Oklahoma
Geological
Survey
1995

Special Publication 95-3

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

ERRATA

Oklahoma Geological Survey Special Publication 95-3

The Booch Play

Page 14, Figure 13 — "**OSAGE UPLIFT**" should read "**OZARK UPLIFT**"

Page 16, Figure 15 — The shelf area is represented by the stippled pattern

Page 23, Figure 24 — "R8N" should read "R8E"

Pages 42 and 43, Figures 41 and 42 — Figure 41 (results of the first chemical tracer survey) is on p. 43; its caption is at the bottom of p. 42. Figure 42 (results of the second chemical tracer survey) is on p. 42; its caption is at the top of p. 43.

Page 56, left column, line 10 — The following sentence should be inserted before the sentence beginning "The No. 2 Robbin . . .": "After the No. 1 Hall discovery well, three more wells were drilled in the Booch oil reservoir during 1961; two were completed as Booch oil wells and one was completed as a dry hole."

The following corrections are according to Dr. Michael Wiggins, Assistant Professor, OU School of Petroleum and Geological Engineering:

Page 57, right column, line 20 — "2.4" should read "1.7"; line 21 — "0.83" should read "1.5"

Page 61, right column, line 11 — "54%" should read "77%"

Oklahoma Geological Survey
Charles J. Mankin, *Director*

Special Publication 95-3
ISSN 0275-0929

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

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 Booch Play**

by

Robert A. Northcutt
with contributions from Kurt Rottmann

PART III.—**Reservoir Simulation of a Booch Oil Reservoir in the Greasy Creek Field, Hughes County, Oklahoma**

by

R. M. Knapp and X. H. Yang

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

The University of Oklahoma
Norman, Oklahoma

1995

SPECIAL PUBLICATION SERIES

The Oklahoma Geological Survey's Special Publication series is designed to bring timely geologic information to the public quickly and economically. Review and editing of this material has been minimized in order to expedite publication.

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Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma

Richard D. Andrews
Geo Information Systems

with contributions from

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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 sources of publicly accessible information on FDD reservoirs, including the OGS Resources Facility, a computer laboratory.

The computer laboratory contains all the data files for the plays, as well as other oil and gas data files for the State, and the necessary software to analyze the information. Technical support staff are available to assist interested operators in the evaluation of their producing properties, and professional geological and engineering outreach staff are available to assist operators in determining appropriate improved-recovery technologies for those properties. The lab is equipped with PCs, plotters, laser printers, CD-ROM readers, and scanning and digitizing equipment. Geology-related mapping software, such as GeoGraphix, ARC/INFO, ArcView, Surfer, Atlas MapMaker for Windows and Radian CPS/PC, is available for public use. Access to data is through menu-driven screen applications that can be used by computer novices as well as experienced users.

The OGS Resources Facility opened June 1, 1995. In the future, it will be possible to access the facility from other locations through remote modems and, eventually, 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 Prue & Skinner play, 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

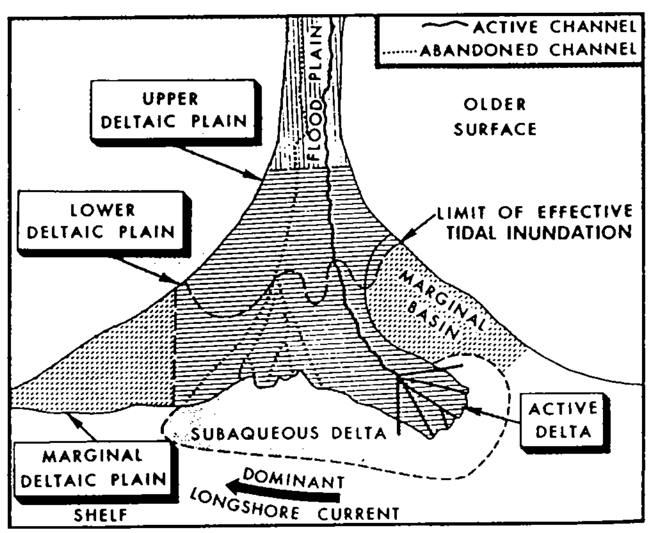
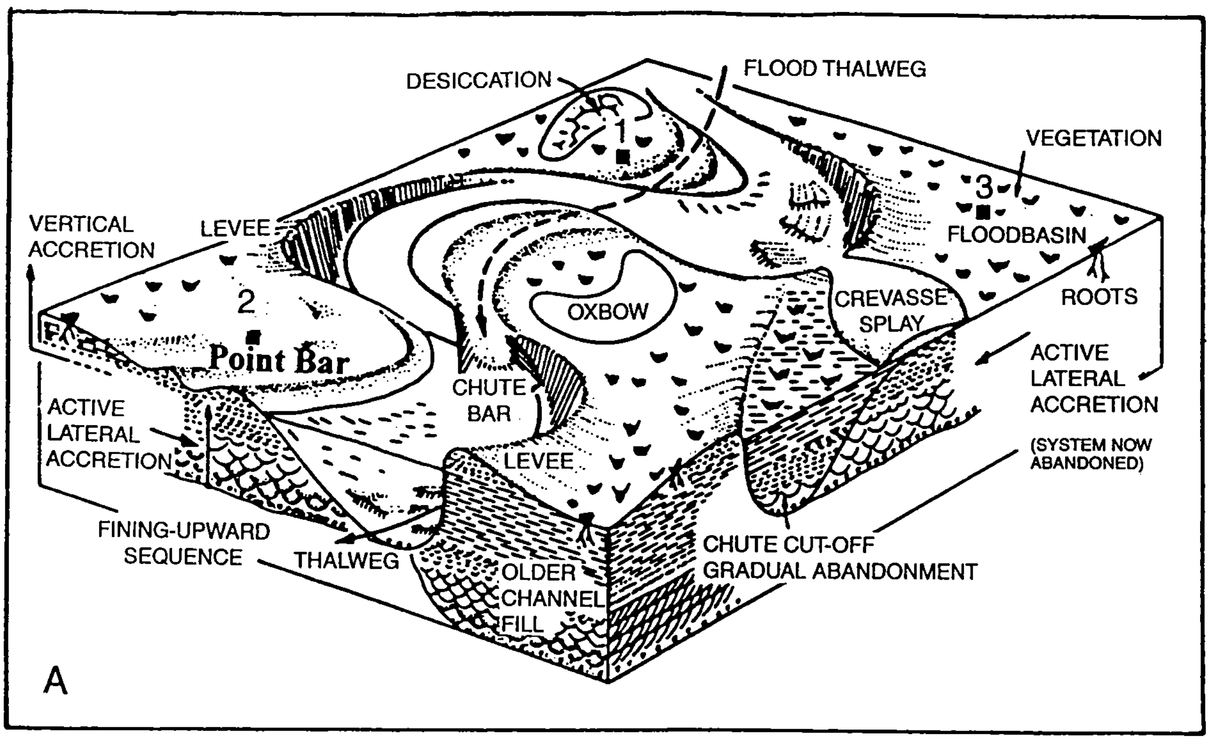


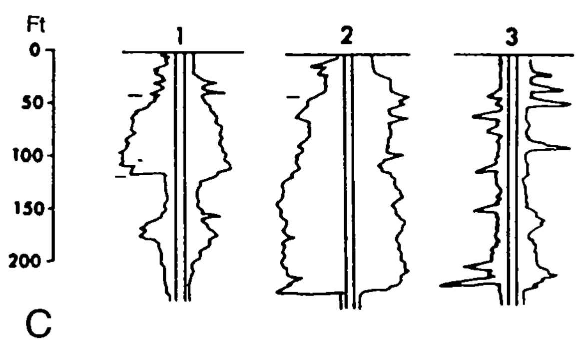
Figure 1. Components of a delta system. From Coleman and Prior (1982).

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





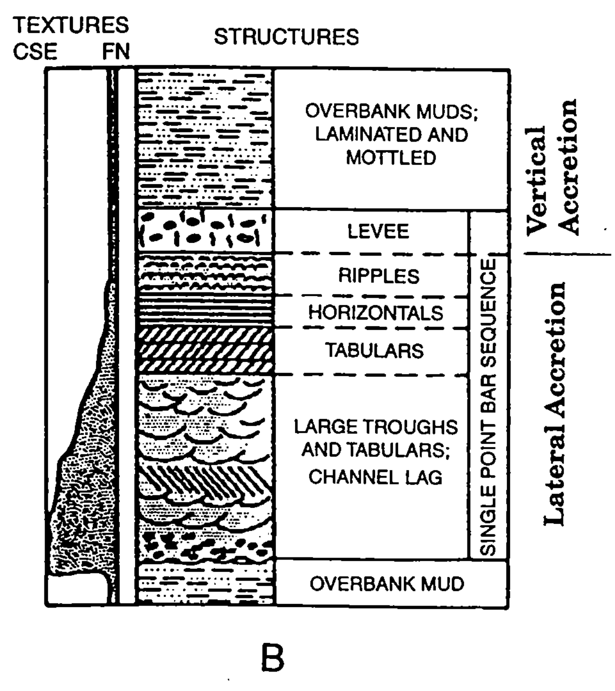


Figure 2. (A) Schematic model of a meandering river system. Erosion of the outside bend of a meander loop leads to lateral accretion of a point bar down-flow on the inside bank of the meander bed. Modified from Walker (1984). (B) Textural and facies characteristics of typical point-bar deposits. Modified 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

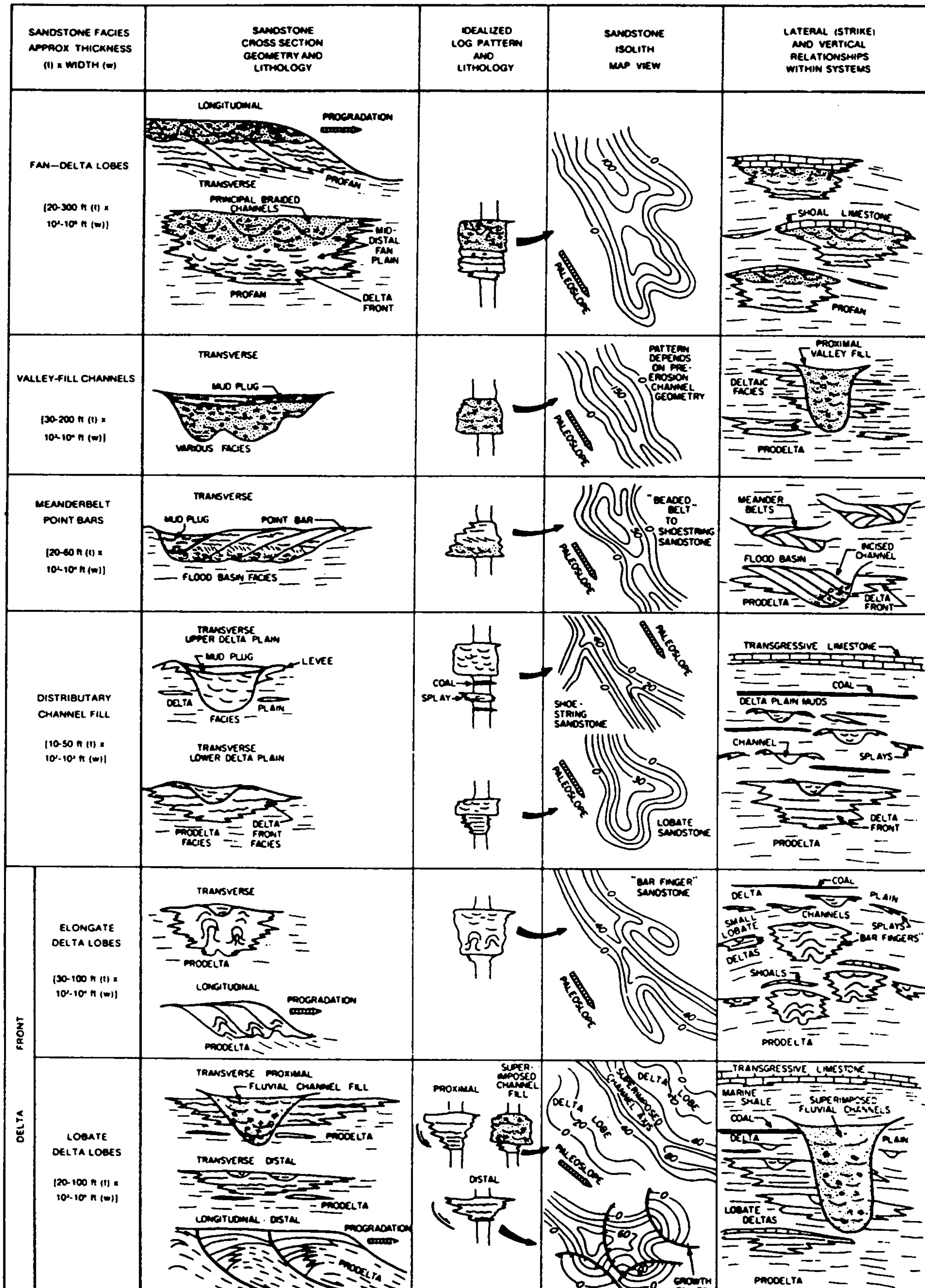


Figure 3. Summary of the characteristics of Midcontinent fluvial and deltaic sandstone bodies. From Brown (1979).

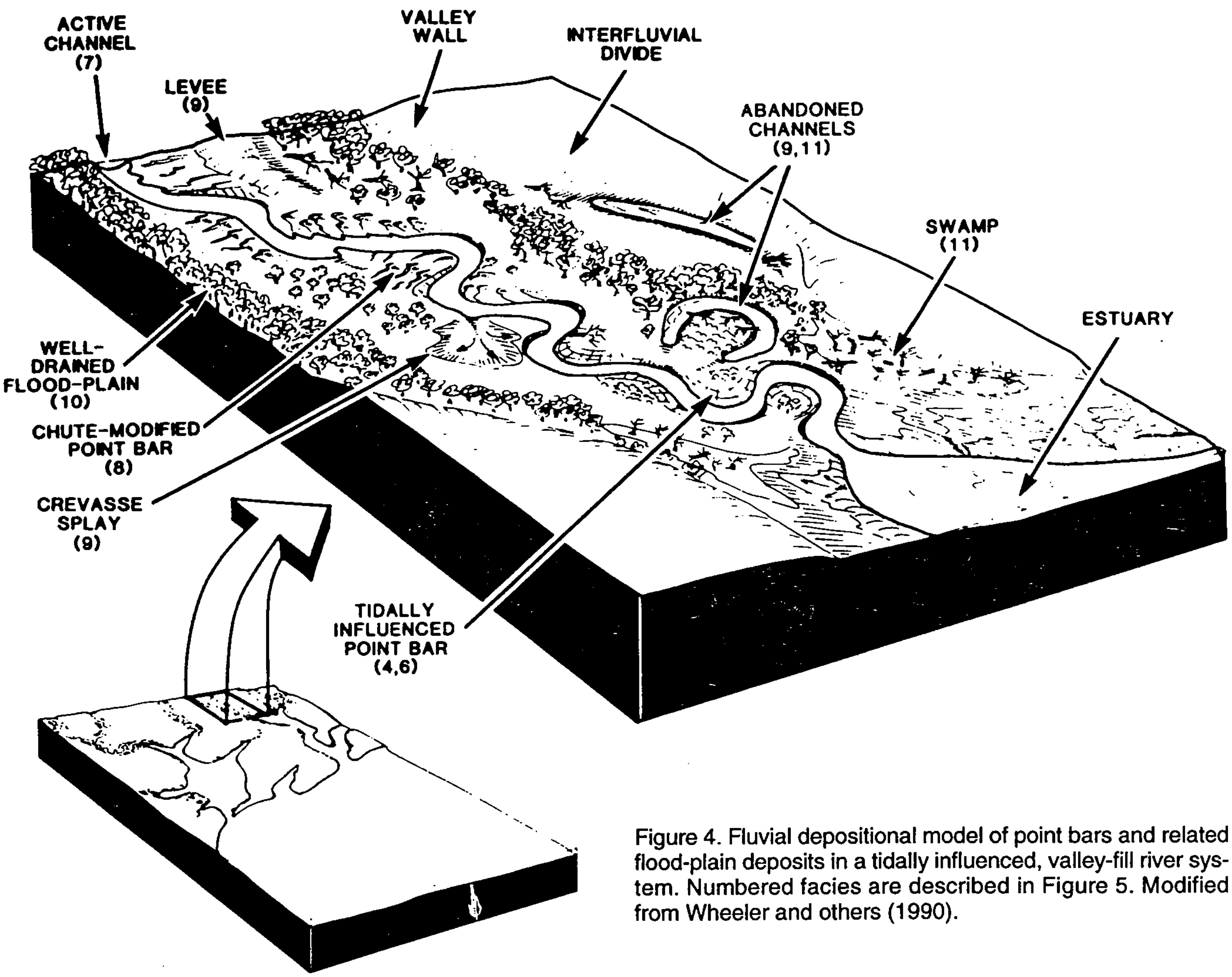


Figure 4. Fluvial depositional model of point bars and related flood-plain deposits in a tidally influenced, valley-fill river system. Numbered facies are described in Figure 5. Modified from Wheeler and others (1990).

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

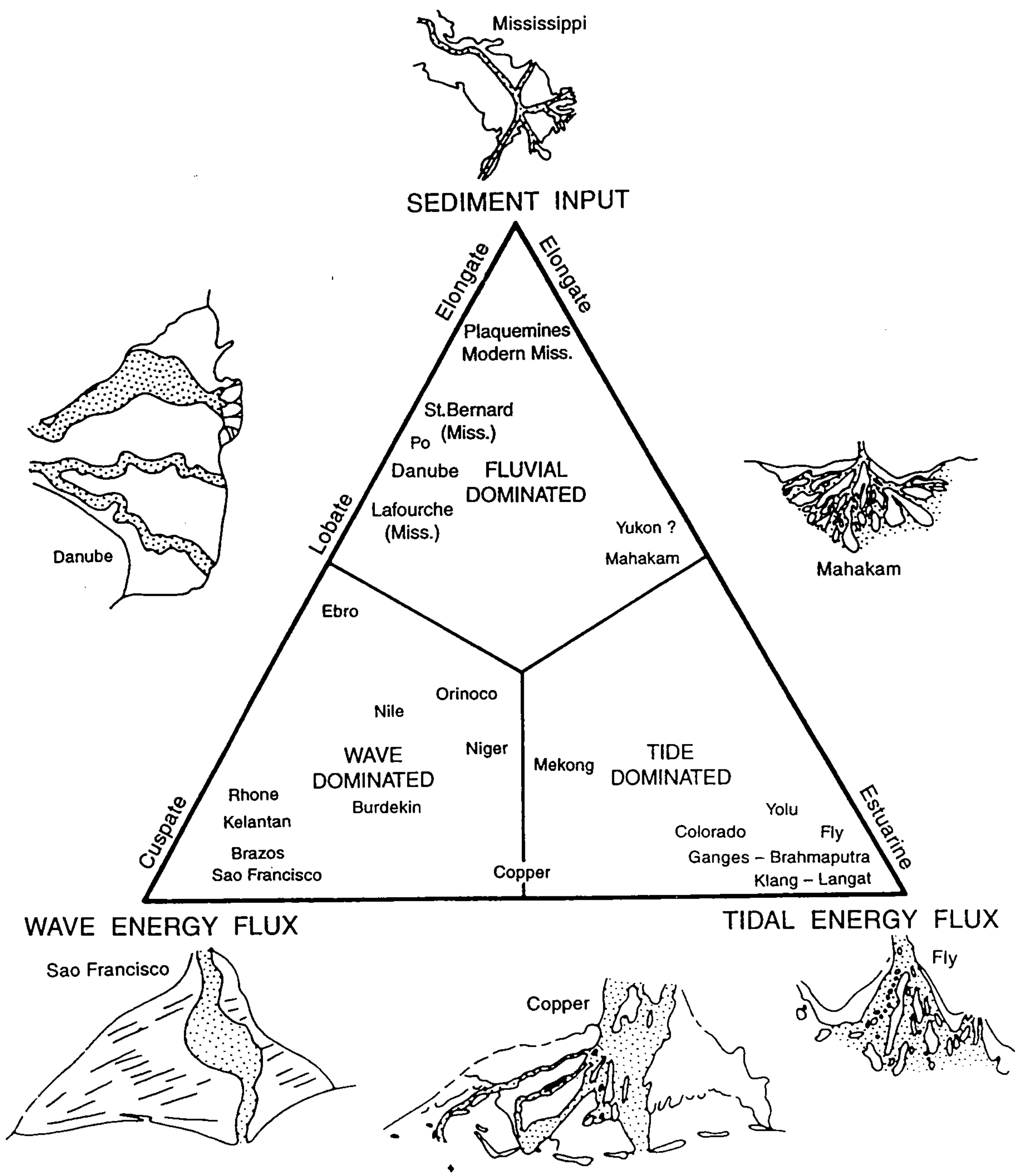


Figure 6. Morphologic and stratigraphic classification of delta systems based on relative intensity of fluvial and marine processes. From Galloway and Hobday (1983).

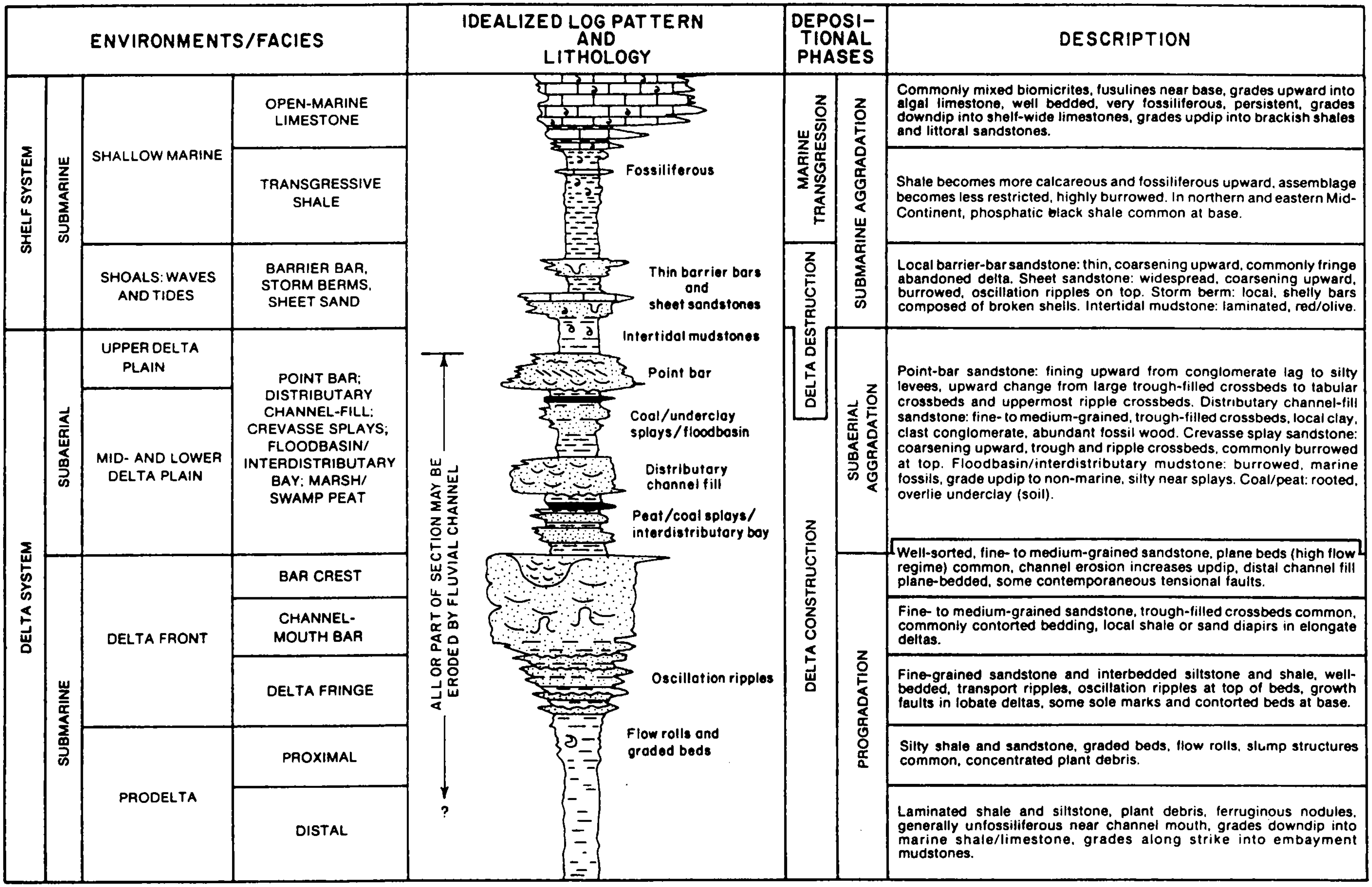


Figure 7. Idealized cratonic delta sequence showing principal depositional phases, idealized electric log pattern, and facies description. From Brown (1979).

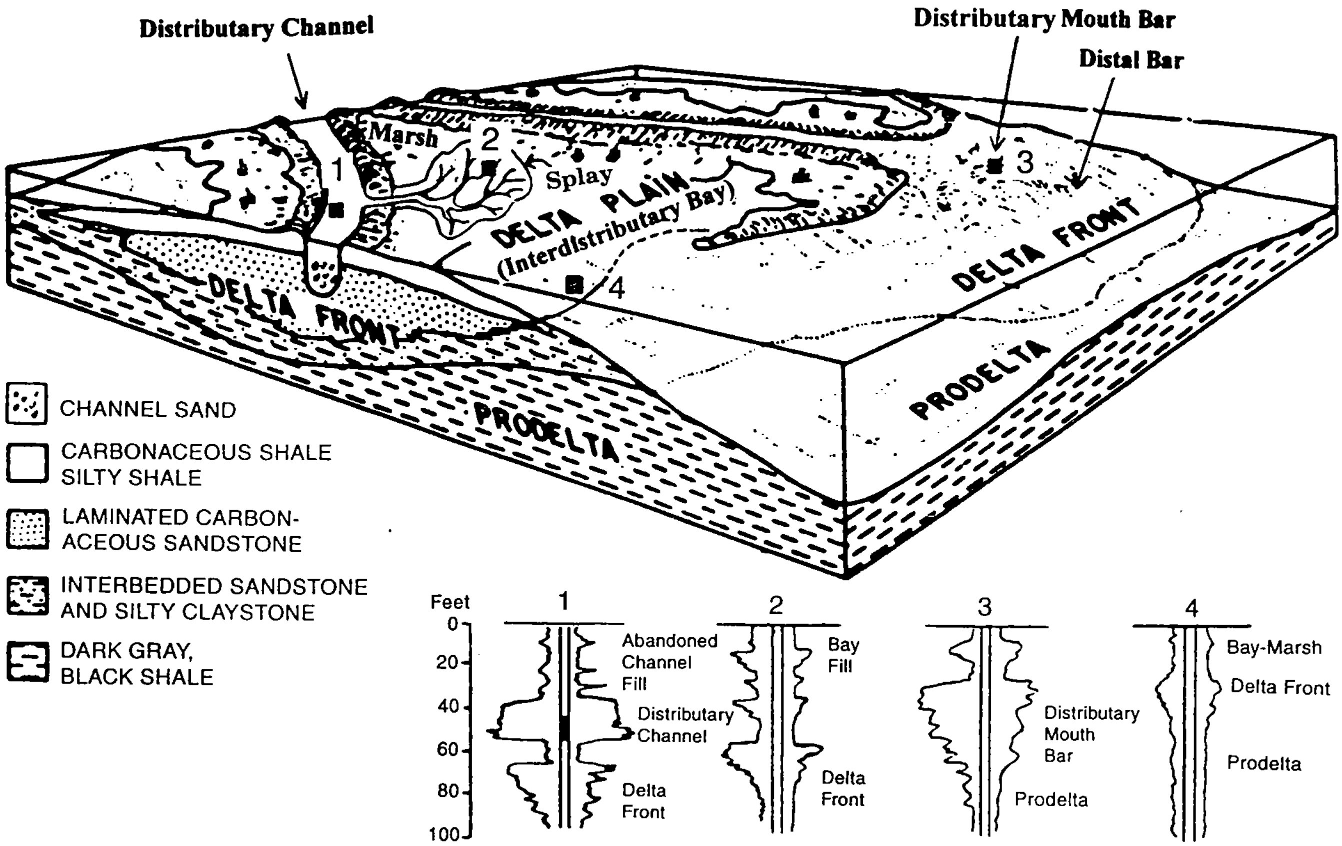


Figure 8. Schematic model of deltaic depositional environments. Idealized electric log responses and inferred facies are shown for locations Nos.1–4. Modified from Brown (1979).

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-

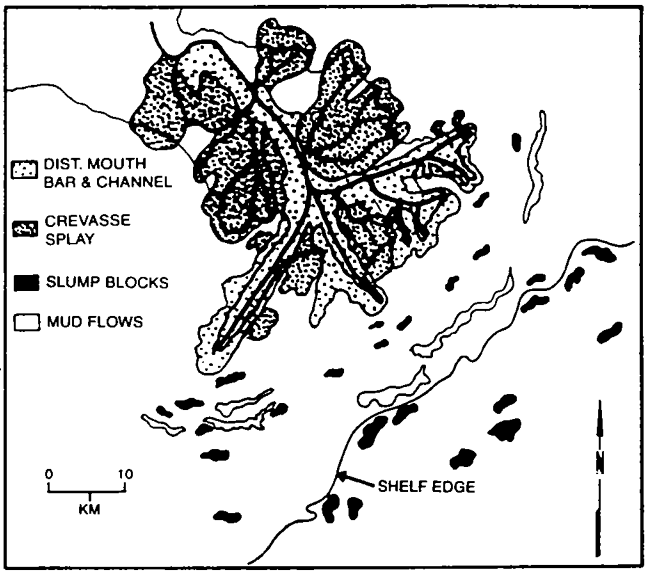


Figure 9. Distribution of principal sand facies in the modern Mississippi River fluvial-dominated delta. From Coleman and Prior (1980).

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

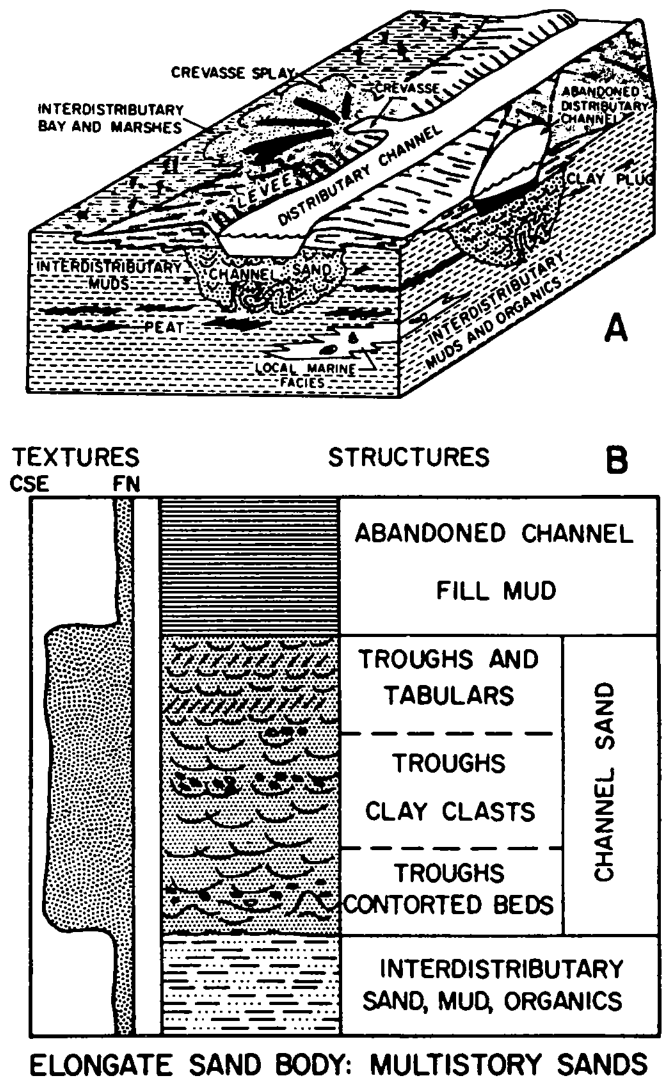


Figure 10. Distributary channel model. (A) Schematic model of channel-fill sands, lower delta plain setting; (B) idealized vertical sequence of distributary channel-fill sandstones. Modified from Brown (1979).

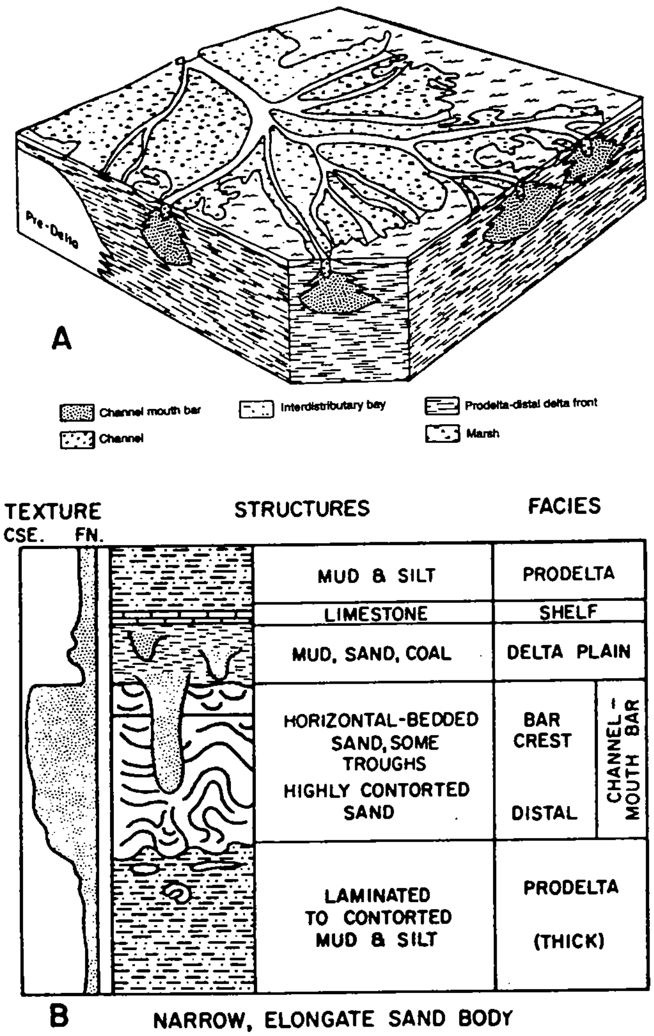


Figure 11. Elongate-delta model. (A) Birdfoot lobe, Holocene Mississippi delta; (B) idealized vertical sequence of a distributary mouth bar and associated deposits in an elongate delta. Modified from Brown (1979).

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 Booch Play

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with contributions from

Kurt Rottmann
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INTRODUCTION

The Pennsylvanian sandstones in the Booch were significant oil reservoirs during the early history of the oil industry in Oklahoma. The Booch sands are the informal subsurface equivalents of the sandstone members of the McAlester Formation in the Krebs Group of the Desmoinesian Series. In the Okmulgee area, early development of Booch reservoirs occurred prior to statehood in 1907. Booch reservoirs still are important today for potential recovery of additional oil by waterflooding or other enhanced-recovery methods. Booch oil and gas reservoirs dominantly occur in stratigraphic traps in fluvial-dominated deltaic environments, such as fluvial, upper and lower delta-plain, and delta-front deposits. Local uplifting and faulting, as well as sediment compaction, have influenced the localization of oil and gas in these traps.

The Booch play is located on the Cherokee Platform in northeastern Oklahoma and extends southward beyond the hinge line of the McAlester Formation into the Arkoma basin. Oil and gas are produced from reservoirs on the Cherokee Platform, but only gas is produced in the Arkoma basin. This study of FDD reservoirs that produce the majority of the Booch oil includes only the play area on the Cherokee Platform, which produces both oil and gas. The play area in Oklahoma, shown on Figure 12 and Plate 1, is limited on the

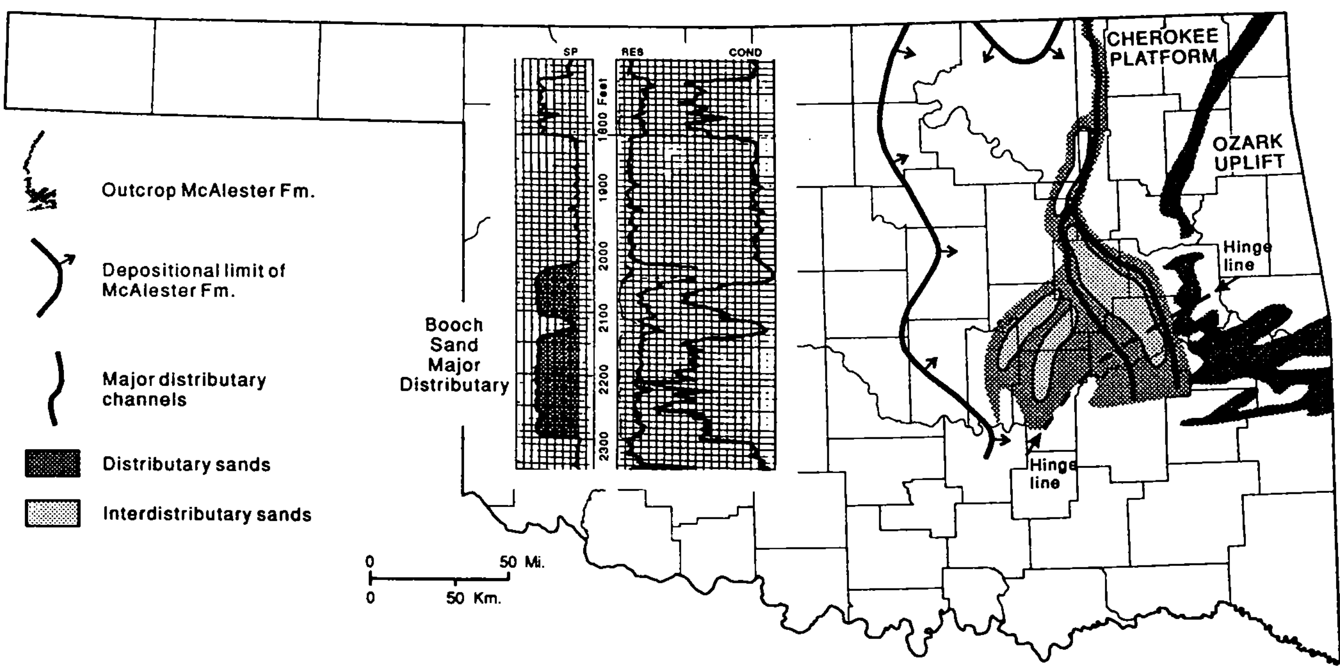


Figure 12. The Booch play in Oklahoma. The Booch play is located on the Cherokee Platform in northeastern Oklahoma and extends southward beyond the hinge line of the McAlester Formation into the Arkoma basin. It is limited on the east and south by the outcrop of the McAlester Formation and, on the west, by the depositional limit of Booch sand. The inset log represents spontaneous potential (SP), resistivity, and conductivity log patterns for a thick distributary channel.

east and south by the outcrop of the McAlester Formation and, on the west, by the depositional limit of sandstone in the Booch. From the surface outcrop on the east, the depth to the Booch sand increases to ~3,200 ft at the western limit of the play. To the south in the Arkoma basin, the depth is >4,000 ft. A generalized regional structure map of the Booch sand in the play area is shown in Figure 13.

Five plates are included in this study of the Booch play. Plate 1, Map of the Booch Sandstone Play Area, shows the area in eastern Oklahoma of the Booch fluvial-deltaic system, the limits of the McAlester Formation, and the geologic provinces. Plate 2, Regional Stratigraphic Cross Sections A–A′ and B–B′, Booch Sand Play Area, Northeastern Oklahoma, shows a stratigraphic cross section from north to south along the longitudinal axis of the Booch delta distributary system (A–A′) and a stratigraphic cross section from southwest to northeast across the lower delta plain (B–B′). Plate 3, Map of Leases with Booch Oil Production, shows leases with current Booch oil production (1979–95) listed in the Natural Resources Information System (NRIS) data files at the University of Oklahoma's Geo Information Systems (GeoSystems). Plate 4, Map of Fields with Oil Production from the Booch Sandstone, shows the 78 fields with current Booch oil production keyed to field name and location. Plate 5, Index to Selected References, shows outlines of the area covered by the selected references listed on the map.

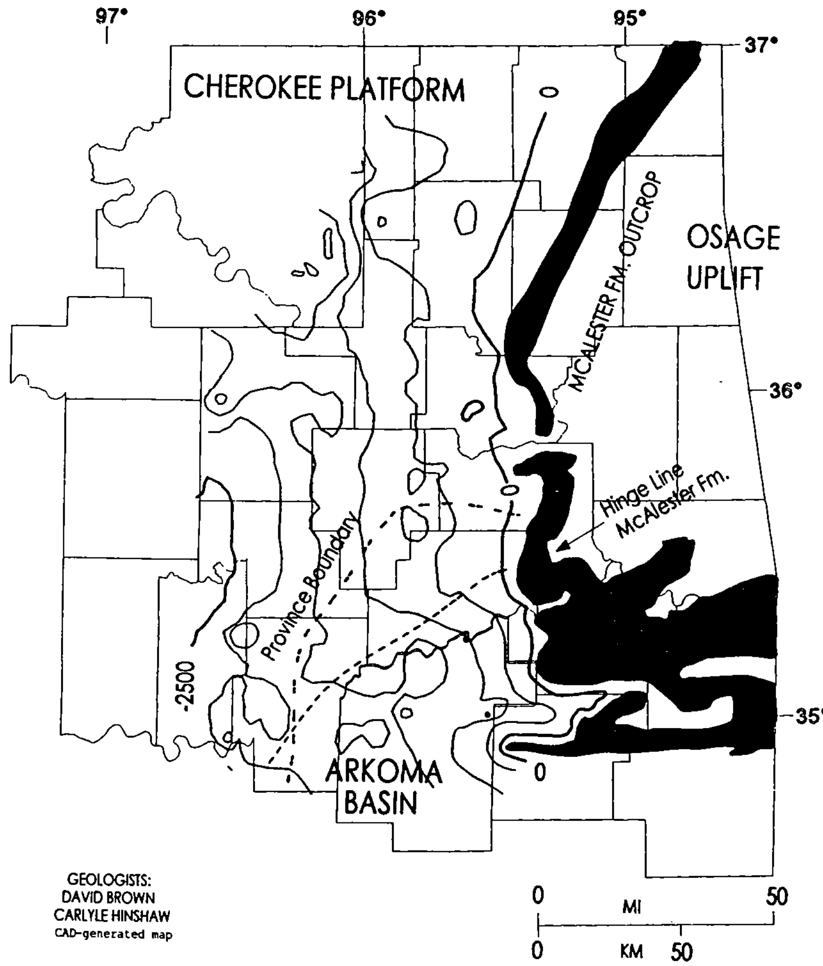


Figure 13. Regional structure map of the Booch sand and its equivalents, northeastern Oklahoma. This study focuses only on the FDD reservoirs that produce the majority of the Booch oil and, thus, includes only the play area on the Cherokee Platform. The study does not include Booch reservoirs in the Arkoma basin, which produce only gas.

All available sources of information were used in identification of Booch FDD areas, including the published scientific literature, unpublished theses, published (but sometimes obscure) articles from local geological societies, and investigations by consultants and the authors. Selected references used for Booch sandstone mapping are listed on Plate 5. A list of recommended references, including those cited, is included as part of this publication.

Commercially available computer programs were used to construct some of the figures in this publication. Well and production data were obtained from the NRIS data files at GeoSystems. The NRIS files are maintained on a mainframe computer but can be accessed through personal computers at the OGS NRIS Facility. The regional structure map of the Booch sand and its equivalents (Fig. 13), for example, was constructed using typical digital map-making operations. The NRIS well data were edited in a spreadsheet program and imported into a mapping program. The same process was used to produce the digital land grid. After machine contouring was done, the map was exported to a computer-assisted-drafting (CAD) program and superimposed on a county base map derived from the U.S. Geological Survey's 1:2,000,000 digital-line-graph (DLG) files. Final editing was done in the CAD environment.

BOOCH STRATIGRAPHY

Booch sediments are Middle Pennsylvanian (Desmoinesian) in age and consist of shale, sandstone, and coal. Shales were deposited in marine, delta-front, lagoonal, and coastal-plain environments; the greatest thicknesses of sandstone were deposited in distributary channels on the delta plain. Coals were deposited in the lagoonal areas associated with the delta plain. During Desmoinesian time, repeated transgressions and regressions made deposition cyclical, and there were repeated deltaic episodes during stillstands.

An interpretative cross section of paleoenvironmental patterns by Bennison (1979) shows the thick Booch delta on the Cherokee Platform dividing into five distinct deltaic episodes as it approaches the Arkoma basin to the south (Fig. 14). This expansion of the Booch occurs approximately at the hinge line of the McAlester Formation, shown on the isopach map of the McAlester Formation (Fig. 15). This expanded part of the Booch primarily produces gas and was not investigated for this study. During the Ouachita orogeny of Desmoinesian time, strong folding and uplifting formed the Ouachita Mountains. Continuing basinal downwarping north of the mountains formed the Arkoma basin, which, by the end of the Desmoinesian, had been folded and faulted (Johnson, 1971). The paleogeography of the Desmoinesian is shown in Figure 16.

The "Booch sand" is an informal subsurface term, which was used first in 1906 in the Morris field of Okmulgee County, as reported by Clark (1930, p. 64):

> In 1906 two gas wells were drilled in the townsite of Morris to the 1,200 foot sand, afterwards called the Booch sand.... Another important well drilled in 1906 was located in the NW¼ sec. 20, T. 13 N., R. 14 E., on the Booch farm and gave the name to the Booch sand, which afterwards became famous for large wells. This well, however, was only a 10 barrel well after a shot and was never commercially produced.

Later, Jordan (1957, p. 21) made reference to the original occurrence of the name:

> First ref.—Fohs and Gardner (1914), Fuel Oil Jour., Aug. Suppl. Named for Booch farm, 20–13N–14E, Morris field, Okmulgee Co. C[entral] Oklahoma. Equal to Warner ss. At places Upper, Lower, First, Second, Third Booch. At places over 150 feet thick. Equal to Taneha sand. See also Youngstown sand.

The electric log of a dry hole drilled in 1962 in the Morris field in the NW¼ sec. 20, T. 13 N., R. 14 E., showing a thin Booch sand at 1,256 ft, is representative of the original well (Fig. 17).

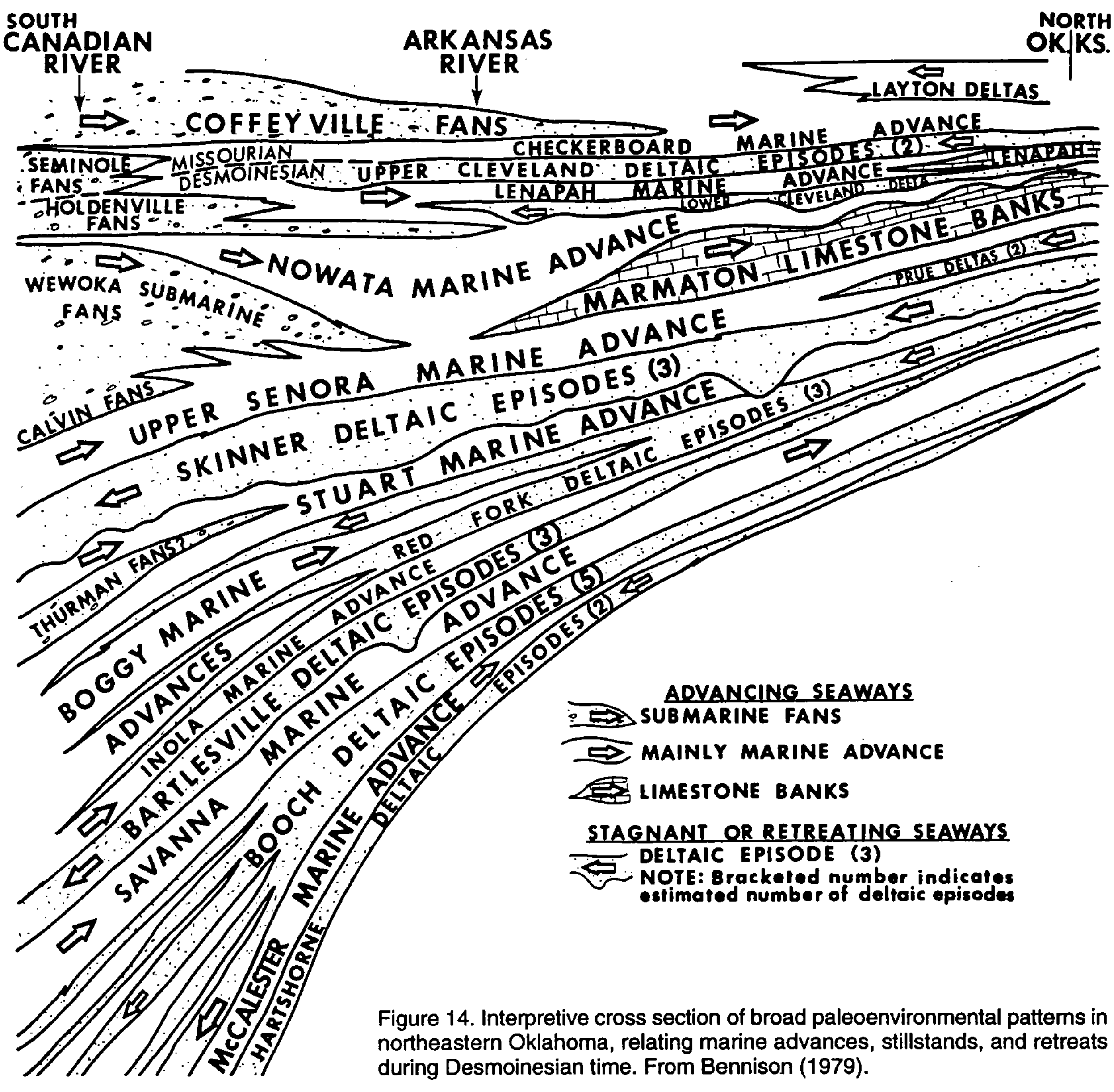


Figure 14. Interpretive cross section of broad paleoenvironmental patterns in northeastern Oklahoma, relating marine advances, stillstands, and retreats during Desmoinesian time. From Bennison (1979).

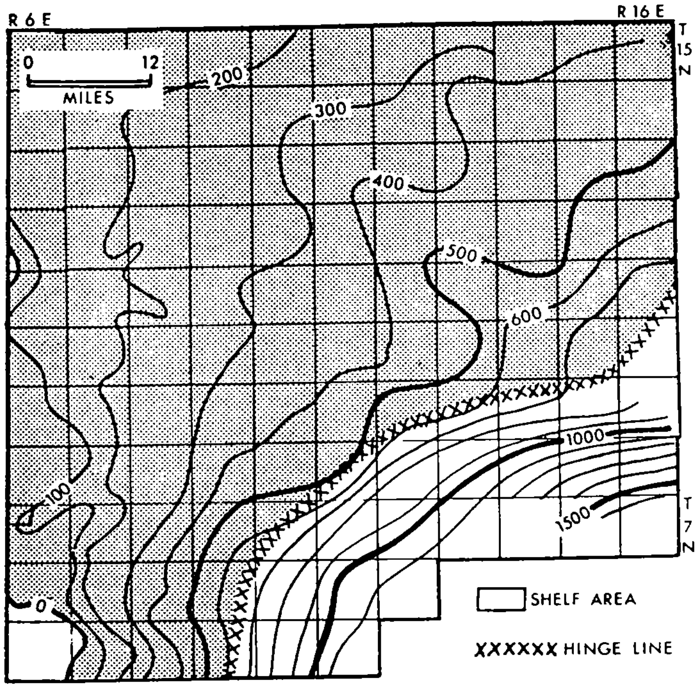


Figure 15. Isopach map of McAlester Formation, greater Seminole district, eastern Oklahoma. Hinge line separates the shelf environment to the northwest from the more abruptly subsiding basin area to the southeast. From Busch (1974).

The formal stratigraphic nomenclature of the rocks deposited during Desmoinesian time has been in use for some time. Figure 18 shows a generalized stratigraphic section for the McAlester Formation, established from surface exposures. This formal nomenclature generally is not used by operators for subsurface equivalents. Names given by various operators to the rocks they find in drilled wells are the names used by others in the area or names that they, themselves, have used elsewhere. This practice has created nomenclatures particular to specific areas, or to only one field in some cases. Many authors working in surface and subsurface areas throughout the Booch play have helped to correlate a large number of these informal names with their formal equivalents. Foremost among these authors are Scruton (1950), Oakes (1953), Jordan (1957), Branson (1968), Bissell (1984), and Hemish (1993).

The top of the Booch now is recognized at the base of the overlying Savanna Formation (called Brown lime in the subsurface). The base of the Booch is at the top of the Hartshorne Formation, represented by the upper Hartshorne sand of the subsurface. Many operators have designated an upper and a lower Booch. The upper Booch commonly is located either at the top of the Lequire–Cameron Sandstone equivalent or at the top of the Tamaha Sandstone equivalent, whichever is developed. In the regional stratigraphic cross sections on Plate 2, the top of the upper Booch is placed at the Tamaha Sandstone equivalent. The lower Booch consistently is located at the top of the Warner Sandstone equivalent (Pl. 2). A stratigraphic nomenclature chart for the McAlester Formation (Fig. 19) includes the commonly accepted informal names used in the Booch play area.

BOOCH DEPOSITIONAL ENVIRONMENT CONSIDERATIONS

In exploration and development of the Booch, correct interpretation of the depositional environment is critical to mapping the trends of the 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 electric well logs. In reality, however, there are few cores available for examination, and well cuttings seldom are helpful unless they demonstrate marine indicators, which limits their usefulness in deltaic environments. Thus, well logs are the main interpretive tools in subsurface work.

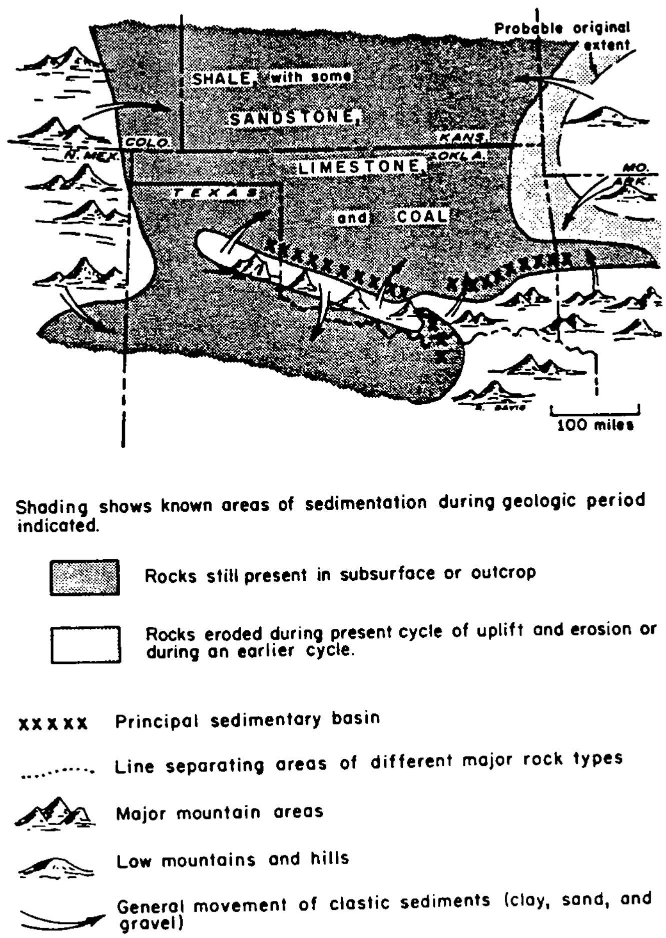


Figure 16. Middle Pennsylvanian (Desmoinesian) paleogeography of Oklahoma. From Johnson (1971).

Many workers have correlated typical profiles of gamma ray, spontaneous potential, and resistivity curves to the various depositional environments drilled in wells. Typical log profiles for the lower Booch sand (Warner Sandstone) interval, shown in Figure 20, are the basis for interpreting the elements in the depositional environment of the Booch play.

BOOCH FDD DEPOSITIONAL MODEL

The presence of a thick channel sand in the Booch has been recognized for many years. Reed (1923) identified this sand in the Henryetta–Okmulgee district and speculated that it was a river channel or bar. He also compared the characteristics of the sand with those of a delta. His map shows the thick Booch sand channel trending from north to south until it enters T. 12 N., R. 12 E., where it veers to the southeast (Fig. 21). This Booch channel reaches a thickness of nearly 300 ft at the southeast limit of the mapped area.

In a surface outcrop investigation of the Warner Sandstone in the Warner–Pryor district in northeastern Oklahoma, Scruton (1950) identified deposits that he interpreted as indicating a delta of moderate size. The area of that investigation is shown on Plate 5.

The map of the Booch sandstone play area (Pl. 1) is a composite constructed from work done by the various authors listed on Plate 5. The majority of the subsurface information used to produce Plate 1 is derived from three of those authors, Busch, Bissell, and Cole, and from James E. O'Brien (personal communication, 1995).

Busch (1953,1959,1971,1974) published several articles on prospecting for stratigraphic traps in deltaic environments that included his study of the Booch delta in the greater Seminole district. His map of the Booch delta shows a major delta lobe on the west and branching distributaries trending in a southerly direction into the Arkoma basin, southeast of the line of flexure (hinge line) of the McAlester Formation (Fig. 22). The major distributary has a sand thickness of >240 ft. Northeast of the main lobe of the Booch delta is a smaller lobe, which seems to trend in the same direction as the main lobe.

Bissell (1984) studied the Eufaula Reservoir area, from the eastern part of the Busch studies on the west to the outcrop of the McAlester Formation on the east (Pl. 5). His work completed coverage of the major part of the Booch delta.

Cole (1969) mapped the subsurface units of the Cherokee Group in the northwestern part of the Cherokee Platform. As part of his study, he included the McAlester Formation, containing the Booch sand, as one of the units. The western limits of the McAlester Formation, containing the Booch sand, are approximated on Plate 1. Plate 5 shows the area studied by Cole (1969).

James E. O'Brien, a consulting geologist in Tulsa, is conducting a proprietary subsurface study of the Booch area from the Oklahoma/Kansas border to the Arkoma basin. Study data indicate a fluvial system that extended from Kansas into Oklahoma and was the source of sediments to the distributary system of the

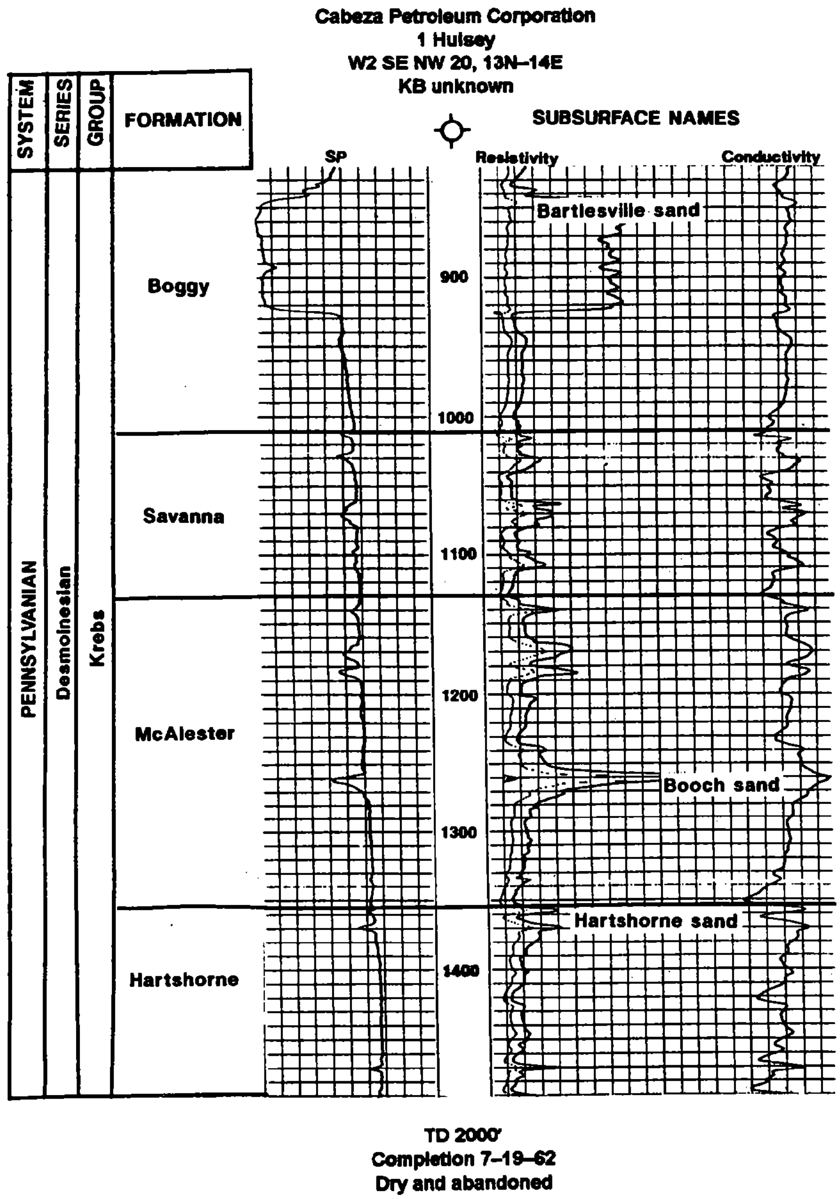


Figure 17. Electric log showing the Booch sand at the location of the name origin in the Morris field, in the NW¼ sec. 20, T. 13 N., R. 14 E., Okmulgee County, Oklahoma. Log patterns for spontaneous potential (SP), resistivity, and conductivity measurements are shown.

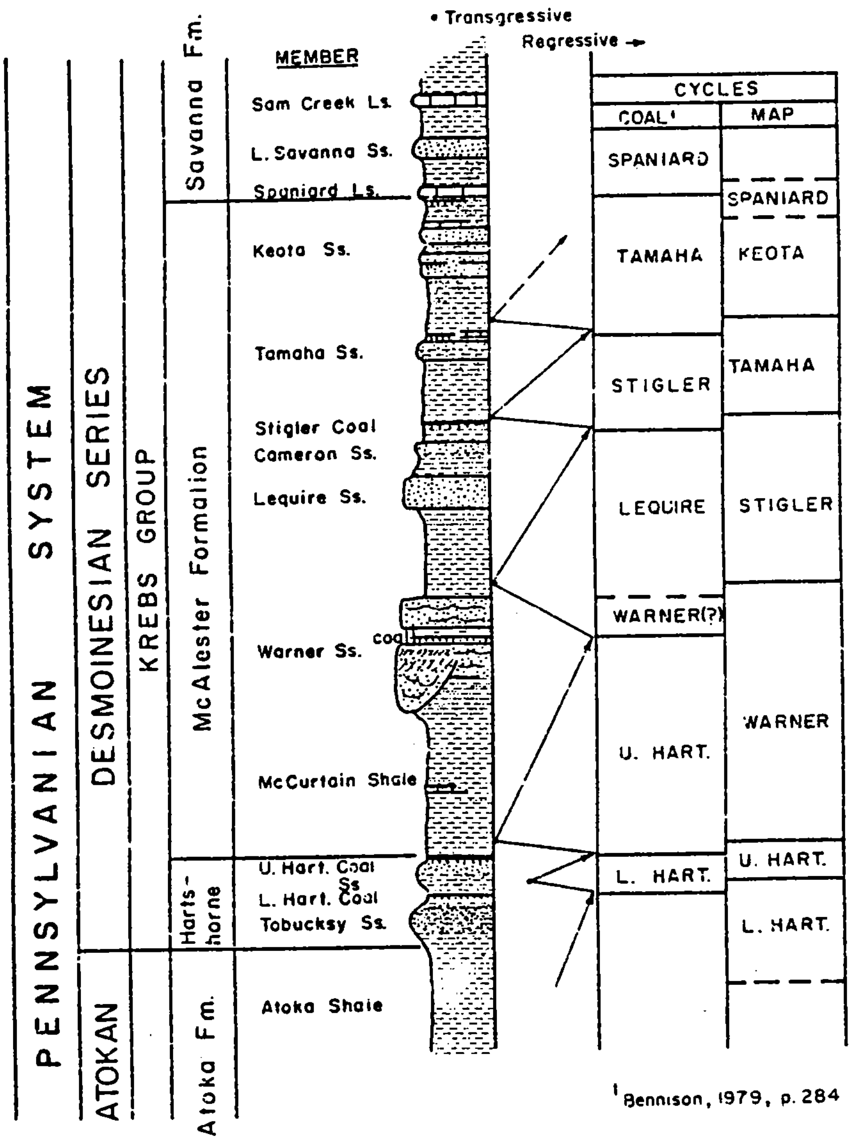


Figure 18. Generalized stratigraphic section for the McAlester Formation, established from surface exposures. From Bissell (1984). This formal nomenclature generally is not used by operators for subsurface equivalents in the Booch play area.

Booch delta (James E. O'Brien, personal communication, 1995).

The Booch delta is classified best as an elongate, fluvial-dominated delta system, as shown in Figure 6 (Part I). A large fluvial system apparently was supplying sediment to the delta from an emergent granitic terrain to the north.

The large Booch delta system shown on Plate 1 extends from the Kansas/Oklahoma boundary south for a distance of ~160 mi to the hinge line of the McAlester Formation, where it continues into the Arkoma basin. The depositional systems tracts shown in Figure 23 can be related to the Booch delta. On Plate 1, isolated sandstones are shown bordering the upper, or fluvial, part of the Booch system. These thin sandstones of the upper Booch (McAlester Formation) were deposited in a nearshore marine environment during a transgression (TST on Fig. 23) and provide only limited potential for Booch oil reservoirs (Pls. 3,4). Booch point bar sandstones of the fluvial system and upper delta plain (Pl. 1), which were deposited during a highstand (HST on Fig. 23), provide better potential for oil reservoirs. These sandstones are ≥40 ft thick and produce oil. On Plate 1, the unshaded (open) areas in the upper delta plain are either lagoonal deposits of shale (and sometimes coals) or carbonaceous material in interdistributary areas. Farther south, on the lower delta plain, branches from the two main distributaries of the Booch delta formed distributary channel fill sandstones, channel mouth bars, and crevasse splay sandstone deposits during a lowstand (LST on Fig. 23). Booch oil reservoirs are found in abundance on the delta plain, where the sandstone deposits are as much as 100 ft thick. The main distributaries, where sandstone is >240 ft thick (shown on Plate 1 by the coarse stipple pattern), also were deposited during a lowstand (LST on Fig. 23). These sandstones generally are not oil reservoirs; where they are, the sandstones are cleaner and coarser grained than in nonreservoir deposits. Stratigraphic traps in the massive channel sandstones occur where the axes of westward-plunging structural noses intersect the channel course (Busch, 1971). Sandstones overlying these massive channel sandstones may contain oil reservoirs trapped by differential sediment compaction or by drape associated with the thick channel sandstones. On Plate 1, a solid line separates the area that produces oil and associated gas (primarily on the Cherokee Platform) from the area in the Arkoma basin that produces only gas. This study did not extend into the gas area, although the distributary system continues into the basin.

Plate 2 shows regional stratigraphic cross sections A–A′ and B–B′ of the Booch delta. These cross sections show the electric log characteristics and stratigraphic relationships of the Booch sand in this deltaic environment. Cross section A–A′ shows the Booch interval, from the thin shales and sands of the coastal plain on the north to the massive distributary sands incised into older marine shales to the south (Pl. 1). This line of section follows the general course of the main distributary channel in the Booch, from the fluvial system in the north to the divergence of the distributaries on the upper delta plain in T. 15 N. (Pl. 1). The major distributary

System	Series	Group	Formal Surface Names (Formation)			Informal Subsurface Names	
Pennsylvanian	Desmoinesian	Krebs	Boggy Fm.	Taft Ss. Inola Ls. Bluejacket Ss.	Cherokee Group	Red Fork sand Inola lime Bartlesville sand	Salt sand
			Savanna Fm.	Doneley Ls. Sam Creek Ls. Spaniard Ls.		Brown lime	
			McAlester Fm.	Keota Ss. Tamaha Ss. Cameron Ss. Lequire Ss. Warner Ss. McCurtain Sh.		upper Booch sand lower Booch sand	Taneha sand Tucker sand
			Hartshorne Fm.	Hartshorne Ss.		Hartshorne sand	
	Atokan	Atoka	Atoka Fm.	Atoka Ss.		Atoka sand	Gilcrease sand Dutcher sand

Figure 19 (left). Stratigraphic nomenclature chart of the McAlester Formation showing the formal surface names and the commonly accepted informal names used in the Booch play area. After Scruton (1950), Oakes (1953), Jordan (1957), Branson (1968), Bissell (1984), and Hemish (1993).

channel, shown in the coarse stipple pattern on Plate 1, is filled with channel sandstone sequences >240 ft thick. These thick Booch sands continue across the lower delta plain beyond the area of this study. Cross section B–B′ was constructed across the lower delta plain in a southwest-to-northeast direction to show the sandstones in the primary area of Booch oil production in FDD reservoirs. Sandstones shown on this cross section were deposited as delta-front bars, point bars, and distributary-channel and stacked-channel sequences. Both cross sections have been correlated to subsurface cross sections that Bissell (1984) correlated to the surface outcrops of the McAlester Formation and to the overlying and underlying formations.

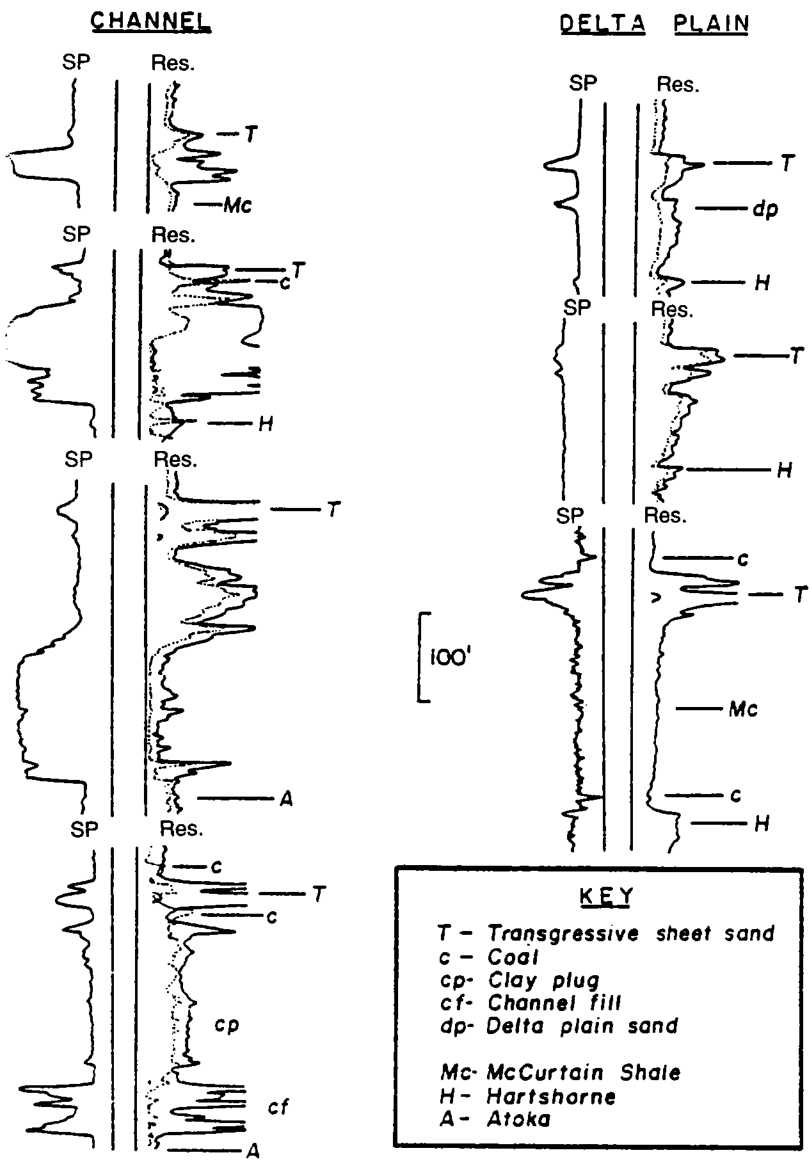


Figure 20. Typical lower Booch sand (Warner Sandstone) geophysical log responses: spontaneous potential (SP), and resistivity (Res.). After Bissell (1984).

FDD IN THE BOOCH

Fluvial-dominated deltaic oil reservoirs abound on the Booch delta. Leases that currently (1979–95) produce Booch oil are shown on Plate 3. Many leases that produced oil from the Booch and were abandoned before 1979 are not included on this map.

Fields with Booch oil reservoirs that have produced at least 5,000 BO since 1979 are shown on Plate 4. There are other reservoirs in all of these fields, and their production may be derived, in part, from the Booch. On Plate 4, however, only leases with exclusive Booch production were used to meet the 5,000 BO/field criterion. Field names and boundaries are consistent with field designations by the Oklahoma Nomenclature Committee of the Midcontinent Oil and Gas Association. There are producing Booch leases outside the field boundaries where the boundaries have not been updated.

Hawkins Pool Area (Holdenville Field) Study

(Secs. 2–4, 9–11, 14–16, 21–23, and 26–28, T. 6 N., R. 8 E., Hughes County, Oklahoma)

The Hawkins pool area is located in southwestern Hughes County, 6 mi south of Holdenville in the Holdenville field. The Booch FDD oil reservoirs are in, and associated with, a distributary channel near its distal end as the channel approaches the McAlester Formation hinge line (Pl. 1; Fig.

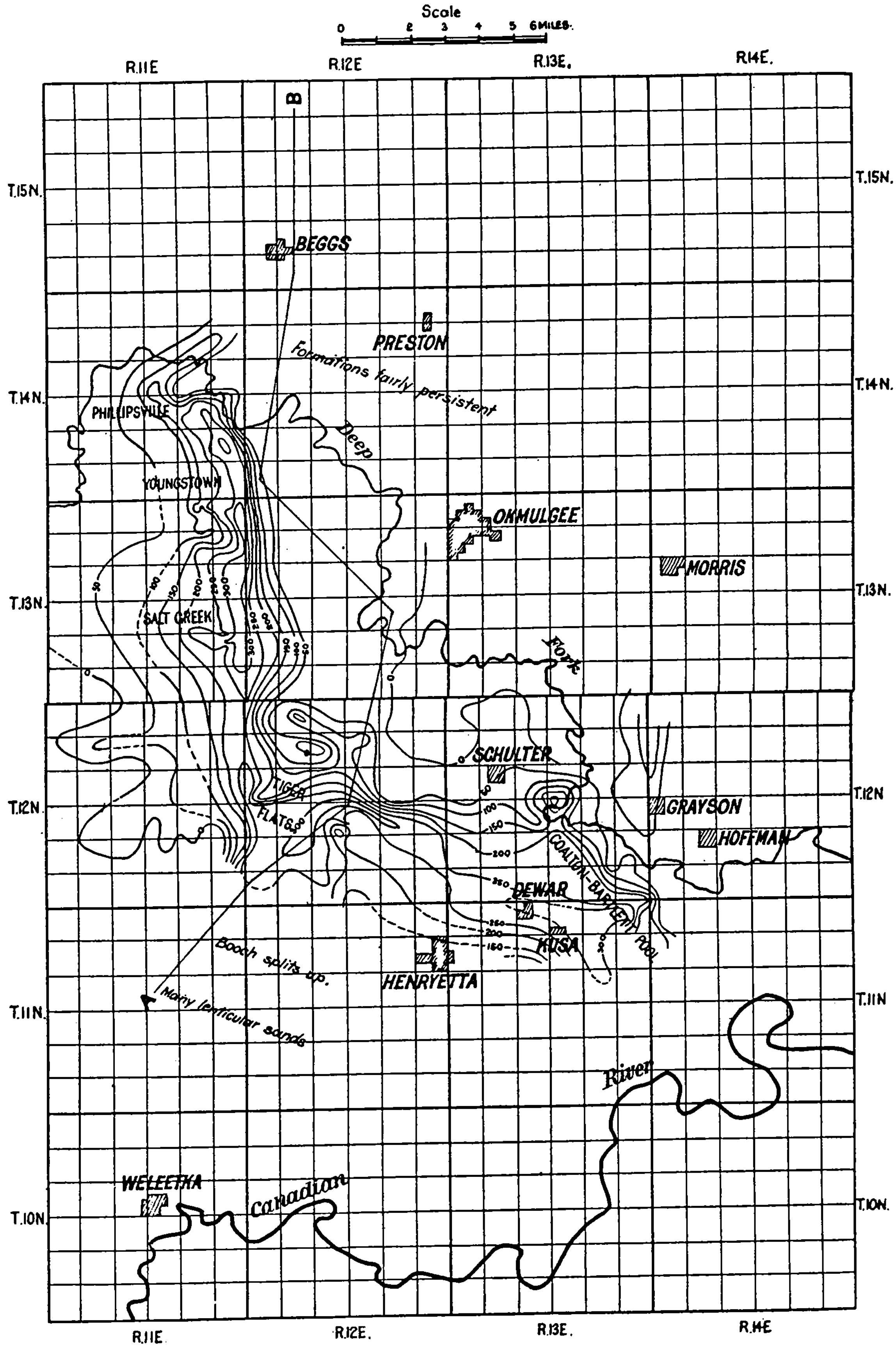


Figure 21. Reed's (1923) map of the Henryetta–Okmulgee district, Oklahoma, showing thickness of the Booch sand. Contour interval = 50 ft. From Reed (1923).

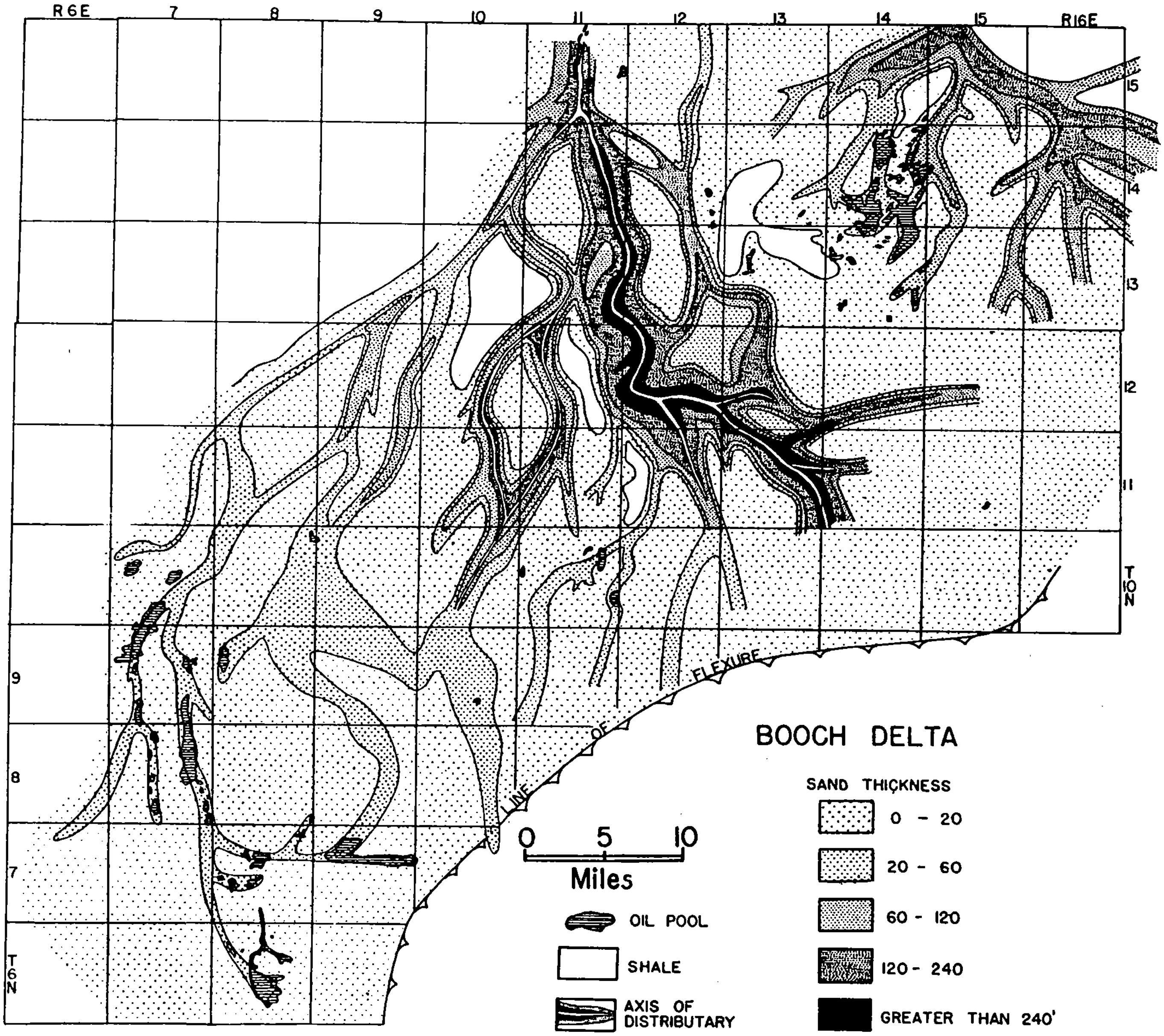


Figure 22. Isopach map of the Booch sand in greater Seminole district of eastern Oklahoma. Sand thickness is given in feet. Line of flexure is the hinge line of the McAlester Formation. From Busch (1959).

24). NRIS well history files show that there was Booch oil production in the Hawkins pool area as early as 1939. Rapid development of the reservoir began in 1944 and continued through 1947. A representative electric log in the Hawkins pool area identifies the subsurface intervals of the Booch (Fig. 25). Three maps from Busch (1974) show the channel trend in the Hawkins pool (Figs. 26–28).

Stratigraphy: The Booch sand in the Hawkins pool area has three sandstone intervals: upper, middle, and lower. Each interval is developed at some location in the area. Sandstones in the Booch are described as very fine grained graywacke containing many rock fragments in a relatively large amount of clay matrix. The grain size of the channel sandstones is somewhat larger than that of the sandstones in the interdistributary areas, and the channel sandstones are better sorted and have a lower clay content than the interdistributary sandstones (Busch, 1974). The middle sandstone in the Hawkins pool is overlain by a thin coal bed and appears to be a delta-front sand at its lower limit. The Booch is overlain by the Savanna Formation and overlies the Hartshorne Formation with apparent conformity.

Structure: The structure of the Hawkins pool area is shown in Figure 26. This map is contoured on the top of the Booch sand. There is a branching, narrow, ridge-

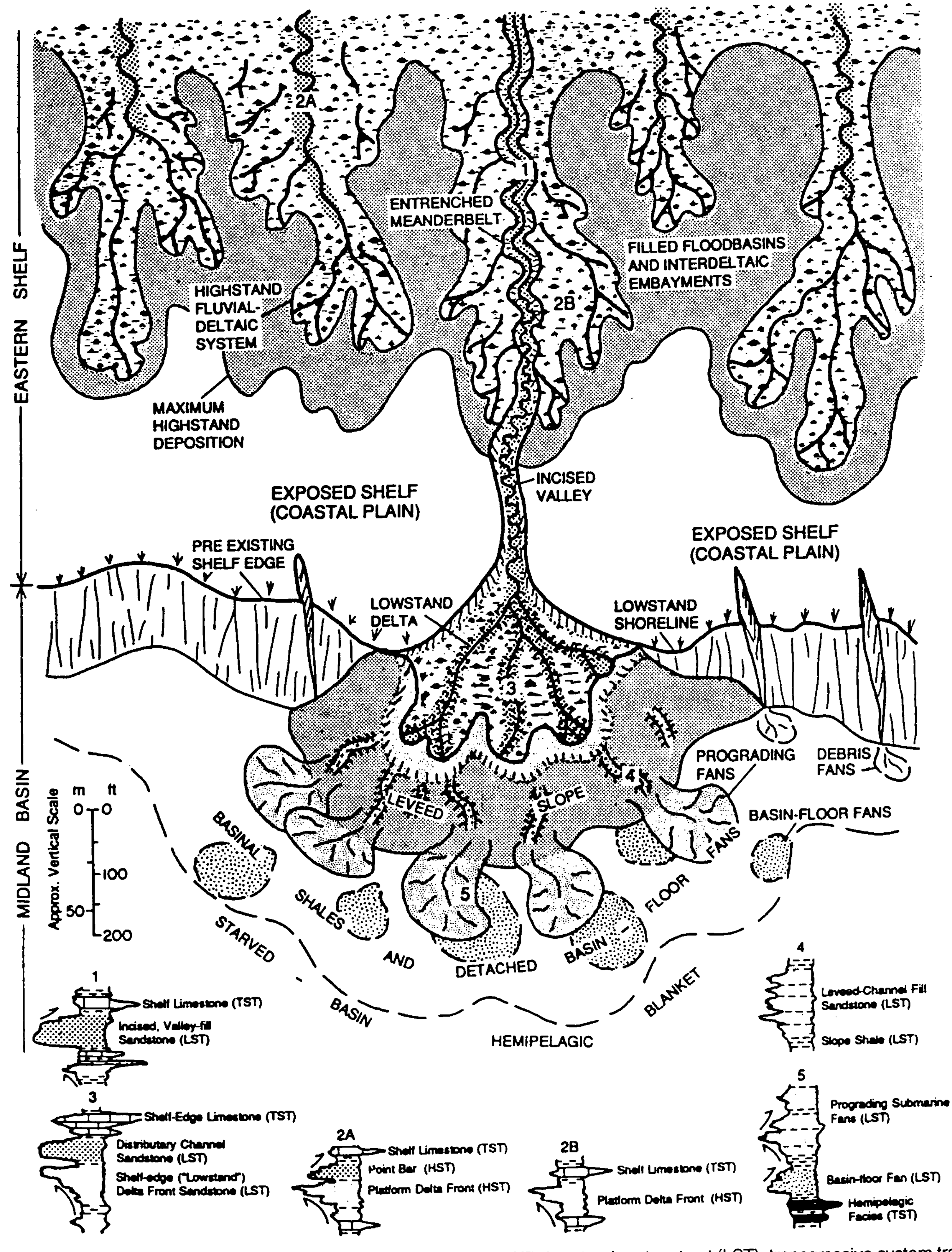
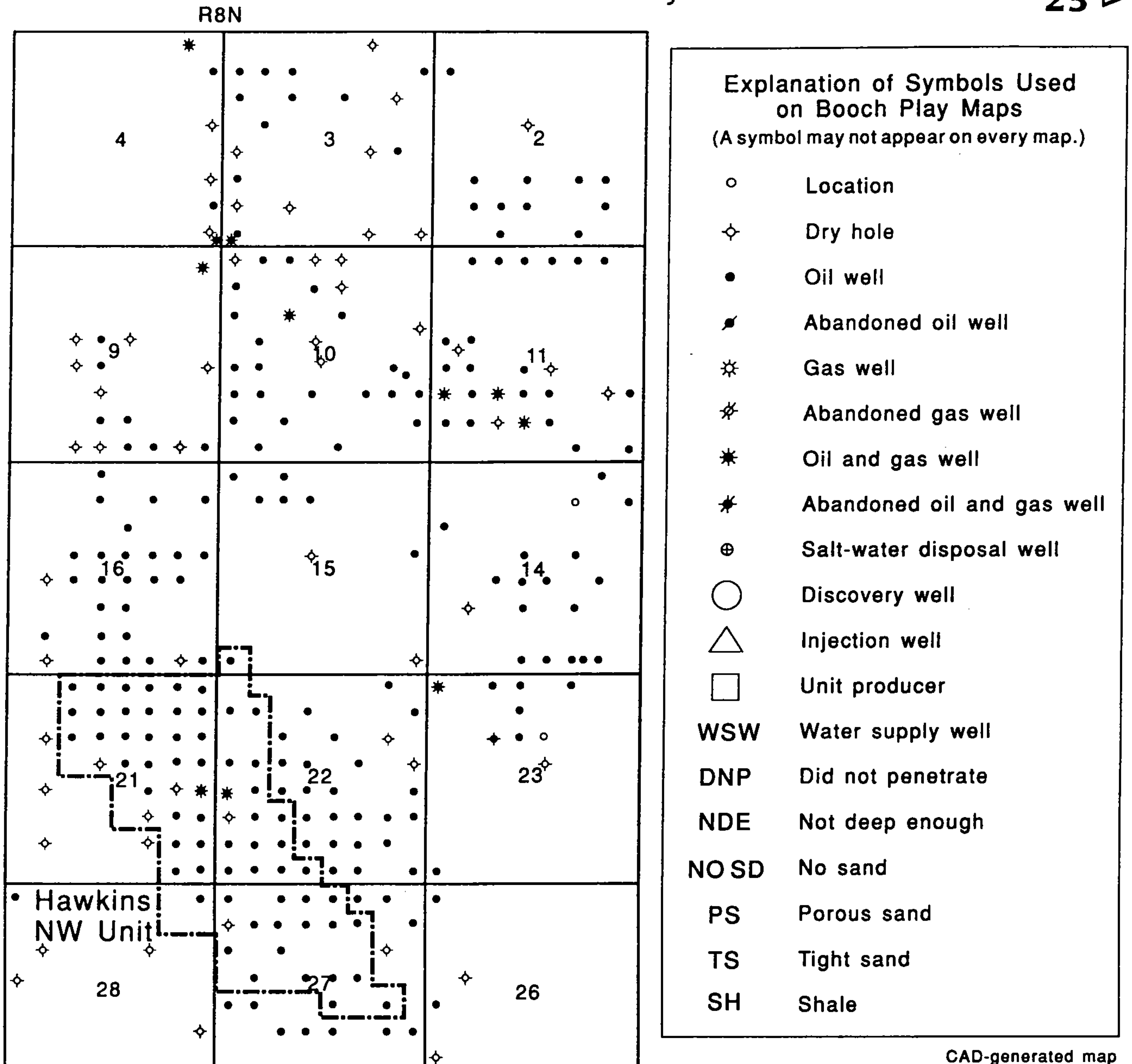


Figure 23. Depositional systems tracts—highstand system tract (HST), lowstand system tract (LST), transgressive system tract (TST)—at maximum progradation of terrigenous clastic systems. Representative logs illustrate facies within various systems comprising the tracts. From Brown (1989).



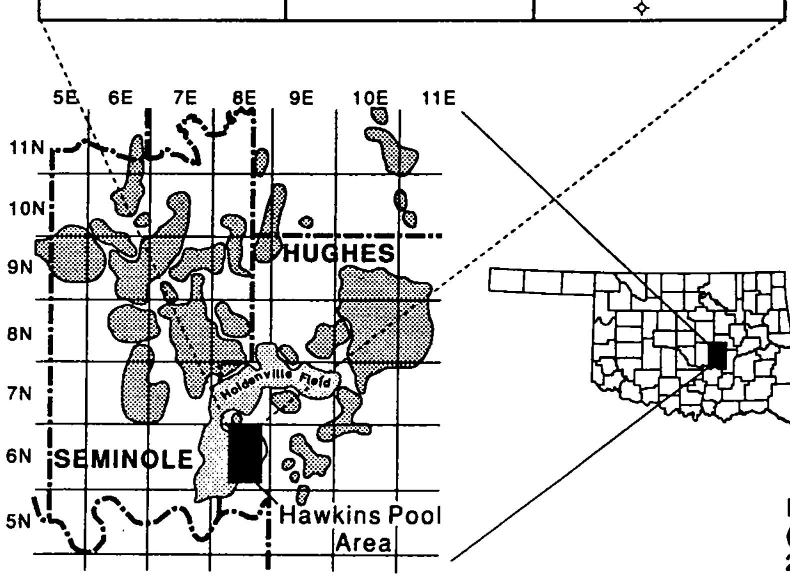


Figure 24. Location map of the Hawkins pool area (Holdenville field), secs. 2–4, 9–11, 14–16, 21–23, 26–28, T. 6 N., R. 8 E, Hughes County, Oklahoma.

like feature at the northern end of the area; a sinuous, arcuate feature at the southern end represents the main part of the pool. There is ~75 ft of structural relief in the southern part of the pool area, and >100 ft of structural relief in the northern part. Postdepositional compaction of the shale has increased the structural relief along the axes of the thick sand.

Isopach Mapping: The isopach map of the Booch sand shows the thickness of the middle Booch sand in the Hawkins pool area (Fig. 27). The interpretation (Busch, 1974) shown on this map illustrates the sinuous and branching character of the sandstone, which possibly was deposited as a delta-front sand at the distal end of a distributary channel. Several small branches from the main part of channel represent splay or overbank deposits. The indications of coal in the area confirm the presence of interdistributary deposits. The channel sand has a maximum thickness of 35 ft and is encased in shale.

Isopotential Mapping: The isopotential map (Fig. 28) was constructed using the initial potential, expressed in BOPD, reported for the Booch sand wells in the Hawkins pool area. Most of these wells were completed during the rapid development of the Hawkins pool from 1944 through 1947, before the use of hydraulic fracturing techniques that artificially increase the initial potential. Therefore, the map represents the relative permeability and thickness of the sand and confirms the trends indicated on the Booch sand isopach map (Fig. 27). The isopotential map is a useful tool in determining trends when the wells do not penetrate the entire sand thickness and are completed after penetrating only the top few feet of the sand. Busch (1971, p. 1142) states: "Isopach and isopotential maps assist in carrying out a systematic step-out drilling development program. From the isopach, drillsite locations most likely to extend axial trends are selected."

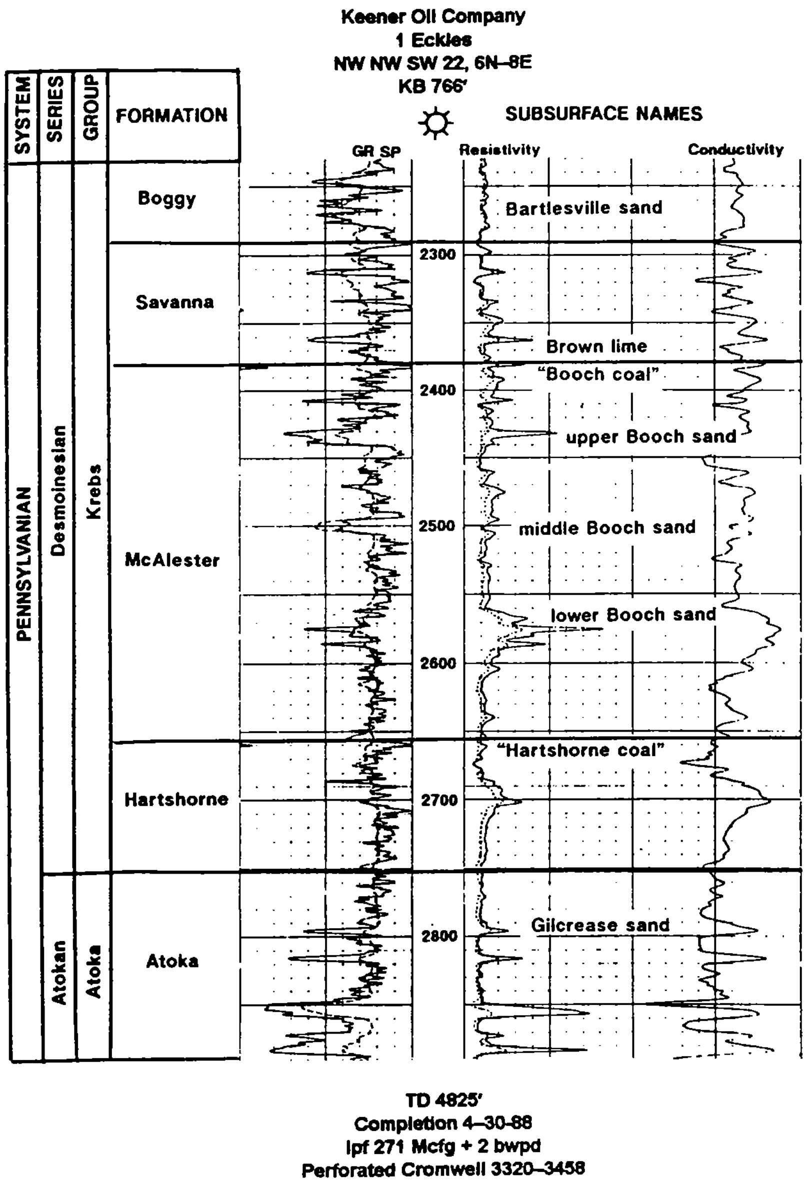


Figure 25. Representative log, Hawkins pool area (Holdenville field) showing log patterns of gamma ray (GR), spontaneous potential (SP), resistivity, and conductivity measurements. Booch sand intervals are identified.

Production and Development: Ashland Oil Company formed the Hawkins N.W. Unit in the area of the Hawkins pool in February 1954 (Fig. 24). Figure 29 shows well locations within the outline of the Hawkins N.W. Unit. At unitization, primary production was 1,170,374 BO. In 1956, the unit had 31 active oil wells and 23 water input wells. During 1956, average daily oil production was 311 BO; average daily water injection was 3,392 barrels; and average daily water production was 906 barrels. In 1982, five active oil wells produced a total of only 150 BO. The unit was reported as inactive in 1983. The last reported production from the unit was in October 1989. Cumulative production after unitization was 791,493 BO; total cumulative production was 1,961,867 BO. Total water injection reported for this unit was 13,026,222 barrels. Currently, six Booch waterflood projects are active in the Holdenville field.

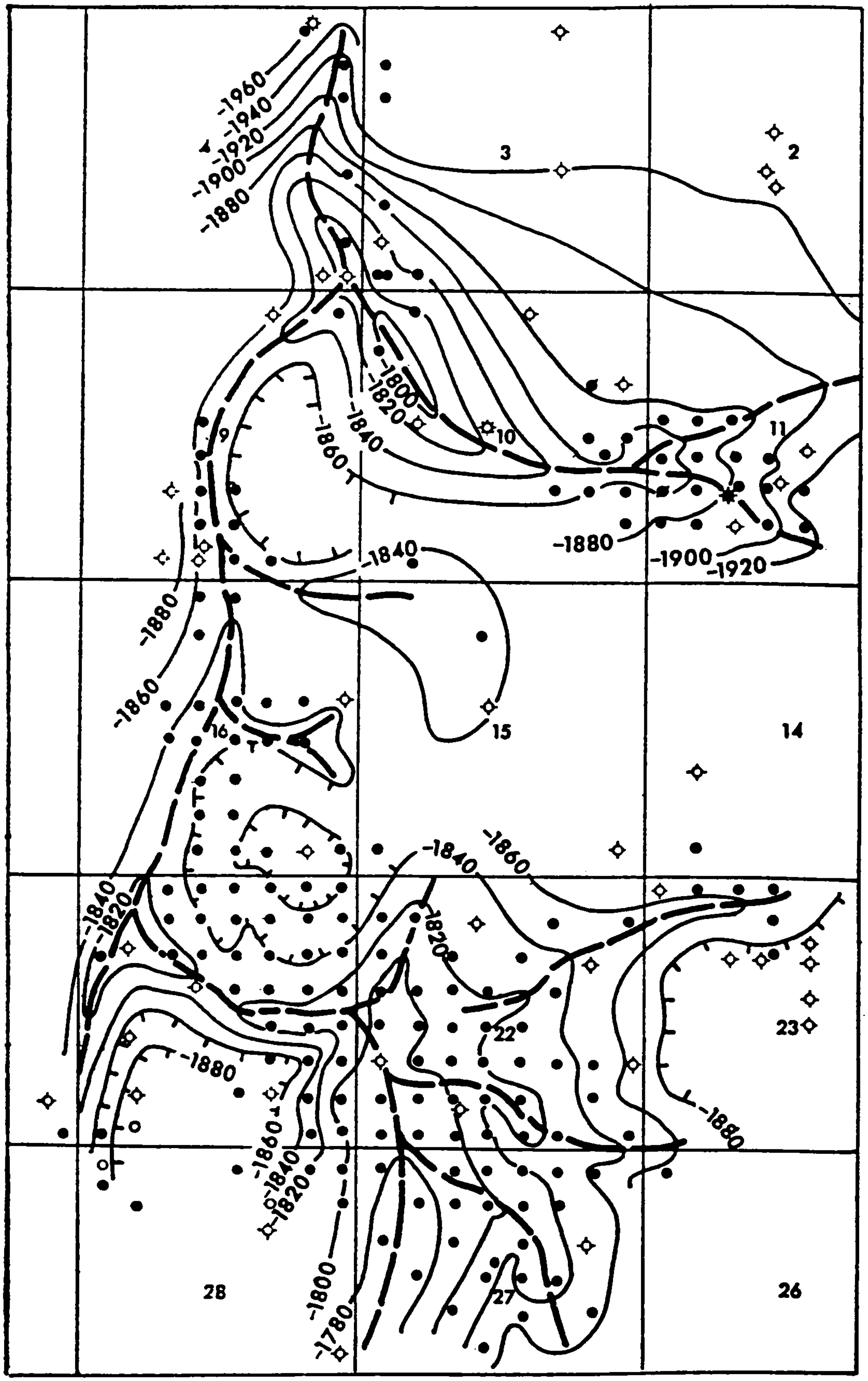


Figure 26. Structure map of the top of the Booch sand, Hawkins pool area (Holdenville field), part of T. 6 N., R. 8 E., Hughes County, Oklahoma. Contour interval = 20 ft. From Busch (1974). See Figure 24 for explanation of map symbols.

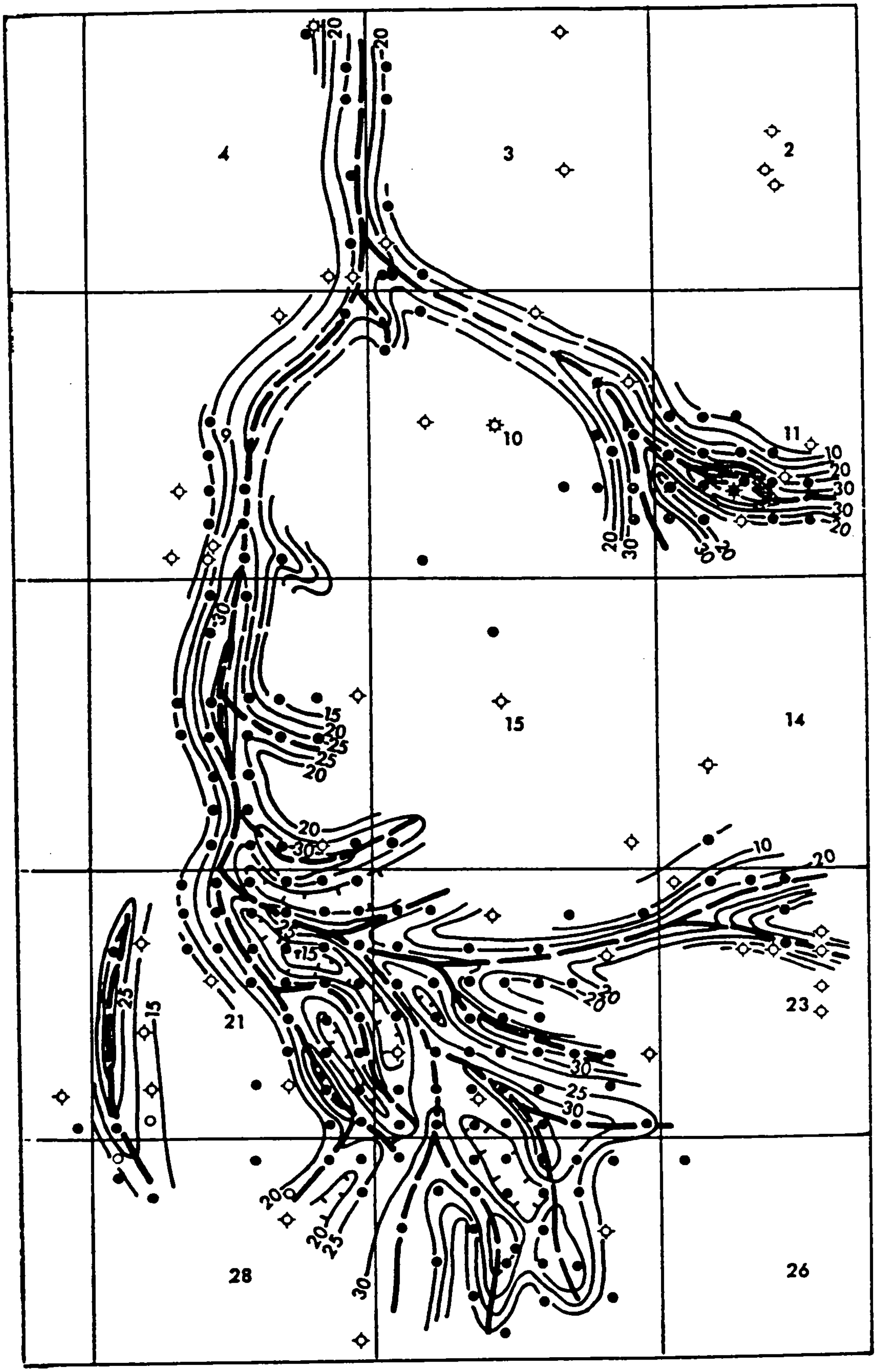


Figure 27. Isopach map of the Booch sand (middle sand?), Hawkins pool area (Holdenville field), part of T. 6 N., R. 8 E., Hughes County, Oklahoma. Contour interval = 5 ft. From Busch (1974). See Figure 24 for explanation of map symbols.

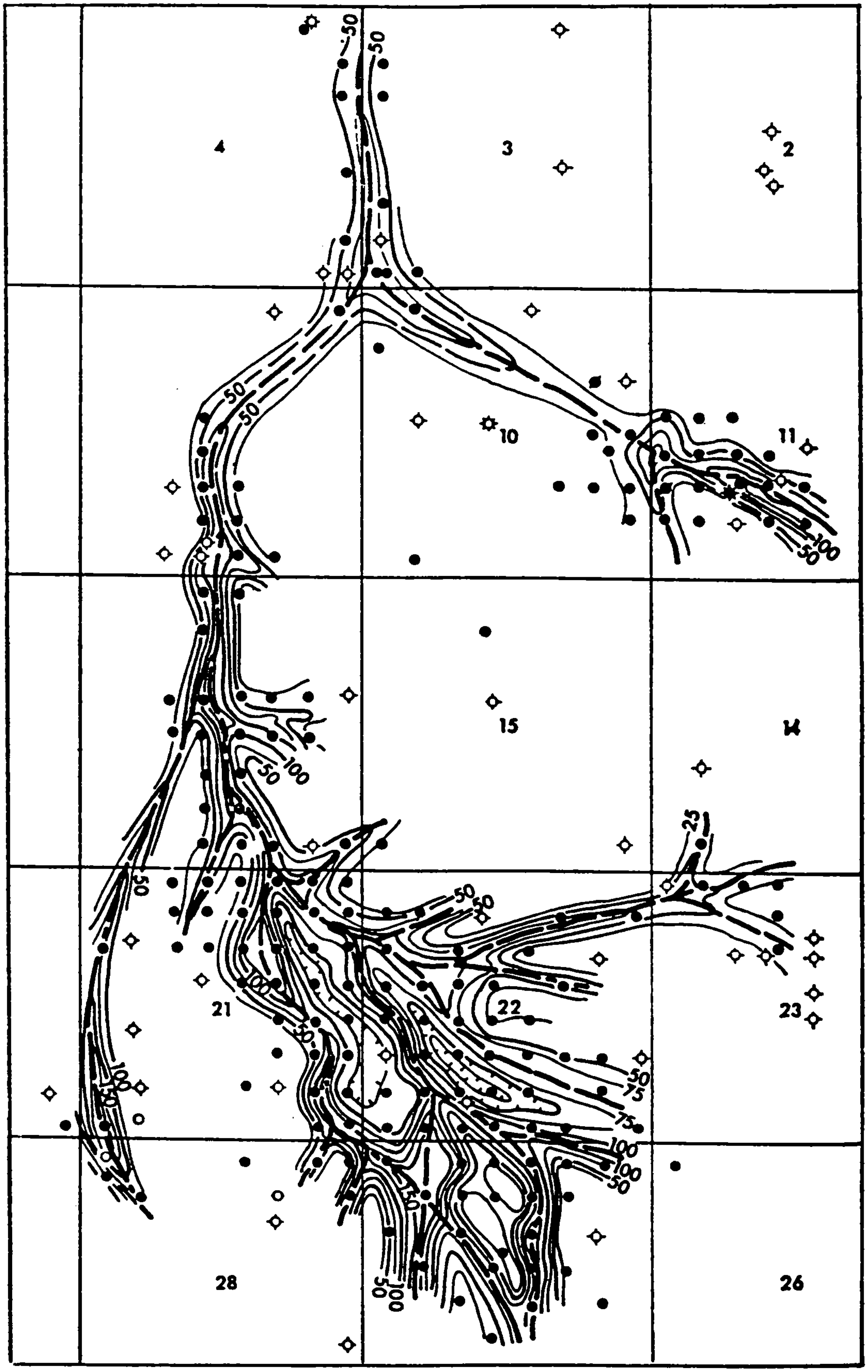


Figure 28. Isopotential map of the Booch sand, Hawkins pool area (Holdenville field), part of T. 6 N., R. 8 E., Hughes County, Oklahoma. Contour interval = 25 BOPD. From Busch (1974). See Figure 24 for explanation of map symbols.

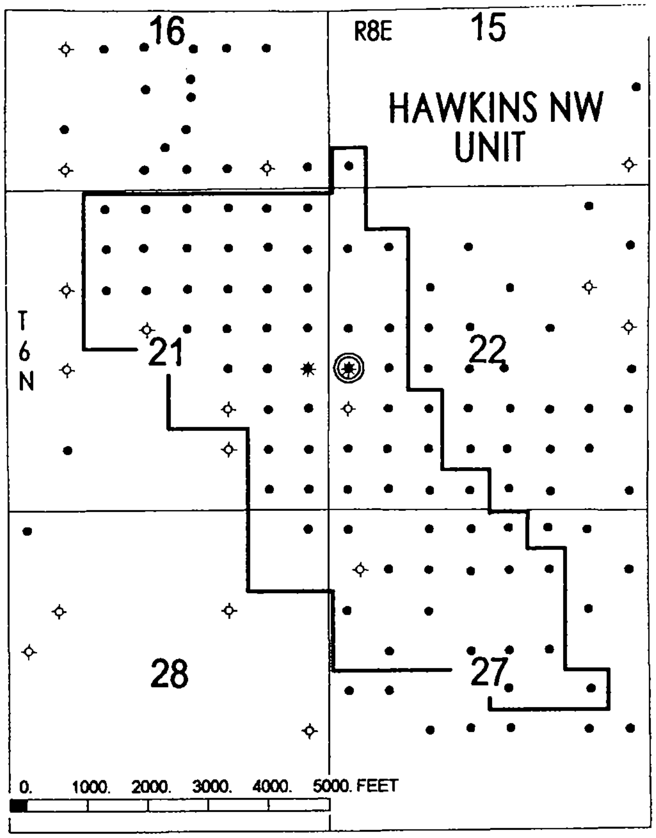


Figure 29. Well location map and outline of the Hawkins N.W. Unit, Hawkins pool area (Holdenville field), part of T. 6 N., R. 8 E., Hughes County, Oklahoma. See Figure 24 for explanation of map symbols. The representative-log well (Fig. 25), the Keener Oil Company No. 1 Eckles, is identified with a double circle.

Wewoka N.W. Booch Sand Unit Study

(T. 9–10 N., R. 7 E., Seminole Field, Seminole County, Oklahoma)

by Kurt Rottmann

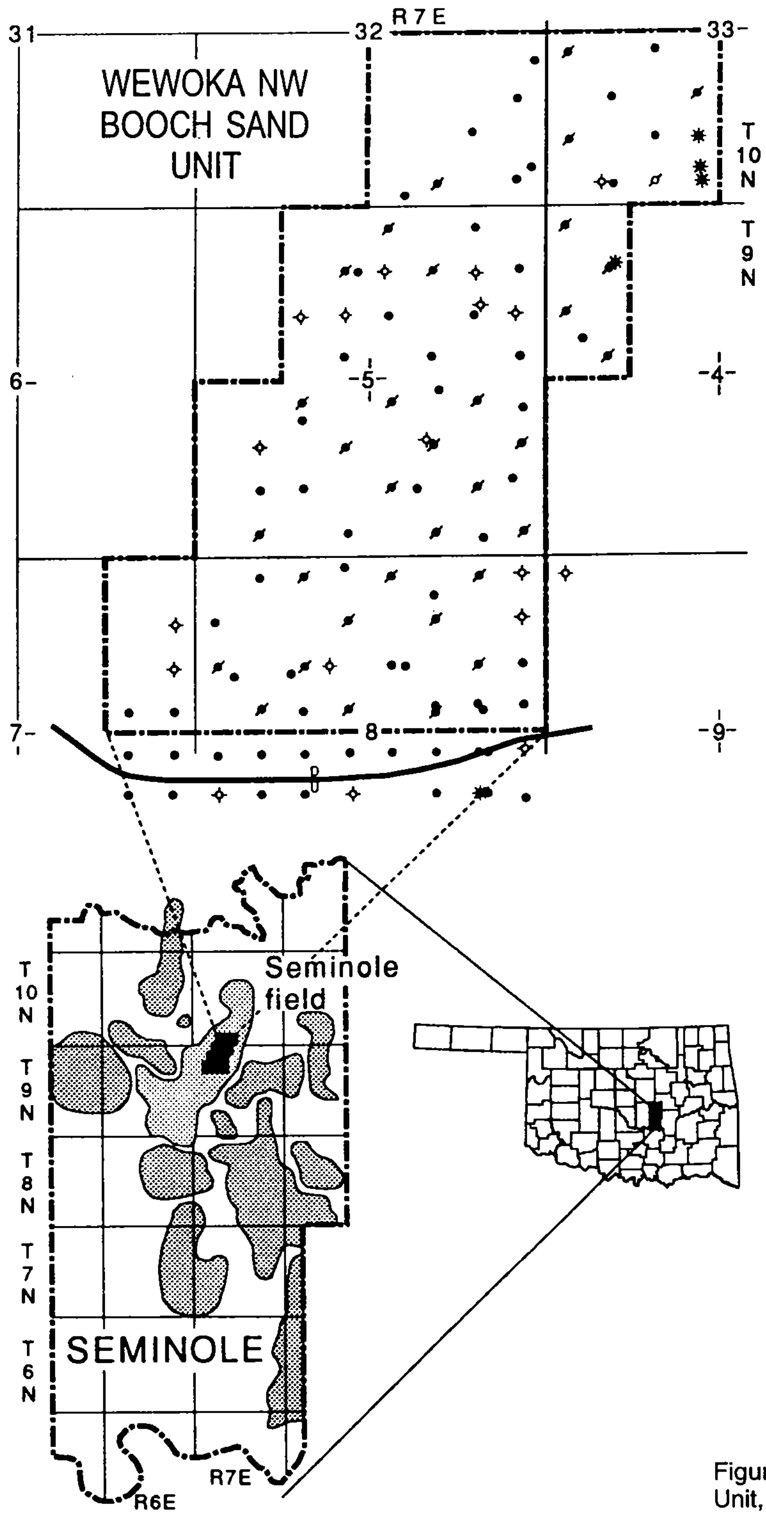
This FDD unit study area is part of what was originally the Cheyarha field. In 1948, the field was included in the Seminole field as the Seminole field, Cheyarha sector. In 1989, Beard Oil Company unitized portions of secs. 4, 5, 7, and 8 of T. 9 N., R. 7 E. and portions of secs. 32 and 33 of T. 10 N., R. 7 E. and named it the Wewoka N.W. Booch Sand Unit. These sections all are included within the Seminole field, Seminole County, Oklahoma (Fig. 30). Production from the area of the Wewoka N.W. Booch unit was established on August 22, 1944, with the discovery of oil from the Troup–Moore–Hall No. 1 Austin in the SE¼NE¼SW¼ of sec. 33, T. 10 N., R. 7 E., Seminole County, Oklahoma. The discovery well was completed with an initial potential flow of 170 BOPD. Within two years, 55 additional oil wells had been completed and the field was fully developed. Table 1 gives a summary of the geological and engineering data for the Wewoka N.W. Booch unit; characteristics of the field are discussed in more detail in the following sections.

Stratigraphy: The stratigraphy for the Booch sand in the Wewoka N.W. Booch unit is shown in detailed cross sections of the field. Cross section A–A′ (Fig. 31, in envelope) is a north-to-south dip section. The stratigraphic datum for this cross section is a local limestone layer identified on resistivity logs (resistivity marker) just above the Booch sand. The Booch sand interval appears to be divided into three distinct layers, labeled the upper layer, the middle layer, and the lower layer on the cross section. All three layers produce oil where porous sand is developed. There does not appear to be an initial oil/water contact within this reservoir. Log signatures for wells within the reservoir indicate the presence of channel, splay, and flood-plain facies of a fluvial depositional environment. The sandstone in the Booch approaches 30 ft in thickness in the central part of the channel. The Beard Oil Company No. 831-W (NE¼NE¼NW¼ sec. 8, T. 9 N., R. 7 E.) was cored in the Booch interval. Detailed core descriptions are included in following sections. The log from the Beard Oil Company No. 572-W (NW¼SW¼SE¼ sec. 5, T. 9 N., R. 7 E.) is the type log for the field (Fig 32).

Cross section B–B′ (Fig. 33, in envelope) is a stratigraphic strike section. The datum is the same resistivity marker that is used for cross section A–A′. This cross section also shows three distinct layers for the Booch sand interval. The Beard Oil Company No. 851 (NW¼ SW¼NE¼ sec. 8, T. 9 N., R. 7 E.) is a tie well for cross sections A–A′ and B–B′. The Geoex Resources, Inc., No. 9-A King (NW¼NW¼NW¼ sec. 9, T. 9 N., R. 7 E.) was cored in the Booch sand interval; the core description is included in following sections.

Structure: Figure 34 is a structure map contoured at the top of the Booch sand horizon. The structure of the Wewoka N.W. Booch unit generally is homoclinal and dips to the northwest at ~100 ft/mi or <2°. In the SW¼ of sec. 5, T. 9 N., R. 7 E., there appears to be a minor closure at the top of the Booch sand horizon. This small closure apparently did not influence the type of production from the Booch as the completion reports indicate only oil production. Adjacent to the southern portion of the Wewoka N.W. Booch unit, there is an east–west normal fault. The Wewoka N.W. unit is on the downthrown block. Throw on the fault is ~50 ft and decreases in a westward direction. The fault does not appear to affect the Booch reservoir as there is Booch production on both sides of the fault. However, the presence of the fault may have influenced the development of Cheyarha field. In 1934, oil was discovered in the Booch sand at the No. 1 Johnson Halsee in the SW¼SW¼SW¼ of sec. 8, T. 9 N., R. 7 E. Within four years, the entire southern half of sec. 8 was developed, and all of the wells had been drilled on the upthrown side of the fault. Operators probably were aware of the fault and avoided drilling on the downthrown side. The No. 1 Austin discovery well actually was a southern extension of Booch production farther to the north, but the No. 1 Austin and its subsequent offset development locations soon demonstrated that sec. 5 and the northern half of sec. 8 also were part of the regional oil play.

Production History: Cumulative oil production through 1994 was 2,539,922 BO for the Wewoka N.W. Booch unit. Table 2 gives the annual oil production, the well count, the average monthly oil production, and the average daily oil production per well. All of the production was reported on a lease basis.



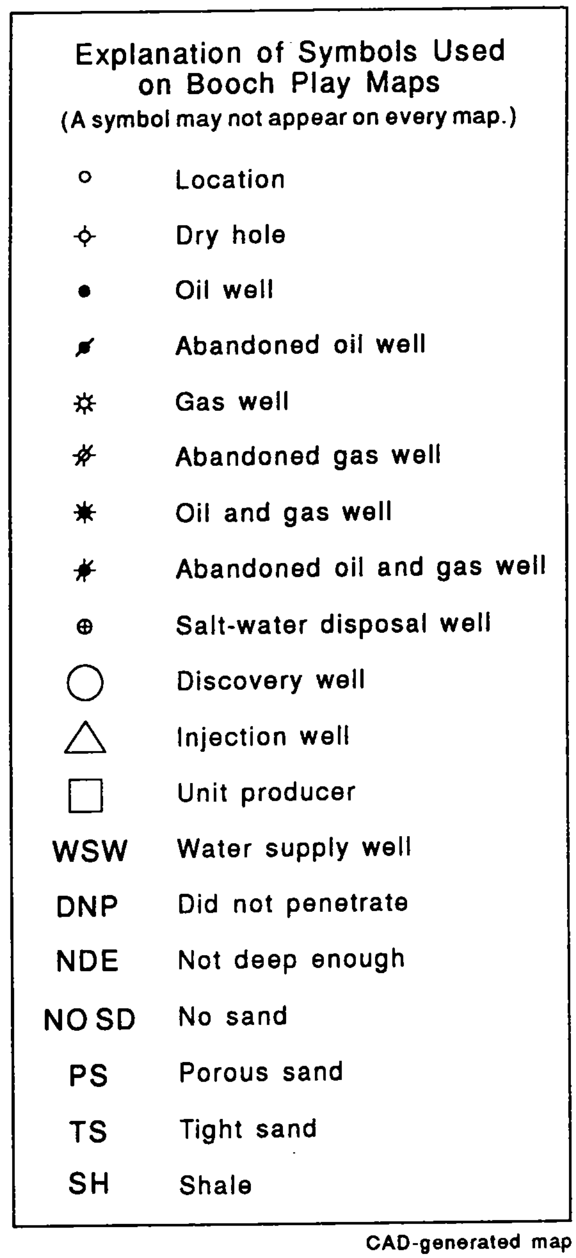


Figure 30. Location map of the Wewoka N.W. Booch Sand Unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma.

TABLE 1. – Geological/Engineering Data for the Wewoka N.W. Booch Sand Unit, Seminole County, Oklahoma

Reservoir size	1,192.22 acres
Well spacing (oil)	10 acres
Oil/water contact	none
Gas/oil contact	none
Porosity	17.1% average
Permeability	35 md average
Water saturation	45%
Thickness (net sand) (ø ≥10%)	16.4 ft
Reservoir temperature	112° F
Oil gravity	37.9° API
Initial reservoir pressure	~1,150 PSI
Initial formation-volume factor	1.1477
Original oil in place (volumetric)	13,158 MSTBO
Cumulative primary oil	2,300 MSTBO (EST)
	117 BO/acre-ft
Recovery efficiency (oil)	~17.5%
Cumulative gas	Not determined

The production and decline curve (Fig. 35) shows the production history for the field. In 1949, the curve shows a period of increased production. Many producing Booch wells were declining rapidly, but Gilcrease production had been established to the east, adjacent to the Cheyarha field. Several operators had recompleted a few of the Booch wells within the Cheyarha field as Gilcrease producers. Since production from those wells was reported on a lease basis and commingled with Booch production, the amount of oil produced from the Gilcrease can only be estimated. The Gilcrease produced ~240,000 BO, and the Booch produced ~2,300,000 BO.

The Booch sand interval often was completed uncased (open hole) or by setting a casing through the Booch, cementing, and then perforating the casing in the oil-bearing zone. Some of the wells that were completed open hole were deepened later to penetrate the entire Booch interval. Nitroglycerin was used as an explosive in early completions to stimulate production in the Booch. The explosion created a bell-shaped cavern in the reservoir rock below the well casing. The flow rates varied, but 100–200 BOPD was not unusual, and flow rates for several wells were >500 BOPD, indicating high porosities and permeabilities.

Reservoir Characteristics: Reservoir characteristics of the Wewoka N.W. Booch unit are given in Table 1. Effective porosities, as measured primarily with compensated neutron density logs, generally range from 12% to 23–24%; 17.1% is the average for the unit. Permeabilities commonly range from 2.4 to 57.0 md, as can be seen in the core analysis results for the Beard Oil Company No. 831-W (Table 3). An estimated average of 35 md is a reasonable figure for the reservoir; higher permeabilities, however, should be expected in the channel portion of the reservoir. Calculated water saturations averaged 45% initially. Several of the recent wells drilled on the west side of the Wewoka N.W. Booch unit had calculated water saturations of 70%. This high water saturation could have been the result of water encroachment from adjacent waterfloods to the north and south. The injector located in the NW¼NW¼ SW¼ of sec. 8, T. 9 N., R. 7 E., Seminole County, Oklahoma (Fig. 34), could have been a possible source of water encroachment for this portion of the reservoir; however, there is no indication of a response on the production curve (Fig. 35).

Core Data: The first core analyzed was from the Beard Oil Company No. 831-W (NE¼NE¼NW¼ sec. 8, T. 9 N., R. 7 E.) (Table 3). Whole rock analysis was not done for the core. Core Laboratories (Oklahoma City) described the core as fine grained with some micaceous and shale laminations; occasional siderite nodules were noted, as were sedimentary structures including horizontal bedding and cross-bedding.

The second core analyzed was from the Geoex Resources, Inc., No. 9-A King (NW¼NW¼NW¼ sec. 9, T. 9 N., R. 7 E.) (Table 4). This well was drilled on the edge of the reservoir. Core Laboratories (Oklahoma City) described the core as fine grained with some siltstone; the core also was described as calcitic to very calcitic, indicating the presence of carbonate matrix; micas, siderite nodules, and shale laminations also were noted.

The No. 831-W well is close to the center of the channel belt, while the No. 9-A King well is close to the edge of the channel belt. The differences in the porosities and permeabilities for the cores from these two wells are indications of conditions that may occur in the different facies of the channel belt. The No. 831-W core has an average porosity of 15.4% and an average permeability (to air) of 20 md, while the No. 9-A King core has an average porosity of 12.2% and an average permeability (to air) of 2 md.

Isopach Mapping: Isopach mapping of the Wewoka N.W. Booch unit is complicated because open hole porosity logging tools were not available when the majority of the wells were drilled. Net sand for those wells had to be interpreted from the shape of the SP curve: a U-shaped curve indicates permeability—and, therefore, effective porosity; a V-shaped curve indicates less permeability—with or without porosity. Available modern porosity logs were compared to their associated SP curves to establish a standard for inter-

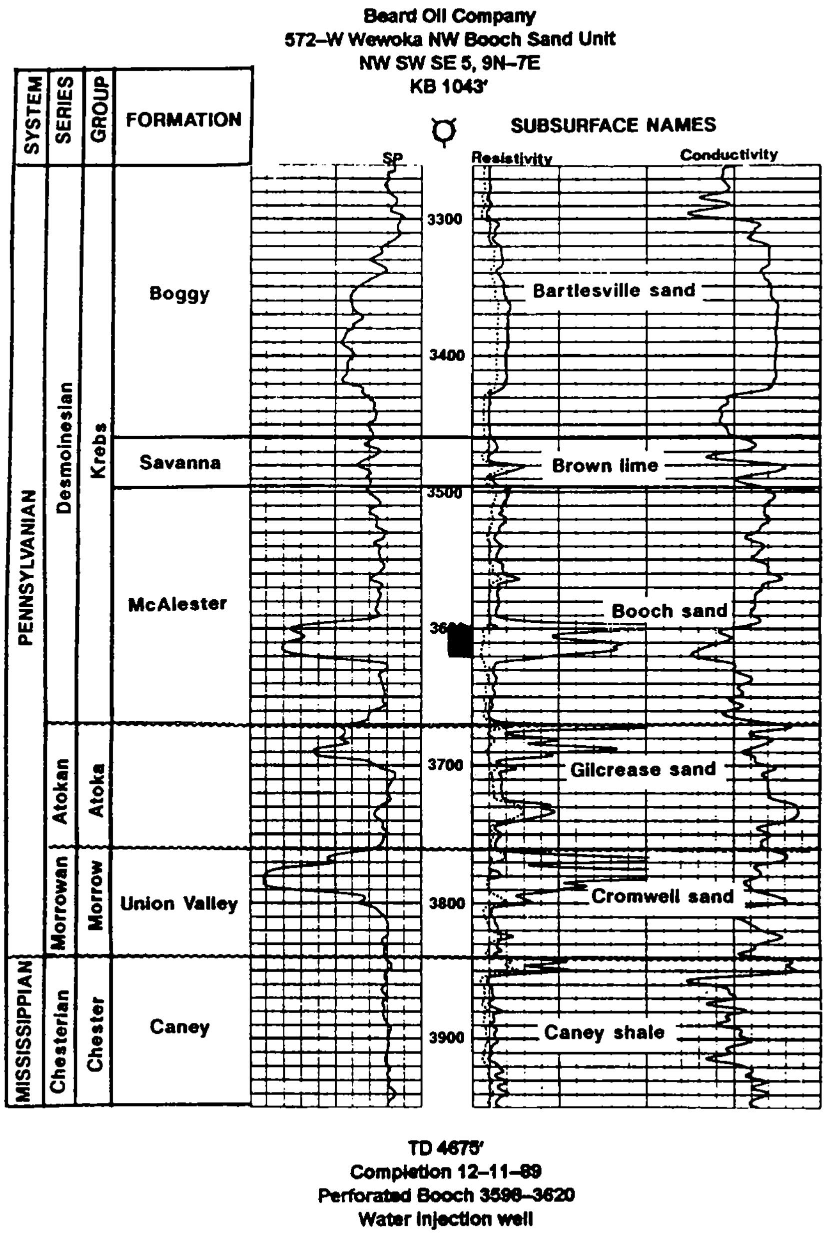


Figure 32. Type log for the Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma, showing log patterns of spontaneous potential (SP), resistivity, and conductivity measurements. Perforated interval (■) is shown.

preting the older logs. Then all of the older SP curves could be interpreted by comparing them to that standard. The gross sand isopach map (Fig. 36) incorporates such interpretations. In many cases, where the SP curve indicates permeability—and, therefore, porosity—the thickness of the gross sand and the net sand are approximately the same.

Booch Sand Gross Isopach: The Booch sand is found in almost every well within the Wewoka N.W. Booch unit. The map of the gross sand isopach, which was interpreted in 1989, is shown in Figure 36. This interpretation did not recognize the sand geometries of the three layers described in the following sections. The general trend of the sand on the gross isopach map is north–northeast to south–southwest. Within this sand trend, the gross thickness for the Booch interval is ~30 ft. The Booch sand is bounded on the west by shale. At the eastern boundary of the Wewoka N.W. Booch unit, there is a facies change from clean, porous, permeable sand to tight, shaly, silty sandstone and/or siltstone with little or no permeability. (A tight sand in this unit has its interstices filled with matrix material, effectively destroying porosity and permeability.) The No. 9-A King core well was drilled close to the eastern boundary of the Wewoka N.W. Booch unit, and its core analysis results reflect the characteristics of the boundary facies (Table 4). The sandstone and siltstone facies grade into shale in the eastern half of secs. 4 and 9, T. 9 N., R. 7 E. The characteristic electric log signatures for the Booch sand indicate fluvial depositional processes (Fig. 32). Almost all of the logs for wells in the channel have blocky SP signatures with sharp basal contacts. The SP and gamma ray curves for most of the wells indicate a gradual fining-upward texture. Such data may indicate that the Booch, within this reservoir, was deposited during a single depositional episode.

Booch Sand Porosity Isopach: The lack of porosity logs from the original wells impeded preparation of the porosity maps. However, the second phase of redrilling in the late 1980s and the drilling of a number of wells in the immediate vicinity provided a fair representation of porosity logs, sufficient to describe the porosity trends for the reservoir. Figure 37 is the porosity isopach for the Wewoka N.W. Booch unit. The porosity cutoff is 10%. The porosities within the channel range from 10% to 23%. The lease production from the field confirms that the highest porosity and permeability trends reflect the channel geometries of the reservoir: wells on the flanks of the channel have markedly poorer reservoir characteristics and correspondingly lower primary production than wells close to the center of the channel.

Lower Layer Isopach: Cross sections A–A′ and B–B′ indicate three layers that may be common within the Wewoka N.W. Booch unit (Figs. 31,33, in envelope). Each layer is essentially uniform in thickness; upper

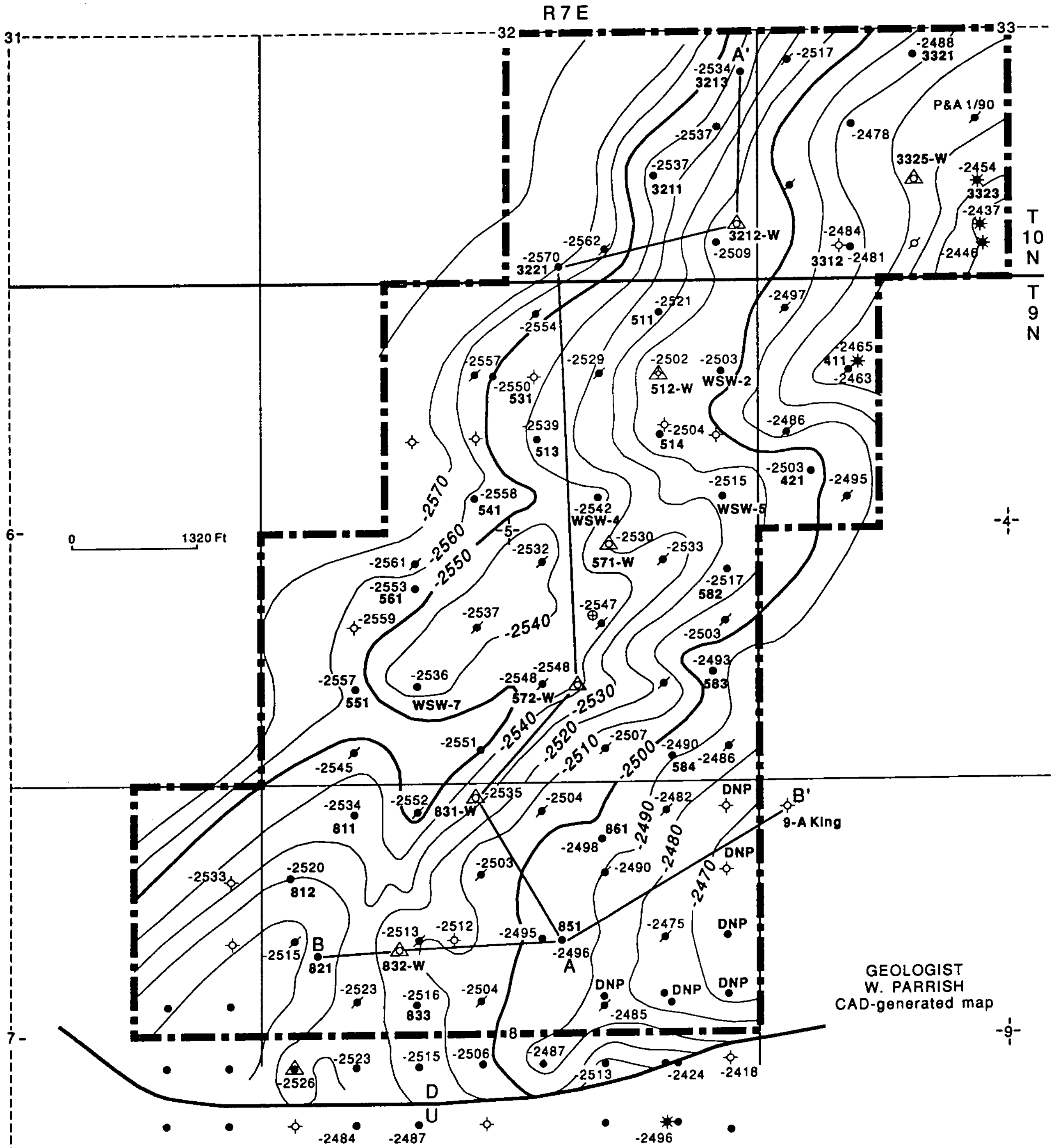


Figure 34. Structure map of the top of the Booch sand in the Wewoka N.W. Booch unit area, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Contour interval = 10 ft. Unless well data are shown, they were not available because no well log could be found, or because the well was not deep enough. Locations of stratigraphic cross sections A–A′ and B–B′ are shown. See Figure 30 for explanation of map symbols.

TABLE 2. – Oil Production Statistics for the Wewoka N.W. Booch Sand Unit, Seminole County, Oklahoma

Year	Number of Oil Wells	Annual Oil Production (Barrels)	Average Monthly Oil Production (Barrels)	Average Daily Oil Production Per Well (BOPD)	Cumulative Oil Production (Barrels)	Year	Number of Oil Wells	Annual Oil Production (Barrels)	Average Monthly Oil Production (Barrels)	Average Daily Oil Production Per Well (BOPD)	Cumulative Oil Production (Barrels)
1944	2	11,366	3,789	63	11,366	1970	23	10,478	873	1	2,445,365
1945	31	305,739	25,478	27	317,105	1971	23	12,540	1045	2	2,457,905
1946	54	728,361	60,697	37	1,045,466	1972	23	10,612	884	1	2,468,517
1947	56	559,021	46,585	28	1,604,487	1973	23	9,935	828	1	2,478,452
1948	56	126,315	10,526	6	1,730,802	1974	23	7,408	617	1	2,485,860
1949	56	145,843	12,154	7	1,876,645	1975	22	7,484	624	1	2,493,344
1950	53	113,600	9,467	6	1,990,245	1976	21	5,257	438	1	2,498,601
1951	52	68,335	5,695	4	2,058,580	1977	18	4,237	353	1	2,502,838
1952	52	51,787	4,316	3	2,110,367	1978	18	4,647	387	1	2,507,485
1953	52	45,032	3,753	2	2,155,399	1979	18	3,128	261	0	2,510,613
1954	52	41,553	3,463	2	2,196,952	1980	18	2,564	214	0	2,513,177
1955	48	30,460	2,538	2	2,227,412	1981	18	1,545	129	0	2,514,722
1956	48	23,537	1,961	1	2,250,949	1982	18	545	45	0	2,515,267
1957	48	19,390	1,616	1	2,270,339	1983	18	528	44	0	2,515,795
1958	46	18,669	1,556	1	2,289,008	1984	3	152	13	0	2,515,947
1959	33	14,553	1,213	1	2,303,561	1985	0	0	0	0	2,515,947
1960	31	13,952	1,163	1	2,317,513	1986	0	0	0	0	2,515,947
1961	29	14,398	1,200	1	2,331,911	1987	0	0	0	0	2,515,947
1962	29	13,468	1,122	1	2,345,379	1988	0	0	0	0	2,515,947
1963	27	12,319	1,027	1	2,357,698	1989*	8/4**	0	0	0	2,515,947
1964	27	12,567	1,047	1	2,370,265	1990	17/7**	2,712	226	0.4	2,518,659
1965	26	13,201	1,100	1	2,383,466	1991	3/7**	1,998	167	2	2,520,657
1966	26	14,187	1,182	2	2,397,653	1992	4/4**	14,969	1247	10	2,535,626
1967	23	12,854	1,071	2	2,410,507	1993	1/2**	3,240	270	9	2,538,866
1968	23	12,815	1,068	2	2,423,322	1994		1,056	88	0	2,539,922
1969	23	11,565	964	1	2,434,887	1995			0	0	2,539,922

*Wewoka N.W. area unitized into N.W. Wewoka Booch Sand Unit.

**Denotes number of injectors.

NOTE: The average daily oil production per well was calculated by dividing the average monthly production by 30 days and the number of active wells.

and lower boundaries are characterized by marked changes in porosity or sandstone texture. These boundaries occur in almost every well. The isopach map for the lower layer suggests two distinct north–south channels separated by an area of less permeable silty sandstone or siltstone (Fig. 38). The sand is bounded on the east and west by shales (see section, above, on the gross sand isopach). The western channel splits into two channels, which suggests an anastomosing stream pattern. The thickness of the lower layer commonly is ~10 ft, but it approaches 13–15 ft locally. In cross section A–A′ (Fig. 31, in envelope), the Beard Oil Company Nos. 3213, 3221, 572-W (type well), and 851 (tie well) all contain a well-developed lower sandstone (Fig. 31, in envelope). These four wells appear to be in the same channel, as shown on the gross sand isopach map (Fig. 36). The No. 3212-W and the No. 831-W contain shaly siltstone in the lower layer. In cross section B–B′ (Fig. 33, in envelope), the log character of the lower layer appears to be similar in Nos. 821, 832-W, and 851 (tie well). The lower layer in these wells appears to be in lateral continuity, especially as interpreted from the gross sand isopach map (Fig. 36). However, the lower layer isopach map (Fig. 38) suggests the presence of an impermeable facies between the Nos. 832-W and 851 (tie well). The importance of this apparent barrier will be discussed in the section on secondary recovery.

Middle Layer Isopach: Channel geometry increases in complexity on the middle layer isopach map (Fig. 39). The pattern suggests an anastomosing stream system oriented northeast–southwest. Shale and impermeable sandstone deposits separate the porous sandstone channels. The layer is ~10 ft thick, but locally its thickness exceeds 12 ft. On the gross sand isopach map (Fig. 36), it appears that this interval of the Booch sand should be in lateral continuity between all wells. The middle layer isopach map (Fig. 39), however, suggests that areas of impermeable strata may prevent continuity. On the northern end of cross section A–A′ (Fig. 31, in envelope), the middle layer in well No. 3213 correlates to the middle layer of well No. 3212-W. The middle layer isopach map (Fig. 39), however, suggests that these two wells are in separate channels that are divided by siltstone of low permeability. On cross section B–B′ (Fig. 33, in envelope), the Nos. 832-W and 851

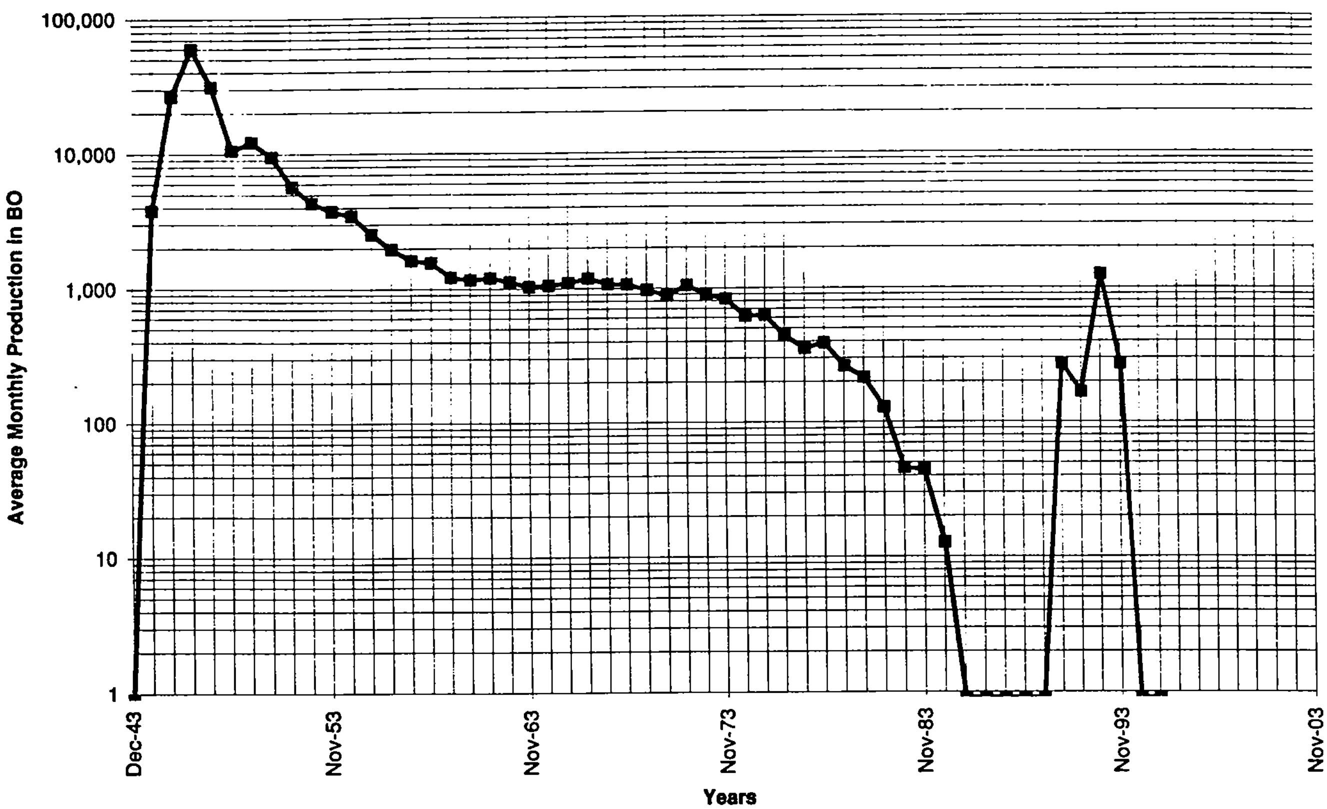


Figure 35. Oil production decline curve for the Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Approximately 240,000 BO of Gilcrease production are included in the curve.

(tie well) correlate. The middle layer isopach map (Fig. 39), however, suggests that there is a barrier of low permeability siltstone between the two wells. The importance of these apparent barriers will be discussed in the section on secondary recovery.

Upper Layer Isopach: The upper layer isopach map (Fig. 40) shows a marked decrease in sandstone. The character of this layer on most electric logs suggests a gradual fining-upward texture. Where sandstone occurs, the upper layer is ~10 ft thick, but the layer may be compacted to a thickness of 7–8 ft where it contains shale. The orientation of the channel geometry is northeast–southwest. The upper layer isopach map (Fig. 40) indicates that most of the wells that contain reservoir-quality sandstone within the upper layer are in the same channel system.

Secondary Recovery: In October 1989, Beard Oil Company formed the Wewoka N.W. Booch Sand Unit. The injection pattern was established as a center-line drive with seven north-to-south injection wells in the middle of the unit and a total of 24 producers (27 potential producers) on either side of this line of injectors (Fig. 36). By December 1990, the unit had a net injection of 1,901,974 barrels of water and a cumulative oil production of 2,712 BO. The average injection rate for each injector was ~1,000 barrels of water per day. All of the producers on the western side produced water and essentially no oil. Only two wells, the Nos. 851 and 861, produced most of the oil (Fig. 36).

By December 1991, the unit had a net injection of 2,618,929 barrels of water and a cumulative oil production of 4,710 BO. The unit had seven active injection wells, each with an average injection rate of 1,100 barrels of water per day. The three remaining active producers, Nos. 421, 851, and 861, were given a small sand fracture treatment in December 1991. The result was an immediate increase in production, from 16 to 41 BOPD. One well, the No. 851, was responsible for almost all of this increased production.

On February 12, 1992, Beard Oil Company introduced chemical tracers into three injectors in the southern part of the unit: polyacrylate into well No. 572-W; organophosphonate into well No. 831-W; and sodium nitrite into well No. 832-W (Fig. 41). Before the tracers were introduced into the injectors, water samples from the producers were analyzed to measure a background base level for the occurrence of any of the tracer chemicals. After introduction of the tracers into the injectors, daily water analysis was run on the producing well No. 851. On February 22, 1992, tracers were introduced into injectors in the northern part of the unit: polyacrylate into well No. 3212-W; organophosphonate into well No. 512-W; and sodium nitrite into well No. 571-W. A background check was done before

TABLE 3. – Core Analysis Results, Beard Oil Company No. 831-W (NE¼NE¼NW¼ sec. 8, T. 9 N., R. 7 E.), Wewoka N.W. Booch Sand Unit, Seminole County, Oklahoma

Sample Number	Depth ft	Permeability (Maximum) Kair md	Permeability (90°) Kair md	Permeability (Vertical) Kair md	Porosity (Helium) %	Saturation (Pore Volume) Oil %	Saturation (Pore Volume) Water %	Grain Density gm/cc
1*	3578.0-79.0		8.00		10.70	16.80	45.70	2.71
2*	3579.0-80.0		29.00		14.90	14.10	47.70	2.70
3*	3580.0-81.0		30.00		16.20	19.20	64.20	2.68
4*	3581.0-82.0		29.00		16.50	23.10	48.40	2.68
5*	3582.0-83.0		57.00		16.90	17.90	55.00	2.68
6*	3583.0-84.0		35.00		17.40	21.90	53.50	2.68
7*	3584.0-85.0		18.00		15.30	26.60	47.80	2.67
8*	3585.0-86.0		15.00		16.10	35.40	49.50	2.67
9	3586.0-87.0	3.70	3.20	0.41	13.80	14.50	76.10	2.68
10*	3587.0-88.0		4.70		15.00	19.50	55.90	2.67
11	3588.0-89.0	7.90	7.60	0.94	13.80	13.00	66.40	2.67
12	3589.0-90.0	16.00	16.00	7.40	17.20	19.50	55.50	2.69
13*	3590.0-91.0		14.00		17.80	18.10	57.50	2.69
14*	3591.0-92.0		53.00		18.00	19.00	49.30	2.67
15	3592.0-93.0	10.80	9.20	3.80	14.90	28.90	47.20	2.69
16	3593.0-94.0	21.00	20.00	13.00	15.70	24.90	47.20	2.70
17	3594.0-95.0	26.00	24.00	20.00	16.90	32.80	56.70	2.68
18*	3595.0-96.0		5.50		14.40	29.50	58.70	2.68
19	3596.0-97.0	4.60	2.40	0.03	11.30	27.60	59.50	2.68

*Denotes plug analysis.

introduction of the tracers; after introduction, a daily water analysis was run on each of the following producers: Nos. 3211, 3213, 3221, 3321, 3323, 411, 421, and 851. Figure 41 illustrates the results of this first tracer survey.

The results of the tracer survey raised several important questions. The Nos. 411 and 421 producers did not respond to injection. Lateral continuity within the reservoir was assumed, as interpreted on the gross isopach map (Fig. 36). Did this lack of response indicate that the flow was impeded by the low permeability strata interpreted on the lower and middle layer isopach maps (Figs. 38,39), or was it possible that an oil front was moving through the low permeability strata toward these two producers?

There also was a question about the source of the oil for the Nos. 851 and 3213 producers (Fig. 36). At the time of the tracer survey, the No. 851 was producing ~40 BOPD and 2–3 barrels of water, and the No. 3213 was producing about 2–3 BO per day and ~20 barrels of water. The No. 3213 appeared to respond to the No. 3212-W injector four days after introduction of the tracer into the injector (Fig. 41). The gross sand isopach map (Fig. 36) suggests that the wells are in lateral continuity, but the lower and middle layer isopach maps (Figs. 38,39) suggest that there is a barrier of low permeability strata between the No. 3212-W injector and the No. 3213 producer. The No. 851 producer responded to the Nos. 831-W and 572-W injectors almost immediately after introduction of tracers and responded very weakly to the tracer from the No. 832-W (Fig. 41). The lower layer and middle layer isopach maps (Figs. 38,39) suggest that there also is an area of low permeability strata between the No. 832-W injector and the No. 851 producer. The No. 9-A King cored a section of low permeability strata comparable to the areas of the low permeability between the No. 3212-W injector and the No. 3213 producer and between the No. 832-W injector and the No. 851 producer (see discussion in the section on the gross sand isopach). Oil saturations for the No. 9-A King, where measured, range from 7.3% to 14.8% (Table 4). Thus, the area of low permeability strata was considered a possible source of oil for the Nos. 851 and 3213 producers. Such

TABLE 4. – Core Analysis Results, Geoex Resources, Inc., No. 9-A King (NW¼NW¼NW¼ sec. 9, T. 9 N., R. 7 E.), Wewoka N.W. Booch Sand Unit, Seminole County, Oklahoma

Sample Number	Depth ft	Permeability (Horizontal) Kair md	Permeability Klinkenberg (Equiv- Liq) md	Porosity (Helium) %	Saturation (Pore Volume) Oil %	Water %	Grain Density gm/cc
1	3520.5- 21.0	0.9	0.63	13.1	7.4	63.7	2.68
2	3521.0- 22.0	4.3	3.63	13.3	10.7	54.2	2.69
3	3522.0- 23.0	3.07	2.49	12.7	7.3	63.1	2.69
4	3523.0- 24.0	3.78	3.14	13.8	13	58	2.71
5	3524.0- 25.0	4.51	3.79	13.3	13.4	54.7	2.69
6	3525.0- 26.0	4.05	3.46	13.3	14.8	58.6	2.7
7	3526.0- 27.0	0.05	0.02	9.7	0	84	2.68
	3527.0- 28.0	Shaly sand					
8	3528.0- 29.0	0.22	0.12	10.7	0	83.8	2.68
9	3529.0- 30.0	0.39	0.27	11	12.2	62.4	2.69
10	3530.0- 31.0	0.29	0.18	11.1	14.2	58.8	2.7
11	3531.0- 32.0	0.42	0.27	12.1	11.6	65.7	2.68

questions about reservoir continuity and oil source need to be addressed by an operator considering implementation or modification of an injection pattern for a unit.

A second tracer survey (Fig. 42) was designed to answer the questions raised by the first survey. On March 14, 1992, three injectors were treated with chemical tracers: the No. 572-W (sodium nitrite); the No. 512-W (polyacrylate); and the No. 571-W (organophosphonate). A background check was done for the tracers, and daily water samples were taken from the Nos. 3213, 411, 421, and 851 producers. The results of the second tracer survey show that the northernmost producer, the No. 3213, and the southernmost producer, the No. 851, responded within two days after injection to all three injectors, which were located in the center of the field. The lower sand isopach map (Fig. 38) indicates that these two producers and three injectors are connected by the same lower sandstone channel, which has high porosity and permeability.

A number of conclusions were reached, based on the results of both tracer surveys (Figs. 41,42). Injected water was confined primarily to the high porosity and permeability channels interpreted on the lower and middle layer isopach maps (Figs. 38,39). The oil from the No. 3213 producer probably was influenced by the Nos. 512-W, 571-W, and 572-W injectors and not by the No. 3212-W injector, as assumed after the first survey. The oil from the No. 851 producer was driven by injection from the Nos. 571-W and 572-W injectors and not from the No. 832-W injector. The polyacrylate recovered in the No. 3213 after February 22 probably came from the earlier introduction of this tracer on February 12 into the No. 572-W injector. It also was concluded that the area of low permeability strata was not the primary source of oil for the Nos. 851 and 3213 producers. In addition, the lack of response from the Nos. 411 and 421 producers indicated that the low permeability strata between them and the injectors acted as a temporary barrier; however, these low permeability strata eventually would be swept of oil.

In August 1993, the Wewoka N.W. Booch Sand Unit was sold for salvage. The unit had a net injection of 3,190,306 barrels of water and a cumulative oil production of 22,919 BO.

Conclusion: The tracer surveys showed that the reservoir in the Wewoka N.W. Booch unit did not behave as a homogeneous sand body. The gross sand isopach map (Fig. 36) did not predict a successful injection pattern. The three layers in the Booch interval are stacked, but vertical permeability may be affected by the layer boundaries. Flow from water injection seems to be confined to the high permeability channels within the layers, where the sandstone porosity and permeability parameters of the layers are markedly different. Where these parameters are similar, cross flow probably occurs. Where there is apparent layering in a reservoir, as in the Wewoka N.W. Booch unit, every effort should be made to determine individual layer trends through correlation and isopach mapping of each layer in order to design a successful injection pattern.

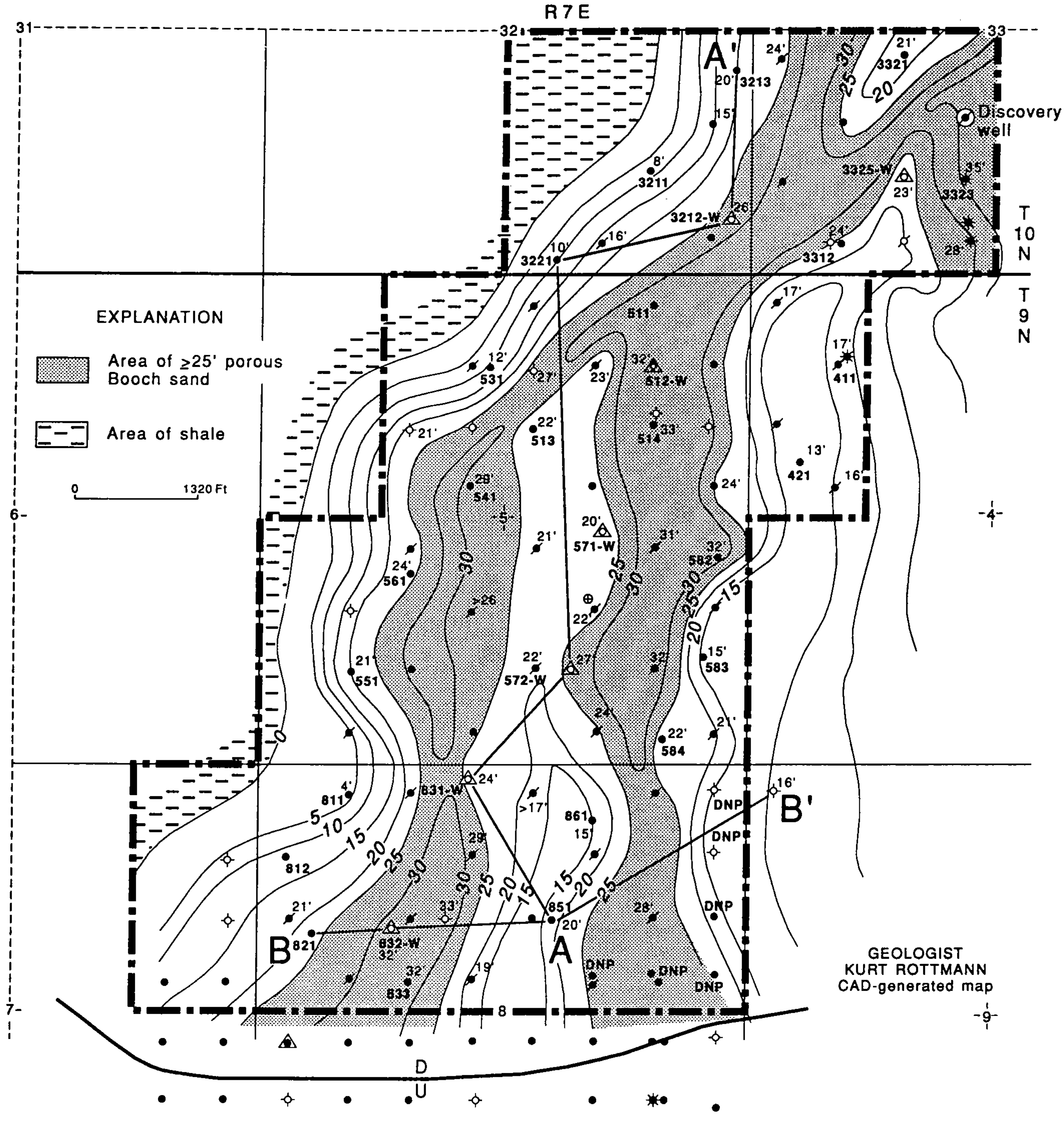


Figure 36. Isopach map of the gross Booch sand in the Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Contour interval = 5 ft. Unless well data are shown, they were not available because no well log could be found, or because the well was not deep enough. The 1989 interpretation represented on this gross sand isopach map does not recognize the sand geometries of the three layers interpreted in Figures 38, 39, and 40. Locations of stratigraphic cross sections A–A′ and B–B′ are shown. See Figure 30 for well numbers and explanation of map symbols.

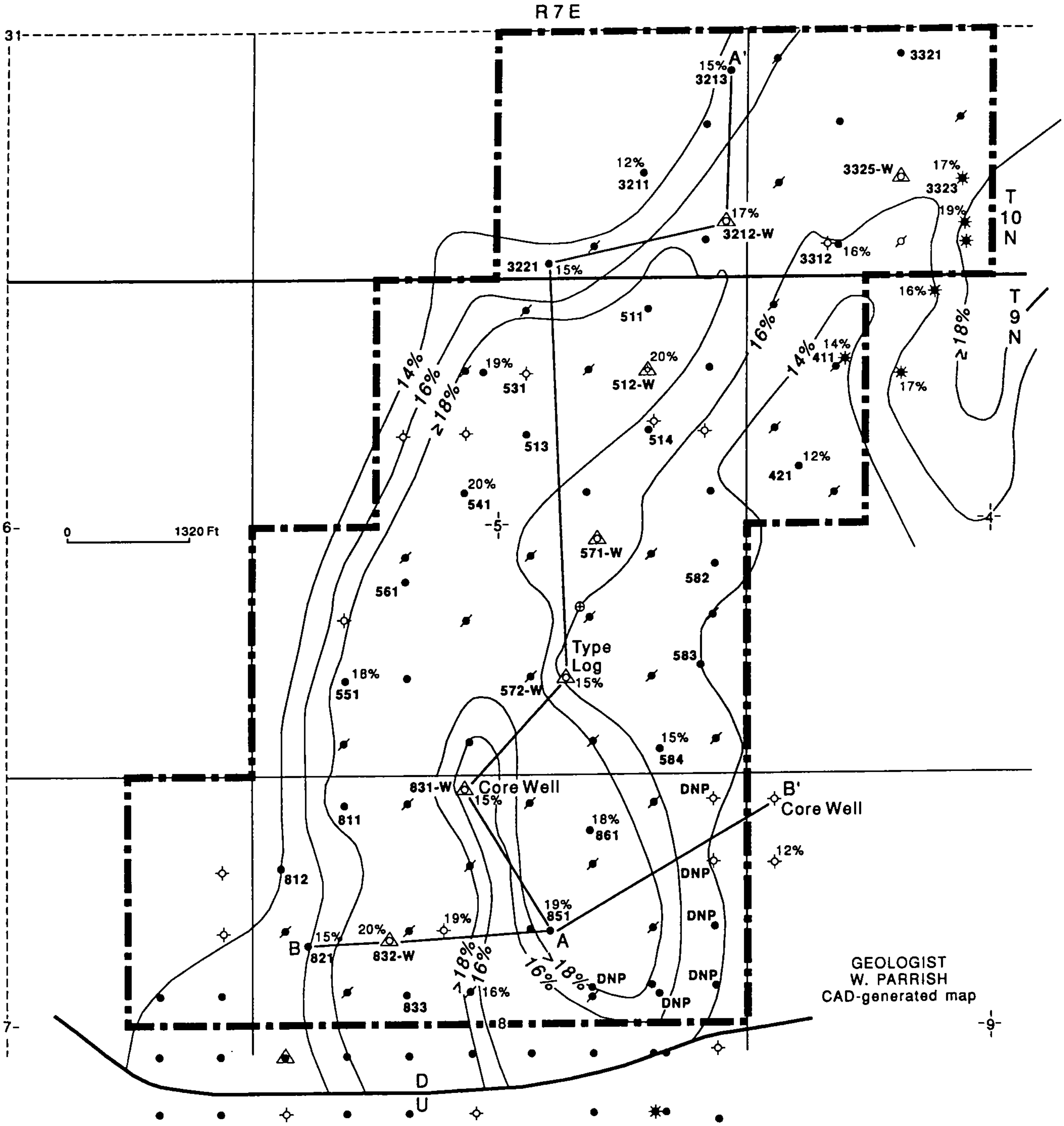


Figure 37. Porosity isopach map of the Booch sand in the Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Contour interval = 2% porosity increments. Unless well data are shown, they were not available because no well log could be found, or because the well was not deep enough. Locations of stratigraphic cross sections A–A′ and B–B′ are shown. See Figure 30 for well numbers and explanation of map symbols.

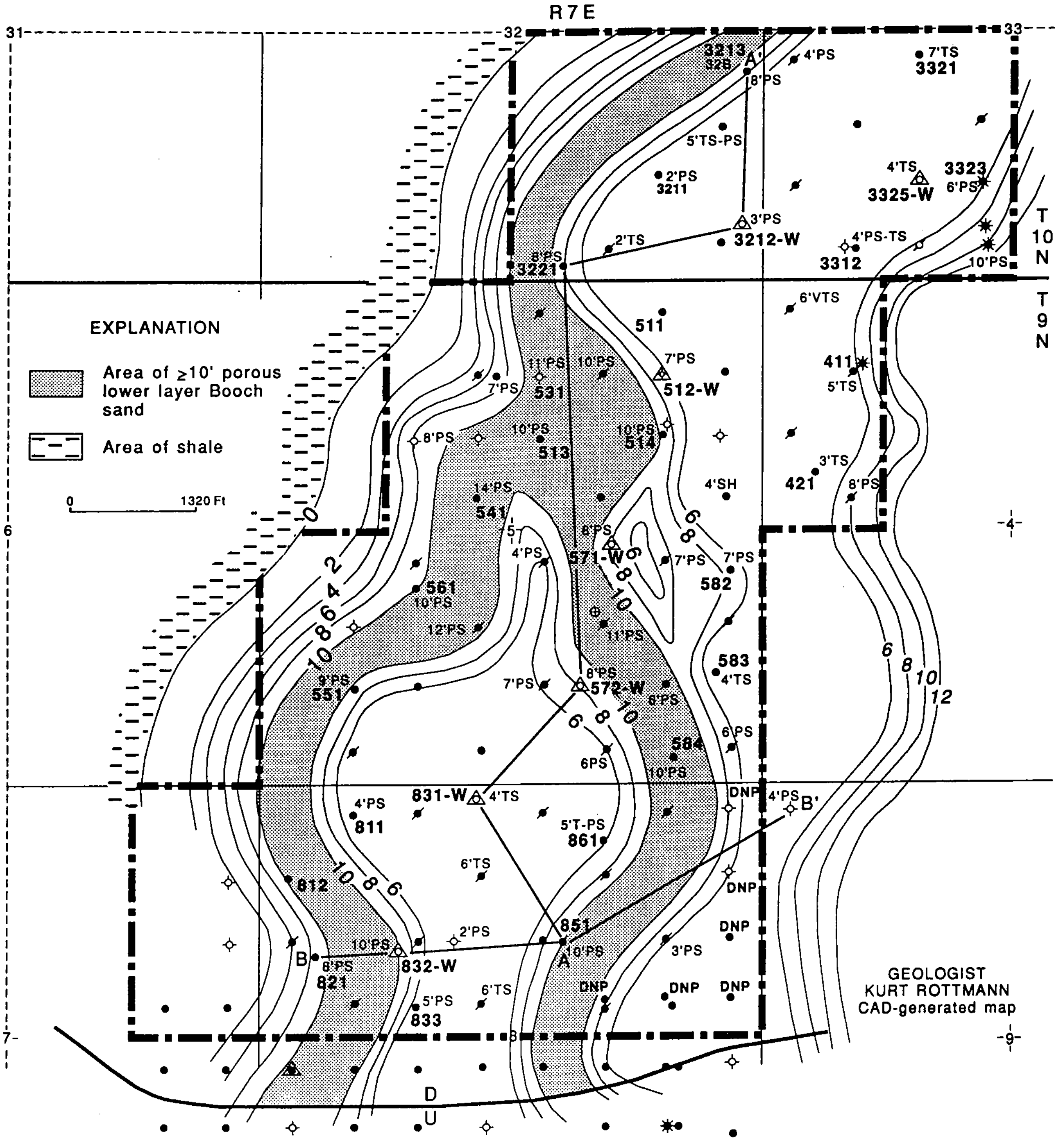


Figure 38. Isopach of the porous sand of the lower layer of the Booch in the Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Contour interval = 2 ft. Unless well data are shown, they were not available because no well log could be found, or because the well was not deep enough. Individual layer data require an interpretation of sand trends different from the interpretation on the gross sand isopach map (Fig. 36). Locations of stratigraphic cross sections A–A′ and B–B′ are shown. See Figure 30 for well numbers and explanation of map symbols.

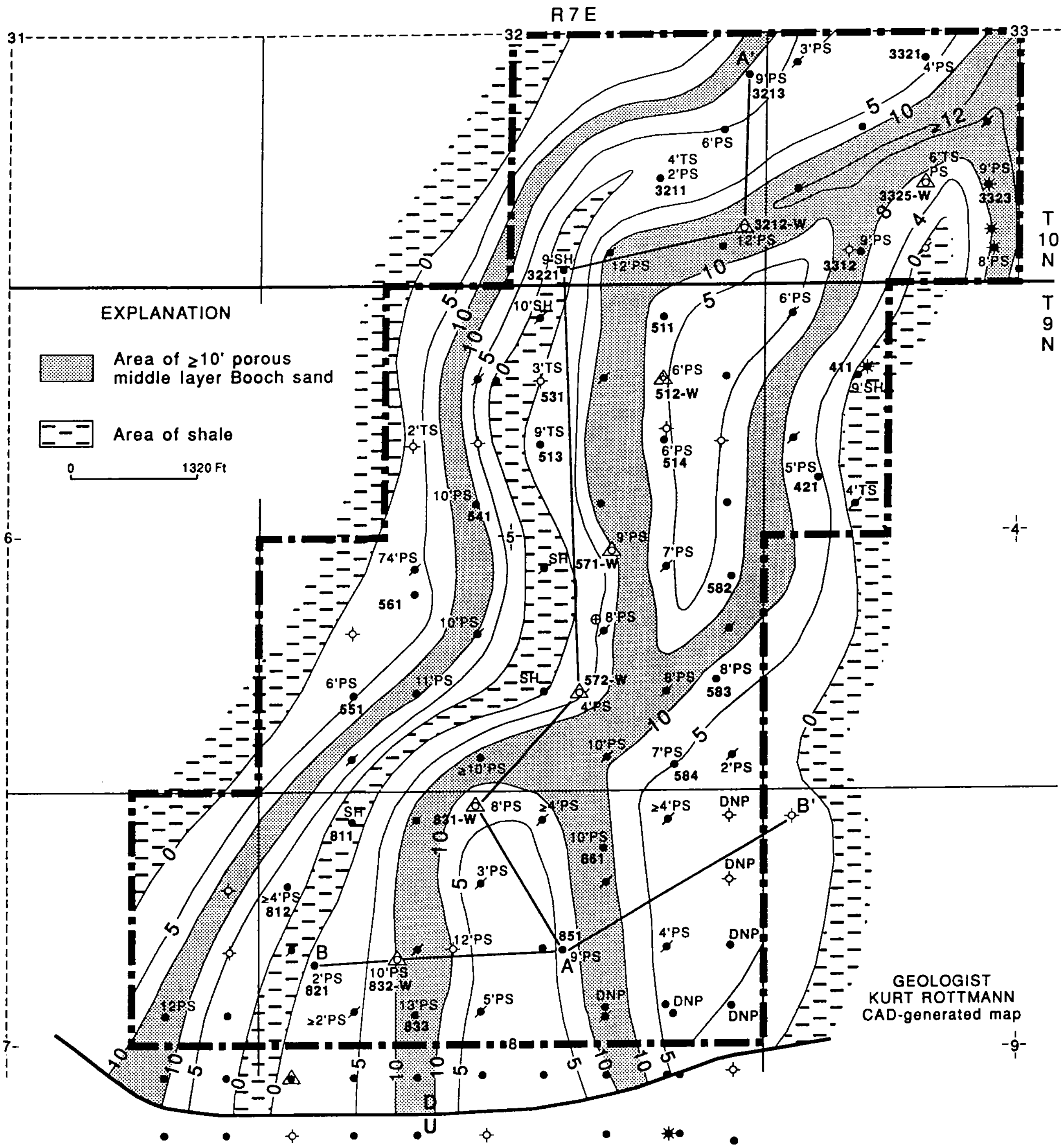


Figure 39. Isopach of the porous sand of the middle layer of the Booch in the Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Contour interval = 5 ft. Unless well data are shown, they were not available because no well log could be found, or because the well was not deep enough. Individual layer data require an interpretation of sand trends different from the interpretation on the gross sand isopach map (Fig. 36). Locations of stratigraphic cross sections A–A′ and B–B′ are shown. See Figure 30 for well numbers and explanation of map symbols.

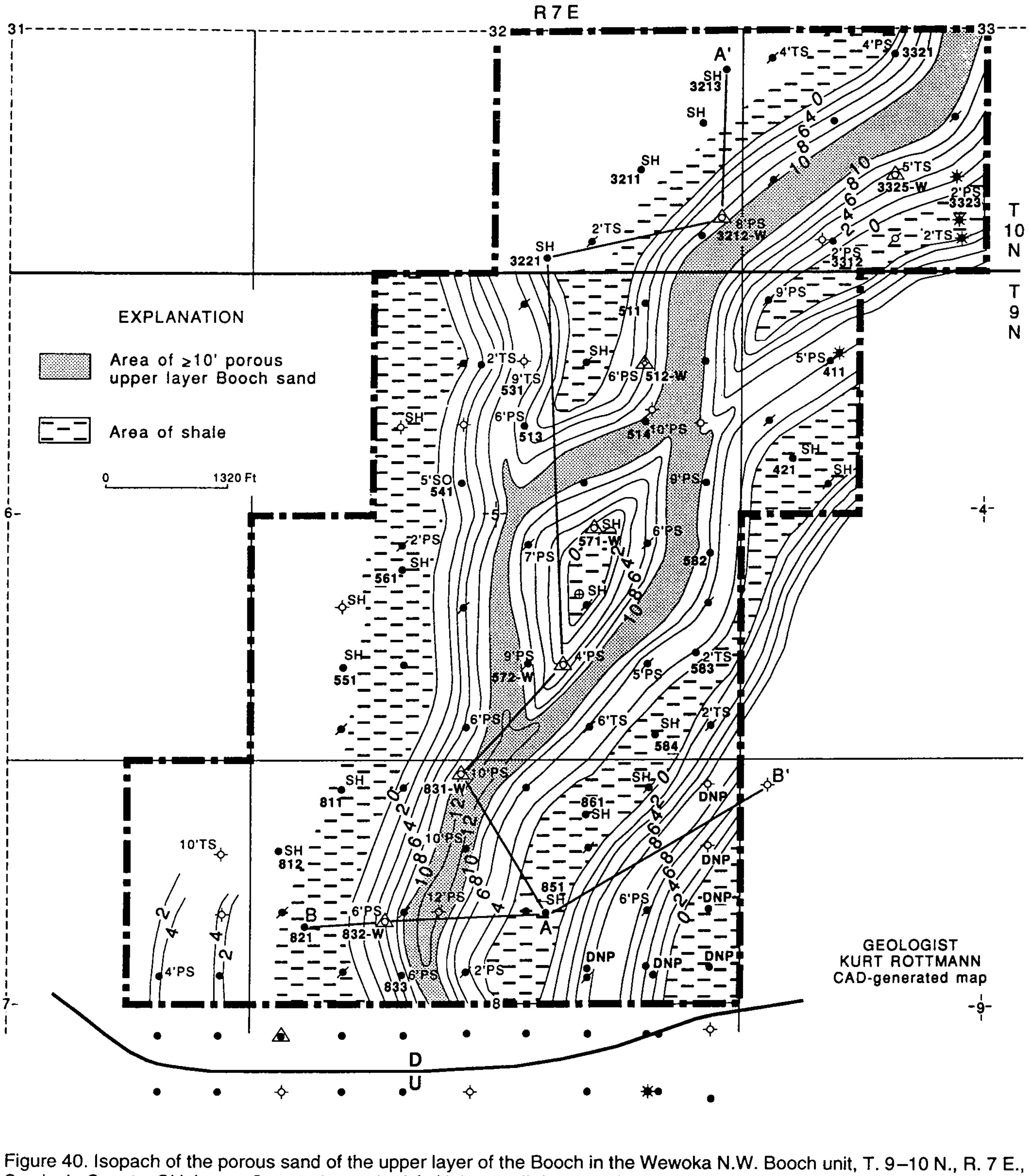


Figure 40. Isopach of the porous sand of the upper layer of the Booch in the Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Contour interval = 2 ft. Unless well data are shown, they were not available because no well log could be found, or because the well was not deep enough. Individual layer data require an interpretation of sand trends different from the interpretation on the gross sand isopach map (Fig. 36). Locations of stratigraphic cross sections A–A′ and B–B′ are shown. See Figure 30 for well numbers and explanation of map symbols.

Figure 42

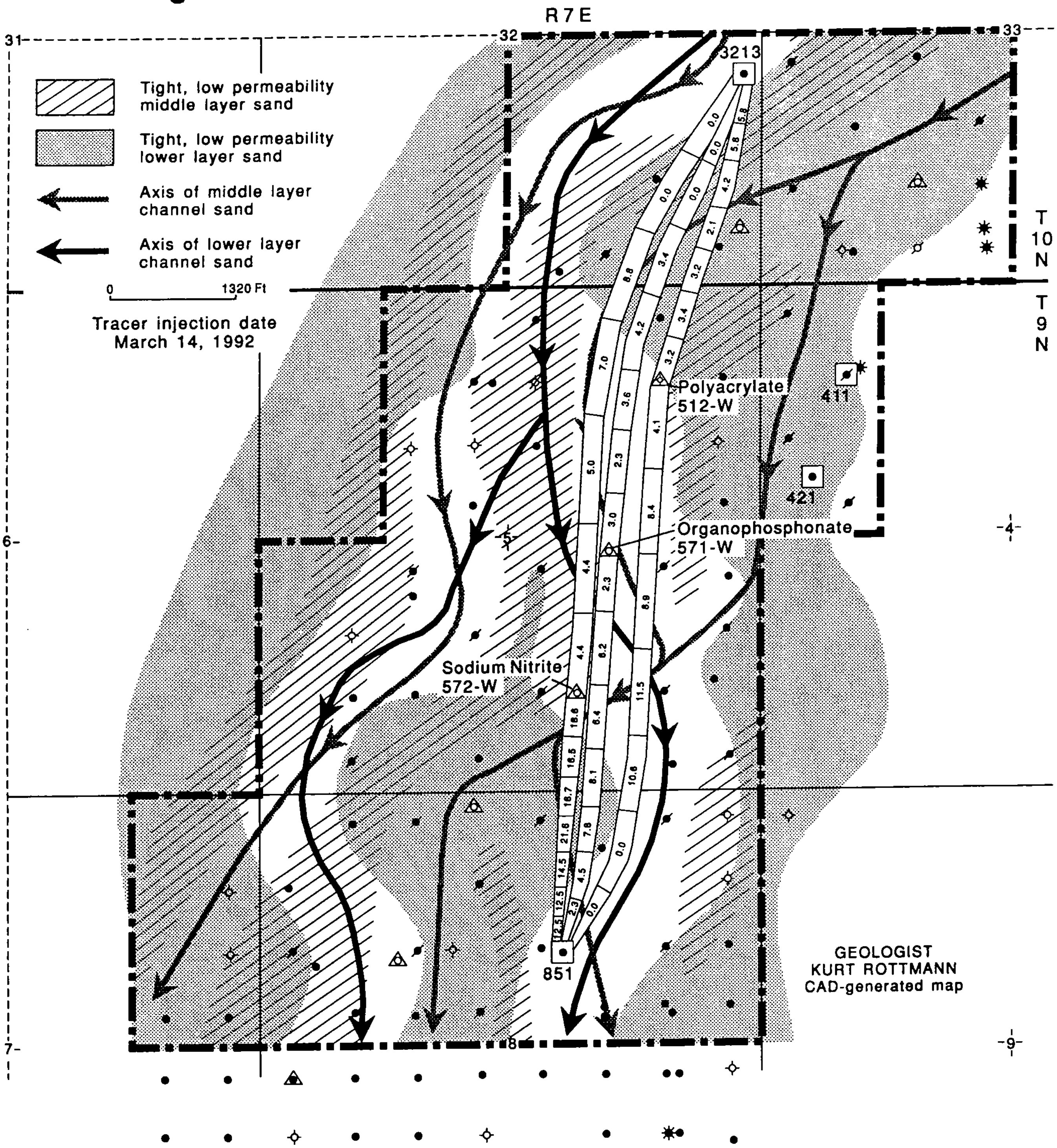
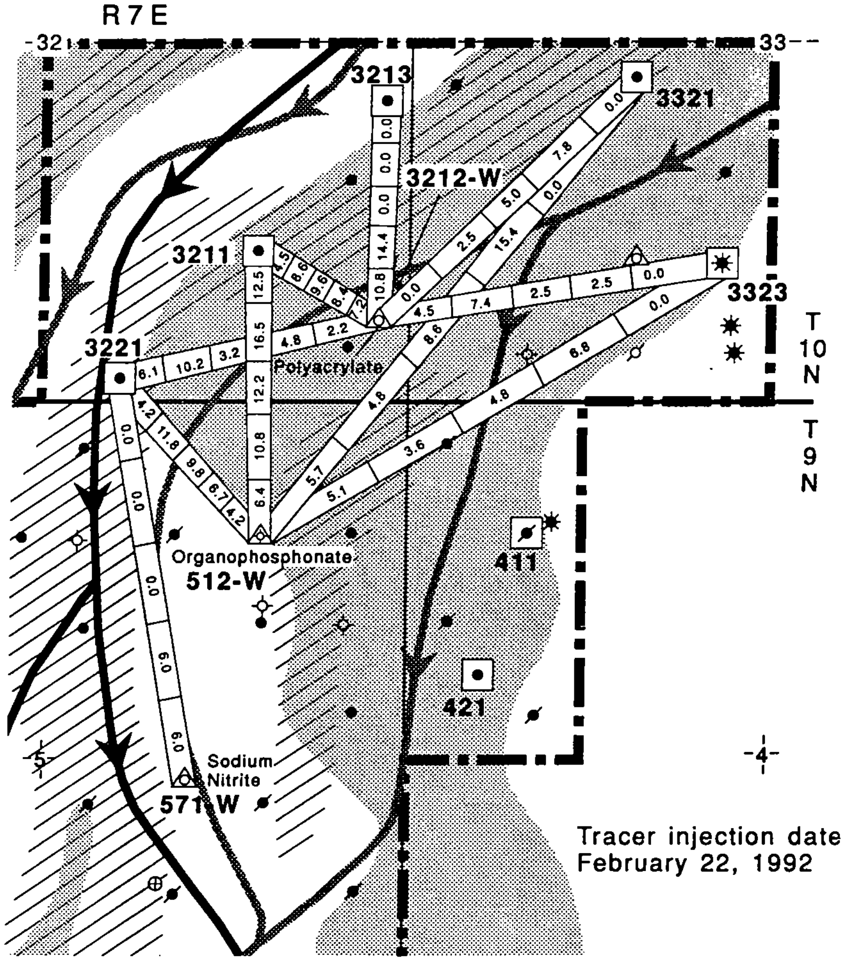


Figure 41. Results of the first chemical tracer survey, Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Chemical tracers were introduced into marked (△) injectors Nos. 572-W, 831-W, and 832-W on February 12, 1992, and into injectors 3212-W, 512-W, and 571-W on February 22, 1992. Daily water samples were collected from marked (□) producer(s) No. 851 (February 12 survey) and Nos. 3211, 3213, 3221, 3321, 3323, 411, 421, and 851 (February 22 survey). The divisions on the connections drawn between the injection wells and the producers represent 24-hr increments; in each case, Day One is adjacent to the producer and subsequent days proceed toward the injector. The amounts, measured in parts per million, of tracer chemicals in daily water samples are recorded for each day of the survey. The No. 411 and the No. 421 did not respond to the tracer survey.

Figure 41

Figure 42. Results of the second chemical tracer survey, Wewoka N.W. Booch unit, T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Chemical tracers were introduced into marked (△) injectors Nos. 512-W, 571-W, and 572-W on March 14, 1992. Daily water samples were collected from marked (□) producers Nos. 3213, 411, 421, and 851. The divisions on the connections drawn between the injection wells and the producers represent 24-hr increments; in each case, Day One is adjacent to the producer and subsequent days proceed toward the injector. The amounts, measured in parts per million, of tracer chemicals in daily water samples are recorded for each day of the survey. The No. 411 and the No. 421 did not respond to the tracer survey.



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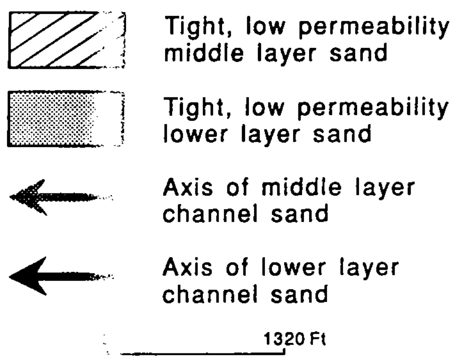

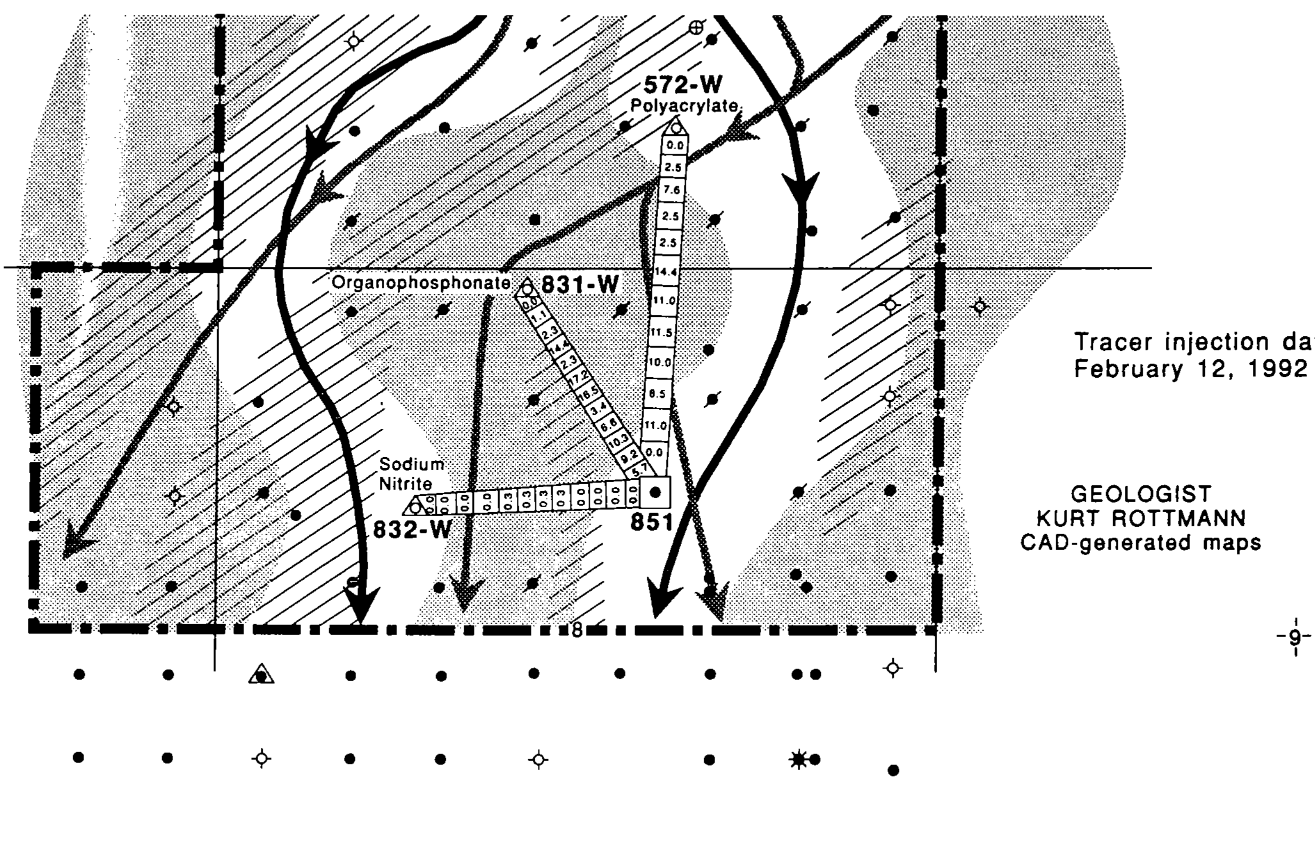

Tracer injection date February 12, 1992

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Greasy Creek Field Study

(Booch oil reservoir in sec. 4, T. 8 N., R. 11 E. and sec. 33, T. 9 N., R. 11 E., Hughes County, Oklahoma)

The Greasy Creek field, located in north-central Hughes County, Oklahoma, was discovered in 1945. Production is primarily gas from Pennsylvanian sandstones, although there are isolated instances of oil production in this large field. One of these, the Booch oil reservoir in sec. 4, T. 8 N., R. 11 E. and sec. 33, T. 9 N., R. 11 E., is the subject of this study (Fig. 43). This Booch oil reservoir was discovered in the No. 1 Hall (SE¼NE¼ sec. 4, T. 8 N., R. 11 E.) drilled by Bell Oil and Gas Company and completed on August 4, 1961. The well had an initial potential pumping of 36 BO and 96 barrels of salt water per day from perforations at 2,314–2,316 ft in the thick Booch channel sandstone. The No. 1 Hall is the southernmost producing oil well in the field; if it had been located any farther south, it would have missed the reservoir. The reservoir was not fully developed until 1971, and it is still producing marginal amounts of oil.

TABLE 5. – Geological/Engineering Data for the Booch Oil Reservoir, Greasy Creek Field, Hughes County, Oklahoma

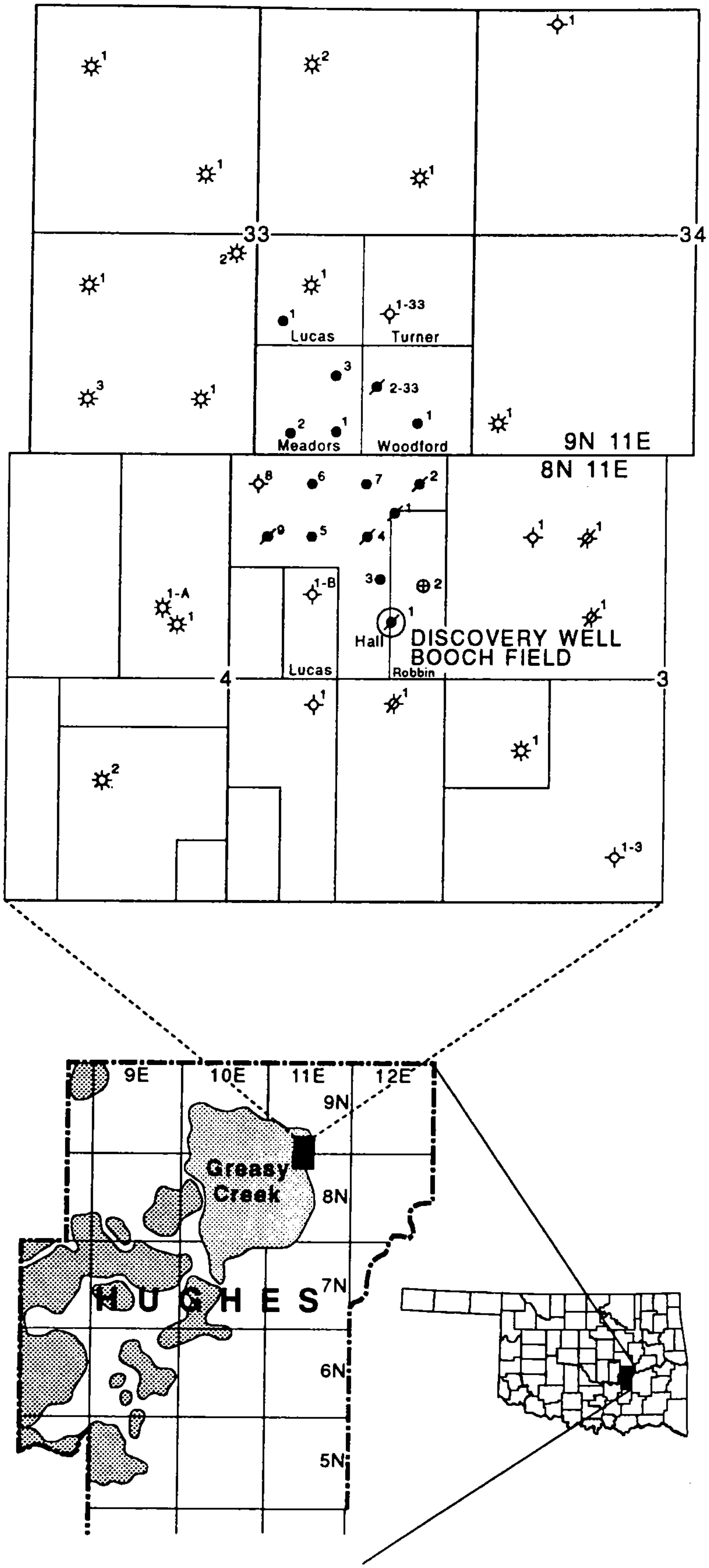
Reservoir size	140 acres
Well spacing (oil)	10 acres
Oil/water contact	~1,555 ft below mean sea level
Gas/oil contact	none
Porosity	15%[a]
Permeability	35 md[a]
Initial water saturation	45%[a]
Thickness (net sand in reservoir)	40 ft average[a]
Reservoir temperature	103° F[a]
Oil gravity	39.5° API[a]
Initial reservoir pressure	940 PSIA[a]
Initial formation-volume factor	1.157[a]
Original oil in place (volumetric)	3.2 MMSTB[a]
Cumulative primary production	692,315 BO[b]
Recovery efficiency	22%[c]
Cumulative gas	no data

[a]Source: Knapp and Yang (Part III, this volume).
[b]Cumulative production includes well data not used in reservoir simulation, Part III.
[c]Differs from reservoir simulation value because different cumulative production data were used in the two studies.

This Booch oil reservoir is in a stratigraphic trap formed in sandstones deposited in a distributary channel that is incised into the prodelta marine shales of the lower Booch. These shales encase the sandstones and provide the seals at the sides and bottom of the reservoir. The top seal is formed by the facies change from sandstone to shale in the overlying lower Booch deposits. Postdepositional faulting in the area provides both updip and downdip barriers to migration, effectively trapping the hydrocarbons in the reservoir as if they were sealed in a bottle. The surrounding marine shales provide one logical source for the hydrocarbons in this reservoir. Oil also may have migrated updip into the reservoir from the Arkoma basin before faulting sealed the reservoir. A summary of geological/engineering data for the reservoir is given in Table 5. Reservoir characteristics and development are discussed in more detail in the following sections.

Stratigraphy: The sandstone in the lower Booch (subsurface) in the Greasy Creek field area is approximately equivalent to the Warner Sandstone (surface) of the McAlester Formation (Fig. 19). The sandstones of this oil reservoir are a stacked channel sequence deposited near the distal end of a distributary channel on the lower delta plain at the hinge line of the McAlester Formation (Pl. 1). Figure 44 is a representative electric log for the reservoir. Stratigraphic cross section A–A′ (Fig. 45, in envelope) is oriented north–south along the axis of this channel. Stratigraphic cross section B–B′ (Fig. 46, in envelope) crosses the channel and shows the development of younger sandstones outside of this main distributary channel. The datum for these stratigraphic cross sections is the resistivity change in the shale that marks the top of the lower Booch.

Three main sandstone intervals are identified in the reservoir. In descending order, they are labeled layer 1, layer 2, and layer 3. Stratigraphic cross sections A–A′ and B–B′ show the relationships of these sandstone intervals (Figs. 45,46, in envelope). The sandstone of layer 3 is the thinnest and least extensive sandstone. It was deposited at the base of this channel system, and it is separated from layer 2 by a thin shale interval, 2–3 ft thick. Layer 2 sandstone is well developed and its blocky log signature is characteristic of massive channel-fill sandstones. Another thin shale interval, 2–3 ft thick, at the top of layer 2 separates it from layer 1. Layer 1 is greater in aerial extent and represents the final stage of sand deposition in this channel. Layer 1 has a fining-upward texture and appears to be point-bar deposits of a delta-plain setting. There is a gradual change in facies in layer 1, from sandstone to shale, which may represent the abandonment of this part of the channel system and its subsequent filling with interdistributary clay and mud. The younger sandstones shown in the No. 1 Lucas and the No. 1 C. H. Crawford in cross section B–B′ (Fig. 46, in envelope) were deposited in later distributary channels in the lower Booch that formed updip on the delta plain at a cutoff or branching in the main distributary channel that had deposited the sandstones of the study area oil reservoir. This cutoff or branching probably caused the abandonment of the original channel.



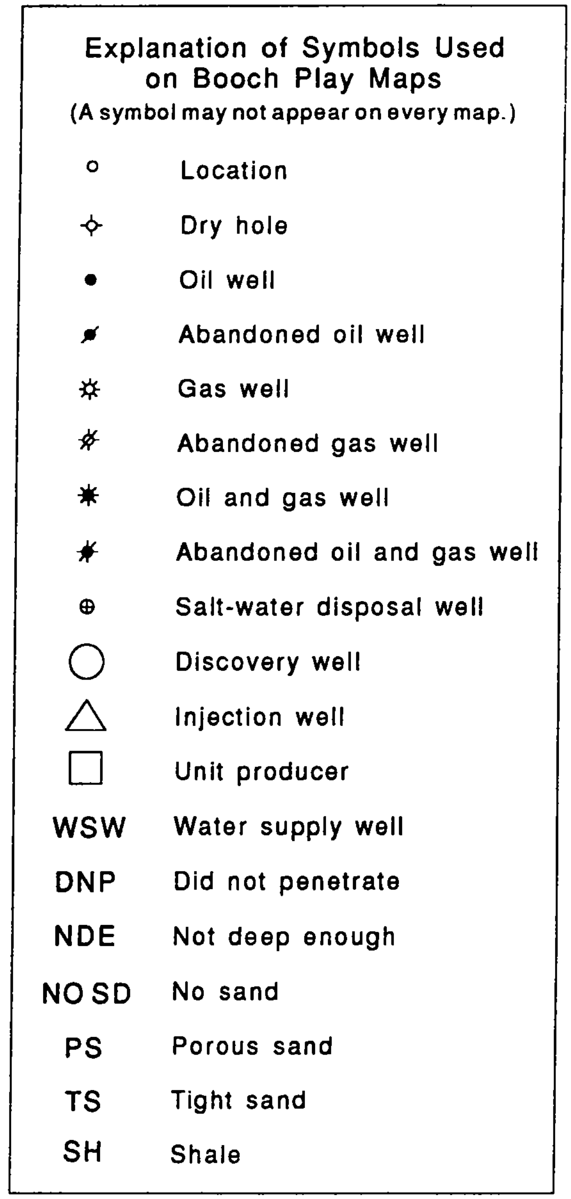


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Figure 43. Location map of the Booch oil reservoir study area (sec. 4, T. 8 N., R. 11 E. and sec. 33, T. 9 N., R. 11 E.), Greasy Creek field, Hughes County, Oklahoma.

Structure: The structure map on the top of the lower Booch sand porosity (Fig. 47) shows the faulting at the northern and southern limits of the oil reservoir area and the domelike appearance of this stratigraphic trap. Sediment compaction in the shale to the east and west of the axis of this thick channel sandstone creates the doming effect. Structural cross section C–C′ (Fig. 48, in envelope), is constructed along the longitudinal axis of the reservoir. Its location is also shown on the structure map (Fig. 47). The Roga Oil Corporation No. 2 Diamond-Viersen well (NE¼NE¼NE¼SW¼ sec. 33, T. 9 N., R. 11 E.) at the northern end of cross section C–C′ produces gas from the sandstone of layer 1 on the upthrown side of the fault. The Bell Oil and Gas Company No. 1 Tiger well (N½NE¼SE¼ sec. 4, T. 8 N., R. 11 E.) at the southern end of the cross section drilled the layer 1 sandstone 61 ft below the oil/water contact and was completed as a gas well from a shallower sandstone in the Thurman.

Structural closure of at least 70 ft is interpreted for this reservoir, from its highest point at the Lubell Oil Company No. 7 Hall (the highest well) to the oil/water contact at ~1,555 ft below sea level.

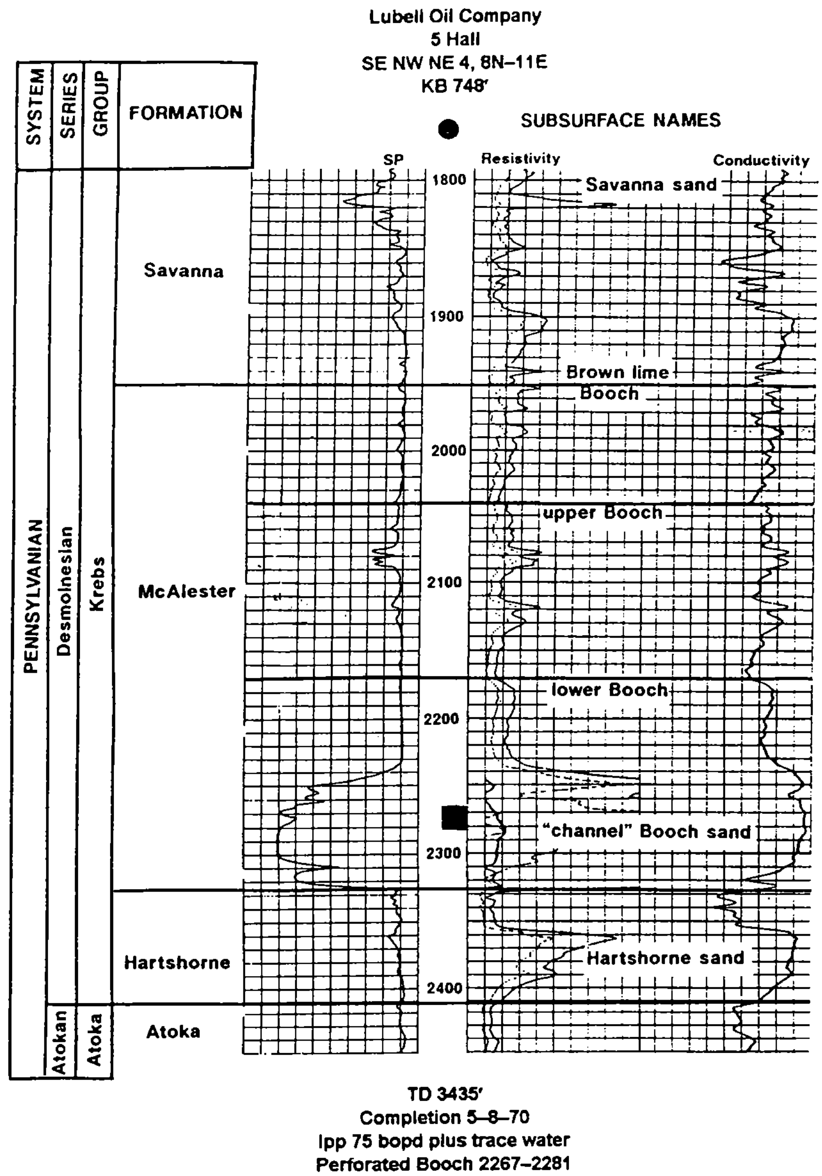

Figure 44. Representative electric log for the Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma, showing log patterns for spontaneous potential (SP), resistivity, and conductivity measurements. Perforated interval (■) is marked.

Isopach Mapping: Isopach maps were prepared on selected sandstone intervals in this reservoir. Figure 49 is an isopach map showing the total, or gross, thickness of the Booch sand in the reservoir; it presents the sand body as a continuous interval. The map of net Booch oil (pay) sand (Fig. 50) shows the thickness of oil-productive sandstone. These maps show the lateral extent and configuration of the reservoir but are not adequate to represent the true architecture of the sandstone body in this channel deposit. The three layers identified in the reservoir must be mapped separately to more accurately represent this stacked channel sandstone sequence. Figures 51, 52, and 53 are isopach maps of the three identified layers. The map of layer 1 (Fig. 51) shows that the sandstone in the uppermost layer (layer 1) is ≤38 ft thick along the axis of the channel, which is ≤½ mi wide. The sandstone in layer 2 (Fig. 52) is interpreted to be ≤50 ft thick, but the channel is only ~¼ mi wide; the axis of the layer 2 sandstone is west of the axis of the layer 1 sandstone channel. The isopach map of layer 3 (Fig. 53), the bottom layer in this sequence, shows that the sandstone is ≤20 ft thick and only ¼ mi wide; the axis of the channel is at approximately the same location as in layer 2.

Core Analysis: Only one core was reported taken in the Booch sand in the wells drilled in the oil reservoir, and the data from that core were not available. Some data from cores in nearby wells in the Wewoka N.W. Booch Sand Unit (Tables 3,4) were used in the reservoir simulation study reported in Part III of this volume.

Reservoir Characteristics: The Booch sand in the Booch oil reservoir in the Greasy Creek field has reservoir characteristics similar to those for other Booch reservoirs in the area with similar depositional environments. The channel sandstones of layers 2 and 3 in the Greasy Creek Booch oil reservoir commonly are cleaner

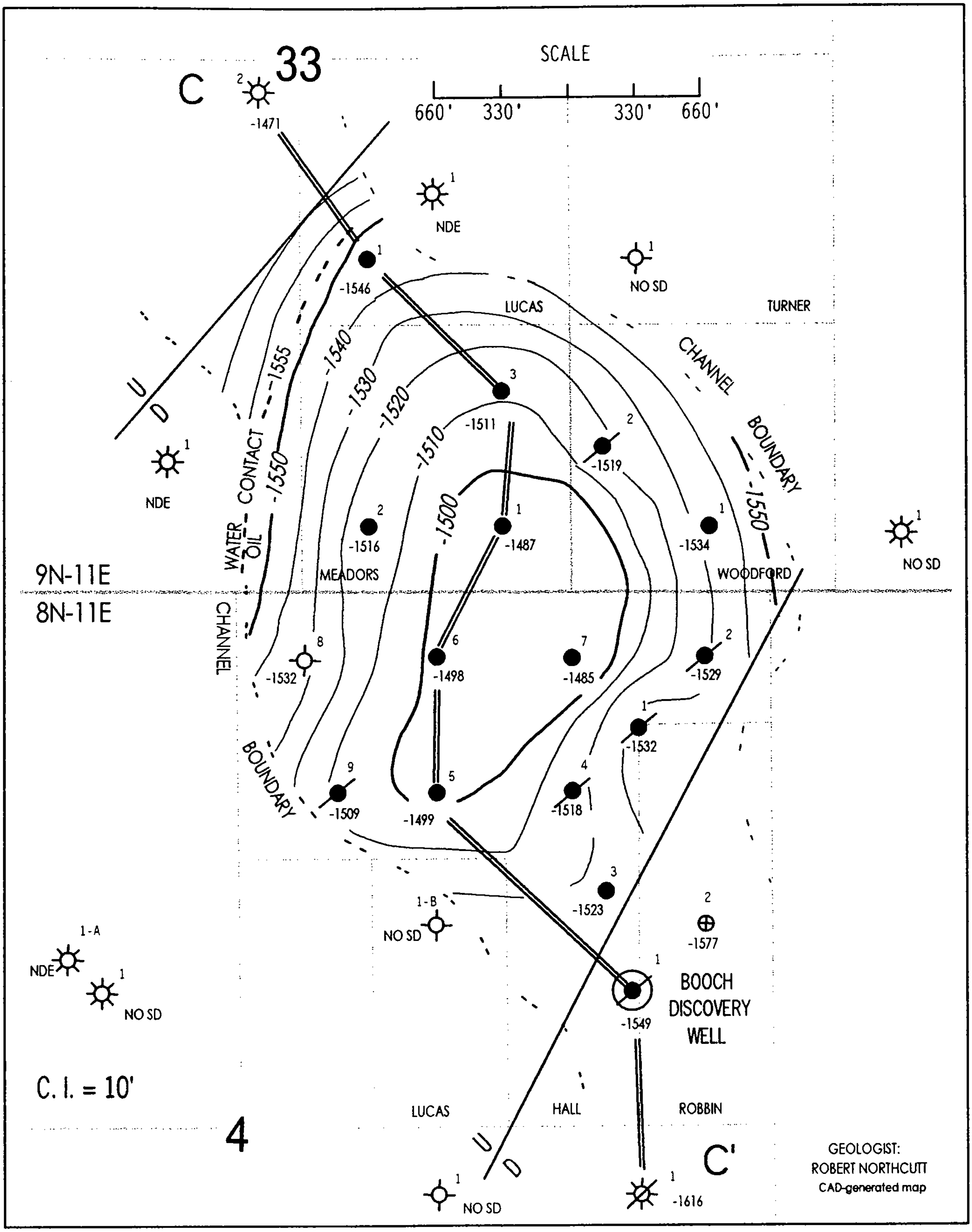

Figure 47. Structure map on the top of the lower Booch sand porosity, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. See Figure 43 for explanation of map symbols.

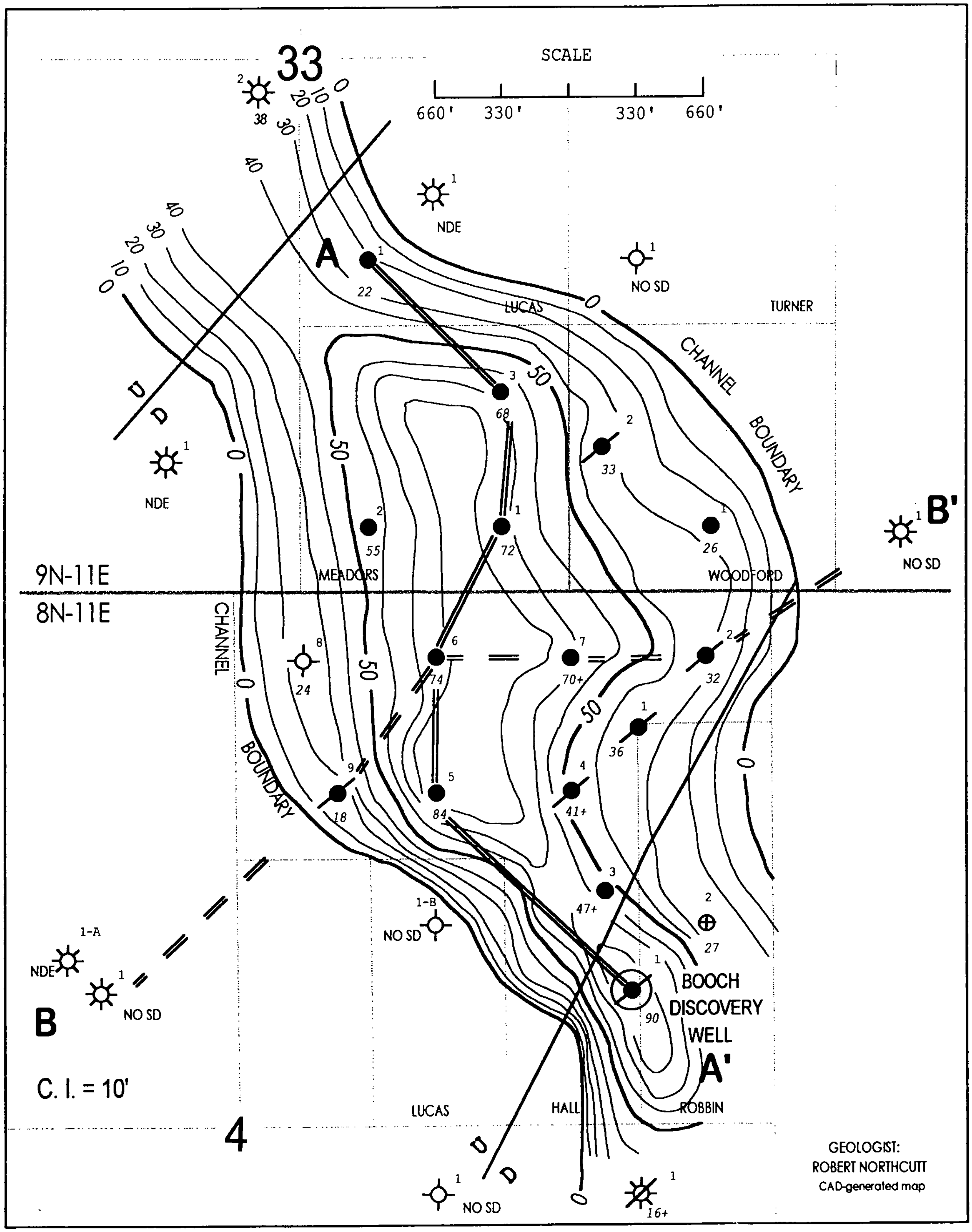

Figure 49. Isopach map of gross Booch sand, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. See Figure 43 for explanation of map symbols.

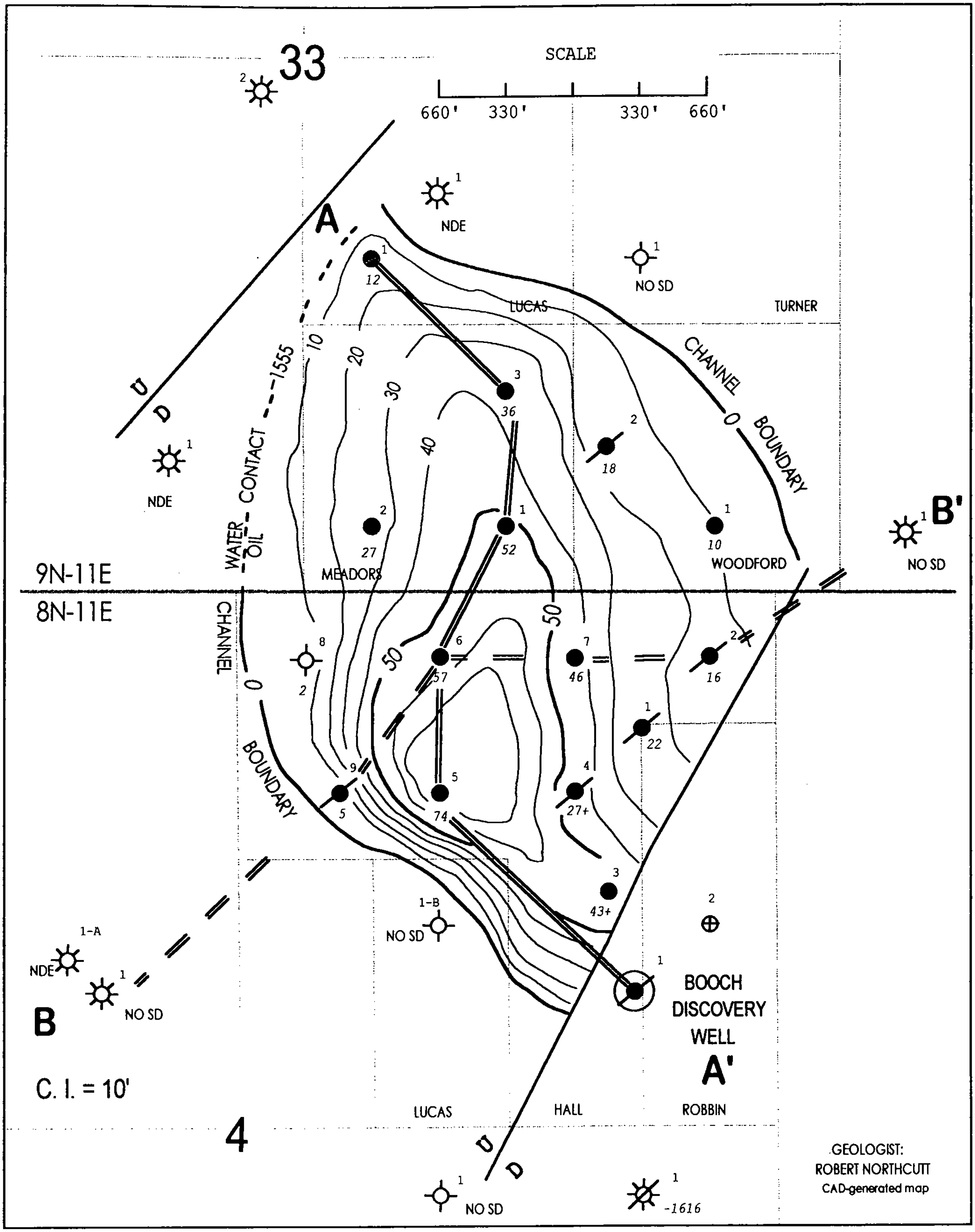

Figure 50. Isopach map of net Booch oil sand (pay sand), Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. See Figure 43 for explanation of map symbols.

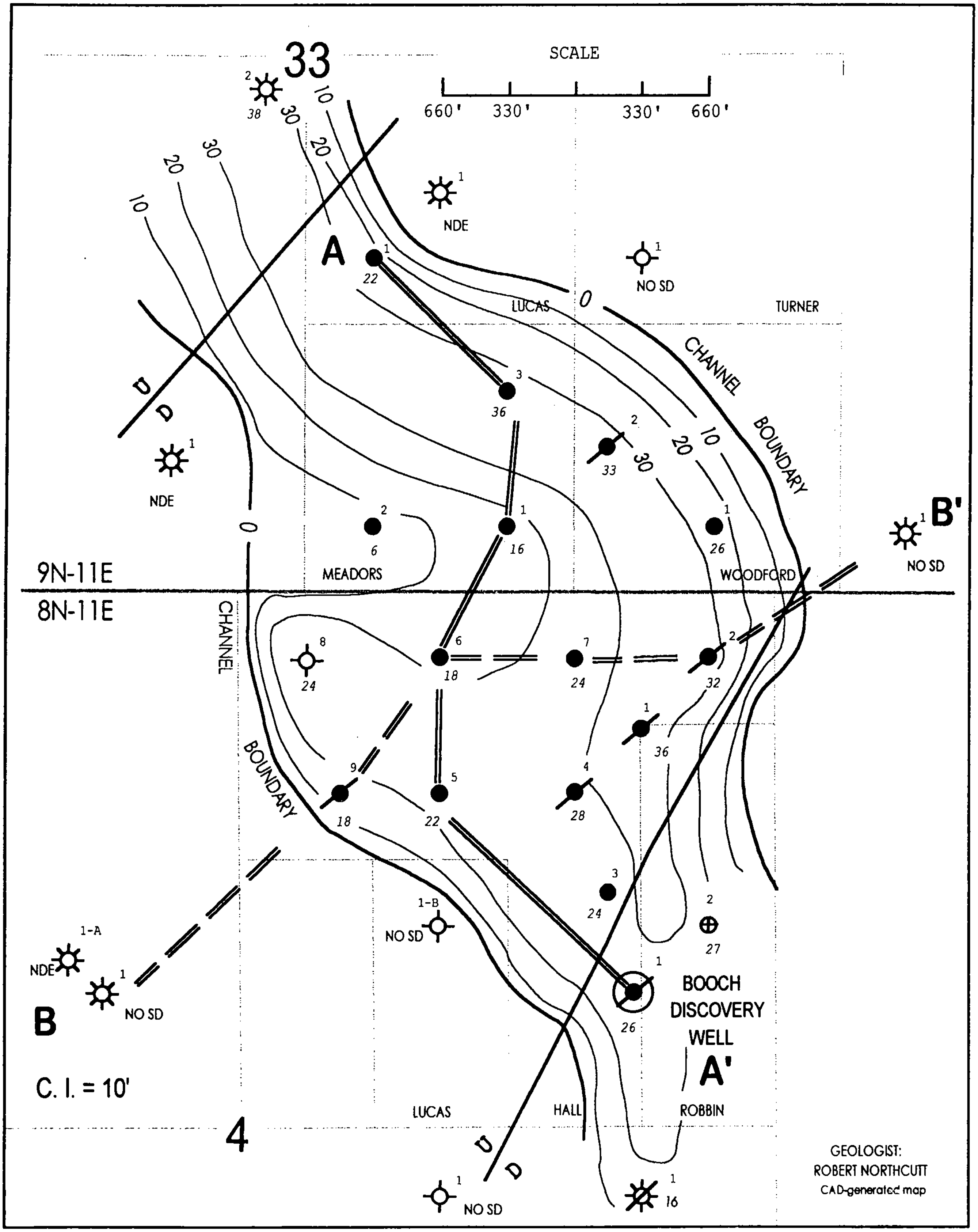

Figure 51. Isopach map of layer 1 (upper layer), Booch sand, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. See Figure 43 for explanation of map symbols.

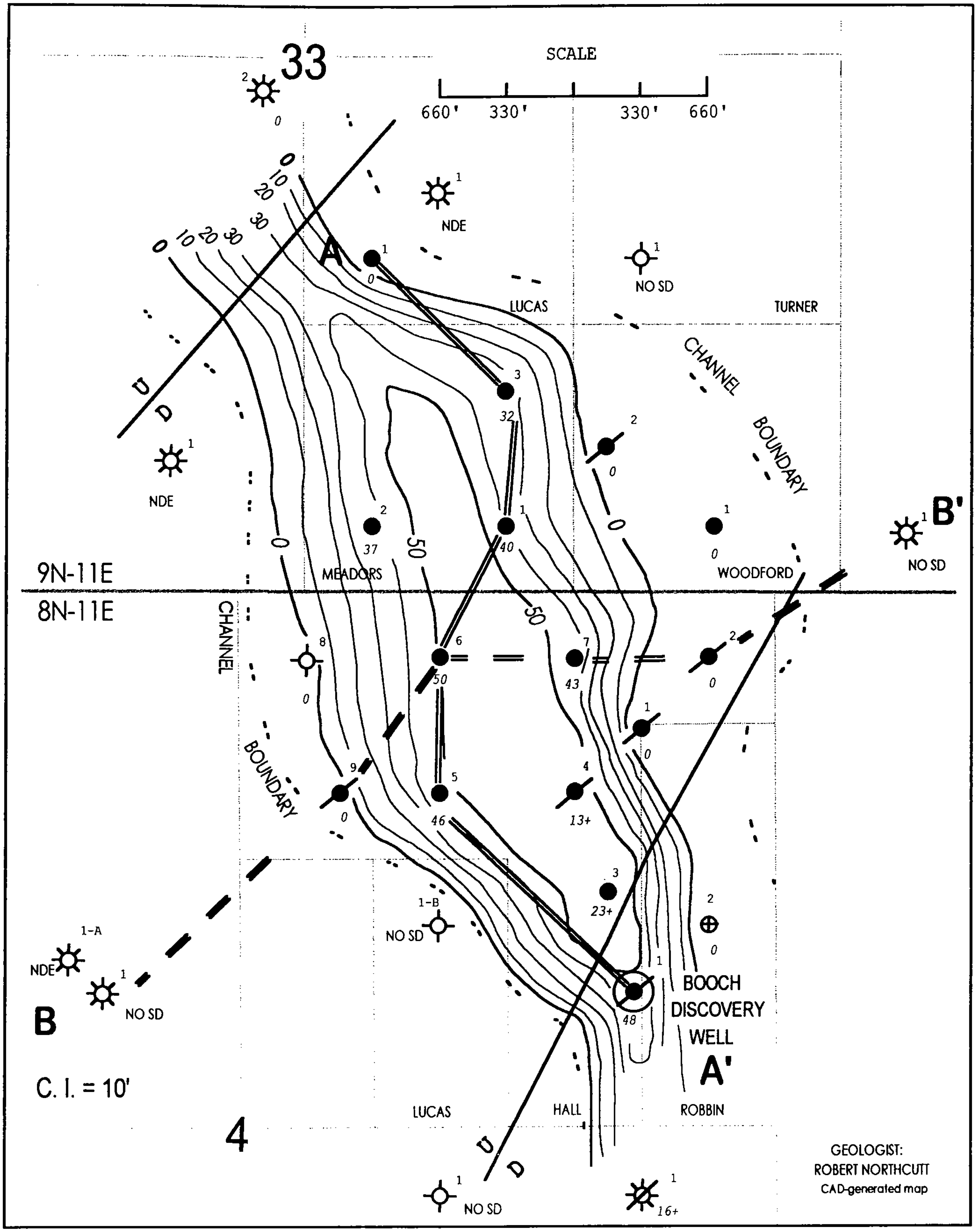

Figure 52. Isopach map of layer 2 (middle layer), Booch sand, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. See Figure 43 for explanation of map symbols.

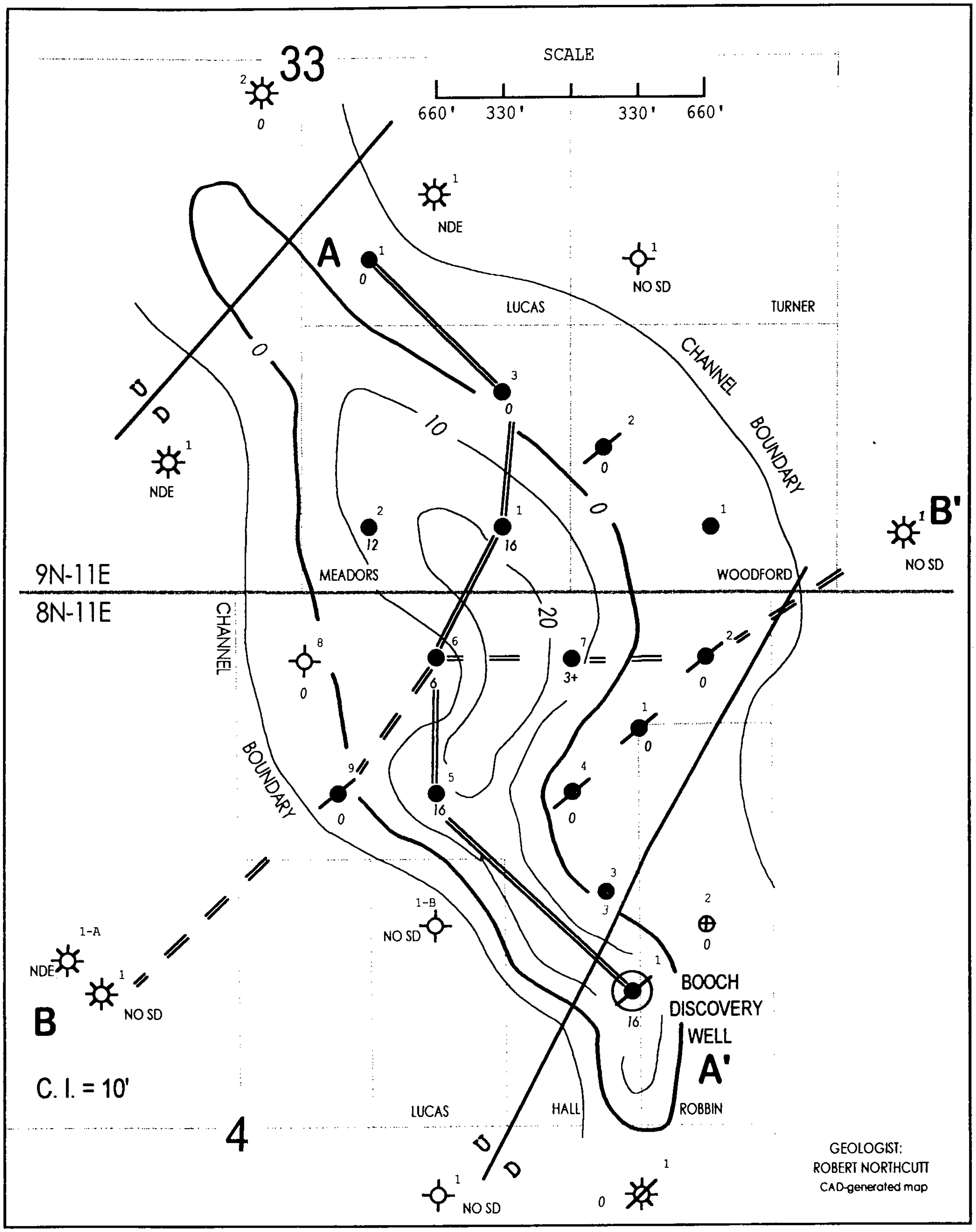

Figure 53. Isopach map of layer 3 (lower layer), Booch sand, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. See Figure 43 for explanation of map symbols.

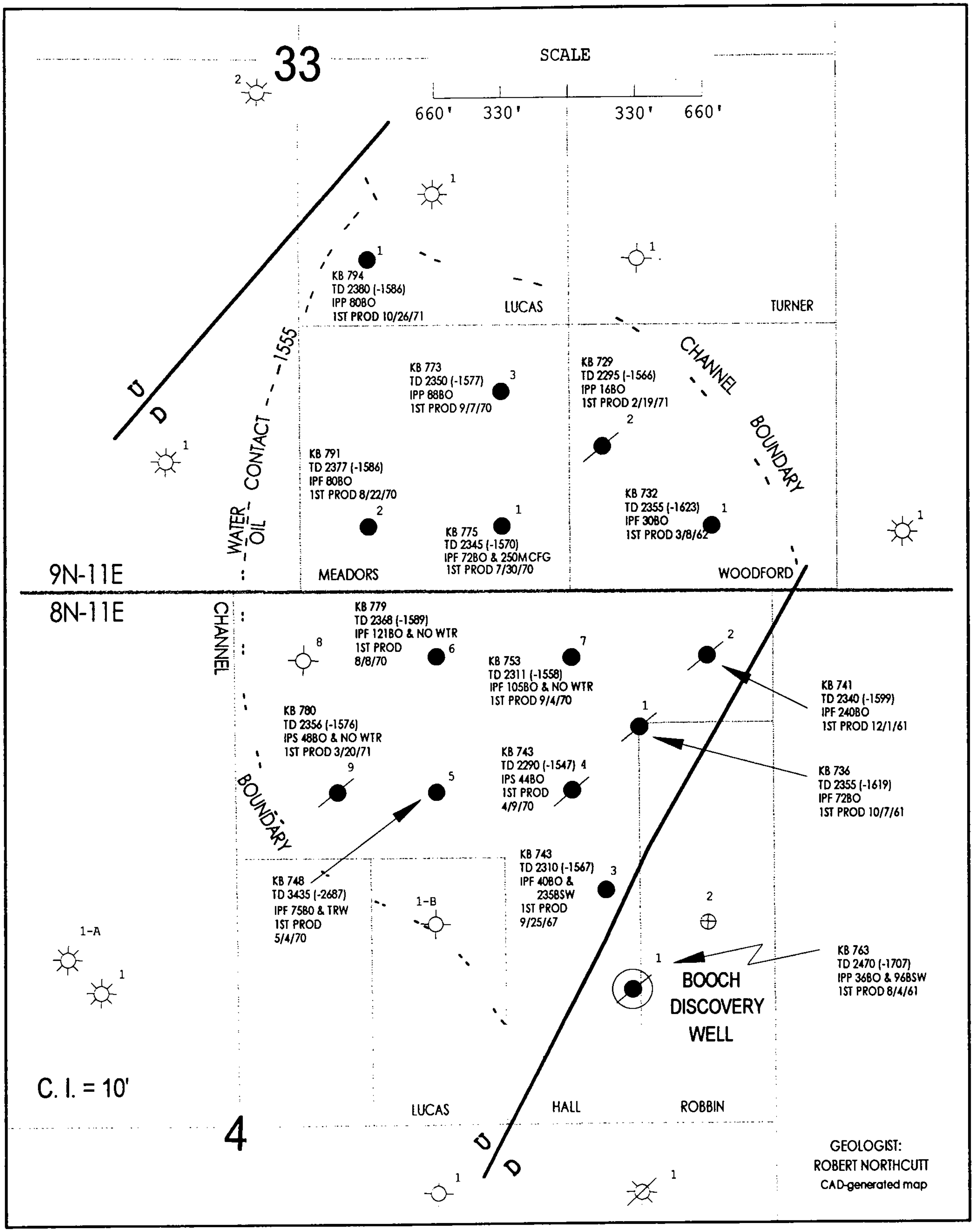

Figure 54. Production map for Booch wells, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. Well completion data, shown, are: kelly bushing elevations (KB) in feet above mean sea level; total depths (TD) of wells in feet below kelly bushing; initial potential pumping (IPP), flowing (IPF), swabbing (IPS); and date of first production.

TABLE 6. – Oil Production Statistics, Booch Oil Reservoir, Greasy Creek Field, Hughes County, Oklahoma

Year	Number of producing wells	Annual oil production (barrels)	Average monthly production (barrels)	Average daily production (barrels)	Average daily production per well (barrels)	Cumulative oil production (barrels)
1961	3	4,873	1,218	41	14	4,873
1962	4	21,212	1,768	59	15	26,085
1963	4	34,864	2,905	97	24	60,949
1964	4	41,195	3,433	114	29	102,144
1965	4	28,342	2,362	79	20	130,486
1966	4	26,520	2,210	74	18	157,006
1967	5	39,286	3,274	109	22	196,292
1968	5	45,657	3,805	127	25	241,949
1969	5	30,018	2,502	83	17	271,967
1970	10	77,064	6,422	214	21	349,031
1971	13	102,065	8,505	284	22	451,096
1972	11	49,576	4,131	138	13	500,672
1973	11	27,824	2,319	77	7	528,496
1974	10	20,647	1,721	57	6	549,143
1975	10	13,959	1,163	39	4	563,102
1976	8	11,416	951	32	4	574,518
1977	7	13,866	1,156	39	6	588,384
1978	7	10,006	834	28	4	598,390
1979	7	11,090	924	31	4	609,480
1980	5	11,376	948	32	6	620,856
1981	5	9,720	810	27	5	630,576
1982	5	10,308	859	29	6	640,884
1983	5	7,668	639	21	4	648,552
1984	5	6,709	559	19	4	655,261
1985	5	5,621	468	16	3	660,882
1986	5	3,378	282	9	2	664,260
1987	5	3,058	255	8	2	667,318
1988	5	2,661	222	7	1	669,979
1989	5	3,704	309	10	2	673,683
1990	5	3,466	289	10	2	677,149
1991	5	3,261	272	9	2	680,410
1992	5	3,896	325	11	2	684,306
1993	4	3,889	324	11	3	688,195
1994	2	4,120	343	11	6	692,315

Sources: Petroleum Information Corporation, Oklahoma Crude Report, and Natural Resources Information System (NRIS) of Oklahoma.

and coarser grained, and contain less clay than the sandstones in interdistributary and delta-front deposits. Porosity varies locally from 5% to 10% in interdistributary sandstones and some distributary point-bar sandstones; it varies locally from 5% to 20% in the thicker channel and point-bar sandstones. Knapp and Yang (Part III, this volume) report that permeability varies in this reservoir from 35 md to 45 md. Core analyses of the Booch in the nearby Wewoka N.W. Booch Sand Unit show permeabilities that range from 0.05 md to 57 md, depending on the grain size, cementation, and clay content of the sandstone (Tables 3,4).

Formation Evaluation: Ideally, formation evaluation is based on a core from the reservoir sandstone and a drill-stem test of the cored interval. Both coring and drill-stem testing delay drilling, but they allow porosity, permeability, fluid content, and mineral composition of the reservoir rock to be measured directly. The appropriate method for well completion can then be chosen. Microscopic inspection of well cuttings provides a visual record of the lithologies and textures of the rocks drilled; it also reveals oil stain under ultraviolet light. Porosity can also be detected visually, but information about drilling time (rate of penetration) is a better indicator of porosity. Such methods of formation evaluation were used in early wells completed in the Greasy Creek Booch oil reservoir.

All of the wells drilled in the reservoir during the 1960s and 1970s were logged with resistivity and microresistivity measuring tools. Today's sophisticated electric and radioactivity logs had not, yet, been developed. Nevertheless, most of the older electric logs can be used effectively in formation evaluation of the sandstone in the Booch. Porosity values can be estimated quantitatively from the microresistivity logs, and water saturation (Sw) can be calculated from resistivity measurements. (Standard calculation formulas are readily available from well logging companies and in many books on the subject.) The calculated Sw for the Greasy Creek Booch oil reservoir is 45% (Table 5). Fine-grained Booch sandstones with Sw values as high as 45–55% can produce oil; coarse-grained Booch sandstones that produce oil commonly have Sw values of <35%.

Reservoir Sensitivity and Formation of Porosity: Porosity of sandstone in the Booch developed chiefly from the dissolution of detrital framework grains, detrital matrix, and authigenic carbonate cements; it is occluded by clay minerals such as kaolinite, illite, and chlorite, and by authigenic cements (Bissell, 1984). Sandstones with high clay content are very sensitive to formation damage. The reaction of hydrochloric acid with the iron compounds in the rock can produce insoluble residue that permanently blocks the pore throats and reduces permeability. Hydraulic fracturing of these reservoir sands tends to dislodge clay particles, which also can block pore throats and destroy permeability. The use of untreated or incompatible water in fracture treatments of the sandstones can also cause significant damage to the reservoir from chemical reactions of the water with minerals in the sandstone. The best procedure for selecting a completion technique is to thoroughly test the rock and rock fluids for compatibility with the treatment fluids before they are introduced into the borehole.

Fracture treatment using sand and water in the completion of many early wells in this Greasy Creek Booch oil reservoir may have caused some formation damage. The use of acid during well completion also may have caused formation damage. In 1970, operators in this Greasy Creek Booch oil reservoir started using oil fracture treatment in well completion, which does not cause borehole damage and increases oil recovery.

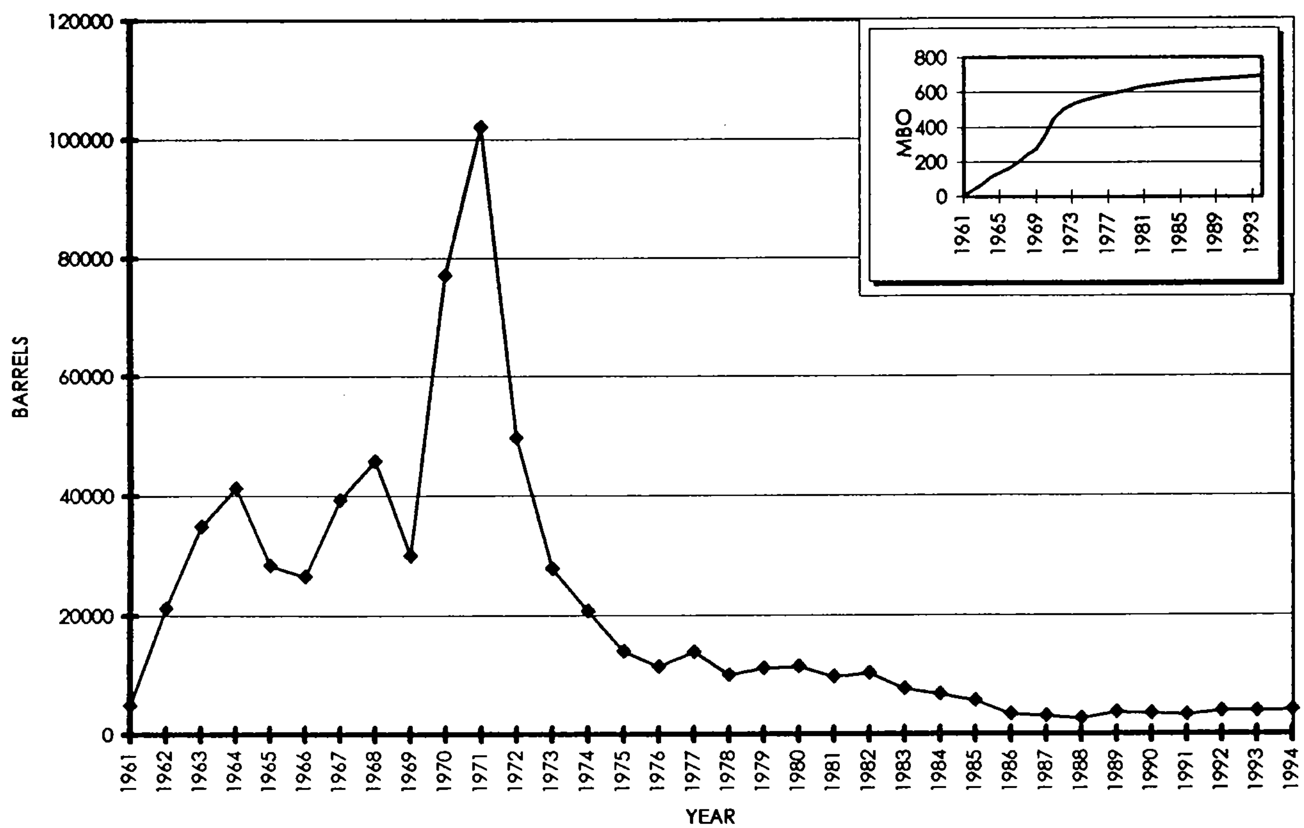

Figure 55. Graphs of annual oil production and cumulative oil production, Booch sand, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma.

Oil and Gas Production and Well Completion: In the 12-quarter-section area of this Booch oil reservoir in the Greasy Creek field (Fig. 43), only nine wells had been drilled before the Booch oil discovery at the No. 1 Hall in 1961. Of these nine wells, seven were completed as gas producers from various Pennsylvanian sandstones; three of these gas producers were completed in Booch sands younger than those in this oil reservoir. Only two wells were dry holes, one drilled before 1946 and one drilled in 1946. The No. 2 Robbin, one of the dry holes, was converted to a salt-water disposal well for the lease (Fig. 43). During the period from 1962 through 1969, two more oil wells were completed in the reservoir. In 1970 and 1971, 10 oil wells and one dry hole were drilled in the reservoir. By the end of 1971, the reservoir had a total of 15 completed oil wells and was fully developed. The Booch production map shows the well locations, the initial potential, dates of first production, and the limit of the reservoir (Fig. 54).

Initial potential reports for the reservoir indicated production rates ranging from pumping 16 BOPD to flowing 240 BOPD. Shut-in bottom-hole pressure obtained from a drill-stem test of the Booch sand in the No. 1 Hall was 920 PSIA in one hour. Eight of the 15 oil wells in the reservoir were completed flowing >72 BOPD. Production data for most individual wells in this reservoir are not available since production is reported by lease or tank battery. Four wells were reported on an individual basis, however. Cumulative production for each of those four wells is: the No. 1 Lucas, 4,831 BO; the No. 4 Hall, 5,142 BO; the No. 1 Robbin, 94,135 BO; and the No. 1 Hall, 95,433 BO.

Oil production statistics for the Greasy Creek Booch oil reservoir through December 31, 1994, are shown in Table 6. Cumulative oil production from the reservoir was 692,315 BO. Casing head (associated) gas production was not reported for this reservoir. The reservoir produced only 4,120 BO in 1994, an average of 6 BOPD for the remaining two producing wells. Figure 55 is a production graph for the Greasy Creek Booch oil reservoir. The production peak in 1971 was the result of completion of 10 new oil wells in 1970–71. The potential for secondary recovery of oil from this reservoir is analyzed in a reservoir simulation study, Part III of this volume.

PART III

Reservoir Simulation of a Booch Oil Reservoir in the Greasy Creek Field, Hughes County, Oklahoma

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The Booch oil reservoir in the Greasy Creek field is located in sec. 33, T. 9 N., R. 11 E., and sec. 4, T. 8 N., R. 11 E., Hughes County, Oklahoma (Fig. 43). This Booch reservoir has three distinct oil-producing sandstone layers, which have been characterized as a stacked channel sequence and identified as the lower Booch sand ("channel" Booch). The lower Booch in this reservoir is at depths of ~2,360 ft, or 1,575 ft subsea (below mean sea level). The three stacked sandstone bodies probably are mostly sealed and separated from each other by thin intervals of impermeable siltstone and shale. The reservoir description is based on geologic interpretations of well-log information.

The total area of the lower Booch sand in this Greasy Creek reservoir is 140 acres, and its average net thickness is 40 ft. The Greasy Creek reservoir appears to be a single, connected stratigraphic trap, faulted on the north and the south; it has a domelike appearance because of sediment compaction and drape on the east and the west. An oil/water contact occurs at ~1,555 ft subsea. The top layer has an average net thickness of 15 ft and an areal extent of 140 acres. The middle layer has an average net thickness of 20 ft and an areal extent of 96 acres. The bottom layer has an average net thickness of 5 ft and an areal extent of 96 acres. The channel sandstones that make up the reservoir are sealed on the east and the west by impermeable shales. On the north and the south, faults effectively seal the reservoir and limit the potential for water influx. No well was perforated in the bottom layer; however, in the simulation some blocks around injection wells were allowed to be connected between layers. Average reservoir properties for the three sandstone units are based on three sources: completion cards; reports from the Wewoka N.W. Booch Sand Unit, a Booch oil reservoir similar to the Greasy Creek reservoir (Kurt Rottmann, Part II, this volume); or the *Petroleum Engineering Handbook* (Bradley, 1987).

One well, the No. 1 Robbin, was reported as cored, but a core analysis report was not available. All wells were logged, and the well-log suites included resistivity, spontaneous potential (SP), and induction conductivity logs. Unfortunately, there was not sufficient information to determine porosities and initial water saturations. A drill-stem test from the No. 1 Robbin, from which to estimate initial pressure and productive capacity, was available. The reservoir-fluid-property and rock-property simulation data are based on samples from the Wewoka N.W. Booch unit (Kurt Rottmann, personal communication, 1995), correlations (McCain, 1990), and completion cards. Average reservoir properties are given in Table 7.

The oil in the Greasy Creek reservoir is a low shrinkage oil with an estimated average initial formation-volume factor of 1.157 RB/STB and an estimated initial oil viscosity at reservoir conditions of 0.87 cp. The initial oil in place was estimated to be 3.2 MMSTB. This estimate is based on an initial oil saturation of 55%. The maximum theoretical recovery, based on an estimated residual oil saturation of 26%, could be as much as 2.4 MMSTB. The unrecoverable immobile oil is estimated to be 0.83 MMSTB. Primary recovery from the wells in the simulated unit through June 1994 was 606,344 STB, or ~19% of oil in place. Behavior of the Greasy Creek reservoir appears to have conformed to that of a saturated, low shrinkage, solution-gas-drive oil reservoir and suggests that the bounding faults have prevented the water drive from being a significant source of reservoir energy.

The Greasy Creek wells that were completed in the Booch oil reservoir and used in the simulation study are listed in Table 8. All depths are true depths as interpreted from the logs and completion cards. A total of 15 wells were drilled and completed in lower Booch sand layers. Eight of the wells were perforated only in the top layer; the No. 8 Hall was a dry hole. The other seven wells were perforated only in the middle layer. No wells were completed in the bottom layer. The first three wells used in the reservoir simulation study were completed in 1961 and 1962. One well was completed in 1967. The other 11 wells were drilled in 1970 and 1971. The field daily oil and gas production rates are shown in Figure 56. During the first 10 years (from

TABLE 7. – Average Reservoir Properties, Lower Booch Oil Reservoir, Greasy Creek Field, Hughes County, Oklahoma

Estimated Properties	Top Layer	Middle Layer	Bottom Layer
Porosity	15.0%	16.0%	15.0%
Permeability	35 md	40 md	35 md
Average Gross Pay	20 ft	40 ft	8 ft
Average Net Pay	15 ft	20 ft	5 ft
Initial Water Saturation	45%	45%	45%
Initial Bottom-Hole Pressure	940 PSIA	940 PSIA	940 PSIA
Initial Gas-Oil Ratio	250 SCF/STB	250 SCF/STB	250 SCF/STB
Initial Formation-Volume Factor	1.157 RB/STB	1.157 RB/STB	1.157 RB/STB
Reservoir Temperature	103° F	103° F	103° F
Oil Gravity	39.5° API	39.5° API	39.5° API
Specific Gas Gravity	0.85	0.85	0.85
Initial Oil in Place 3.2 MMSTB (Total)			

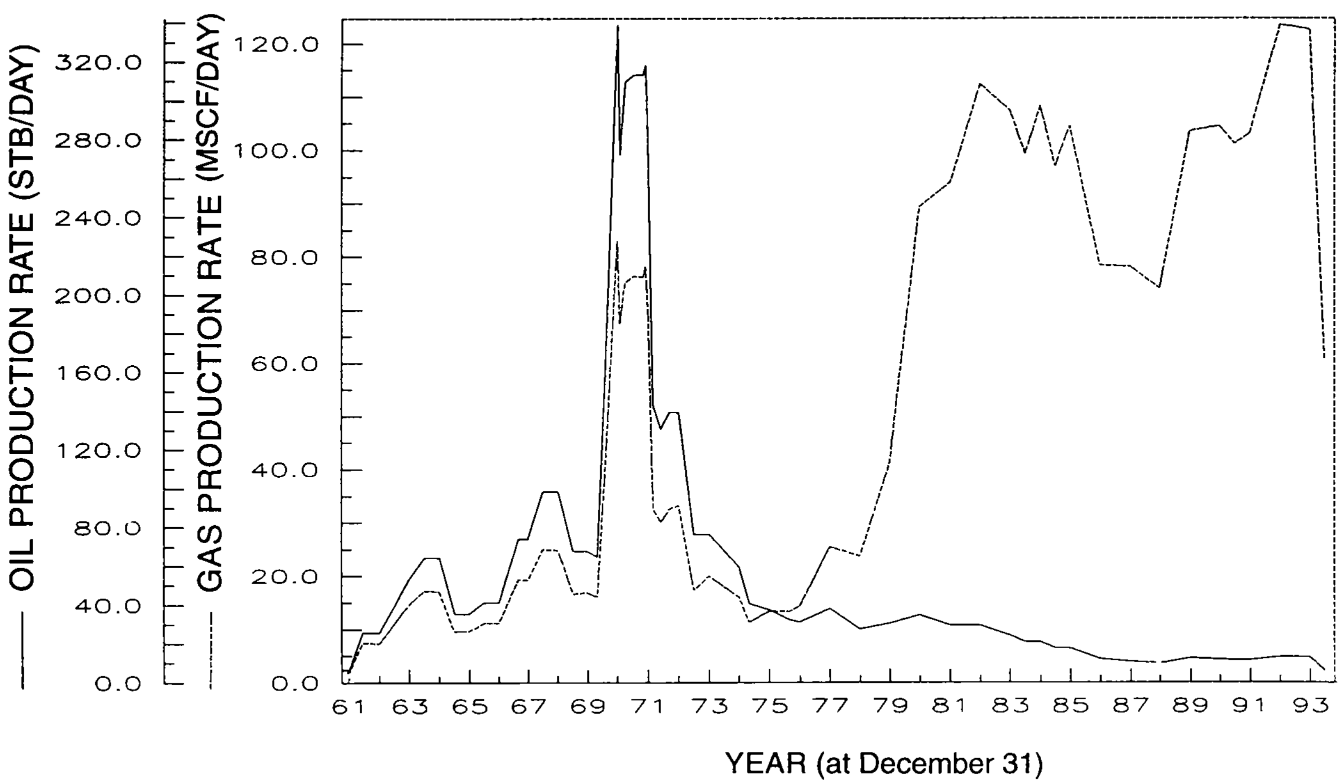

Figure 56. Oil and gas production rates for the Booch oil reservoir in the Greasy Creek field, from October 1961 through June 1994.

1961 to 1970), production increased steadily. During the more extensive development from 1970 to 1972, production rates dramatically increased as 10 additional producing wells were completed in the field. Oil production then declined rapidly over the following four years and continued to diminish more gradually. It declined from 310 STB/day in 1971 to <20 STB/day in 1994.

TABLE 8. – Wells[a] in the Booch Oil Reservoir, Greasy Creek Field, Hughes County, Oklahoma

Well Name	Well Location	Production Dates Initial	Production Dates Final	Cumulative Production[b] (STB)	Formation Top ---- Bottom Depth, ft	Formation Top ---- Bottom Subsea, ft	Perforation Upper ---- Lower Depth, ft	Perforation Upper ---- Lower Subsea, ft
Hall 2	04-8N-11E	12/1/61	4/75	83,232	2250 - 2282	1509 - 1541	2265 - 2275	1524 - 1534
Hall 3	04-8N-11E	9/25/67	9/93	45,626	2260 - 2309	1517 - 1566	2298 - 2302	1555 - 1559
Hall 4	04-8N-11E	4/9/70	4/75	5,142	2246 - 2289	1503 - 1546	2262 - 2268	1519 - 1525
Hall 5	04-8N-11E	5/4/70	95	57,550	2238 - 2326	1490 - 1578	2267 - 2281	1519 - 1533
Hall 6	04-8N-11E	8/8/70	79	52,685	2274 - 2352	1495 - 1573	2314 - 2318	1535 - 1539
Hall 7	04-8N-11E	9/4/70	9/93	62,400	2236 - 2311	1483 - 1558	2274 - 2278	1521 - 1525
Hall 8	04-9N-11E			Dry Hole	2347 - 2371	1523 - 1547	not reported	
Hall 9	04-8N-11E	3/20/71	12/71	1,100	2288 - 2306	1508 - 1526	2285 - 2291	1505 - 1511
Robbin 1	04-8N-11E	10/7/61	2/72	94,135	2260 - 2296	1524 - 1560	2273 - 2285	1537 - 1549
Meadors 1	33-9N-11E	7/30/70	6/94	47,359	2256 - 2334	1481 - 1559	2296 - 2300	1521 - 1525
Meadors 2	33-9N-11E	8/22/70	6/94	63,145	2296 - 2358	1505 - 1567	2312 - 2316	1521 - 1525
Meadors 3	33-9N-11E	9/7/70	6/94	47,359	2270 - 2340	1497 - 1567	2295 - 2299	1522 - 1526
Lucas 1	33-9N-11E	10/26/71	9/76	4,831	2330 - 2352	1536 - 1558	2340 - 2346	1546 - 1552
Woodford 1	33-9N-11E	3/8/62	67	30,378	2252 - 2278	1520 - 1546	2264 - 2276	1532 - 1544
Woodford 2-33	33-9N-11E	2/19/71	11/71	11,400[c]	2238 - 2271	1509 - 1542	2256 - 2258	1527 - 1529

[a]No. 1 Hall excluded.

[b]Does not include production data for July–December 1994. Production was reported on an individual basis only for the No. 4 Hall, the No. 1 Robbin, and the No. 1 Lucas. Allocation of cumulative production for the other wells was based on initial production and location of a well in the reservoir.

[c]Includes production from the No. 1 Woodford. A change of operator for the No. 1 Woodford occurred in July 1967. Cumulative production at 11/71 for the Woodford lease included No. 1 Woodford production for 7/67–11/71 as well as production for the No. 2-33 Woodford, completed in 2/71.

The Greasy Creek Booch reservoir is approaching the economic limit of oil production, and operators are facing the choice between continuing oil production at present marginal rates or initiating field development to recover incremental oil. This reservoir simulation study was carried out to estimate initial oil and gas in place, recovery factors, and waterflood recovery. Early gas-oil ratios reported on completion cards suggest that the reservoir was saturated initially. From a correlation (McCain, 1990), the bubble point pressure was estimated to be 930 PSIA based on a 250 SCF/STB initial separator gas-oil ratio (Kurt Rottman, personal communication, 1995). Pressure measurements reported on completion cards suggest that, in the Greasy Creek Booch oil reservoir, the initial reservoir pressure was 940 PSIA at the ~1,555 ft subsea oil/water contact.

Since no current measured pressures were available for the reservoir, the goal in simulating production history was to calculate flowing well pressures for the producing wells that would barely allow them to match their specified production rates on June 30, 1994. This was accomplished for all wells. The results of the simulation to match primary production history indicate that mobile oil should remain in both the top and middle layers, and that some oil should be left in the bottom layer because it is mostly isolated by the thin shale interval.

After the primary production from 1961 through 1994 was matched, a 20-year forecast of expected waterflood performance was prepared (Figs. 57,58). Two-phase oil-water and oil-gas relative permeabilities were estimated, based on correlations (Honarpour and others, 1986) and a reservoir study from the Wewoka N.W. Booch unit (Kurt Rottmann, personal communication, 1995). The estimated initial water saturation of 45% and the residual oil saturation of 26% from Rottman's study were used to fix end points for the Honarpour correlations.

Several patterns were tested; all 15 wells, whether producing, abandoned, or plugged, were assumed to be available for use in a waterflood. The best sweep efficiency resulted when seven wells (the No. 1 Lucas, the No. 1 Meadors, the No. 1 Woodford, and the Nos. 3, 4, 6, and 8 Hall) were chosen to be water injection wells and six wells (the Nos. 2, 5, and 7 Hall; the Nos. 2 and 3 Meadors; and the No. 2-33 Woodford) were retained as production wells (Fig. 54). The No. 9 Hall and the No. 1 Robbin were not used because of high water production rates and low oil production rates from wells surrounding these two potential injectors. Water injection was assumed to begin in July 1994. For the first two years of the waterflood, all production wells were shut-in to allow the reservoir pressure to increase and to dissolve free gas. After two years, the reservoir pressure was great enough to provide energy for good oil recovery.

The policy followed for waterflood simulation was to control bottom-hole pressures for both injection and production wells. The injection wells were held at 1,750 PSIA beginning in July 1994. When the produc-

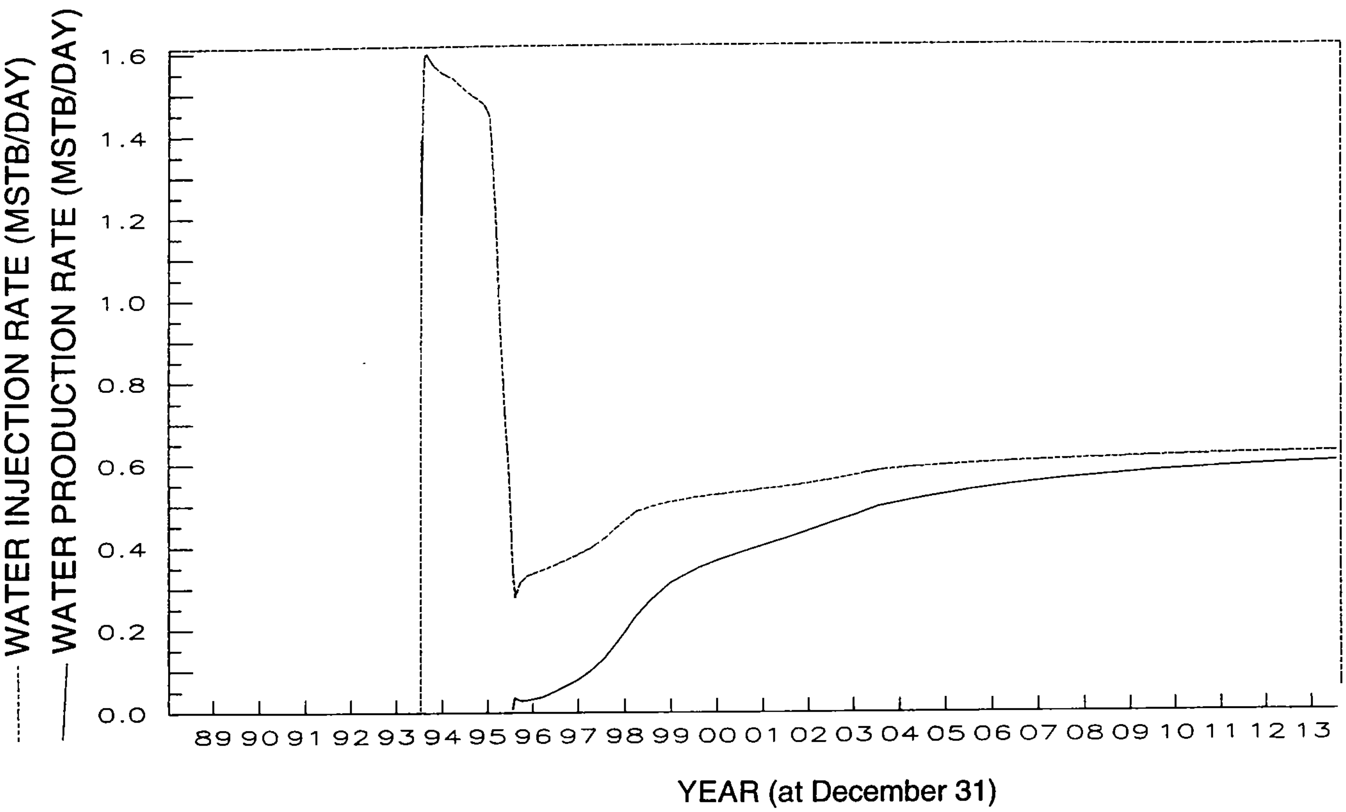

Figure 57. Simulated water injection and production rates for the Booch oil reservoir in the Greasy Creek field.

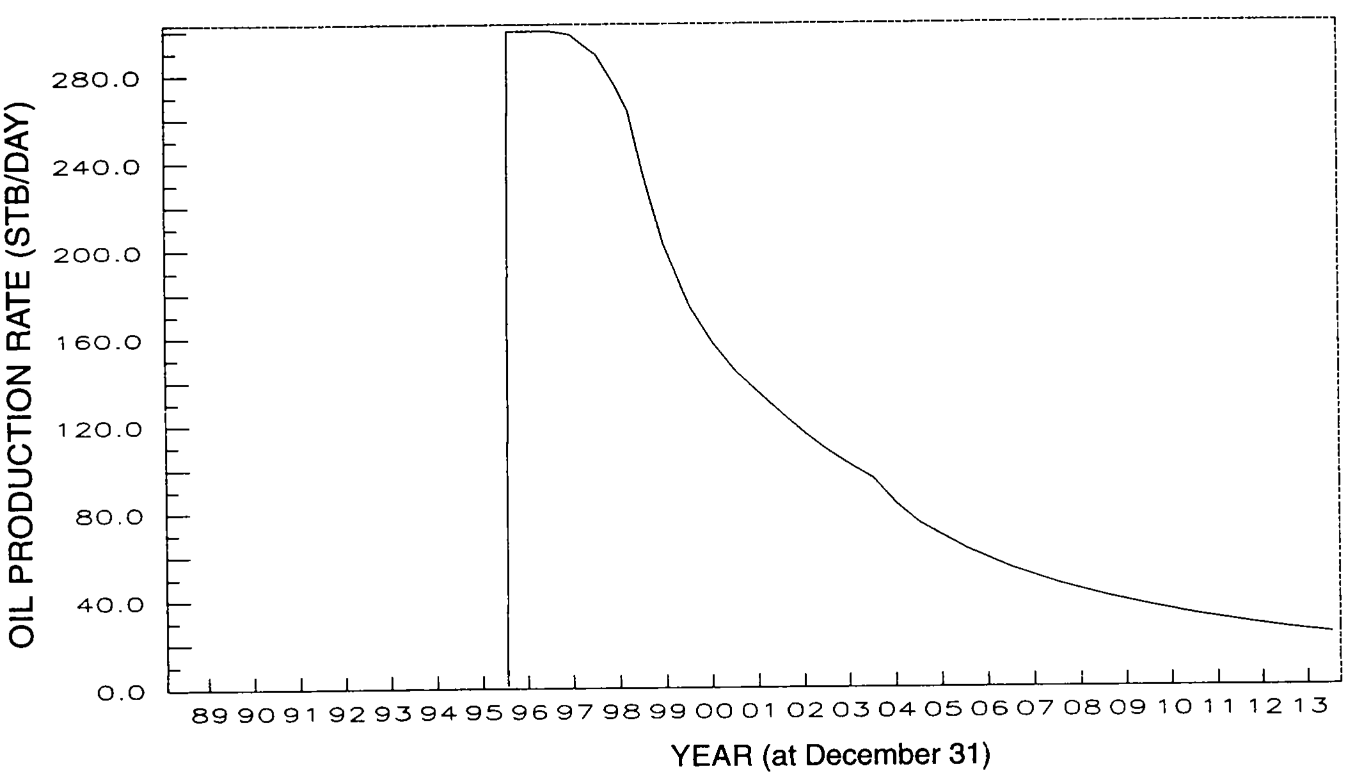

Figure 58. Oil production forecast for a waterflood in the Booch oil reservoir, Greasy Creek field.

tion wells were started, they were held at 300 PSIA. For the field, the initial maximum injection rate was held at 1.6 MSTB/day for a short time until controlled by the specified bottom-hole pressure for injection wells. Reservoir water injection and production rates are shown in Figure 57. As the reservoir filled up, the water injection rate dropped to ~280 STB/day and increased to ~600 STB/day. A constrained maximum oil production rate of 300 STB/day is expected two years after injection begins (Fig. 58). In order to avoid early water breakthrough and high water production rates, the initial oil production rates were constrained to 40 STB/day for the No. 2 Meadors and the No. 7 Hall, to 45 STB/day for the No. 5 Hall, to 50 STB/day for the No. 2 Hall and the No. 2-33 Woodford, and to 75 STB/day for the No. 3 Meadors. The additional oil recovery is expected to be 700 MSTB or about 115% of primary recovery. Early production and injection should be monitored closely to ensure that the reservoir is being swept adequately by the injected water. After water flooding, the total recovery for both primary and secondary production could be 1.3 MMSTB, or 41% of the oil in place initially. That would be 54% of the maximum theoretical recovery.

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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 (Ton)	Clay	

†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
BO	barrels of oil
BOPD	barrels of oil per day
BHP	bottom-hole pressure
cp	centipoise (a standard unit of viscosity)
MBO	thousand barrels of oil
MCF	thousand cubic feet (of gas)
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
OOIP	original oil in place
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
SCF/STB	standard cubic feet per stock tank barrel
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

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.

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

channel deposits—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.

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.

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.

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.

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.

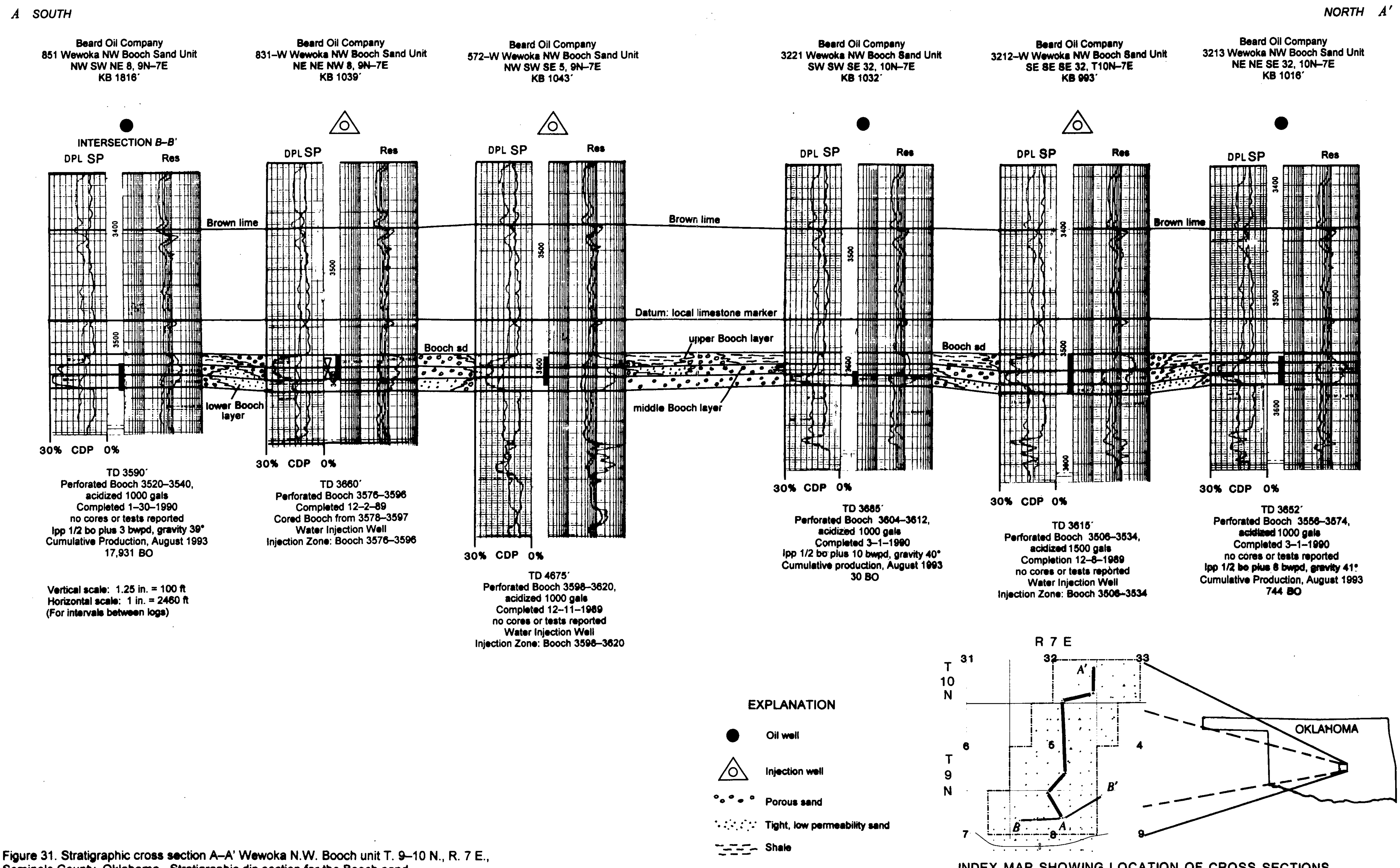
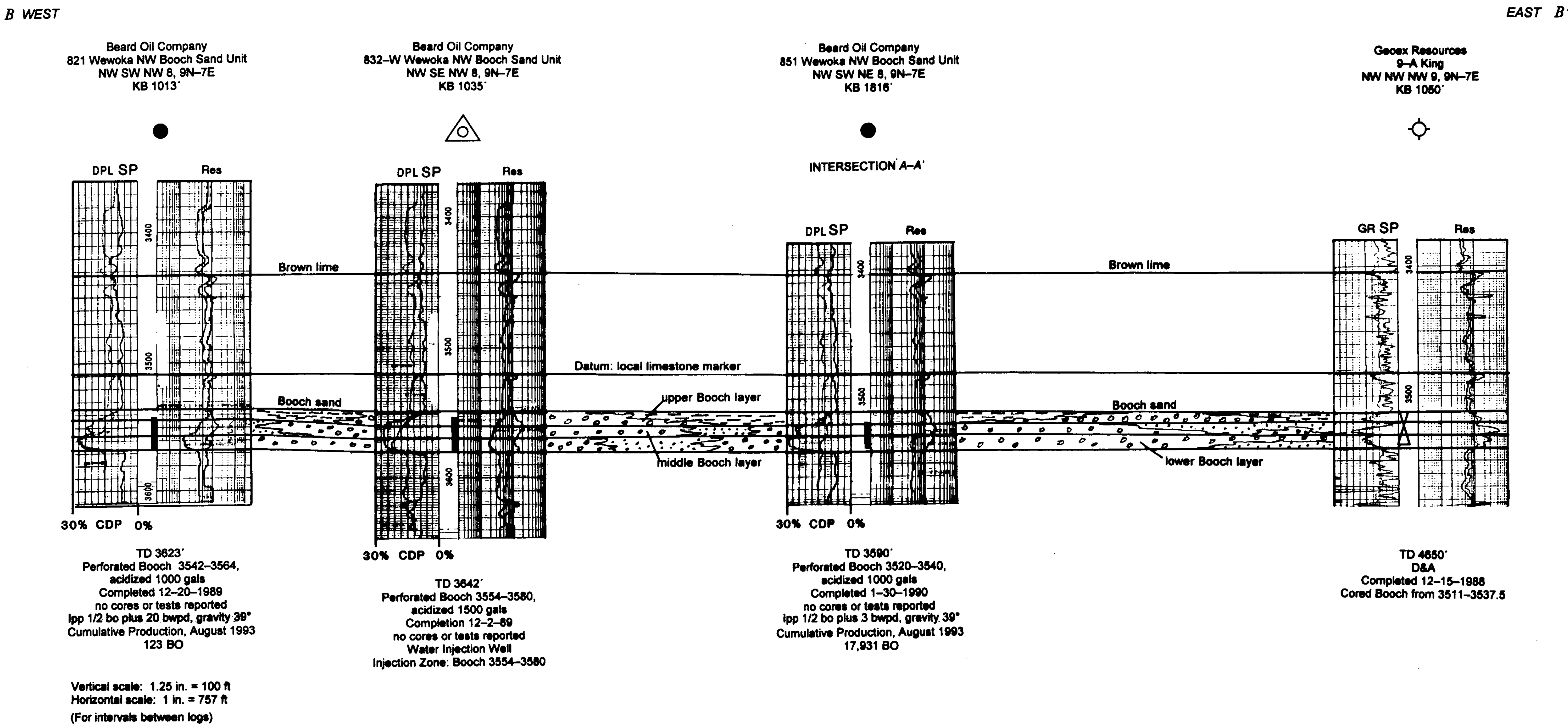
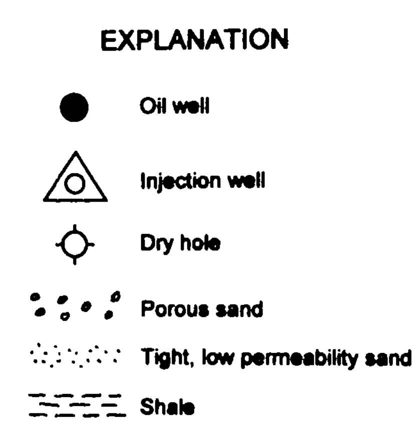
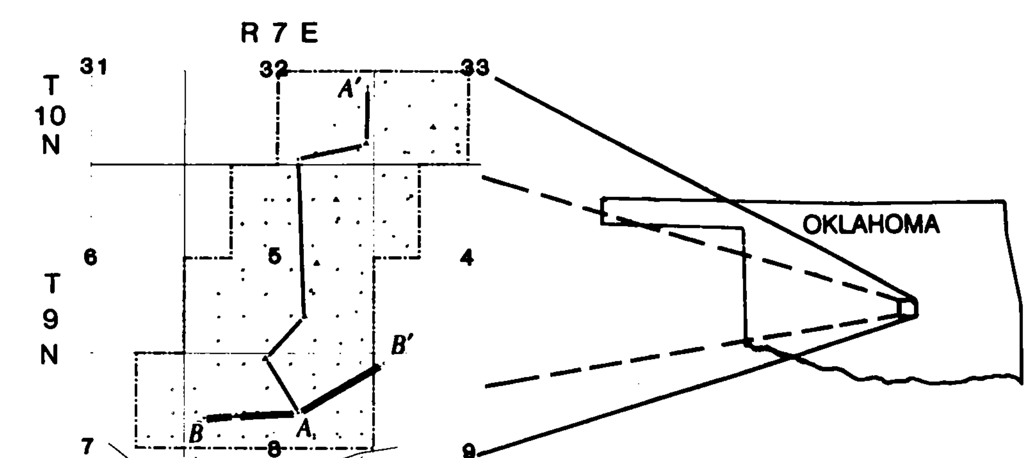


Figure 31. Stratigraphic cross section A–A′ Wewoka N.W. Booch unit T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Stratigraphic dip section for the Booch sand.

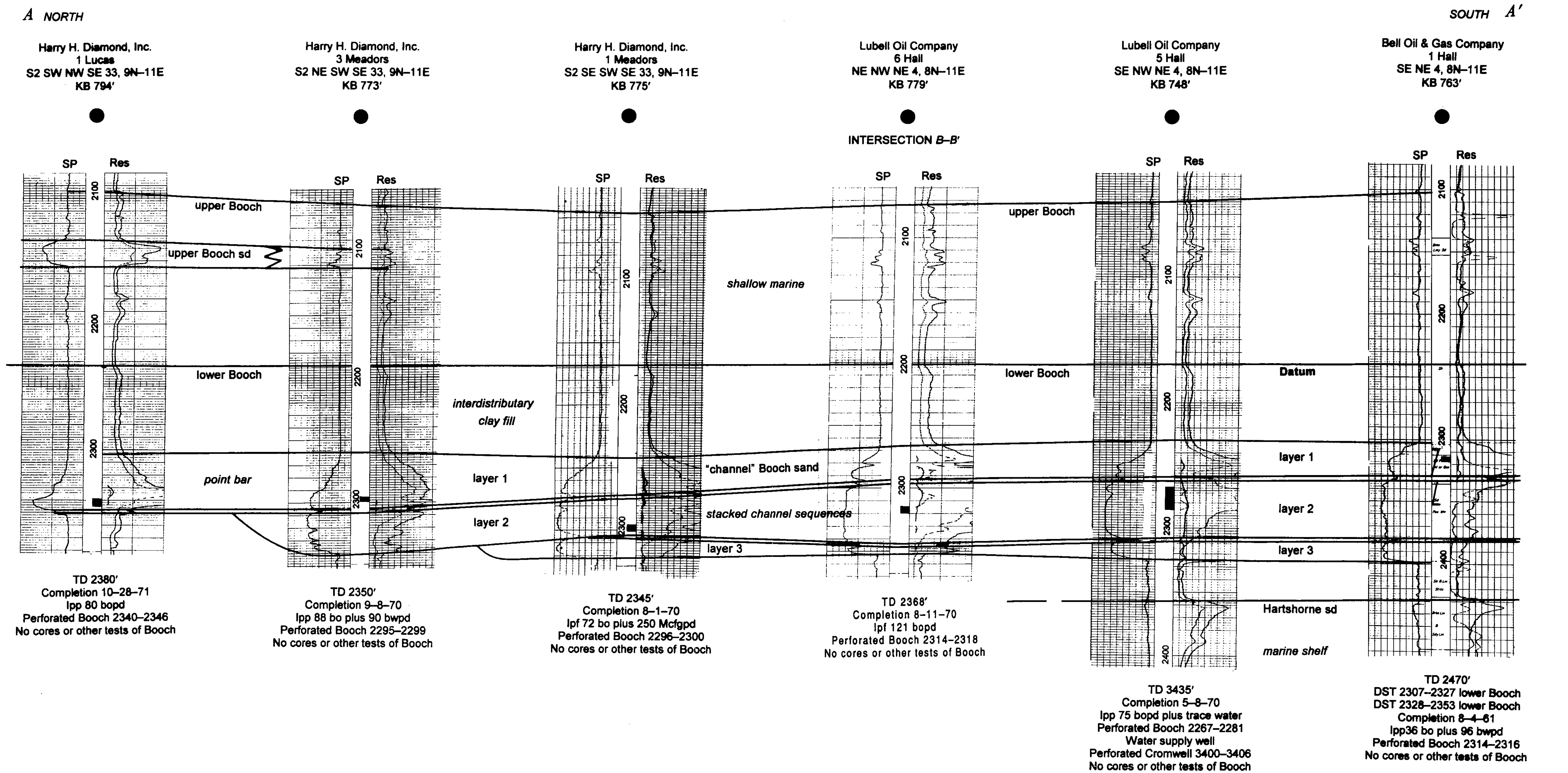






INDEX MAP SHOWING LOCATION OF CROSS SECTIONS

Figure 33. Stratigraphic cross section B–B' Wewoka N.W. Booch unit T. 9–10 N., R. 7 E., Seminole County, Oklahoma. Stratigraphic strike section for the Booch sand.



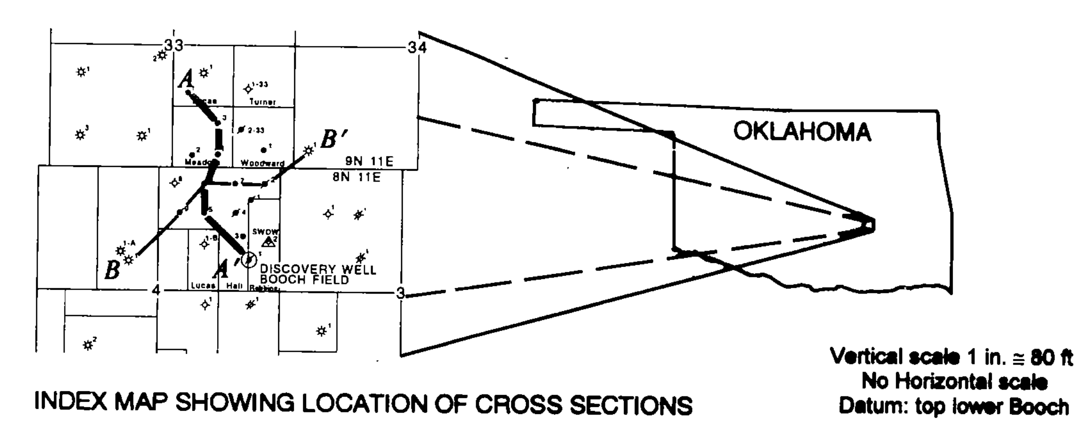
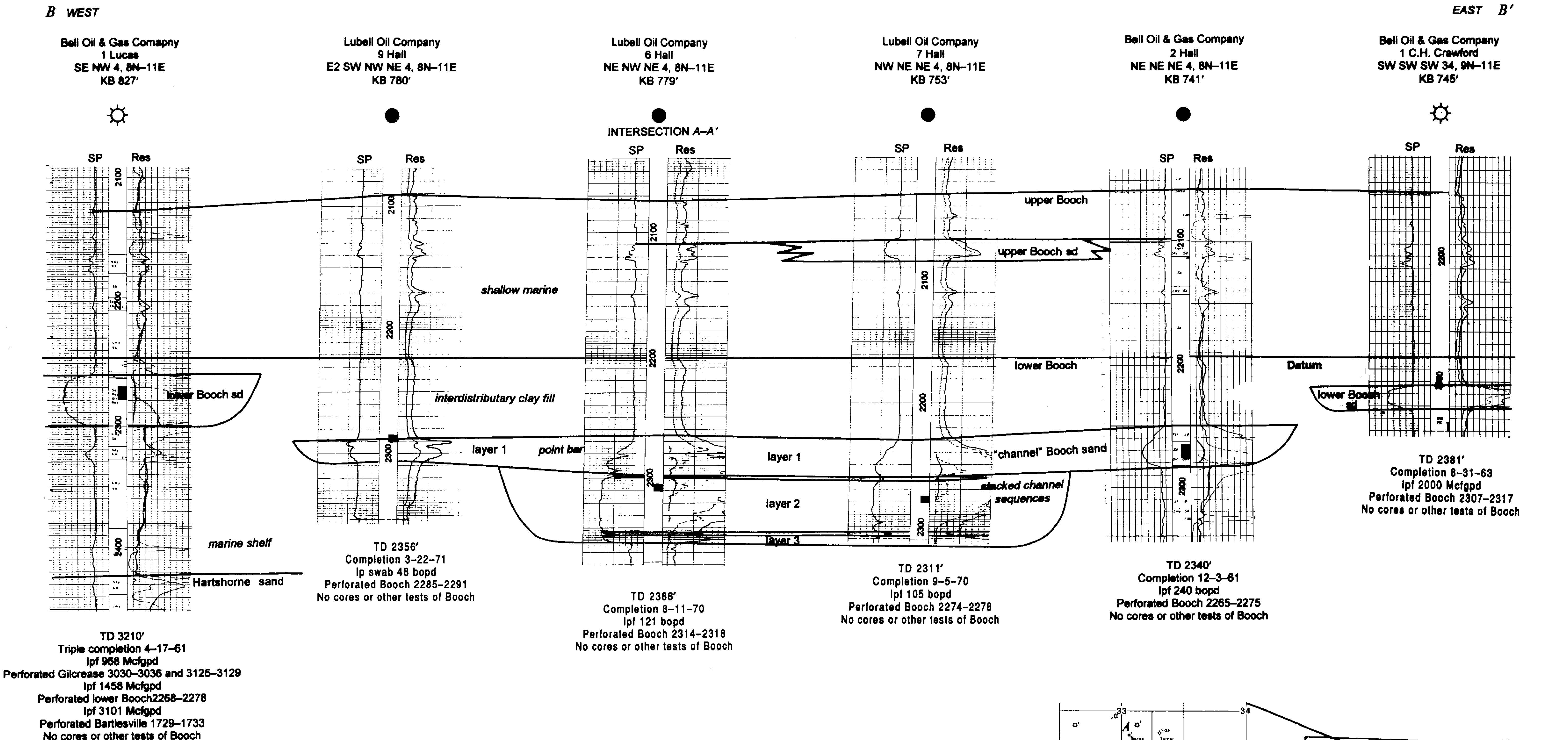


Figure 45. Stratigraphic cross section A–A′, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. Location of wells also shown on Figs. 49–53.



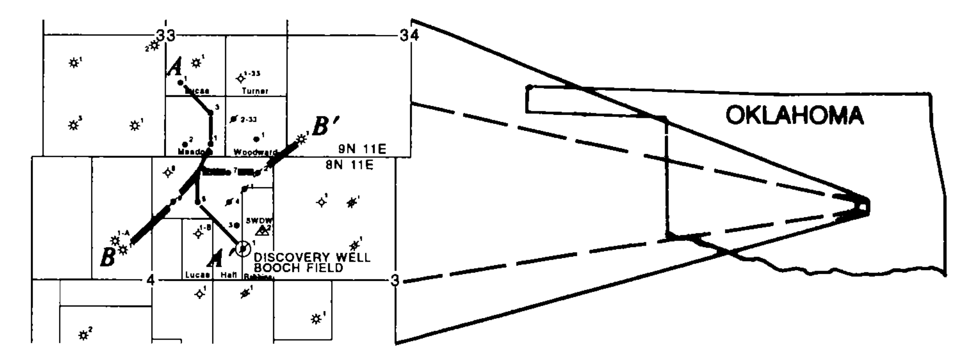
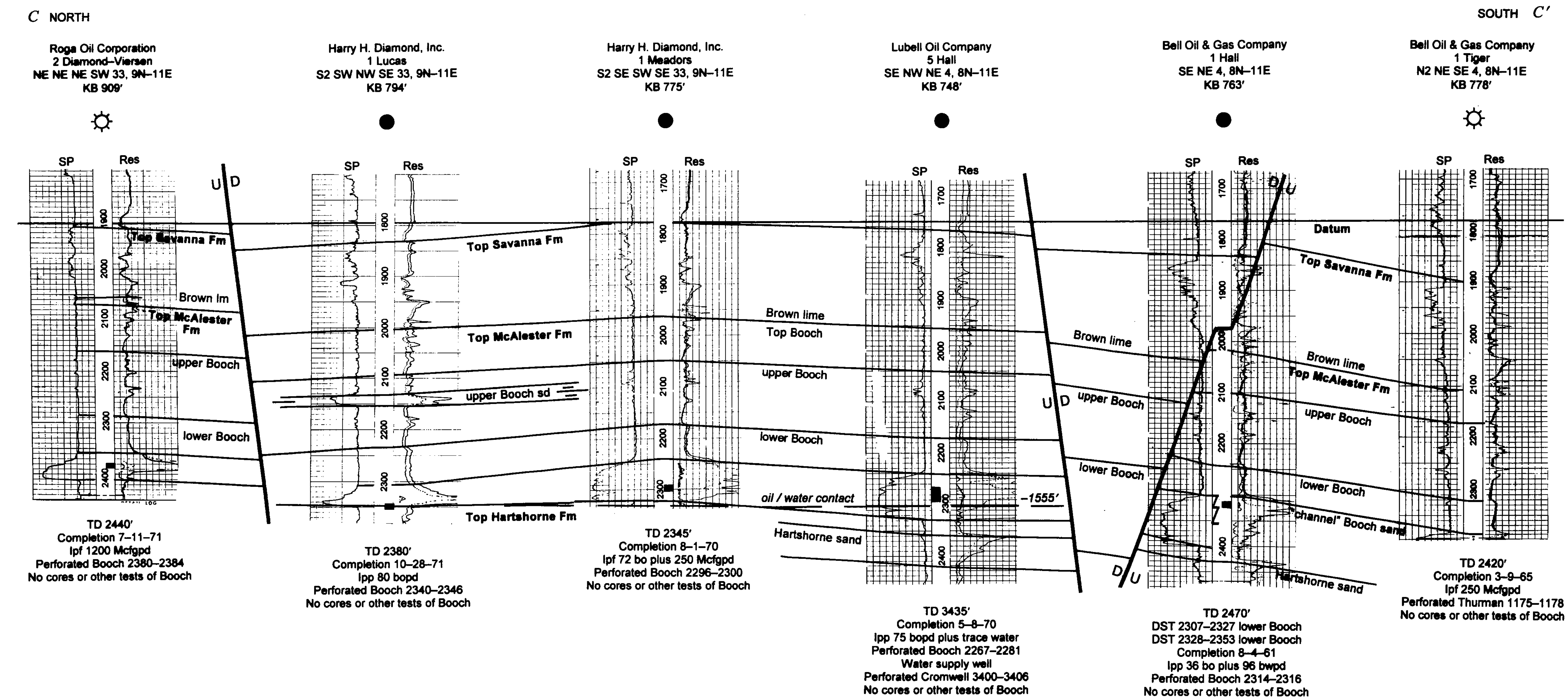
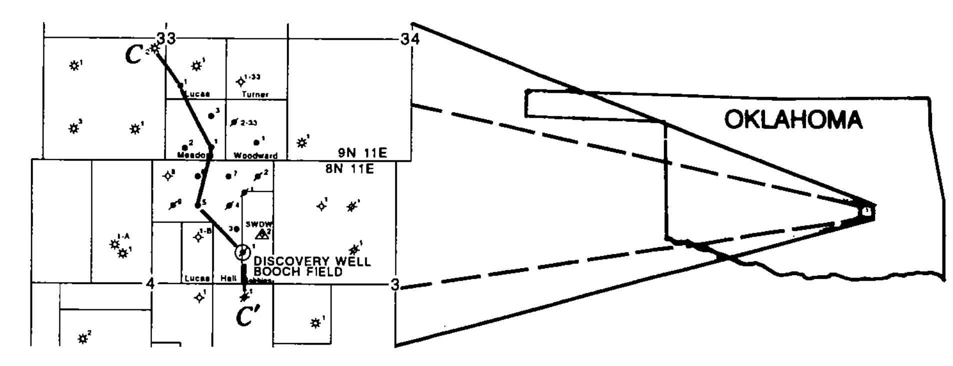


Figure 46. Stratigraphic cross section B–B′, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. Location of wells also shown on Figs. 49–53.

Vertical scale 1 in. ≅ 80 ft
No Horizontal scale
Datum: top lower Booch





INDEX MAP SHOWING LOCATION OF CROSS SECTION

Figure 48. Structural cross section C–C′, Booch oil reservoir, Greasy Creek field, Hughes County, Oklahoma. Location of wells also shown on Fig. 47.

Vertical scale: 1 in. ≅ 200 ft
Horizontal scale: None
Datum: 1000′ below mean sea level