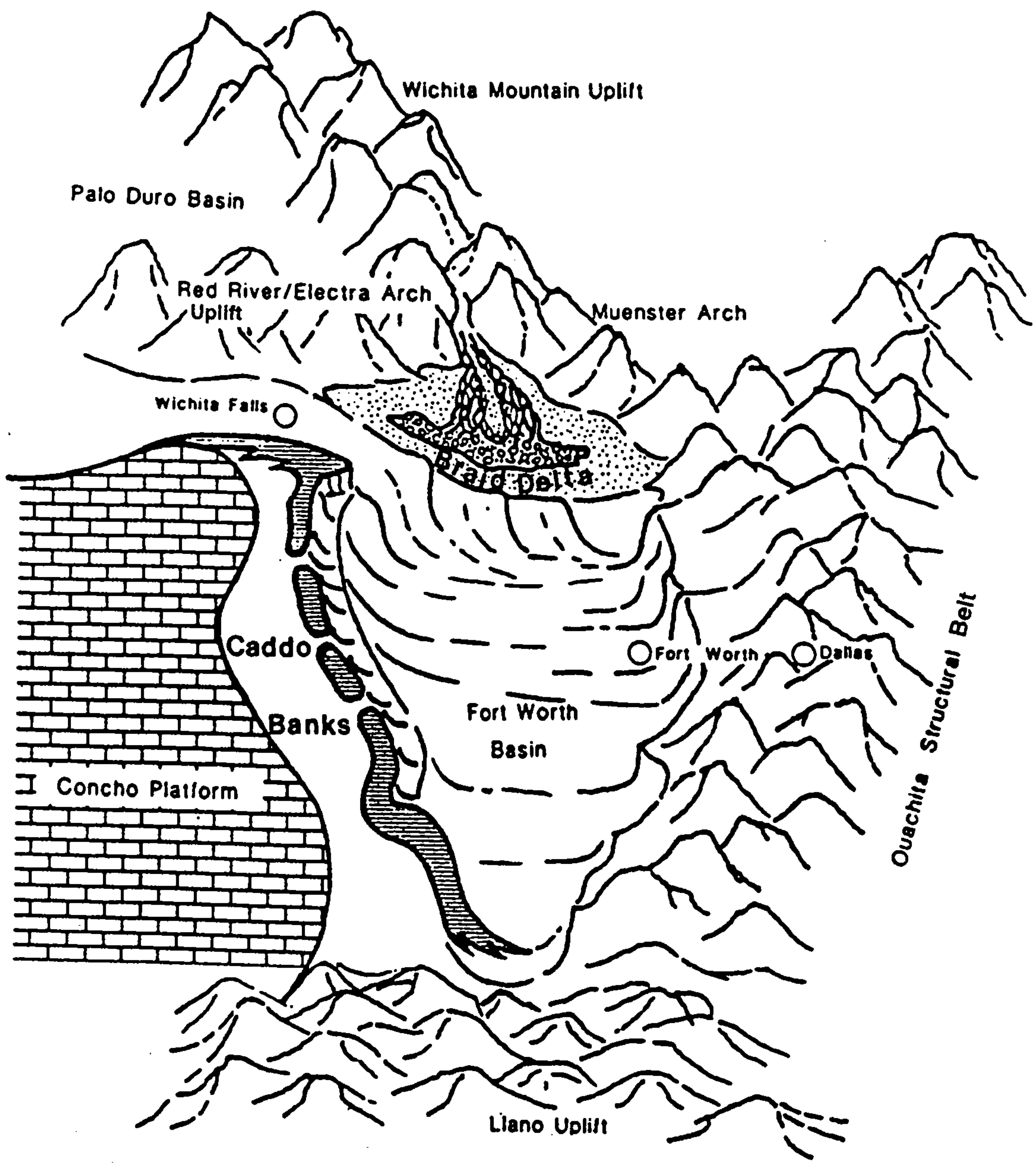

Figure 11. Paleogeographic map for the latest Atokan of north-central Texas. Atoka Group "Caddo" conglomerate, a wave-modified braid-delta complex, is shown at northern margin of the Fort Worth basin (Ammentorp and Cleaves, 1990).

the presence of novaculite-chert conglomerate in the fluvial facies of the Strawn and lower Cisco Groups. The significance of the orogen-derived novaculite-chert clasts will be dealt with later in the discussion.

The West Tuscola field of Taylor County (near Abilene) is typical of Strawn deltaic stratigraphic traps (Figs. 2,13). Well-sorted channel-mouth-bar sandstones, crevasse splays, and distributary-channel fills serve as the reservoir rock in the Eastland delta complex of the Strawn "Gray" sandstone (Table 2) (Shannon and Dahl, 1971). Core description of the delta-front facies suggests that the river-dominated lobate model is the most appropriate one. The sandstone is thinly bedded and lacks large-scale mud diapirism. Distal deltaic facies interfinger downdip with shale and limestone of the Anson carbonate ramp. There is no

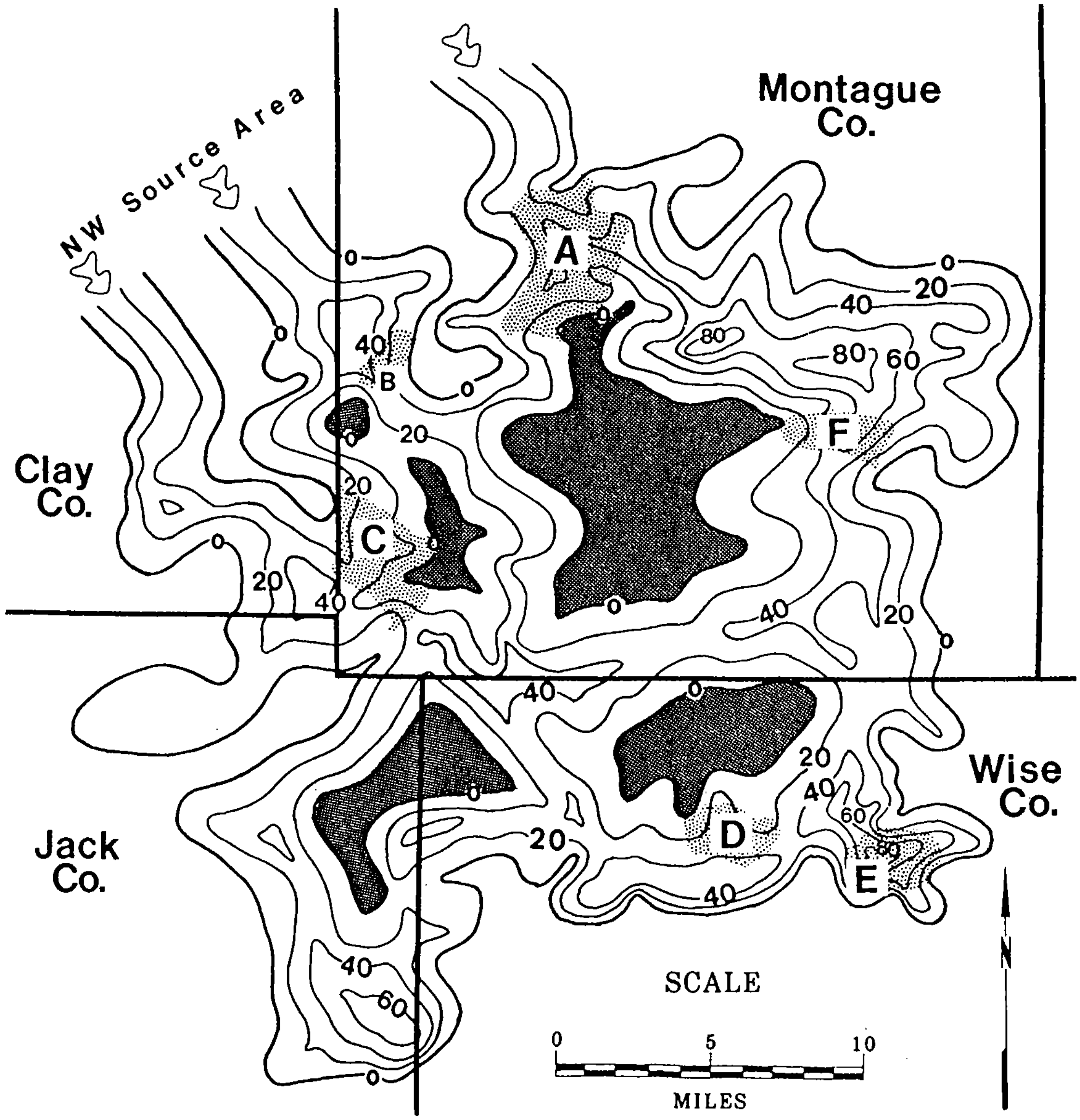

Figure 12. Net coarse-grained siliciclastic rocks (sandstone and conglomerate) isolith map of the "Caddo" conglomerate (Atoka Group), a wave-modified braid-delta system. Specific fields that produce oil and associated gas from the interval: (A) Hildreth; (B) Anson-Ortan; (C) Eanes; (D) Deaver-Malone-Pryor complex; (E) Alvord South, Caddo Conglomerate unit; and (F) Hundley. Contour interval is 20 ft. Modified from Ammentorp and Cleaves (1990).

basinward carbonate-bank or submarine-fan system. Updip stratigraphic entrapment of hydrocarbons occurs owing to pinch-out of delta-front sandstone into embayment and delta-plain mudstone. Incised-valley-fill conglomerate does not extend downdip onto the delta plain, although it is clearly present in the stratigraphically equivalent sandstone unit (Buck Creek Sandstone) of the outcrop zone (Greimel, 1977; Cleaves, 1982). Avulsion of the fluvial system feeding the delta lobe to a different area allowed the channel to fill with fine-grained sediment, thus blocking hydrocarbon migration into terrestrial facies.

Sequence-Stratigraphic Relationships

The third important factor that needs to be considered in this analysis of delta formation style and reservoir-facies distribution involves an evaluation of the systems tracts in which north-central Texas delta systems were deposited. No effort will be expended here to convince the reader as to the efficacy of sea-level eustasy and sequence stratig-

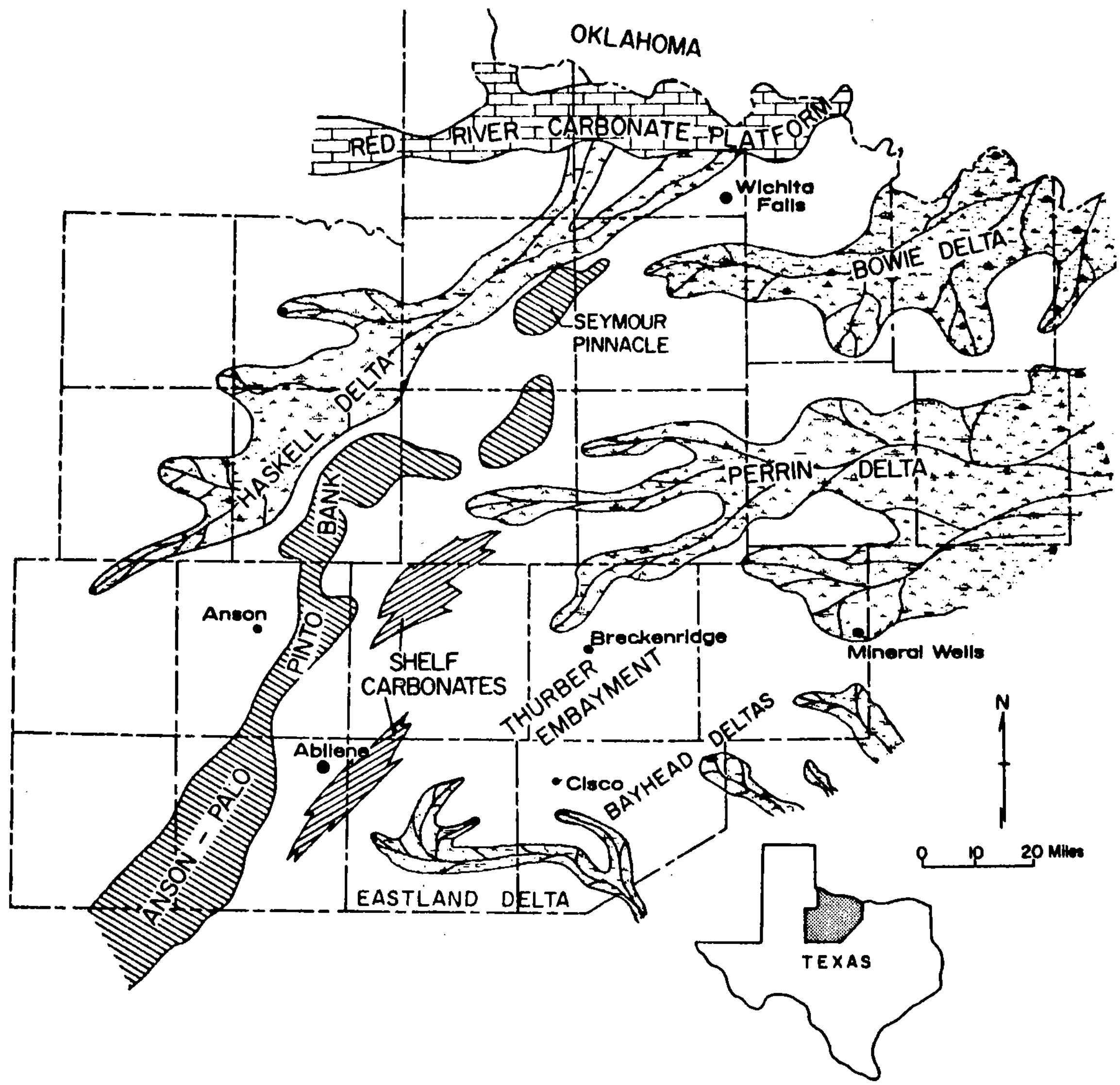

Figure 13. Strawn Group depositional systems in north-central Texas (Cleaves, 1975).

raphy for explaining the observed facies patterns. Detailed discussions as to the strengths and weaknesses of these ideas have been presented by Cleaves and Erxleben (1985), Boardman and Malinky (1985), Yancey and McLerran (1988), and Yancey and Cleaves (1990). What will be attempted is a demonstration of the profound importance for considering the timing of delta formation in relation to the postulated eustatic sea-level curve of Exxon workers (Fig. 14).

Careful study of the outcrop zones for the upper Strawn, Canyon, and Cisco Groups in the Brazos River Valley region has demonstrated that all of the major, mappable (subsurface) transgressive/regressive cycles associated with these units constitute Exxon type-1 sequences (Van Wagoner and others, 1990). Incised-valley-fill systems, usually containing thick intervals of chert conglomerate, have been identified in the coastal-plain facies assemblage of each cycle. Significant valley-fill exposures include the Brazos River Formation and Turkey Creek unit in the Strawn Group, the Kisinger "Sandstone" of the Canyon Group, and the Gonzales Creek, Avis, King, and Cook units in the Cisco Group (Table 2). With each example, the chert's source was the Ouachita fold belt.

Systems tracts that develop with Exxon type-1 sequences include highstand, lowstand, and trans-

TABLE 2.—MAJOR INCISED-VALLEY-FILL UNITS OF THE MIDDLE AND UPPER PENNSYLVANIAN IN THE BRAZOS RIVER VALLEY OF NORTH-CENTRAL TEXAS

Formations	Incised-Valley-Fill Units
Cisco Group (Surface and subsurface)	Top of Pennsylvanian
Harpersville Formation	Cook sandstone (subsurface)
Thrifty Formation	King sandstone (subsurface)
	Avis sandstone
Graham Formation	Gonzales Creek sandstone
Canyon Group (Surface)	
Home Creek Limestone	Kisinger sandstone
Colony Creek Shale	
Ranger Limestone	No major delta systems south of Jack County
Placid Shale	
Winchell Limestone	
Wolf Mountain Shale	
Palo Pinto Formation	
Strawn Group (Surface)	
Mineral Wells Formation	Turkey Creek Member (Cross Cut Sandstone) (Moran Sandstone)
Brazos River Formation	Sandstone and conglomerate
Mingus Formation	Dobbs Valley (Gardner) Sandstone
Grindstone Creek Formation	Buck Creek (Gray) Sandstone
Lazy Bend Formation	
Atoka Group* (Subsurface)	
Caddo limestone	
Caddo conglomerate	Unknown. No Concho platform deltas
Davis sandstone	
Lower Atoka clastic units	

* Atoka Group—Informal subsurface lithogenetic units of Thompson (1982) and Ammentorp and Cleaves (1990) for the northern Fort Worth basin.

gressive elements. In this discussion of the eastern shelf, it is also important to note whether the shelf margin comprises a ramp or rimmed shelf for any given depositional cycle. Rimmed shelves can further be subdivided into those having accretionary rims (vertical growth only) or progradational plus accretionary rims (westward migration of the shelf edge because of sedimentation). All of the highstand systems tracts on the eastern shelf occur in the outcrop zone or in the shallow subsurface. Consequently, hydrocarbon production for this tract is much lower than that of lowstand facies.

Highstand Depositional Pattern

During the earliest phase of a Pennsylvanian highstand in north-central Texas, when a stable shoreline was first established, most of the major delta systems were drowned, and rivers entered the standing body of water at the heads of estuaries (Fig. 15). These bayhead deltas laid down a thin, progradational sequence that was commonly incised by the distributary channels of the delta plain. Incision occurred during stillstand, did not exceed 15 ft, and did not penetrate downward to the subjacent cycle-bounding transgressive limestone. Individual distributaries contain mud rip-ups and fine-grained to very fine grained quartz sandstone, but lack arkose or chert conglomerate. The areally restricted distribution of such bayhead deltas makes them exceedingly poor targets for oil or gas exploration. Good examples of exposed bayhead deltas include the Fambro and Oran units of the Palo Pinto Formation (Fig. 9). A detailed outcrop description of the Fambro unit is provided by Spaid (1982).

After deltas completed filling their estuaries, they began prograding onto the shelf. Basinward coastline migration could then result from either progradational regression during a stillstand or forced regression during a progressive eustatic lowering of sea level. With progradational regression, the amount of accommodation space is directly controlled by deposition; the availability and type of sediment from the source area become the dominant control on delta formation. Thicker prodelta sequences and greater vertical stacking of delta-front facies can be anticipated in this situation. On the other hand, with forced regression, a significant amount of accommodation space is eliminated by the sea-level drop alone (Posamentier and others, 1992). This situation might give rise to much thinner prodelta intervals. It will also bring about incision of the upper delta plain by the trunk stream that is feeding an active delta lobe. If a new lowstand delta becomes established at the shelf margin directly downdip from the terminal highstand delta lobe just noted (and is supplied sediment by the same fluvial feeder system), then the complete high-

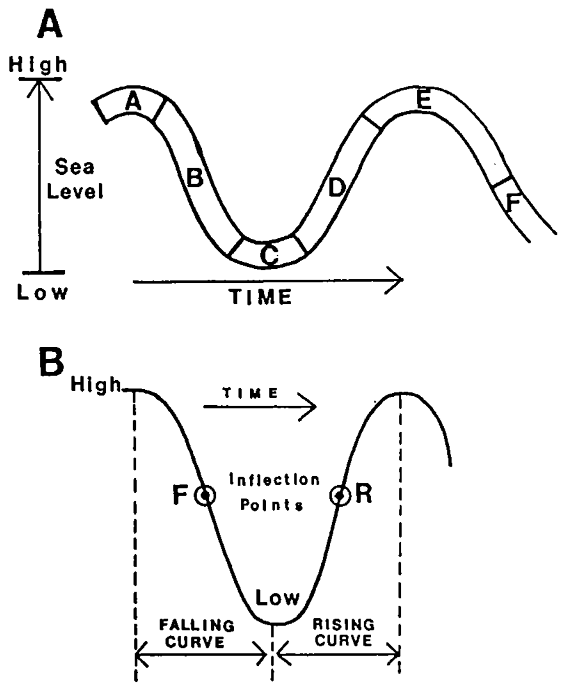

Figure 14. Exxon eustatic sea-level curve (Van Wagoner and others, 1990). (A) Systems tracts and the sea-level curve. Letters A–E correspond to systems tracts associated with Exxon type-1 sequences: A—highstand systems tract, B—forced regression with sedimentation in a lowstand fan or distal delta front, C—lowstand wedge, D—transgressive systems tract, and E—second highstand; F—lowstand shelf-margin systems tract of an Exxon type-2 sequence. (B) Inflection points for one eustatic cycle of sea-level change. Incised-valley-fill unconformities form at position F, which indicates the maximum rate of sea-level drop; position R marks the time of maximum rate of sea-level rise.

stand delta will be incised. With the Strawn and lower Cisco delta lobes, the incised-valley fill involves chert conglomerate. For delta lobes that are abandoned well before forced regression takes hold, no conglomeratic incised fluvial system will be present (Fig. 16).

Two examples of Strawn highstand deltas illustrate these concepts of regression. The outcropping Brazos River Formation of eastern Palo Pinto County is a good example of a terminal-stage highstand delta. Much of the unit is composed of a thinly bedded, marine-reworked sheet sandstone. Near Mineral Wells, delta-plain mudstone and distributary-channel facies are also noted in this wave-modified, river-dominated delta (Fig. 17). A chert-filled incised channel having a maximum thickness of ~60 ft cuts through the sheet-sandstone and delta-plain facies in a direction perpendicular to the trend of the reworked sandstone. The chert conglomerate continues into the subsurface in a northwesterly direction for >40 mi. In the shallow subsurface, both the highstand sheet-sandstone facies and the lowstand conglomerate facies contain the sulfur-rich, mineralized water that gives the town of Minerals Wells its name. Farther downdip, in the outer-ramp lowstand systems tract of Archer, Throckmorton, and Young Counties, the Brazos River Formation (Buttram or Burson subsurface unit) channel-mouth-bar and distributary-channel sandstone facies are major targets for oil exploration (Cleaves, 1975).

A second example of Strawn highstand deltaic sedimentation is the Moran sandstone in the shallow subsurface of northeastern Callahan County (Figs. 2,18). The surface equivalent of the Moran, the lower unit of the Turkey Creek Sandstone Member of the Mineral Wells Formation (Cleaves, 1975), lacks incised-valley-fill facies and was apparently (in outcrop) a delta complex that accumulated during a highstand progradational regression. Hamilton (1990) reported that mud diapirism in the delta-front sandstone served as the primary mechanism of hydrocarbon entrapment within the Moran interval of the Herr-King field. Although the total progradational interval does not exceed 60 ft, there is no channel facies that extends downdip from the field. This small, localized delta lobe was subsequently abandoned owing to avulsion of the trunk stream; a new delta lobe was established farther to the north, before the next eustatic regression took place.

Lowstand Depositional Pattern

Lowstand systems tracts can involve either outer-ramp delta systems that do not have associated submarine fans or deltas that perch on the margins of rimmed shelves and feed slope-system submarine fans. Lowstand Desmoinesian delta systems of the Concho platform accumulated in ramp settings, as noted for the Brazos River Formation, and did not build the shelf margin basinward. Most Cisco lowstand deltas, on the other hand, generated submarine-fan aprons at their edges on the slope and enlarged the eastern shelf of the Midland basin toward the west (Brown and others, 1990).

Bloomer (1977,1991) described in detail the various types of stratigraphic traps that developed in uppermost Pennsylvanian and basal Permian (Cisco Group) lowstand, shelf-margin depositional settings. The Cook sandstone (Figs. 19,20) produces from slope submarine fans, from delta-front and distributary-channel facies, and from updip incised-valley-fill fluvial deposits. All of these systems are aligned east-west along the sediment-dispersal pathway of a single major fluvial-feeder complex. The Jameson field of Coke and Mitchell Counties contains middle-fan channel-fill sandstone reservoirs, as well as proximal-fan canyon-

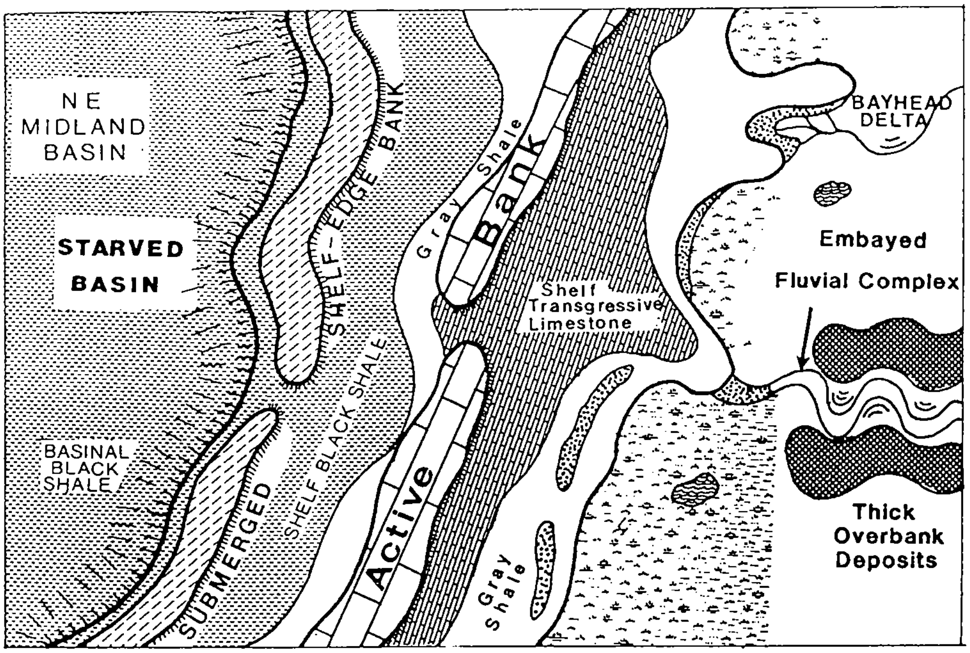

Figure 15. Early highstand systems tract for a Missourian (Canyon Group) eustatic cycle in north-central Texas. Note the presence of a small bayhead delta that has not completely filled in its estuary. The outer, shelf-edge bank is submerged and is not undergoing growth, whereas the inner bank is actively accreting.

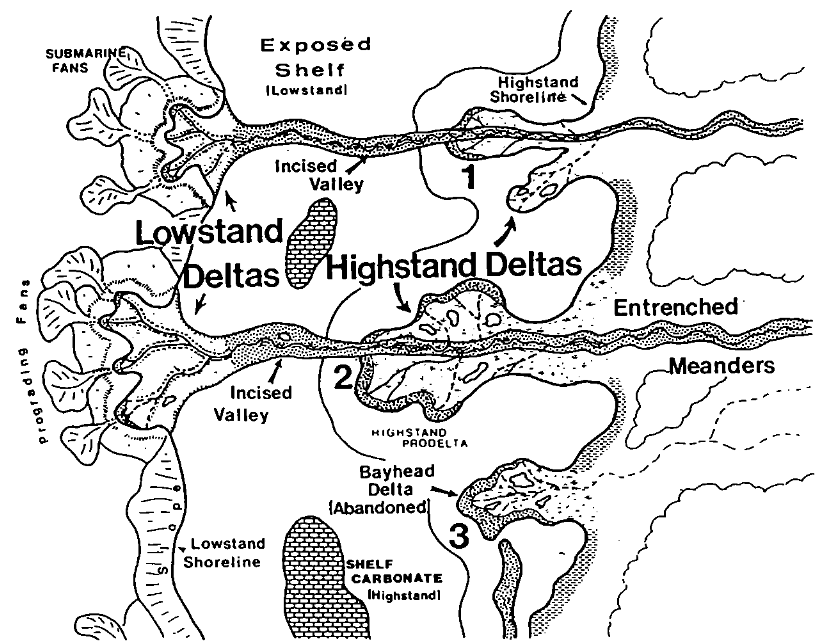

Figure 16. Highstand and lowstand delta lobes for a single Exxon type-1 eustatic cycle. A small bayhead delta (no. 3), having a limited drainage area, filled its estuary and brought about minor local progradation of the local shoreline before being abandoned while the highstand was still in progress. No incised-valley-fill deposits are present on its delta plain. Delta systems 1 and 2 contain both highstand delta complexes that underwent progradational regression and lowstand delta complexes at the shelf edge that fed slope submarine fans. Both of these deltas were active at the end of the highstand. Their highstand deposits contained incised-valley-fill fluvial systems that served as feeder channels for the lowstand deltas. The lowstand deltas are not themselves incised (Cleaves, 1993).

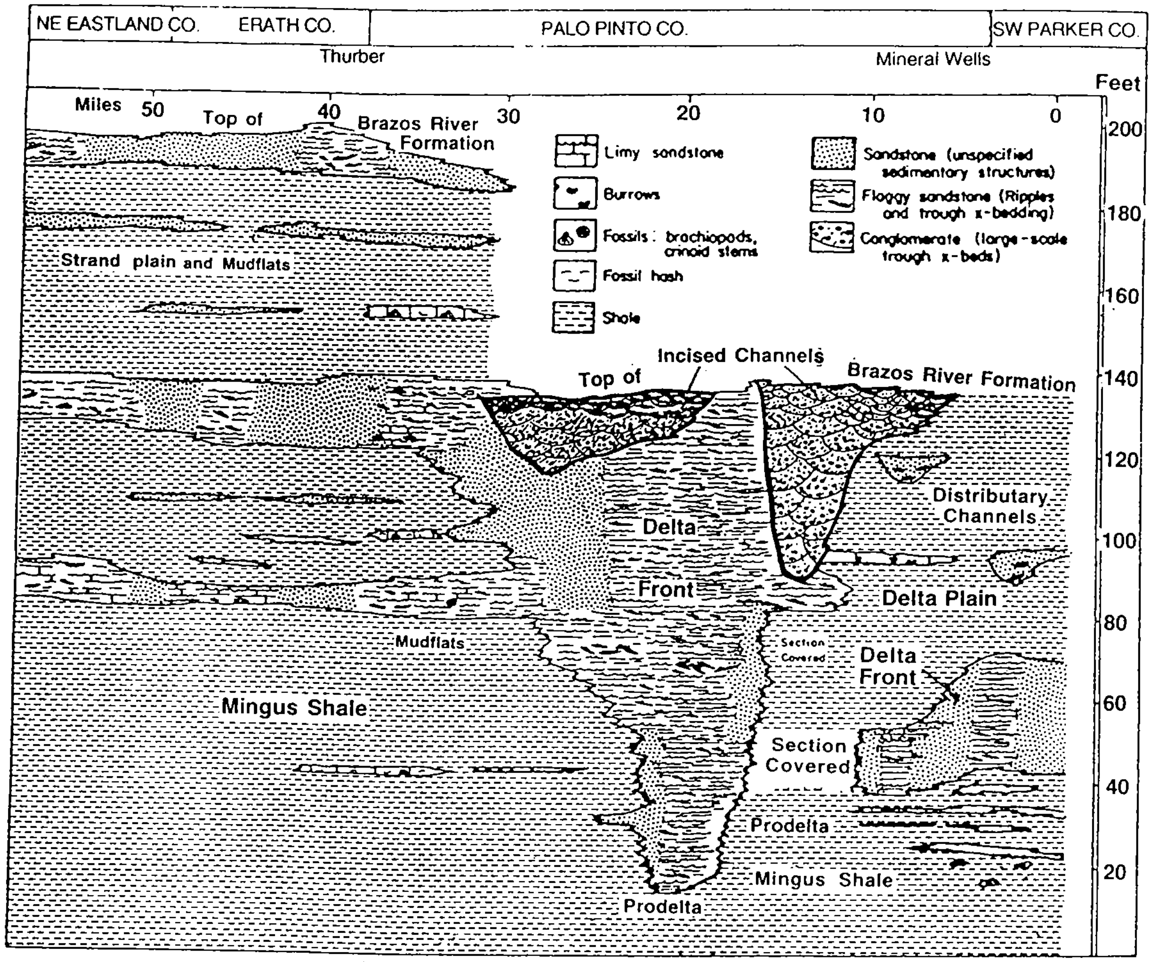

Figure 17. Northeast-to-southwest outcrop cross section parallel to the strike of the Brazos River Formation. Note the presence of two chert-conglomerate–filled incised channels in center of the illustration (Cleaves, 1975).

fill conglomeratic sandstone reservoirs (Bloomer, 1990). Farther to the northeast, in Nolan County, the Group 4000 field produces oil from delta-front sheet-sandstone and unincised distributary-channel-fill facies. This delta lobe is perched at the shelf margin just west of the Waldrip II carbonate bank (Figs. 20,21). The lobe received sediment from an incised-valley system that extends eastward through Taylor and Callahan Counties. A distinct southward loop in eastern Taylor County trapped oil in the Potosi and Blackwell fields. The channel filled with coarse-grained sediment during the marine transgression that came after deposition of the lowstand Cook sandstone delta.

Transgressive Depositional Pattern

Transgressive systems tracts, aside from channel fill trapped in the upper reaches of incised valleys, did not generate widespread reservoir facies in the Pennsylvanian shelf settings of north-central Texas. Stranded delta lobes that may have developed on the middle shelf during temporary stillstands are an obvious possibility, but these are likely to be isolated and hard to identify. Thin, bioturbated sheet-sandstone intervals, present on flooding surfaces beneath the outcropping Winchell and Ranger Limestones of Palo Pinto County, record the reworking of tidal-flat and bayhead-delta siliciclastic deposits (A. Brown, 1982).

CONCLUSIONS

The patterns of Pennsylvanian fluvial-deltaic sedimentation on the Concho platform and eastern shelf and adjacent basins can best be explained in terms of three principal controls. These controls involve two interdependent variables and one vari-

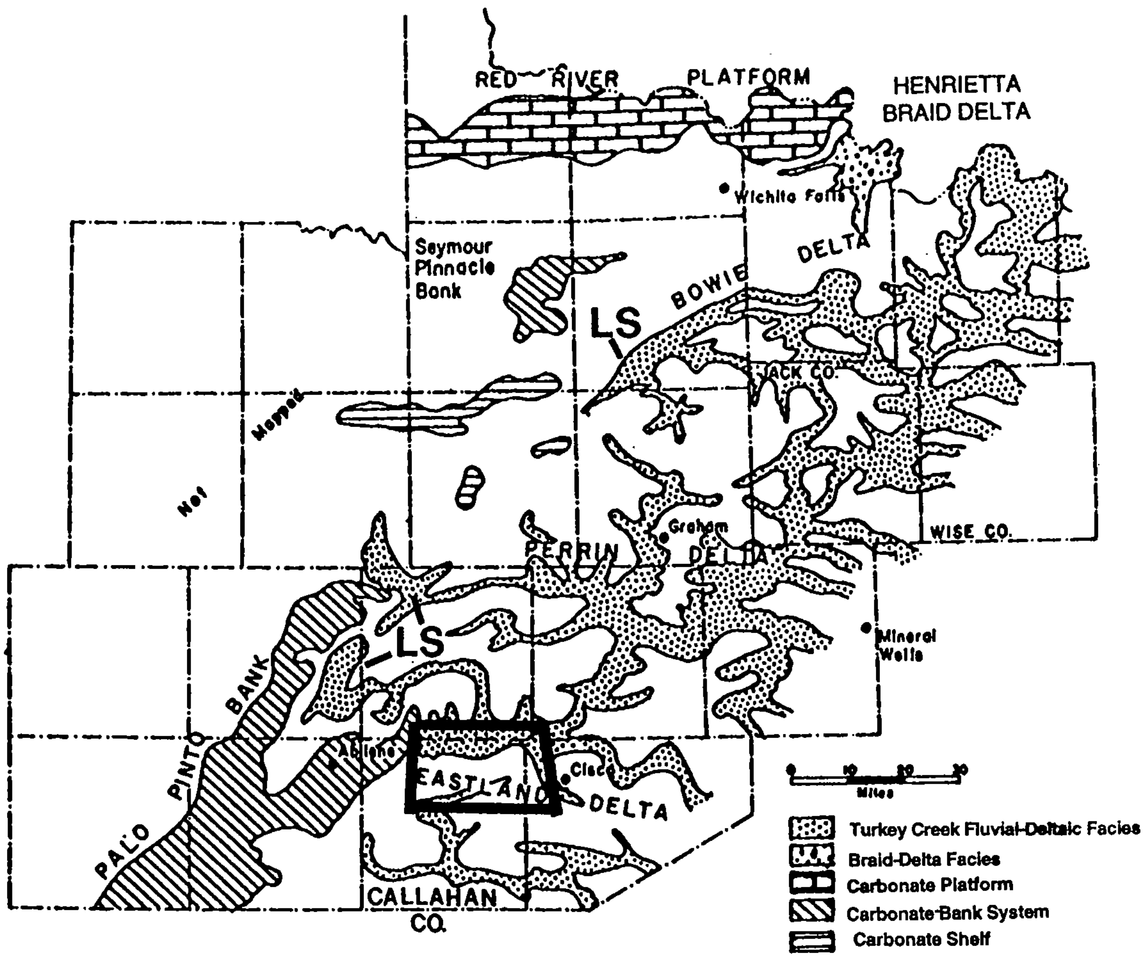

Figure 18. Distribution of coarse-grained siliciclastic facies in the lower Turkey Creek (Moran) and upper Turkey Creek (Cross Cut) deltaic sandstones of north-central Texas. The outlined area corresponds to the area studied by Hamilton (1990) and discussed in the text of this paper. LS—Lowstand delta systems in the upper Turkey Creek unit. Dot pattern indicates areas of >20 ft of sandstone in the Turkey Creek depositional interval. Modified from Cleaves (1975).

able that operated independently from the local and regional geologic setting. (1) The overall length of the sediment-dispersal systems associated with the major siliciclastic depositional systems and (2) the tectonic patterns for source-area uplift and shelf-margin subsidence interacted to help define the reservoir facies distribution across north-central Texas. (3) Eustatic sea-level change operated separately from the regional tectonics and imposed a stacked, allocyclic succession of more than 40 transgressive/regressive cycles on the overall pattern of shelf sedimentation throughout the area. Eustasy, however, did have a significant impact on the length and facies composition of systems tracts laid down on the structurally stable eastern shelf. Glacially induced sea-level changes determined the position of shorelines (hence the specific sites of delta formation) in relation to sediment source areas and the shelf margin.

In terms of length, three basic sediment-dispersal systems have been identified. *Ultrashort* dispersal systems, involving sediment-transport distances of <40 mi, were generated by true fan deltas. Sediments in true fan deltas were shed from horsts in the Red River uplift and from the Wichita-Amarillo uplift into adjacent, rapidly subsiding basins (Palo Duro and Hardeman basins). *Short* dispersal systems also resulted from point-source uplifts, but these gave rise to braid-delta systems that tended to stack vertically and prograde a greater distance from the source. Such systems were preserved in less-rapidly subsiding depressions like the Knox-Baylor trough and the

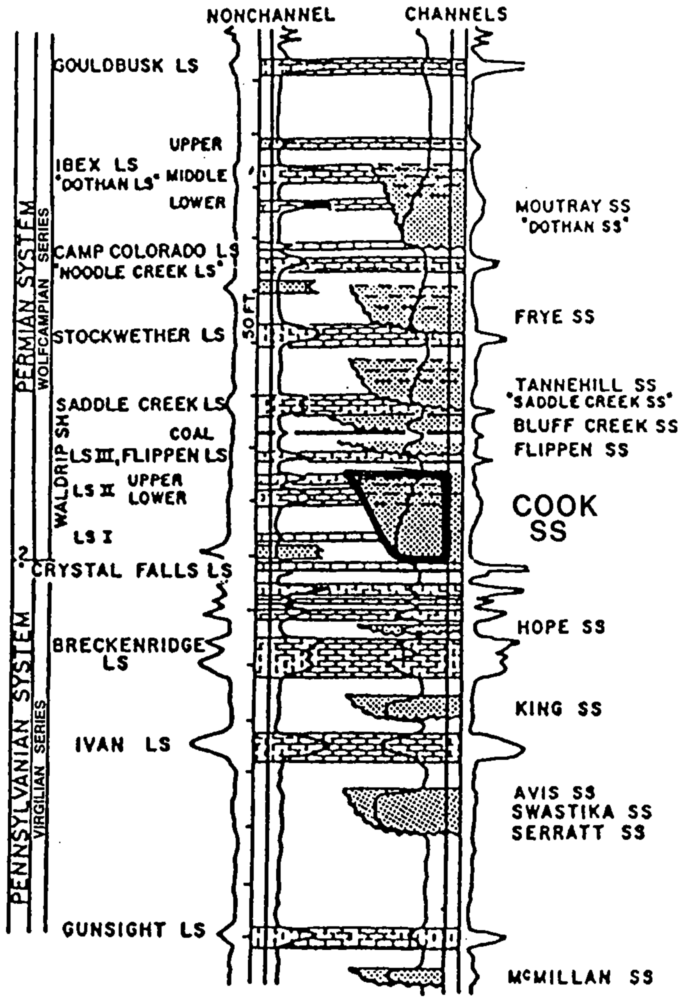

Figure 19. Middle and upper Cisco Group incised-valley-fill units in the subsurface of north-central Texas. The Cook sandstone unit is highlighted. Modified from Bloomer (1991).

northwestern arm of the Fort Worth basin. Early Atokan braid deltas, derived from the Muenster arch, and late Atokan "Caddo" wave-modified braid-delta lobes sourced from the eastern margin of the Red River uplift, supplied important reservoir facies in the major gas fields of north and north-central Texas. *Long-distance* sediment-dispersal systems accumulated as a consequence of uplift along a continuous mountain chain. Desmoinesian and younger Pennsylvanian delta systems prograded westward from the Ouachita front source onto the gradually subsiding, unfaulted Concho platform and eastern shelf. The Perrin and Eastland river-dominated delta systems responded to the structurally stable substrate by depositing a number of relatively thin, multilateral delta lobes that showed little tendency to stack vertically for any given transgressive/regressive cycle. The downdip fluvial and delta-front reservoirs in these systems contain well-sorted, mineralogically mature quartz arenite and sublitharenite sandstone. This composition contrasts greatly with the texturally and mineralogically immature K-feldspar arkose conglomerates yielded by most of the point sources. Volumetrically, the long-distance dispersal system supplied <90% of the total siliciclastic reservoir rock on the eastern shelf and roughly 75% of the total hydrocarbon production for the region.

Tectonics, as just noted above, is the second major variable affecting Pennsylvanian fluvial-deltaic sedimentation in north-central Texas. Tectonics alone controlled the type and rate of uplift in the source area, as well as the areal configuration and rate of subsidence for the depositional basins. It interacted with siliciclastic sedimentation to generate sediment-dispersal systems of varying length, stacking characteristics, and total reservoir volume. Similarly, the evolution of the Concho platform and Midland basin shelf margin resulted from an interplay between basin tectonics, siliciclastic-sediment supply from the Ouachita fold belt, and the in-place carbonate productivity of $CaCO_3$-secreting organisms to form shelf-margin carbonate banks. This evolution began as a homoclinal ramp, proceeded to become a vertically accreting rimmed shelf margin, and, during the Virgilian, developed into an accretionary and prograding rimmed margin.

Neither tectonics nor the characteristics of sediment-dispersal systems are especially helpful to explain the cyclic sedimentation on the eastern shelf. Delta-lobe switching was only a minor component of the overall pattern. Glacially induced eustatic sea-level fluctuations furnish the best explanation of the cyclicity. Eustasy is clearly an allocyclic mechanism that acted independently from, and much more rapidly than, the regional tectonic processes. Eustasy also exercised the dominant, short-term control on the amount of accommodation space available for sediment accumulation.

Almost all of the transgressive/regressive cycles in the Middle and Late Pennsylvanian sedimentary assemblage of north-central Texas represent unconformity-bounded, Exxon type-1 depositional sequences. Each sequence contains areally distinct highstand, lowstand, and transgressive

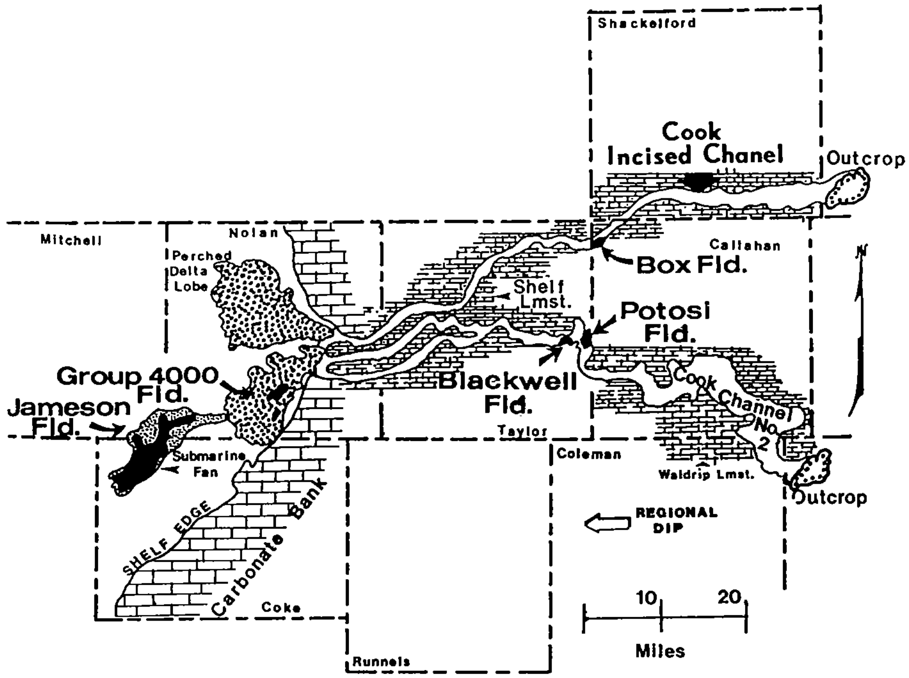

Figure 20. Cook sandstone (middle Cisco Group; upper Virgilian) sediment-dispersal system from outcrop to the submarine-fan system. Two incised-valley-fill channel systems are present. Oil production from the Box, Potosi, and Blackwell fields is obtained from stratigraphic traps in the valley-fill deposits, whereas the Group 4000 field produces from distributary and channel-mouth-bar sandstones of a perched delta lobe. The Jameson field production is derived in part from submarine-fan channels. Map area corresponds to area 1 (dot pattern) in Figure 2. Modified from Bloomer (1991).

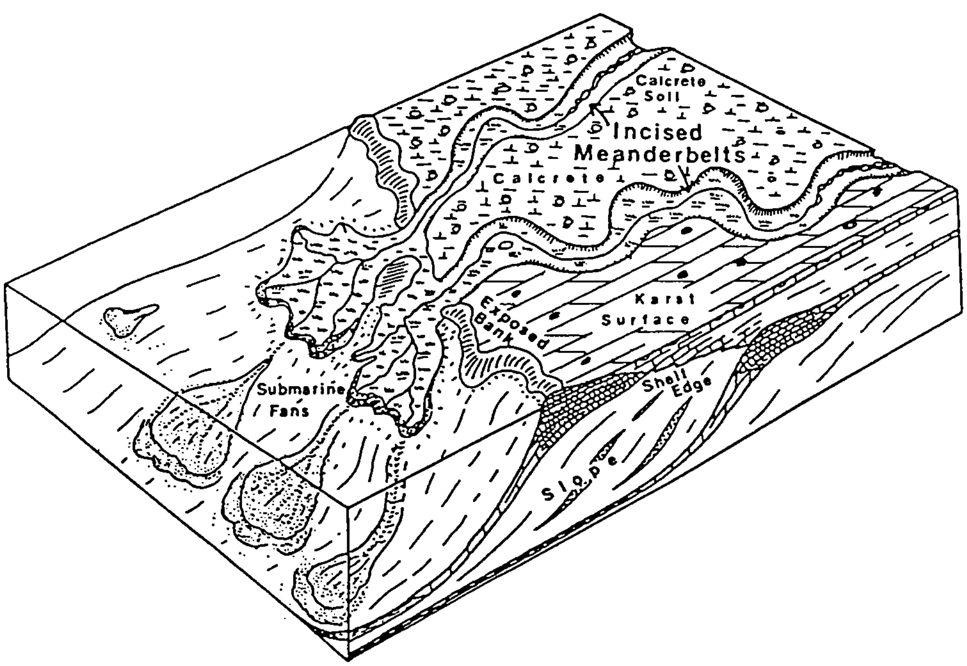

Figure 21. Perched delta lobes, submarine fans, incised-valley-fill channel systems, and exposed shelf associated with the lowstand and transgressive systems tracts preserved in the Cook sandstone (Cleaves, 1993).

systems tracts. Lowstand siliciclastic systems tracts that accumulated at the margin of the rimmed eastern shelf gave rise to submarine-fan systems, as well as perched deltas and incised valleys. Submarine-fan hydrocarbon production is most prominent from the prograding shelf margins of the middle and upper Cisco Group. The incised valleys filled with chert-pebble conglomerate and finer-grained sediment during the marine transgression following the lowstand. In contrast, the Desmoinesian shelf edge for the Concho platform involved a homoclinal ramp. Consequently, no submarine-fan system was laid down. Shallow-basin black shales served as source rocks for lowstand siliciclastic reservoir rocks on both types of shelf margins. Highstand deltas include both early-formed, highly localized bayhead systems and later-formed, progradational regressive systems. Neither of these marine delta types had sufficient volume of reservoir rock to produce large, prolific oil or gas fields.

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Depositional Framework and Representative Oil Reservoirs of the Cherokee Group (Atokan-Desmoinesian, Middle Pennsylvanian), Eastern Kansas

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ABSTRACT.—Sequence stratigraphy provides the basis for reexamining the depositional framework of the Cherokee Group and some oil reservoirs in it. The result points to some basic considerations that geologists and oil operators, working with this succession and other sequences of Pennsylvanian cyclothems, can apply, and modify, during future studies. The Cherokee Group (Atokan-Desmoinesian, Middle Pennsylvanian) of eastern Kansas consists of interbedded shale, siltstone, and sandstone, with minor amounts of limestone and coal. The group is a major producer of oil and the source of most of the coal mined in Kansas. Within the Cherokee Group, marker intervals—consisting of an underclay, a coal, a limestone or sandstone, and a dark-gray or black shale—can be traced over several shallow-shelf basins of the Midcontinent and even as far as the Illinois basin, eastern Colorado, and east-central Oklahoma. Each of the component lithologic units of the marker interval is a few decimeters (i.e., a few tenths of 1 m) to 1 m thick; however, rarely are all components present. The top contact of the underclay is a sequence boundary.

The bodies of rock between sequence boundaries in the Cherokee Group contain upward-coarsening successions, upward-fining successions, and shales. Most upward-coarsening successions (dark shale; streaked shale; lenticular- and wavy-bedded shales, siltstones, and sandstones; and rippled sandstones) represent progradational or regressive shoreface–strand plain environments; a few are deposits of prograding delta fronts or crevasse splays. Upward-fining deposits commonly are valley fills and include (from bottom to top) fluvial and estuarine sandstones with minor amounts of intraclast conglomerate; a mixed lithology comprising interbedded shale, siltstone, and sandstone; and shale. Shale successions are prodeltaic marine deposits, deposits of transgressive systems tracts, or final deposits in valley-filling successions. Reservoirs in several Cherokee oil fields are fluvial or estuarine sandstones that are part of valley-fill successions.

Exploration, development, and production activities in the Cherokee should be carried out with two facts in mind. First, regional marker intervals permit precise correlation of reservoirs within and between fields. Second, valley-fill sandstones are common in the Cherokee Group. Whereas sandstones in valley fills may be discontinuous, the erosional valleys should be continuous. Patterns of erosional absences of the regional marker intervals show the location of the valleys, even where sandstone is absent. Trends of erosional valleys established on a scale bigger than individual lease or field may serve as a guide to planning development of new or existing areas. Waterflooding design should reflect the geometric nature of sandstone bodies—they are in the form of channels rather than sheets.

INTRODUCTION

Efficient exploration for oil and its optimum production require knowledge of the patterns of porosity and permeability of the reservoir. Frequently, these patterns are understood in terms of the stratigraphy and depositional environment of sedimentary rocks that form the reservoir. In mature productive areas, understanding of the reservoir can prolong the productive life of oil fields by defining likely areas for improved recovery and identifying overlooked reserves. The Cherokee Group of southeastern Kansas is one such mature productive area (Figs. 1,2). It has produced >700 million barrels of oil since commercial production began a century ago (L. Brady, personal communication, 1985; Miner, 1987).

This paper summarizes studies over the past

Walton, A. W., 1996, Depositional framework and representative oil reservoirs of the Cherokee Group (Atokan-Desmoinesian, Middle Pennsylvanian), Eastern Kansas, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 168–187.

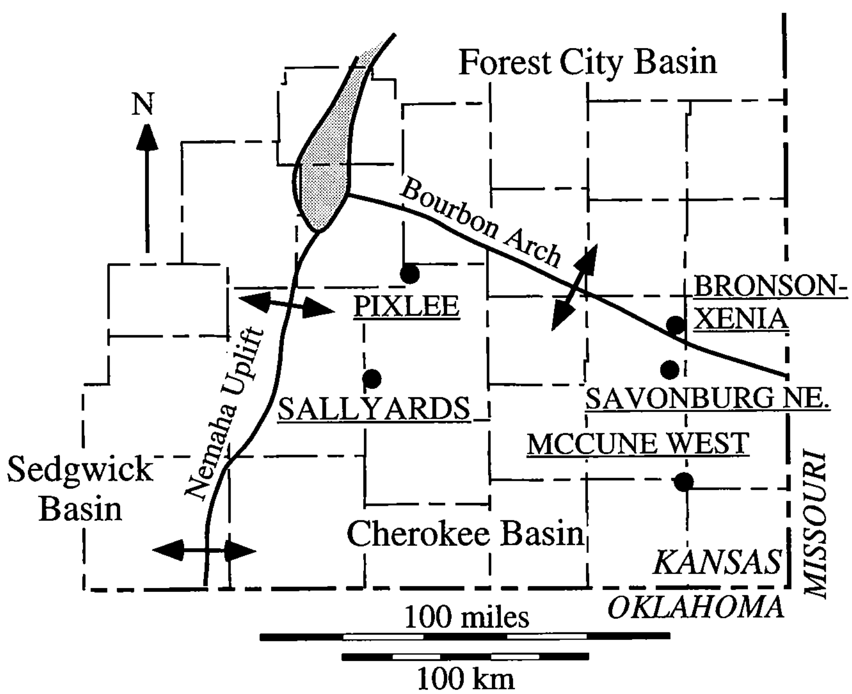

Figure 1. Tectonic features of southeastern Kansas and locations of oil fields discussed in this paper.

two decades by graduate students and others at the University of Kansas and elsewhere. It attempts to define the framework of Cherokee deposition and elucidate the nature of some of its reservoirs through application of the principles of sequence stratigraphy (Van Wagoner and others, 1990), as well as interpretation of depositional environments. It is a progress report, in anticipation of further study and a future synthesis. The working conclusions to date are (1) regional markers provide the best internal correlation in the Cherokee Group; (2) the cyclicity and patterns of sandstone distribution of the Cherokee Group reflect its formation during a time of fluctuating relative sea level; (3) deltaic deposition was im-

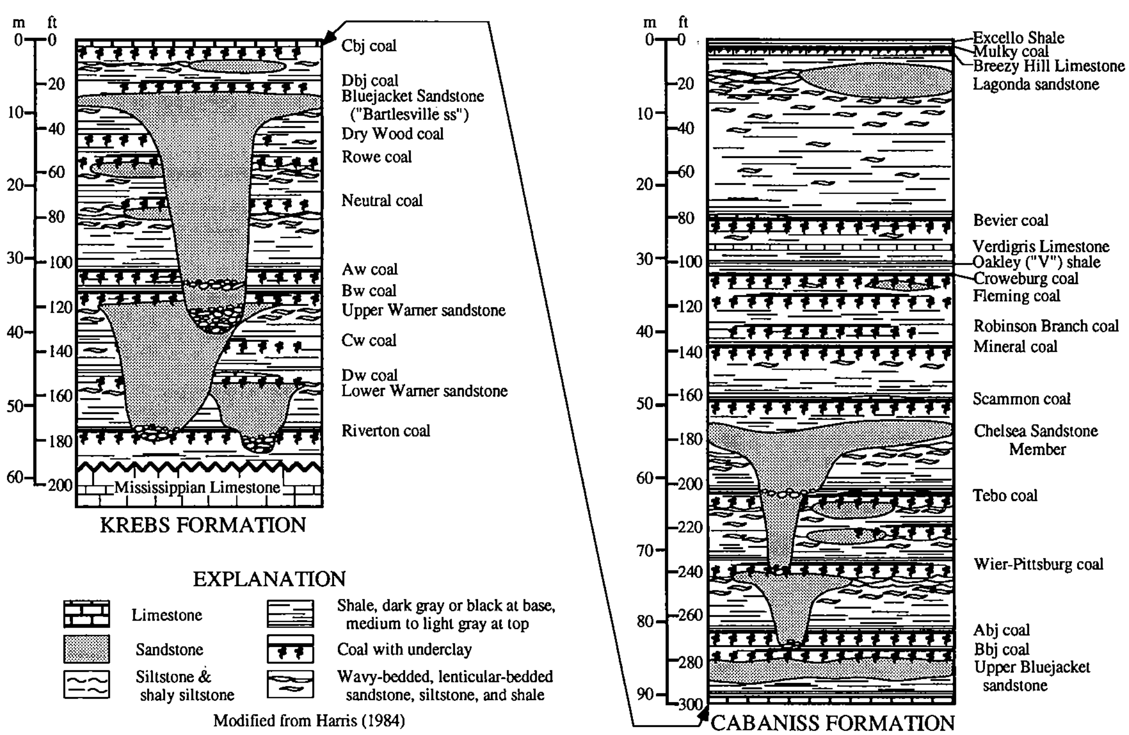

Figure 2. Stratigraphy of the Cherokee Group (Atokan-Desmoinesian, Middle Pennsylvanian) in southeastern Kansas. Coals Abj through Dbj (bj = Bluejacket) and Aw through Dw (w = Warner) are from Harris (1984).

portant along the margins of the Forest City and Cherokee basins, but marine deposition and progradational or regressive shoreface–strand plain complexes account for much of the succession; (4) the major oil reservoirs examined so far are fluvial or estuarine deposits in valleys that were cut during lowstands of sea level; and (5) tidal deposition is probably significant and more common than has been previously recognized. These working conclusions have considerable significance for the oil industry in eastern Kansas. This paper is addressed first of all to oil operators who are interested in the Cherokee Group in eastern Kansas. As an attempt to provide a conceptual framework for understanding the Cherokee Group, the paper may be of interest to geologists who are working on that group or on similar rocks. Insight, commentary, and correction are welcome.

Methods

Most of this paper is a review of several master's theses written at the University of Kansas over the past two decades as well as my own work. Most theses were subsurface studies using gamma-ray–neutron logs and cores that are in the collection of the Kansas Geological Survey or were provided by oil operators. For regional studies, sample density was a minimum of one to three wells per square township (36 mi^2). For studies of individual fields, the density was much higher, reaching one well every 2.5 acres in some fields. Density of core coverage was variable. Large areas were not represented at all, but several cores came from small individual fields. Cores are biased toward sandstone-rich parts of the section, because many of them were collected as part of appraisal efforts on oil fields. One of the studies mentioned here (Harris, 1984) included substantial amounts of field work, including measurement of surface sections.

Wells and surface sections were correlated into a framework of regional markers developed by Ebanks and others (1977), Hulse (1978), and Harris (1984). In regional studies, sets of cross sections were built up by correlating closed loops defined by intersecting sections. Wells necessary to provide a higher density of control were then correlated to the cross sections.

PREVIOUS INTERPRETATIONS

In geological investigations that closely followed discovery of oil in the Cherokee Group, the reservoirs were found to be sandstone "shoestrings" a few hundred meters wide and several kilometers, or even tens of kilometers, long. Early workers concluded that the shoestring reservoirs were deposits either of ancient rivers (Cadman, 1927; Rich, 1923) or of shoreline barrier islands (Bass, 1934). Bass (1934) made the most lasting impression, because of his compelling graphic comparison of Bartlesville shoestring sandstones to the coastal barriers of the U.S. Atlantic Coast.

With development of the cyclothem concept in the 1930s (Wanless and Weller, 1932), the Cherokee Group was interpreted as a succession of cyclic deposits. Abernathy (1936) divided the group into 15 cyclothems, each ideally consisting of a lower nonmarine portion (sandstone, interbedded sandstone and shale, underclay, and coal) and an upper marine portion (black, fissile, phosphatic shale; gray, nonfossiliferous shale; limestone; and gray nonfossiliferous shale). Abernathy (1936) reported that none of the cyclothems was complete, and none of the lithologies was found in all cyclothems. Howe (1956) honored Abernathy's (1936) stratigraphic classification in his work of two decades later, but divided the Cherokee Group into formations extending from the top on one coal bed to the top of the next. He named these formations for the coal bed in each.

Deltas in the Cherokee Group

Wanless and others (1970) called attention to the importance of deltas as environments of sedimentation in the Pennsylvanian of the Illinois basin and Midcontinent regions, including the Cherokee Group of eastern Kansas, Iowa, and parts of Missouri, Oklahoma, and Nebraska. They believed that deltas should lie between source areas that provided siliciclastic sediment, and marine environments, such as those present in shallow basins of the shelf region of the central United States. In detailed studies of small areas, they identified channel sandstones, delta-front or prodelta mudstones, and mudstones, lacustrine deposits, and swamp deposits of the delta plain, in addition to marine deposits. These lithofacies were also interpreted from electric logs and well records and were mapped regionally in several successions over the Illinois basin and Midcontinent region.

Regional maps of the Illinois basin and Midcontinent (Wanless and others, 1970) show deltaic sandstones and channel deposits building from basin margins toward basin centers. The map of deposits below the Croweburg coal shows deltaic sandstones along and southeast of the outcrop belt in extreme southeastern Kansas and in a broad belt, 95–160 km wide, paralleling the Nemaha uplift. They depicted channel sandstones in both belts. More recent mapping has failed to identify deltas in the interval between the Croweburg coal and the Mineral coal, part of the next underlying regional marker interval in southeastern Kansas (Staton, 1987; Huffman, 1991), perhaps because recent mapping, using gamma-ray–neutron logs, is able to resolve depositional intervals more precisely or because the separate studies used different operating definitions of various lithologies.

Several other workers also interpreted the Cherokee Group, or parts of it, as deltaic deposits.

These studies adopted both a regional approach, involving study of the thickness, distribution, and character of sandstones, and a local examination of the stratigraphic succession. Murphy (1978), Harris (1984), and Brenner (1989), in particular, examined many outcrops or cores and found features that they attributed to delta-front, distributary, and delta-plain environments. Murphy (1978) and Harris (1984) showed regional cross sections that placed the facies they found in lateral juxtaposition into patterns that support their interpretations. Like the maps of Wanless and others (1970), Brenner's (1989) regional depiction of the Banzet interval (Verdigris Limestone to Excello Shale) at the top of the Cherokee Group over eastern Kansas and Ebanks and others' (1977) maps of the lower Cherokee Group in Bourbon, Crawford, and Cherokee Counties, Kansas, support introduction of sediment into the Forest City and Cherokee basins from marginal point sources, as rivers would be, and progradation of deposits into the basins in deltalike fashion.

Clearly, deltaic deposits have been identified in the Cherokee Group. However, none of the Cherokee Group reservoirs studied to date by students at the University of Kansas is related to nearby, contemporaneous delta-front or delta-plain deposits in a simple fashion. Furthermore, mapped ancient deltas are marginal to the Cherokee and Forest City basins, whereas upward-coarsening sedimentary successions can be traced across entire basins and from basin to basin with reasonable certainty (see Brenner, 1989, fig. 58). Existing deltaic interpretations do not convincingly describe the environment of deposition of either these upward-coarsening successions or sandstone reservoirs in the Cherokee Group.

Sequence Stratigraphy

The advent of sequence stratigraphy permits reinterpretation of the depositional framework of the Cherokee Group. Sequences are stratigraphic units defined by bounding unconformities or by conformable surfaces laterally equivalent to unconformities. Sequence boundaries develop because eustasy, tectonic activity, and sediment supply combine through time to change relative sea level, causing a history of submergence and emergence to develop in the sedimentary record (Van Wagoner and others, 1990).

The Cherokee Group includes a number of regional marker intervals that are described below. The top of the underclay unit in a regional marker interval is a sequence boundary, i.e., a surface of subaerial exposure. In places, the regional marker intervals and other sedimentary units have been removed by erosion during formation of valleys. The contact between the scoured sedimentary units below and the valley-filling deposits above is also a sequence boundary. Both types of boundaries represent times when relative sea level was low. Each sequence comprises the deposits between two successive sequence boundaries. Sequences are commonly quite thin in the Cherokee Group, a few meters to a few tens of meters thick. Valleys may reach depths of several tens of meters, so that sequences may be much thicker locally.

Sequence stratigraphy differs from the earlier styles of interpretation because it emphasizes boundaries that separate older and younger deposits, and relationships of lithologic bodies to those boundaries, at least as much as it emphasizes the distribution of lithologies within units. Sequences represent deposition as relative sea level shifted and sediment accumulated; therefore, different facies can replace each other at a point within a single sequence, as well as forming lateral and temporal equivalents. Interpretations based upon sequence stratigraphy and upon environment of deposition thus depict the same rocks at different scales. Single sequences of the Cherokee Group can comprise deposits of deltas, marine shelves, rivers, tidal estuaries, beaches, and other environments.

Three other features of sequences are worth mentioning; these ideas are fully and very nicely developed for siliciclastic rocks by Van Wagoner and others (1990) and are only summarized here. The three features are parasequences, systems tracts, and sequence sets. Parasequences are the building blocks of sequences. They are local units, a few meters thick, that are bounded by surfaces showing a marked shift from more landward facies below to more seaward facies above. Analysis of the Cherokee Group has not yet been conducted at the parasequence level. Within sequences, it is possible to recognize systems tracts, which are the lithologic expression of the different conditions of deposition that occur during the lowstand, transgression, highstand, and falling stage of relative sea level. Each systems tract has characteristic lithologic development or shows a characteristic pattern of spatial relationships among lithologic bodies. The pattern reflects the distribution of depositional environments and their preservation potential during accumulation of each systems tract. In general, sequences can be grouped into higher-order units called sequence sets, which represent longer-term fluctuations of relative sea level. Sequence sets, like sequences, can be subdivided into systems tracts reflecting deposition and distribution of environments during times of low, rising, high, and falling relative sea level.

NATURE OF CHEROKEE GROUP SEDIMENTARY ROCKS

Marker Intervals

Examination of gamma-ray–neutron logs from the Cherokee Group reveals a number of sets of sharp peaks on both sides of the logs (Fig. 3). Cor-

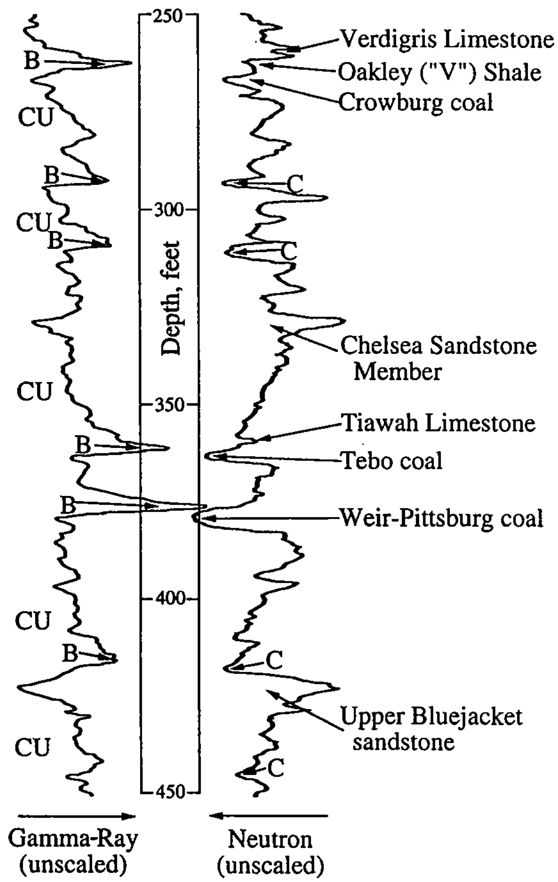

Figure 3. Part of log from the Jarboe-Lackey no. 1 OW, NW¼ sec. 30, T. 30 S., R. 21 E., Neosho County, Kansas. The illustration covers the Cabaniss Formation of the Cherokee Group, including several prominent marker intervals of underclay, coal (C), and dark-gray or black shale (B). Limestone beds, if present between coals and dark-gray or black shales, are too thin to register on the log. Upward-coarsening successions (CU) between marker intervals at coal and dark-gray or black shale horizons are well displayed in this part of the Cherokee.

relation establishes that these sets of peaks can be identified across eastern Kansas, into adjacent Missouri and Oklahoma, and into the Sedgwick basin of south-central Kansas, west of the Nemaha uplift (see log cross sections in Killen, 1986; Staton, 1987; and Huffman, 1991). Such sets of peaks are referred to as marker intervals. Complete marker intervals include an underclay, a coal bed that overlies it, a thin caprock (either a limestone or coarse sandstone), and dark-gray or black mudstone or shale (Fig. 4). In most places, one or more of the members of the marker interval set is missing, but the marker can be correlated on the basis of the other members.

Underclays are as much as 1 m thick, but commonly are thinner, and they have gradational lower contacts. They are very poorly indurated, slickensided, blocky clays with root marks, and generally they lack internal stratification. Coals are generally a few decimeters (1 dm = 0.1 m) thick, but may reach 5–6 dm in places or even 1.5 m locally. Both the bottom and top contacts of most coals are sharp. Caprocks are normally thin, up to 10 cm thick, but are noticeably fossiliferous. Limestone caprocks are normally argillaceous, fossiliferous limestones. Sandstone caprocks, which are rather rare, are coarse, fossiliferous sandstones. Caprocks grade up into dark-gray or black shales. Dark-gray or black shales are a few decimeters thick and grade into medium-gray shales that may pass into coarser lithologies of an overlying upward-coarsening succession (Fig. 4). Dark-gray or black shales may be fissile and phosphatic, or they may be massive in cores and blocky in outcrop. Marker horizons are easily recognized by distinctive responses of their component lithologies in gamma-ray–neutron logs (Figs. 3,5).

The exact number of marker intervals in the Cherokee Group is not known. Abernathy (1936) recognized 15 cyclothems in Cherokee and Crawford Counties. He found that underclay and dark mudstone or shale were present in 14 of the cyclothems, and coal was present in 13. Harris (1984), examining complete cores from the Cherokee Group in the same area, identified a number of other underclays with thin coal (or no coal) above them (Fig. 2). Subsequent investigation on my part has shown that dark-gray or black mudstones or shales are present above some underclays, with or without an intervening coal. Harris (1984) found that limestone caps about 50% of the coal occurrences in cores he studied. My experience is that a caprock is characteristic of some marker intervals, but is absent at all occurrences of others.

Marker intervals can be informally designated by the name of the associated coal (Tebo marker, Mineral marker, etc.). Where the coal has no formal name, the informal nomenclature of Harris (1984) (e.g., Bluejacket Bbj; Fig. 2) is useful. A few of the black shale beds in the marker intervals have formal names that were assigned in other areas. The Excello Shale lies at the top of the Cherokee Group; Brenner (1989) has assigned it to the Marmaton Group, because it has a presumed relationship with the overlying Blackjack Creek Limestone Member of the Fort Scott Limestone. The Oakley, or Mecca Quarry, shale (Coveney and others, 1987; Brenner 1989), which lies below the Verdigris (or Ardmore) Limestone and above the Croweburg coal, has been informally designated the "V" shale by Schlinsog and Angino (1983) in Kansas.

Interpretation

The following is an operational scenario for the formation of the marker intervals and their sequence-stratigraphic significance. Underclays of

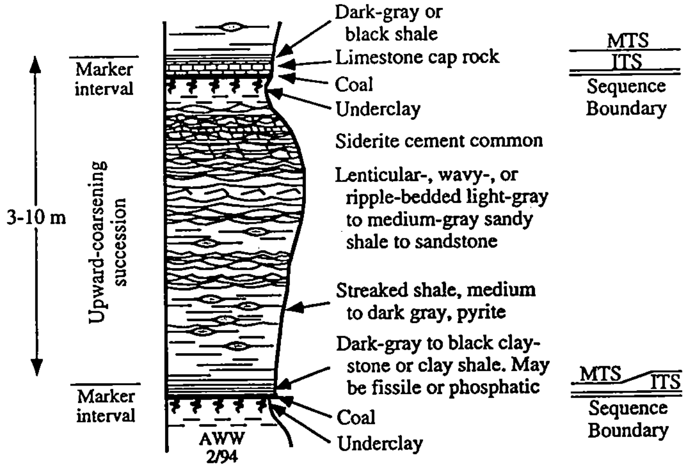

Figure 4. Schematic section showing marker intervals and upward-coarsening succession in the Cherokee Group of southeastern Kansas. Sequence boundaries lie at the contact of the coal and underclay. ITS = initial transgression surface, MTS = maximum transgression surface.

marker intervals, which contain root marks and appear to be altered equivalents of underlying sedimentary deposits, are interpreted as paleosols and represent subaerial exposure. Overlying coals formed as sea level, and therefore the local water table, rose at the beginning of a transgression, permitting peat to accumulate. The caprock represents lag deposits left on a ravinement surface formed when the shoreface passed. The dark-gray or black shales are marine shales that represent a period of rapidly rising or high sea level, when a stratified water body developed, anoxic conditions impinged on the bottom, and terrigenous sediment was trapped in estuaries rather than being delivered to the shelf. In sequence-stratigraphic terms, the sequence boundary lies at the top of the underclay; the initial transgression surface is the ravinement surface, which may be overlain by either a caprock or a dark-gray to black shale; and the surface of maximum transgression lies in the upper part of the dark-gray shale or in the overlying medium-gray shale.

Lithology of Sequences

Marker intervals make up only a small fraction of the Cherokee Group. The remainder consists, for the most part, of three basic lithologic successions: upward-coarsening successions that grade from shale to fine sandstone; thick sandstones, with associated conglomerates and shales, that generally fine upward; and thick successions of shale that contain little siltstone or sandstone and few primary sedimentary structures.

Upward-Coarsening Successions

Upward-coarsening successions are the next most obvious feature of logs of the Cherokee Group rocks, after the sharp spikes associated with the marker intervals (Figs. 3–5). These are particularly well developed in the middle part of the Cabaniss Formation (upper Cherokee Group) in southeastern Kansas (Murphy, 1978; Staton, 1987; Huffman, 1991) (Figs. 3,5) and in the upper part of that formation in northeastern Kansas (Brenner, 1989). Similar upward-coarsening successions are present in the younger Missourian Pleasanton Group (Late Pennsylvanian) in the Kansas City area of Missouri and Kansas.

Upward-coarsening successions are 3–10 m thick and form parts of sequences that can be traced from south-central Kansas to at least the Kansas City area, across parts of three shelf basins and two intervening highs (Fig. 1) (Killen, 1986; Staton, 1987; Huffman, 1991). Complete upward-coarsening successions in the Cherokee Group include the dark-gray to black mudstone or shale of the marker intervals at the base (Fig. 4). They grade through streaked shale or lenticular- and wavy-bedded mudstone, siltstone, and sandstone. Infrequently, they have rippled or even cross-bedded sandstone at the top. The thickness of each of the component lithologies ranges from ≤1 m to virtually the entire thickness of the succession, i.e., as much as about 10 m thick.

Features of the upward-coarsening successions of the Cherokee Group include abundant macerated plant debris on bedding surfaces and sparse burrows. Commonly, the top of the upward-coarsening succession, or of a mudrock interval that gradationally overlies it, is a well-developed underclay, which is the base of the overlying marker interval (Fig. 4). Parts of upward-coarsening successions just below the underclay are commonly light gray, with a bleached appearance, and are tightly cemented. Siderite is common in such rocks in the form of small red blebs, locally referred to as buckshot or birdshot siderite. In the Nelson lease in the Savonburg NE oil field in southeastern Allen County, Kansas, dense cementation and an abundance of siderite in siltstones at the top of upward-coarsening successions make them resemble sandstones on gamma-ray–neutron logs (see dark-blue marker in well RW-9 in Fig. 5).

Discussion

Upward-coarsening successions from marine shale to siltstone or sandstone, with underclay and coal at the top, might form in progradational shoreline environments such as prograding deltas or siliciclastic shoreface-foreshore successions (see

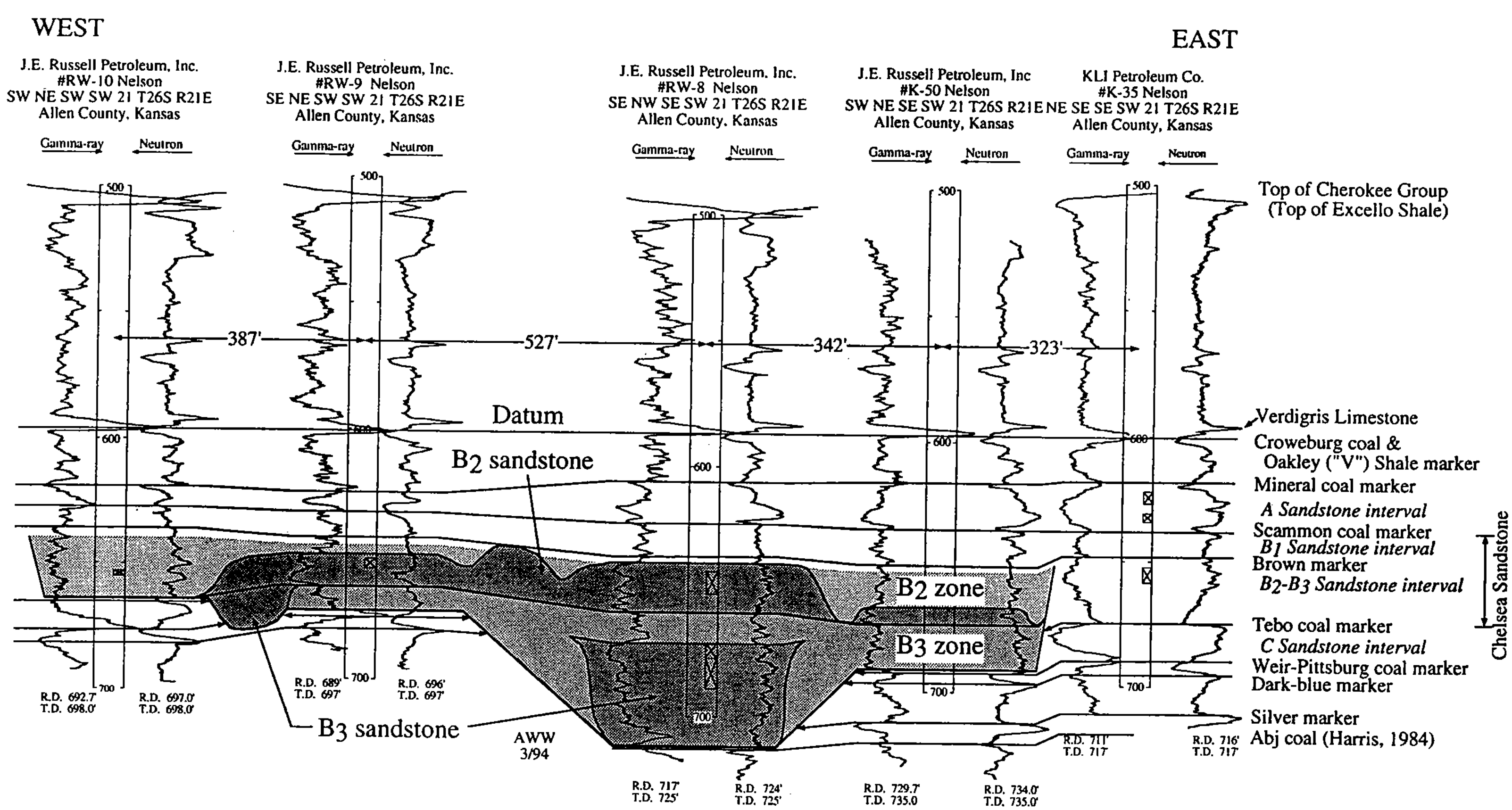

Figure 5. Log cross-section of the valley-fill succession in the Chelsea Sandstone Member of the Cabaniss Formation, Nelson Lease, Savonburg NE oil field. Location of wells shown in Figure 11. Log pattern of regional marker intervals nicely shown in these logs. Truncation of regional marker intervals (Tebo and Weir-Pittsburg markers) and field-wide markers (dark-blue marker and silver marker) indicates the position and extent of scour. Within valley fill, B_2 and B_3 zones include sandstone, mixed lithology, and shale. Patterns of thickness of sandstone are based partly upon information from wells off the line of section. Well K-35 shows upward-coarsening successions, as does well RW-10, below the B_2 zone. Interval in all logs above the Verdigris Limestone shows the shale that characterizes the top of the Cabaniss Formation in southeastern Kansas. Compare logs of well RW-9 with description of core in Figure 8A.

Murphy, 1978; Brenner, 1989). If these upward-coarsening successions formed in prograding deltas or shoreface-foreshore environments, the coal would represent swamps developed on the delta plain or strand plain, or it could be related to subsidence of the area as sedimentation slowed or stopped, e.g., during the destructional phase of deposits of delta lobes.

Upward-coarsening successions may also represent regressive successions, where a drop of relative sea level, as opposed to accumulating sediment, causes environments to shift in an offshore direction and eventually subaerial conditions to develop. In regressive successions, the environment of deposition may have been a wave-dominated shoreface and strand plain, tidal shoreface and tidal flat, or delta, but the shift of environments was at least partially in response to an allocyclic change of relative sea level, not entirely the result of autocyclic constructional processes. If relative sea-level change is the main driving force in determining the character and rate of accumulation of sediment, the coal bed is part of the next sequence.

With the exception of work by Murphy (1978) and Harris (1984), little detailed attention has been paid to the question of origin of upward-coarsening successions in the Cherokee Group, and practically no studies have been done since the recent spate of work on tidal environments has greatly improved understanding of characteristic features of sediments deposited in them (Smith and others, 1991) and the importance of sequence boundaries in interpreting siliciclastic successions has been pointed out (Van Wagoner and others, 1990). While the very great lateral extent of sequences in the Cherokee Group argues that sea-level change, not accumulation of sediment, is the major cause of lateral shift of environments, actual interpretation of most upward-coarsening successions in the Cherokee Group awaits their careful description and analysis.

Some Varieties of Upward-Coarsening Successions

Harris (1984) described lateral relations in upward-coarsening successions along the outcrop belt of the Cherokee Group in southeastern Kansas (Bourbon, Crawford, and Cherokee Counties) and adjacent Missouri and Oklahoma. These successions have a high percentage of siltstone and very fine sandstone, which is generally concentrated near the top of the interval. Over distances of some 50 km, lithology ranges from mostly cross-bedded sandstone to nearly all mudstone, and sequences include significant amounts of wavy-bedded siltstone and flaser-bedded to rippled sandstone. Some intervals contain numerous graded beds several centimeters thick. These intervals are associated with wavy-bedded siltstones. Harris also found thick but lenticular beds of rippled and flaser-bedded sandstone.

Harris (1984) concluded that these deposits formed in a suite of deltaic environments. His maps of sandstone thickness support this interpretation; the sandstone accumulations are lobate and marginal to the Cherokee basin. He assigned thick sandstones to deposition in distributaries, and the upward-coarsening successions to a delta-front environment. The thin, graded beds may have been deposits of delta-front turbidites or storms.

In a small oil field in the Grandview area of Jackson County, Missouri, just south of Kansas City, I encountered a distinct variety of upward-coarsening succession. Here, in the upper Bluejacket sandstone (*sensu* Ebanks, 1979), a single upward-coarsening succession consists of shale, streaked and lenticular-bedded shale, upward-fining interbeds of sandstone and shale, and cross-bedded or rippled, very fine sandstone. The upward-fining interbeds of sandstone and shale are centimeter- to decimeter-scale, upward-fining successions from parallel-bedded, very fine sandstone, to wavy-bedded sandstone and siltstone, to shale. These thin, upward-fining successions have sharp bases and gradational tops. The overall sequence is capped by an underclay and very thin coal bed and totals ~3 m thick. In one well, the upward-coarsening succession is not present, and a shale bed of comparable thickness to the upward-coarsening succession overlies a thin sandstone bed with intraclasts.

The upward-coarsening nature of this deposit and the associated shale-filled channel led to the conclusion that this succession formed in a delta-front environment and the shale filled a small distributary channel, overlying a small lag deposit. This deposit may represent a bay-filling crevasse between distributaries, or the front of a shallow-water delta. Episodic deposition by floods or storms prevailed, creating the decimeter-scale upward-fining successions of the delta front.

Channel-Filling Sequences

As will become apparent in the following descriptions, many oil reservoirs in the Cherokee Group are in sandstones that are parts of upward-fining successions. Very fine to medium sandstones form the most obvious part of upward-fining sequences (Figs. 6–8). Such successions are commonly conglomeratic at the base and in zones higher in the succession.

Conglomerates, if present, are generally <1 m thick, and most clasts are concretions or intraclasts of shale. Clasts are most commonly of pebble size, but larger ones, of cobble and boulder size, are present and may be mistaken for shale beds in cores. Coalified wood is a common feature. Only close to the Nemaha uplift, such as in northwestern Greenwood County, do conglomeratic beds contain abundant granules and small pebbles of polycrystalline quartz. Conglomeratic beds may be at the base of a thick sandstone interval (Fig. 8), may be found within them (where they overlie internal scour surfaces and appear to mark the lower boundary of stages of the fill of the channel (Fig. 6B)), or may overlie a scour surface but be overlain in turn by interbeds of shale, siltstone, and sandstone (Fig. 7).

The bulk of each sandstone is very fine to fine or, less commonly, medium; it may be structureless, plane laminated, or cross-bedded. Such beds are overlain by rippled sandstones, then interbeds of sandstone, siltstone, and shale, and ultimately by shales, underclays, or coals. On gamma-ray–neutron logs, sandstone beds, with associated intraclast conglomerates, may appear to be several meters to several tens of meters thick. However, cores normally show that beds are divided by scour

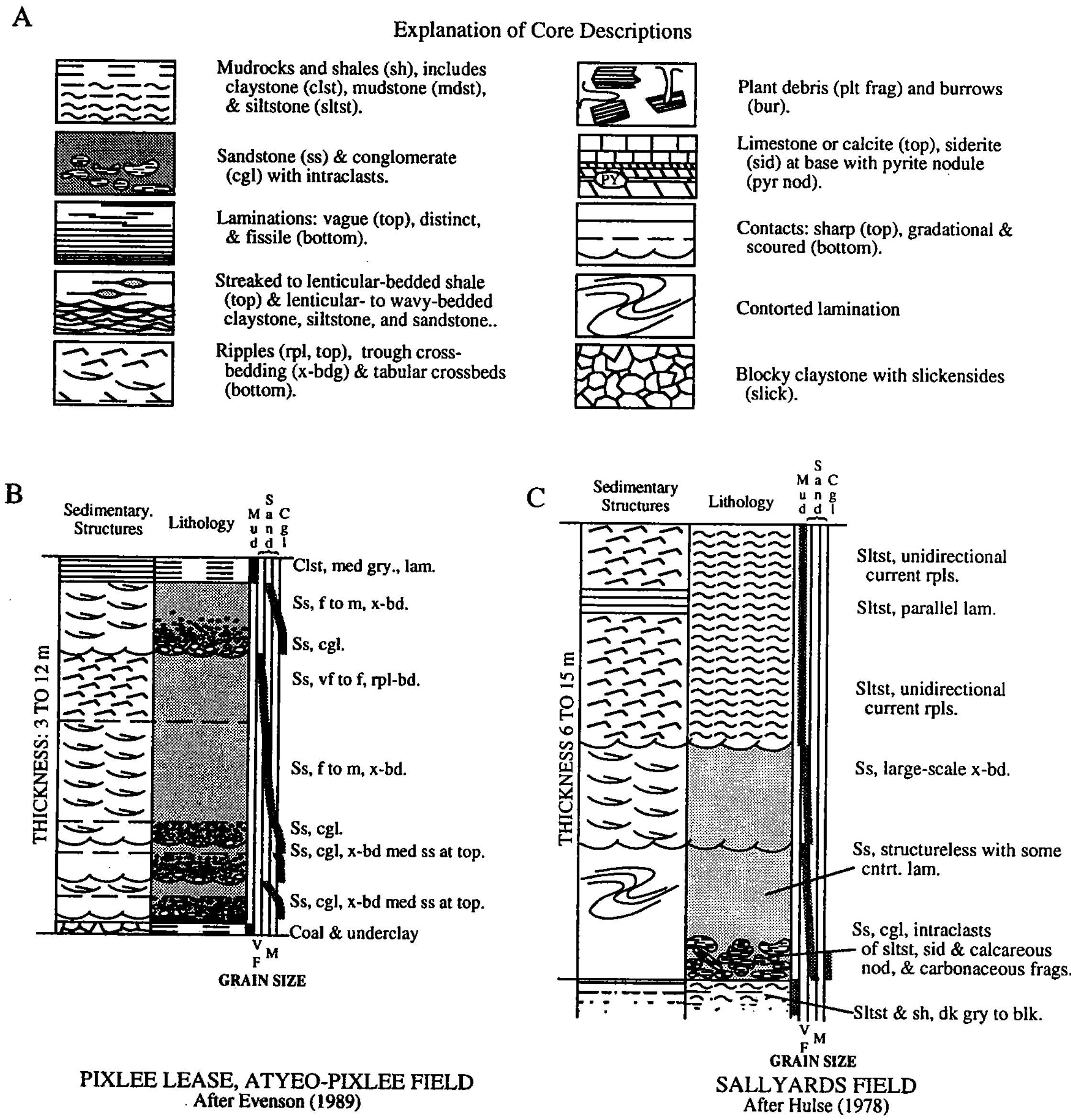

Figure 6. (A) Symbols used in graphic core descriptions in Figures 6B and 6C, 7, and 8. Abbreviations here and in other figures from Swanson (1981). (B, C) Lithologic successions from the Pixlee Lease (Evenson, 1989) and the Sallyards field (Hulse, 1978). These fields are part of the shoestring sandstone trend of Greenwood County, Kansas, and are listed as fluvial-dominated deltaic reservoirs in the TORIS database. Described features of the sandstones are consistent with a fluvial origin, but a connection with a nearby, contemporaneous delta is not demonstrated.

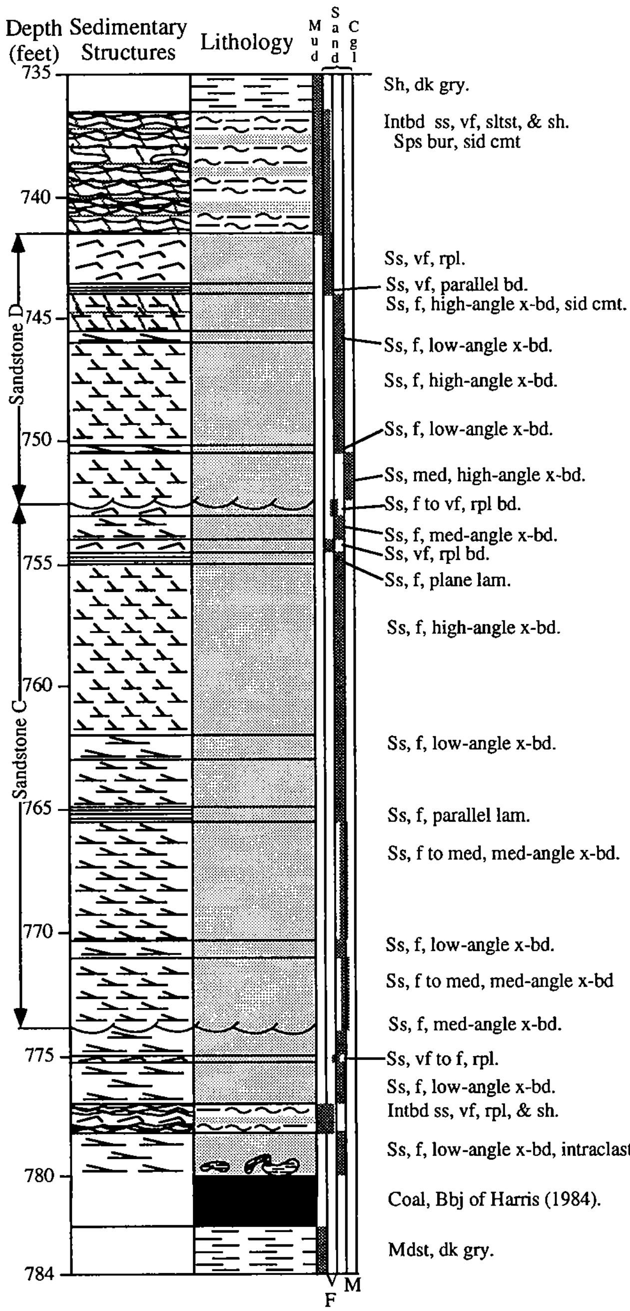

Figure 7. Core description from the Colt no. 5A Harvey from the KB lease in the Bronson-Xenia field, Allen County, Kansas (modified from Rofheart, 1985). This core shows a character that is consistent with a fluvial origin for the reservoir sandstones. It includes parts of two of the four sandstone bodies that Rofheart recognized in this field. Symbols in Figure 6.

surfaces into intervals a few meters to about 10 m thick (Figs. 6,7). Each such interval may begin with coarser sediment than is present at the top of the next lower interval and show all or, more likely, part of a upward-fining succession.

Sandstone bodies range widely in size. Although most upward-fining successions are about 10–15 m thick, some are much thicker, reaching 50 m (Staton, 1987; Huffman, 1991). The bodies are decidedly elongate; they extend over distances ranging from a few kilometers or tens of kilometers, as in the case of shoestring sandstones of Greenwood County or the McCune West oil field (Fig. 9) described below, to distances of hundreds of kilometers for the Bluejacket sandstone channel fill, which extends from Franklin County to Montgomery County, Kansas, and well into Oklahoma (Visher and others, 1971; Staton, 1987; Huffman, 1991). Sandstone bodies range in width from a few hundred meters, in the case of the Greenwood County shoestrings, and others described below (Figs. 5,9,10), to the 20-km-wide swath of the Bluejacket sandstone channel fill.

Upward-fining successions overlie surfaces that truncate underlying regional marker intervals and are younger than laterally adjacent upward-coarsening successions (Figs. 5,9–11). Thus the sandstones are valley fills. Where relationships can be rigorously established, sandstone forms only part of the valley fill (Fig. 5). The remainder of the fill includes a mixed lithology and shale. Mixed-lithology deposits consist of decimeter-scale alternations of rippled sandstone; lenticular- or wavy-bedded sandstone, siltstone, and shale; and streaked, laminated, or apparently structureless shale (Fig. 8B). Mixed-lithology intervals are most common in the upper or lateral parts of valley fills. They may also overlie thin intervals of intraclast conglomerate that are in contact with the underlying scour surface. Contacts between these different lithologies are gradational. Sedimentary units are sparsely burrowed. Shale beds may form the uppermost part of the valley fill (see below).

Discussion

In sequence-stratigraphic terms, the valleys were cut during periods when sea level dropped to the point that rivers needed to incise their valleys (Van Wagoner and others, 1990). The sediment filling the valleys included material eroded farther upstream during valley cutting and then deposited at lowstand and material accumulated during the initial stages of the rise in sea level, when raised base level prevented seaward transportation of sediment.

Many upward-fining successions in the Cherokee Group have been interpreted as deposits of fluvial environments, either rivers or distributaries of deltas (Harris, 1984; Bouquet, 1984; Rofheart, 1985). Fluvial deposition is supported by a linear trend of greatest thickness, large-scale cross-beds that do not show any features of tidal or wave deposition, internal subdivision into successions a few meters thick, and assembly into thick beds that indicate deposition by unidirectional currents.

Modern valley-fill deposits commonly have fluvial and estuarine parts (Allen, 1991), so Cherokee Group valley fills might also be expected to have them. Modern estuaries are frequently the site of deposition of sediment by tidal currents. Unfortunately, criteria for recognizing tidal deposits became widely known only after much of the description of Cherokee sandstones was carried out, so investigators may have missed key details. Some features of the mixed-lithology parts of the valley-fill succession of the Nelson lease in the Savonburg NE oil field are possibly best interpreted as the result of deposition by tidal currents (see below). Thicker bodies of sandstone on the Nelson lease, including some excellent reservoir beds, are intimately associated with these deposits of mixed lithology (Figs. 5,8), suggesting that they are the result of deposition by tidal currents as well.

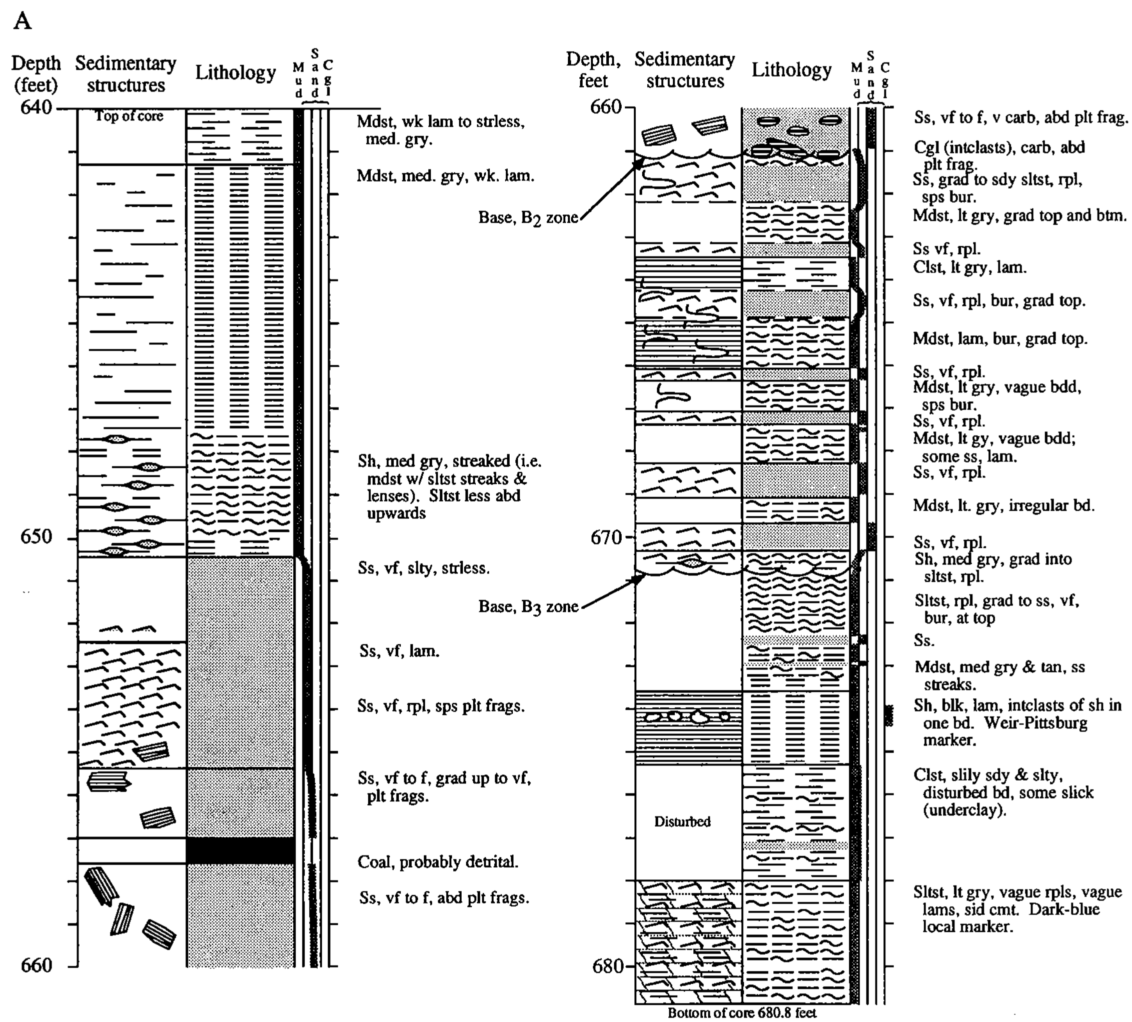

Figure 8. Descriptions of two cores from the Nelson Lease, Savonburg NE oil field. (A) Core RW-9 (see Fig. 5 for log) includes mixed lithology in zone B_3 and sandstone overlain by shale in zone B_2. The base of the core includes a marker interval correlated to the Weir-Pittsburg marker and part of the underlying upward-coarsening succession (labeled on figure as dark-blue local marker), which has extensive development of siderite giving its log character a sandstonelike appearance. (B) Core O-1, which is from near the axis of the Chelsea paleovalley. Erosion cut down to the level of the top of a prominent fieldwide marker, through the Tebo and Weir-Pittsburg markers. The valley fill includes sandstone of good reservoir quality, which overlies intraclast conglomerate in the B_3 zone, and a thick sandstone with a shale interval above it in the B_2 zone. For the log of a comparable well near the valley axis, see Figure 5, well RW-8.

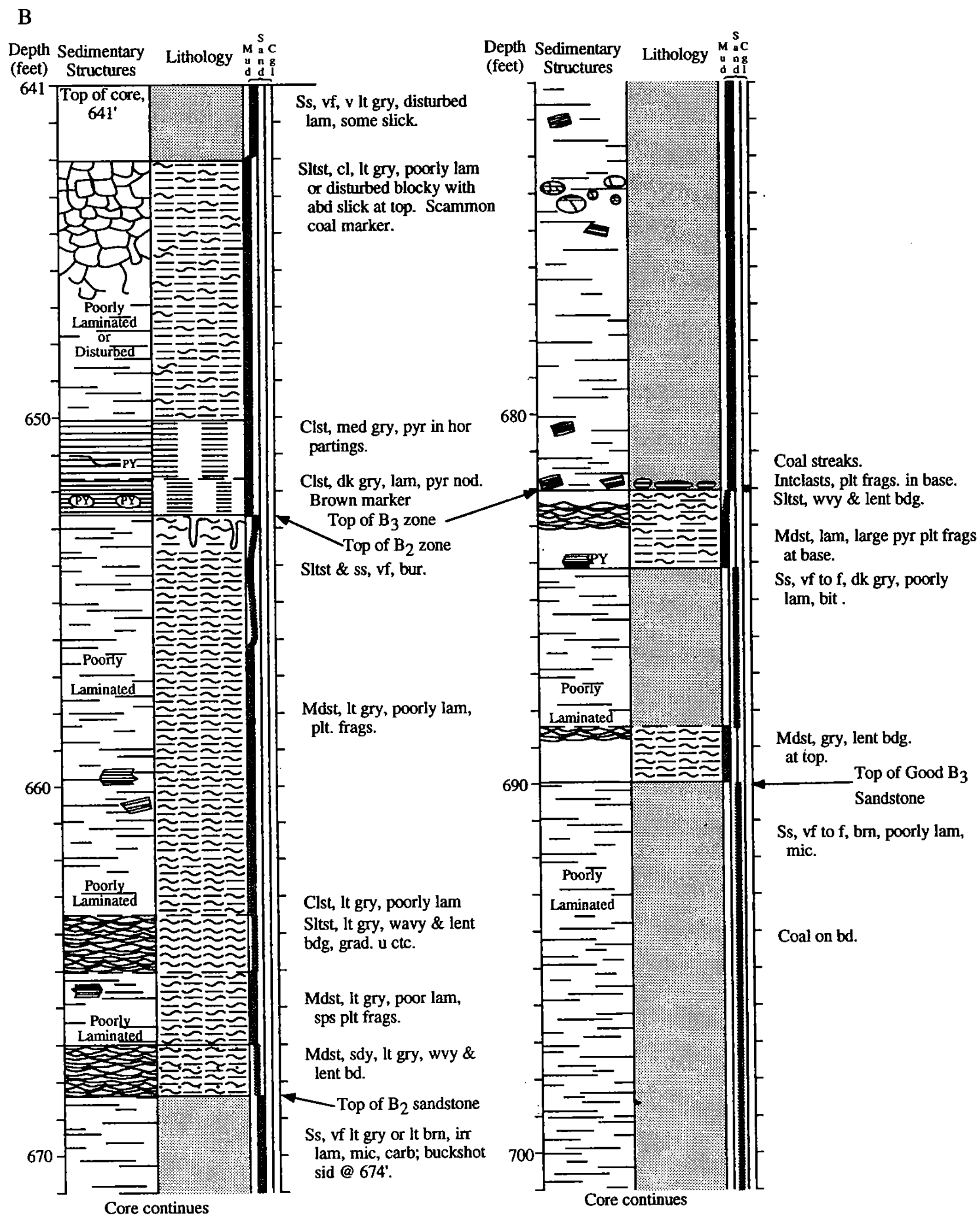

Figure 8, continued.

B, continued

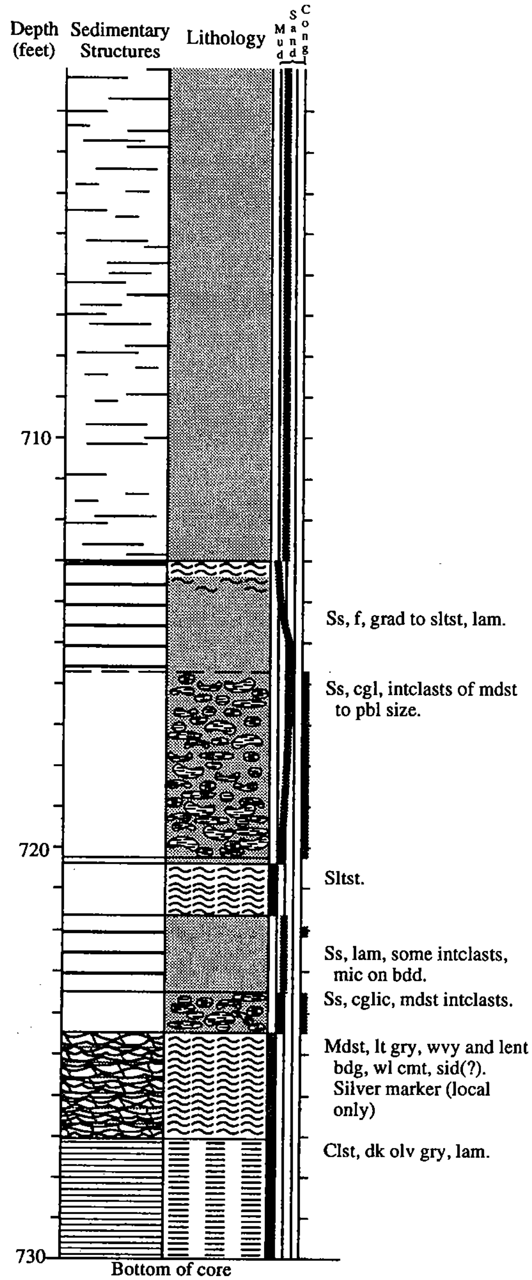

Figure 8, continued.

Thick Shale Intervals in the Cherokee Group

Thick shales in the Cherokee Group have not attracted as much attention as the sandstones and coal beds. There appear to be several kinds of shale in the group. One is found in the upper Cherokee Group, above the Verdigris and the Breezy Hill Limestones in southern Kansas (Figs. 2,5,9), and it is described extensively by Brenner (1989). This interval consists of nondescript mudstone with little indication of bedding, lamination, changes of grain size, or other features. Harris (1984) reported plant fragments in this interval in the P&M no. 20 core in sec. 8, T. 32 S., R. 22 E., in Cherokee County. The interval does include two coal beds, the Bevier coal and the Iron Post coal (Staton, 1987). It is coarser at the top, just below the Breezy Hill Limestone (Figs. 2,5). Brenner (1989) concluded that this shale succession, which is as much as ~30 m thick, is a prodeltaic shale.

Harris (1984) described mudstone-dominated successions in the lower Krebs Formation (Fig. 2, left column) along a 50-km-long transect in southeasternmost Kansas. Successions grade upward from dark-gray shale to lenticular-bedded shale and even wavy-bedded siltstone and pass into underclays at the top, but shale is the dominant lithology. Such beds contain a few fossil brachiopods and echinoderms as well as sparse burrows. They contain scattered plant remains, numerous concretions of pyrite, and some concretions of siderite.

Harris (1984) attributed these successions to deposition in nearshore bays on delta plains or between delta lobes. He concluded that the environment was restricted during deposition of the dark-gray shales. This interpretation is consistent with the lateral relationships of shale-rich successions that he attributed to deltaic deposition, including delta-front and distributary deposits. Dark-gray shales may also be lithified equivalents of dark muds deposited in a transgressive systems tract of a sequence set, i.e., deposited on marine shelves away from sites of detrital influx. The transgressive systems tract forms as relative sea level rises (Van Wagoner and others, 1990). Further investigation is necessary to analyze these possibilities.

A shale bed as much as 5 m thick occurs below the Scammon coal in the Nelson lease of the Savonburg NE oil field in Allen County (Figs. 5,8). It overlies deposits interpreted herein as estuarine valley-fill deposits that were deposited by tidal processes. This particular bed consists of medium-gray shale that is weakly laminated and includes some lenses of silt. The upper part is structureless or is pervasively bioturbated. Individual burrows are visible only in the very lowest part of the shale bed. The shale bed grades upward into the underclay beneath the Scammon coal. This shale bed is the final clay filling of an estuary that is described below. It is a kind of shale that has not been previously described from the Cherokee Group.

DESCRIPTIONS OF CHEROKEE OIL FIELDS

Students, other workers, and I have examined cores, well logs, and other information from several oil fields in the Cherokee Group in southeastern Kansas (Hulse, 1978; Reinholtz, 1982; Bou-

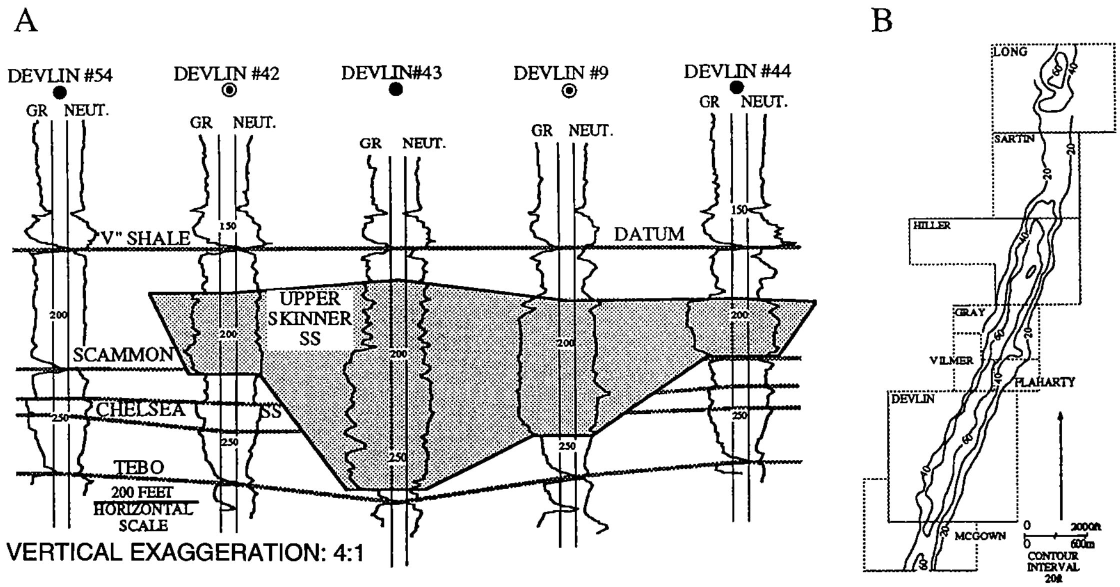

Figure 9. Cross section and net-sandstone isopach map of the McCune West (or Strauss) oil field, Crawford, Neosho, and Labette Counties, Kansas (modified from Bouquet, 1984). (A) Channel clearly cuts through older deposits to depths of 80 ft (~25 m). Sequence boundary lies at base of channel fill. (B) Isopach map shows the elongate (~6 km), narrow character of sandstone body. Sparse data define sandstone body over a distance of 4 km to the south (Bouquet, 1984). Polygons in B show boundaries and names of leases.

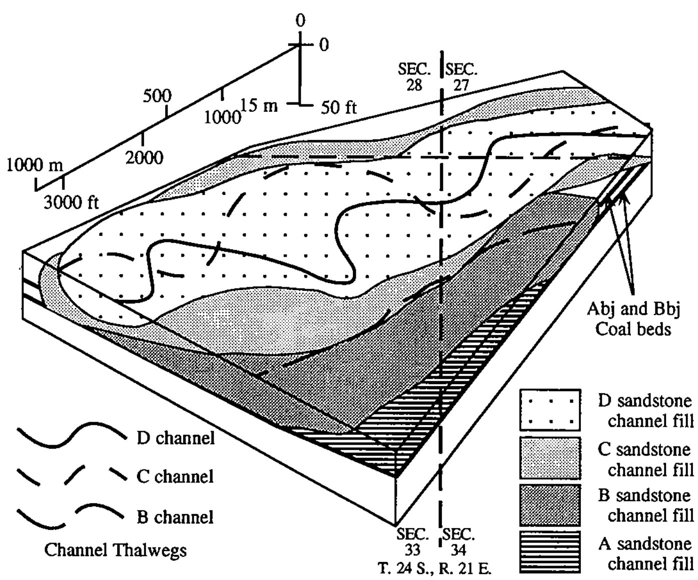

Figure 10. Block diagram of nested sandstone bodies in the KB lease of the Bronson-Xenia field, Allen County, Kansas (modified from Rofheart, 1985). The sandstone fills a valley that was cut through the Abj coal into the Bbj coal (bj = Bluejacket). The thalweg of sandstone A is presumed to lie southeast of the mapped area. If so, it and sandstones B and C indicate a gradual westward shift of deposition, whereas sandstone D shows stacking over sandstone C.

quet, 1984; Rofheart, 1985; Chesser, 1987; Evenson, 1989; D. G. Stewart, personal communication); some of these oil fields are listed in the TORIS database as being the result of deposition in river-dominated deltas. Summary descriptions of several examples follow. Where clear criteria exist, oil production in most Cherokee fields is from fluvial or possibly tidal deposits in valley-fill successions above an erosional surface cut through underlying marker beds. Although fluvial channels may have been distributaries of deltas that formed in erosional valleys, no clear relationship with contemporaneous delta-plain or delta-front deposits was observed.

Shoestring Sandstones of Greenwood County

The Pixlee lease, which is an extension of the Atyeo-Pixlee field, and the Sallyards field show the characteristics of two reservoirs among many in the shoestring trends of Greenwood County (Bass, 1934; Hulse, 1978; Evenson, 1989). The sandstones are developed below the Weir-Pittsburg coal and are assigned to the informal Bartlesville sandstone. However, re-

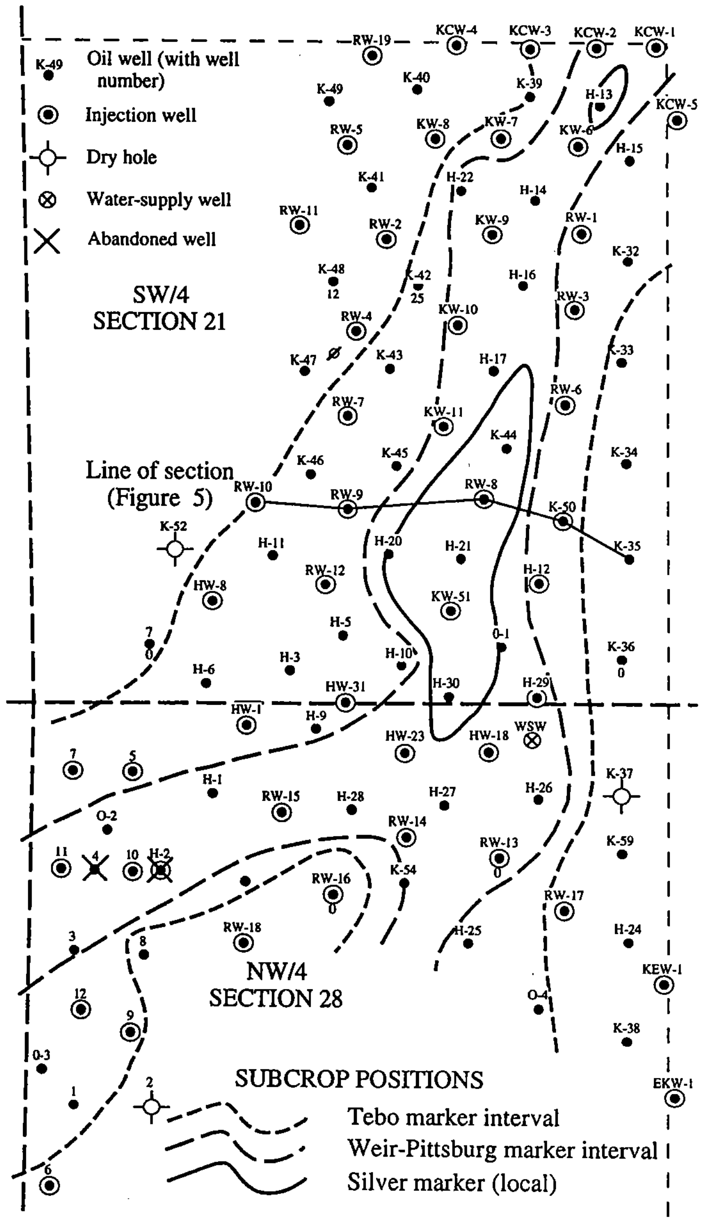

Figure 11. Map of the Nelson leases, Savonburg NE field, T. 26 S., R. 21 W., Allen County, Kansas, showing marker intervals subcropping beneath the valley-filling succession. Total depth of cut exceeds 15 m, and deepest part of valley is 100 to 200 m wide.

gional marker intervals of the Krebs Formation of eastern Kansas are not easily correlated into the area, and the exact stratigraphic level of the reservoir sandstones is not known. This description is summarized from the work of Evenson (1989) and Hulse (1978).

The reservoir sandstone on the Pixlee lease totals as much as 10 m thick and consists of upward-fining cycles, each a few meters thick (Fig. 6). Conglomeratic sandstone overlies the scour surface at the base of all 17 of the upward-fining cycles that Evenson (1989) described in five cores from the field. Conglomeratic sandstone intervals range from 5 to 76 cm thick. Granules and pebbles in this lithofacies consist of polycrystalline quartz, chert fragments, and argillaceous rock fragments. Plant fragments are common. Clasts are set in a matrix of medium- to coarse sandstone.

Medium- to coarse, cross-bedded sandstone makes up ~71% of cores from this field. This lithology occurs in beds 15 cm to 3.8 m thick, consisting of cross-strata 0.5–5 cm thick in sets as much as 1 m thick. Thickness of beds and of sets decreases upward through the reservoir sandstone. Coarse, cross-bedded sandstone gradationally overlies conglomeratic sandstone. Coarse sandstone may grade into rippled sandstone or may be sharply overlain by either mudstones or conglomerate. Rippled sandstones in cores from the Pixlee lease are fine to very fine and make up only about 7% of the reservoir rock. Ripples occur in beds (cosets) as much as ~50 cm thick. Ripple-bedded intervals are overlain either by scour surfaces and conglomeratic sandstone or by mudrocks (Evenson, 1989).

Evenson (1989) concluded that reservoir sandstone in the Pixlee Lease formed in a fluvial channel. He pointed out that the sandstone is anomalously coarse among Cherokee Group reservoirs and that it contains coarse sand grains, granules, and pebbles of quartz and chert, which are rare or absent in reservoir rocks elsewhere in the Cherokee Group. It differs in another respect as well: upward-fining successions here do not have well-developed mudrock components. The Pixlee lease is close to the Nemaha uplift, a likely source of sediment. Its reservoir rock may have been deposited in a river that had highly variable discharge or a more braided channel pattern than the rivers that formed other Cherokee Group reservoirs. A lack of information about surrounding lithofacies prevents differentiating between a distributary and an upstream fluvial environment.

The Sallyards field lies along the major trend of shoestring sandstones in Greenwood County and was one of the first to be discovered. Hulse (1978) found that the reservoir consists of a upward-fining succession of sandstone, with conglomeratic sandstones at the base and rippled, very fine sandstones at the top (Fig. 6). He concluded that the reservoir sandstone formed in a fluvial environment.

KB Lease, Bronson-Xenia Field

The KB lease, in the Bronson-Xenia field of eastern Allen County, Kansas, produces from sandstone in the upper Bartlesville, below the Weir-Pittsburg coal and above the Bluejacket Bbj coal (Figs. 7,10; Rofheart, 1985; unit names from Ebanks, 1979, and Harris, 1984). The reservoir in this area consists of four units of upward-fining sandstone, which form a nested sandstone body as much as 15 m thick and some 1,200 m wide at its widest point. Individual sandstone bodies range from 6 to 12 m thick at their thickest points, but erosional relationships prevent assessing true original thickness of individual channel bodies at most points. Rofheart (1985) provided a description of the reservoir.

Internally, sandstone units consist of (1) structureless, medium sandstone with pebble- to cobble-sized intraclasts and fragments of coalified wood; (2) low- to high-angle cross-bedded, fine sandstone; (3) horizontally bedded, very fine to fine sandstone; (4) current-ripple–bedded, very fine sandstone; (5) burrowed, interbedded, or lenticular-bedded sandstone, siltstone, and black shale; and (6) dark-gray mudstone with common siderite concretions (Fig. 7).

Rofheart (1985) concluded that the sand bodies were deposited by a meandering river that had eroded through slightly older peats and marine deposits. His main reasons for coming to this conclusion were the gradual upward decrease in grain size and scale of sedimentary structures, the indications of deposition by unidirectional currents, and the lack of marine indicators. He did not mention the sinuous channel patterns that he mapped, but they are very suggestive of a meandering channel. Rofheart (1985) suggested that the four separate channel fills would act as separate reservoirs because the shale beds and channel lag deposits at the base of each and the shale beds that were present at their tops in some wells would combine to isolate the porous, permeable sandstones of each channel fill from the others. This effect would be enhanced by compaction of soft intraclasts in conglomeratic beds and the presence of diagenetic chlorite. The operator, M. C. Colt, reported multiple gas-oil and oil-water contacts in the field (Rofheart, 1985), which would be likely in a compartmentalized reservoir.

McCune West Field

The McCune West, or Strauss, field produces from a shoestring sandstone that is at least 10 km long, but <500 m wide in Crawford, Labette, and Neosho Counties (Figs. 1,9) (Bouquet, 1984; Chesser, 1987; D. G. Stewart, personal communication). The productive horizon, at a depth of only ~60 m, lies just below the Croweburg coal and "V" shale and is younger than the Mineral coal. The position of the sandstone relative to the less-continuous Fleming and Robinson Branch coals is not clear. The producing sandstone overlies a scour surface that cuts the Mineral and Scammon markers, the Chelsea Sandstone, and even reaches the Tebo marker (Figs. 2,9), an incision of as much as 30 m.

The producing sandstone ranges to as much as 27 m thick (Fig. 9) and consists of stacked, upward-fining sequences 2–5 m thick. Complete upward-fining sequences begin with a conglomerate or conglomeratic sandstone, in which the clasts are intraclasts of mudstone or concretions. Coalified wood is common. The most abundant lithology is a cross-bedded or structureless sandstone that gradationally overlies conglomerate or rests directly on a scour surface. Cross-bedded or structureless sandstones pass upward into rippled sandstone and then into interlaminated sandstone, siltstone, and mudstone. Burrows are a widespread, but not common, structure in finer lithologies. A scour surface commonly separates the base of each cycle from the youngest-preserved beds of the underlying cycle. Up to six such cycles may be visible in the core from a single well in the field (description in Bouquet, 1984).

Bouquet (1984) concluded that the producing sandstone in the McCune West field had fluvial characteristics. He attributed the multiple incomplete upward-fining successions in the channel-filling succession to flood events, rather than to deposition in a meandering channel. He also pointed out the linear nature of the sandstone (Fig. 9B) and concluded that it formed in the distributary channel of a delta. He reported that the channel cut down into older upward-coarsening successions, such as the Chelsea Sandstone between the Scammon and Tebo coals (Fig. 9A). He interpreted the upward-coarsening successions as bay-fill deposits of prograding lobes of the delta.

Bouquet's (1984) conclusion that the reservoir sandstone in the McCune West oil field formed in the distributary channel of a delta is not entirely convincing. Whereas deposition of the upward-coarsening succession in the Chelsea Sandstone might be attributed to a prograding delta, it is probably much older than the reservoir sandstone. The upward-coarsening successions Bouquet described above the Scammon marker are not common and are not clearly the same age as the reservoir sandstone. If deltaic facies are temporally equivalent to the reservoir sandstone, they would lie between the Mineral and Croweburg coals. That interval does not generally have the upward-coarsening character of a delta-front or distributary-mouth-bar succession, either in the field area or generally (Fig. 9A) (Staton, 1987; Huffman, 1991), although it includes two discontinuous coal beds, the Robinson Branch and Fleming coals (Harris, 1984).

A conclusion that the reservoir is in a valley-filling sandstone related to a rise in sea level is equally defensible from current knowledge. In any case, the reservoir sandstones were formed by unidirectional flow, as in a river channel. Whether that fluvial channel was a distributary deposit or formed upstream in a fluvial channel not associated with a delta, its character for exploration and production is fluvial, not deltaic.

Nelson Lease of the Savonburg NE Oil Field

Production in the Nelson lease in the Savonburg NE field is clearly from a valley-filling succession in the Chelsea Sandstone Member of the Cabaniss Formation; the Chelsea is younger than the Tebo coal and older than the Scammon coal (Figs. 1,2). The scour surface cuts >12 m below the Tebo coal, into the Bluejacket Abj coal bed in places (Figs. 5,11). The overall valley is narrow, <600 m wide, with a deep trench that is <200 m wide in the eastern part. The valley-filling succession is divisible into an upper and a lower part, separated by a persistent scour surface. These are informally called the B_2 and B_3 zones (Figs. 5;8A,B).

Sandstone beds in the two zones are subtly different. Sandstones in the lower, B_3 zone are generally structureless and partially fill the deepest scour of the valley (Figs. 5,8B,11). This rock is an excellent reservoir, despite being very fine sandstone, and is as much as 11 m thick. Mixed lithologies form most of the rest of the B_3 zone (Fig. 8A). The western part of the lower unit is lithologically the same as the eastern part, but is thinner and less productive (Fig. 5). Above a persistent scour surface, conglomerate at the base of the B_2 zone is overlain by either successions of mixed lithology or by rippled sandstone (Figs. 5;8A,B). B_2 sandstones have lower oil saturations and are thinner than those in the B_3 zone. They range up to ~5 m thick. Over most of the field, they are marginal oil reservoirs at best, although locally they do reach high-enough saturations to be productive.

Possible Tidal Origin

As mentioned above, mixed-lithology successions in both the upper and lower sandstone bodies of the Nelson lease display several features that may indicate a tidal origin. The decimeter-scale beds of mixed lithologies have gradational contacts, e.g., shale grades into interlaminated mudstone, siltstone, and sandstone, which may pass back into shale or into rippled sandstone. Frequently, the decimeter-scale beds contain millimeter- to centimeter-scale interbeds, such as lenticular- or wavy-bedding, or streaks of silt in shale. These features suggest frequent changes of current intensity at two time scales: the one suitable for making the millimeter- to centimeter-scale interbeds may reflect individual semidiurnal or diurnal tide cycles; the other, which creates the decimeter-scale interbeds, may be neap-spring cycles. Gradational boundaries between beds in these successions are more likely to have formed as a result of tidal variation in current intensity than by episodic deposition during waning flow after a storm or flood, which produces scour surfaces and upward-fining grain size in decimeter-scale beds.

Another characteristic lithology present in the Chelsea Sandstone Member valley fill of the Nelson lease is interlaminated fine to very fine sandstone and macerated organic material and mica. The sandstone beds are generally not rippled, but occur in millimeter-scale laminations. Macerated organic material, with mica, is in laminae of similar thickness.

This interlaminated lithology also may be a tidal deposit. It seems unreasonable that a current that would form parallel-laminated beds of fine sand (upper flow regime) would alternate so rapidly with still water in which macerated plant debris and mica could accumulate. A more likely explanation is that these successions represent tidal deposition, in which gentle currents that deposited poorly structured sand from suspension alternated with conditions of no current, during which plant debris and mica settled. No obvious periodicity was noticed in this succession, but careful analyses of lamina thickness have not been attempted.

Interpreting deposits of the Chelsea valley fill in the Savonburg NE field as tidal features has significant effects on the projection of sandstone into areas between wells. Estuarine sandstone bodies are commonly convex upward and form irregular to elongate, current-parallel mounds. Erosional scours and channel-filling sandstones are convex downward. Cross sections, like that in Figure 5, are drawn with this in mind; convex-upward mounds of the B_2 zone are shown in an overall convex-downward valley. This configuration of the sandstone bodies accords well with the thin layers of conglomeratic sandstone that are present between the thicker accumulations of sandstone. In both the B_2 and B_3 zones, mounds and intervening valleys are projected from outside the plane of the section in Figure 5, where they intersect other lines of wells.

Sandstones of the Chelsea Sandstone Member valley fill in the Savonburg NE oil field do not show fluvial character, nor are they associated with delta-front or delta-plain deposits. The most convincing case can be made that they are tidal sandstone bodies that formed when rising sea level flooded an estuary in a valley that erosion had cut during a lowstand of sea level.

DISCUSSION

A clear geologic picture at the regional and reservoir scale permits optimal exploration for, and recovery of, oil. Although incomplete information and the infinite variety of nature prevent development of an entirely accurate and precise geologic picture, it is possible to use information about a particular succession, and knowledge of similar successions in both ancient rocks and modern sediments, to make some preliminary sketches. Once drawn, sketches are the basis for further study or practical application. New information from these uses will allow revision and modification of the picture, possibly bringing it to a higher level of accuracy and detail. For the Cherokee Group, several aspects of an early draft of the picture can be sketched here verbally. These aspects deal with correlation of bodies of rock in the Cherokee, prediction of distribution of reservoir sandstones and properties, and internal continuity of reservoirs. The sketch draws from environmental interpretations and sequence stratigraphy.

Regional marker intervals of the Cherokee Group provide a basis for correlation of strata within it. Observations of the Cherokee Group suggest two interpretations based upon characteristics of marker intervals. First, marker intervals include surfaces of exposure (at the top of underclays) that are sequence boundaries, surfaces of initial marine transgression (at the base of caprocks or dark-gray to black shales), and surfaces of maximum marine transgression (within dark-gray to black shales or overlying medium-gray shales); therefore, they are interpreted to reflect changes of relative sea level. Second, marker intervals can be traced over an area larger than the Cherokee and Forest City basins, so the relative changes of sea level that the markers represent are interpreted to be eustatic changes of sea level (or largely eustatic), rather than more local effects of tectonics or sediment supply. If these interpretations are correct, all of the rocks overlying a marker interval are younger than all of the rocks underlying it, and the framework of marker intervals provides a precise basis for temporal correlation of Cherokee Group rocks. This correlation framework can be applied to both analysis of individual oil fields at the reservoir scale, as was described above, and to regional reconstructions of depositional environments.

The appropriate vertical scale for describing lithofaces and environments of deposition in the Cherokee Group is that of the sequence, or the vertical distance between regional marker horizons. Murphy (1978), Harris (1984), and Brenner (1989) were able to do this analysis for parts of the section and, in the case of Harris and Murphy, a restricted area. Regional studies, such as those by Staton (1987) and Huffman (1991), were less successful in describing the internal features of particular sequences, because they used a low density of data and had mostly logs, not cores or outcrops, to draw upon. Nevertheless, such studies promise significant payoffs in terms of understanding the patterns and timing of deposition and in pointing out potential economic resources.

Local absence of regional markers means either that they were never formed in an area or were formed and subsequently removed. They would not form in areas that were relatively high. Staton (1987) and Huffman (1991) have demonstrated that each marker of the Cherokee Group generally oversteps older markers, forming an onlapping succession onto the slightly elevated area of the Nemaha uplift. In this paper, analysis of distribution of markers in some oil fields suggests that they were removed at times of lowered sea level, when erosion formed valleys. Reservoir sandstones described herein are interpreted to be parts of the sedimentary succession that filled the valleys when sea level rose from its lowstand.

The conclusion that the reservoir sandstones are indeed parts of valley fills restricts the range of interpretation of depositional environments in which they formed and provides significant guides for exploration and development of oil resources. Valley-filling sandstones should not be considered parts of facies tracts that include rocks of the adjacent valley walls that are parts of older sequences. Even where valley fills are correlated to the correct sequence, they are among its oldest parts, formed while sea level is rising. The distribution of lithofacies in younger parts of the sequence may reflect periods of higher or falling sea level. Environmental reconstruction should be attempted only with these facts in mind.

On the other hand, valley-filling sandstones accumulate in fluvial and estuarine environments, for the most part, and investigators can begin the analysis of their distribution and reservoir properties by assuming deposition in such environments. The literature on fluvial rocks is very large and that on estuarine sediments is rapidly growing. Deltas are rare components of valley-fill successions, so that a major class of sandstone-forming environments can be neglected, at least initially.

Sandstones, even shoestring sandstones, can be discontinuous in their distribution and unpredictable in their orientation when considered alone. Valley-fill deposits of the Nelson lease, as reported here, underscore the fact that valley fills are not entirely made of sandstone. However, it is possible to trace the extent of a valley by the lack of the regional markers and intervening strata, even where sandstone is not part of the fill. To the extent that reservoir sandstones are valley-fill deposits, mapping of the valley is a useful substitute for mapping of the sandstone. Distribution of valley walls can guide predictions of the direction toward new sandstone bodies or of the orientation of a sandstone body that is found in a few wells. It can help establish the stratigraphic relationships among different sandstones in a reservoir or other small area. Knowledge of the position of valley walls can also point out boundaries that may be important in designing waterflooding operations, as well as other oil-related activities.

CONCLUSION

Earlier literature, cited above, had indicated that the Cherokee Group originated in deltas. Perhaps because of that, a number of Cherokee reservoirs have been classified in the TORIS data base as having accumulated in river-dominated deltaic environments: Atyeo-Pixlee, Big Sandy, Blankenship, Burkett, Bush City, Edna, Fox-Bush-Couch, Humbolt-Chanute, Iola Consolidated, Lamont, Leon, Madison, Owl Creek, Paola-Rantoul, Quincy, Rainbow Bend, Rock, Sallyards, Seeley-Wick, Slick-Carson, Teeter-Scott, Thrall-Agaard, Vernon, Virgil North, Wayside-Havana, and Winterschied fields.

Depositional environments, such as deltas, rivers, and tidal estuaries, are recognized in ancient sedimentary rocks by the lithofacies that make up the rocks and their patterns of distribution, vertically and laterally. Lithofacies are important guides to interpreting depositional environments, because lithofacies are commonly defined by characters that are imparted by the processes that formed them. Depositional environments, in turn, are characterized by particular sets of processes. Thus the environment determines the processes, the processes determine the nature of the rocks, and the nature of the rocks controls reservoir properties. The environment also provides a guide to the spatial and vertical distribution of particular lithofacies. Application of interpretations of depositional environments to problems in the oil industry is widespread and fruitful.

An assertion that the reservoirs in the Cherokee Group formed in deltaic environments is testable, by examining the rocks. The key groups of environments in deltas are the delta front, the delta plain, and the distributary. In order to be considered deltaic, a reservoir should be closely associated both temporally and spatially with all of the major deltaic environments, or the reason for their absence should be clear. In this paper, it was demonstrated that some sandstone reservoirs of the Cherokee Group are not closely associated with contemporary deltaic deposits. This paper proposes an alternative interpretation for those reservoirs as fluvial or tidal sandstones in valley fills.

The regional marker intervals of the Cherokee are important in developing the alternative interpretation. They provide a firm basis for correlation and also lead to the interpretation that relative sea level changed substantially and frequently during Cherokee deposition. Change of sea level permitted erosion of valleys at lowstand and their filling during transgression. The existence of regional marker intervals and the enclosed sequence boundaries, which are characteristic of the Cherokee Group, also suggests that deposition of upward-coarsening successions could have taken place during periods of high or falling sea level, rather than as prograding lobes of deltas. The proposed interpretation of the markers, valley-fill reservoir, and upward-coarsening successions depends heavily upon the principles of sequence stratigraphy as well as observations of the rocks. Application of these principles provides significant insight at both regional and field scales.

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Reservoir Geochemistry: Concepts, Applications, and Results

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INTRODUCTION

Petroleum geochemistry has developed rapidly over the past two or three decades (Peters and Moldowan, 1993), and until recently most of the emphasis was directed toward the application of geochemical concepts to exploration problems. The pace of this development has inevitably slowed, and, as a result, there has been a tendency to apply geochemistry to areas that are concerned more with the exploitation and production of fossil fuels. This in turn has led to the development of reservoir geochemistry, which has already been used to investigate a number of production and reservoir-characterization problems.

Typically, two-thirds of the oil in place in a reservoir is not produced, even following secondary- and tertiary-recovery techniques. A number of features are responsible for this poor production, including reservoir heterogeneity; the formation of petroleum-derived barriers, either during accumulation or production (e.g., tar mats, asphaltenes, waxes); interaction of the petroleum with the mineral content; low viscosity of waxy oils; and petroleum biodegradation. An understanding of the processes responsible for the emplacement of petroleum fluids, the nature of the organic/inorganic interactions, and how petroleum compositions vary with respect to time will lead to improved methods in the recovery of residual oils, over and above those currently available.

A reservoir, in the context of petroleum, is simply defined as a rock containing petroleum (North, 1985). Consequently, reservoir geochemistry can be considered as the study of the geochemical processes that take place in a porous stratum following the commencement of petroleum accumulation. Within a reservoir, a number of immiscible phases are present, including petroleum, which may be in the form of liquid, gas, solid, or a combination of the three; rock; and water. Additionally, a biological component may be present in the reservoir, in the form of microorganisms, depending on the reservoir conditions. The interactions between each of these phases, and changes in the composition of the petroleum entering the reservoir with respect to time, give rise to a complex and unique biogeochemical environment. The aim of this paper is to give a brief summary of the key processes that take place in a reservoir, showing how they may interact with each other. It should be emphasized that when the term "reservoir geochemistry" is used in this paper, it refers to organic geochemistry and not inorganic geochemistry.

CONCEPTS, APPLICATIONS, AND RESULTS

Organic/Inorganic Interactions

A great deal of research has already been undertaken on the topic of inorganic diagenesis in reservoirs; therefore, it will not be discussed in detail here. The interested reader is directed to papers by Surdam and others (1989), Bjørlykke and others (1989), and references therein as a starting point for obtaining information on inorganic diagenesis. Relatively little is known of the effects of mineral species on sedimentary organic materials and, hence, what effects minerals may have on the composition of an oil in a reservoir. A number of processes, which are discussed below, may be fundamentally dependent on this interaction.

Wettability

The "tendency of one fluid to spread or adhere to a solid surface in the presence of other immiscible fluids" is termed "wettability" (Anderson, 1986). This characteristic of mineral surfaces in petroleum reservoirs is an important factor governing the location, flow, and distribution of fluids (see Anderson, 1986, for a review of this topic). In particular, wettability is likely to play an important role in the initiation of reservoir filling. Prior to petroleum accumulation, all reservoirs will have been filled by water, with the surfaces consequently water wet. Obviously, if the petroleum is to infiltrate the reservoir, it will need to displace this water. A simple buoyancy mechanism may allow the petroleum to displace the water out of the larger pores; however, the smaller pores

Philp, R. P.; and Bishop, A. N., 1996, Reservoir geochemistry: concepts, applications, and results, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 188–196.

will remain water filled because of capillary forces.

A number of recent studies have focused on the potential for wettability preconditioning in reservoirs. If polar organic compounds from the petroleum dissolve in the pore waters and subsequently move ahead of the migrating petroleum front, they may later be preferentially adsorbed by the mineral phases, changing the wettability of the mineral surfaces. Thus, the petroleum phase would find it easier to infiltrate the narrow pore spaces, displacing the water. Research is now being focused on the types of compounds that could facilitate this process.

Brothers and others (1991) showed that nitrogen compounds, such as quinoline, may be so strongly adsorbed by clay minerals as to be unextractable. However, the solubility of these compounds in water is probably too low to significantly alter the wettability of the mineral surfaces (Li and Larter, 1993). In contrast, phenols are highly water soluble and are also strongly adsorbed by minerals; hence, these compounds do have the potential to accomplish surface wetting (Taylor and others, 1993). The efficiency of this process, and its dependability on other factors (e.g., mineral content and cation-exchange capacity), may in turn dictate how much water remains in the petroleum-filled parts of the reservoir. If large amounts of water remain, this situation may facilitate biodegradation.

Asphaltenes, which are an important constituent of crude oils, are also strongly adsorbed by clay minerals. Although the solubility of these components in water is likely to be too low to fulfill the requirements of the mechanism described above, it may be sufficient to allow transport through thin aqueous films (Anderson, 1986). Consequently, asphaltenes may play an important role in reinforcing the oil-wetness of mineral surfaces, following petroleum emplacement in a preconditioned reservoir. Clementz (1982) noted that clay-mineral properties were irreversibly altered as a result of asphaltene and resin adsorption, with a very stable complex of clay and organic constituents formed as a result. As asphaltenes are macromolecular structures with numerous functional groups (Fig. 1), they offer a number of points of attachment for interaction with clay-mineral surfaces (Fig. 2). The low probability of simultaneously desorbing these points of attachment results in the inherent stability of the clay-asphaltene complex, which assists in the stabilization of fines against dispersion and migration. However, Downs and Hoover (1989) have reported that asphaltenes can be displaced from minerals through the use of compounds such as alkoxylated nonphenol resins, producing water-wet surfaces. In a test of the efficiency of this process in waterflooding operations, the application of such resins resulted in a significant improvement in areal-sweep efficiency.

Mineralogical Controls on Petroleum Composition and Properties

In the preceding section, it was shown that adsorption of polar organic compounds is an important process in the control of mineral-surface wettability. As a result, certain compounds will be extracted from the petroleum, changing its overall composition. Additionally, the enhanced adsorption of polar compounds, as a result of high clay-mineral concentrations in specific reservoir lithologies, may lead to a heterogeneous distribution of polar composition, relative to the overall petroleum composition. Larter and others (1990) showed that there may be considerable local variations in the polar compositions on a submeter scale, with high polar contents associated with the

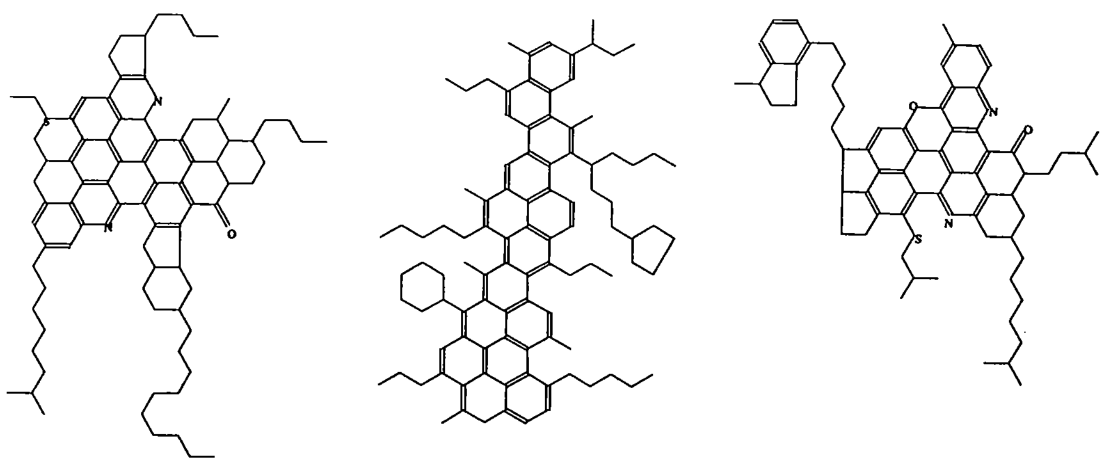

Figure 1. Examples of three hypothetical asphaltene structures (after Speight, 1980).

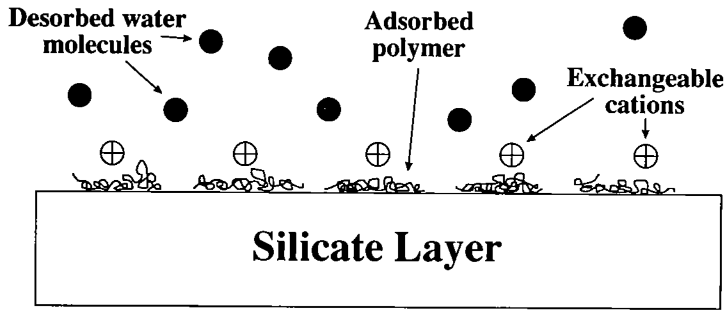

Figure 2. Model showing adsorption of macromolecular polymeric material by clay surfaces (after Theng, 1982).

bases of coarsening-upward sequences, and other studies have noted a relationship between high polar contents and less permeable horizons (Leythaeuser and Ruckheim, 1989). The mineral constituents of clastic reservoirs may therefore influence the distribution of petroleum compositions; hence, it is necessary to understand the effects of such processes on petroleum behavior. Clay minerals, by virtue of their very high effective surface areas, in comparison with other typical sedimentary minerals, are likely to be the main mineralogical control leading to changes in the composition and physical properties of a petroleum. However, it is important to distinguish between the composition of the mobile petroleum phase in a core sample and its solvent extract. It is possible that material adsorbed by the mineral surfaces will be extracted by the solvent to a greater or lesser extent, depending on the type of solvent and the nature of the organic/inorganic interactions. However, this extracted material may bear little relationship to the composition of the mobile petroleum phase that is likely to be produced and may have a reduced polar content.

Effect of Microorganisms

The sources of the microorganisms are likely to be circulating ground waters, either from above (through filtration) or via lateral migration. The lateral movement of microorganisms can occur over distances in excess of 2 km (Ghiorse and Wilson, 1988). But there is also evidence to suggest that microorganisms may survive even long periods of sedimentary burial. Ghiorse and Wilson (1988) suggested that it is possible, in shallow aquifers, that some of the organisms present may have colonized the formation at the time of deposition, and they may subsequently be reactivated following the emplacement of a petroleum charge.

A significant amount of work has been undertaken on the characterization of oils that are known to be biodegraded and also on the biodegradation of oils under surface conditions. However, mechanisms of biodegradation, especially within a reservoir, are not well characterized. Factors that control the onset and cessation of biodegradation in a reservoir are not totally understood, although microbial abundances will be controlled by factors such as pore size, nutritional availability, water, surface activity, pH, temperature, hydrostatic pressure, and salinity. Furthermore, it is still unclear whether the process of biodegradation is aerobic or anaerobic. Initially it was thought to be aerobic, but evidence has been obtained to show that anaerobic mechanisms may also be a factor in reservoir biodegradation (Connan, 1984; Bertrand and others, 1989; Connan, 1992).

Peters and Moldowan (1993) have published the most recent ranking of the levels of petroleum biodegradation, based on the geochemical compositions of oils. Lightly biodegraded oils are likely to have lost only the light n-alkanes, with progressive losses of the higher-molecular-weight homologues as biodegradation increases. In moderately to heavily degraded oils, the concentration of the branched and cyclic saturated hydrocarbons is also affected, and severely biodegraded oils are those that begin to lose their aromatic hydrocarbons. Eventually, all that remains in a very severely degraded oil is asphaltic material. This is the situation with the Athabasca tar sands, which represent one of the world's largest petroleum accumulations. Palmer (1993) has documented a number of case studies that illustrate the effects of biodegradation on crude-oil compositions in a number of different regions.

Biodegradation is generally thought to be limited to within a few hundred meters of the surface (Peters and Moldowan, 1993). However, Moldowan and others (1992) noted the presence of a biodegraded oil in a 2,500-m-deep reservoir in the Adriatic basin; biodegradation was interpreted to result from protection of the microbial community by a low geothermal gradient. Only in the past decade has significant research effort been devoted to the microbial ecology of deep-subsurface environments. Even now, little is known of the extent and viability of microbial populations below 500 m depth. However, there is every reason to suppose that microorganisms may exist as much as 4,000 m deep (Ghiorse and Wilson, 1988). Only with continued research to greater and greater depths, using aseptic sampling techniques to prevent contamination, will the microbial ecology of petroleum reservoirs be documented and the potential for and controls on microbial alteration of petroleum be understood.

Factors that control the onset and cessation of biodegradation in a reservoir are not totally understood. Traditionally, as mentioned above, it was believed that the process was aerobic and hence controlled by the availability of oxygen (Palmer, 1991), but recent studies have indicated that anaerobic metabolism may also play an important role in biodegradation. Sinclair and others (1990) suggested that significant anaerobic populations may be present in buried aquifers in northeastern Kansas. Ghiorse and Wilson (1988) suggested that anaerobic conditions were likely to prevail if an excess of organic material is present in an aquifer. Clearly, petroleum reservoirs represent aquifers that are typically saturated with petroleum; thus it might be expected that anaerobic conditions are likely to prevail. More direct evidence has been presented by Hermann and others (1992), who quantified the presence of anaerobic microflora in a number of petroleum reservoirs. Those authors speculated that a syntrophic association may exist in some reservoirs, in which sulfate-reducing bacteria supply hydrogen to methanogens through the degradation of petroleum.

Precipitation of Petroleum-Derived Solids

In a number of petroleum-producing regions, the precipitation of solids from the oil, either during accumulation or production, is a major problem. The composition of the precipitated solids ranges from high-molecular-weight hydrocarbons to bitumens and asphaltenes (Carnahan, 1989). Usage of the term "reservoir bitumens" to describe petroleum-derived solids should not to be encouraged, as this will simply lead to confusion with the bitumen of organic extracts and of native bitumens, such as the gilsonite veins of the Uinta basin.

Precipitation may occur either in the reservoir or in the production string, as far up as the storage tanks. As a result, barriers may form within the reservoir, and/or blockages may develop in the pipelines themselves. As a result of filling the pores, the solids may restrict the pore throats and change the wettability characteristics, which in turn will influence reservoir-quality predictions in play assessments and basin evaluations. Consequently, petroleum-derived solids are as significant as carbonate and silicate cements, or authigenic clay minerals, when it comes to the characterization and evaluation of petroleum-reservoir systems. Finally, the presence of these materials can also cause reservoir damage by the migration of fines, leading to the reduction of porosity.

Lomando (1992) discussed the importance of petroleum-derived solids and the significance of these materials for the estimation of reserves and reservoir quality. In the past, this material, which in some cases may represent a significant portion of oil-in-place, has been overlooked owing to difficulties in both its detection and quantification. Lomando (1992) recognized five morphotypes of petroleum-derived solids and called them droplets, carpets, peanut brittle, vesicular, and digitate. Although the relationship between each of these morphologies and composition is as yet unknown, the general composition of petroleum-derived solids ranges from high-molecular-weight hydrocarbons and bitumens to asphaltenes (Carnahan, 1989).

High-Molecular-Weight Hydrocarbon Waxes

Waxes consisting primarily of high-molecular-weight hydrocarbons, often referred to as "paraffins" or "paraffin waxes," are a common problem in a number of petroleum-producing regions. The factors controlling the deposition of such waxes have been reviewed by Carnahan (1989). Wax deposition is related to changes in the supercritical character of petroleum fluids during accumulation and production. The temperature in deeper reservoirs can exceed the critical temperature of the low-molecular-weight petroleum constituents (e.g., methane, ethane, etc.); hence, these compounds may act as supercritical solvents for the high-molecular-weight hydrocarbons. Petroleum production inevitably results in a loss of reservoir pressure, which results in a reduction in the carrying capacity of the supercritical solvent system. This leads to the precipitation and deposition of the high-molecular-weight hydrocarbons. Deposition in the production facilities is a result of the drop in temperature of the petroleum after it has left the reservoir (Carnahan, 1989).

The carbon-number distributions of the hydrocarbons present in the waxes can now be characterized by high-temperature gas chromatography (del Rio and others, 1992). The results of such analyses reveal that the waxes are enriched in high-molecular-weight *n*-alkanes (Fig. 3). Many oils contain quantifiable concentrations of high-molecular-weight hydrocarbons; however, it is common for crude oils not to display such compounds, even though waxes consisting of hydrocarbons ranging between C_{40} and C_{50} precipitate from them (Fig. 4). These compounds are probably in the oil, but at concentrations currently below detection limits (Philp and others, 1995). A number of approaches have been utilized to remediate the effects of wax deposition (see Tuttle, 1983, and Ashford and others, 1990, for reviews); these include hot oiling, wireline cutting, and chemical treatments to prevent the wax from being deposited. In higher latitudes and below the sea, insulation may be necessary to prevent deposits from forming in the well and transfer pipelines (Ashford and others, 1990). However, the application of such techniques clearly results in an addition to production costs, the actual amounts being linked to the wax content of the petroleum (Tuttle, 1983).

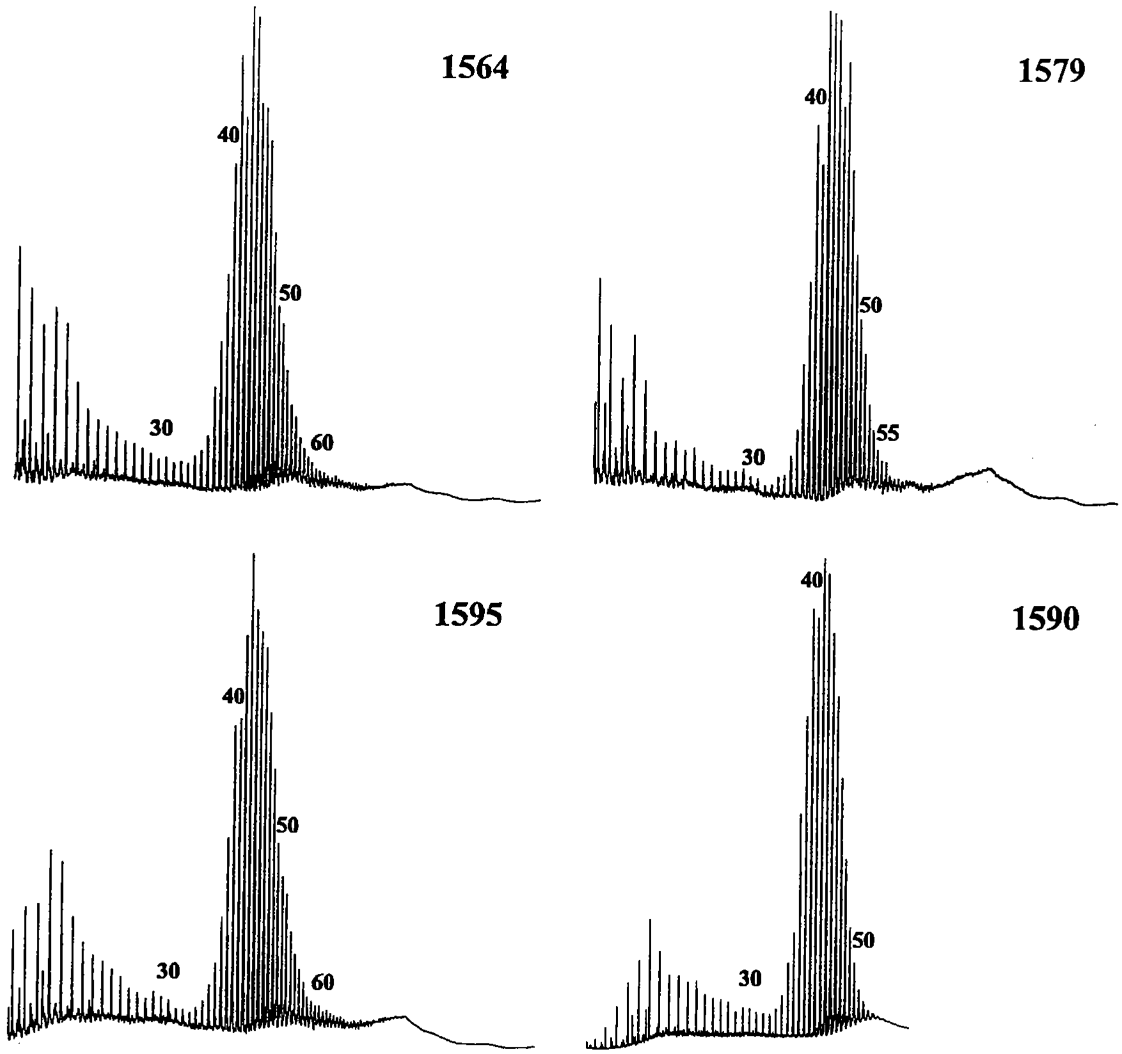

Figure 3. The high-molecular-weight hydrocarbon distributions of waxes from four oils of central Oklahoma as determined by high-temperature gas chromatography. Carbon numbers of individual components are indicated by the numbers 30, 40, 50, and so forth. (The numbers 1564, and so forth, are sample numbers.)

Asphaltenes

The operational definition of asphaltenes is "the material that precipitates out of a crude oil on the addition of excess light n-alkanes" (Speight and Moschopedis, 1979); they comprise macromolecular compounds consisting of polyaromatic nuclei, linked by aliphatic units and/or functional groups (Fig. 1). It is generally believed that asphaltenes are held in solution in petroleum via the peptizing action of the resin compounds (Leontaritis, 1989). The deposition of asphaltenes in reservoirs and production facilities was reviewed by Leontaritis (1989). The key factors responsible for asphaltene flocculation are reservoir-fluid temperature, changes in pressure and/or fluid composition, and electrokinetic effects related to reservoir-fluid flow. Unlike its effect on wax deposition, the reduction in pressure as a result of production will actually lead to the inhibition of asphaltene deposition. Thus, as a reservoir gets older, problems connected with asphaltene deposition should diminish. Such a relationship was noted by Tuttle (1983) for the Ventura Avenue field in California.

An important example of in-reservoir asphaltene deposition is the formation of tar mats. These are defined as reservoir zones, usually sharply defined, that contain petroleum enriched in asphaltenes relative to the composition of the main oil-bearing zone (see Wilhelms, 1992, for a review on the formation of tar mats and their associated properties). Tar mats tend to occur in reservoirs

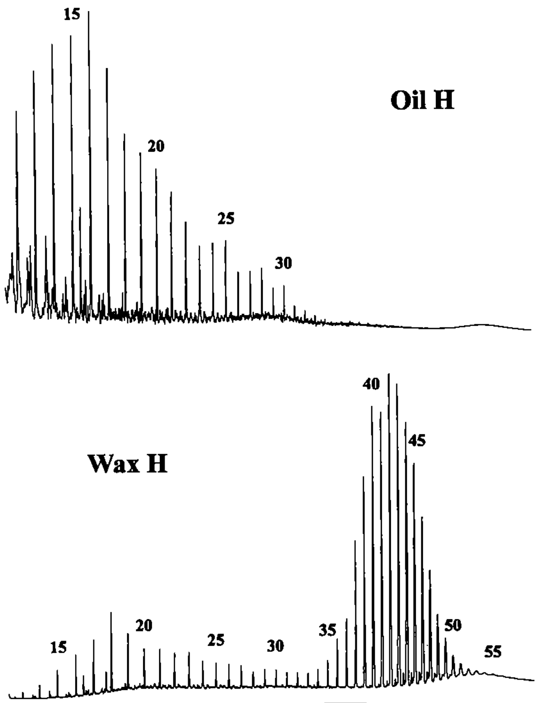

Figure 4. An example of a discrepancy in the high-molecular-weight hydrocarbon composition between a wax and a produced oil from the same well (high-temperature gas chromatography).

containing paraffinic oils with high permeability and porosity. As the mats may only be a few meters thick, they may be missed by routine core analysis; however, the lateral extent may be much greater. Hence, significant, effectively invisible barriers may be present in many reservoirs. Reservoirs containing tar mats typically have production deasphalting problems associated with them, including safety problems (Thawer and others, 1990). Prediction of tar-mat formation could provide an early warning of potential production hazards.

Changes in Petroleum-Charge Composition with Time

The generation of petroleum in a source-rock kitchen is followed by hydrocarbon migration along a carrier bed until it encounters a trap. There, assuming it arrives from one side of the trap, it will advance as a series of fronts, since it cannot bypass the main flow paths through the coarser beds. As the total accumulation increases, the buoyant pressure rises and causes the petroleum to displace water from ever smaller and smaller pores (Fig. 5). England (1990) noted that statistically significant geochemical differences could be observed in petroleum-fluid compositions, which could be used to evaluate the extent of mixing processes, as well as distinguishing oils from separate source kitchens.

It has been known for some time that compositional variations exist in petroleum accumulations, both laterally and horizontally, with differences resulting from biodegradation and water-washing having long been recognized. They may also result from source facies and maturity variations in the petroleum charge(s) feeding the reservoir. As proposed by England (1990), the most recently arrived (most mature) oil is nearest the source-rock kitchen. If two source rocks are present, one would predict that, at first, parts of the reservoir nearest the migration pathway for one source rock will inherit a geochemical signature predominantly from that facies. During filling, the volume of oil-saturated rock is very discontinuous, which restricts mixing of oils generated from separate sources and at different levels of maturity. However, when the reservoir is 50% full, or more, mixing will start to occur, eliminating some of these heterogeneities, although incomplete mixing may lead to their preservation. Previous work by England and Mackenzie (1989) has shown that, although diffusive or density-driven mixing can eliminate vertical compositional variations in a petroleum column, within the time scale of reservoir filling, lateral variations are likely to be preserved. Effects of mineral-surface adsorption may also locally control the petroleum polar content, such that diffusive processes may be unable to homogenize gross petroleum compositions even on a submeter scale in a reservoir rich in clay minerals (Larter and others, 1990). From these observations, it is possible to determine field filling directions and place limits on probable locations, and types, of the relevant source-rock kitchens.

In many areas the vast majority of wells are drilled on structural highs; thus the source rocks responsible for the oil formation are rarely sampled. The determination of the source-rock characteristics, via differences in the petroleum composition, may allow the more accurate quantification of the petroleum carrier system, with the potential to identify additional exploration targets, such as satellite traps. An assessment of the mixing process within a field will assist in the development of production programs and also show whether barriers exist that may prevent mixing or communication between the individual reservoir chambers.

Leythaeuser and Ruckheim (1989) studied spatial variations within a small oil field in Germany and noted pronounced heterogeneities in the bulk and-molecular-compositions of the petroleum being produced. Oils in high-porosity and high-permeability sandstone intervals contained a higher proportion of saturated hydrocarbons, and, on the basis of biomarker parameters, appeared more mature than those in the lower-porosity and

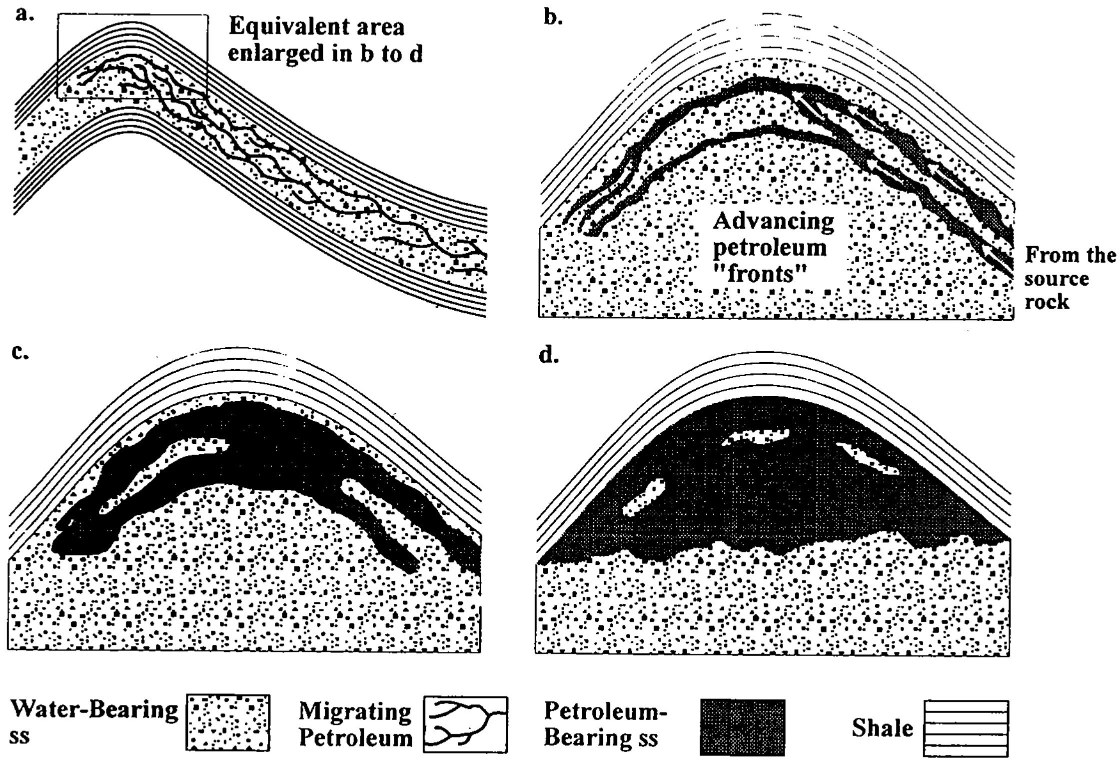

Figure 5. Schematic representation of progressive emplacement of a petroleum charge into a reservoir (modified from England and others, 1991).

lower-permeability zones. It was proposed that such spatial maturity variations reflected successive stages of trap filling due to episodes of increasing burial and maturation of the relevant source rocks, together with low rates of in-reservoir mixing by convection or diffusion. Oils extracted from reservoir rocks of <13% porosity showed regular bulk compositional changes with decreasing porosity and permeability, as well as a systematic change in molecular composition. From these observations it was concluded that higher-porosity zones are filled with higher-maturity oils, whereas areas of lower porosity are filled with lower-maturity oils. This phenomenon was explained by Leythaeuser and Ruckheim (1989) as resulting from inefficient mixing of different petroleum charges present in the higher- and lower-porosity zones, arising from an extended filling history. Furthermore, the source rocks were also subsiding and generating during the accumulation period and were expelling progressively more mature oil that subsequently migrated to the reservoir. As the volume of oil continued to grow, buoyancy exceeded the capillary entry pressure of the lower-porosity reservoir zones. Consequently, in the higher-porosity zones, the lower-maturity oil was displaced by the higher-maturity oil, forcing the low-maturity oil into the lower-porosity intervals. For this to be valid, there must have been little in-reservoir mixing. Leythaeuser and Ruckheim (1989) also noted the possibility of contamination from indigenous organic matter, but they were not able to assess its significance owing to the presence of the oil. Biomarker concentrations decrease sharply in the oil window (Rullkötter and others, 1984); thus, even though the indigenous total organic carbon concentration of a reservoir rock is likely to be low, the biomarker concentration of a low-porosity unit may be enough to dilute the biomarker concentration of a mature oil, reducing the oil's apparent maturity and source characteristics.

Horstad and others (1990) undertook a geochemical mapping study of the Gullfaks reservoir in the Norwegian North Sea and, by examination of a large number of reservoir-core, drill-stem-test, and repeat-formation-test samples, were able to show lateral compositional heterogeneities in the oil column. These different populations were related to lateral filling of the field from two source formations and a subsequent episode of in-reservoir biodegradation. Results obtained by Horstad and others (1990) also suggested that fractionation effects could be observed between the core extracts and the drill-stem-test samples. Hence, if geochemical techniques are to be successful in the interpretation of reservoir petroleum columns from mixed-sample sets, it is essential that we obtain a better understanding of these fractionation effects, which to a large extent are controlled by organic and inorganic interactions in the reservoir itself.

CONCLUSIONS

The above has been a brief summary of how reservoir geochemistry has started to develop from an organic geochemical perspective. Clearly, petroleum reservoirs represent a unique biogeochemical environment, with the interplay between the key processes of mineral diagenesis, interactions between organic constituents and minerals, biodegradation, and changes in petroleum-charge composition with time, giving rise to a complex variety of problems that ultimately result in the poor recovery of petroleum (Fig. 6). However, the composition of oil produced at the well head represents a record of the reservoir conditions over the history of accumulation and production. An understanding of the factors that control the physical and chemical properties of petroleum should lead to significant advances in reservoir characterization.

In addition, secondary-recovery techniques, such as water or polymer flooding and steam injection, will modify the conditions within a reservoir. The effects of such changes could be significant, with the potential for the initiation of asphaltene precipitation, etc. Only with a detailed understanding of reservoir geochemical processes can the implications of any such action on the chemistry and physical properties of the reservoir biogeochemical environment be anticipated.

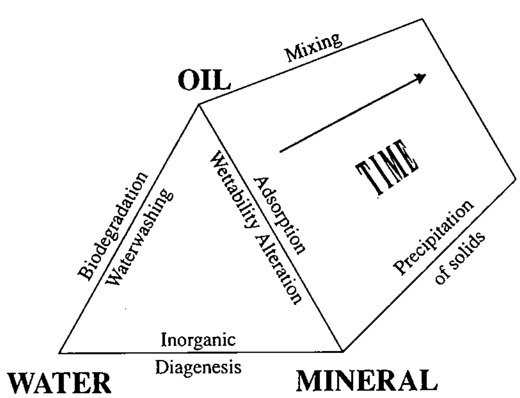

Figure 6. Simplified model illustrating the key interactions that control the petroleum-reservoir biogeochemical environment.

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General Reservoir and Production Characteristics for Fluvial-Dominated Deltaic Reservoirs

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ABSTRACT.—Reservoir properties and production characteristics of 229 fluvial-dominated deltaic (FDD) reservoirs listed in the U.S. Department of Energy's Tertiary Oil Recovery Information System (TORIS) reservoir data base are analyzed. Histograms and statistical analysis of reservoir properties and oil recovery of FDD reservoirs are presented. As the median values suggest, FDD reservoirs are generally high-quality reservoirs at moderate depth (4,954 ft), having good porosity (19%) and permeability (128 md), and they produce light oil (39° API gravity) at a reasonable primary-recovery factor (26%). Among four individual fluvial-dominated deltaic plays analyzed, Bartlesville sandstone reservoirs have the shallowest depth (2,000 ft) and the highest original oil in place (82.7 million bbl), whereas Wilcox Group sandstone reservoirs show the highest permeability (524 md) and the highest primary recovery (479 bbl/acre-ft). Rock-permeability values were found to be the best indicator among formation parameters for primary production in such reservoirs. The permeability contrast in the vertical direction, or efficient primary recovery, may result in low secondary recovery in fluvial-dominated deltaic reservoirs.

The Enhanced Oil Recovery (EOR) Project data base of the Department of Energy contains information on 132 EOR projects in 37 fields producing from deltaic reservoirs and indicates that chemical flooding (surfactant, alkaline-surfactant, and polymer flooding) has been the prime EOR method applied in the deltaic reservoirs considered. Lower-than-expected oil recovery was partially attributed to heterogeneity related to depositional processes in the projects. The fluid-flow problems most often reported in publications were channeling, directional-flow trends, compartmentalization, and contact of high-salinity fluids.

INTRODUCTION

Reservoir properties and production characteristics of 229 fluvial-dominated unstructured deltaic reservoirs in the TORIS data base were analyzed. TORIS is the acronym for the Tertiary Oil Recovery Information System developed by the U.S. Department of Energy (DOE). TORIS is a collection of a reservoir data base, an EOR data base, EOR-screening models, and reservoir simulators. For several years, DOE has been collecting data on major U.S. reservoirs for TORIS. In 1983, it was decided to seek additional data for all reservoirs having ≥20 million bbl of original oil in place (OOIP), and crude-oil gravities of ≥10° API (National Petroleum Council, 1984). Requests were sent to each major operator of 1,300 identified reservoirs for reservoir data and production data of primary and secondary recovery. The collection effort was a reiterative process with continuous requests to research organizations and operators for additional information on reservoirs, and it was not limited to OOIP ≥20 million bbl. The end result of this effort is a reservoir data base far larger and more complete than had previously been available.

A total of 229 fluvial-dominated deltaic reservoirs were identified among 359 unstructured deltaic reservoirs contained in the TORIS data base. Eighty-one wave-dominated and 24 tide-dominated deltaic reservoirs were identified. The TORIS reservoir data base contains only average values of production and reservoir parameters (such as porosity, permeability, and recovery factor). The detail of data is not suitable for a rigorous statistical analysis; however, it is presented here to illustrate the range of reservoir properties and production characteristics in deltaic reservoirs.

Since the early 1970s, and until recently, many EOR pilots and commercial field tests were performed, and many papers and reports evaluating the causes and reasons for successes and failures of these projects have been written. Unfortunately, most of the evaluations concentrated on the recov-

Chang, M.-M.; Tham, M. K.; and Jackson, S. R., 1996, General reservoir and production characteristics for fluvial-dominated deltaic reservoirs, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 197–210.

TABLE 1. — STATISTICS OF RESERVOIR PROPERTIES OF FLUVIAL-DOMINATED DELTAIC DEPOSITS (FROM TORIS DATA BASE)

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Standard deviation
Well spacing, acres	219	0.4077	735	75.47	41.03	85.87
Net pay, ft	229	2	201	22.71	16	21.99
Gross pay, ft	228	2.4	241.2	31.05	22	28.87
Porosity, %	229	7.5	35	20.16	19	5.667
Initial oil saturation, %	229	41	90	67.32	68	7.454
Current oil saturation, %	228	10.01	68.79	41.61	42.67	12.11
Depth, ft	227	580	10,250	4684	4,954	2,027
Permeability, md	229	0.2	3,100	275.4	128	418.9
API gravity	229	21.8	50	38.18	39	4.557
Total dissolved solids, ppm	134	300	244,000	83,500	50,000	73,990
Original oil-in-place, bbl x 10^6	229	0.1685	1,189	89.71	26.6	17.73
Primary recovery factor	228	0.01211	0.836	0.2896	0.26	0.1696
Secondary recovery factor	142	0	0.64	0.08372	0.02122	0.1193
Cumulative recovery, bbl x 10^6	229	0.39	325.4	23.99	6.59	51.76
Primary recovery, bbl/acre-ft	228	6.433	1134	254.5	205.2	193.1
Primary recovery, bbl x 10^6	228	0.02588	348	22.82	5.99	51.39
Ultimate recovery factor	229	0.012	0.836	0.3321	0.302	0.1706

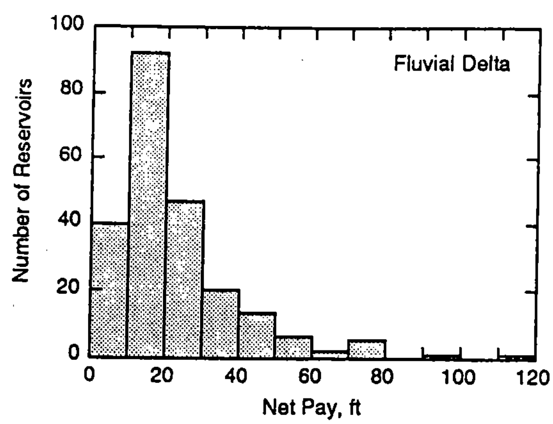

Figure 1. Histogram of net pay in the fluvial-dominated deltaic reservoirs studied.

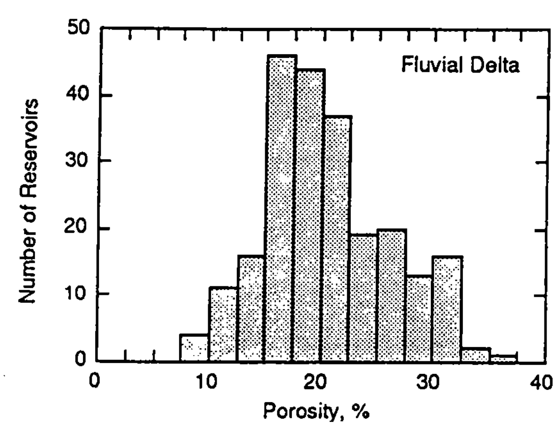

Figure 2. Histogram of porosity in the fluvial-dominated deltaic reservoirs studied.

ery processes, and even when the geologic factors were evaluated, little effort was expended in relating the project performance to heterogeneities induced by the depositional environment.

In an attempt to determine the effect of these heterogeneities on EOR recovery efficiency, reports and publications on EOR projects performed in deltaic reservoirs were reviewed. It is interesting that almost all DOE-sponsored, and a large proportion of industry-sponsored, chemical EOR pilot tests were conducted in deltaic reservoirs.

RESERVOIR PROPERTIES

General statistics of formation and production characteristics of fluvial-dominated deltaic reservoirs are listed in Table 1. Median values are used for comparison because determination of significant mean values requires that the data be distributed normally, which is rarely the case. A "median" fluvial-dominated deltaic reservoir has a net pay of 16 ft (Fig. 1), porosity of 19% (Fig. 2), permeability of 128 md (Fig. 3), and a reservoir size of

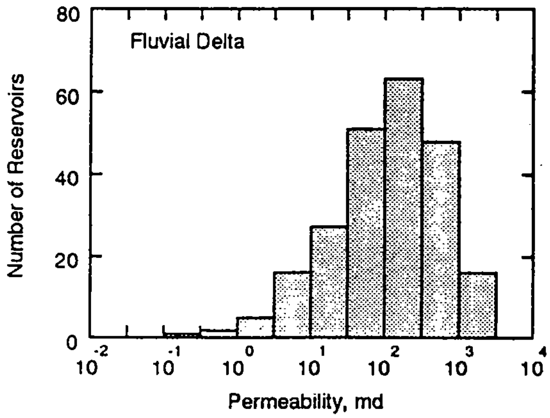

Figure 3. Histogram of permeability in the fluvial-dominated deltaic reservoirs studied.

1,840 acres. The logarithmic values of permeability show a somewhat linear relationship with the porosity values in Figure 4. Of the fluvial-deltaic reservoirs studied, 50% have >26.6 million bbl OOIP (Fig. 5) and have produced >205 bbl/acre-ft (Fig. 6). Fluvial-dominated deltaic reservoirs produce light oil with a median gravity of 39° API (Fig. 7). The reservoir depth ranges from 580 to 10,246 ft, with a median value of 4,954 ft (Fig. 8). Neither the permeability value nor the original oil in place shows a correlation with the reservoir depth. The median value of the primary recovery factor is 26%, and the median value of the primary and secondary recovery factors, taken together, is 30% (Fig. 9).

General statistics of wave- and tide-dominated deltaic reservoirs contained in the TORIS data base are listed in Tables 2 and 3 for comparison. Fluvial-, wave-, and tide-dominated deltaic reser-

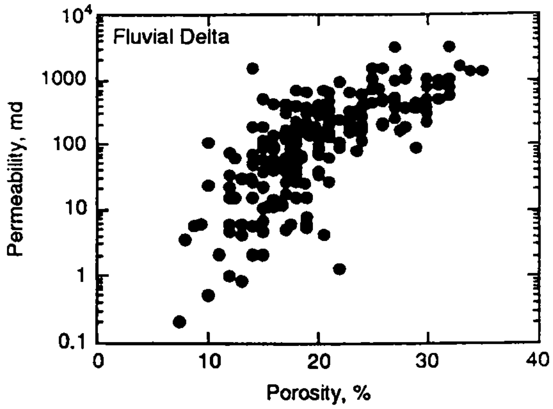

Figure 4. Semilog plot of permeability vs. porosity in the fluvial-dominated deltaic reservoirs studied.

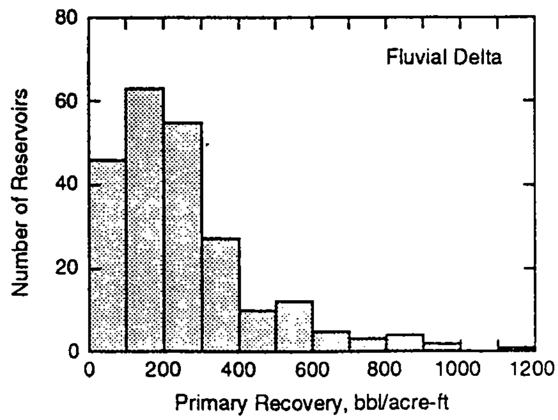

Figure 6. Histogram of primary recovery in the fluvial-dominated deltaic reservoirs studied.

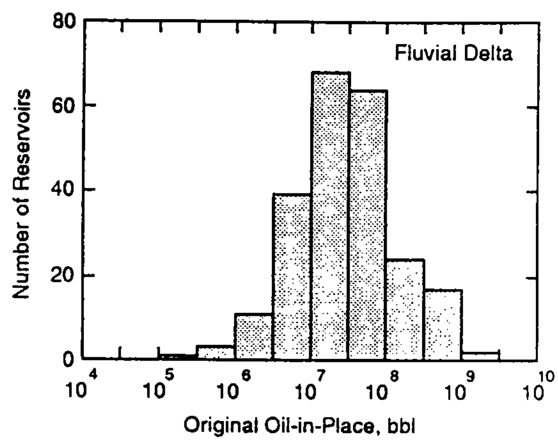

Figure 5. Histogram of original oil in place in the fluvial-dominated deltaic reservoirs studied.

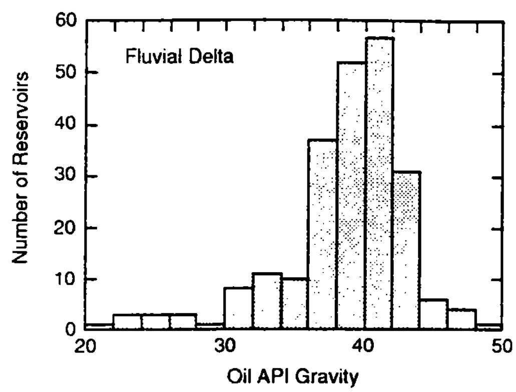

Figure 7. Histogram of oil gravity in the fluvial-dominated deltaic reservoirs studied.

TABLE 2. — STATISTICS OF RESERVOIR PROPERTIES OF WAVE-DOMINATED DELTAIC DEPOSITS (FROM TORIS DATA BASE)

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Standard deviation
Well spacing, acres	81	0.1471	293.6	63.62	40	63.69
Net pay, ft	81	4	272	24.36	12.5	41.41
Gross pay, ft	81	4.8	1,560	48.3	16.8	177.1
Porosity, %	81	6	35	20.42	21	6.715
Initial oil saturation, %	81	28.1	85	64.93	68	12.57
Current oil saturation, %	81	7.928	73.16	39.99	40.55	14.63
Depth, FT	81	400	9,800	4,655	4,423	2,271
Permeability, md	81	0.03467	2,800	335	95	583.1
API gravity	81	21.2	46	37.17	38	5.314
Total dissolved solids, ppm	59	31.9	250,000	72,660	68,000	56,020
Original oil-in-place, bbl x 10^6	81	0.03074	7,558	212.6	22.5	92.01
Primary recovery factor	81	0.033	0.84	0.3	0.2479	0.184
Secondary recovery factor	46	0	0.85	0.1238	0.07765	0.1664
Cumulative recovery, bbl x 10^6	81	0.01232	5,004	93.86	5.294	561.6
Primary recovery, bbl/acre-ft	81	11.76	910	267.6	152.5	250.1
Primary recovery, bbl x 10^6	81	0.01232	4,939	84.51	5.173	549.9
Ultimate recovery factor	81	0.08766	0.8604	0.3438	0.307	0.1931

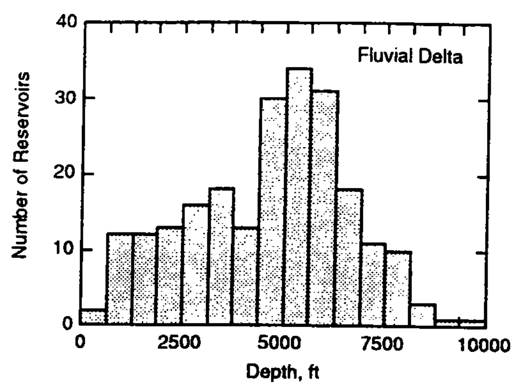

Figure 8. Histogram of reservoir depth in the fluvial-dominated deltaic reservoirs studied.

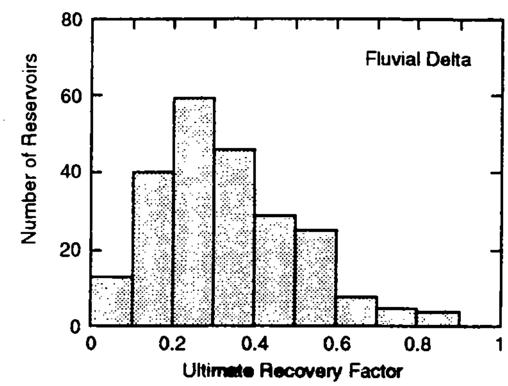

Figure 9. Histogram of cumulative recovery in the fluvial-dominated deltaic reservoirs studied.

voirs have similar values for porosity, permeability, initial oil saturation, and oil gravity. Tide-dominated deltas have a median depth of 2,065 ft, in contrast to median depths of >4,000 ft for fluvial- and wave-dominated deltas.

Reservoir and production data were analyzed for four individual plays within fluvial-dominated deltaic reservoirs as a sample of this group of reservoirs. The following plays were selected on the basis of geographic distribution and availability of data: (1) Cherokee or Bartlesville sandstone in Oklahoma and Kansas; (2) Dakota Group, including the D and J sandstones, in the Denver-Julesburg basin of Colorado and Nebraska; (3) Strawn Group sandstones in Texas; and (4) Wilcox Group sandstones in Texas, Louisiana, and Mississippi. The general statistics of formation and production properties of fluvial-dominated deltas in Bartlesville, Dakota, Wilcox, and Strawn reservoirs are listed in Tables 4, 5, 6, and 7, respec-

TABLE 3. — STATISTICS OF RESERVOIR PROPERTIES OF TIDE-DOMINATED DELTAIC DEPOSITS (FROM TORIS DATA BASE)

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Standard deviation
Well spacing, acres	24	1.616	150.5	36.94	19.45	40.51
Net pay, ft	24	7	100	26.71	16.5	24.75
Gross pay, ft	24	8.4	1,100	96.03	26.85	229.2
Porosity, %	24	13	40	21.25	18.75	6.701
Initial oil saturation, %	24	55	77	67.87	69	4.73
Current oil saturation, %	24	29.43	50.63	38.03	34.73	7.108
Depth, ft	24	765	4,807	2,240	2,065	930.3
Permeability, md	24	10	800	219.6	150	220.6
API gravity	24	17	39.5	34.32	36	6.22
Total dissolved solids, ppm	18	152.7	140,000	76,000	65,950	53,170
Original oil-in-place, bbl, x 10^6	24	2.5	1,750	215.3	24.5	453.8
Primary recovery factor	24	0.03	0.5597	0.2288	0.23	0.1308
Secondary recovery factor	23	0	0.35	0.1842	0.24	0.1166
Cumulative recovery, bbl x 10^6	24	0.76	464.6	63.94	10.9	121.1
Primary recovery, bbl/acre-ft	24	24.29	1,447	369.2	195.4	422.5
Primary recovery, bbl x 10^6	24	0.13	462.2	61.58	5.8	121.4
Ultimate recovery factor	24	0.12	0.565	0.6597	0.4121	0.1205

TABLE 4. — STATISTICS OF RESERVOIR PROPERTIES OF THE BARTLESVILLE SANDSTONE (FROM TORIS DATA BASE)

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Standard deviation
Well spacing, acres	31	2.416	310.9	28.92	15.41	54.04
Net pay, ft	31	3	74	28.99	25	17.54
Gross pay, ft	31	3.6	88.8	35.39	31.2	20.12
Porosity, %	31	12	28	17.25	17.9	3.097
Initial oil saturation, %	31	47	80	66.12	68	7.012
Current oil saturation, %	31	23.3	66.26	45.43	47.16	11.56
Depth, ft	31	580	7,742	2,178	1,950	1,470
Permeability, md	31	4.666	359	66.91	43	88.12
API gravity	31	22	42	36.06	38	4.546
Total dissolved solids, ppm	13	10,000	220,000	98,670	110,000	57,830
Original oil-in-place, bbl x 10^6	31	0.1685	1,058	199	82.76	241
Primary recovery factor	31	0.01211	0.629	0.2598	0.233	0.1693
Secondary recovery factor	7	0.000061	0.309	0.05037	0.000374	0.1151
Cumulative recovery, bbl x 10^6	31	0.039	373.5	51.18	13.54	89.91
Primary recovery, bbl/acre-ft	31	10.26	655.4	206.3	183	156.8
Primary recovery, bbl x 10^6	31	0.04437	414	53.59	13.56	97.16
Ultimate recovery factor	31	0.012	0.629	0.2691	0.233	0.1773

TABLE 5. — STATISTICS OF RESERVOIR PROPERTIES OF THE D/J (DAKOTA) SANDSTONE (FROM TORIS DATA BASE)

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Standard deviation
Well spacing, acres	29	0.1628	316.7	135	120	91.4
Net pay, ft	34	2	30	12.46	10	6.99
Gross pay, ft	34	2.4	37	15.55	12	9.48
Porosity, %	34	10	26	19.63	19	2.95
Initial oil saturation, %	34	58	90	71.51	71	6.07
Current oil saturation, %	34	14.14	68.79	41.88	42.1	11.5
Depth, ft	34	3,938	6,731	5,255	5,077	665
Permeability, md	34	17.94	2,238	336.2	234.5	385
API gravity	34	23	43	37.47	38	3.69
Total dissolved solids, ppm	17	300	18,000	7,905	7,363	5,110
Original oil-in-place, bbl x 10^6	34	0.02829	135	16.87	8.419	23.5
Primary recovery factor	34	0.153	0.798	0.3628	0.325	0.147
Secondary recovery factor	21	0	0.38	0.07847	0.01744	0.101
Cumulative recovery, bbl x 10^6	34	0.008887	55.35	6.38	3.906	9.61
Primary recovery, bbl/acre-ft	34	15.19	908.3	290.2	277	198
Primary recovery, bbl x 10^6	34	0.008887	55.26	5.157	2.836	9.48
Ultimate recovery factor	34	0.1611	0.798	0.4035	0.3717	0.137

TABLE 6. — STATISTICS OF RESERVOIR PROPERTIES OF THE WILCOX FORMATION (FROM TORIS DATA BASE)

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Standard deviation
Well spacing, acres	20	22.01	220	84.19	62.58	56.39
Net pay, ft	20	4	70	12.55	9	14.11
Gross pay, ft	20	4.8	84	15.06	10.8	16.94
Porosity, %	20	26	35	30.05	30	2.417
Initial oil saturation, %	20	41	71	59.2	62	8.788
Current oil saturation, %	19	10.55	57.01	33.97	35.85	15.49
Depth, ft	19	4,330	6,666	5,995	6,174	675.3
Permeability, md	20	89.7	1,540	644.1	523.9	441.5
API gravity	20	31	47	39.45	39.5	3.364
Total dissolved solids, ppm	12	130,000	178,600	147,300	146,000	12,790
Original oil-in-place, bbl x 10^6	20	1.404	36.66	7.809	6.435	7.547
Primary recovery factor	19	0.114	0.836	0.4187	0.438	0.238
Secondary recovery factor	11	0.000001	0.000467	0.0001808	0.000147	0.0001792
Cumulative recovery, bbl x 10^6	20	0.2566	5.879	2.662	2.674	1.77
Primary recovery, bbl/acre-ft	19	121.4	1,134	484	479	278.1
Primary recovery, bbl x 10^6	19	0.3485	6.403	2.908	2.723	1.903
Ultimate recovery factor	20	0.114	0.836	0.4037	0.427	0.2419

TABLE 7. — STATISTICS OF RESERVOIR PROPERTIES OF THE STRAWN SAND (FROM TORIS DATA BASE)

Variable	Number of reservoirs	Minimum	Maximum	Mean	Median	Standard deviation
Well spacing, acres	20	8.5	183.3	58.41	44	42.22
Net pay, ft	21	6	110	24.21	15	26.59
Gross pay, ft	21	7.2	2,000	120.8	22.8	431.1
Porosity, %	21	10	23.5	17.41	17	3.002
Initial oil saturation, %	21	60	74	65.9	65	4.158
Current oil saturation, %	21	12.47	61.34	41.55	42.36	11.25
Depth, ft	21	850	6,400	4,043	3,970	1,077
Permeability, md	21	0.5102	335	80.59	55	78.78
API gravity	21	33.7	44	39	40	2.916
Total dissolved solids, ppm	11	50,000	240,600	146,600	120,000	84,260
Original oil-in-place, bbl x 10^6	21	2.495	593	70.71	18.17	154
Primary recovery factor	21	0.07	0.812	0.2885	0.2616	0.1856
Secondary recovery factor	11	0	0.29	0.05635	0.03	0.08818
Cumulative recovery, bbl x 10^6	21	0.2911	169.4	21.02	3.688	48.79
Primary recovery, bbl/acre-ft	21	43.86	675.3	204.3	194.6	131.5
Primary recovery, bbl x 10^6	21	0.2911	171.8	20.4	3.459	50.12
Ultimate recovery factor	21	0.09594	0.812	0.3396	0.302	0.1638

tively. Histograms of porosity, permeability, depth, net pay, OOIP, primary production (in bbl/acre-ft), and ultimate-recovery factor of these four plays are shown in Figures 10–16. The cross-plots of permeability and porosity of individual plays are shown in Figure 17.

Table 8 lists median values of important formation and production characteristics for the Bartlesville, Dakota, Wilcox, and Strawn reservoirs, together with those for all fluvial-dominated deltaic reservoirs. The primary-recovery value is not necessarily equal to the product of the OOIP and the primary-recovery factor, because median values are listed in Table 8. Bartlesville sandstone reservoirs have shallow depths of about 2,000 ft (Fig. 12), relatively thick net pay of 25 ft (Fig. 13), and high values of original oil in place (~82.7 million bbl) (Fig. 14). Wilcox sandstone reservoirs show the highest median values in porosity (30%) (Fig. 10), permeability (524 md) (Fig. 11), and primary recovery in barrels per acre-foot (479 bbl/acre-ft) (Fig. 15) among the four listed individual plays. The primary recovery from Wilcox sandstone reservoirs are known to benefit from a bottom-water drive. This water-drive mechanism helps Wilcox reservoirs to produce high primary recoveries and to require no secondary recovery. Oil gravities of all four plays in Table 8 are about the same as those of other fluvial-dominated deltaic reservoirs.

PRODUCTION CHARACTERISTICS

Visual analysis of cross-plots indicate that primary production is most strongly correlated with permeability and that the primary recovery factor increases with an increase in permeability in the reservoirs studied (Fig. 18). According to principles of reservoir engineering, reservoirs of high-permeability values result in high production rates, but not necessarily in high recovery factors. Recovery factor is determined by several qualities such as permeability, formation heterogeneity, fluid-rock properties, and reservoir-drive mechanisms.

Permeable reservoirs produce greater amounts of oil because lower-pressure drawdown is required to produce the same amount of oil, and capillary forces are smaller with more permeable rock, resulting in lower amounts of remaining oil. High permeability, in addition to the bottom-aquifer drive, may explain why the Wilcox reservoirs have produced more primary oil than the average fluvial-dominated deltaic reservoir.

Primary recovery in bbl/acre-ft decreases with increased well spacing (Fig. 19). The compartmentalization of fluvial-dominated deltaic reservoirs reduces the drainage area from a single vertical well. Primary production seldom reaches 500 bbl/acre-ft where well spacing is >160 acres. This relationship suggests that the application of infill drill-

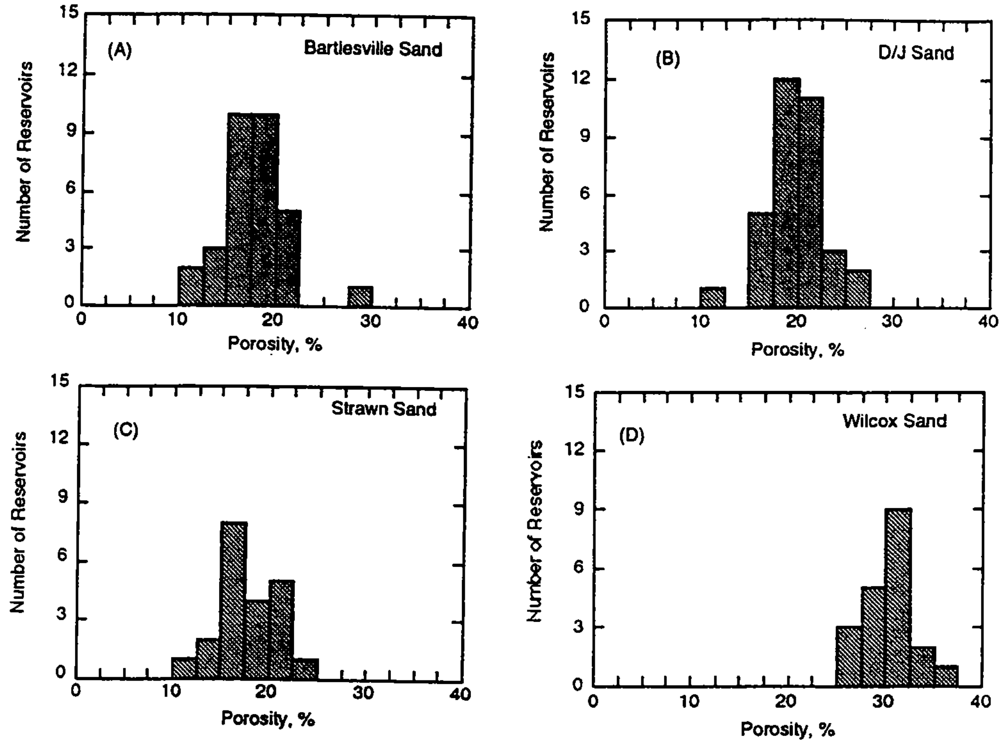

Figure 10. Histograms of porosity for four plays in the fluvial-dominated deltaic reservoirs studied.

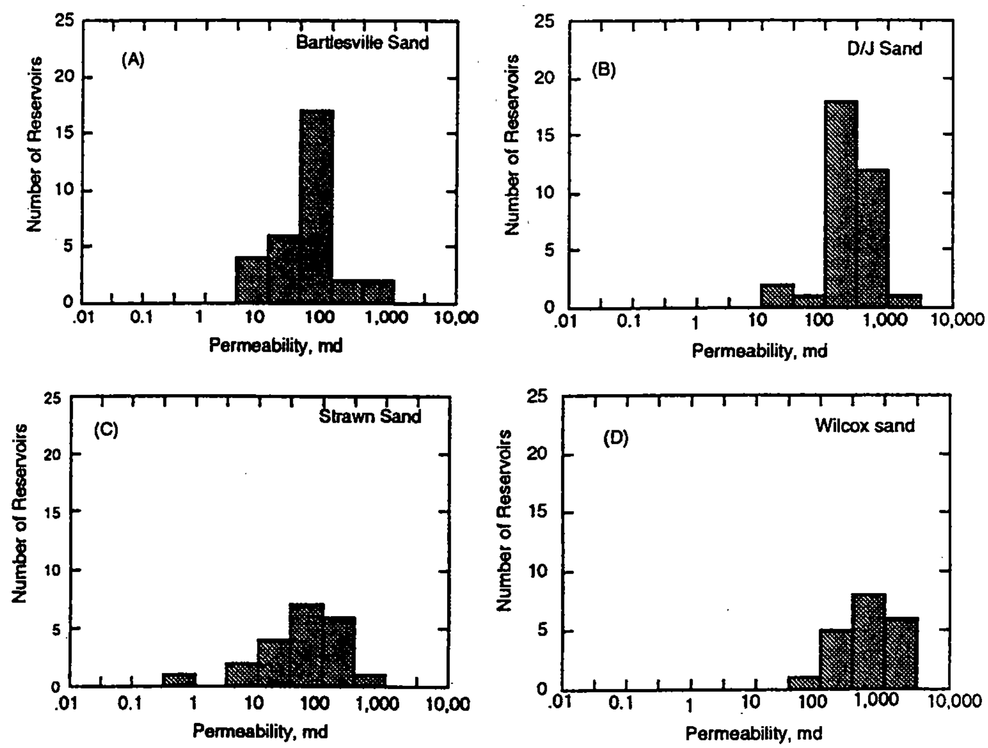

Figure 11. Histograms of permeability for four plays in the fluvial-dominated deltaic reservoirs studied.

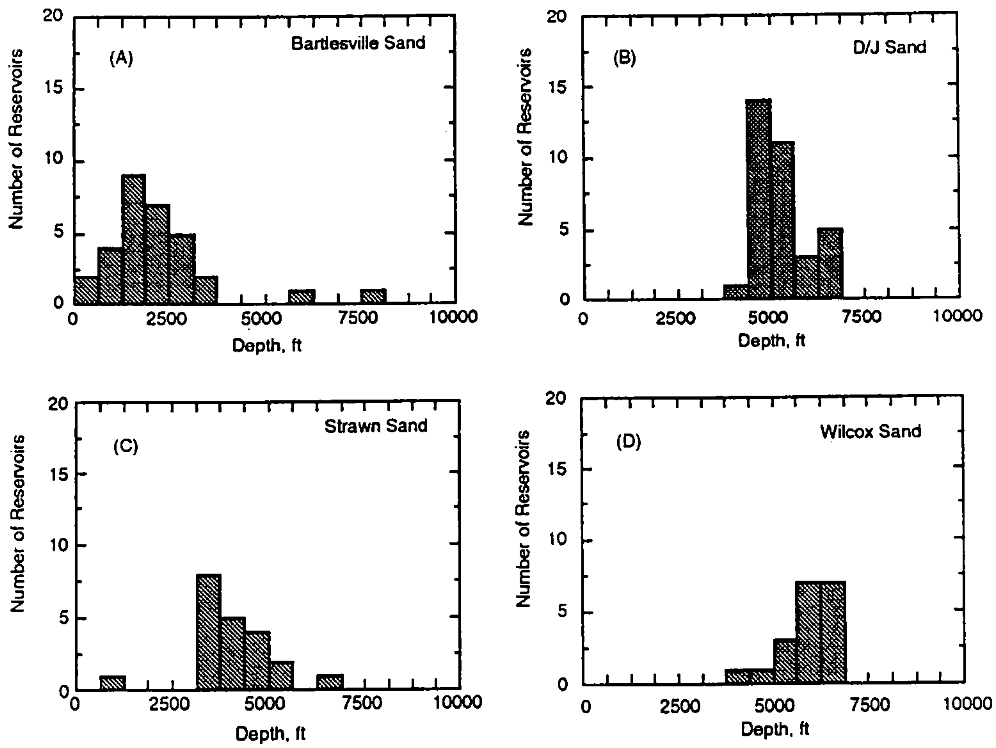

Figure 12. Histograms of reservoir depth for four plays in the fluvial-dominated deltaic reservoirs studied.

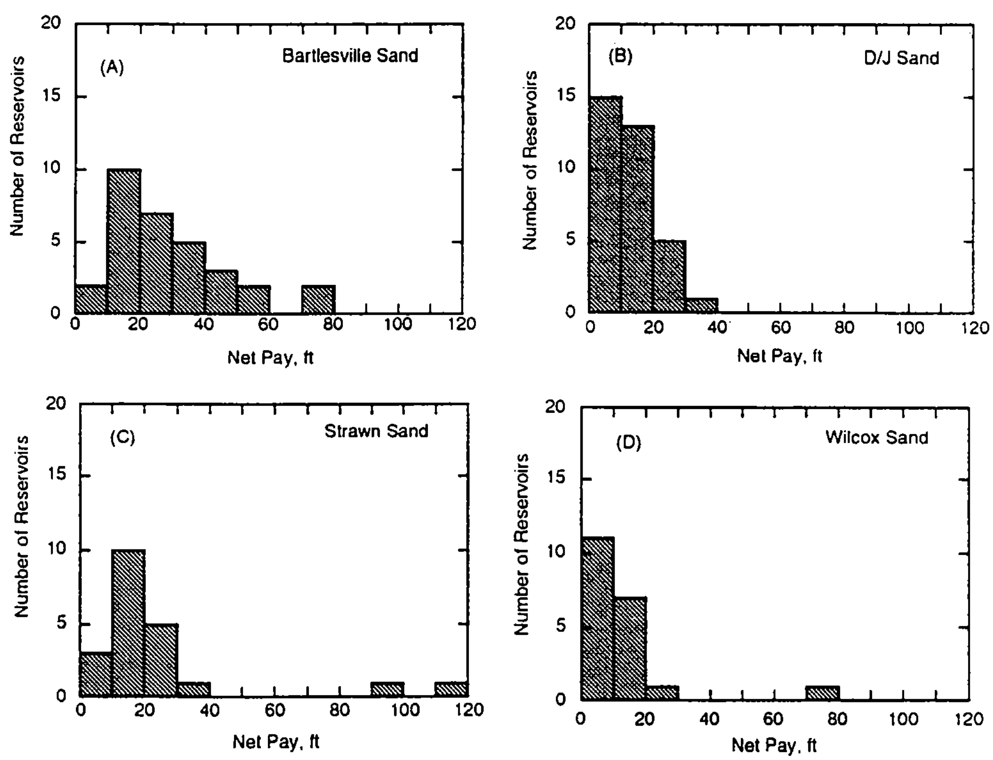

Figure 13. Histogram of net pay for four plays in the fluvial-dominated deltaic reservoirs studied.

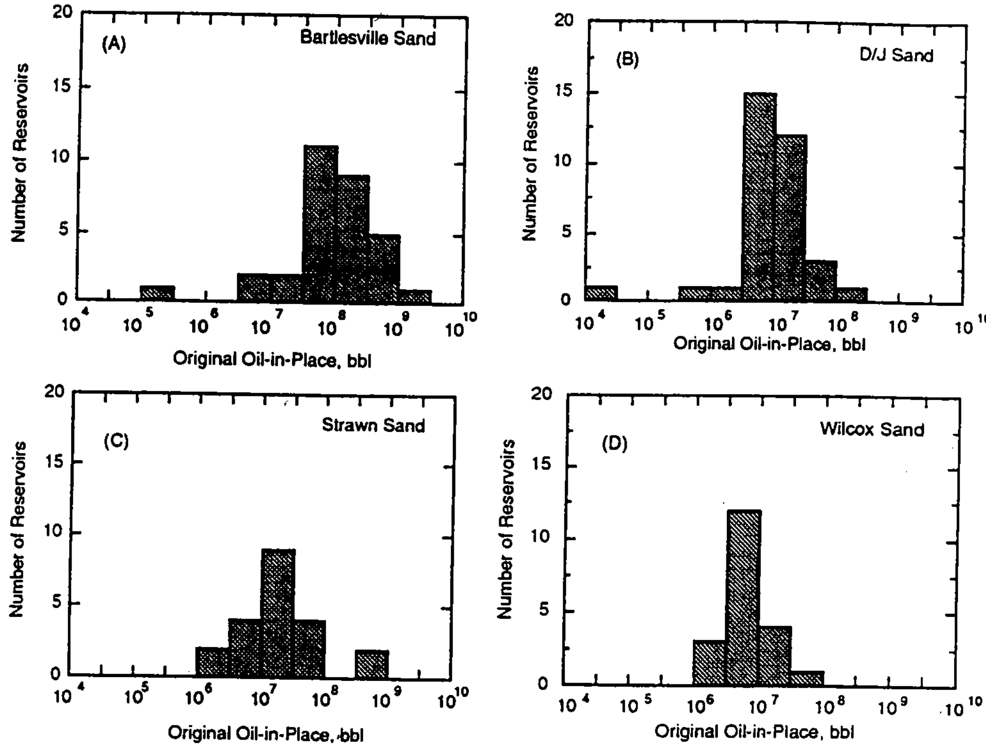

Figure 14. Histograms of original oil in place for four plays in the fluvial-dominated deltaic reservoirs studied.

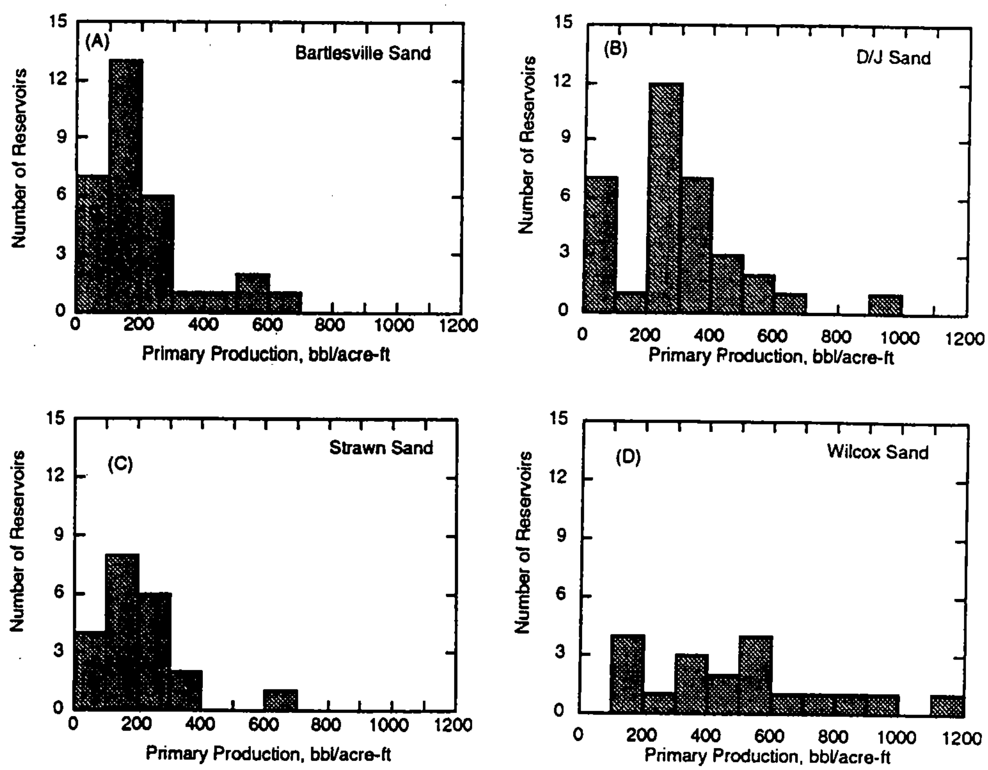

Figure 15. Histograms of primary production for four plays in the fluvial-dominated deltaic reservoirs studied.

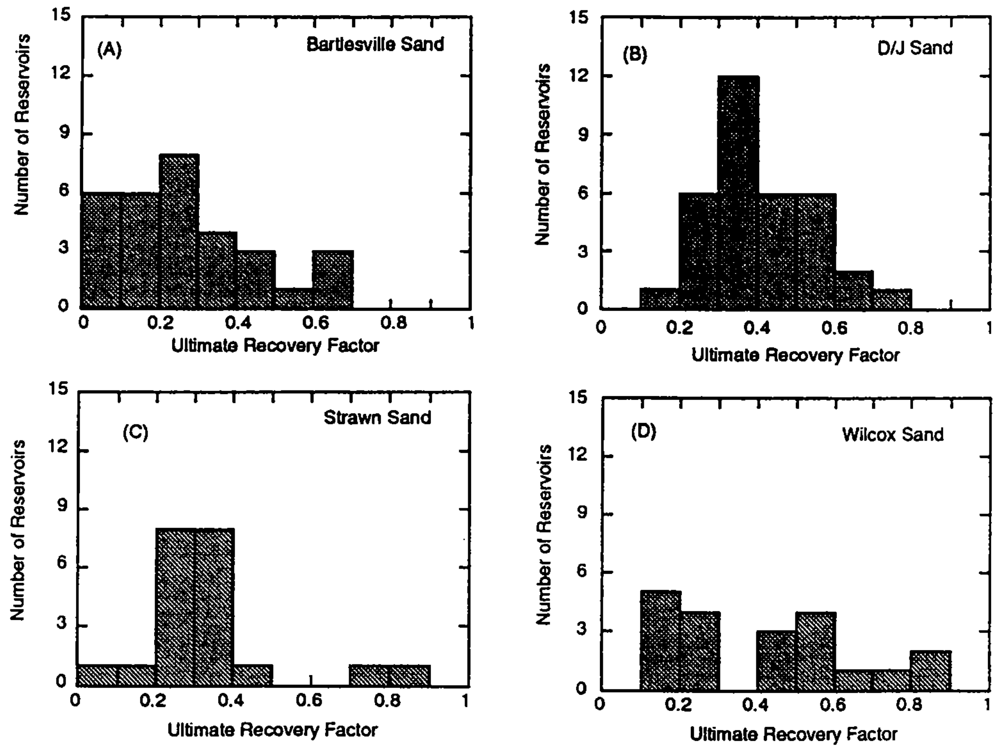

Figure 16. Histograms of ultimate recovery factor for four plays in the fluvial-dominated deltaic reservoirs studied.

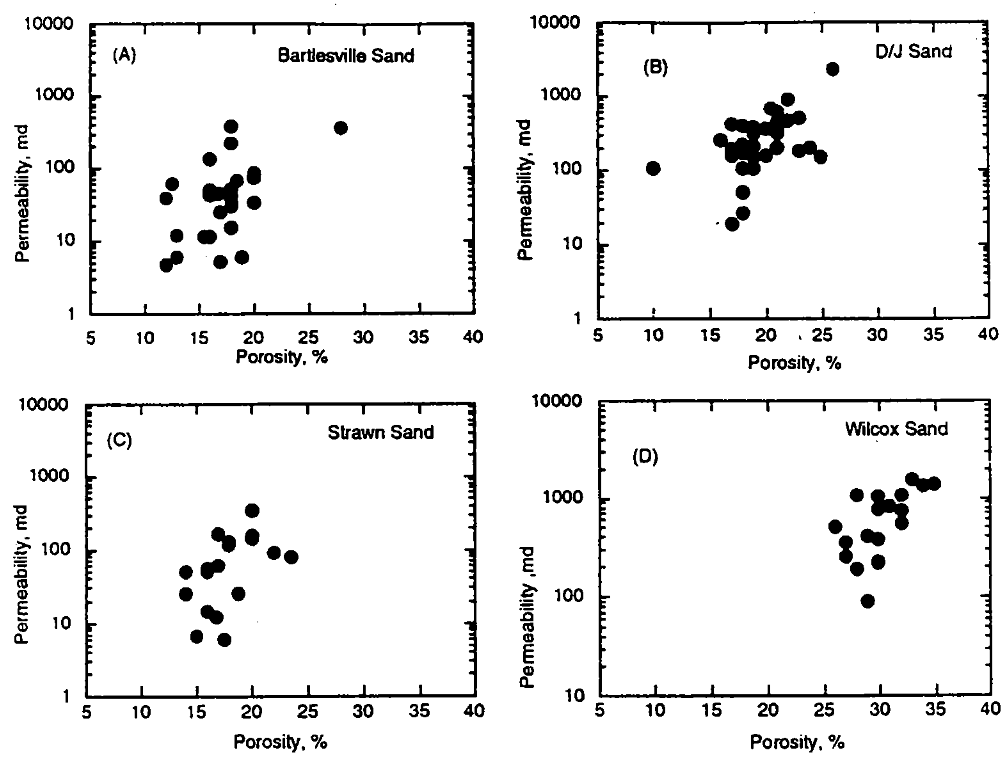

Figure 17. Semilog plot of permeability vs. porosity of four plays in the fluvial-dominated deltaic reservoirs studied.

TABLE 8. — MEDIAN VALUES OF RESERVOIR AND PRODUCTION DATA OF FLUVIAL-DOMINATED INDIVIDUAL PLAYS AND ALL DELTAIC RESERVOIRS (FROM TORIS DATA BASE)

	Fluvial delta	Bartlesville	D/J	Wilcox	Strawn
Number of fields	229	31	34	20	21
Porosity, %	19	18	19	30	17
Permeability, md	128	43	235	524	55
S_{oi}, %	68	68	71	62	65
Net pay, ft	16	25	10	11	15
Depth, ft	4,954	1,950	5,078	6,174	3,970
API gravity	39	38	38	39.5	40
Original oil-in-place, 10^6 bbl	26.6	82.8	8.4	6.4	18.2
Primary recovery, bbl/acre-ft	205	183	277	479	195
Primary recovery, 10^6 bbl	5.98	13.54	2.84	2.72	3.46
Primary recovery factor	0.26	0.23	0.32	0.44	0.26
Ultimate recovery factor	0.30	0.23	0.37	0.44	0.30

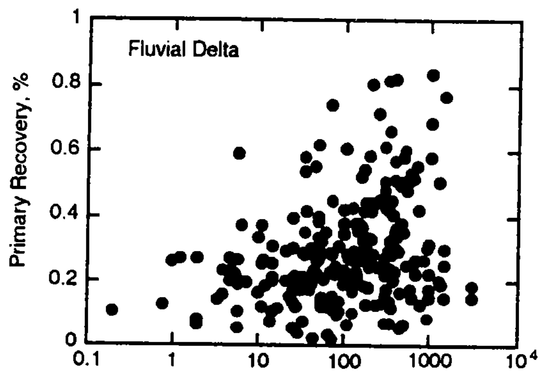

Figure 18. Effect of permeability on primary recovery factor for fluvial-dominated deltaic reservoirs studied.

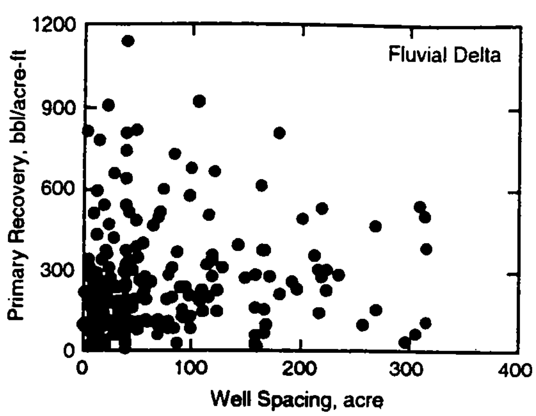

Figure 19. Well spacing vs. primary recovery of the fluvial-dominated deltaic reservoirs studied.

ing or horizontal-well drilling may be required to recover additional oil from fluvial-dominated deltaic reservoirs with a well spacing of >160 acres. Horizontal wells may be effective in penetrating laterally continuous, multiple reservoirs in high-quality coastal-barrier sandstones in wave-dominated deltas, but may be less effective in discontinuous reservoir sandstones from the same stratigraphic horizon in tide- and fluvial-dominated deltas.

Primary and secondary recovery were analyzed for fluvial-, wave-, and tide-dominated deltaic reservoirs. Primary recoveries from the different genetic types of deltaic reservoirs were similar, with median values ranging from 24% to 26% OOIP; however, differences in secondary-recovery production were apparent. The secondary-recovery factor (median value) for fluvial-dominated reservoirs was the lowest at 2% OOIP, in contrast to 8% OOIP for wave-dominated and 24% OOIP for tide-dominated deltaic reservoirs. The significantly higher recovery rates for tide-dominated reservoirs may be an artifact of well spacing, where the median well spacing is 20 acres in tide-dominated reservoirs as opposed to 40 acres in the fields producing from fluvial- and wave-dominated deltaic deposits (Tables 1–3).

The low secondary-recovery factors recorded for fluvial-dominated deltaic reservoirs (69 of the 142 reservoirs reported <1% secondary recovery) can be attributed to (1) reservoir heterogeneity, which prevents efficient water-flooding sweep; (2) extremely efficient primary production, which leaves relatively small amounts of oil for secondary recovery; and (3) incomplete data from many producing fields, where secondary-recovery data were not available. Fluvial-dominated deposits tend to have a greater amount of compartmentalization than wave- or tide-dominated deposits, which may explain the lower recovery factors.

An example of efficient primary recovery in a fluvial-dominated deltaic deposit is illustrated in the Wilcox reservoirs, where the production mechanism of bottom-water drive combined with high permeability resulted in higher primary recovery rates than the average from other fluvial-deltaic plays (Table 8).

Production characteristics reported for deltaic reservoirs located in Texas also indicate higher recovery efficiency in wave-dominated deltaic reservoirs (Tyler, 1988). This study showed that the unrecovered mobile oil (UMO) remaining in fluvial-dominated reservoirs averaged 43% for water-drive reservoirs and 27% for solution-gas–drive reservoirs, whereas the UMO in wave-dominated deltas averaged 37% for water-drive reservoirs and 10% for solution-gas–drive reservoirs.

REVIEW OF ENHANCED OIL RECOVERY (EOR) PILOT PROJECTS

EOR Projects in Deltaic Reservoirs

After primary and secondary recovery, an average of ~69% of the OOIP will remain unrecovered in deltaic reservoirs (see ultimate-recovery factor in Tables 1–3). This remaining oil will be the target of improved oil recovery. Improved oil-recovery methods include advanced secondary methods, such as targeted infill drilling, profile modification (chromium or aluminum cross-linked polymer, foams, etc.), and polymer flooding. These methods improve the sweep efficiency of water flooding and mitigate reservoir-scale and small-scale heterogeneities that cause movable oil to be left behind, even after extended water flooding. EOR processes include steam-flooding, cyclic steam, in-situ combustion, miscible- and immiscible-gas (CO_2, natural gas, enriched natural gas, and N_2), microbial, alkaline, surfactant, and alkaline-surfactant methods.

The DOE Bartlesville Project Office EOR Project data base showed 132 EOR projects in 37 fields producing from deltaic reservoirs. Of these 132 projects, 46 are steam (cyclic or steam drive); 4, in-situ combustion; 10, gas-injection; 38, polymer; 32, surfactant; 1, alkaline; and 1, microbial EOR projects. Of the 46 steam projects, 44 are in Coalinga, Lost Hill, and Elk Hills fields, which have crude oils in the 20.5°–22.8° API gravity range. The recovery methods in these cases were dictated by the process criteria. It is interesting that the number of gas-injection projects is small, most probably because of the lack of availability of CO_2. From these historic data, chemical flooding (surfactant, alkaline-surfactant, and polymer flooding) appears to be the prime EOR method to be applied in the deltaic reservoirs considered.

To maximize the economic recovery of oil by water flooding, application of an optimum advanced-secondary-recovery method (infill drilling, profile modification, and polymer flooding) will be needed to mitigate the effects of different scales and types of heterogeneities that affect water-flooding efficiency. The effective application of EOR methods to recover remaining oil after water flooding will depend upon a knowledge of the type and scale of heterogeneities limiting oil recovery. Venuto (1989) advocated tailoring EOR processes to geologic environments. Geoscientists and engineers should work together to design an EOR process to mitigate inefficient recovery due to geologic (rock properties and rock-fluid interactions) and production-induced heterogeneities.

Polymer flooding has been effectively applied to recover additional oil economically in the North Burbank field, Oklahoma, a deltaic reservoir, by mitigating channeling caused by field-scale heterogeneities (Zornes and others, 1986). In the same field, a more cost-effective polymer-flood method is being applied in which freshwater preflush is not required. The successful pilots at Loudon field, Illinois (Bragg and others, 1982; Reppert and others, 1990), also demonstrate the successful application of surfactant-polymer technology to improve displacement and sweep efficiencies and to mitigate small-scale heterogeneity. Application of the gravity-stable CO_2-miscible method in a tilted deltaic reservoir (Palmer and others, 1981) is another example of tailoring EOR processes to geologic environments.

SUMMARY

This study provides background information about the general reservoir and production characteristics of fluvial-dominated deltaic reservoirs. The main points presented are as follows:

As the median values of 229 fluvial-dominated unstructured deltaic reservoirs in the TORIS data base suggest, such reservoirs are generally high-quality reservoirs at moderate depth (4,945 ft), have good porosity (19%) and permeability (128 md), and produce light oil (39° API gravity) at a reasonable primary-recovery factor (0.26).

Permeability values were found to be the best indicator among formation parameters for the primary production in fluvial-dominated unstructured deltaic reservoirs. A low secondary recovery from fluvial-dominated deltaic reservoirs might be due to channeling, to flow barriers within the formation, or to efficient primary recovery.

Reservoir heterogeneities are the likely cause of poor performance of EOR projects. Comparison of chemical EOR projects in deltaic reservoirs shows that the recovery efficiency decreased from 60% to <30% for well spacing greater than 2 acres.

ACKNOWLEDGMENT

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Heterogeneities Related to Deltaic Depositional Proccesses and Their Effect on Water Flooding and Enhanced-Oil-Recovery (EOR) Processes

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ABSTRACT.—This paper presents a summary of reservoir heterogeneities related to deltaic depositional processes, their effect on fluid movement within the reservoir, and production methods to mitigate their effect on recovery efficiency.

Heterogeneities that occur as a result of deltaic depositional processes may cause significant recovery problems on scales ranging from the scale of the whole field to that of the individual pores. Field-scale heterogeneities include lateral continuity and interconnectedness of sandstone bodies and differences in reservoir quality due to the location within the depositional system. This scale of variability has been the cause of numerous problems in enhanced-oil-recovery (EOR) pilot projects. Examples illustrating field-scale heterogeneities are presented from the five-spot micellar-polymer pilot conducted in Sloss field, Nebraska, and two EOR pilots conducted in El Dorado field, Kansas.

Interwell-scale heterogeneities include (1) boundaries between genetic units, (2) lateral facies changes, (3) permeability zonation within genetic units, (4) permeability baffles within genetic units, and (5) permeability variations due to cross-bed sets. Boundaries between genetic units, such as channel deposits, often consist of clay drapes or mud-pebble conglomerates that range from low to zero permeability. These permeability barriers strongly affect horizontal and vertical sweep and contribute to compartmentalization of the reservoir. Examples of lateral facies changes on the interwell scale are distributary channels cutting into an adjacent, thinly bedded bay-fill or crevasse-splay deposit. These heterogeneities tend to cause channeling that strongly affects horizontal-sweep efficiency and moderately affects vertical-sweep efficiency. Permeability zonation within genetic units can consist of decreasing permeability upward, as occurs in distributary-channel deposits, or increasing permeability upward, as occurs in delta-front distributary-mouth-bar deposits. Permeability zonation strongly affects vertical-sweep efficiency, moderately affects horizontal-sweep efficiency, and can cause nonuniform residual-oil saturation (ROS) in swept zones. Permeability baffles within genetic units are typically caused by clay drapes between cross-bed sets and along scoured surfaces. The presence of these baffles strongly affects vertical-sweep efficiency and moderately affects horizontal-sweep efficiency and nonuniform ROS in swept zones. Cross-bed sets are a source of anisotropy in the reservoir, and their effect on fluid flow is dependent on the viscosity of the reservoir fluids, with adverse effects increasing as oil viscosity increases. Studies indicate that anisotropy from cross-bedding is greater in consolidated sandstone than in unconsolidated sand.

Microscopic heterogeneities include those caused by grain-size variations within cross-bed laminae and pore-size variations.

In general, infill drilling, horizontal and/or slant-well completion, and hydraulic fracturing are stimulation and production methods that are most applicable to overcoming field-scale heterogeneities, whereas EOR processes are most applicable to interwell and microscopic-scale heterogeneities.

In an analysis of 27 chemical EOR projects conducted in deltaic reservoirs from 17 fields, the fluid-flow problems most often reported were channeling, directional trends (preferential direction of fluid flow), and compartmentalization. Although fractures and faults may cause similar flow anomalies, they were not reported to be the cause in the cases studied.

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INTRODUCTION

Deltas are stream-fed depositional systems that occur along and create an irregularity in the shoreline of lakes, bays, lagoons, or the ocean. Deltas are created by the rapid influx, deposition, reworking, and subsidence of sediment at a rate that exceeds its removal by wave and tidal action. The scale of deltas can be small or large: for example, Kanes (1970) showed that the Colorado delta of Texas was only 1,300 ft wide at the turn of the century; on the other hand, the Nile delta is ~170 mi wide along the shoreline and nearly 100 mi from its apex to the shoreline.

The configuration of deltaic deposits in plan view has been described by Coleman and Prior (1982) (Fig. 1). Proceeding in a seaward direction, there are three major depositional settings: (1) The *upper deltaic plain* is dominated by fluvial processes. Representative facies include braided, straight, and meandering distributary-channel, lacustrine, and flood-plain deposits. (2) The *lower deltaic plain* lies within the range of high and low tides. The principal facies are deposited as interdistributary-bay fill, in crevasse splays, levees, and marshes, and as abandoned distributary-channel fill. (3) The *subaqueous delta* is dominated by marine processes (waves and currents) and tends to consist of reworked sediments. These facies include distributary mouth bars, channel-mouth tidal ridges, subaqueous slumps, mud diapirs, and prodelta muds.

Heterogeneities that occur as a result of delta genesis or depositional processes may cause significant recovery problems from the scale of the field to that of the pore. Heterogeneities that are not directly caused by depositional processes such as structural faults and fractures, diagenetic features, and rock-fluid interactions will not be discussed here although they exert significant effects on fluid flow.

The types of heterogeneities found in deltaic reservoirs are presented in Figure 2 in a decreasing order of scale. Although these heterogeneities are common in deltaic deposits, they may also apply to other depositional systems because the processes that formed them operate in a number of environments. For example, channelized flow occurs in fluvial systems as well as in delta distributary channels, and wave and tide processes shape coastal beaches, sand ridges, and shoreface sediments as well as delta-front sediments.

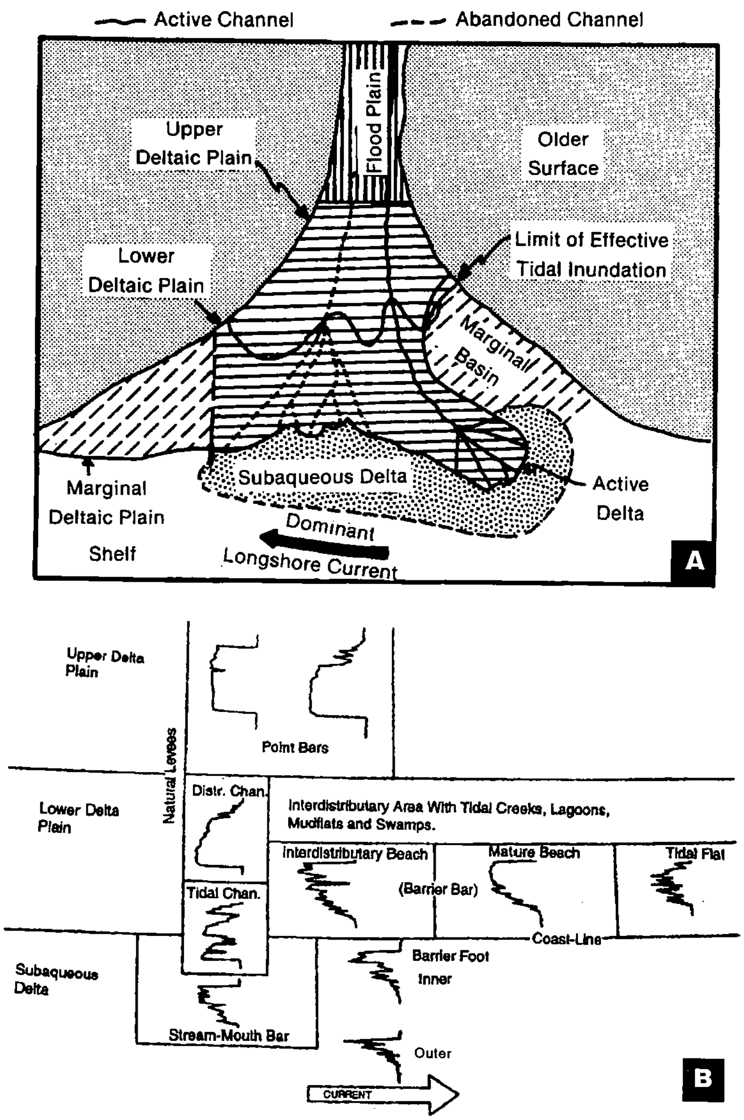

Figure 1. (A) Components of a typical delta system. After Coleman and Prior (1982). (B) Typical gamma-ray log patterns for major components of a typical wave-dominated delta. After Weber (1986). The log patterns are representative of the major depositional facies, but in no way do they indicate all of the possible variations.

DEPOSITIONALLY RELATED HETEROGENEITIES

Field-Scale Heterogeneities

Interconnectedness of Sandstone Bodies

On the field scale, the lack of interconnectedness of distributary sandstone bodies may present a major problem to sweep efficiency. Figure 2A illustrates three different degrees of distributary-channel interconnectedness separated by shale. Statistics of the widths, thicknesses, and lengths of distributary sandstone bodies presented above indicate that their dimensions can vary over an order of magnitude. Depositional controls on channel-sandstone interconnectedness are primarily related to the amount of sand that was in the depositional regime and the lithology of the underlying unit being cut into. If the underlying unit is shale, the channels do not tend to migrate laterally, resulting in deep, straight channels. If the underlying unit is sandstone, which is not as easily eroded as shale, the channels are shallower and wider, and the tendency to migrate laterally is increased. Lateral migration results in greater channel-sandstone interconnectedness. Theoretical studies on lateral migration patterns of river channels have shown that the channel-sandstone interconnectedness increases substantially when the sand/shale ratio exceeds 0.55 (Allen, 1970).

Figure 3 is a conceptual model of the effect of sandstone-body interconnectedness on waterflooding sweep efficiency. The reservoir model in Figure 3A is similar to the Statfjord reservoir in the North Sea (van de Graaff and Ealey, 1989) and consists of three units separated by shale. Each unit consists of different sand/shale ratios and degrees of interconnectedness between the sandstone bodies. Figure 3B presents the fluid distribution after water flooding showing that the middle unit remains unswept and illustrates the importance of sandstone-body connectedness on waterflooding sweep efficiency.

Location Within the Depositional System

A second type of field-scale heterogeneity is the variability of reservoir quality due to location within the depositional system. Previous studies have shown a generally good correlation between facies type and permeability in a number of different environments (Dreyer and others, 1990; Jack-

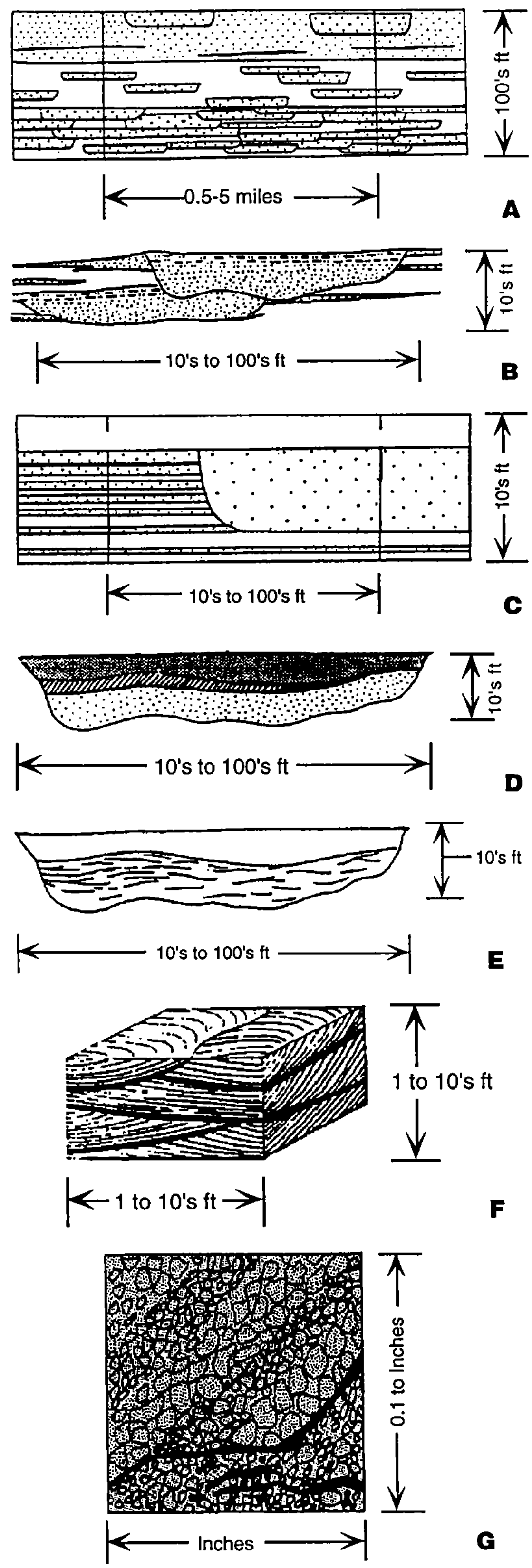

Figure 2 (right). Heterogeneities related to deltaic depositional processes. Modified from Weber (1986). (A) Sandstone-body continuity and interconnectedness. (B) Boundaries between genetic units. (C) Lateral facies changes. (D) Permeability zonation within genetic units. (E) Permeability baffles within genetic units. (F) Cross-bed sets. (G) Cross-bed laminae.

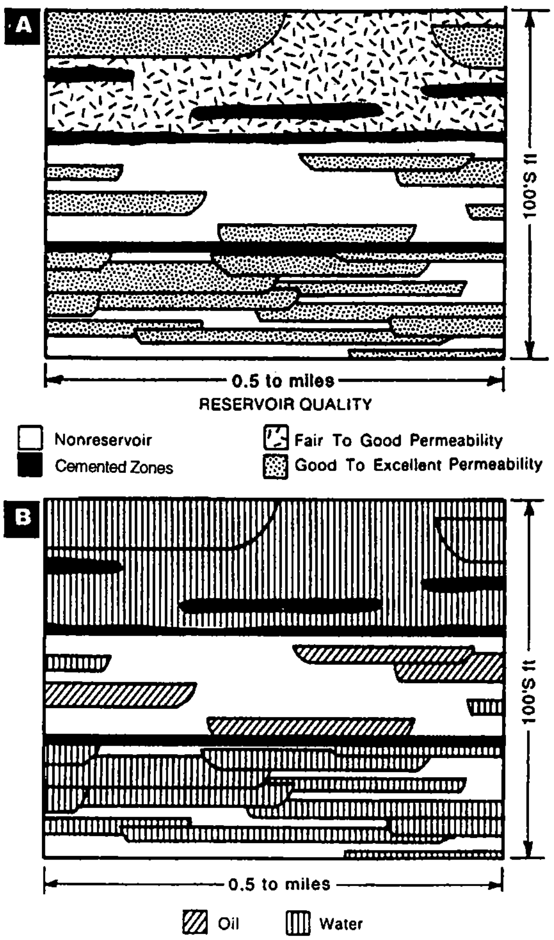

Figure 3. (A) Various distributions and degrees of interconnectedness of distributary-channel-sandstone bodies. (B) Conceptual fluid distribution after water flooding, illustrating the effect of sandstone-body distribution on sweep efficiency. After van de Graaff and Ealey (1989).

son and others, 1987,1991; Stalkup and Ebanks, 1986; Jones and others, 1987). The facies distribution, therefore, can be used to indicate the permeability distribution within a reservoir. Figure 1B illustrates the reservoir complexity due to the lateral variations of facies that occur within the area of the lower deltaic plain.

This scale of variability has been the cause for numerous problems in enhanced-oil-recovery (EOR) pilot projects. In Sloss field, Nebraska, for example, a five-spot micellar-polymer pilot was located in interdistributary crevasse-splay sandstones, which are discontinuous and have poor areal and vertical communication (Basan and others, 1978). Performance data collected during preflush water injection could not be matched with mathematical model results because they were based upon the more favorable properties of a distributary-channel sandstone recorded in another part of the field.

Another example of mislocated pilots in deltaic reservoirs is discussed in Szpakiewicz and others (1987). In El Dorado field, Kansas, producing from the Admire sandstone, two pilots were initiated with the objective to compare two separately designed tertiary oil-recovery methods (Van Horn, 1983). Comparison of the two methods was not valid because the pilot projects were located in different parts of the deltaic system—one pilot was located in interdistributary-bay shales, crevasse-splay deposits, and beach sandstone, and the second was located within distributary-channel sandstone and crevasse-splay deposits (Van Horn, 1983).

Field-scale heterogeneities can often be recognized deterministically by detailed well-log correlations and through sedimentological models derived from core descriptions and outcrop information. Recent advances in imaging technology and geostatistics have been applied to outcrop exposures. These advances allow quantification of the spatial distribution of facies and sandstone bodies in a fluvial-deltaic deposit (Ravenne and others, 1989; Ravenne and Beucher, 1988; Matheron and others, 1987). Detailed seismic studies may also be of value in delineating field-scale variations in reservoir quality.

Interwell-Scale Heterogeneities

Boundaries between genetic units, such as channel deposits (Fig. 2B), often consist of clay drapes or mud-pebble conglomerates that range from low to zero permeability. These permeability barriers strongly affect horizontal and vertical sweep and contribute to compartmentalization of the reservoir. The lengths of these shales are usually <1,000 ft.

Examples of lateral facies changes on the interwell scale are a distributary channel cutting into an adjacent, thinly bedded bay fill or crevasse splay (Fig. 2C) or a distributary channel prograding out over thinly bedded prodelta deposits. These heterogeneities tend to cause channeling, strongly affect horizontal-sweep efficiency, and moderately affect vertical-sweep efficiency.

An example of reservoir-scale heterogeneity is presented in Figure 4A, which depicts a single channel sandstone that has cut down into thinner sandstones interbedded with shales. The laterally equivalent thinner sandstones are commonly formed in crevasse splay or subaerial levees and have lower permeabilities and poorer vertical communication than the adjacent channel sandstone. Figure 4B shows the expected fluid distribution after water flooding that results from the permeability contrast, influence of gravity, and sandstone continuity. A field example similar to this is presented by Hartman and Paynter (1979).

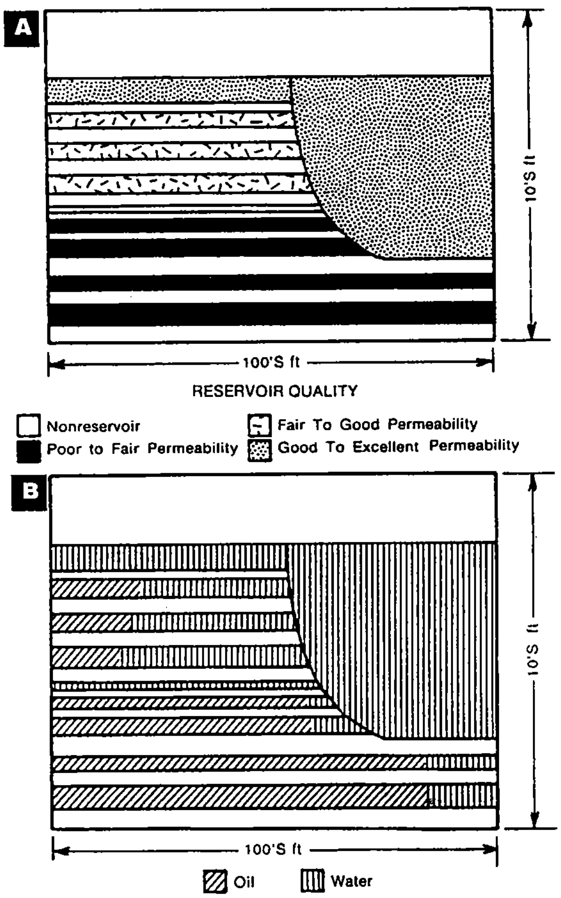

Figure 4. (A) Distributary-channel sandstone and its lateral facies equivalents, illustrating heterogeneity on the scale of the reservoir to that of the genetic sandstone body. (B) Conceptual fluid distribution after water flooding, showing unswept layers. After van de Graaff and Ealey (1989).

Another example of the effect of lateral facies changes is from the Mississippi delta area. The M_6 sandstone in the South Pass Block 27 is discussed by van de Graaff and Ealey (1989). This reservoir consists of a distributary channel that has prograded over and cut into a delta-front deposit. Figure 5A shows the fluid distribution within the M_6 sandstone at the time of field development in 1959. Figure 5B depicts the fluid distribution after 15 years of water-flooding production and illustrates the preferential sweep of the high-permeability zones.

Permeability zonation within genetic units (Fig. 2D) can consist of decreasing permeability upward, as occurs in distributary-channel deposits, or increasing permeability upward, as occurs in delta-front distributary-mouth-bar deposits. These heterogeneities strongly affect vertical-sweep efficiency, moderately affect horizontal-sweep efficiency, and cause nonuniform residual-oil saturation (ROS) in swept zones.

The effect of this type of heterogeneity on oil recovery was investigated by simulation studies by van de Graaff and Ealey (1989). Figure 6 shows the percentage of oil cut versus dimensionless oil recovery (equal to cumulative produced oil divided by movable oil) resulting from simulation studies. The two cases considered are a fining-upward (decreasing permeability) channel deposit typical of distributary channels and a coarsening-upward (increasing permeability) barrier bar typical of distributary-mouth bars and delta-front deposits.

The same parameters for both scenarios were used: uniform porosity, oil viscosity of 20 mPa•s (i.e., an unfavorable mobility ratio), and three layers of equal thickness with cross flow and with the same average permeability and absolute permeability. Only the position of the high-permeability layer is different.

Simulation results show that in the channel sandstone, a 5% oil cut (economic limit) is reached after ~35% of mobile oil has been produced (Fig. 6). By contrast, in the barrier-bar sandstone, oil cut is still 20% after 60% of mobile oil has been recovered. The reverse response may occur in a gas- or steam-injection scheme, however, because of the combined effect of gravity and presence of a high-permeability zone at the top of the sandstone. A barrier in a sandstone reservoir will give an unfavorable sweep as compared to a channel sandstone.

A field example from the North Sea Brent formation of the effect of an upward-decreasing permeability profile on injected water movement is discussed by Archer (1983). At the location where injected water channeled along the base of a distributary-channel fill, sweep efficiency was lower, and much less oil was recovered than expected.

Lateral-permeability zonation within genetic sandstone bodies is most strongly influenced by sedimentary structures and stratification type, clay content, and grain-size distribution. Permeability variations within distributary-channel sandstones were documented in an analysis of permeability data from outcrop exposures (Dreyer and others, 1990). The study indicated that the sandstone bodies consist of numerous interlocking permeability lenses that rarely exceed 3 ft in thickness or 60 ft in length or width. The lens-shape geometry of these zones is attributed to the channel depositional processes of infilling of scours and migration of bed forms along the channel bottom. Semivariogram analyses and correlation of permeability profiles indicated that permeability measurements tend to be unrelated at distances exceeding 6–10 ft. These heterogeneities strongly affect both horizontal- and vertical-sweep efficiency and cause nonuniform ROS in swept zones.

Permeability baffles within genetic units (Fig.

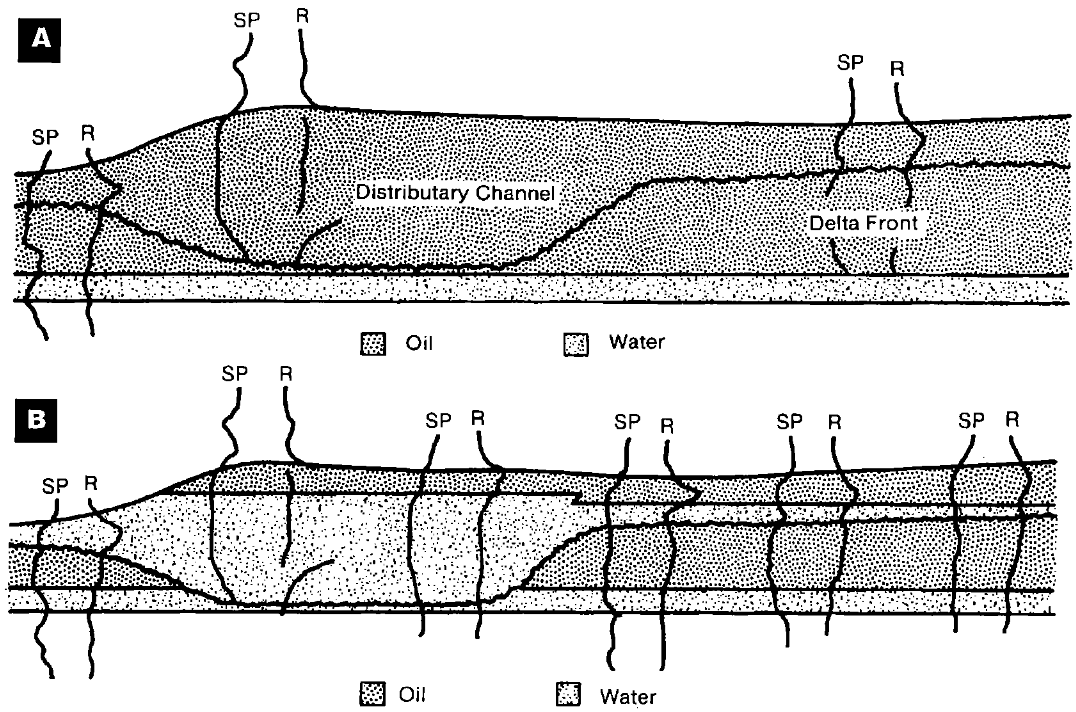

Figure 5. (A) Fluid distribution in M_6 sandstone (Mississippi delta area, South Pass Block 27) in 1959, at time of field development. (B) Fluid distribution in M_6 sandstone in 1974, after 15 years of production. After Hartman and Paynter (1979). Logs: SP = spontaneous potential, R = resistivity.

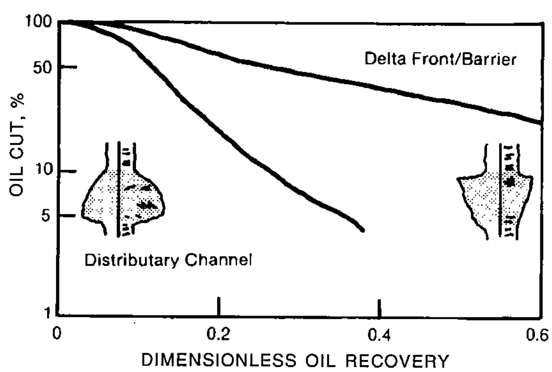

Figure 6. Influence of vertical distribution of permeability on oil recovery. Permeability profiles typical for the distributary-channel (decreasing permeability upward) and distributary-mouth-bar (increasing permeability upward) facies result in different oil-cut vs. oil-recovery curves, even with identical absolute permeability values. After van de Graaff and Ealey (1989).

2E) are typically caused by clay drapes between cross-bed sets and along scoured surfaces. Their presence strongly affects vertical-sweep efficiency and moderately affects horizontal-sweep efficiency and nonuniform ROS in swept zones.

Cross-bed sets (Fig. 2F) are a source of anisotropy in the reservoir. Emmett and others (1971) described the influence of cross-bedding on infill drilling and secondary recovery in the Tensleep Formation in Wyoming. They found that permeability parallel to the cross-bed laminae is about four times higher than that perpendicular to the laminae. The effect of the permeability contrast is dependent on the viscosity of the fluid, where the higher the viscosity of the oil, the greater the effect. Jones and others (1987) documented permeability ranges and the degree of anisotropy for the stratification types of trough cross-bedding, as well as ripples and dewatering structures in outcrop exposures of the Mesaverde Formation in Colorado.

Weber and others (1972) determined the permeability distribution in an unconsolidated, trough cross-bedded distributary-channel fill and developed a model for calculating permeability anisotropy. In-situ flow experiments were performed in the channel-fill sandstone to check the permeability anisotropy calculations. Weber and others concluded that permeability anisotropy in unconsolidated distributary-channel fill is negligible; however, in consolidated sand, the anisotropy is expected to be very large.

Microscopic-Scale Heterogeneities

Permeability variations caused by grain-size variations within cross-bed laminae are a small-scale heterogeneity common in distributary-channel deposits (Fig. 2G). The permeability contrasts between cross-bed lamina can range from very slight to great where impermeable shale laminae are interlayered with sandstone laminae and may impart a significant effect on ROS and log response.

Kortekaas (1983) analyzed the effect of permeability variations on the displacement of oil by water within cross-beds with a permeability contrast of 5 between laminae. His work shows that when fluid flow is perpendicular to the cross-bed laminae and the rock is water-wet, oil within the higher permeability laminae may be initially bypassed because of the higher capillary pressures in the lower-permeability (finer-grained) laminae (Fig. 7). His simulation study also showed that low-tension (dilute surfactant) and polymer floods would improve recovery in these cross-laminated zones.

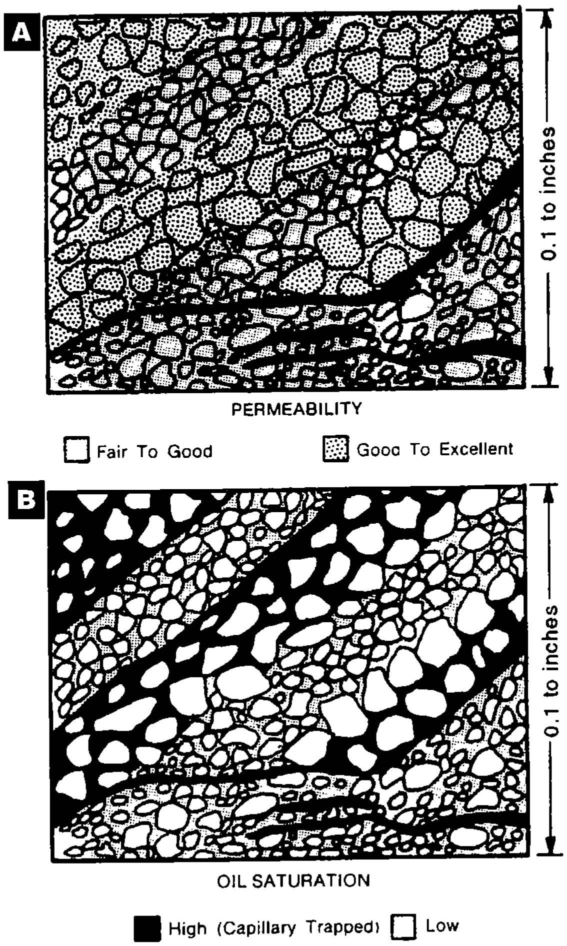

Figure 7. (A) Conceptual model of permeability heterogeneity in cross-bed laminae. After van de Graaff and Ealey (1989). (B) Hypothetical fluid distribution after water flooding. After Kortekaas (1983).

These results are consistent with those of Tomutsa and others (1990), who used computed tomography (CT) scanning techniques to monitor fluid distributions while flooding a cross-bedded rock sample first with oil and then with water. They found that the lower-permeability laminae accepted less oil than the higher-permeability layers after flooding, as expected. After flooding with water, however, the water entered the lower-permeability layers first. This response can be partly explained by the higher water saturations in the lower-permeability layers, which therefore have higher initial relative permeability to water than the higher-permeability, oil-saturated zones. As flooding continues, the relative permeability to water increases in the lower-permeability zone with an increase in water saturation.

Textural variations may create errors in the calculation of irreducible water saturation and permeability (Jacobsen, 1991). This error may be increased by diagenetically altered, cross-bed laminae that result in erroneously high water-saturation measurements. Salle and Wood (1984) reported on a reservoir in which laminae with high kaolinite content, plugged pores, and low permeabilities alternate with laminae that contain moderate amounts of kaolinite and permeability in the darcy range. Average water saturations derived from geophysical logs were as high as 60%, but the reservoir maintained water-free production of up to 6,000 b/d (Salle and Wood, 1984). The kaolinite forms a microporosity system that is filled by immobile water in the low-permeability layers, whereas oil can flow through the cleaner, higher-permeability laminae. Advances in logging techniques, such as improved dipmeter (Salle and Wood, 1984) and the dielectric (EDT) approach along with geochemical methods (GLT log), are showing much promise in the analysis of thin-bedded rocks (Jacobsen, 1991).

APPLICATION OF ADVANCED PRODUCTION METHODS TO MITIGATE DEPOSITIONALLY RELATED HETEROGENEITIES

In general, the methods of infill drilling, horizontal and/or slant wells, and hydraulic fracturing are most applicable to larger field-scale heterogeneities, whereas EOR processes are most applicable to interwell and microscopic-scale heterogeneities. Table 1 summarizes the enhanced production methods that may be applicable in overcoming the heterogeneities related to depositional processes described in the previous section.

TABLE 1. — APPLICATION OF ENHANCED PRODUCTION METHODS TO HETEROGENEITIES RELATED TO DELTAIC DEPOSITIONAL PROCESSES

	Infill	Horizontal or slant	Hydraulic fracturing	Gel polymer	Polymer	Surfactant alkali-surf.	CO_2	Steam	In-situ combustion
Field scale sandstone body continuity:									
Continuous	X	X	X						
Semicontinuous	X		X						
Separated	X								
Boundaries between genetic unit	X	X	X						
Lateral facies changes	X	X		X					
Permeability zonation				X	X				
Permeability baffles			X						
Cross-bed sets			X			X	X	X	X
Cross-bed laminae					X	X	X	X	X

Sandstone-body Continuity and Interconnectedness

For sandstone bodies that are separated both laterally and vertically by large distances (as in the top third of Fig. 2A), the only recourse for increased oil production is to infill drill. As the connectivity between sandstone bodies increases (as in the middle part of Fig. 2A), the drilling of both vertical infill wells and horizontal wells may mitigate the effects of this field-scale heterogeneity. The degree of lateral connectedness of the sandstone bodies will determine whether a horizontal or infill well would be most effective. Horizontal wells are best applied when the sandstone bodies are well interconnected; such wells can cut across flow barriers between stacked sandstone bodies. Hydraulic fractures increase production from a horizontal well by connecting two or more neighboring sandstone bodies, providing that the shale layer in between will propagate a fracture.

For an offshore reservoir with similar field-scale permeability barriers but a pattern that is inverse to the one illustrated in Figure 2A, Johnson and Krol (1984) illustrated through simulation studies the possibility that simultaneous miscible-gas flooding in the top, laterally continuous (transgressive) unit and water flooding in the lower individual and multistory channel-sandstone unit would improve recovery efficiency in the top unit by 14%.

Boundaries Between Genetic Units

Infill drilling would be best applied to overcome permeability barriers caused by boundaries between genetic units with dimensions in the 10s to 100s of feet in the *x-y* directions. The use of hydraulic fracturing or short laterals from the vertical well may be desirable to provide better flow.

Lateral Facies Changes

The residual oil after water flooding, indicated in Figure 4, suggests that thin laminae adjacent to a channel with good permeability will not be swept efficiently. One effective technique to overcome directional permeability or channeling is to apply a line-drive pattern so that the injected water flows perpendicular to the direction of the permeability trend. The line-drive pattern has been successfully applied in numerous reservoirs including North Burbank field in Oklahoma (Trantham and others, 1980). In reservoirs having significant quantities of oil in thin laminae, another effective method to correct for lateral facies changes is the use of infill wells (i.e., vertical or steeply angled wells) in the tight thin zones; in some instances, polymer gel may be used to modify the flow profile.

Permeability Zonation Within Genetic Units

Heterogeneity caused by the vertical arrangement of permeability can usually be mitigated through properly designed, improved water-flooding methods such as polymer flooding or profile modification or a combination of the two. Cross-linked polymers including chromium acetate, chromium propionate, and aluminum acetate polymers in profile modification and polymer flooding have been successfully used to improve the sweep efficiency in high-permeability zones in deltaic reservoirs such as the North Burbank and North Stanley Units of Burbank field (Zornes, 1986; Harpole and Hill, 1983). These methods reduce drive-water mobility and decrease the degree of water channeling, thereby improving conformance and overall water-flooding volumetric sweep efficiency. Profile modification and polymer flooding may not be an economic solution in large, high-permeability zones or when the ratio of vertical to horizontal permeability is >0.01, where the water will revert back to the high-permeability zone after it flows past the gel-polymer slug (Gao and others, 1990). In these cases, targeted infill drilling may be a better solution.

In reservoirs having a small permeability contrast between zones, polymer flooding can compensate for the imbalance in water intake due to the differences in fluid conductivity. However, polymer flooding cannot completely correct for permeability-zonation–induced flow imbalances, as indicated by pilot evaluation studies of post–surfactant-polymer flooding in which higher residual saturations in tighter zones were reported (Taggart and Russell, 1981; Smith, 1991). Mechanical methods, such as flow baffles and selected perforation have also been used with some success.

Permeability Baffles Within Genetic Units

Horizontal permeability baffles reduce vertical permeability and may affect horizontal wells more adversely than vertical wells. Hydraulic fracturing stimulation will improve injectivity or productivity around the well bore.

Cross-bed Sets

As indicated in the previous section, water flooding in cross-bedded intervals can be highly inefficient because of trapping of oil by capillary forces and bypassing zones because of shale layers. In this situation, the recovery efficiency can be improved by using a miscible displacement (CO_2, hydrocarbon gas, etc.) process that reduces the capillary forces that trap the crude oil and overcomes the viscous forces that tend to retard crude-oil flow (Hornof and Morrow, 1988). A dilute surfactant or alkali-surfactant process may be useful and should be investigated. However, the use of polymer for mobility control may not be desirable because of the potential filtering effect of the shale streaks that occur between the cross-bed sets. This phenomenon may be the cause of problems encountered in a number of pilots in which only the surfactant slug but not the polymer reached an observation well or evaluation well (Lorenz and others, 1986; Cole, 1988a,b; Huh and others, 1990).

Cross-bed Laminae

The difference in pore size in cross-bed laminae tends to promote nonwetting phase trapping. For water-wet rock, rapid imbibition of water into the tighter laminae leaves the higher-permeability laminae unswept and with a high ROS (immobile oil). This effect was shown in the simulation work of Kortekaas (1983) and the theoretical review of Stegemeir (1976).

The only way to overcome this type of heterogeneity is by increasing the capillary number and improving the displacement efficiency via one of the EOR methods. Any of the conventional EOR methods—chemical, miscible gas (reduction of interfacial tension), and thermal (reduction of viscosity)—can overcome the effect of oil trapping induced by cross-bed laminae.

EFFECTS OF SEDIMENTOLOGICAL FACTORS ON EOR PILOT PROJECTS

The influence of sedimentological factors on water flooding was discussed in previous sections. Since most EOR processes involve injection of fluid to mobilize and displace residual oil, the same sedimentological factors are expected to influence EOR recovery efficiency. Any effect is amplified because of the small pore volume of the EOR fluid injected.

Since the early 1970s and until recently, many EOR pilots and commercial field tests were performed, and there are a significant number of papers and reports evaluating the causes and reasons for successes and failures of these projects. Unfortunately, most of the evaluations concentrated on the recovery processes, and even when the geologic factors were evaluated, little effort was expended in relating the project performance to heterogeneities induced by the depositional environment.

In an attempt to determine the effect of these heterogeneities on EOR recovery efficiency, reports and publications on EOR projects performed in deltaic reservoirs were reviewed. It is interesting that almost all DOE-sponsored and a large proportion of industry-sponsored chemical EOR pilots tests were conducted in deltaic reservoirs. In this review, only the effects of sedimentologically related reservoir heterogeneity were considered. Although the efficacy of the recovery process is also important, it is outside the scope of this paper and will not be discussed here.

Table 2 is a compilation of the observations reported in the literature from 17 fields and 27 chemical EOR projects conducted in deltaic reservoirs. The fluid-flow problems most often reported were channeling, directional trends (preferential direction of fluid flow), and compartmentalization. Although fractures or faults may cause similar flow anomalies, they were not reported to be the cause in the examples listed.

Channeling

A project is considered to be affected by channeling when a high-permeability zone affects the distribution of fluids or when a zone is taking a disproportionate volume of the injected fluid. Ver-

TABLE 2. — GEOLOGIC FACTORS AFFECTING EOR RECOVERY

Field name	EOR type[a]	Well spacing (acre)	Recovery efficiency (%)	Channeling	Compartments	Contact high salinity	Formation parting	Directional trend	Facies[b]
Benton, IL[1]	S/P	1	27	yes	yes	yes			
Big Muddy 1, WY[2]	S/P	1	36				yes		dc, dfr
Big Muddy 2, WY[3]	S/P	10	14	yes			yes		
Delaware Childer, OK[4]	S/P	2.5	7	yes		yes		yes	
El Dorado, KS[5]	S/P	6.4	0			yes			
Glennpool, OK[6]	S/P			yes	yes		yes	yes	
Loudon 1, IL[7]	S/P	0.625	15.3			yes			
Loudon 2, IL[8]	S/P	0.68	60	yes		yes		yes	dmb, mb, df
Loudon 3, IL[9]	S/P	0.71	68	yes	yes				
Loudon 4, IL[10]	S/P	2.5/5	27/33	yes	yes				
Main Consolid.1, IL[11]	S/P	0.75	63	yes			yes		dc, pb
Main Consolid.2, IL[12]	S/P	10	39	yes					
Main Consolid.3, IL[13]	S/P	3	27 to 33						
Main Cons.4, IL[14,15]	S/P	2.5/5	20/17	yes	yes	yes	yes		
Manvel,TX[16]	S/P								
North Burbank, OK[17]	S/P	10	25	yes	yes	yes	yes	yes	fc, mmtl
North Burbank, OK[18,19]	P	20		yes			yes	yes	fc, mmtl
North Stanley, OK[20]	P		1.4	yes					
Ranger, TX[21]	S/P	40	25		yes				dc
Salem 1, IL[22,23]	S/P	5	14	yes	yes	yes			df
Salem 2, IL[24,25]	S/P	5	47	yes		yes			
Sloss, NE[26]	S/P	9	yes	yes	yes				
Bay St. Elaine, LA[27]	CO_2M	—	—	—	—	—	—	—	obs
Garber, OK[28]	CO_2M	10.4	14	yes	yes				dc, df
Rock Creek 1, WV[29]	CO_2M	10	3	yes	yes				
Rock Creek 2, WV[30]	CO_2M	1.55	11	yes	yes				
Grann. Creek, WV[31]	CO_2M	0.85/6.7	37/6	yes	yes				

[a]S/P = Surfactant (including microemulsion, low tension and soluble oil)-polymer. P = Polymer. CO_2M = Carbon dioxide miscible.

[b]dc = distributary channel; df = delta front; dfr = delta fringe; dmb = distal mouth bar; fc = fluvial channel; mb= mouth bar; mmtl = marginal-marine tidal or lagoonal deposit; obs = overbank splay; pb = point bar.

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1. French and others (1973).
2. Ferrell and others (1984).
3. Cole (1988a).
4. Thomas and others (1982).
5. Ferrell and others (1987).
6. Crawford and Crawford (1985).
7. Pursley and others (1973).
8. Bragg and others (1982).
9. Reppert and others (1990).
10. Huh and others (1990).
11. Gogarty and Surkalo (1971).
12. Earlougher and others (1975).
13. Howell and others (1979).
14. Cole (1988b).
15. Stover (1988).
16. Hamaker and Frazier (1978).
17. Lorenz and others (1986).
18. Zornes and others (1986).
19. Moffitt and others (1990).
20. Harpole and Hill (1983).
21. Holley and Cayais (1990).
22. Strange and Talash (1977).
23. Widmeyer and others (1977).
24. Ware (1983).
25. Widmeyer and others (1985).
26. Basan and others (1978).
27. Taggart and Russell (1981).
28. Kumar and Eibeck (1984).
29. Brummert and others (1986).
30. Watts and others (1982).
31. Palmer and others (1981).

tical permeability zonations within genetic sandstone bodies are common in deltaic reservoirs, with higher permeabilities (and therefore preferred conduits for fluid flow) occurring at the bases of distributary-channel deposits and at the tops of distributary-mouth-bar and delta-front deposits.

The high-permeability channels reduce the effectiveness of the designed slug because most of the injected EOR fluid will flow in the high-permeability zone, which has low ROS because of waterflooding sweep efficiency. The lower-than-expected recovery reported for the M-1 surfactant pilot was attributed to a similar situation (Smith, 1991), where only a small fraction of the slug contacted the zone with high oil saturation. This phenomenon was observed in 20 of 27 (74%) of the field tests listed in Table 2.

Compartmentalization

Compartmentalization—i.e., barriers to flow of EOR fluids—was reported in 13 of 27 (48%) projects reviewed. Compartmentalization may result from boundaries between genetic units, lateral facies changes, and clay drapes between cross-bed sets (discussed above) that prevent communication between injectors and producers or result in unswept areas of the reservoir. In certain cases, barriers to flow were not detected when low-viscosity fluids such as preflush, tracer, or surfactant solutions were injected. However, when polymer solution was injected, the progress of the polymer slug was impeded. Compartmentalization could reduce the effectiveness of an otherwise well-designed EOR project.

Directional Permeability Trends

Directional trends of permeability may be caused by the orientation of cross-bedding or higher-permeability channel deposits that lie in lower-permeability facies, both of which generate a preferential direction of flow. Tracer tests or recovered surfactant and polymer are often able to confirm the presence and directions of high-permeability trends (Holley and Cayais, 1990). This feature was observed in six (22%) of the projects reviewed.

Contacting High-Salinity Region

Channeling, compartmentalization, and/or directional trends may result in bypassing of areas within a reservoir and preservation of the original formation brines. As a consequence of better mobility control of the EOR process, these high-salinity pockets are contacted during an EOR project. This phenomenon was reported only in chemical EOR projects in which high salinity was found to reduce the effectiveness of the EOR fluids.

Formation Parting

The phenomenon of formation parting is not related to the depositional environment of a deltaic reservoir; rather it is caused by exceeding the parting pressure when injecting fluids. It is included here, however, because it was reported in eight of the projects reviewed. Formation parting was reported in many of the chemical-flooding projects where high-viscosity fluids were injected for mobility control. Formation parting may be caused by the presence of fractures or low in-situ stresses in shallow reservoirs. Natural fractures, however, were not cited as the cause of formation parting, even though fractures were present in some of the fields.

Discussion

Lower-than-expected oil recovery was partially attributed to heterogeneity related to depositional processes in the projects listed in Table 2. Quantification of the effects on recovery are not possible at this point. However, comparison of performance to well spacing may indicate the scale of the features controlling production. Figure 8 is a plot of recovery efficiencies against well spacing for a number of micellar-polymer field tests performed in Loudon, Main Consolidated (Robinson), and Big Muddy fields. These fields were chosen because several projects had varying well spacing but similar chemical slugs. The 1973 pilot test at Loudon was not included because the slug was different from that of subsequent field tests, and pilot "119" at the Main Consolidated (Robinson) field was also excluded because of the different well pattern used (it was a line-drive pilot with 10-acre spacing between injectors and producers and 2.5-acre spacing between injectors).

Figure 8 shows that the recovery efficiency decreased from 60–70% to <30% for well spacings greater than 1 acre. Although other explanations can be advanced, reservoir heterogeneities are the likely cause. Smith (1991) showed that poor vertical and areal sweep efficiencies within the Main Consolidated (Robinson) field, caused by the presence of stacked sandstone bodies and directional permeability, are the probable reason for the lower than anticipated oil recovery. He suggested that a line-drive pattern may alleviate these geologic problems. The higher recovery efficiency of the "119" project using a line-drive pattern supports this hypothesis. In another case, Holstein (1991), in his discussion of Loudon field, attributed the lower recovery efficiency in pilots with larger well spacing to poor polymer transport. The probable causes for poor polymer transport are (1) disassociation of polymer from surfactant slug (Holstein, 1991), (2) low-permeability rock (Huh and others, 1990), and (3) reservoir compartmentalization.

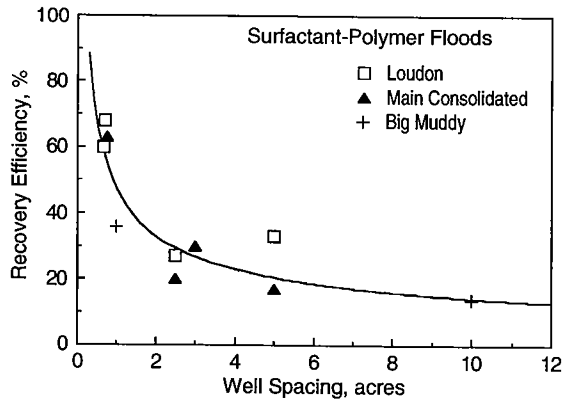

Figure 8. Relationship between well spacing and recovery efficiency in EOR pilot projects.

SUMMARY

Geologic heterogeneities within reservoirs are related to deltaic depositional processes, may cause significant recovery problems, and occur on a wide variety of scales. Field-scale heterogeneities include the degree of interconnectedness of sandstone bodies and the location within the depositional system. Interwell-scale heterogeneities include boundaries between genetic units, lateral facies changes, style of bedding, and permeability variations within genetic units. Heterogeneities on the core-plug scale include lamination, textural variations, and diagenetic alteration of the mineral content of the fluids in the pore system.

In general, the methods of infill drilling, horizontal and/or slant wells, and hydraulic fracturing are most applicable to larger field-scale heterogeneities, whereas EOR processes are best applied to interwell and microscopic-scale heterogeneities.

The fluid-flow problems most often reported from EOR projects in deltaic reservoirs are channeling, directional permeability trends, compartmentalization, formation parting, and contacting high-salinity regions.

Reservoir heterogeneities are the likely cause of poor performance of EOR projects. Comparison of recovery efficiencies from chemical EOR projects in deltaic reservoirs shows that the recovery efficiency decreased from 60–70% to <30% for well spacing greater than 1 acre.

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Understanding Reservoir Depositional Environments Contributes to Optimizing Oil Production: Muskogee Oil Field, A Classical Example

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ABSTRACT.—A combined geologic and petroleum engineering evaluation of the Muskogee oil field region in northeastern Oklahoma was conducted with emphasis on the sedimentary environments. This depositional environment study provided the basis for a subsequent subsurface structural and stratigraphic geologic study and an oil-production evaluation. Stratigraphic units evaluated included the Timber Ridge, Muskogee, Bad Hole, Gas, and Limestone Marker sandstones.

The analysis of sedimentary environments was based on well logs and isopach maps of the Timber Ridge and Muskogee sandstones, which are the major productive zones. Unambiguous interpretation of the spontaneous potential and neutron logs was possible because of the characteristic responses of the logs. The Muskogee oil field is identified as a delta-dominated type of reservoir. Delta fronts and prodelta environments were interpreted for the Timber Ridge and Muskogee sandstones; isopach maps clearly corroborate these findings. Well-log correlations were also performed for the productive Dutcher sandstone.

An engineering study of the field, analyses of production history, and analyses of different methods of depletion were conducted to the extent that the data were available. An extensive literature review of the location's geology, tectonics, and oil and gas production was also conducted.

Primary development of the Muskogee oil field, beginning in 1905, was principally by solution-gas drive, which resulted in considerable waste of reservoir energy by unnecessary production of gas reserves during the early life of the reservoir. This process left unusually large amounts of oil in place, which led to various early enhanced-oil-recovery (EOR) methods for production. Gas injection began in 1928 and water-flooding projects in 1956. Low sweep efficiency was a constant problem in the numerous projects because of drastic changes in rock permeability of the delta-dominated reservoirs. Water flooding, however, allowed a peak production of >1.5 million barrels per year, which was higher than the maximum primary production (>1.3 million barrels during 1910).

This study provides evidence that polymer flooding could profitably produce considerably more of the oil remaining in place.

Perez, J. M.; Donaldson, E. C.; and Poston, S. W., 1996, Understanding reservoir depositional environments contributes to optimizing oil production: Muskogee oil field, a classical example, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 225.

PART II

ABSTRACTS AND SHORT REPORTS RELATED TO POSTER PRESENTATIONS

Relationships of Fluvio-Deltaic and Tidal-Estuarine Facies Within the Douglas Group (Missourian-Virgilian) of Eastern Kansas

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STRATIGRAPHY AND SANDSTONE-BODY DISTRIBUTION

There are two major sequences within the Douglas Group (Missourian-Virgilian) in Kansas, each of which started with valley incision and delta formation during a lowstand and ended with widespread marine deposition (Fig. 1). The sequence boundaries can be placed at the contact between incised fluvial sandstones and eroded underlying, commonly marine, strata. During valley incision in the northern and central parts of eastern Kansas (Lins, 1950), deltas were being deposited in southern Kansas (Walton and Griffith, 1985) (Fig. 2). The delta complex of the Tonganoxie sequence (lower Douglas Group) has an east-west lateral extent of ~250 km, and the facies indicate significant tidal influences. North of the deltas, incised paleovalleys were filled during lowstands and subsequent transgressions (Lins, 1950). One paleovalley exhibits 34 m of incision, is approximately 32 km wide, and can be traced laterally along outcrops and into the subsurface to the south for approximately 140 km. Paleovalleys were filled with a succession of (base to top) fluvial to estuarine to marine facies (Fig. 1), and in one of the paleovalleys, the marine influence is seen to have increased significantly to the south. The valley-fill fluvial and estuarine facies were deposited during lowstands and subsequent sea-level rises. Marine shales and limestones were deposited during highstands and were partly eroded during subsequent falls in sea level. During valley incision, lithified carbonates in the eroded stratigraphic units impeded downcutting of the paleovalleys, resulting in a benched paleotopography of some paleovalleys in which lithified carbonates formed valley-wall erosional terraces and valley floors. Evidence for subaerial exposure of the valley walls includes the presence of in-situ coals and paleosols (Goebel and others, 1989).

The Tonganoxie Sandstone and its southern equivalent, the "Stalnaker" sandstone, form the main sandstone bodies in the lower sequence of the Douglas Group in Kansas (Fig. 2). The Tonganoxie in the northern part of Kansas is largely confined to paleovalleys and is part of a valley-fill succession. Conversely, the "Stalnaker" is not valley confined, and its geometry is broad and tabular, apparently reflecting deposition in a lowstand deltaic system that was penecon-temporaneous with valley incision to the north. The upper parts of the valley-fill facies and deltaic facies exhibit tidally influenced sedimentation; however, such influences were most strongly developed within estuarine portions of the valley-fill system (Archer, 1991; Lanier and others, 1993).

Archer, A. W.; Feldman, H. R.; Lanier, W. P.; and Tessier, B., 1996, Relationships of fluvio-deltaic and tidal-estuarine facies within the Douglas Group (Missourian-Virgilian) of eastern Kansas, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 229–235.

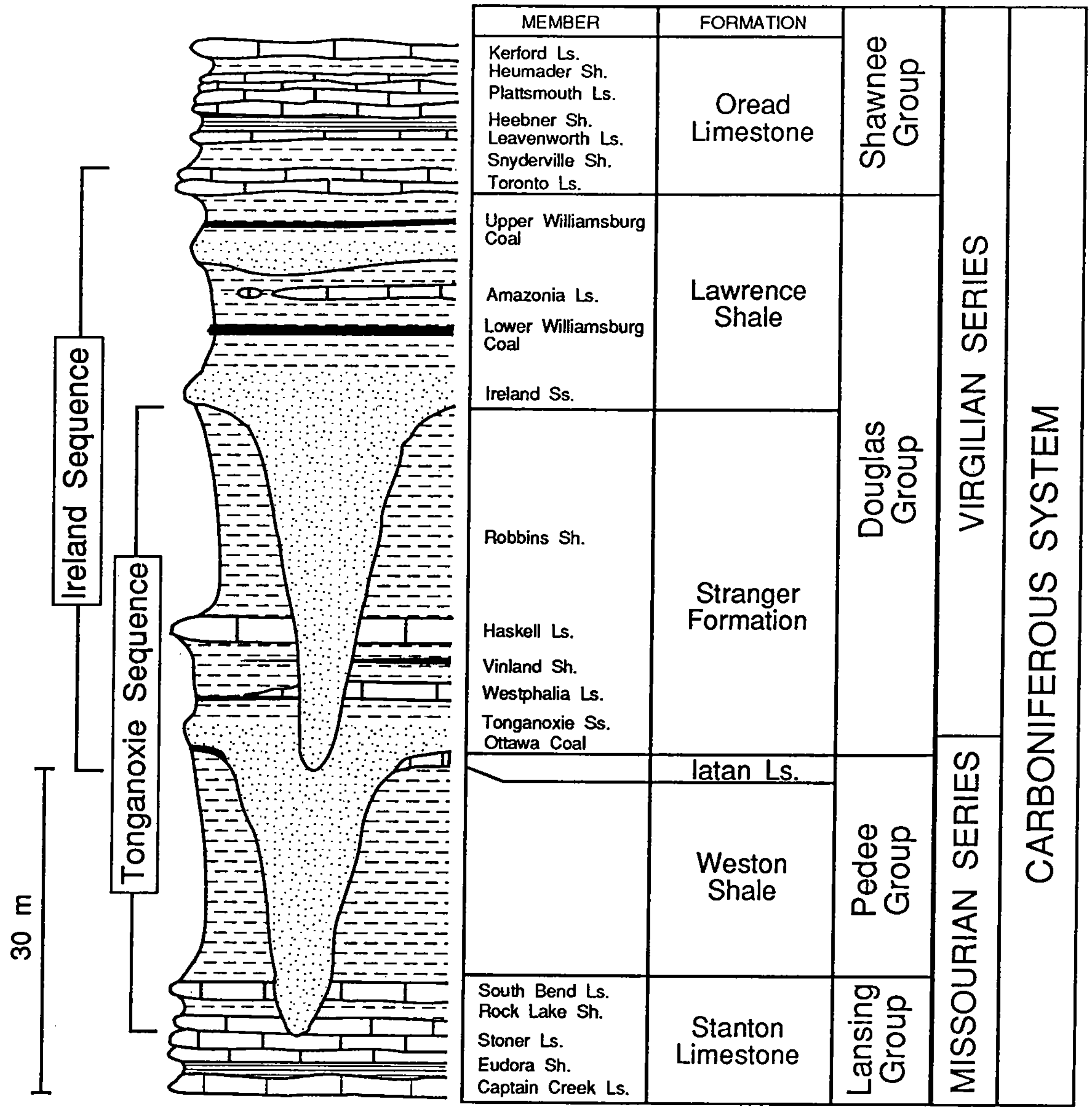

Figure 1. Schematic stratigraphic section of the Douglas Group in the study area, based primarily on well logs and exposures in Leavenworth and Douglas Counties, Kansas. The vertical section can be subdivided into two major unconformity-bounded sequences. Based upon Moore and others (1951).

VERTICAL SEQUENCES

Paleovalleys were filled with a fining-upward succession of facies (Fig. 3), with the lowest facies composed of cross-bedded conglomerate and sandstone. The conglomerate contains rock fragments and fossils eroded from older units exposed within the paleovalley and also contains abundant plant fossils. Sandstone beds exhibit large-scale trough (up to 1 m thick) and tabular-planar cross-beds. Paleocurrent directions (Fig. 4) are generally toward the southwest in the fluvial and upper-estuarine environments and indicate deposition via large-scale fluvial systems that were constrained within the paleovalleys.

Overlying the fluvial sandstone is a diverse suite of lithofacies, including planar-bedded sandstones and siltstones, heterolithic facies, sheetlike sandstones, bioturbated sandstones, and marine facies. Some planar-bedded sandstones and siltstones exhibit neap-spring tidal cycles, which were formed in high-intertidal settings (Lanier and others, 1993). Heterolithic facies are typically laminated and contain pinstripe laminations, starved

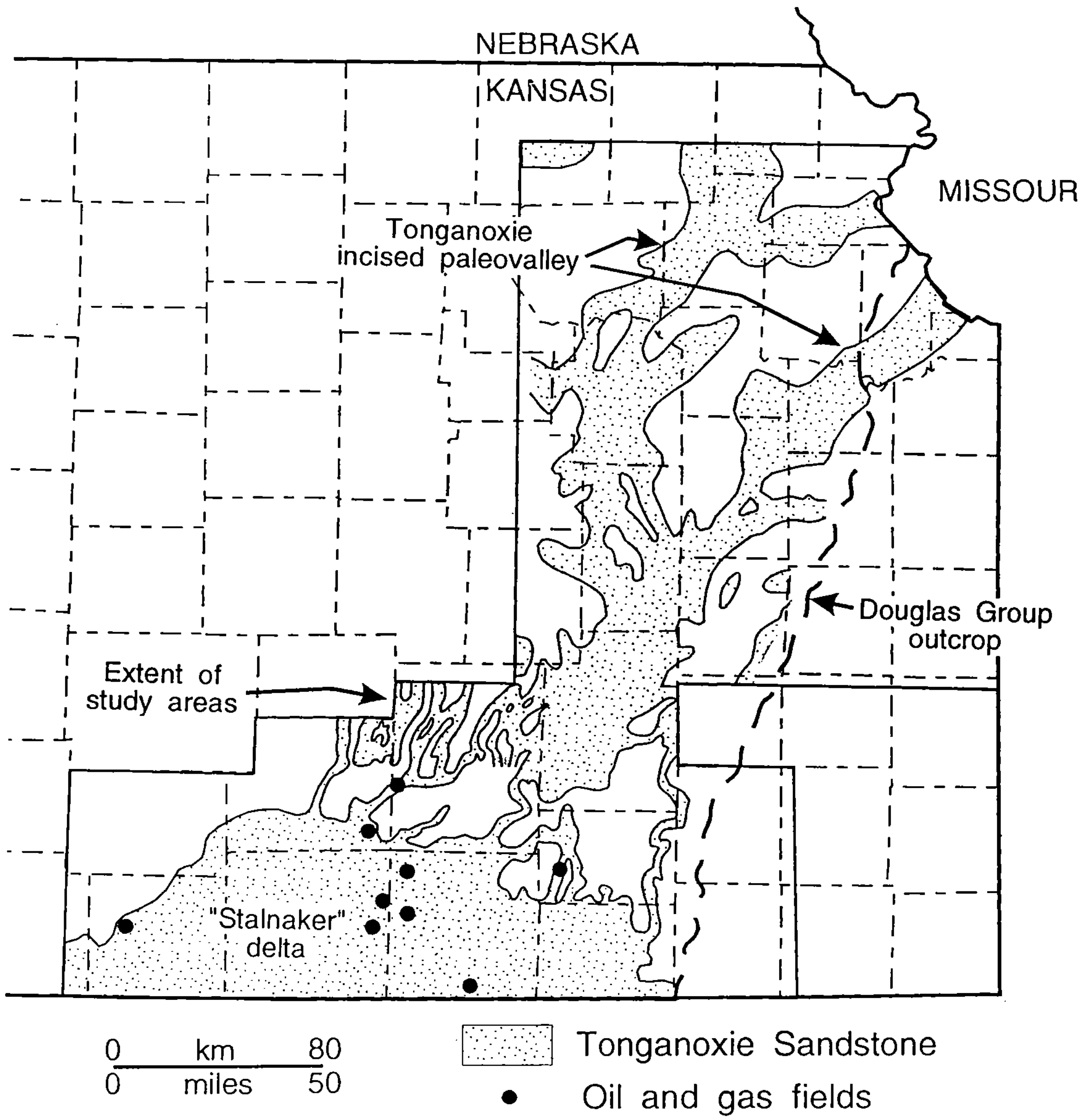

Figure 2. Map of eastern Kansas showing approximate outcrop of the Douglas Group and the extent of the Tonganoxie Sandstone. In northern Kansas, the Tonganoxie occurs within paleovalleys (Lins, 1950; Sanders, 1959). In southern Kansas, the Tonganoxie is a widespread unit that has been termed the "Stalnaker" sandstone (Winchell, 1957) or delta (Walton and Griffith, 1985). Intervening areas exhibit transition from incised valley to deltaic phase (Griffith, 1981).

ripples, and well-developed tidal cycles or cyclical tidal rhythmites (Archer, 1991). Neap-spring tidal cycles are common and range in thickness from 1 cm in heterolithic facies to as much as 1 m in planar-bedded siltstones. An interpretation invoking very high localized depositional rates is substantiated by the presence of buried upright trees, some of which have attached foliage. Some rocks of the heterolithic facies, which includes deposits of both estuarine and bay-fill paleoenvironments, contain much organic material. This diversity of facies in the Douglas Group has a number of similarities to modern macrotidal systems (Tessier and others, 1992).

The sheetlike sandstone bodies are dominated by small-scale trough cross-bedding, along with ripple and planar laminations. Paleocurrents are bimodal to the southwest and northeast in the estuarine environments (Fig. 4), reflecting ebb and flood tidal currents. Features such as flat-topped

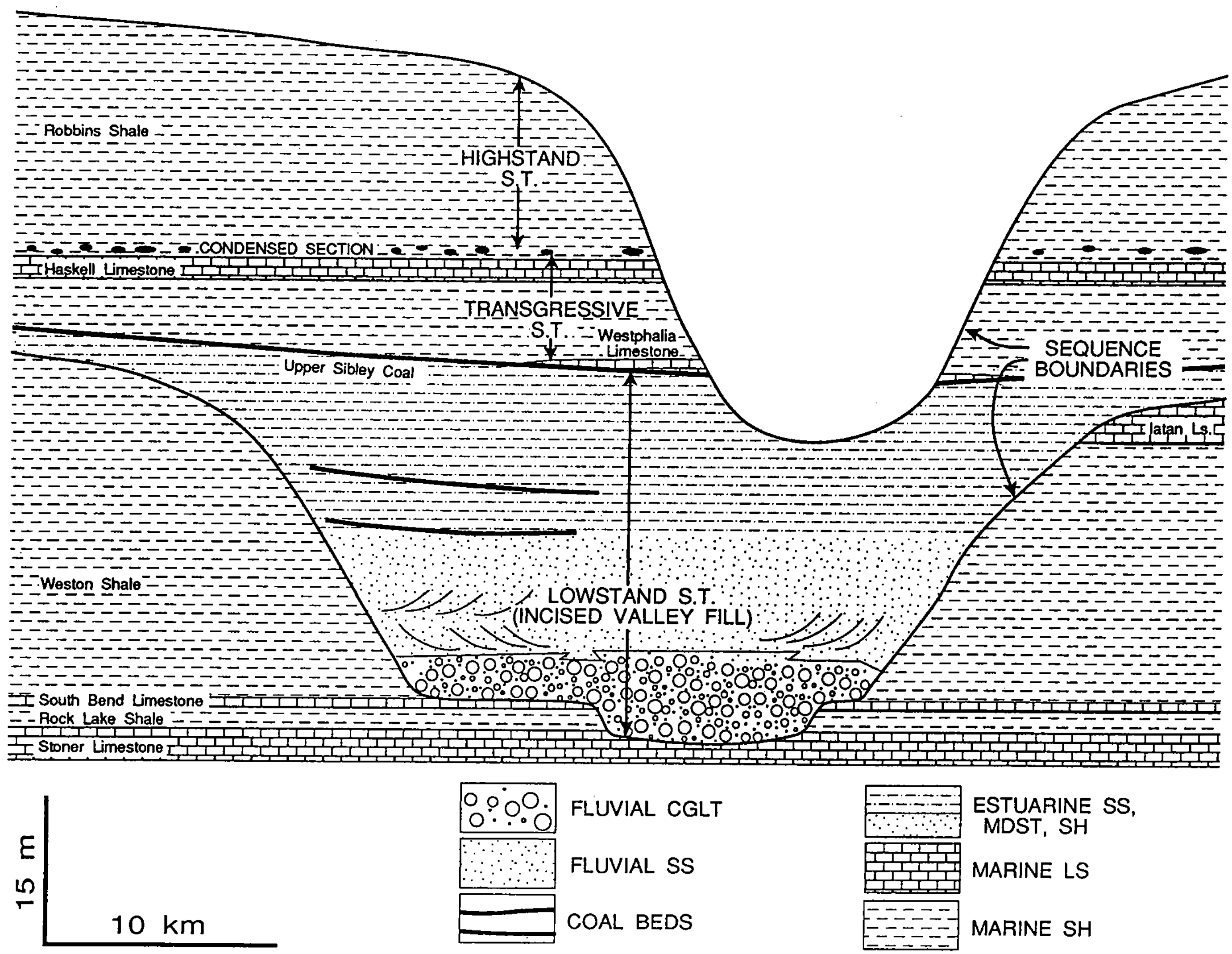

Figure 3. Sequence stratigraphic model for incised valley-fill sequences developed within the Tonganoxie sequence (lower Douglas Group) of Kansas. Placement of systems-tract (S.T.) boundaries shown is based upon the definitions proposed by Van Wagoner and others (1990). Depending on criteria used to establish the transgressive surface, the incised-valley fill can be placed into either the lowstand- or transgressive-systems tract.

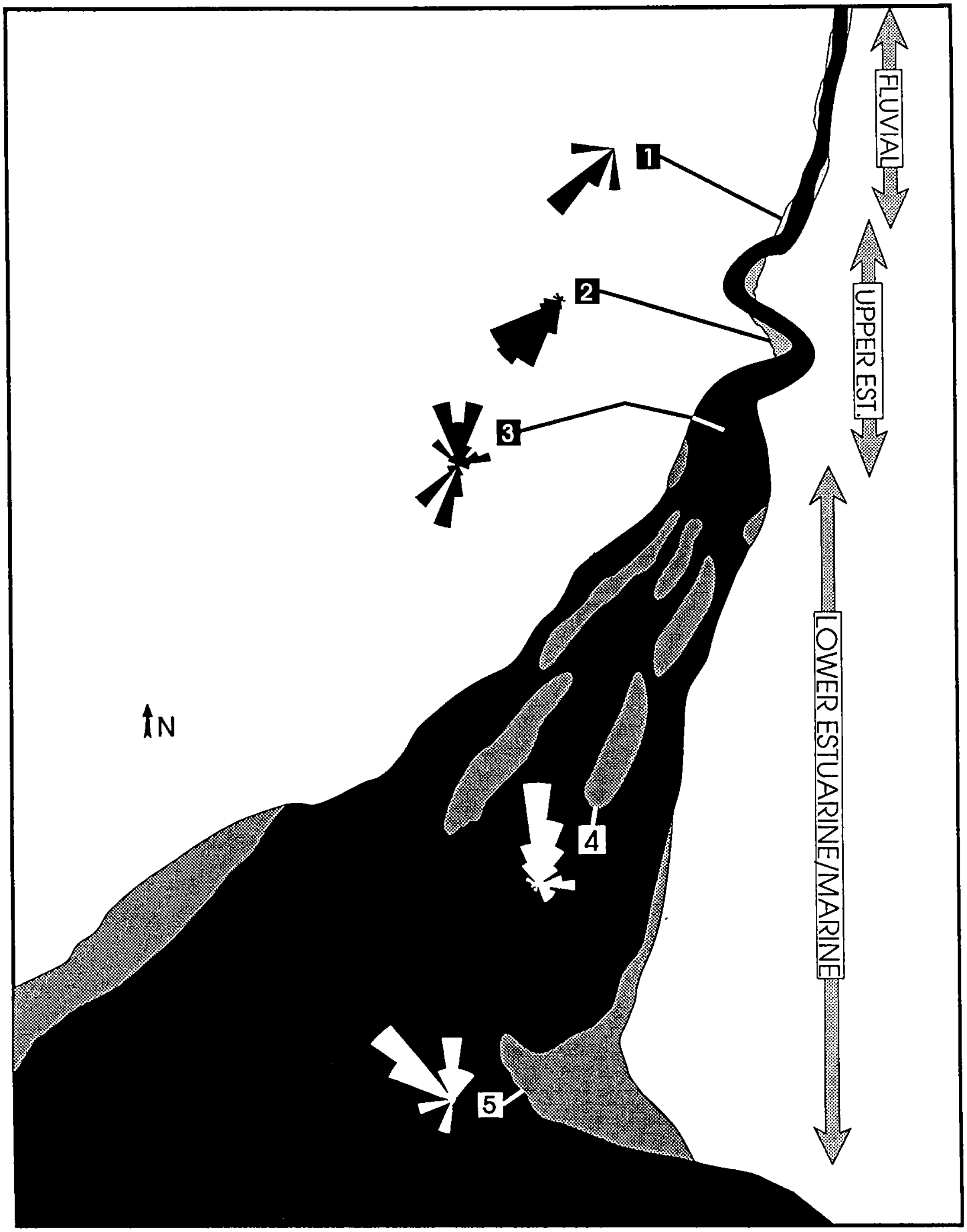

Figure 4. Facies model for valley-fill, estuarine-to-marine depositional sequences developed within the incised valleys in the Douglas Group of eastern Kansas. The numbers and accompanying paleoflow patterns shown on the map indicate five principal facies: (1) fluvial facies in Leavenworth County; (2) silty rhythmites in Franklin County; (3) heterolithic rhythmites in Douglas County; (4) tidal sand-flat and sandbar facies in Greenwood and Woodson Counties; and (5) marine coastal sand deposits in Chautauqua County. This reconstruction is intended to represent the lateral relationships of the lithofacies developed during early transgression to mid-transgression. Adapted from models of Dalrymple and others (1992).

ripples, rain-drop imprints, and tetrapod trackways indicate deposition within the intertidal zone. "Flaggy" bioturbated sandstones indicate significant marine influences. These sandstones are capped by widespread marine shales and limestones that extend far inland beyond the limits of paleovalleys. Some shales are extensively bioturbated, lack laminations, and locally contain marine fossils. Limestones form widespread lithostratigraphic markers and contain abundant marine fossils such as bivalves, fusulinids, brachiopods, crinoids, and bryozoans. Some of the limestones consist of shell lags, which indicate the development of transgressive surfaces of erosion.

FACIES MODEL AND RESERVOIR CHARACTERIZATION

The facies within the valley-fill succession of the Douglas Group share many similarities with Morrowan sandstones of Indiana (Archer and Kvale, 1993; Archer and others, 1994) and of eastern Colorado and western Kansas (Wheeler and others, 1990). To the north, the lower valley-fill facies are dominated by thick quartz arenite to subarkosic, medium- to fine-grained sandstone with an underlying, thinner, cross-bedded conglomerate (Fig. 4). The fluvial facies, although too shallow in northern Kansas for oil accumulation, probably has the greatest reservoir potential of the various sandstones developed within the Douglas Group.

Strong tidal influences are apparentare apparent within upper-estuarine parts of the paleovalley-fill facies (Fig. 4), and these have a number of effects on reservoir potential. During falling and low sea-level stands, the paleovalleys contained fluvially dominated facies. However, during base-level rise, these fluvial valleys were transformed into estuarine depositional systems. Funnel-shaped estuarine geometries can significantly amplify tidal ranges and thus enhance tidal velocities and tidally influenced sedimentation. Within such systems, estuarine tidal ranges can be macrotidal (>4 m), although open-coastal ranges may be only microtidal (<2 m). The transition from channelized fluvial systems to nonchannelized estuarine systems is a major locus of sand deposition. Sands at the fluvio-estuarine transition are essentially analogous, in terms of depositional environment, to sands in distributary-mouth bars or channel-mouth bars, but are more strongly tidally influenced. The most important effect of tides, in terms of reservoir heterogeneity, is the deposition of extensive clay-draped bars and bed forms. Clay draping of sandy bed forms becomes most pronounced in the middle parts of estuaries, where high rates of turbidity, in part related to fresh- and saline-water mixing, result in high depositional rates for fine-grained siliciclastic sediments. Clay drapes in the Douglas Group can extend for hundreds of meters and could be potentially important barriers to flow within reservoirs. Increased marine influence, fluvial influence, or bioturbation reduces the lateral continuity of clay drapes and increases reservoir homogeneity.

Toward the seaward end of the Douglas Group estuaries, a number of depositional settings were potentially developed, including lower-estuarine tidal sand flats and sandbars, subtidal sand ridges, and other marine sand environments (Fig. 4). The resulting sandstones are generally fine grained; they have a substantially greater degree of marine influence and may exhibit substantial degrees of bioturbation. Because of lowered turbidity and decreased rates of clay deposition and resuspension of fines via wave reworking, these outer-estuarine to marine sandstones are cleaner and exhibit fewer and less-continuous clay partings as compared to upper-estuarine sandstones. Absence of clay partings and vertical bioturbation reduces vertical permeability barriers in outer-estuarine sandstones; such barriers generally are present in sandstones that represent deposits farther within the estuarine system.

CONCLUSIONS

A strong emphasis needs to be placed upon the transgressive context of the fluvio-estuarine sequences where various types of sandstone bodies (potential reservoir facies) are intercalated with finer-grained, commonly heterolithic, organic-rich estuarine and bay-fill sedimentary rocks (source rocks). These fine-grained facies are characterized by tidal rhythmites formed in the intertidal and subtidal zones and by offshore mud-dominated facies, which can develop the trapping rocks overlying the estuarine sandstones.

Traceable discontinuities within sandstone facies are extremely important for reservoir characterization, and they are potentially traceable by using well logs, especially when cores are available to adequately characterize the well-log signatures. Marked heterogeneity will occur within valley-fill successions because of both depositional variability within the valley-fill deposits and localized and irregular erosion of older, preincision deposits. In the Douglas Group, the presence of at least two stacked, valley-fill sequences creates a complex reservoir, especially where the younger (Ireland) sequence erosionally truncates the older (Tonganoxie) sequence (Fig. 1).

In general, it commonly is difficult to adequately constrain the nature of incised paleovalleys and paleovalley-fill sequences, because it cannot always be determined if the incision was due to base-level lowering (e.g., eustatic lowstand or uplift) or was related to autogenic processes (e.g., upper-delta-plain incision). However, within the Douglas Group of Kansas, it is clear that base level was significantly lowered, because paleovalleys were incised into marine units with well-defined stratigraphic markers. In fact, it is the presence or absence of the underlying marine markers that allows delineation of the paleovalleys even when they are not primarily filled with sandstone. Without the "layer cake" stratigraphy of the pre-Douglas Missourian units, it would not readily be possible to differentiate between allogenic processes of lowstand valley incision and autogenic processes developed during deltaic sedimentation (e.g., channel shifting).

Insofar as the Douglas Group was formed during a lowstand and was deposited above an erosional surface developed upon highstand marine sequences, delineation of incised valley fills is particularly easy. This contrasts with older Pennsylvanian sandstones, such as Morrowan, Atokan, and Desmoinesian units, that were formed during a protracted transgression (Absaroka Sequence). Valley incision, except where it cut down into Mississippian bedrock, is more difficult to delineate in these rocks because the incised strata have a more-terrestrial and less-marine character. In addition, Illinois and Appalachian basin sandstones, particularly those of Morrowan and Desmoinesian age, also share many similarities with a depositional model that can be generalized from our ongoing studies of the Douglas Group.

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Landward to Seaward Variation in Heterogeneity Style in a Distributary-Channel and Mouth-Bar Facies Tract, Ferron Sandstone, Utah

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INTRODUCTION

The superbly exposed Cretaceous Ferron Sandstone in east-central Utah presents an excellent opportunity to determine three-dimensional variation in heterogeneity style in a distributary and delta-front facies tract of a retrogradational, wave-modified delta system. The Ferron Sandstone was selected for study because it displays a wide range of depositional environments similar to those represented by Gulf Coast deltaic gas reservoirs.

STUDY AREA

The Ferron Sandstone was deposited during a regressive maximum of the Cretaceous seaway and is divided into discrete depositional units bounded by time-significant surfaces (Gardner, 1991). These units are arranged as a succession of seaward-stepping, vertically stacked, and landward-stepping deltaic units. This well-constrained stratigraphic framework serves as a basis for examining changes in facies architecture that occur along depositional dip with a strongly retrogradational deltaic unit.

The field site for this study is in east-central Utah, between the Wasatch Plateau to the west and the San Rafael Swell to the east. Along the eastern margin of Castle Valley, the Ferron Sandstone forms a succession of northwest-dipping, northeast-trending ridges that are oriented subparallel to the northeasterly progradation of the late Turonian shoreline. A series of outcrops 3–8 mi east to northeast of the town of Emery provided an opportunity for documenting changes in sandstone-body dimensions, continuity, and distribution. Field investigations concentrated on a strongly landward-stepping deltaic unit referred to as genetic sequence (GS) 5.

REGIONAL FACIES ARCHITECTURE

With the Ferron GS 5 interval, the entire deltaic facies tract is compressed; total length from landward to seaward extent is only ~4 mi. Over this distance, a full range of shallow-marine through coastal-plain strata is displayed. At proximal exposures, middle- to upper-delta-front sedimentary units are extensively eroded and replaced by distributary and associated delta-plain deposits. By comparison, distal portions are characterized by an extremely regular, upward-shoaling succession of laterally continuous, lower- to middle-delta-front sedimentary units. Delta-plain deposits are restricted to deeply incised distributary channels, and these deposits display significant evidence of marine modification. Regionally, the succession is truncated by a broad, low-relief erosional surface and is overlain by a thin sedimentary veneer that records marine flooding and reworking of the abandoned lobe.

AREAL DISTRIBUTION AND GEOMETRIC ATTRIBUTES

In the GS 5 interval, distributary channel deposits are the dominant type of sandstone body, and they form sandstone belts, elongate parallel to depositional dip, that interdigitate with overbank, crevasse-splay, and abandoned-channel-fill deposits. Each sandstone belt was formed of multiple-channel sand bodies arranged in multilateral to multistoried fashion. These units are several feet to tens of feet thick and tens of feet to several hundreds of feet wide. In profile they consist of an erosive-based lag overlain by a succession of stratal types. The distributary sequence can include multiple compound bars called macroforms.

The delta front—characterized by an extremely regular, large-scale, upward-coarsening sequence

Barton, M. D.; Tyler, N.; and Fisher, R. S., 1996, Landward to seaward variation in heterogeneity style in a distributary-channel and mouth-bar facies tract, Ferron Sandstone, Utah, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 236–239.

that consists of upward-thickening beds of interbedded, hummocky, stratified sandstone and bioturbated mudstone—records deltaic progradation in a wave- to storm-dominated shallow-marine setting. On a regional scale, the delta front forms a strike-aligned deposit elongated northwestward. In cross section, the deposit displays a broadly asymmetrical lenticular shape that abruptly thickens near the landward pinch-out, and it gradually thins to a feather edge at its seaward extent. Internally, the interval is composed of offlapping, seaward-dipping subunits that range from several feet to 15 ft in thickness. Laterally continuous fine-grained sedimentary units bound progradational sigmoids, each of which extends downdip for several miles and along strike for tens of miles. Thus, vertical stratification is the dominant style of heterogeneity in the delta-front sandstones.

Distributary and associated deposits combine to form a complex network of broad, tabular sandstone bodies that removed and replaced almost the entire delta front (Fig. 1). Within this complex, the sandstone bodies display a wide range of internal and external variability. Three states of distributary-channel sedimentation, corresponding to periods of channel incision, expansion, and aggradation, have been recognized. Each stage, characterized by a distinctive geometry, internal character, and associated deposits, is predictably related to its geographic position along depositional profile of the delta lobe.

Early-stage channel fill is best preserved near the seaward limit of the distributary system and displays significant evidence of marine modification. Channel belts (average width of 700 ft and thickness of 50 ft) are laterally restricted and deeply incised into coeval delta-front deposits. Internally, the channel fill is composed of several laterally inclined and offset sigmoidal sandstone

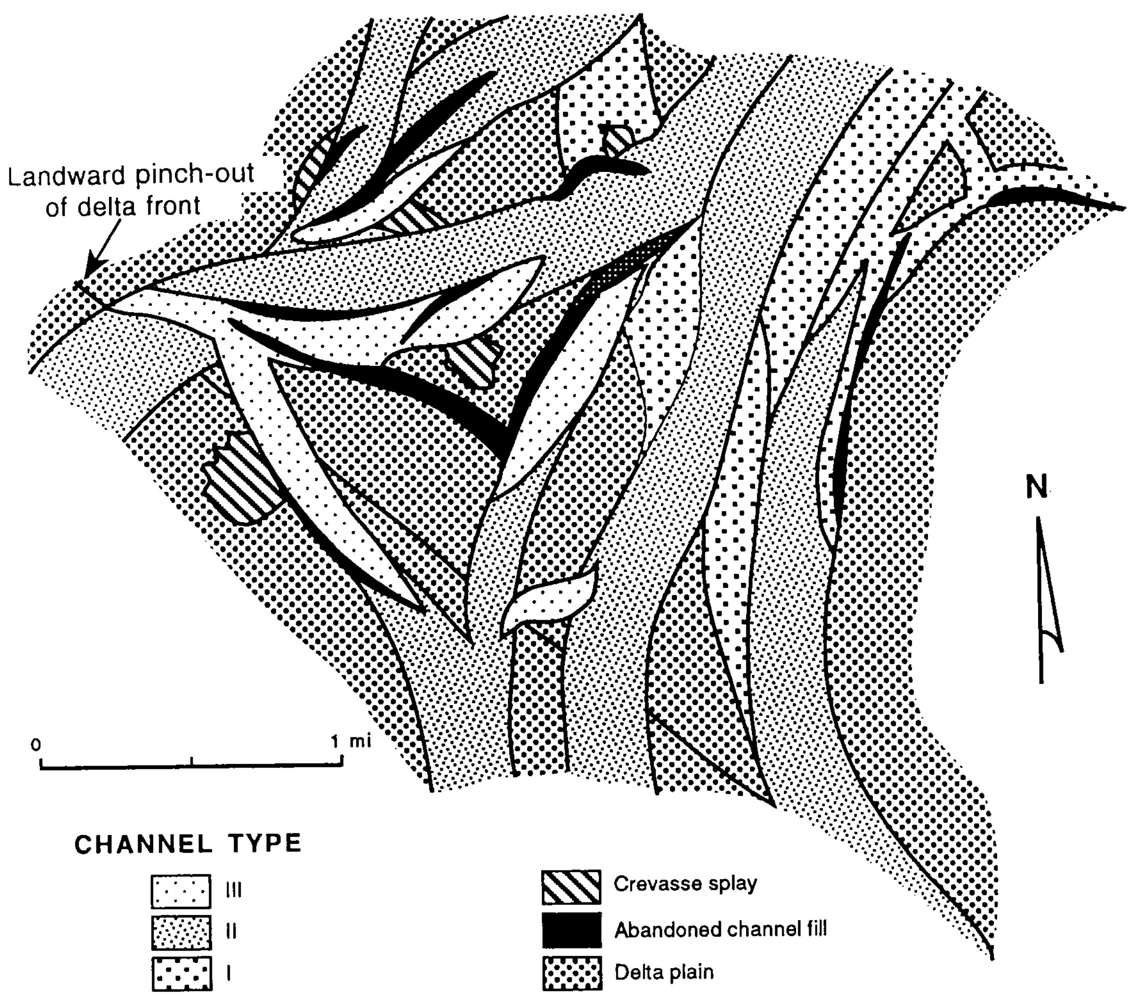

Figure 1. Aerial view of regional facies architecture within GS 5 between Muddy Creek and Cedar Ridge Canyon.

bodies that average 200 ft in width and 16 ft in thickness. Well-developed mudstone layers bound sandstone bodies that consist of a uniform assemblage of trough cross-stratified sandstones. Near the middle of the facies tract, middle-stage channel fill partially replaces early-stage channel fill.

Middle-stage channel belts are laterally expansive (average width of 1,200 ft and thickness of 40 ft) and are composed of numerous multilateral sandstone bodies separated by thick, inclined, laterally continuous mudstone-clast lags. The middle-stage sandstone-body widths (200 ft) are similar to, and thicknesses (10 ft) are somewhat less than, those of early-stage channel-sandstone bodies. The main difference between the middle- and early-stage sandstone bodies is the nature of the bounding surfaces between them. Late-stage channel fill records channel aggradation and is best developed in proximal parts of the delta lobe. These deposits consist of wide (300–700 ft) and thick (15–35 ft) sandstone bodies that are laterally isolated from adjacent ones by fine-grained interchannel, abandoned-channel-fill, and crevasse-splay deposits. Sandstone bodies display a high diversity of stratal types, as well as mudstone and siltstone drapes developed along accretion surfaces that disrupt internal continuity.

A comparison of distributary-macroform dimensions (Fig. 2) reveals that geometric differences are related to preservational processes within the delta-plain facies tract. Macroform thickness and width tend to increase from early- to late-stage channels. Macroform dimensions in early-stage channels vary from the seaward limit to landward erosional truncation, showing that preserved deposits are widest and thickest at their seawardmost extent and become progressively thinner and narrower landward (Fig. 3).

In addition to heterogeneities resulting from bounding lithologies separating macroforms within the channel fill and offlapping sigmoids of the delta front, mudstone drapes and mudstone-clast-lag–covered erosional surfaces along channel flanks and floors and fine-grained abandoned-channel-fill and interchannel deposits provide higher-order heterogeneities that separate discrete channel deposits and belts, respectively.

SUMMARY

Within the Ferron depositional system, the architectural style of sandstone bodies and the nature of bounding lithologies that mantle them vary dramatically along depositional profile in a single

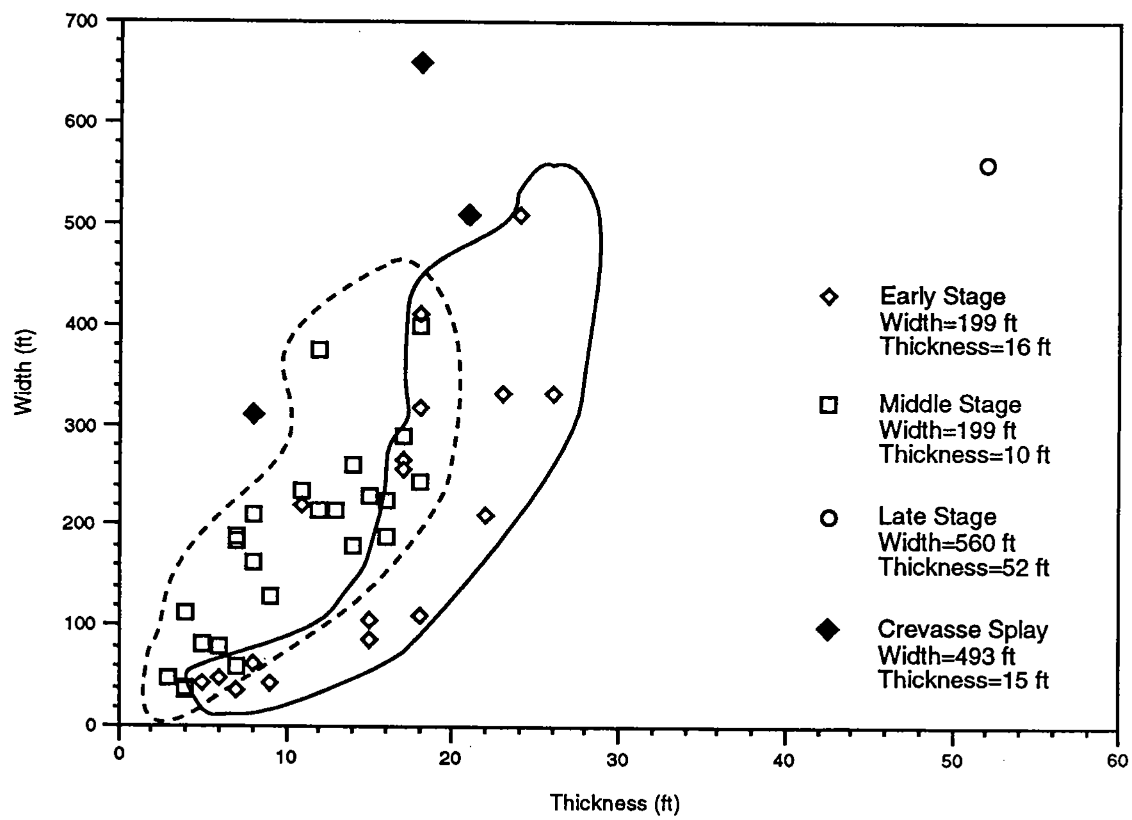

Figure 2. Comparison of distributary macroform dimensions from Ferron GS 5 exposed along Muddy Creek.

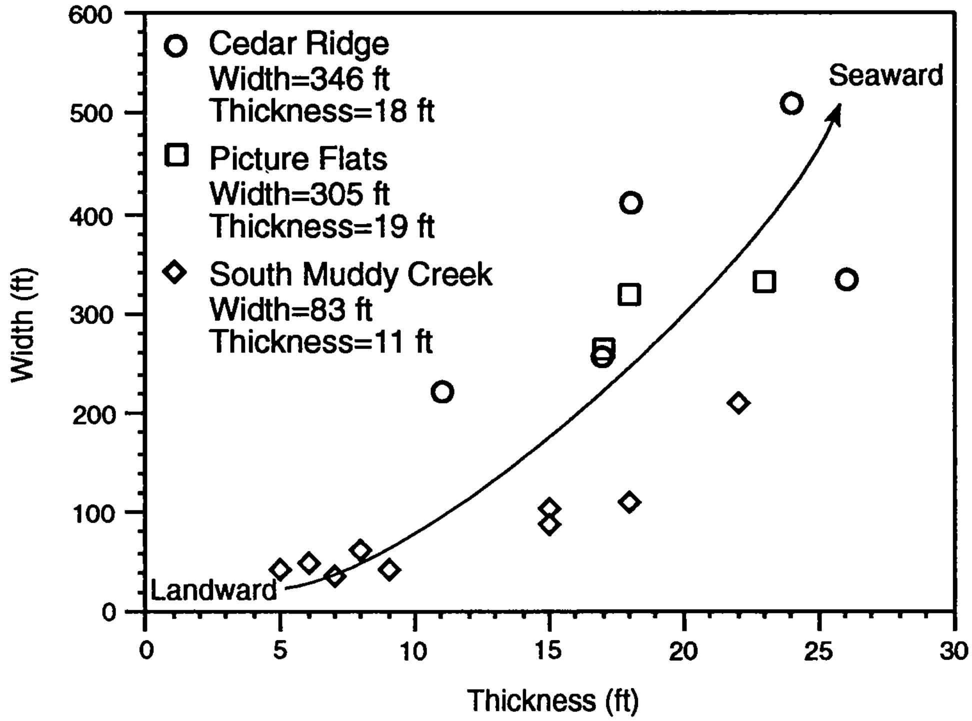

Figure 3. Comparison of early-stage distributary macroform dimensions in Ferron GS 5 exposed between Muddy Creek and Cedar Ridge.

landward-stepping deltaic genetic sequence. A five-order hierarchy of heterogeneities, each with a characteristic geometric style and extent, has been identified for retrogradational, wave-modified deltaic-reservoir analogues. From largest to smallest, this hierarchy consists of (1) variations between the coastal-plain and delta-front facies tract, (2) variations related to the mud-rich delta-plain and sand-rich distributary-channel deposits that compose the coastal-plain facies tract, (3) differences related to mud-rich abandoned-channel-fill bodies and sand-rich distributary-channel bodies that compose the distributary-channel deposits, (4) variations related to clay-clast conglomerates that separate distributary-channel macroforms, and (5) variations in lithofacies that compose distributary-channel macroforms.

ACKNOWLEDGMENTS

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Fluvial-Deltaic Facies Patterns in the Lower Deese Group (Middle Pennsylvanian), Ardmore Basin, Oklahoma

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INTRODUCTION

The objective of this paper is to describe the various facies and facies assemblages within the lower Deese Group (Desmoinesian, Middle Pennsylvanian) in the Ardmore basin (Fig. 1), to better define the origin and depositional setting for the Deese Group. The Ardmore basin in south-central Oklahoma is a small structural basin, ~530 km long by 100 km wide, within the southeast part of the southern Oklahoma aulacogen (Fig. 2), which developed in three phases: rifting, subsidence, and deformation (Ham and others, 1964). During the early history of the Ardmore basin (i.e., rifting and subsidence), it was the southeast part of the much larger Anadarko basin. During Late Mississippian through Pennsylvanian deformation in the southern Oklahoma aulacogen, successive orogenies uplifted areas adjacent to the Ardmore basin; these areas were then eroded, and the material was added to the basin sedimentary fill. The Anadarko, Marietta, and Ardmore basins—and the Wichita, Criner, and Arbuckle uplifts, which separate the basins—were created during this final development phase (Granath, 1989; Johnson, 1989).

The coarser clastic Middle and Upper Pennsylvanian (Deese, Hoxbar, and Vanoss) groups were deposited in the later half of the deformational phase, during intermittent regional tectonic activity involving strong compression (Granath, 1989). By middle Desmoinesian time, the Ouachita system was being uplifted, spreading chert pebbles into the basin (Sutherland, 1988). The thick Devil's Kitchen and Rocky Point chert-pebble conglomerates record the main Ouachita tectonic pulses (Liesch, 1988).

FACIES AND FACIES ASSEMBLAGES

The location of the sections used in this study are provided in Billingsley (1992). Ten facies, designated A through J and described and interpreted in Table 1, were defined in the Deese sections examined. The individual facies observed in the lower Deese sections could have formed in many environments. However, within the sections examined, the facies combine to form seven distinctive facies patterns or sequences. Certain of these sequences are likely to occur in succession, creating three assemblage packages that indicate deposition in similar and adjoining environments. The three assemblages represent shallow-marine sedimentation, deposition on braidplains and/or alluvial fans, and deltaic and/or fluvial sedimentation.

Shallow-Marine Assemblages

Shoal Sequences and Shale-Dominated Patterns

The sandy fossiliferous limestones and fine- to medium-grained fossiliferous sandstones (both are facies A in Table 1) are cross-stratified, plane-bedded, and/or rippled. These most likely were formed as part of stacked, winnowed shoal sequences in which wave and current action removed mud and silt, concentrating coarser clastic material and fossils.

The shoal sequences are interbedded with thick, dark-gray shale sections (facies C) and scattered thinner sandstone beds. Some fine-grained quartz sandstones are so clean and well sorted that sedimentary structures cannot be seen (facies E); other fine- to medium-grained sandstones have trough (facies H), ripple (facies G), and/or large-scale, low-angle (facies F) cross-bedding. At the top

Billingsley, P.; Banerjee, S.; Elmore, R. D.; Sutherland, P. K.; and Grayson, R. C., Jr., 1996, Fluvial-deltaic facies patterns in the lower Deese Group (Middle Pennsylvanian), Ardmore basin, Oklahoma, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 240–248.

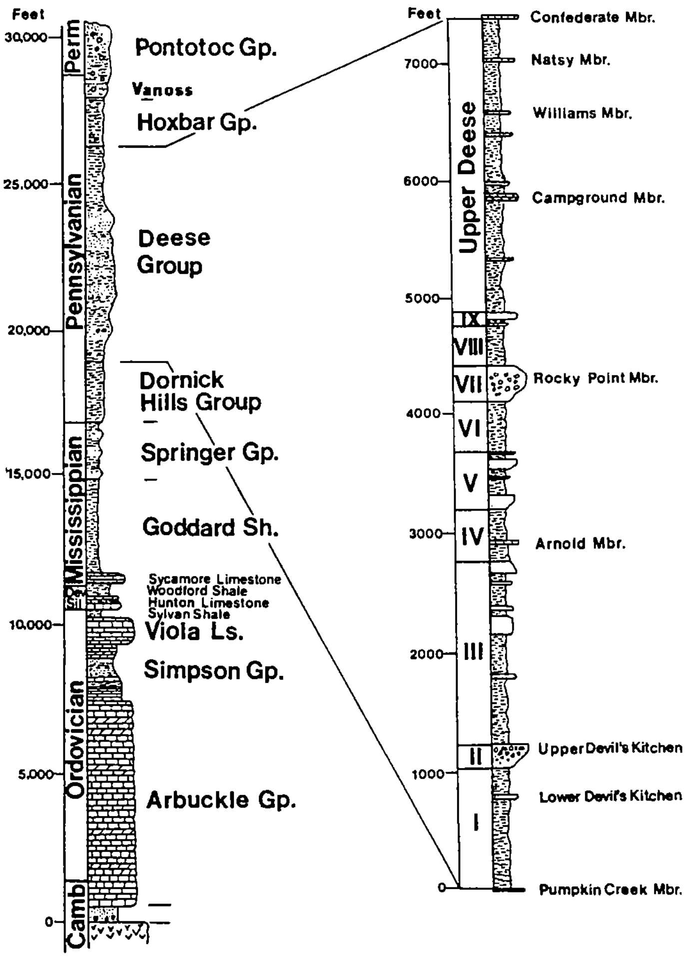


Figure 1. Generalized stratigraphic section of the Ardmore basin (after Raymer, 1987).

of one fine-grained marine sequence there is a distinctive unit with numerous foreset reactivation surfaces and sandstone and shale couplets (facies D).

The sandstones are probably wave-reworked shallow-marine bars and beach deposits, similar to those described by Elliott (1986) and Johnson and Baldwin (1986). Reactivation surfaces are typical of tidal flats (Elliott, 1986) and tide- and current-dominated, shallow siliciclastic seas (Johnson and Baldwin, 1986). The cross-beds with reactivation surfaces may have been deposited in tidal channels, whereas the plane-laminated beds with reactivation surfaces could be tidal bundles deposited on a tidal flat. The overall pattern to these shale-dominated sections is that of offshore to interdistributary-bay shale deposition, with episodes of sand-bar, shoal, and possibly tidal-flat deposition.

Rippled, Fining-Upward Sequences

At the base of a complete fining-upward sequence, 2.5–15 m thick (Fig. 3), there is a rippled and flaser-bedded sandstone 0.15–1 m thick (facies G). Some sandstone beds have *Cruziana* trails and horizontal tube burrows on bedding surfaces. Above these beds (or forming the base of some sequences) are alternating thin, rippled, flaser-bedded sandstones and lenticular to wavy-bedded shales (facies D). Some of the sandstones have apparent herringbone cross-stratification and/or interference ripples. The herringbone pattern could indicate deposition from alternating tidal currents, but a more likely interpretation is superimposed interference ripple foresets. The fining-upward sequences are capped with lenticular to wavy-bedded, light-gray, tan, olive, and reddish-brown blocky shales (facies B).

These rippled, fining-upward sequences occur as a set of five distinct cycles (Fig. 3) plus a separate single cycle. They resemble stacked tide- and current-dominated estuarine and tidal-flat sequences (Johnson and Baldwin, 1986). An alternative interpretation for these cycles is shoreface-detached sand ridges on a tide- or storm-dominated shelf, similar to those described by Fruit and Elmore (1988).

Rippled, Coarsening-Upward Sequences

There is a set of five rippled, coarsening-upward sequences, each 2.5–9 m thick (Fig. 4), plus another set of thinner cycles. Both are between dark-gray shales. At the base of each sequence there are wavy to lenticular, nonfossiliferous, light-colored (tan to light gray and green or reddish, with a few siderite zones) facies B shales. These coarsen upward to wavy- and lenticular-bedded, alternating sandstones and shales (facies D) and are capped with highly rippled (mostly unidirectional current ripples, but also some interference ripples), flaser-bedded sandstones (facies G) with apparent herringbone cross-stratification.

Coarsening-upward sequences like these can form in several tide- and wave-dominated shallow-marine settings. One possibility is shoreline or bayfill deltas, similar to those described by Tankard (1986), in which tides and waves, not distributary channels, control the deposition. Alternatively, these sequences could represent aggrading transgressional tidal flats, in which the intertidal and subtidal mixed flats and sand flats have migrated over the shallow-water mud flats or have

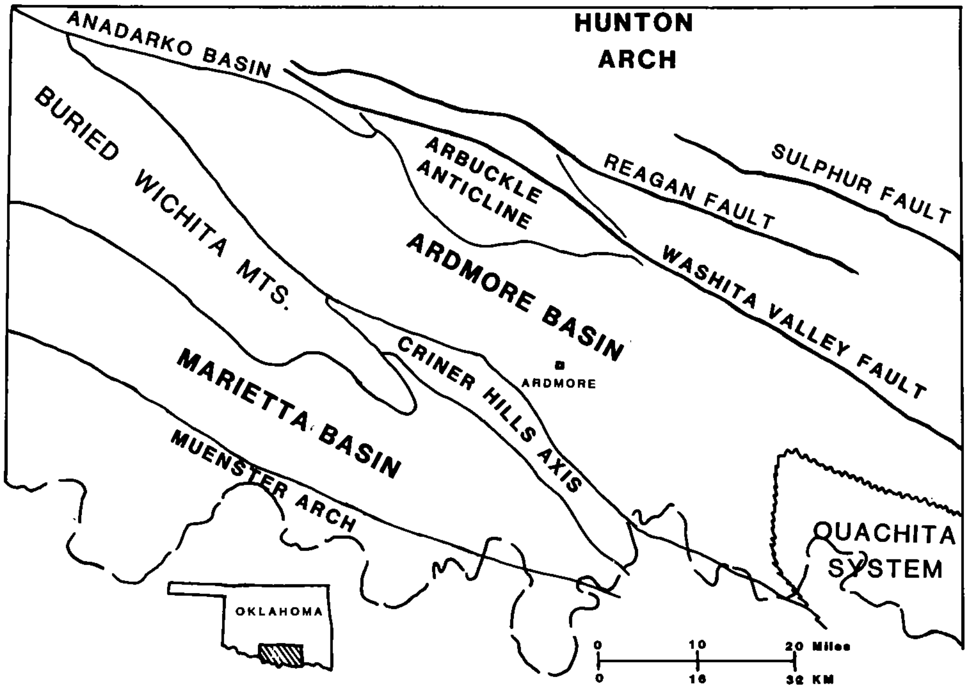


Figure 2. Location map of the Ardmore basin in southern Oklahoma (after Sutherland, 1988).

formed on the flanks of nearshore bars (Johnson and Baldwin, 1986).

Conglomeratic Braidplain and Alluvial-Fan Assemblages

Fan-Delta and/or Alluvial-Fan Sequences

Overlying the dominantly marine section is a sandstone and conglomerate sequence 65 m thick (Upper Devil's Kitchen Member; Fig. 5). The sequence includes a thick sandstone with trough cross-bedding (facies H) overlain by a cherty, cross-bedded sandstone with conglomeratic sandstone and/or chert-pebble conglomerate (facies J). This pattern repeats up to the top sandstone. The lower cross-bedded sandstone portion of the Devil's Kitchen Member is interpreted as a fan delta that deposited a high bed load while prograding over the shallow-marine sequences. The alluvial fans and/or fan deltas were at least 32 km long (Saether, 1976; Clark, 1983). The size of the fan and the presence of plant fossils *(Calamites)* are more in keeping with humid fans than with typical southwestern United States arid fans.

Incised-Valley and/or Braidplain Sequences

Within a largely covered mudstone section near the base of the lower Deese there is a thick (8 m), fining-upward, chert-flake sandstone that is massive (facies E) to trough cross-bedded (facies H) and contains a few thin chert-pebble and/or mudstone-pebble conglomerate (facies J) beds. One bed has pronounced flute clasts at its base. Fifteen meters higher in the section there is a second, thinner (1.3 m), poorly sorted to bimodal, coarse-grained sandstone with many scattered chert pebbles and some low-angle cross-beds. Both units have an abrupt coarse-grained base.

The thicker sequence is interpreted as braided-stream alluvium, similar to the distal alluvial-plain sequences of Steel and others (1977). It was probably deposited within a valley incised into shelf sediments following a tectonic uplift, as indicated by the abrupt appearance of this coarse material above finer-grained mudstones. The thinner unit is more like the proximal facies of Steel and others (1977), i.e., deposited near a basin margin. It may also have formed in a shallow valley incised into shelf sediments, but its bimodal nature indicates that it could be a very coarse fanglomerate that was deposited directly onto shallow-marine shelf mudstones following a tectonic episode.

Delta-Front, Delta-Plain, and Fluvial Assemblages

Rippled and Cross-Bedded, Coarsening-Upward Sequences

Between two of the shallow-marine assemblages there is a set of five cross-bedded, coarsening-upward sequences, each 3–6 m thick. Each

TABLE 1. — FACIES SUMMARY

Facies	Description, sedimentary structures	Processes	Interpretations, environment
A	Macrofossil zones, sandstone and sandy limestones, with bedding; some have trough and/or ripple cross-bedding Random fossil orientations.	Short (unbroken fossils) to medium distance transport; concentration into lags.	Marine (brachiopod, bryozoan, coral) to brackish-water (pelecypod) deposition, by storms or currents, at delta margins, in estuaries, on the shelf.
B	Shale to silty shale, red to tan, brown, and light greenish gray.	Shallow quiet-water deposition, swamps. Fairly well-oxygenated conditions.	Back bar lagoon, delta top ponds, shallow lakes, overbank and levee deposits, and/or swamp deposition; generally nonmarine to brackish waters. Many of the reddish clay-rich zones may be paleosols.
C	Shale, gray to black. May contain brachiopods or other marine fossils.	Quiet-water deposition.	Interdistributary bay (delta) to deeper offshore waters.
D	Alternating thinly laminated to thin-bedded shale and fine-grained sandstone or siltstone and fine-grained sandstone units. May have reactivation surfaces or convolute lamination. Wavy and lenticular bedding.	Variable flow regime.	Distal delta-mouth bar, splay overbank deposits, tidal-flat or estuarine environment. Reactivation surfaces may indicate tidal deposits.
E	Unstructured siltstone or sandstone, thick to no apparent bedding. May have a few clean climbing ripples or graded bedding. Light-gray to buff and tan. May be bioturbated and have convolute lamination.	Rapid uniform deposition winnowing, deposition by decelerating sediment-laden currents, or sediment structures destroyed by burrowing.	Deposition in a number of settings, ranging from delta mouth and nearshore bars to upper-channel-fill-deposits.
F	Sandstone with large-scale, low-angle bedding, wedging, or hummocky cross-stratification. A few beds have undulating surfaces.	(1) Beach swash, waves, storms. (2) Successive accreting with high bed loads.	(1) Beach to offshore storm-influenced bar environment. Can occur below fair-weather wave base. High energy. (2) Braided streams.
G	Ripple or climbing-ripple cross-stratified sandstones and siltstones, small-scale trough or tabular. Flasers common; unidirectional, bidirectional, and interference-wave cross-stratification. May have tracks (*Cruziana*) on bedding surfaces.	Lower (moderate) flow than facies H (sand dunes or waves) or I (planar beds), with current, wave, and/or wind ripples.	Deposition on delta-mouth bars, tidal flats and channels, point bars, splay or overbank deposits, and beach or estuary areas. Apparent herringbone pattern created by bidirectional (e.g., tidal) currents, or interference-wave ripples.
H	Sandstones with tabular or trough cross-stratification, ~6 cm to 1 m high. May have large curved channel shape; mudstone-pebble and/or chert-pebble lags. May be incised into lower units, have lines of pebbles on foreset planes.	Often erosion followed by rapid deposition of migrating sand waves and sand dunes.	Deposition in a channel, (river, delta distributary, tidal), point bar, or offshore bar yielding cross-stratification.
I	Thin planar-bedded to platy sandstone beds. Some beds have lineations on bed surfaces. May have convolute lamination.	Upper-flow-regime planar-bedding due to high flow, shallow depth, and/or sand coarser than 0.6 mm.	River bar, distributary channel-mouth bars, river or delta overbank deposits, or braided-stream and/or alluvial fan sheet-flood deposits.
J	Coarse cherty sandstone, 50% conglomerate. Commonly thick-bedded to trough cross-stratified, often cut into underlying bed.	Very high flow, lag deposits.	Channel lag or alluvial-fan deposition, longitudinal bars in braided streams. Streams often subject to extremely fluctuating flow conditions.

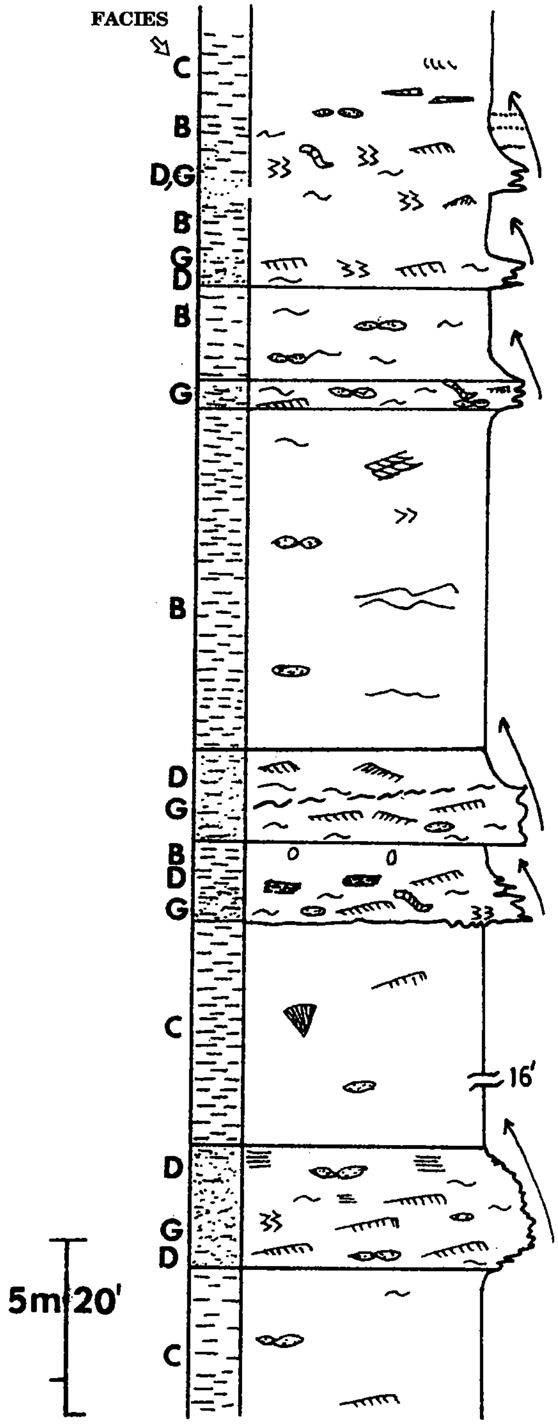
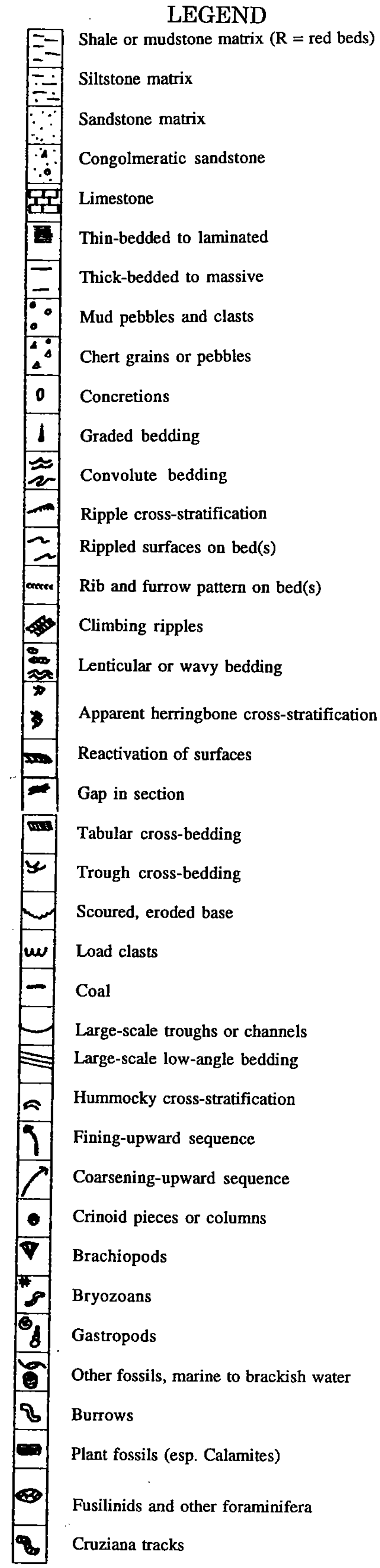


Figure 3. Rippled, fining-upward sequences in the Deese I interval (letters designating the facies are explained in Table 1).



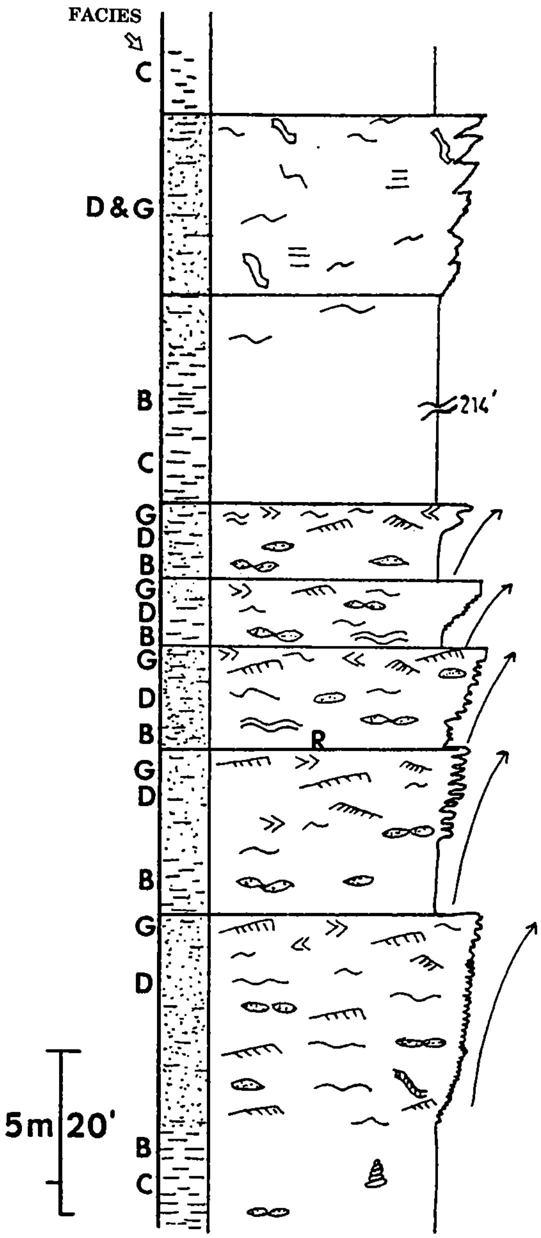


Figure 4. Rippled, coarsening-upward sequences in the Deese I interval (see Fig. 3 for legend; letters designating the facies are explained in Table 1; R = red beds).

coarsening-upward sequence within the set begins with sandy, wavy- to lenticular-bedded, tan to yellowish-brown, reddish-brown, or light greenish-gray shale (facies B). Above this shale (or forming the base of some cycles) are rippled, alternating fine sandstone and shale beds (facies D). These two facies dominate the lower two cycles. Above these facies (in no particular order) are rippled sandstone beds (facies G); a few thin, upper-flow-

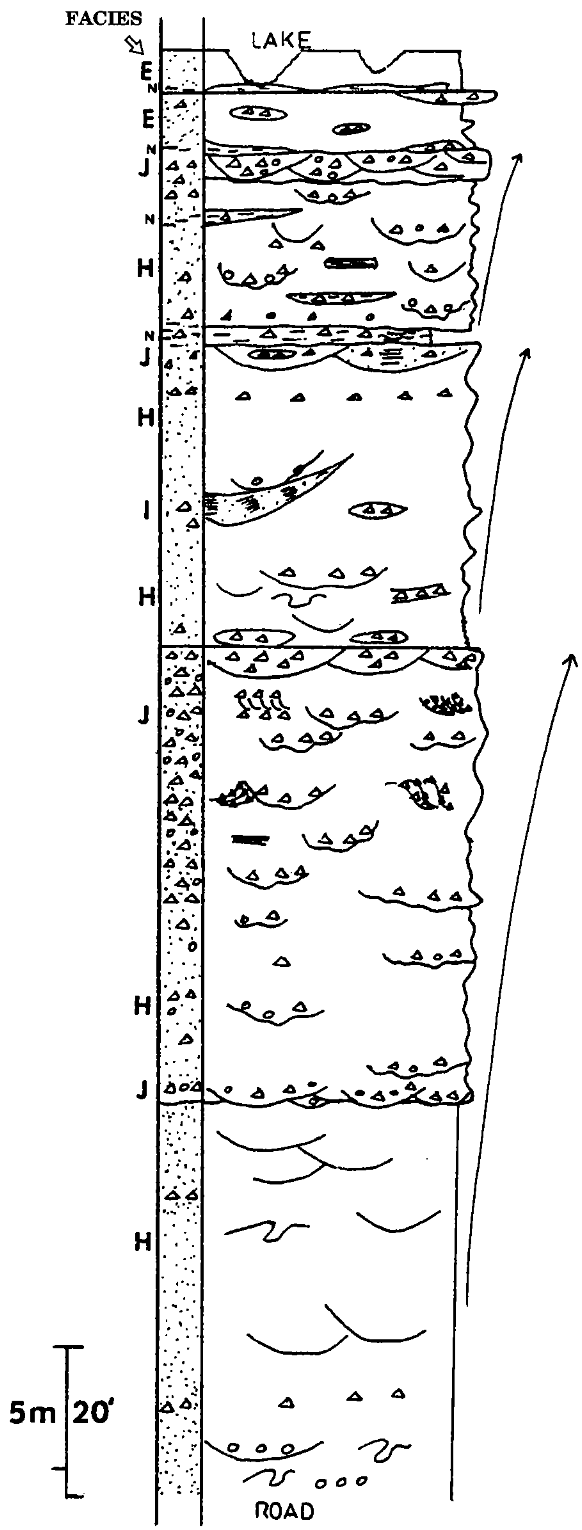


Figure 5. Upper Devil's Kitchen Member, Deese II interval (see Fig. 3 for legend; letters designating the facies are explained in Table 1).

regime, planar beds (facies I) or sandstones with tabular cross-bedding; and many sandstones with trough cross-bedding (facies H).

Thin (1 mm to ~5 cm) siltstone or shale beds lie between some of the (2 cm to 1 m thick) sandstone beds, and there are several fine, thin, rippled, coarsening-upward sandstone and shale couplets. The foresets in successive beds sometimes indicate opposing flow directions. Many bed surfaces, especially near the tops of the sequences, have unidirectional, straight-crested ripples and/or interference-ripple patterns (facies G). There is a gray shale (facies C) above this set of five sequences.

This set of five coarsening-upward cycles between gray shales can be interpreted in two ways. They could be a record of deposition in wave- and tide-influenced, fluvially dominated delta-mouth bars. The cross-bedding could have formed in delta-distributary channels; the sandstone and shale couplets may be levee deposits at the sides of distributary channels. The abundant unidirectional- and interference-ripple patterns on many bed surfaces indicate the presence of waves, perhaps with some tidal influence. The alternative explanation is that these rocks represent large, coarsening-upward shallow-marine sand waves and sand ridges similar to those described by Walker (1984). Cross-bedded and rippled, coarsening-upward sandstones make up the bulk of these elongate sandstone bodies; the shales would be interridge deposits. Both the delta-front and marine sand-ridge interpretations are consistent with the shallow-marine assemblages found above and below these sequences.

Thick, Cross-Bedded, Coarsening-Upward Sequences

Overlying the Devil's Kitchen are finer-grained sedimentary rocks, including some marine limestones. Above these are many thick (19–40 m thick) cross-bedded, coarsening-upward sequences interpreted as representing delta-front sediments. One typical sequence coarsens upward from tan shales with a few crinoids into alternating sandstone and shale beds (facies D), medium- to coarse-grained sandstone with trough cross-bedding (facies H) and thin conglomerate beds (facies J), and a few plane-bedded sandstones (facies I); the sequence is capped by coarse, cross-bedded sandstones. Other sequences contain thick sandstones with the hummocky and large-scale, low-angle cross-bedding typical of wave- and storm-dominated deltas (Elliott, 1986) and/or the convolute bedding and water-escape structures typical of rapidly prograding deltas (Tankard, 1986).

Delta-Plain Sequences

The thick, coarsening-upward delta-front sequences are sometimes capped with thick sections of gray-green to pale-tan or reddish shales and siltstones (facies B), locally containing thin sandstones with ripple cross-stratification (facies G) and/or fining-upward sequences. These are interpreted as upper-delta-plain and fluvial and/or flood-plain deposits.

One typical section (Fig. 6) consists of sandstones with parallel laminations and fine ripple cross-bedding, light-gray shales, and greenish-gray to red and tan siltstones (facies B). The laminated fine material was probably deposited on the flood plain or in delta-plain ponds, whereas the finely rippled or climbing-rippled siltstones were overbank deposits in splays and on levees. The sandstones are 0.1–0.4 m thick and have upper-flow-regime planar beds (facies I) or ripple cross-stratification (facies G). These sandstones are interpreted as splay deposits and small flood deltas into shallow delta-plain lakes. There are also cross-bedded, fining-upward sequences interpreted as point bars; some are capped by red mudstones (facies B), which may be relict paleosols.

Cross-Bedded, Fining-Upward Sequences

The middle of the lower Deese, above some delta-front and delta-plain sequences, contains a series of stacked, fining-upward sequences. The base of a sequence is usually cross-bedded sandstone, typically deposited on a scoured surface and/or with obvious large channels and troughs. Above this sandstone are finer-grained sandstones, typically cross-bedded, planar-bedded, and/or rippled; siltstones (including some thick beds with climbing ripples); and shales. These are interpreted as fluvial point-bar sequences; several within a delta-plain setting are shown in Figure 6.

DISCUSSION AND SUMMARY

The lower Deese Group can be divided into several distinct sections (Fig. 1): (1) the shallow-marine and delta-front Deese I interval, from the top of the Pumpkin Creek Member to the base of the Lower Devil's Kitchen Member; (2) the conglomeratic Upper Devil's Kitchen Member (Deese II); (3) the fluvial-deltaic Deese III section; (4) the marine (Deese IV) Arnold Limestone Member; and (5) the fluvial-deltaic Deese V section.

Most of the Deese I interval consists of shales containing, and/or alternating with, thin sandstones; cross-bedded fossil zones; rippled, coarsening-upward sandstone and shale sequences; and rippled, fining-upward sandstone and shale sequences. The thicker dark-gray shales probably record deposition in deeper water, below wave base. The repeating rippled, and/or cross-bedded, fining- and coarsening-upward sequences that contain light-colored shales occur as sets between darker-gray shales, suggesting that there were both bundled small-scale and more pronounced, larger-amplitude changes in depositional water depth. This fivefold bundled pattern is similar to

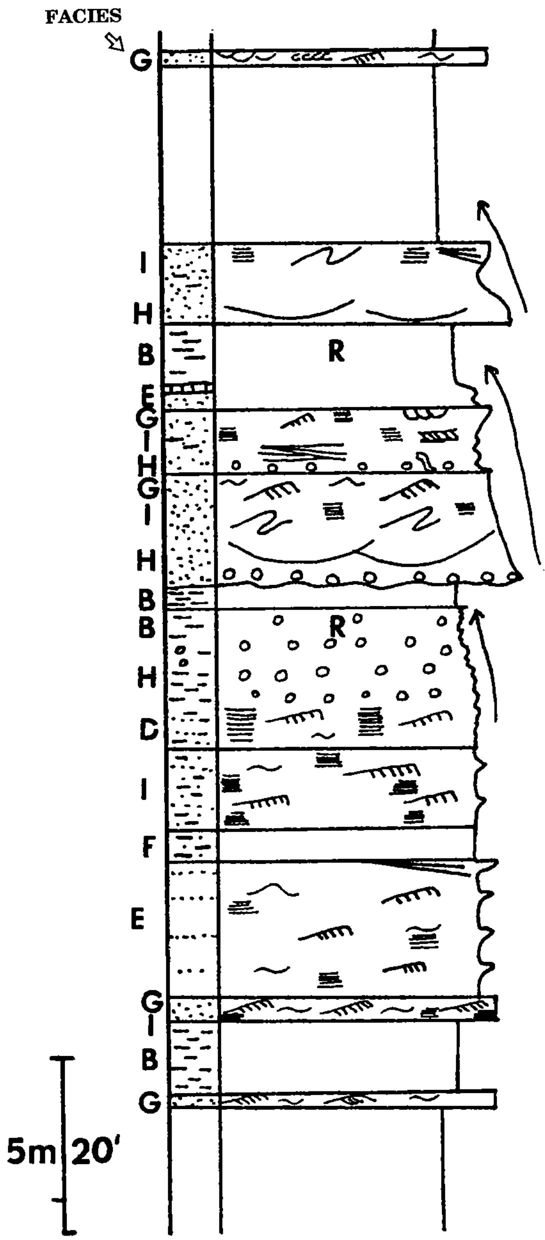


Figure 6. Delta-plain and point-bar sequences in the Deese III interval (see Fig. 3 for legend; letters designating the facies are explained in Table 1; R = red beds).

Pleistocene sediments that reflect climatic changes with Milankovich periodicity. These shallow-marine to shoreline-bar, shoal, delta-front, tidal-flat and estuarine, and possibly supertidal facies assemblages could be, but are not necessarily, part of delta-margin complexes.

The shoal deposits at the base of the Deese I section, the alluvial and braided-stream deposits within the Deese I, and the conglomeratic (Deese II) Upper Devil's Kitchen Member all have coarse cherty material. The chert sandstones and conglomerates within the Deese I section grade into sandstones that thin and pinch out to the northwest across the basin. The Upper Devil's Kitchen Member (Deese II) can be correlated across the basin; south of Ardmore, nearer the Ouachita thrust belt, it is a very thick chert-pebble conglomerate deposited in an alluvial-fan delta, but on the north side of the basin, the Deese II is a thinner, sandy, deltaic sequence (Saether, 1976).

The Ouachita fold belt, to the southeast of the Ardmore basin, contains the Ordovician Big Fork Chert and the (cherty) Devonian Arkansas Novaculite, which are sources for the chert in the conglomerates. Similar chert-rich sources are not known in the uplifts southwest or north of the Ardmore basin. Coarse conglomeratic deposits generally indicate periodic mountain-front uplift (Steel and others, 1977; Rust and Koster, 1984; Burbank and others, 1988). The conglomeratic deposits, in the southeast part of the Ardmore basin within the Deese I shallow-marine section, suggest that deposition was periodically interrupted by episodes of tectonic uplift of the Ouachita fold belt. Shallow-marine deposition ended when the coarse-grained deposits of the fan delta and/or alluvial fan that produced the Upper Devil's Kitchen Member (Deese II) prograded over this shallow shelf.

The Deese III and Deese V intervals are dominantly siltstone and sandstone. Thick sandstone units are separated by shales. There are thick, coarsening-upward delta-front deposits and upper-delta-plain siltstones with sandy splay deposits. There are indications of changing water depths in that thin marine limestones and prodelta deposits alternate with thick sections of delta-front, delta-plain, and fluvial deposits. No definite cyclic pattern can be demonstrated. The delta and flood-plain sedimentary units resemble the red-shale–capped flood-plain deposits described by Gibling and Bird (1994).

Many fining-upward, nonmarine fluvial (point bar) deposits in the Deese I and Deese II intervals are stacked into thick (up to 80 m thick) sequences; these indicate the possibility of nearby uplifts (Shanley and others, 1991). However, other evidence for later tectonic activity, i.e., in the Deese III through Deese V intervals, is weak; in these rocks, the many alternations of marine and delta-front sedimentary units with nonmarine sedimentary units could be due to eustatic, climatic, and/or tectonic forces.

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Cherokee Group (Pennsylvanian) Production in Oklahoma: Data from Fluvial-Dominated Deltaic Reservoirs

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ABSTRACT.—The Lower Desmoinesian Cherokee Group (Pennsylvanian) in Oklahoma is partly represented by a series of sandstones and shales deposited during cyclic periods of progradation and marine transgression. Mapped occurrences of oil and gas production from four selected Cherokee sandstones (Bartlesville, Red Fork, Skinner, and Prue) illustrate some patterns that have been interpreted as fluvial channels. These fluvial systems generally had their sources in the north and northeast; they formed deltas across parts of the Anadarko shelf in northwestern Oklahoma and the northeastern Oklahoma platform. These sandstones are usually stratigraphically separated by limestones and shales deposited during periods of marine transgression.

The Oklahoma Geological Survey's Natural Resources Information System (NRIS) was used to study the production profiles from these four selected Cherokee sandstones. A 12-year production history shows data for those leases that report a selected sandstone as the only producing interval. Those leases that report more than one producing interval are shown as "co-reported" and are used for comparative analyses only. The NRIS database is a useful tool for analyzing occurrence and/or production from reservoirs across the State of Oklahoma.

The Tecumseh NW field, located in T. 9–10 N., R. 3 E., in Pottawatomie County, Oklahoma, is an example of a successful development in a Cherokee Group sandstone. The field, discovered in 1979, produces oil and associated gas from stratigraphic traps in the upper and lower Red Fork sandstone. These reservoirs have been interpreted as a series of valley-fill shoreline deposits laid down by a fluvial-dominated estuarine deltaic system. Data indicated that the Red Fork sandstone was well suited for secondary development, and a water-flooding program was implemented in the field in 1991. As of August 1992, the NRIS Oil and Gas Production file indicates Red Fork sandstone cumulative production in the Tecumseh NW field to be 7 MMBO and 24 Bcf of associated gas. Data from the NRIS Well History file show a total of 89 wells have been drilled within the field since its inception.

Brown, D. P.; Northcutt, R. A.; and Grasmick, M. K., 1996, Cherokee Group (Pennsylvanian) production in Oklahoma: data from fluvial-dominated deltaic reservoirs, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 249.

Using Flooding Surfaces as Interpolation Guides: Three-Dimensional Modeling Concepts for a Fluvial-Dominated Deltaic Reservoir

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ABSTRACT.—This paper proposes the use of process-based methods of three-dimensional interpolation between two bounding surfaces as an approach to building three-dimensional models of fluvial reservoirs. The bounding surfaces best suited for interpolation purposes in fluvial-dominated deltaic reservoirs appear to be the marine- and fluvial-flooding surfaces. The resulting modeling scheme is very much like the interpretation process in a fluvial-dominated deltaic environment. The advantages gained via three-dimensional modeling in this manner are the visualization and the constraints upon the interpretation that result from a process-based interpolation.

INTRODUCTION

How can a three-dimensional model of a reservoir deposited in a fluvial-dominated delta be constructed? One easy way is to give a geologist a large number of wooden blocks of different colors representing the different facies and let him or her stack the blocks into a three-dimensional model of the Earth. Admittedly, this method seems rather awkward compared to the cross sections and structural maps that have been used by the oil and gas industry for years. However, this example is not very different from some of the early computer-based three-dimensional modeling packages. The user almost has to define every cube of the reservoir in order to build a three-dimensional model that is representative of the user's intuitive picture of a particular depositional environment. This is not a very satisfactory approach because of the intensive extra effort required to build a three-dimensional model of a reservoir. In order to ease the problem of assembling a three-dimensional model of a reservoir, interpolation methods have been introduced to reduce the amount of input effort required to construct a three-dimensional model. This paper describes a process-based interpolation concept that can be used to incorporate a priori information about fluvial systems into the three-dimensional modeling process.

I begin by describing how surfaces can be used to interpolate information between well control. Next, I deal with the issue of which kind of surfaces are best suited for interpretation and interpolation. Finally, process-based interpolation algorithms are suggested for filling the volumes between the surfaces. The ideas presented here are for fluvial-dominated deltaic environments, but the basic principles can be used in all depositional environments.

EARLY IDEAS FOR INTERPOLATION

Sequence stratigraphy (Sloss, 1963) and the concepts of seismic stratigraphy (Vail and others, 1977) have successfully been applied in large-scale marine environments where sea-level changes leave pronounced unconformities. The unconformities can often be recognized on seismic data and in the well control so that the surfaces associated with the unconformities can be mapped. The depositional package or "sequence" of genetically related strata between surfaces represents the rise and fall of sea level. This understanding of the volume enclosed by the sequence boundaries is then used by sequence stratigraphers in their efforts to interpret the distribution of facies between the sequence boundaries. The process of interpolating to build a three-dimensional model can proceed in very much the same way.

Consider Figure 1, in which two sequence boundaries are identified. The layers between these two sequence boundaries are treated as if they vary in proportion to the thickness of the interval between the two sequence boundaries. Fig-

Brown, R. L., 1996, Using flooding surfaces as interpolation guides: three-dimensional modeling concepts for a fluvial-dominated deltaic reservoir, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 250–253.

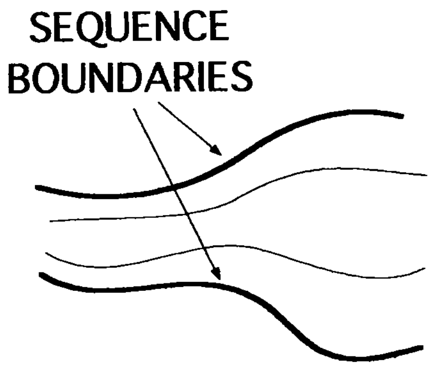

Figure 1. Proportional interpolation. Sequence boundaries can be used to guide interpolation. In this illustration, the lighter lines represent the distribution of similar values distributed in proportion to the separation of the sequence boundaries.

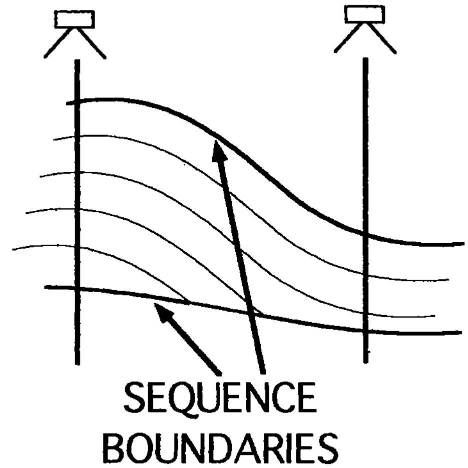

Figure 2. Onlap and downlap. Another way to use a sequence boundary to guide an interpolation is by using the top sequence boundary as a guide to interpolation. In this case, only the geologic data at the top of the sequence in the well on the left influence the predictions of the geology in the well on the right.

ure 2 illustrates a case in which the top sequence boundary is used to guide the interpolation. This approach to interpolation simulates onlap and downlap. Figure 3 shows a circumstance in which the bottom sequence controls the interpolation. This can be used to simulate the effects of toplap.

However, in fluvial-dominated deltaic environments, the reservoirs are deposited under mixed circumstances in which the fluvial and marine forces play their respective roles. Unconformities are not easy to recognize at the reservoir scale in the subsurface. Alternatives to sequence stratigraphy have to be sought.

WHICH SURFACES SHOULD BE USED TO GUIDE INTERPOLATION IN A FLUVIAL ENVIRONMENT?

Deciding which surfaces should be used for three-dimensional subsurface modeling of a fluvial environment is a matter of practicality. The sequence boundaries associated with sea-level rise and fall are certainly useful for unraveling the big picture related to a fluvial-dominated delta. However, a detailed analysis required for exploration and development work requires the construction of models at smaller scales, and the sequence stratigraphy does not offer much information about the strictly fluvial portion of the environment.

Miall (1988) has suggested a hierarchy of surfaces associated with fluvial systems that was based upon field observations. However, the surfaces described by Miall are generally not easy to recognize in subsurface studies unless specialized logs are used.

Fortunately, fluvial-dominated deltaic environments are characterized by flooding surfaces at all scales. At the smallest scale, the flooding surfaces represent the localized flooding episodes of a river. At the largest scale, the flooding surfaces can represent a marine flooding surface or even a large-scale avulsion or a period of nondeposition. Conveniently, these surfaces can be used for relative correlation purposes and to control estimates of the geology confined between the surfaces. Figure 4 illustrates how these flooding surfaces can often be recognized across the flood plain of a fluvial system. The interpretation then proceeds by first correlating these surfaces in all the wells and then attempting to recognize the facies between the flooding surfaces in the well control. Once these

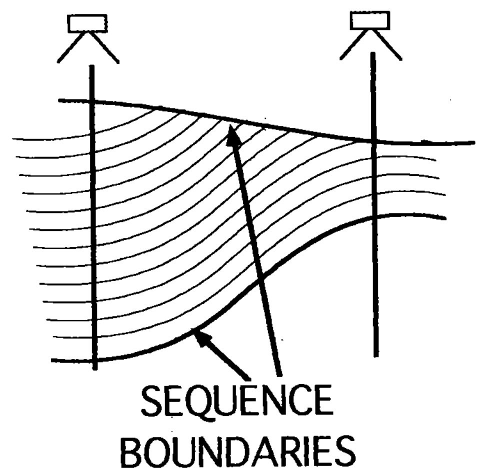

Figure 3. Toplap. If the bottom sequence boundary is used to guide the interpolation, the effects of toplap can be simulated in a three-dimensional model.

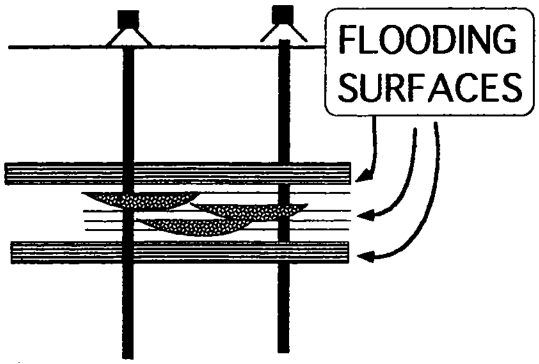

Figure 4. Flooding surfaces. Sequence boundaries are not easy to recognize at the reservoir scale, but flooding surfaces associated with fluvial-dominated deltaic deposits can be used as a substitute.

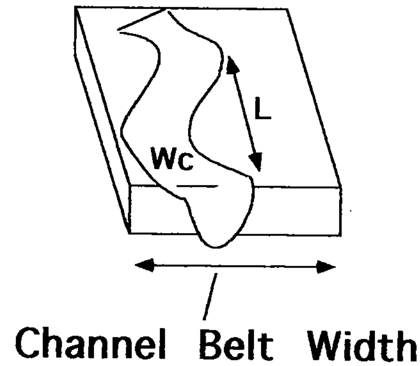

Figure 5. Process-based modeling. Much observational data concerning fluvial systems can be used to construct models of fluvial environments guided by the interpreted flooding surfaces shown in Figure 4. The data have been constructed into equations (see Bridge and Mackey, 1993) that can be used to construct realistic geometries for channels. These ideas can further be extended to include the distribution of facies with respect to the channels.

facies have been identified, the geologist extends the interpretation away from the well control.

In three-dimensional modeling on a computer, the process is very much the same. The difference suggested here is that the interpretive process be augmented by process-based modeling procedures that can significantly improve the accuracy of any final model. Some ideas for process-based modeling are described in the next section.

PROCESS-BASED INTERPOLATION BETWEEN SURFACES

Process-based interpolation is an attempt to use what is known about a geologic environment, e.g., the fluvial-dominated deltaic environment, as a guide to the interpolation process. There is much empirical information about fluvial systems (e.g., see Bridge and Mackey, 1993) and even fluvial-dominated deltas (e.g., Tyler and others, 1991). The equations and quantitative information available from a priori information about fluvial-dominated deltaic reservoirs can significantly improve the accuracy of the modeling effort. At the largest scale, for example, parameters such as the width of a channel, W_c, observed in a well can be related via empirical equations to the wavelength, L, of the river meander (Fig. 5). At smaller scales, the distribution of facies within the fluvial-dominated deltas can be related to the distributions assigned to the larger-scale features. The ultimate result is a three-dimensional model in which various properties can be assigned for seismic and reservoir-simulation studies.

SUMMARY

It is clear from the foregoing that three-dimensional computer modeling of reservoirs can and probably should be designed very much like the interpretation process. For fluvial-dominated deltaic reservoirs, unconformities for the large scale combined with flooding surfaces (both marine and fluvial) can be used for interpolation as well as correlation purposes. Then, three-dimensional interpolation between these surfaces can be accomplished by using process-based algorithms that basically incorporate available data about depositional environments into the interpolation. The result will be a more realistic three-dimensional capability that can be used for visualizing a model from different views and for interactively constructing models that can be used for various studies associated with the reservoir.

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Stratigraphic Characterization of Selected Pennsylvanian Petroleum-Producing Sandstone Reservoirs from Integrated Core and Well-Log Data, Conoco 33-5 Well, Conoco Test Borehole Facility, Kay County, Oklahoma

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Detailed sedimentological and stratigraphic characterization using wireline logs and cores is required to understand the heterogeneity found in deltaic reservoirs and for planning advanced production methods and related enhanced-oil-recovery processes.

The lithostratigraphic framework characterized in the Conoco 33-5 well ranges from the Barneston Limestone (Chase Group—early Wolfcampian) at the top to the Lagonda Sandstone Member of the Senora Formation (Cabaniss Group—Desmoinesian) below. The stratigraphic interval comprises a total stratigraphic thickness of 3,067.1 ft, of which 1,373.5 ft was cored.

Facies observed in cores were correlated with their appropriate geophysical log signatures; in uncored wells, facies were identified from log signatures that enabled the subsurface stratigraphic units to be correlated with outcrop analogues. Core-to-log correlations are being used in a series of stratigraphic sections to delineate depositional environments throughout the test borehole facility and in selected parts of the immediate area.

One of the main sandstone reservoirs of interest in the cored sequence is the upper part of the "Osage-Layton sandstone" interval (Cottage Grove Sandstone Member—Missourian) of the Chanute Formation. Eight core facies, or reservoir zones, are recognized in this sandstone-dominated sequence that is 123 ft thick. The core-facies boundaries are defined by lithofacies, sedimentary structures, and wireline log responses, particularly gamma-ray log markers. The composition of the eight core facies is described below, in stratigraphic order.

Core facies	Lithology	Thickness (ft)
8	Sandstone, very fine grained, noncalcareous, massive with abundant carbonized plant fragments	9.9
7	Sandstone (98%), very fine grained, noncalcareous with abundant carbonized plant fragments; rare beds of shale (2%) showing low-angle cross-bedding	10.9
6	Sandstone (99%), very fine grained, noncalcareous, massive, with abundant carbonized plant fragments	53.1
5	Sandstone (98%), very fine grained, noncalcareous with wavy laminae of shale (2%); conglomeratic lag at base	12.7
4	Interlaminated noncalcareous, very fine grained sandstone (60%) and shale (40%)	3.4
3	Sandstone (98%), very fine grained, very calcareous with very thin bands of interlaminated shale (2%) and ripple-marked sandstone	27.5
2	Interlaminated, fissile, black shale (60%) and noncalcareous, very fine grained sandstone (40%)	2.2
1	Sandstone, very fine grained, noncalcareous, with carbonaceous shale laminae	1.4

Chaplin, J. R.; and Kareem, M. R, 1996, Stratigraphic characterization of selected Pennsylvanian petroleum-producing sandstone reservoirs from integrated core and well-log data, Conoco 33-5 well, Conoco test borehole facility, Kay County, Oklahoma, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 254.

Surface Geochemical Hydrocarbon Signatures of the Eastern Colorado and Western Kansas Morrow Group

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ABSTRACT.—Meandering fluvial deposition joined with valley-fill stratigraphic and combination traps makes the Pennsylvanian Morrow Group sandstones of eastern Colorado and western Kansas a very challenging exploration target. Surface geomicrobial analysis of shallow soil samples enhances and ranks geophysical and geologic leads by identifying hydrocarbon microseepage signatures. Productive versus nonproductive Morrow traps are delineated by microbial prospecting that locates and measures concentrations of specific microbial populations associated with hydrocarbon gases leaking from buried reservoirs. Examples of microbial signature profiles over known production and prospect locations prior to drilling are provided, including the Moore-Johnson stateline field and Colorado's Second Wind field.

INTRODUCTION

The Microbial Oil Survey Technique (MOST) is based on the presence of hydrocarbon microseeps leaking from buried reservoirs. The microseeps are detected by observing concentrations and distributions of hydrocarbon-indicating microorganisms found in shallow soils. More specifically, when the upward-migrating hydrocarbon gases from hydrocarbon reservoirs enter the shallow soil environment, they are utilized by a specific group of microorganisms. There is a direct, positive relationship between the hydrocarbon concentrations in the soils and these microbial populations (Fig. 1). This relationship between increased hydrocarbon concentrations and increased hydrocarbon-indicating microorganism populations is easily measurable and distinctly reproducible (Tucker and Hitzman, 1994). High hydrocarbon-indicating microbial populations are therefore reliable indicators of hydrocarbon gas migration (Pareja Lopez and others, 1993).

The specific microorganism populations are measured from shallow soil samples collected from depths of between 6 and 8 in. The soils are analyzed by microbiological screening techniques for hydrocarbon-indicating microbes (Hitzman and others, 1994). The process used in this survey screened for only those microorganisms that indicate the presence of light hydrocarbons, particularly butane.

Sample patterns and sample density are selected to best define the hydrocarbon potential of the target area, subject to considerations of terrain and accessibility. Reconnaissance and more detailed surveys of acreage or prospects may be completed in this manner. The predictive value of this technology has been demonstrated by extensive field surveys. Microbial surveys are highly effective when used in conjunction with geologic and geophysical data.

MORROW MICROSEEPAGE SIGNATURES

Morrow reservoirs are usually identified from subsurface mapping and seismic profiles. The locations of trapped hydrocarbons with sufficient commercial value are more difficult to determine. Although improved seismic studies can sometimes locate Morrow channel deposits, the presence of hydrocarbons is still unknown until tested by the drill bit. Microbial surveys indicate the presence of hydrocarbon microseepage and both confirm and deny the presence of commercial hydrocarbons. When used with sufficient sample spacing and density, microbial surveys act as a lead exploration tool and can identify meandering channel prospects with positive hydrocarbon microseepage. However, the common role of surface geochemical surveys has been to rank and screen good seismic prospects against poor seismic prospects.

Hitzman, D. C.; Tucker, J. D.; and Rountree, B. A., 1996, Surface geochemical hydrocarbon signatures of the eastern Colorado and western Kansas Morrow Group, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 255–262.

Stateline Reservoirs

The Moore-Johnson field, located in northwest Greeley County, Kansas, T. 18 S., R. 43 W., is believed to be a braided-stream deposit with two sandstone lenses containing moderately sorted, coarse-grained quartz. Lower Morrow Group limestones and shales form both the bottom and top traps (Adams, 1990). The Moore-Johnson No. 1 initially produced 522 barrels of oil per day in October 1989. Microbial samples were collected every 330 ft along a 6-mi east-west traverse across the narrow reservoir area. A microbial profile (Fig. 2) shows an anomalous microbial signature at the reservoir location and a second strong signal 2 mi to the east. A second microbial profile exhibits similar anomalies over recently discovered deltaic traps 2 mi south of the Moore-Johnson field (Fig. 3). The Amoco 2 Settles gas well and the Murfin Schmidt C oil well were surveyed with a 3-mi traverse and a sample spacing of every 530 ft.

The Sidney field, located farther north in

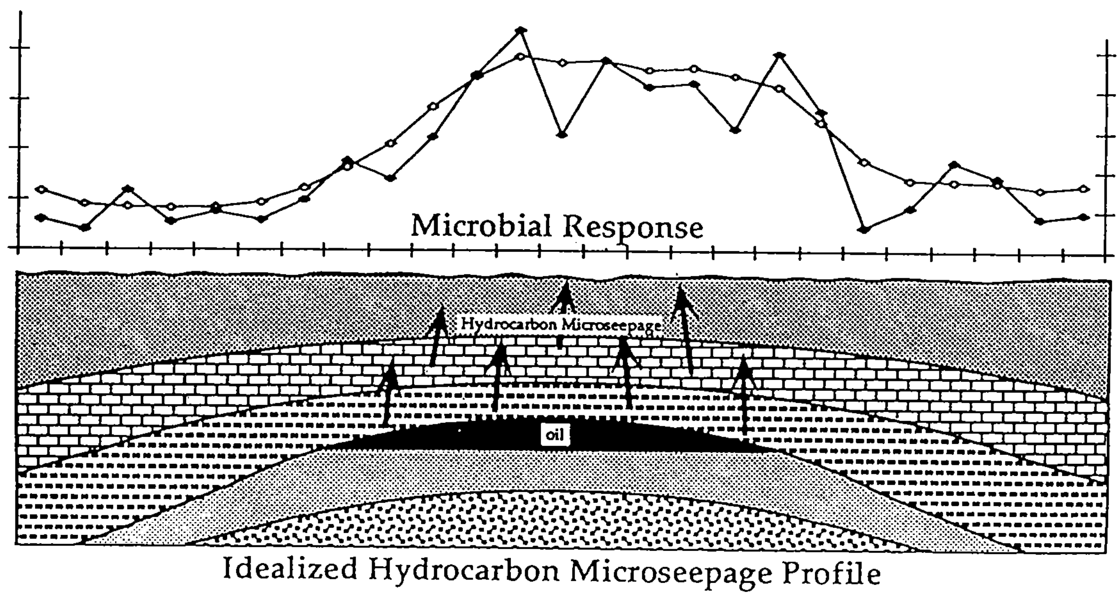


Figure 1. Model hydrocarbon microseepage profile with microbial response profile.

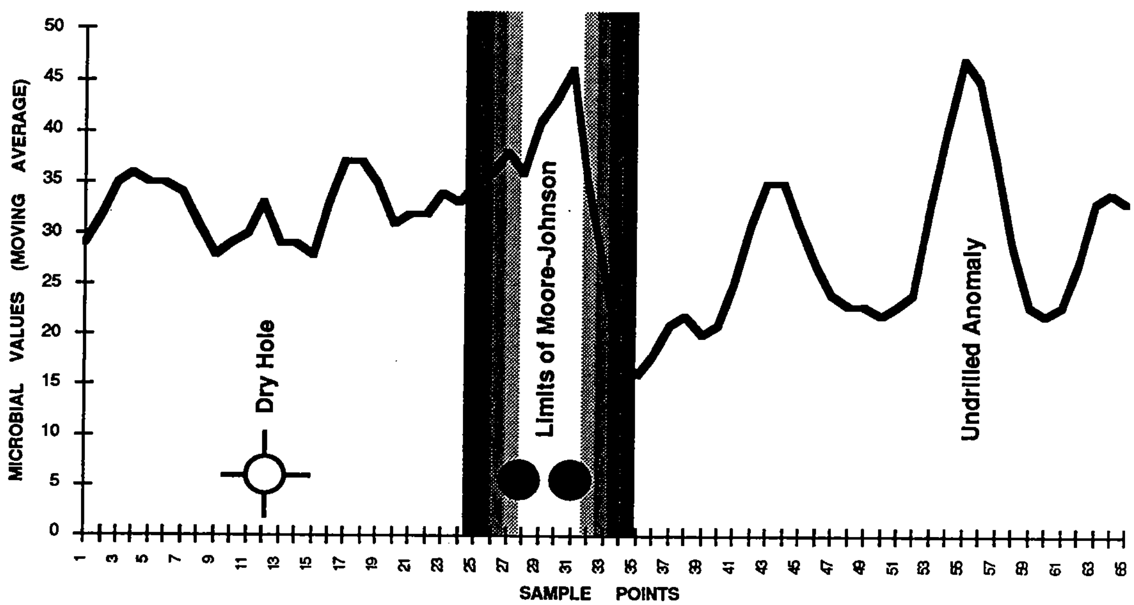


Figure 2. Microbial plot of Moore-Johnson field after discovery. Anomalous microbial values define the Moore-Johnson stateline field.

Greeley County, T. 16 S., R. 42 W., was tested with a 5-mi traverse and a sample spacing of 330 ft (Fig. 4). The microbial signature of the Sidney field is positive compared to the background and dry-hole areas of the rest of the traverse. These three reconnaissance traverses exhibit high microbial microseepage signatures associated with the known producing Morrow channels. More complete prospect definition and evaluation requires additional samples in closer parallel or grid traverses along with comparison with geologic and geophysical data.

Colorado Wildcats

Predictive microbial surveys of wildcat wells correctly tested microseepage signatures of the

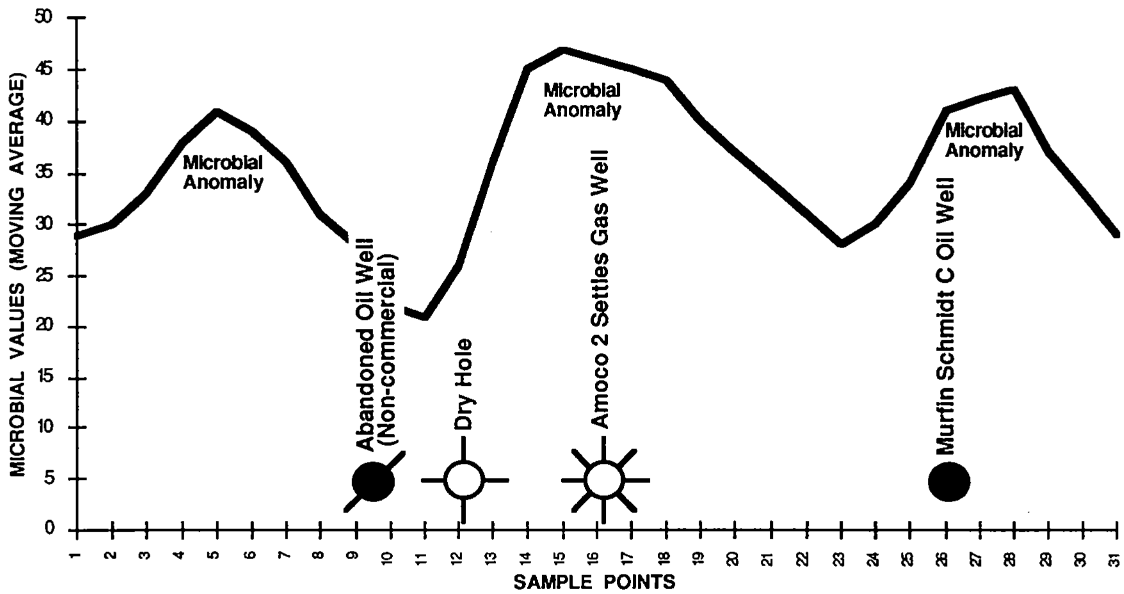


Figure 3. Microbial plot of Amoco no. 2 Settles and Murfin Schmidt C traverse. Stateline area Morrow prospects exhibit anomalous microbial responses.

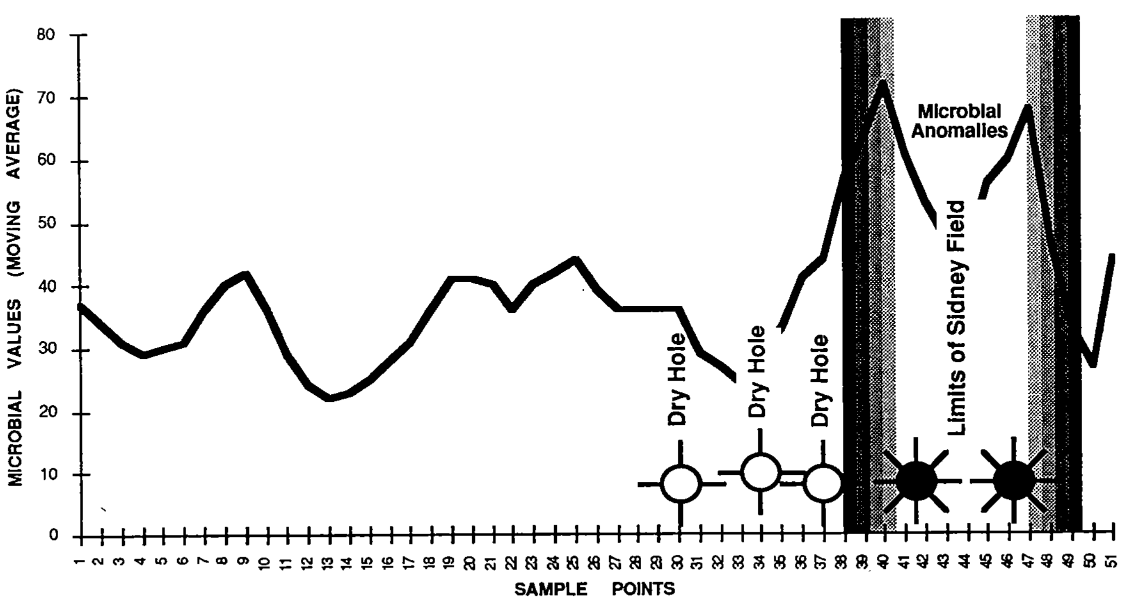


Figure 4. Microbial plot of the Sidney field (after discovery) in northwest Greeley County, Colorado.

Mt. Pearl and Second Wind fields and, just as significantly, clearly identified Morrow target dry holes prior to drilling. As part of a large (400 mi^2) evaluation of the Las Animas arch area of eastern Colorado, Phillips Petroleum Company collected approximately 10,000 MOST samples (Sundberg and others, 1994). Sampling along county road right-of-ways and seismic traverses, Phillips mapped a microseepage pattern in 1983 that delineated the Sorrento field and predicted the subsequent Mt. Pearl extension (Figs. 5,6).

The Second Wind field in Cheyenne County, Colorado, was surveyed by Phillips prior to the field's discovery well. In this case, Phillips used a histogram-distribution interpretation of microbial values to predict whether the wildcat's section was microseepage prone (Fig. 7). After hundreds of similar comparisons, Phillips has determined that a microseepage-prone area exhibits a high microbial average and multimodal and right-hand–skewed frequency distribution (Beghtel and others, 1987). Dry holes exhibit histogram distri-

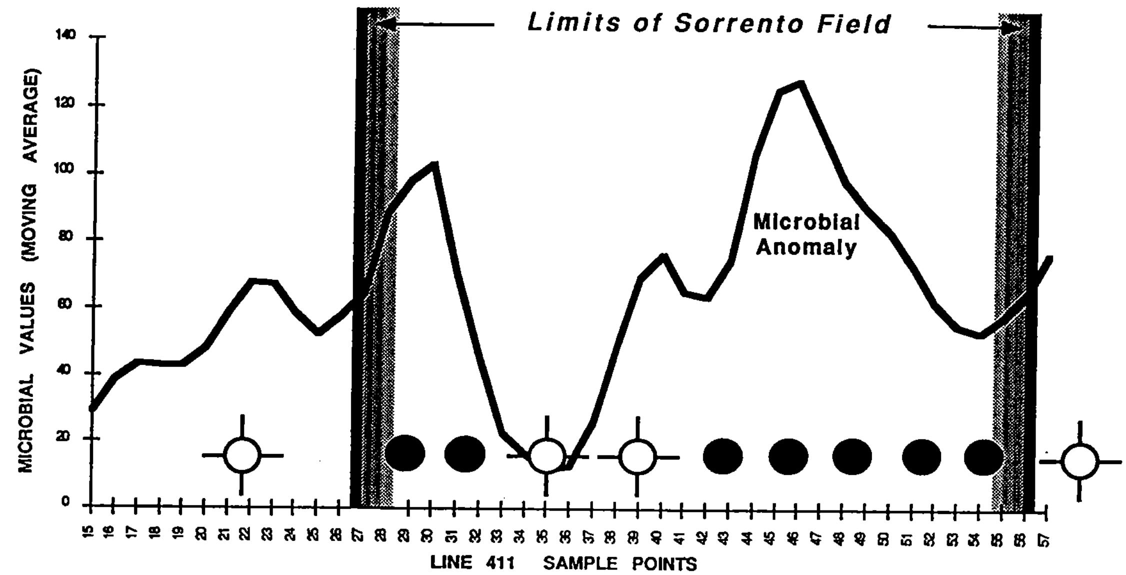


Figure 5. Microbial plot of the Sorrento field after discovery.

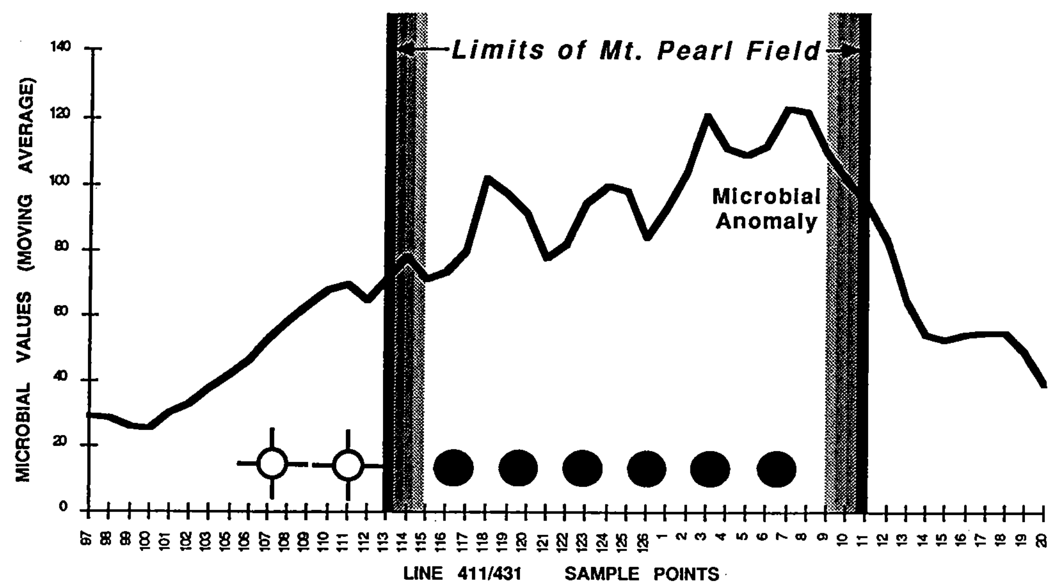
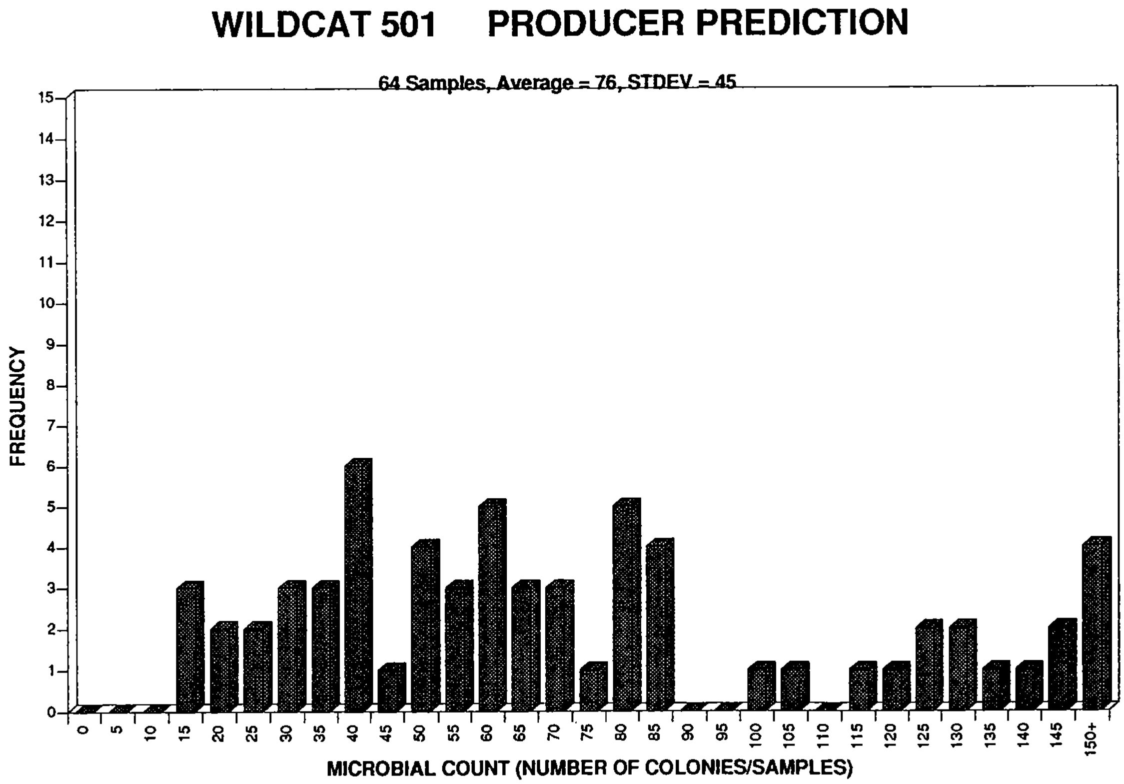


Figure 6. Microbial plot of the Mt. Pearl field prior to discovery.



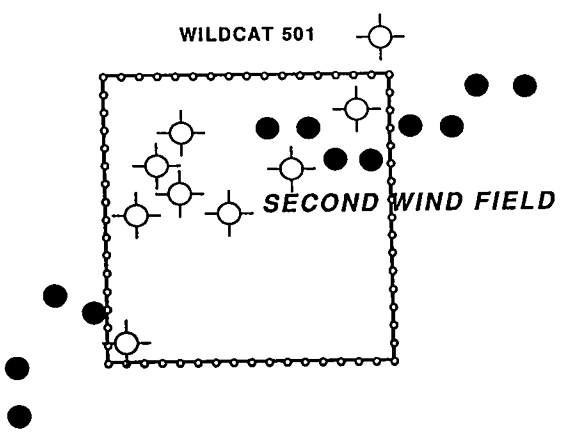


Figure 7. Second Wind field's frequency-distribution histogram (above) exhibiting high microbial average and right-hand–skewed distribution. Successful prediction of new discovery made prior to drilling (below).

butions with lower averages and more normal or bell-shaped distributions (Fig. 8). Phillips has used this analysis to correctly rank hundreds of prospects.

Two examples of dry-hole predictions were mapped in Kiowa and Cheyenne Counties, Colorado (Figs. 9,10). Parallel, 2-mi traverses, with a sample spacing of every 330 ft, searched for Morrow channels in areas previously screened by geophysical data. A total of four wildcats located away from the best microseepage pathways were correctly predicted to be dry holes. In each case, additional microbial samples would be recommended for exact drill-site placement.

CONCLUSIONS

Meandering fluvial-deltaic Morrow reservoirs are difficult to locate with conventional seismic and geology. These tools do not indicate the presence of hydrocarbons, only possible traps. Microbial surveys measure hydrocarbon microseepage leaking from Morrow channel deposits. Predictive microbial case studies warned against dry holes and accurately defined the Mt. Pearl and Second Wind fields of Cheyenne County, Colorado. The Moore-Johnson and Sidney fields of Greeley County, Kansas, show anomalous microbial microseepage signatures. Ideal microbial exploration strategy includes the collection of samples approximately 330 ft apart in parallel traverses nearly perpendicular to the prospect channels and alignments. The integration of microbial microseepage data with geology and geophysics creates a triad of technology that seeks to eliminate dry holes and increase exploration success.

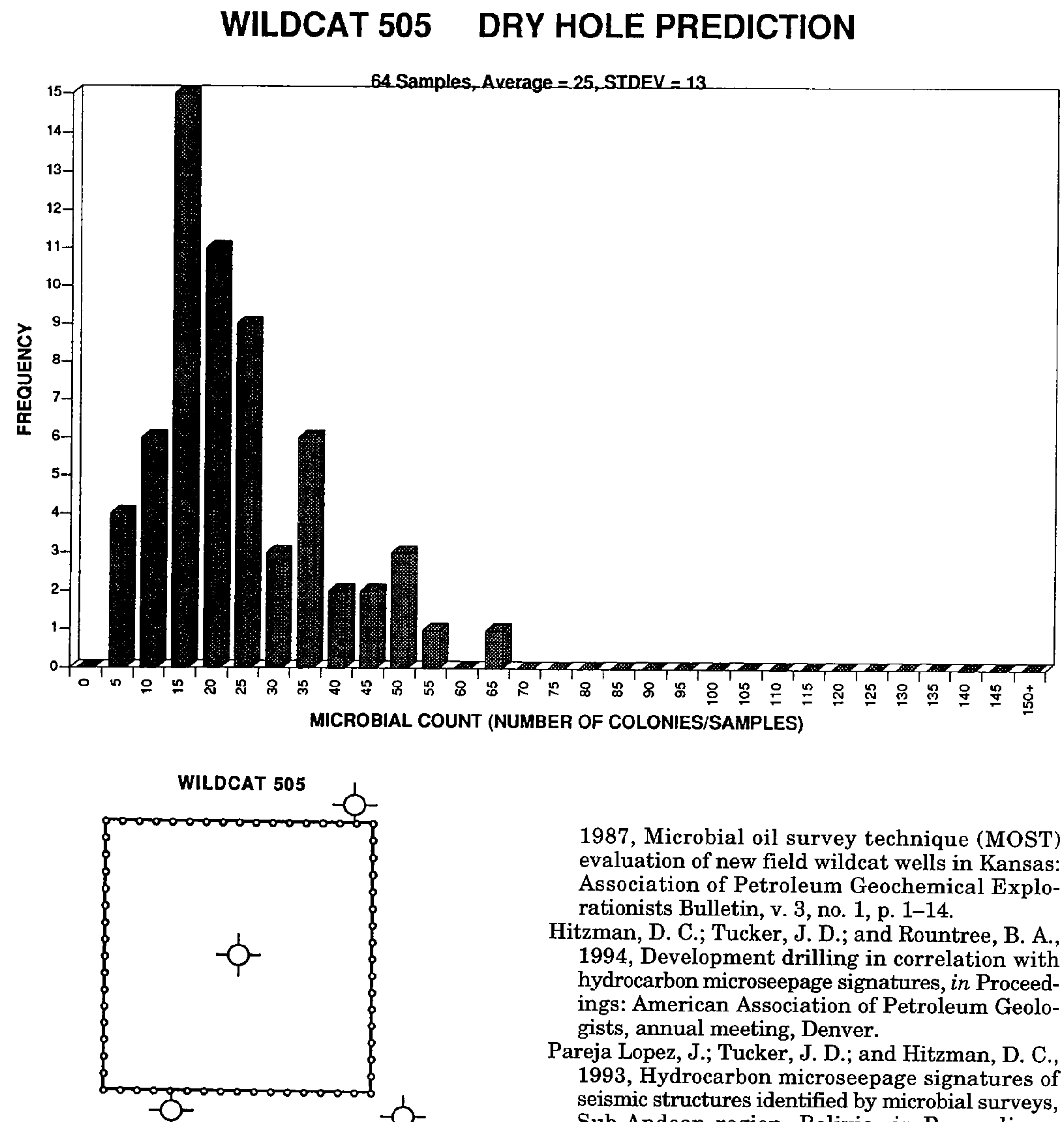


Figure 8. Morrow target dry hole predicted (below) with microbial-distribution histogram (above) that shows low average and normal (bell-shaped) distribution.

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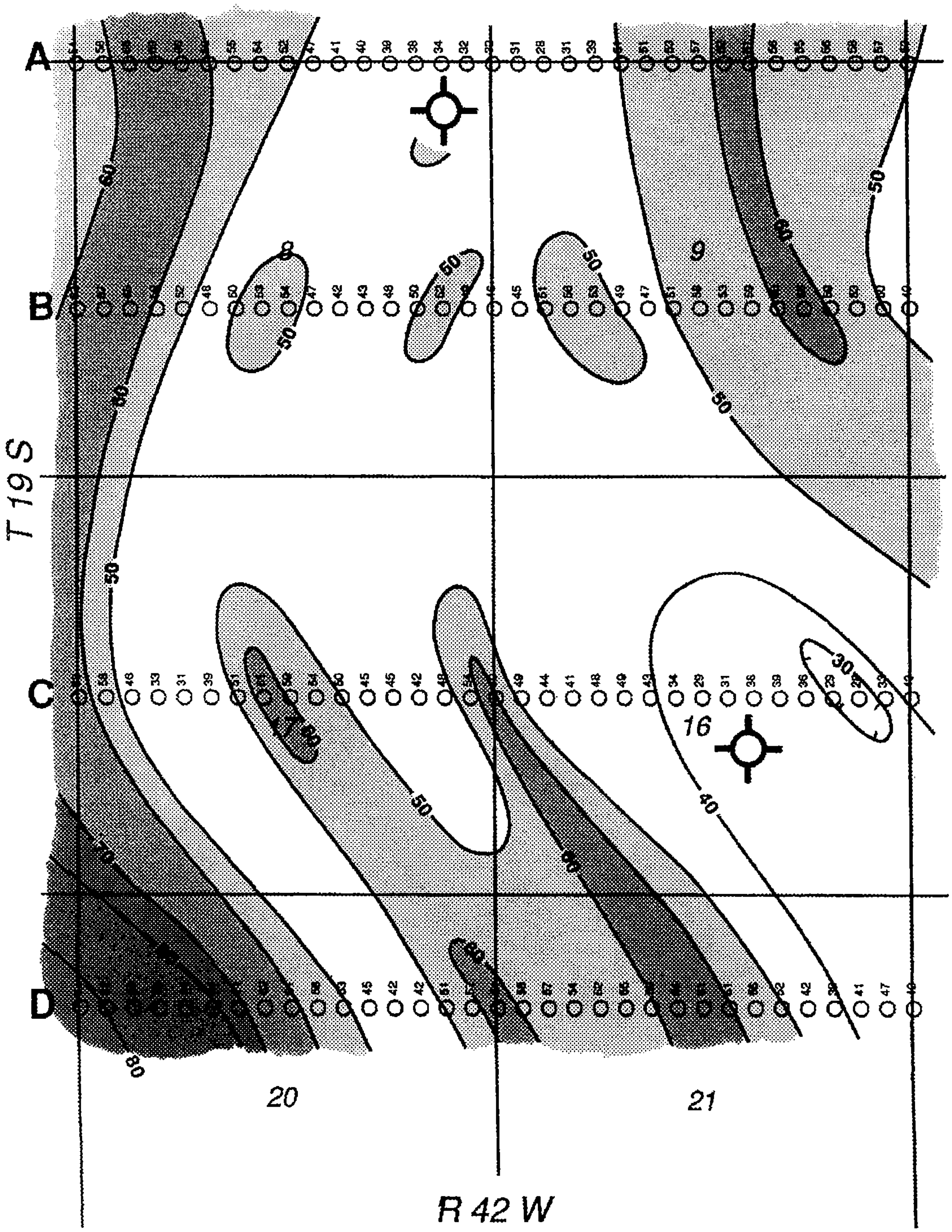

Figure 9. Mapped microbial signatures of four traverses at approximate 0.75-mi spacing predict dry holes in Kiowa County, Colorado.

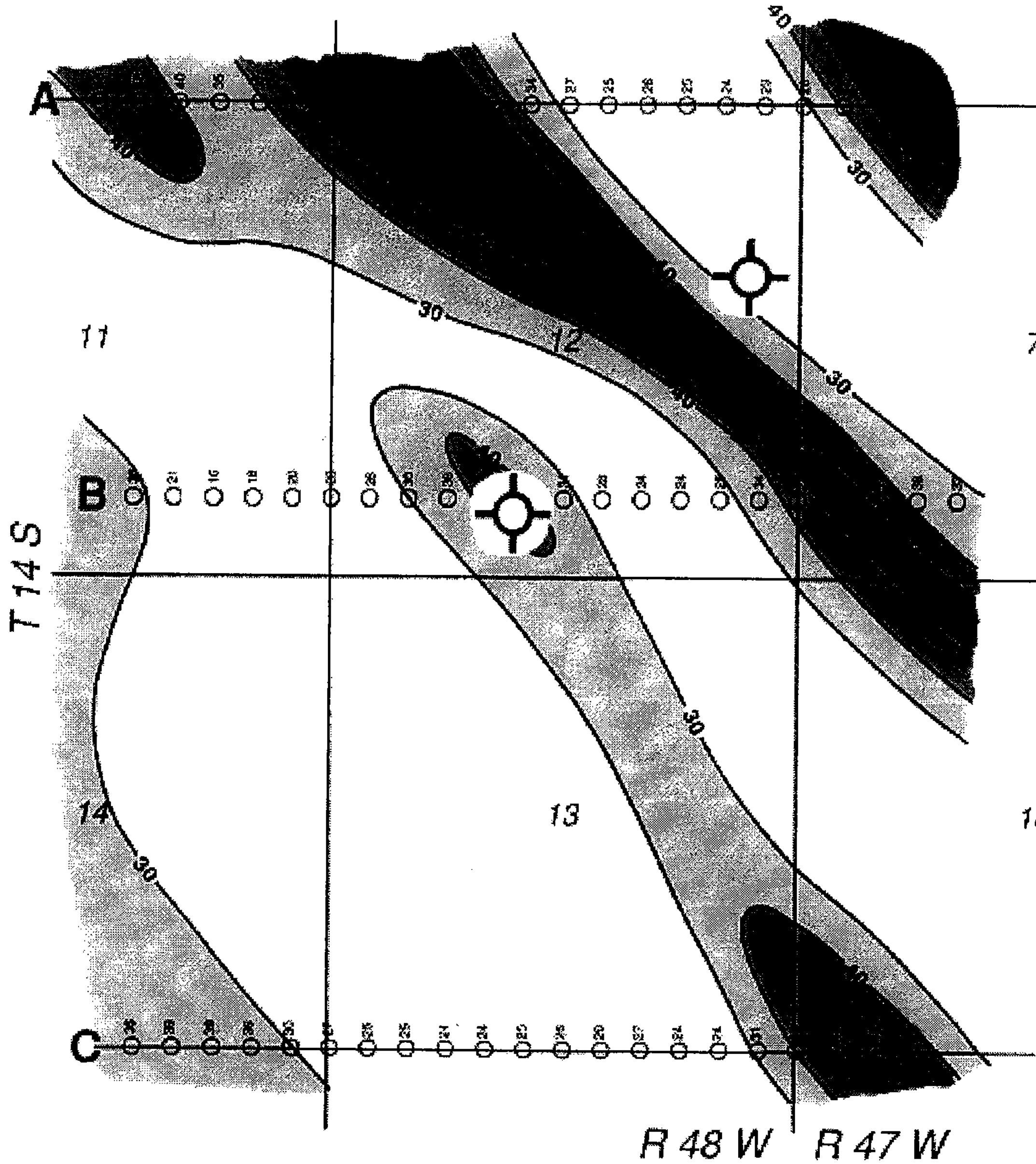

Figure 10. Mapped microbial signatures of three more widely spaced traverses at approximately 1-mi spacing predict dry holes in Cheyenne County, Colorado.

Improved Recovery Alternatives for the Alamo SW Field: A Tight Fluvial-Deltaic Sandstone Reservoir

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Norman, Oklahoma

ABSTRACT.—The Alamo SW field, discovered in 1988, produces 50° API oil from an "unconformity" sandstone (Bartlesville) reservoir that consists of upper and lower sandstones separated by 10 ft of silt and shale. Cumulative primary production from the 10 field wells was 294,968 STB of oil and 0.572 BCF of gas through November 1992. Most of the production has been from the lower sandstone zone. The geologic model constructed for the field with well-log and core data was used in reservoir-simulation studies to evaluate water-flooding performance and to determine the effects of horizontal completions for production and injection wells during primary and secondary recovery.

The simulation model contained 322 active cells, each with a length and width of 330 ft and a thickness interpreted from the sandstone isopach maps for each zone. The average porosity and permeability for the lower zone was 12% and 2.25 md. The average water saturation was 26%.

Simulation results showed that conversion of three wells to water-flooding injectors would produce 400,000 STB more oil than projected primary recovery. Using a horizontal completion (1,000 ft), simulation results showed that there would be very little improvement in primary recovery, but that a horizontal completion would provide a more uniform water-flooding front, thus bypassing less oil. Simulation results also showed that, compared to a vertical injection well, a horizontal injector would have a significantly greater recovery efficiency per barrel of water injected.

INTRODUCTION

The Alamo SW field, located largely in sec. 19, T. 7 N., R. 1 W., Cleveland County, Oklahoma, produces 50° API oil and gas from the "unconformity" sandstone, interpreted in this area to be equivalent to the Bartlesville sandstone. The discovery well was completed in January 1988 as a reentry of a previous well abandoned in 1959. Currently, this field has 10 wells, all conventional vertical completions (Fig. 1). Completion procedures usually included a fracture treatment using 20,000 to 40,000 gallons of gelled oil and 60,000 to 70,000 pounds of 20/40 sand. Cumulative production through November 1992 from the 10 wells completed in the field was 294,968 STB of oil and 0.572 BCF of gas, estimated to be 11% of the original oil in place. Solution-gas drive is the primary recovery mechanism for the field. Evidence for an initial gas cap was not found, and no water has been produced from the field wells.

The purpose of this study was to determine (1) whether horizontal well completions could improve either remaining primary recovery or water-flooding performance in this field and (2) the optimum locations for such wells.

RESERVOIR GEOLOGY

The reservoir consists of two small, discontinuous sandstone bodies separated by a shale interval 10 ft thick. The areal extent of this basal Desmoinesian reservoir is approximately 652 acres. The base of the lower sandstone is incised into the Woodford Shale. The upper sandstone is limited to 152 acres and only produces in three wells. The reservoir is referred to as the unconformity sandstone or the Bartlesville sandstone.

Knapp, R. M.; Forgotson, J. M., Jr.; Collins, T.; Genuzio, A.; and Gossling, J. M., 1996, Improved recovery alternatives for the Alamo SW field: a tight fluvial-deltaic sandstone reservoir, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 263–273.

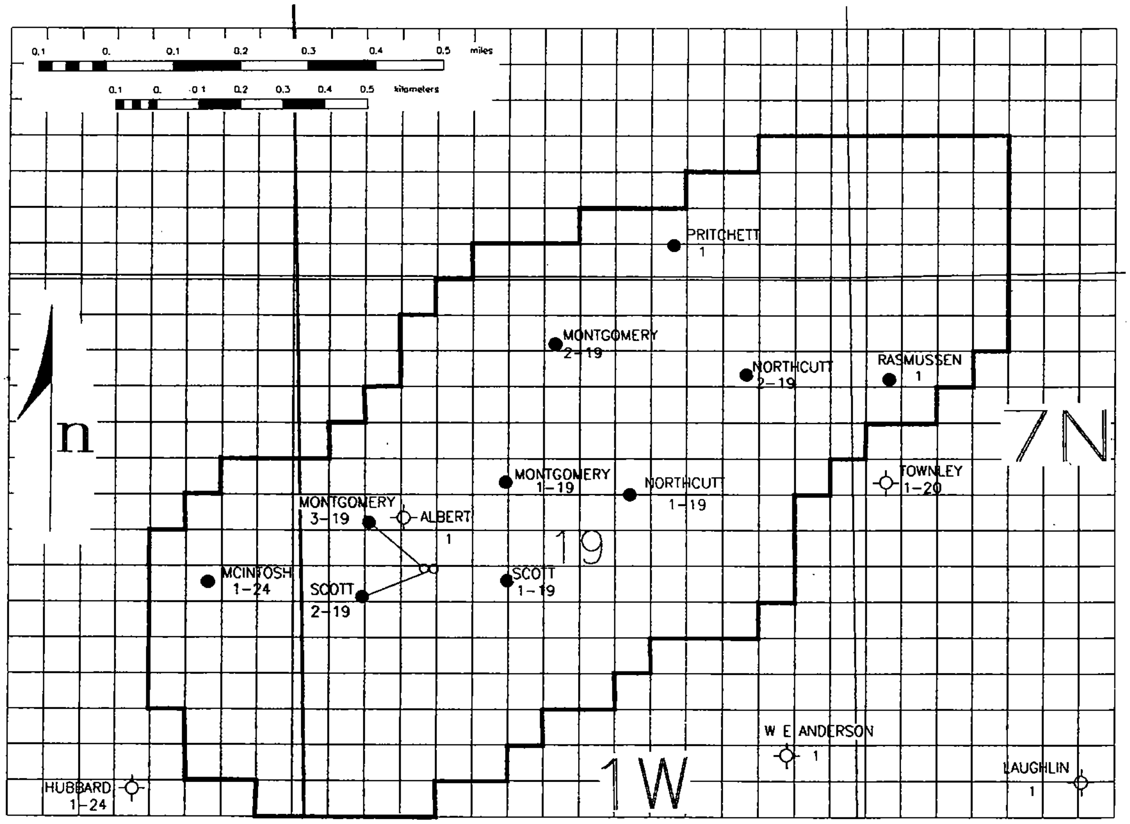

Figure 1. Base map of Alamo SW field showing well locations in sec. 19, T. 7 N., R. 1 W., Cleveland County, Oklahoma; also shown are well names and grid used for simulation. Active grid cells are within heavy outline.

Core Description and Environmental Interpretation

Figure 2 shows the well logs illustrating the stratigraphic position and log characteristics of the reservoir in the J. & T. Operating Inc. Montgomery no. 1-19 well located in the CSE¼NW¼ of sec. 19. Figure 3 depicts the lithology and interpreted depositional environments of the interval cored between 6,797 and 6,834 ft. The core has been subdivided into six distinct lithofacies, as shown on the stratigraphic column in Figure 3.

The sharp erosional contact between the Woodford Shale and the overlying basal Bartlesville sandstone represents a major uncon-formity. The lower 10 ft of this section represent a channel cut into the underlying Woodford and infilled with very fine grained, lithic-rich quartz sand exhibiting large-scale bed forms. The bed forms and grain size decrease upward through the section. The fining-upward sequence is interrupted by a 2-ft-thick, structureless, fine-grained sandstone that grades upward into a 10-ft-thick interval of intercalated shale and thin sandstone. The upper contact of the shale unit appears to be conformable and exhibits a distinct coarsening-upward sequence. This transition from fine-grained clastic sediment to coarser-grained material may represent filling of an oxbow lake by crevasse-splay deposits. The total sandstone package near the top of the core may be related entirely to the crevasse splay. However, it is probable that a fluvial channel overlies the upper surface of the crevasse splay and that the contact between the two sandstones is not distinguishable. The contact between the upper sandstone unit and the overlying marine prodelta shales is missing.

The net porosity isopach of the lower Bartlesville reservoir is shown in Figure 4. The net porosity isopach of the upper zone is shown in Figure 5. The average connate water saturation calculated from well logs is 26%. A monoclinal structure mapped on the top of the lower Bartlesville sandstone dips approximately 100 ft/mi uniformly westward. The stratigraphic trap is formed by lateral gradation of the reservoir sandstones into nonpermeable siltstones and shales. Development wells have been drilled at least 660 ft apart along the trend of the sandstone body.

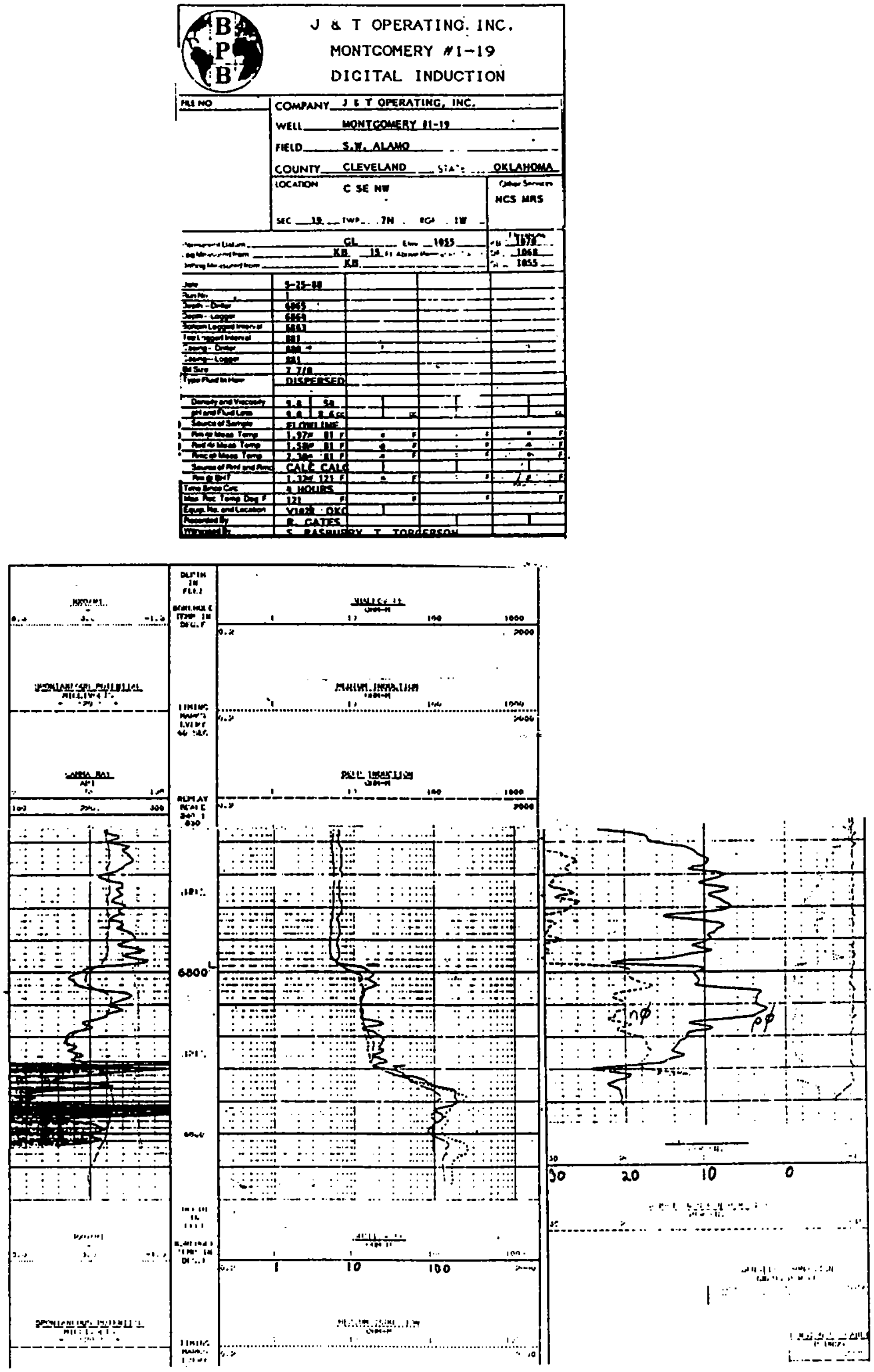

Figure 2. J. & T. Operating, Inc., Montgomery no. 1-19 well logs; from left to right—spontaneous potential/gamma ray, dual induction, and neutron porosity/density porosity.

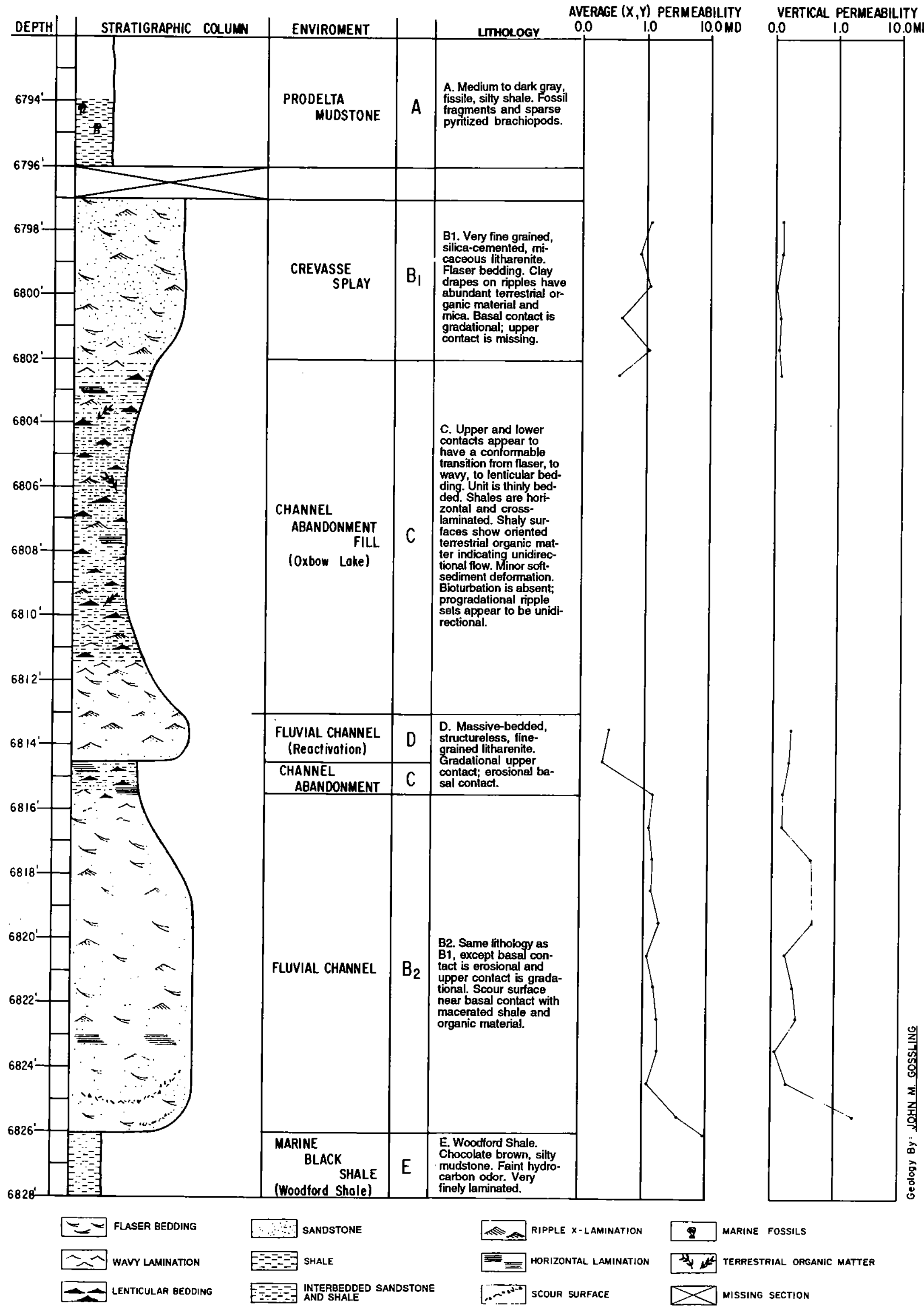

Figure 3. Lithology and interpreted depositional environments of the interval cored between 6,797 and 6,834 ft in the J. & T. Operating, Inc., Montgomery no. 1-19 well, SE¼NW¼ sec. 19, T. 7 N., R. 1 W., Cleveland County, Oklahoma.

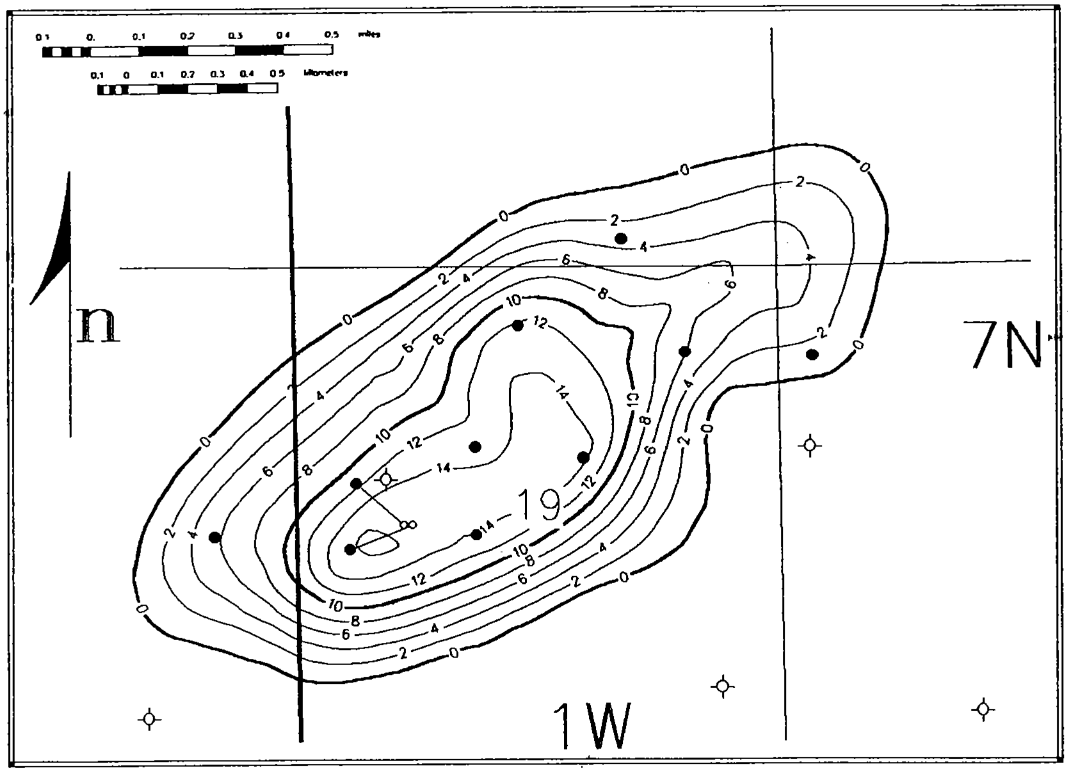

Figure 4. Net porosity isopach (porosity >8%) for the lower Bartlesville reservoir, Alamo SW field.

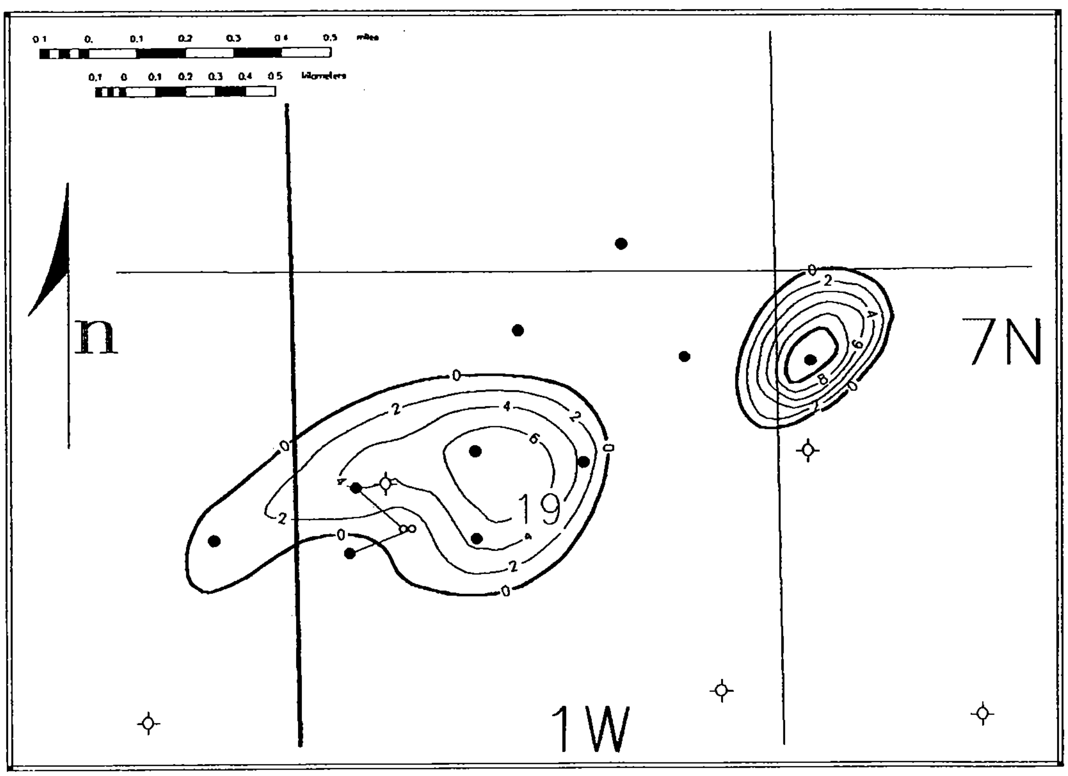

Figure 5. Net porosity isopach (porosity >8%) for the upper Bartlesville reservoir, Alamo SW field.

TABLE 1. — RESERVOIR PROPERTIES

Third layer (lower Bartlesville)	
Horizontal permeability: x direction	2.25 md
Horizontal permeability: y direction	2.25 md
Vertical permeability: z direction	0.6 md
Thickness (Avg.)	15 ft
Porosity (Avg.)	12%

DESCRIPTION OF THE SIMULATOR INPUT DATA

A grid of 24 × 20 × 3 in the x, y, and z directions, respectively, was used to simulate this three-phase reservoir. The grid size was chosen to provide a close description of the reservoir, to describe the initial physical properties, and to model the behavior of individual wells so that it would be possible to simulate future reservoir behavior under different strategies, such as horizontal completions or water flooding. The x axis of the grid was oriented parallel to the east-west trend of the net-sandstone isopach and the maximum permeability vector. Three layers were used to model the upper and lower sandstones separated by an impermeable shale layer. The total number of cells was 1,440, and the number of active cells was 322.

The depths to the top faces of all reservoir grid cells were interpolated from the structure map.

The length and width of each grid block was 330 ft (Fig. 1). This size was chosen to maintain at least two grid blocks in each direction between wells. Thickness values for the upper and lower sandstone layers of the reservoir were interpolated from the isopach maps to the center coordinate for each grid block. Zone thicknesses shown in Figures 3 and 4 were interpreted from logs of the wells. A uniform 10-ft shale layer completely separated the upper and the lower sandstones.

Reservoir Properties

Porosity values calculated by using log data from the wells were used to prepare isoporosity maps for the upper and lower zones. The average porosity value for each zone in each well was assigned to the grid block where that well is located, and by using those ten grid blocks containing wells, the porosity values for the rest of the grid blocks were obtained by interpolation or extrapolation. The shale layer was defined as having zero effective porosity.

Permeability was defined in each of the x, y, and z directions (for example, see Table 1). The core report for the Montgomery no. 1 presented evidence of directional permeabilities. Because permeabilities in the x and y directions were of similar magnitude, the geometric average values were used. The permeability in the vertical, z, direction was taken directly from the core analysis report. The shale layer was considered impermeable.

Petrophysical Data

Several tables within the Eclipse software (INTERA, 1992) describe the petrophysical relationships between the reservoir rock and the pore fluids. Because capillary-pressure data were not measured on the Montgomery no. 1 core, a capillary-pressure curve for a low-permeability water-wet sandstone was obtained from Amyx and others (1960). By using that general curve, curves for water-oil and gas-oil fluid systems for each zone were generated from the Leverett J-function and log-derived data (Amyx and others, 1960).

The relative permeability curves were based on relationships from Justus and others (1953) because no data were available for the Alamo SW field. The Justus and others (1953) curves were adjusted by shifting the connate water and residual oil saturation to those values for the SW Alamo field reservoirs.

Reservoir-Fluid Data

The *PVT* data obtained from reports for J. & T. Operating, Inc. (1988) and from a reservoir-fluid study for Harbart Energy (Core Laboratories, 1988) are shown in Table 2.

Well Definition Data

The completed zones and depths to perforations were obtained from completion reports. Other data necessary were the economic limit, 1 STB/day, and the productivity index (PI) for the wells. The PI values were adjusted by trial and error until calculated results matched the history of the production of the field. Production reports were for six-month intervals.

SIMULATION RESULTS

The following assumptions were made for history matching. (1) *PVT* data for both zones are identical, (2) no communication existed between the upper and lower zones, (3) permeabilities in the x and y directions have the same values for the upper and lower zones, but permeabilities in the z direction have different values for the zones, (4) upper limits of production rates were set at 100 BPD for any forecast runs, (5) minimum allowed bottom-hole pressure was set at 350 PSIA, and (6) predicted production simulation was confined to a 10-yr period.

Primary Recovery Using Existing Vertical Wells

A 10-yr forecast period was selected to compare recovery factors. The "base case" for comparing alternative strategies is a continuation of the cur-

TABLE 2. — RESERVOIR FLUID PROPERTIES

Connate-water saturation (for both layers)	26%
Oil gravity	50° API
Gas viscosity at bubble pressure	0.0156 cP
Oil viscosity at bubble pressure	0.310 cP
Oil density at surface	47.6 lbm/ft^3
Gas density at surface	0.06054 lbm/ft^3
Water density at surface	64.0 lbm/ft^3
Solution gas/oil ratio at bubble pressure	1008 SCF/STB
Oil formation volume factor at bubble pressure	1.582 RB/STB
Gas formation volume factor at bubble pressure	0.00986 RCF/SCF
Reservoir temperature	170 °F
Initial reservoir pressure	2745 PSIA
Bubble point pressure	1632 PSIA

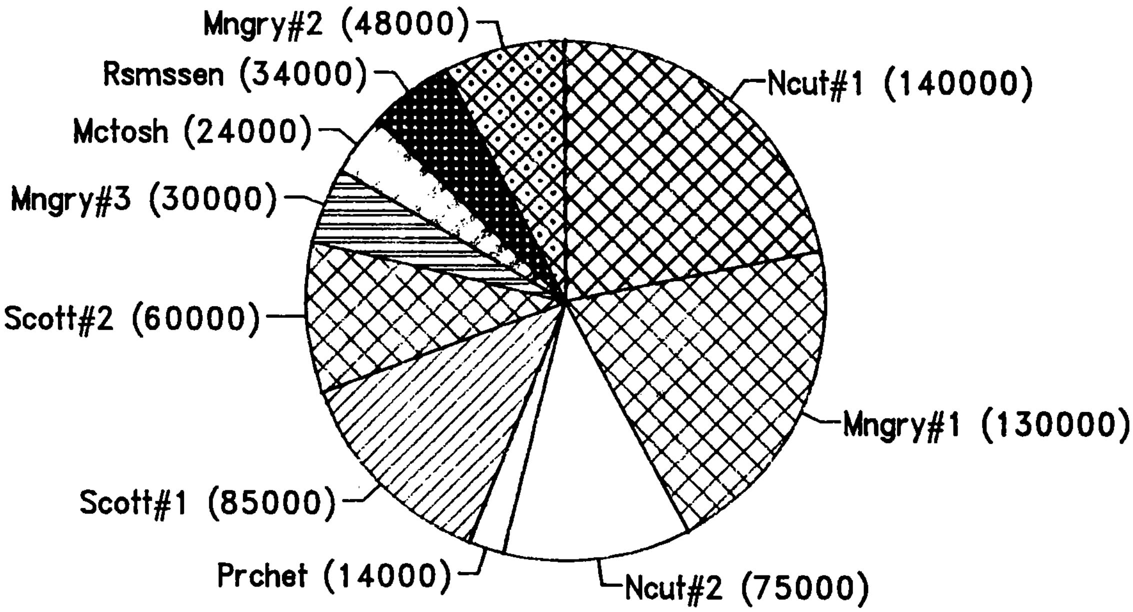

Figure 6. Simulated cumulative oil production (in STB units) by well projected for 10 yr from November 1992. Field total is 640,000 STB.

rent field production practices with the ten existing wells. The estimated original oil in place from both sandstone zones was 2,700,000 STB. If the field were to produce at 350 PSIA constant bottom-hole pressure for an additional 10 yr, the expected recovery factor would be 23.7%. Figure 6 shows the expected cumulative oil production for all individual wells. Two wells, the Northcutt no. 1 and the Montgomery no. 1, account for 42% of the expected production. The historical match period is previous to 1,752 days. Projected production is from 1,751 to 5,351 days. Figure 7 shows the oil-saturation map for the lower zone at the end of the base case.

Primary Recovery Using a Single Horizontal Well

To find the best location in the reservoir for a horizontal production well, every vertical well was simulated with a 1,000-ft horizontal segment at various orientations. This analysis indicated that the best location for a horizontal recompletion would be the Northcutt no. 2 with the horizontal segment oriented northward from the existing well bore. The productivity index (PI) for the horizontal well was estimated by using Joshi's (1987,1989,1991) method. Multiple simulations using critical gas saturations varying from zero to

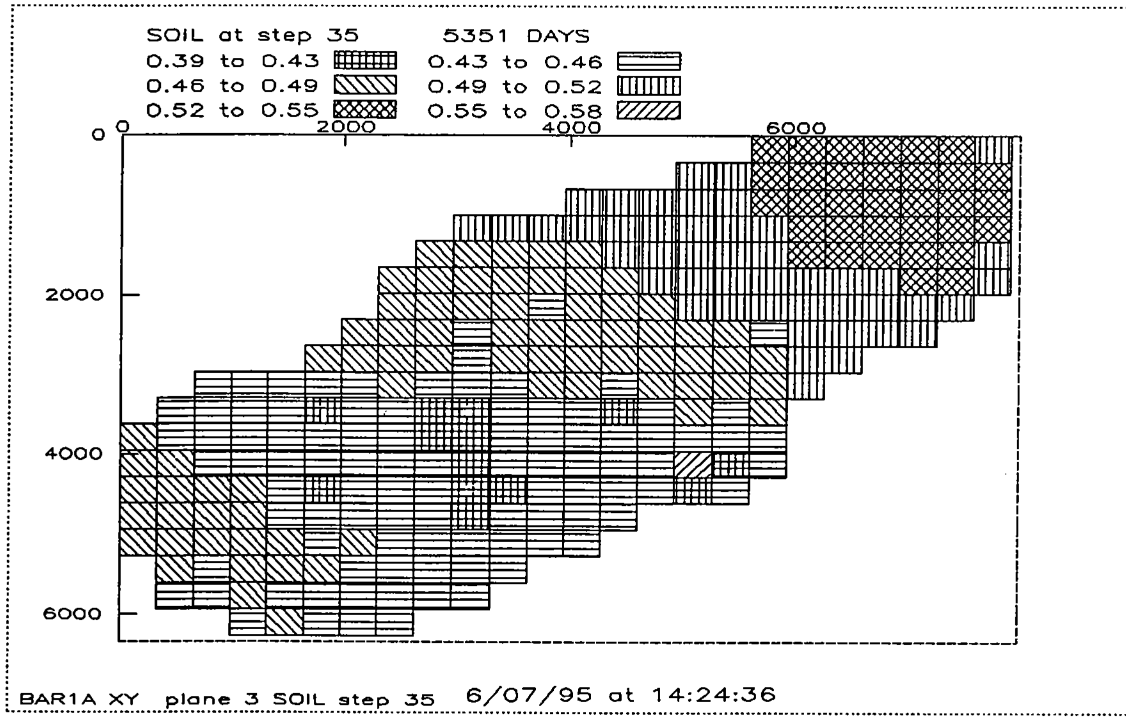

Figure 7. Simulated oil-saturation map for lower Bartlesville zone; primary recovery projected for 10 yr from November 1992. SOIL = oil saturation.

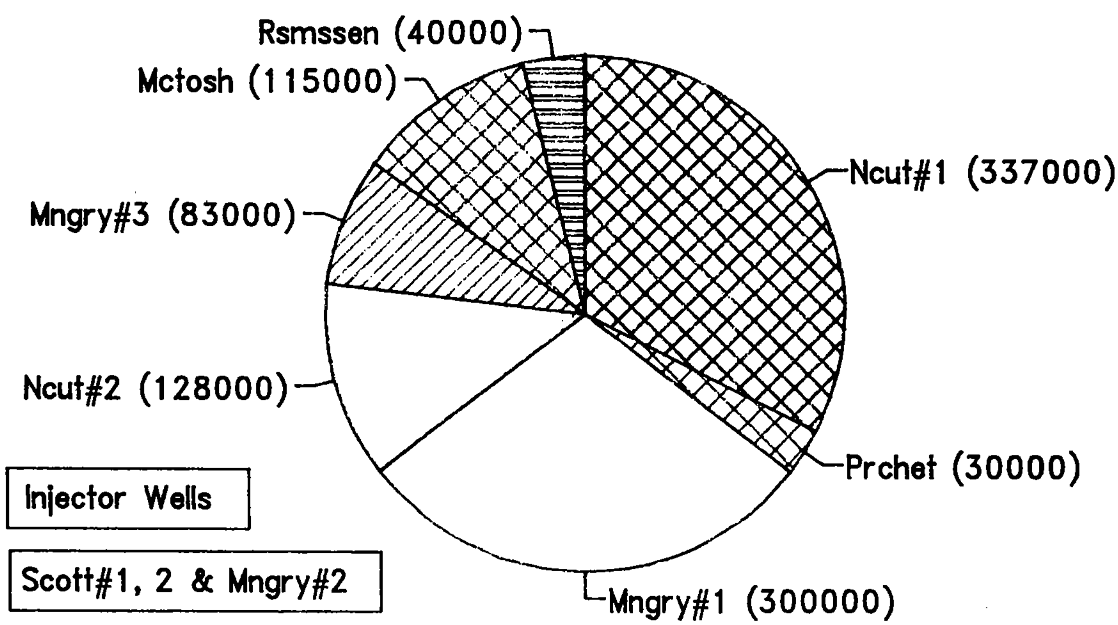

Figure 8. Simulated cumulative oil production (in STB units) by well for 10-yr period from November 1992 for water flooding using three vertical injection wells. Field total is 1,033,000 STB.

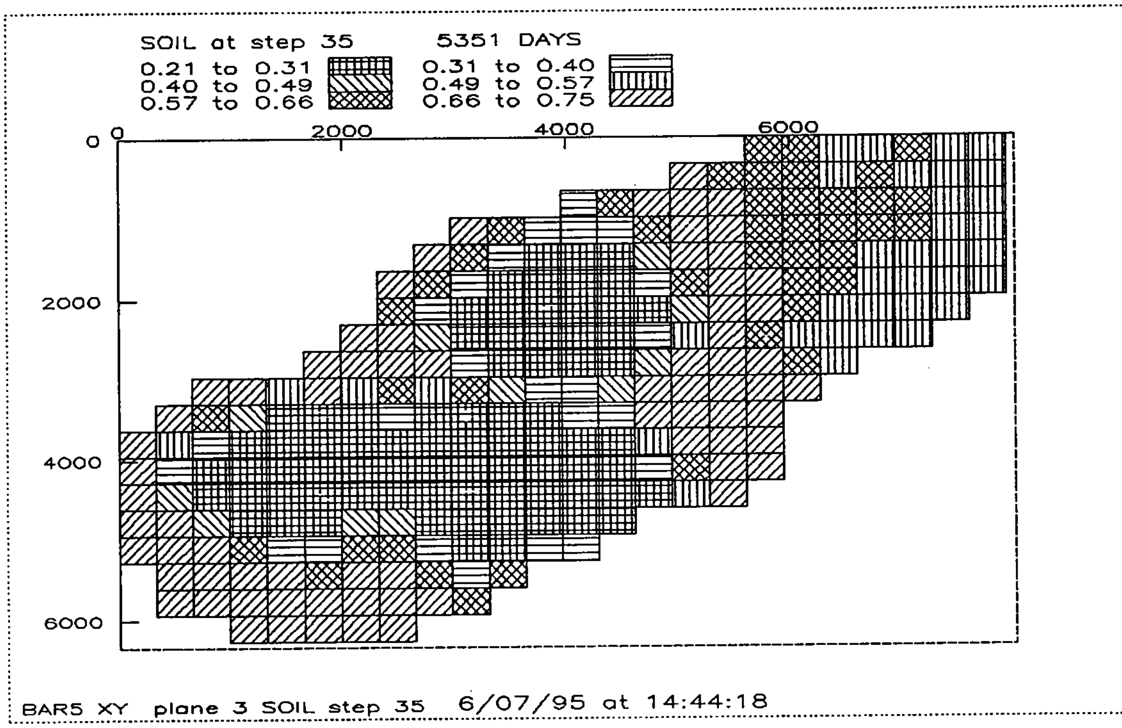

Figure 9. Simulated oil-saturation map for lower Bartlesville sandstone based on water-flooding performance with three vertical injection wells for 10-yr period from November 1992. SOIL = oil saturation.

0.4 show no significant difference in oil recovery. The field production with a horizontal completion in the Northcutt no. 2 well would be 2.3% (60 MSTB) higher than with vertical wells only.

Water-Flooding Analysis

Water-flooding performance was analyzed to compare the sweep efficiency of vertical injectors or producers with horizontal injectors or producers for this reservoir and to evaluate the recovery sensitivity to permeability anisotropy for vertical injection wells, compared to a horizontal injection well in this reservoir.

Water Flooding with Vertical Injection and Production Wells

The vertical-wells water-flooding program converted the Scott no. 1, Scott no. 2, and Montgomery no. 2 wells to injection wells. Figure 8 shows the cumulative oil production for all wells after 10 yr of water-flooding operations. Figure 9 shows the expected oil saturation in the lower zone of the reservoir after 10 yr of water-flooding operations for this case. Based on the simulation results in the homogeneous case ($kx = ky$), the oil recovery was 38% of the original oil in place (OOIP) (1.03 MMSTB). This value represents an increase in recovery of 14.3% (390 MSTB) over the primary case and suggests that a water-flooding operation should be effective for increasing recovery in the Alamo SW field. Reservoir anisotropy where $kx = 6ky$ increases the oil recovery to 41% of the OOIP. These results show that water flooding using vertical completions is relatively insensitive to formation anisotropy in this model.

Water Flooding with a Horizontal Injection Well

Simulations were conducted to determine the effect of placement of the horizontal injection well. The Northcutt no. 2, Scott no. 2, and Montgomery no. 1 wells were considered in sequence as being converted to horizontal injection wells. Oil recovery after 10 yr of water injection into one of these wells was as follows for the homogeneous reservoir case: Northcutt no. 2—28.7% (775 MSTB), Scott no. 2— 33% (890 MSTB), and Montgomery no. 1—34.8% (940 MSTB). For the anisotropic case in which the permeability was $kx = 2ky$, the recovery using the Montgomery no. 1 improved to 40.7% (1.10 MMSTB).

Figure 10 shows the calculated water saturation in the lower reservoir zone after 10 yr of water injection into the Montgomery no. 1 well with a 1,000-ft horizontal segment extending northward from the vertical well location. During the 10-yr period, the amount of water injected through the single 1,000-ft horizontal segment would be ap-

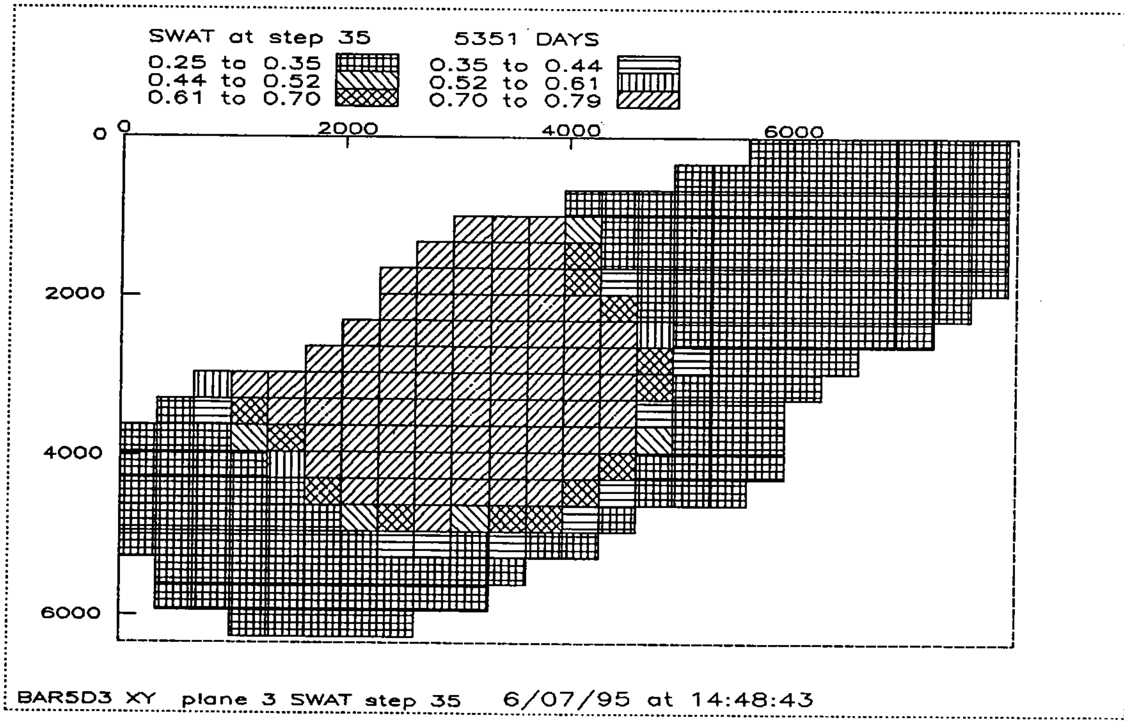

Figure 10. Simulated water-saturation map for lower Bartlesville sandstone based on water-flooding performance with single horizontal injector for 10-yr period from November 1992. SWAT = water saturation.

proximately one half the volume that would be injected if the three vertical wells were used during this same period. The recovery values using the Montgomery no. 1 well show that the recovery efficiency per barrel of water injected is nearly doubled for the horizontal injector compared to three vertical injectors. Water-saturation maps show that the water front is more uniform with the horizontal injector, thus reducing the amount of bypassed oil during this flood-performance period. It is expected that the project life would be extended with additional recovery.

Water Flooding with a Horizontal Production Well

To evaluate water-flooding performance with a single horizontal producing well, the Scott no. 1, Scott no. 3, and Montgomery no. 3 wells were used as vertical injection wells and the Northcutt no. 2 as the horizontal producer. One of the injection wells is different from the base water-flooding case to avoid early water breakthrough at the horizontal producer. Because of this change, only one half of the water was injected during the 10-yr period compared to the base water-flooding case. The recovery of oil, after 10 yr of injection, was 29.6% (800 MSTB) of the OOIP. The recovery is lower than the base water-flooding case because of the much lower volume of injected water. However, the sweep efficiency is significantly greater when the horizontal producer is used. The larger area of low pressure resulting from the horizontal producer results in much lower oil saturations and higher gas saturations in the eastern part of the reservoir compared to the vertical-wells base case.

CONCLUSIONS

1. Simulations indicated that water flooding would result in recovery of approximately 400,000 barrels of additional oil within a 10-yr period.
2. Simulations indicated that the production increase from the conversion of a vertical well to a horizontal producer during primary recovery would not justify the risk-weighted expense of the horizontal well segment.
3. Simulations indicated that a single horizontal injection well would result in a significantly greater oil recovery per barrel of water injected compared to using three vertical injection wells. Unfortunately, for the 10-yr simulation period, less water was injected and less oil was recovered.
4. Simulation results showed that the horizontal injection well produced a more uniform water

front than the vertical wells, thus reducing the amount of bypassed oil.

5. Horizontal permeability anisotropy had little influence on primary recovery. However, $kx > 2ky$ produced a significant increase in the simulated recovery during water-flooding operations for a 10-yr period.

6. Simulation results using the water-flooding scenarios presented indicated that the field would be economically productive beyond the 10-yr period that was evaluated.

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Significance of Detrital Ore Minerals in the Basal Atoka Formation (Middle Pennsylvanian), Pope County, Arkansas

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ABSTRACT.—Conglomerates of the Spiro Sandstone Member, basal Atoka Formation (Middle Pennsylvanian), in Pope County, Arkansas, contain alkali feldspars and fragments of metamorphic rocks, as well as detrital galena and sphalerite. The lithology of the conglomerates, combined with dispersal directions for the Spiro Sandstone Member, suggests the core area of the Ozark dome (St. Francois Mountains) as the likely source for these sediments and supports the existence of a broad erosional surface at the Morrowan-Atokan boundary across the southern Midcontinent. Detrital ore minerals at the base of the Atoka Formation suggest that some lead-zinc mineralization in southeastern Missouri is not related to fluids produced by the Ouachita orogeny, which did not begin until middle Atokan time (Middle Pennsylvanian).

INTRODUCTION

Mississippi Valley–type lead-zinc mineralization is well known in the southern Midcontinent from the Tri-State district (Oklahoma-Kansas-Missouri), and the Central and Southeastern Missouri districts (Viburnum, Old Lead Belt, Annapolis, Indian Creek, and Fredericktown trends). Similar, but less-well-known, deposits also occur in Arkansas, as the North Arkansas district (particularly from mines at Ponca, Newton County, and Rush, Marion County), and the West-Central Arkansas district (particularly the Kellogg mine in Pulaski County) (Stroud and others, 1969, p. 148–152). The origin of these Mississippi Valley–type deposits has been attributed to a single event involving the migration of brines derived from the dewatering of sediments deformed by the Ouachita orogeny (Leach and others, 1975; Leach, 1979; Leach and Rowan, 1986), which began in middle Atokan time (Middle Pennsylvanian) (Sutherland and Manger, 1979).

Not all the mineralization can be attributed to the Ouachita orogeny, however. Detrital ore minerals occur in the conglomerates associated with the Spiro Sandstone Member, basal Atoka Formation (Middle Pennsylvanian), along the margin of the northern Arkoma basin, in northern Pope County, Arkansas (Meeks and Manger, 1992). Although the occurrence of these minerals has been known for at least 20 years (Stroud, personal communication), they have not been reported in the literature, and their significance to the Pennsylvanian history of the southern Midcontinent has not been recognized.

GEOLOGIC SETTING

The primary exposures used for this study are located on a tributary of Moccasin Creek in northwestern Pope County, Arkansas (SW¼SW¼ sec. 21, T. 11 N., R. 20 W.) (Fig. 1), and are part of a larger mineralized area that covers ~3 mi^2. A second area of exposures, known as the Brewer-Robin prospect, is located ~3.5 mi south of the Moccasin Creek locality (SW¼NE¼ sec. 9, T. 10 N., R. 20 W.) (Fig. 1) and also covers ~3 mi^2. The latter were studied in a thesis by Knight (1985). Both localities occupy the Treat 7.5-minute quadrangle (1980).

Both the Moccasin Creek and Brewer-Robin localities occur in the Spiro Sandstone Member, basal Atoka Formation (Atokan Series, Middle Pennsylvanian) (Fig. 1). The Spiro Member—including interbedded shale, sandstone, and pebble conglomerate—rests unconformably on Morrowan strata and is overlain conformably by the Patterson Member of the Atoka Formation. The Spiro sediments were laid down initially in a fluvial-deltaic system; they were partly redistributed into a sheetlike deposit by a broad marine transgression at the beginning of Atokan time (Sutherland,

Meeks, L. K.; and Manger, W. L., 1996, Significance of detrital ore minerals in the basal Atoka Formation (Middle Pennsylvanian), Pope County, Arkansas, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 274–278.

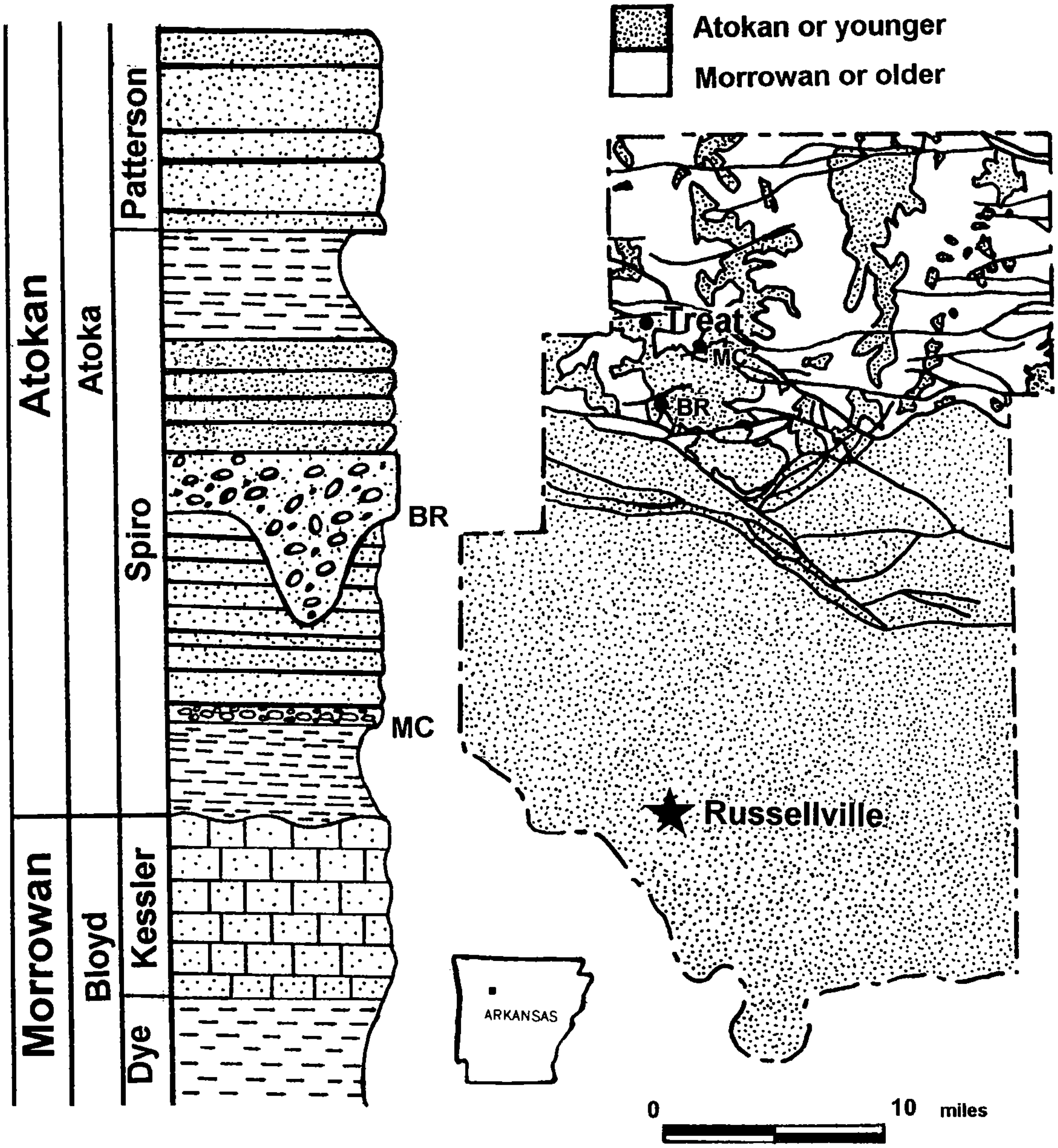

Figure 1. Location, geologic setting, and lithostratigraphic succession of the Moccasin Creek (MC) and Brewer-Robin (BR) localities. No vertical scale intended for the stratigraphic column.

1988). Spiro thicknesses are typically 150–200 ft, but exceed 300 ft in some sections (Knight, 1985; Sutherland, 1988).

Sandstone of the Spiro Sandstone Member at the Moccasin Creek locality overlies a black shale of indeterminate thickness; the shale is presumed to lie within the Spiro Member. Contact with the Kessler Member of the Bloyd Formation (Morrowan) was not observed at this locality, but the Bloyd Formation is mapped in the immediate area of Treat, Arkansas, which is <2 mi away (Fig. 1). A dark shale above the Kessler Member has been observed at localities elsewhere in the Treat and adjacent Simpson 7.5-minute quadrangles (Knight, 1985), and we believe that it forms the base of the Moccasin Creek outcrop; however, a position within the Spiro Member cannot be discounted. At the Brewer-Robin prospect, the Spiro

Member contains a conglomeratic channel sequence ~40 ft thick that truncates most of the underlying Spiro Member, but it is succeeded by another 150 ft of shale-free, calcareous sandstone (Knight, 1985). Marine fossils and limestone lenses are common in the channel facies, suggesting reworking of a fluvial-deltaic sequence by marine transgression as postulated by Sutherland (1988).

LITHOLOGY OF THE BASAL ATOKAN CONGLOMERATES

Moccasin Creek

Of all the rock types in this study, the conglomerates of the Spiro Sandstone Member at Moccasin Creek have been examined in the most detail. They are immature, lithic, subarkosic wackes. The gravel fraction falls within the granule- to pebble-size class. Clasts of siltstone and very fine grained to fine-grained sandstone make up ~78% of the gravel fraction. Shale and limestone clasts, phosphatic bodies that are probably limestone replacements, and quartz, chert, granite, and fossil fragments compose the remaining gravel fraction. Most of the gravel clasts are well rounded. The clasts are matrix supported; they do not form a framework for the rock.

The sand fraction is mostly medium and finer size grades, and some samples are distinctly bimodal. Approximately 72% of the sand is composed of quartz (monocrystalline and polycrystalline) and chert; 12% is alkali feldspars (microcline, orthoclase, and albite). Most of the monocrystalline quartz contains vacuoles, and acicular mineral inclusions are common. Fragments of metamorphic rocks contribute 7% of the sand fraction, and the remaining 9% consists of fossils and miscellaneous grains. The quartz sand fraction varies from subangular to well rounded, reflecting a mixture of reworked grains with first-cycle sand. In general, the coarser sand sizes exhibit better rounding. The feldspars and fragments of metamorphic rocks are all well rounded and vary from fresh to highly altered. Cements include silica, iron oxide–iron hydroxide, calcite, and ankerite. The matrix, which forms ~22% of the lithology, is clay, probably sericite. As a consequence, the rocks at Moccasin Creek are most properly termed wackes.

Brewer-Robin Prospect

The description, by Knight (1985), of the Spiro lithologies from the Brewer-Robin prospect indicates a character similar to that of the Spiro at Moccasin Creek. The only significant difference is that clay matrix forms only ~3% of these rocks; therefore, they may be classified as immature, arkosic litharenites, rather than wackes. The smaller amount of clay matrix at the Brewer-Robin prospect is consistent with the higher-energy channel setting exhibited by the Spiro at that locality.

Sphalerite and Galena

Detrital sphalerite occurs in the sand and coarse-silt fraction as rounded grains and subrounded cleavage fragments at both the Moccasin Creek and Brewer-Robin localities (Meeks and Manger, 1992; Knight, 1985) (Fig. 2). No sphalerite was observed in the gravel fraction. At Moccasin Creek, galena occurs with calcite as well-rounded pebbles (Fig. 3) and as an infilling of fossil fragments that appear to be reworked. No detrital galena was observed in the sand fraction of the conglomerate at either locality.

Both the Moccasin Creek and Brewer-Robin localities show evidence of postdepositional mineralization. Sphalerite and galena are found as veinlets and disseminated grains.

PROVENANCE AND DISPERSAL

The basal Spiro conglomerates reflect erosion from sedimentary, igneous, and metamorphic sources, in decreasing order of their contribution. The sedimentary clasts that dominate the gravel fraction and much of the well-rounded sand component are similar to those in the underlying Morrowan and older strata occurring throughout the southern Ozarks. Limestone clasts are also consistent with an Ozark source. The presence of fresh feldspars, granite, and quartz gravel clasts indicates a nearby igneous source that is most probably the St. Francois Mountains region of southeastern Missouri. The first-cycle sands, clay matrix, and fragments of metamorphic rocks suggest more distant source areas, probably related to the Canadian Shield or perhaps the southern Appalachians.

Dispersal directions for the lower Atoka Formation indicate fluvial systems flowing onto the Ozark shelf from the northeast, accompanied by longshore currents that moved east to west (Zachry and Sutherland, 1984; Sutherland, 1988). Detrital sphalerite and galena and the granitic components could only have been derived from the St. Francois Mountains area of southeastern Missouri, the core of the Ozark dome, which is only ~200 mi northeast of the study area. We note that many existing rivers draining the St. Francois Mountains region have courses that approach 200 mi. Availability of the St. Francois Mountains as a source during Atokan time is further supported by the presence of Atokan sedimentary deposits (Chelthenham Clay) filling sinkholes in southeastern Missouri (Searight and Howe, 1961), indicating that the region was emergent and undergoing erosion at the time of Spiro deposition on the southern Ozark shelf and in the Arkoma basin.

SIGNIFICANCE AND CONCLUSIONS

The suggestion that all Mississippi Valley–type lead-zinc mineralization in the Ozark region is related to a single emplacement event caused by

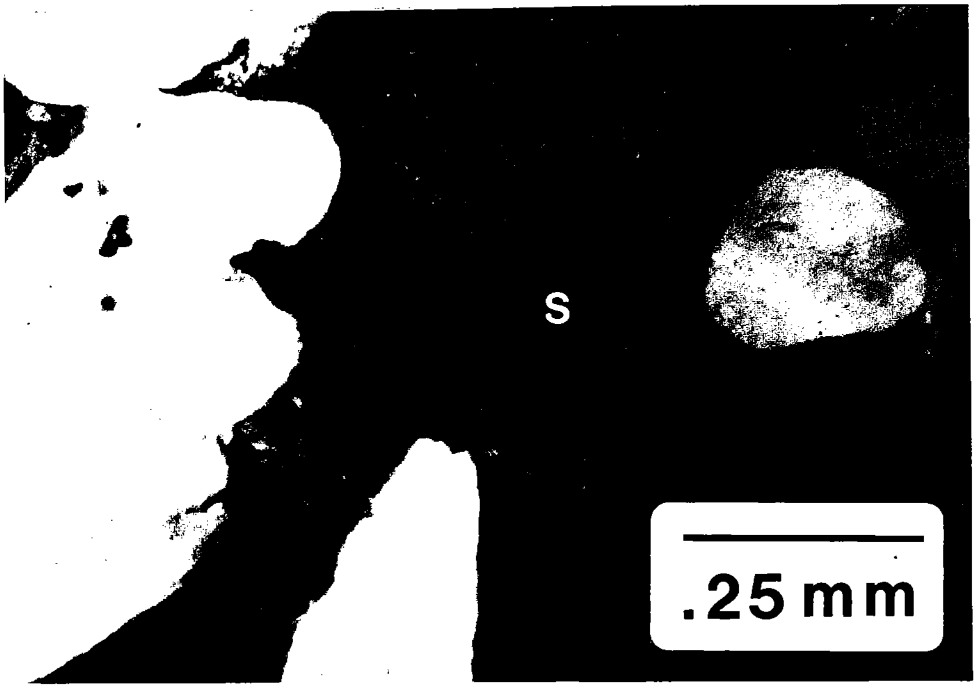

Figure 2. Detrital sphalerite cleavage fragment (S) with quartz sand and carbonate cement; viewed under crossed polarizers. Spiro Sandstone Member, Atoka Formation, Moccasin Creek locality.

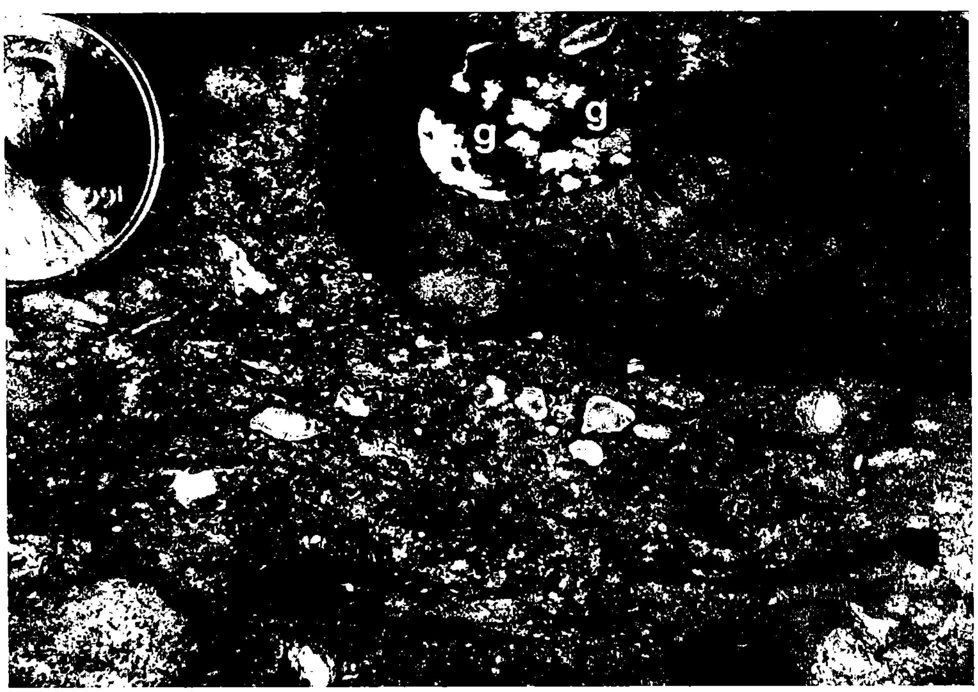

Figure 3. Polished slab of conglomerate with rounded pebble (arrow) mineralized by galena (g), chalcopyrite, and calcite. Spiro Sandstone Member, Atoka Formation, Moccasin Creek locality.

the Ouachita orogeny (Leach and Rowan, 1986) is not supported by the occurrence of detrital sphalerite and galena in the Spiro Sandstone Member in Pope County, Arkansas (Meeks and Manger, 1992) (Figs. 2,3). The first major pulse of the Ouachita orogeny during the Pennsylvanian occurred during middle Atokan time (Sutherland and Manger, 1979) and thus could not have caused the mineralization represented by detrital grains in the basal Atoka. Stein and Kish (1985) proposed an Early Mississippian age (359 ± 22 Ma) for mineralization at the Magmont mine, Viburnum trend, in southeastern Missouri, and this Arkansas occurrence may be viewed as supporting that age, if only indirectly. Since there is no evidence of major tectonic movement prior to Atokan time in the Ouachita region, another mechanism for mineralization is required to explain this pre-Pennsylvanian event. Nevertheless, mineralization associated with the Ouachita orogeny certainly occurs throughout the southern Ozarks, including the Moccasin Creek and Brewer-Robin localities, both of which contain sphalerite and galena in small veinlets and as disseminated grains.

ACKNOWLEDGMENTS

We acknowledge the contribution of the late Raymond B. Stroud, retired director of the Arkansas Mining Institute, Russellville, Arkansas, to our research in the northern Arkoma basin. We thank Kenneth Johnson, Oklahoma Geological Survey, for encouraging our participation in the fluvial-dominated deltaic reservoirs workshop. Our study utilizes data from the thesis submitted by B. Thomas Knight (1985) for the degree of Master of Science at the University of Arkansas, but who interpreted the section at the Brewer-Robin prospect differently from the presentation here.

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Heterogeneity in Delta-Destructive Oil Reservoirs: Deposition and Diagenesis of the Carter Sandstone (Upper Mississippian), Black Warrior Basin, Alabama

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INTRODUCTION

More than 85% of the oil produced from the Black Warrior basin is from the Carter sandstone in Lamar and Fayette Counties, Alabama, and >65% of that production is from the North Blowhorn Creek oil unit (Fig. 1A). The Carter sandstone is in the lower Parkwood Formation and is of Chesterian (Late Mississippian) age. Most oil is produced from localized sandstone bodies that were deposited as part of a muddy strand plain that formed by progressive shoaling during delta destruction (Pashin and Kugler, 1992).

Interdeltaic barrier-island deposits have been a primary focus of studies of reservoir heterogeneity (Sharma and others, 1990; Schatzinger and others, 1992), but heterogeneity in muddy strand-plain deposits, such as cheniers and delta-destructive barrier-island arcs, has yet to be analyzed. This paper characterizes heterogeneity in Carter sandstone and examines ways in which muddy strand-plain deposits differ from better-known barrier-island deposits. Investigation of heterogeneity in Carter oil reservoirs in the Black Warrior basin is based on analysis of well logs and cores and has employed stratigraphic, sedimentologic, petrologic, and petrophysical methods. Production and engineering data also were used to evaluate the performance of recovery operations in Carter oil fields.

STRATIGRAPHY AND SEDIMENTOLOGY

Lower Parkwood Lithofacies

The lower Parkwood Formation overlies the Bangor Limestone and is overlain by the interbedded limestone and shale of the middle Parkwood Formation, which locally contains the *Millerella* sandstone at the base (Fig. 2). The lower Parkwood contains shale, siltstone, and sandstone and was divided into three lithofacies by Pashin and Kugler (1992). The shale-and-siltstone facies forms the base of the lower Parkwood and is composed of interbedded gray shale and siltstone with wavy, lenticular, and flaser bedding. Sedimentary structures include current ripples, wave ripples, load structures, graded bedding, and feeding burrows.

In the upper half of the lower Parkwood Formation is the Carter sandstone, which comprises the two remaining lithofacies, the sandstone facies and the variegated facies. The sandstone facies is the principal Carter reservoir rock and is yellowish brown, thick bedded, very fine to fine grained, and moderately to well sorted. Sedimentary structures include current-ripple cross-laminae, horizontal laminae, and planar cross-strata dipping at <5°. In some cores, accumulations of shale pebbles or shells form conglomeratic zones as thick as 4 ft.

The variegated facies typically composes the upper part of the Carter sandstone and is so named for diverse colors and rock types. Sandstone, siltstone, and shale with wavy, flaser, and lenticular bedding predominate in the facies. Much of the sandstone has a mottled texture, and some sandstone is composed of pebble- to cobble-size, intraclastic flat pebbles separated by anastomosing claystone laminae. Root structures and slickensides are abundant, and burrows are present in parts of the facies. Thick beds of gray and red shale are also in the variegated facies and contain slickensides, plant fossils, and pisoidal carbonate nodules (large coated grains resembling pisolites).

Reservoir Architecture

Although Carter cores from the study area exhibit the same general succession of lithofacies, a sandstone-isolith map establishes marked variation in the plan of the sandstone bodies (Fig. 1B). This variation is especially pronounced among the oil fields. In the area containing the South Fairview, Central Fairview, South Brush Creek, and Blowhorn Creek oil units, isolith patterns are

Pashin, J. C.; and Kugler, R. L., 1996, Heterogeneity in delta-destructive oil reservoirs: deposition and diagenesis of the Carter Sandstone (Upper Mississippian), Black Warrior basin, Alabama, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 279–285.

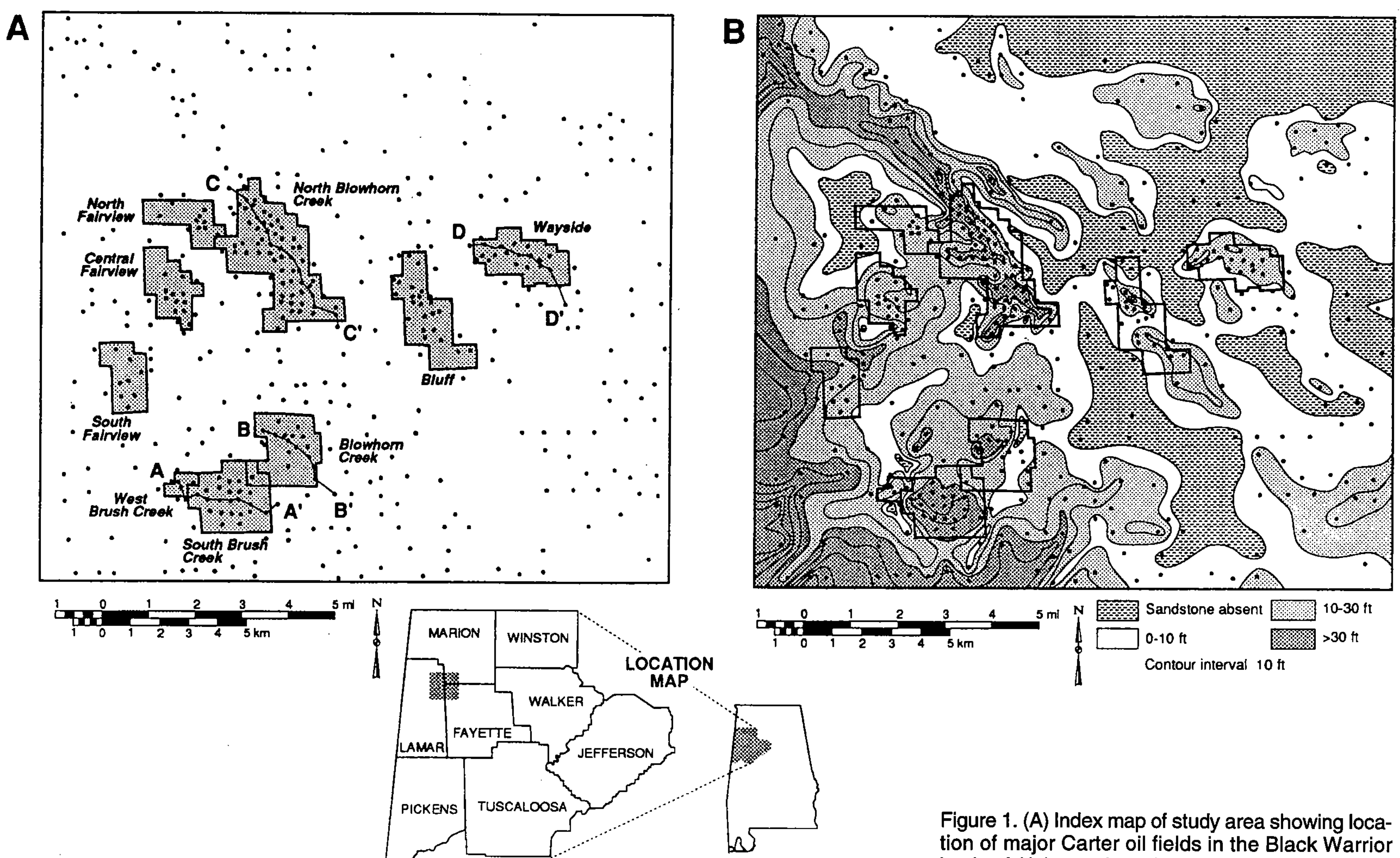

Figure 1. (A) Index map of study area showing location of major Carter oil fields in the Black Warrior basin of Alabama. Locations of cross sections (Fig. 2) given. (B) Net-sandstone-isolith map of the Carter sandstone in parts of Fayette, Lamar, and Marion Counties, Alabama.

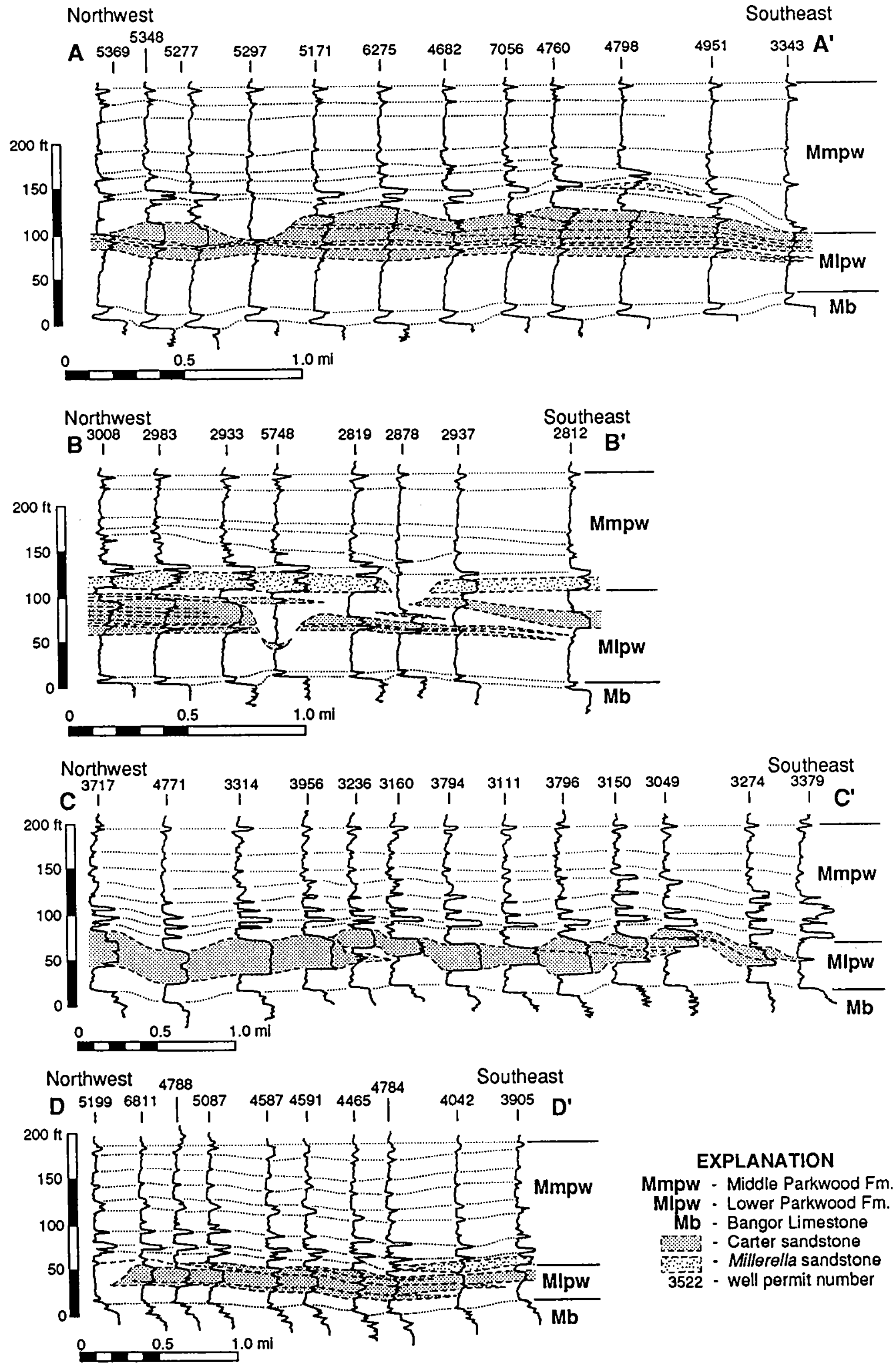

Figure 2. Resistivity-log cross sections of the Carter sandstone and associated strata in parts of Fayette, Lamar, and Marion Counties, Alabama. See Figure 1A for locations.

lobate to concentric. In the North Blowhorn Creek oil unit, by contrast, the reservoir is in the terminus of a linear sandstone body with an irregular southwest margin and a comparatively smooth northeast margin. Bluff field was established in a linear series of lensoid sandstone bodies that extend southeastward from the North Blowhorn Creek sandstone axis, and the Wayside oil unit was established in one of several lensoid sandstone bodies near the northeast limit of the Carter sandstone.

Internally, all Carter sandstone bodies in the study area are made up of imbricate, clinoformal sandstone lenses, but the lithologic characteristics and spatial arrangement of those lenses differ greatly among the fields (Fig. 2). In the South Brush Creek and West Brush Creek oil units, well logs have a serrate, coarsening-upward log signature reflecting vertical gradation of the shale-and-siltstone lithofacies into the sandstone lithofacies. Clinoformal sandstone beds dip gently toward the northwest and southeast, and the sandstone is truncated by a scour surface that is overlain by shale of the variegated facies. The Carter sandstone in the Blowhorn Creek oil unit is a continuation of that in the South Brush Creek oil unit, and channels locally truncate the full thickness of the sandstone. Oil in the Blowhorn Creek oil unit is produced from the *Millerella* sandstone, which also is truncated by a channel.

In the North Blowhorn Creek oil unit, the size of imbricate sandstone lenses decreases southeastward toward the terminus of the reservoir (Fig. 2). The sandstone lithofacies forms the axis of the sandstone body and typically has a blocky resistivity pattern. Southwest of the axis, sandstone and shale of the variegated lithofacies predominates, and resistivity logs typically have a serrate pattern. In Bluff field, the oil reservoir comprises isolated sandstone lenses that define four separate Carter and *Millerella* pools. The Wayside oil unit, by comparison, was developed in a single lensoid sandstone body. Depositional dip of the imbricate sandstone lenses is gentler than in the other oil fields. The sandstone generally has a serrate resistivity signature, except at the western end of the sandstone body, where the sandstone is thickest and has a blocky resistivity signature.

Depositional Systems

Lower Parkwood lithofacies have been interpreted to represent open-marine to backshore environments (Pashin and Kugler, 1992). The shale-and-siltstone lithofacies represents a muddy, storm-dominated shelf on the basis of wave ripples, graded bedding, and load structures. Predominance of horizontal laminae and gently dipping planar cross-strata in the sandstone lithofacies is characteristic of shoreface and foreshore environments. By contrast, root structures and pisoidal carbonate in the variegated facies signify vegetation and soil formation in backshore environments. The variety of isolith patterns and stratigraphic architecture (Figs. 1,2) demonstrates that Carter beach systems were diverse. Moreover, the change of sandstone-body geometry from lobate bodies in the southwest to thin, isolated lenses in the northeast records systematic evolution of the strand plain.

The lobate geometry and serrate, coarsening-upward resistivity signature of the Carter sandstone in the South Brush Creek oil unit and adjacent areas (Figs. 1,2) signify sedimentation in a cuspate delta. Truncation of the top of the sandstone suggests subaerial degradation of the beaches as the delta prograded farther seaward. Similar degraded beaches are present in the Doce Delta of Brazil (Dominguez and Wanless, 1991). The Carter reservoir in the Blowhorn Creek oil unit apparently accumulated at the distal fringe of the cuspate delta. The shale-filled scours are interpreted as tidal channels that were part of the cuspate delta, because the uppermost Carter sandstone lenses extend above the scour structures.

The Carter sandstone in the North Blowhorn Creek oil unit has been interpreted as a spit-style beach system by Pashin and Kugler (1992) (Figs. 1,2). They suggested that the irregular southwest margin of the sandstone body and the southward decrease in size of the imbricate sandstone lenses delineate spit arms. Bluff reservoirs apparently formed in a string of beaches extending southeast from the axis of the North Blowhorn Creek spit. The localized geometry of the Carter reservoir in the Wayside oil unit is suggestive of the small, arcuate beaches that form in areas of high tidal range (Hayes, 1979). Indeed, localized sandstone bodies in the Wayside area apparently accumulated along the margin of an estuarine tidal embayment where no sand was deposited. Thick sandstone with a blocky log signature adjacent to the embayment may reflect reworking by tide- and storm-generated currents.

PETROLOGY, DIAGENESIS, AND PETROPHYSICAL PROPERTIES

The Carter sandstone is dominantly very fine grained to fine-grained, moderately well sorted quartzarenite. Heterogeneity in the Carter sandstone is influenced by grain-size distribution, intrabasinal framework grains, and authigenic minerals. Volumetrically important authigenic minerals are quartz, kaolinite, and carbonate minerals, including nonferroan and ferroan calcite, ferroan dolomite–ankerite, and siderite (Kugler and Pashin, 1992). The distribution of diagenetic components in some oil units is related directly to depositional facies, but the present distribution and composition of authigenic minerals and the nature of compactional features resulted from burial diagenesis. Carbonate-cemented sandstone, which is associated with the margins of reservoir zones and with shell accumulations, forms baffles and barriers to fluid flow. Pressure-solution seams also form effective barriers to flow and mark the lower limit of oil-stained sandstone in several cores. Deformed intraclasts and wispy microstylolites increase tortuosity of fluid flow.

The pore system in the Carter sandstone consists of effective macropores between framework grains and ineffective micropores between detrital and authigenic clay particles. In general, shoreface and foreshore deposits of the sandstone facies have a well-interconnected pore system, whereas backshore deposits of the variegated facies contain the most authigenic clay and carbonate and thus have a poorly interconnected pore system. The primary pore system was modified to some extent during burial. Some aluminosilicate framework grains, such as feldspar, were dissolved and redistributed as kaolinite; redistribution did not enhance porosity significantly. Authigenic carbonate is common in Carter sandstone but occludes all pores only in the vicinity of shell accumulations; secondary porosity related to dissolution of carbonate is scarce. Of all the factors affecting the pore system, dispersed and laminated clays have the most detrimental effects on reservoir properties.

A weak correlation exists between porosity and permeability ($R^2 = 0.52$) in the Carter reservoir of the North Blowhorn Creek oil unit. Capillary-pressure data indicate that pore-throat size distribution is typically polymodal, reflecting the mixture of micropores and macropores and, hence, the distribution of authigenic and detrital clay minerals. Order-of-magnitude variation of permeability in some shoreface and foreshore sandstone may be related to grain-size variation. This variation affects sweep efficiency during water flooding, because fluids are channeled preferentially through high-permeability zones.

DISCUSSION: PRODUCTION PERFORMANCE AND RESERVOIR HETEROGENEITY

To sustain or increase oil production in the Black Warrior basin of Alabama, five Carter oil fields have been unitized for water flooding, gas injection, or a combination of the two processes. Production patterns of oil and water correlate well with depositional features and petrophysical parameters, reflecting progressive evolution of the Carter strand plain and subsequent burial diagenesis. In the North Blowhorn Creek oil unit, for example, the distribution of original oil in place corresponds favorably with sandstone-isolith patterns (Fig. 3A). Most of the oil extracted in the northern part of the oil unit has been from shoreface and foreshore sandstone northeast of the sandstone-body axis; production from backshore and recurved-spit deposits behind the axis is minimal (Fig. 3B). Oil production in the southern part of the unit is variable, reflecting segmentation of the reservoir by imbricate sandstone lenses (Fig. 2, cross section C–C′; Fig. 3B). Similar patterns are visible in the cumulative volume of injected water (Fig. 3C). Although similar amounts of water have been injected in the northern and southern parts of the field, cumulative water production is exceptionally high in the southern part of the oil unit (Fig. 3D), signifying early breakthrough. Injected fluids channeled through high-permeability thief zones and fractures may have bypassed some producible oil where breakthrough occurred early; similar relationships exist in the other oil units.

Because the geologic processes that form a sandstone reservoir operate at multiple scales, heterogeneity in petrophysical and other engineering properties in the reservoir also is scale dependent. Knowledge of controls on reservoir heterogeneity becomes increasingly important at smaller scales as field development progresses from primary production through a variety of improved-recovery techniques. This is especially apparent in the Carter oil reservoirs of the Black Warrior basin. Carter reservoirs are unusually heterogeneous for beach deposits, because they are localized and shaly. Imbricate sandstone lenses present a critical megascopic heterogeneity in the Carter sandstone, and the arrangement of those lenses differs in each producing oil unit, reflecting environmental variability within the delta-destructive strand plain. Mesoscale heterogeneity within the sandstone lenses is controlled in part by the transition from shoreface to backshore facies. Porosity and permeability contrasts inherent in this facies transition, moreover, have been amplified by diagenetic factors operating at a microscopic scale, which include the development of authigenic clay minerals and carbonate cement.

Although Carter oil reservoirs in Alabama were deposited as part of a single strand-plain system and were subjected to similar diagenetic conditions during burial, these reservoirs are morphologically diverse and have correspondingly diverse production characteristics. Therefore, these reservoirs must be characterized on a field-by-field basis. In each oil unit, the success of recovery operations depends on the ways that problems related to specific depositional and diagenetic heterogeneities are addressed. Continued success necessitates careful evaluation of the sedimentologic, petrologic, and petrophysical characteristics of individual sandstone bodies to gain the fullest understanding of controls on oil production and the methods that can best be applied to improve recovery.

ACKNOWLEDGMENTS

This research is part of a larger study of heterogeneity in Carboniferous sandstone reservoirs of

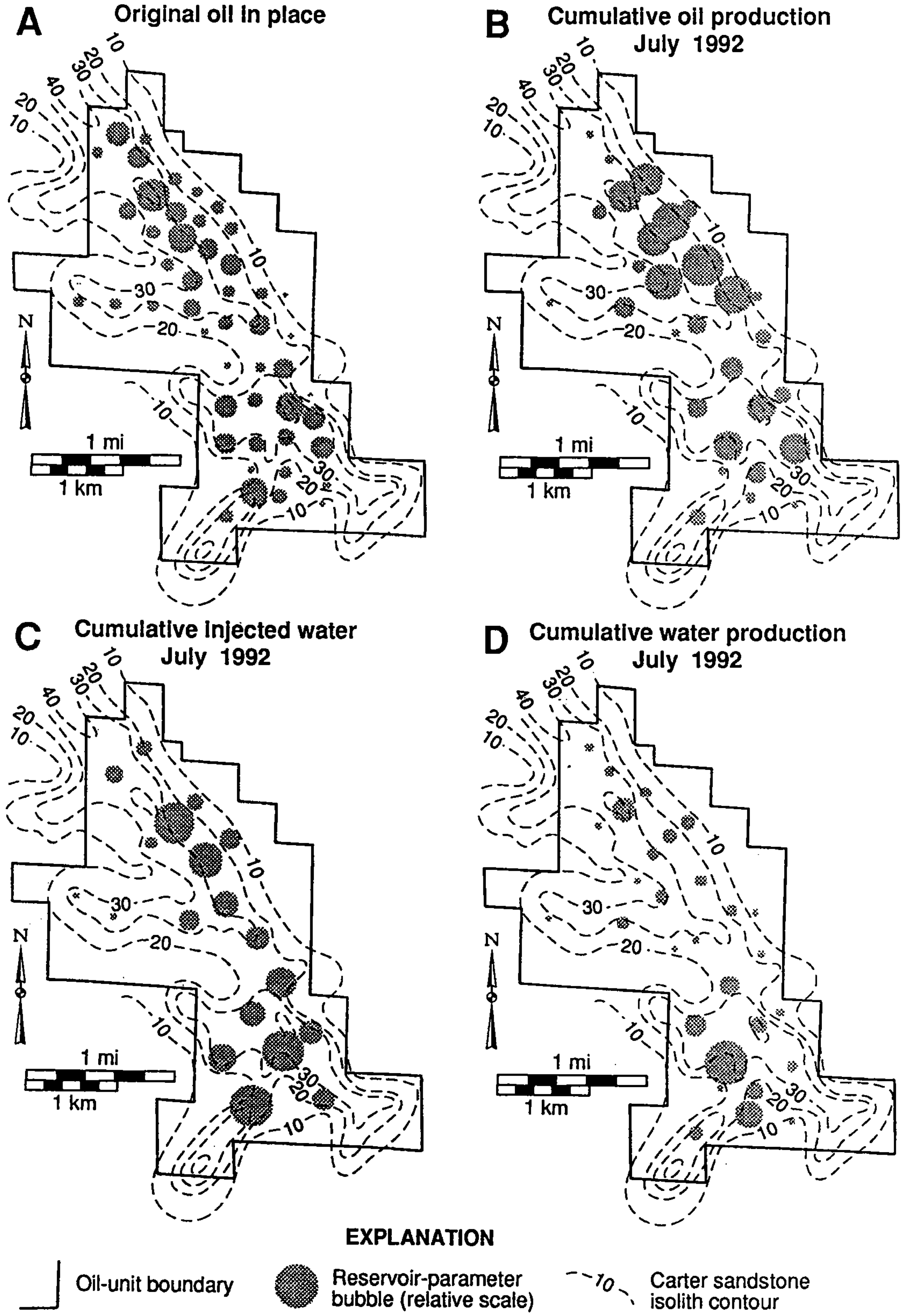

Figure 3. Bubble maps showing the relationship of key production parameters to sandstone-isolith patterns in the North Blowhorn Creek oil unit, Black Warrior basin, Alabama.

the Black Warrior basin. Support for this research was provided by the U.S. Department of Energy, Bartlesville Project Office, under contract DOE/BC/14448.

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Reservoir Characterization of Pennsylvanian Sandstone, Nelson Lease, Savonburg N.E. Field, Allen County, Kansas

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The Nelson lease comprises three 160-acre tracts in secs. 21, 28, and 29, T. 26 S., R. 21 E., within the Savonburg N.E. field in Allen County, Kansas. The eastern part of the lease (SW¼ sec. 21 and NW¼ sec. 28) has the greatest potential for additional oil recovery and will be considered here. There are 48 injection wells, 48 producing wells, and four dry holes forming an irregular five-spot pattern on a 2.5-acre spacing in those quarter sections. The first well in this area was drilled in 1962. A pilot water-flooding project began in March 1981 and was expanded in 1983, with full development in 1985. Total production as of November 1991 for all three tracts has been 347,304 bbl. Of this production, 131,530 bbl were attributed to primary depletion, and 215,774 bbl have been produced by water-flooding operations, including augmentation by 11 gel-polymer treatments undertaken in 1986. The lease currently produces an average of 22 bbl of oil and 800 bbl of water per day, placing it at the economic limit.

Analysis of the reservoir was undertaken as part of a project to demonstrate the use of existing technologies to prolong the life of marginal oil fields under a cost-sharing program funded by the U.S. Department of Energy for fluvial-dominated deltaic reservoirs. Any data or methods developed in characterizing and managing the Savonburg N.E. field could be applied to many of the similar fields developed in the Cherokee Group sandstones in Kansas. Production on the Nelson lease comes from multiple sandstone lenses in the Cabaniss Formation of the Cherokee Group (Desmoinesian, Pennsylvanian). These lenses appear to be channel sandstones of different ages, separated by regional marker beds that consist of underclay, coal, sandy shell lag, and dark shale. The most prominent marker beds, which can be precisely correlated over much of southeast Kansas and beyond, are the Verdigris Limestone–"V Shale"–Croweburg Coal, the Tebo Coal with associated limestone and dark shale, and the Weir-Pittsburg Coal. Other markers correlate to coal beds of the Cabaniss Formation and associated dark shales. Although informally referred to as the Bartlesville sandstone, reservoir sandstones in the Nelson lease actually may be part of the informal Cattleman, Chelsea, or Skinner intervals of the subsurface.

Channel sandstones consist of structureless or cross-bedded sandstone with pebble conglomerates or pebbly sandstones at the base; the pebbles are locally derived interclasts of claystone. The main reservoir consists of a north-south channel just east of the center of the pattern, where it cuts through the underlying Tebo and Weir-Pittsburgh markers. A separate, older channel cuts across the southern part of the lease, and it is also productive. To the east and west, the main reservoir breaks up into interbedded sandstones and shales that are not as productive. These channel trends intersect and form different, but possibly interconnected, reservoirs. Because of the similarity of the producing lenses to each other, and the presence of multiple unconformities, defining flow units in the Nelson lease is very difficult. One to three lenses might be present in a single well. There also might be one lens incised directly into another partially eroded lens, with no discernible boundary but with a permeability barrier.

Volumetric analysis of the reservoir shows that only 10% of the oil originally in place (OOIP) has been recovered, leaving an estimated 822,000 bbl of mobile oil remaining in the two quarter sections. By using viscosity data and relative-permeability characteristics from similar reservoirs, the mobility ratio was found to be near unity, or only slightly unfavorable. This result indicates that the sweep efficiency of water flooding should be reasonably high, with total recovery being as much as 20–30% of the OOIP at the completion of the operation. Poor sweep efficiency has caused the field to prematurely water out. With improved water quality and better understanding of the flow units, the water flooding can be optimized.

There will be both geologic and engineering

Phares, T. L.; Walton, A. W.; and Schoeling, L. G., 1996, Reservoir characterization of Pennsylvanian sandstone, Nelson lease, Savonburg N.E. field, Allen County, Kansas, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 286–287.

components to the reservoir characterization. The initial part of reservoir characterization will be to determine the stratigraphy of the units in the reservoir as identified by their gamma-ray–neutron logs. If the log analysis does not provide enough resolution to determine boundaries between the different sandstone lenses, sporadic core-analysis data and the cores themselves may be employed to define the flow-unit boundaries. Correlation from well to well will establish the continuity and distribution of these flow units. Correlations with perforation and differential-temperature or spinner-survey data should reveal the injection profile and determine if all the proper zones are being flooded.

The other part of the reservoir characterization will consist of a series of pulse tests. The pulse testing will reveal the transmissibility between wells and the formation compressibility. It should identify any water channeling due to fractures and should show if there is a directional-permeability trend. The pulse testing will be conducted with either downhole pressure gauges or surface pressure transducers. Both testing methods may be employed on several patterns to check the validity of the surface transducers since they have not been field tested for accuracy. By coming to understand the reservoir better, we hope to see ways to economically reach bypassed mobile oil by rearranging the water-flooding pattern or infill drilling, or by implementing profile-modification treatments.

Like so many Cherokee oil fields, the quality of injected water is "poor," so plugging of the reservoir, precipitation of ferric hydroxides in tubing and tanks, and other related problems are likely. The demonstration includes designing and installing a water-treatment facility to reduce the particulate matter and oxygen injected into the reservoir during water-flooding operations.

Additional Comments by Anthony W. Walton and Lanny G. Schoeling

Reservoir characterization of the reservoirs in the Nelson lease and engineering analysis of the field led to implementation of several steps to enhance oil production and reduce operating costs. Currently 28 injection wells and 16 production wells remain active, producing 27 bbl oil and 450 bbl water daily. Injection rate is 750 bbl per day. Production to date is 363,000 bbl, including 131,000 bbl during primary production and 232,000 bbl under water flood.

Geological reservoir characterization has shown that the major reservoir sandstones are part of a valley-fill system (Walton, 1996). The valley-fill succession includes three intervals, informally referred to as B_1, B_2, and B_3 (from top to bottom). Sandstones in the B_3 interval are the most productive part of the reservoir. Sandstone in the B_2 interval is also productive, but is only an adjunct to the larger production from the deeper sandstone. The B_3 interval and its sandstone is best developed in a belt down the eastern part of the lease, but the interval thins and becomes less sandy in the southern part.

Much of the effort to improve production was directed at cleaning the wells of junk, verifying that they were perforated in the proper interval, redesigning the pattern to take advantage of knowledge of the reservoir, and performing gelled polymer treatments to block fractures that transmitted injected water quickly to producing wells. Unproductive wells have been abandoned, at least temporarily, and the operators efforts have concentrated on the most favorable part of the field, including less productive parts where thick sandstones are known to exist. The operator drilled one replacement injection well, which encountered good oil saturation in a thick B_3 sandstone, as predicted by the geological model. The operator installed a floatation system to remove sulfides from the produced water before filtration and reinjection. The results have been economical removal of nearly all particles down to 10 microns, with resulting savings in workovers and maintenance (Schoeling and others, 1996).

This project has involved exemplary collaboration among engineers and geologists of the Tertiary Oil Recovery Project (TORP) of the University of Kansas (KU) and employees of J.E. Russell Petroleum Inc., the operator. Collaboration has included frequent meetings of participants, exchange of technical information and knowledge based upon experience, and discussion of major steps in field operations. The most frequent participants have included Bob Barnett and Wendell Weatherbie of Russell Petroleum, Lanny Schoeling and Michael Michnick of TORP, and A.W. Walton of the KU Department of Geology. Don Green and G. Paul Willhite provided overall supervision of TORP's effort in this project. All involved are grateful for funding under the Department of Energy Class 1 program.

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Integrated Reservoir Management to Maximize Oil Recovery from a Fluvial-Estuarine Reservoir: A Case Study of the Sooner Unit, Colorado

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Geologically targeted infill drilling and a multidiscipline reservoir-management plan are expected to boost ultimate recovery from a fluvial-estuarine Upper Cretaceous (Cenomanian) sandstone reservoir, located in the Denver-Julesburg basin (Fig. 1). The "D" sandstone member of the Graneros Formation has typically yielded only 20–25% of the original oil in place (OOIP) after primary and water-flooding operations in nearby fields. The project includes reservoir characterization in which high-density 3-D seismic studies, detailed stratigraphy, and reservoir simulation are used to identify optimal infill well sites, relocate injection patterns, and schedule injection-withdrawal rates.

Production and pressure data provided early clues that the relatively small reservoir, 2.5 mi long by 0.75 mi wide, is composed of several pressure compartments. Pressure measurements taken early in the primary production phase of the reservoir suggested low permeability barriers or baffles between some wells (Fig. 2).

During water-flooding repressurization, variations of static pressures of more than 1,000 psi between wells spaced on 40-acre locations added to the evidence of reservoir operational compartments. Some wells were unaffected by injection in offset wells; however, other wells had early water breakthrough, indicating strongly directional permeability.

Core examination and log comparison indicate that the sandstones of the Sooner unit were deposited in an estuarine environment, where fluvially transported sands and silts were redistributed by tidal and marine processes. Thin carbonaceous-shale and silt laminae probably affect flow of fluids in reservoirs. There are four mappable intervals that contain separate flow units; flow units in each interval may be subdivided into separate pressure compartments (Fig. 3).

Integration of geophysics with geology was made by recording a 3-D seismic grid over the unit area (and the adjacent perimeter) to image the entire reservoir. A vertical seismic profile, recorded in a well near the center of the 3-D seismic grid, allowed calibration of seismic traveltimes during data interpretation. Seismic data indicate the presence of basement faults; these define valley edges that form boundaries for deposition of Sooner reservoir sediments.

Discontinuous seismic events near the top of the "D" sandstone member suggest shingling of sandstones in a transgressive sequence (Figs. 4,5). Minor faults appear to cut across the valley-fill reservoirs. The faults, in combination with depositional boundaries, probably affect fluid flow (Fig. 6).

Engineering observations of static reservoir pressure and production data, such as gas/oil and water/oil ratios, were integrated with geologic descriptions and maps of separate or disconnected flow units. Integrated analysis led to conversion of one well from production to injection, and the drilling of one well to increase the efficiency of secondary recovery from one reservoir compartment (Fig. 2). Similar opportunities are available in other

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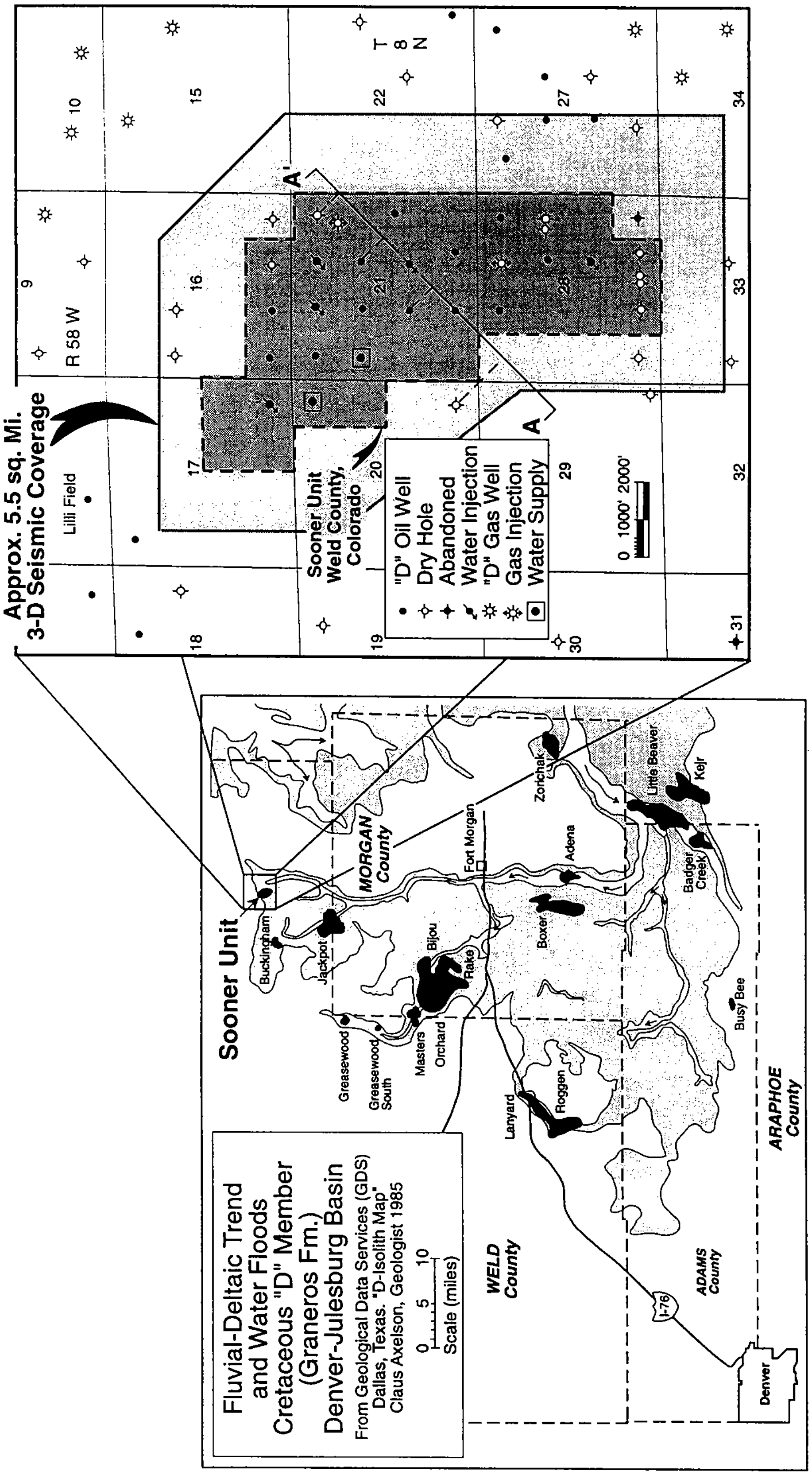

Figure 1. Map of part of the Denver-Julesburg basin, Colorado, showing the location of the Sooner unit and that of the cross section A–A′ (see Fig. 3).

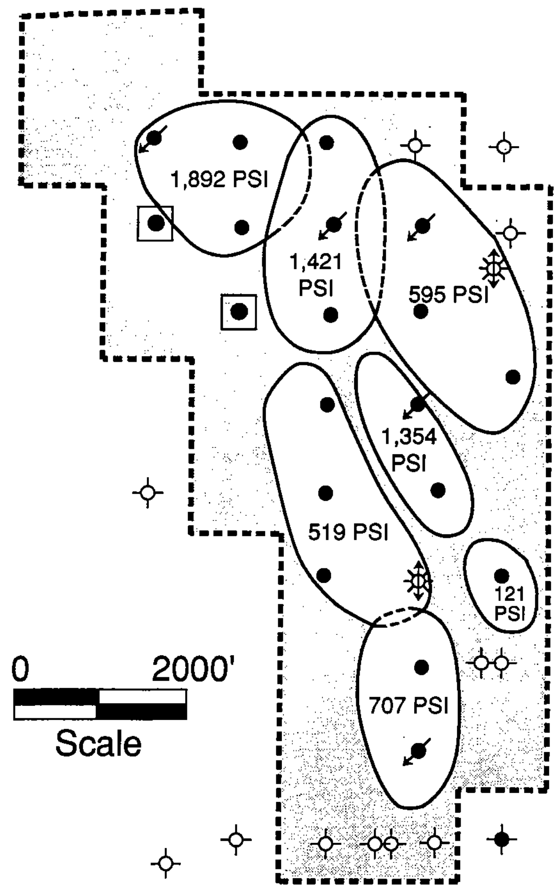

Figure 2. Map of the Sooner unit in Weld County, Colorado. Operational compartments (outlined areas) are parts of the reservoir that contain wells with similar static pressure and that are influenced by a common injection well or wells.

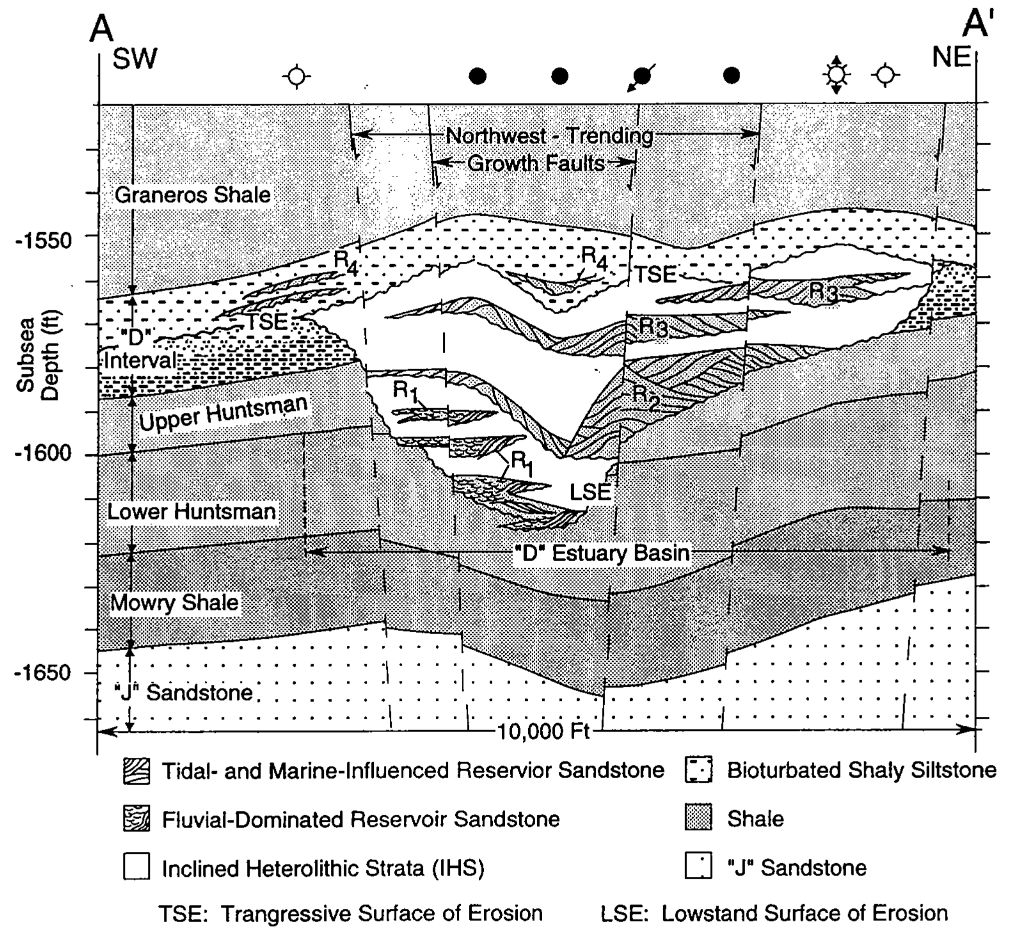

Figure 3. Diagrammatic southwest-northeast structural cross section across the Sooner unit showing spatial relationships between oil-productive "D" subreservoirs R1, R2, R3, and R4. Location shown in Figure 1.

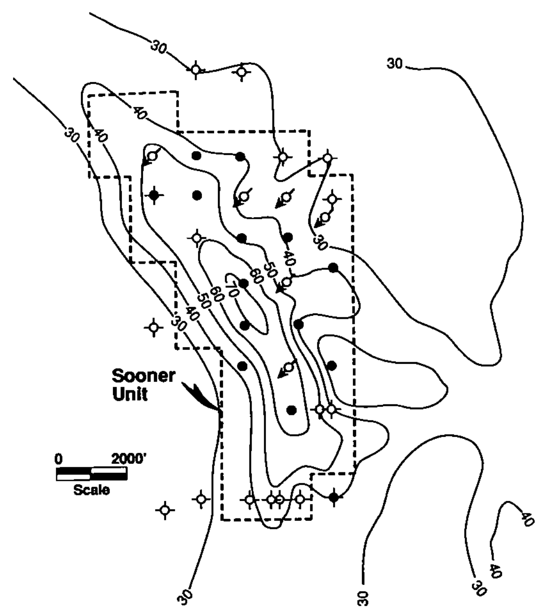

Figure 4. Gross thickness of the "D" sandstone member of the Graneros Formation in the Sooner unit; contour interval, 10 ft.

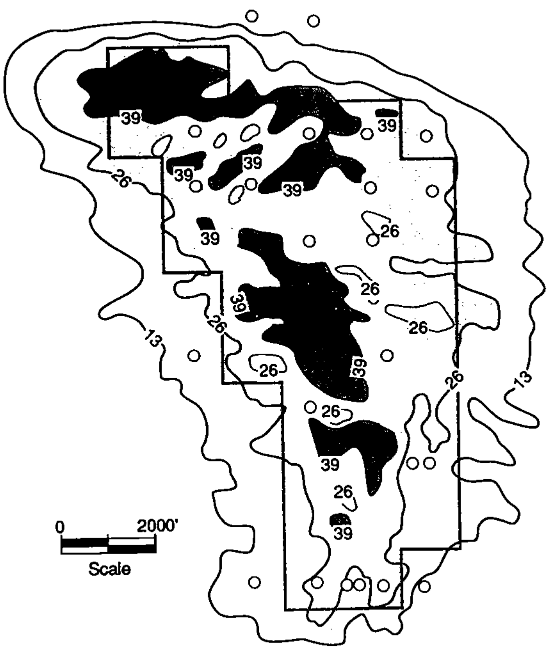

Figure 5. Seismic amplitude of "D" sandstone waveform peak. Seismic amplitude corresponds very well with sandstone thickness; contour interval, 13,000 amplitude units.

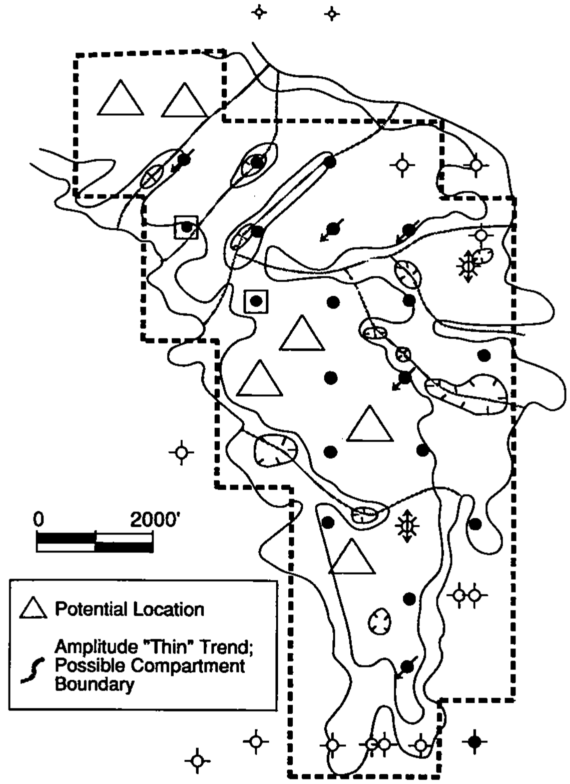

Figure 6. Potential reservoir boundaries inferred from seismic amplitude of "D" sandstone waveform peak where linear trends of low amplitude may be related to faults. Integrating these potential-reservoir flow boundaries with engineering and geologic observations has led to identification of infill-drilling opportunities.

reservoir compartments, and evaluations are underway to maximize oil recovery in a cost-effective manner (Figs. 2,6).

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Demonstration of the Electrically Initiated Heat-Flooding Process in the Peru Sandstone—A Fluvial-Dominated Deltaic Reservoir

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ABSTRACT.—Electrofrac is the tradename of the electrically initiated heat-flooding process that has been demonstrated in an oil lease located in Neosho County, Kansas. The oil reservoir in the Peru Sandstone at that location is shallow and generally unproductive, with essentially no natural driving pressure, and natural flow is typically just 1–3 gallons per day per well from ~20 ft of pay sandstone. Commercial-scale prototype facilities have been employed to increase production beyond 10 times the natural rate for extended periods during field-scale research and development work. Increased production was sustained for more than two years. The ultimate potential may prove much better, because the field was only partially stimulated during those demonstrations.

INTRODUCTION

Application of thermal energy as primary, secondary, and even tertiary oil-recovery techniques has been tried in oil fields with mixed results. It was initially considered a process suitable for heavy-oil reservoirs, but later research and investigation revealed mechnisms involved in the thermal-recovery processes that can be taken advantage of for light-oil reservoirs as well. Examples of thermal-recovery techniques are in-situ combustion, more commonly known as "fireflood," and steam flooding. Other less-known thermal-recovery techniques are the detonation of thermonuclear devices and the use of electrical energy. Electrical energy can be used for bottom-hole heating within a single wellbore to initiate combustion, or for heating of injected or produced fluid.

An alternate technique is to take advantage of, and alter the natural earth resistance between, two electrodes spaced a considerable distance apart. This technique has been successfully applied to "electrocarbonization" experiments with coal in both the laboratory and the field (Sarapuu, 1951), tar sands (Schoeppel and Sarapuu, 1962), and oil shale (Sarapuu, 1945). Successful electrocarbonization and creation of fractures have been documented in the literature (Sarapuu, 1957; Hill, 1952; Slezak and Davis, 1952). It seems to be feasible to take advantage of the electrocarbonization and the eventual creation of electrical linkage to initiate combustion within the reservoir far from the wellbore. This process can be used as a stimulation technique for the kind of reservoirs in which a displacing front cannot be created because of the existence of extensive natural fractures or simply because of the nonhomogeneity of the reservoir.

ELECTRICALLY INITIATED HEAT-FLOODING PROCESS

The electrically initiated heat-flooding process entails the use of downhole electrodes mounted in the oil-bearing sandstone, a specially configured electrical-power unit, and facilities for injecting air and fuel into a controlled-combustion zone within the area to be stimulated. One essential feature is creation of electrically conductive paths within the oil-bearing sandstone. This requirement is accomplished in either, or both, of two mutually supportive ways: (1) electrocarbonization of a small por-

Vossoughi, S.; Sarapuu, E.; and Crowther, R. H., 1996, Demonstration of the electrically initiated heat-flooding process in the Peru Sandstone—a fluvial-dominated deltaic reservoir, *in* Johnson, K. S. (ed.), Deltaic reservoirs in the southern Midcontinent, 1993 symposium: Oklahoma Geological Survey Circular 98, p. 293–295.

tion of the oil present between electrodes mounted in the oil-bearing sandstone and (2) injection of electrically conductive pellets with, or in place of, the sand normally injected during hydraulic fracturing as part of the original well completion.

RESERVOIR AND DEMONSTRATION SITE

The reservoir is located within the Saint Paul–Walnut field in the east-central portion of Neosho County, Kansas, at a depth of ~200 ft. The oil is trapped in fluvial-deltaic channel sandstones of the Peru Sandstone that form a depositional system averaging ~1 mi wide and elongated to the northeast. The shallow-marine environment of deposition has caused the sandstone to occur in irregular, islandlike patterns of fluvial-deltaic channels and to have varying degrees of thickness. Permeability of the reservoir increases from top to bottom and is directionally oriented southwest-northeast.

The oil left in the formation is hard to recover by conventional recovery techniques, because of the unfavorable reservoir characteristics. The greatest difficulties are caused by the highly heterogeneous character of the oil-bearing sandstone. Within just a few feet, a large variation of permeability (in the range of 25–150 millidarcies) is observed. In addition, some of the thin stringers in the formation have permeabilities of only a few millidarcies, thus creating serious lateral and vertical heterogeneities.

The electrically initiated heat-flooding process was tested in two leases, totaling 240 acres, called the Beachner-1 and Beachner-2 leases. Both are located in Neosho County, Kansas, in T. 29 S., R. 21 E.

FIELD-TEST RESULTS

The original field research (in 1960–61) included both air injection and electrically enhanced in situ combustion. The capability of the process was later demonstrated in 1979–81, when production was enhanced by a factor of 4.5–5.4 during the periods of intermittent (cyclic) stimulation. Figure 1 shows oil production before, during, and after field trials at the Beachner-1 lease during 1979–81.

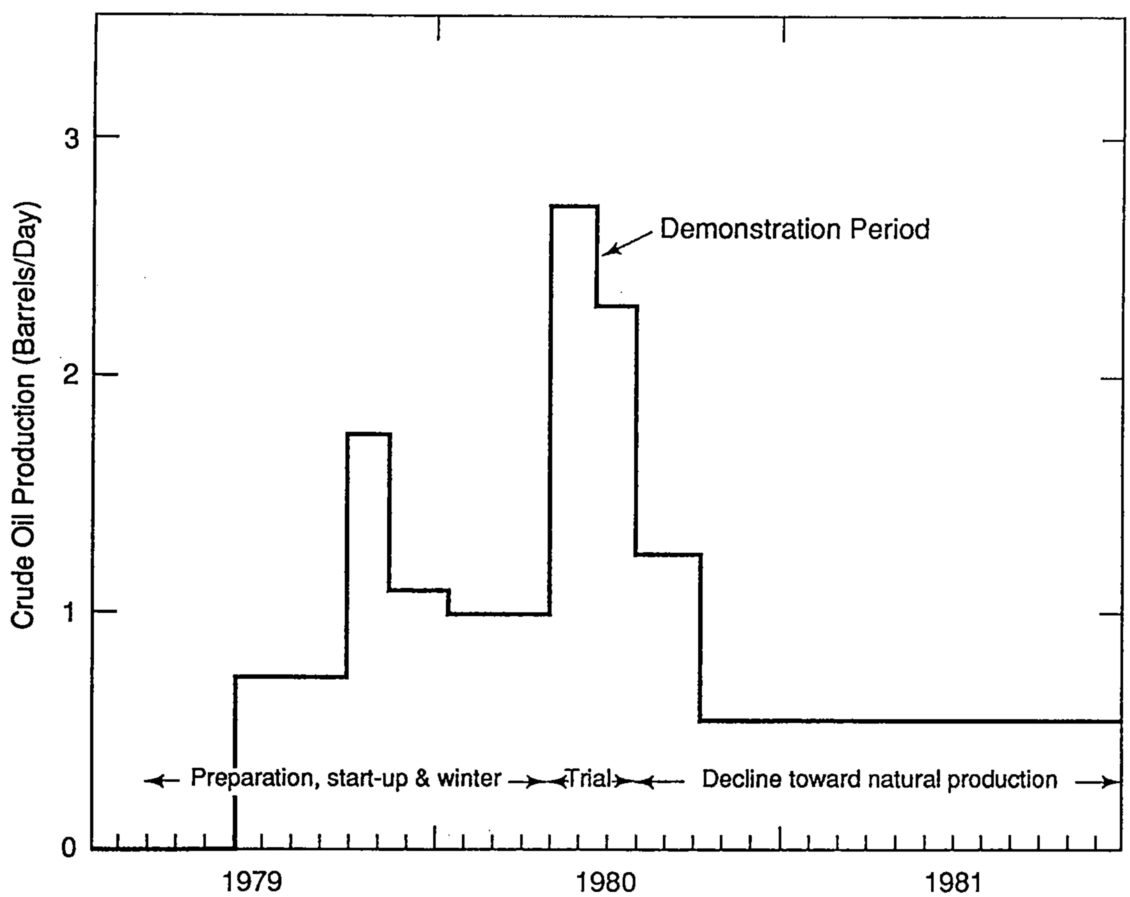

Figure 1. Oil production during first field trial at Beachner-1 lease.

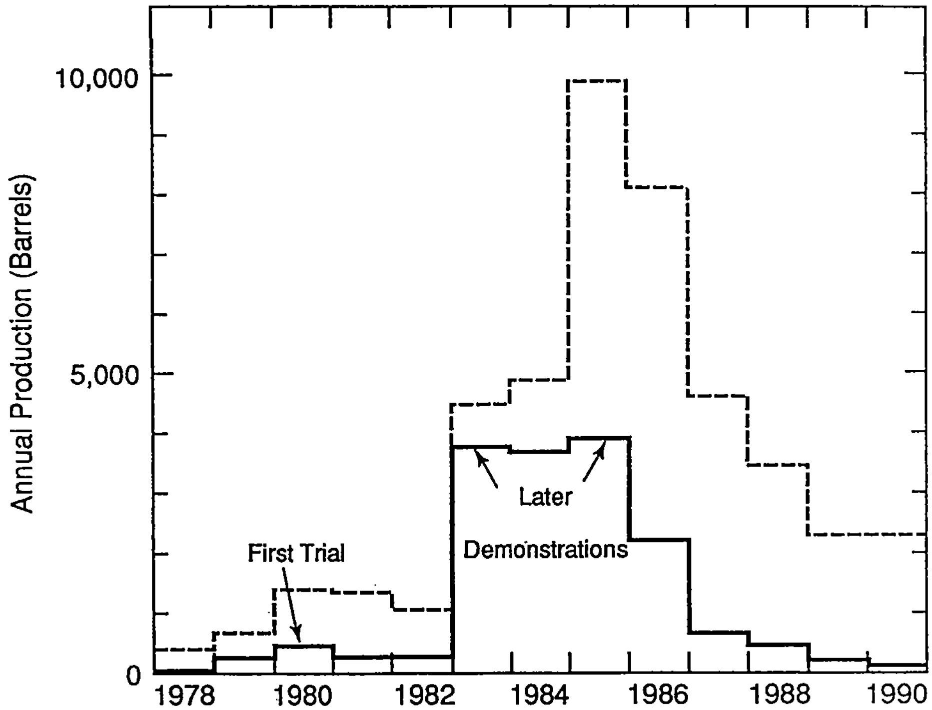

Figure 2. Crude-oil production history during and after application of the electrically initiated heat-flooding process in the Beachner-1 and Beachner-2 leases (solid lines) and selected (nonfractured) neighboring leases (total production shown by dashed lines).

Better evidence of effectiveness was recorded in a later commercial-scale trial during 1983. The average production from test wells was enhanced by a factor ranging from 5.2 to 10.7 in a five-spot test pattern where electrical stimulation, air injection, and cyclic heating were introduced at the center well. This trial was then expanded to include partial stimulation at several wells in a field of 49 wells. The overall result, based on average annual production, was an enhancement ratio in excess of 20 for the field as a whole. Figure 2 shows historic annual production for the Beachner-1 and Beachner-2 leases combined and for neighboring leases to the south that also benefited indirectly from the stimulation and cyclic heating conducted at some of the wells on the Beachner-1 and Beachner-2 leases.

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