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Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Bartlesville Play

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PART I.—Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma

by

Richard D. Andrews

with contributions from Jock A. Campbell and Robert A. Northcutt

PART II.—The Bartlesville Play

by

Robert A. Northcutt

with contributions from Richard D. Andrews

This volume is one in a series published as part of the Fluvial-Dominated Deltaic (FDD) Oil Reservoirs project, jointly funded by the Bartlesville Project Office of the U.S. Department of Energy and by the State of Oklahoma.

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PART I

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma

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INTRODUCTION TO THE FDD PROJECT

This volume is one in a series addressing fluvial-dominated deltaic (FDD) light-oil reservoirs in Oklahoma, published as part of the Fluvial-Dominated Deltaic (FDD) Reservoir project conducted by the Oklahoma Geological Survey (OGS), with participation from the University of Oklahoma Geo Information Systems and OU's School of Petroleum and Geological Engineering (all located in the Sarkeys Energy Center). Primary funding for project, which began in 1993, is provided through a grant from the Department of Energy's Bartlesville Project Office under the Class I reservoir program, and by matching State funds.

The objectives of the Fluvial-Dominated Deltaic (FDD) Reservoir project are to identify all FDD light-oil reservoirs in the State of Oklahoma; to group the reservoirs into plays with similar depositional and diagenetic histories; to collect, organize, and analyze all available data on the reservoirs; to conduct characterization and simulation studies on selected reservoirs in each play; and to implement an information- and technology-transfer program to help the operators of FDD reservoirs learn how to increase oil recovery and sustain the life expectancy of existing wells.

The FDD project was designed to assist operators in Oklahoma by providing them with practical ways to improve production from existing leases and/or to reduce operating costs. Currently available technologies can improve recovery in FDD reservoirs if there is sufficient information about a reservoir to determine the most appropriate course of action for the operator. The needed reservoir-level information is available through the FDD project, and staff will advise interested operators about the implementation of appropriate improved-recovery technologies.

Light-oil production from FDD Class I oil reservoirs is a major component of Oklahoma's total crude oil production. Nearly 1,000 FDD Oklahoma reservoirs provide an estimated 15% of the State's total oil production. Most FDD reservoir production in Oklahoma is by small companies and independent operators who commonly do not have ready access to the information and technology required to maximize exploitation of these reservoirs. Thus, production from Class I oil reservoirs in Oklahoma is at high risk because individual well production commonly is low (1–3 barrels per day) and operating costs are high. Declines in crude oil prices or increases in operating costs can cause an increase in well-abandonment rates. Successful implementation of appropriate improved-recovery technologies could sustain production from these reservoirs well into, and perhaps throughout much of, the 21st century. Without positive intervention, most of the production from Oklahoma FDD oil reservoirs will be abandoned early in the next century.

The technology-transfer program has several parts. Elements include play publications and workshops to release play analyses that identify improved recovery opportunities in each of the plays. In addition, there are other sources of publicly accessible information related to FDD reservoirs, including the OGS Natural Resources Information System (NRIS) Facility, a computer laboratory located in north Norman.

First opened in June 1995, the OGS NRIS Facility provides access to computerized oil and gas data files for Oklahoma and software necessary to analyze the information. Both well history data and oil and gas production data are available for the entire State. Plugging report data are currently being added to the system on a county-by-county basis. Access to the files is through menu-driven screen applications that can be utilized by computer novices as well as experienced users. There are technical support staff to assist operators in obtaining information about their producing properties as well as geological and engineering outreach staff to help operators determine appropriate improved-recovery technologies for those properties. The lab is equipped with Pentium PCs—each with a CD-ROM drive, full-scale inkjet plotter, laser printer, log scanner, and Zip drive. Geology-related software to do mapping, contouring, modeling and simulations, log analysis, volumetrics and economics, pump optimization, fracture design and analysis, and 3D seismic interpretation is available for public use. In the future, it will be possible to access the facility's data files remotely, most likely via the Internet.

Technology-transfer events began with the first workshop and publication, addressing the Morrow play, on June 1, 1995. Other plays in this series include the Booch play, the Layton & Osage-Layton play, the Skinner and Prue plays, the Cleveland and Peru plays, the Red Fork play, the Bartlesville play, and the Tonkawa play.

FDD-DETERMINING CRITERIA

For purposes of this project, fluvial-dominated deltaic (FDD) reservoirs were interpreted to consist of sandstones that were deposited in a deltaic or strictly fluvial environment.

Depositional environments of sandstone bodies in the Midcontinent region were identified using specific criteria which differentiate between fluvial-dominated deltaic (FDD) and marine deposits. These criteria were interpreted from information gathered from well logs and from the literature and include:

1. Electric log signatures (gamma ray, density-neutron, and resistivity are the most dependable).
2. Geometry of the sand body (from isopach mapping).
3. Texture (grain size and sorting).
4. Fossils and trace fossils.
5. Authigenic minerals (formed in-place after deposition). *Glauconite* is considered a marine indicator although its presence can indicate postdepositional reworking by marine processes (then it is allogenic). *Siderite* is considered evidence of subaerial deposition, of fresh-water origin.
6. Sedimentary structures (bedding types, bioturbation, soft-sediment deformation).
7. Thickness.
8. Contacts (sharp or gradational).
9. Rock type and lithologic relationships (vertical and lateral).
10. Paleocurrents.

DEPOSITIONAL SETTING OF FLUVIAL-DOMINATED DELTAIC RESERVOIRS

The depositional setting of a fluvial-dominated deltaic reservoir system is located at the boundary between a continental landmass and the marine environment where the products of a drainage basin are deposited. The character and distribution of the depositional products depend upon the size and relief of the drainage basin, the composition and distribution of the source rocks, the climate of the region, and the behavior of the marine environment. Brief discussions of the significant features of such a depositional setting are presented here to help readers better understand the properties of the individual fluvial-dominated deltaic reservoirs identified in this project.

For more detailed background information, readers are referred to Brown (1979), Coleman and Prior (1982), Galloway and Hobday (1983), and Swanson (1993).

COASTAL FLOOD-PLAIN SYSTEMS

In the context of fluvial-dominated deltaic reservoir systems, a subaerial coastal plain is considered a depositional environment that extends inland from a marine shoreline or landward from a delta plain. A coastal plain can overlie preexisting strata of any origin or age and may include a variety of fluvial depositional settings, such as flood plains (Fig. 1), incised valley-fill systems, and lowlands containing swamps or marshes. These settings may be controlled structurally or they may be topographic depressions caused by subsidence or erosion. In the case of incised valley-fill systems, the transition from fluvial to marine deposits may be abrupt, and there may be little or no delta formation. On the other hand, there may be a gradational transition in the coastal plain from fluvial to deltaic deposits, and it may be difficult to distinguish between coastal-plain (or flood-plain) deposits and those of an upper delta plain (Fig. 1) except by their geographic relationship to the shoreline. Nevertheless, a coastal flood plain is considered distinct from an upper delta plain, and subaerial deposition in an identified coastal flood-plain environment is considered to occur inland from a delta or marine shoreline.

The most common reservoirs in coastal flood-plain environments occur in channel deposits. Several types of such deposits are identified in the Pennsylvanian of the Midcontinent region; they include point bars, braided river deposits, anastomosing river deposits, and longitudinal and transverse river bars. Point bars

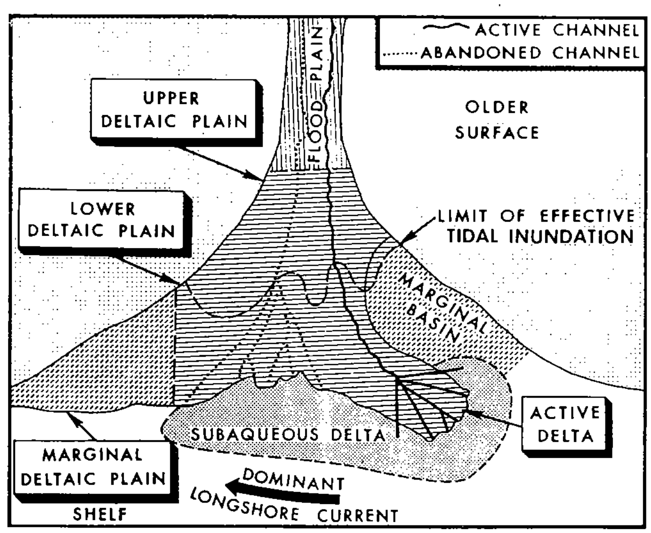

Figure 1. Components of a delta system. From Coleman and Prior (1982).

are the most common components of fluvial systems in Oklahoma.

Fluvial Point Bars

Point bars are fluvial accumulations of sand, silt, and mud that are deposited on the down-flow, inside bank of a meander bend, commonly referred to as the depositional bank (Fig. 2A). They are formed by common depositional processes and are not unique to any single depositional environment. Point bars occur in all coastal flood-plain systems as well as in upper delta plains. Point bars also are found in nondeltaic, semimarine environments such as estuarine channels where tidal forces, rather than riverine processes, are the principal sources of energy. Individual point bars may be much more than 100 ft thick and can extend

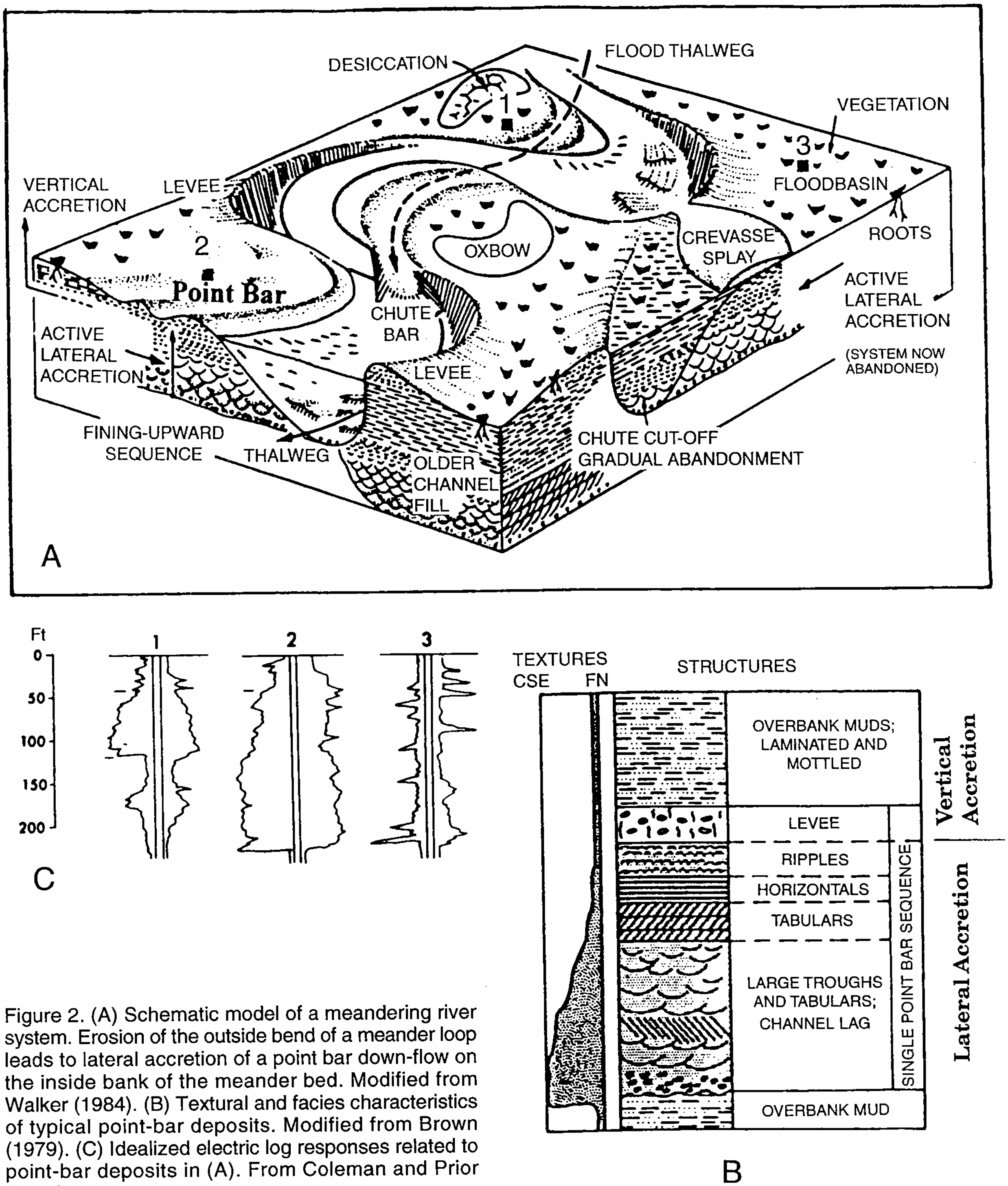

Figure 2. (A) Schematic model of a meandering river system. Erosion of the outside bend of a meander loop leads to lateral accretion of a point bar down-flow on the inside bank of the meander bed. Modified from Walker (1984). (B) Textural and facies characteristics of typical point-bar deposits. Modified from Brown (1979). (C) Idealized electric log responses related to point-bar deposits in (A). From Coleman and Prior (1982).

laterally for more than a mile. Stacked assemblages commonly are hundreds of feet thick. In the Pennsylvanian of the Midcontinent, point bars commonly are 20–50+ ft thick and occur laterally within meander belts that are <2 mi wide. Important attributes of point-bar deposits are included in a summary of fluvial-deltaic sandstone characteristics (Fig. 3).

In the sense of depositional processes, point bars are unique because they form by lateral accretion rather than direct vertical aggradation of the sand body. This depositional style promotes the lateral growth of a sand body over considerable distances without complete inundation. Lateral accretion also accounts for inconsistent deposition of sand which in turn causes compartmentalization of potential reservoirs. This compartmentalization promotes hydrocarbon entrapment but also is an impediment to hydrocarbon recovery and stimulation, and to reservoir characterization. Figure 4 illustrates the depositional environment of point bars and related flood-plain deposits in a tidally influenced, valley-fill river system. This type of depositional model is applicable to many Pennsylvanian sandstones in Oklahoma that were deposited during transgressive events. Descriptions and depositional-environment interpretations are given in Figure 5.

Point bars can make excellent reservoirs but their heterogeneity is a significant problem in reservoir management. In a vertical profile, such as in outcrop, core, or well logs, a typical point bar has a finer grain size upward or blocky textural profile (Fig. 2B). In the lower point bar, coarser fractions commonly are medium to coarse grained, in places are conglomeratic, and commonly contain pebble-size rip-up clasts. Successively higher sediments include fine- to medium-grained sand, silt, and clay. Overall, point bars have individual graded-bed sets that become thinner and finer grained vertically. Shale commonly is interbedded with sandstone in the middle and upper part of a point bar and these bed sets are inclined at a distinct angle that is unrelated to true dip. These shale interbeds, referred to as clay drapes, are effective visual illustrations of the lateral accretionary nature of point-bar deposits. They also are effective in isolating individual sand layers even within a single point bar. Clay drapes originate during periods of decreasing river discharge in mixed-load fluvial systems. Clay drapes seldom are mentioned or implied in most core studies, yet, they can be interpreted from serrated log signatures such as in Figure 2C. They also are visible in outcrops of practically any fluvial meandering system. Sedimentary structures commonly found in lower point-bar sequences consist of massive to graded bedding, high angle tabular and trough cross-bedding, and rip-up clasts. Common sedimentary features found in the upper part of a point bar include root traces, carbonaceous debris, and sandstone with horizontal and ripple laminations.

Because of the above-mentioned heterogeneities in point bars, the potential for hydrocarbon entrapment in a meandering system is very good. However, recovery of oil and/or gas from these types of deposits commonly is restricted to those portions of a point bar that have a reasonable degree of vertical and lateral continuity. Although many authors avoid this issue for fear of being overly pessimistic, in reality, recovery is concentrated in only certain portions of point bars. If a water-saturated zone is present, the best portion of the reservoir (lower point-bar facies) may occur below the oil/water contact. Hydrocarbons then may be concentrated within the central and upper portions of the point bar which commonly are finer grained and more likely to have the greatest amount of reservoir heterogeneity. If the upper part of a point bar is absent due to erosion or nondeposition, hydrocarbons then may be trapped lower within the point-bar interval. This situation is considerably more favorable for oil recovery because sandstone within the lower part of a point bar is generally coarser grained, occurs in thicker beds, and normally has better effective porosity. Consequently, recoverable reserve calculations can be vastly incorrect when they are based on the assumption that the entire sand body represents the true reservoir thickness. Corresponding recoveries from primary production methods commonly are only about 10–20% of the calculated recoverable reserve, and yield is mostly in the range of 50–150 BO/acre-ft, which is typical for many Pennsylvanian sandstones in Oklahoma. Secondary recovery methods, such as water flooding, normally will double the primary recovery, but reservoir response is highly dependent upon proper field engineering and reservoir characterization.

Point bars sometimes are referred to as shoestring or ribbon sands because of their tendency to occur in a sinuous, meandering pattern. An awareness of this characteristic pattern is important to understanding the spatial relationships within, and the physical parameters of, fluvial systems and associated sand deposits. Swanson (1976) and Coleman and Prior (1982) show that the average meander amplitude of an active meandering stream is about half the width of its enclosing meander belt. But as a meander system aggrades vertically above its own flood plain, the hydraulic difference creates instability and leads to avulsion, a lateral shift of the fluvial system to other portions of the flood plain. Obviously, in such a system, lateral and vertical relationships of sandstone beds are complicated.

DELTA SYSTEMS

In this study, a delta is defined as an accumulation of river-derived sediment that is deposited as an extension to the coast (Fig. 1). In a relatively stable tectonic setting and in a moderately subsiding shelf, sediments commonly consist of sand and finer grained clastics, which are deposited in interdistributary bays and in front of the delta. In such settings, however, marine forces such as waves and tidal currents commonly redistribute the sediments and produce different delta

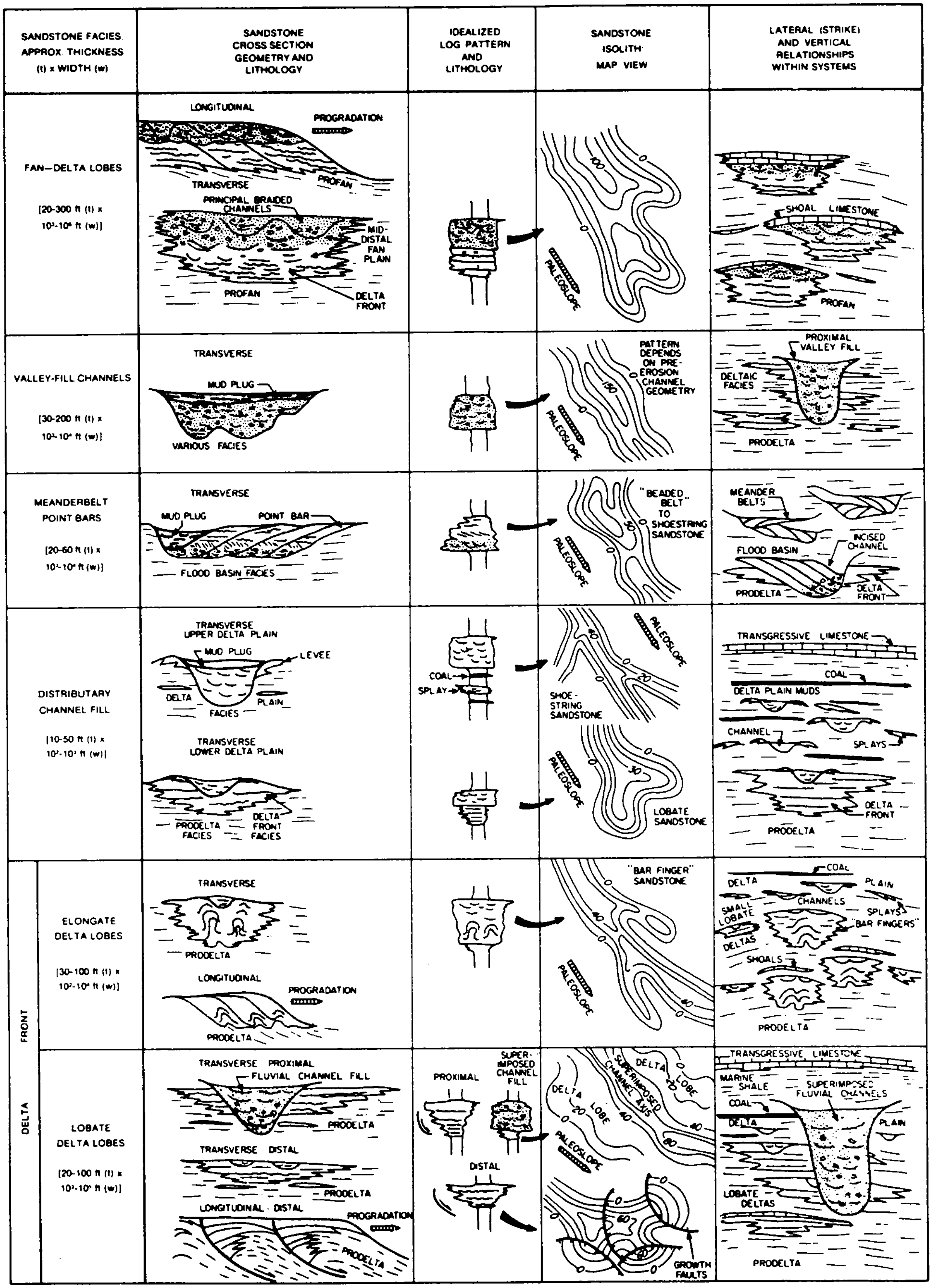

Figure 3. Summary of the characteristics of Midcontinent fluvial and deltaic sandstone bodies. From Brown (1979).

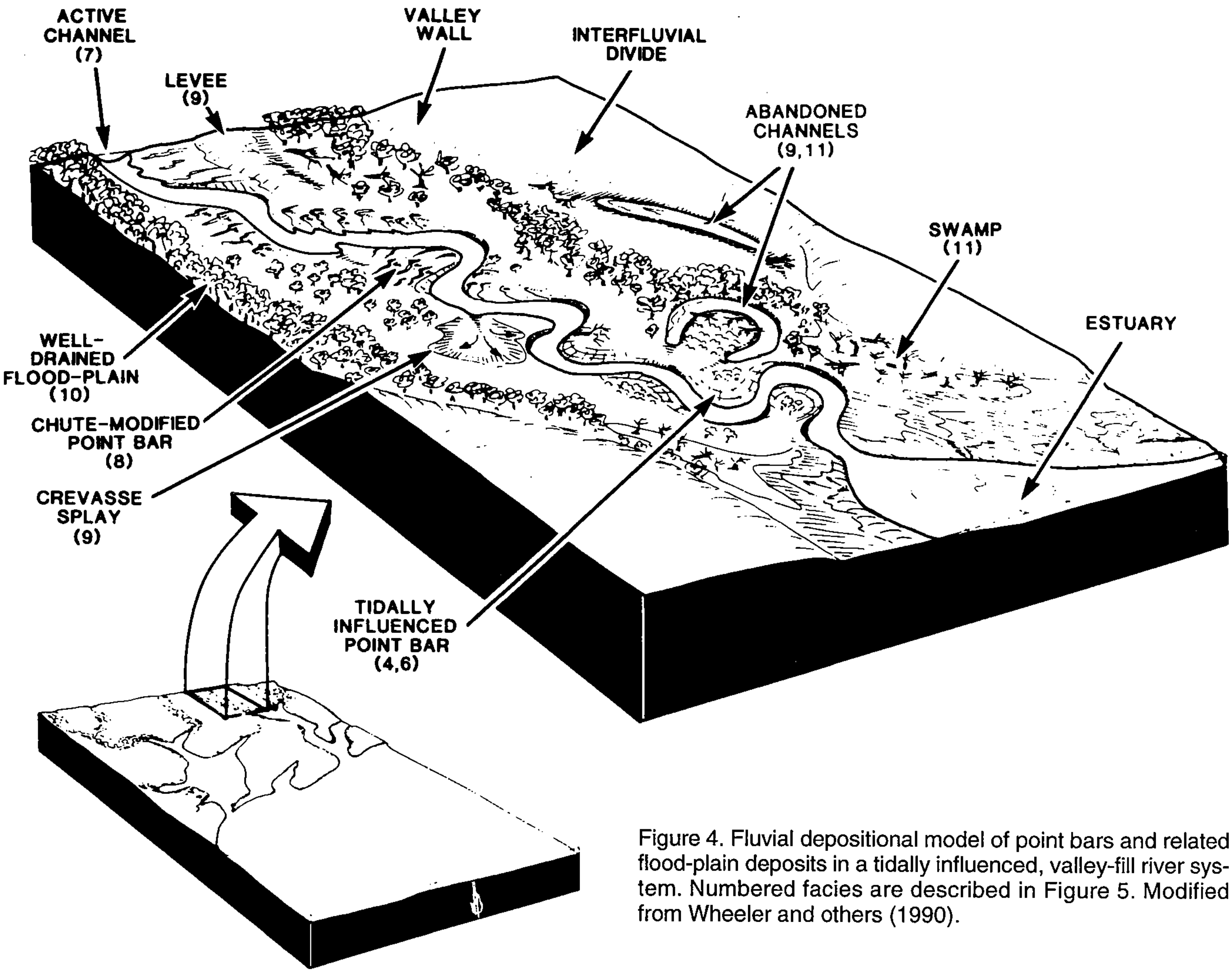

Figure 4. Fluvial depositional model of point bars and related flood-plain deposits in a tidally influenced, valley-fill river system. Numbered facies are described in Figure 5. Modified from Wheeler and others (1990).

morphologies. Figure 6 illustrates the classification of delta systems, which is based on the relative intensity of fluvial versus marine processes. The main emphasis in this project is on reservoir-quality sandstones that are components of fluvial-dominated delta systems.

The basic components of a prograding delta system are shown in Figure 1 and include the upper delta plain, lower delta plain, and subaqueous delta or delta front. In an idealized vertical depositional sequence, fluvial point bars and distributary channels of the delta plain overlie delta front sands and prodelta shale. This relationship is illustrated in Figure 7, which also shows typical log patterns, lithology, and facies descriptions of the various depositional phases of a typical progradational sequence. Progradation refers to a depositional system that is built seaward (offlap). Sedimentary facies in a progradation typically show an upward shallowing depositional origin. Progradation is similar in meaning to regression, which refers to a general retreat of the sea from land areas so that shallower water environments occur in areas formerly occupied by deeper water. This is in contrast to transgression (onlap), which occurs when the position of the sea moves landward and brings deeper water depositional environments to areas formerly occupied by shallower water or by land.

Upper Delta Plain

As shown in Figure 1, the upper delta plain extends from the down-flow edge of the coastal flood plain to the limit of effective tidal inundation of the lower delta plain. The upper delta plain essentially is the portion of a delta that is unaffected by marine processes. Recognizable depositional environments in the upper delta plain include meandering rivers, distributary channels, lacustrine delta-fill, extensive swamps and marshes, and fresh-water lakes. Some of these environments are recognized in normal well log interpretations. For example, meandering rivers have the classic bell-shaped electric log curves of fluvial point bars, and distributary channels tend to have more blocky log profiles. Coal and interbedded shale deposits, evidence of swamps and marshes, also can be interpreted from well logs. Although not diagnostic by

#	FACIES DESCRIPTION	INTERPRETATION
1	**DARK-GRAY, THINLY LAMINATED SHALE:** Slightly calcareous or dolomitic; thinly planar- to wavy-laminated, fissile or platy; includes starved ripple-laminations; rare Planolites, Zoophycus, and Thalassinoides; occurs in both the lower and upper Morrow; ranges from 1 to 57ft (0.3 to 17.4m) in thickness.	**OFFSHORE MARINE:** Inner to Outer Shelf
2	**SHALY CARBONATE:** Gray to dark-gray calcareous wackestone to packstone; generally wavy-laminated but may be burrow-mottled or cross-bedded; skeletal material generally re-oriented and moderately abraded; includes crinoid, brachiopod, bryozoan, mollusc and pelecypod fragments; 0.5 to 10ft (0.2 to 3.1m) thick in the upper Morrow, up to 18ft (5.5m) thick in the lower Morrow.	**SHALLOW MARINE:** Open Shelf or Transgressive Lag
3	**SKELETAL WACKESTONE TO GRAINSTONE:** Gray to tan, limestone or dolomite; planar- to wavy-laminated or cross-bedded; may appear massive or nodular due to weathering or burrowing; includes crinoids, brachiopods, bryozoans, corals, molluscs, gastropods, echinoderms, peloids and intraclasts; occurs only in the lower Morrow; 0.5 to 46ft (0.2 to 14m).	**RESTRICTED TO OPEN MARINE PLATFORM:** Shoals and Bioherms
4	**INTERLAMINATED TO BIOTURBATED SANDSTONE AND SHALE:** Includes interbedded and homogenized lithologies; light-gray, very fine- to fine-grained sandstone and gray to dark-gray shale and mudstone; planar-, wavy- and ripple-laminated; convoluted bedding common; glauconitic; moderately burrowed to bioturbated; Thalassinoides, Planolites, Skolithos, Asterosoma, Chondrites and Rosellia(?); occurs in both the lower and upper Morrow; 1 to 28ft (0.3 to 8.5m) thick.	**NEARSHORE MARINE OR ESTUARINE:** Shoreface or Delta Front; Tidal Flat or Tidal Channel
5	**CROSS-BEDDED, FOSSILIFEROUS SANDSTONE:** Light-gray, fine- to coarse-grained quartz arenite to sublitharenite; trough or tabular cross-bedded in 3 to 18in (7.6 to 45.7cm) thick sets; up to 50% skeletal debris; crinoid, brachiopod, bryozoan and coral fragments; glauconitic; occurs only in the lower Morrow; units up to 25ft (7.6m) thick.	**UPPER SHOREFACE OR TIDAL CHANNEL**
6	**CROSS-BEDDED SANDSTONE WITH SHALE DRAPES:** Gray to tan, fine- to coarse-grained quartz arenite or shaly sandstone; trough or tabular cross-bedded with incipient stylolites, shale drapes and interlaminations between foreset laminae; foresets are often tangential with the lower bounding surfaces and grade laterally into ripple laminations, some oriented counter to the cross-bedding; cross-bed set thickness is 3 to 12in (7.6 to 30.5cm); sparsely burrowed, Planolites; glauconite and carbonaceous debris; occurs primarily in the upper Morrow; up to 28ft (8.5m) thick.	**FLUVIAL OR ESTUARINE:** Upper Point-Bar or Flood-Plain; Tidally Influenced Fluvial Channel
7	**CONGLOMERATE TO CONGLOMERATIC SANDSTONE:** Gray to light-brown; granules and pebbles of mudstone and composite quartz; matrix is fine- to very coarse-grained, poorly sorted, quartz arenite or sublitharenite to subarkose; massive appearing, planar-bedded or cross-bedded; carbonaceous debris; glauconite and phosphate scarce; occurs only in the upper Morrow; up to 21ft (6.4m) thick.	**FLUVIAL CHANNEL:** Braided Stream, Channel-Bottom Lag or Lower Point-Bar
8	**COARSE-GRAINED, CROSS-BEDDED SANDSTONE:** Medium- to very coarse-grained quartz arenite or subarkose to sublitharenite; trough or tabular cross-bedded in sets ranging from 3in (7.6cm) to over 2ft (0.6m) thick; in many cases foreset laminae alternate between coarser and finer grain-size fractions; convoluted bedding is common; carbonaceous debris, including coaly fragments, macerated organic material ("coffee grounds"), leaf and log impressions is prevalent; Planolites burrows are rare; occurs in the upper Morrow; units up to 29ft (8.8m) thick.	**FLUVIAL CHANNEL:** Chute-Modified Point-Bar
9	**RIPPLE-LAMINATED SANDSTONE:** Very fine- to fine-grained quartz arenite; symmetrical or asymmetrical ripples; glauconite and carbonaceous debris are common; trace fossils include Planolites and Skolithos; occurs with many other facies throughout the Morrow; ranges up to 30ft (9.2m) thick.	**FLUVIAL OR MARINE SHOREFACE:** Upper Point-Bar, Splay, Levee or Abandoned Channel-Fill; Middle Shoreface
10	**GRAY-GREEN MUDSTONE:** May have brick-red iron oxide speckles; generally blocky and weathered in appearance; very crumbly; moderate to abundant amounts of carbonaceous debris; compaction slickensides and root-mottling common; calcareous nodules occur in the lower Morrow and beds are 0.5 to 2ft (0.2 to 0.6m) thick; up to 30ft (9.2m) thick in the upper Morrow.	**FLUVIAL FLOOD-PLAIN OR EXPOSURE SURFACE:** Well-Drained Flood-Plain; Alteration Zone or Soil
11	**DARK-GRAY CARBONACEOUS MUDSTONE:** Generally planar-laminated; abundant carbonaceous debris including leaf and stick impressions; pyrite, root traces and slickensides common; occurs only in the upper Morrow; units range up to 30ft (9.2m) in thickness.	**FLUVIAL FLOOD-PLAIN:** Swamp or Abandoned Channel-Fill
12	**COAL:** Massive or laminated; commonly pyritic; occurs only in the upper Morrow; generally 1 to 6in (2.5 to 15.2cm) thick, but ranges up to 2ft. (0.6m).	**SWAMP**

Figure 5. Fluvial facies descriptions and depositional environment interpretations for numbered facies shown in Figure 4. This information was used originally by Wheeler and others (1990) to describe the Morrow in southeastern Colorado and southwestern Kansas, but it is also useful in clastic facies interpretations of many other Pennsylvanian meandering river systems in Oklahoma.

themselves, point bars, coal, and migratory distributary channels are primary elements that characterize the upper delta plain. By combining information about those elements with other data, such as from cores or sequential stratigraphic analysis (Fig. 7), a more accurate depositional interpretation can be made. Such a combination of data can lead to a better understanding of sandstone distribution trends and reservoir characteristics in any depositional environment.

The principal reservoirs found within the upper delta plain are fluvial point bars and distributary channel sands. Point bars have been discussed in the section on coastal plain deposits. Distributary channels are more characteristic of the lower delta plain and are discussed in the following section.

Lower Delta Plain

In the rock record, each component of a delta has characteristics that are determined largely by vertical

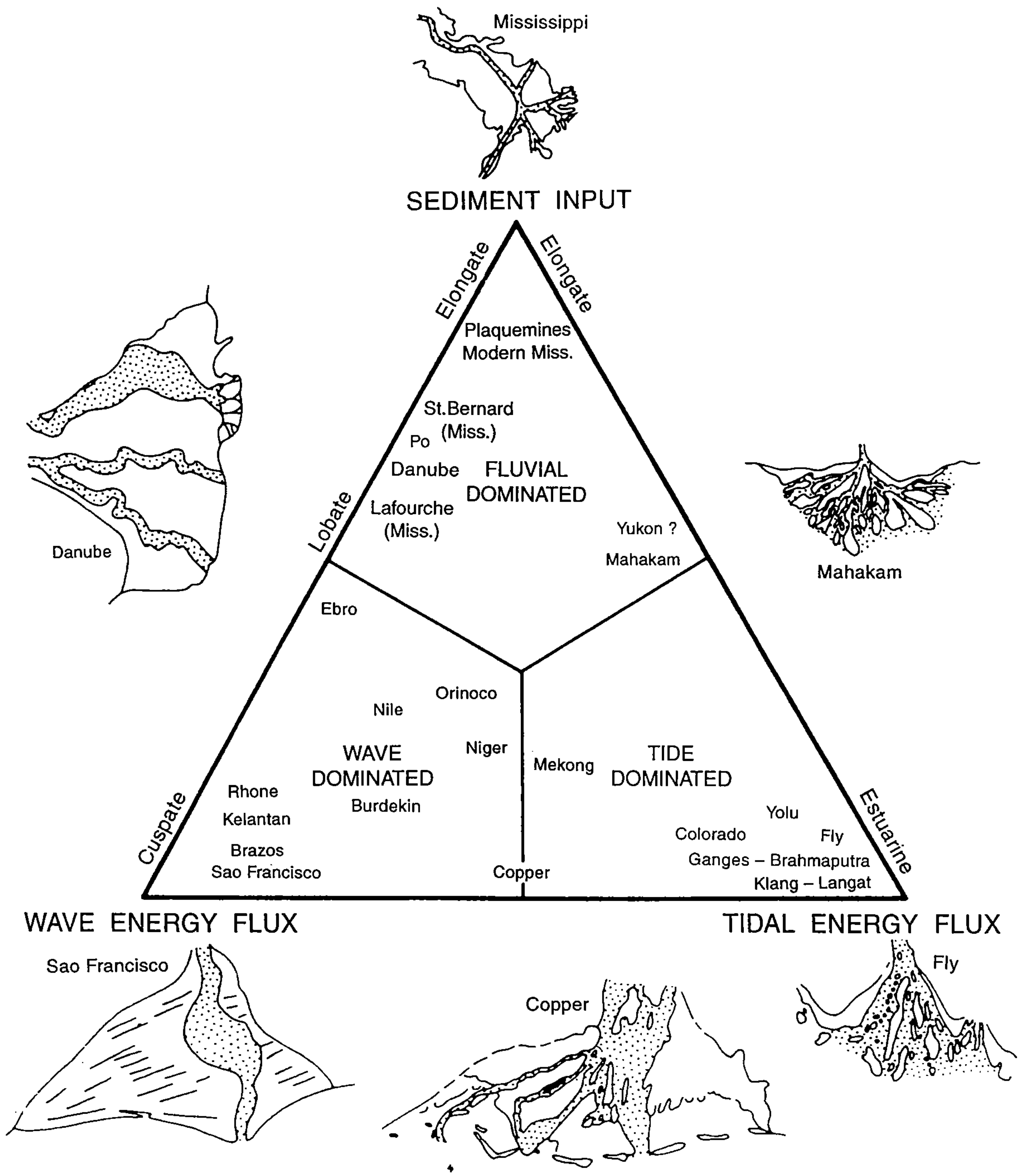

Figure 6. Morphologic and stratigraphic classification of delta systems based on relative intensity of fluvial and marine processes. From Galloway and Hobday (1983).

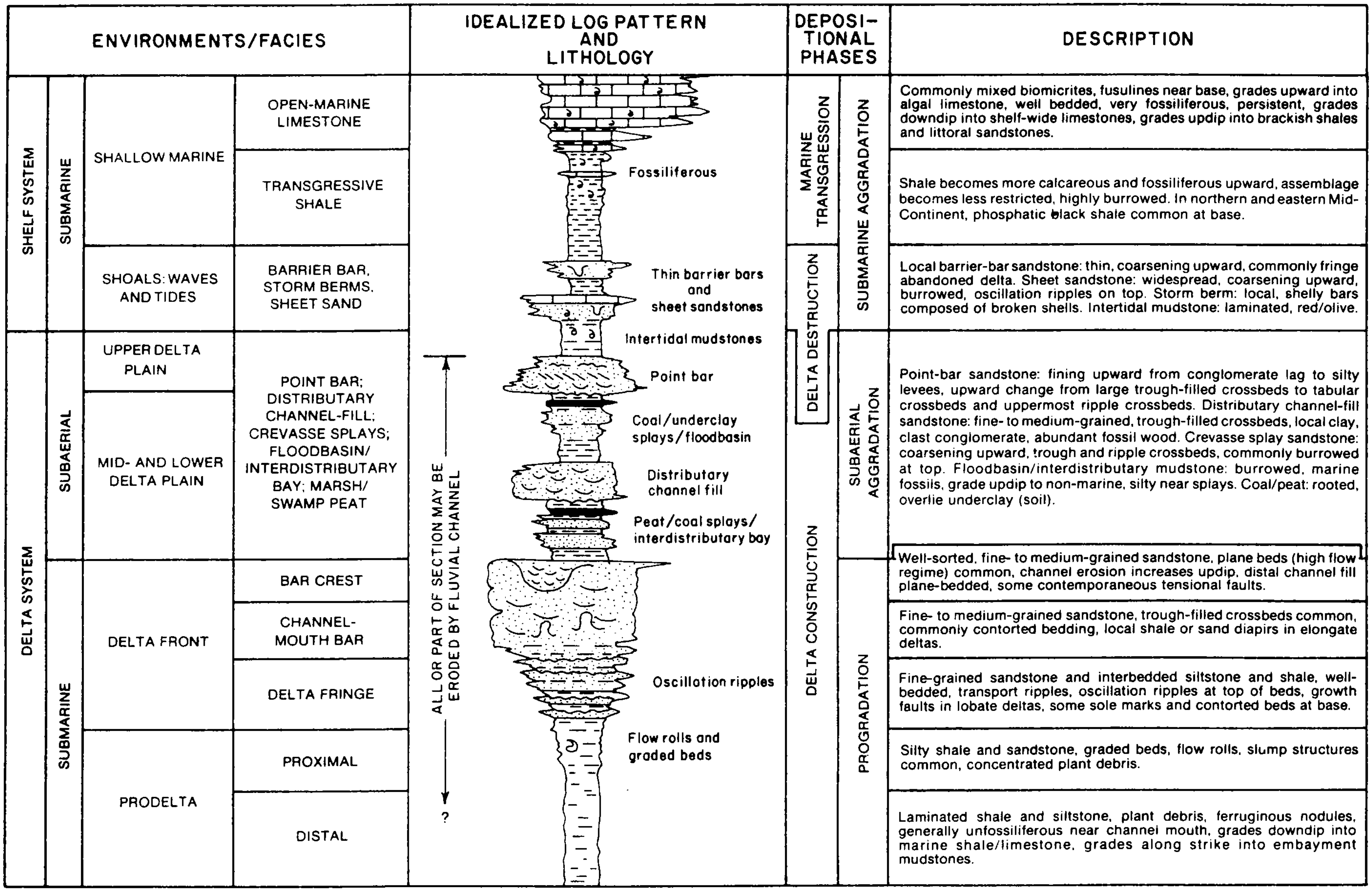

Figure 7. Idealized cratonic delta sequence showing principal depositional phases, idealized electric log pattern, and facies description. From Brown (1979).

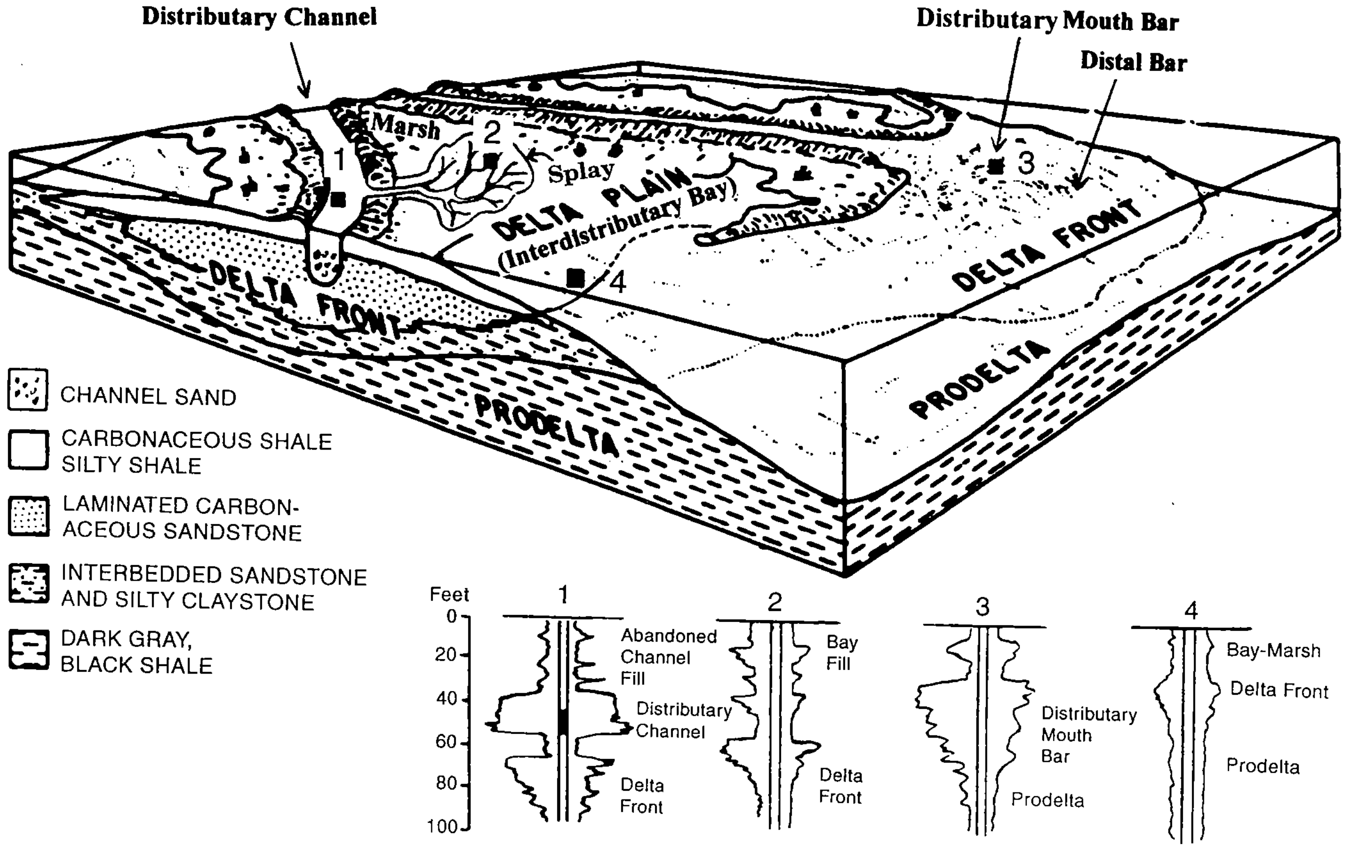

Figure 8. Schematic model of deltaic depositional environments. Idealized electric log responses and inferred facies are shown for locations Nos.1–4. Modified from Brown (1979).

and lateral relationships of rock facies and by faunal content. In the lower delta plain, sediments are influenced highly by marine conditions, which extend from the subaqueous delta front to the landward limit of marine (tidal) influence (Fig. 1). The lower delta plain consists primarily of bay-fill deposits, which occur between or adjacent to major distributaries, and secondarily of distributary-channel deposits. Distributary mouth bars and bar-finger deposits are the principal components of the subaqueous delta front (Fig. 1) and are attached to the lower delta plain. These environments and idealized electric log patterns of associated clastic facies are illustrated in Figure 8.

Lower-delta-plain sediments characteristically overlie delta-front sands and prodelta shale. In the upper reaches of the lower delta plain, coal commonly is associated with marshy areas that are insulated from rapid sedimentation or destructive marine events that typify the lower reaches of the delta plain. Through continued progradation of a delta, the lower delta plain is overlain by upper-delta-plain sediments. Unless the stratigraphic relationship is unconformable, coastal flood-plain sediments commonly are not recognized in succession above delta-plain deposits.

Bay Fill and Splays

Bay-fill sediments originate from several sources including effluent plumes of major distributaries and crevasse splays. Splays, however, are the dominant source of bay-fill sandstone and constitute much of the sediment in fluvial-dominated deltas as shown in Figure 9, which identifies the distribution of principal sand facies in the modern Mississippi River delta. Splays originate during flooding events when sediment is carried through a breach in a distributary levee and distributed into shallow bays through a branching network of smaller channels. The lenticular, fan-shaped deposits (crevasse splays) commonly are 10–40 ft thick and consist of individual sequences of sand and mud that increase in grain size upward. This stratigraphic characteristic is caused by the rapid deposition of suspended sediments ahead of current-induced bed-load transport of coarser sand. However, because splays are driven by fluvial processes, thin distributary-channel deposits also are constituents of every splay. The thickness of a splay deposit commonly is proportional to the depth of the interdistributary bay and the hydraulic advantage between the distributary channel and the receiving area. Thus, splays characteristically are thinner than distributary mouth bars and contain less sand. After abandonment of a crevasse system and subsequent subsidence, the area reverts to a bay environment when marine waters encroach. This entire cycle lasts about 100–150 years (Coleman and Prior, 1982) and may be repeated several times to form a stacked assemblage such as that shown in log signature on Fig-

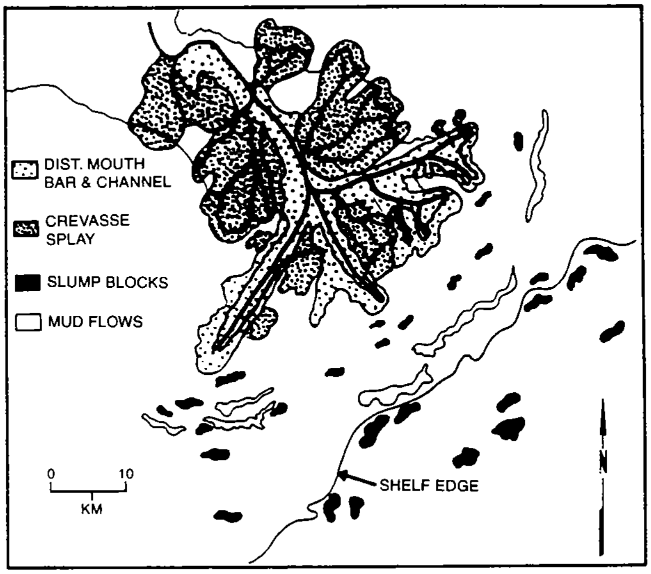

Figure 9. Distribution of principal sand facies in the modern Mississippi River fluvial-dominated delta. From Coleman and Prior (1980).

ure 8. Splay deposits are not considered to be good reservoirs because they contain large amounts of detrital clay, which reduce the effective porosity and permeability of the sandstone beds.

Distributary Channels

Distributary channels are responsible for the primary distribution of nearly all sediments within the lower delta plain. Despite their conspicuous presence, however, they account for a relatively small volume of sediment in the delta, as is illustrated in the schematic model of a delta (Fig. 8) and in the sand facies distribution map of the modern Mississippi River delta (Fig. 9).

Distributary channels typically are incised upon preexisting interdistributary or delta-front sediments. Because they occur at the end of a fluvial transport regime, distributary-channel sands commonly are uniformly fine grained and well sorted. As shown in Figure 3, distributary-channel sand bodies commonly are 10–50 ft thick and 100–1,000 ft wide. Sedimentary structures consist of tabular and trough cross-bedding, clay clasts, and contorted beds (Fig. 10).

The extension of distributary channels into the subaqueous marine environment and the concurrent deposition of levee structures help prevent lateral migration of distributary channels. This stabilizing condition inhibits the formation of point bars that characterize coastal flood-plain meander-belt systems. Since distributary channels occur within, or in close proximity to, marine conditions, they may incorporate marine constituents such as shell fragments, fossils, and glauconite.

Distributary Mouth Bars and Bar Fingers

The progradation of a fluvial-dominated system such as the modern Mississippi River delta is sustained by a series of finger-like sand bodies that are deposited ahead of the main river distributaries. These sand bars are the subaqueous extensions of major distributary channels formed because of confined flow and directed transport of suspended sediments into the open gulf. The tendency of distributary channels and accompanying bar-finger sands to be nonbranching seems to be a result of several factors such as sediment load characteristics of the river, water depth and salinity contrasts in the receiving basin, and river discharge rates. Most investigators believe that bar fingers form when river discharge is confined by the development of subaqueous levees and when sediment transport is aided by the buoying effect of saline water. Conversely, non-directed dispersal of river-mouth sediment in shallow, fresher water bays causes multiple branching distributaries

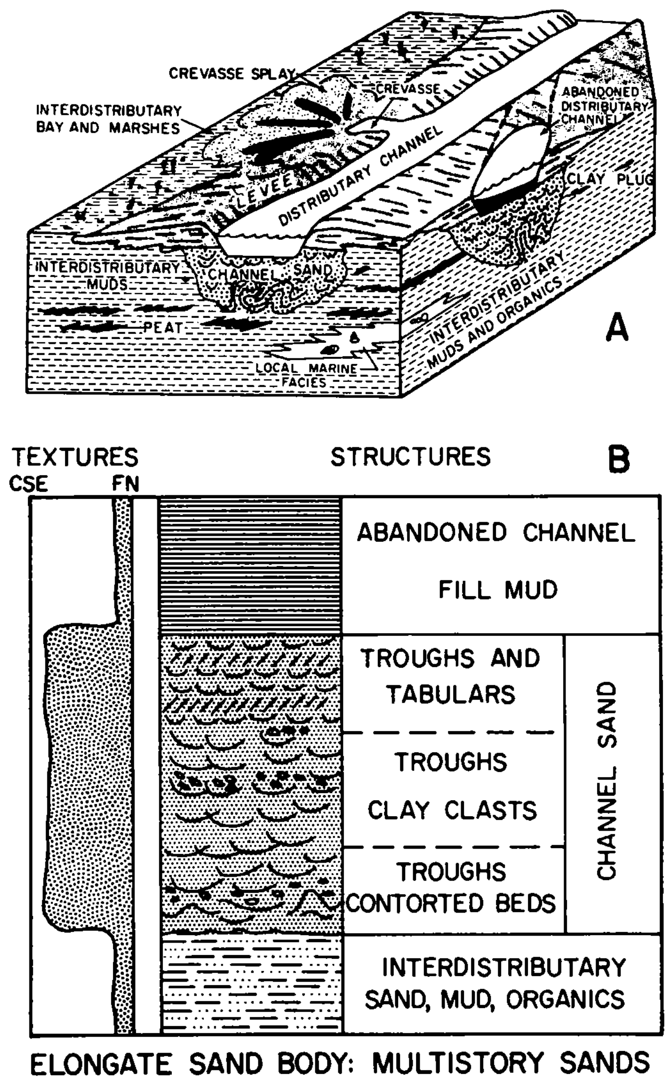

Figure 10. Distributary channel model. (A) Schematic model of channel-fill sands, lower delta plain setting; (B) idealized vertical sequence of distributary channel-fill sandstones. Modified from Brown (1979).

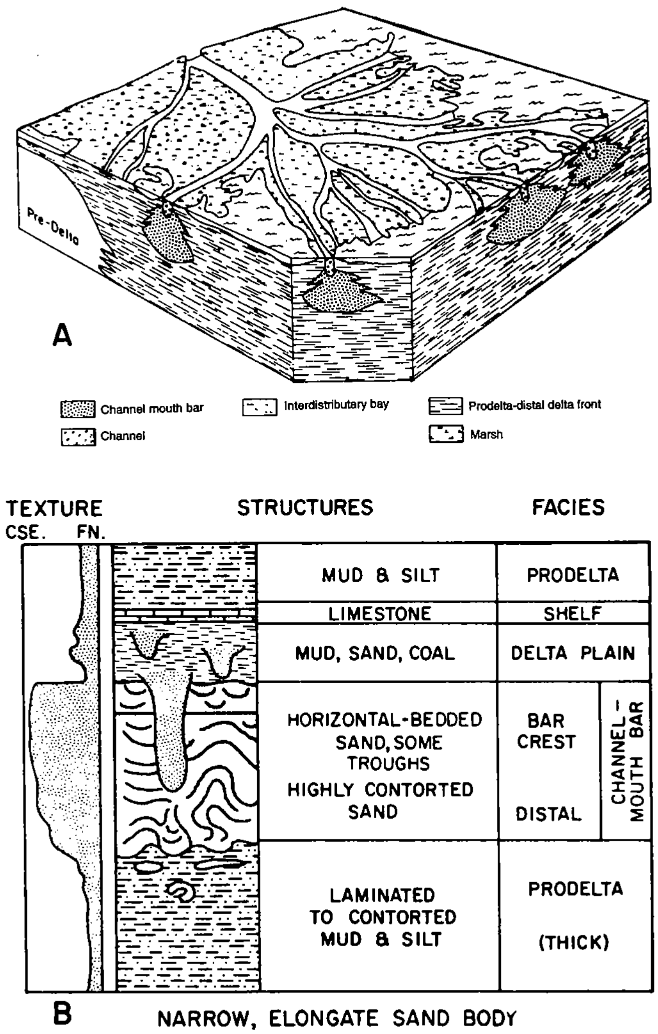

Figure 11. Elongate-delta model. (A) Birdfoot lobe, Holocene Mississippi delta; (B) idealized vertical sequence of a distributary mouth bar and associated deposits in an elongate delta. Modified from Brown (1979).

such as those that characterize other parts of the Mississippi River delta. In the latter case, distributary mouth bars are lobate rather than elongate and become progressively finer grained seaward.

Distributary mouth bars have the highest rate of deposition in the subaqueous portion of a delta. They are composed of the same sediments that constitute splays and distributary channels in the lower delta plain but are distinctly different morphologically. In the upper portion of the bar (bar crest), sands are reworked continually by wave and storm currents to produce some of the best and most laterally extensive reservoirs in delta environments. Large-scale sedimentary structures, such as high-angle and trough cross-bedding, are the result of this energy. The rapid clastic buildup also causes soft-sediment instability in the form of mud diapirs and contorted beds. These types of sedimentary structures are illustrated in Figure 11.

Distributary mouth bars make up most of the delta front and may be >200 ft thick, but commonly they are ~100 ft thick. Redistribution of the same sand by marine currents may promote the deposition of distal bars; in the event of eustatic sea level rise (transgression), barrier islands may form. Characteristically, distributary mouth bars have serrated, coarsening-upward logs and textural profiles (Figs. 8,11). In places, the facies are subdivided into a distal bar facies (lower, shaly part of profile) and a proximal bar facies (upper, sandy part of profile). The coarsening-upward stratigraphic profile is caused by the dispersal of buoyed sediment and progressive deposition of coarse-grained sediment on top of previously dispersed fine-grained sediment. Additionally, carbonaceous debris from continental sources commonly is interbedded with the sand. Distributary mouth bars commonly overlie prodelta muds and provide a relatively stable foundation over which delta-plain sediments are deposited during regressive depositional periods.

NOTE TO READERS

Industry participation in the FDD program is heartily encouraged. We welcome any comments that you may have about the content of this publication and about the ongoing needs of industry with respect to information and technology relating to FDD reservoirs. Please contact Charles J. Mankin at the Oklahoma Geological Survey, 100 East Boyd, Room N-131, Norman, OK 73019 with your questions or comments.

PART II

The Bartlesville Play

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with contributions from
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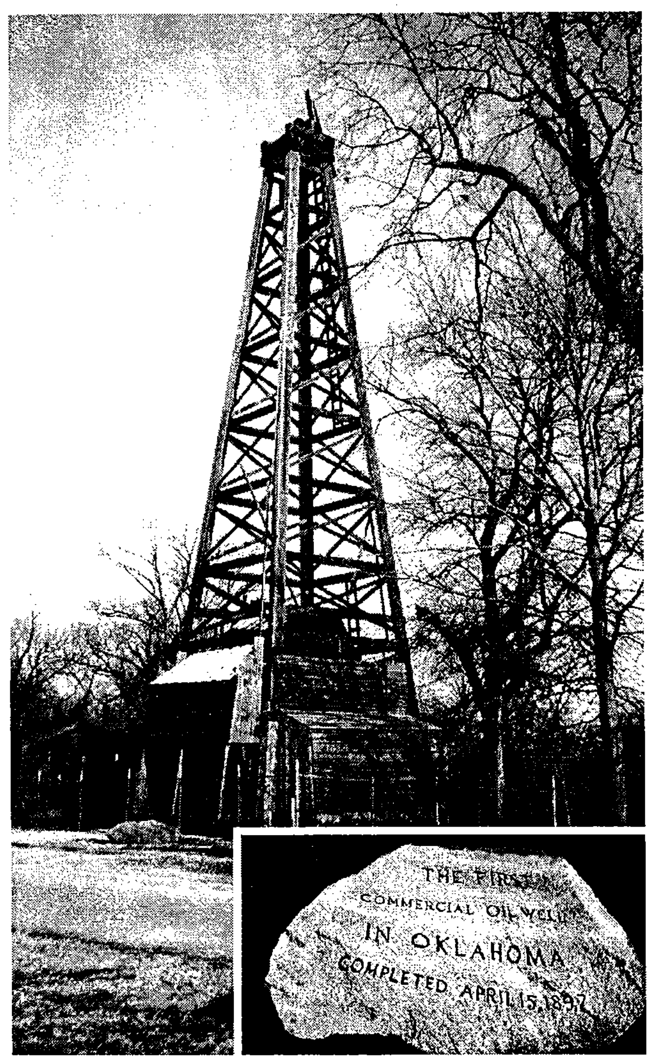
INTRODUCTION

Oil reservoirs in the Bartlesville sandstone were the foundation for the preeminence of Oklahoma as an oil-producing State. On April 15, 1897, Cudahy Oil Co. No. 1 Nellie Johnstone, a Bartlesville sand oil well, opened the first commercial oil field in Oklahoma. Although oil was found in wells drilled earlier in northeastern Oklahoma, the Bartlesville field discovery well in Washington County (Fig. 12) is recognized as the first commercial oil well in Oklahoma (Taylor and Branan, 1964, p. 10). Subsequent discoveries of Bartlesville oil fields made Oklahoma the leading oil-producing state from Statehood in 1907 until 1923.

During this time of rapid development of Bartlesville oil fields in northeastern Oklahoma, Tulsa emerged as the "Oil Capitol of the World." Oklahoma oil companies, such as Phillips Oil Co., Indian Territory Illuminating Oil Co. (Cities Service), and Sinclair Oil and Gas Co., were created and grew to major oil-company status (Franks, 1980) largely because of their successes in developing the Bartlesville reservoirs.

The Bartlesville play in Oklahoma is situated on the Cherokee platform of northeastern Oklahoma (Fig. 13). The play is limited on the east at the outcrop, where the Bartlesville surface equivalent is the Bluejacket Sandstone, and on the south by its outcrop along the front of the Ouachita Mountains uplift. To the west the play is bounded by the limit of deposition of sand or onlap of the Bartlesville interval around the Nemaha uplift. Marine shales, scattered shallow-marine sands, and shoreface-sand deposits are present from the Nemaha uplift and Nemaha fault zone westward onto the Anadarko shelf. Southwest of the Cherokee platform, the Bartlesville interval either was not deposited or was removed by erosion on the Oklahoma City uplift. West of the central Oklahoma fault zone, only marine deposits occupy the Bartlesville interval of the Anadarko basin and are outside the play area.

Four plates are included in this study of the Bartlesville play and are in the envelope with this publication.



Photograph by Robert A. Northcutt

Figure 12. Cudahy Oil Co. No. 1 Nellie Johnstone, NE¼ sec. 12, T. 26 N., R. 12 E., was completed as a Bartlesville sand oil producer at 1,320 ft on April 15, 1897. The wooden derrick and cable-tool drilling rig are replicas built through financing by private citizens. This structure is at the site of the original rig in what is now Johnstone Park in Bartlesville, Oklahoma.

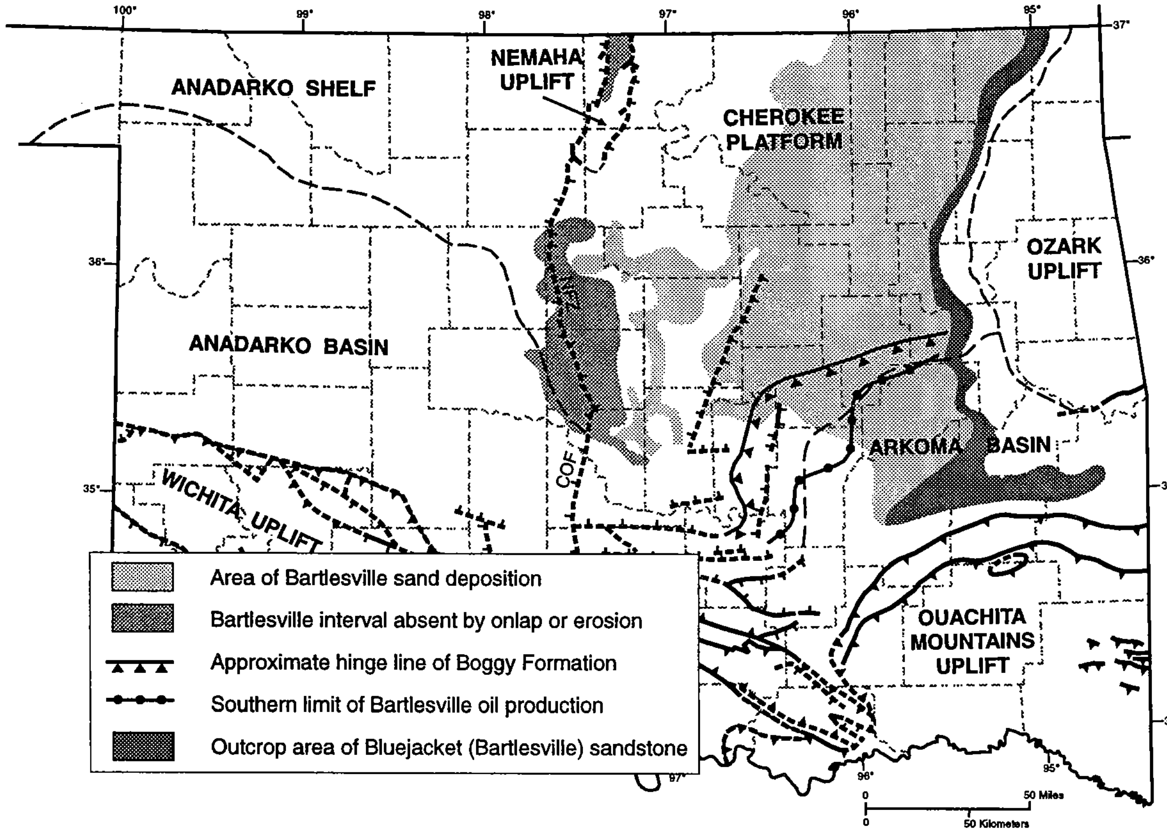


Figure 13. The Bartlesville oil play in Oklahoma. The Bartlesville play lies on the Cherokee platform in northeastern Oklahoma and extends southward to the southern limit of Bartlesville oil production, shown on the map. The play is limited on the east by the outcrop of the Bluejacket Sandstone (Bartlesville equivalent) and on the west and southwest by the limit of Bartlesville sand deposition; it extends northward into Kansas. *NFZ* = Nemaha fault zone; *COF* = central Oklahoma fault zone.

Plate 1, "Map of the Bartlesville Sandstone Play Areas," shows the Bartlesville fluvial-dominated deltaic (FDD) system in northeastern Oklahoma, the limits of sandstone deposition, the geologic provinces, and the positions of the regional stratigraphic cross sections.

Plate 2, "Regional Stratigraphic Cross Sections *A–A′*, *B–B′*, and *C–C′*, Anadarko Shelf, Nemaha Uplift, Cherokee Platform, and Arkoma Basin," are geophysical-log cross sections hung on the Pink lime stratigraphic datum. Cross section *A–A′*, from northwest to southeast, begins on the Anadarko shelf, crosses the Nemaha uplift and Cherokee platform, and continues to the Arkoma basin on the southeast. Cross section *B–B′*, west to east, begins on the lower Anadarko shelf, crosses the Nemaha fault zone, and continues east across the main Bartlesville sand area on the Cherokee platform. Cross section *C–C′*, west to east, begins in the eastern Anadarko basin, crosses the central Oklahoma fault zone south of the Oklahoma City uplift, extends across the southern part of the Cherokee platform, and ends in the Arkoma basin.

Plate 3, "Map of the Fields with Oil Production from the Bartlesville Sandstone," shows 183 fields having current (1979–96) Bartlesville oil production listed in the Natural Resources Information System (NRIS) data files at the University of Oklahoma's Geo Information Systems (GeoSystems). All the fields are keyed by location and field name. Producing leases with Bartlesville production within the fields, and unassigned producing leases, are indicated by shaded patterns on the map.

Plate 4, "Index to Selected References Used for Bartlesville Sandstone Mapping," shows outlines of the areas covered by the selected references used in construction of the Bartlesville sand map (Pl. 1).

Available sources of information used in identifying Bartlesville FDD areas include published scientific literature, unpublished theses, published articles (some obscure) from local geological societies, and investigations by consultants and the authors. A list of cited and selected references is included as part of this publication. Two Bartlesville sandstone cores are presented in Appendix 5. One core recovered deposits from a fluvial channel, and the other, from a marine bar. These cores will be available for examination by workshop participants. Appendix 6 is a stratigraphic column for the Fluvial-Dominated Deltaic Reservoirs project, showing the combined formal and informal nomenclature used in each of the FDD plays.

BARTLESVILLE STRATIGRAPHY

The formal stratigraphic nomenclature of the rocks deposited during Desmoinesian (Middle Pennsylvanian) time has been in use for some time. *Bluejacket Sandstone* is the formal name for the sandstone member of the Boggy Formation called the *Bartlesville* in the subsurface. It was named by Ohern (1914, p. 28) for the town of Bluejacket in Craig County, Oklahoma, and he gave as the type locality the hills west of the town. Howe (1951, p. 2090), after investigating, defined the type locality as "the NE¼NE¼ of sec. 25, T. 27 N., R. 20 E., along the road from Bluejacket west to Pyramid Corners, in the east slope of Timbered Hill, on Oklahoma Highway 25, in Craig County, Oklahoma." This stated type locality was later found to be in error; the correct location is the NW¼NE¼ sec. 25, T. 27 N., R. 20 E. (Hemish, 1989). (See Plate 1 for location and discussion.) For more detailed discussions of this subject, see Hemish (1989, 1997).

Figure 14 is a chart that shows the formal stratigraphic nomenclature for most of the Desmoinesian Series and includes the commonly accepted informal subsurface names used in northeastern Oklahoma, including the Bartlesville play area. This formal nomenclature generally is not used by operators for subsurface equivalents. A few formal names, however, such as *Verdigris Limestone* and *Inola Limestone* have been adopted for subsurface terminology. The names given by various operators to the rocks they recovered from drilled wells are the names used by others in the area or names they have used elsewhere. This practice has, in the past, created nomenclatures particular to specific areas or, as in the case of the term *Glenn sand,* to only one field. Problems of subsurface correlation of producing strata arose with the advent of petroleum geology in the 1910s, and these problems intensified with the expansion of geological exploration and development during the late teens and into the 1920s. Later workers in northeastern Oklahoma helped to correlate a large number of the informal names with their formal surface equivalents. Among the most helpful studies are those by Jordan (1957), Cole (1965, 1970), Berg (1966, 1969), Bissell (1984), the Tulsa Geological Society (1984–89), and Hemish (1989, 1993, 1997).

The Bartlesville sand occurs in the interval of the Middle Pennsylvanian (Desmoinesian) Boggy Formation between the Inola Limestone above and the Brown limes of the Savanna Formation below. The Bartlesville sand was named for the city of Bartlesville, Washington County. The discovery well of the Bartlesville field was Cudahy Oil Co. No. 1 Nellie Johnstone, NE¼NE¼NE¼ sec. 12, T. 26 N., R. 12 E., in which the Bartlesville sandstone was encountered at 1,303 ft. Here, the Bartlesville sandstone is correlative with the Bluejacket Sandstone, a member of the Boggy Formation. The Bartlesville sand is also called *Glenn sand* (for the Ada Glenn farm at Glennpool field, Creek County; the name *Glenn* is also applied to this sand in fields in Creek, Tulsa, and Okmulgee Counties. The name *Salt sand* is also applied to the Bartlesville sand in the Okmulgee area (Jordan, 1957, p. 14, 76, 169). Figure 15 is a reference electric log for the Bartlesville play that

SYSTEM	SERIES	GROUP		FORMAL SURFACE NAMES OF FORMATIONS OR MEMBERS		FORMAL & INFORMAL SUBSURFACE NAMES
PENNSYLVANIAN	DESMOINESIAN	Marmaton	Ft. Scott Limestone	Higginsville Limestone	Oswego lime	"Wheeler sand"
				Little Osage Shale		
				Blackjack Creek Ls.		
		Cabaniss	Senora Formation	Excello Shale		
				Breezy Hill Ls.		
				Lagonda Sandstone	Cherokee group	Prue sand
				Verdigris Limestone		Verdigris Limestone
				Croweburg coal		Henryetta coal
				Oowala Sandstone		Upper Skinner sand
				Mineral coal		Morris coal
				Chelsea Sandstone		Middle Skinner sand Lower Skinner sand
				Tiawah Limestone		Pink lime
		Krebs	Boggy Formation	Taft Sandstone		Red Fork sand Burbank sand Earlsboro sand
				Inola Limestone		Inola Limestone
				Bluejacket Sandstone		Bartlesville sand Glenn sand Salt sand
			Savanna Fm.	Doneley Limestone		Brown lime
				Sam Creek Ls.		
				Spaniard Limestone		
			McAlester Formation	Keota Sandstone		Upper Booch sand
				Tamaha Sandstone		
				Cameron Sandstone		Taneha sand
				Lequire Sandstone		Tucker sand
				Warner Sandstone		Lower Booch sand
				McCurtain Shale		
			Hartshorne Formation	Hartshorne Sandstone		Hartshorne sand

Figure 14. Stratigraphic nomenclature of the Krebs, Cabaniss, and lower Marmaton Groups of the Desmoinesian Series, showing the formal surface names and the commonly accepted subsurface names used in northeastern Oklahoma. Modified from Scruton (1950), Oakes (1953), Jordan (1957), Branson (1968), Cole (1967, 1970), Berg (1966, 1969), Chandler (1977), Bennison (1979), Bissell (1984), Lojek (1984), Tulsa Geological Society (1984–89), and Hemish (1989, 1993, 1997).

shows both formal and informal nomenclatures for the lower Marmaton, Cabaniss, and Krebs Groups. The reference log is also log 10 on Plate 2, cross section *B–B′*.

The top of the Savanna Formation is defined as the base of the Bluejacket Sandstone. This contact is generally the base of an incised channel deposit, which typically has scoured down into the lower Savanna interval of the Doneley, Sam Creek, and Spaniard Limestones—also called *Brown limes* in subsurface terminology. At the southern extent of the play area (Pl. 1), however, the contact of the Bluejacket (Bartlesville) Sandstone appears gradational with the underlying marine shale, as shown in logs 7 and 8 in cross section *C–C′* (Pl. 2). In

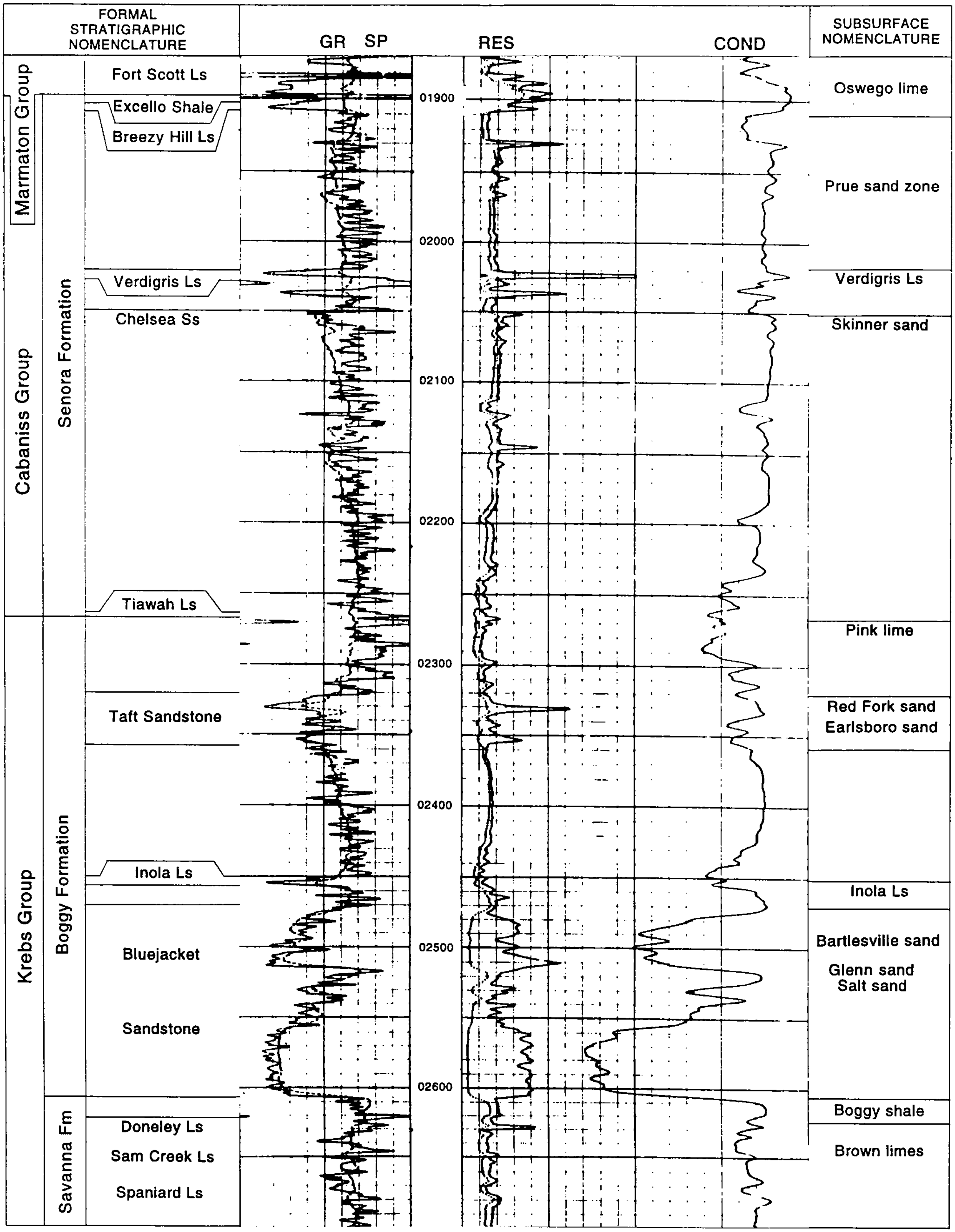


Figure 15. Reference log for the Bartlesville play area, Ram Operating Corp. No. 10 Rowland Creek, NE¼SW¼NE¼ sec. 35, T. 17 N., R. 9 E., Creek County, Oklahoma. Total depth is 3,075 ft; completed July 13, 1982. It is also shown as well 10 on Plate 2, cross section *B–B′*. Log profiles shown are gamma ray (*GR*), spontaneous potential (*SP*), resistivity (*RES*), and conductivity (*COND*).

other areas, logs exhibit this same relationship, leaving the observer to wonder if the sand at the top of the shale section is Bluejacket (Bartlesville) or an older deposit. Some interpretations consider these sands to be distributary-mouth bars deposited by the Bluejacket (Bartlesville) at the delta front. This relationship warrants additional investigation.

REGIONAL GEOLOGY

Basement rocks of Oklahoma are igneous and metamorphic rocks of Precambrian and Cambrian age that underlie the entire State. Thick sequences of marine strata were deposited on the partially eroded basement surfaces during the Late Cambrian through the Mississippian. Shallow seas moved across Oklahoma from the east or southeast during the Late Cambrian, depositing basal Reagan sand in the southeastern part of the State. The overlying Late Cambrian and Ordovician formations—Arbuckle Group limestones and dolomites, Simpson Group sandstones and shales, and Viola Group limestones—were deposited mostly statewide, with the thickest amounts in the Anadarko basin; but in the Ouachita trough, thick sequences of shale, sandstone, and chert of equivalent age were deposited.

During the Silurian and Devonian Periods, the Sylvan Shale and the Hunton Group limestones were deposited throughout Oklahoma, again except in the Ouachita trough, where deposition of equivalent-age shale, sandstone, and chert continued. After deposition of the Hunton Group, a conspicuous, widespread area of uplift and erosion—the pre-Woodford unconformity—removed up to 1,000 ft of strata. Following uplift and erosion at the end of Hunton time, the Late Devonian to Early Mississippian Woodford Shale was deposited generally on top of Silurian and Ordovician rocks. During the Mississippian Period, shallow seas covered the State. Limestone and interbedded chert were deposited during Early Mississippian time in the Anadarko basin, while chert deposition (Arkansas Novaculite) continued in the Ouachita trough. Shale and sandstone were the dominant deposits during Late Mississippian time, with great thicknesses in the Ouachita trough and in the Anadarko and Ardmore basins of southern Oklahoma.

At the close of Mississippian time, a period of active orogeny and basinal subsidence, commonly known as the Wichita orogeny, occurred throughout Oklahoma. This Early Pennsylvanian uplift and erosion removed much of the Mississippian strata in central and northeastern Oklahoma and exposed older rocks on the emergent Ozark uplift. A large, north-trending arch extended from southern through central Oklahoma and northward into Kansas. This emergent arch separated the Anadarko basin on the west from the Ouachita trough and Cherokee platform on the east. A trend of fault-block structures formed along the axis of this arch, now known as the Nemaha uplift and the Nemaha fault zone.

The frontal fold belt was forming and, with northward thrusting of the Ouachitas, the basinal downwarp shifted northward to the Arkoma basin. Early Pennsylvanian sediments (Atokan and Morrowan) were deposited in the Arkoma basin and on the stable Cherokee platform to the north. By the end of Morrowan time, the Ouachita trough had filled with sediment and the Ouachita Mountains were becoming emergent.

The above discussion of geologic history was summarized from Johnson (1971), to which the reader is directed for additional information, including a series of paleogeographic and other maps.

At the beginning of Desmoinesian sedimentation in the Arkoma basin, sands of the Hartshorne Formation prograded from Arkansas westward into Oklahoma, forming a deltaic system along the axis of the Arkoma basin (Houseknecht, 1984). Following Hartshorne deposition, sands of the McAlester Formation were deposited from a northern source as a sequence of five deltaic episodes prograding southward across the Cherokee platform into the Arkoma basin. A study of these fluvial-dominated deltaic sandstones by Northcutt and others was published in 1995 by the Oklahoma Geological Survey as *Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: the Booch Play* (Special Publication 95-3). A transgressive period of deposition of marine shales and thin limestones of the Savanna Formation (Brown limes) onlapped the McAlester Formation and older strata on the Cherokee platform. Savanna deposition reached its maximum western extent east of the Nemaha uplift and Nemaha fault zone, whereas on the eastern side of the Cherokee platform the Savanna was exposed in outcrop west of the Ozark uplift.

The Boggy Formation overlies the Savanna Formation and contains the Bluejacket Sandstone Member, whose subsurface equivalent is the Bartlesville sandstone, the subject of this study. The Bartlesville play is situated primarily on the Cherokee platform between the outcrop on the east and the limit of sand deposition to the west and southwest. South of the Cherokee platform, the Bartlesville play is limited by its outcrop in the Arkoma basin (Fig. 13).

The Bartlesville sand increases in depth from the outcrop on the east to ~2,400 ft at the western sand limit in southeastern Osage County in T. 22 N., R. 7 E. The depth to the Bartlesville sand increases to ~4,800 ft in the lower Anadarko shelf area, as shown in the western part of regional cross section *B–B′* (Pl. 2). Along the line of cross section *C–C′* (Pl. 2), the depth to the Bartlesville sand increases from ~700 ft on the east to ~5,600 ft on the upthrown (east) side of the central Oklahoma fault zone. On the downthrown (west) side of the central Oklahoma fault zone, the depth increases rapidly to ~8,200 ft. To the north near the city of Bartlesville, the sand is ~1,300 ft deep and increases in depth southward to ~1,700 ft in the Tulsa vicinity. At the southeast end of cross section *A–A′* (Pl. 2), which is near the outcrop and frontal thrust zone of the Ouachita uplift, the Bartlesville is only about 700 ft deep.

Figure 16 is a structure map that depicts the top of the Bartlesville sand. The map was constructed from well records in the NRIS data base that are maintained on a mainframe computer but can be accessed at the Oklahoma Geological Survey's NRIS facility. These data can be imported to personal computers, and by using routine programs available for personal computers, they can be used to produce a final map. Because of the high well density in such a large area, only data from wells identified as Bartlesville sand producers were used in constructing this map.

The regional dip of the Bartlesville sand zone is to the west from the Ozark uplift in northeastern Oklahoma. The dip is ~25 ft/mi across the northern part of the Cherokee platform and increases slightly near the Nemaha uplift–Nemaha fault zone. West of Tulsa, the dip is westward ~40 ft/mi to the 1,500-ft subsea datum, where the contours reflect the structural uplift along

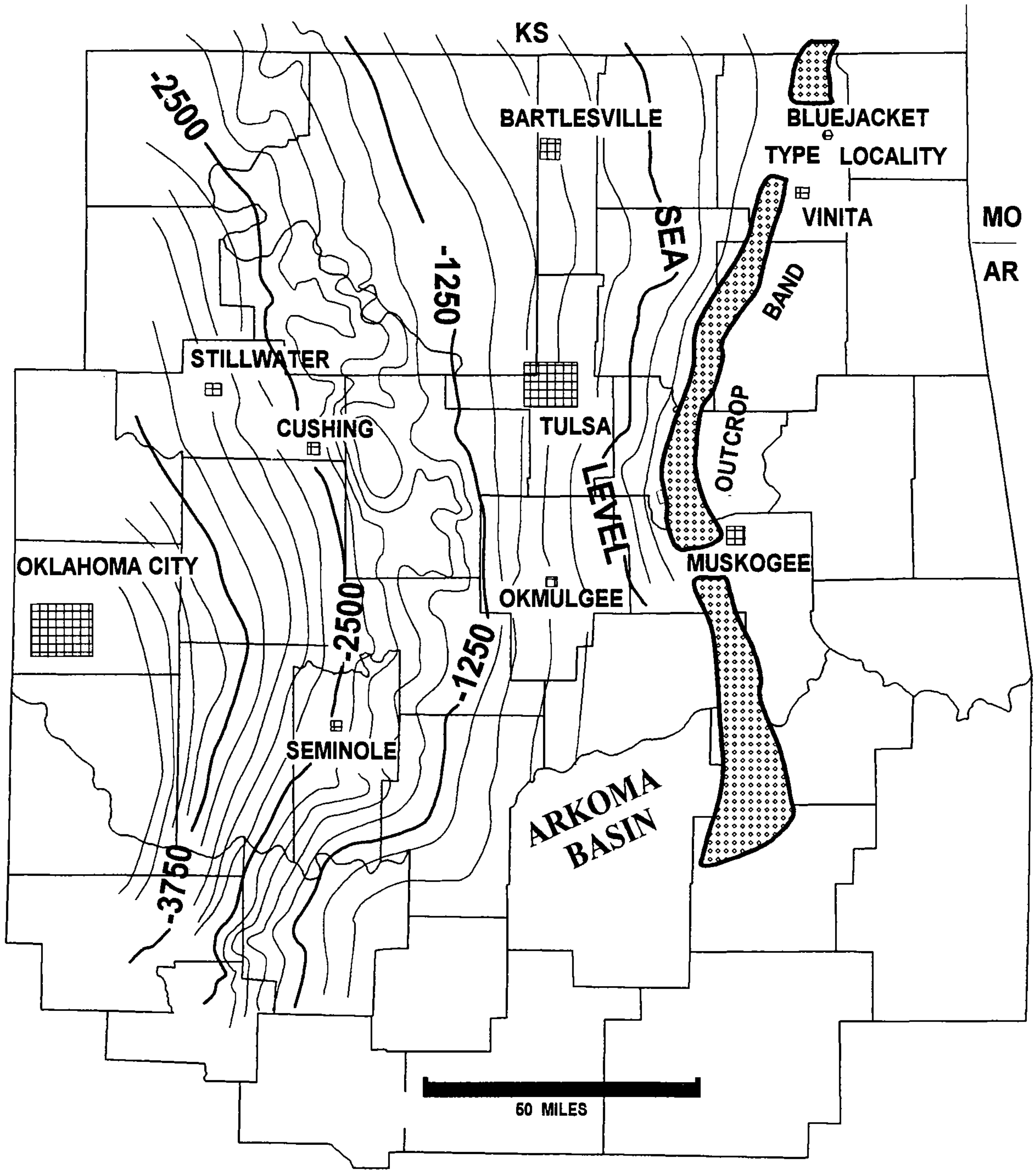


Figure 16. Regional structure map of the Bartlesville sand, covering the major part of the Bartlesville play area in northeastern Oklahoma. Noted on the map are the type locality and outcrop band of the Bluejacket (Bartlesville) Sandstone. Contour interval is 250 ft. Computer-aided drafting (CAD), using a selected well grid from the NRIS data available at the OGS NRIS facility. Constructed by Carlyle Hinshaw, Geo Information Systems, Norman, Oklahoma.

the axis of the Cushing–Drumright anticline. West of Cushing, the dip steepens to ~50 ft/mi to the edge of the area shown on the map. In the Seminole vicinity, the dip is to the west at ~65 ft/mi, and south of Seminole the dip increases to >100 ft/mi as the rocks plunge into the Anadarko basin.

The thickness of the Bartlesville interval is generally controlled by intensity and duration (time) of depositional processes and the spatial relationship to structural provinces; hence this interval thickens basinward of the Cherokee platform and away from the Nemaha uplift. The sand is up to 200 ft thick in places along the main transport direction. Local interval-thickness variations are large and are due mainly to variations in the thickness of the sand bodies. The Bartlesville interval generally thins from the southeast to the northwest, where it onlaps older strata. It is absent over some of the structural features in northeastern Oklahoma, either by nondeposition or erosion. It is absent on the Nemaha uplift in northwestern Kay County and over a large area associated with the Oklahoma City uplift (Pl. 1).

BARTLESVILLE DEPOSITIONAL ENVIRONMENTS: CONSIDERATIONS

In the exploration for and development of petroleum in the Bartlesville sand, correct interpretation of depositional environments is critical to mapping the trends of reservoir sands. Reservoir characteristics such as sand limits, thickness, clay content, and reservoir quality are influenced by depositional environment. Inferences about subsurface depositional environments commonly are made from well cores, well cuttings, and geophysical well logs. In reality, however, few cores are available for examination, and well cuttings seldom are helpful unless they demonstrate marine indicators, which limit their usefulness when working with deltaic environments. Thus, well logs are the main interpretive tools in subsurface work. Many workers have correlated typical profiles of gamma-ray, spontaneous-potential, and resistivity curves to the various depositional environments drilled in wells. Figure 7 (p. 9, this volume) shows generalized log profiles for principal depositional phases of a deltaic sequence. Workers in the FDD program have found from experience that gamma-ray profiles from density logs are more reliable as indicators of depositional environments than other log profiles. In a mature play such as the Bartlesville sand play, however, spontaneous-potential curves generally are the only ones available and must be utilized in interpreting depositional environments.

BARTLESVILLE FDD DEPOSITIONAL MODEL

Bartlesville Sandstone Distribution

Figure 17 is a map by Weirich (1953) that shows distribution of the Bartlesville sand. This map covers both northeastern Oklahoma and eastern Kansas. Weirich reported that the Precambrian granite that was exposed over an area of about 1,000 mi² on the Nemaha anticline and the broad region of granite that was exposed on the Siouxia uplift farther north were plausible sources for the Bartlesville sand that was deposited on the Cherokee platform.

Plate 1 shows the distribution of the Bartlesville sand in northeastern Oklahoma. This map was constructed from information found in the selected references listed on Plate 4. Sand thicknesses >100 ft are shown by a darker pattern, whereas thicknesses <100 ft, generally <50 ft, are shown by a lighter pattern. Areas where sands are thinner than 20 ft are labeled. The thick sand trends are interpreted as the principal transport direction from north to south. At the hinge line of the Boggy Formation, the direction veers to the southeast toward the outcrops in the Arkoma basin. These thick sandstones are stacked channel sequences, also called amalgamated channels. They are incised into the country rock of marine shale or Brown limes of the Savanna Formation (wells 10 and 11, cross section *B–B′*, Pl. 2). Thinner sands <100 ft thick are also incised channel sequences but generally represent individual channels with some layering. They probably also represent either older channel systems or distributaries from the main channel system, as indicated by wells 7 and 8, cross section *A–A′* (Pl. 2).

East of the main fluvial channel through Washington and Osage Counties is an area of sand extending into Nowata County that was noted as 25–50 ft thick. This sand lobe is probably an overbank- or crevasse-splay deposit formed during a time of severe flooding. Logs in this area exhibit both upward-fining sands with a sharp base, characteristic of incised channels, and upward-coarsening sands with a gradational base, characteristic of distributary bars.

An area of sand extends west from the main sand system in eastern Payne County. The log character of the Bartlesville sand in well 8, cross section *B–B′* (Pl. 2), may represent lower-delta-plain or delta-front distributary bars. Well 7, farther west, represents more marine or distal characteristics from the delta front. Farther west are areas of sand near the exposed area associated with the Oklahoma City uplift. These sands are probably shallow-marine bars, shoreface sands, and channels draining from the uplift filled with tide-deposited marine sand.

Visher and others (1971) published a map that interprets depositional environments of the Bartlesville sandstone, using electric-log profiles of both spontaneous-potential (SP) and resistivity curves (Fig. 18). Not all resistivity curves show the same textural profile as the SP curves, owing to differences in fluid content, sand sorting, and cementation. Therefore, care should be taken when using resistivity curves in interpreting depositional environments. The study by Visher and others (1971) presented a thorough study of the Bartlesville sand over the entire delta, and we drew on their study in constructing Plate 1. Their study indicates that the source for Bartlesville sand deposition

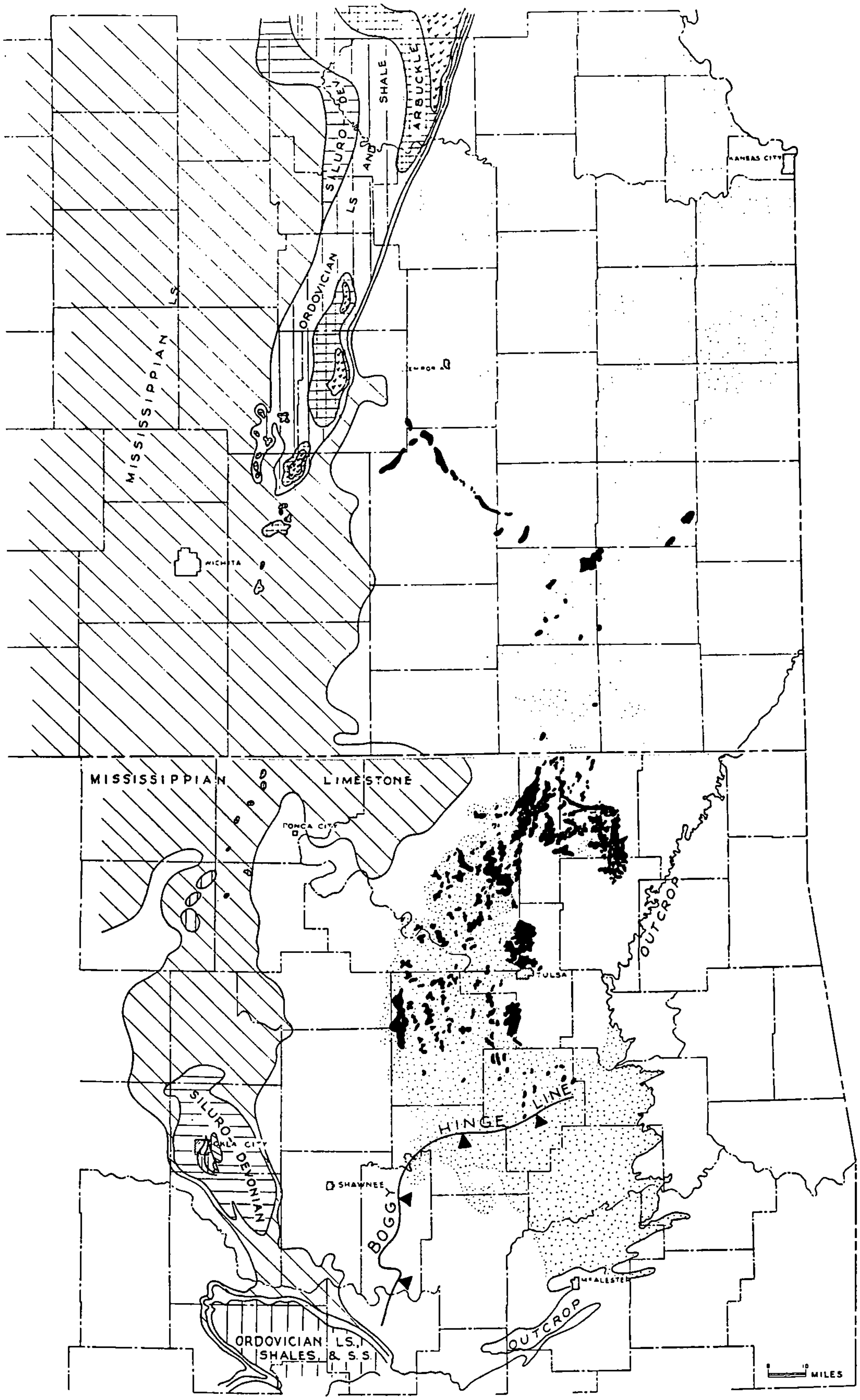


Figure 17. Map of Bartlesville sand (dot pattern) in Oklahoma and Kansas. Oil fields are shown in black. The sand contains no oil southeast of the Boggy (middle Cherokee) hinge line, although ample anticlinal and well-defined stratigraphic traps occur. Exposures of the landmass to the west were largely Paleozoic limestones during Bartlesville time. Precambrian granite is indicated by checkmarks. From Weirich (1953, fig. 5, p. 2040–2041).

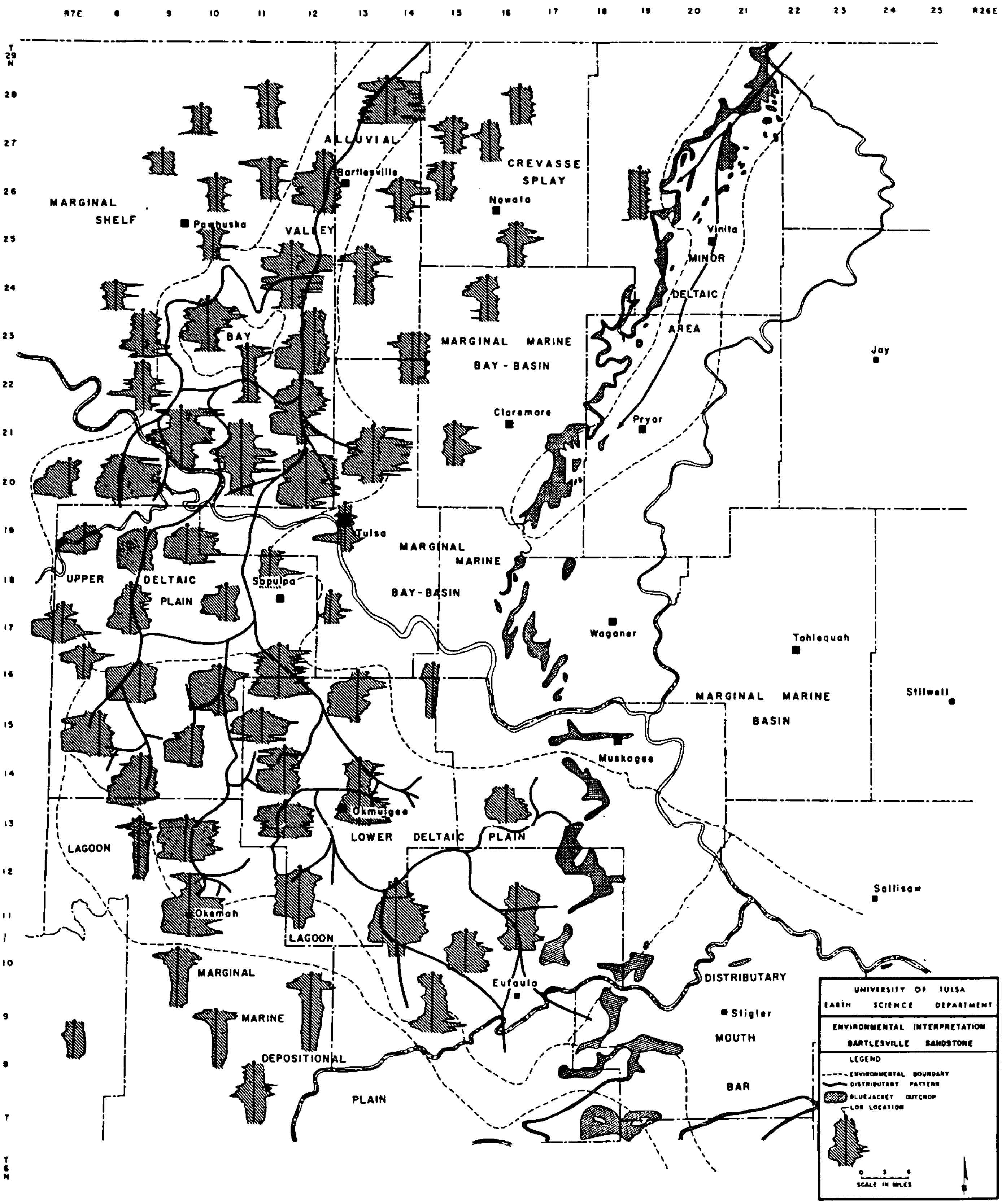


Figure 18. Electric-log patterns and environmental reconstruction of deltaic elements. Environmental interpretations based on sandstone geometry, vertical sequences, sedimentary structures, textures, and clay mineralogy. From Visher and others (1971, fig. 12, p. 1224–1225).

TABLE 1. – Earliest Fields of Northeastern Oklahoma Producing from Bartlesville Sands[a]

Field name[b]	Discovery year[b]	Depth to Bartlesville sand (ft)[b]	Bartlesville sand initial oil production (bbl)[b]	Field oil production 1979–96 (bbl)[c]
Bartlesville–Dewey (includes Dewey, 1904; Weber, 1906; Copan, 1907)	1897	1,265	100-500	9,587,964
Coody's Bluff	1904	850	25–125	27,299
Alluwe	1904	400–450	25–500	278,334
Chelsea	1904 (1889)	463	20–100	787,679
Flat Rock	1904	1,110	20–400	2,026,096
Nowata-Claggett	1905	950	20–180	880,927
Glennpool	1905	1,350	40–600	17,452,967
Hogshooter	1906	1,080	10–500	997,484
Bird Creek	1906	1,110	20–400	5,090,031
Delaware-Childers	1906	700–850	15–150	3,900,971

[a] Taylor and Branan, 1964, p. 13.
[b] Mills-Bullard, 1928.
[c] Natural Resources Information System (NRIS) of Oklahoma, 1997.

was to the north and that three deltaic sequences are generally present.

BARTLESVILLE PETROLEUM RESERVOIRS

Early Oil Production

Although oil was discovered in the Bartlesville sand in 1897, it could not be produced for lack of a ready market and also because of lease-title complications with the U.S. Government pertaining to Indian lands. When the title problem with the Government was resolved in 1904, a frenzy of drilling began. Several more Bartlesville oil fields were discovered in northeastern Oklahoma. Rapid development of these fields during 1904–07 made Oklahoma the leading oil producer at Statehood in 1907.

Figure 19 is a map showing the earliest Bartlesville oil and gas fields in northeastern Oklahoma. All but two of these fields were discovered prior to Statehood, the exceptions being Curl Creek (1935) and Turley (1914). Table 1 lists selective data for each Bartlesville field discovered before Statehood, as shown in Figure 19. Production data for these early fields generally are incomplete. After 90 years of production, these fields are still producing substantial amounts of oil. For 1979–96, total oil production is listed for each field, based on NRIS data files. Taylor and Branan (1964) estimated total oil production for a few of these fields: Nowata–Claggett, ~9,400,000 bbl; Hogshooter, ~10,734,000 bbl; Delaware–Childers, ~88,000,000 bbl. This author prepared a tabulation for total oil production from two fields through 1984, which, with the additional production years through 1996 added, shows that Bartlesville–Dewey field produced 182,004,258 bbl and Glennpool field produced 332,894,287 bbl.

Trapping Conditions

Oil reservoirs in the Bartlesville sand are dominantly trapped by stratigraphic conditions. Most commonly the trap is formed by a pinchout of sand against shale. This occurs in channel and marine-bar deposits where the shale is the updip seal for the sand. Other stratigraphic traps are created where a channel meanders updip or crosses over an existing structural nose. Sometimes even a change in sand-grain size or sorting can form a trap. An element of structural trapping can contribute to a stratigraphic trap from compaction of the encasing shale on the sides of a thick channel. Rarely are Bartlesville sands found as structural traps with four-way closure unless they were deposited in an area of later structural growth or uplift. Many of the larger structural features have Bartlesville sand traps associated with them, but trapping is due to stratigraphic rather than structural conditions.

Hydrocarbon-Source Rocks

Marine-shale deposits and encasing organic-rich shales of flood-plain and lagoonal origin are close to all Bartlesville sand reservoirs. Studies of the organic geochemistry of Cherokee rocks in southeastern Kansas and northeastern Oklahoma by Barker (1962) found that Cherokee shales and other nonreservoir rock are sources of hydrocarbons that can readily migrate into

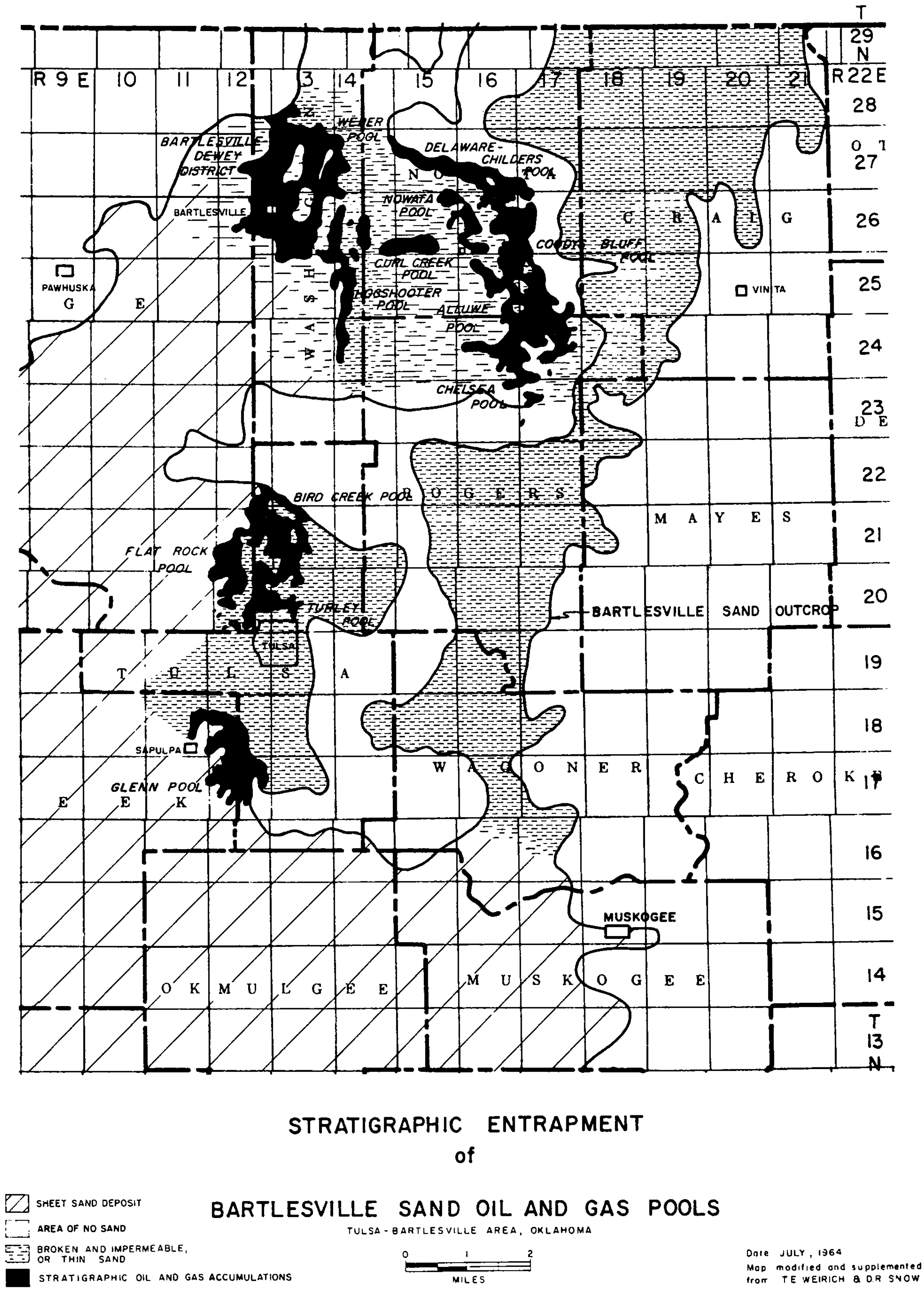


Figure 19. Earliest oil fields producing from the Bartlesville sand in northeastern Oklahoma. From Taylor and Branan (1964, p. 13).

TABLE 2. – Annual and Daily Average Oil Production from the Bartlesville Sand in Oklahoma by Lease, 1979–96

	Bartlesville only			Bartlesville & other		
Year	Barrels of oil	Number of leases	Daily avg. per lease	Barrels of oil	Number of leases	Daily avg. per lease
1979	5,482,416	1,623	9	3,849,487	603	17
1980	6,100,946	1,865	9	4,149,177	689	16
1981	6,653,944	2,128	9	4,563,403	787	16
1982	5,999,280	2,258	7	4,344,103	838	14
1983	6,045,241	2,315	7	4,044,413	843	13
1984	6,177,209	2,341	7	4,000,458	861	13
1985	6,152,801	2,334	7	3,655,350	873	11
1986	5,813,207	2,274	7	3,056,566	851	10
1987	5,439,718	2,122	7	2,545,435	814	9
1988	5,162,804	2,038	7	2,446,230	777	9
1989	4,867,344	1,975	7	2,284,737	752	8
1990	4,512,033	1,938	6	2,251,257	728	8
1991	4,305,399	1,894	6	2,324,761	715	9
1992	4,100,272	1,878	6	2,182,044	684	9
1993	3,856,617	1,735	6	1,899,072	659	8
1994	3,422,468	1,611	6	1,774,323	630	8
1995	3,139,211	1,547	6	1,689,421	612	8
1996	3,046,807	1,468	6	1,656,095	601	8
Totals	90,277,717			52,716,332		

Production data from NRIS lease master files, University of Oklahoma.

adjacent reservoir rock. Studies of Desmoinesian shales in the Arkoma basin indicate that they are potential source rocks with sufficient maturity to generate hydrocarbons (Johnson and Cardott, 1992). On the basis of these studies and reports, as well as those of many other workers, it is likely that the sources of hydrocarbons in Bartlesville sand reservoirs can be nearby as well as distant.

Current Bartlesville Oil Production

The Bartlesville sandstone was the leading oil producer during the early days of the petroleum industry in Oklahoma, and it is still one of the major producers. Plate 3, "Map of Fields with Oil Production from the Bartlesville Sandstone," shows the 183 fields in northeastern Oklahoma keyed to field name and location that have current (1979–96) Bartlesville oil production listed in the NRIS data files at the University of Oklahoma. The areas of Bartlesville producing leases within fields, and unassigned producing leases outside of fields, are indicated by shaded areas on the map. Oklahoma production data are reported on a lease basis; therefore, production data for the Bartlesville sand are sometimes included with production data for other reservoirs. This situation makes the analysis of historical Bartlesville oil production difficult.

Table 2 shows annual oil production in Oklahoma from 1979 through 1996 for leases producing only from the Bartlesville sand and also for leases with production from the Bartlesville commingled with other reservoirs. Also shown are the number of Bartlesville producing leases and average daily lease production. Figure 20 shows the production curve for each lease category; during 1979–96, the Bartlesville-only leases produced 90,277,717 bbl of oil, while the Bartlesville commingled leases produced 52,716,332 bbl of oil. Production from this very long-lived oil reservoir continues its slow decline. The number of producing leases is declining as more of the wells are being abandoned because of unfavorable economic conditions. The average daily lease production has declined from 9 to 6 bbl, or about one-sixth bbl per year in the 18 years of this production history. Reservoir studies included later in this publication show that even in the mature Bartlesville play, new reservoirs with favorable economic attributes are being developed beyond the older fields.

Secondary and Enhanced Recovery in the Bartlesville Sand

Early completion and production methods used in Oklahoma, as elsewhere, were aimed at getting the oil out as fast as possible. In doing so, the dissolved gas in the reservoirs was vented to the atmosphere to allow the oil to flow at high rates. Thus, all reservoir pressure was lost, and wells were put on pumps very early in their life.

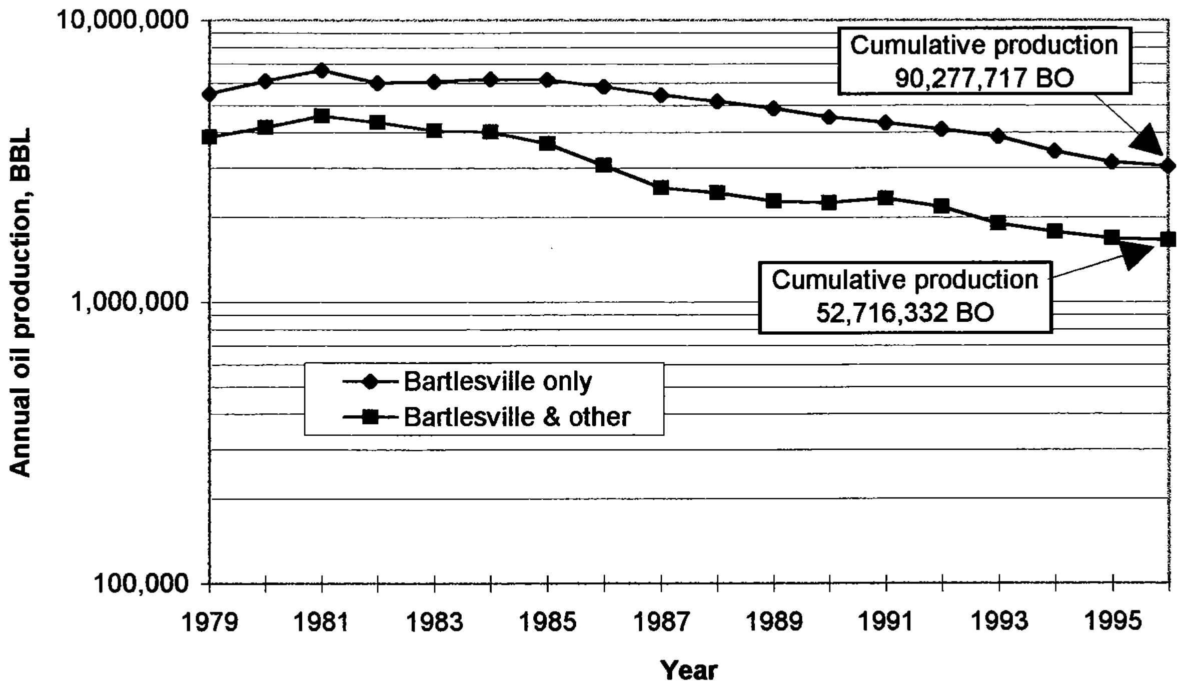


Figure 20. Graph of Bartlesville oil production, 1979–96, from NRIS lease master files.

Many methods have been used to recover greater amounts of oil from these reservoirs. The first attempt was application of vacuum pumps to shallow wells as early as 1914, with only limited success. In the 1920s, air and gas were injected into reservoirs, which proved successful. In 1937, the first systematic waterflood was installed in Bartlesville–Dewey field (Taylor and Branan, 1964). During the 1950s, waterflooding entered its most intense development period. A report by Jordan (1958) listed waterflood projects by producing zone. In this report, the Bartlesville had the largest acreage (100,777), the most wells (10,091), and the greatest daily production (37,739 bbl) of the 364 projects in the State. Other than the Burbank sand, no other zone was even close.

The extremely heavy demand for crude oil during World War II (1939–45) prompted the U.S. Bureau of Mines to investigate several northeastern Oklahoma oil fields for secondary-recovery potential. The reports that resulted from these investigations are excellent sources of information on many of these older fields. The reports, together with other articles concerning secondary-recovery potential and results for the Bartlesville sand, are listed in a separate section of the references included toward the back of this publication.

ACKNOWLEDGMENTS

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FDD Bartlesville Reservoirs

Paradise Field

(Bartlesville oil pool in secs. 33 and 34, T. 18 N., R. 1 E., and sec. 4, T. 17 N., R. 1 E., Payne County, Oklahoma)

by
Richard D. Andrews

INTRODUCTION

Paradise field is located in southwestern Payne County in north-central Oklahoma (Fig. 21). The field area is about 25 mi east of the Nemaha uplift, in an area commonly referred to as the Cherokee platform province (Pl. 1). Paradise field produces oil and gas from several types of Bartlesville sand deposits, including various kinds of channel deposits such as point bars in addition to tidal(?)-mouth bars. A map identifying operators, well locations, well numbers, and principal leases within the field area is shown in Figure 22.

Oil production was first established in the Paradise study area in the 1950s with the completion of two wells in the northern part of sec. 34, T. 18 N., R. 1 E. These wells were completed in the marine facies of the Bartlesville sand for up to 174 barrels of oil per day (BOPD). Thirty years later, in the early to mid-1980s, several wells were drilled in the central part of sec. 33, T. 18 N., R. 1 E., which established Misener (Devonian) oil production. In an effort to extend the Misener play to the south, Canadian Exploration (Pinnacle Oil) drilled the No. 3 Downey well (SE¼SW¼SW¼ sec. 33, T. 18 N., R. 1 E.) and accidentally discovered the Bartlesville oil pool in Paradise field. This well was completed in March 1986 and had an initial flowing potential of 290 BOPD, 133 thousand cubic feet of gas per day (MCFGPD), and 2 barrels of water per day (BWPD) from 30 ft of net productive Bartlesville sandstone. Field development was relatively slow and continued to the east until July 1990. However, several dry holes were drilled as late as 1992 in the hope of extending the field to the north and northeast. A total of 13 wells were completed in the Bartlesville reservoir, which has an oil gravity ranging from 34° to 40° API. The lighter oil is found in the eastern part of the field, and the heavier oil in the structurally lower western part. No gas cap or oil–water contact was encountered. Only one well found additional pay below the Bartlesville within the field: the No. 1 Minnich (NE¼NW¼NW¼ sec. 4, T. 17 N., R. 1 E.), which was a dual completion with the Mississippian limestone.

Paradise field is fully developed on 10–20-acre spacing. Two of the wells in the western part of the field were plugged and abandoned in 1995, one well in the center of the field was converted to a water-supply well, and one well in the extreme eastern part of the field was converted to a water-injection well. In March 1994, the eastern part of the field was unitized by Pin-

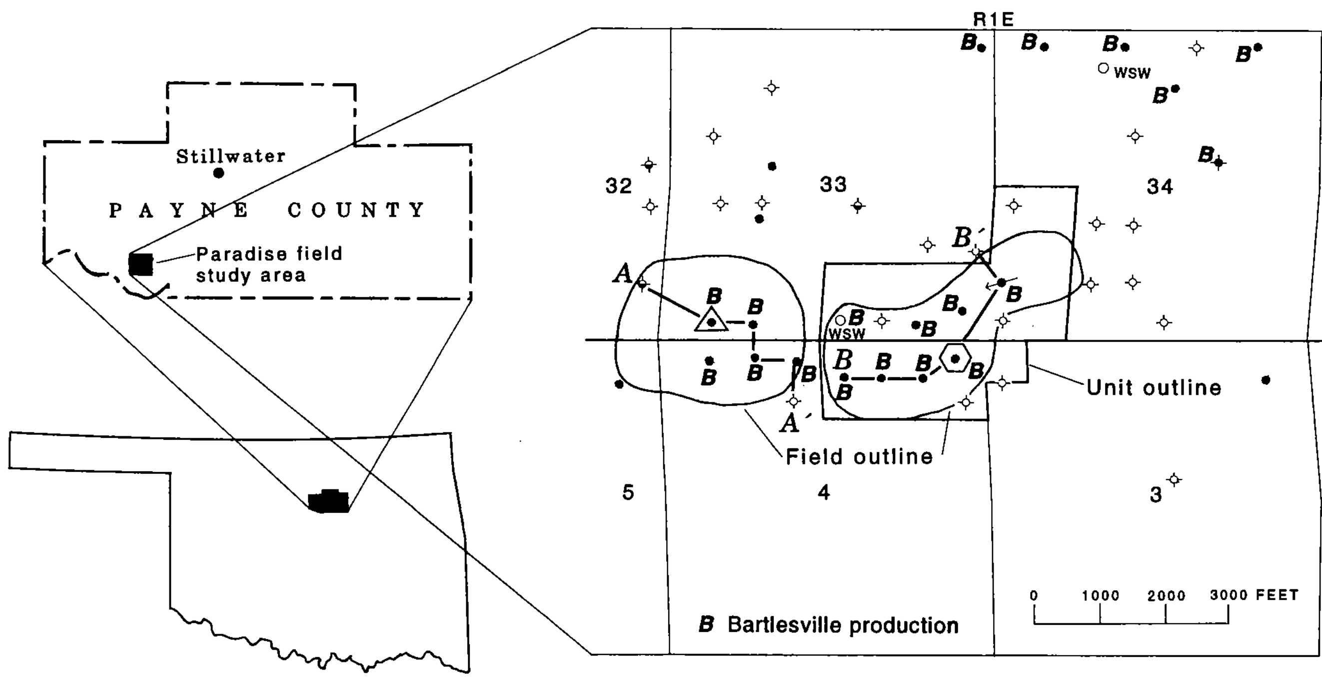


Figure 21. Generalized location map of the Paradise field study area in southwestern Payne County, Oklahoma.

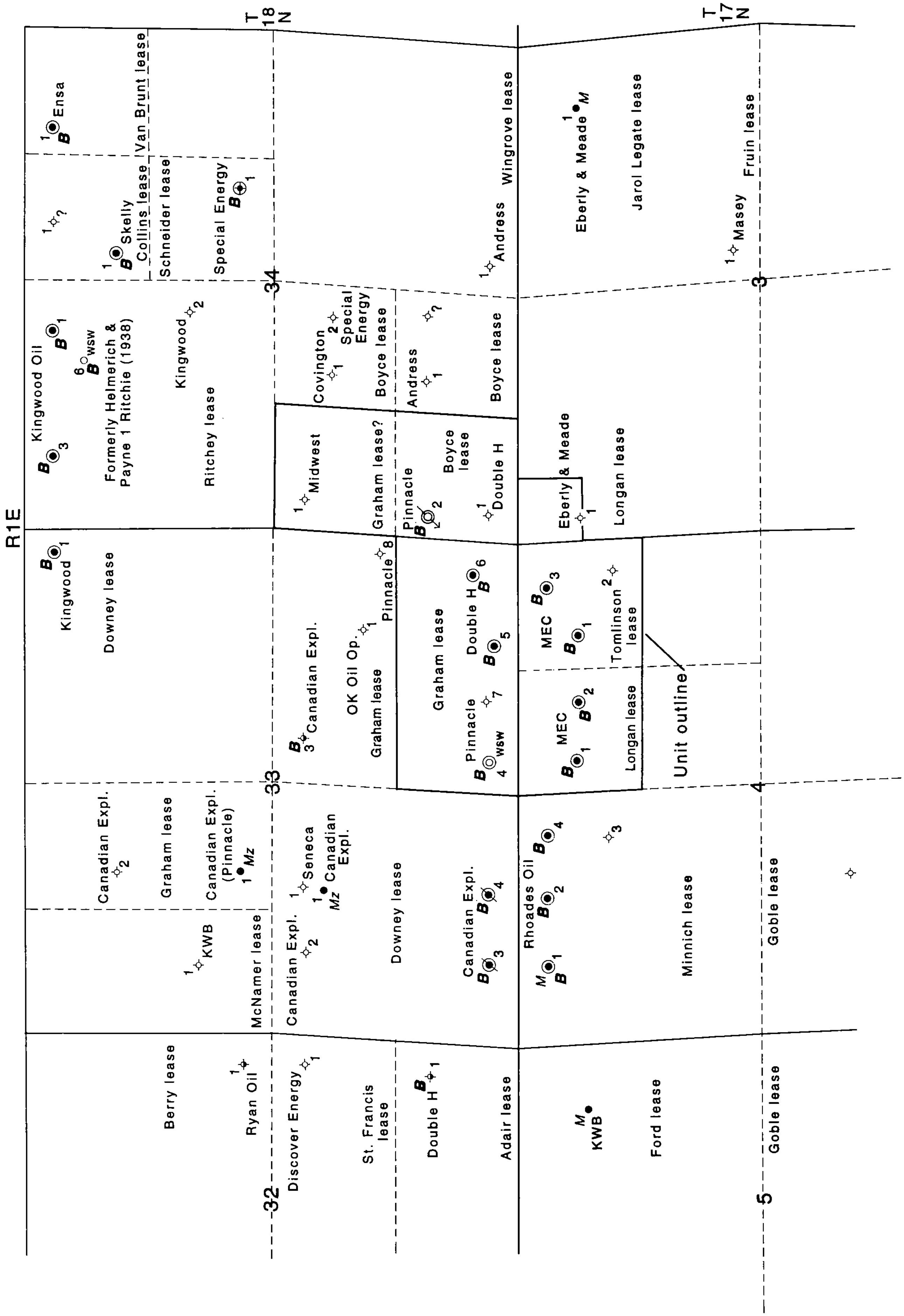


Figure 22. Well-information map, showing operators, lease names, well numbers, and producing reservoirs for wells in the Paradise field study area. See Appendix 4 for explanation of symbols.

nacle Oil, and a waterflood was initiated. In mid-1995, the first significant response in oil production was measured.

STRATIGRAPHY

A typical log from the Paradise field, with stratigraphic nomenclature, is shown in Figure 23. The Bartlesville interval is about 60 ft thick and is directly overlain by ~8 ft of low-resistivity shale that normally encompasses the Inola Limestone. However, the Inola is absent throughout the study area. The base of the Bartlesville interval is interpreted to extend down to the top of the Mississippi lime, including the 2 to 8 ft of shale that normally underlies the Bartlesville sand. The Bartlesville sandstone, which occupies most of the Bartlesville interval, occurs in two main horizons or beds. The lowermost sand bed generally has a sharp basal contact with shale and a blocky to slightly increasing gamma-ray (GR) response on well logs. The upper part of the sand zone typically consists of dirty sandstone or interbedded sandstone and shale. This interpretation reflects an upward-fining textural profile (a decrease in grain size) and is typical of multiphase fluvial cycles. In the western part of the field, the distinctive bell-shaped GR and spontaneous-potential (SP) log profile of the Bartlesville sandstone is strongly indicative of a single-phase point-bar deposit.

The stratigraphy of the Bartlesville interval is best shown by detailed structural–stratigraphic cross sections *A–A′* through the western part of the field and *B–B′* through the eastern part (Fig. 24, in envelope).

Wells 2–5, cross section *A–A′*, produced oil and gas from the Bartlesville. The western limit of the field, however, extends to well 1, which recovered small amounts of oil and gas in the Bartlesville during a drill-stem test (DST). On the basis of the bell-shaped GR and SP log profiles, the sandstone in these wells is interpreted to be a point-bar deposit. Thin shale layers

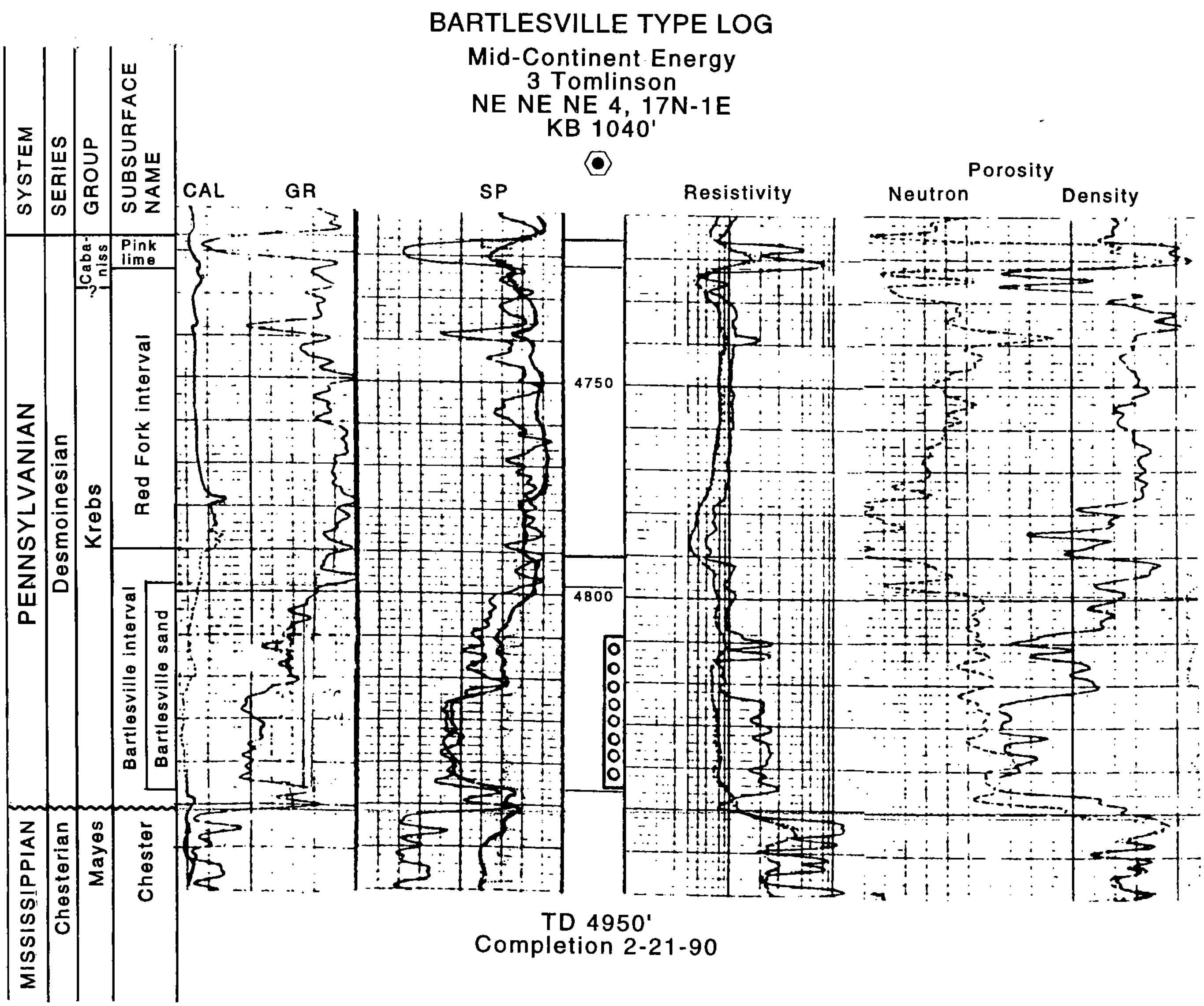


Figure 23. Paradise field type log, showing stratigraphic markers and characteristic log signatures. *SP* = spontaneous potential; *CAL* = caliper; *GR* = gamma ray.

interbedded within the sandstone, as interpreted from the serrated GR log profile in wells 2 and 3, are probably "clay drapes." Clay drapes originate from thin layers of mud deposited on top of point bars after flooding events. Unless the mud is eroded when higher flow rates resume, the clay drapes become interbedded within the point-bar sandstone. Most of the shale interbeds are only ~1 ft thick, but they probably form effective barriers to fluid flow across the bar (in a north–south direction).

Sandy or silty shale in the upper part of the Bartlesville interval in wells 1 and 5 is interpreted to be a shaly channel fill (i.e., channel-margin facies). It is laterally equivalent to the upper part of the point-bar sandstone in wells 3 and 4. The clean sandstone in the bottom part of the Bartlesville interval thins appreciably between wells 1 and 2 and also between wells 4 and 5. Abrupt changes in sandstone thickness such as these are common in fluvial deposits.

The Bartlesville interval in wells 1 and 5 in cross section *A–A′* is distinctly different than it is in the other wells in the cross section. It consists mostly of shale, but, more importantly, beds within the shale section of well 6 cannot be correlated with beds in the shale section of well 5. Based in large part on the resistivity log of well 6, in which the shallow and deep resistivity traces "track" one another, the Bartlesville interval in that well is interpreted to have been deposited in a marine environment. This type of shale log signature is widespread, unlike shale sequences contained within flood-plain environments. Because of the differences in details of bedding and lithology, the marine shale can be distinguished from the shaly channel fill. In well 5 (near the southeast end of section *A–A′*), the Bartlesville interval consists of very thin beds of sandstone and coal interbedded with shale and siltstone. The Bartlesville in this well is interpreted to consist of channel-margin and flood-plain deposits. Even though no significant amount of sandstone is present in well 5, there still is an erosional boundary between sediments within the channel environment and those in the adjacent marine-shale sequence. This same spatial relationship occurs between channel-margin sediments in well 1 and incised marine shale farther west.

Cross section *B–B′* (Fig. 24) extends across the eastern part of the field. Most apparent from well logs in this cross section is the presence of sandstone beds having different log responses in the Bartlesville interval. This is probably due to a more complex geologic setting characterized by variations in depositional processes that may or may not be part of the same depositional system. In general, Bartlesville facies gradually change from nonfluvial sediments (tidal or channel-mouth bars) in wells 2 and 3 to flood-plain sediments (channel, channel margin, and marsh) in wells 4, 5, and 6. Along the west edge of cross section *B–B′*, in well 1, the Bartlesville again reverts back to flood-plain deposition with the presence of thin, basal channel sands.

Sandstone beds in wells 2 and 3, cross section *B–B′*, are characterized by an upward-coarsening textural profile. In well 2, the sand zone clearly shows a gradual upward increase in porosity and a decreasing GR response. Well 3 shows two sandstone beds, both of which have indications of an upward increase in sand as interpreted from the SP and resistivity logs. However, the GR profile across the two sandstone beds in well 3 is not definitive with regard to textural composition. In general, log patterns of Bartlesville sandstone in wells 2 and 3 are more typical of marginal-marine sandstone deposits (tidal-mouth bar) rather than channel deposits. They contrast sharply in texture with sandstone beds to the east in wells 4 and 5, which have a sharp basal contact with shale and a blocky to upward-fining textural profile as indicated by the GR log. These characteristics are more typical of fluvial deposits. Farther to the east, in well 6, the Bartlesville interval is mostly shale with a thin coal bed near the top. This sequence is interpreted to have originated in a flood-plain environment—an area within the incised valley adjacent to the active channel.

The spatial relationship of most sandstone beds illustrated in cross section *B–B′* can best be described as interfingering. This is illustrated between wells 3 and 4, and between wells 1 and 2. Both exemplify a lateral relationship between channel and nonchannel deposits. The boundary between these two facies is fairly abrupt, and fluid communication is expected to be attenuated from one facies to another (compartmentalization). This boundary should have a significant effect in waterflooding operations.

STRUCTURE

The regional dip of the lower Cherokee section in the Paradise field area (see Fig. 16) is to the west–southwest at only about 0.5° (<50 ft/mi). However, a structure map contoured on the top of the Mississippian limestone shows a distinct east–west-trending trough in the exact area of Paradise field (Fig. 25). This deviation from the regional structure is caused by an erosional unconformity at the top of the Chester limestone, creating a small erosional valley. The Bartlesville sandstone is separated from the Mississippian by only a few feet of shale, but the sandstone is entirely within the paleovalley as delineated on the Mississippian structure map. A detailed structure map depicting the top of the Bartlesville sand (Fig. 26) primarily shows the attitude of the sand body within the channel, although the structure of the marine Bartlesville sandstone outside of the channel conforms well with sandstone within the channel. As can be seen in Figure 26, the highest position of the Bartlesville sandstone within Paradise field is above –3,760 ft and occurs in the far eastern part of the unit. The western part of the field, which is separate from the eastern part, is mostly below –3,780 ft.

As at many places within the Anadarko shelf and platform areas, fracturing may have a significant effect on fluid flow, especially during water injection. The dominant fracture pattern in this area is interpreted to

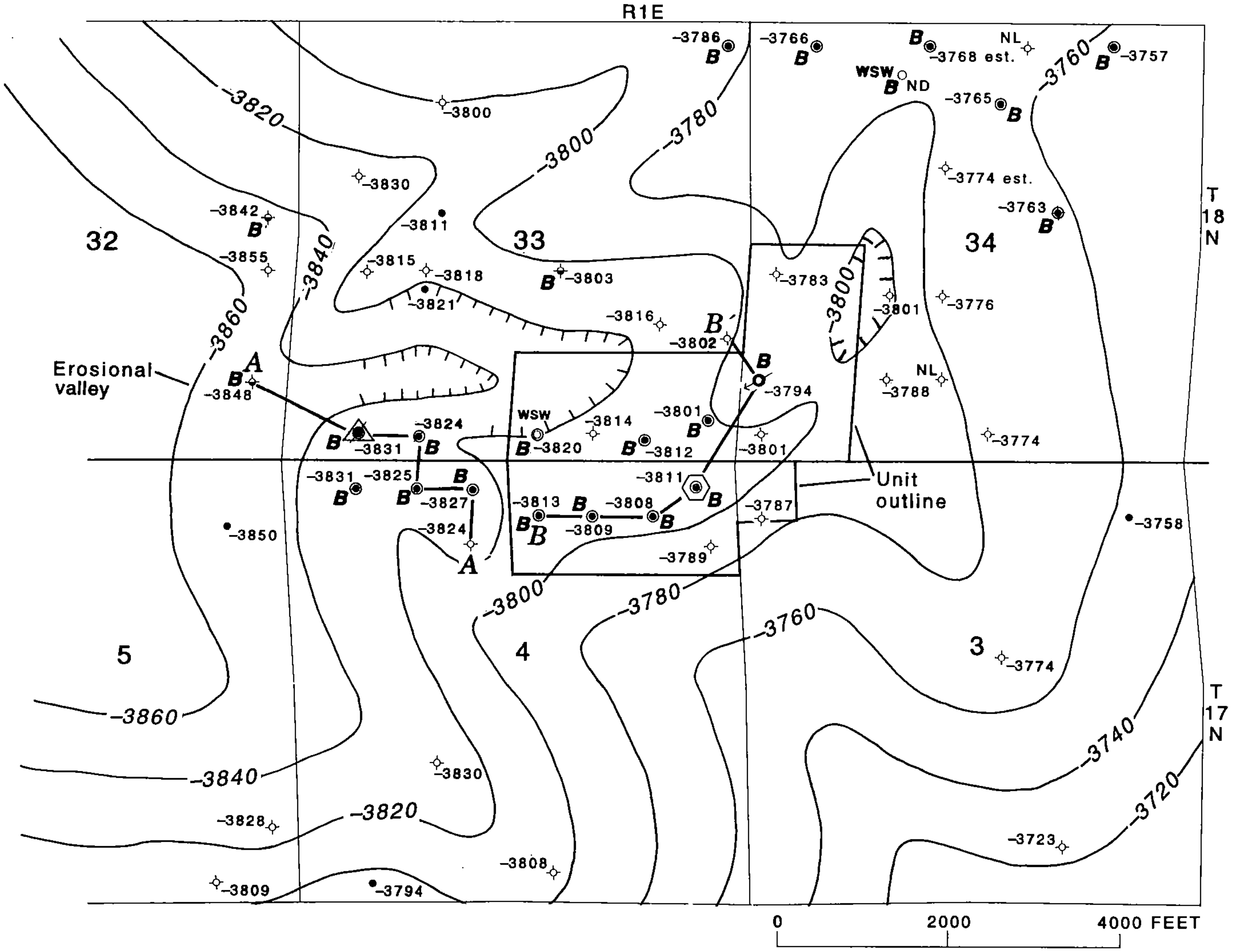


Figure 25. Structure map of the top of the Mississippian limestone, Paradise field study area. Contour interval is 20 ft. See Figure 22 for well names. See Figure 23 for type log. See Appendix 4 for explanation of symbols.

be in a northeast–southwest direction, although other fracture patterns may be enhanced in the field area due to a significant east–west-trending fault zone located about 6 mi to the west.

BARTLESVILLE SANDSTONE DISTRIBUTION AND DEPOSITIONAL ENVIRONMENT

Figure 27 shows the gross thickness of the Bartlesville sandstone for all the wells in the study area. This thickness is the total thickness of sandstone, regardless of porosity, determined from GR and resistivity logs. The zero-thickness line is the limit of sand deposition within the channel and generally includes a larger area than the limits of the actual reservoir or net sandstone. The spatial limits of the incised valley are generally somewhat larger than the gross sandstone distribution, as areas within the channel may not contain sandstone. From this map, the channel is inferred to be about 0.3–0.5 mi wide. Within the general area, the course of the channel is meandering and extends beyond the area mapped to the northeast and northwest. The channel sandstone pinches out near the east edge of the unit but reappears about 0.5 mi to the northeast in sec. 34. West–northwest of the study area, the Bartlesville sandstone is not continuous but occurs in a series of fields (a "trend"), interpreted to be largely channel (tidal?)–mouth bars rather than channel deposits. The fields in this trend are prone to oil production.

The gross sandstone thickness of the channel sandstone ranges from only a few feet to 40 ft but generally is in the range of 20–40 ft. However, the sands do not occur everywhere within the channel. In many places, such as at the east end of the field, channel deposits are predominantly shale rather than sand, since they occur along the channel margin or in places within the channel where little sand was deposited. These shaly intervals form the stratigraphic barriers that isolate hydrocarbons along the course of the channel. Bartlesville sandstones north of the channel are part of a regionally

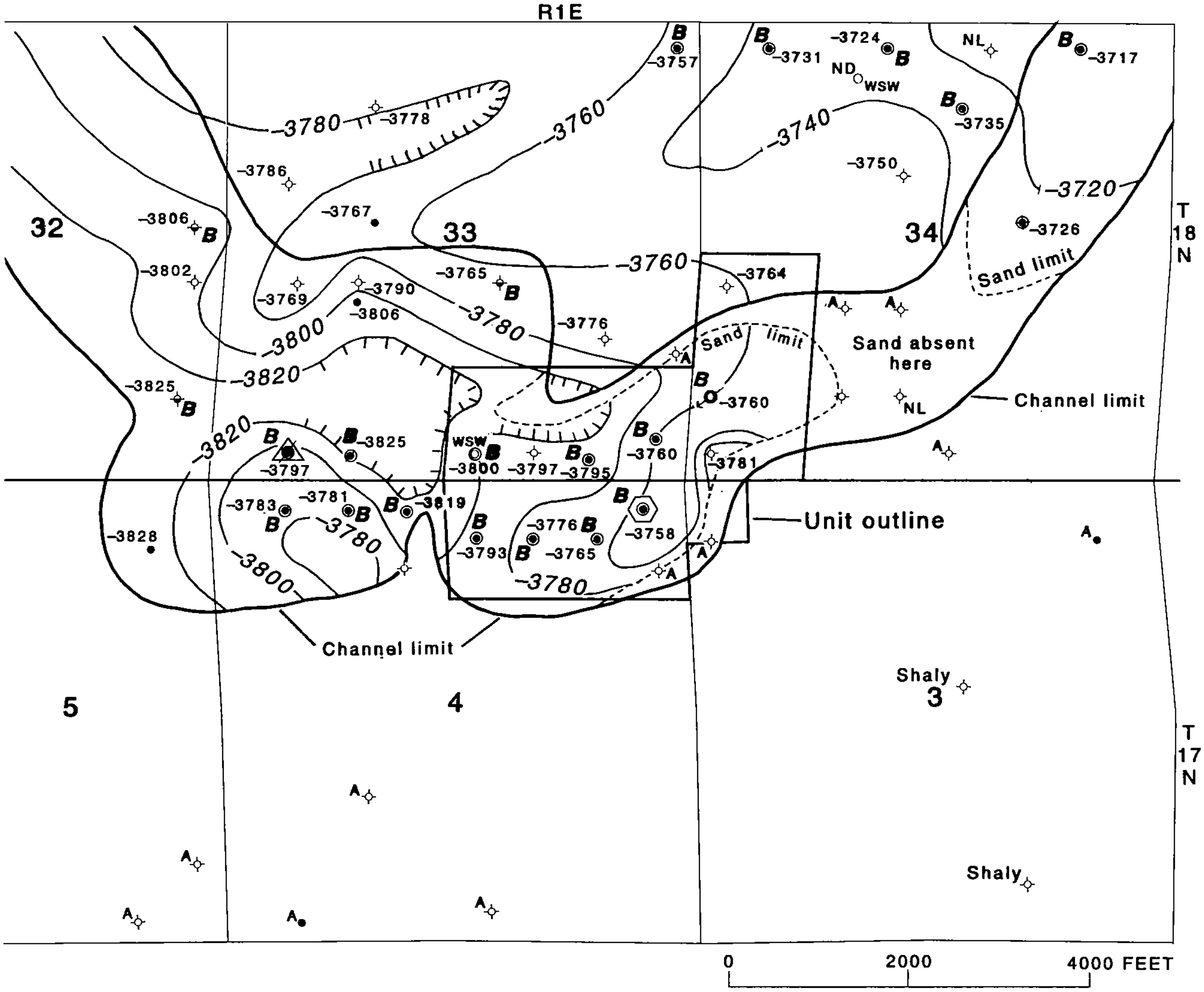


Figure 26. Structure map of the top of the Bartlesville sandstone, Paradise field study area. Contour interval is 20 ft. See Figure 22 for well names. See Figure 23 for type log. See Appendix 4 for explanation of symbols.

extensive marine-shelf deposit that existed prior to deposition of the Bartlesville channels. These marine sandstones produce from stratigraphic traps in the northeastern part of the study area.

The net sandstone isopach map (Fig. 28) shows the thickness of sandstone with ≥10% porosity. The net sand thickness ranges from 6 to 37 ft, and the average thickness is about 16–17 ft. The net sand map is similar in overall appearance to the gross sand map (Fig. 27) and clearly shows that much of the sandstone identified in the gross sand map has good porosity. The main difference between the two is seen in the upper part of the point bar, where dirty sandstone reduces the net sand thickness by several feet. Although much of the sandstone in the lower part of the sand zone has porosity considerably greater than the 10% cutoff value, a higher cutoff value, such as 12% or 14%, would have significantly decreased the amount of net sand.

There is no water leg in the field, so the reservoir includes the entire area with >0 ft of net sand (Fig. 28). The field is actually divided into an east reservoir and a west reservoir, with a narrow zone of shale separating the two. Because of facies variations in the east reservoir (the unit), further compartmentalization may be recognized. Just north of Paradise field is another small channel-sand body that is not commercially productive, although two wells tested oil in the Bartlesville. Northeast of the unit, the Bartlesville channel again has net sand and is productive from two wells in the northeast corner of sec. 34.

The best reservoir and the most productive wells in the study area produce from point bars (as opposed to marine facies and channel-mouth bars). The direction of flow has not been determined but is inferred to have been from east to west. In map view, the sand bodies are podlike to elongate, with a width of about 0.3–0.5 mi and a length of 0.5–1.0 mi. As seen in field wells, the point bars have a sharp basal contact with shale and an upward-fining textural profile that becomes more shaly at the top. The marine-shelf sands adjacent to the north

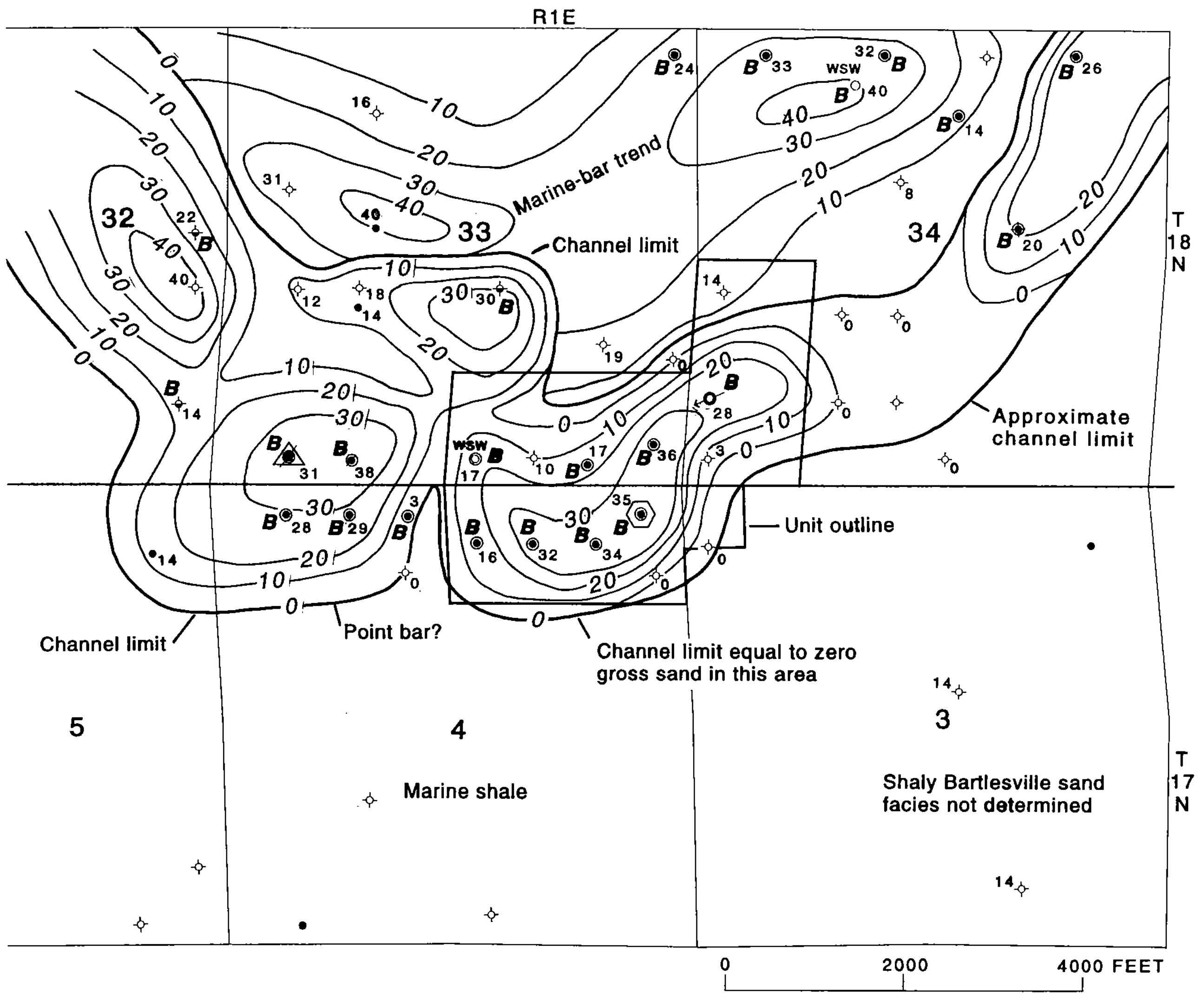


Figure 27. Bartlesville gross sand isopach map, Paradise field. Contour interval is 10 ft. See Figure 22 for well names. See Figure 23 for type log. See Appendix 4 for explanation of symbols.

boundary of the field are not part of the reservoir in Paradise field and have a distinctive upward-coarsening textural profile. The marine deposits were probably incised by fluvial channels during lowering of eustatic sea level.

FACIES MAPPING

Depositional environments were interpreted from wireline-log signatures, particularly GR and resistivity logs (Fig. 29). Two distinctly different depositional environments are interpreted for productive Bartlesville sandstones in Paradise field and include fluvial (flood-plain) and channel (tidal?)–mouth bars.

Fluvial (Channel) Facies

The depositional origin of these sediments appears to be a simple meandering stream contained within a flood plain (rather than a delta plain). This distinction is important for exploration purposes, as there is no delta front underlying the channel facies and, therefore, no progradation—i.e., no deposition extending basinward into a marine environment (definition of a delta!). Within the fluvial (channel) facies, sediments are either predominantly sandstone or shale with thin, interbedded sand layers and coal. Because of the morphology of the sandstone, the western part of the field is interpreted to be a point bar. The reasons for this interpretation include (1) a sharp basal contact with shale, (2) an upward-fining textural profile on GR logs, (3) distinct shale breaks in the upper half of the sand zone (clay drapes), and (4) an almond- to pod-shaped map outline. The eastern part of the field appears to be a modified or reworked point bar grading into some type of river or tidal-mouth bar. The distribution of channel sandstone in the eastern part of the field is elongated, possibly owing to longitudinal extension during bar growth. Sediments deposited within the fluvial regime that are predominantly shale are interpreted to be channel-margin, abandoned-channel, or flood-plain deposits and are not part of the reservoir. It

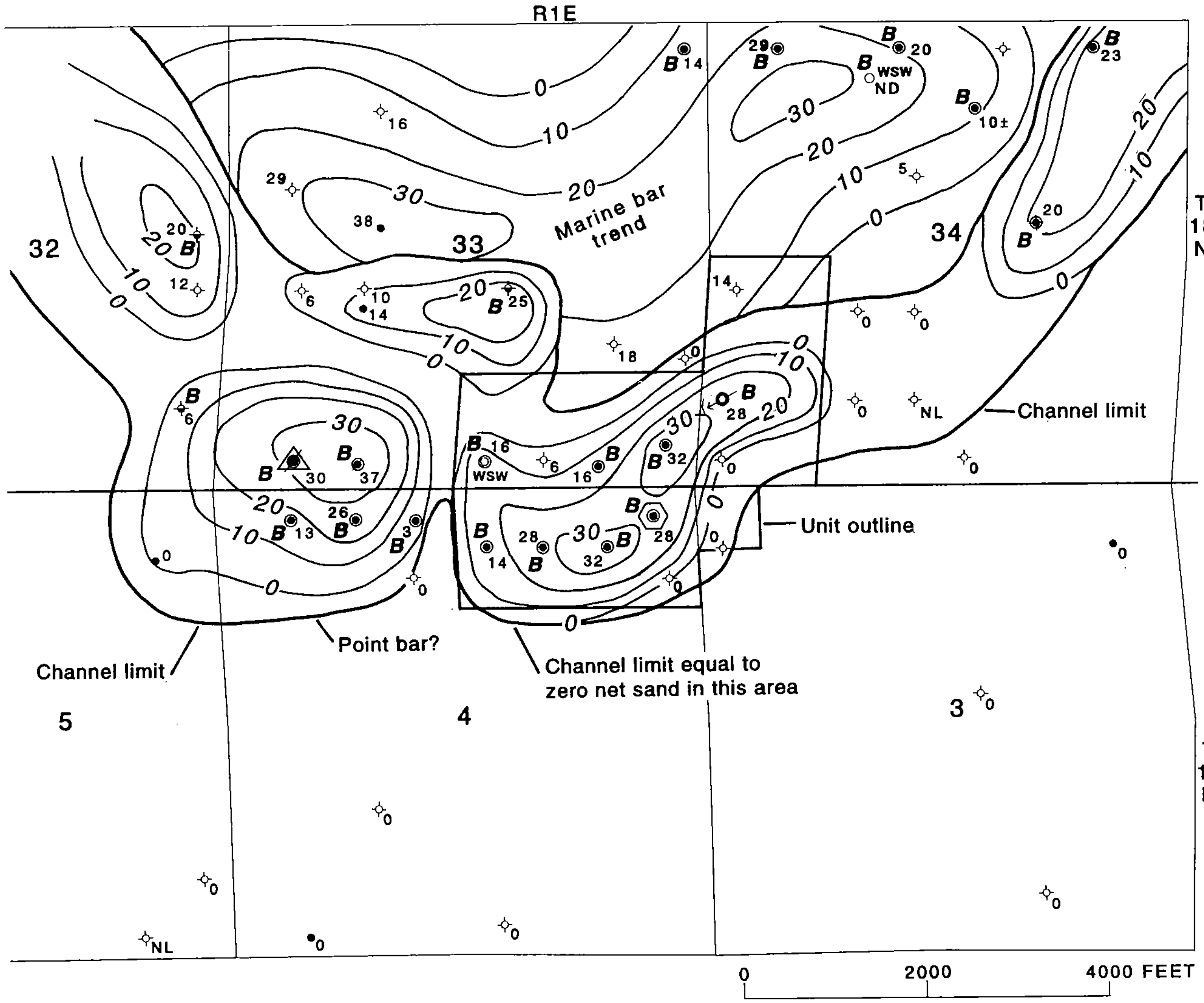


Figure 28. Bartlesville net sand isopach map, Paradise field. Net sand is considered to be sand with log porosity ≥10%. Contour interval is 10 ft. See Figure 22 for well names. See Figure 23 for type log. See Appendix 4 for explanation of symbols.

is necessary to be able to identify these types of sediments on well logs so they can be distinguished from the laterally adjacent marine facies.

Channel (Tidal?)–Mouth-Bar Facies

Sandstone that is interpreted to have an upward-coarsening textural profile, as indicated from GR, resistivity, and porosity logs, is considered to have originated from different depositional processes in comparison to the fluvial point-bar deposits. Sandstones having these characteristics are productive within Paradise field as well as in the northern part of the study area. Some of the upward-coarsening lithologies in the northern part of the study area appear to be marine-shelf sands, whereas those within Paradise field appear to reflect a lateral facies change (interfingering) within a fluvial regime. The distinction between the marine-shelf sandstone and channel-mouth-bar sandstone is not always possible to make, except that the latter is productive within the channel limits (see wells 2 and 3 in cross section *B–B′*, Fig. 24). In some areas, a well producing from a channel sandstone (No. 2 Boyce, NW¼SW¼SW¼ sec. 34) lies adjacent to an updip dry hole containing porous sandstone having an upward-coarsening texture (as in the No. 1 Graham well in the NW¼NW¼SW¼ sec. 34). In this case, it is clear that the sandstone in the No. 1 Graham well is a marine-shelf sandstone incised by the younger Bartlesville channel sandstone in the No. 2 Boyce well. Even though it is difficult in some instances to differentiate between fluvial and marine facies, the recognition of these two facies is an important skill that can be used effectively in step-out drilling in the development of fluvial trends such as Paradise field.

CORE ANALYSIS

Two wells were cored within Paradise field, the No. 1 Berry (SE¼SE¼NE¼ sec. 32, and the No. 2 Longan (E½ NW¼NE¼ sec. 4). The No. 2 Longan was the only well from which data were available. From this well, the

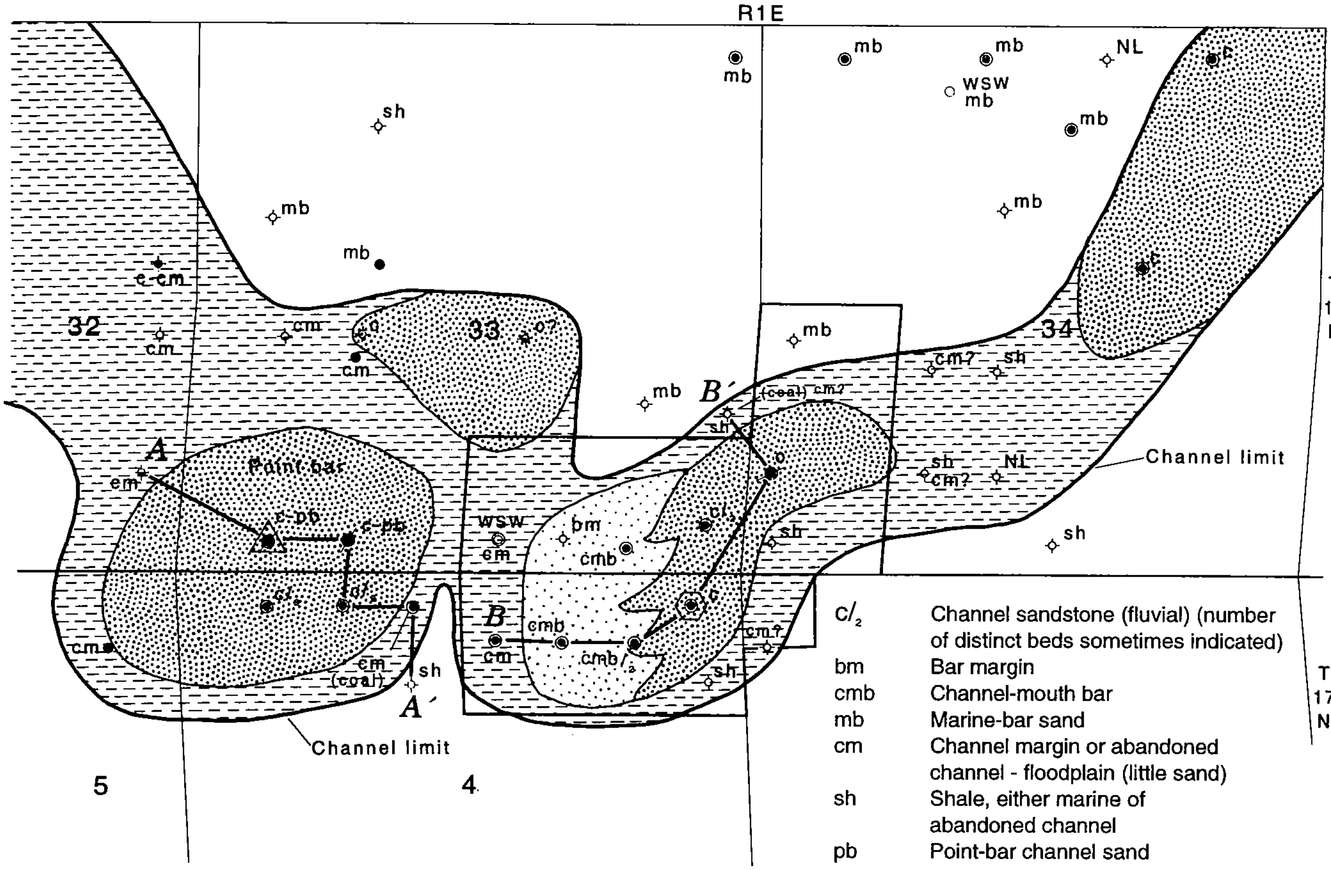


Figure 29. Depositional-facies map of the Bartlesville sand interval in the Paradise field study area.

sandstone's grain density ranges from about 2.63 to 2.67, but most samples indicated a density of 2.67. X-ray diffraction analysis shows the Bartlesville sandstone to consist mostly of quartz (40–65%), with slightly less feldspar (20–40% Na–plagioclase). Chlorite and illite were the most common clays (5–10%), while kaolinite and mixed-layer clays occupied 2–5% (Halliburton Services, unpublished data). Porosity and permeability measurements are listed and plotted in Figure 30. The porosity ranges from 10.9% to 17.4%. Permeability measurements range from 0.5 to 50.9 md, and most are between 1 and 20 md and average about 12 md. The porosity–permeability curve shows that for ~10% porosity, the permeability should be about 0.3 md, which is considered too tight for oil production. However, the expected permeability of sandstone in Paradise field having an average porosity of 16–17% should be between 10 and 20 md, which is favorable for oil production and waterflooding. In the cored well, core porosity is generally 2 percentage units lower than the porosity determined from the density log run with a 2.71 matrix density. In the most porous interval sampled, the measured core porosity was about 4–5 percentage units lower than density log porosity.

FORMATION EVALUATION

The identification and evaluation of the Bartlesville sandstone in Paradise field is straightforward. The productive sandstone is relatively clean (i.e., GR and resistivity logs are not significantly affected by interstitial clay or mica). Porosity determinations from the density logs run on a 2.71 matrix density were at least 2 percentage units higher than core measurements. Reservoir characteristics are shown in Table 3.

The deep or "true" resistivity of productive intervals ranges from about 5 to 13 ohm-meters and is generally 8–10 ohm-meters. The higher resistivities generally occur in sandstones within the eastern part of the field, which is up to 20 ft higher than the western part. A relatively strong separation of about 15–25 ohm-meters exists between the shallow and deep resistivity readings in the producing interval. The separation of the shallow and deep resistivity curves indicates the presence of permeability. Notice that in the upper part of the sand zone, the separation is much less owing to the increasing amount of shale.

Additional evidence regarding reservoir quality is interpreted from the caliper log (CAL). As shown in wells 3 and 4 of cross section *A–A′* (Fig. 24), the borehole diameter through the Bartlesville sand zone is reduced by up to 1 in. owing to mud-cake buildup. This situation generally happens where the sandstone has good porosity, as indicated on the density–neutron porosity log. Significant reductions in borehole size from mud-cake buildup generally occur in reservoirs having at least 15–30-md permeability (see Ohio–Osage

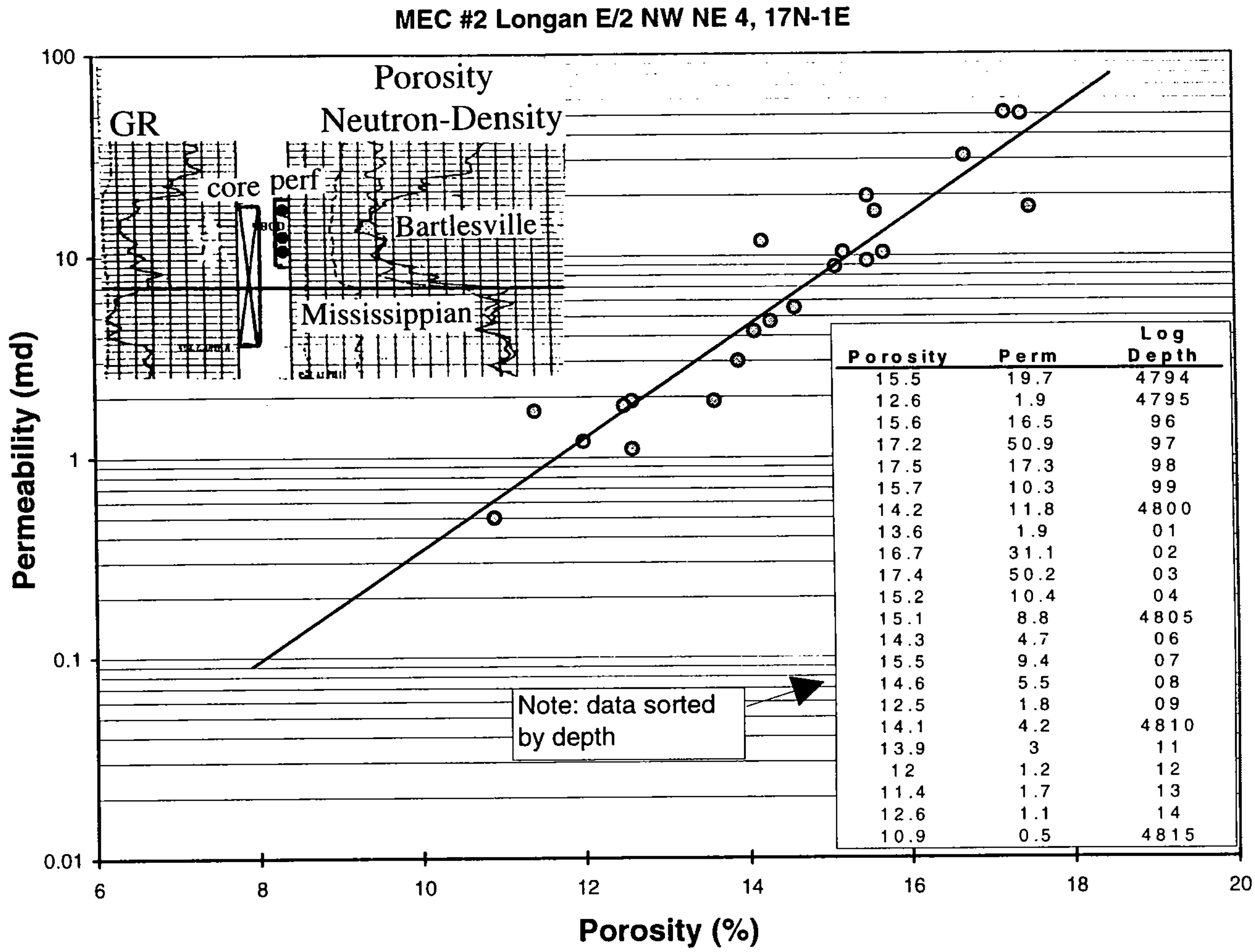


Figure 30. Core porosity and permeability data of a nonchannel Bartlesville sandstone from a well within Paradise field.

field-study cross sections, Figs. 53, 54). Therefore, sand zones having good porosity (see well 4, cross section *A–A′*, Fig. 24) are expected to have relatively good permeability in this area.

Water-saturation (S_w) calculations for the Bartlesville sandstone ranged from about 25% to 45%. The S_w in most of the lower (productive) part of the sandstone was about 35%. Calculations were made by using the equation $S_w = \sqrt{F \times R_w / R_t}$. The formation-water resistivity (R_w) was assumed to be 0.035 ohm-meters at formation temperature. The Archie equation for formation factor ($F = 1/\phi^2$) was used because S_w calculations seemed more reasonable when using this equation for this particular reservoir. The use of a modified F equation generally resulted in calculated S_w values that were unrealistically low and, conversely, oil-saturation values that were too high. R_t or true resistivity was taken directly from the deep resistivity log. Porosity values were also taken directly from density logs and reduced about 2 porosity units to reflect actual reservoir conditions as determined from core data. Neutron porosity was not used for cross-plot porosity determinations, because the highly variable clay content in the upper part of the sand zone causes the log neutron porosity to be too high. The log density porosity was calculated by using a matrix density of 2.71 g/cm^3.

OIL AND GAS PRODUCTION

The estimated cumulative oil and gas production from the Bartlesville sandstone in Paradise field from March 1986 through July 1996 is 427,752 BO and 450,718 MCFG (Table 4). This table also shows annual oil and gas production, average monthly production, average daily production per well, and average annual gas/oil ratios (GOR). The peak in annual oil production was in 1990, when 12 wells produced 83,866 BO; average daily production was 20 BO per well. In 1994, when unitization began, 11 wells were producing; annual production was only 8,445 BO, and average daily production had fallen to 2 BO per well. Another interesting and useful production trend indicated in Table 4 is the average annual GOR increase from field development in 1986 until 1995. Although this ratio increased sharply, it is still relatively low, indicating minimal gas evolution and oil shrinkage. The reduction in GOR during 1995 occurred during water injection and reservoir repressurization in the unitized eastern part of the field. The amount of gas produced and the average GOR

TABLE 3. – Reservoir/Engineering Data for the Bartlesville Sandstone in Paradise Field, Payne County, Oklahoma

Reservoir size (total)	~314 acres
East sand body	~164 acres
West sand body	~150 acres
Depth	~4,800 ft
Well spacing (oil)	10 acres, irregular
Oil–water contact	None observed; little water produced during primary production
Gas–oil contact	None observed
Porosity (in net sand)	12–21% (avg. ~16%)
Permeability[a]	2–51 md (avg. ~12 md)
Water saturation (calculated)	25–45% (avg. ~35%)
Thickness (net sand $\phi \geq 10\%$)	10–35 ft (avg. ~16.6 ft)
East sand body (unit area)	17.3 ft
West sand body	15.9 ft
Reservoir temperature	120°F
Oil gravity	
East sand body (unit area)	34°–38° API
West sand body	37°–40° API
Initial reservoir pressure	1,888(?) PSI
Initial formation-volume factor[b]	1.23 RB/STB
Original average GOR (1987 avg.)	479 (SCF/BBL); varied from about 250–800 initially
Final average GOR (from 1996 cums.)	1,054 (SCF/BBL)
OOIP (volumetric–field)	3,647,881 STBO
East sand body (unit area)	1,980,756 STBO
West sand body	1,667,125 STBO
Cumulative field oil (to 8/96)	427,752 BO
East sand body (unit area) to 8/96	259,398 BO
West sand body to 8/96	168,354 BO
Cumulative unit oil since unitization	14,587 BO
Recovery efficiency (field)	11.7%
East sand body (unit area)	13.1%
West sand body	10.1%
Recovery (field)	~82 BO/acre-ft
Est. secondary oil recovery (7/95 to 8/96)	10,428 BO
Cumulative gas production (field)	450,718 MCF

[a]Taken from Bartlesville core in No. 2 Longan, E½NW¼NE¼ sec. 4, T. 17 N., R. 1 E.
[b]Data provided by Crystal Energy, Inc. (Pinnacle Oil).

within the field as shown in Table 4 may not be entirely accurate, as no gas was reported from any of the Minnich wells (NW¼ sec. 4). Initial-potential tests of three wells in this lease are similar to other nearby wells that reported gas sales.

Production trends within Paradise field are illustrated in Figure 31. As the field is compartmentalized into two main sand bodies, production curves were prepared separately for the western and eastern parts of the field. The upper plot (Fig. 31A) shows the production curves representing five wells in the western part of the field. Sandstone here is interpreted to have been deposited in a point bar. Note that about 87% of the oil was produced from the two Downey wells drilled in the northern part of the sand body. For the western part of the field, a relatively gradual production decline is noted for several years until 1994, when production decreased sharply. By the end of 1995, the two best wells (Nos. 3 and 4 Downey) were abandoned, and by the end of 1996, only a trickle of oil was noted from the remaining three wells within the western part of the field. The corresponding annual GOR is plotted for the two Downey wells in the inset graph. It shows that the GOR was relatively stable at a little above 2,000 standard cubic feet per stock tank barrel (SCF/BBL) for several years following an initial jump in gas production in 1988. The GOR plot does not take into account production from the three Minnich wells, because they reported no gas production. The western part was not unitized, but it would have made a great waterflood.

The production curve for wells within the eastern part of the field is shown by the plot in Figure 31B. This graph represents production primarily from seven wells developed over a 2-year period starting in mid-1988. Sandstone in this part of the field was deposited in a variety of current-induced bar forms, and the production decline is considerably more rapid here. The steep decline in production continued until 1994, when this part of the field was water flooded. Since 1994, oil production increased steadily through 1996, while gas production ceased during water fill-up. The corresponding annual GOR trend (inset) shows a sharp increase from 1988 to 1989, but the ratio is still considerably smaller than for wells in the western part of the field. The first point in both GOR plots (IP) represents the calculated GOR of the combined initial-potential results for wells in each part of the field.

The annual oil- and gas-production history for individual wells is shown in Table 5 (oil) and Table 6 (gas). Additionally, Table 5 shows the amount of oil production attributed to the unit (259,398 BO) as well as the amount attributed to secondary recovery since unitization (13,403 BO). The cumulative oil- and gas-production map (Fig. 32) shows cumulative production and the dates of first production for each well in the field. High production values on this map correspond to wells having the thickest net sandstone. Cumulative production does not appear to be related to the date of first production (wells were completed over a 5-year time span).

Almost half the wells in the field (6 of 13) produced >39 thousand barrels of oil (MBO) from the Bartlesville. Two wells, Nos. 3 and 4 Downey (SW¼ sec. 33, T. 18 N., R. 1 E.), both in the western part of the field, produced

TABLE 4. – Oil- and Gas-Production Statistics for the Bartlesville Sandstone in Paradise Field, Payne County, Oklahoma

Year	Number of wells		Annual production		Average	Average Monthly production per well		Average daily production per well		Cumulative production	
	Oil	Gas	Oil BBL	Gas MCF	GOR	Oil BBL	Gas MCF	Oil BBL	Gas MCF	Oil BBL	Gas MCF
1986	2	1	30,349[a]	11,348[a]	374	1,686	1,135	56	38	30,349	11,348
1987	4	2	53,564[a]	25,688[a]	480	1,275	1,284	43	43	83,913	37,036
1988	10	5	80,429[a]	52,661[a]	655	1,072	1,699	36	57	164,342	89,697
1989	10	6	80,308	87,824	1,094	669	1,220	22	41	244,650	177,521
1990	12	8	83,866	78,619	937	612	1,062	20	35	328,516	256,140
1991	12	9	38,399	91,236	2,376	267	861	9	29	366,915	347,376
1992	12	9	22,321	48,640	2,179	155	450	5	15	389,236	396,016
1993	12	9	16,697	32,111	1,923	116	297	4	10	405,933	428,127
1994[b]	11	8	8,445	19,011	2,251	64	198	2	7	414,378	447,138
1995	11	7	6,577	3,580	544	50	37	2	1	420,955	450,718
1996[c]	9	0	6,797	0	0	63	0	2	0	427,752	450,718

[a] Includes wells having only a partial year's production. [b] Unitization occurred January 1994. [c] Production through July 1996.

>68 MBO each (Table 5; Fig. 32). The poorest producers—those with cumulative production <10,000 BO—were in the southwestern part of the field (Minnich lease), plus a well in the SW¼SW¼SE¼ sec. 33 (Fig. 32).

Initial oil-production rates ranged from 8 to 376 BOPD; most of the wells in the field flowed 150–300 BOPD (Fig. 33). The range in initial production rates is probably due to variations in completion practices, reservoir quality and thickness, and localized pressure depletion, as development occurred over a relatively long time period (~5 years). Another probable reason may be due to reservoir compartmentalization, which is more evident when examining initial shut-in pressures of wells in the eastern part of the field versus wells completed several years earlier in the western part. In some cases, the shut-in pressure of a newer well was 300 pounds per square inch (PSI) more than the initial pressure in an adjacent well completed 2–4 years earlier. Flowing-tubing-pressure data were sparse and ranged from 43 to 453 PSI.

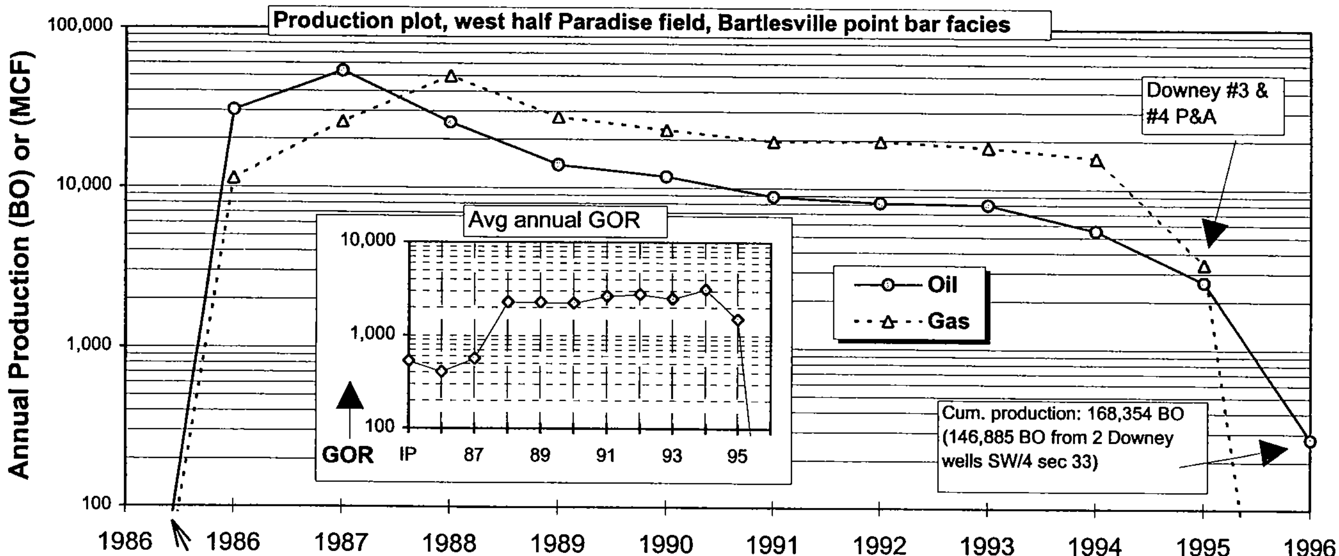
The API gravity was measured in most wells in the field and varied from 34° to 40° API. The oil gravity from four wells in the western part of the field was 37°–40° API (Fig. 32), whereas the oil gravity from six wells in the eastern part was 34°–38° API. The heavier oil (lower API gravity) was produced from the structurally higher part of the field (eastern part), and the lighter oil (higher API gravity), from the structurally lower part (western part). The variation in oil gravity strongly indicates reservoir compartmentalization, which is also indicated by the net sand isopach map (Fig. 28). Most wells produced a significant amount of gas, regardless of structural position (see Figs. 26, 32). Initial gas/oil ratios (IGOR) for most wells in the field were <800 SCF/BBL, and only one good producing well had an IGOR >1,000. The final GOR for most wells was between 455 and 1,754 SCF/BBL but was usually a little more than 1,000. These data can be calculated from the data provided in Figures 32 and 33. The annual average GOR is included in Table 4.

WELL COMPLETION

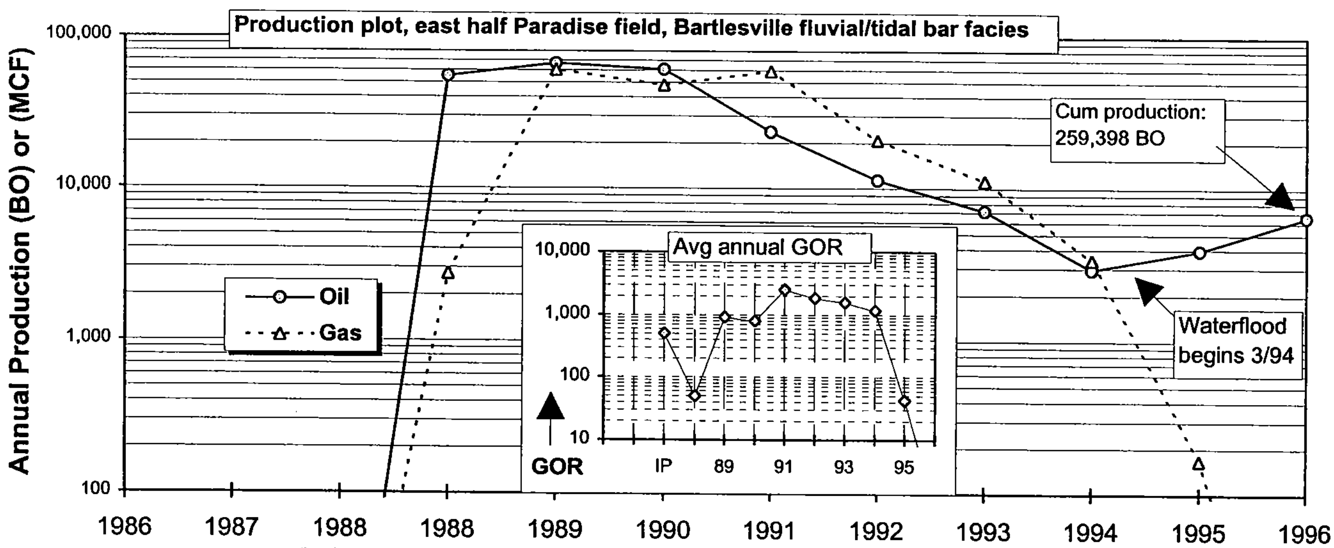
Operators set 4.5-in. production casing at or very near the bottom of the hole. In most productive wells, the entire sand zone was perforated, including much of the shaly sandstone within the upper part of the Bartlesville zone. The wells were acidized and then stimulated with a fracture treatment. Because there is no water leg in this field, any sand with porosity was perforated. Most fracture treatments used gelled water or gelled oil as the mobilizing agent; typically 20,000–45,000 gal of water and something on the order of 20,000–35,000 lb of sand were used. Most of the wells responded favorably after stimulation, but the wells in the Minnich lease near the northwest corner of sec. 4 responded poorly. The sandstone was much the same as that to the north in sec. 33, but well production was much less. This must be attributed in part to poor completion practices, the details of which are not known.

SECONDARY RECOVERY

The eastern part of Paradise field was unitized for purposes of waterflooding in early 1994. The western part of the field would also have been a logical waterflood objective, but operator indifference forestalled unitization of this part of the field. Because this reservoir is separate from the eastern part of the field, Pinnacle Oil decided to plug and abandon its two wells near the southwest corner of sec. 33, thereby making it impractical for the operators of the Minnich lease, near the northwest corner of sec. 4, to waterflood.



A



B

Figure 31. Bartlesville oil and gas production curves, showing average annual production from five wells in the western part of Paradise field (*A*) and average annual production from seven wells in the eastern part of the field (*B*). Production data through July 1996. Inset graphs show average annual gas/oil ratios (GOR). Water injection began in the eastern part of the field during March 1994.

The water-supply well for the unit, SW¼SW¼SE¼ sec. 33, was completed in the Hoover sandstone (Upper Pennsylvanian). This well was originally completed in the Bartlesville sandstone, but the thin sand and poor reservoir characteristics of the Bartlesville made it a good candidate for recompletion in another zone. The initial injection pattern called for two wells, one in the NW¼NE¼NE¼ sec. 4 (No. 1 Tomlinson), and a second in the NW¼SW¼SW¼ sec. 34 (No. 2 Boyce). After only about 20,000 BW was injected in the Tomlinson well, water breakthrough occurred in the Longan wells to the west (mostly in the No. 2 Longan, which was closest). The Tomlinson injector was then reconverted to a producer, leaving the Boyce No. 2 well as the only water-injection well. Water was injected at a rate of about 800 to 950 BW per day, and by August 1996, 712,000 BW was injected (which is about twice the volume of primary oil produced!). It is interpreted that much of the injected water entered the underlying Mississippian limestone, which may have been naturally fractured or may have been fractured during well completion. A small increase in oil production was noticed in mid-1995, primarily from the No. 6 Graham (SE¼ SE¼SE¼ sec. 33), and, to a lesser degree, from the No. 5 Graham to the west in the SW¼SE¼SE¼ sec. 33. Production climbed steadily from about 350 BOPD (mid-1995) to slightly more than 1,000 BOPD by August 1996—largely from the two Graham wells. By late 1996, 2 of the 6 producing wells had responded significantly to the waterflood, while the remaining 4 had not.

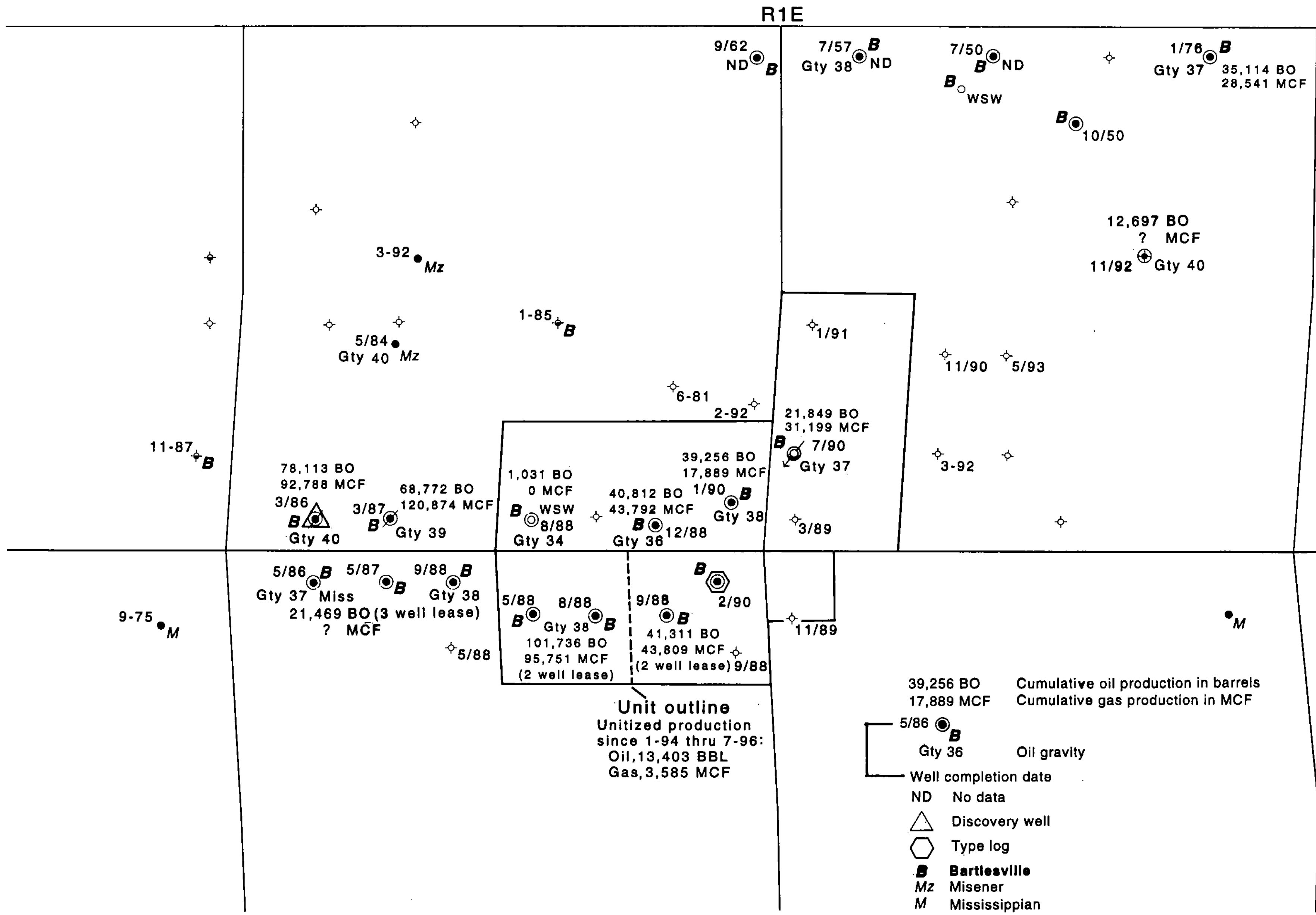


Figure 32. Map showing cumulative oil and gas production, dates of first production, and oil gravity for wells in Paradise field. See Figure 22 for well names.

TABLE 5. – Annual Oil Production from the Bartlesville Sandstone for Wells in Paradise Field

Well information						Date of	Annual Oil Production (BBL)											Cum. Prod.
S3	S2	S1	SEC	Lease name	Well	first prod.	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	(to 8-96)
T. 17 N., R. 1 E.																		
W/2 Nw		Ne	4	Longan[a]	1	5-88	0	0	41,011	34,104	11,542	7,798	4,265	3,016	Unitized ———			101,736
E/2	Nw	Ne	4	Longan[a]	2	8-88	0	0	Production reported with No. 1 Longan						Unitized ———			
Sw	Ne	Ne	4	Tomlinson[b]	1	8-88	0	0	9,302	10,890	12,320	4,356	2,507	1,936	Unitized ———			41,311
Ne	Ne	Ne	4	Tomlinson[b]	3	2-90	0	0	0	0	Production reported with No. 1 Tomlinson				Unitized ———			
Ne	Nw	Nw	4	Minnich[c]	1	5-86	2,460	8,236	3,541	1,593	1,351	1,434	1,029	693	501	357	274	21,469
Nw	Ne	Nw	4	Minnich[c]	2	5-87	0	Production reported with No. 1 Minnich										
Ne	Ne	Nw	4	Minnich[c]	4	10-88	0	0	Production reported with No. 1 Minnich									
T. 18 N., R. 1 E.																		
Sw	Sw	Se	33	Graham[d]	4	8-88	0	0	621	410	0	0	0	0	Unit water-supply well			1,031
Sw	Se	Se	33	Graham	5	12-88	0	0	4,008	21,053	10,553	3,487	1,254	457	Unitized ———			40,812
Se	Se	Se	33	Graham	6	1-90	0	0	0	0	26,377	7,922	3,250	1,707	Unitized ———			39,256
Se	Sw	Sw	33	Downey[e]	3	3-86	27,889	16,047	7,904	5,977	6,439	4,670	3,581	2,900	1,905	801	P&A 12-95	78,113
Sw	Se	Sw	33	Downey[e]	4	3-87	0	29,281	14,042	6,281	3,945	2,743	3,544	4,358	3,102	1,476	P&A 12-95	68,772
Nw	Sw	Sw	34	Boyce[f]	2	7-90	0	0	0	0	11,339	5,989	2,891	1,630	Unit water-injection well			21,849
Tract 1																		
(Unit oil production since 1994)						2-94	0	0	0	0	0	0	0	0	2,937	3,943	6,523	13,403
Unit cumulative annual production (BO)							0	0	54,942	66,457	72,131	29,552	14,167	8,746	2,937	3,943	6,523	**259,398**
Field cumulative annual production (BO)							30,349	53,564	80,429	80,308	83,866	38,399	22,321	16,697	8,445	6,577	6,797	**427,752**
Estimated number of producing oil wells							2	4	10	10	12	12	12	12	11	11	9	

[a]Reported lease oil production from the Nos. 1 and Nos. 2 Longan wells is combined.

[b]Reported lease oil production from the Nos. 1 and Nos. 3 Tomlinson wells is combined.

(The No. 1 Tomlinson was the unit's first injector well. Water injection began about 3-94 and breakthrough occurred to the west in the Longan wells after injection of only about 20,000 BW. Thereafter, the No. 1 Tomlinson was converted back to a producer and the No. 2 Boyce,SW SW 34, was converted to an injection well.)

[c]Reported lease oil production from the Nos. 1, Nos. 2, and Nos. 4 Minnich wells is combined.

(These wells were never included within the Bartlesville sand unit because of operator conflicts.)

[d]Converted to water-supply well (Hoover) during 3-94.

[e]These wells were P&A just after unitization.

[f]Converted to a water-injection well about 4-94.

TABLE 6. – Annual Gas Production from the Bartlesville Sandstone for Wells in Paradise Field

Well Information						Date of	Annual Gas Production (MCF)											Cum. Prod.
S3	S2	S1	SEC	Lease name	Well	first prod.	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	(to 8-96)
T. 17 N., R. 1 E.																		
W/2	Nw	Ne	4	Longan[a]	1	12-88	0	0	1,791	29,716	18,348	28,211	11,280	6,405	Unitized			95,751
E/2	Nw	Ne	4	Longan[a]	2	9-90?	0	0	0	0	Production reported with No. 1 Longan				Unitized			
Sw	Ne	Ne	4	Tomlinson[b]	1	12-88	0	0	328	7,692	14,679	13,250	4,905	2,955	Unitized			43,809
Ne	Ne	Ne	4	Tomlinson[b]	3	9-90?	0	0	0	0	Production reported with No. 1 Tomlinson				Unitized			
Ne	Nw	Nw	4	Minnich	1		No gas production reported											
Nw	Ne	Nw	4	Minnich	2		No gas production reported											
Ne	Ne	Nw	4	Minnich	4		No gas production reported											
T. 18 N., R. 1 E.																		
Sw	Sw	Se	33	Grahac[c]	4	8-88	0	0	621	410	0	0	0	0	Unit water-supply well			1,031
Sw	Se	Se	33	Graham	5	1-89	0	0	0	22,411	14,954	4,978	1,442	7	Unitized			43,792
Se	Se	Se	33	Graham	6	3-91	0	0	0	0	0	12,876	3,193	1,820	Unitized			17,889
Se	Sw	Sw	33	Downey[d]	3	3-86	11,348	9,584	11,307	12,702	15,014	13,585	7,957	5,046	4,952	1,293	P&A 12-95	92,788
Sw	Se	Sw	33	Downey[d]	4	5-87	0	16,104	38,614	14,893	7,898	5,918	11,700	12,986	10,641	2,120	P&A 12-95	120,874
Nw	Sw	Sw	34	Boyce[e]	2	7-90	0	0	0	0	7,726	12,418	8,163	2,892	Unit water-injection well			31,199
Tract 1																		
(Unit gas production since 1994)						1-94	0	0	0	0	0	0	0	0	3,418	167	0	3,585
Unit cumulative annual production (MCF)							0	0	2,740	60,229	55,707	71,733	28,983	14,079	3,418	167	0	**233,471**
Field cumulative annual production (MCF)							11,348	25,688	52,661	87,824	78,619	91,236	48,640	32,111	19,011	3,580	0	**450,718**
Estimated number of producing gas wells							1	2	5	6	8	9	9	9	8	7	0	

[a]Reported lease gas production from the Nos. 1 and Nos. 2 Longan wells is combined.

[b]Reported lease gas production from the Nos. 1 and Nos. 3 Tomlinson wells is combined.
(The No. 1 Tomlinson was the unit's first injector well. Water injection began about 3-94 and breakthrough occurred to the west in the Longan wells after injection of only about 20,000 BW. Thereafter, the No. 1 Tomlinson was converted back to a producer and the No. 2 Boyce, SW SW 34, was converted to an injection well.)

[c]Converted to water-supply well (Hoover) during 3-94.

[d]These wells were P&A just after unitization.

[e]Converted to a water-injection well about 4-94.

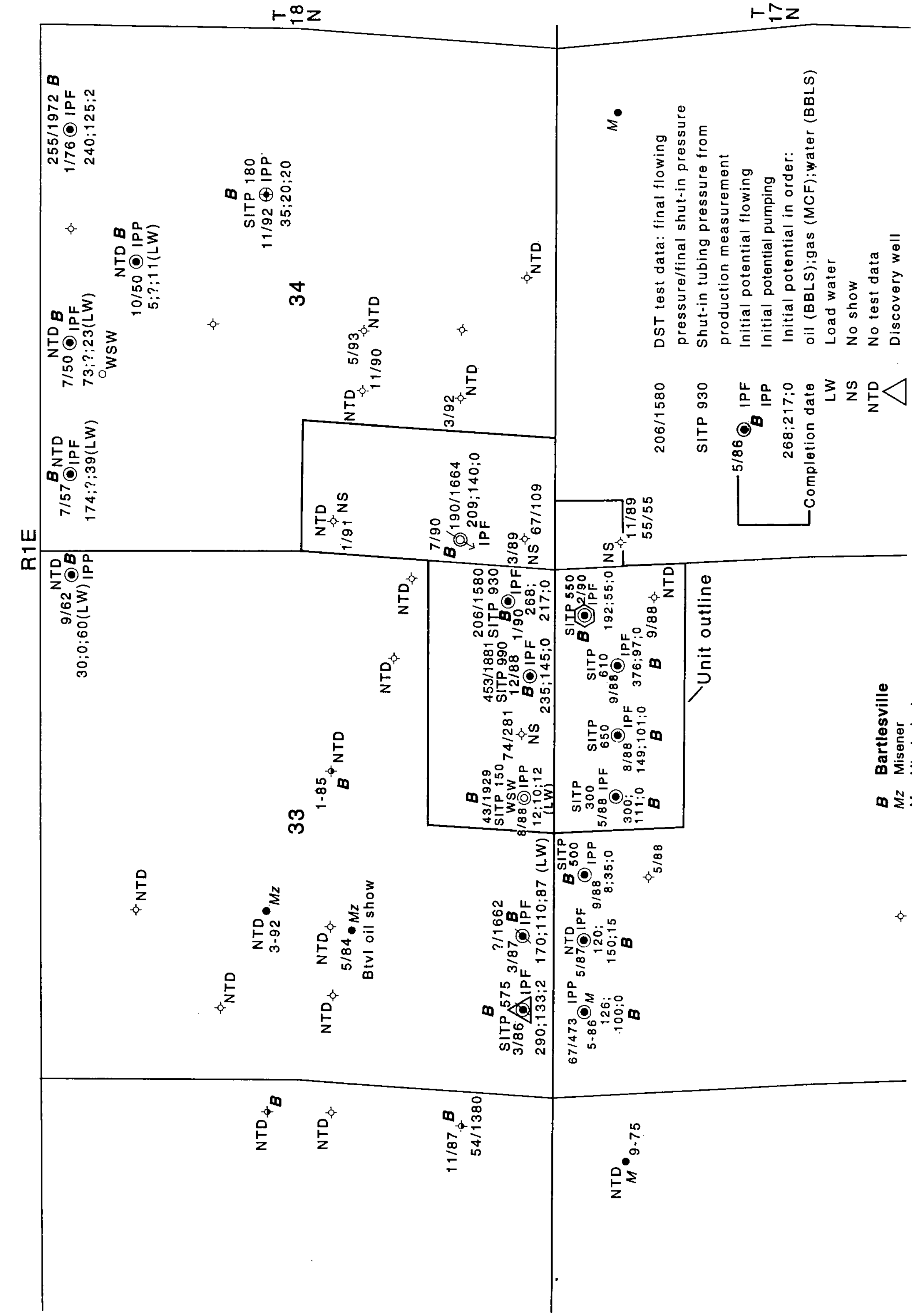


Figure 33. Map showing well-pressure data, dates of first production, and initial potentials for wells in Paradise field. See Figure 22 for well names.

NW Russell Field

(Bartlesville oil pool in secs. 19, 20, 29, and 30, T. 18 N., R. 2 W., and secs. 24 and 25, T. 18 N., R. 3 W., Logan County, Oklahoma)

by
Richard D. Andrews

INTRODUCTION

NW Russell field is located in northern Logan County in north-central Oklahoma (Fig. 34). The field area is about 11 mi east of the Nemaha uplift, in an area commonly referred to as the Cherokee platform province (Pl. 1). NW Russell field produces oil and gas from several reservoirs, although the Bartlesville sand, the Mississippi lime, and the Oswego lime are the principal supply sources. Oil and gas production from these reservoirs is generally commingled, and only a few wells produce from single-zone completions strictly in the Bartlesville.

The Bartlesville is a relatively thin reservoir. It is composed of 5–15 ft of sandstone that is interpreted to be primarily tidal or shallow, nearshore marine in origin. Some wells also have sandstone that could be fluvial, such as tidal-channel deposits in an estuarine setting. A map identifying producing reservoirs, well locations, operators, well numbers, and principal leases within the field area is shown in Figure 35.

Oil production was first established in the NW Russell study area in mid-1970 with the completion of two wells in sec. 25, T. 18 N., R. 3 W. These wells were completed in the Oswego lime for 63–148 BOPD. Nearly every other well in the study area was completed about 10 years later during 1979 and 1980, with development of the Mississippian limestone reservoir, the Bartlesville sand, and, to a lesser extent, the Oswego lime. The Bartlesville oil pool in NW Russell field probably was discovered in a deliberate effort to extend known productive fluvial trends farther to the west. This same trend is productive in Paradise field (~12 mi to the east). In this effort, Bobby Darnell drilled the No. 3 Brown (SE¼ NE¼ sec. 29, T. 18 N., R. 2 W.) and discovered the Bartlesville oil pool in NW Russell field. This well was completed in March 1977 with an initial flowing potential of 18 BOPD from 8 ft of net Bartlesville sandstone. (In 1980 it was recompleted in the younger Oswego lime.) Field development stalled for 2 years but accelerated in 1979. A total of 27 wells were completed in the Bartlesville, which appears to be about equal in potential for hydrocarbon production in comparison with the more widespread production from the thick Mississippian section. Bartlesville oil has a gravity ranging from 39° to 42° API. No gas cap or oil–water contact was identified.

NW Russell field is fully developed on 80-acre spacing. Most if not all wells continue to produce small amounts of gas and oil, and the field has never been developed for secondary oil recovery. The Bartlesville reservoir is relatively shallow (~5,400 ft), although the estimated high shrinkage factor of oil and a significant

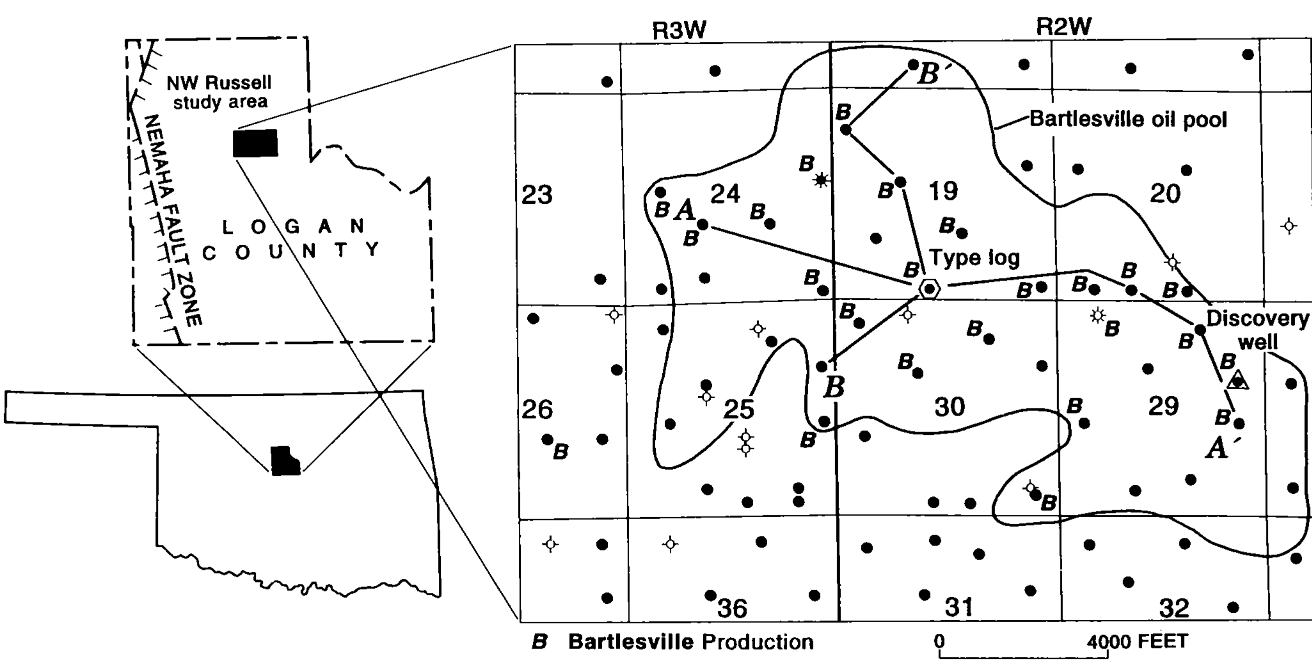


Figure 34. Map showing location of the Bartlesville oil pool in the NW Russell field area, Logan County, Oklahoma.

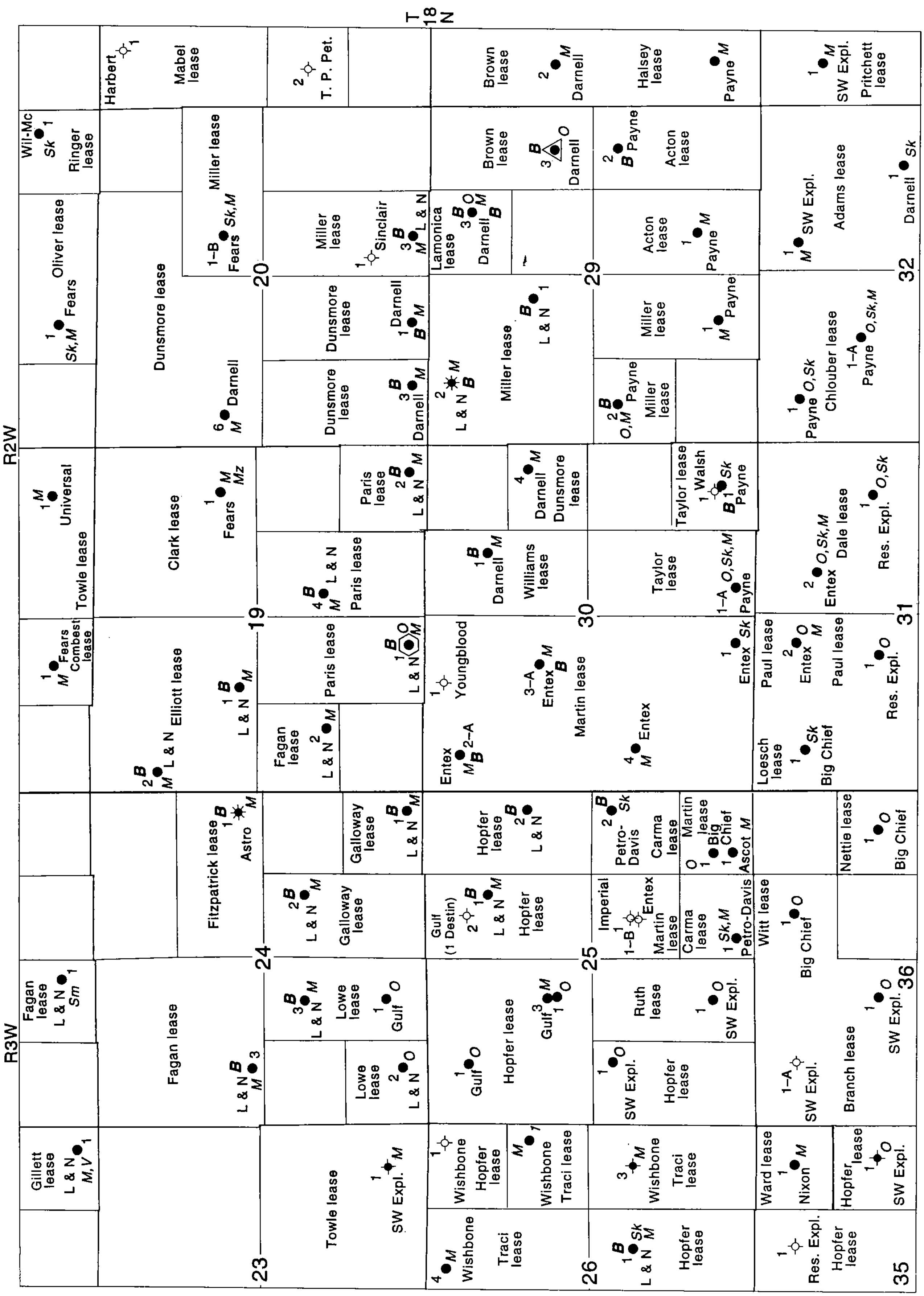


Figure 35. Well-information map, showing operators, lease names, well numbers, and producing reservoirs for wells in the NW Russell field study area. See Appendix 4 for explanation of symbols.

amount of gas production may be deleterious to waterflooding, despite the relatively low IGOR.

STRATIGRAPHY

A typical log from the NW Russell field and the stratigraphic nomenclature are shown in Figure 36. The Bartlesville interval is directly overlain by ~7 ft of low-resistivity shale that normally encompasses the Inola Limestone. This same zone is also noted by an enlarged borehole, as recorded on the caliper log. The Inola is present only as a thin, 2-ft bed but has a characteristic log signature that includes a sharp kick on the resistivity log (normally the shallow recording), a sharp response on the density log, and a small response on the GR log. In this study area, the base of the Bartlesville interval is interpreted to coincide with the top of the eroded Mississippian limestone. The Bartlesville sand zone, which occupies about half the Bartlesville interval, is underlain by 10–25 ft of shale. The basal contact of the sandstone generally is a rapid transition to shale, as seen on the GR logs. Occasionally, a sharp basal contact is observed. This same contact relationship appears even more sharp on the resistivity log. The textural relationship of sediments above the main sand bed is commonly gradational, indicating an upward-fining lithology (or increasing amount of shale), which is sometimes characteristic of channel deposits. These textural characteristics of the Bartlesville sandstone are unusual because they are similar to what is found in both channel and marine (or marginal-marine) bars. Different facies of the Bartlesville sandstone within NW Russell field are interpreted to have been deposited within the same depositional system, but as a result of variable depositional processes. The resulting sand facies may represent sandstone-redistribution patterns from the interaction of high-current (channel?) and shoreline (or tidal) environments.

The stratigraphy of the Bartlesville interval is shown by detailed structural–stratigraphic cross sections *A–A′* (Fig. 37, in envelope), along the depositional trend of the field, and *B–B′* (Fig. 38, in envelope), which is trans-

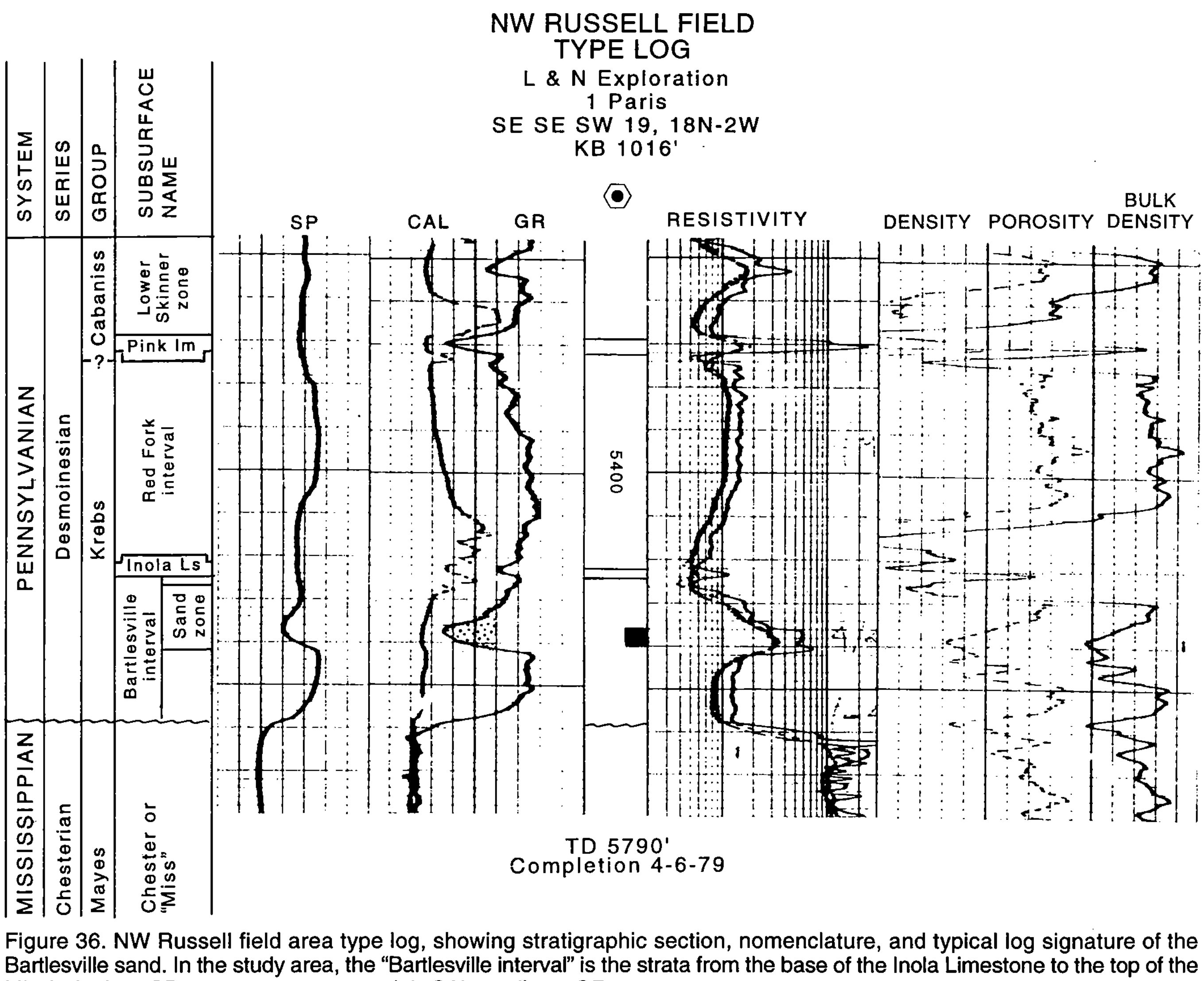


Figure 36. NW Russell field area type log, showing stratigraphic section, nomenclature, and typical log signature of the Bartlesville sand. In the study area, the "Bartlesville interval" is the strata from the base of the Inola Limestone to the top of the Mississippian. *SP* = spontaneous potential; *CAL* = caliper; *GR* = gamma ray.

verse across the field. In both cross sections, the highly variable spatial relationship of sandstone deposits is interpreted from the various log traces provided.

In cross section *A–A′*, the Bartlesville interval is shown to dip to the west, yet no wells encountered any indication of an oil–water contact. Wells 1, 3, and 5 clearly have an upward-coarsening textural profile, as indicated on the GR and/or resistivity curves. Contrasting with these log signatures are those of the Bartlesville sands noted in wells 2 and 4, which have a much sharper basal contact with shale. In well 4, the basal Bartlesville sandstone appears to have started out as a channel, whereas the sand bed directly above is clearly different in its vertical log (textural) profile. The reversal of apparent depositional processes (channel versus nonchannel bar morphologies) that occur within the same depositional system is common in tidal (estuarine) environments. It is possible that the sandstone having a definitive upward-coarsening log (textural) profile may represent tidal-mouth bars, whereas the sand beds having a sharper basal contact represent bar deposits modified by tidal currents or possible remnants of channel deposition within a coastal inlet. As shown in wells 1, 3, 5, and the upper bed in well 4, the best part of the Bartlesville reservoir (cleanest or highest porosity) is the upper part of the sand zone. This characteristic is common in nonchannel deposits. Density-porosity measurements in the upper part of the sand beds in wells 4 and 5 are routinely 14–16%. The best reservoir in sands interpreted to be channel or modified bar deposits (well 2) occurs in the lower part of the sand zone. This same relationship is illustrated in wells used in cross section *B–B′*.

Cross section *B–B′* (Fig. 38) is oriented across the longitudinal axis of the field roughly parallel to strike. The end wells (1 and 2) are at the field margins, where the Bartlesville sand is either thin or absent. Well 3 is structurally high within the field, where the Bartlesville sand is interpreted to be a marginal-marine or a tidal-mouth bar. This interpretation is based upon its known proximity to fluvial-terrestrial deposits several miles to the east, a well-developed upward-coarsening textural profile, and an interfingering with sand beds having a "channel-like" log signature (wells 2 and 4). To the northwest, the Bartlesville sandstone in well 4 is interpreted to be a channel deposit because of its sharp basal contact with shale and gradational upward-fining textural profile in the upper part of the sand zone. Although the channel sand appears to be somewhat lower in the Bartlesville interval (possibly owing to scour), it is believed to be part of the same depositional system as that of the nonchannel bars. The different log signatures probably reflect spatial variations in current energy within a coastal embayment or estuary.

Sandstone facies represented in both cross sections are interpreted to interfinger laterally rather than having abrupt erosional boundaries from unrelated depositional events. Because of this interpretation, it is believed that all of the Bartlesville sandstone is related to a common depositional system characterized by redistribution and modification of original sand deposits. These types of depositional processes may, however, lead to reservoir compartmentalization, despite the apparent assimilation of different sandstone facies into one sand zone.

STRUCTURE

Localized structure within the study area, as represented by an Inola Limestone structure map (Fig. 39), shows a west–southwest dip of about 0.5° or about 50–75 ft/mi. This structure coincides with the regional structure of the Bartlesville sand, as shown in Figure 16. Both structural interpretations are similar to the structural expression of the Mississippian (Fig. 40) and indicate that deposition was not controlled by a unique pre-Pennsylvanian erosional-unconformity feature, as was the case in the Paradise field area. As can be seen in either structure map, the highest position within the field occurs in the far eastern part of the mapped area. In this area, the Bartlesville sandstone is above –4,350 ft. The lowest part of the field is in the far western part of the mapped area, where the Bartlesville is slightly below –4,450 ft.

As at many places within the Anadarko shelf and platform areas, fracturing may have a significant effect on fluid flow, especially during water injection. The dominant fracture pattern in this area is interpreted to occur in a northeast–southwest direction, although there is no clear-cut evidence indicating that fracturing occurs within the field.

BARTLESVILLE SANDSTONE DISTRIBUTION AND DEPOSITIONAL ENVIRONMENT

Figure 41 shows the gross thickness of the Bartlesville sandstone for all the wells in the study area. The gross sand thickness is the total thickness of sandstone, regardless of porosity, determined from the GR and resistivity logs. The zero-thickness line is simply the limit of sand deposition but not necessarily the limit of the Bartlesville reservoir, which is almost always smaller in areal extent.

The gross sandstone thickness, regardless of facies, ranges from only a few feet to about 15 ft but is generally in the range of 7–14 ft. Near or at the depositional limits of sandstone, the entire sand zone is very dirty (or shaly), which is a characteristic unlike that of many channel deposits that have clean sand beds of various thicknesses that extend to the depositional edges of the channels. The gross depositional pattern is not particularly suggestive of either a channel or a marine bar, which may lend support to the tidal-inlet theory proposed in this study.

A net sandstone isopach map (Fig. 42) shows the thickness of sandstone with ≥8% porosity. This value was selected because it best identifies the known limit of Bartlesville oil and gas production versus selecting a higher porosity cutoff value such as 10%. The net sand thickness ranges from a few feet to 11 ft, with an average thickness of ~6 ft. Although the basic distribution pattern of the net sand is similar to that of the gross sand, the thickness of net sand is ~50% to 60% of the thickness of gross sand. A higher cutoff value, such as 10%, would have significantly decreased the amount of net sand in most wells that had production attributed to the Bartlesville. Also, by using a higher net sand cutoff, several Bartlesville wells would appear to have no net sand, and this would seriously affect reserve calculations. There is no water leg in the field, so the reservoir includes the entire area with >0 ft of net sand (Fig. 42).

The areal distribution pattern of Bartlesville sandstone within the NW Russell field study area is somewhat funnel shaped. The sand body is roughly 3 mi long and 1.5 mi wide but narrows to only ~0.5 mi along the eastern edge of the study area. Within the general area, the Bartlesville sandstone extends several townships to the east in a discontinuous manner (Fig. 43). Nearly everywhere the Bartlesville sandstone is present, it is productive, giving rise to a series of fields (a "trend") interpreted to be largely fluvial in depositional origin, although nonchannel facies are locally prevalent. The fields in this trend are prone to oil production.

Speculation exists as to whether deposition occurred from the east to the west, or just the opposite. Although pronounced thickening of the Bartlesville interval occurs to the east away from the Nemaha uplift—thereby implying an easterly flow direction and a westerly source—the sandstone facies gradually thin to the west and become marine (nonfluvial) (Fig. 43). This sandstone-facies interpretation supports the concept of a westward-trending depositional system with an easterly source. Although sandstones with channel-like log profiles are present in this study area, they are not typical of fluvial flood-plain or delta-plain deposits.

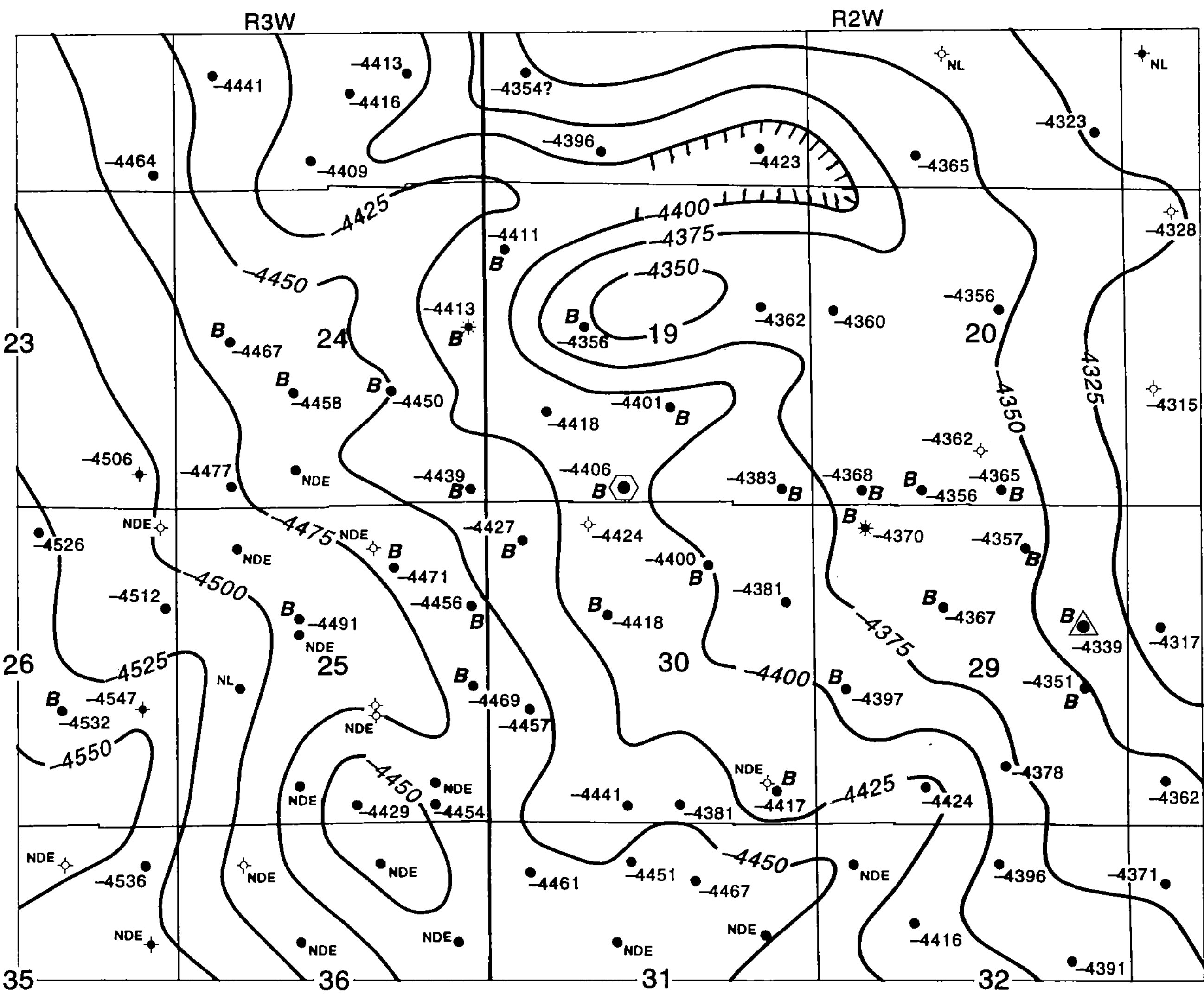


Figure 39. Structure map of the top of the Inola Limestone in the NW Russell field study area. This datum is a regional stratigraphic and structural marker. Contour interval is 25 ft. See Figure 35 for well names. See Figure 36 for type log. See Appendix 4 for explanation of symbols.

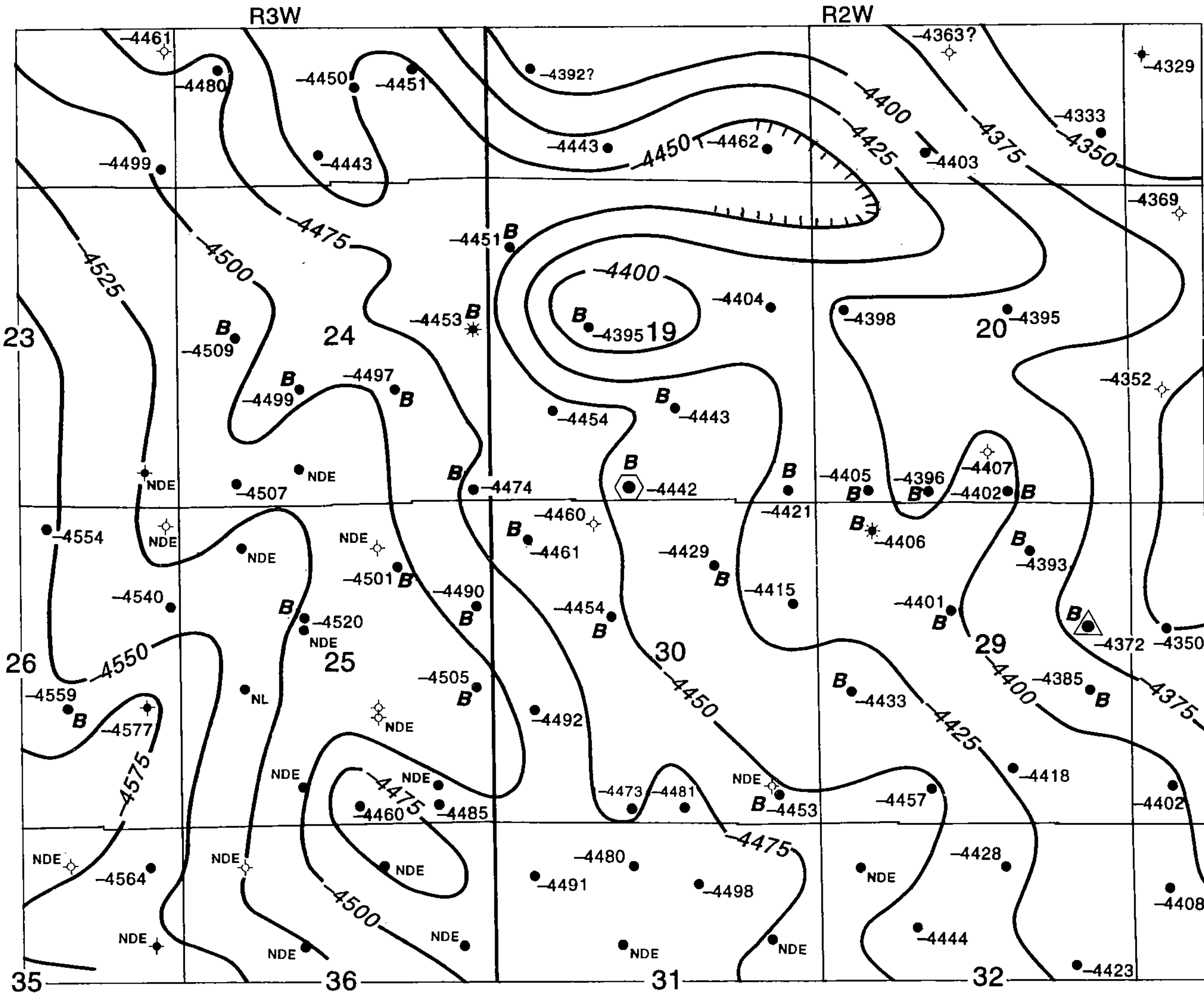


Figure 40. Structure map of the top of the Mississippi lime in the NW Russell field study area. This datum is a pre-Cherokee erosional surface, although in this area it closely resembles the true structure as shown in Figure 39 (structure of top of Inola Limestone). Contour interval is 25 ft. See Figure 35 for well names. See Figure 36 for type log. See Appendix 4 for explanation of symbols.

Reasons supporting this interpretation include the paucity of facies that clearly define a channel or flood-plain environment, such as point-bar facies, coal, channel incision, or abandoned-channel facies. In NW Russell field, a clearly defined channel system is not present; rather, certain areas appear to contain channel remnants or sand bodies that may have been reworked by strong currents in a relatively narrow, winding depositional trend.

FACIES MAPPING

Depositional environments, as illustrated in Figure 44, were interpreted from spatial distribution patterns of sandstone from isopach mapping and by comparing wireline-log signatures, particularly the GR and resistivity logs. Two distinctly different facies are interpreted in NW Russell field for productive Bartlesville sandstone, although they do not appear to represent two different depositional episodes. The two sandstone facies include channel and marginal marine (tidal-mouth bar?).

Channel Facies

Within the depositional limit of the Bartlesville sandstone, ~30% of the wells contain sand beds that have log signatures somewhat resembling channel deposits (i.e., sandstone beds having a relatively sharp basal contact with shale and an overall shaling-upward textural profile). These log signatures are generally much different than bar or nonchannel deposits, which have a distinctive upward-coarsening textural profile. Although these two facies occur simultaneously throughout the field, they seem to interfinger, and production is not necessarily facies related. The channel facies do not occur as incised deposits of a unique depositional event. They have a general log appearance of upward fining but may also have a rapid basal transi-

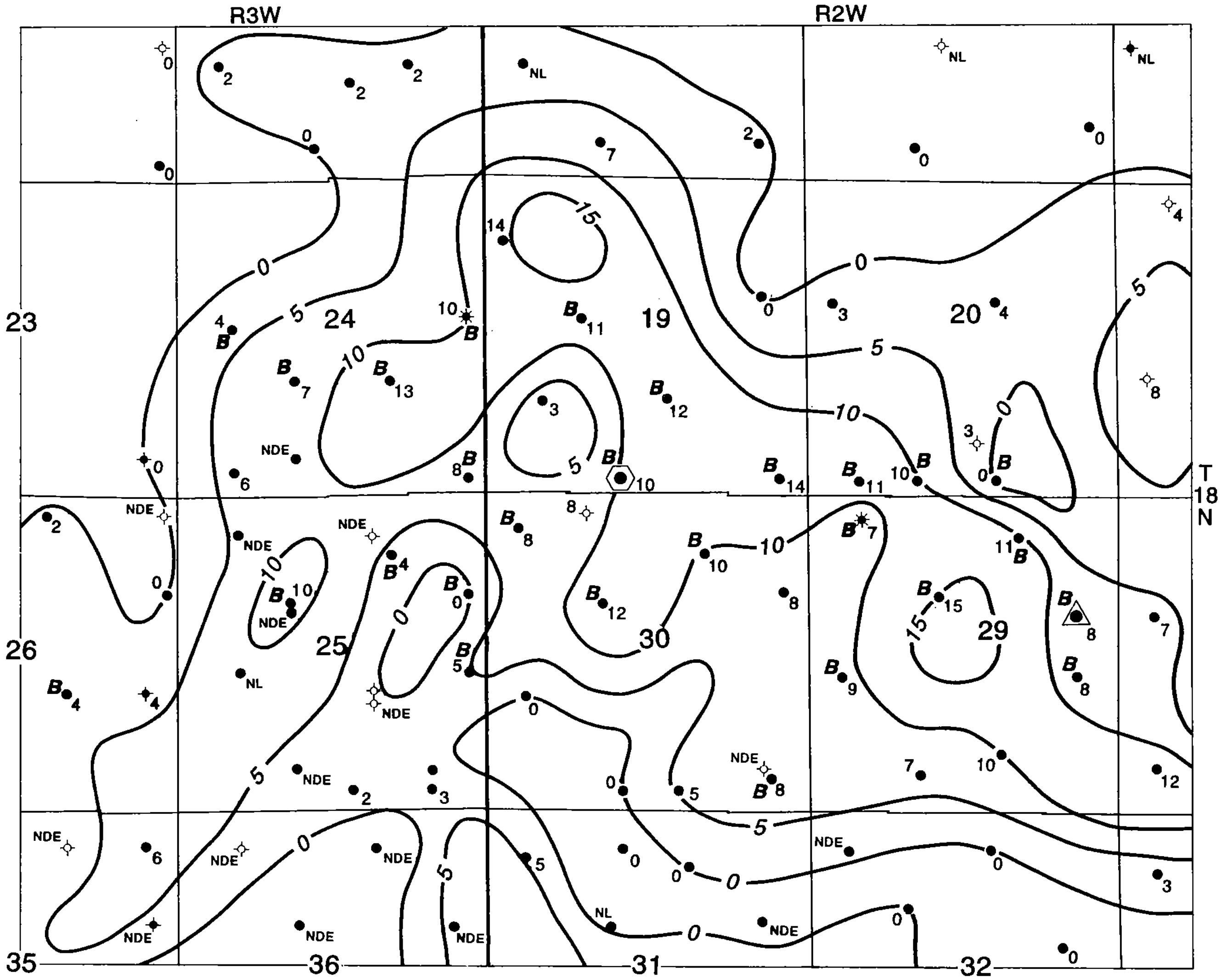


Figure 41. Gross sand isopach map of the Bartlesville sandstone in the NW Russell field study area. Gross sand includes all sandstone, regardless of porosity, in the interval from the base of the Inola Limestone to the top of the Mississippi lime. Contour interval is 5 ft. See Figure 35 for well names. See Figure 36 for type log. See Appendix 4 for explanation of symbols.

tion from shale to sand, which can be interpreted as upward coarsening. The channel sands do not have distinctive shale breaks in the upper half of the sand zone, which is typical of point bars; and lateral facies of flood-plain environments, such as channel-margin or abandoned-channel deposits, are not present. Additionally, channel-like sand beds are more prevalent in the eastern part of the study area, whereas to the west, in R. 3 W., the Bartlesville sand zone shales out with little, if any, indication of channeling. In the absence of clearly delineated flood-plain sediments, the "channel sands" may represent areas of deposition more affected by current-induced sedimentation, such as in a tidal-inlet channel or a proximal tidal-mouth bar (estuary). This distinction is important for exploration purposes, as there is no indication from subsurface-mapping techniques of a delta front or a delta plain extending farther west along the NW Russell field trend.

Marginal-Marine or Tidal-Mouth-Bar Facies

Sandstone that is interpreted to have an upward-coarsening textural profile, as indicated from GR, resistivity, and porosity logs, is considered to have originated from different depositional processes in comparison to the channel-like deposits previously described. Sandstones having these characteristics are productive within NW Russell field as well as in Bartlesville fields extending farther east (Fig. 43). The interfingering spatial relationship of nonchannel deposits with sandstone beds that resemble channel deposits is ubiquitous. This concept can be envisioned in a tidal inlet where closely related depositional processes that prevail in high-current areas occur adjacent to environments where deposition results from the emanation of suspended sediments in lower current areas. The nonchannel sandstone beds are probably not detached offshore bars.

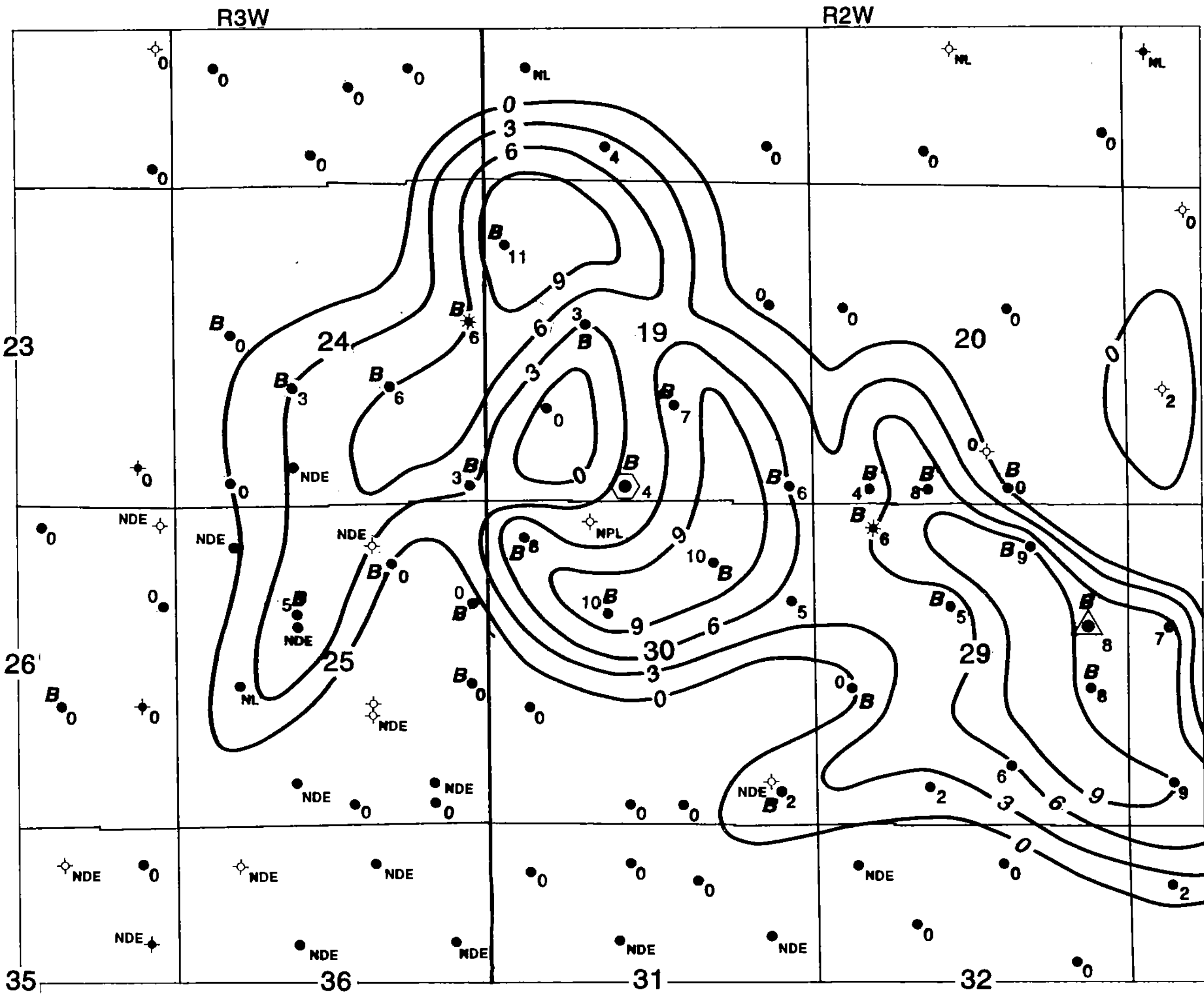


Figure 42. Net sand isopach map of the Bartlesville sandstone in the NW Russell field study area. Net sand is considered to be sand with log porosity ≥8%. Contour interval is 3 ft. See Figure 35 for well names. See Figure 36 for type log. See Appendix 4 for explanation of symbols.

CORE ANALYSIS

Principal operators of the Bartlesville oil pool were contacted about core availability and analysis for the Bartlesville sandstone in the NW Russell field study area. Evidently, no cores were recovered in this area.

FORMATION EVALUATION

The identification and evaluation of Bartlesville sandstone in NW Russell field are fairly straightforward, even though the sand zone has a highly variable clay content (as interpreted from GR logs). In fact, only a portion of the sand zone may actually be classified as sandstone (>50% sand fraction) versus sandy-silty shale. However, the productive interval that is generally perforated is relatively clean (i.e., GR and resistivity logs are not significantly affected by interstitial clay or mica). Porosity determinations of the sandstone from density or density–neutron logs (run on a standard 2.71 matrix density) were generally in the range of 8–14% and averaged ~12%. Based on core data from nearby Paradise field (this publication), these porosity values are probably only 1–2 percentage units higher than those of the actual reservoir rock. Reservoir characteristics of the Bartlesville sandstone in NW Russell field are shown in Table 7.

The deep or "true" resistivity of productive intervals ranges from about 15 to 32 ohm-meters and is usually about 20–30 ohm-meters. The higher resistivities occur in sandstones within the eastern part of the field, which is up to 100 ft higher structurally than the western part. Sandstone in the eastern part of the field (R. 2 W.) also has better reservoir properties (cleaner sand with higher porosity). A relatively strong separation of about 20–30 ohm-meters exists between the shallow and deep resistivity readings in the producing interval, whereas these two measurements generally "track" one another in the more shaly zones. The separation of the shallow

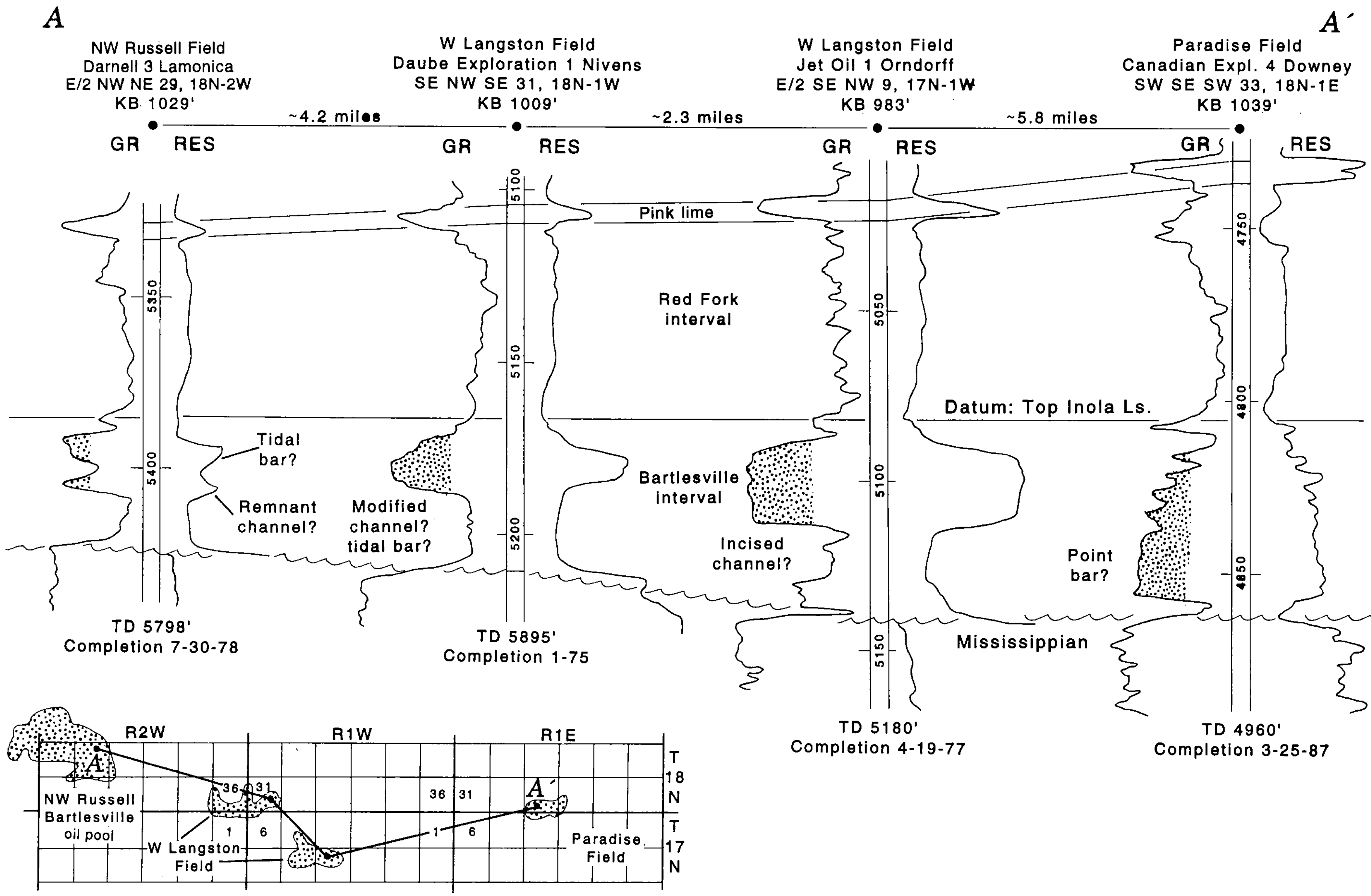
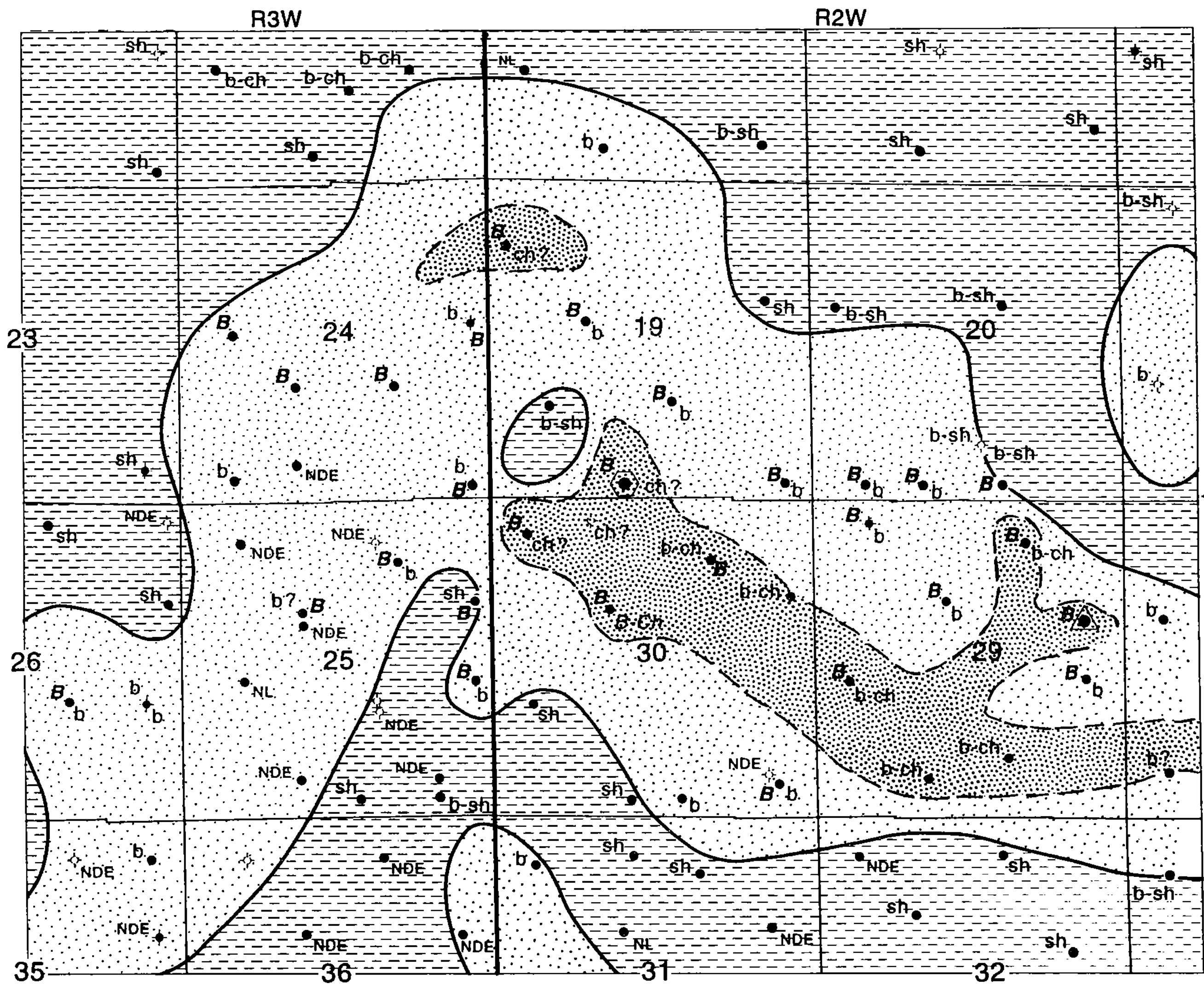


Figure 43. Generalized stratigraphic cross section showing facies relationships of the Bartlesville sand across western Payne and eastern Logan Counties, Oklahoma. Within the same depositional system, the sandstone facies become increasingly nonfluvial to the west. This may indicate a tidal influence, as interpreted from well logs, since both channel and nonchannel sand deposits are interfingering.

and deep resistivity curves indicates the presence of permeability, which has not been measured from cores in the study area. Nevertheless, on the basis of the relatively small initial-potential and low flowing-pressure data from two wells initially completed in the Bartlesville (Fig. 45), the permeability is probably rather low, possibly <10 md. Additional evidence regarding reservoir quality is interpreted from the caliper log (CAL). As shown in all the cross-section wells (Figs. 37, 38), the borehole diameter through the Bartlesville sand zone is not reduced by mud-cake buildup. Such reduction generally happens in reservoirs having a permeability of at least 15–30 md (see Ohio–Osage field study cross sections, Figs. 53, 54).

Water-saturation (S_w) calculations for the Bartlesville sandstone ranged from ~22% to 60%. The higher values appear to be adversely affected by low porosity. The S_w in most productive sandstones averaged ~37%. Calculations were made by using the equation $S_w = \sqrt{F \times R_w / R_t}$. The formation-water resistivity (R_w) was assumed to be 0.035 ohm-meters at formation temperature. The Archie equation for formation factor ($F = 1/\phi^2$)



B	Bartlesville
b	Bar sand, possibly tidal or near-shore marine
ch	Channel sand, possibly tidal influenced
b-ch	Sand deposits having log profile resembling both a channel and marine bar (rapid basal transition from shale to sand but not sharo), and upward-finning textural profile in upper part of sandy body. Sand commonly occurs in two beds.
sh	Predominantly shale

Figure 44. Depositional-facies map of the Bartlesville sand in the NW Russell field study area.

TABLE 7. – Reservoir/Engineering Data for the Bartlesville Sandstone in NW Russell Field, Logan County, Oklahoma

Reservoir size	~2,650 acres
Depth	~5,400 ft
Well spacing (oil)	80 acres, irregular
Bartlesville completions	27, usually commingled with Mississippian production
Oil–water contact	None observed; formation water not produced during primary production; load water recovered during IP tests
Gas–oil contact	None observed
Porosity (in net sand)	Generally 8–14% (avg. ~12%)
Permeability	Unknown, probably <10 md
Water saturation (calculated)	Generally 22–60% (avg. ~37%)
Thickness (net sand ϕ >8%)	Generally 3–9 ft (avg. ~6.1 ft)
Reservoir temperature	120°F
Oil gravity	39°–42° API
Initial reservoir pressure	Unknown
Initial formation-volume factor	1.35 RB/STB (est.)
Initial average GOR (first year)	2,135–3,407 (SCF/BBL)
Final GOR (last full year O&G production)	3,254–63,500 (SCF/BBL)
OOIP (volumetric)	5,817,000 STBO
Cumulative primary oil prod. (to 1/97)	Probably <350,000 STBO; 10–20 MBO per Bartlesville completion (est.)
Primary recovery efficiency (oil)	<6%
Primary recovery (oil)	<25 BO/acre-ft
Cumulative gas production	Probably <2,000,000 MCF; 50–100 MMCF per Bartlesville completion (est.); some wells >200 MMCF

was used because it seemed more reasonable for this particular reservoir. Using a modified F equation generally resulted in calculated S_w values that were unrealistically low and, conversely, oil-saturation determinations that were too high. R_t, true resistivity, was taken directly from the deep resistivity log. Porosity values were also taken directly from density logs and reduced about 1 porosity unit to reflect actual reservoir conditions. Neutron porosity was not used for crossplot porosity determinations because of the highly variable clay content in the sandstone, which causes the neutron-log porosity to be too high. Log density porosity was calculated by using a matrix density of 2.71 g/cm^3.

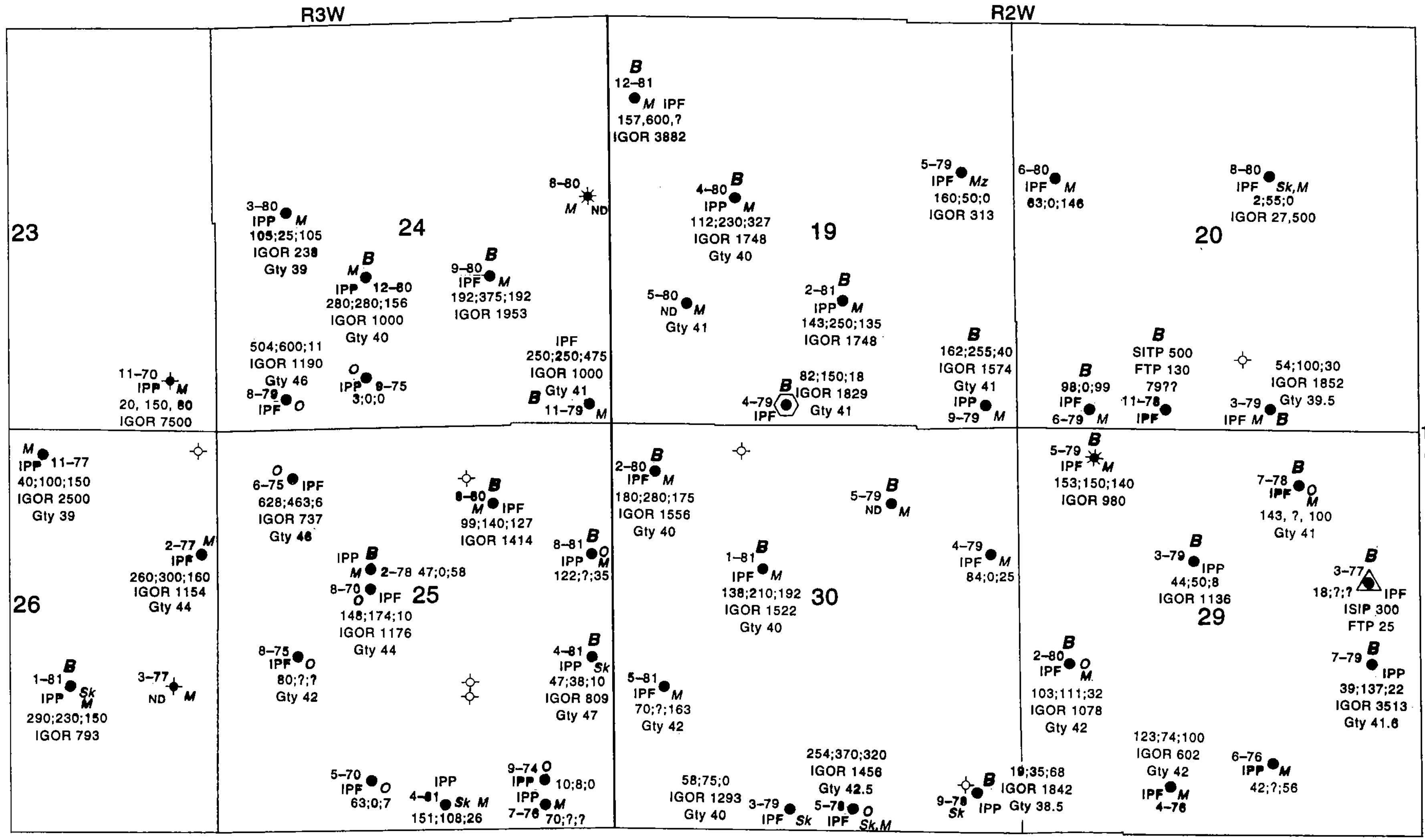
OIL AND GAS PRODUCTION

The estimated cumulative oil and gas production from the Bartlesville sandstone in NW Russell field is unknown, despite good production records for all wells or leases in the study area. This is because production from several reservoirs was commingled. Nevertheless, a few wells have single-zone completions in the Bartlesville, and other wells were completed sequentially over long time periods, which enabled the interpretation of Bartlesville production. As an example, production data for three wells having single-zone completions exclusively in the Bartlesville are presented in Table 8. These three wells have typical sand development in the nonchannel facies and average about 17,500 BO and 176,000 MCFG per well. These values are reasonable except for the gas production, which is probably high, as the eastern part of the field is more prone to gas production versus the western part (R. 3 W.). Assuming average production from 20 wells (there are 27 within the field), oil production would have been about 350,000 BO. Gas production, however, is likely less than about 2 billion cubic feet (BCF), because cumulative gas production from all wells completed in the Bartlesville (including commingled wells) is less than ~3.3 BCF. As a comparison of well performance with regard to producing zone, cumulative-production values for oil and gas are posted in Figure 46. Some wells are completed only in the Mississippian, others only in the Oswego. Many wells have commingled production from the Bartlesville and one or more of these zones. A few wells have production attributed only to the Bartlesville.

Oil production from the Bartlesville declined rapidly after the first full year of production. Of the three wells included in Table 8, annual oil production fell between 52% and 60% after the first full year. The rapid decline in oil production is illustrated by the production decline curve in Figure 47. Gas production was much more stable and actually increased after the first full year of production, then declined gradually (Fig. 48). Cumulative production does not appear to be totally related to the date of first production; rather, reservoir quality is the most important factor for good production.

Initial oil-production rates of wells initially completed in the Bartlesville ranged from 18 to 44 BOPD (Fig. 45). The low rates and small range in initial production probably are due to low reservoir permeability with little natural fracturing. The general paucity of test data made it impossible to interpret any type of local pressure depletion over time. Flowing-tubing-pressure data were sparse and ranged from 25 to 130 PSI.

The API gravity was measured in many wells in the field having commingled production and varied from 39° to 42° API (Fig. 45). The single API gravity measurement of Bartlesville oil from a single-zone completion was 41.6° API.



PRODUCING FORMATIONS

O	Oswego
Sk	Skinner
B	**Bartlesville**
M	Mississippian
Mz	Misener

2–80		Completion date
●	IPF	Initial potential flowing
	IPP	Initial potential pumping
100;300;50		Initial potential in order of: Oil (BBL); Gas (MCF); Water (BBL)

ISIP	Initial shut-in pressure
FTP	Flowing tubing pressure
Gty 40	Oil gravity in API°

Figure 45. Map showing initial potentials, completion dates, and API gravity for wells in the NW Russell field area. Two wells initially completed in the Bartlesville sand (No. 1 Dunsmore, sec. 20 SE¼SW¼, and No. 3 Brown, sec. 29 SE¼NE¼) have shut-in and flowing tubing pressures. See Figure 35 for well names. See Appendix 4 for explanation of symbols.

TABLE 8. – Annual Production and GOR for Three Wells Completed Exclusively in the Bartlesville Sandstone

Year	SE SW 20, 18N-2W #1 Dunsmore			NE SE 29, 18N-2W #2 Acton			SE NW 29, 18N-2W #1 Miller		
	Oil (BBL)	Gas (MCF)	GOR	Oil (BBL)	Gas (MCF)	GOR	Oil (BBL)	Gas (MCF)	GOR
1978	0	0		0	0		0	0	
1979	5,214	15,134	2,903	4,859	10,376	2,135	6,593	22,465	3,407
1980	2,523	2,016	799	6,868	28,952	4,215	2,911	45,004	15,460
1981	1,322	5,912	4,472	2,757	29,963	10,868	1,330	32,959	24,781
1982	750	6,070	8,093	1,462	21,921	14,994	724	15,370	21,229
1983	532	8,014	15,064	1,263	14,615	11,572	757	14,122	18,655
1984	691	4,578	6,625	866	17,560	20,277	738	13,806	18,707
1985	205	3,992	19,473	864	16,086	18,618	540	11,424	21,156
1986	300	2,096	6,987	574	14,992	26,118	543	11,113	20,466
1987	260	2,203	8,473	345	9,720	28,174	360	10,321	28,669
1988	262	1,631	6,225	517	10,268	19,861	352	8,205	23,310
1989	332	2,434	7,331	351	10,520	29,972	181	8,712	48,133
1990	396	1,774	4,480	350	9,597	27,420	364	8,107	22,272
1991	364	1,830	5,027	350	8,668	24,766	178	7,417	41,669
1992	227	1,425	6,278	126	5,675	45,040	180	6,519	36,217
1993	264	1,350	5,114	333	7,538	22,637	179	5,589	31,223
1994	397	1,730	4,358	87	5,525	63,506	175	5,633	32,189
1995	0	1,399		0	6,656		171	3,712	21,708
1996	327	1,064	3,254	0	5,518		0	0	
Cumulative	14,366	64,652	4,500	21,972	234,150	10,657	16,276	230,478	14,161

Most wells initially produced a significant amount of gas, regardless of structural position (Fig. 45). Initial gas/oil ratios (IGOR) for wells having commingled production were mostly in the range of 1,000–3,500 SCF/BBL and were commonly ~1,500 SCF/BBL. Of the wells completed originally or solely in the Bartlesville, the IGOR during the first full year of oil and gas production was between 2,135 and 3,407 SCF/BBL (Table 8). The final GOR calculated for single-zone completions in the Bartlesville during the last full year in which gas and oil were produced varied from 3,254 to 63,506 SCF/BBL. Overall, the GOR increased significantly during the first 4 years of production and then stabilized. The trend of annual GOR for the three wells completed only in the Bartlesville is plotted in Figure 49. Two of these three wells had an overall increasing GOR during the life of the well. The No. 1 Dunsmore (SE¼SW¼ sec. 20, T. 18 N., R. 2 W.), however, actually had a decrease in the GOR during the last 10 years of production. Altogether, the increase in GOR during production indicates that a significant amount of gas evolved following depressurization of the reservoir and that significant oil shrinkage probably occurred within the reservoir.

WELL COMPLETION

Operators set 4.5-in. production casing at or very near the bottom of the hole. In most productive wells, the high-resistivity zones (>20 ohm-meters) were perforated, which encompassed essentially the entire sand-bed thickness. The wells were acidized and then flushed with potassium chloride (KCl) water. They were then stimulated with a fracture treatment (in stages for multizone completions). Fracture treatments in single or multiple zones regularly used 10,000–15,000 bbl of formation water and no sand. In some wells, 1,000 bbl of versa-gel or gelled KCl was used to mobilize sand as a proppant. This practice used something on the order of 20,000–40,000 lb of sand. Most of the wells responded fairly well after stimulation, but, as mentioned previously, oil production fell rapidly from the onset of well completion.

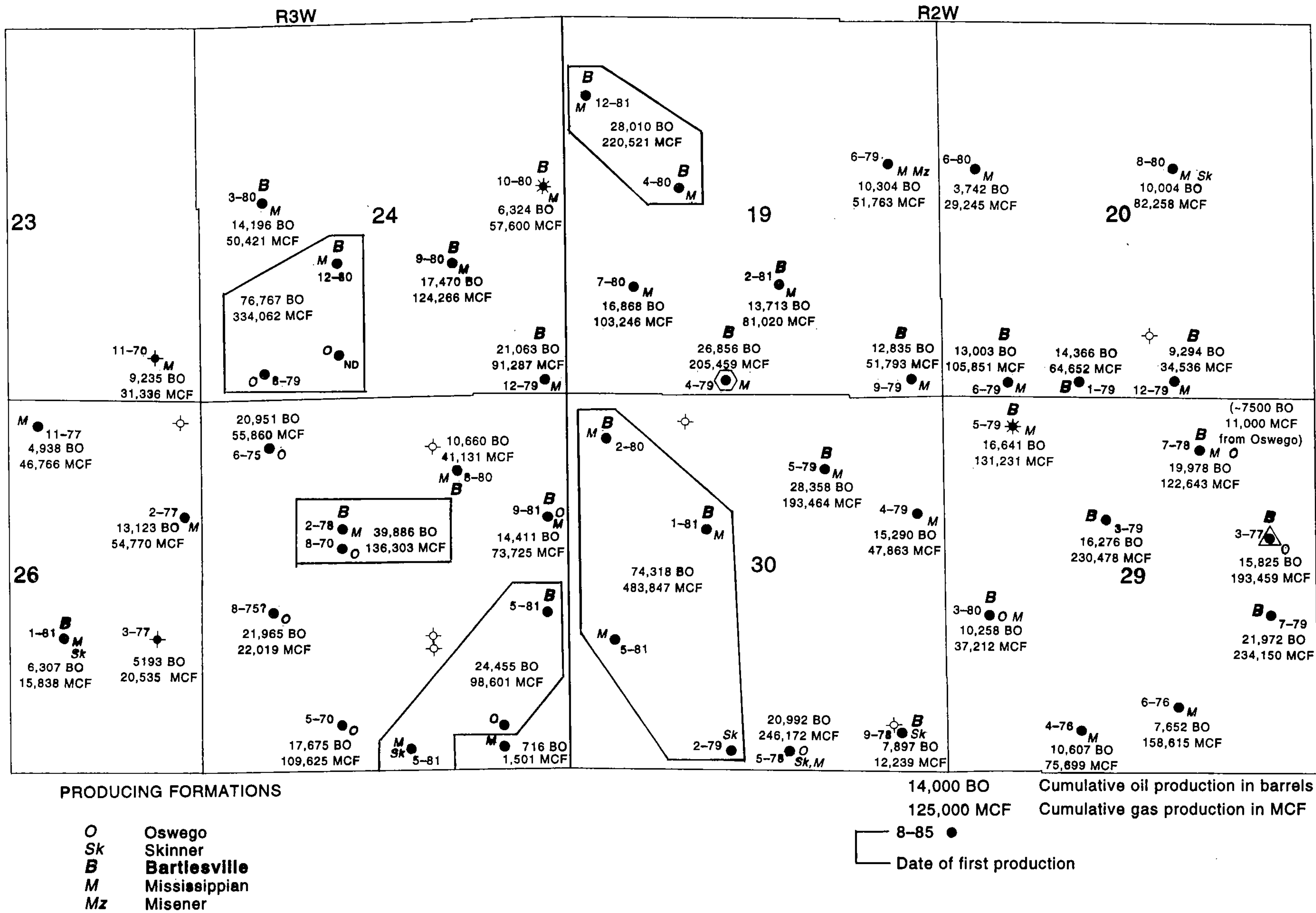


Figure 46. Map showing cumulative oil and gas production since January 1979 and dates of first production (completion date if before 1979) for wells in the NW Russell field area. Most wells in this area have commingled production from the Bartlesville and Mississippi lime and/or Oswego lime. One well in sec. 20 (No. 1 Dunsmore, SE¼SW¼) and three wells in sec. 29 (No. 1 Miller SE¼NW¼, No. 3 Brown SE¼NE¼, and No. 2 Acton NE¼SE¼) have production primarily or entirely from the Bartlesville. See Figure 35 for well names. See Appendix 4 for explanation of symbols.

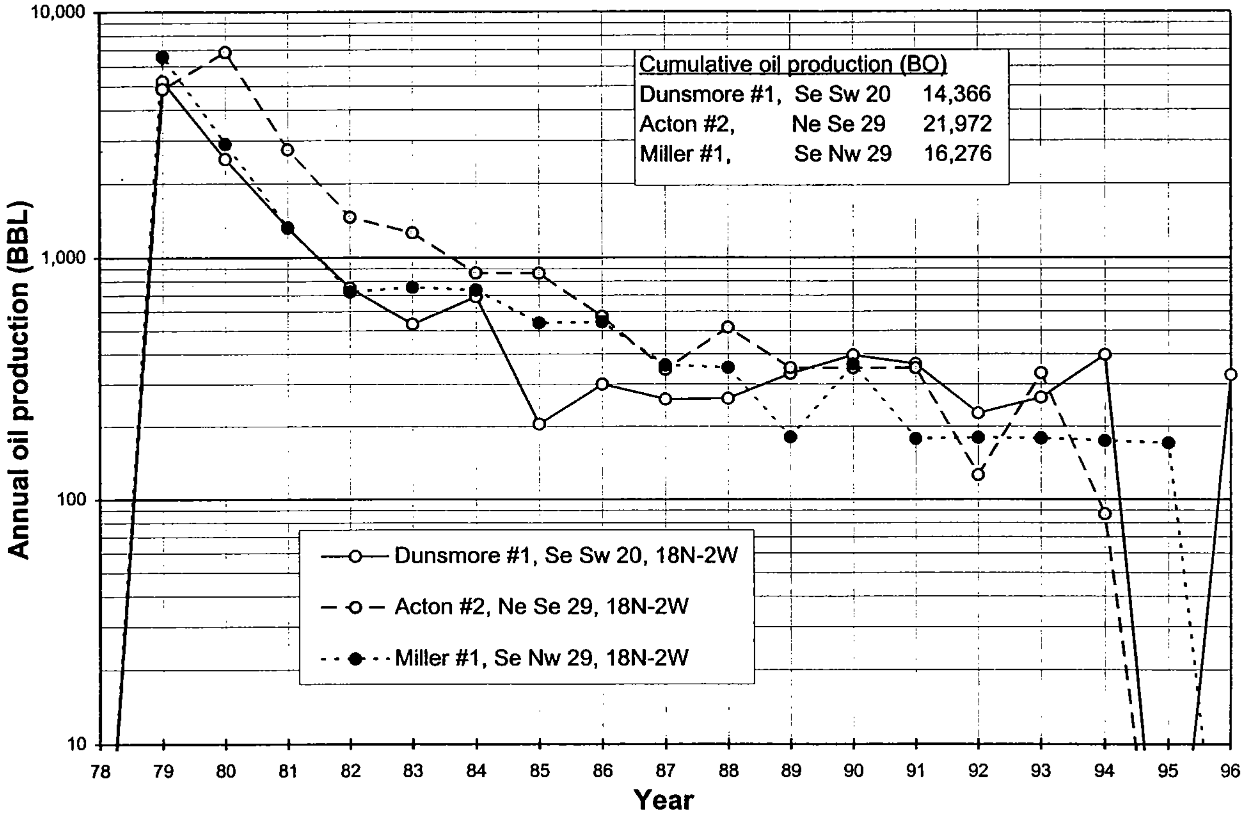


Figure 47. Oil-production decline curves, showing annual production from three wells having single-zone completions exclusively in the Bartlesville sandstone.

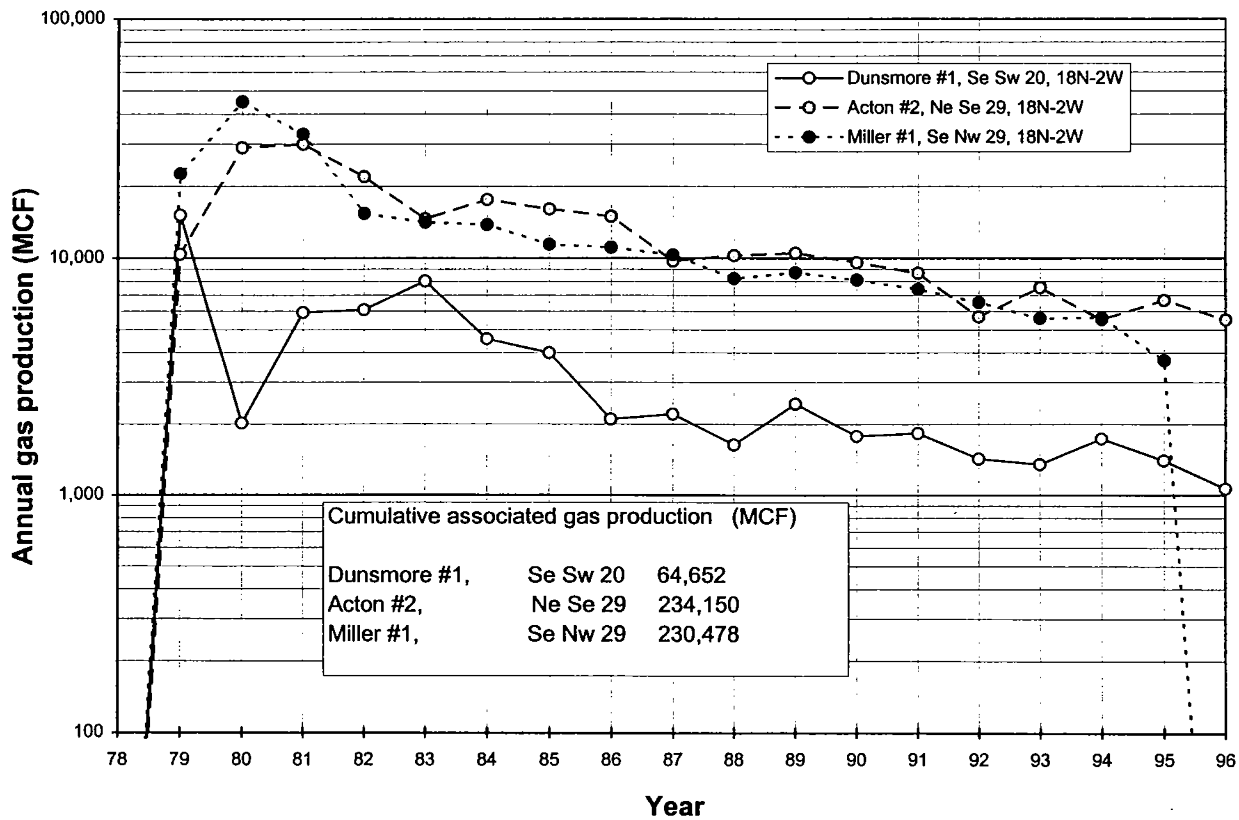


Figure 48. Gas-production decline curves, showing annual production from three wells having single-zone completions exclusively in the Bartlesville sandstone.

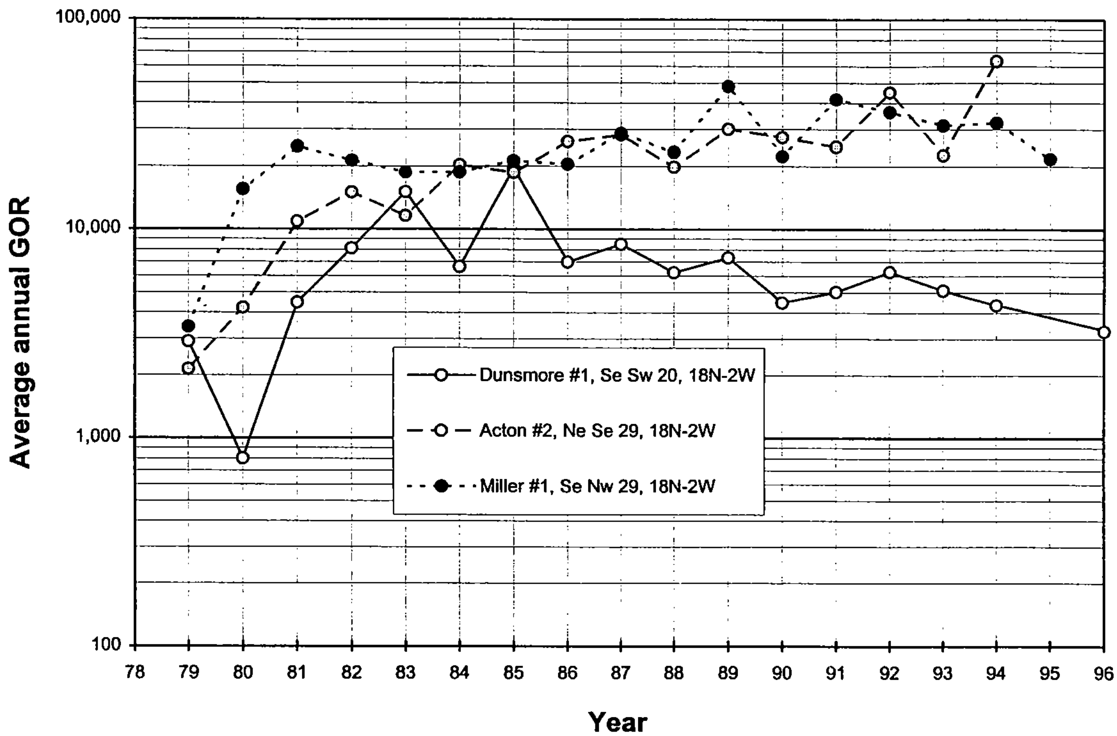


Figure 49. Plot showing average annual gas/oil ratios (GOR) for three wells producing exclusively from the Bartlesville sandstone. Data presented in Table 8.

Ohio–Osage Field

(Bartlesville oil pool in sec. 28, T. 21 N., R. 9 E., Osage County, Oklahoma)

by
Richard D. Andrews and Robert A. Northcutt

INTRODUCTION

Ohio–Osage field is located in southern Osage County in north-central Oklahoma (Fig. 50). This part of the State is characterized by small anticlinal structures and is near the center of the Cherokee platform province (Pl. 1). The Bartlesville oil pool in Ohio–Osage field was discovered in 1984, although field designation was the result of much earlier development of the shallower Layton reservoir (Upper Pennsylvanian, Missourian). Consequently, many of the wells along the eastern boundary of the study area do not penetrate the older Bartlesville interval. The depositional trend of the Bartlesville is speculative at some places, and the field is prone to oil production, as little or no gas was reported.

Within the area mapped, the Bartlesville sandstone occurs primarily in deeply incised channels. The sandstone accumulated in relatively thick, elongated longitudinal bars that are typically 50 to >75 ft thick. These fluvial sediments are flood-plain deposits that extended basinward, owing to a fall in eustatic sea level. As with most of the younger Cherokee events, this type of channel system resulted in deltaic environments farther basinward as they entered a marine environment. The incised channels and enclosed sandstone reservoirs cut across older Bartlesville marine sediments deposited during an earlier marine depositional event. These marine sediments consist of shale and dirty sandstone interpreted to be delta front and prodelta in origin.

Oil production was first established in the Ohio–Osage field study area in mid-1930 with the completion of several wells in the SW¼ sec. 27 and the NW¼ sec. 34, T. 21 N., R. 9 E. These wells were completed in the younger Layton sandstone, which is about 1,300 ft uphole from the Bartlesville. The first deeper drilling in the area came in 1959, when Jet Petroleum drilled the No. 1 Mills well in the SE¼SE¼NW¼ sec. 28, which is near the center of the Bartlesville oil pool. This well fully penetrated the Bartlesville interval but was aban-

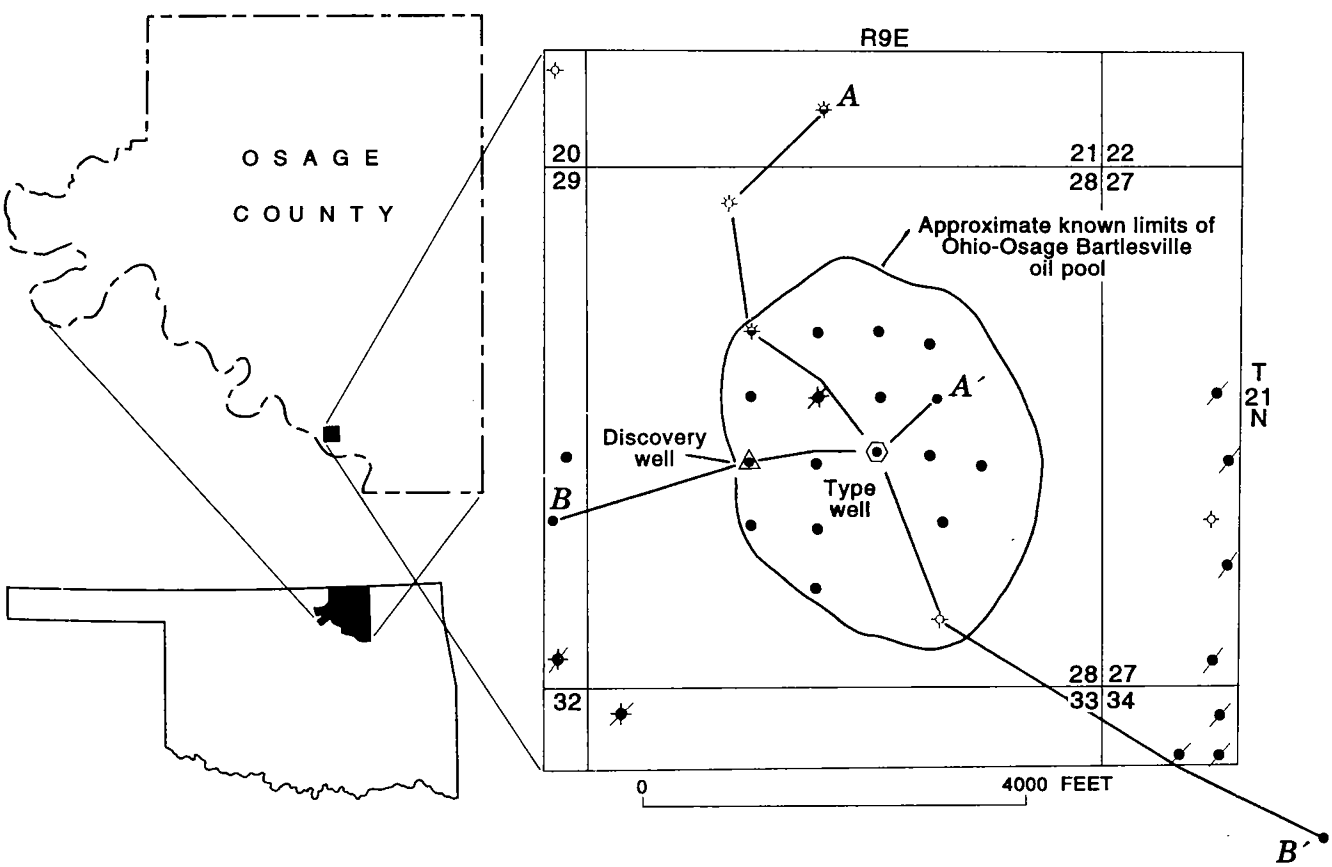


Figure 50. Map showing location of the Bartlesville oil pool in the Ohio–Osage field area, Osage County, Oklahoma.

doned despite favorable log signatures that indicated hydrocarbon saturation in the upper part of the lower Bartlesville channel sandstone. No tests were completed in the Bartlesville interval in the Jet well. The area remained inactive for about 16 years, when in 1975 Tesoro drilled the No. 1 Drummond in the NE¼ NW¼ sec. 28 and encountered significant gas from a Bartlesville channel sandstone during a drillstem test. About 3 years later, in 1978, an updip well was drilled by Riddle Oil in the SE¼SW¼ sec. 21. This well had shows of oil and gas from the same Bartlesville interval, but the sandstone was that of a marine bar. This relationship should have made it obvious that the channel trended in the direction of the Jet well to the southeast into sec. 28, although no further drilling took place for 6 more years.

Probably with the assimilation of information mentioned above, Petroleum Resources discovered the Bartlesville oil pool in the Ohio–Osage field in September 1984 with the completion of the No. 1 Hess (NW¼ NE¼SW¼ sec. 28). This well had an initial potential (flowing) of 28 BO, 32 BW, and no gas. The shut-in tubing pressure was measured at 840 PSI, which is probably very close to the initial reservoir pressure. Field development occurred mostly during the following 1.5 years, although some development wells were drilled as late as August 1987. A total of 16 wells were completed in the Bartlesville sandstone, along with two dry holes. It seems likely that one or two additional drilling locations exist in the southeastern part of the field, although the likelihood of high water production may be a compelling reason to leave well enough alone. The Bartlesville oil has a gravity of 39° API. Although gas was recovered during many Bartlesville tests in the immediate area, no gas cap has been identified in the field, and no associated gas production has been reported. Current production information indicates that only one well is shut in, although most wells currently average only about 1 BOPD. The Bartlesville reservoir has produced about 183 MBO and an unknown amount of water from a relatively shallow depth of ~2,400 ft.

This field study was completed with the use of standard wireline well logs and production information from the National Resources Information System (NRIS). A map identifying producing reservoirs, well locations, operators, well numbers, and principal leases within the field area is shown in Figure 51.

STRATIGRAPHY

A typical log from the Ohio–Osage field and the stratigraphic nomenclature are shown in Figure 52. On this log, the Bartlesville interval is identified as the strata extending from the top of an overlying "hot" shale marker bed to the top of the underlying "Mississippi chat." Although this sequence is easy to see on the type log, the precise stratigraphic boundaries may be difficult to identify, as both the Inola Limestone and the Brown lime are absent. (Most geologists interpret the Bartlesville interval to include the strata between the base of the overlying Inola Limestone to the top of the underlying Brown lime.) The approximate stratigraphic position of the Inola Limestone, however, can be determined, as it characteristically lies within a low-resistivity shale zone just above the "hot" shale marker. Therefore, the top of the Bartlesville interval is very near the top of the 2–3-ft-thick "hot" shale marker. The top of the Bartlesville (sand) zone is at the base of the "hot" shale marker bed. These stratigraphic relationships are shown in Figure 52.

The base of the Bartlesville interval is more difficult to identify precisely, partly because of the absence of the underlying Brown lime. The reported presence of pre-Savanna lithologies, such as the Burgess sand and the "Mississippi chat," also make the determination of the basal Bartlesville interval questionable. The base of the Boggy shale (the base of the Bartlesville interval in the type well) was therefore determined on the basis of changes in resistivity and porosity above the Mississippi lime, and a significant departure of the "clean" GR response above the Mississippi lime toward the shale base line. For surface mapping purposes, the base of the Boggy Formation is picked at the base of the Bluejacket (Bartlesville) Sandstone.

The Bartlesville interval is ~225 ft thick and can be informally divided into an "upper" and a "lower" sand zone. The upper Bartlesville zone is not productive within the study area except in two wells in the SE¼ sec. 29 that contain marine-sandstone facies. The identification of this zone, however, is important in order to recognize the different depositional systems that occur within the Bartlesville interval. Normally, the upper zone consists of marine sandstone and shale having an upward-coarsening textural profile, which in turn is overlain by a persistent coal bed, and finally by ~30 ft of shale and sandstone (Fig. 52). The top of the Bartlesville zone is identified by a resistivity spike just below the "hot" shale marker bed. This horizon is used for structural-mapping purposes because of its clarity throughout the study area. The upper Bartlesville zone is incised by a thick channel sequence just southeast of the study area. Although this channel does not produce oil or gas in the study area, it provides a clue regarding the timing of major fluvial cycles and corresponding sea-level changes that occurred during Bartlesville time.

The lower Bartlesville sand zone is productive in this field study area and generally consists of sandstone deposited within an incised fluvial-channel system. The sandstone is generally 50 to >75 ft thick and has an excellent porosity of about 16%. The lower sandstone thickens and thins greatly, and basal scour of at least 20 ft can be interpreted from well-log correlations. Significant thinning of sandstone also occurs within the upper part of the lower sand zone, which causes a paleotopographic effect along the upper boundary of the sandstone deposit. Thinning within the upper part of the sand body is an important trapping component within the field, particularly along the northern, eastern, and western pool limits. Where the incised channel is not present, the lower Bartlesville sand zone is composed of marine sediments such as thin bar deposits and open-marine shale. The marine bars of the lower Bartlesville zone are not productive within the study area except in two wells in the SE¼ sec. 29.

The stratigraphy of the Bartlesville interval is shown by detailed structural–stratigraphic cross sections *A–A′* (Fig. 53, in envelope) along the depositional trend of the field, and *B–B′* (Fig. 54, in envelope), which is transverse across the incised channel. In both cross sections, the highly variable spatial relationship of sandstone is interpreted from the various log traces provided.

In well 1, cross section *A–A′*, the Bartlesville interval is shown to consist mostly of shale with thin sandstone beds in the lower sand zone. This lithology is interpreted to be of very shallow-marine origin except for the coal bed in the upper part of the section. About 0.25

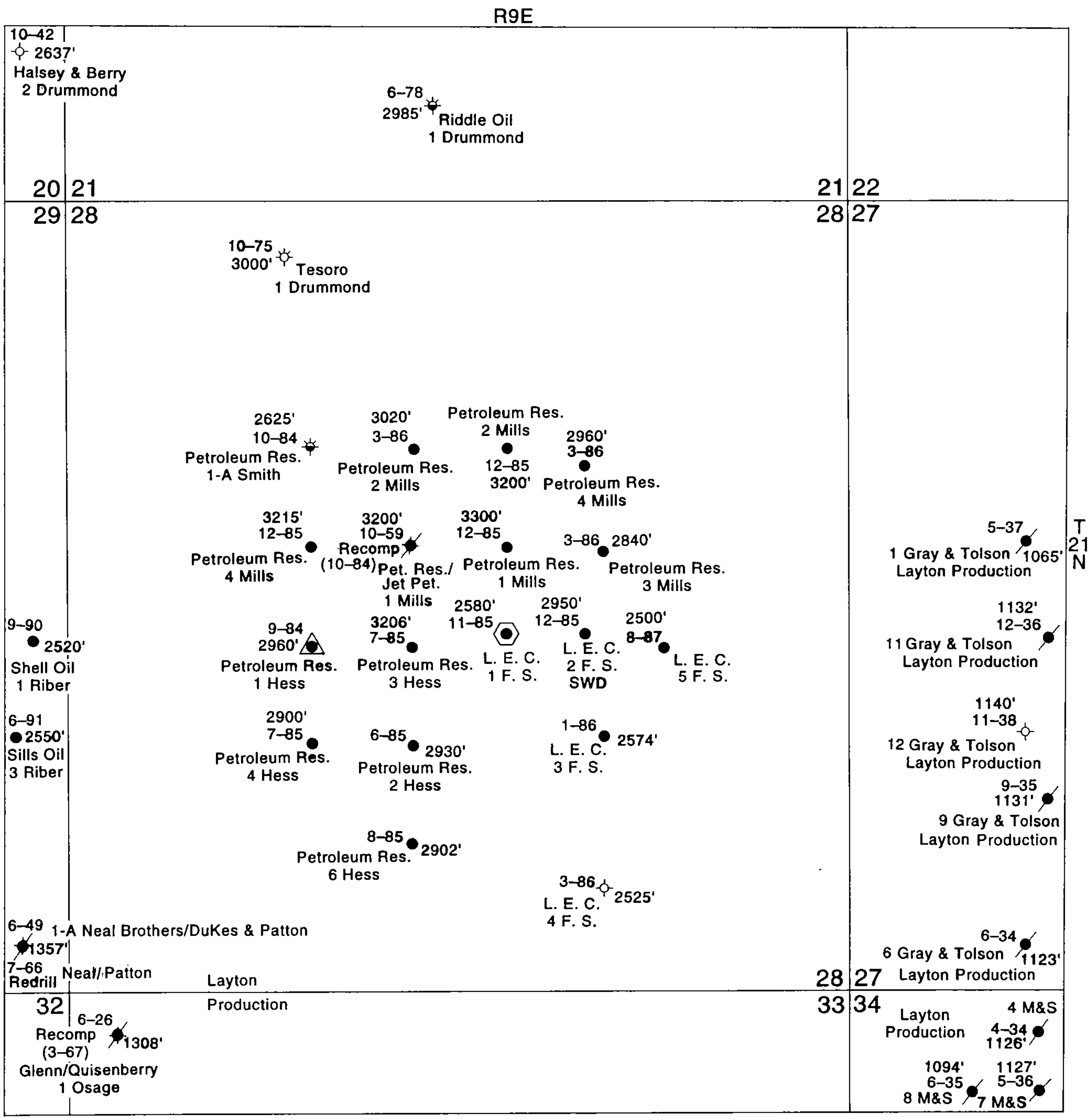


Figure 51. Well-information map, showing operators, well names, well numbers, producing reservoirs, completion dates, and total depths for wells in the Ohio–Osage field study area. See Appendix 4 for explanation of symbols.

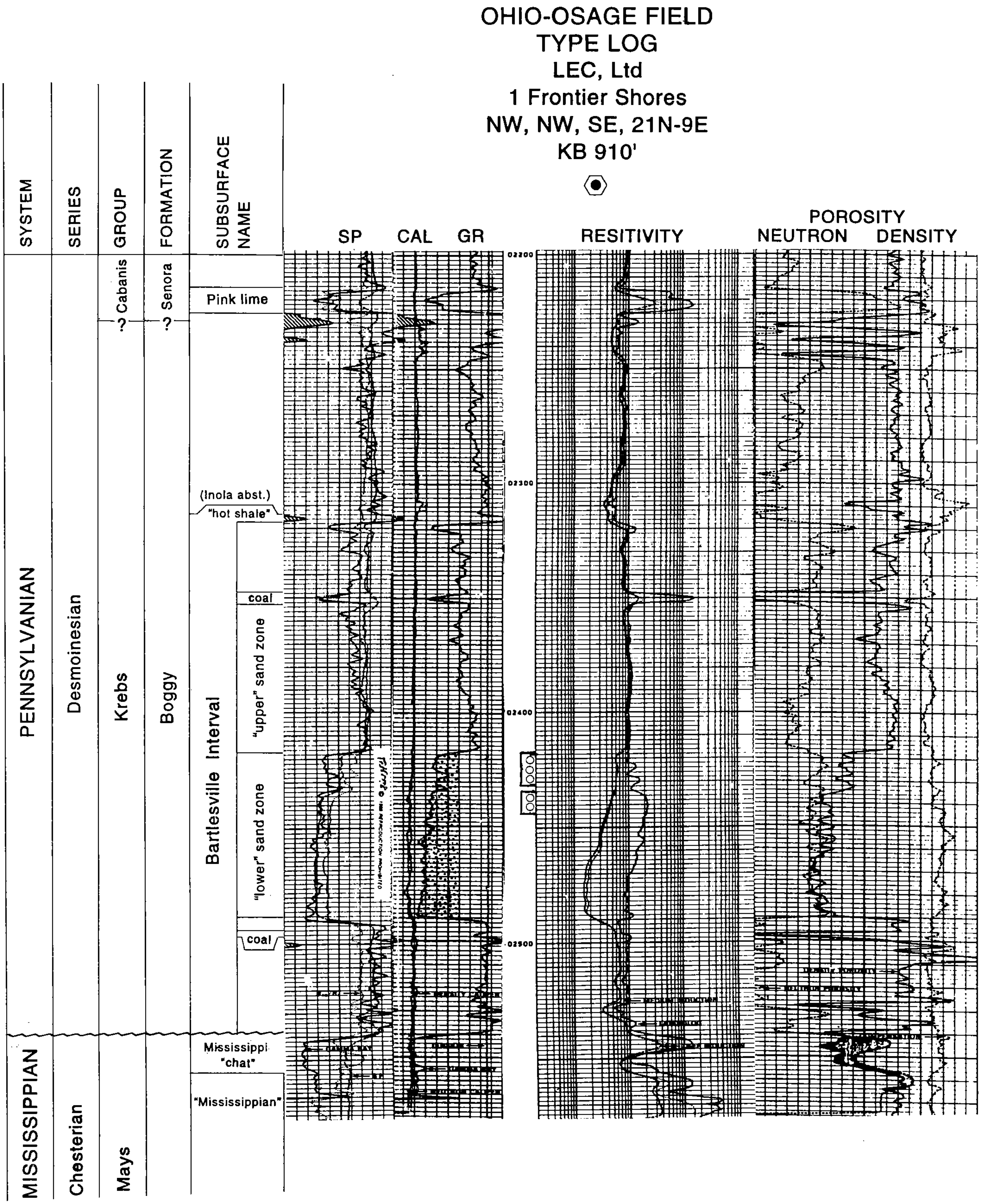


Figure 52. Ohio–Osage field area type log, showing stratigraphic section, nomenclature, and typical log signatures of the Bartlesville sand. In the study area, the "Bartlesville interval" encompasses the strata from the base of the "hot" shale underlying the Red Fork interval to the top of the Mississippian. The Inola Limestone, which normally separates the Red Fork and Bartlesville intervals, is absent in this area. *CAL* = caliper; *GR* = gamma ray; *SP* = spontaneous potential.

mi southwest of well 1, the marine sediments in the lower Bartlesville zone are incised by a large fluvial channel (well 2). The sandstone here appears to occur in a relatively continuous stratigraphic section about 52 ft thick without any major shale breaks. The sand body represented in well 2 is wet and appears to be mostly separated from the producing reservoir, which is in the center of sec. 28. This relationship is illustrated in well 3, where the lower Bartlesville sand zone is composed of considerably less sand, especially in the upper part of the zone. Along the depositional strike, the lower Bartlesville sand thickens to 72 ft at well 4. This is near the center of the incised channel, and the stratigraphy of the sand body is most apparent. The bottom part of the sand body (~40 ft) is considered the basal channel facies, and throughout most of the field this part of the lower sand zone is generally wet (see resistivity profile in well 4). The water saturation gradually decreases higher in the section, where the inferred oil–water contact is interpreted where the S_w approaches 50% (at about –1,540 ft, well 4). The upper part of the lower channel deposit appears to represent a different depositional episode, but it is still within the same depositional system. Variations in log profiles are most apparent in the upper part of the lower Bartlesville sandstone, and this stratigraphic section is most likely to have compartmentalization rather than the lower part of the sand body. Carrying the cross section another 850 ft to the east shows the sandstone to thin considerably along the lower part of the sand interval here. The incised channel is interpreted to be discontinuous only a short distance farther east, perhaps only a few hundred feet, and this is the major trapping component along the eastern part of the field. Notice that in well 5, the oil–water contact is not definitive on the resistivity-log trace, so its position is inferred on the cross section. Calculated S_w values in the depth tract more clearly show evidence of increasing water saturation lower in the section, but lithologic changes and large variations in porosity make water-saturated zones more difficult to identify.

Cross section *B–B′* (Fig. 54) is oriented diagonally across the longitudinal axis of the field. The end well (1) is outside the incised channel, and the Bartlesville interval is characterized by sandstone sequences having a distinct upward-coarsening textural profile. About 0.5 mi to the east, at well 2, the lower Bartlesville zone contains sandstone and shale interpreted as channel-margin facies. This well proved to be the discovery well for the Bartlesville oil pool and is at the very western edge of the sand body. Water-saturation calculations shown in the depth tract of this well are relatively high (~56%), and the sand zone is interpreted to be largely below the oil–water contact. The spatial relationship between marine facies in well 1 and fluvial facies in well 2 is interpreted to be abrupt, as shown in the cross section. Farther to the east, the channel sandstone thickens to 72 ft at well 3 (type well) and reaches more than 80 ft at well 4. Well 4 was not completed as an oil well, but log calculations indicate that the uppermost part of the sand zone (upper 12 ft) is probably just above the oil–water contact, as shown, and therefore within the limits of the Bartlesville oil pool. At well 5, there is very little sandstone in the lower Bartlesville zone; however, a thick channel sequence is present higher in the section. This channel sequence incised through the entire upper Bartlesville zone subsequent to the marine sequence previously described, and the upper Bartlesville sequence, including the coal, are all eroded. As shown in the depth tract for well 5, this sandstone is wet. Therefore, the chronology of main depositional events is as follows (oldest to youngest): (1) lower Bartlesville coal and shale sequence (below incised channel), (2) lower Bartlesville marine sequence, (3) lower Bartlesville incised channel, (4) upper Bartlesville coal and marine sequence, (5) upper Bartlesville incised channel. The incised channels identified in the field study terminate in a deltaic sequence several townships to the south (see regional sand trend map, Pl. 1).

STRUCTURE

The regional dip of the Bartlesville sandstone in north-central Oklahoma is to the west-southwest at ~50 ft/mi or ~0.5° (Fig. 16). In the study area, this trend is similarly represented by a structure map (Fig. 55) that depicts the top of the Bartlesville zone. This datum is the most consistent marker horizon in the area. As shown on this map, the oil pool is largely contained within the limits of a small anticlinal structure having at least 15 ft of closure. The highest position within the field, about –1,407 ft, occurs very near the center. The lowest part of the field is in the southern part of sec. 28, where the Bartlesville zone lies at –1,436 ft. A well at this location was abandoned; yet the upper part of the lower Bartlesville sandstone is above the oil–water contact and therefore is considered to be within the oil pool. The small structure represented in Figure 55 is typical of numerous Pennsylvanian structures that are present in this area. Had this structure been present during Bartlesville deposition, the channel system surely would not have gone directly over its top.

As structure is a major component in hydrocarbon entrapment in the study area, it was necessary to approximate the paleotopographic surface of the channel-sand body. Figure 56 is a structure map depicting the top of the lower Bartlesville channel sandstone. With the combined effects of structural nosing and sandstone thinning within the upper part of the sand body, the extent of the oil pool is more evident. To a large degree, the oil–water contact along the updip (east) and downdip (west) edges of the oil pool are approximately equal to the limit of net (reservoir) sandstone.

BARTLESVILLE SANDSTONE DISTRIBUTION AND DEPOSITIONAL ENVIRONMENT

Figure 57 shows the gross thickness of the lower Bartlesville sandstone for all wells in the study area.

The gross sand thickness is the total thickness of sandstone, regardless of porosity, determined from the GR and resistivity logs. The zero-thickness line is the limit of sand deposition but not necessarily the limit of the Bartlesville reservoir, which is almost always smaller in areal extent. The spatial limits of the incised valley are generally somewhat larger than the gross sandstone distribution, as areas within the channel may not have sandstone.

The gross thickness of the lower sandstone, regardless of facies, ranges from only a few feet to >80 ft but generally is in the range of 50–75 ft in the channel. Areas along the channel edge have considerably less sandstone and more shale, yet the quality of sand present is still good. The channel sandstone thins appreciably in the NW¼ sec. 28 to <30 ft but thickens to >50 ft farther northwest. This variation in sandstone distribution probably resulted in compartmentalization of the

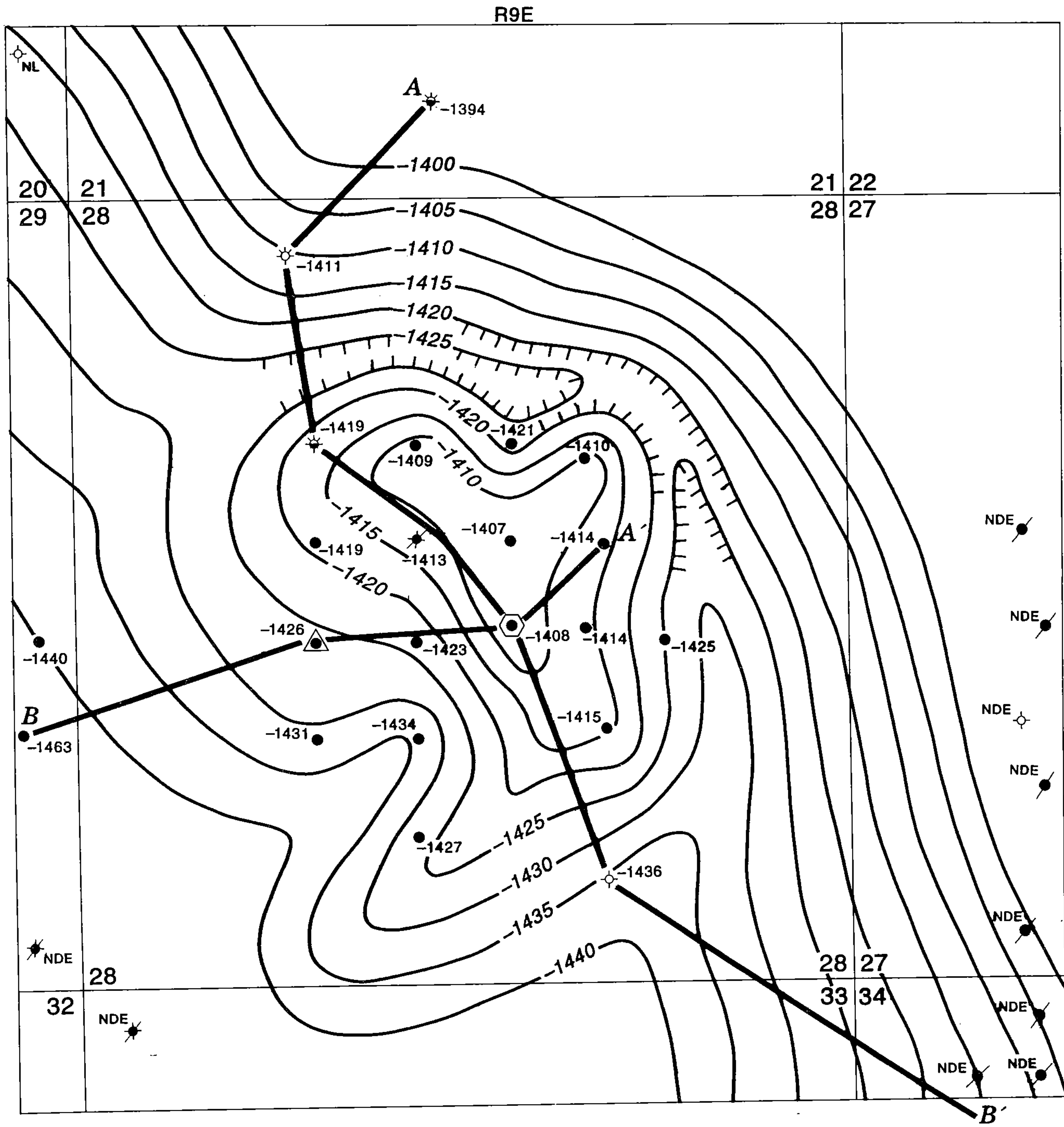


Figure 55. Structure map of the top of the Bartlesville zone (base of "hot" shale) in the Ohio–Osage field study area. This datum is a regional stratigraphic and structural marker and lies only a few feet beneath the top of the Bartlesville interval. Contour interval is 5 ft. See Figure 51 for well names. See Figure 52 for type log. See Appendix 4 for explanation of symbols.

two sand bodies. The gross sandstone isopach map shows values for all wells having data, although the sandstone thicknesses are contoured only within the channel facies.

A net sandstone isopach map (Fig. 58) shows the thickness of sandstone with ≥10% porosity. This value was selected because it best identifies the distribution of reservoir-quality sandstone at the producing depth. The thickness of net sandstone within the channel facies ranges from 14 to 83 ft, although net productive sandstone above the oil–water contact is much thinner. This was determined by comparing the net sandstone distribution map with the structure map of Figure 56. The closure identified in Figure 56 within the limits of the net sandstone defines the approximate sandstone thickness above the oil–water contact. The maximum productive reservoir thickness was therefore interpreted to be ~20 ft. Unlike the sandstone mapped within the NW Russell field (Figs. 41, 42), the basic distribution pattern of net sand is nearly identical to that

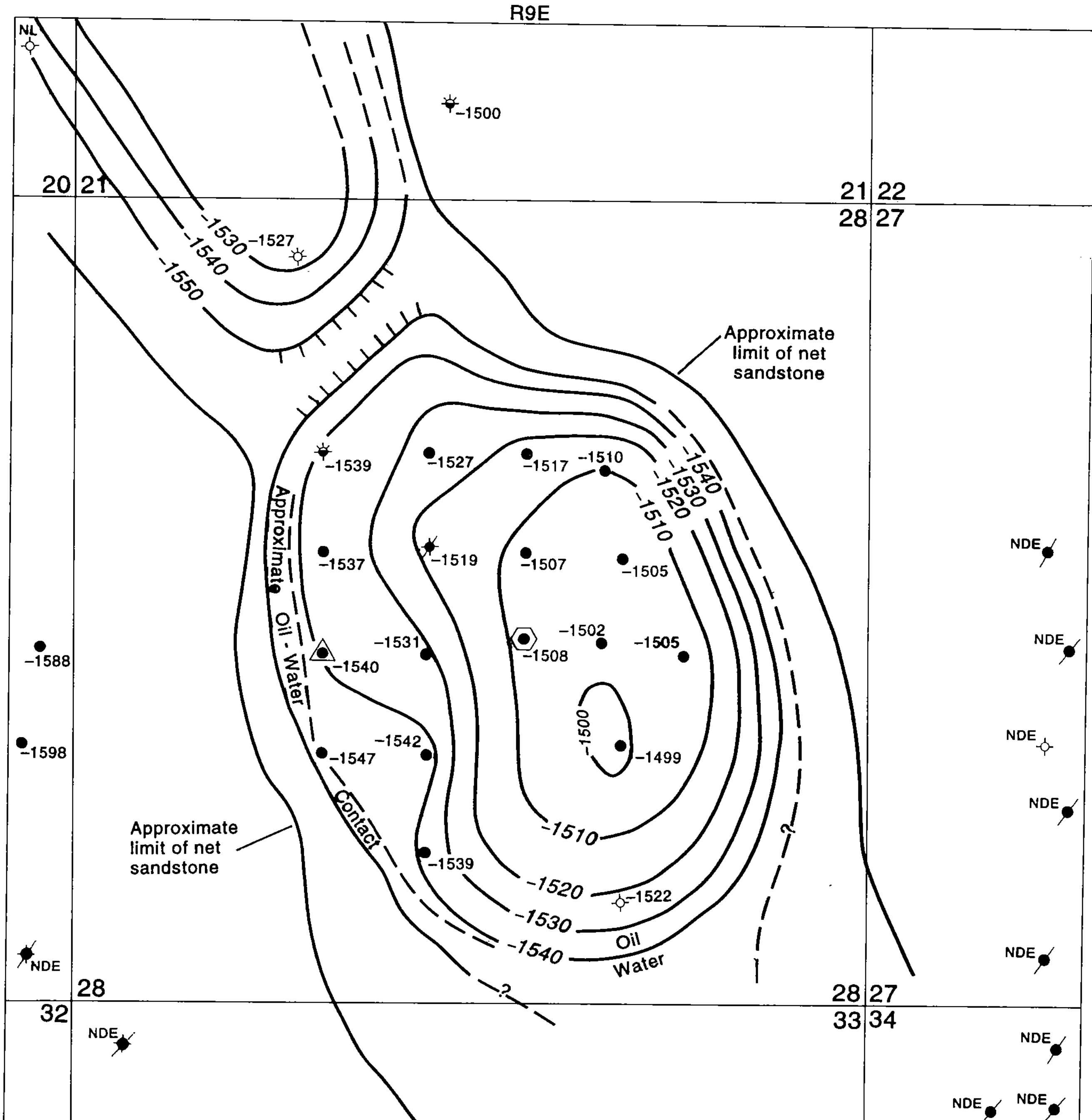


Figure 56. Structure map of the top of the lower Bartlesville sandstone in the Ohio–Osage field study area. Contour interval is 10 ft. See Figure 51 for well names. See Figure 52 for type log. See Appendix 4 for explanation of symbols.

of the gross sand, which indicates good reservoir quality regardless of sandstone thickness.

The depositional pattern of the lower Bartlesville sandstone in the Ohio–Osage field is highly suggestive of a longitudinal bar. There is no indication from well logs or isopach mapping that sandstone in this field was deposited in a point bar. As in most deposits of this type, however, the upper sandstone beds appear to represent a different depositional episode as interpreted from the well-log signatures. The channel bar is elongated, with a width of ~0.5 to 0.75 mi. The length of the bar was not determined, as the bar extends south of the area mapped, but its length is probably at least twice its width. In an exploration sense, mapping this channel to the south could result in additional prospective areas where structural closure or stratigraphic

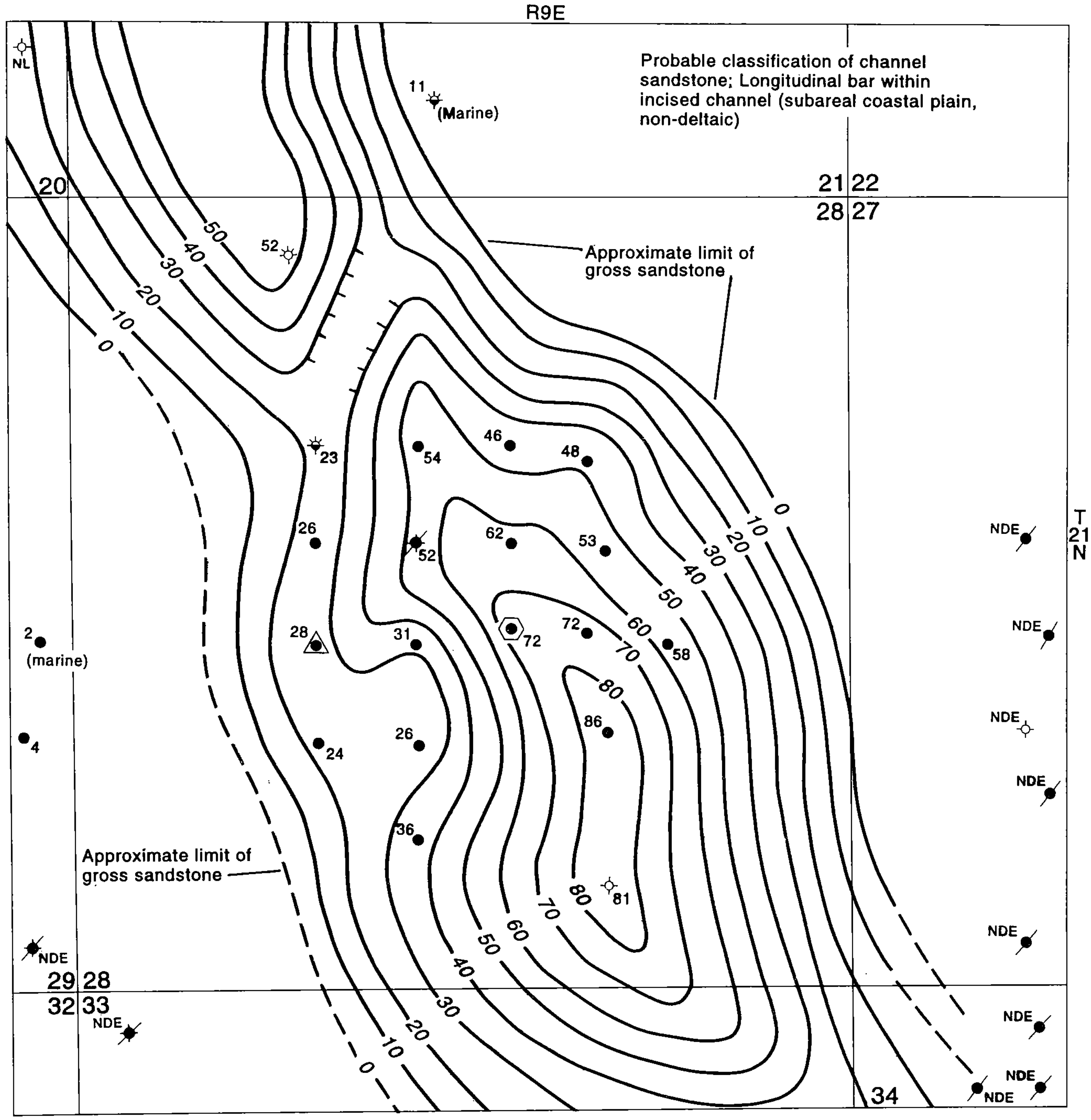


Figure 57. Gross sand isopach map of the lower Bartlesville channel sandstone in the Ohio–Osage field study area. Gross sand includes all sandstone, regardless of porosity. Contour interval is 10 ft. Thickness values for nonchannel Bartlesville sandstone is indicated on the map but not contoured. See Figure 51 for well names. See Figure 52 for type log. See Appendix 4 for explanation of symbols.

irregularities occur. This fluvial trend continues off the Cherokee platform and eventually enters a marine environment. At this point, prospective Bartlesville sandstone deposits would have shallow-marine attributes, such as those found in distributary-mouth bars, shelf bars, or tidal-mouth bars. Some of these facies types are found in outcrop at Robbers Cave State Park, and some of the slides shown during the introduction to this workshop were taken there.

FACIES MAPPING

Depositional environments were interpreted from wireline-log signatures, particularly GR and resistivity logs (Fig. 59). Two distinctly different depositional environments are interpreted for Ohio–Osage field and include incised channels (flood-plain channel sandstone and shale) and shallow marine shelf (nearshore bars, distributary-mouth bars).

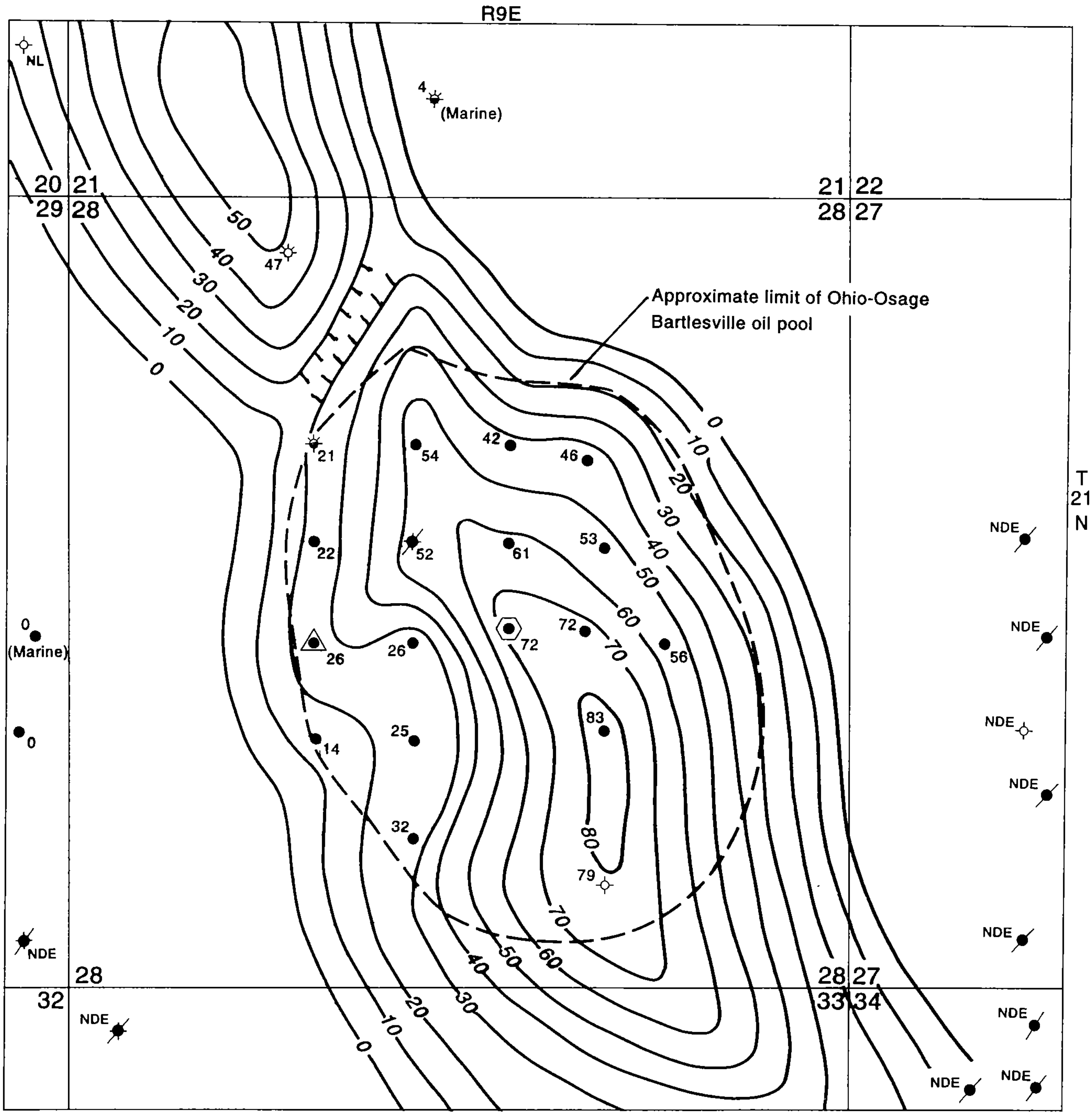


Figure 58. Net sand isopach map of the lower Bartlesville channel sandstone in the Ohio–Osage field study area. Net sand is considered to be sand with log porosity ≥10%. Contour interval is 10 ft. See Figure 51 for well names. See Figure 52 for type log. See Appendix 4 for explanation of symbols.

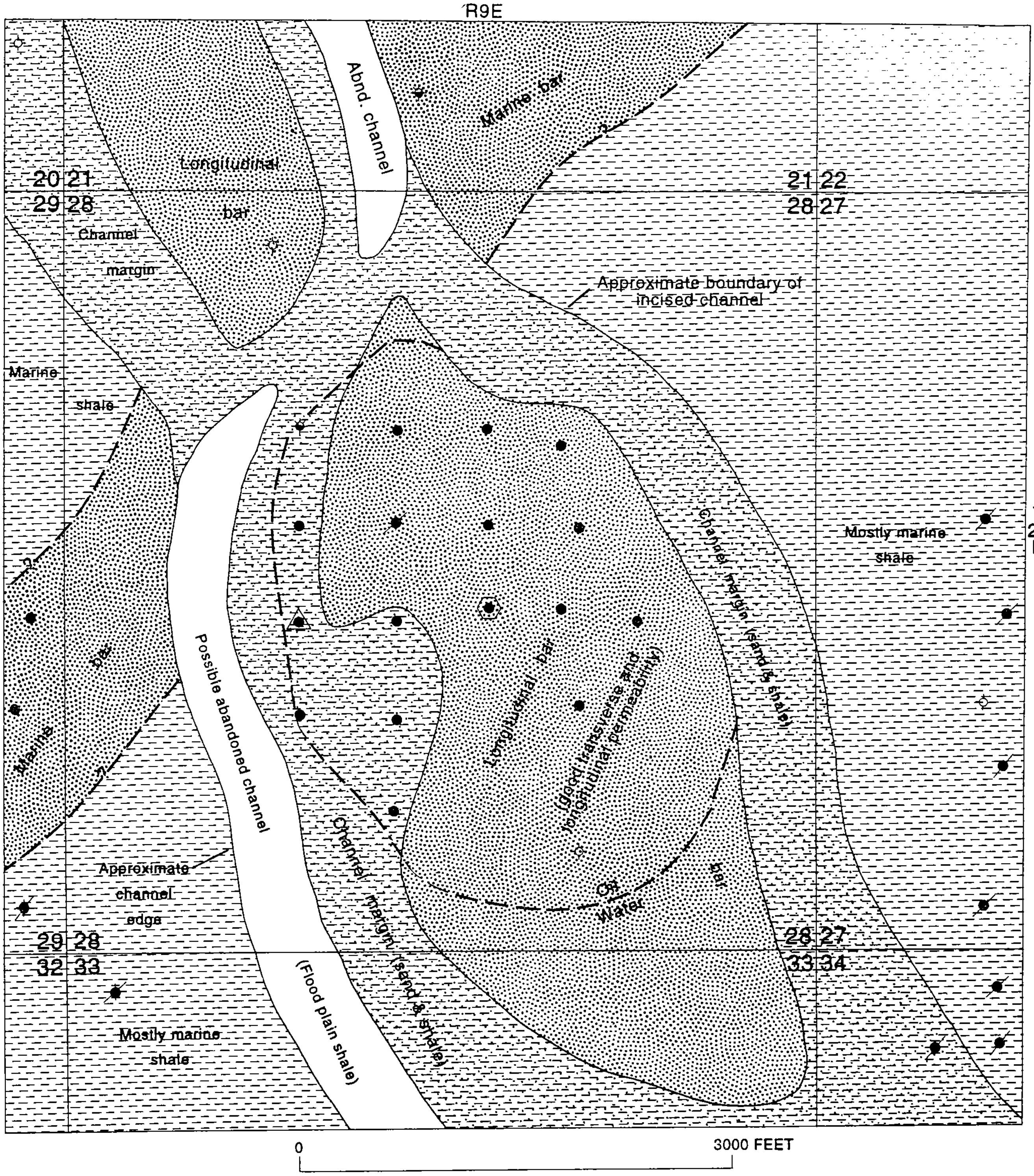


Figure 59. Depositional-facies map of the lower Bartlesville sand zone in the Ohio–Osage field study area. See Appendix 4 for explanation of symbols.

Incised (Channel) Facies

The depositional origin of these sediments appears to be a simple, nonmeandering river system contained within a flood plain (rather than a delta plain). This distinction is important for exploration purposes, as no delta front underlies the channel facies, and therefore no progradation has occurred—i.e., no deposition extended basinward into a marine environment (definition of a delta!). Within the fluvial (channel) facies, sediments either are predominantly sandstone or are shale with thin interbedded sand layers and coal. Because of the blocky well-log signatures, simple elon-

TABLE 9. – Reservoir/Engineering Data for the Bartlesville Sandstone in Ohio-Osage Field, Osage County, Oklahoma

Reservoir size	~230 acres
Depth	~2,400 ft
Well spacing (oil)	10 acres
Bartlesville completions	16 in fluvial facies
Oil–water contact	About –1,540 to –1,550 ft below sea level
Gas–oil contact	None observed
Porosity (in net sand)	13–25% (avg. ~16%)
Permeability	Unknown
Water saturation (calculated)	About 37–50% above oil–water contact
Thickness (net sand $\phi \geq 10\%$)	Avg. ~46 ft (avg. 19 ft above oil–water contact)
Reservoir temperature	101°F
Oil gravity	39° API
Initial reservoir pressure	~850 PSI
Initial formation-volume factor	1.10 RB/STB (est. from GOR, BHT, oil and gas gravity)
Initial average GOR	Assumed <50 SCF/BBL, as no gas reported in sales
OOIP (volumetric)	1,986,000 STBO
Cumulative primary oil production (to 12/96)	183,063 STBO; about 10–15 MBO per Bartlesville well (est.)
Primary recovery efficiency (oil)	~9.2%
Primary recovery (oil)	~42 BO/acre-ft
Cumulative gas production	None reported

gate bar shape, and linear channel outline, the fluvial sandstone is interpreted to be part of a longitudinal-bar complex. Therefore, porosity and permeability are expected to be good in a transverse direction across the bar as well as in a longitudinal or downstream direction. Sediments deposited within the fluvial regime that are predominantly shale are interpreted to be channel-margin or abandoned-channel deposits and are not part of the reservoir. They are, however, important in delineating the marine from the nonmarine facies and appear uniquely different on electric logs.

Shallow-Marine-Shelf Deposits (Nearshore Bars, Distributary-Mouth Bars)

Sandstones that are interpreted to have an upward-coarsening textural profile, as indicated from GR, resistivity, and porosity logs, are considered to have originated from different depositional processes in comparison to fluvial channel-sandstone deposits. Sandstones having these characteristics are not productive within Ohio–Osage field except in the SE¼ sec. 29. The marine-bar facies in the lower Bartlesville zone have been incised by a younger channel complex that forms the main producing Bartlesville reservoir within the study area. This indicates that after deposition of the marine sediments, sea level fell, causing fluvial systems to "follow" the retreating shoreline. This is what is meant by an "induced" fluvial system and is the principal mechanism for the formation of most incised channels within FDD plays in the Cherokee platform province.

CORE ANALYSIS

No cores were reported in completion reports for any well drilled within the study area.

FORMATION EVALUATION

The identification and evaluation of the Bartlesville sandstone in Ohio–Osage field is straightforward. The productive sandstone is relatively clean (i.e., GR and resistivity logs are not significantly affected by interstitial clay or mica). Porosity determinations from the density–neutron logs run on a 2.71 matrix density (used on most porosity logs in the study area) are estimated to be about 1 to 2 percentage units higher than those of the actual reservoir sandstone. Therefore, porosity determinations used in water-saturation (S_w) calculations were adjusted downward by about 1.5 porosity units, as indicated on the density-porosity logs. Neutron-porosity values were not used for cross-plot porosity determinations because of their sensitivity to clay, which results in the neutron log's porosity being too high. Reservoir characteristics are shown in Table 9.

The deep or "true" resistivity of productive intervals in the channel facies ranges from about 3 to 7 ohm-meters. Channel sandstones with values below 2.5 ohm-meters are always water wet and not productive. Higher resistivities generally occur in the upper part of the sand zone, and generally there is no sharp oil–water contact. This is shown in well 4, cross section *A–A′* (Fig. 53), in which the resistivity within the sandstone gradually decreases from 6 ohm-meters at the top of the sand body to only 1.5 ohm-meters at the base. The corresponding calculated water saturation increases from 53% to about 72% within this interval. Changes in porosity also greatly affect the deep resistivity and apparent water saturation. This situation is identified in well 4, cross section *B–B′* (Fig. 54), where, at a depth of 2,372 ft, the deep resistivity changes from 1.4 (above) to 0.4 ohm-meters (below). Although the calculated water saturation does increase where the resistivity decreases, part of the reason is that the porosity also changes from 18% to 26% at this same depth. All the channel-sandstone zones have a strong separation of about 10–40 ohm-meters between the shallow and deep resistivity readings, although this varies greatly depending on structural position of the sandstone and corresponding water saturation. The separation of the shallow and deep resistivity curves indicates the presence of good permeability, as does the presence of mud-cake buildup. As shown for some of the wells in which caliper logs (CAL) were run (cross sections *A–A′* and *B–B′* (Figs. 53, 54), the borehole through the Bartlesville sandstone has at least 0.5 in. of mud-cake buildup, as the hole diameter has been reduced by 1 in. or more through this interval.

Water-saturation (S_w) calculations for the Bartlesville channel sandstone range from about 37% to 100%. The S_w in most of the lower (nonproductive) part of the sandstone was generally above 70%. Water saturations in the upper producing part of the Bartlesville sand

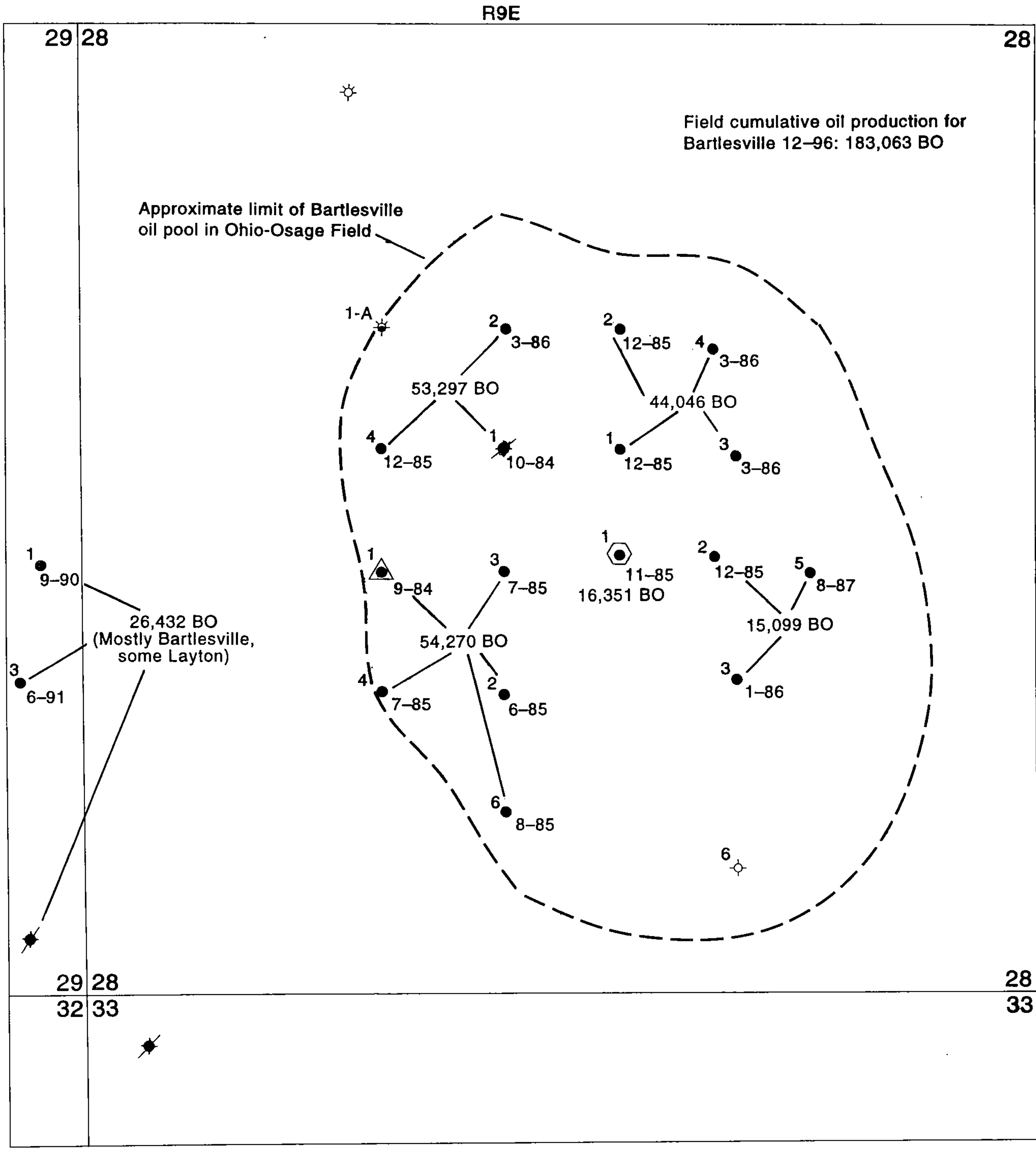


Figure 60. Map showing cumulative oil production, well numbers, and completion dates for wells in the Ohio–Osage field area. Production is always reported by lease, which in this area usually includes 3–5 wells. See Figure 51 for well names. See Appendix 4 for explanation of symbols.

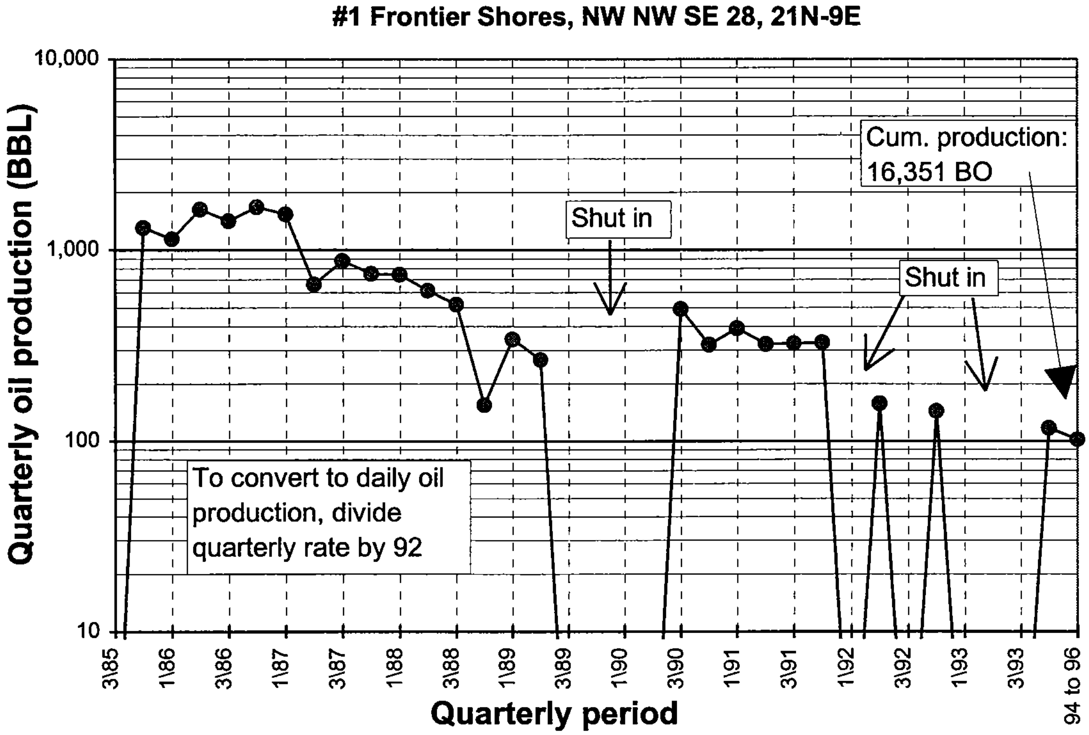


Figure 61. Oil-production curve for L.E.C.'s Frontier Shores lease. On the basis of lease-production records and completion dates for all Bartlesville wells in this quarter section, production from this lease is interpreted to be primarily or entirely from one well, L.E.C. No. 1 Frontier Shores (NW¼NW¼SE¼ sec. 28, T. 21 N., R. 9 E.).

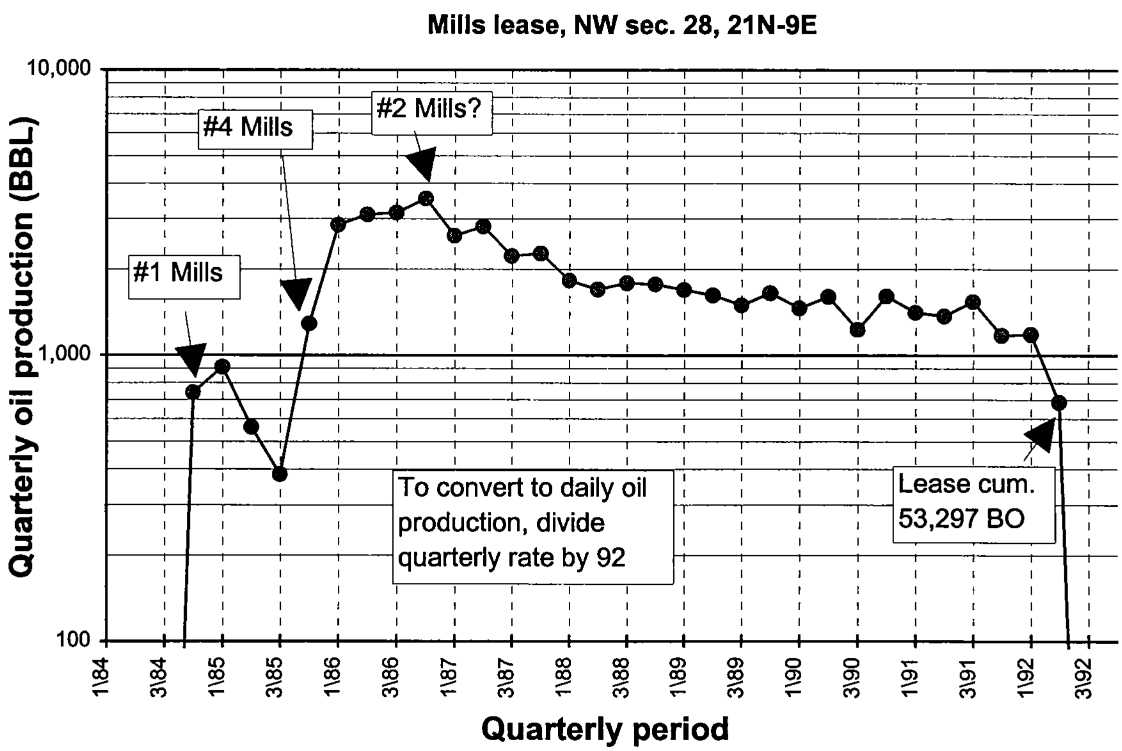


Figure 62. Oil-production curve for the Mills lease, NW¼ sec. 28, T. 21 N., R. 9 E. On the basis of known completion dates of individual wells and production spikes along this curve, production appears to include three wells, Petroleum Resources Nos. 1, 2, and 4 Mills.

zone were generally between 40% and 50%; the higher value was chosen to approximate the inferred oil–water contact. Calculations were made by using the equation $S_w = \sqrt{F \times R_w / R_t}$. The formation-water resistivity (R_w) was assumed to be 0.035 ohm-meters at formation temperature. The equation used for formation factor (F) was a modified Archie equation ($F = 0.81/\phi^2$) so as to reflect the average reservoir lithology (consolidated sand). Using the Archie equation of $F = 1/\phi^2$ would have resulted in water-saturation calculations considerably above 100% in many of the wet zones, which is unreasonable. R_t, true resistivity, was taken di-

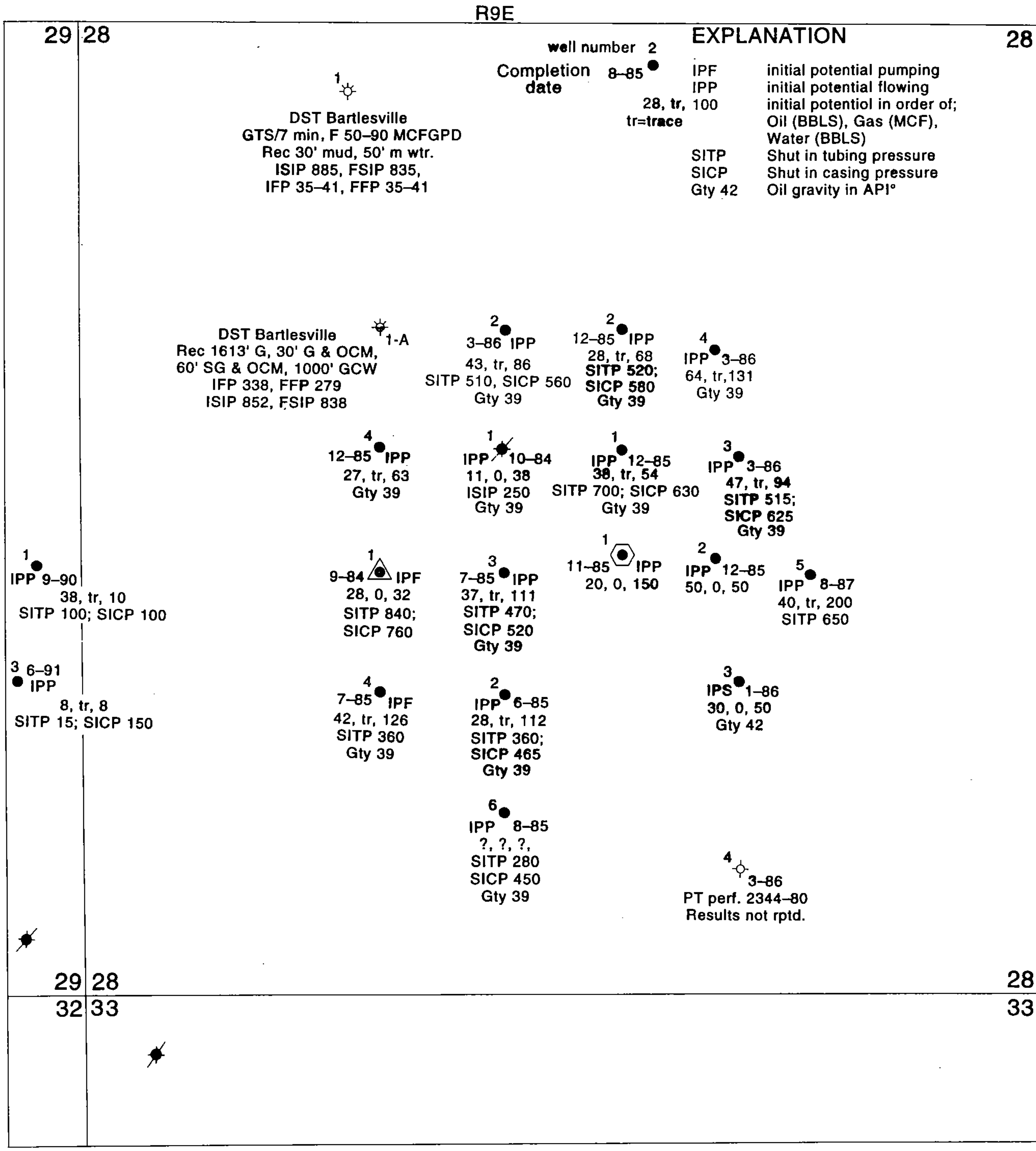


Figure 63. Map showing initial potentials (IP), completion dates, API oil gravity, shut-in tubing pressure (SITP), shut-in casing pressure (SICP), and well numbers for wells in the Ohio–Osage field area. Drillstem-test (DST) data and production-test (PT) data are presented for three nonproductive wells along the edges of the field. See Figure 51 for well names. See Appendix 4 for explanation of symbols.

rectly from the deep resistivity log. Porosity values were also taken directly from density logs and reduced about 1.5 porosity units to reflect actual reservoir conditions. Log density porosity was calculated by using a matrix density of 2.71 g/cm^3.

OIL AND GAS PRODUCTION

The estimated cumulative oil production from the Bartlesville sandstone in Ohio–Osage field from September 1984 through December 1996 was 183,063 BO (Table 9). No Bartlesville gas production was reported from any of the wells within this field. With the possible exception of one well, production information for individual wells was not available, as lease-production records involve more than one well; also, it was not always possible to extract individual well performance. All lease-production information was taken from from NRIS data and is summarized in Figure 60. From this illustration, three leases are shown to have oil production of 44 MBO to 54 MBO each. Since these leases have from 3 to 5 wells each, average individual well production is estimated at about 11 to >15 MBO. The lease attributed to single-well production is in the NW¼NW¼SE¼ sec. 28 and has produced 16,351 BO.

Lease-production records for two leases are plotted in the decline curves shown in Figures 61 and 62. Figure 61 is the production-decline curve representing the No. 1 Frontier Shores lease, NW¼NW¼SE¼ sec. 28, T. 21 N., R. 9 E., and is believed to be for a single well. The production history has no large production spikes within the chart, although several periods are identified as being shut in. Cumulative production for this lease (or well) is 16,351 BO. Figure 62 is the production-decline curve for the Mills lease in the NW¼ sec. 28. Based on completion dates of wells within the same quarter section, three wells are believed responsible for the production history of this lease, the Nos. 1, 2, and 4 Mills. Cumulative production for this lease is 53,297 BO, an average of about 17,765 BO per well.

Initial oil-production rates ranged from 11 to 64 BOPD (Fig. 63). All the wells in the field except the Nos. 1 and 4 Hess (SW¼ sec. 28) were on pump from the onset of completion. The two Hess wells flowed initially after completion. The No. 1 Hess is the discovery well and had the highest initial tubing pressure (840 PSI) in the field. The range in initial production rates is surprisingly small and may be due to the relatively low reservoir pressure or similar reservoir properties. Some of the wells recorded a trace of gas during completion, but none of the wells reported any gas production. All the Bartlesville wells reported water production following completion, and all the wells except one produced oil with an API gravity of 39°. Only the No. 3 Frontier Shores in the SE¼ sec. 28 produced oil with a different gravity (42°).

WELL COMPLETION

Operators set 4.5-in. or 5.5-in. production casing at or very near the bottom of the hole. In most productive wells, only the upper part of the sand interval was perforated to avoid the ever-present water-saturated zones deeper within the sand sequence. The wells were acidized with 1,500 to 3,000 gal of 15% hydrochloric acid (HCl) containing clay stabilizers and iron inhibitors. Fracture treatment consisted of the use of 25,000–56,000 lb of sand, 16,000–23,000 gal of gelled foam, and 175,000–424,000 SCF of nitrogen.

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APPENDIX 1

Various Size Grade Scales in Common Use

(from Blatt and others, 1980)

Udden–Wentworth	ϕ *values*	*German scale*† *(after Atterberg)*	*USDA and Soil Sci. Soc. Amer.*	*U.S. Corps Eng., Dept. Army and Bur. Reclamation*‡
		(Blockwerk)		
Cobbles		—200 mm—	Cobbles	Boulders
			—80 mm—	—10 in.—
—64 mm—	−6			Cobbles
				—3 in.—
Pebbles		Gravel (Kies)		
				Gravel
—4 mm—	−2		Gravel	
				—4 mesh—
Granules				Coarse sand
—2 mm—	−1	—2 mm—	—2 mm—	—10 mesh—
Very coarse sand			Very coarse sand	
—1 mm—	0		—1 mm—	
Coarse sand		Sand	Coarse sand	Medium sand
—0.5 mm—	1		—0.5 mm—	
				—40 mesh—
Medium sand			Medium sand	
—0.25 mm—	2		—0.25 mm—	
Fine sand			Fine sand	Fine sand
—0.125 mm—	3		—0.10 mm—	
Very fine sand			Very fine sand	—200 mesh—
—0.0625 mm—	4	—0.0625 mm—		
			—0.05 mm—	
Silt		Silt		
			Silt	Fines
—0.0039 mm—	8			
		—0.002 mm—	—0.002 mm—	
Clay		Clay	Clay	
		(Ton)		

†Subdivisions of sand sizes omitted.

‡Mesh numbers are for U.S. Standard sieves: 4 mesh = 4.76 mm, 10 mesh = 2.00 mm, 40 mesh = 0.42 mm, 200 mesh = 0.074 mm.

APPENDIX 2

Abbreviations Used in Text and on Figures, Tables, and Plates

API	American Petroleum Institute
BCF	billion cubic feet (of gas)
BCFG	billion cubic feet of gas
BCPD	barrels of condensate per day
BLWPD	barrels of load water per day
BO	barrels of oil
BOPD	barrels of oil per day
BHP	bottom-hole pressure
BLWPD	barrels of load water per day
BWPD	barrels of water per day
CAL	caliper
COF	calculated open flow
COND	conductivity
cp	centipoise (a standard unit of viscosity)
D & A	dry and abandoned
DST	drill stem test
GeoSystems	Geo Information Systems
GL	ground level
GOR	gas to oil ratio
GR	gamma ray
gty	gravity
IP	initial potential
IPF	initial production flowing
IPP	initial production pumping
KB	kelly bushing
MBO	thousand barrels of oil
MCF	thousand cubic feet (of gas)
MCFGPD	thousand cubic feet of gas per day
md	millidarcies, or 0.001 darcy
MMBO	million barrels of oil
MMCF	million cubic feet (of gas)
MMCFG	million cubic feet of gas
MMCFGPD	million cubic feet of gas per day
MMSCF	million standard cubic feet (of gas)
MMSTB	million stock tank barrels
MSCF/STB	thousand standard cubic feet per stock tank barrel
MSTB	thousand stock tank barrels
NRIS	Natural Resources Information System
OA	over-all (gross interval of perforations)
OGS	Oklahoma Geological Survey
OOIP	original oil in place
OWC	oil-water contact
OWWO	oil well worked over
perf	perforation interval
PSI	pounds per square inch
PSIA	pounds force per square inch, absolute
PVT	pressure volume temperature
RB	reservoir barrels (unit of measurement of oil in the subsurface where the oil contains dissolved gas); see STB or STBO
RB/STB	reservoir barrels per stock tank barrels
RES	resistivity
SCF/STB	standard cubic feet per stock tank barrel
SICP	shut in casing pressure
SITP	shut in tubing pressure
SP	spontaneous potential
STB or STBO	stock tank barrels of oil (unit of measurement for oil at the surface in a gas-free state rather than in the subsurface reservoir where the oil contains dissolved gas); see RB
STB/DAY	stock tank barrels (of oil) per day
S_w	calculated water saturation
TD	total depth
TSTM	too small to measure

APPENDIX 3

Glossary of Terms

(as used in this volume)

Definitions modified from Bates and Jackson (1987), Sheriff (1984), and Van Wagoner and others (1990).

allogenic—Formed or generated elsewhere.

anastomosing stream—A fluvial depositional system characterized by a branching network of shallow channels. Similar in form to braided river systems except that anastomosing rivers have alluvial islands covered by dense and permanent vegetation that stabilizes river banks.

authigenic—Formed or generated in place.

avulsion—A sudden cutting off or separation of land by a flood or by an abrupt change in the course of a stream, as by a stream breaking through a meander or by a sudden change in current whereby the stream deserts its old channel for a new one.

bar finger—An elongated, lenticular body of sand underlying, but several times wider than, a distributary channel in a bird-foot delta.

bed load—The part of the total stream load that is moved on or immediately above the stream bed, such as the larger or heavier particles (boulders, pebbles, gravel) transported by traction or saltation along the bottom; the part of the load that is not continuously in suspension or solution.

braided stream—A stream that divides into or follows an interlacing or tangled network of several small branching and reuniting shallow channels separated from each other by branch islands or channel bars.

capillary pressure—The difference in pressure across the interface between two immiscible fluid phases jointly occupying the interstices of a rock. It is due to the tension of the interfacial surface, and its value depends on the curvature of that surface.

centipoise—A unit of viscosity equal to 10^{-3}kg/s.m. The viscosity of water at 20°C is 1.005 centipoise.

channel deposit—An accumulation of clastic material, commonly consisting of sand, gravel, silt, and clay, in a trough or stream channel where the transporting capacity of the stream is insufficient to remove material supplied to it.

clay drapes—Layers of clay and silt deposited on lateral accretionary surfaces of point bars during periods of decreased river discharge.

crevasse-splay deposit—See *splay.*

delta—The low, nearly flat, alluvial tract of land at or near the mouth of a river, commonly forming a triangular or fan-shaped plain of considerable area, crossed by many distributaries of the main river, perhaps extending beyond the general trend of the coast, and resulting from the accumulation of sediment supplied by the river in such quantities that it is not removed by tides, waves, and currents. See also: *delta plain, delta front, prodelta, lower delta plain,* and *upper delta plain.*

delta front—A narrow zone where deposition in deltas is most active, consisting of a continuous sheet of sand, and occurring within the effective depth of wave erosion (10 m or less). It is the zone separating the *prodelta* from the *delta plain,* and it may or may not be steep.

delta plain—The level or nearly level surface composing the landward part of a large delta; strictly, an alluvial plain characterized by repeated channel bifurcation and divergence, multiple distributary channels, and interdistributary flood basins.

diagenesis—All changes that affect sediments after initial deposition, including compaction, cementation, and chemical alteration and dissolution of constituents. It does not include weathering and metamorphism of preexisting sediments.

diapir—A dome or anticlinal fold in which the overlying rocks have been ruptured by the squeezing-out of plastic core material. Diapirs in sedimentary strata usually contain cores of salt or shale.

distributary channel—(a) A divergent stream flowing away from the main stream and not returning to it, as in a delta or on an alluvial plain. (b) One of the channels of a braided stream; a channel carrying the water of a stream distributary.

distributary mouth bar—The main sediment load of a distributary channel in the subaqueous portion of a *delta* (also called the *delta front*). It consists predominantly of sand and silt; grain size decreases seaward.

eustatic—Pertaining to worldwide changes of sea level that affect all the oceans.

facies—(a) A mappable, areally restricted part of a lithostratigraphic body, differing in lithology or fossil content from other beds deposited at the same time and in lithologic continuity. (b) A distinctive rock type, broadly corresponding to a certain environment or mode of origin.

fluvial—(a) Of or pertaining to a river or rivers. (b) Produced by the action of a stream or river.

formation-volume factor—The factor applied to convert a barrel of gas-free oil in a stock tank at the surface into an equivalent amount of oil in the reservoir. It generally ranges between 1.14 and 1.60. See also: *shrinkage factor.*

highstand—The interval of time during one or more cycles of relative change of sea level when sea level is above the shelf edge in a given local area.

highstand system tract (HST)—The stratigraphically higher (or younger) depositional system(s) in a succession of genetically related strata bounded by unconformities or their correlative counterparts.

incised valleys—Entrenched fluvial systems that extend their channels basinward and erode into underlying strata.

infilling—A process of deposition by which sediment falls or is washed into depressions, cracks, or holes.

isopach—A line drawn on a map through points of equal true thickness of a designated stratigraphic unit or group of stratigraphic units.

lacustrine—Pertaining to, produced by, or formed in a lake or lakes.

lower delta plain—Depositional environment within a *delta* which extends from the subaqueous *delta front* to the landward limit of marine (tidal) influence.

lowstand—The interval of time during one or more cycles of relative change of sea level when sea level is below the shelf edge.

lowstand system tract (LST)—The stratigraphically lower (or older) depositional system(s) in a succession of genetically related strata bounded by unconformities or their correlative counterparts.

meander—One of a series of regular freely developing sinuous curves, bends, loops, turns, or windings in the course of a stream. See also: *meander belt.*

meander belt—The zone along a valley floor across which a meandering stream shifts its channel from time to time; specifically the area of the flood plain included between two lines drawn tangentially to the extreme limits of all fully developed meanders. It may be from 15 to 18 times the width of the stream.

meteoric water—Pertaining to water of recent atmospheric origin.

millidarcy (md)—The customary unit of measurement of fluid permeability, equivalent to 0.001 darcy.

mud cake—A clay lining or layer of concentrated solids adhering to the walls of a well or borehole, formed where the drilling mud lost water by filtration into a porous formation during rotary drilling.

natural water drive—Energy within an oil or gas pool, resulting from hydrostatic or hydrodynamic pressure transmitted from the surrounding aquifer.

offlap—A term commonly used by seismic interpreters for reflection patterns generated from strata prograding into deep water.

onlap—The progressive submergence of land by an advancing sea.

point bar—One of a series of low, arcuate ridges of sand and gravel developed on the inside of a growing meander by the slow addition of individual accretions accompanying migration of the channel toward the outer bank.

prodelta—The part of a delta that is below the effective depth of wave erosion, lying beyond the *delta front,* and sloping gently down to the floor of the basin into which the delta is advancing and where clastic river sediment ceases to be a significant part of the basin-floor deposits.

progradation—The building forward or outward toward the sea of a shoreline or coastline (as of a beach, delta, or fan) by nearshore deposition of river-borne sediments or by continuous accumulation of beach material thrown up by waves or moved by longshore drifting.

proppant—As used in the well completion industry, any type of material that is used to maintain openings of induced fractures. Proppants usually consist of various sizes of sand, silica beads, or other rigid materials, and they are injected into the formation while suspended in a medium such as water, acid, gel, or foam.

regression—The retreat or contraction of the sea from land areas, and the consequent evidence of such withdrawal (such as enlargement of the area of deltaic deposition).

residual oil—Oil that is left in the reservoir rock after the pool has been depleted.

ribbon sand—See: *shoestring sand.*

rip-up—Said of a sedimentary structure formed by shale clasts (usually of flat shape) that have been "ripped up" by currents from a semiconsolidated mud deposit and transported to a new depositional site.

river bar—A ridge-like accumulation of alluvium in the channel, along the banks, or at the mouth, of a river.

shoestring sand—A shoestring composed of sand or sandstone, usually buried in the midst of mud or shale; e.g., a buried distributary mouth bar, coastal beach, or channel fill.

shrinkage factor—The factor that is applied to convert a barrel of oil in the reservoir into an equivalent amount of gas-free oil in a stock tank at the surface. It generally ranges between 0.68 and 0.88. See also: *formation-volume factor.*

splay—A small alluvial fan or other outspread deposit formed where an overloaded stream breaks through a levee (artificial or natural) and deposits its material on the flood plain or delta plain.

stillstand—Stability of an area of land, as a continent or island, with reference to the Earth's interior or mean sea level, as might be reflected, for example, by a relatively unvarying base level of erosion between periods of crustal movement.

subaerial—Said of conditions and processes, such as erosion, that exist or operate in the open air on or immediately adjacent to the land surface; or of features and materials, such as eolian deposits, that are formed or situated on the land surface. The term is sometimes considered to include fluvial.

tabular cross-bedding—Cross-bedding in which the cross-bedded units, or sets, are bounded by planar, essentially parallel surfaces, forming a tabular body.

thalweg—The line conecting the lowest or deepest points along a stream bed or valley, whether under water or not.

transgression—The spread or extension of the sea over land areas, and the consequent evidence of such advance.

transgressive system tract (TST)— A depositional episode that is bounded below by the transgressive surface and above by sediments representing a period of maximum flooding. The depositional environment of a TST becomes progressively deeper upward in the section.

transverse river bar—A channel bar deposit which is generally at an angle across the channel but prograding on the downstream side. This type of river deposit may be lobate, straight, or sinuous in map view.

trough cross-bedding—Cross-bedding in which the lower bounding surfaces are curved surfaces of erosion; it results from local scour and subsequent deposition.

upper delta plain—Depositional environment in a *delta* that extends from the down-flow edge of the flood plain to the effective limit of tidal inundation of the *lower delta plain*. The upper delta plain essentially is that portion of a delta unaffected by marine processes.

unitized—Consolidating the management of an entire oil or gas pool, regardless of property lines and lease boundaries, in the interest of efficient operation and maximum recovery.

valley fill—Sediment deposited in a valley or trough by any process; commonly, fluvial channel deposition is implied.

water leg—A water-saturated zone that extends below an oil- or gas-saturated zone.

APPENDIX 4

Well Symbols Used in Figures and Plates

EXPLANATION

●	Oil well
	Gas well
	Oil & gas well
	Dry hole
	Dry, show of oil
	Dry, show of gas
	Dry, show of oil & gas
WSW ○	Water-supply well
	Water-injection well
	Oil well, plugged & abandoned
△	Discovery well
⬡	Type log
NL	No log
NDE	Not deep enough
ND	No data
A	Sand absent

Producing Formations

O	Oswego
Sk	Skinner
B	**Bartlesville**
M	Mississippian
Mz	Misner
V	Viola
Sm	Simpson

APPENDIX 5

Core Descriptions, Well Logs, and Digital Images of Select Rock Intervals for Two Wells:

1. **Appleton Oil Company No. 1 Graves**
   C NW¼SW¼ sec. 32, T. 18 N., R. 2 E.
   Bartlesville, marine bar
   Cored interval: 4,412–4,443 ft

2. **Shell Oil No. 10-C Bayless**
   C SE¼SE¼ sec. 30, T. 24 N., R. 12 E.
   Bartlesville, marine bar
   Cored interval: 4,412–4,443 ft

Appleton Oil Company No. 1 Graves

C NW¼SW¼ sec. 32, T. 18 N., R. 2 E.

Bartlesville sandstone core

Marine bar (delta front?)

Log depth ≈ Core depth ± a few feet

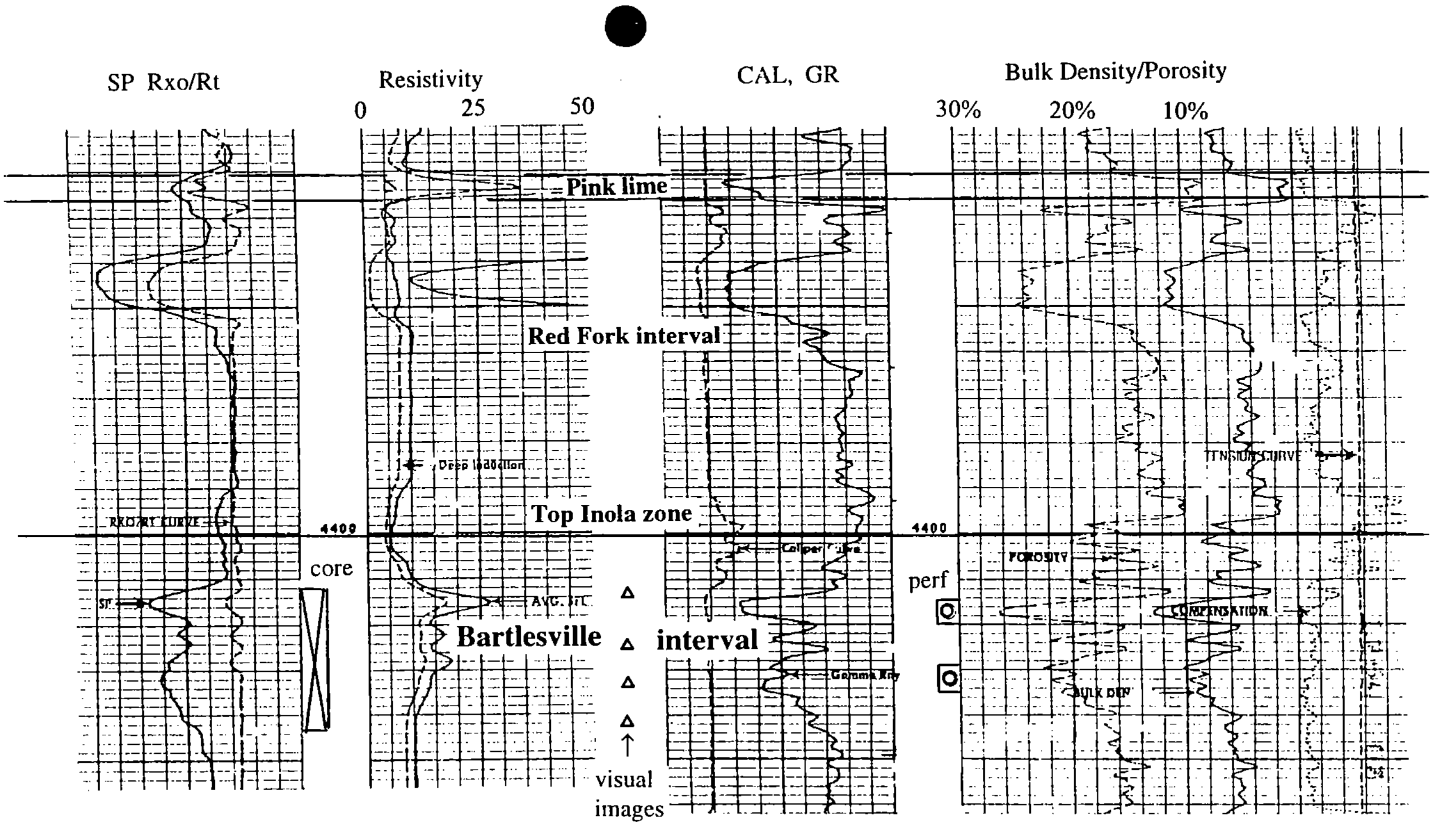
Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
4,412–4,413.3	Interbedded sandstone and shale. Sand is very fine grained, mostly greenish but, in places, rusty in color. Bedding is horizontal to wavy. Shale is silty, slightly micaceous, with no carbonaceous material.
4,413.3–4,418.0	TOP OF UPPER SAND BED *Upper marine-bar facies.* Sandstone, fine-grained; sharp upper contact with interbedded sequence described above. Massive bedding and, in places, medium-angle cross-bedding. Oil staining occurs throughout sand interval. Sand becomes increasingly interbedded with thin shale layers with depth. Sand has excellent porosity and permeability and is relatively clean, with little mica. Burrowing and bioturbation at 4,417.4 ft.
4,418.0–4,421.8	*Bar transition.* Sandstone with interbedded shale. Sand is very fine grained, has good porosity, but occurs in thin beds 0.25 in. to several inches thick or in thin lenses or pods between shale layers. Shale occurs in thin beds or laminae and is slightly micaceous, with small amounts of carbonaceous material.
4,421.8–4,423.3	Sandstone, very fine grained, with some thin shaly interbeds or laminations.
4,423.3–4,425.9	Sandstone and interbedded shale. Sand occurs in thin layers or lenses <0.5 in. thick. Horizontal and ripple bedding predominates. Shale is slightly micaceous and has only small amounts of carbonaceous material. Possible burrows at 4,424.9 ft.
4,425.9–4,426.6	Sandstone, very fine grained, with carbonaceous shale laminations.
4,426.6–4,427.4	Shale and interbedded sandstone lenses with ripple and horizontal bedding.
4,427.4–4,429.5	TOP OF LOWER SAND BED *Middle to upper marine-bar facies.* Sandstone, very fine grained, with shale laminations between 4,428.1 and 4,428.5 ft. Sandstone has faint ripple bedding or is massive, and has very good porosity. Shale beds are moderately micaceous and have numerous small pieces of organic debris.
4,429.5–4,430.5	Interbedded sandstone, very fine grained, and shale. Shale is silty to sandy, occurs in thin beds or laminations, and is somewhat carbonaceous, with moderate amounts of mica. Bedding is mostly horizontal.
4,430.5–4,434.3	Sandstone, very fine to fine-grained, irregular to slightly ripple bedded, with numerous interbedded shale laminations that increase with depth. Sandstone has good porosity. Dark-colored intervals are oil stained, whereas light-colored layers are tightly cemented with calcite. Shale partings are slightly micaceous and have abundant small pieces of carbonaceous debris.
4,434.3–4,443	*Bar transition.* Interbedded sandstone and shale. Sand is very fine grained, in thin layers <1 in. thick, and is wavy to horizontal bedded. Shale as above. Bioturbation and burrowing are evident below 4,440 ft.

Appleton Oil Company No. 1 Graves (C NW¼SW¼ sec. 32, T. 18 N., R. 2 E.)

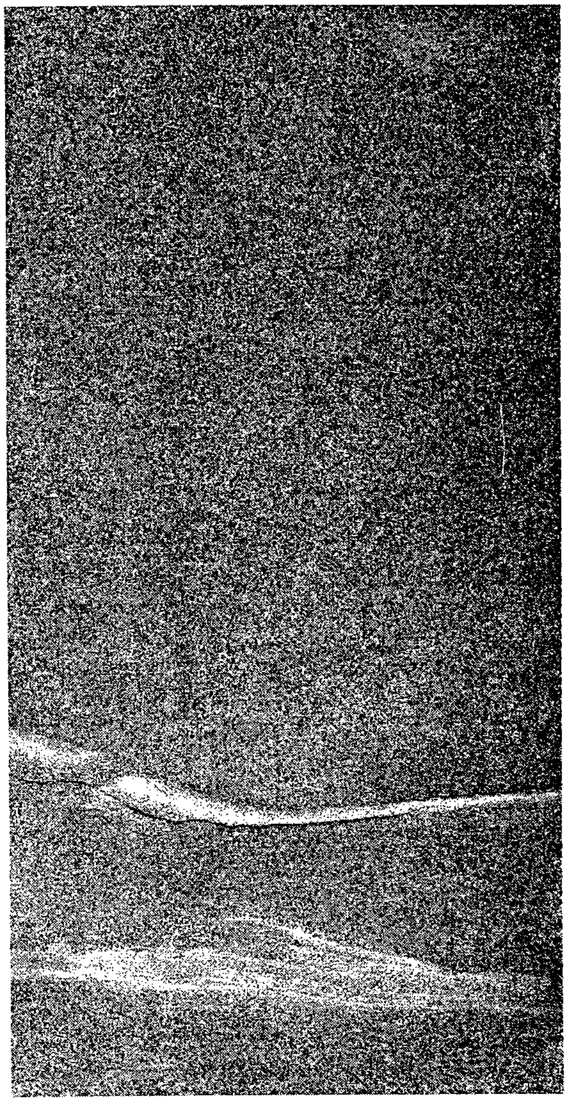
Reservoir: Bartlesville sandstone
Depositional environment: Marine bar, possibly distributary-mouth bar

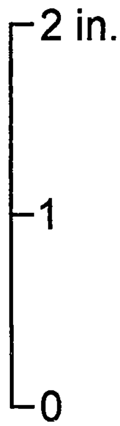
Log depth: 4,412–4,443 ft ± a few feet
Core depth: 4,412–4,443 ft



T.D.: 4,465 ft
Completion date: 10/18/80
Perforated: 4,414–4,420 ft, 4,429–4,435 ft
Frac 21,000 lb sand, 28,224 gal wtr
IPF (Bartlesville) 154 BOPD
FTP 600 PSI, Gty 36° API

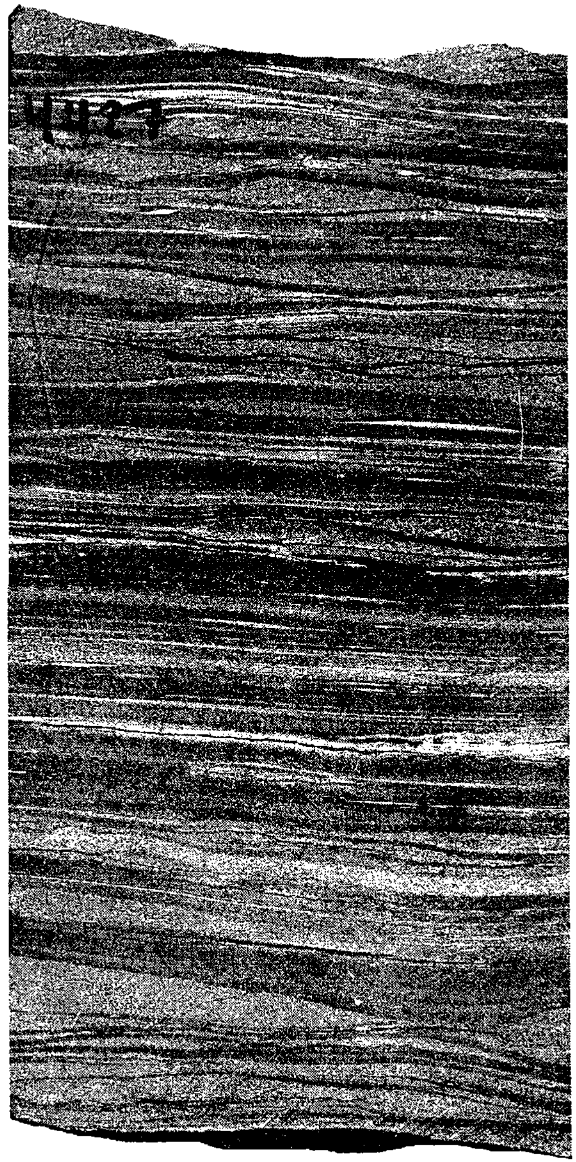
Appleton Oil Company No. 1 Graves (C NW¼SW¼ sec. 32, T. 18 N., R. 2 E.)





Core depth: 4,413.4–4,413.9 ft
Log depth: about 4,413.4–4,413.9 ft

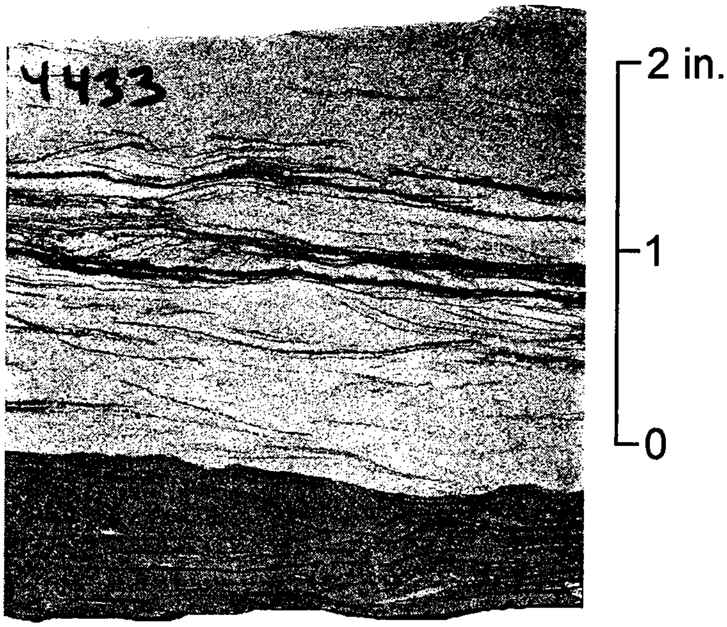
Upper marine-bar facies (upper sand bed). Sandstone, fine-grained, sharp upper contact with shale (not shown). Excellent porosity and permeability. Massive bedding, owing to rapid deposition. Faint shale lamination in bottom part of sample shows uneven bedding. This well-sorted sandstone occurs in the upper part of the sandstone bed but is increasingly interbedded with shale lower in the section. No bioturbation or burrowing is apparent. The upward-coarsening textural profile and lack of rip-up clasts characterizes this sand bed as being a marine-bar rather than a fluvial-channel deposit.



Core depth: 4,427–4,427.5 ft
Log depth: about 4,425–4,425.5 ft

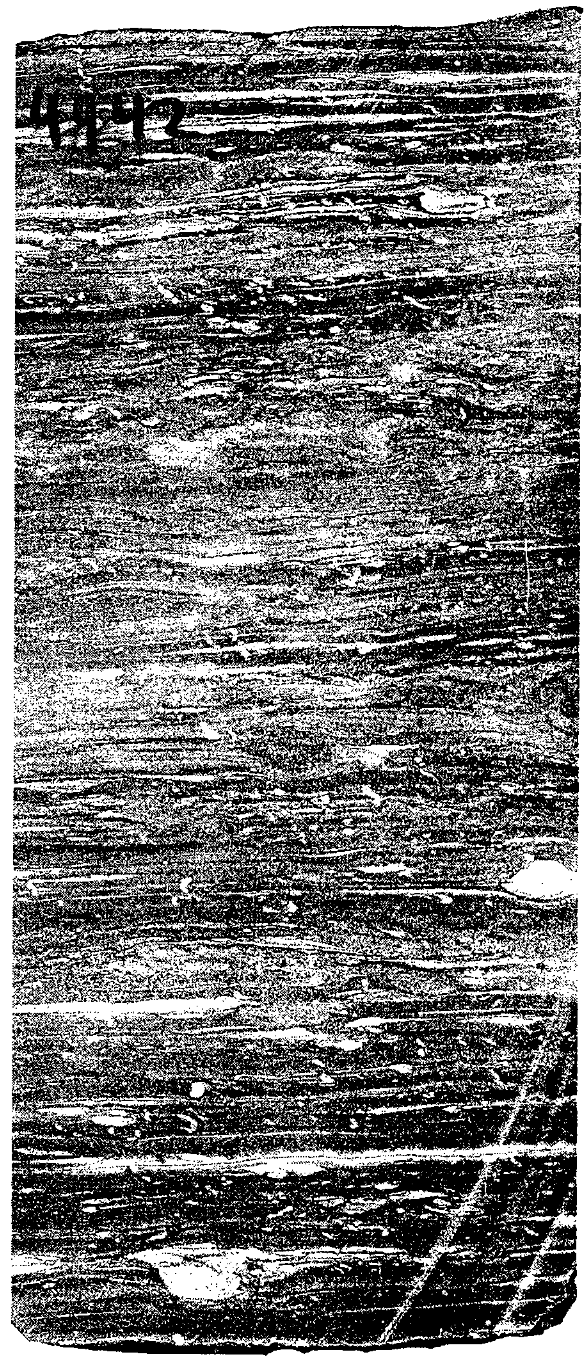
Bar-transition facies. Sandstone and interbedded shale. Faint ripple bedding in upper 2 in. Rhythmic pattern of subhorizontal beds of shale and very fine grained sand is most unlike that of sand–shale sequences in channel facies. Most apparent in this sample is the lack of interbedded sandstone lenses having small-scale cross-bedding, which is more characteristic of facies within the upper part of channel deposits in fluvial environments (see Shell core at 1,601–1,601.5 ft in this Appendix). The bar-transition facies probably grades upward into the clean sandstone of the marine-bar facies described in left column.

Appleton Oil Company No. 1 Graves (C NW¼SW¼ sec. 32, T. 18 N., R. 2 E.)



Core depth: 4,433–4,433.25 ft
Log depth: about 4,433–4,433.25 ft

Marine-bar facies of lower sand bed. Sandstone, very fine to fine-grained, with irregular to slight ripple bedding. Shale laminae are moderately carbonaceous and micaceous and are more numerous with depth. The light-colored sandstone (upper three-fourths of sample) is tight and calcareous. The darker sandstone in the bottom part of sample is not cemented with calcite and is slightly more porous, hence the visible oil staining. Overall, the lower marine-sand bed has less porosity and permeability and considerably more shale as compared to the upper marine-sand bed.



Core depth: 4,442–4,442.6 ft
Log depth: about 4,442–4,442.6 ft

Lower bar-transition facies. Shale and interbedded thin sandstone lenses. The indistinct bedding throughout this sample and small, numerous, inclined, light-colored areas appear to be the result of bioturbation and burrowing. A few feet lower in the section, shale predominates, which may be analogous to prodelta facies of a subaqueous delta front.

Shell Oil No. 10-C Bayless

C SE¼SE¼ sec. 30, T. 24 N., R. 12 E.

Bartlesville sandstone core

Incised Channel

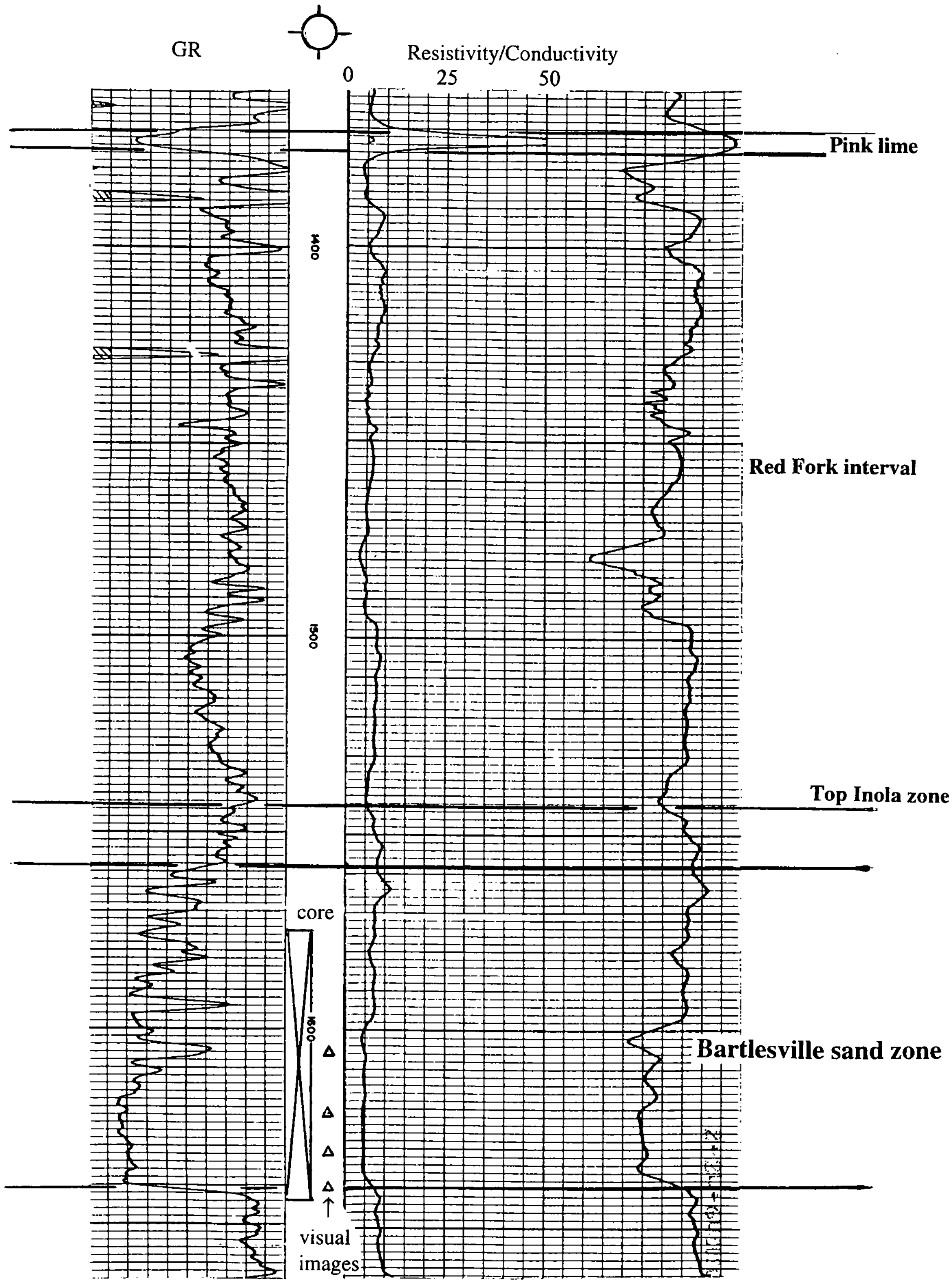
Log depth ≈ ~5 ft lower than core depth — Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
	UPPER CHANNEL FACIES
1,570–1,572.2	Sandstone, very fine grained; medium- to high-angle cross-bedding, possible slumping at 1,571.2 ft. Very porous, relatively clean sand with few shale laminations.
1,572.2–1,575	Sandstone and shale. Sand is very fine grained with small-scale cross-bedding or indistinct bedding, with some interbedded black-shale laminations. Ripple bedding is present but not common.
1,575–1,575.9	Sandstone, very fine grained, with scattered rip-up clasts. Mud clasts are elongate, ~0.1 in. high and ~0.5 in. long. Bedding is mostly horizontal with scattered ripples. Climbing ripples poorly developed at 1,575.5 ft.
1,575.9–1,577.2	***Shale parting.*** Shale, black, and interbedded sandstone, very fine grained; mostly horizontal bedding.
1,577.2–1,580.1	Sandstone, very fine to fine-grained; slightly inclined bedding. Relatively clean sand with few shale laminations.
1,580.1–1,580.6	***Shale parting.*** Shale, black, with interbedded very fine grained sandstone. Low-angle to horizontal bedding.
1,580.6–1,587.6	Sandstone, fine- to very fine grained; upper part has medium-angle cross-bedding and few shale laminations. Lower part is coarser (fine grained) and has horizontal bedding and scattered shale laminations. All sand is relatively clean, with little mica, and has excellent porosity. Sand has sharp basal contact with shale.
1,587.6–1,590	***Shale parting.*** Shale and interbedded sandstone. Sand is very fine grained and has horizontal and small-scale cross-bedding. Shale occurs in thin beds and laminations. Small pieces of organic debris are scattered throughout the shale layers.
1,590–1,599	Sandstone, fine-grained, with medium-angle cross-bedding. Sand is relatively clean, with few shale laminations, and has excellent porosity. Sharp basal contact with shale.
1,599–1,602.1	***Shale parting.*** Shale and sandstone. Sand is very fine grained, has small-scale ripple- and cross-bedding, and is interbedded with numerous black-shale laminations. Shale partings are slightly inclined and have small amount of mica and little organic debris.
1,602.1–1,605.5	***Lower channel facies (top of lower [main] sand bed).*** Sandstone, fine- to very fine grained, with horizontal and low-angle cross-bedding. Sand is is slightly micaceous with little or no shale laminations.
1,605.5–1,606.5	Sandstone and interbedded shale. Sand is very fine grained, with horizontal bedding. Shale beds have minor to moderate amounts of mica.
1,606.5–1,625.2	Sandstone, fine- to medium-grained. Continuous sand section with downward-coarsening grain-size texture. Medium-angle cross-bedding predominates, with some horizontal bedding. Good to excellent porosity. Relatively clean sand is nearly all quartz. A few rounded mud clasts occur at 1,614.5 and at 1,615.8 ft.
1,625.2–1,626	Sandstone, fine- to medium-grained; contorted bedding (flowage).
1,626–1,636.2	Sandstone, fine- to medium-grained; low- to medium-angle cross-bedding. Widely scattered shale laminations are coaly and highly carbonaceous. A small amount of carbonaceous debris (in very small pieces) occurs throughout the bottom part of this interval. Sandstone is mostly quartz, with a small amount (<10%) of rock fragments. Possible flowage at 1,628 ft.
1,636.2–1,637.3	Basal conglomerate with rounded, orangish mud clasts up to 2 in. in diameter. Sharp basal contact with underlying shale.
	BASE OF CHANNEL
1,637.3–1,639	Black shale, fissile to finely bedded; little or no mica or carbonaceous debris.

Shell Oil No. 10-C Bayless (C SE¼SE¼ sec. 30, T. 24 N., R. 12 E.)

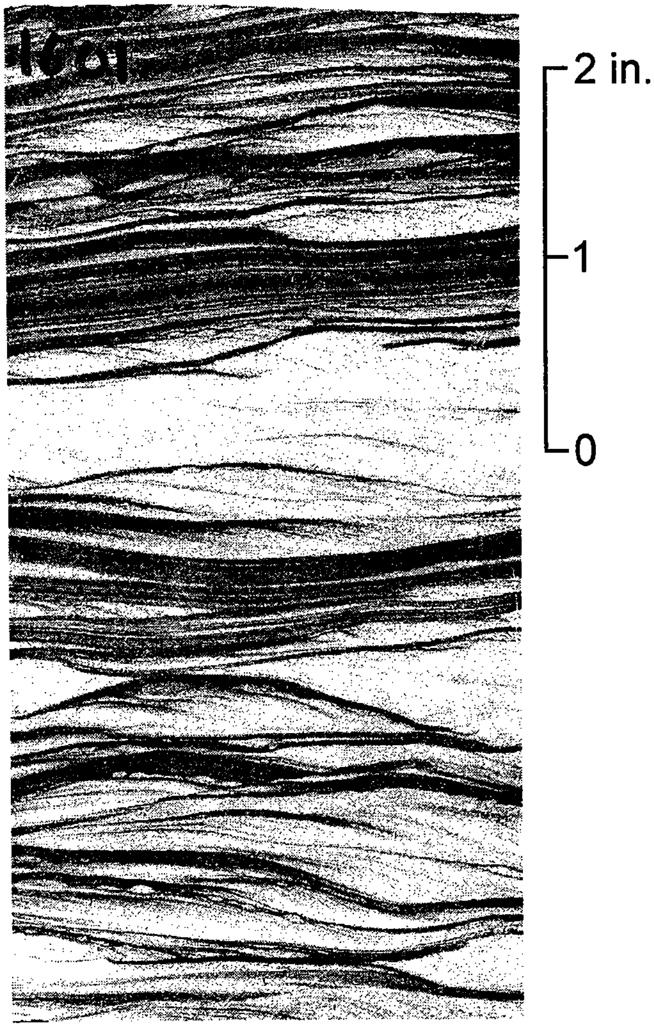
Reservoir: Bartlesville sandstone
Depositional environment: Incised fluvial channel

Log depth: about 1,575–1,644 ft
Core depth: 1,570–1,639 ft



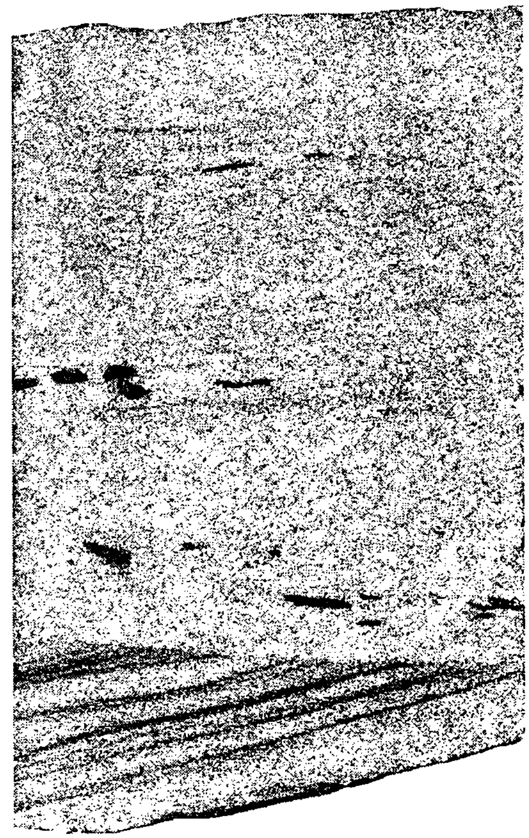
T.D.: 1,665 ft
P & A: 2/26/64

Shell Oil No. 10-C Bayless (C SE¼SE¼ sec. 30, T. 24 N., R. 12 E.)



Core depth: 1,601–1,601.5 ft
Log depth: about 1,606–1,606.4 ft

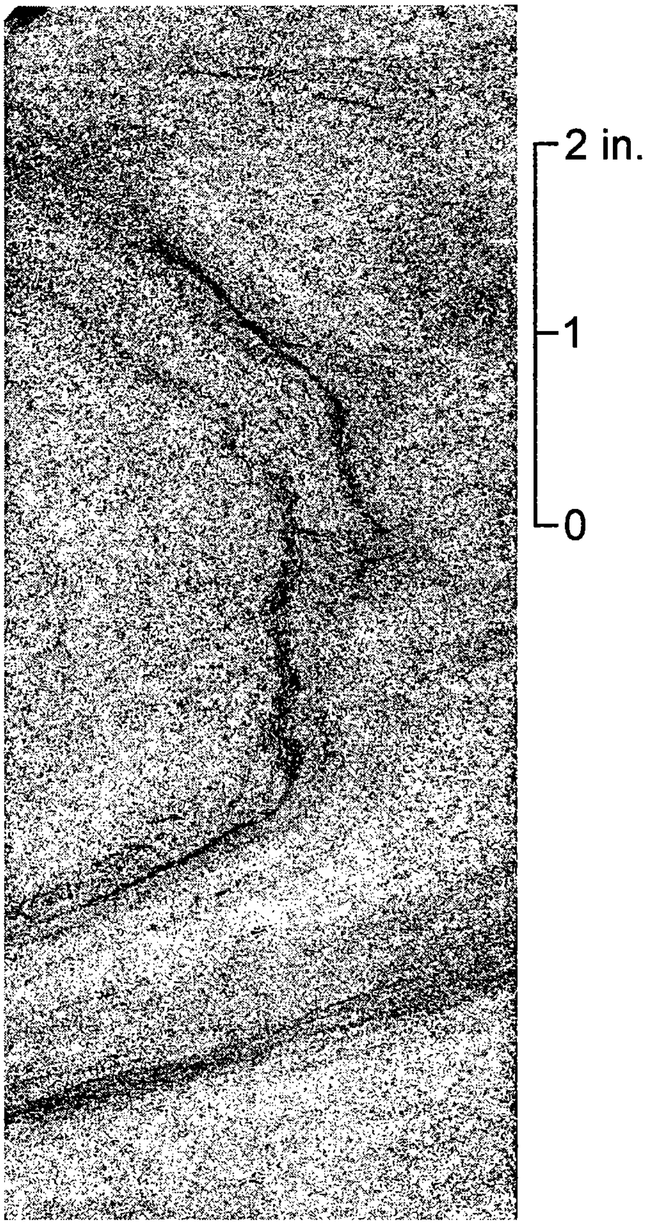
Shale parting. Sandstone and interbedded shale. Sand is very fine grained and has small-scale cross-bedding. Possible climbing ripples just above right-center part of sample. Shale laminations have a small amount of mica and little organic debris. This core interval appears to correlate with a distinct shale break on the gamma-ray log and represents either the upper facies of the main, basal sand bed or a shale parting (clay drape?).



Core depth: 1,615.7–1,616 ft
Log depth: about 1,620.7–1,621 ft

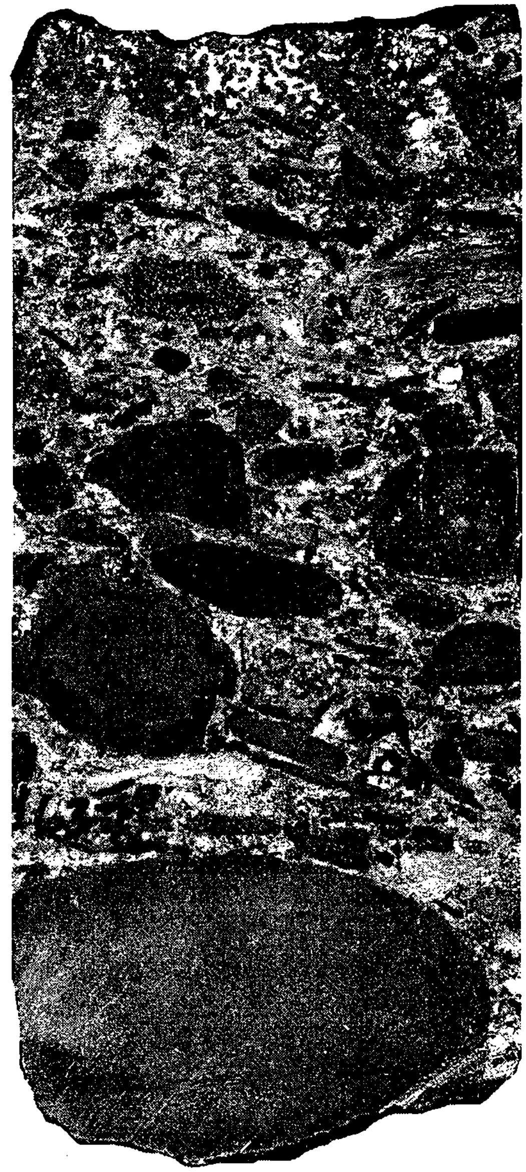
Lower sand-zone facies. Sandstone is fine grained but gradually increases to medium grained several feet lower in the section. Porosity is good to excellent. This sample shows mostly horizontal bedding with scattered mud clasts in the center and lower parts of the sample. In the lower part of the sample, medium-angle cross-bedding is well developed and shows erosional truncation. Textural and bedding features such as these are characteristic of strong current energy in a fluvial environment.

Shell Oil No. 10-C Bayless (C SE¼SE¼ sec. 30, T. 24 N., R. 12 E.)



Core depth: 1,625.3–1,625.8 ft
Log depth: about 1,630.3–1,630.8 ft

Lower sand-zone facies. Sandstone, fine- to medium-grained, showing contorted bedding (flowage). Bedding such as this is common in most environments experiencing rapid deposition, including channel-mouth bars and fluvial channels. The association of other textural features of this lower sand bed, including downward-coarsening grain size, interbedded coaly layers, conspicuous presence of rock fragments, and sharp basal contact, supports a fluvial-environment interpretation.



Core depth: 1,636.6–1,637.1 ft
Log depth: about 1,640.6–1,641.1 ft

Basal channel facies. Conglomerate with rounded mud clasts up to 2.5 in. across. Smaller mud clasts (up to ~1 in. across) are elongate parallel to bedding. These coarse fragments are rip-up clasts deposited along the river bottom as the result of bank erosion during highest relative stream current. The sharp basal contact of this sequence with the underlying shale is evidence of significant scouring.

APPENDIX 6

Stratigraphic Column for the Fluvial-Dominated Deltaic (FDD) Reservoirs Project

Series	Group	FORMAL TERMINOLOGY	COMMON SUBSURFACE USAGE	Play
PENNSYLVANIAN SYSTEM				
VIRGILIAN SERIES	SHAWNEE GROUP	OREAD FORMATION	OREAD LIME	
		HEEBNER SHALE		
		WYNONA SANDSTONE	ENDICOTT SAND	
		TORONTO LIMESTONE		
	DOUGLAS GROUP	LAWRENCE FORMATION (KS)		
		HASKELL LIMESTONE		
		STRANGER FORMATION (KS)		
		CHESHEWALLA SANDSTONE [OK]	TONKAWA SAND (OK)	TONKAWA PLAY SP-97-3
		TONGANOXIE SANDSTONE [KS]	STALNAKER SAND (KS)	
MISSOURIAN SERIES	OCHELATA GROUP	BARNSDALL FORMATION		
		WILDHORSE LIMESTONE	"AVANT LS" MISCORRELATION	
		WANN FORMATION		
		TORPEDO SANDSTONE		
		IOLA FORMATION	AVANT LIMESTONE	
		CHANUTE FORMATION		
		COTTAGE GROVE SANDSTONE	OSAGE-LAYTON SAND ("LAYTON", MUSSELEM SANDS)	LAYTON AND OSAGE-LAYTON PLAY SP-96-1
	SKIATOOK GROUP	DEWEY LIMESTONE	DEWEY LIMESTONE	
		NELLIE BLY FORMATION	("LAYTON" SAND)	
		HOGSHOOTER LIMESTONE	HOGSHOOTER LIMESTONE (LOST CITY LIME)	
		COFFEYVILLE FORMATION		
		DODDS CREEK SANDSTONE	LAYTON SAND (TRUE LAYTON SAND)	
		CHECKERBOARD LIMESTONE	CHECKERBOARD LIMESTONE	
		SEMINOLE FORMATION	SEMINOLE SAND ("CLEVELAND SAND")	
DESMOINESIAN SERIES	MARMATON GROUP	HOLDENVILLE FORMATION		
		TULSA SANDSTONE	U. CLEVELAND SAND (JONES SAND)	CLEVELAND AND PERU PLAYS SP-97-5
		JENKS SANDSTONE	L. CLEVELAND SAND (DILLARD SAND)	
		LENAPAH LIMESTONE		
		NOWATA FORMATION		
		WALTER JOHNSON SANDSTONE	WAYSIDE SAND	
		OOLAGAH FORMATION	BIG LIME	
		LABETTE FORMATION		
		ENGLEVALE SANDSTONE	PERU SAND	
		FORT SCOTT LIMESTONE	OSWEGO LIME	

FORMAL TERMINOLOGY	COMMON SUBSURFACE USAGE
DESMOINESIAN SERIES / CABANISS GROUP	
SENORA FORMATION	
LAGONDA SANDSTONE	PRUE SAND (SQUIRREL, PERRYMAN, GIBSON, BIXLER, 2ND & 3RD DEESE, WANETTE SANDS)
CALVIN SANDSTONE	CALVIN SANDSTONE
VERDIGRIS LIMESTONE	VERDIGRIS LIMESTONE, ARDMORE LIME
CROWEBURG COAL	HENRYETTA COAL
OOWALA SANDSTONE	SKINNER SAND U. (VERDIGRIS, SENORA, ALLEN, CATTLEMAN SANDS)
	SKINNER SAND M. (ALLEN, OLYMPIC, SENORA SANDS)
CHELSEA SANDSTONE	SKINNER SAND L. (HART, SENORA, THURMAN, 4TH DEESE SANDS)
	SKINNER AND PRUE PLAY SP-96-2
TIAWAH LIMESTONE	PINK LIME, SENORA LIME
KREBS GROUP	
BOGGY FORMATION	
TAFT SANDSTONE	RED FORK SAND (EARLSBORO, BURBANK, DORA, OSBORN, PEACH ORCHARD & CHICKEN FARM SANDS)
INOLA LIMESTONE	INOLA LIMESTONE
	RED FORK PLAY SP-97-1
BLUEJACKET SANDSTONE	BARTLESVILLE SAND (GLENN SAND)
	BARTLESVILLE PLAY SP-97-6
SAVANNA FORMATION	
DONELEY LIMESTONE	BROWN LIME
SAM CREEK LIMESTONE	
SPANIARD LIMESTONE	
MCALESTER FORMATION	
KEOTA SANDSTONE	BOOCH SAND
TAMAHA SANDSTONE	
CAMERON SANDSTONE	
LEQUIRE SANDSTONE	
WARNER SANDSTONE	"TANEHA SAND"
	BOOCH PLAY SP-95-3
HARTSHORNE FORMATION	BURGESS (UNCONFORMITY) SAND
ATOKAN SERIES / ATOKA GROUP	
ATOKA FORMATION	ATOKA
	THIRTEEN FINGER LIME
MORROWAN SERIES / MORROW GROUP	
MORROW FORMATION	UPPER MORROW
	PURDY SAND
	STURGIS SAND
	BOWLES SAND
	KELLY SAND
	LIPS SAND
	A, B, C, D, etc. SANDS
	PURYEAR SAND (deep Anadarko)
	LOWER MORROW
	"SQUAW BELLY" ZONE
	MOCANE-LAVERNE SAND
	KEYES SAND
	MORROW PLAY SP-95-1

MISSISSIPPIAN SYSTEM

COMPILED BY: RICHARD ANDREWS, JOCK CAMPBELL, CARLYLE HINSHAW AND ROBERT NORTHCUTT

Notes

Oklahoma Geological Survey
Supplement to Special Publication 97-6

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Bartlesville Play

PART III

Reservoir Simulation of the Bartlesville Sand Reservoir, Paradise Field, Payne County, Oklahoma

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ABSTRACT.—A three-dimensional, three-phase oil-reservoir model was constructed to estimate the original oil in place (OOIP), simulate historical field production, and investigate strategies to improve oil recovery from the Bartlesville sandstone in the Paradise field, southwestern Payne County, Oklahoma. The Bartlesville sandstone comprises fluvial-channel and point-bar deposits. The reservoir descriptions were based on geologic interpretations of reservoir-sandstone distribution structure, depositional history, and correlation between well-logging and core data.

The estimated OOIP from the geological study was 3,650,000 stock tank barrels of oil (STBO), and the OOIP from the simulation model is estimated to be 4,000,000 STBO. After 10 years of primary production, nearly 11.2% of the OOIP (409,000 STBO) had been recovered, as of April 30, 1994. The primary reservoir-energy source appears to have been solution-gas drive. A water-injection project was started in May 1994, and it achieved some oil-production response. The volume of unproduced mobile oil, about 42% of the OOIP, is a strong incentive to consider additional oil-recovery opportunities from this field by improving waterflood sweep or expanding operations. After comparing three 5-year development strategies, it appears that converting the No. 2 Longan well to an injector would be an attractive choice. We believe there is a target of additional oil recovery of about 460,000 STBO (or 13% of the OOIP).

INTRODUCTION

Paradise oil field, in southwestern Payne County, Oklahoma, lies in sec. 4, T. 17 N., R. 1 E., and secs. 33 and 34, T. 18 N., R. 1 E. This field produces oil and gas from fluvial-channel and point-bar deposits in the Bartlesville sandstone in two areas, an east sand body and a west sand body. It appears that the eastern and western parts produce from different channel paths and that little or no hydraulic continuity exists between them. The boundaries of the channels were assumed to be no-flow boundaries. The Bartlesville sand in this reservoir lies at a depth of 4,800 ft and covers a total area of 314 acres, the eastern part comprising 164 acres and the western part 150 acres. The average net sand thickness in the whole study area is 16.6 ft, 17.3 ft in the east and 15.9 ft in the west. A complete discussion of the field can be found in Part II of this volume.

The major objectives of this study were (1) to use existing data to develop a reservoir-simulation model of Paradise field for use in BOAST3 (Mathematical & Computer Services, Inc., 1995); (2) to analyze past field-production performance, especially the results of water injection; and (3) to identify potential strategies to improve oil recovery using the developed reservoir model.

OVERVIEW OF FIELD DEVELOPMENT

The Bartlesville oil pool in Paradise field was accidentally discovered in March 1986 when Canadian Exploration tried to extend a Misener sandstone (Devonian) play toward the south. The discovery well was the

No. 3 Downey (SE¼SW¼SW¼ sec. 33, T. 18 N., R. 1 E.). The field was developed on 10–20-acre spacing. Through July 1990, 13 wells had been drilled and completed in the Bartlesville sand. The reported cumulative oil and gas production through July 1997 was 444 million stock tank barrels (MMSTB) and 489 million standard cubic feet (MMSCF), respectively. No gas production was reported from three of the wells.

The development of this field was relatively slow and continued to the east until July 1990. The primary source of reservoir energy was solution-gas drive. Oil- and gas-production rates continually decreased until water injection began in 1994. In March 1994, the eastern half of the field was unitized by Pinnacle Oil. One well, the No. 2 Boyce, in the extreme eastern part, was converted to a water-injection well, and a waterflood began in May 1994. In mid-1995, the first significant response in oil production occurred. Two wells in the western part were plugged and abandoned in 1995, and one well in the center of the field was converted to a water-supply well.

DATA AVAILABILITY

Data used for reservoir characterization and simulation included depths to the top of the sandstones, net-sand thickness, porosity, permeability, lithology, and initial water saturation. Values for these parameters were obtained from well logs and core analyses.

Richard D. Andrews (Part II, this volume) interpreted the depths to the top of each zone and net-pay thicknesses for each zone. Porosity and absolute permeability were evaluated from the core analysis of the No. 2 Longan. The initial water-saturation data were calculated, using Archie's equation and data from the deep-resistivity log. The initial reservoir pressure of 1,888 PSIA and the initial gas/oil ratios (GOR) of 479 SCF/STB were obtained from Andrews (Table 3, Part II, this volume). Individual well records of oil, gas, and water production, plus water injection, were provided by Andrews and Pinnacle Oil. Data that are useful for reservoir studies but were not available for this study include (1) reservoir-pressure data during production, (2) relative-permeability and capillary-pressure data, and (3) production data for individual wells.

ROCK DATA AND FLUID PROPERTIES

The average porosity, permeability, and water-saturation values used in the reservoir-simulation model are based on data provided by Andrews and reported in Table 3 (Part II, this volume). Wells completed in Paradise field were usually acidized and then stimulated with a fracture treatment. An average permeability of 60 md was assumed for the simulation model. An average initial water saturation of 35% was used for the simulation blocks. A residual-oil saturation of 30% was assumed. Initial relative permeabilities were estimated, using Honarpour's method (Honarpour and others, 1986).

The average reservoir temperature reported from well logs was 120°F. The specific gravity (1.165) and salinity (200,000) of the formation water were estimated from Bradley (1987). Different saturation functions and pressure-volume-temperature (PVT) regions were established for the east and west sand bodies, since the fluids and rocks appear to be different. The reported oil gravity ranged from 340 to 380 API (east sand) and from 37° to 40° API (west sand). An average oil gravity of 37.8° API was chosen for the east sand, and 39° API for the west sand. The initial GOR was reported as 250 through 800 SCF/STB. Average values of 653 SCF/STB for the east and 611 SCF/STB for the west were used in the simulation studies. The fluid properties were estimated from the Standing correlations (Craft and others, 1991), using the data above as reported by Andrews (Part II, this volume). Specific gas gravities of 0.99 (east) and 0.88 (west) were selected to match the average initial gas/oil ratios. The original saturation pressure was assumed to be the initial reservoir pressure of 1,888 PSIA. The estimated average initial oil formation-volume factors were 1.37 reservoir barrels per stock tank barrels (RB/STB) (east) and 1.33 RB/STB (west), and initial oil viscosities at reservoir conditions were 0.61 cp (east) and 0.57 cp (west).

HISTORY MATCHING

For confidence that the reservoir model adequately represents the behavior of Paradise field, history-match runs were used to test the reservoir model's ability to reproduce observed field performance. Oil production was chosen as the specified history production

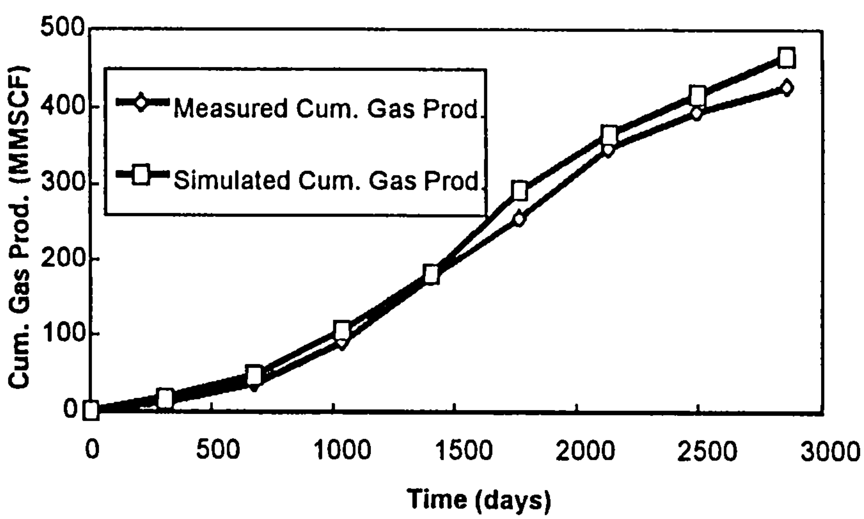

Figure 64. Curves showing measured and simulated cumulative gas production from the Bartlesville sand reservoir in Paradise field.

variable, as these data were considered to be the most reliable of those that were available. As water- and gas-production data were also available, the goals in simulating production history were to match (1) the gas-production rate and cumulative gas production before and after water injection began, and (2) the cumulative water production by lease by specifying oil-production rates and water-injection rates in the injector up to July 1997. No pressure data were available for the depletion or the injection period. History-match parameter adjustments for the field included the following: (1) the relative permeability functions for gas were partitioned by each region and were modified to allow for higher gas mobility; (2) the critical gas saturations, the minimum saturation required for "free"" gas flow, were selected to match historical gas production; (3) water injection amounts were decreased to keep reservoir pressure at a reasonable level; and (4) permeability in the area around the No. 5 Graham well was locally increased from the average permeability to match its response to water injection.

To match water production, the water-injection rates were reduced to one-fourth the reported amounts. This resulted in a cumulative injection of 223 thousand stock tank barrels (MSTB) to July 1997. The simulated water front had just arrived at the nearest producer by that time. Figure 64 shows the simulated cumulative gas production and the reported cumulative gas production for the field.

ESTIMATION OF RESERVES AND OIL-RECOVERY FACTOR

The estimated total original oil in place in this field was 4.0 MMSTB, based on an initial water saturation of 35%, and the maximum theoretical recovery could be 2.2 MMSTB, or 54% of the OOIP. This assumes no change in the oil formation volume factor, and a residual-oil saturation of 30%. The cumulative oil production (primary and waterflood) for this field through July 1997 was 444 MMSTB, or 11% of the OOIP. About 42% of the OOTP in the field is unrecovered mobile oil and is a target for additional recovery.

EVALUATION OF FUTURE DEVELOPMENT OPPORTUNITIES

Based on inspection of the response of the reservoir model to 2.5 years of water injection, and comparing the simulated performances with different water-injector locations, three cases were investigated for Paradise field. One represents a base case, and the other two, additional cases for waterflooding. The predicted 5-year results for the three cases are listed in Table 10.

Base Case (Case 1)

The base-case simulation assumes no changes in the July 1997 well configuration and well-operating conditions. There was no injection at that time. The field is assumed to exhaust its reservoir energy in 1 year. Additional oil recovery is expected to be 120 MSTB (3% of the OOIP), water cut should be 30%, and no wells are expected to produce beyond 1 year. Simu-

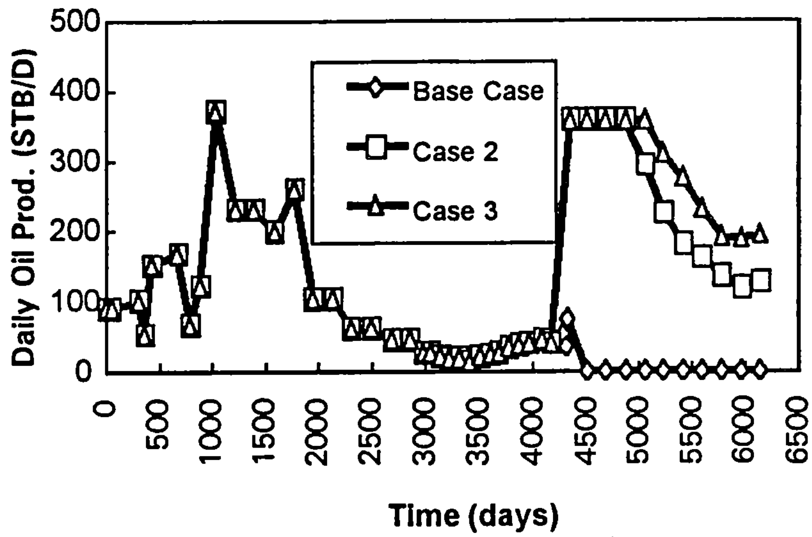

Figure 65. Curves showing simulated daily oil production from the Bartlesville sand reservoir in Paradise field for case (base case), case 2, and case 3.

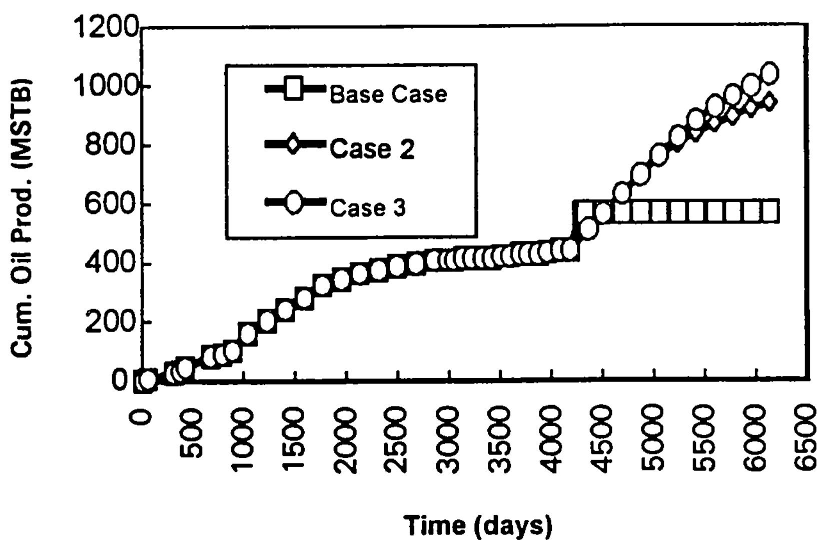

Figure 66. Curves showing simulated cumulative oil production from the Bartlesville sand reservoir in Paradise field for case I (base case), case 2, and case 3.

TABLE 10. – Production Data for Bartlesville Sand Reservoir in Paradise Field, Payne County, Oklahoma

			At end of 5 years				
	Cum. prod. Primary (%OOIP) (MSTB)	Cum. prod. Waterflood (%OOIP) (MSTB)	5-year prod. (%OOIP) (MSTB)	Oil rate (STB/D)	Water cut (%)	Cum. inj. (MSTB)	Avg. press. (PSI)
Case 1	406 (11)	444 (12)	123 (3)	0	29	223	1,200
Case 2	406 (11)	444 (12)	500 (13)	130	68	1,300	1,250
Case 3	406 (11)	444 (12)	590 (15)	190	62	1,700	1,360

lation results are shown in Table 10 and Figures 65 and 66. The saturation output indicates a large area with high oil saturation and suggests that water-sweep efficiency is not high.

Case 2

For this case, the No. 2 Longan well in the east sand body would be converted to inject water at the rate of 800 B/D, with a bottom-hole pressure (BHP) not exceeding 2,000 PSI. The No. 2 Longan well should be the best injector in comparison to the No. 1 or 3 Tomlinson well. After 5 years of simulated production, the expected additional recovery of oil for this case is 500 MSTB (13% of the OOIP), with daily oil production of 130 STB and a water cut of 68%. The cumulative injected water would be 1,300 MB. Simulation results are shown in Table 10 and Figures 65 and 66.

Case 3

The third case uses the No. 2 Longan and retains the No. 2 Boyce as injection wells, with the 800 B/D rate and 2,000 PSI BHP controls. The simulated oil production for the 5-year period is 590 MSTB, or 15% of the OOIP. After 5 years, the cumulative injected water for the field should be 1,700 MB, the water cut 62%, and the daily oil production 200 STB. The results are shown in Table 10 and Figures 65 and 66.

CONCLUSIONS AND RECOMMENDATIONS

The 2.5-year history match of waterflooding indicates that only one-fourth of the injected water had entered the formation just as the water front arrived at the nearest producer. Because the recovered oil was only about 12% of the OOIP by that time, additional oil should be producible by effective waterflooding.

Both cases 2 and 3 support the above point. Case 2, with one water injector, increases oil recovery significantly (9.0% of the OOIP over the base case). Case 3 achieves the best simulated result, with two water injectors forming an effective sweep of the reservoir (12% of the OOIP over the base case).

Apparently, no more than one-fourth of the injected water entered the formation. Thus, it is important to monitor the performance of a waterflooding operation to assure that it efficiently recovers as much oil as possible.

The west sand body is a candidate for oil recovery by waterflooding. If an exploitable oil reserve in the north sand body can be confirmed, a well may be appropriate in that area.

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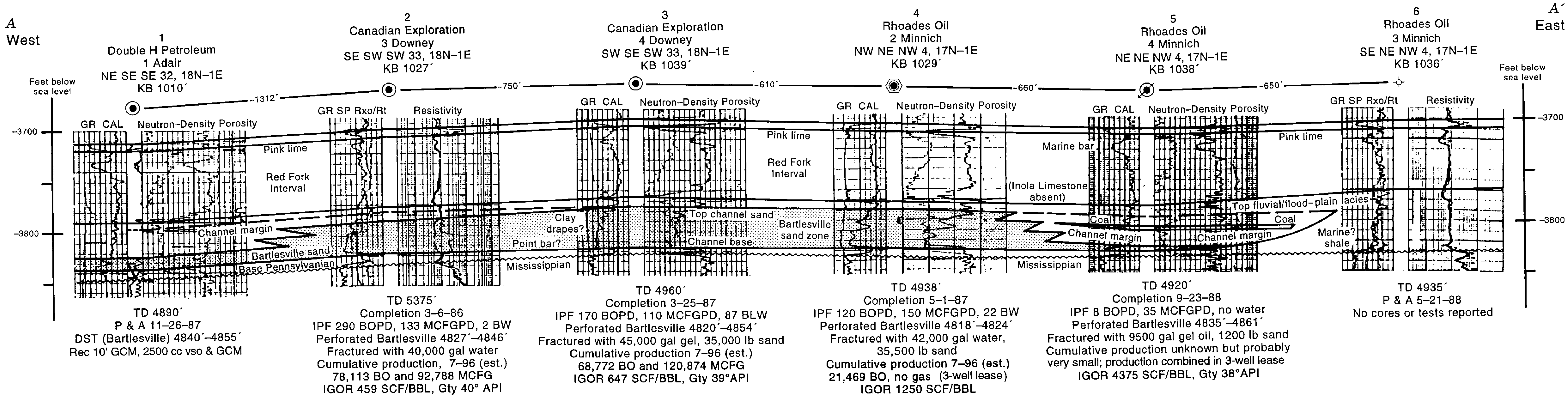
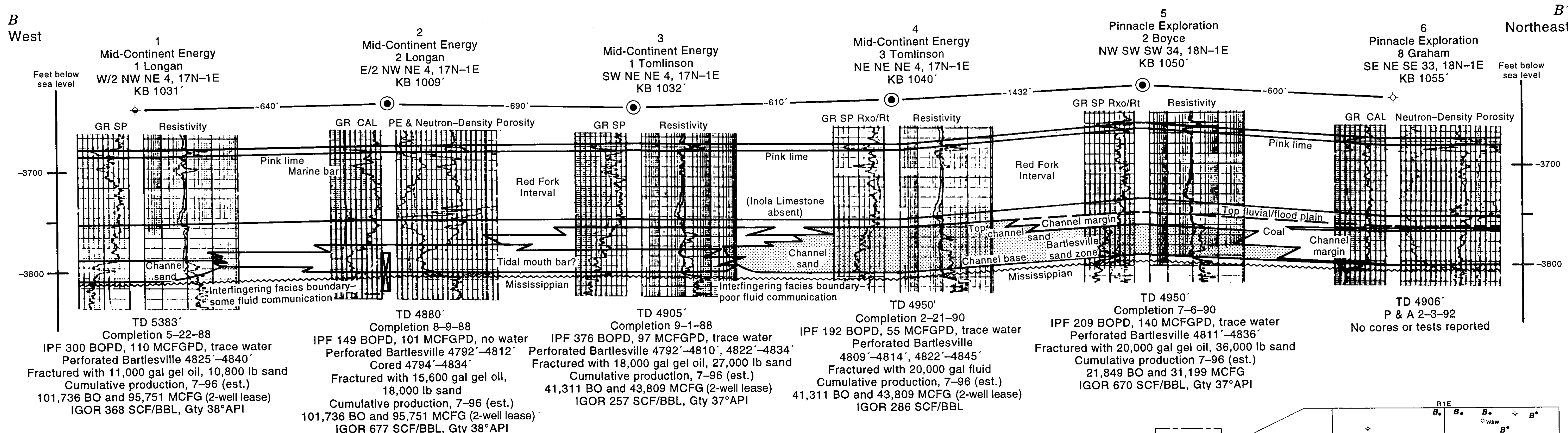




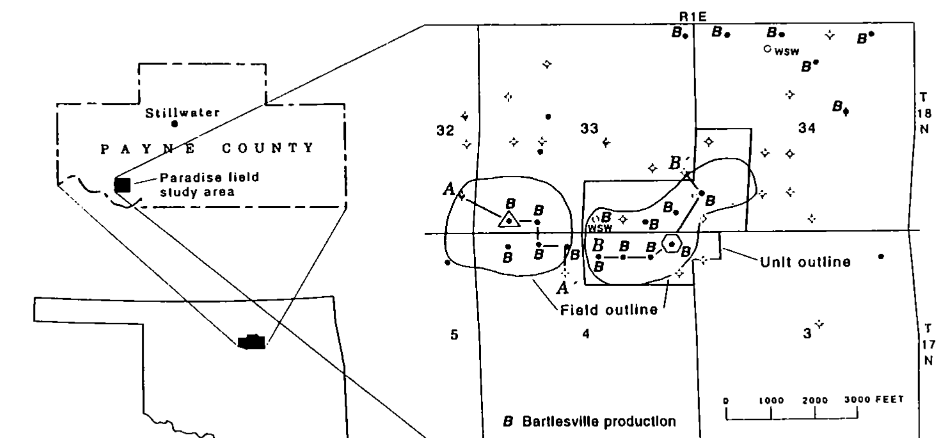
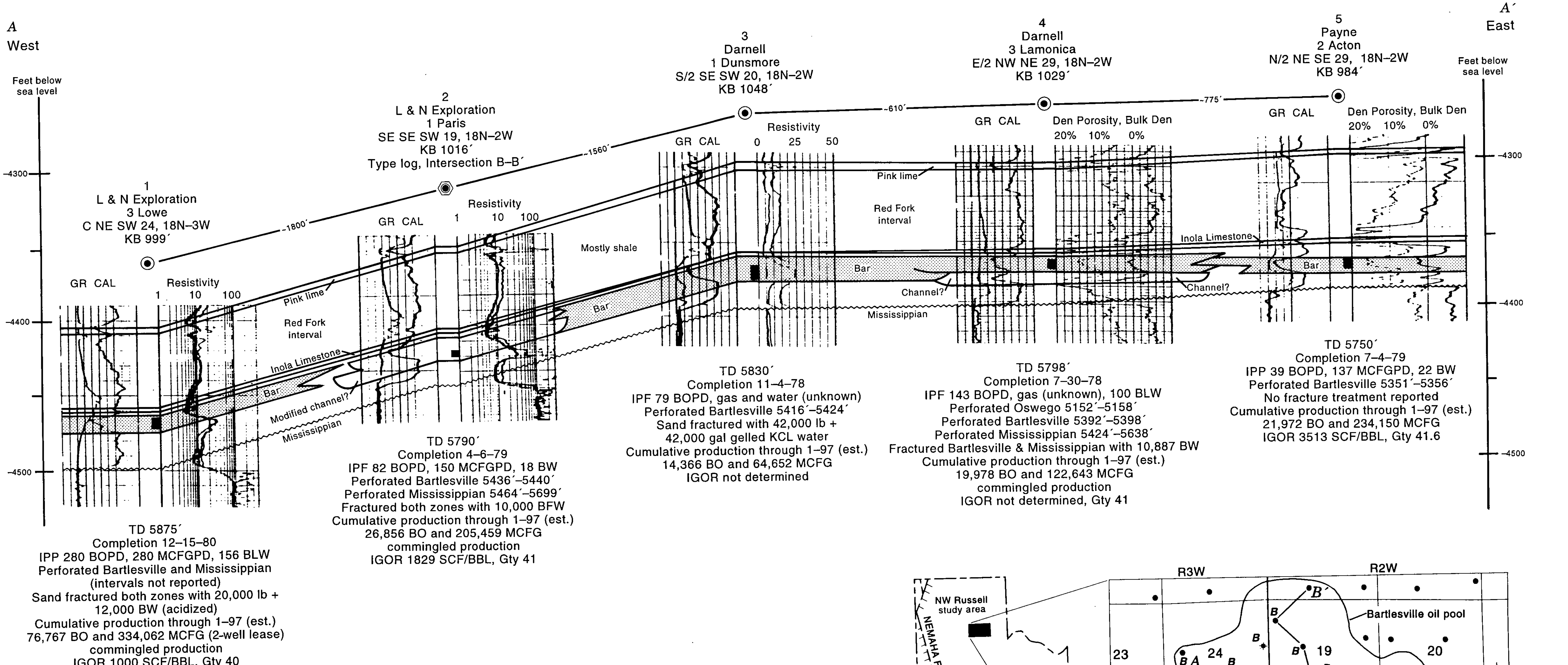


Figure 24. Structural and stratigraphic cross sections *A–A′* (western part), and *B–B′* (eastern part), Paradise field. Datum: sea level; no horizontal scale.



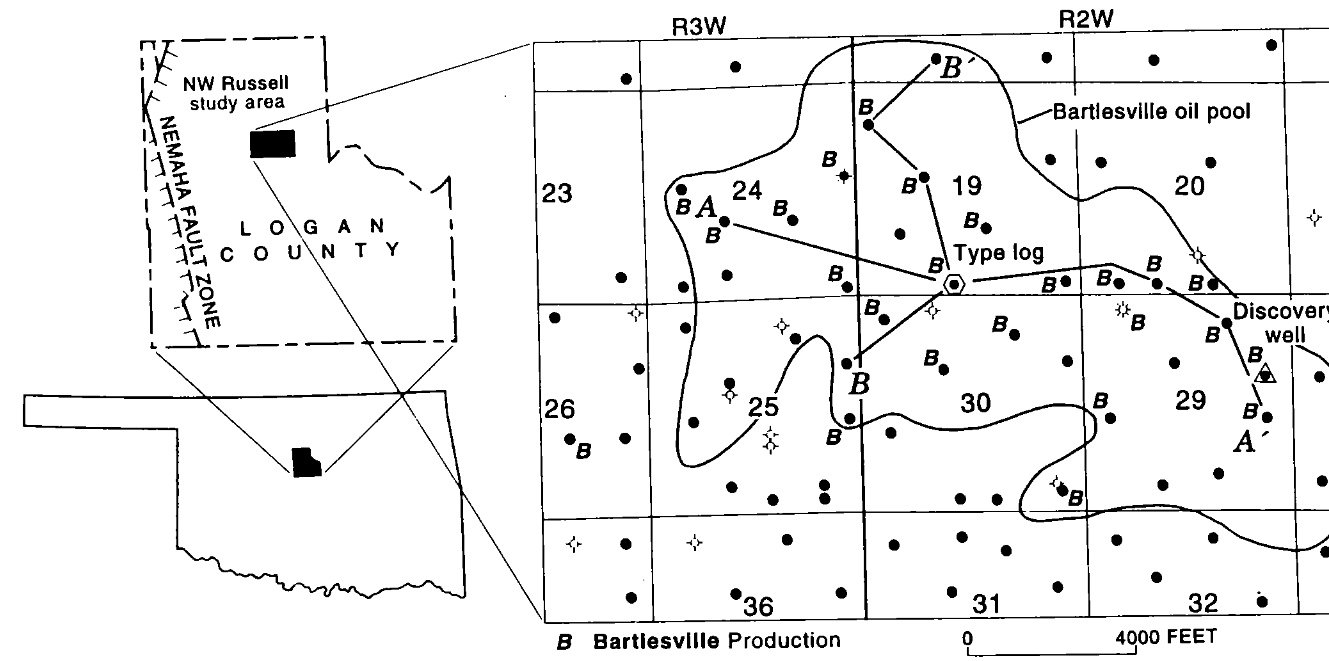
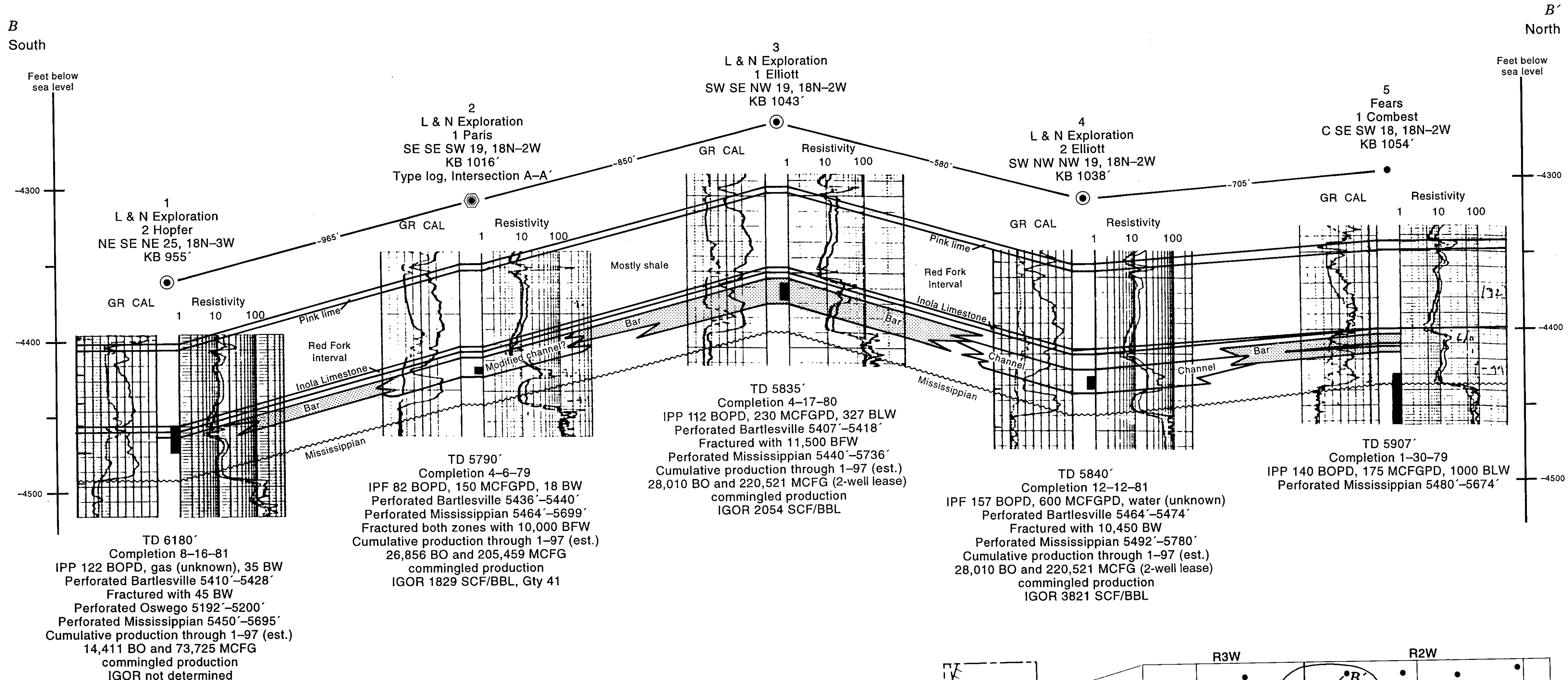


Figure 37. Structural and stratigraphic cross section *A–A′* and index map, Bartlesville oil pool, NW Russell field area. Datum: sea level; no horizontal scale.



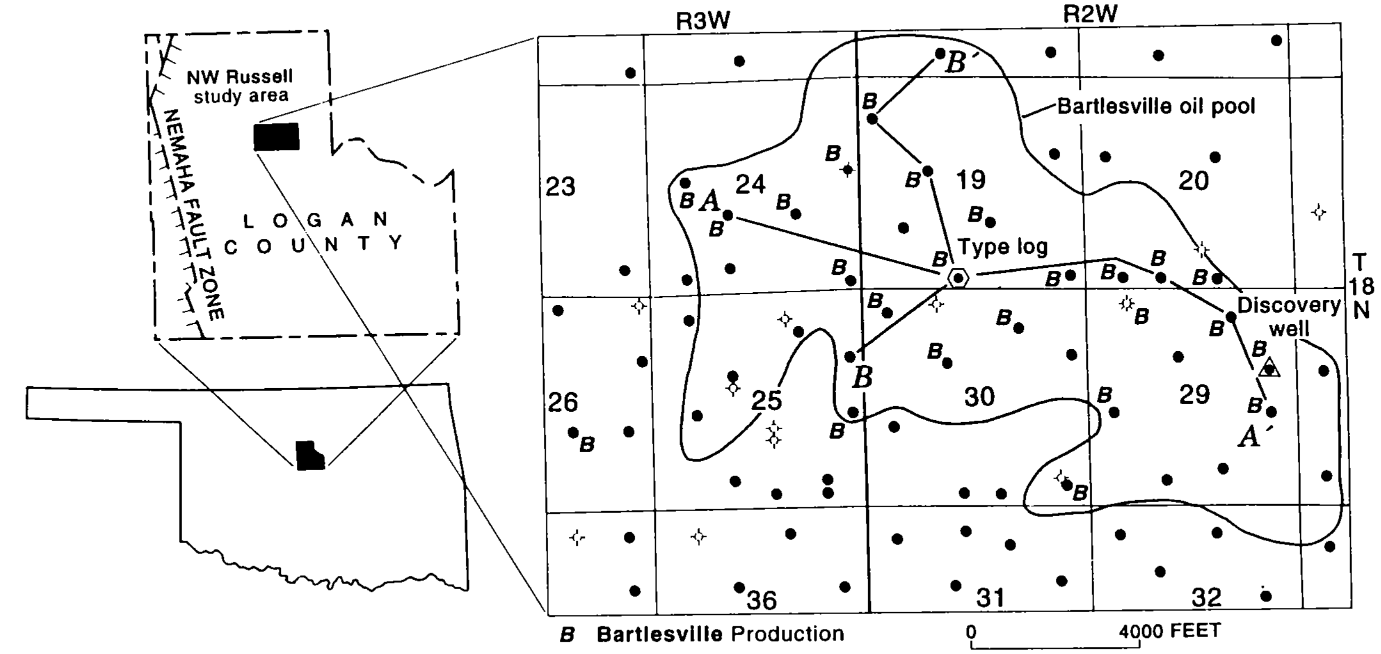


Figure 38. Structural and stratigraphic cross section *B–B′* and index map, Bartlesville oil pool, NW Russell field area. Datum: sea level; no horizontal scale.

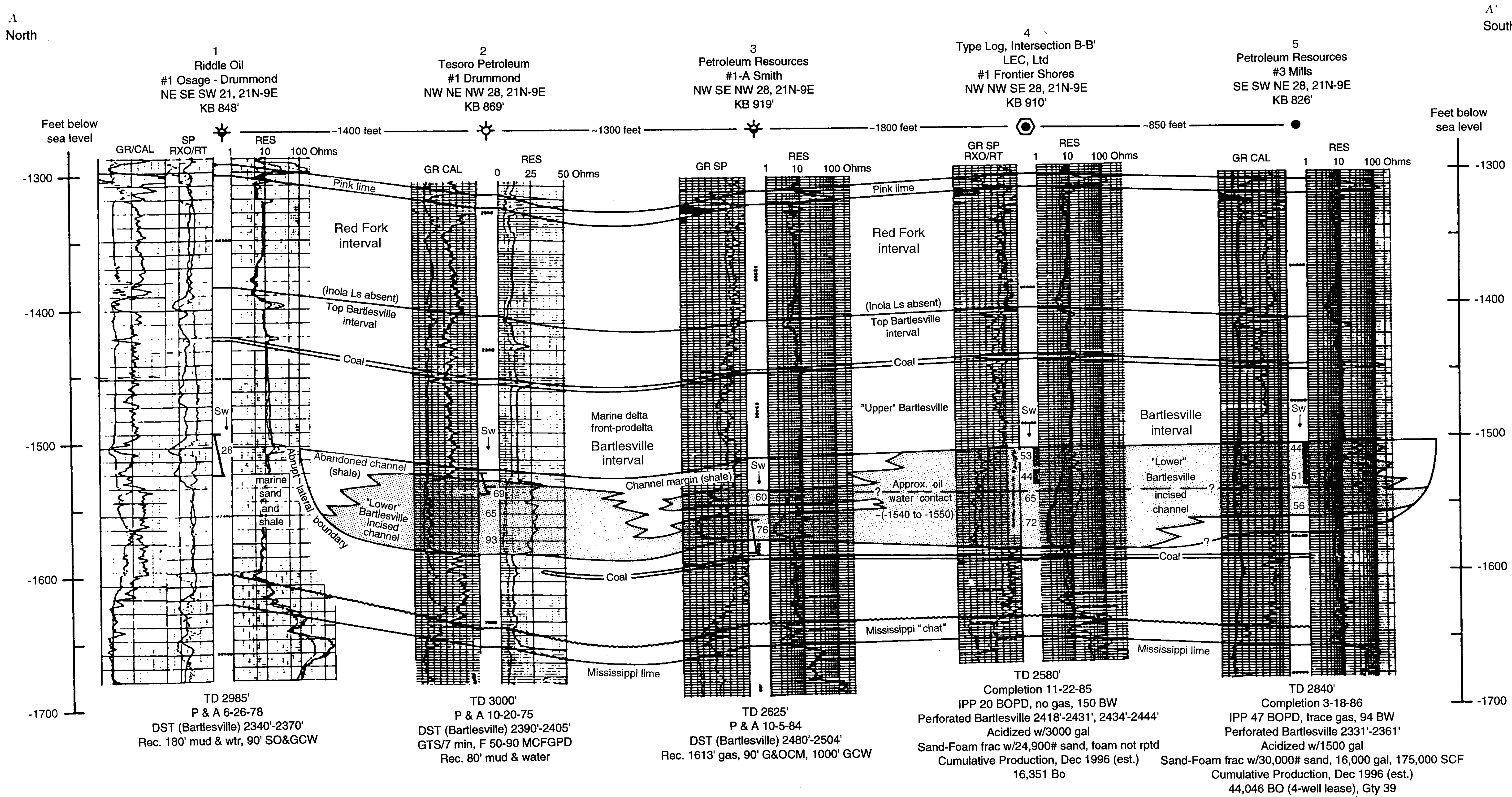


Figure 53. Structural and stratigraphic cross section *A–A'* and index map, Bartlesville oil pool, Ohio–Osage field area. Datum: sea level; no horizontal scale. Calculated water saturation (S_w) is shown in the depth tract. See Figure 50 for location map.

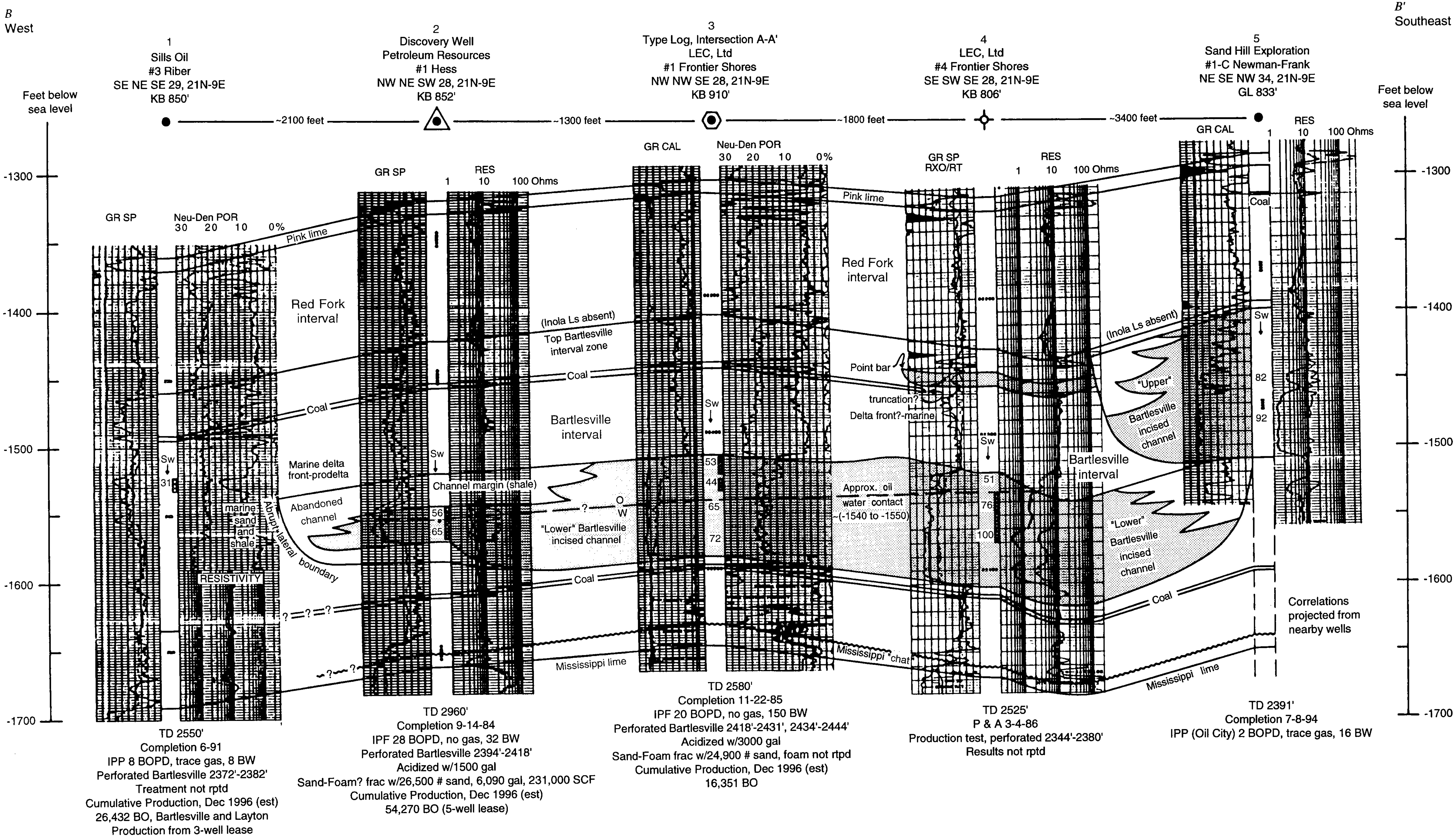


Figure 54. Structural and stratigraphic cross section B–B' and index map, Bartlesville oil pool, Ohio–Osage field area. Datum: sea level; no horizontal scale. Calculated water saturation (S_w) is shown in the depth tract. See Figure 50 for location map.