Oklahoma
Geological
Survey
1997

Special Publication 97-5

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Cleveland and Peru Plays

FLUVIAL-DOMINATED DELTAIC OIL RESERVOIRS PROJECT IN OKLAHOMA

Oklahoma Geological Survey
Charles J. Mankin, *Director*

Special Publication 97-5
ISSN 0275-0929

Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma: The Cleveland and Peru Plays

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by

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

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

The University of Oklahoma
Norman, Oklahoma

1997

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Fluvial-Dominated Deltaic (FDD) Oil Reservoirs in Oklahoma

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INTRODUCTION TO THE FDD PROJECT

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

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

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

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

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

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

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

FDD-DETERMINING CRITERIA

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

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

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

DEPOSITIONAL SETTING OF FLUVIAL-DOMINATED DELTAIC RESERVOIRS

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

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

COASTAL FLOOD-PLAIN SYSTEMS

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

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

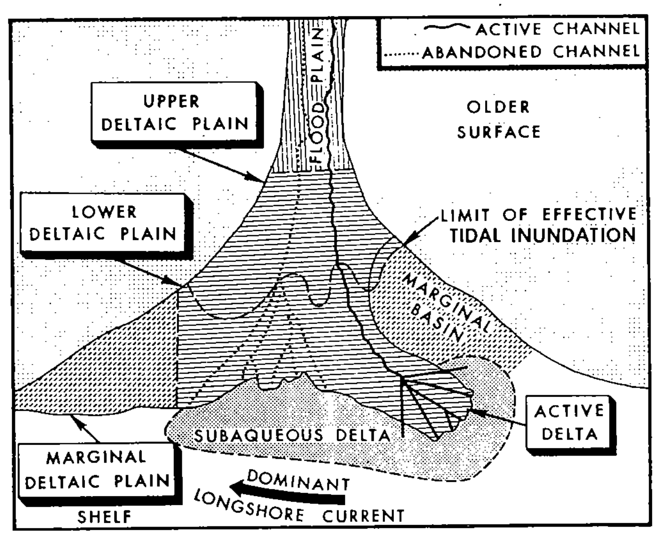
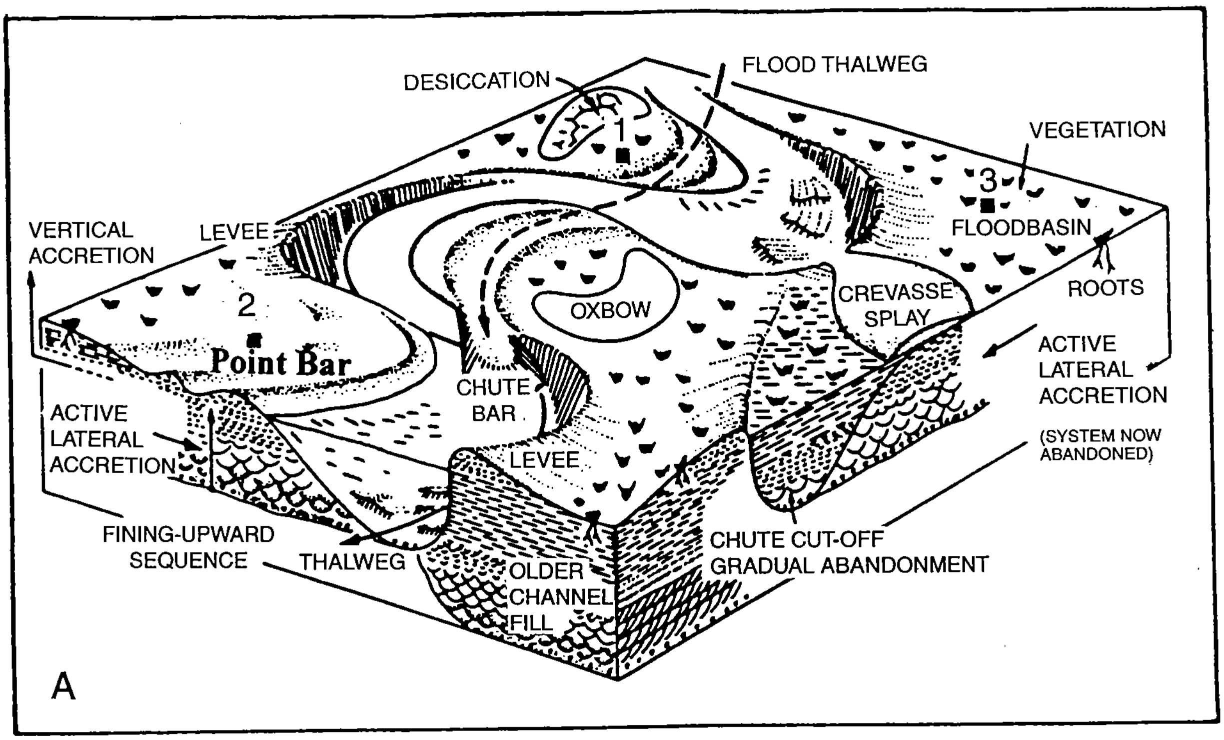


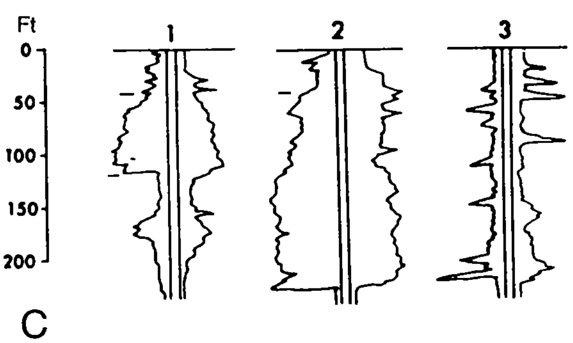
Figure 1. Components of a delta system. From Coleman and Prior (1982).

are the most common components of fluvial systems in Oklahoma.

Fluvial Point Bars

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





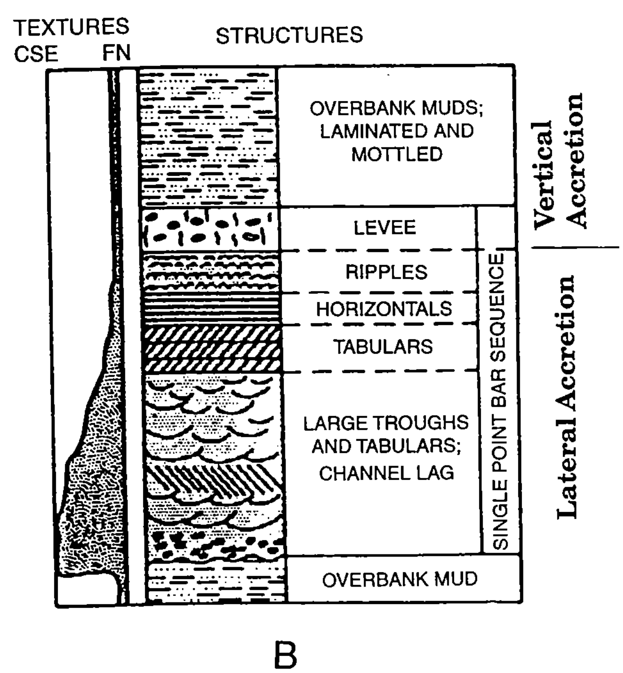


Figure 2. (A) Schematic model of a meandering river system. Erosion of the outside bend of a meander loop leads to lateral accretion of a point bar down-flow on the inside bank of the meander bed. Modified from Walker (1984). (B) Textural and facies characteristics of typical point-bar deposits. Modified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

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

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

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

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

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

DELTA SYSTEMS

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

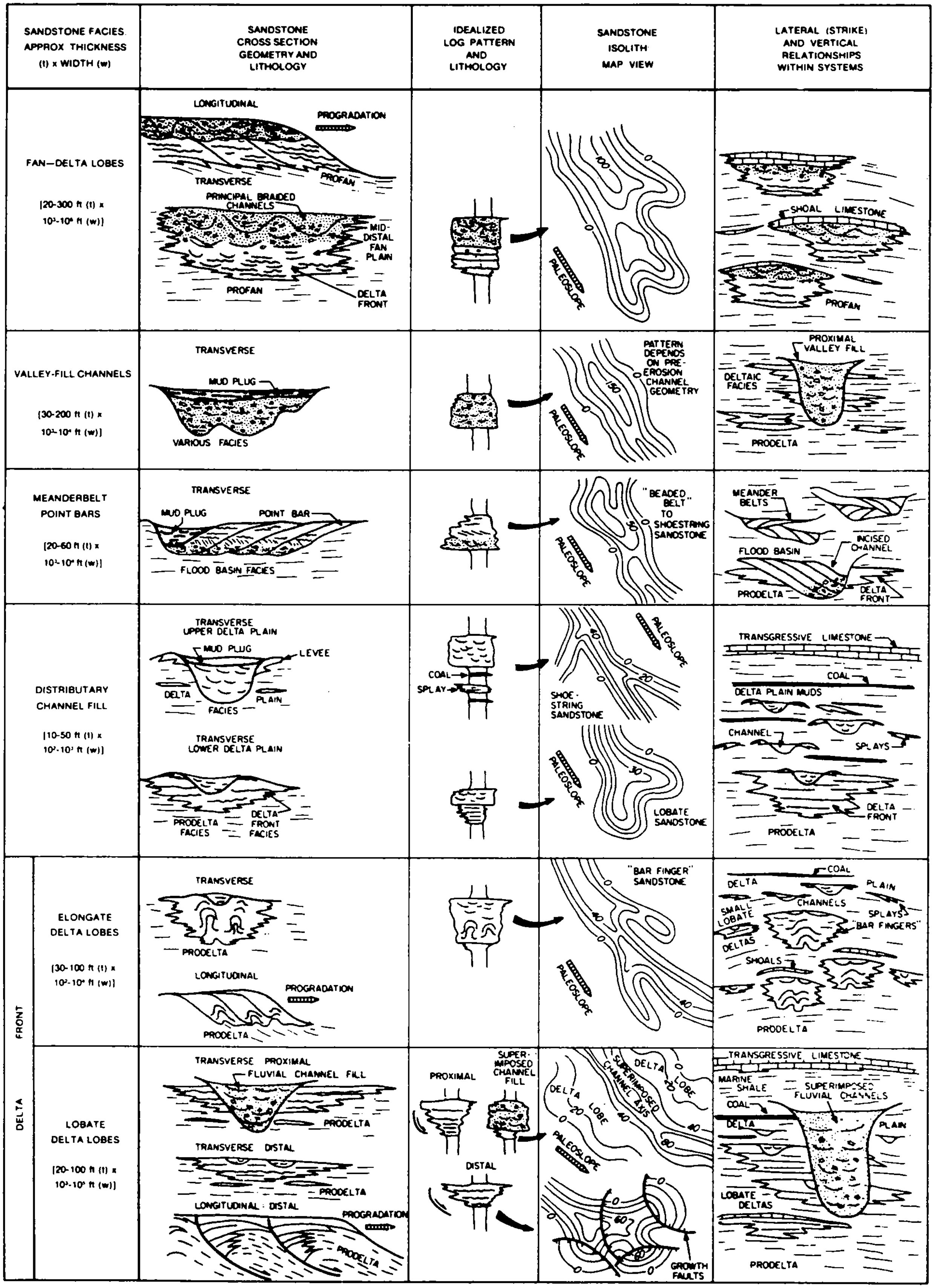


Figure 3. Summary of the characteristics of Midcontinent fluvial and deltaic sandstone bodies. From Brown (1979).

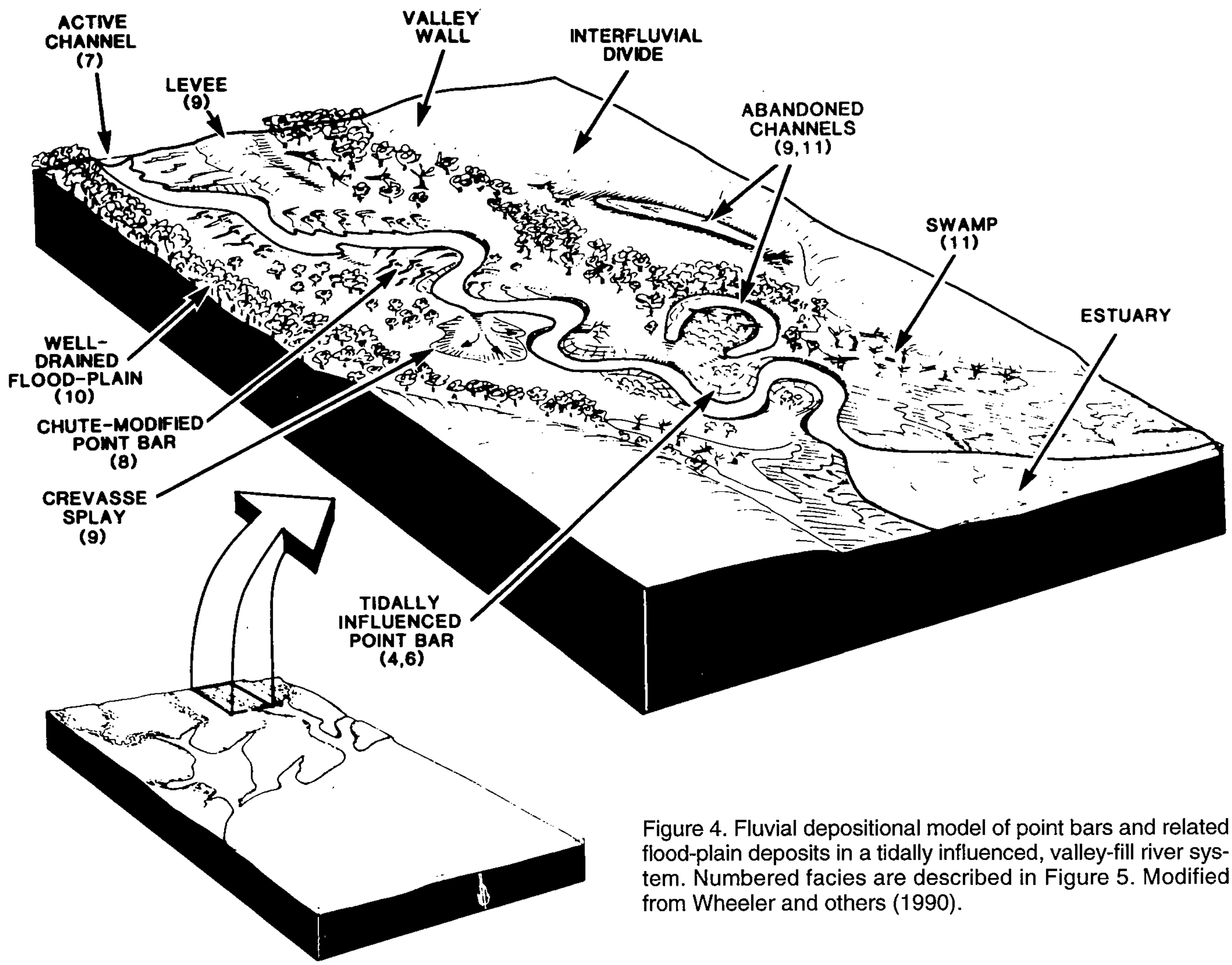


Figure 4. Fluvial depositional model of point bars and related flood-plain deposits in a tidally influenced, valley-fill river system. Numbered facies are described in Figure 5. Modified from Wheeler and others (1990).

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

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

Upper Delta Plain

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

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

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

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

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

Lower Delta Plain

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

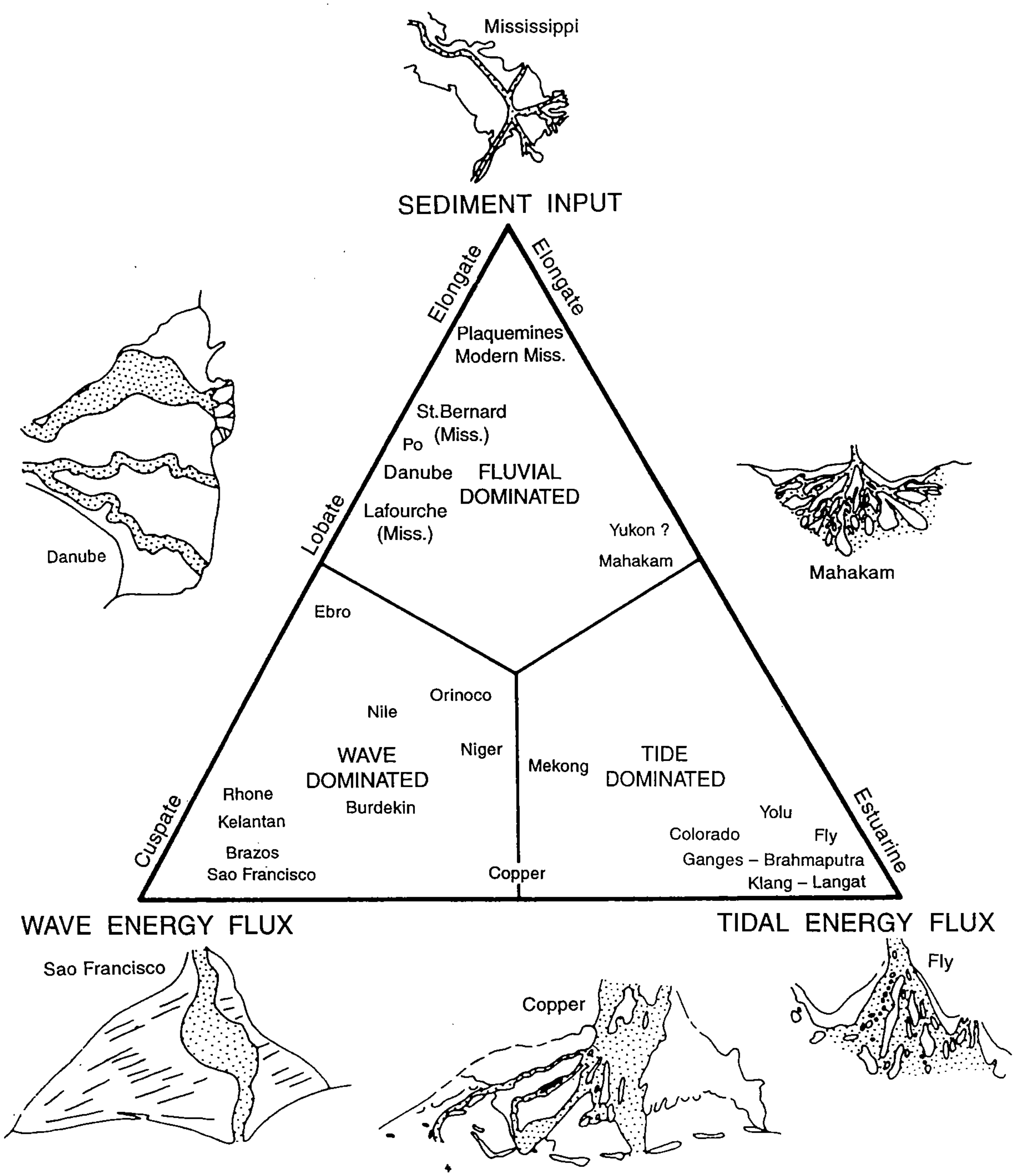


Figure 6. Morphologic and stratigraphic classification of delta systems based on relative intensity of fluvial and marine processes. From Galloway and Hobday (1983).

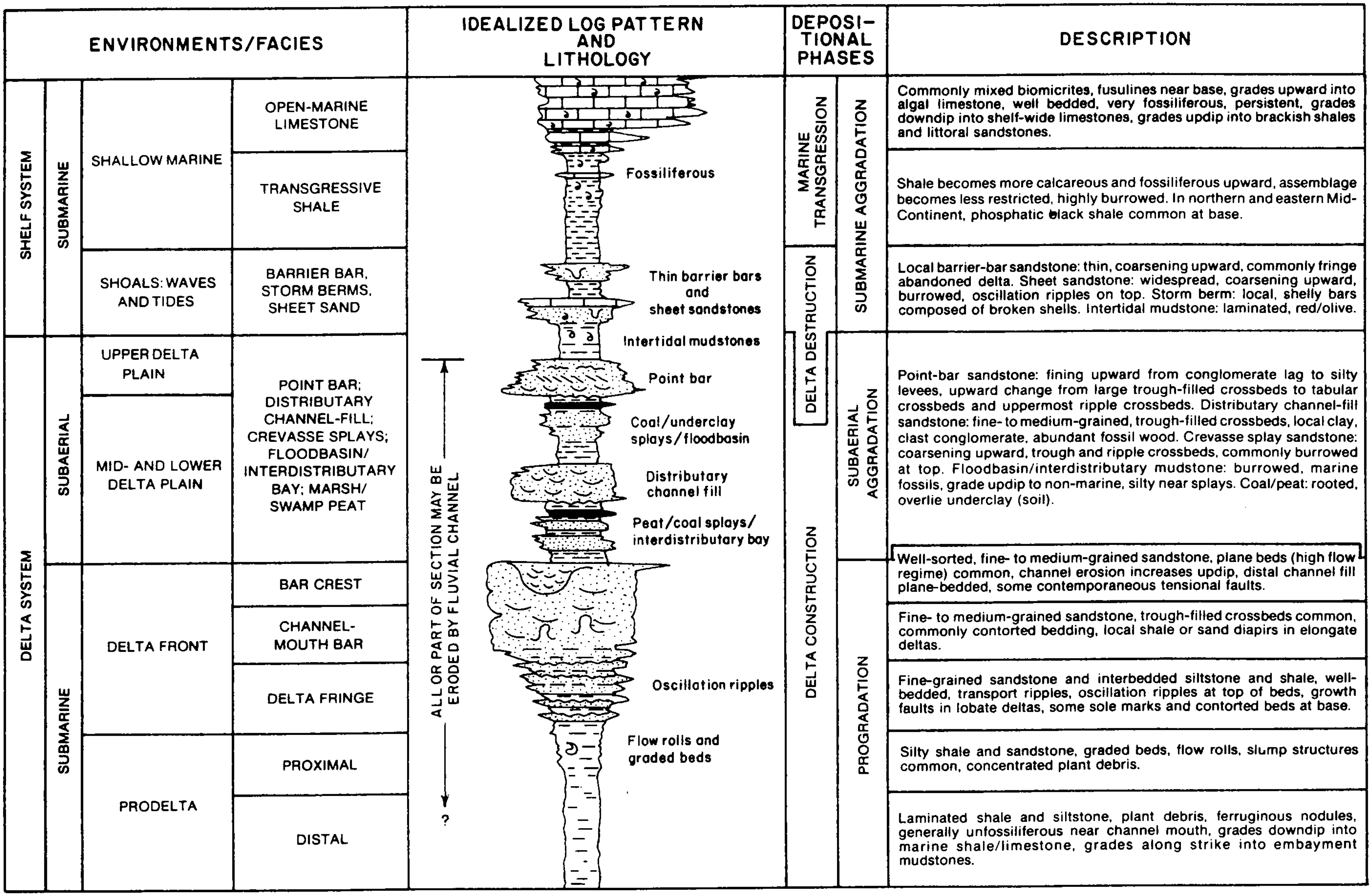


Figure 7. Idealized cratonic delta sequence showing principal depositional phases, idealized electric log pattern, and facies description. From Brown (1979).

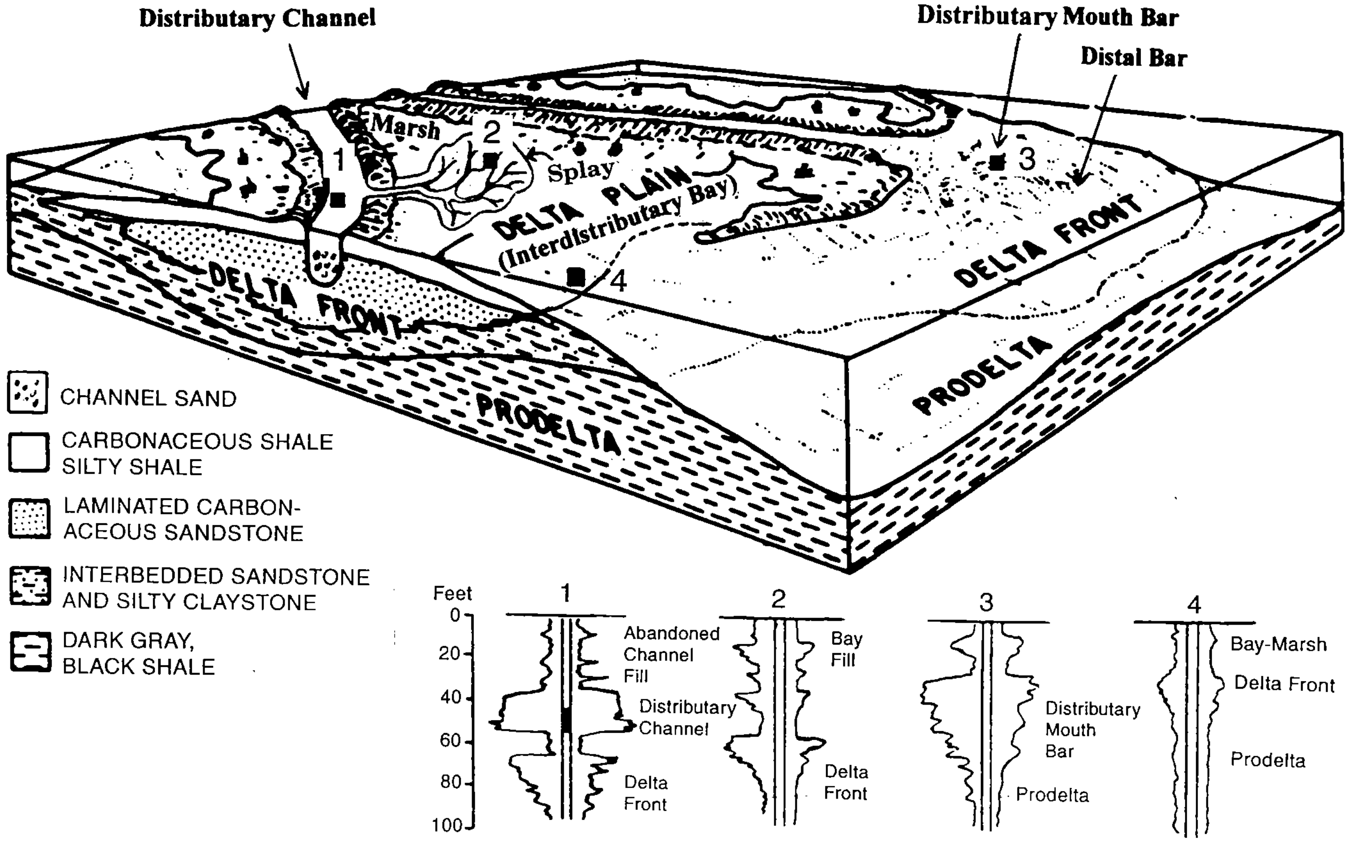


Figure 8. Schematic model of deltaic depositional environments. Idealized electric log responses and inferred facies are shown for locations Nos.1–4. Modified from Brown (1979).

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

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

Bay Fill and Splays

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

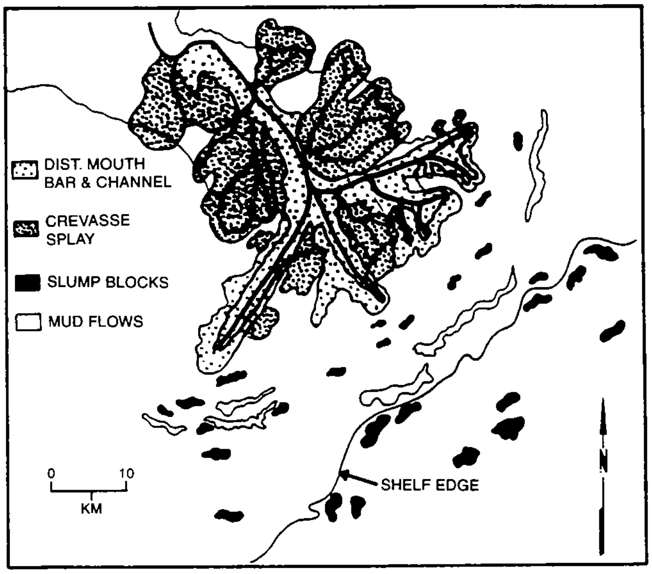


Figure 9. Distribution of principal sand facies in the modern Mississippi River fluvial-dominated delta. From Coleman and Prior (1980).

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

Distributary Channels

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

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

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

Distributary Mouth Bars and Bar Fingers

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

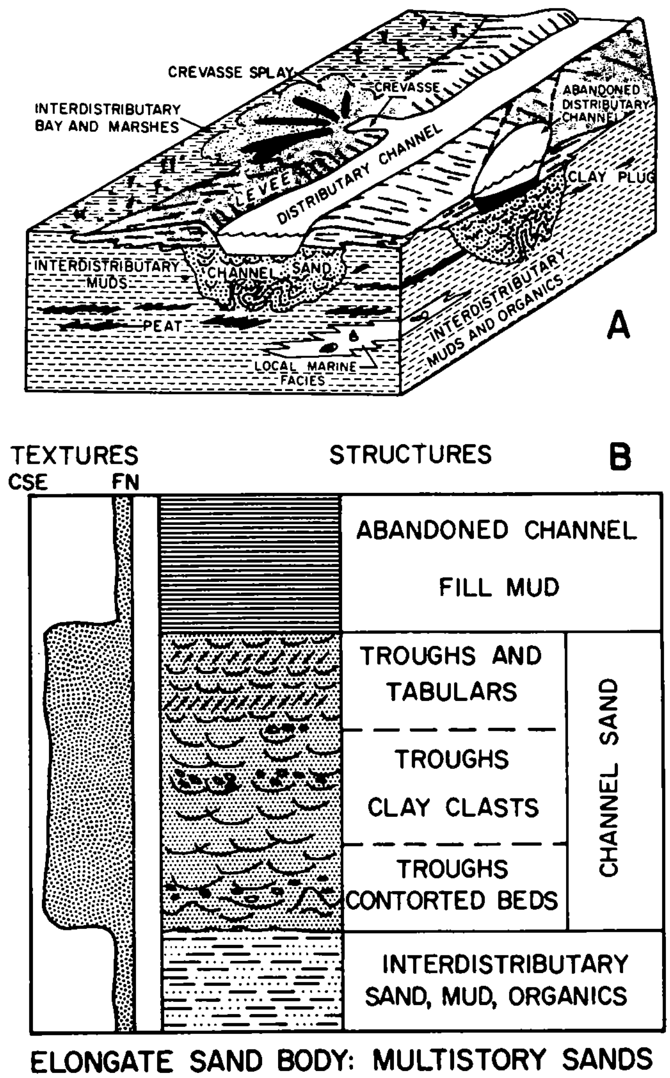


Figure 10. Distributary channel model. (A) Schematic model of channel-fill sands, lower delta plain setting; (B) idealized vertical sequence of distributary channel-fill sandstones. Modified from Brown (1979).

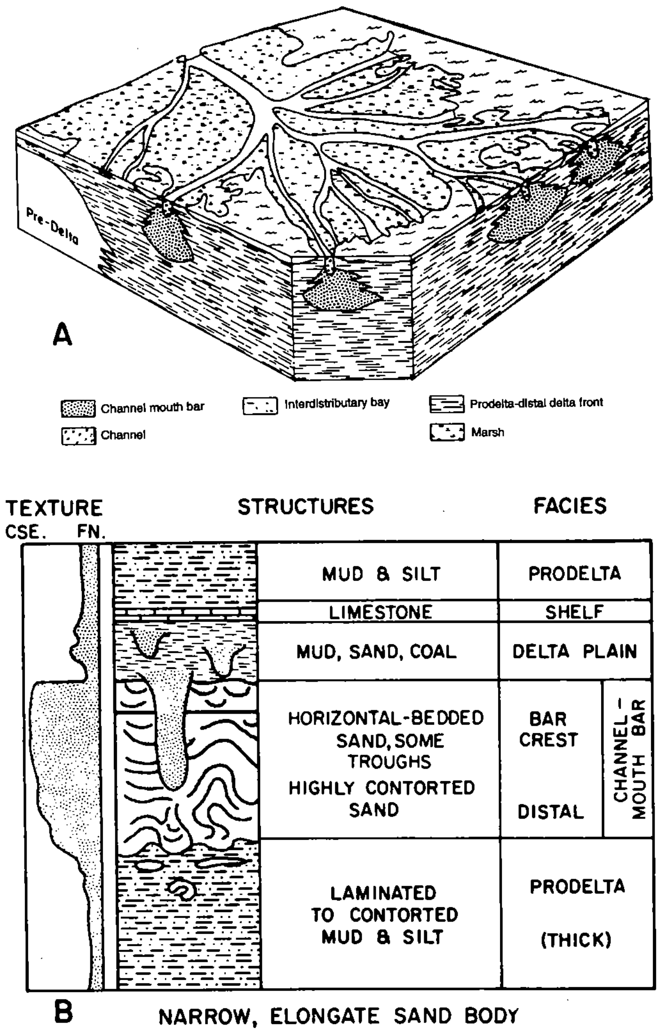


Figure 11. Elongate-delta model. (A) Birdfoot lobe, Holocene Mississippi delta; (B) idealized vertical sequence of a distributary mouth bar and associated deposits in an elongate delta. Modified from Brown (1979).

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

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

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

NOTE TO READERS

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

PART II

The Cleveland Play–Regional Geology

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INTRODUCTION

There are numerous sandstones of Pennsylvanian age at the surface and at shallow to intermediate depths on the Cherokee platform in northeastern Oklahoma. The area of the Cherokee platform is also commonly called the Chautauqua shelf or platform, especially in adjacent Kansas. As explained in the following section on stratigraphy and nomenclature, "Cleveland sand" is a general term applied to at least three Pennsylvanian sandstone intervals that commonly have irregular distribution in the study area in northeastern Oklahoma, shown in Figure 12.

Regional geologic structure in the Cleveland sand play area is a homoclinal dip to the west and to the west-southwest (Fig. 13). There are a few large folds and faults in the area (e.g., the Cushing anticline), as well as many local, commonly subtle, folds and faults. In Osage County, most of the minor structures were mapped by the U.S. Geological Survey (White and others, 1922; Bass and others, 1942); elsewhere, mapping was done by teams of company geologists and technicians (Owen, 1975; Withrow, 1965). Hydrocarbons are trapped both structurally and stratigraphically in Cleveland reservoirs. A linear nature, parallel to regional dip, is common to many deposits of Cleveland sands (Krumme, 1981). As a result, there are structural traps in some areas, many of which were discovered in the early decades of petroleum development in Oklahoma. However, in recent decades, stratigraphic traps have been the more common discoveries (see Rottmann, this volume).

The Cleveland sand has produced mostly oil, and locally gas, in central Oklahoma, from depths as shallow as ~200 ft in southeastern Osage County (Bird Creek field) to depths of ~5,700 ft in central Oklahoma County (Witcher field). First production from a Cleveland sand reservoir was in July 1904, in Indian Territory (later Pawnee County) in sec. 17, T. 21 N., R. 8 E., south of the Cleveland town site, where entrapment is mainly the result of local structure (Mills-Bullard, 1928). Initial production was ~50 BOPD, from a depth of ~1,615 ft (Clare, 1963). Bosworth (1920) and Greene (1928) report that early wells in the reservoir were completed at rates of 25–300 BOPD, from 1,500–1,700-ft depths. Although the Cleveland sand reservoir was reported to be 20 ft thick (Greene, 1928), it reaches thicknesses of well over 100 ft in the local area (Krumme, 1981).

There also was early production from the Cleveland sand in the Wildhorse field, southeastern Osage County. Discovery was in 1912, but significant development did not begin until 1917, evidently because of legal considerations (Mills-Bullard, 1928). Entrapment of hydrocarbons appears to be mainly the result of local geologic structure (Beckwith, 1927; Kirk and others, 1941). The Cleveland sand occurs ~1,150 ft below the surface and reportedly is as much as 100 ft thick. Initial production was 6–20 BOPD (Mills-Bullard, 1928); however, according to Bass and others (1938), initial production from the Cleveland sand reservoir varied from less than 10 to 150 BOPD. In many wells it was less than 25 BOPD, evidently because of the extremely lenticular character of the sandstone. Both of these fields continue to produce oil from Cleveland sand reservoirs. The Cleveland sand is also recognized in western Oklahoma (Pls. 1–3, in envelope), where gas production is mainly from marine sandstones, and in adjacent northwestern Texas. Although the sediment source areas were adjacent uplifts, the Cleveland sand of that western region occupies a stratigraphic position similar to that in the area of the present study in northeastern Oklahoma. The Cleveland sand of the Texas Panhandle has been reported on by Hentz (1994).

The Cleveland sand has produced oil and gas for more than 92 years, but the cumulative production total is lost to history. Although Cleveland sands are widely regarded as secondary objectives today, production from them has been significant, and they probably still have production potential locally. The historical record of oil production from the Cleveland sand is incomplete. However, from 1979 through 1994, Cleveland production was reported from 158 fields and also was reported locally from leases not assigned to fields. Several fields produce only from Cleveland sand reservoirs (Pl. 1). Leases and wells with reported production from the Cleveland sand are presented in support of the fields map (Pls. 2 and 3). Table 1 and Figure 14 summarize oil production, mostly by "stripper" wells, from Cleveland sand reservoirs in recent years.

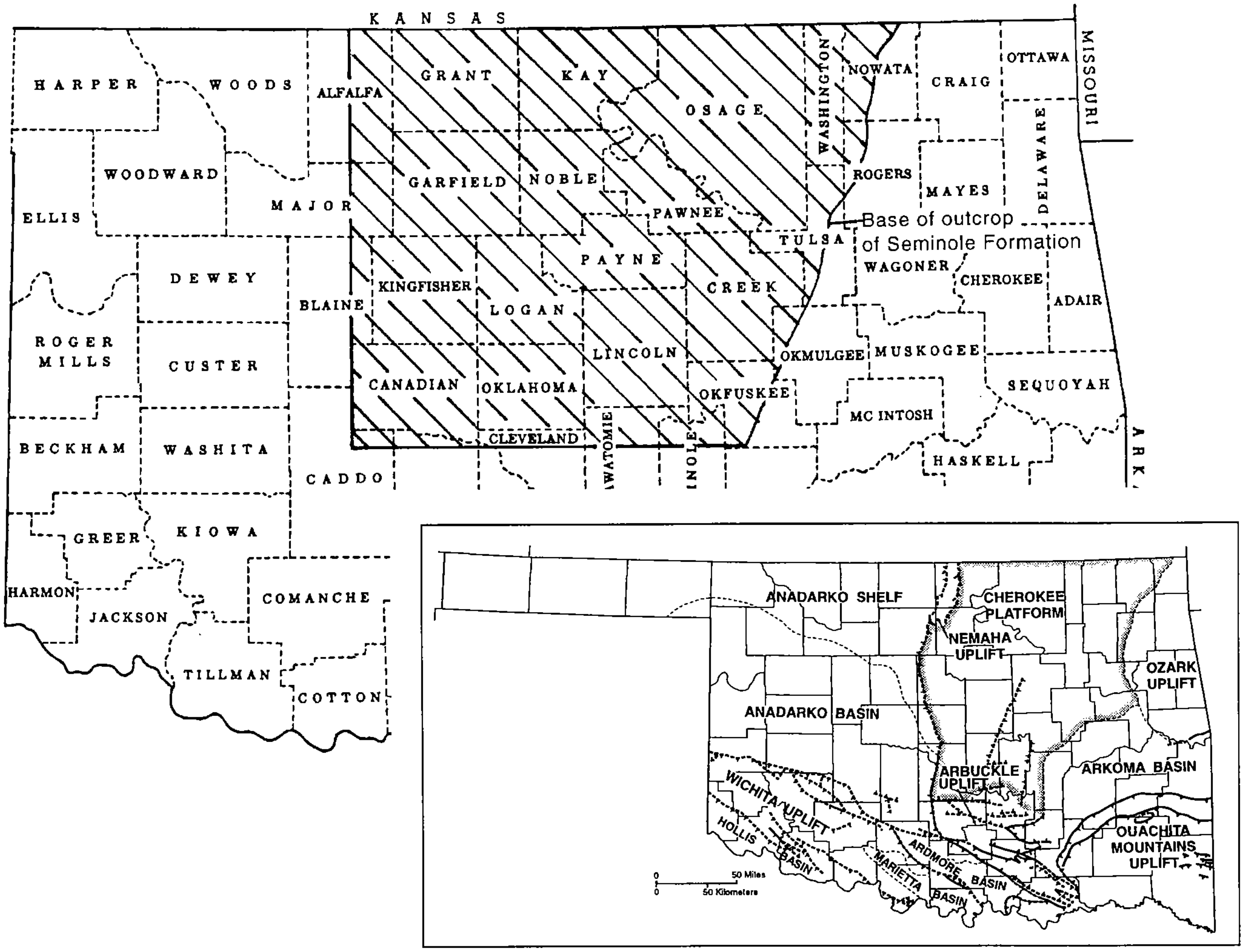

Figure 12. The Cleveland sand play is located in northeastern Oklahoma (hatch-marked area), primarily on the Cherokee platform structural province. The eastern limit of strata with which the play is concerned is generalized from Johnson and others (1988).

The source of oil and gas in these reservoirs has not been demonstrated in any published study. There may be multiple sources; however, Ece (1987, 1989) showed that the Excello Shale (Desmoinesian) is rich in organic matter and thermally mature in the Midcontinent region. Although the Excello Shale is older, I speculate that oil and gas also have been generated locally from marine shales of Late Desmoinesian age that are associated with Cleveland reservoir sandstones. In the case of large structural traps, hydrocarbons may have migrated vertically along faults and fracture systems from deeper source rocks.

CLEVELAND SAND PLAY STRATIGRAPHY AND NOMENCLATURE

The Cleveland sand occurs in the stratigraphic interval between the Oologah (Big lime) and Checkerboard Limestones (Figs. 15, 16). That interval is >700 ft thick in east-central Creek County, but it is <100 ft thick in northern Osage County (Krumme, 1981; this report). The Checkerboard Limestone is extensive regionally and provides a convenient datum for mapping regional geologic structure (Fig. 13), and for two regional stratigraphic sections (Pl. 4, in envelope). In common subsurface practice, the Cleveland sand is recognized as occurring just below the Checkerboard Limestone, but locally it extends to 300 ft or more below the Checkerboard. The three major sandstones that form the Cleveland sand interval are persistent in part of the study area. However, as is typical of sandstone intervals, locally each of them may separate into two or more sandstone bodies, or be absent. Thus, the application of the terms "upper" and "lower" Cleveland sand cannot be expected to be consistent or meaningful except very locally.

Cleveland sand is an informal subsurface term, first used by drillers at the Cleveland oil field in eastern Pawnee County in 1904. The Cleveland sand interval (term defined below) in the study area commonly consists of as many as three persistent, but not continuous,

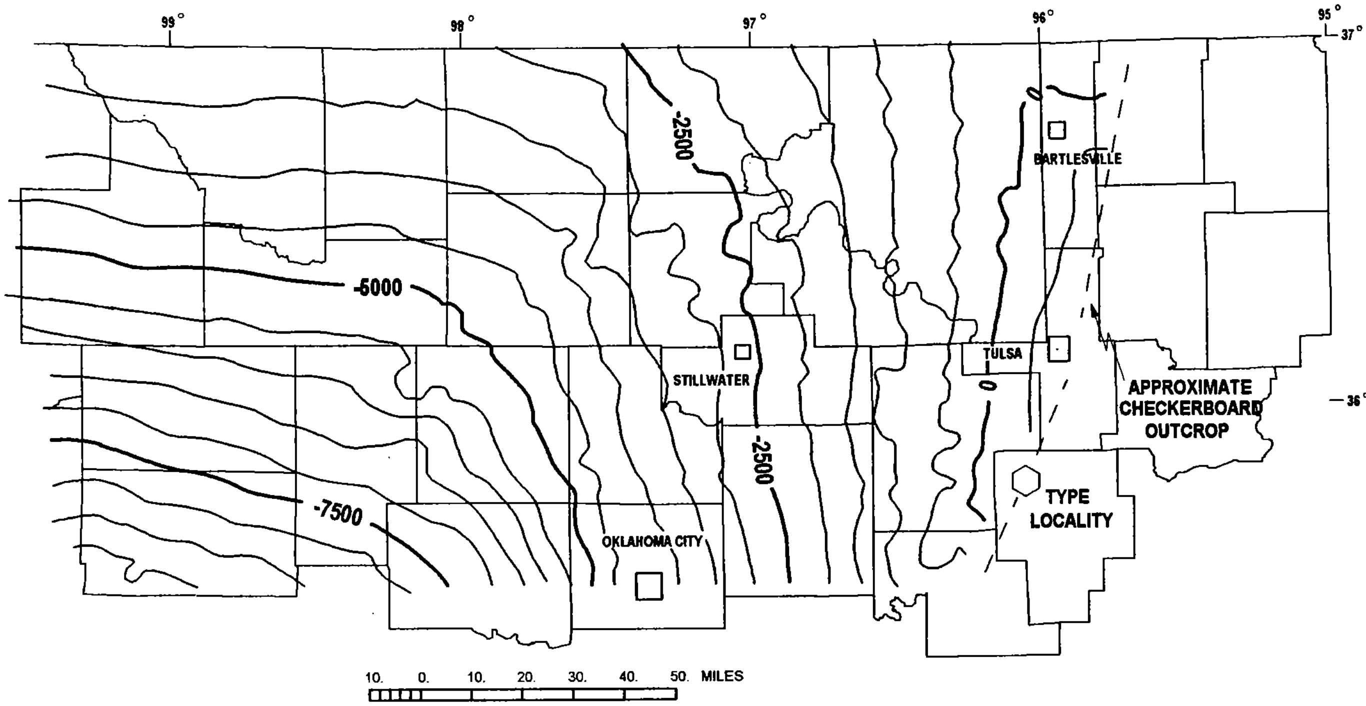

Figure 13. Regional geologic structure on top of the Lower Missourian Checkerboard Limestone, a persistent subsurface marker at the top of the Cleveland sand interval. Sea-level datum; contour interval 500 ft. Compiled from more than 2,300 wells in the Natural Resources Information System (NRIS) data base; wells in five sections (secs. 5, 8, 15, 26 and 29) were selected initially. Edited CAD map by Carlyle Hinshaw, petroleum geologist.

bodies of sandstone. The lowermost ("lower" Cleveland sand in the subsurface) occurs most widely and commonly is the thickest. The upper two sandstone bodies are less widespread, but also are significant hydrocarbon reservoirs locally. The use of the terms "upper" Cleveland sand and "lower" Cleveland sand causes considerable confusion, especially since, in fact, there are three major sandstone intervals. Jordan (1959, p. 97) reports that the 200 ft of rock section below the Checkerboard Limestone contains "...four sandstone beds, each 20 to 30 feet thick, separated by shale beds of comparable thickness" locally in north-central Creek County. This will be explained in the following several paragraphs.

It is generally recognized that, where the Dawson coal occurs, the "lower" and "upper" Cleveland sands occur below and above the Dawson coal (Jordan, 1957, p. 45). This definition, accepted by most published stratigraphers, is synthesized in Figure 15.

In spite of efforts to define the term accurately, "Cleveland sand" commonly is an indefinite stratigraphic name in much of the area in which it is applied. The term has been part of the historical record of more than 90 years, and it would be counterproductive to attempt to revise the subsurface nomenclature. Because of the discontinuous nature of sandstone bodies, and the fact that radioactive shale, e.g., Nuyaka Creek shale (Fig. 15; Pl. 4), and coal stratigraphic markers do not occur everywhere with the subject sandstones, the name "Cleveland sand" is nonspecific. Because of the highly variable development of the Cleveland sand, and the presence of sandstone in the overlying Seminole Formation, application of the term "Cleveland" commonly is vague. It is useful, however, as a general term applied to any sandstone development in the middle and upper part of the Holdenville Shale, and in the Seminole Formation, and certainly *below* the Checkerboard Limestone. Thus, many workers (e.g., Bass, 1942; Jordan, 1959; Clare, 1963; Krumme, 1981; Tulsa Geological Society, Stratigraphic Committee, 1984–1989) prefer to identify it as the Cleveland sand zone in electric log sections and/or in text. Because the term "zone" is commonly applied to oil and/or gas production intervals, and because "zone" has specific application to biostratigraphic units (North American Commission on Stratigraphic Nomenclature, 1983), the designation "Cleveland sand interval" will be used in this report to refer to subsurface sections where the Nuyaka Creek shale is not identifiable (Pl. 4). In this study of the Cleveland sand, quotation marks are used with "upper" and "lower," as well as with other stratigraphic terms that commonly are applied to more than one stratigraphic interval, or are meaningless because of lack of definition.

The sandstone intervals known as the Cleveland sand in the subsurface are prominent at the surface locally; they are in the lower part of a surface section in southwestern Tulsa County measured by Oakes (1959,

TABLE 1. – Crude Oil Production from Cleveland Sand Reservoirs, 1979–95

Reservoir	Leases reporting[a]	Cumulative oil	Average BO/lease	Other leases[a,b]
Cleveland sand	326	11,445,443	35,109	264
"Jones sand"[c]	56	999,696[d]	17,852	34

[a]Average number of leases reporting per year during the time frame, 1979–95.
[b]Production commingled with that from other formations.
[c]Locally, the "upper" Cleveland sand is known as the "Jones sand."
[d]"Jones sand" reservoirs include production from Cleveland sand and other formations.
SOURCE: Natural Resources Information System (NRIS) oil and gas production data base, Oklahoma Geological Survey, Norman.

plate II). The sandstones, which are separated by the Dawson coal, were not given formal names until Bennison (1984) proposed the names *Jenks Sandstone* and *Tulsa Sandstone* as members of the Holdenville Formation (Fig. 15). The Jenks Sandstone is the same interval as the lower, or basal, sandstone of the Seminole Formation of Bennison (1972), of Krumme and Visher (1972), and of many previous reports (e.g., Ries, 1954; Greig, 1959; Oakes, 1959; Jordan, 1959; Clare, 1963).

The Tulsa Sandstone was formerly identified as the middle sandstone of the Seminole Formation by Bennison (1972) and Krumme and Visher (1972, p. 105); locally, it is as much as 85 ft thick in the city of Tulsa (Bennison, 1972). In addition, Bennison (1984) and Heckel (1991) agree that the Tulsa Sandstone is the stratigraphic equivalent of the Hepler Sandstone in southeastern Kansas.

The correct identification of the Cleveland sand(s) depends on the presence and recognition of the Dawson coal (Jordan, 1957; Bennison, 1979, fig. 1; 1984). A more extensive stratigraphic marker, especially in the subsurface, is the Nuyaka Creek shale, a black marine shale. It occurs immediately above the Dawson coal on the surface in eastern Oklahoma and adjacent Kansas (Heckel, 1991; L. A. Hemish, personal communication, 1996). The Dawson coal was correlated in the subsurface in much of Creek County by Jordan (1959) and in southeastern Pawnee County by Clare (1963). The Nuyaka Creek black shale bed was not recognized until much later (Bennison, 1981), but it seems probable that the subsurface marker identified by Jordan (1959) often is the Nuyaka Creek shale rather than the Dawson coal, or is a combination of the two. Occurrences of the Nuyaka Creek shale are identified on Plate 4. Neither the Dawson coal nor the Nuyaka Creek shale occurs in the area of the Cleveland oil field; however, in the 1950s, defining the Cleveland sand stratigraphically in relation to the Dawson coal was the consensus of geological and petroleum-industry understanding and usage (Jordan, 1957), and the practice continues in the 1990s (Fig. 15). The Nuyaka Creek shale commonly is absent where the Cleveland sand is relatively thick; either it was eroded prior to deposition of the Tulsa Sandstone ("upper" Cleveland sand), or, it was not deposited because of fluvial influx of the Jenks Sandstone ("lower" Cleveland sand).

An additional complexity is added to nomenclature and correlation by at least one persistent sandstone that overlies the Jenks and Tulsa Sandstones (Fig. 15). It is the same interval as the upper sandstone member of the Seminole Formation of Bennison (1972). Although commonly it is less well developed than the underlying sandstones, it appears to have considerable lateral extent in the subsurface. In the subsurface, it has been called the "Cleveland sand," the "upper Cleveland sand," or the "Seminole sand," as it is within the Seminole Formation (Fig. 15). The latter name causes confusion because of its earlier application to sandstones of Ordovician age in the Seminole field, Seminole County (Levorsen, 1928). The Dawson coal (probably includes the Nuyaka Creek shale) has been identified by Jordan (1959) and Clare (1963) in the subsurface. They described at least *two* sandstone intervals *above* the Dawson coal locally in much of northern Creek and southeastern Pawnee Counties (also see Pl. 4: A–A′, wells 5 and 6; B–B′, well 6). Thus, it is apparent that this sandstone may have significant continuity in the subsurface. In the absence of the Dawson coal and/or Nuyaka Creek shale, or if their presence is not recognized, this sandstone interval in the Seminole Formation is inseparable from the Cleveland sand. It would seem to be convenient to have a name for this sandstone; however, it can be separated only locally from underlying sandstone bodies. Therefore, the most pragmatic way to deal with this sandstone interval in the Seminole Formation is to continue to recognize it as part of the informal *Cleveland sand interval* in the Cherokee platform (Fig. 15).

The term "Checkerboard sand" has been applied locally to sandstone that occurs immediately *above* the Checkerboard Limestone (Jordan, 1957; Kurash, 1964). Sandstone in this stratigraphic position is part of the Seminole Formation, as shown by Hemish (1987). The name "Checkerboard sand" also has been applied (on wireline logs and completion cards) to sandstone just *below* the Checkerboard Limestone. Sandstone in this stratigraphic position, also part of the Seminole Formation (Bennison, 1984; Hemish, 1987), is part of the Cleveland sand interval in the subsurface (Fig. 15). The term "Checkerboard sand" seems to serve no useful purpose, and its continued use is discouraged.

The "upper" Cleveland is also known locally as the "Jones sand," and the "lower," as the "Dillard sand" (Jordan, 1957, 1959). A review of lease production found that oil production from "Jones sand" is associ-

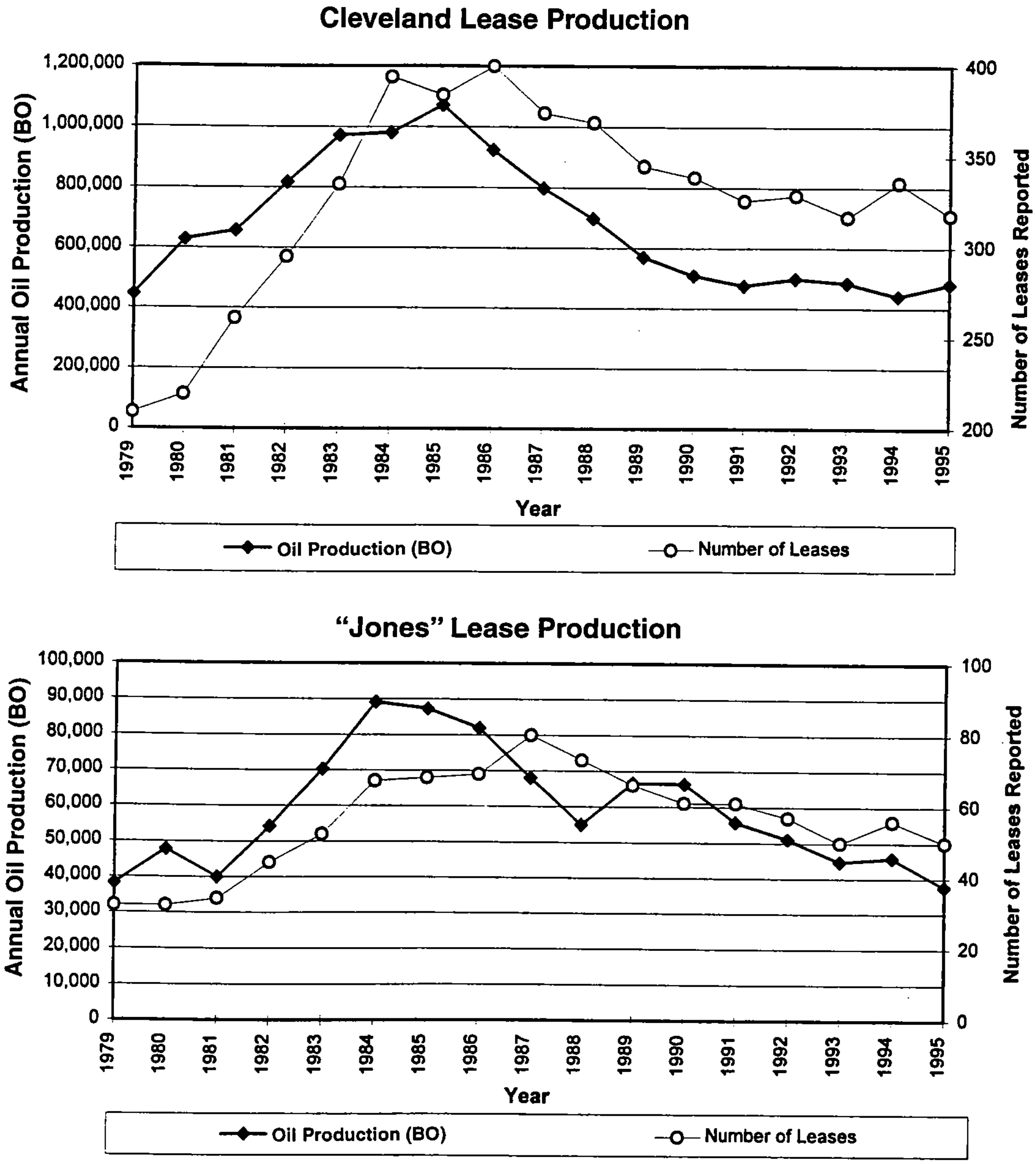

Figure 14. Crude oil production from Cleveland sand and "Jones sand" reservoirs, 1979–1995. (Locally, the "upper" Cleveland sand is known at the "Jones sand.")

ated with that from Cleveland sand, especially in west-central Creek County. However, production from "Jones sand" also occurs locally in the Cherokee Group (below the Fort Scott Limestone). The name "Jones" apparently has been applied so widely that it would be best to discontinue its use where possible. A review of lease production from "Dillard sand" found no production from any reservoir so named in the Cherokee platform in the time interval 1979–1996. Thus, use of the name "Dillard sand" in the Cherokee platform has no merit except in the historical record. In her study of Creek County, Jordan (1959, p. 97) states: "...these names [e.g., 'upper Cleveland,' 'lower Cleveland,' and 'Jones'] are variously applied depending on the number of separate sand bodies locally present above the Fort Scott Limestone." Certainly the "Dillard sand" needs to be added to her list.

The name "Wayside sand" also has been applied to sandstones that occur locally in the stratigraphic position of the Cleveland sand. The name was applied originally in the subsurface to the Walter Johnson Sandstone Member of the Nowata Shale, in southern Montgomery County, Kansas (Jordan, 1957). It is known to be 4–10 ft thick where it crops out in Kansas (Zeller, 1968, p. 26). The "Wayside" occurs below the Cleveland, and both sandstones occur in the interval between the Oologah and Checkerboard Limestones, which may be <100 ft thick in northern Osage County.

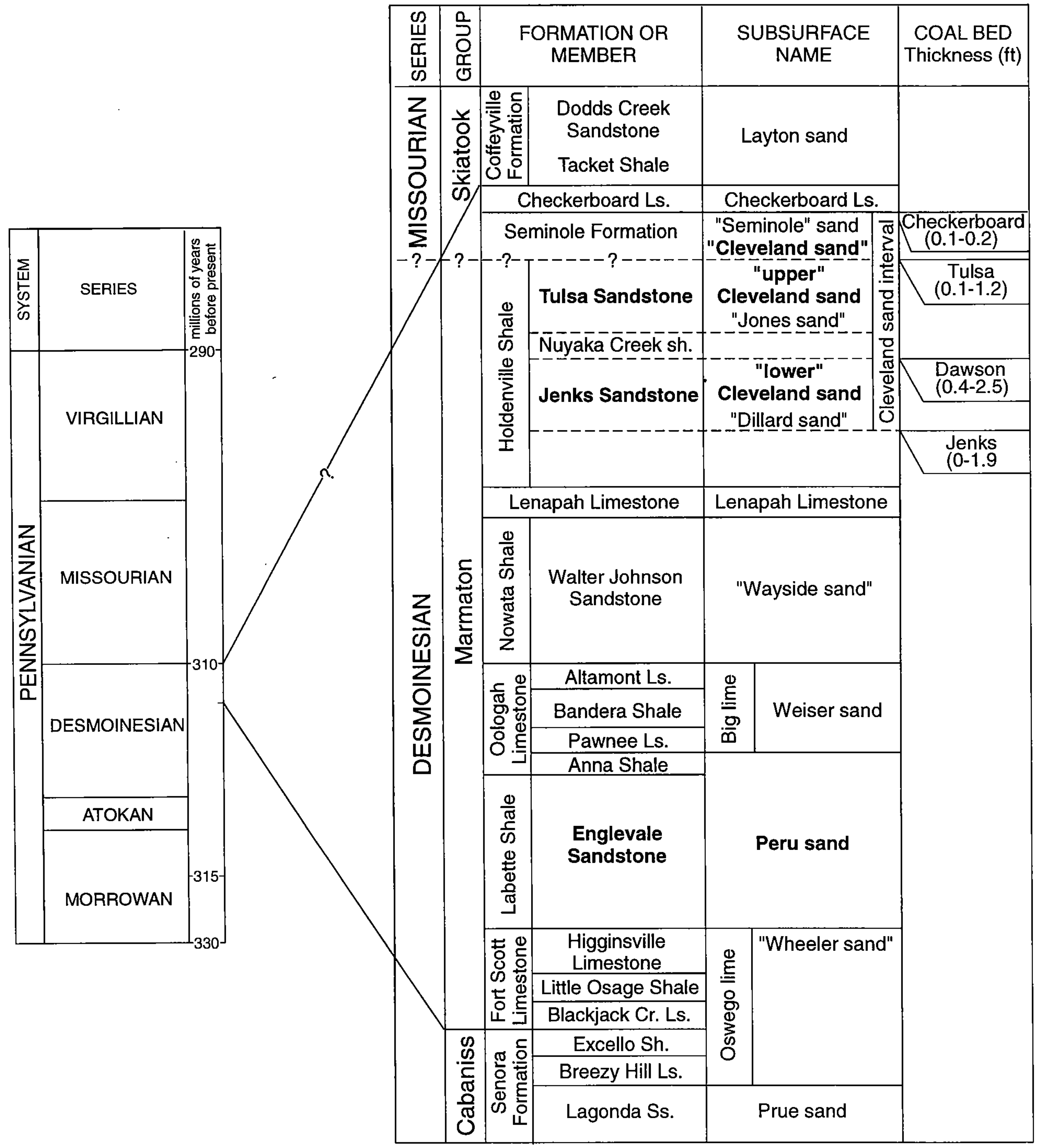

Figure 15. Stratigraphic nomenclature of the Marmaton Group (late Desmoinesian) and adjacent strata on the Cherokee platform, northeastern Oklahoma. See page 15 of text for explanation of use of quotation marks. Modified from Hemish (1989, 1990), Tulsa Geological Society (1984–89), Cole (1967), Heckel (1991), and Fay (1987).

However, they are separated locally by the Lenapah Limestone, as shown on Plate 4 (B–B′, wells no. 7, 8) and on the type log for north-central Osage County, sec. 22, T. 27 N., R. 8 E. (Tulsa Geological Society, 1989). The "Wayside sand" is easily recognized in the Nowata Shale, above the Oologah and below the Lenapah Limestone (Fig. 15). The Stratigraphic Committee of the Tulsa Geological Society also recognizes the "Wayside sand" in northern Washington County, sec. 11, T. 28 N., R. 13 E (Tulsa Geological Society, 1989), where it is ≤25 ft thick. In his study of the Marmaton Group, Krumme (1981, fig. 32) shows the "Wayside sand" in thicknesses of <20 ft in northeastern Osage County. The common confusion of "Wayside sand" with the

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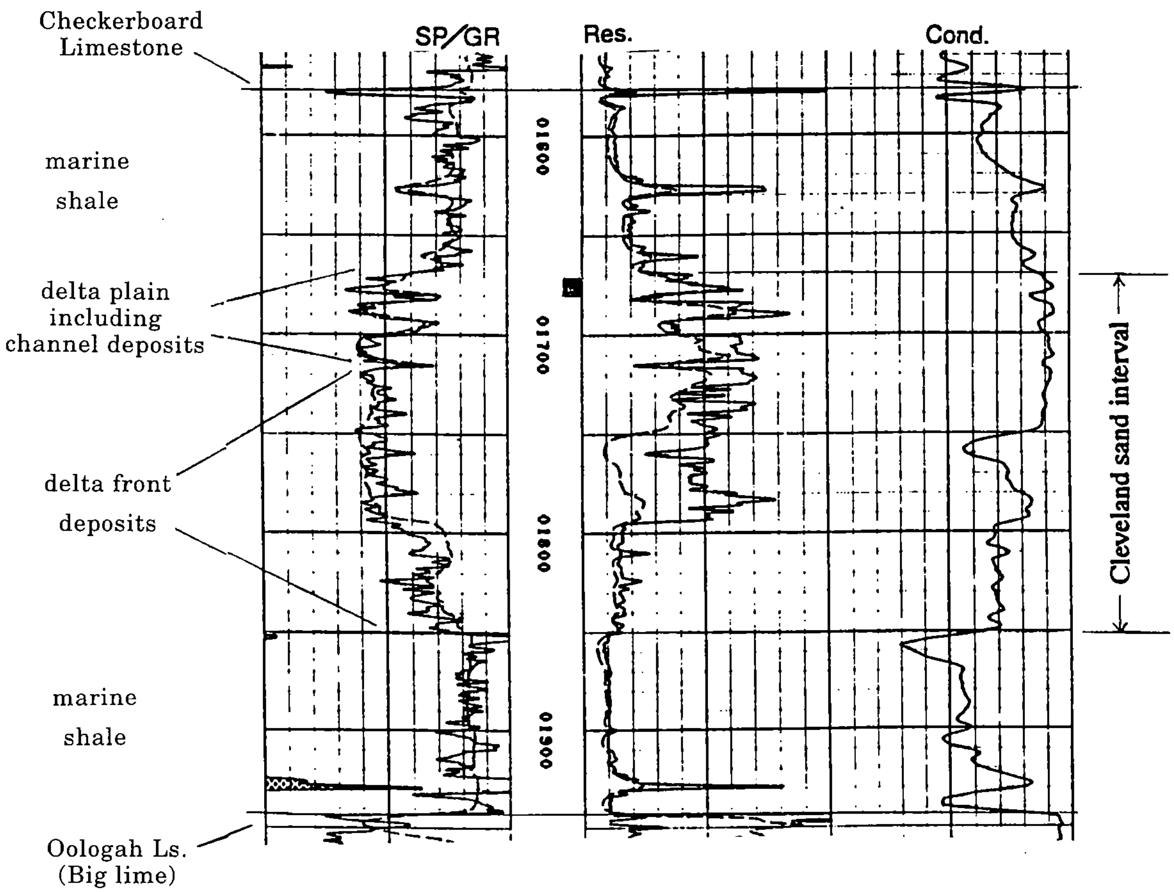


T.D. 2,430 ft
Comp. 1–17–1984
Perf. Prue sand 2,070–2,078
Perf. Skinner sand 2,194–2,202
Perf. Bartlesville sand 2,324–2,350
IPP: 9 BOPD and 30 BWPD

OWWO 7–29–1988
Prue sand: no new treatment
Skinner sand: no new treatment
Perf. Big lime 1,943–1,955
Perf. Cleveland sand 1,672–1,680, 1,684–1,692, 1,700–1,712
IPP: 18 BOPD and 265 BWPD, API Gravity 39°

Figure 16. Reference log for the Cleveland sand. Spontaneous-potential (SP), gamma-ray (GR), resistivity, and conductivity log profiles for the stratigraphic interval of the Cleveland sand.

Cleveland sand in northern Osage and Kay Counties is demonstrated by the habit of the Checkerboard and Lenapah Limestones, as shown by Krumme (1981, fig. 9). The Checkerboard and Lenapah Limestones are separated locally by only a few feet of shale in Kay and northwestern Osage Counties (Fig. 17). Drillers (and some geologists) are inclined to call the entire carbonate interval "Checkerboard" because it is the first of the two limestones penetrated by the drill. Therefore, because the Lenapah is difficult to recognize, the sandstone that occurs locally *below* that limestone interval commonly is taken to be Cleveland.

There is a more significant geographic association of the "Wayside sand" with the Peru sand play (Northcutt, this volume). However, the Peru sand occurs in the Labette Shale; thus, it is separated from the position of the "Wayside" by two important limestones, the Pawnee and the Altamont (Big lime of the subsurface), as shown in Figure 15. The above information should help eliminate confusion of the "Wayside sand" with either the Cleveland sand or the Peru sand in most of the Cherokee platform.

In the absence of the Lenapah Limestone, the correct identification of the "Wayside sand" is more difficult. The "Wayside" would be anticipated to occur in the lower to middle part of the undivided Nowata and Holdenville Formations. Sandstone occurs locally in that stratigraphic position in Creek County (Pl. 4, B–B′, wells no. 3, 4), where it was identified as the "Wayside zone" by Jordan (1959, pl. D). However, it seems unlikely that this sandstone is genetically related to the "Wayside sand" that occurs in northern Osage and Kay Counties.

There is also local sandstone development within the Big lime of the subsurface, called the Weiser sand. It is a coarse facies of the Bandera Shale Member of the Oologah Limestone (Jordan, 1957), as shown on Figure 15. Oil has been produced from the Weiser sand in northeastern Osage and central and southwestern Nowata Counties (Sartin, 1958), and locally the name has been misapplied to the Peru sand interval.

Finally, the "Wheeler sand" occurs in the upper part of the Oswego lime (Fort Scott Limestone) (Fig. 15). The name originated with a well completed in 1912 on the Wheeler lease in Cushing Field, northwestern Creek County (Buttram, 1914). At that time, according to Buttram (1914), it was the second most important reservoir in the Cushing field, after the Bartlesville sand. The "Wheeler sand" consists of two beds of light-brown, coarse-grained limestone, separated by a thin shale, and it is ~75 ft thick (Buttram, 1914). In parts of Osage County, the "Wheeler sand" interval is a sandstone or sandy limestone that composes the uppermost 10–25 ft of the Oswego (Bass, 1942). Locally, the interval is also an oolitic limestone (Jordan, 1957; R. A. Northcutt, personal communication, 1996).

As with most informal subsurface names, the name Cleveland has been applied locally to sandstones in varying stratigraphic positions. A case in point is Riggs and others (1958), who apply the name Cleveland in the Cushing field to a sandy interval nearly 300 ft below the Checkerboard Limestone. It has been a minor oil- and gas-producing zone, apparently in the stratigraphic position of the "Wayside sand" (discussed above).

A better understanding of Middle Pennsylvanian strata in eastern Oklahoma and Kansas has brought about recent changes in Series, Group, and Formation boundaries that affect this study. For many years, the top of the Marmaton Group, and of the Holdenville Formation, was placed at the top of the Desmoinesian Series (Moore and others, 1937; Branson, 1962). On the surface as well as in the subsurface, the boundary between the Holdenville Shale and overlying Seminole Formation commonly was drawn arbitrarily at the base of the lowest sandstone, or the "lower" Cleveland sand (Cole, 1967; Jordan, 1959; Lukert, 1949). If no sandstone was present, the boundary was not definable, a reminder that the boundary was more a convenient geologic horizon than a known entity. However, Desmoinesian fossils have been identified in the Dawson coal and in the overlying shale (Pearson, 1975; Wilson, 1979, 1984), and the top of the Holdenville Formation (and of the Marmaton Group and the Desmoinesian Series) has been moved up in the geologic section. Rocks formerly assigned to the Seminole Formation are now included in the Holdenville. Thus, previous workers (Greig, 1959; Oakes, 1959; Jordan, 1959; Clare, 1963; Bennison and others, 1972) placed the Cleveland sand, or sandstones of the Cleveland interval, in the Seminole Formation. Plate 5 (in envelope) illustrates the outcrop of the Seminole Formation according to stratigraphic concepts at the time the geologic map of the State was compiled (Miser, 1954); therefore, the outcrop of the equivalents of the Cleveland sand occur in the lower (eastern) part of the Seminole Formation, as mapped on Plate 5 (in envelope). This study, however, recognizes the current stratigraphic understanding, synthesized in Figure 15.

The age of the Tulsa coal has not been determined with certainty, but Hemish (1990) has tentatively placed the Missourian-Desmoinesian boundary at the base of that coal (Fig. 15). The placement of the Hepler Sandstone in the Seminole Formation in earlier works (Branson, 1962; Zeller, 1968) relates to that evolution of understanding of the Missourian-Desmoinesian boundary. The upper part of the Holdenville Formation has been studied in greater detail and separated into new formational units by Heckel (1991). The more detailed nomenclature is not presented in this report, with the exception of the Nuyaka Creek shale, which is recognizable locally in the subsurface.

Beginning with Taff (1901), it was widely believed that there was an unconformity, possibly of regional significance, at the base of the lowest sandstone in the Seminole Formation (now within the upper part of the Holdenville Shale, as shown on Fig. 15). That interpretation was based on the extensive occurrence of con-

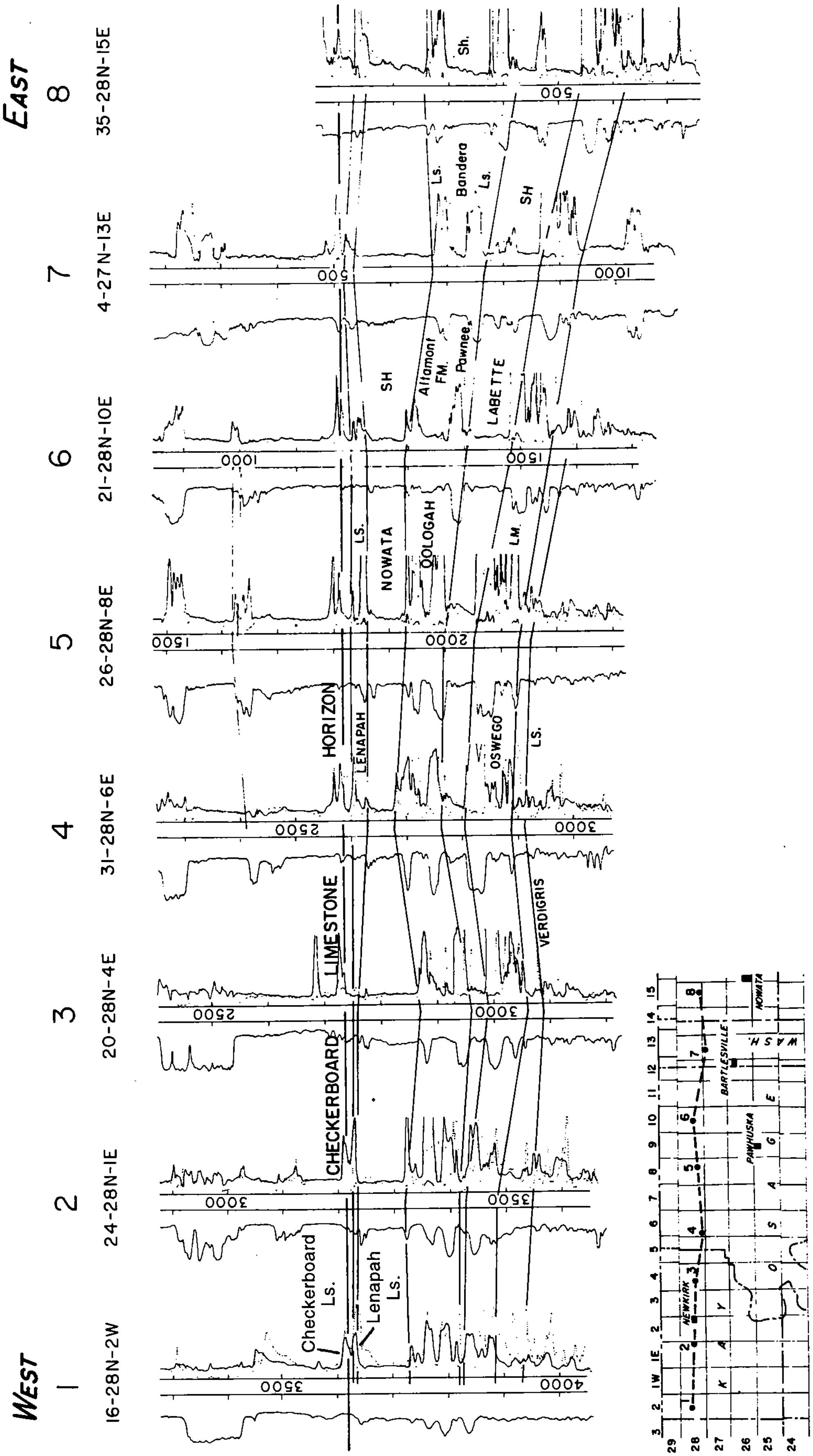


Figure 17. West–east electric-log cross section across northern platform, showing proximity of Checkerboard and Lenapah Limestones. From Krumme (1981).

glomerate and sandstone at the base of an irregular erosion surface, particularly in Seminole and Okfuskee Counties. That proposed unconformity also provided much of the logic for placement of the Desmoinesian-Missourian boundary prior to biostratigraphic studies in recent decades. The erosion surface was recognized as a local disconformity by Cole (1965, 1967). Erosion and subsequent deposition may be local functions of scour and forced regression due to progradation of fluvial and deltaic sandstones of the Jenks Sandstone, or "lower" Cleveland sand.

DEPOSITIONAL ENVIRONMENTS OF THE CLEVELAND PLAY

Introduction

The interpretation of depositional environments in this study is based on the limited published literature and on review of hundreds of wireline logs (spontaneous potential [SP] and gamma-ray [GR] profiles). Tens of thousands of wells penetrate the subject intervals; very few cores exist, and many of them are from a few oil fields. There are no core studies and few lithologic descriptions in the published record.

The interpretation of sandstone depositional environments from well logs dates at least to the late 1960s (Krueger, 1968). Concepts of typical well-log response to sedimentary sequences that represent specific depositional environments have developed through continuing study (Walker and Cant, 1984; Serra, 1985). Early studies were based on SP-log profiles, but concepts matured as gamma-ray logs became available more widely. Many practitioners continue to use SP-log profiles in the absence of gamma-ray logs. The most dependable interpretations are based on studies of well-developed depositional systems, where wireline logs can be related directly to the geologic interpretation of cores (Coleman and Prior, 1982).

The modern and ancient Mississippi River delta systems are very well developed fluvial-dominated systems, which have been studied more extensively than any other delta system in the world. Knowledge gained from studies of these systems does not necessarily apply in detail to ancient depositional systems, especially if the ancient systems cannot be shown to be similarly river- and sediment-dominated, with sediment delivery to a subsiding basin of deposition. Deltaic systems tend to be highly variable at virtually any scale because they are characterized by many depositional environments (see Part I, this volume); Chaplin (1996) reviewed the difficulties and hazards of interpreting deltaic systems in the subsurface, especially where such interpretations are based on wireline logs from widely spaced wells and on minimal core data. Rider (1990) believes that the interpretation of depositional environments from log profiles has been oversimplified and overextended. However, the method has proved itself useful both in regional exploration for hydrocarbons and in petroleum reservoir characterization studies.

Lithology

In the literature, lithologic descriptions of the Cleveland sand are generalized and commonly incomplete. However, several descriptions are instructive. The most complete single description is that of Clare (1963, p. 30): "...clear to dull-white or gray, locally tan to 'salt and pepper,' fine- to coarse-grained, porous, micaceous, and calcareous sandstone containing green shale fragments." Baker (1958) and Cary (1955) described it as medium to coarse grained. Most other authors describe the Cleveland as fine to medium grained (Cole, 1956; Cutolo-Lozano, 1969; Campbell, 1975). Quartz-grain texture has been described as angular to subangular by Stringer (1957), and as subround to subangular by Baker (1958).

The presence of glauconite, indicating shallow-marine facies, was noted by Baker (1958) and Cutolo-Lozano (1969). Numerous authors have noted that Cleveland sandstones are micaceous (Baker, 1958; Campbell, 1975; Cary, 1955; Clare, 1963; Kirk, 1957; McElroy, 1961; and Stringer, 1957). One would expect to find clay minerals associated with Cleveland sandstones; however, only one investigator (Campbell, 1975, p. 12) describes them as "argillaceous."

Provenance

It is widely accepted by geologists that the Ouachita uplift was the source of sediment for the Cleveland sand delta, as illustrated by Rascoe and Adler (1983, figs. 8, 9) and Krumme (1981, fig. 39). However, the eroding Ouachita uplift was composed of multi-cycle, Late Mississippian and Early Pennsylvanian siliciclastics, and older carbonates, shales, and cherts. Micas weather quickly to clay and tend not to survive in multi-cycle sandstones. Therefore, the micaceous Cleveland sandstones indicate the presence of a granitic source area in addition to the Ouachita uplift. Such a source area is probably the Ozark uplift to the east (Fig. 18).

Depositional Environments

Little detail is known about the Cleveland depositional system. No detailed study has been made of the outcrop, although Cole (1967), Bennison (1981, 1984), Krumme (1981), and Krumme and Visher (1972) have reported on local aspects of sandstone intervals at the surface. In a study of the entire Midcontinent region, Orlopp (1964; Wanless and others, 1970, fig. 21) illustrated extensive deltaic sandstones in the Cleveland sand interval in northeastern Oklahoma, eastern Kansas, and western Missouri. The present study recognizes a similar distribution of sandstone, but a smaller Cleveland delta in northeastern Oklahoma (Fig. 18).

Cole (1968, 1970) constructed an isolith map that included the Cleveland sand in part of the Cherokee platform. His study interpreted a number of linear thick areas, but it did not discuss depositional environ-

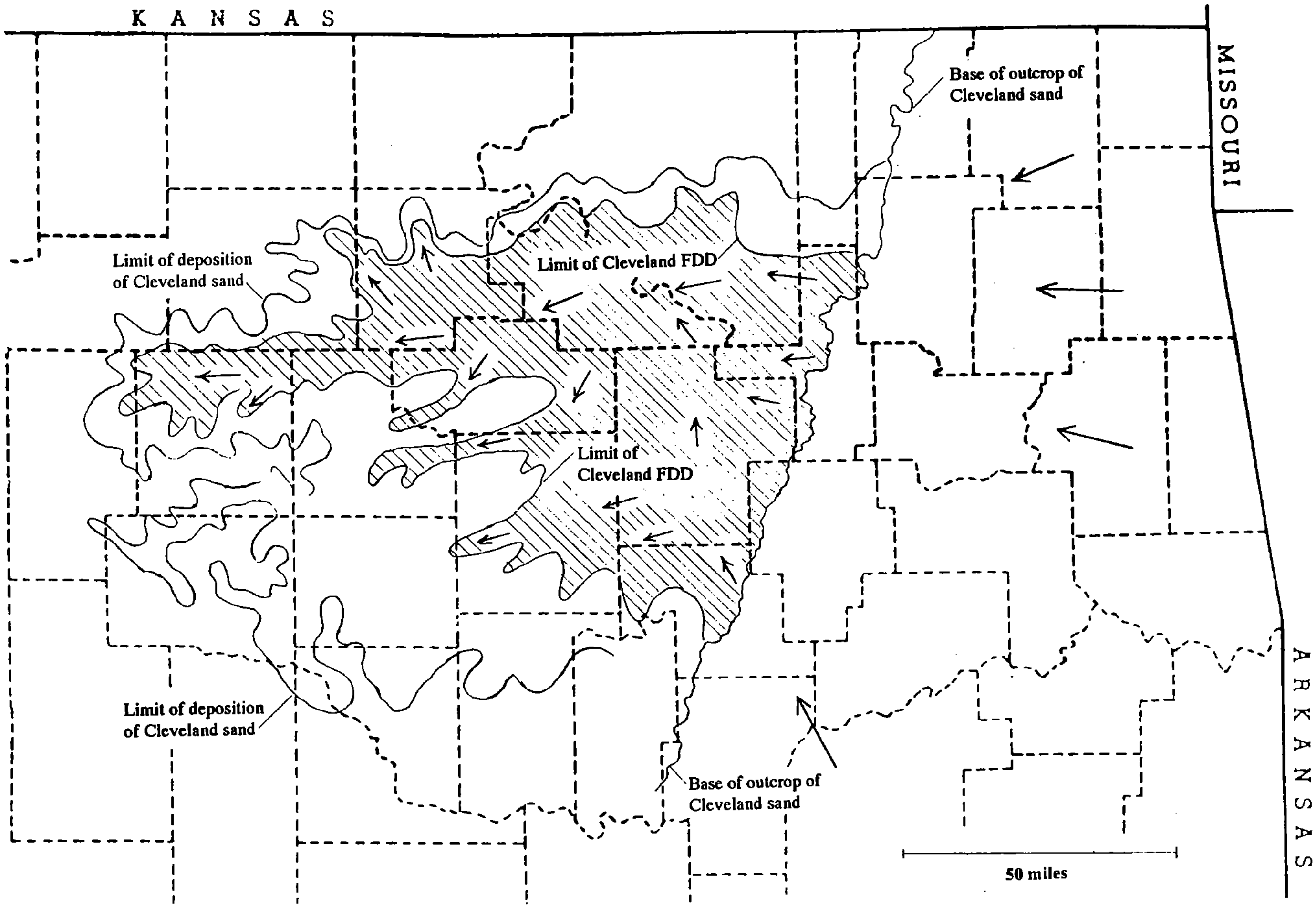


Figure 18. Paleogeography of the southern Midcontinent in late Desmoinesian time, illustrating maximum progradation of the Cleveland sand delta. Arrows indicate principal directions of fluvial transport. Modified from Cole (1970), Berg (1973), and Krumme (1981) on the basis of review of hundreds of GR and SP well-log profiles.

ments. A similar study was completed in an adjacent area to the west by Berg (1973). Abrupt changes in thickness of the Cleveland sand were mapped by Cole (1970); it seems probable that such changes in thickness are likely to be associated with changes in depositional environment, especially in the absence of fault control. Krumme (1981, p. 48) mapped the depositional thick areas of the Cleveland sand in greater detail than any previous work and termed the continuous linear thick areas "channels" (his quotation marks) (Fig. 19; Pl. 5). Plate 5 is compiled from my review of stratigraphic sections in regional studies (Pl. 6, in envelope) and from my interpretation of hundreds of individual wireline logs.

There is strong evidence for fluvial channel and other delta plain deposits in proximity to marine sandstones in the Cleveland sand interval, both vertically and laterally. The relatively abrupt changes from thicknesses of 40 ft or less to thicknesses of 100 ft or greater are shown in Plate 5. In areas of thinner Cleveland sand, gamma-ray log profiles commonly indicate a marine environment, although no log signatures are particularly diagnostic of any specific depositional environment.

The reference log (Fig. 16) was selected because the No. 55 J. A. Jones well is located in an area of well-developed Cleveland sand (within the Cleveland field) and because the log includes a gamma-ray profile to use in interpreting depositional environments. The "upper" and "lower" Cleveland sands are not separable here, but that is common in areas of relatively thick development of sandstone in the Cleveland sand interval, as discussed previously. Sandstones of both fluvial and marine origin in the Cleveland sand are penetrated by the No. 55 J. A. Jones well. The section consists of ~135 ft of delta-front deposits (marine) overlain by ~50 ft of delta-plain deposits that are predominately of fluvial channel origin.

Well logs shown on regional stratigraphic sections A–A′ and B–B′ (Pl. 4) were selected primarily because the wells are located in or near areas of Cleveland sand production (Pls. 1–3), and because the logs include gamma-ray log profiles that are interpreted by the concepts of this study (Part I). The presence of the Nuyaka

Creek shale and distance between points along the line of section were secondary criteria used in selection.

The line of section A–A′ was selected to show variable thicknesses of the Cleveland sand in and near the major east-west thickness trend (Fig. 19; Pl. 5). In general, the gamma-ray profiles indicate mixed marine and deltaic depositional environments. Where the Cleveland sand is relatively thick, strata that can be interpreted as of fluvial origin (channels and other delta-plain deposits) are common and may compose half or more of the Cleveland sand interval. Examples of apparent predominantly fluvial Cleveland sand are found in the No. 1 Tiner well (Pl. 4, no. 2, A–A′), the No. 3-17 Groom well (Pl. 4, no. 3, A–A′) and the No. 3 Brown well (Pl. 4, no. 7, A–A′). Probable channel deposits also occur in the No. 1-3 Frank well (Pl. 4, no. 1, A–A′), the No.

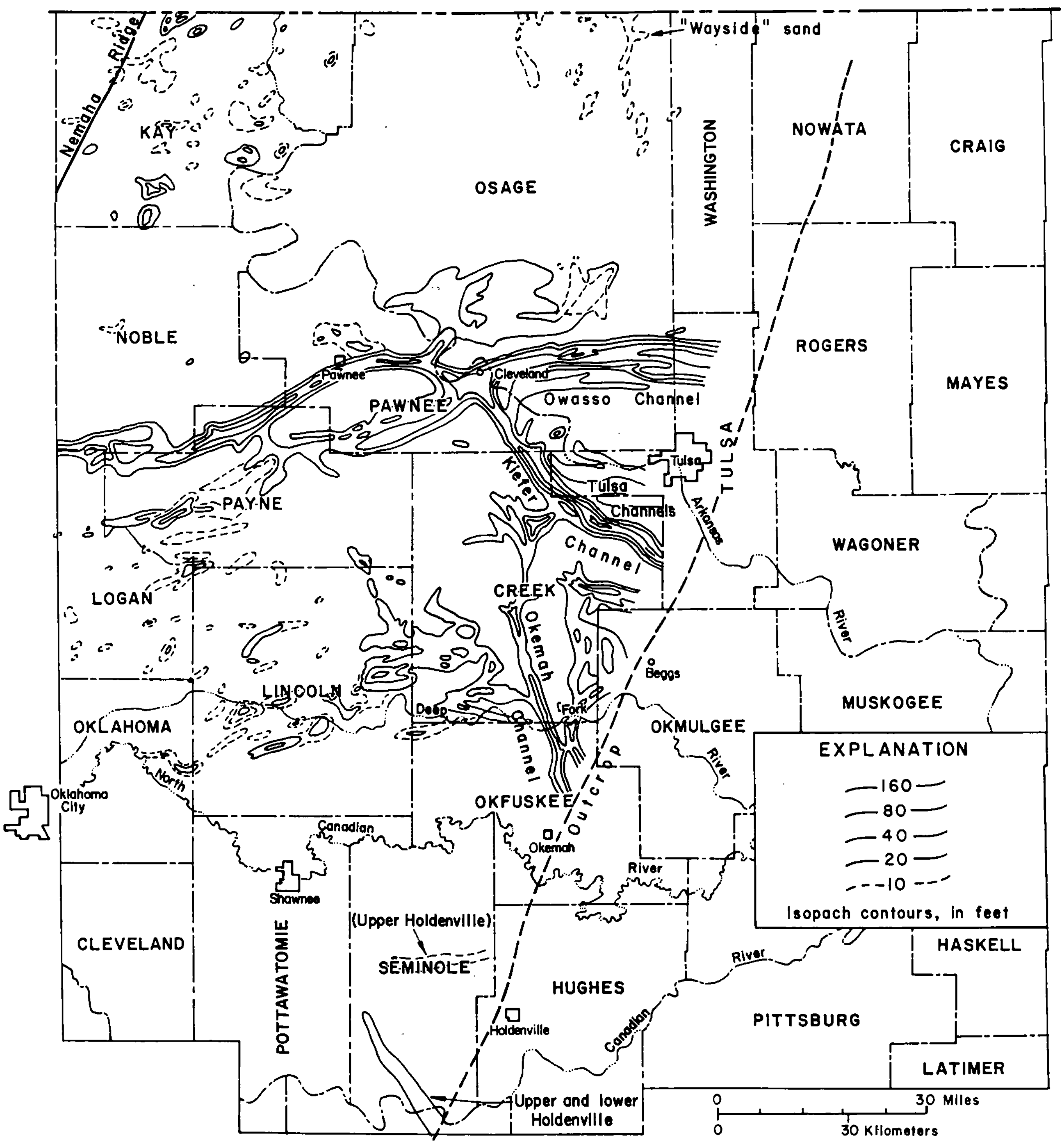


Figure 19. Generalized thickness of Cleveland sand in eastern Oklahoma. From Krumme (1981).

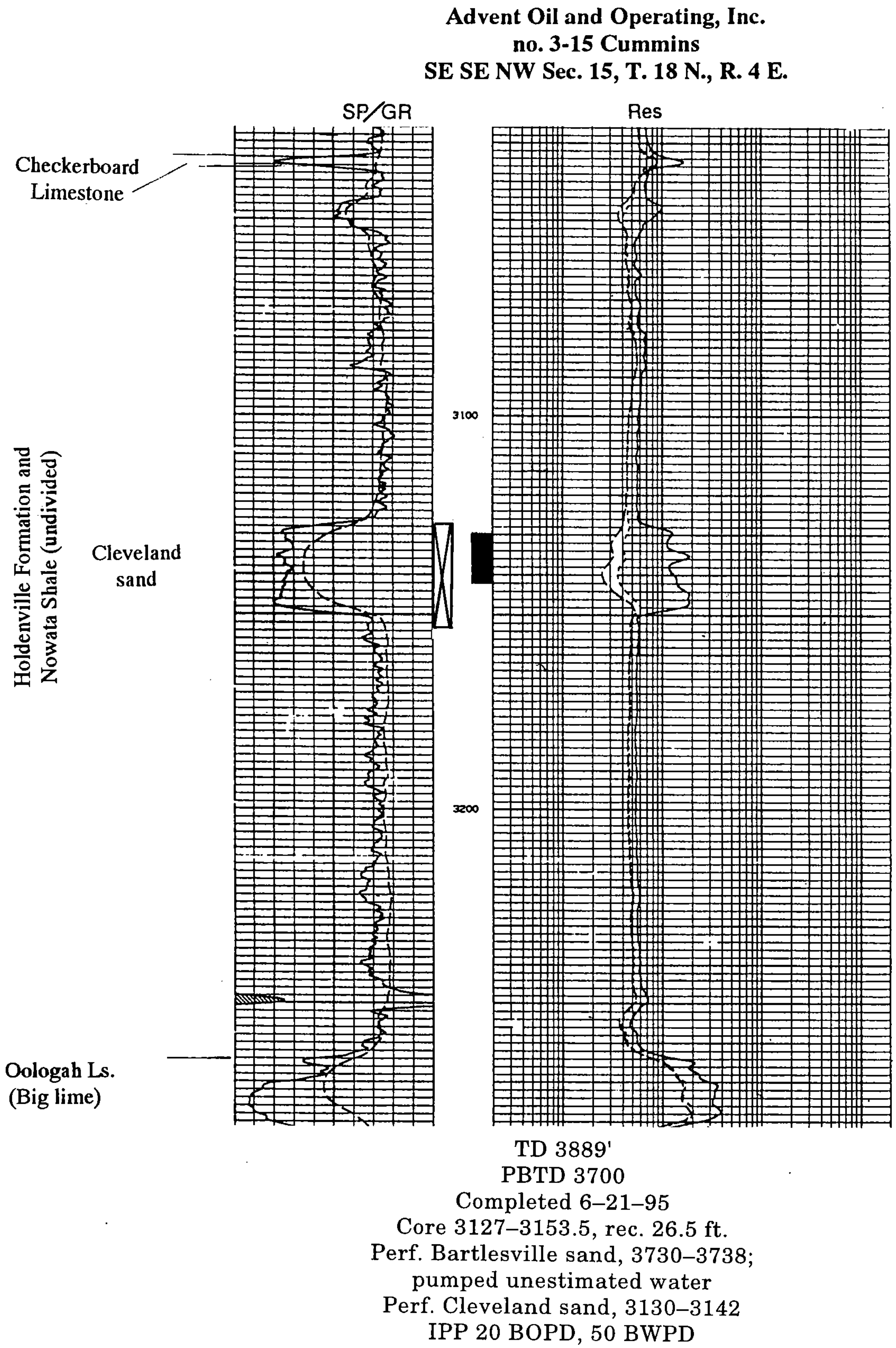


Figure 20. Wireline log of the Advent Oil and Operating, Inc., No. 3-15 Cummins well, SE¼SE¼NW¼ sec. 15, T. 18 N., R. 4 E., Payne County. Gamma-ray (GR), spontaneous-potential (SP), resistivity, and conductivity log profiles.

TABLE 2.—Description of the Cleveland Sand from the Core of the Advent Oil and Operating, Inc., No. 3-15 Cummins, SE¼SE¼NW¼ sec. 15, T. 18 N., R. 4 E., Payne County, Oklahoma

Core: 3,127–3,153.5 ft, recovered 26 ft

Depth (ft)	Lithologies and depositional environments
3,127.0–3,128.1	Sandstone, very fine grained, dolomitic, with abundant gray shale lamina. Irregular bedding. Tidal flat?
3,128.1–3,134.1	Sandstone, fine-grained to very fine grained; gray shale lamina common; local burrowing.
	Channel-mouth bar or offshore bar, 3,128.1–3,148.9 ft; relative paucity of organic material suggests some distance from terrestrial source.
3,134.1–3,148.9	Sandstone, fine-grained to very fine grained; bedding indistinct except for local organic matter lamina; burrowing common to extensive. Very fossiliferous 3,143.3–3,143.5 ft.
3,148.9–3,149.4	Gap.
3,149.4–3,153.5	Shale, dark gray to black, with partings of silty, fine-grained sandstone. Calcareous; very fossiliferous at top. Marine.

3 Sechrist well (Pl. 4, no. 5, A–A′), and the No. 1-A Greer well (Pl. 4, no. 8, A–A′). However, at these locations of generally thinner Cleveland sandstone, the depositional environment is more likely to be predominately marine. Interpretation of the Cleveland sand in the 3,400–3,450-ft interval of the CMS No. 1-C Driskel well (Pl. 4, no. 4, A–A′) has been identified as deltaic (?); however, the gamma-ray profile is atypical and the interval may be of marine origin.

Well logs shown on regional stratigraphic section B–B′ (Pl. 4) were selected to transect the area of the Cleveland sand from the marine depositional environment on the southwest to the limit of Cleveland sandstone occurrence on the northeast. It also intersects points in or near production from Cleveland sand and includes some of the thickest parts of fluvial Cleveland sandstone. Section B–B′ also represents variable thicknesses and depositional environments of the Cleveland sand.

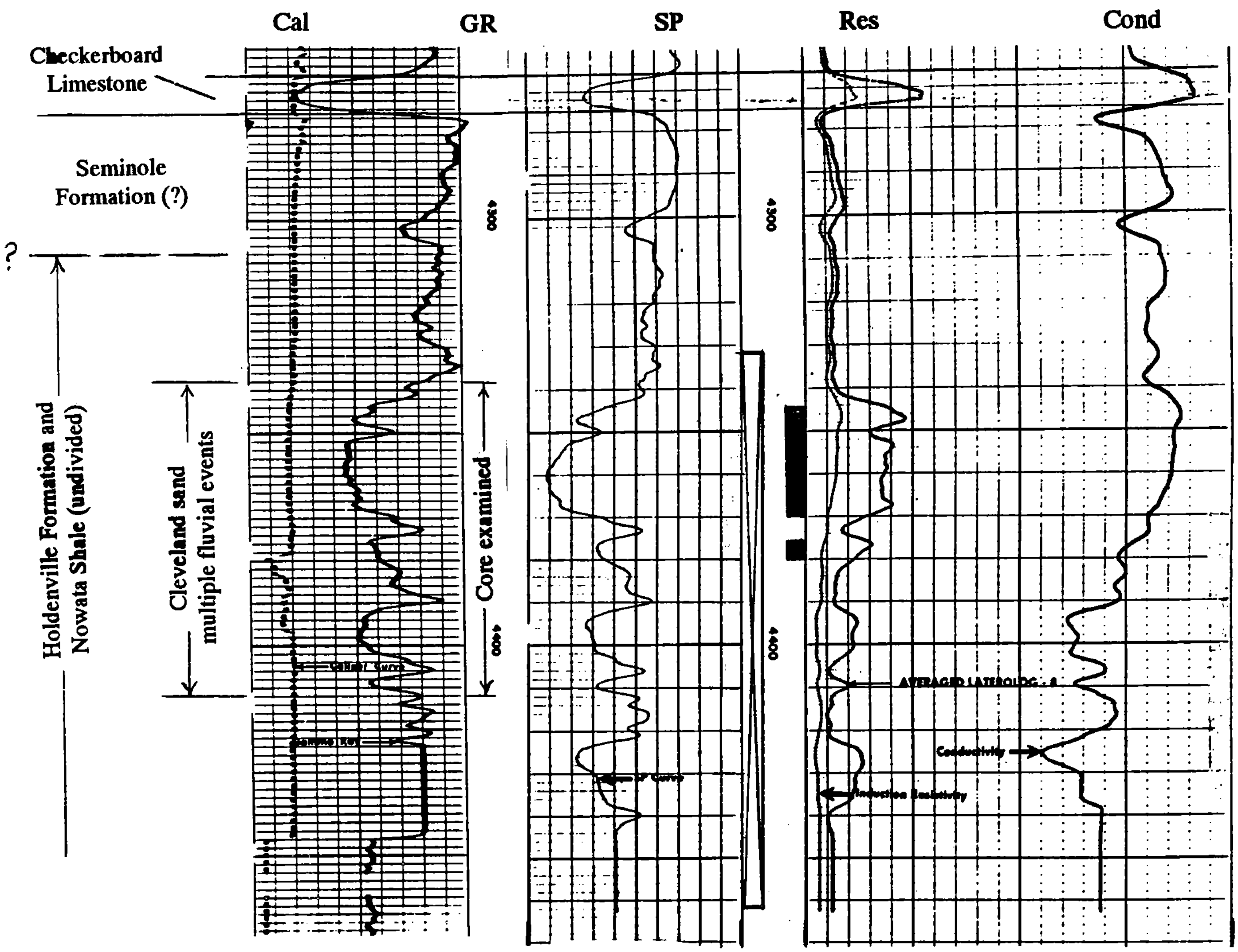
The No. 39 Booher well (Pl. 4, no. 5, B–B′) and No. 1-A Schuler well (Pl. 4, no. 6, B–B′) wells have relatively thick intervals of Cleveland sandstone; they are located within the Kiefer channel and at the northern edge of the Owasso "channel," respectively, of Krumme (1981) (Fig. 19; Pl. 5). The No. 39 Booher well is interpreted as having penetrated ~100 ft of marine strata and ~67 ft of delta-plain strata that includes a distributary channel ~18 ft thick. The No. 1-A Schuler well penetrated ~50 ft of marine sandstone that is overlain by as much as 58 ft of deltaic strata; it includes two (6- and 14-ft-thick) sandstones that appear to be channel deposits. The uppermost sandstone of the sequence (1,090–1,095 ft) probably was deposited in a marine environment.

Five other wells in section B–B′ (Pl. 4) penetrate Cleveland sand. Most of these sandstone intervals are best interpreted as having been deposited in marine environments. However, it will be shown by Rottman (this volume) that fluvial deposits occur in the vicinity of the No. 1 Prewitt well (Pl. 4, no. 3, B–B′), in northeastern Lincoln County.

The core of a thin (26.5 ft thick) Cleveland sand interval in east-central Payne County is a significant point of reference. Many geologists would interpret the gamma-ray profile of the Cleveland sand in the Advent Oil and Operating, Inc., No. 3-15 Cummins well (Fig. 20; Pl. 5) as representative of a channel sandstone that has incised a marine shale. Such an interpretation recognizes the abrupt basal contact and the generally fining-upward profile. However, the upper core (Table 2) consists of 22.5 ft of the gray, calcareous to slightly calcareous or dolomitic, fine to very fine grained sandstone, with local gray shale lamina. Bedding is mostly indistinct, and there is local bioturbation in the sandstone; it also contains marine fossils locally. The core has no characteristics that one would expect to find associated with a fluvial sandstone: there are no distinct cross-beds, no clay clasts or localized coarser grains, and there is relatively little organic matter (which suggests that this particular sand body may not have been near a fluvial distributary at the time of sand deposition!). The gamma-ray profile of the cored interval (Fig. 20) is similar to the gamma-ray profile of the No. 1-C Driskel well in the 3,430–3,450-ft interval (Pl. 4, no. 4, A–A′). Therefore, the identification of the latter as a channel (?) sandstone is questionable, even though it is located close to the major east-west trend of thick sandstone (Pl. 5), and it is in or very near to part of the Kiefer "channel" of Krumme (1981) (Fig. 19).

The core of the Tenneco No. 62 South Lone Elm well (Fig. 21; Pl. 5) is also instructive. Interpretation of only the gamma-ray and resistivity profiles suggests depositional environments as follows (from the bottom of the logged interval): lower delta front, 4,406–4,414 ft; distributary channel, 4,391–4,402 ft; delta front (channel mouth bar), 4,351–4,390 ft (there is a significant shale interval [4,369–4,373 ft] within an *apparent* coarsening-upward sequence overall); point bar, 4,338–4,349 ft. However, examination of the core suggests a contrasting interpretation: it is apparent that the gamma-ray and resistivity profiles (Fig. 21) are controlled more by organic-matter content than by grain-size distribution. The core has characteristics common to channel sandstones rather than to those of marine origin (Table 3). Cursory study of the 50 ft of core below the interval examined (Fig. 21) reveals mainly sedimentary structures similar to those described in Table 3. However, the 4,447–4,456.5-ft sandstone interval is characterized

Tenneco Oil Company
No. 62 S. Lone Elm Cleveland Sand Unit
N½ SW NE SW Sec. 13, T. 20 N., R. 1 W.



TD 4462'
Completion 12–31–75
Core 4332–4462
Perf. 4344–70; 4376–80
Treatment 500 gals. 15% HCI
IPP 40 BOPD, 80 BWPD

Figure 21. Composite wireline log of the Tenneco Oil Company No. 62 S. Lone Elm Cleveland Sand Unit, N½SW¼NE¼SW¼ sec. 13, T. 20 N., R. 1 W., Noble County. Gamma-ray (GR), spontaneous-potential (SP), caliper, resistivity, and conductivity log profiles.

by indistinct bedding, with soft-sediment deformation and possible localized bioturbation. That interval is interpreted herein to be a channel-mouth bar. It is underlain by black shale (4,456.6–4,458.3 ft) and limestone (4,458.4–4,462.0 ft). (Also see core descriptions in Appendix 5.)

The regional image that emerges from the evidence at hand is that of a pronounced elongate (or "bird foot") Cleveland delta, and adjacent deltaic and marine environments that occur for linear distances of ≥80 mi (Fig. 18). It must be realized, however, that the strata penetrated by well bores represent only those rocks

TABLE 3. – Description of the Cleveland Sand from the Upper Part of the Core of the Tenneco Oil Company No. 62 South Lone Elm Cleveland Sand Unit, N½SW¼NE¼SW¼ sec. 13, T. 20 N., R. 1 W., Payne County, Oklahoma

Core: 4,332–4,462 ft (130 ft)
Core described: 4,338–4,412.1 ft (74 ft)

Depth (ft)	Lithologies and depositional environments
4,338.0–4,349.1	Fine- to medium-grained sandstone. Ripple-bedding and small rip-up clasts. Thin lamina of organic matter; micaceous. Abundant dark shale partings in upper part. Probable point-bar deposit.
4,349.2–4,350.3	Fine-grained to very fine grained sandstone; parallel, mostly flat bedded with abundant organic matter. Depositional environment?
4,350.4–4,371.7	Fine- to medium-grained sandstone. Locally ripple-bedded and partings of micaceous organic matter. Red shale partings at 4,354.2 ft; 4,355.6 ft; 4,360.7 ft; 4,363.5 ft; and 4,369.7 ft. Channel-fill sandstone.
4,371.8–4,374.5	Fine-grained to very fine grained sandstone and siltstone with abundant micaceous organic matter. Ripple-bedded. Channel-fill sandstone.
4,374.6–4,388.6	Fine- to medium-grained sandstone; ripple-bedding common; local rip-up clasts. Organic matter abundant in lower part and generally decreasing upward. Channel-fill sandstone.
4,389.0–4,391.6	Fine-grained to very fine grained sandstone, poorly sorted. Abundant silty, micaceous organic partings. Foreset beds to 20°; abundant clasts in lower part. Base of channel-fill sandstone, 4,350.3–4,391.6 ft.
4,391.6–4,412.1	Fine-grained to very fine grained sandstone, poorly sorted. Ripple-bedding in upper and lower parts; rip-up clasts abundant in lower part. Chaotic, indistinct bedding (storm deposit) 4,408.3–4,411.3 ft. Oxidized zones at 4,393.2 ft, 4,396.4 ft, 4,398.0 ft, 4,398.3 ft, 4,399.8 ft, and 4,400.9 ft. Channel-fill sandstone.

that are *preserved* at any given location; they are not a complete geologic record. Also, it is not possible to determine relative time between unlike deposits. For example, it may be virtually unknowable how the cored interval of the No. 3-15 Cummins well (Table 2; Fig. 20) relates to the thicker, predominantly fluvial Cleveland sand intervals represented on Plate 4 (A–A′, nos. 2, 3, 7; B–B′, nos. 5 and 6), and in the core of the Tenneco South Lone Elm well (Table 3; Fig. 21).

It is well known that the Pennsylvanian of the Midcontinent region was a time in which numerous rises and falls of sea level occurred (Moore, 1950; Bennison, 1985; Watney, 1985). Two major lowstands of sea level are shown by Bennison (1985, fig. 3). One precedes and the other follows deposition of the Nuyaka Creek shale. Because deltas form at sea level and have very low relief (Part I, this volume), even a modest rise of sea level would result in marine deposition (and/or reworking of fluvial/deltaic deposits by shallow marine processes) in areas where a delta had formerly existed. Similarly, during a fall in sea level, the distributaries would become incised and carry sediment far to the west of marine deposits then isolated in the interdistributary areas. Eventually, the incised valleys would fill with sediment, probably of *both* fluvial and marine origin, which is apparent on regional stratigraphic sections A–A′ and B–B′ (Pl. 4). If this interpretation is correct, paleosoils would have developed, particularly in the interstream areas, during relative lowstands of sea level. Paleosoils are unlikely to be detectable in drill cuttings or on wireline logs, but may be identified in well cores or at the outcrop.

The striking changes in thickness mapped by Krumme (1981) (Fig. 19) and confirmed in this study (Pl. 5) present an enigmatic "delta" geometry. However, it is apparent that the areas of predominantly thin (less than ~35 ft) sandstone were deposited mostly in marine environments, and are herein interpreted as being largely older than areas of thicker Cleveland sands (>40 ft).

A withdrawal of sea level followed deposition of much of the older part of the Cleveland sand, resulting in entrenchment of rivers delivering sediment to the sea (the "channels" of Krumme, 1981). The entrenched river courses subsequently filled with a combination of fluvial, tidal-channel, tidal-flat, and near-shore marine sediments, which form the thicker parts of the Cleveland sand (Fig. 19; Pl. 5). An attempt to separate the predominantly fluvial from the predominantly marine deposits results in a more elongate delta form (Fig. 18). This synthesis is general, for it does not show how the Jenks and Tulsa Sandstones ("lower" and "upper" Cleveland sands) relate to the major change in thickness. Given the fact that it is only locally possible to recognize the two parts of the Cleveland sand (Pl. 4), no amount of study would be likely to prove or disprove this interpretation of deposition of the Cleveland sand.

The Cleveland sand also is recognized in western Oklahoma (Pls. 1–3) and adjacent Texas. Although it occurs in the same stratigraphic position as the Cleveland sand of the Cherokee platform, sediment sources for that area are located farther to the west. Cleveland sand reservoirs in western Oklahoma are of marine origin. However, fluvial-dominated depositional systems occur in the Cleveland in northwestern Texas, where they have been reported on by Hentz (1993, 1994) and Pertl (1993).

Exploration and Development

Continuing opportunities for development of Cleveland sand reservoirs occur in stratigraphic traps that have been penetrated by drilling to deeper reservoirs. An area on the south side of the Pleasant Mound oil field is an example of unexploited Cleveland reserves (see Rottmann; and Knapp and Yang; this volume). Other small unidentified Cleveland accumulations probably occur in stratigraphic traps in minor distributary-channel and delta-front sandstones related to the major distributary systems identified on Figure 18 and Plate 5. Such resources may or may not have been penetrated by wells drilled to deeper formations; indeed, such wells may have penetrated favorable Cleveland sandstone bodies, but not the hydrocarbon trap. However, subtle resistivity anomalies recorded on wireline logs may be clues to the locations of hydrocarbon traps.

Potential opportunities for water flooding Cleveland sand reservoirs may also occur where primary production has become uneconomical.

PART III

Geology of a Cleveland Sand Reservoir, Pleasant Mound Oil Field

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INTRODUCTION

The Pleasant Mound oil field is located in northeastern Lincoln County in central Oklahoma (Fig. 22). The field lies on the Cherokee Platform province (Pls. 1, 5). Table 4 gives detailed information for the wells shown on the map of the oil field area (Fig. 22).

Production from the Pleasant Mound oil field was established on September 5, 1956, with the discovery of oil and gas in the Nadel & Gussman No. 1 Alice Teters well in the NE¼NE¼SW¼ sec. 14, T. 16 N., R. 6 E. The well was completed with an initial potential flow of 112 BOPD and 8.1 MMCFGPD. Within four years, an additional 35 oil and gas wells had been completed in the reservoir.

STRATIGRAPHY

The reference log for the field is from the Old York Drilling Company, Inc., No. 1 Prewitt well in the SW¼SW¼SE¼ sec 23, T. 16 N., R. 6 E. (Fig. 23). "Cleveland sand" is an informal name applied to the sandstone interval that occurs in the upper part of the Holdenville Formation of the Marmaton Group (Fig. 15). The Cleveland sand is divided informally into an "upper" Cleveland sand (known locally as the "Jones sand") and a "lower" Cleveland sand. The "upper" and "lower" Cleveland are separated by the Nuyaka Creek shale. In the absence of the Nuyaka creek shale in the Pleasant Mound field area, the sandstones can be identified only as the Cleveland sand interval; it occurs directly below the Checkerboard Limestone. In the Pleasant Mound field area, the Cleveland sand apparently was deposited in four layers, labeled A, B, C, and D (in descending order) on Figures 24 and 25 (in envelope). Sandstone reservoir facies occur locally within layers B, C, and D. Layer D forms a hydrocarbon reservoir only in the southeastern part of the field (Figs. 24, 25). More detailed description of these layers is given in the section on isopach mapping.

The stratigraphy of the Cleveland sand in the Pleasant Mound oil field area is shown in two detailed cross sections of the field, A–A′ (Fig. 24) and B–B′ (Fig. 25). Cross section A–A′ is a north-to-south cross section (Fig. 22). The stratigraphic datum for the top half of Figure 24 (A–A′) is the base of the Checkerboard Limestone. The lower half of Figure 24 represents present structure. The various facies that can be identified on cross section A–A′ are evidence of the progradation of the Cleveland sand delta front. The Cleveland sand lies on marine prodelta shale. Layer D (the lowest sandstone stratigraphically) becomes coarser upward, which is characteristic of a delta-front facies; the log for the Tennessee Gas Transmission Co. No. 1 Coward well (NE¼NW¼SE¼ sec. 26, T. 16 N., R. 6 E.) best shows this facies. The electric log signature of the layer C sandstone facies in the Pleasant Mound oil field area generally is blocky and has a sharp basal contact, which is indicative of a distributary channel sand.

The electric log signature of layer B is similar in character to that of layer C; however, for many wells, the logs for layer B have fining-upward profiles, which indicates that the sandstones in layer B are becoming shalier upward. The fining-upward log profiles for layer B suggest point-bar deposits. The log for the Resource Development No. 1 Jarvis well (NE¼SW¼SW¼ sec. 23, T. 16 N., R. 6 E.) shows a good example of the profile for the layer B sand. The layer B sand is the primary oil reservoir in the Pleasant Mound field; it is discussed in greater detail in the section on isopach mapping.

A regional shale overlies the layer B sand. The base of this shale is the datum for the structure map (Fig. 26). The presence of this shale suggests that there was a minor transgression, which ended the progradational sequence indicated by layers B, C, and D. Then, as the sea again receded, the layer A sand was deposited partly by fluvial processes; deposits possibly included point bars.

Cross section B–B′ is a west-to-east cross section (Figs. 22, 25). The top half of Figure 25 is a stratigraphic cross section; the bottom half represents present structure. The stratigraphic datum for cross section B–B′ also is the Checkerboard Limestone. The Nadel & Gussman No. 1 Harrison well (NE¼NW¼NW¼ sec. 23, T. 16 N., R. 6 E.) is the tie well for cross sections A–A′ and B–B′ (Fig. 22). There is an oil-water contact between the No. 1 Harrison well

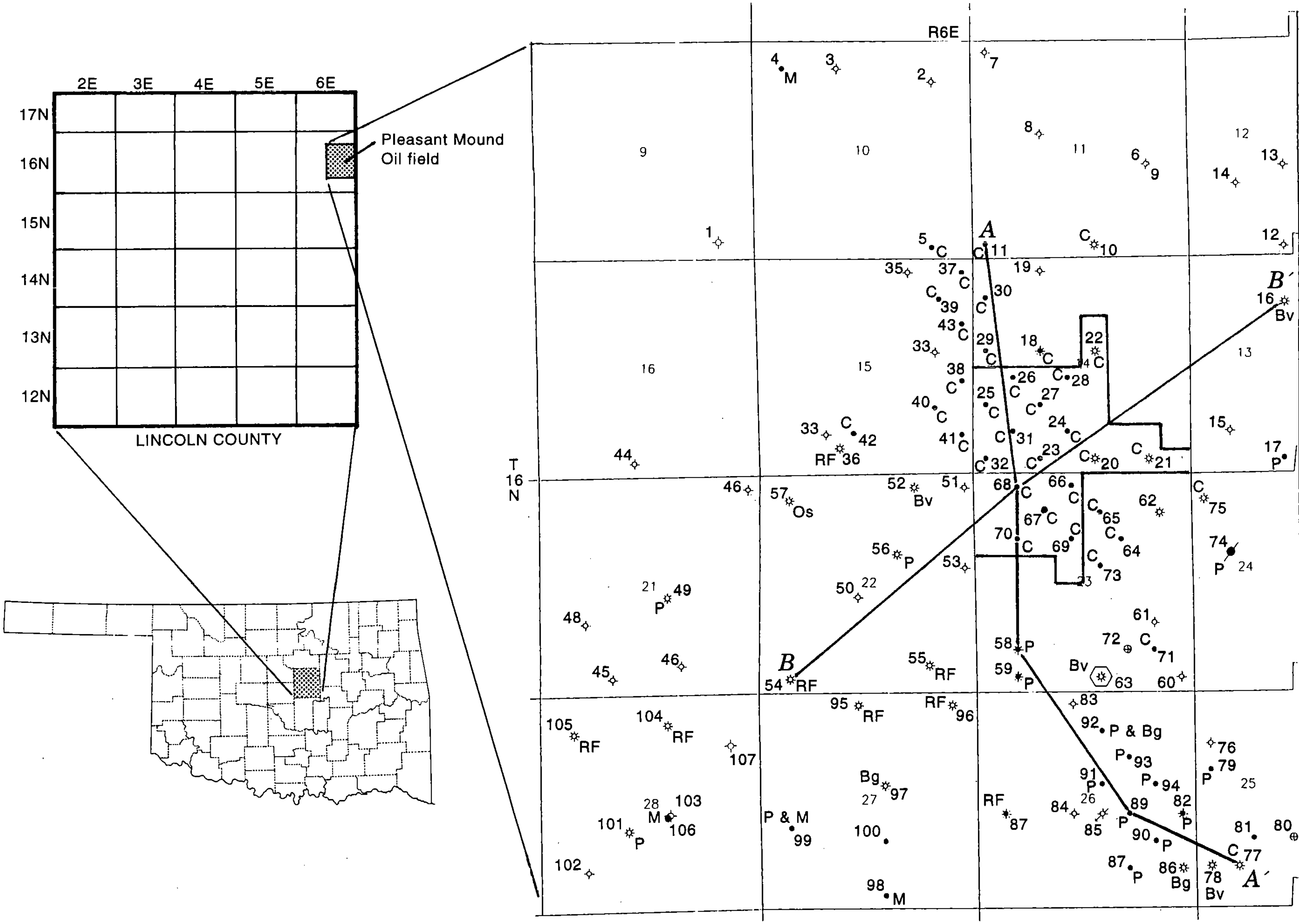


Figure 22. Map showing location of Pleasant Mound oil field (a Cleveland sand reservoir), Lincoln County, Oklahoma. Locations of stratigraphic and structural cross sections, A–A′ and B–B′, are shown. Wells in the oil field area are numbered and keyed to Table 4 (next two pages), which provides detailed information for each well. (The thicker black line in secs. 14 and 23 outlines the Pleasant Mound Cleveland Sand Unit, which was formed in June 1960.)

TABLE 4. – Wells, Operators, Leases, and Section Locations, Pleasant Mound Cleveland Sand Reservoir

SPOT NO.	LOCATION			COMPANY NAME	LEASE NAME		SECTION	TOWNSHIP	RANGE
1	SE	SE	SE	R. L KEMP, WHAN & HOWARD DRLG.	BOYD CAVES	1	9	16N	06E
2	SW	NE	NE	SAC & FOX OIL CO	WUMAN	1	10	16N	06E
3		NE	NW	PRICE EXPL CO	TITUS	1	10	16N	06E
4		NW	NW	RESOURCE DEV INC	TITUS	1-10	10	16N	06E
5	SW	SE	SE	SUNRAY MID-CONTINENT OIL CO	M INGALLS	1	10	16N	06E
6	NW	NE	SE	LINK OIL CO	CARL LANGLEY	1	11	16N	06E
7	NW	NW	NW	SCAT DRLG CO	PICKARD	1	11	16N	06E
8	SW	SE	NW	T C CRAIGHEAD & CO	RUBY WRIGHT	11-1	11	16N	06E
9	NW	NE	SE	LINK OIL CO	EARL LANGLEY	1-A	11	16N	06E
10	SW	SW	SE	KETCHUM OIL CO	LANGLEY	1	11	16N	06E
11	SW	SW	SW	CARTER OIL CO	GIVENS HEIRS	1	11	16N	06E
12	SE	SE	SW	OWEN H RIVES	LANGLEY	1	12	16N	06E
13	NE	NE	SW	KETCHUM OIL CO	LANGLEY	B-1	12	16N	06E
14	SE	NW	SW	A B C OIL CO	LANGLEY	1	12	16N	06E
15	NE	SW	SW	HUBBELL DRLG CO	WHEELAND	1	13	16N	06E
16	NE	SE	NW	ROBERT GORDON OIL CO	BOND	13-1	13	16N	06E
17	SE	SE	SW	COASTAL OILS INC	WOODS	1-13	13	16N	06E
18	SW	SE	NW	CARTER OIL CO	SADIE TYNER	2	14	16N	06E
19	NW	NE	NW	ROBINOWITZ OIL CO	TYNER	4	14	16N	06E
20	SW	SW	SE	NADEL & GUSSMAN	AMERMAN A	1	14	16N	06E
21	SW	SE	SE	NADEL & GUSSMAN	AMERMAN	1	14	16N	06E
22	SW	SW	NE	NADEL & GUSSMAN	GOOCH	1	14	16N	06E
23	SW	SE	SW	NADEL & GUSSMAN	TETERS	4	14	16N	06E
24	NE	SE	SW	NADEL & GUSSMAN	TETERS	6	14	16N	06E
25	SW	NW	SW	NADEL & GUSSMAN	TETERS	7	14	16N	06E
26	NE	NW	SW	NADEL & GUSSMAN	TETERS	5	14	16N	06E
27	SW	NE	SW	NADEL & GUSSMAN	TETERS 3	3	14	16N	06E
28	NE	NE	SW	NADEL & GUSSMAN	TETERS	1	14	16N	06E
29	SW	SW	NW	CARTER OIL CO	SADIE TYNER	1	14	16N	06E
30	SW	NW	NW	CARTER OIL CO	SADIE TYNER	3	14	16N	06E
31	NE	SW	SW	NADEL & GUSSMAN	TETERS	2	14	16N	06E
32	SW	SW	SW	NADEL & GUSSMAN	TETERS	8	14	16N	06E
33	SW	SE	NE	CARTER OIL CO	D S CLINKENBEARD	1	15	16N	06E
34	NW	SE	SW	FLOYD G HUBBELL	WEAVER	1	15	16N	06E
35	NE	NW	NE	SABRE DRLG CO	CLINKENBEARD	1	15	16N	06E
35	NE	NW	NE	HUBBELL DRLG CO	CLINKENBEARD	1	15	16N	06E
36		SE	SW	RESOURCE DEV INC	JAMES	1-15	15	16N	06E
36		SE	SW	RED FORK OIL CO	JAMES	1-15	15	16N	06E
37	NE	NE	NE	CARTER OIL CO	D S CLINKENBEARD	4	15	16N	06E
38	NE	NE	SE	AURORA GASOLINE CO	CONGER	2	15	16N	06E
39	SW	NE	NE	CARTER OIL CO	D S CLINKENBEARD	3	15	16N	06E
40	SW	NE	SE	AURORA GASOLINE CO	CONGER	3	15	16N	06E
41	NE	SE	SE	AURORA GASOLINE CO	HATTIE CONGER	1	15	16N	06E
42	NE	SE	SW	RAMSEY PROPERTY MANAGEMENT INC	JAMES	1	15	16N	06E
43	NE	SE	NE	CARTER OIL CO	D S CLINKENBEARD	2	15	16N	06E
44	SE	SE	SW	FLOYD G HUBBELL & JOHN J FLEET	SCHOOL LAND LEASE	3	16	16N	06E
45	SW	SE	SW	SOUTHLAND OIL CORP	SILL	21-1	21	16N	06E
46	NE	NE	NE	BERG & BUCK DRLG CO	JEFFERSON	1	21	16N	06E
47		SW	SE	PETROLEUM RESOURCES CO	STARR	1	21	16N	06E
48	SE	NW	SW	SUNRAY D X OIL CO	DESSIA JACK	1	21	16N	06E
49	NW	NW	SE	SUNRAY D X OIL CO	STARR HEIRS	1	21	16N	06E
50	NE	NE	SW	NADEL & GUSSMAN	ENGLISH	1	22	16N	06E
51	NE	NE	NE	APACHE OIL CORP	REMINGTON B	1	22	16N	06E
52	NE	NW	NE	NADEL & GUSSMAN	REMINGTON	2	22	16N	06E
52	NE	NW	NE	C W DOBBINS JR	REMINGTON	1	22	16N	06E
53	SE	SE	NE	NADEL & GUSSMAN	REMINGTON	1	22	16N	06E
54	SH	SW	SW	WIL-MC OIL CORP	PETERSON	1	22	16N	06E
55	WH	SE	SE	WIL-MC OIL CORP	HEIRS OF JAY CONGER	1	22	16N	06E
56		SW	NE	RESOURCE DEV INC	REMINGTON	1-22	22	16N	06E
57		NW	NW	RAMSEY PROPERTY MANAGEMENT INC	REMINGTON	1	22	16N	06E
58	NE	SW	SW	RESOURCE DEV INC	JARVIS	1-23	23	16N	06E
59	SE	SW	SW	RESOURCE DEV INC	JARVIS	2-23	23	16N	06E
60	SE	SE	SE	DAY & DEMPSEY	ROSENSTIHL	1	23	16N	06E
61	SW	NE	SE	KINGSIX OIL CO	PREWITT	2	23	16N	06E
62	SW	NE	NE	CARTER OIL CO	E L PREWITT	4	23	16N	06E
63	SW	SW	SE	OLD YORK DRLG CO INC	PREWITT	1	23	16N	06E
64	NE	SW	NE	CARTER OIL CO	E L PREWITT	3	23	16N	06E
65	SW	NW	NE	CARTER OIL CO	E L PREWITT	1	23	16N	06E
66	NE	NE	NW	NADEL & GUSSMAN	ROBINSON	2	23	16N	06E

TABLE 4. – *Continued*

SPOT NO.	LOCATION			COMPANY NAME	LEASE NAME		SECTION	TOWNSHIP	RANGE
67	SW	NE	NW	NADEL & GUSSMAN	ROBINSON	1	23	16N	06E
68	NE	NW	NW	NADEL & GUSSMAN	HARRISON	1	23	16N	06E
69	NE	SE	NW	NADEL & GUSSMAN	ROBINSON	3	23	16N	06E
70	NE	SW	NW	NADEL & GUSSMAN	HARRISON	2	23	16N	06E
71	NW	SE	SE	BANK OIL SERVICE	PREWITT	1-A	23	16N	06E
71	NW	SE	SE	GENO OIL & GAS CORP	PREWITT	1-A	23	16N	06E
72	NE	SW	SE	J N KING JR	PREWITT	1	23	16N	06E
72	NE	SW	SE	GENO OIL & GAS CORP	PREWITT	1	23	16N	06E
73	SW	SW	NE	CARTER OIL CO	E L PREWITT	2	23	16N	06E
74	SE	SW	NW	C W SMITH & ASSOC INC	PREWITT	1	24	16N	06E
75	SW	NW	NW	NADEL & GUSSMAN	PREWITT	1	24	16N	06E
76	NW	SW	NW	C J BROWN	RAINWATER	1	25	16N	06E
77	NE	SW	SW	SOJOURNER DRLG CORP	LOUIE RAINWATER	1	25	16N	06E
78	NW	SW	SW	WILLIAM C ROBERTSON	ROBERSON	2	25	16N	06E
79	SW	SW	NW	C W SMITH & ASSOC	STECKLER	1	25	16N	06E
80	SE	NE	SW	CADDO OIL CO INC	CRESCENT	1-SWD	25	16N	06E
81			SW	?	?	?	25	16N	06E
82	NE	NE	SE	CANAMCO RESOURCES CORP	KINNAMON	1-26	26	16N	06E
83	NE	NE	NW	INLAND PRODUCERS CO	MURPHY	1	26	16N	06E
84	NE	NE	SW	NELSON PETROLEUM CO	KINNAMON	1	26	16N	06E
84	NE	NE	SW	APACHE OIL CORP	COWARD	1	26	16N	06E
85	NW	NW	SE	J GARFIELD BUELL	SMITH	1	26	16N	06E
85	NW	NW	SE	APACHE CORP	COWARD	4	26	16N	06E
86	NE	SE	SE	CANAMCO RESOURCES CORP	KINNAMON	2-26	26	16N	06E
87	NH	NW	SW	RED FORK OIL CO	KINNAMON	1-26	26	16N	06E
87	NH	NW	SW	RESOURCE DEV INC	KINNAMON	1-26	26	16N	06E
88	NE	SW	SE	TENNESSEE GAS TRANSMISSION CO	G W COWARD	3	26	16N	06E
89	NE	NW	SE	TENNESSEE GAS TRANSMISSION CO	G W COWARD	1	26	16N	06E
90	SW	NE	SE	TENNESSEE GAS TRANSMISSION CO	G W COWARD	2	26	16N	06E
91	SW	SW	NE	APACHE OIL CORP	HALL	1	26	16N	06E
92	SW	NW	NE	GENO OIL & GAS	HALL	1A	26	16N	06E
93	NE	SW	NE	APACHE OIL CORP	HALL	3	26	16N	06E
94	SW	SE	NE	APACHE OIL CORP	HALL	2	26	16N	06E
95	NE	NE	NW	AURORA GASOLINE CO	ANDREW CONGER	1	27	16N	06E
95	NE	NE	NW	WIL-MC OIL CORP	ANDREW CONGER	1	27	16N	06E
96	NH	NE	NE	WIL-MC OIL CORP	REMINGTON	1	27	16N	06E
97	SW	SW	NE	WIL-MC OIL CORP	REMINGTON	2	27	16N	06E
98	SW	SW	SE	RESOURCE DEV INC	KINNAMON	2-27	27	16N	06E
99		NW	SW	CRAIG MCGRIFF EXPL INC	ETHRIDGE	1-27	27	16N	06E
100	SW	NW	SE	DAUBE EXPL CO	COWARD	1	27	16N	06E
100	SW	NW	SE	RESOURCE DEV INC	KINNAMON	1-27	27	16N	06E
101		NE	SW	RESOURCE DEV INC	SILL	1-28	28	16N	06E
102	NE	SW	SW	E F MORAN INC	PETERSON	1	28	16N	06E
103	NW	NW	SE	L B JACKSON CO	THOMAS MORRIS	1	28	16N	06E
104	SW	NW	NE	WIL-MC OIL CORP	HEIRS OF MARY LOGAN	2	28	16N	06E
105	SH	NW	NW	F C D OIL CORP	SILL	1-28	28	16N	06E
106	NW	NW	SE	CRAIG MCGRIFF EXPL INC	MORRIS	1-28	28	16N	06E

and the Wil-Mc No. 1 Peterson well (510 ft FWL + 330 ft FSL), in sec. 22, T. 16 N., R. 6 E (Fig. 25). The log of the Robert Gordon No. 1 Bond well (SE¼NE¼-NW¼ sec. 13, T. 16 N., R. 6 E.) shows an example of the prodelta shale facies that surrounds the delta-front facies for all layers (Fig. 25). The log for the No. 1 Alice Teters discovery well has a signature for the layer A sandstone that is common for that layer within the mapped area. The sandstone commonly grades laterally to limestone and is capped by a regional oolitic limestone, which indicates that the sand geometry may have been influenced by marine processes. The layers in the Cleveland sand in the Pleasant Mound oil field area are discussed in more detail in the section on isopach mapping.

STRUCTURE

The geologic structure underlying the study area generally is one of homoclinal dip to the west–southwest, at ~80 ft/mi (Fig. 26). There is a minor anticlinal nose in the northwestern part of sec. 14 (Figs. 24, 26). The nose is not essential to hydrocarbon entrapment in the Cleveland sand. There are common oil-water and gas-oil contacts in the reservoir. The sandstones of layers D, C, and B exhibit an oil-water contact at approximately –1,247 ft, and a gas-oil contact at approximately –1,197 ft (Figs. 25–29).

ISOPACH MAPPING

As mentioned in the section on stratigraphy, the Cleveland sand consists of four layers in the area of the

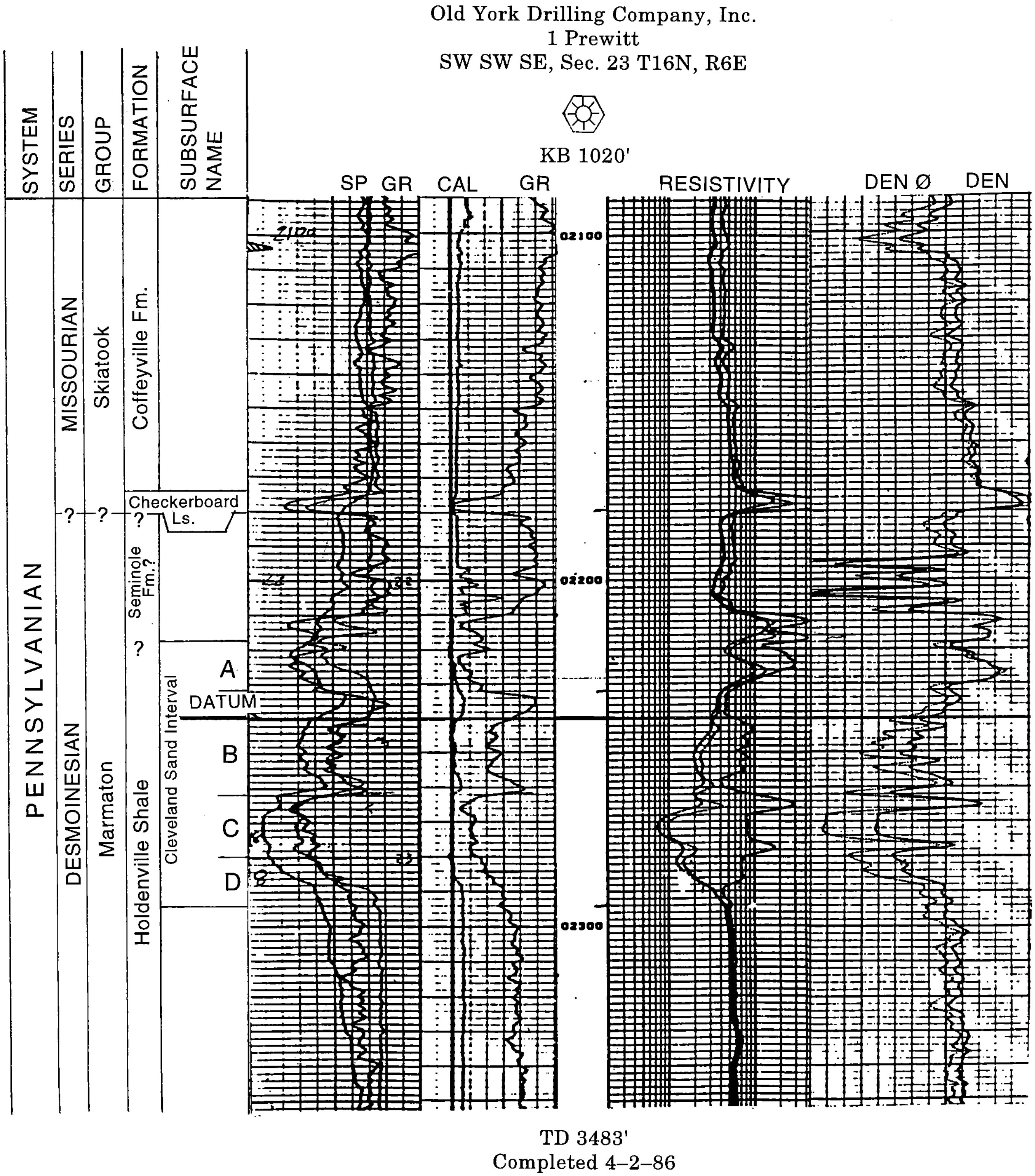
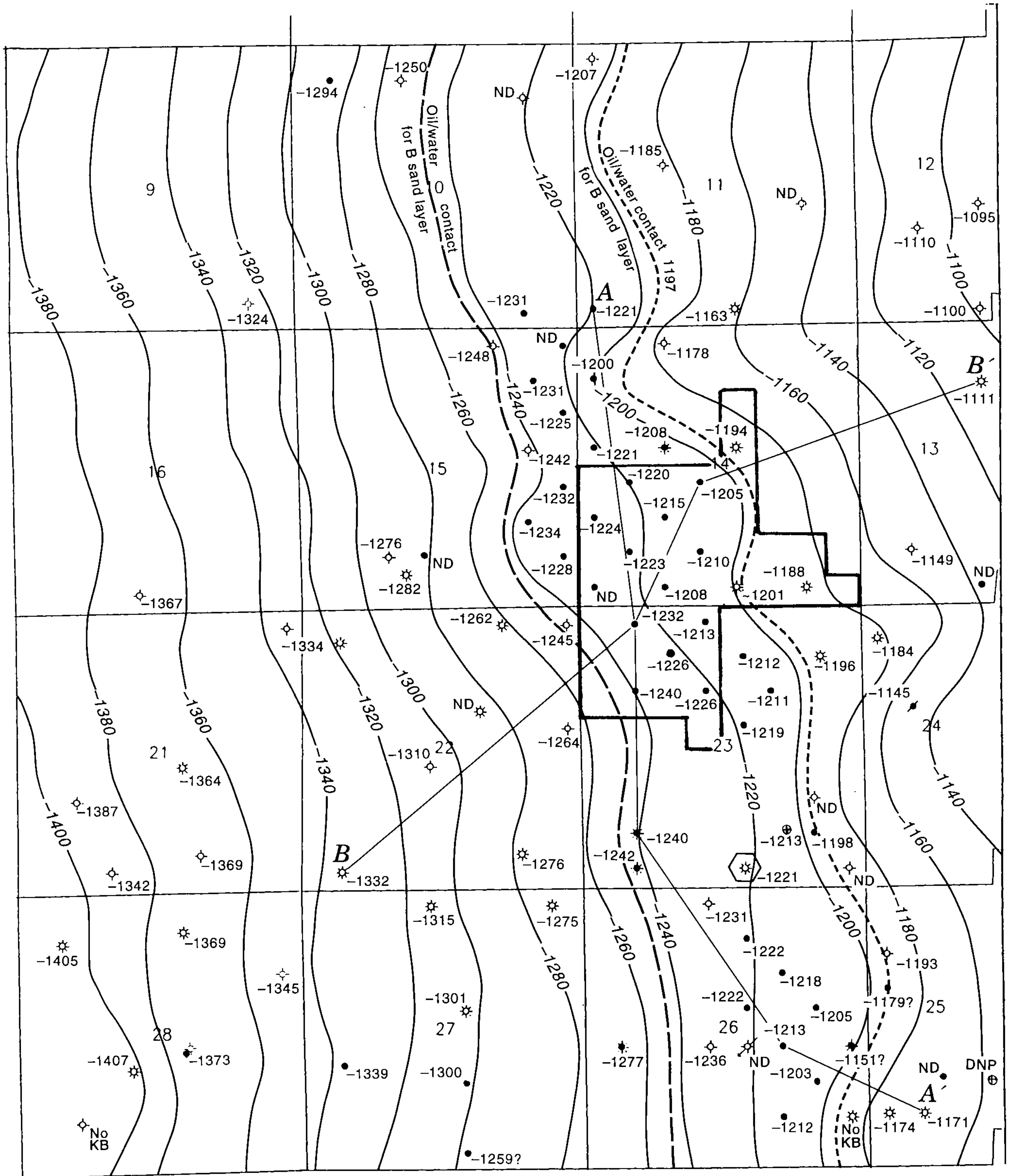


Figure 23. Reference log for the Pleasant Mound Cleveland sand reservoir, showing stratigraphic intervals, structural datum, and log patterns of spontaneous potential (SP), gamma-ray (GR), caliper (CAL), resistivity, density porosity (DEN ϕ), and density (DEN) measurements. Also shown are the positions of four layers (A, B, C, D) within the Cleveland sand interval. Arrow indicates position of structural datum for Figure 26.



EXPLANATION

Contour Interval 20 ft

DNP Did not penetrate subject interval

ND No data

0 5000 feet

Figure 26. Structure map at the top of the layer B of the Cleveland sand reservoir in the Pleasant Mound oil field, Lincoln County, Oklahoma. Contour interval = 20 ft. Where elevation data are shown, they were not available because no well log could be found, or because the well was not deep enough. See Figure 22 for explanation of map symbols. See Figure 23 for stratigraphic position of structural datum.

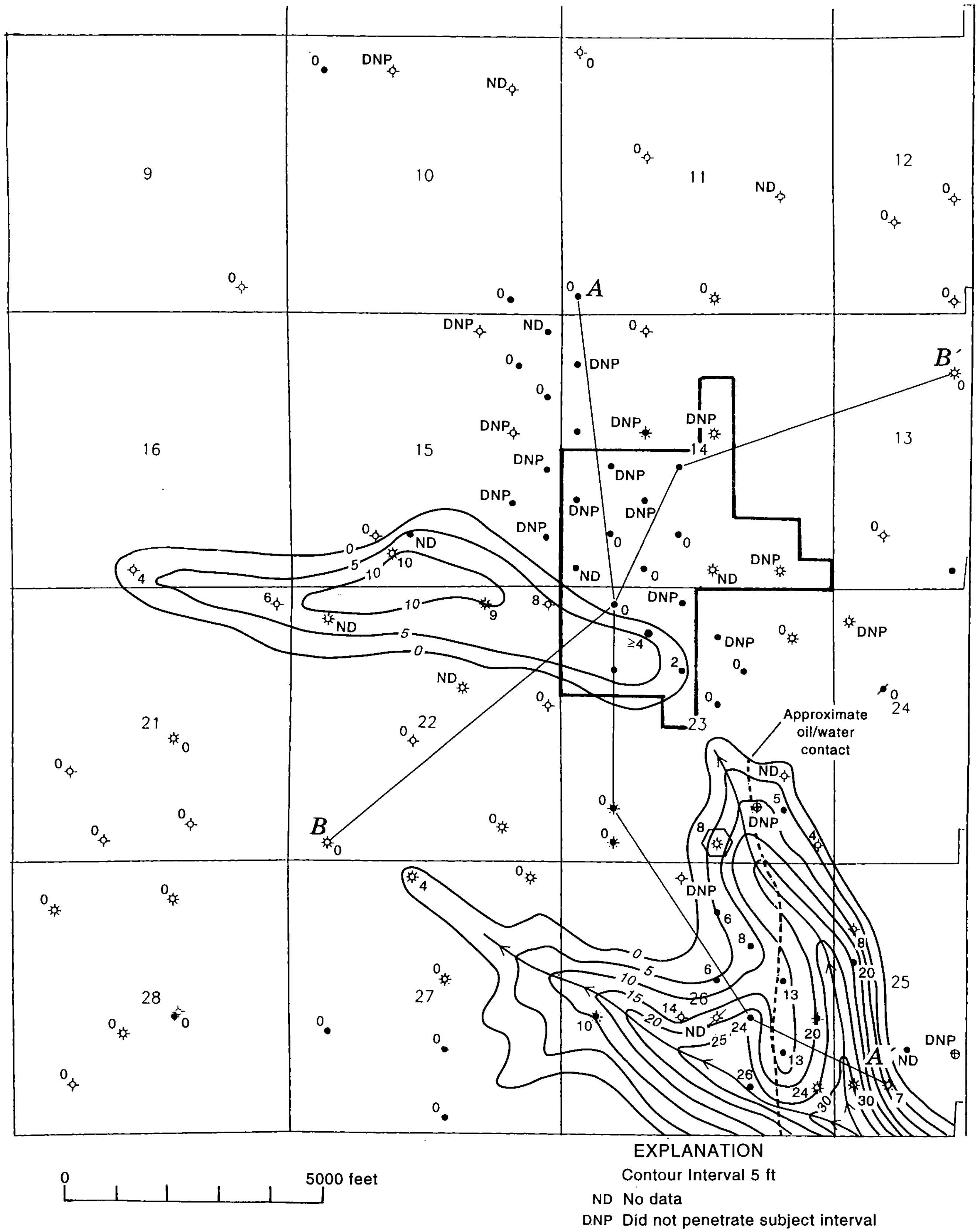


Figure 27. Isopach map of sandstone in net layer D, Cleveland sand reservoir, Pleasant Mound oil field, Lincoln County, Oklahoma. Contour interval = 5 ft. Where thickness is not shown, data were unavailable because no well log could be found, or because the well was not deep enough. See Figure 22 for explanation of map symbols. See Figure 23 for stratigraphic position of isopach interval. Arrows indicate apparent directions of fluvial distributary transport.

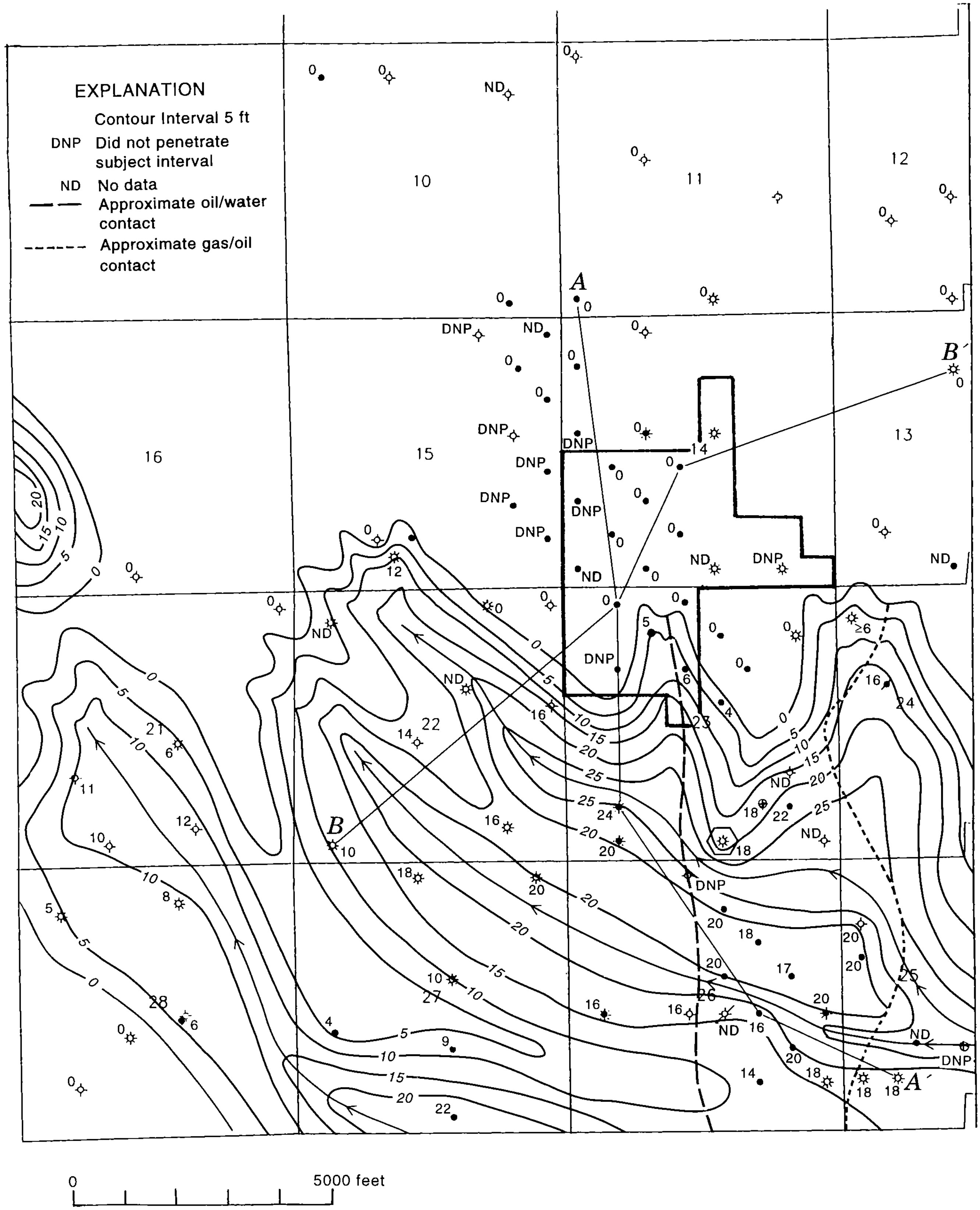
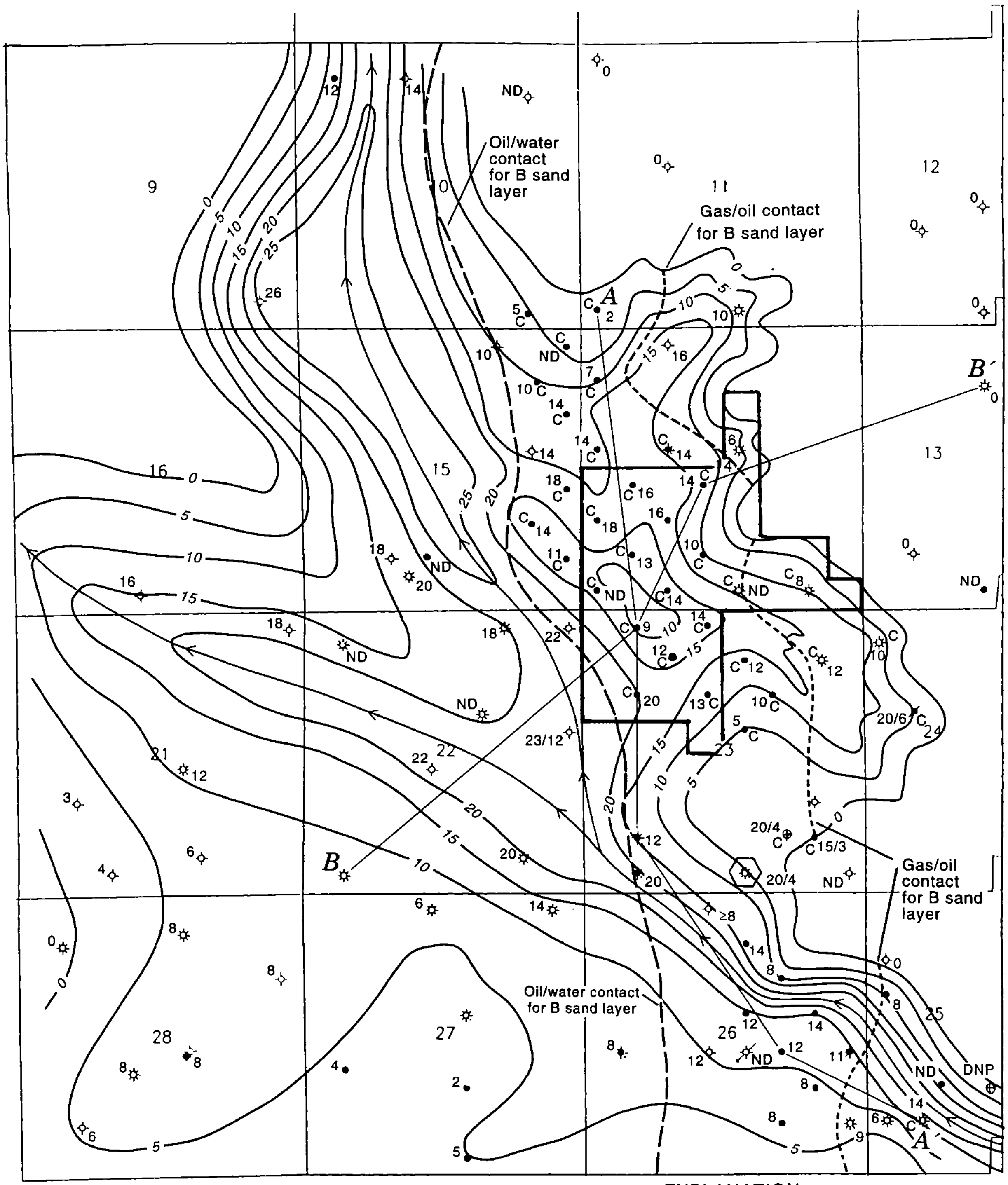


Figure 28. Isopach map of net sandstone in layer C, Cleveland sand reservoir, Pleasant Mound oil field, Lincoln County, Oklahoma. Contour interval = 5 ft. Where thickness is not shown, data were unavailable because no well log could be found, or because the well was not deep enough. See Figure 22 for explanation of map symbols. See Figure 23 for stratigraphic position of isopach interval. Arrows indicate apparent directions of fluvial distributary transport.



0 5000 feet

EXPLANATION

Contour Interval 5 ft

15/3 Thickness, gross interval over net sandstone (ft)

C Cleveland sand producer

12• Thickness of sandstone

ND No data

DNP Did not penetrate subject interval

Figure 29. Isopach map of net sandstone in layer B, Cleveland sand reservoir, Pleasant Mound oil field, Lincoln County, Oklahoma. Contour interval = 5 ft. Where thickness is not shown, data were unavailable because no well log could be found, or because the well was not deep enough. The ratio of the gross interval thickness to the net thickness is shown in feet (for example, 15/3). See Figure 22 for explanation of map symbols. See Figure 23 for stratigraphic position of isopach interval. Arrows indicate apparent directions of fluvial transport.

Pleasant Mound oil field. These distinct layers, which represent depositional facies, can be correlated in all wells on the cross sections. In his interpretation of the regional Cleveland sand isopach map, Krumme (1981, fig. 32) suggests that the Cleveland sand in the area of the Pleasant Mound oil field was deposited as a prograding delta sequence, and that the Okemah channel (Pl. 5) was the probable source. Isopach maps of layers D, C, and B (Figs. 27–29) support this interpretation. A net sand isopach map for each layer was constructed by comparing the gamma-ray logs and porosity logs of wells, using a cutoff value for porosity of ≥8%. In wells for which only the SP curve was available, an approximate net isopach value was interpreted by comparing the shape of that SP curve to the shapes of SP curves associated with porosity logs.

Figure 27 is an isopach map of the net layer D sandstone, in the "lower" Cleveland sand, Pleasant Mound oil field area. It indicates that the source of the clastics for layer D was in the southeast. Distributary channel sands and probable delta-front sandstones are present mainly in secs. 25 and 26, T. 16 N., R. 6 E. The profile of the gamma-ray curve on the type log (Fig. 23) indicates that these sandstones coarsen upward. There is a separate occurrence of layer D sand in secs. 15, 16 and 21–23, T. 16 N., R. 6 E. (Fig. 27), which has a geometry characteristic of a distributary mouth bar, or a longshore bar. Throughout the rest of the Pleasant Mound oil field area, layer D consists of silty shale or siltstone.

Figure 28 is an isopach map of the net layer C sandstone, which occurs immediately above the layer D sand in the Pleasant Mound oil field area. However, the SP and gamma-ray log profiles for layer C differ from those for layer D. On the reference log (Fig. 23), the SP and gamma-ray profiles for layer C are blocky and have sharp basal contacts. This layer probably was deposited as a distributary channel sand in secs. 25–27 and in the southern halves of secs. 22–24, T. 16 N., R. 6 E. These sandstones grade into delta-front deposits or distributary mouth bars in the southwestern part of sec. 16 and the northern halves of secs. 22–24. When the isopach maps for the layer D and layer C sands (Figs. 27, 28) are compared, a pattern of progradation to the northwest is apparent. Arrows on Figure 28 mark the apparent position of three distributary channels.

The layer B sand is important because it is the only oil and gas reservoir within the Pleasant Mound Cleveland sand unit, which is discussed in the section on secondary recovery. Figure 29 is an isopach map of the net layer B sandstone. The sandstone is bounded by delta-plain shale deposits on the east and on the west. The geometry of the sandstone of layer B more clearly indicates a distributary channel environment than does the geometry of the layer C sandstone. The layer B sandstone was transported north, from a source southeast of the Pleasant Mound field area. The central, thickest, part of the sandstone in layer C is interpreted to be a clean, non-shaly reservoir. Its characteristic gamma-ray log profile is shown on the log for the Resource Development, Inc., No. 1 Jarvis well (Fig. 24). For layer B, however, the type log (Fig. 23) indicates a shalier sandstone facies. The gamma-ray log profile for layer B suggests a point-bar deposit, and the shaliness indicates that the interval was deposited in a lower energy environment than the one in which layer C was deposited.

There are two fluid contacts in the sandstone facies of layer B (Figs. 26, 29). The oil-water contact is at the subsea elevation of –1,247 ft, and the contact appears to be consistent with respect to elevation (Fig. 26). A gas-oil contact at the approximate altitude of –1,197 ft also appears to be consistent with respect to altitude (Fig. 26). The Cleveland sand oil and gas reservoir in the Pleasant Mound field is best described as bounded on the west by the oil-water contact and, on the east, by the limit of the sandstone in layer B (Fig. 29). The outline of the Cleveland sand unit (discussed in the section on secondary recovery) is shown in secs. 14 and 23, T. 16 N., R. 6 E., but the Cleveland layer B sand is productive outside the unit. Therefore the Pleasant Mound Cleveland sand unit was established in only part of the area of entrapment of the Cleveland sand (Fig. 29).

Figure 30 is the isopach map of the net layer A sandstone. Because of the marine shale that occurs between layers B and A (Figs. 24, 25), layer A is interpreted as representing a separate event, not directly related to the depositional sequences of layers D, C and B. The layer A sandstone also has tight, interbedded limestone stringers within it, which are not included in the net isopach map. These limestone stringers probably represent brief, episodic transgressive and regressive events that occurred during deposition of the layer A sandstone. There is an oolitic limestone immediately above the layer A sandstone. throughout the area of the Pleasant Mound oil field, which indicates a higher sea level after layer A was deposited. The layer A sandstone does not bear hydrocarbons in the study area.

The isopach map of the cumulative, or gross, Cleveland reservoir sandstone (Fig. 31) was constructed by adding together the contours of layers D, C, and B (from Figs. 27–29). The maximum progradation for each layer is also shown on Figure 31. Chronologically, this lobe of the Cleveland sand delta, in the Pleasant Mound oil field area, prograded farther northwestward with each depositional "event," D, C, and B.

CORE DESCRIPTION

The Cleveland sand was cored in two wells in the Pleasant Mound Cleveland sand unit, the Carter Oil Co. No. 1 Prewitt well in the SW¼NW¼NE¼ sec. 23, T. 16 N., R. 6 E. (Table 5) and the Nadel & Gussman No. 1 Harrison well in the NE¼NW¼NW¼ sec. 23, T. 16 N., R. 6 E. (Table 6). Both cores reveal interesting characteristics of the B sandstone. There is a level in each core at which both the permeabilities and oil saturations change dramatically. In the core from the No. 1

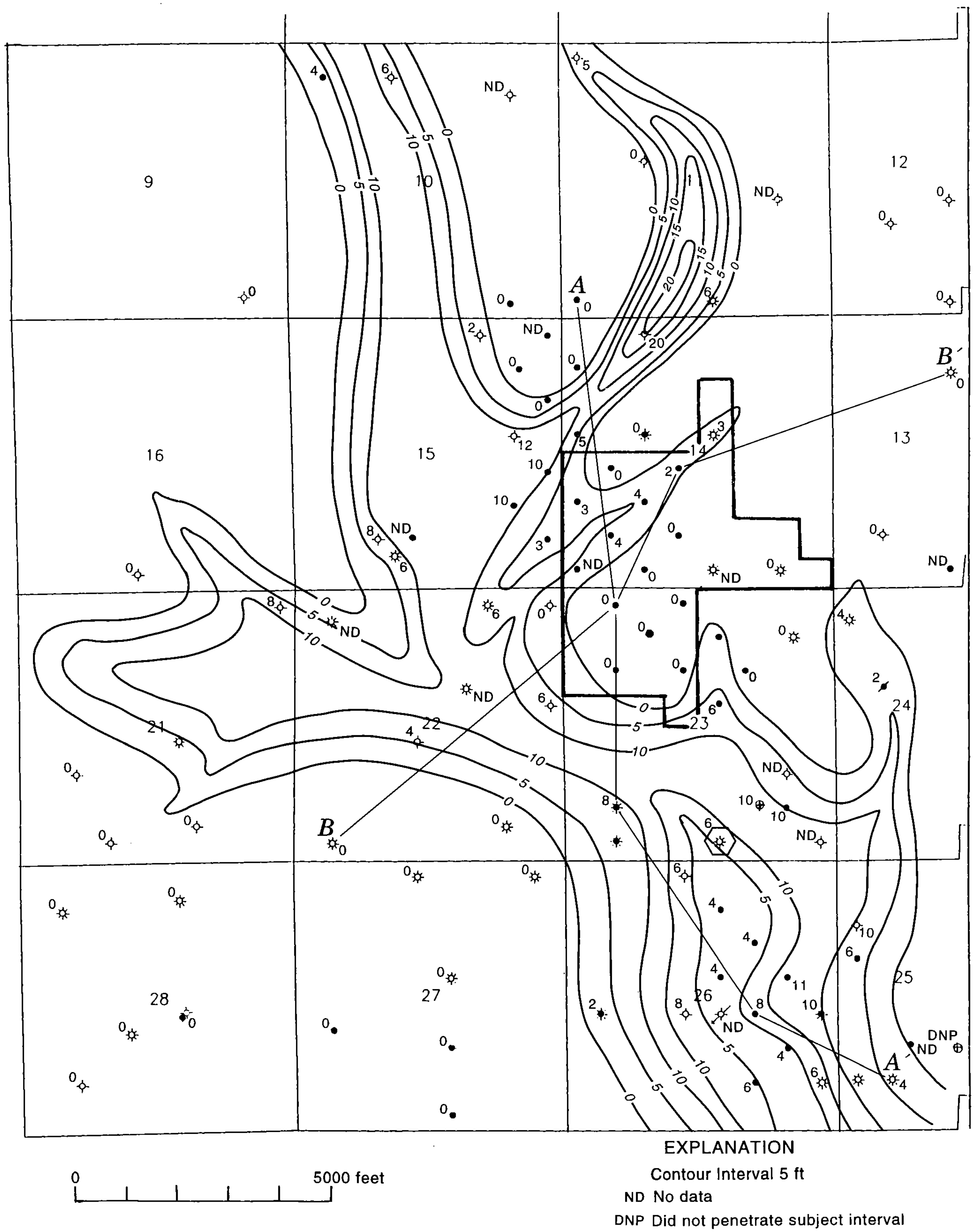
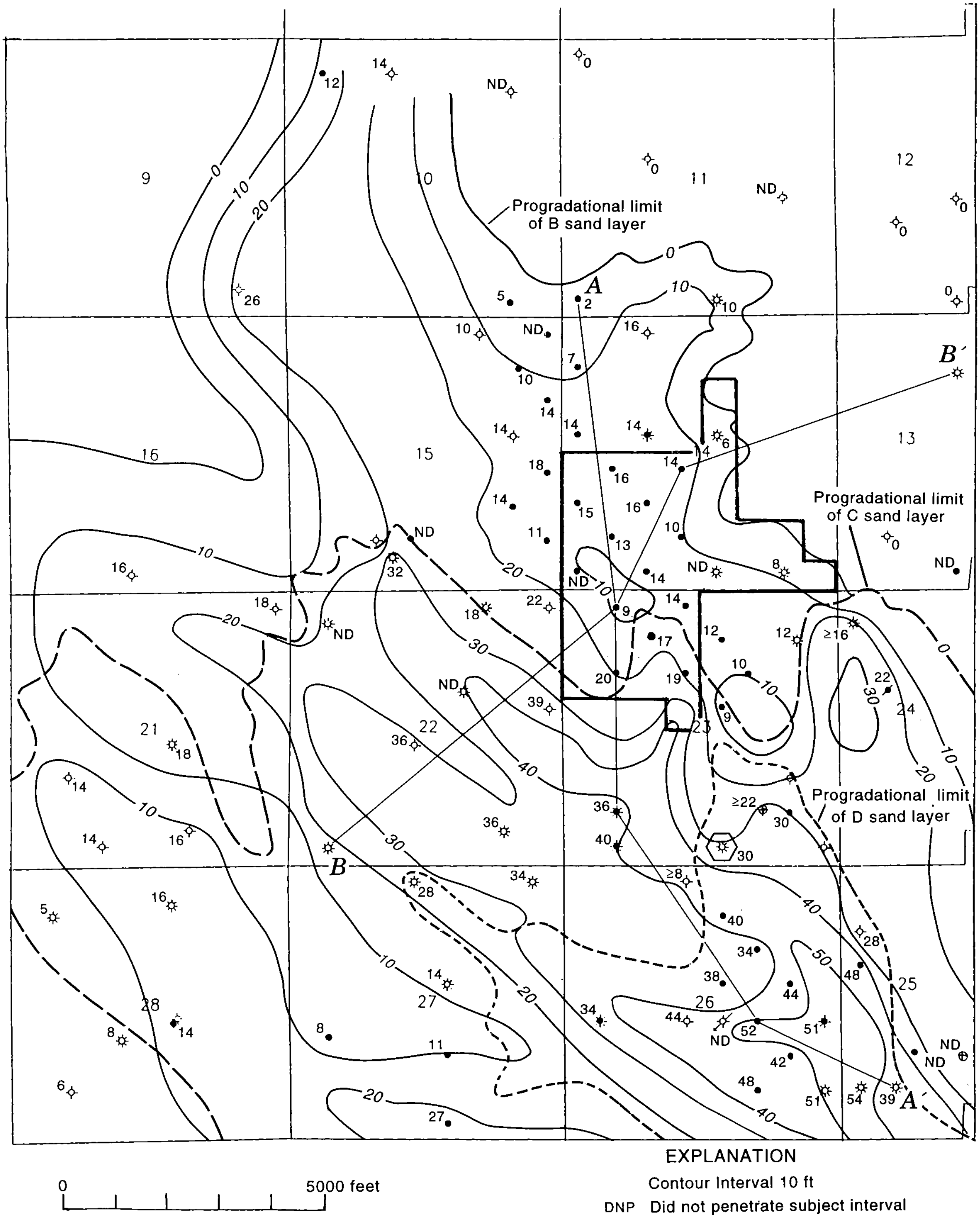


Figure 30. Isopach map of the net sandstone in layer A, Cleveland sand reservoir, Pleasant Mound oil field, Lincoln County, Oklahoma. Contour interval = 5 ft. Where thickness is not shown, data were unavailable because no well log could be found, or because the well was not deep enough. See Figure 22 for explanation of map symbols. See Figure 23 for stratigraphic positions of isopach intervals. Contour interval = 5 ft.



EXPLANATION

Contour Interval 10 ft

DNP Did not penetrate subject interval

ND No data

Figure 31. Isopach map of cumulative, or gross, sandstone in the Cleveland sand interval, Pleasant Mound oil field, Lincoln County, Oklahoma. Map is constructed by adding the contours of layers D, C, and B (Figs. 27–29). Contour interval = 10 ft. Where thickness data are not shown, they were unavailable because no well log could be found, or because the well was not deep enough. Progradational limits of layers D, C, and B (from Figs. 27–29) are shown. See Figure 22 for explanation of map symbols. See Figure 23 for stratigraphic position of isopach interval.

TABLE 5. – Core Analysis Results, Cleveland Sand, Carter Oil Company No. 1 Prewitt, SW¼NW¼NE¼ sec. 23, T. 16 N., R. 6 E., Lincoln County, Oklahoma

Sample no.	Depth (ft)	Permeability (md)		Porosity (%)	Residual saturation percent pore space	
		Horiz.	Vert.		Oil (%)	Water (%)
1	2,219–2,220	134.0	93.0	22.7	8.8	41.8
2	2.220–2,221	130.0	27.0	24.7	8.5	47.0
3	2,221–2,222	113.0	38.0	22.9	9.2	50.0
4	2,222–2,223	101.0	95.0	22.5	8.5	44.3
5	2,223–2,224	70.0	35.0	18.5	7.6	44.0
6	2,224–2,225	24.0	21.0	12.3	9.8	47.2
7	2,225–2,226	63.0	47.0	15.5	12.9	43.2
8	2,226–2,227	105.0	95.0	20.6	9.8	46.2
9	2,227–2,228	101.0	58.0	22.9	9.2	39.0
10	2,228–2,229	62.0	16.0	22.2	9.0	47.4
11	2,229–2,230	73.0	33.0	23.0	8.1	47.0
12	2,230–2,231	42.0	31.0	21.0	9.1	53.2
13	2,231–2,232	5.0	0.9	13.0	0.0	76.0
14	2,232–2,233	6.5	1.6	11.5	3.6	74.8

Harrison well (Table 6), the average permeability in the 2,214.6–2,223.2-ft interval (samples 1-P10) is 176.4 md, and the average residual oil saturation is ~15.8%. In the interval below, 2,223.5–2,235.5-ft (samples 10–15), the average permeability is 4.1 md, and the average residual oil saturation is 4.4%. The core from the No. 1 Prewitt well (Table 5) shows a similar change. In the 2,219–2,231-ft interval (samples 1–12), the average permeability (horizontal) is 84.8 md, and the average residual oil saturation is 9.2%. However, in the 2,231–2,233-ft interval (samples 13, 14), the average permeability is 5.75 md and the average oil saturation is only 1.8%. The corresponding electric logs for these wells (Figs. 32, 33) indicate that the contacts in both cores are related to facies changes, from sandstone to siltstone. These two facies have dramatically different reservoir characteristics. The facies change can be seen in the No. 1 Harrison well in Figures 24 and 25.

RESERVOIR CHARACTERISTICS

Reservoir characteristics for the Pleasant Mound Cleveland Sand Unit are given in Table 7. The initial gas-to-oil ratio (GOR) was ~385 SCF/STB, based upon production tests in the Carter Oil Co. No. 1 Tyner well (SW¼SW¼NW¼ sec. 14, T. 16 N., R. 6 E.) and No. 2 Prewitt well (SW¼SW¼NE¼ sec. 23, T. 16 N., R. 6 E.). The presence of a free gas cap indicates the saturated conditions of the oil. Calculated water saturations average 32%. The oil gravity ranges from 48° to 52.0° API. The initial formation-volume factor was 1.21.

PRODUCTION HISTORY

Cumulative oil production through December 1995 for the Cleveland Sand Reservoir in the Pleasant Mound oil field area was 838,664 BO. The number of active wells per year, the annual oil production, the average monthly oil production, the average daily oil production per well, and the cumulative oil production for the field are summarized in Table 8. Completion techniques varied from well to well, but they generally consisted of setting casing through the Cleveland; cementing the casing; and perforating, acidizing, and fracture treating the reservoir.

The production-decline curve (Fig. 34) shows the production history for the field. In June 1960, part of the reservoir was unitized for secondary recovery and water injection commenced. The increase in production starting in 1970 was the response to water injection, which is discussed in greater detail in the section on secondary recovery.

Figure 35 is an isopleth map of initial production for the area of the Cleveland sand in the Pleasant Mound oil field. The contour interval for areas of equal potential is 100 BOPD. The greatest initial potential is located in two elongate pods in the central part of the oil field area, which probably indicates regions of greater porosities and permeabilities associated with the center of a major distributary channel (Fig. 29). Figure 35 also shows the gas-oil contact above which the reservoir produced gas, with very little associated oil. The field outline consists of two boundaries. The boundary on the east is the zero sand contour from the layer B net sand isopach (Fig. 29). The boundary on the west is the structural contour of −1,147 ft subsea, which represents the oil-water contact in the layer B sandstone (Fig. 26).

Figure 36 is a cumulative production map for the Cleveland sand in the Pleasant Mound oil field area. The production is listed by individual wells, or by lease.

TABLE 6. – Core Analysis Results, Cleveland Sand, Nadel & Gussman No. 1 Harrison, NE¼NW¼NW¼ sec. 23, T. 16 N., R. 6 E., Lincoln County, Oklahoma

Sample no.	Depth (ft)	Permeability (md)	Porosity (%)	Residual saturation percent pore space Oil (%)	Water (%)	Total (%)	Average oil content (BO/acre-foot)
1	2,214.6	182.0	23.5	15.0	45.0	60.0	270.0
2	2,215.5	223.0	23.2	14.0	44.0	58.0	250.0
3	2,216.6	150.0	23.2	14.0	45.0	59.0	240.0
4	2,217.7	205.0	23.8	14.0	45.0	59.0	270.0
5	2,218.6	188.0	23.4	16.0	46.0	62.0	290.0
6	2,219.6	207.0	24.0	16.0	44.0	60.0	300.0
7	2,220.5	177.0	23.7	18.0	46.0	64.0	330.0
8	2,221.6	160.0	23.2	19.0	44.0	63.0	350.0
9	2,222.7	173.0	24.0	16.0	45.0	61.0	300.0
P10	2,223.2	99.0	23.2	nd	nd	nd	nd
10	2,223.5	12.0	19.7	6.6	58.0	65.0	100.0
11	2,224.6	8.2	20.6	4.8	54.0	59.0	77.0
12	2,226.6	0.2	18.8	4.6	66.0	71.0	68.0
13	2,230.4	4.0	20.0	2.9	63.0	66.0	44.0
14	2,233.5	0.3	19.7	3.0	66.0	69.0	47.0
15	2,235.5	imp.	12.1	4.3	61.0	65.0	40.0

Note: nd = no data; imp. = impermeable.

The gas from the gas cap was depleted fairly rapidly, which probably is what forced the operator to unitize and waterflood the oil field early in its life. The Prue producers in the eastern half of sec. 26 all had good shows of oil in the Cleveland; however, during early attempts to complete the Cleveland in these wells, large amounts of water were found with the oil. There is a significant difference between the layer B sand in sec. 26 and that found in secs. 14, 15, and 23 (northern half), which is indicated by the reference log and the isopach map of the cumulative net sandstone (Figs. 23, 31). In secs. 14, 15, and 23 (northern half), the layer B sandstone overlies only fine-grained, non-reservoir facies of layers C and D. In sec. 26, however, the sandstone facies of the three layers overlie one another, and a common oil-water contact crosses the three layers.

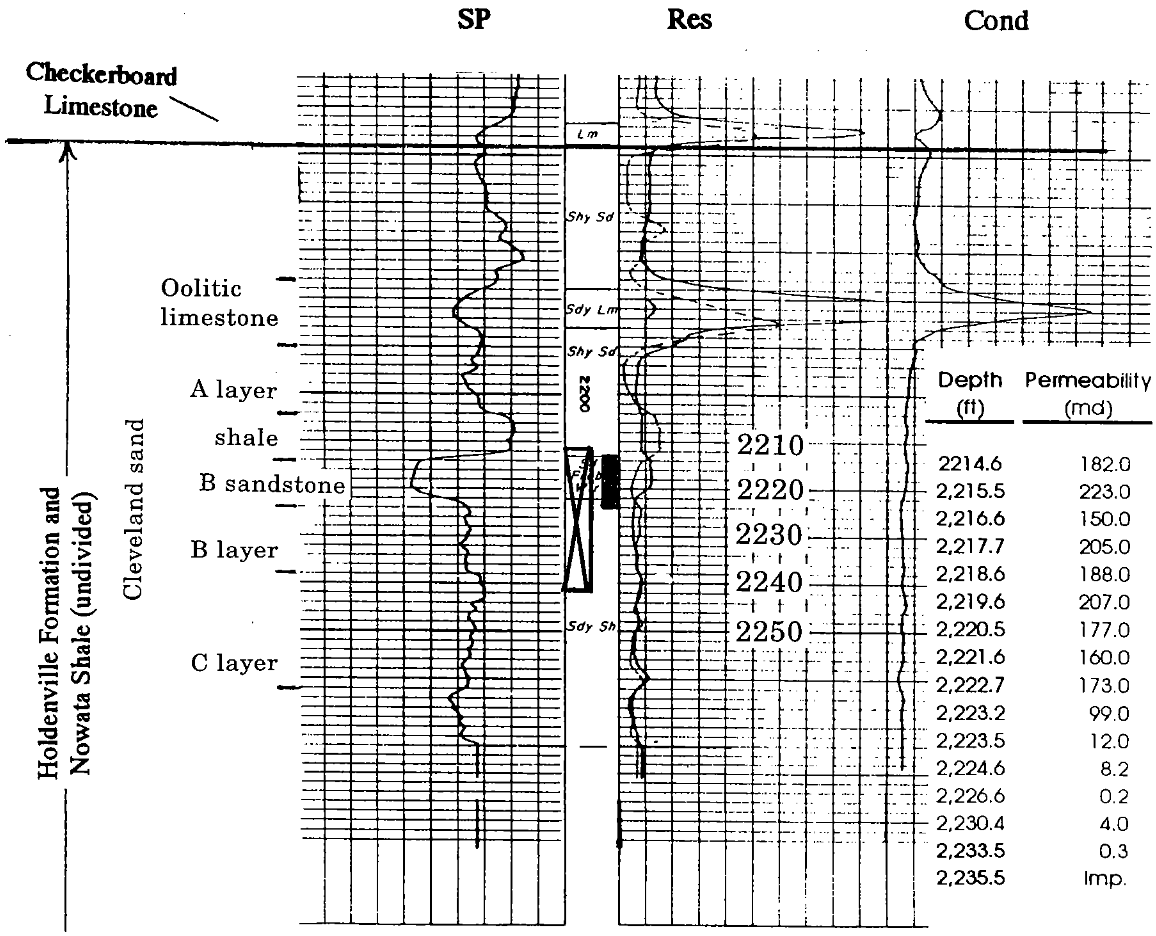
Early operators commonly perforated the upper part of the productive interval (Layer B), and with stimulation encountered oil with water production where water-bearing sandstones of layers C and D were present below. The productive B sandstone in the northern half of sec. 23 and in secs. 14 and 15 is not underlain by reservoir facies of either the layer C or the layer D sandstone (Fig. 31); therefore, water production was not a consideration except at or near the oil-water contact.

SECONDARY RECOVERY

The Pleasant Mound Cleveland sand unit was formed in June 1960. It can be assumed that the operators were concerned about oil migrating into the depleted gas reservoir. A proposed peripheral pattern of water injection wells is mentioned in the operator's files, but it is apparent that lines of water injection wells were installed at the oil-water contact and at the oil-gas contact (Fig. 37). Water injection commenced in June 1960. The injection rate appears to have averaged 100–400 barrels of water per day per injector well. The files do not indicate why all of the producing leases were not unitized. There is an interesting note in the operator's files from June 26, 1969: "In order to try and force some kind of response on the Pleasant Mound Unit, let's start injecting all of the fresh water produced by the Reda pump into #1 and #6 Teters. In other words we would be putting about 360 bbls a day in each of these wells." There was no response to water injection for nine years, in spite of considerable remaining primary production capability (hence, high oil saturation) at the time of unitization. This lack of response is dealt with in Part IV, Reservoir Simulation, this volume.

In 1971, when response to the waterflooding finally became apparent, the operator was permitted to install four additional injector wells (Fig. 37). These additional wells injected at a rate of 200–300 barrels of water per day per well. A fifth water-injection well was premitted and installed in 1985. Peak secondary production occurred in 1974, when the average monthly production rate was 3,295 barrels of oil per month (Table 8).

Nadel & Gussman
1 Harrison
NE NW NW 23, T16N, R6E
KB 981'

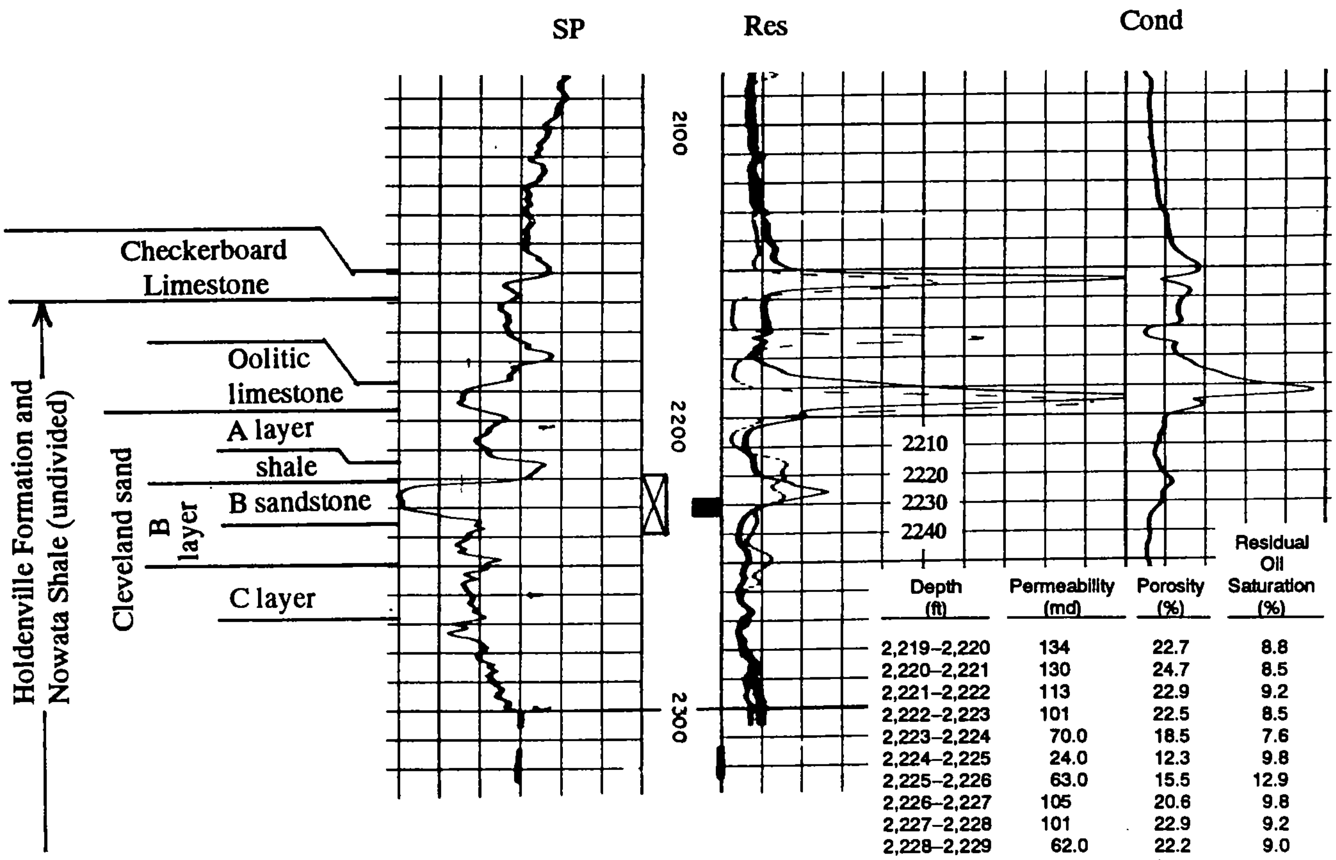


Depth (ft)	Permeability (md)	Porosity (%)	Residual Oil Saturation (%)
2214.6	182.0	23.5	15.0
2,215.5	223.0	23.2	14.0
2,216.6	150.0	23.2	14.0
2,217.7	205.0	23.8	14.0
2,218.6	188.0	23.4	16.0
2,219.6	207.0	24.0	16.0
2,220.5	177.0	23.7	18.0
2,221.6	160.0	23.2	19.0
2,222.7	173.0	24.0	16.0
2,223.2	99.0	23.2	nd
2,223.5	12.0	19.7	6.6
2,224.6	8.2	20.6	4.8
2,226.6	0.2	18.8	4.6
2,230.4	4.0	20.0	2.9
2,233.5	0.3	19.7	3.0
2,235.5	Imp.	12.1	4.3

TD 2,276
Core 2,211–41/ 13' sd, 17' sdy sh, sli stn & od,
Completed 9/26/56
Perf,60/2,213–24, acidize,
IPF 86 BOPD, gty 51.0°
Cumulative Production 43,473 (3 wells)
12/56–6/56

Figure 32. Electric log of the Cleveland sand interval in the Nadel & Gussman No. 1 Harrison well, NE¼NW¼NW¼ sec. 23, T. 16 N., R. 6 E. Cored interval, 2,211–2,242 ft. Porosity, permeability, and oil saturation data from Table 6.

Carter Oil Company
No. 1 Prewitt
SW NW NE 23, T. 16 N., R 6 E.
KB 1,008 ft



Depth (ft)	Permeability (md)	Porosity (%)	Residual Oil Saturation (%)
2,219–2,220	134	22.7	8.8
2,220–2,221	130	24.7	8.5
2,221–2,222	113	22.9	9.2
2,222–2,223	101	22.5	8.5
2,223–2,224	70.0	18.5	7.6
2,224–2,225	24.0	12.3	9.8
2,225–2,226	63.0	15.5	12.9
2,226–2,227	105	20.6	9.8
2,227–2,228	101	22.9	9.2
2,228–2,229	62.0	22.2	9.0
2,229–2,230	73.0	23.0	8.1
2,230–2,231	42.0	21.0	9.1
2,231–2,232	5.0	13.0	0
2,232–2,233	6.5	11.5	3.6

TD 2,300 ft

Core 2,219–2,239 ft
Completed 12/12/56
Perf. 24/2,228–34, sand frac
IPF 33 BOPD, gty 47.1

Figure 33. Electric log for Carter No. 1 Prewitt well, SW¼NW¼NE¼ sec. 23, T. 16 N., R. 6 E.

TABLE 7. – Geological/Engineering Data for the Cleveland Sand in the Pleasant Mound Oil Field, Lincoln County, Oklahoma

Upper Cleveland Sand	
Reservoir size	6,520 acre-ft
Well spacing (oil)	20 acres
Oil/water contact	–1,247 ft
Gas/oil contact	–1,197 ft
Average porosity	22.1%
Average permeability	140 md
Water saturation	32%
Gas to oil ratio	385 SCF/STB
Thickness (net sand) (ϕ >8%)	8.8 ft
Reservoir temperature	106°F
Oil gravity	48°–52°API
Initial reservoir pressure	~950 PSI
Initial formation-volume factor	1.2
Original oil in place (volumetric)	6,334 MSTBO
Cumulative primary production	~400 MSTBO 61 BO/acre-ft
Recovery efficiency (oil)	~6.3%
Cumulative gas	~1,350 MMCF

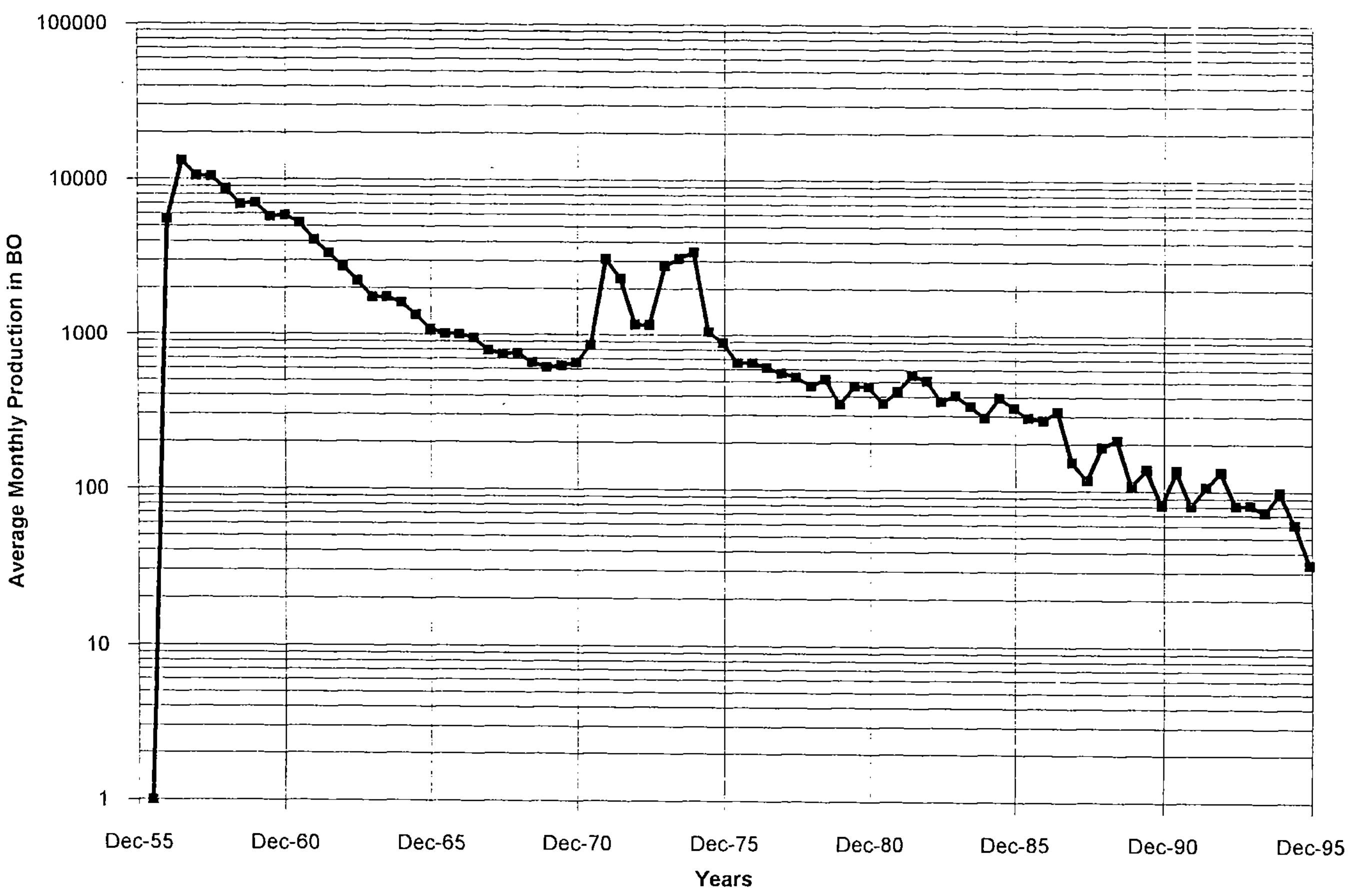
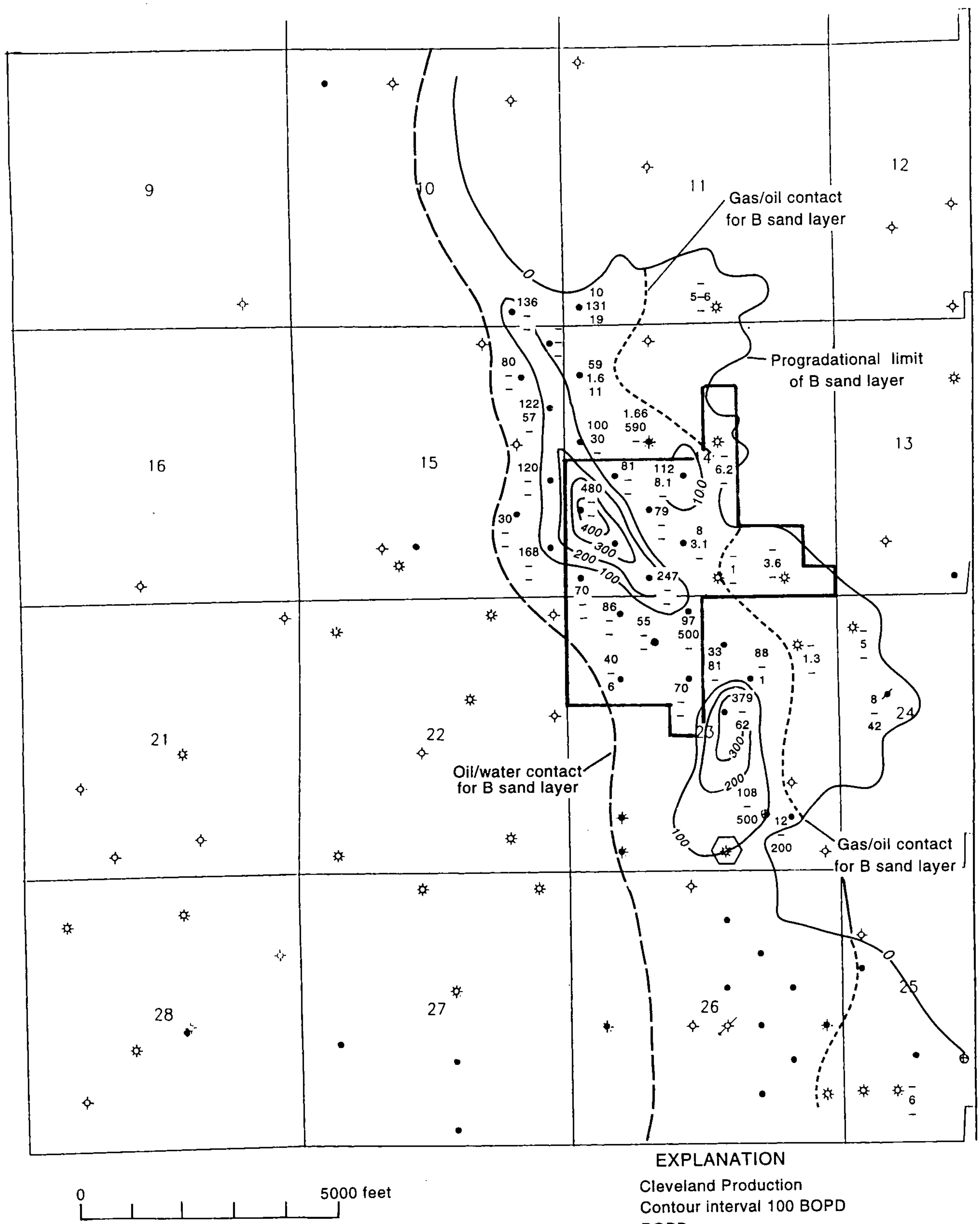


Figure 34. Cumulative oil production graph for the Cleveland sand reservoir in the Pleasant Mound oil field, Lincoln County, Oklahoma.

TABLE 8. – Oil Production Statistics for the Cleveland Sand Reservoir, Pleasant Mound Area, secs. 10, 11, 14, 15, 22, 23, 25, and 26, T. 16 N., R. 6 E., Lincoln County, Oklahoma

Year	Number of active oil wells	Annual oil production (BO)	Average monthly oil production (BO)	Average daily oil production per well (BOPD)	Cumulative oil production (BO)
1956	13	33,399	?	?	33,399
1957	20	143,495	11,958	19.6	176,894
1958	23	115,323	9,610	13.7	292,217
1959	23	84,111	7,009	10.0	376,328
1960	24	70,098	5,842	8.0	446,426
1961	23	56,237	4,686	6.7	502,663
1962	23	36,875	3,073	4.4	539,538
1963	23	24,035	2,003	2.9	563,573
1964	23	20,228	1,686	2.4	583,801
1965	23	14,628	1,219	1.7	598,429
1966	23	12,171	1,014	1.4	610,600
1967	23	10,513	876	1.2	621,113
1968	23	9,067	756	1.1	630,180
1969	22	7,667	639	1.0	637,847
1970	22	7,750	646	1.0	645,597
1971	20	23,956	1,996	3.3	669,553
1972	20	21,050	1,754	2.9	690,603
1973	20	23,948	1,996	3.3	714,551
1974	21	39,541	3,295	5.1	754,092
1975	20	11,718	977	1.6	765,810
1976	20	7,904	659	1.1	773,714
1977	20	7,105	592	1.0	780,819
1978	20	6,021	502	0.8	786,840
1979	21	5,296	441	0.7	792,136
1980	21	5,609	467	0.7	797,745
1981	21	4,792	399	0.6	802,537
1982	21	6,377	531	0.8	808,914
1983	21	4,699	392	0.6	813,613
1984	18	3,866	322	0.6	817,479
1985	18	4,435	370	0.7	821,914
1986	17	3,457	288	0.6	825,371
1987	17	2,866	239	0.5	828,237
1988	17	1,859	155	0.3	830,096
1989	17	1,924	160	0.3	832,020
1990	13	1,317	110	0.3	833,337
1991	11	1,305	109	0.3	834,642
1992	11	1,445	120	0.4	836,087
1993	11	973	81	0.2	837,060
1994	11	1,034	86	0.3	838,094
1995	11	570	48	0.1	838,664



EXPLANATION

Cleveland Production

Contour interval 100 BOPD

10 BOPD

131 MCFGPD

19 BWPD

\- No data reported

Figure 35. Isopleth map of initial production for the Cleveland sand reservoir in the Pleasant Mound oil field. Contour interval is 100 BOPD. See Table 4 for well names.

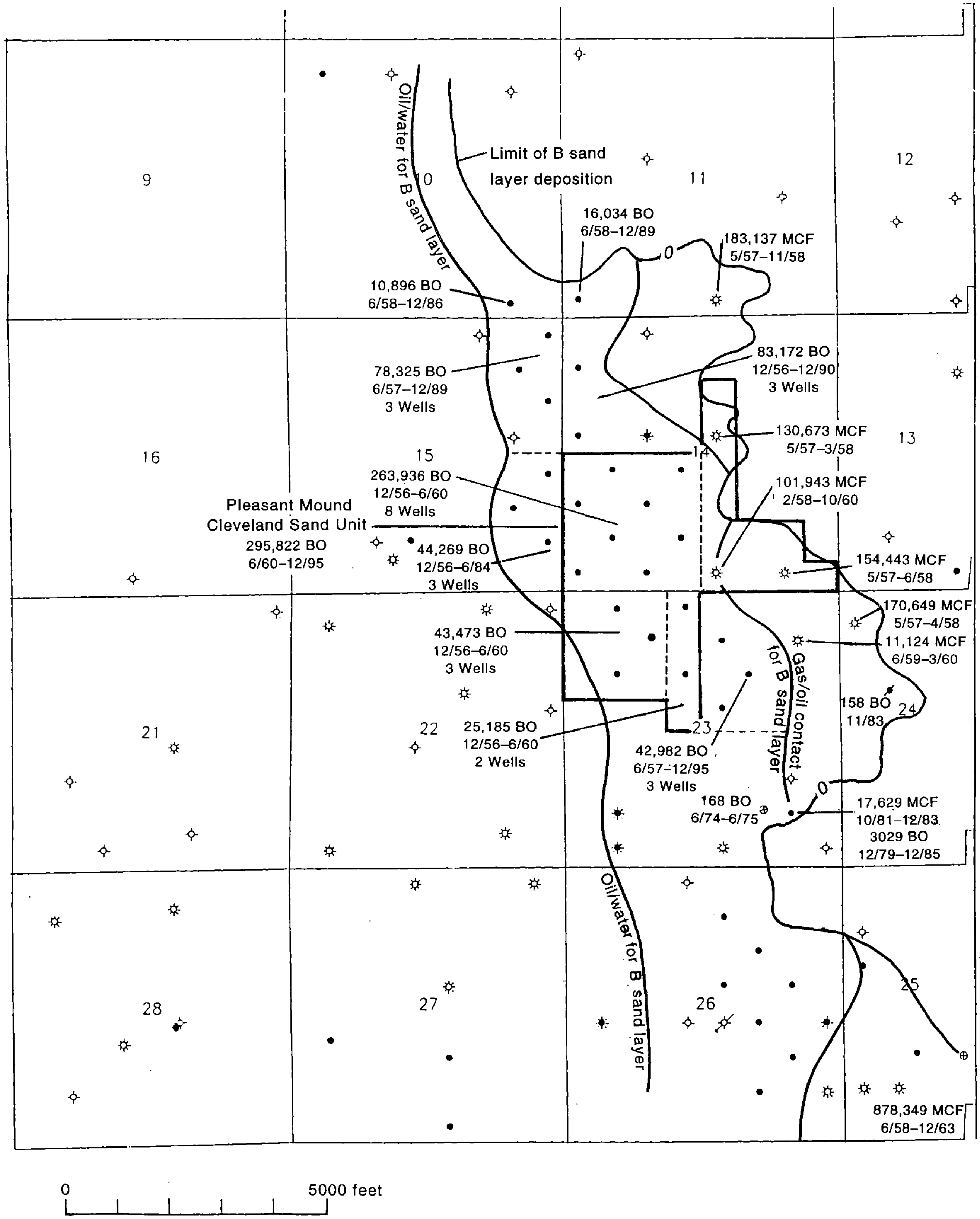


Figure 36. Map of cumulative production by lease for the Cleveland sand reservoir in the Pleasant Mound oil field area. See Table 4 for well names.

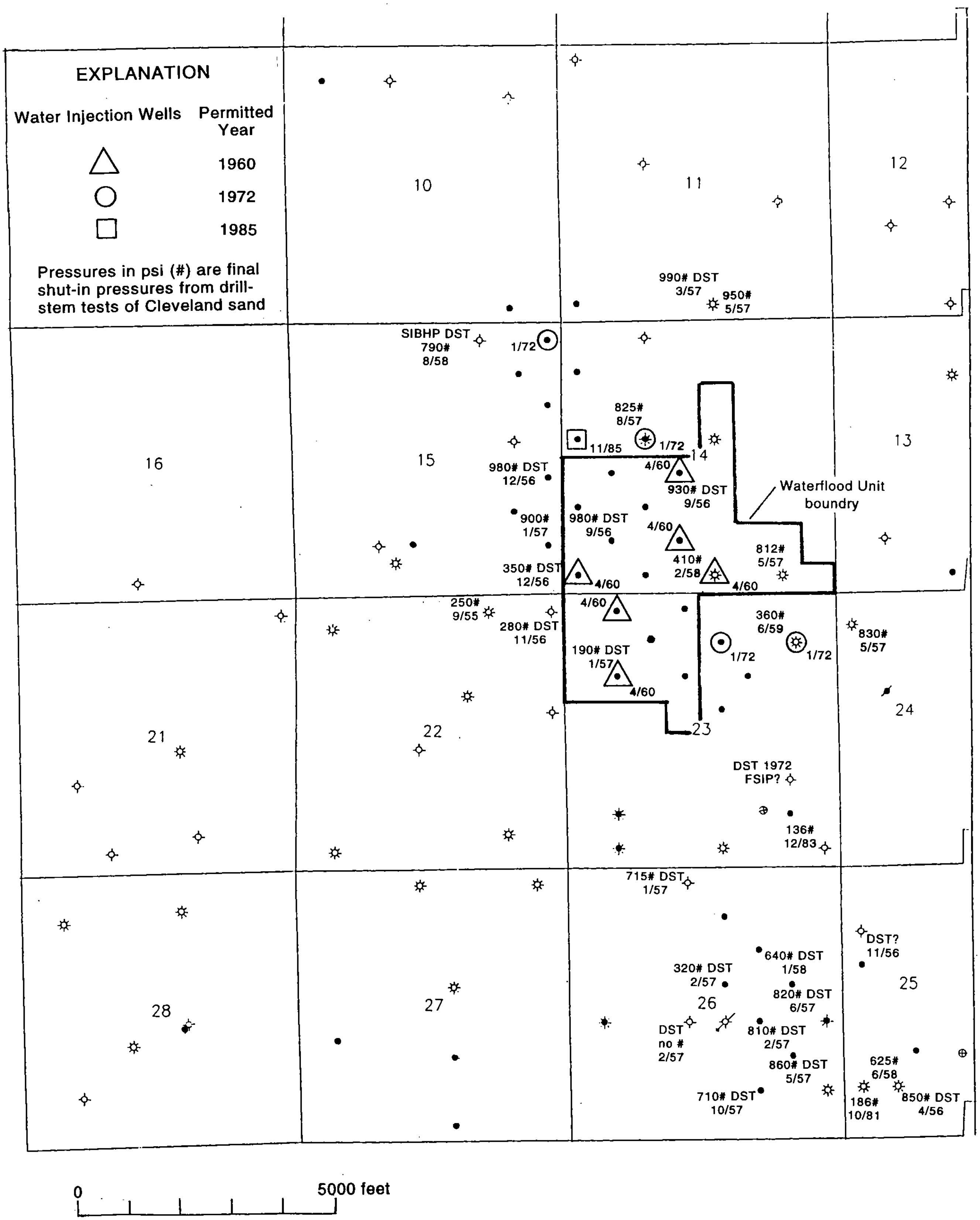


Figure 37. Status of water injection wells for the Pleasant Mound Cleveland sand unit and vicinity. Pressures in psi (#) are final shut-in pressures from drill-stem tests of Cleveland sand, with month and year of test. See Table 4 for well names.

PART IV

Reservoir Simulation of the Cleveland Sand Reservoir, Pleasant Mound Oil Field, Lincoln County, Oklahoma

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INTRODUCTION

The Cleveland sand reservoir in the Pleasant Mound oil field in northeastern Lincoln County, Oklahoma, is located in secs. 10, 11, 14, 15 and secs. 22–26, T. 16 N., R. 6 E. In this study, the study area consists of ~2,000 productive acres that are bounded by oil-water contacts on the west and by the sand-body limits on the east. The southern boundary of the study area is assumed to be a no-flow boundary. The Cleveland sand in this reservoir is at depths of 2,220 ft, or –1,220 ft subsea (below mean sea level). The oil-bearing Cleveland sand within the Pleasant Mound field appears to have been deposited in three layers, B, C, and D, in descending order (Rottmann, Part III, this volume). The top zone, B, is the largest sandstone body; it has an average net thickness of 12 ft and an areal extent of 3,000 acres. The middle zone, C, has an average net thickness of 16 ft and an areal extent of 2,200 acres. The bottom zone, D, has an average net thickness of 12 ft and an areal extent of 700 acres. At the western sides of zones B and C, there appear to be aquifers that provide water influx. There also appears to be an aquifer at the southern edge of zone D, which has sand boundaries at its other edges. By 1960, 36 wells were completed in zone B, and five wells were completed in zone C. No well has been completed in zone D. It appears that all three zones communicate in the southeast corner of the study area because well logs do not show any shale breaks in this area. A complete discussion of the Pleasant Mound field reservoirs, including petrography and depositional environments, can be found in Rottmann (Part III, this volume).

Cleveland oil completions in the study area included 36 production wells on 20 leases (Table 9). Another six wells penetrated the Cleveland sand reservoirs but were not completed in them. By the end of 1995, the 36 production wells had produced nearly 860,000 barrels of oil since the reservoir was discovered in 1956 (Table 10). Initial development of the Pleasant Mound field began when zone B was discovered and began producing from the Nadel & Gussman No. 1 Alice Teters well in September 1956. In late 1956, the No. 1 Alice Teters lease (eight wells) averaged 29 BOPD per well with no reported water production. Twenty-six additional wells were drilled and completed in zones B and C (in secs. 10, 11, 14, 15, and 23–25) during the next three years. Two gas wells were drilled and completed in 1974 and 1979 (in sec. 23). Most of the production has been from zone B, which was perforated in all 36 producing wells.

There were two phases of production in this field, primary production from 1956 through 1960 and waterflood production, which started in June 1960. The primary oil-production rates declined from 400 BOPD in 1958 to 30 BOPD in 1965 with no observed waterflood response (Figure 38). In June 1960, six wells were converted to water injectors within the waterflood unit, which included half of sec. 14 and a quarter of sec. 23. An additional five wells outside the waterflood unit were converted to water injection beginning in 1972 and ending in 1985 (Rottmann, Fig. 37, Part III, this volume). Water breakthrough (the first waterflood response) occurred in 1971, when the field water cut reached 80%; by 1975, it had reached 95%. The highest waterflood oil-production rate was 100 BOPD in 1972; it dropped to 20 BOPD in 1976. By the end of 1995, the field oil-production rate was <2 BOPD and the water cut had reached 99%.

The average initial bottom-hole pressure in the field was 950 PSIA (Table 11), and it is thought that there was a gas cap initially. Reservoir behavior indicates that the dominant source of reservoir energy for this field has been the water injection drive. The major objective of this study was to use the available field data to develop a reservoir simulation model. The model could then be used to evaluate past field performance and to develop potential strategies for improving oil recovery.

DATA AVAILABILITY

Data used for reservoir characterization and simulation included depths to the tops of the sandstones, net sand thicknesses, porosity, permeability, lithology, initial water saturation, and depths to the oil-water contacts and oil-gas contacts for each zone. Values of these

TABLE 9. – Well Information for Cleveland Sand Reservoir in Pleasant Mound Field (T. 16 N., R. 6 E.)

No	WELLS	Grid X	Grid Y	Grid Z	Perf. Intval (ft)	B-Thknes (ft)	Totl-Thknes (ft)	Start.–Shut (Mon/Year)	Conv.Time (Mon/Year)	Cum. Prod (stb, mscf)	Locations		Well Names & Operators	
1	INGALS1	9	34	1	1238-1250	5	5	06/58-12/65		10,896	Sec. 10,	SW SE SE	Ingalls #1,	Sunray Mid-Continent Oil Company
2	GIVENS1	9	29	1	1212-1220	2	2	06/58-12/89		16,034	Sec. 11,	SW SW SW	Givens Heirs #1,	Carter Oil Company
3	LANDLEY1	9	20	1	1173-1183	10, Shaly	10, Shaly	05/57-11/58		183,137(g)	Sec. 11,	SW SW SE	Langley #1,	Ketchum Oil Company
4	CLINK2	17	31	1	1225-1243	14	14	06/57-12/88		78,325+	Sec. 15,	NE SE NE	Clinkenbeard #2,	Carter Oil Company
5	CLINK3	14	33	1	1229-1241	10	10	12/58-12/88		+	Sec. 15,	SW NE NE	Clinkenbeard #3,	Carter Oil Company
6	CLINK4	12	31	1	1224-1234	n.a	n.a	02/58-	01/72,	+	Sec. 15,	NE NE NE	Clinkenbeard #4,	Carter Oil Company
7	CONGER1	27	32	1	1228-1240	11	11	12/56-06/82		44,269+	Sec. 15,	NE SE SE	Conger #1,	Aurora Gasoline Company
8	CONGER2	22	32	1	1232-1241	18	18	12/56-06/82		+	Sec. 15,	NE NE SE	Conger #2,	Aurora Gasoline Company
9	CONGER3	24	33	1	1233-1242	14	14	01/57-06/82		+	Sec. 15,	SW NE SE	Conger #3,	Aurora Gasoline Company
10	TYNER1	19	29	1	1221-1237	14	14	12/56-	11/85,	83,172+	Sec. 14,	SW SW NW	Tyner #1,	Carter Oil Company
11	TYNER2	19	24	1	1208-1224	14, Shaly	14, Shaly	12/56-	01/72,	+	Sec. 14,	SW SE NW	Tyner #2,	Carter Oil Company
12	TYNER3	14	29	1	1213-1219	7	7	07/57-12/89		+	Sec. 14,	SW NW NW	Tyner #3,	Carter Oil Company
13	GOOCH1	19	20	1	1194-1210	6, Shaly	6, Shaly	05/57-03/58		130,673(g)	Sec. 14,	SW SW NE	Gooch #1,	Nadel & Gussman
14	AMERM1-A	29	19	1	1201-1209	n.a	n.a	03/58-	06/60,	101,943(g)	Sec. 14,	SW SW SE	Amerman #1-A,	Nadel & Gussman
15	AMERM1	29	15	1	1188-1200	8	8	05/57-06/58		154,443(g)	Sec. 14,	SW SE SE	Amerman #1,	Nadel & Gussman
16	TETERS1	22	22	1	1216-1227	14	14	9/56-	06/60,	263,936+	Sec. 14,	NE NE SW	Teters #1	(Discovery well), Nadel & Gussman
17	TETERS2	27	27	1	1224-1234	13	13	10/56-		+	Sec. 14,	NE SW SW	Teters #2,	Nadel & Gussman
18	TETERS3	24	25	1	1217-1229	16	16	12/56-		+	Sec. 14,	SW NE SW	Teters #3,	Nadel & Gussman
19	TETERS4	29	25	1	1219-1231	14	14	12/56-		+	Sec. 14,	SW SE SW	Teters #4,	Nadel & Gussman
20	TETERS5	22	27	1	1220-1233	16	16	12/56-		+	Sec. 14,	NE NW SW	Teters #5,	Nadel & Gussman
21	TETERS6	27	22	1	1209-1224	10	10	12/56-	06/60,	+	Sec. 14,	NE SE SW	Teters #6,	Nadel & Gussman
22	TETERS7	24	29	1	1227-1243	18	18	12/56-		+	Sec. 14,	SW NW SW	Teters #7,	Nadel & Gussman
23	TETERS8	29	30	1	1231-1239	n.a	n.a	12/56-	06/60,	+	Sec. 14,	SW SW SW	Teters #8,	Nadel & Gussman
24	HARRISN1	32	27	1	1232-1243	9	9	12/56-	06/60,	25,185+	Sec. 23,	NE NW NW	Harrison #1,	Nadel & Gussman
25	HARRISN2	36	26	1	1242-1245	20	20	06/57-	06/60,	+	Sec. 23,	NE SW NW	Harrison #2,	Nadel & Gussman
26	ROBINSN1	34	24	1 & 2	1227-1239	12	17	1/57-		43,473+	Sec. 23,	SW NE NW	Robinson #1,	Nadel & Gussman
27	ROBINSN2	32	22	1	1212-1224	14	14	1/57-		+	Sec. 23,	NE NE NW	Robinson #2,	Nadel & Gussman
28	ROBINSN3	37	22	1	1228-1235	13	19	1/57-		+	Sec. 23,	NE SE NW	Robinson #3,	Nadel & Gussman
29	PRUIT1-A	47	14	1 & 2	1200-1206	3	30	12/79-12/83		3029, 17629(g)	Sec. 23,	C NW SE SE	Prewitt #1-A,	Geno Oil & Gas Corp.
30	PRWIT1-K	47	17	1 & 2	1213-1217	4	>22	06/74-06/75		168	Sec. 23,	NE SW SE	Prewitt #1,	J.N. King, Jr
31	PRWIT1-C	34	19	1	1220-1226	12	12	06/57-	01/72,	42,982+	Sec. 23,	SW NW NE	Prewitt #1,	Carter Oil Company
32	PRWIT2-C	39	19	1 & 2	1221-1229	5	9	06/57-		+	Sec. 23,	SW SW NE	Prewitt #2,	Carter Oil Company
33	PRWIT3-C	37	17	1	1213-1223	10	10	03/58-		+	Sec. 23,	NE SW NE	Prewitt #3,	Carter Oil Company
34	PRWIT4-C	34	14	1	1201-1212	12	12	06/59-03/60	01/72,	11,124(g)	Sec. 23,	SW NE NE	Prewitt #4,	Carter Oil Company
35	PRWIT1-N	33	10	1	1184-1189	10, Shaly	>16	05/57-04/58		170,649(g)	Sec. 24,	SW NW NW	Prewitt #1,	Nadel & Gussman
36	RAIN1-SO	67	7	1	1169-1181	14	39	06/58-		878,349(g)	Sec. 25,	NE SW SW	Rainwater #1,	Sojourner Drilling Corp.

TABLE 10. – Oil Recovery Comparisons for Different Development Cases, Cleveland Sand Reservoir, Pleasant Mound Oil Field, Lincoln County, Oklahoma

Formation	Primary & Water-flooding (12/1995)			Base (12/2005)			Recompletion-Option 1 (12/2005)			Recompletion-Option 2 (12/2005)		
	Cum. Oil (STB)	Rec. Factor (%)	Cum.Wtr. (MSTB)	Cum. Oil (STB)	Rec. Factor (%)	Cum. Wtr (MSTB)	Cum. Oil (STB)	Rec. Factor (%)	Cum. Wtr (MSTB)	Cum. Oil (STB)	Rec. Factor (%)	Cum. Wtr (MSTB)
Zone B	835,000	11.1	2,700	940,000	12.5	2,900	1,550,000	21	11,000	2,000,000	26.7	40,000
Zone C	25,000	0.4	400	30,000	0.5	500	470,000	8.4	380	650,000	11.6	2,000
Zone D	0	0	0	0	0	0	80,000	13	20	150,000	25	1,000
Total	860,000	6.3	3,100	970,000	7.1	3,400	2,100,000	15.5	11,400	2,800,000	20.6	43,000

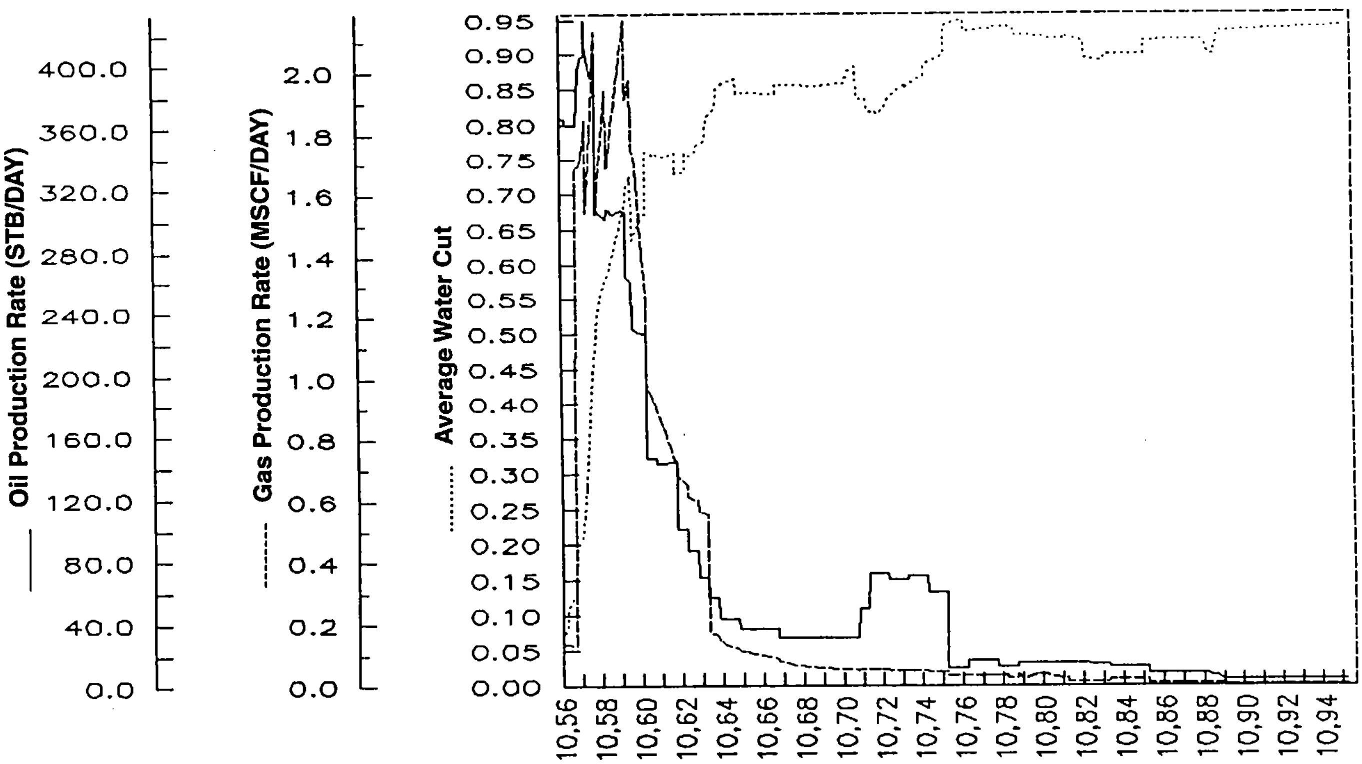

Figure 38. Field production and water cut history.

parameters were obtained from well logs and core analyses.

Rottmann (Part III, this volume) interpreted the depth to the top of each zone and net-pay thickness of each zone. Porosity, absolute permeability, and initial water saturation data were evaluated from the core analyses of the Carter Oil Co. No. 1 Prewitt and the Nadel & Gussman No. 1 wells (Figs. 32 and 33, Part III, this volume). The initial reservoir bottom-hole pressure of 950 PSIA was determined from drill stem tests reported on completion cards. The initial gas-oil ratio of 385 SCF/STB was obtained from Rottmann's report (Table 7, Part III, this volume). Kurt Rottmann also provided records of core analyses and water injection, as well as oil, gas, and water production, for individual wells. (Data that are useful for reservoir studies but were not available for this study include data about reservoir pressure during production as well as relative permeability and capillary pressure data.)

ANALYSES OF ROCK DATA

Reservoir properties for the Pleasant Mound Cleveland sand reservoir are shown in Table 11. Two wells, the Carter Oil Co. No. 1 Prewitt and the Nadel & Gussman No. 1 Harrison, were cored in zone B (Figs. 32 and 33, Part III, this volume). Average values of absolute

TABLE 11. – Reservoir Properties, Cleveland Sand Reservoir, Pleasant Mound Oil Field, Lincoln County, Oklahoma

Estimated properties	Zone B	Zone C	Zone D
Porosity	23%	20%	20%
Absolute permeability	130 md	50 md	50 md
Average gross pay	20 ft	20 ft	25 ft
Average net pay (ϕ >8%)	10 ft	15 ft	13 ft
Initial water saturation	32%	32%	32%
Initial bottom-hole pressure (average)	950 PSIA (from DST)	950 PSIA (from DST)	950 PSIA (from DST)
Initial gas-oil ratio	385 SCF/STB	385 SCF/STB	385 SCF/STB
Initial formation-volume factor	1.20 RB/STB	1.20 RB/STB	1.20 RB/STB
Reservoir temperature	106°F	106°F	106°F
Average oil gravity	~48°API	48°API	48°API
Specific gas gravity	0.8	0.8	0.8
Original oil in place	7.5 MMSTB	5.6 MMSTB	0.5 MMSTB
Original gas in place	3,800 MMSCF	3,000 MMSCF	220 MMSCF

permeability, porosity, and water saturation from the core reports were used to develop the reservoir simulation model of zone B. Archie's (1942) method and the Humble correlation (Winsauer, 1953) were used to estimate an average permeability of 50 md and a porosity of 20% for zones C and D from well logs of the Sojourner Drilling Corp. No. 1 Rainwater well, and the values were used for simulation. Because porosity logs for the wells in this field were not available, uniform porosities and permeabilities were used in all three zones. The initial water saturation value of 32% (as determined from core analyses of the Carter Oil Co. No. 1 Prewitt and the Nadel & Gussman No. 1 Harrison wells and supported by resistivity log interpretation) was used for all three zones (Table 7, Part III, this volume). The residual oil saturation of 30% was estimated from the resistivity log of the Carter Oil Co. No. 3 Tyner well.

Capillary pressure data, calculated using the method of Smith (1991), were used to determine phase transition zone distributions. A single set of relative permeability saturation functions, calculated using Honarpour and others' (1986, p. 40) method, was used for all three zones.

The original oil-water contact, interpreted by Rottmann from geophysical logs, is –1,247 ft subsea in zones B, C, and D. The original oil-gas contact (OGC) is interpreted to be –1,197 ft subsea in zones B and C. Zone D is entirely in the oil leg and there is no OGC. The geophysical log interpretations were confirmed by analyses of the cores from the Carter Oil Co. No. 1 Prewitt and the Nadel & Gussman No. 1 Harrison wells.

The average reservoir temperature of 106° F used in simulation was from temperature surveys in the Nadel & Gussman No. 1 Harrison and No. 1 Robinson wells (M & M Oil Well Service, unpublished data, 1957). The shut-in bottom-hole pressure of 950 PSIA from the completion cards for the Nadel & Gussman No. 1 Alice Teters well was chosen as the initial average reservoir pressure at a depth of –1,245 ft subsea.

FLUID PROPERTIES

Average reservoir properties are listed in Table 11. The fluid properties are consistent with the low-shrinkage assumption. Oil gravity values were 41.8°–54.0° API on completion cards. The average oil gravity of 48.0° API was used to develop fluid properties for the simulation. The gas specific gravity of 0.80 (specific gravity of air = 1.0) was estimated using Standing's (1947, 1952) correlations. A formation water salinity of 120,000 ppm (NaCl) was estimated from well log interpretations, and a water specific gravity of 1.12 was used to estimate water phase properties. The initial gas-oil ratios varied from 146 SCF/STB to >1,000 SCF/STB. An estimate of 385 SCF/STB initial gas-oil ratio was used. The original saturation (bubble-point) pressure of the oil, estimated using Al-Marhoun's correlation (McCain, 1990, p. 519), was 1,150 PSIA. An estimated average initial oil formation-volume factor of 1.20 RB/STB and an estimated initial reservoir oil viscosity of 0.61 cp were used in the study.

FIELD DEVELOPMENT OVERVIEW

Primary Production

Wells that penetrated in the Pleasant Mound Cleveland sand reservoir and were used for the simulation study are listed in Table 9 and Table 12 (for proposed recompletion wells). The depths of perforated intervals were obtained from completion cards. A total of 36 wells were drilled and completed in the Cleveland sand in the Pleasant Mound field. All of the wells were perforated in zone B. Only four of the wells were perforated in zone C, and no well was perforated in zone D. The total primary field production, before waterflood re-

TABLE 12. – Proposed Recompletion Wells for Cleveland Sand Reservoir in Pleasant Mound Field

No.	Wells	Grid X	Grid Y	Grid Z	Proposed perf. interval (ft)	B-thickness (ft)	C-thickness (ft)	D-thickness (ft)	Completion (Mon/Yr)	Locations	Well names & operators
1	PRWIT1-S	39	7	2	1,160–1,165	6	16, shaly	0	09/83	Sec. 24, C SE¼ SW¼NW¼	Prewitt #1, C. W. Smith & Associates, Inc.
2	KIN1-CAN	61	12	1	1,210–1,215	11	20	20	01/82	Sec. 26, C NE¼ NE¼SE¼	Kinnamon #1-26, Canamco Resources Corp.
3	KIN1-RED	62	28	2	1,270–1,275	8	16	10	11/88	Sec. 26, N½ NW¼SW¼	Kinnamon #1-26, Red Fork Oil
4	HALL1-A	54	19	1	1,220–1,225	14	20	6	07/82	Sec. 26, C SW¼ NW¼NE¼	Hall #1-A, Geno Oil & Gas
5	RAIN1-CJ	54	10	2	1,195–1,200	0	20	8	11/56	Sec. 25, NW¼ SW¼NW¼	Rainwater #1, C. J. Brown
6	ROB2-WR	68	9	3	1,185–1,190	6	18	30	06/82	Sec. 25, C NW¼ SW¼SW¼	Roberson #2, W. C. Roberson

sponse occurred in 1971, was ~700,000 STBO for 22 producers.

Eight wells—the Ketchum Oil Co. No. 1 Langley; the Nadel & Gussman No. 1 Prewitt, No. 1 Gooch, No. 1-A Amerman, and No. 1 Amerman; the Geno Oil and Gas Corp. No. 1-A Prewitt; the Carter Oil Co. No. 4 Prewitt; and the Sojourner Drilling Corp. No. 1 Rainwater—were gas production wells. The Geno Oil and Gas Corp. No. 1-A Prewitt produced 3,000 STBO and 17.6 MMCF between December 1974 and December 1985. The Sojourner Drilling Corp. No.1 Rainwater well produced 878 MMCFG from June 1958 through December 1963. The other six gas wells produced for less than two years early in the field production. Some of the gas wells produced a little condensate.

Secondary Production

A waterflood unit was developed in June 1960 and six wells—the Nadel & Gussman No. 1-A Amerman, Nos. 11, 6, and 8 Teters, and Nos. 1 and 2 Harrison—were converted to water injectors. The water injection rates appear to have averaged 100–400 barrels of water per day (BWPD) per injector (Rottmann, Part III, this volume). Apparently waterflood response did not occur until 1971. Five additional wells—the Carter Oil Co. No. 4 Clinkenbeard, Nos. 1 and 2 Tyner, and Nos. 1 and 4 Prewitt—were converted to water injection wells starting in 1971. The water injection rates for these wells averaged 250 BWPD per injector (Rottmann, Part III, this volume). The waterflood oil-production rate peaked in 1974 at 100 BOPD and dropped to 20 BOPD in 1976.

The 40-year oil-production history of the Cleveland sand study area within the Pleasant Mound field is shown in Figure 38. Oil production began in October 1956 and peaked in 1958 at >400 BOPD from 23 wells. There was a dramatic production decline over the following six years, 1959–64, while water cut increased dramatically from 20% in 1958 to 85% in 1964. The oil-production rate in December 1995 was <2 BOPD. The average water cut for the field in December 1995 was >95%. The 1995 reservoir average bottom-hole pressure is unknown. The late performance of the Pleasant Mound field reservoirs shows that they were driven almost entirely by the injected water.

The reservoir performance in the Pleasant Mound field clearly indicates that water injection configurations and injection rates were not optimal. Simulations for the reservoirs as mapped in this study show that the waterflood sweep was not efficient, especially in the southern portions of secs. 23 and 26. There should have been more producers perforated in the Cleveland sand in that area.

The geologic model indicates that zone B, the top and most widespread zone in the field, is a continuous sand body. All three zones, including zones C and D, should be in communication in the southern part of the field. The Cleveland sand reservoir in the southern part of the field actually continues into sec. 36. To account for likely drainage, a third of the gas produced from the Blackstock Petroleum No. 2 English Dennis (the only Cleveland sand production well in sec. 36) was attributed to the Sojourner Drilling Corp. No. 1 Rainwater during the simulation. The southern boundary of the study area was assumed to be a no-flow boundary.

ESTIMATION OF RESERVES AND OIL RECOVERY FACTOR

The estimated total original oil in place (OOIP) in this field was 13.6 MMSTB based on an initial 32% wa-

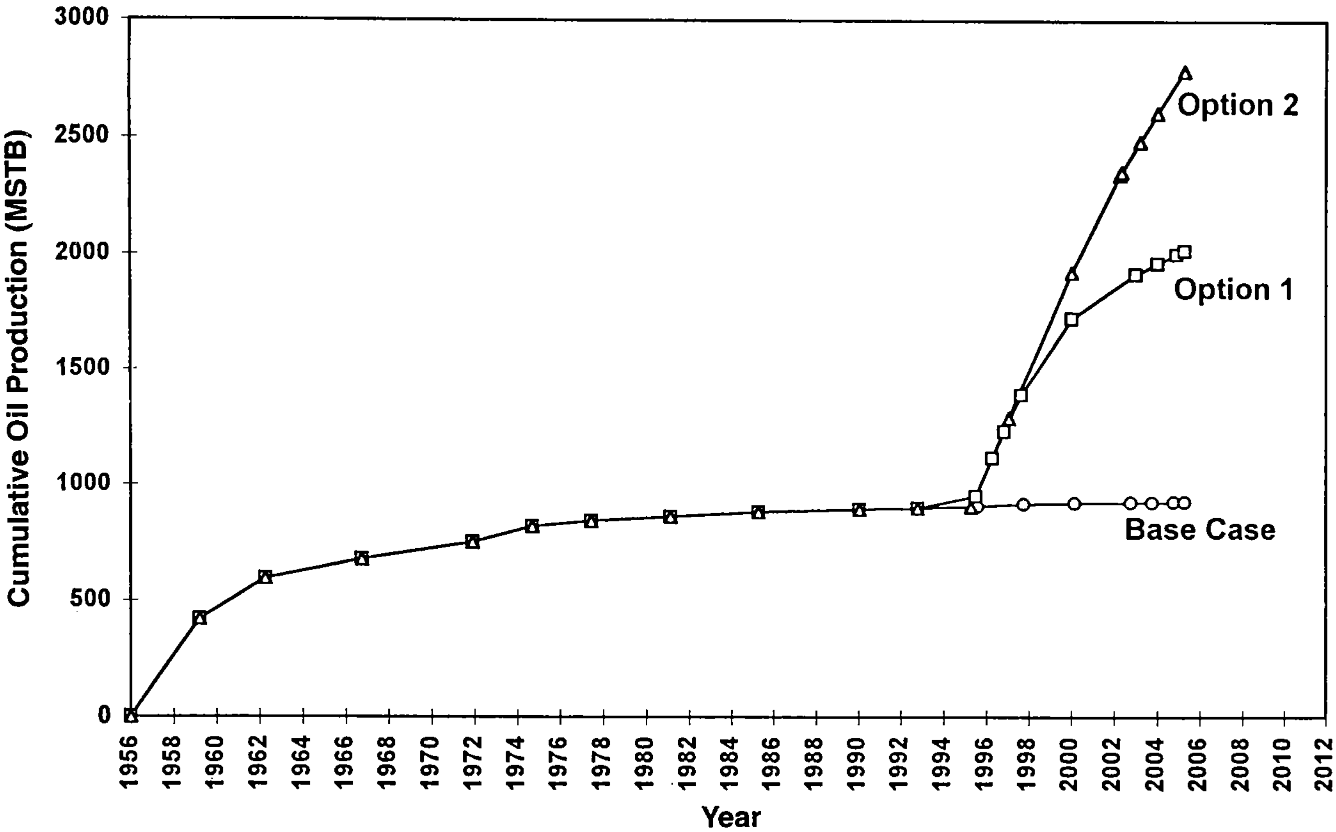

Figure 39. Cumulative Cleveland sand oil production, 1956–1995, and predicted Cleveland sand oil production, 1996–2006.

ter saturation. Zone B had 7.5 MMSTB or ~55% of the OOIP, zone C had 5.6 MMSTB or 41% of OOIP, and zone D had 0.5 MMSTB or ~4% of OOIP (Table 11). The maximum theoretical recovery, based on an estimated residual oil saturation of 30%, could be as much as 7.6 MMSTB, or 56% of OOIP. The unrecoverable immobile oil was estimated to be 6.0 MMSTB. Primary and secondary recovery from the wells in the simulated area through December 1995 was only ~860,000 STB, or ~6.3% of OOIP (Fig. 39). Consequently, ~50% (~6.8 MMSTB) of OOIP in the Pleasant Mound Cleveland sand reservoir is unproduced mobile oil; it represents a target for this simulation study and future field management.

HISTORY MATCHING

The capability of the reservoir model to reproduce observed field performance was tested by several history-matching runs. Because they were considered to be the most reliable data available, oil-production rates in oil wells and gas-production in gas wells were chosen as the specified production variables for the history-matching runs. Since water production data for the reservoir (Figure 40) also were available, the goal in simulating production history was to match the specified oil and gas production rates as well as the cumulative water production for the field by December 1995.

The process of history matching consisted of adjusting uncertain parameters to simulate the production behavior of the actual reservoir. Through the history matching, significant adjustments made to estimated model parameters included: (1) the water relative permeability at residual oil saturation was set to 0.6 to fit the water production history, (2) zone B transmissibility was increased by ~20% to meet the injected-water flow behavior in reservoirs, and (3) initial oil-water contacts were lowered about a foot for each zone.

An analytic aquifer was defined for each oil zone. Aquifer volumes were adjusted to fit water production before the waterflood response occurred. All aquifers were assumed to have a single face connection with each oil zone based on the geological maps. Because it realistically predicts the performance of irregularly shaped volumetric aquifers, the Fetkovich (1971) aquifer model was used to estimate water influx in this study.

Compared to the reservoir history before 1985, the simulated cumulative water production was overestimated somewhat (Fig. 40). For the 10-year period, 1986–95, the water injection and production data do not appear to be very accurate, so little effort was made to match water histories exactly. The primary and secondary oil, gas, and water production for the last 40 years are shown in Figure 38.

EVALUATION OF FUTURE DEVELOPMENT OPPORTUNITIES

The analysis of current oil reserves in the Cleveland sand reservoir in the Pleasant Mound oil field showed

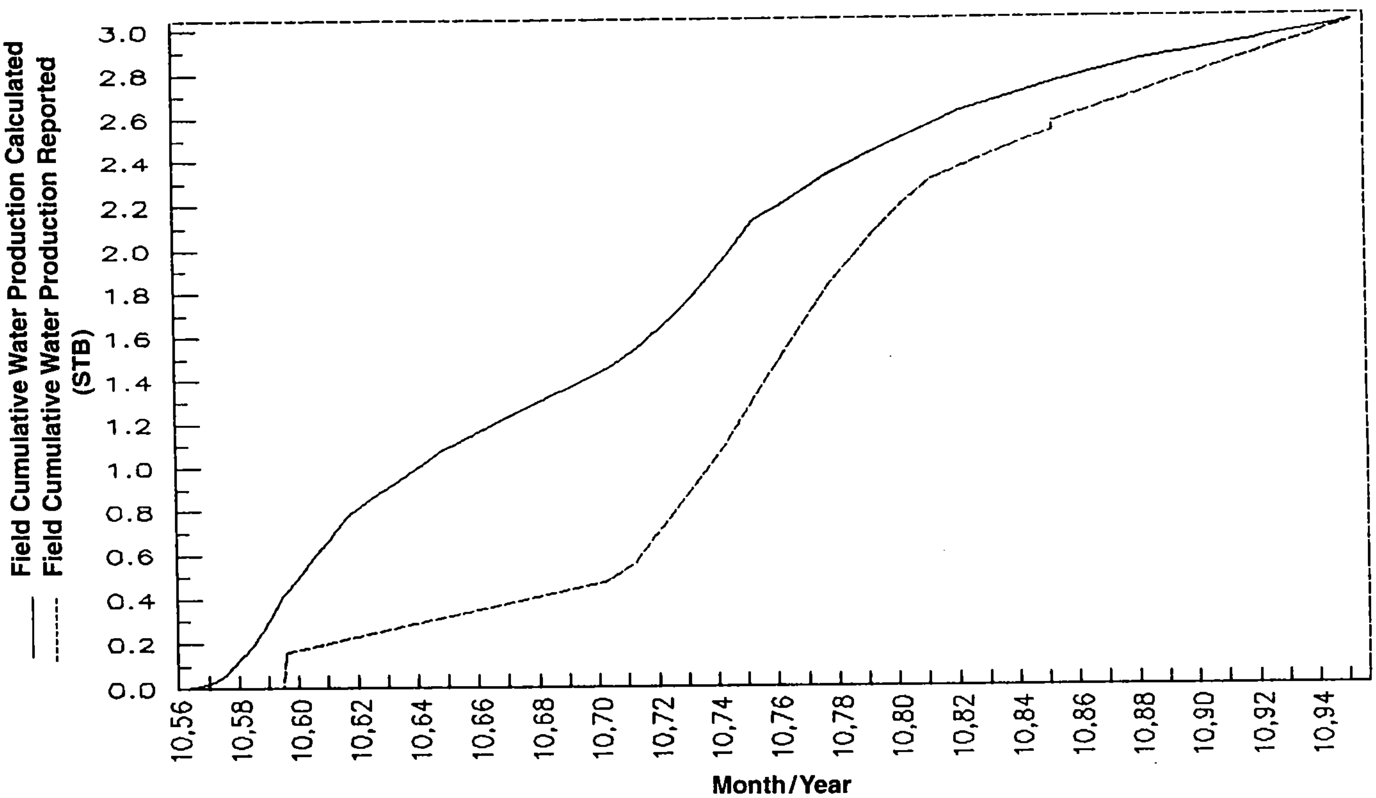

Figure 40. Field cumulative water production history matching.

that 50% of the estimated OOIP, or ~6.8 MMSTB oil, should be mobile. Since the field water cut for present recovery strategy is at 99% with little oil production, using this reservoir model to test field development opportunities in the Pleasant Mound Cleveland sand reservoirs makes sense. One base-case and two recompletion options for reservoir management were investigated and compared. The base-case option extended production using the present field operating policy; well recompletion option 1 used specified rate controls; and well recompletion option 2 used specified bottom-hole pressure (BHP) control in injection wells to accelerate recovery.

Base-Case Option

The base-case simulation assumed that there were no changes in field development and that the well operating conditions (including BHPs) of December 1995 were maintained for an additional 10 years. At the end of those 10 years, additional oil recovery is expected to be ~0.8% of OOIP, or 110,000 STB, and additional water production is expected to be 300,000 STB (Table 10).

Well Recompletion Options

For these cases, six wells that penetrated the Cleveland sand but produced from a lower formation were perforated in the Cleveland sand. The wells are the C. W. Smith & Associates, Inc., No. 1 Prewitt; the Canamco Resources Corp. No. 1-26 Kinnamon; the Red Fork Oil No. 1-26 Kinnamon; the Geno Oil & Gas Corp. No. 1-A Hall; the C. J. Brown No. 1 Rainwater; and the W. C. Roberson No. 2 Roberson. Their suggested perforation intervals are listed in Table 12. Two recompletion wells, the C. W. Smith & Associates, Inc., No. 1 Prewitt, and the Red Fork Oil No. 1-26 Kinnamon, were chosen to be water injectors, and the other four recompletion wells were chosen to be producers. The Ketchum Oil Co. No. 1 Langley, a current shut-in well, was converted to a water injector because it appears to control a large area and was expected to sweep unrecovered oil to producers in the south. The 11 existing injectors were retained and 11 previously active producers were kept as producers.

Well Completion Option 1

For this option, all 14 injectors were controlled by injection rates that averaged 200 BWPD per well, (roughly the current well rates), and all producers were controlled by production rates that averaged 50 BOPD per well, or by BHPs of 300 PSIA. A maximum water cut of 95% was used as an economic limit. Five wells were shut in after five to seven years of recompletion production because they had water cuts of >95%. In year 2000, the Nadel & Gussman No. 4 Teters and Nos. 1 and 3 Robinson wells were shut in. In year 2002, the Carter Oil Co. No. 3 Prewitt well was shut in, and, in year 2003, the Nadel & Gussman No. 1 Alice Teters was shut in. After 10 years of simulated production for this

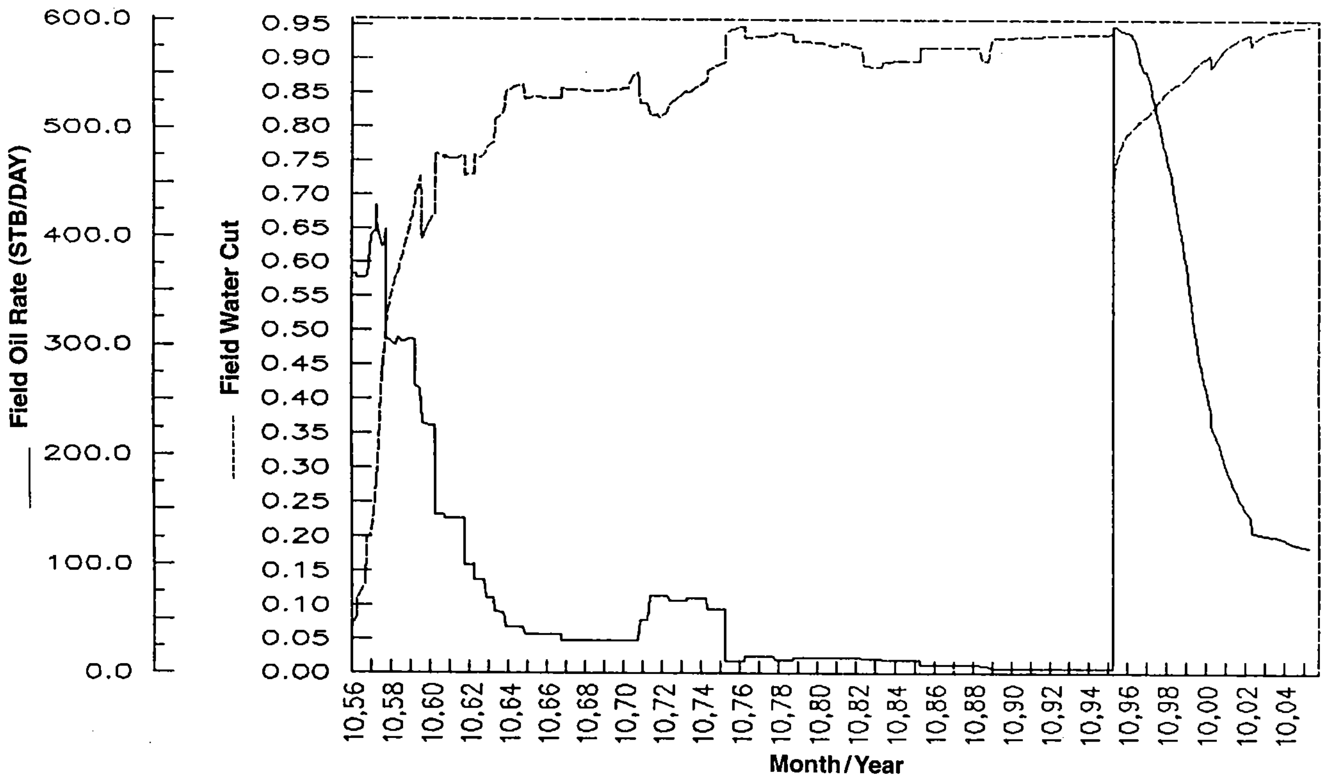

Figure 41. Field oil rate and water cut for recompletion option 1.

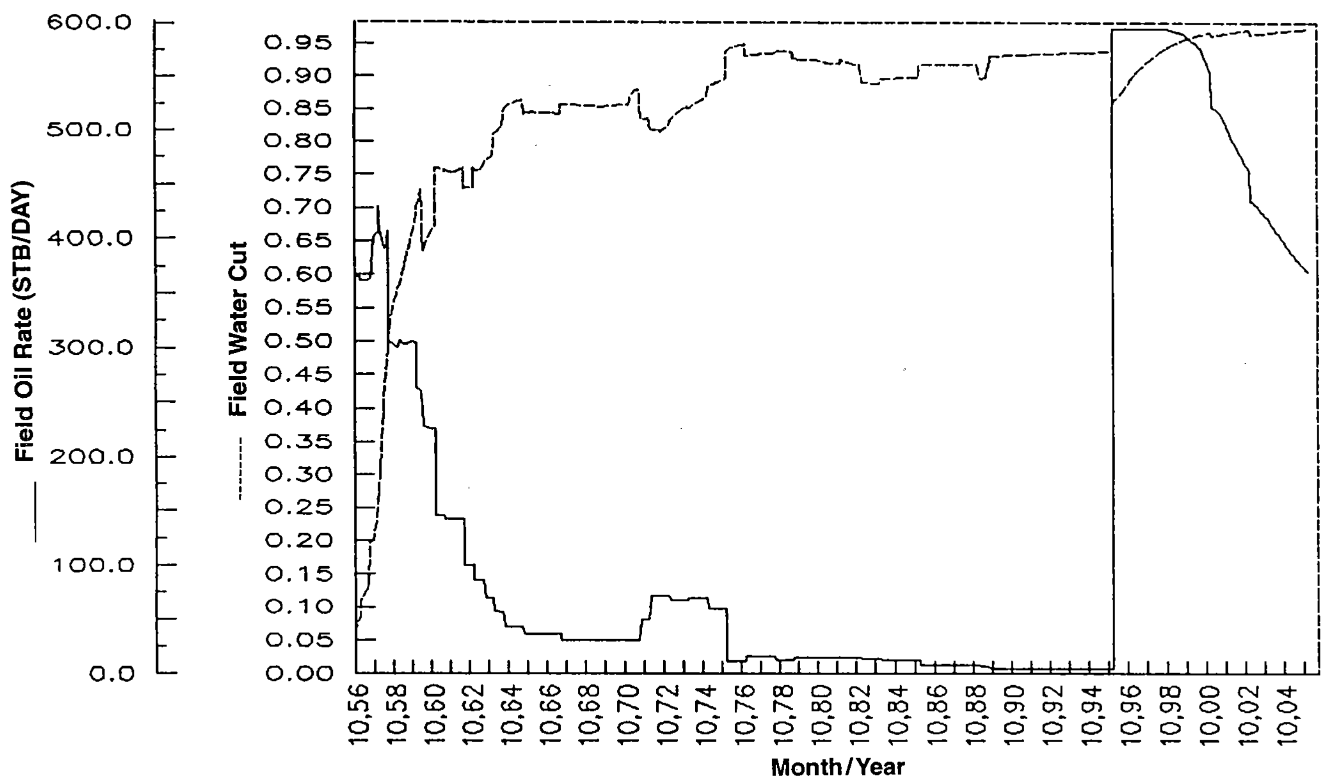

Figure 42. Field oil rate and water cut for recompletion option 2.

option, the additional recovery above the base-case option is expected to be ~8% of OOIP (~1.1 MMSTB) with additional water production of ~8.0 MMSTB (Table 10 and Fig. 41). An interesting point is that since the reservoir is completely filled with water and oil, reservoir response to changes in injection and production locations and rates is rapid. Peak oil production is expected to be close to 600 STB. At the end of 10 years, the oil rate should be about 100 STB with a water cut of 95%.

Well Completion Option 2

For this case, the same producers and injectors as in option 1 were specified. The option 1 specifications were used to control oil production wells. The water injection wells were controlled using a specified BHP of 1,800 PSIA. After 10 years of simulated production for this option, the oil recovery above that of the base-case option is expected to be ~14% of OOIP (~1.9 MMSTB) with additional water production of 39 MMSTB (Table 10 and Fig. 42). Note that the maximum oil-production rate of 600 STB is maintained for about four years and the oil rate at the end of 10 years is still expected to be 400 STB. Water production for option 2 is much larger than for option 1, although the water cut is about same.

SUMMARY

The original oil in place in the Pleasant Mound Cleveland sand reservoir was estimated to be 13.6 MMSTB. Only ~6% of that amount has been recovered after 40 years of primary and waterflooding production. The estimated volume of unproduced mobile oil in this field, ~6.8 MMSTB, or 50% of OOIP, provided a strong motivation for considering future oil recovery opportunities.

Among the alternatives considered for development of the Pleasant Mound Cleveland sand reservoir, a base-case option and two options for recompletions of existing wells in the Cleveland sand were simulated. The results of the model simulations show existing wells recompleted as in option 2 could result in additional oil recovery of ~15% of OOIP (~2.0 MMSTB) in 10 years, or about 2.3 times the recovery during last 40 years. After the option 2 recompletion program, the total oil recovery during both phases could be as much as 2.8 MMSTB, or 21% of the OOIP (Fig. 39).

PART V

The Peru Play

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INTRODUCTION

The Peru fluvial-dominated deltaic (FDD) play has centered on the Cherokee platform in northeastern Oklahoma (Fig. 43) and extends into southern Kansas. The play is limited by the outcrop on the east and by the depositional limit of the sand on the south and west. *Peru* is an informal subsurface term for the Englevale Sandstone, within the Labette Shale, which is Middle Pennsylvanian (Desmoinesian) in age. The Labette Shale is overlain by the Oologah Formation and underlain by the Fort Scott Limestone. In subsurface terminology, the Labette is the shale interval between the Big lime (above) and the Oswego lime (below) (Fig. 44). The Peru sand is not as prolific as some of the other Cherokee sands, especially the Bartlesville, and has long been overlooked as an objective reservoir. It is quite shaly and commonly appears "wet" on resistivity logs; however, the Peru does produce oil and can be economic in spite of its poor appearance on wireline logs. The shallow Peru sand lies in that part of Oklahoma where extensive oil reservoirs have been developed since 1904. Most wells in the area were drilled through the Peru zone and into the Bartlesville; therefore, a large amount of subsurface data and a large number of existing wells are available for calculating the oil potential of the Peru sand.

In the early 1900s, production from the Peru sand, which was named for the small town of Peru in southern Kansas, was being developed in the Peru–Sedan oil field just north of the state line in Chautauqua County, Kansas. In 1907, development spread southward into the Domes–Pond Creek field area in northern Osage County, Oklahoma. Several oil wells were completed in secs. 17 and 18, T. 29 N., R. 12 E., in what the drillers at that time called the *Peru sand.* However, according to Goldman (1922), the wells were actually completed in a shallower sand (called the *Red* or *Stray* sand in Kansas drillers' terminology). Other wells drilled in the same township did encounter the Peru sand, which was reported to have shows of oil and some gas (Goldman, 1922). However, the Peru sand was generally ignored, because the Bartlesville sand, which is only 500–600 ft deeper than the Peru, was much more prolific. Although the Peru sand was not noted for high initial-production rates, the production, once established, tended to be long-lived (Bass and others, 1939).

The Natural Resources Information System (NRIS) production data include the amount of production and the names of the producing reservoirs by lease for the period beginning in 1979. Most leases with Peru production also have production from other reservoirs, the Bartlesville sand in particular. Annual oil-production figures from Peru-only leases and total production from leases that produce(d) from the Peru and one or more other reservoirs (Peru-commingled) are listed in Table 13 and shown in Figure 45. For the period 1979–95, the number of Peru-only leases ranged from 18 to 51, and the number of Peru-commingled leases ranged from 43 to 79. For the same time period, the total production from Peru-only leases in Oklahoma was 910,262 barrels of oil (BO). The Peru contribution to

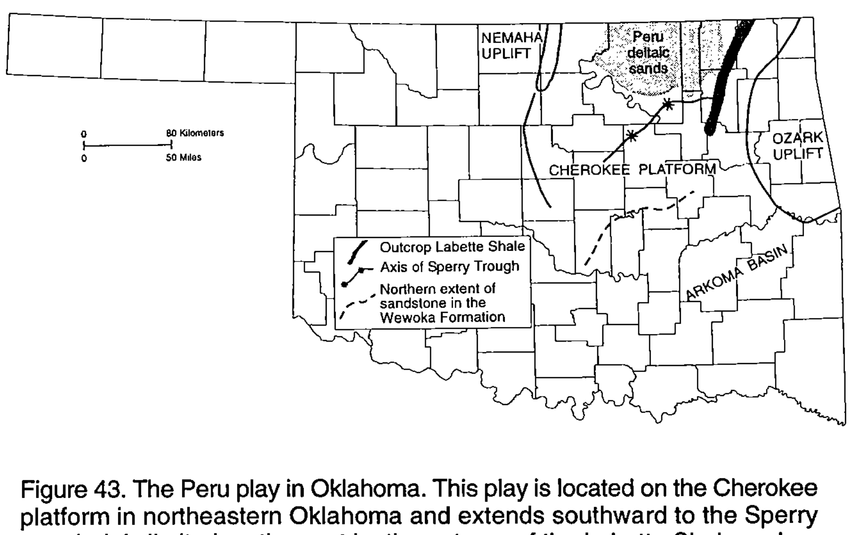

Figure 43. The Peru play in Oklahoma. This play is located on the Cherokee platform in northeastern Oklahoma and extends southward to the Sperry trough. It is limited on the east by the outcrop of the Labette Shale and on the south and west by the depositional limit of Peru sand; it extends northward into Kansas.

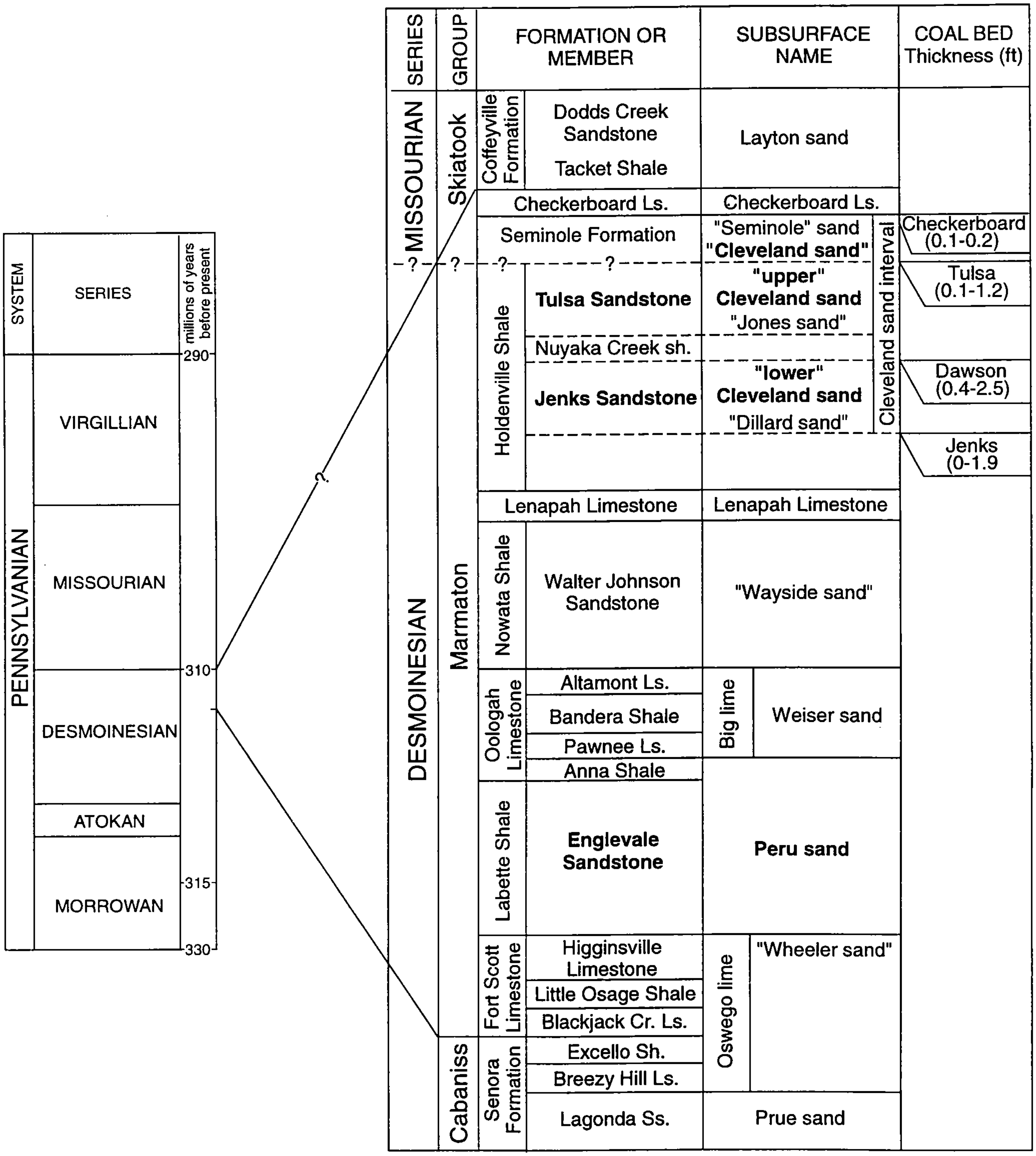

Figure 44. Stratigraphic nomenclature of the Marmaton Group (late Desmoinesian) and adjacent strata in the Cherokee platform, northeastern Oklahoma. Modified from Hemish (1989, 1990), Tulsa Geological Society (1984–89), Cole (1965), Heckel (1991), and Fay (1987). The precise boundary between the Marmaton Group (Desmoinesian) and the overlying Skiatook Group (Missourian) has been in question for some time and still awaits resolution. This problem is discussed further in Campbell (Part II, this volume), Bennison (1984), and Krumme (1981).

TABLE 13. – Annual Oil Production from the Peru Reservoirs in Oklahoma, 1979–95

	Peru only		Peru commingled	
Year	Production (BO)	Number of leases	Production (BO)	Number of leases
1979	26,193	18	115,404	43
1980	38,452	25	133,522	54
1981	97,699	39	182,572	68
1982	112,461	45	166,658	76
1983	88,198	51	171,909	79
1984	69,441	50	164,290	78
1985	42,972	49	144,761	73
1986	39,885	40	128,705	76
1987	39,966	35	100,726	72
1988	50,254	41	80,717	58
1989	53,499	38	66,281	64
1990	53,532	36	89,104	59
1991	47,679	36	80,236	57
1992	41,086	36	72,367	54
1993	37,145	27	71,023	54
1994	35,007	31	81,484	47
1995	36,793	29	94,812	46
Cumulative	910,262		1,944,571	

SOURCE: Natural Resources Information System (NRIS) oil and gas production data base, Oklahoma Geological Survey, Norman.

statewide production (<1 million BO) was relatively small compared to that of other fluvial-dominated deltaic reservoirs such as the Skinner (almost 36 million BO) and the Prue (about 23 million BO) (Andrews, 1996). The annual production curves for Peru-only and Peru-commingled oil in Figure 45 have roughly parallel trends, increasing from 1979 to 1981 or 1982, and then decreasing. Peru-only production leveled out and dropped slightly, beginning in 1985; from 1985 through 1995, 35,000–53,000 BO per year was produced. Peru-commingled production continued to decline until 1989, when the decline was reversed (Fig. 45).

PERU STRATIGRAPHY

The stratigraphic column in Figure 44 was compiled from several sources. It shows the formal and informal subsurface stratigraphic nomenclature, geologic ages, and named coal beds in the study area. *Peru* is the informal subsurface name for a discontinuous sandstone in the Labette Shale of the Marmaton Group (Desmoinesian) and is the subsurface equivalent of the Englevale Sandstone in Kansas (Jordan, 1957). The Englevale is a channel sandstone up to 50 ft thick within the Labette Shale, which was mapped by Pierce and Courtier (1935) near the town of Englevale in eastern Crawford County, Kansas.

The formal stratigraphic nomenclature for Marmaton Group rocks has been in use for some time. The original stratigraphic work was done along Marmaton outcrops in northeastern Oklahoma and southeastern Kansas by many workers, beginning in the late 1890s (Wilmarth, 1938). Detailed outcrop work in northeastern Oklahoma was done by Oakes (1940, 1952), Cade (1953), Faucette (1955), and Branson and others (1965). The top of the Marmaton Group—the boundary between the Holdenville Shale and the overlying Seminole Formation—is still in question (see discussion by Campbell, Part II, this volume). Surface work is continuing in the area, and recent detailed work by LeRoy Hemish (in preparation) has helped to further define the boundaries of some of the Marmaton Group formations.

The Labette Shale is overlain by the Oologah Limestone and is underlain by the Fort Scott Limestone. The Oologah consists of four members: Altamont Limestone, Bandera Shale, Pawnee Limestone, and Anna Shale, in descending order. Where the Bandera Shale is relatively thin (less than 10 or 20 ft thick), the upper three members correspond to the interval referred to as the Big lime in the subsurface. The lowest member, the Anna Shale, is a distinctive persistent bed described from outcrops (Faucette, 1955) as black, fissile, and carbonaceous shale with phosphatic concretions. The Anna Shale Member is present in much of northeastern Oklahoma and is more widespread than the overlying Pawnee and Altamont Limestone Members. The Anna Shale is recognized easily on gamma-ray logs as the "hot shale" directly below the Pawnee Limestone, or Big lime. On the basis of its lithologic similarity to known hydrocarbon-source rocks, the Anna Shale is considered to be a possible hydrocarbon-source rock. The presence of phosphatic concretions is indicative of deposition in deep water. The Labette Shale is underlain by the Fort Scott Limestone. The Fort Scott, and the underlying Excello Shale and Breezy Hill Limestone Members of the Senora Formation, correspond to what is called the *Oswego lime* in the subsurface (Fig. 44).

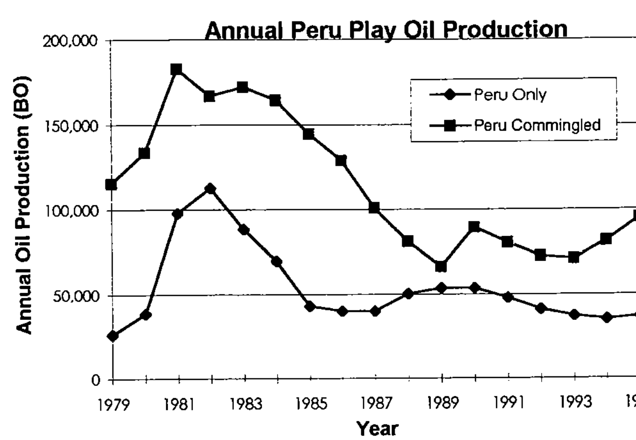

Figure 45. Chart showing annual oil production from leases that produce(d) only from Peru reservoirs and leases that produce(d) Peru oil commingled with oil from other reservoirs from 1979 through 1995. Data from Natural Resources Information System (NRIS).

The Excello Shale, which is a black, phosphatic "hot" shale, can be identified and correlated on gamma-ray logs beyond the limits of the Fort Scott and Breezy Hill Limestones.

During the early days of drilling, before wireline logs were routinely run, sandstones above and below the Labette Shale were mistakenly called *Peru*. In most cases, one or more of the limestones that serve as stratigraphic markers between sandstone intervals were not recognized or not logged by drillers, so the proper stratigraphic sequence was not known. The sandstones most commonly mistaken for the Peru are the "Wayside" and Weiser sands (Fig. 44). The "Wayside" sand interval is within the Nowata Shale, between the Lenapah Limestone above and the Altamont Limestone (Big lime) below. The Weiser sand interval is within the Bandera Shale, which is between the Altamont and Pawnee Limestone Members of the Oologah Formation (Fig. 44).

As shown in Figure 46, the Oswego limestone, Labette Shale, and Oologah Limestone are approximately equivalent to the Wewoka Formation, which was originally mapped and described from outcrops in Hughes County, Oklahoma, by Taff in 1901 (Wilmarth, 1938). Historically, and as a matter of practicality, the term *Labette* has not been used in areas where the Big lime and/or the Oswego lime are absent. South of the Peru FDD area shown in Figure 43, the Big lime and Oswego lime thin and disappear, making it difficult, if not impossible, to establish precise correlations between the Marmaton Group platform rocks and the Wewoka Formation (Fig. 46). The Wewoka Formation sandstones have a southern source and have been interpreted as nearshore-marine sandstones and marine-bar deposits (Krumme, 1981).

LABETTE SHALE AND PERU SANDSTONE THICKNESS AND DISTRIBUTION

Figure 47 shows the thickness of the Labette Shale. The Labette thins westward from about 220 ft at the outcrop in northwestern Rogers County, Oklahoma, to less than 20 ft in Pawnee County near the western depositional limit of the Peru sandstone (Fig. 47). From the western edge of the outcrop on the Tulsa–Wagoner County line, the Labette Shale thins to the north, west, and south. The Labette Shale in the study area, including the Sperry trough, is conformable with both the underlying Fort Scott Limestone and the overlying Pawnee Limestone of the Oologah Formation (Fig. 44). The Fort Scott Limestone beneath the thin Labette Shale is not abnormally thick. Thus, there is no evidence that the Labette is thin because of erosion or that the Labette is draped over a thick buildup in the underlying Fort Scott. Therefore, the thin Labette is interpreted to be a depositional feature, an area that received very little sediment in comparison to adjacent areas.

Plate 7 (in envelope), "Map of the Peru Sandstone Play Area," shows the subsurface distribution and thickness of the Peru sandstone. The information shown on this plate was compiled from well data and numerous sources that are indexed on Plate 10 (in en-

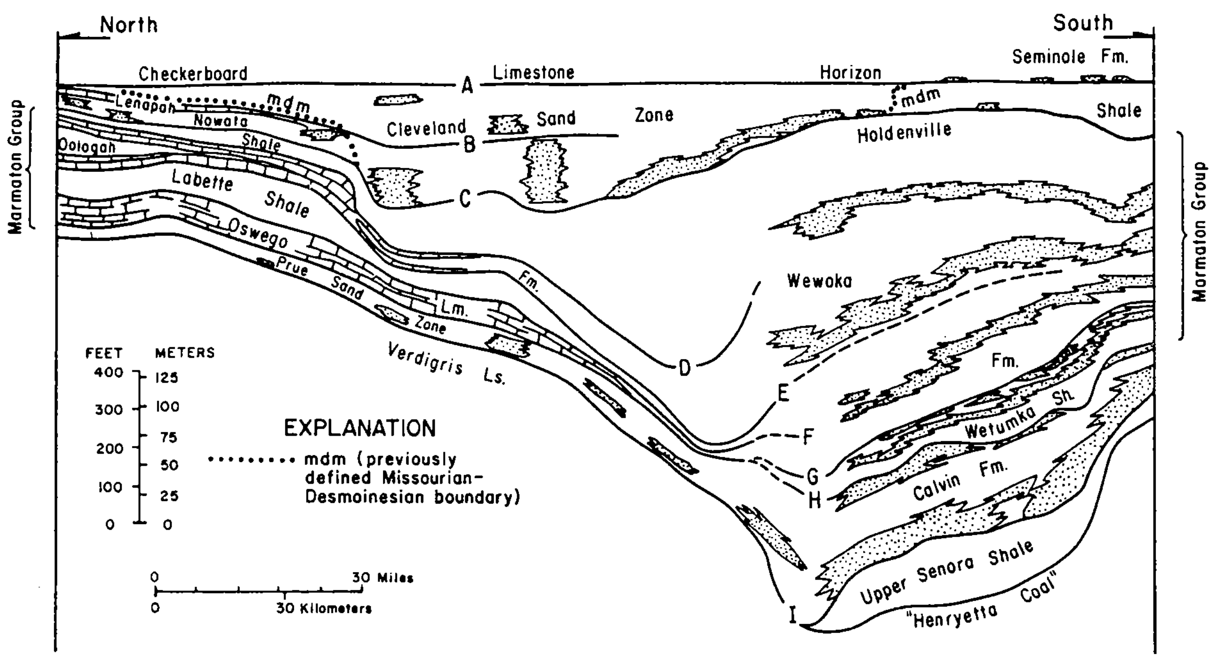

Figure 46. North–south stratigraphic profile from the Kansas state line to Pontotoc County, Oklahoma, showing the relationship of the Marmaton Group limestones on the platform to the shale and interbedded sandstone of the Wewoka Formation in the Arkoma basin. The Peru sand is present only on the platform, within the Labette Shale interval, in the area represented by the northern one-third of the profile. A through H are log markers at or near formation boundaries that were used for correlation. This figure, from Krumme (1981), is based on the log cross section shown in his figure 10.

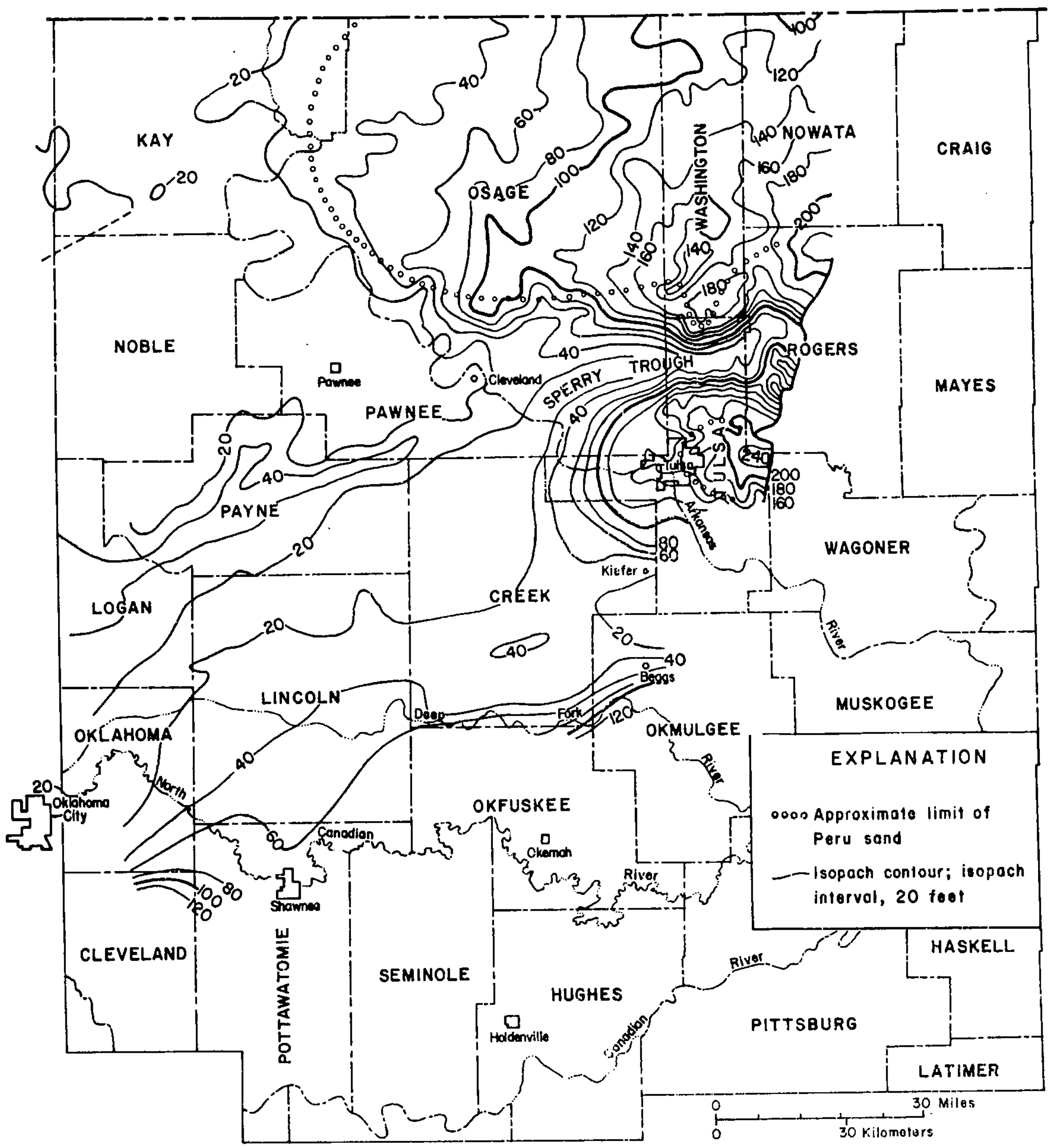

Figure 47. Isopach map of the Labette Shale (including the Peru sand) in eastern Oklahoma. The Sperry trough, a shallow seaway, defines the southern limit of the Peru play; most of the Peru sand lies north of the trough. Nonproductive Peru sand is present in a small area south of the trough, in the vicinity of Tulsa. This map was modified from Cole (1965, 1970) by Krumme (1981).

velope). The Peru sandstone is limited by the outcrop on the east and by the depositional limit of sand on the south and west. The Peru sandstone, like the Labette Shale, is thicker in the east and pinches out on the north side of the Sperry trough (Pl. 7). The Peru sand is also present in a small area south of the Sperry trough (Fig. 47). However, no production has been reported from the Peru on the south side of the trough. Most of the Peru sandstone lies north of the Sperry trough (north of T. 22 N.) in an area that extends roughly 80 mi westward from the outcrop (Pl. 7). The sandstone is generally thicker in the east, ranging from 0 to >75 ft, and occurs in fairly narrow (2–10-mi-wide) belts that have a sinuous to anastomosing pattern. Westward, the sandstone is somewhat thinner, ranging from 0 to ~40 ft thick, and the sandstone belts are a bit broader.

Plate 8 (in envelope) shows two stratigraphic cross sections, A–A′ and B–B′, that were constructed using the base of the Big lime as the stratigraphic datum. Cross section A–A′ is oriented from south (left) to north (right) through Rs. 13 and 14 E., approximately parallel to the dominant trend of the major distributary channels. Cross section B–B′ is oriented from west (left) to east (right) across T. 26 N. and shows the relationship of the strata across the lower delta plain of the Peru delta.

Regional Stratigraphic Cross Section A–A′

At the north end of cross section A–A′ (Pl. 8), the Altamont and Pawnee Limestones of the Oologah Formation are separated by about 60 ft of Bandera Shale. Southward, the Bandera Shale thins, and the Altamont–Pawnee interval is referred to as the Big lime. The Bandera Shale is not evident on the log of the DalTex Oil Co., Inc., No. 3 Bucklin well (sec. 13, T. 22 N., R. 13 E.; cross section A–A′, Pl. 8); the Oologah Limestone (Big lime) is part of a massive limestone bank that extends farther west and is south of the Peru play area.

The Labette Shale interval (shale plus Peru sandstone between the Big lime and the Oswego lime) contains several examples of distributary-channel sands. Whether or not these channels are connected was not determined; however, they are all in the upper part of the Labette Shale. The Peru sand is absent in the DalTex Oil, Inc., No. 3 Bucklin (sec. 13, T. 22 N., R. 13 E.) and in the two wells to the south in cross section A–A′ (Pl. 8). The Cherokee Resources, Inc., No. 4 MTR Trust well (sec. 4, T. 21 N., R. 13 E.) was drilled near the axis of the Sperry trough in northern Tulsa County (Pl. 7). In this well, the Labette Shale interval has thinned to less than 70 ft, the Oswego lime is of normal thickness, and the Oologah (Big lime) has changed facies to mostly shale with interbedded thin limestone beds (Pl. 8). In this log, the top of the "hot" Anna Shale is a reliable marker for the base of the Big lime.

The Lenapah Limestone is seen in the northernmost well (right side) on cross section A–A′ (Pl. 8). Southward, the Lenapah becomes indistinct and is not recognizable south of T. 23 N., but it is present to the west across the entire play area. The "Wayside" sand in the Nowata Shale sequence (between the Lenapah and Oologah Limestones; Fig. 44) is present but not well developed in the A L N Resources No. 8A Little Mary well (sec. 8, T. 23 N., R. 13 E.) and in the Michael Hall No. 2 Watson well (sec. 12, T. 24 N., R. 13 E.) (cross section A–A′, Pl. 8).

Regional Stratigraphic Cross Section B–B′

The Labette Shale, below the Oologah Limestone, ranges in thickness from 105 ft on the west to ~200 ft on the east across the line of cross section B–B′ (Pl. 8). Within the Labette Shale, the Peru sand can be seen on all the well logs in the cross section. These sands were deposited in distributary channels and distributary-mouth bars or splay sand deposits. In many places the distributary channels are stacked, forming thick sandstone sequences. The log of the Davis/Osage Corp. No. 4-C Cummings well, SE¼NW¼SE¼ sec. 14, T. 26 N., R. 11 E., at the west end of cross section B–B′ (Pl. 8), has a 55-ft-thick Peru distributary-channel sandstone overlying distributary-mouth-bar or delta-front sandstone deposits. Below the Labette Shale, the Fort Scott Limestone is continuous across the area and provides a convenient datum for mapping.

The Lenapah Limestone is correlated across cross section B–B′ but is cut off on the east by its exposure at the outcrop. The Nowata Shale thins from ~170 ft on the east to ~80 ft on the west. A good development of the "Wayside" sand at a depth of 930 ft is shown on the west of the cross section in the well log of the Davis/Osage Corp. No. 4-C Cummings (sec. 14, T. 26 N., R. 11 E.). This well log is also shown at the east end of stratigraphic cross section B–B′ in the report on the Cleveland play by Campbell (Pl. 4, Part II, this volume).

PERU DEPOSITIONAL MODEL

During my investigation for this study, I found very little published information about the Peru other than where it is located and the fact that it produces oil or gas in certain areas. Even in his extensive work on the Marmaton Group, Krumme (1981) only alludes to a Peru delta.

Depositional environments are interpreted largely from lithology, sedimentary structures, and, most importantly, vertical and lateral changes in lithology and sedimentary structure. Ideally, core and/or outcrops are studied and correlated with wireline logs. In the study of subsurface deltaic systems, there are seldom enough cores available where they are most needed, necessitating heavy reliance on wireline logs. Because gamma-ray logs reflect the amount of clay present (among other things), gamma-ray-log profiles are an indirect indicator of vertical changes in lithology and therefore provide information about depositional environments. Many workers have correlated typical log profiles (gamma ray, spontaneous potential, and resistivity) with vertical lithologic sequences that are characteristic of various depositional environments identified in core. Campbell and others (1996, p. 19) discuss the interpretation of depositional environments from wireline logs and the cautions advanced by recent authors about these interpretations.

Figures 3, 7, and 8 in Part I (this volume) show idealized log profiles that typify various depositional sequences in deltaic environments. After examining a number of electrical logs in the Peru play area, I found (1) examples of fining-upward sand sequences, suggesting channel deposits; (2) stacked channel sands; and (3) coarsening-upward sequences interpreted as delta-front sands and distributary-mouth bars. Many of the Peru log profiles (see Pl. 8) also closely resemble log 2A in Figure 48, which is an idealized log of a well in a fluvial-dominated delta deposited on the platform during a sea-level highstand. Features that characterize lowstand deltas, such as a preexisting shelf edge, leveed slope deposits, and prograding fans (see log profiles 3, 4, and 5 in Fig. 48) are not recognizable in the Peru delta study area. Sandstones in the eastern part of the lower delta plain are as thick as 75 ft; some of the stacked distributary-channel sands are somewhat thicker. The sandstone in the western part of the delta

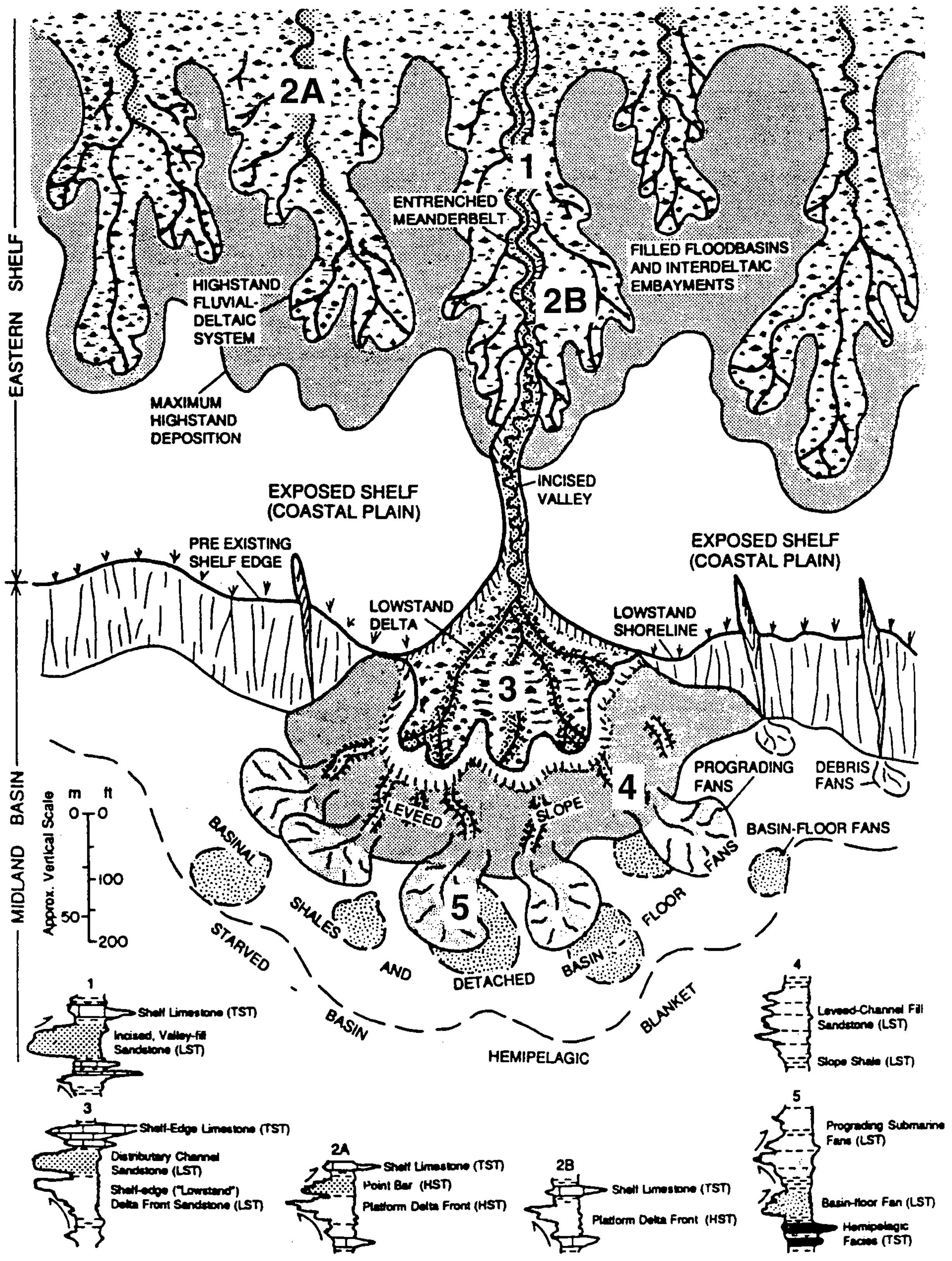

Figure 48. Depositional systems tract models for the Eastern shelf and Midland basin in Texas (from Brown, 1989). In this model, deltas form on the platform (upper half of figure) during sea-level highstands. During sea-level lowstands, sea level is at or below the platform edge, valleys are incised into the platform, and sediment is carried to the shelf edge, where the lowstand delta is deposited. Schematic logs illustrate the vertical sequence of facies at several places. HST = highstand system tract; LST = lowstand system tract; TST = transgressive system tract. The Peru delta resembles the highstand delta model (upper part of diagram). Log profiles 2A and 2B resemble some of the logs in the cross sections (Pl. 8, in envelope).

is generally 20–40 ft thick, with fewer indications of distributary channels (Pl. 7). Many of the logs near the western edge of the Peru sand exhibit coarsening-upward profiles that are interpreted to indicate coarsening-upward delta-front deposits and, perhaps, some distributary-mouth-bar or other shallow-marine deposits. (See the gamma-ray log of the Davis/Osage Corp. No. 4-C Cummings well at the west end of cross section B–B′, Pl. 8.) The wireline-log character of the Peru, which suggests the presence of channel deposits overlying coarsening-upward sequences (shale to shaly sand to sand); the similarity of the Peru to other Pennsylvanian deltaic deposits such as the Prue in Oklahoma (Andrews, 1996); and evidence from some of the outcrop descriptions convinced me that the Peru sand was probably deposited in a deltaic environment.

Plate 7 shows the thickness of the Peru sand in the subsurface and its inferred environments of deposition. The distribution of sand in the subsurface supports the evidence from log signatures. Cole (1965, p. 20) made the following observation about Peru sandstone distribution: "... in general the contour lines indicate an anastomosing dendritic type pattern with a north–south trend. This may possibly be indicative of channels." The north–south trend also suggests that the sand was derived from a cratonic source to the north and northeast (Cole, 1965, p. 20) and was transported across western Missouri and eastern Kansas by the fluvial system that deposited the Englevale Sandstone in eastern Kansas. Outcrops in Kansas and northeastern Oklahoma support that interpretation.

Howard and Schoewe (1965) determined that the Englevale Sandstone is a fluvial channel deposit more than 25 mi long and up to 60 ft thick, and that the transport direction was to the south. The south-flowing river that deposited the Englevale channel sandstones may have been part of the fluvial system that supplied sediment to the Peru delta. Channel sandstones in the Labette Shale were also noted in northeastern Oklahoma outcrops by Cade (1953) and Faucette (1955). Cade (1953) identified a Peru channel sandstone that was 19.6 ft thick in sec. 24, T. 28 N., R. 18 E. (Pl. 7). He described the basal part as soft, massive, and micaceous with no evidence of cross-bedding. South of Cade's study area, in sec. 31, T. 26 N., R. 17 E. (see Pl. 7), Faucette (1955) identified a 50.4-ft-thick channel sandstone that he described as coarse grained, cross-bedded, friable, and, near the base, limy with large clay galls, crinoid stems, and river clams.

Although most of the Peru sandstone lies north of the Sperry trough, an outcrop of Labette Shale and Peru sandstone south of the Sperry trough, west of Catoosa in sec. 30, T. 20 N., R. 15 E. (Pl. 7), was described in detail by Tanner (1981) and briefly by Krumme (1981). The outcrop coarsens upward and is dominantly mudstone and rippled siltstone and interlaminated shale with a subordinate amount of very fine to fine-grained clay-rich sandstone (Tanner, 1981). Tanner interpreted the deposits as prodelta mudstone overlain by delta-front siltstone and distributary-mouth-bar deposits. Asymmetrical ripple marks indicate a westerly transport direction (Tanner, 1981; Krumme, 1981). On the basis of chert fragments in the siltstone, Tanner invoked a Ouachita source for the sediment. Krumme (1981) theorized that the sediments "are most likely distal deposits of another distributary that flowed southwestward into Oklahoma from eastern Kansas" and that "the Sperry trough probably originated as an interdistributary depression between lobes of adjoining systems, one of which reached farther south than the other."

East of the outcrop, the Labette Shale and Peru sand have been eroded, leaving part of the picture unknown. South of the Sperry trough, the amount of sandstone is minor, and the sandstone is not of reservoir quality.

Figure 49 is my interpretation of the paleogeography of the central Midcontinent region after deposition of the Peru sand. The Englevale Sandstone and the two channels in northeastern Oklahoma are apparently part of the fluvial-distributary system that fed the Peru delta. The Peru sand, which is generally fine grained, shaly, and micaceous, with interlaminated shale and a gamma-ray response that is considerably greater than that of clean, porous sand (Pl. 8), was presumably deposited in channels characterized by flow rates that were relatively slow and cyclical. Beyond the western limit of the Peru sand, west of the Peru delta, the Labette Shale thins, and the Fort Scott and Oologah Limestones merge to form a thick carbonate bank (Cole, 1965; Krumme, 1981). Figure 6 of Part I (this volume) is a classification of modern delta systems that relates delta morphology to the relative importance of fluvial-sediment input rate and marine processes (wave and/or tidal reworking). In this classification, the

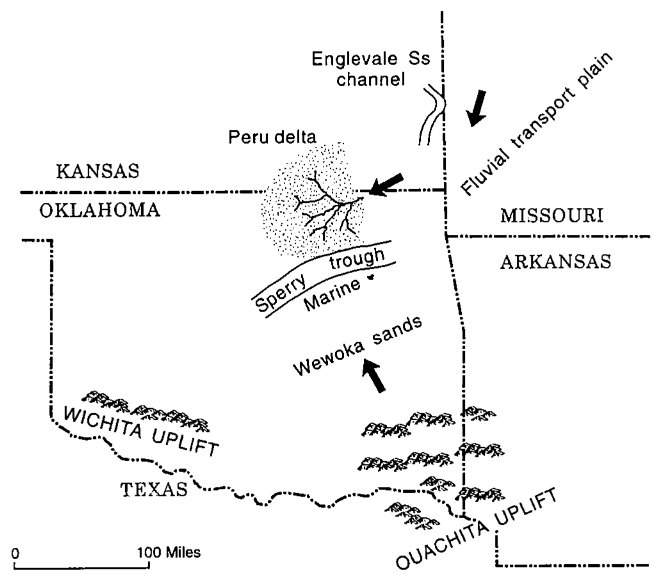

Figure 49. Paleogeography of the central Midcontinent region during deposition of the Peru sand. The Englevale Sandstone in eastern Kansas is the formal surface equivalent of the Peru sand (Fig. 44).

Peru delta best fits between the elongate and lobate types of fluvial-dominated deltas.

PERU FDD RESERVOIRS

The Peru sandstone petroleum reservoirs have been developed primarily in distributary-channel deposits of a fluvial-dominated deltaic environment. The reservoirs are generally stratigraphic traps where the sand is present on local structural noses or where the sand pinches out updip. Local uplift and sediment compaction also influence the localization of these oil reservoirs.

A generalized structure map of the Checkerboard Limestone in eastern Oklahoma (Fig. 50) reflects the westward regional dip of the underlying Marmaton Group, including the Peru sand interval. In the Peru play area, the regional dip of the Checkerboard and the Peru sand is about 25 ft/mi. Westward from the outcrop in Craig, Rogers, and Nowata Counties to the western edge of the sandstone in western Osage County and far eastern Kay County, the depth to the Peru sand increases to about 2,800 ft.

In Oklahoma, Peru oil production is limited to Osage, Washington, and Nowata Counties. Plate 9 (in envelope) shows the 15 fields in northeastern Oklahoma that have leases that produce(d) oil from the Peru from 1979 through 1995 (the period covered by NRIS data). Many leases that produced oil from the Peru

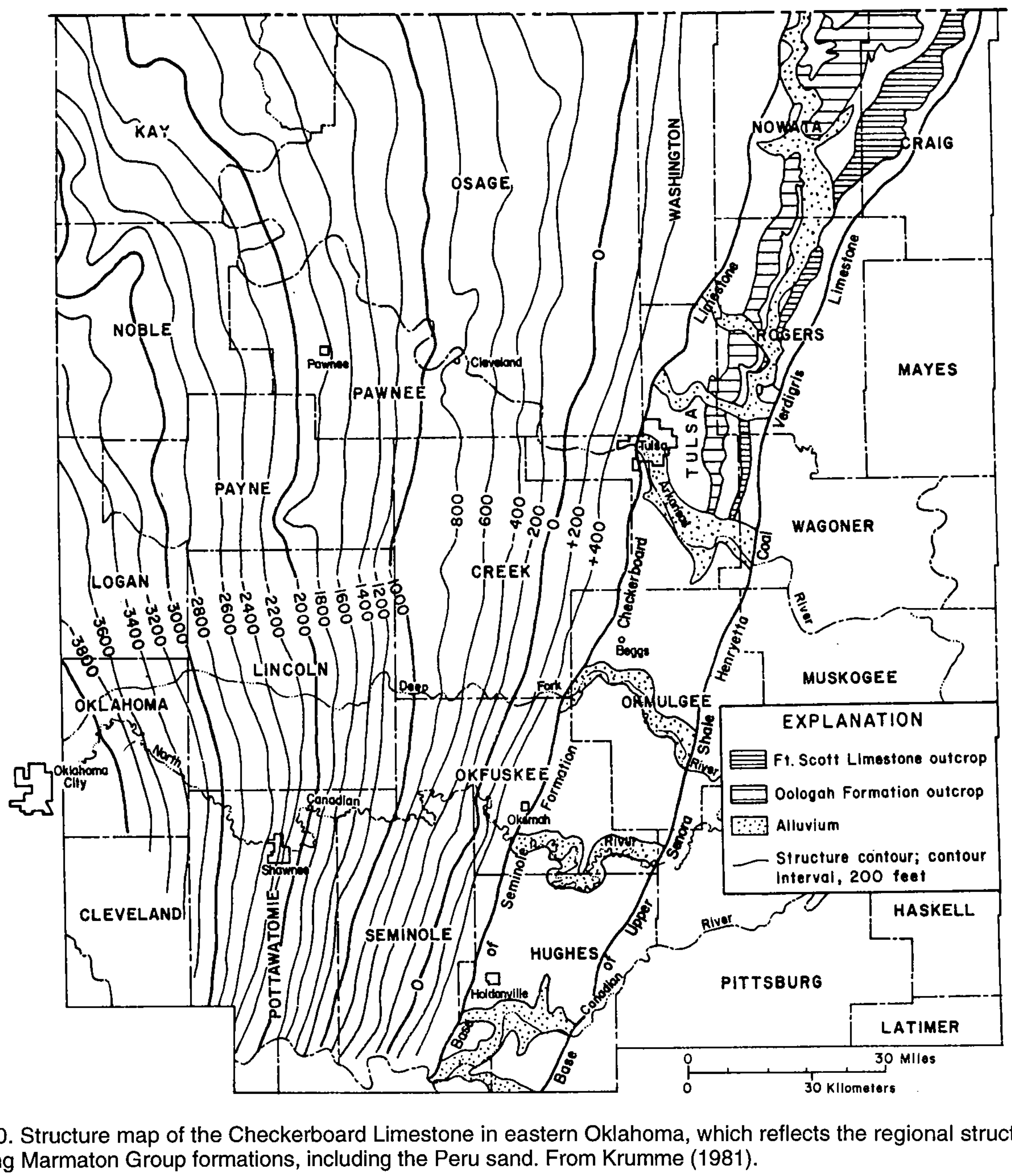

Figure 50. Structure map of the Checkerboard Limestone in eastern Oklahoma, which reflects the regional structure of the underlying Marmaton Group formations, including the Peru sand. From Krumme (1981).

were abandoned before 1979 and are not included on this map. Most Peru production is from fields and unassigned areas adjacent to fields that produce dominantly from the Bartlesville sand.

The Peru sandstone in Oklahoma covers an area only 42 mi from north to south and 84 mi from east to west (Pl. 7). However, most of the leases that produce from the Peru are in an area that extends only about 30 mi south from the Kansas state line and roughly 40 mi west from the outcrop (Pl. 9). This area corresponds roughly to the eastern half of the sandstone area, where the Peru is generally thicker, up to 75 ft (Pl. 7).

To conduct a petroleum-reservoir-characterization study, it is important that many elements of data be available. First, a complete drilling and completion history of each well in the study area is crucial. The data therein include the operator, well name and number, location, dates of drilling and completion, total depth, perforated intervals, test results, completion procedure, initial production, and whether or not wireline logs were run or cores taken. Second, modern well logs of the entire stratigraphic unit must be available for a substantial number of wells. Finally, a complete history of lease oil and/or gas production is essential. Because oil-production records are generally kept on a lease or tank-battery basis rather than by well and by reservoir, the best data apply to leases that produce from only one reservoir.

Naturally, all of the information outlined above is seldom available. Since we work in the "real world," we do the best with what we have. Several areas were investigated during the selection process for the Peru play reservoir study area, and most were found lacking in too many of the requirements. The shallow Peru play is in that part of Oklahoma where extensive oil development has been ongoing since 1904. Therefore, the data needed for a reservoir-characterization study do not exist for many, if not most, Peru leases. Generally, the present operators are individuals or small companies and do not have the staff or the time to maintain detailed records.

The Peru pool in sec. 24, T. 26 N., R. 13 E., of the Hogshooter field was selected as the subject for a Peru field study, because a large amount of current data is available. The leases produce almost exclusively from the Peru. Modern logs were available for most of the wells, and for one of the wells a core-analysis report was available.

PART VI

Hogshooter Field Study Area

(Peru oil reservoir in sec. 24, T. 26 N., R. 13 E., Washington County, Oklahoma)

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INTRODUCTION

The Hogshooter field, in east-central Washington County, Oklahoma (Fig. 51), was discovered in 1906. The first oil production was from the Bartlesville sand, with initial production rates ranging from 225 to 500 barrels of oil per day (BOPD). Early in the development of the field, a minor amount of oil was found in the Peru sand (Fox and others, 1944, p. 8). Areas with Peru oil production in and around the Hogshooter field are shown in Figure 52.

The earliest known report of oil in the Peru in the study area—sec. 24, T. 26 N., R. 13 E.—is an Oklahoma Geological Survey well record dated January 15, 1923, for the No. 1 Eorp (NW¼NE¼NW¼), which was drilled to the Mississippi lime by Hoskins and Geiger in 1914(?) (Fig. 52). The well was a dry hole, but the well record indicated that 8 BO was bailed from a sand 770–800 ft deep, presumably the Peru. Figure 52 is a map of the area published by Fox and others in 1944. In addition to the No. 1 Eorp, this map shows nine abandoned Bartlesville oil wells along the east line of sec. 24 and one abandoned oil well in the SE corner SW¼ sec. 24. Because no well records (drillers' logs or completion reports) were found, these wells are not shown in Figure 51 or in the maps that follow.

Production from the Peru oil reservoir in sec. 24, T. 26 N., R. 13 E., was established on November 24, 1981, with the completion of the Chautauqua Oil, Inc., No. 2 Maberry (N½NE¼SE¼NE¼; Fig. 53). The well had an initial pumping potential of 10 BOPD and 190 barrels of salt water per day (BSWPD) from perforations at 739–743 ft in a 50-ft-thick Peru channel sandstone. Chautauqua Oil, Inc., drilled the No. 2 Maberry, also in sec. 24, as a confirmation well after having completed the No. 1 Maberry in the Bartlesville sand two months earlier. Figure 53 shows operators, lease names, well numbers, and producing reservoirs for wells in the Peru sandstone study area. Well records of some form were found for all the wells on the map. No information was found for a No. 5 or a No. 11 Maberry well; either they were not drilled, or they were drilled and not reported. According to a note found on the well log, the No. 4-SW Maberry (W½E½NW¼) was an old well drilled in 1922 that was reentered and logged by Chautauqua Oil, Inc., in 1982. No other information was found for the 1922 completion or for the 1982 reentry, so the well is shown merely as a drilled location.

On some of the illustrations that accompany this study of the Peru sandstone, the operator of the Maberry lease, Chautauqua Oil, Inc., is shown as *Chautauqua Oil Co.* The subsequent operator of the lease, Burlington Oil, Inc., is shown on some of the illustrations as *Burlington Oil Co.*

SANDSTONE CHARACTER AND DISTRIBUTION

The type log for the study area (No. 9 Maberry, N½NW¼SE¼NE¼) is shown in Figure 54. The gamma-ray curve (GR) shows that the Peru sand is separated into discrete layers by thin (2–3-ft-thick) shales or shalier beds. In this well, four main layers are evident. Upward, the gamma-ray curve for each layer, and for the sandstone overall, increases slightly, suggesting an upward decrease in grain size. The fining-upward log profile and the relatively sharp contact with the underlying shale or sandy shale suggest that this is a channel deposit. Below the sandstone, the Labette Shale becomes sandier upward, grading from shale to sandy shale. The position of the channel sandstones at the top of a shallowing-upward sequence of marine shale to sandy shale is an indication that the channels are distributary channels (Pl. 7, in envelope). The Peru oil-reservoir sandstone consists of vertically stacked layers, which are the deposits of individual channels. Sandstones such as this are commonly called stacked or multistory sandstones. These sandstones were deposited by distributary channels and are at the top of a

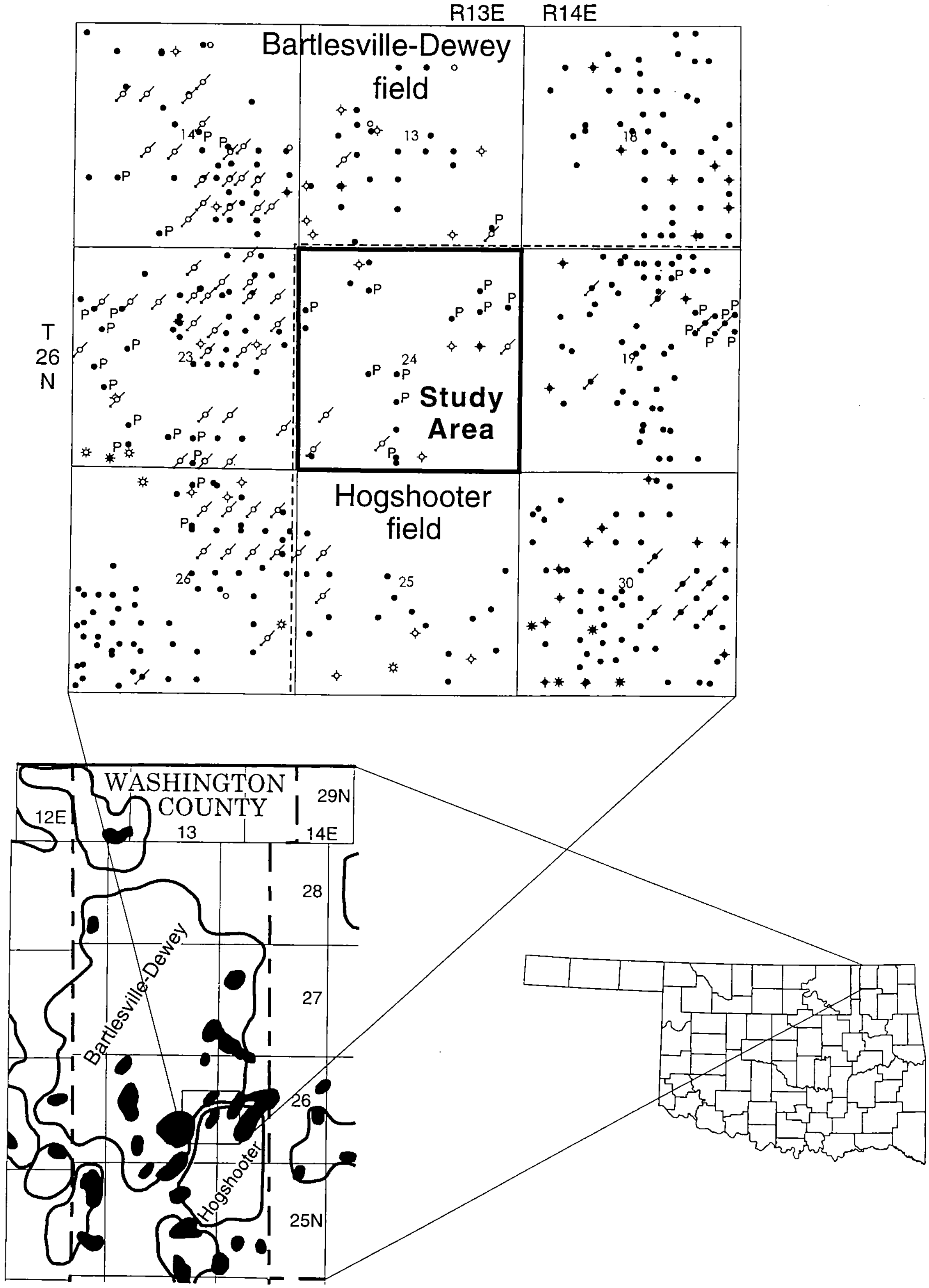


Figure 51. Maps showing the Hogshooter field, areas with Peru oil production (shown in black), and the Peru oil-reservoir study area in sec. 24, T. 26 N., R. 13 E., Washington County, Oklahoma. On the detailed map, large well spots with *P* denote wells that produce(d) oil from the Peru or from the Peru commingled with oil from another reservoir. Well data from Natural Resources Information System (NRIS).

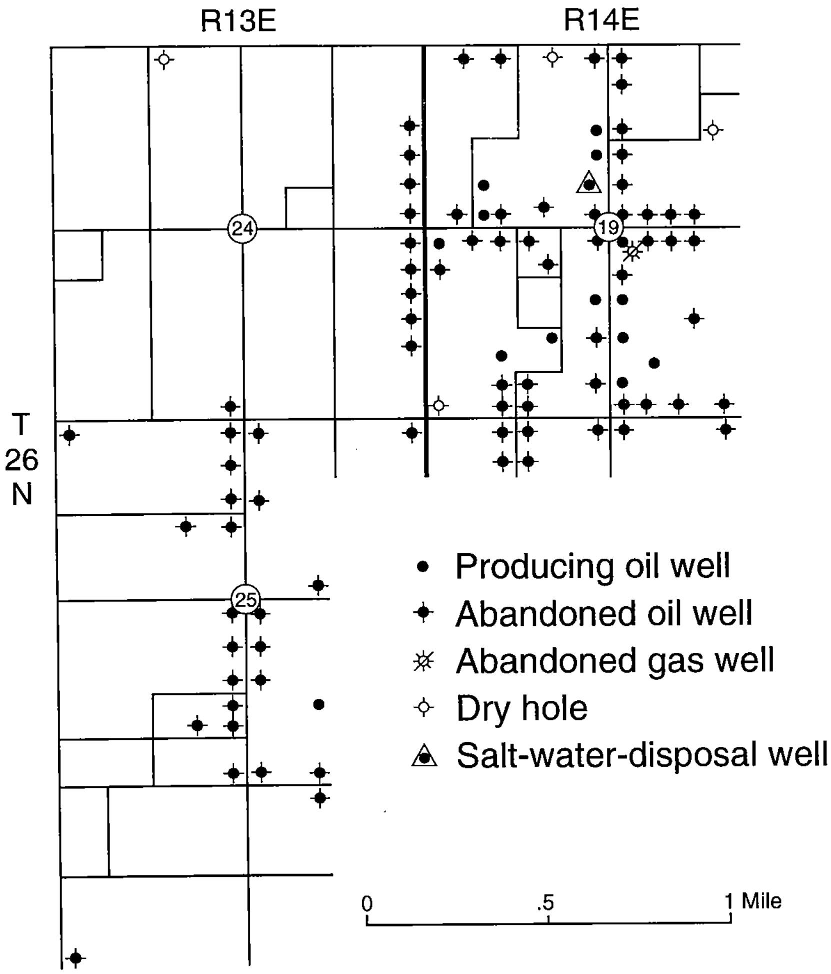


Figure 52. Early-development map of sec. 24 and adjacent parts of the Hogshooter field, showing 10 abandoned Bartlesville wells drilled in sec. 24. Modified from Fox and others (1944, pl. 2). Other than this map and the well record for the No. 1 Eorp (NW¼NE¼NW¼), no records were found for these wells.

shallowing-upward (prograding) deltaic sequence of strata.

Three stratigraphic cross sections (Figs. 55–57, in envelope) were constructed, using the base of the Big lime, a readily recognized subsurface unit, as the datum. The lines of the cross sections are shown on Plate 7 and in Figure 53. On all the logs in the cross sections, the Labette Shale becomes sandier upward and is abruptly overlain by the Peru channel sandstone. Although the layers are not sharply delineated on many of the logs in the cross sections, thin shale laminae are present throughout the sandstone interval. Some of the well logs indicate layers that do not have a distinct increasing or decreasing gamma-ray trend; however, the layers are part of, and fit, the overall fining-upward sequence of the distributary-channel deposits.

Distribution

The sandstone intervals in the distributary channels are layered but were not individually mapped. Figure 58 is an isopach map that shows the total or gross thickness of the Peru channel sandstone in the study area; it presents the sandstone as a continuous interval. The total thickness of the sandstone does not differ significantly from the thickness of the porous (net) sand. (The construction of an isopach map of the net pay sand was not attempted because of the lack of sufficient resistivity logs.) The map shows a distributary channel entering the study area from the north, branching to the east and southwest, and extending beyond the study area. Sandstone in the east-trending north branch is as thick as 66 ft. Stratigraphic cross section A–A′ (Fig. 55) is oriented west–east along the axis of the northern branch of the distributary.

In the southern part of the study area, across the Keefer lease, a southeast-trending channel sandstone is as thick as 54 ft (see cross section B–B′, Fig. 56). The No. 10 Keefer well (SE¼SE¼SW¼), completed as a Peru producer of an undetermined amount of oil, indicates that the sandstone and the reservoir probably extend farther to the southeast. The interpretation of the extent of the reservoir to the south and west would be more reliable if more logs were available for study.

Stratigraphic cross section C–C′ (Fig. 57) is oriented south–north along the course of the main channel.

FORMATION EVALUATION

Ideally, formation evaluation is based on core analysis, drill-stem tests of the cored intervals, and a suite of modern logs. Both coring and drill-stem testing delay drilling activity, but they allow porosity, permeability, fluid content, and mineral composition to be measured directly. The appropriate method for well completion can then be chosen. The delay in drilling and the additional cost of recovering the data are usually worthwhile when evaluating a new reservoir.

Well logging in the Peru study area was done with several different tools. The Phillips No. 1 Maberry well (SE¼SW¼NE¼) was logged in 1956 with an electrical log (spontaneous potential and resistivity) and a microlog. Eleven wells drilled after 1981 were logged with dual induction–laterologs or induction–electrical logs (for resistivity) and compensated density logs (for porosity). An induction log and a compensated neutron-density log were run in the No. 1 Anderson (NW¼SW¼NW¼). At least five wells were logged only with cased-hole gamma-ray–neutron logs.

CORE ANALYSIS

According to completion reports, the Peru sand was cored in the No. 1 Maberry (NW¼NE¼NW¼) and in

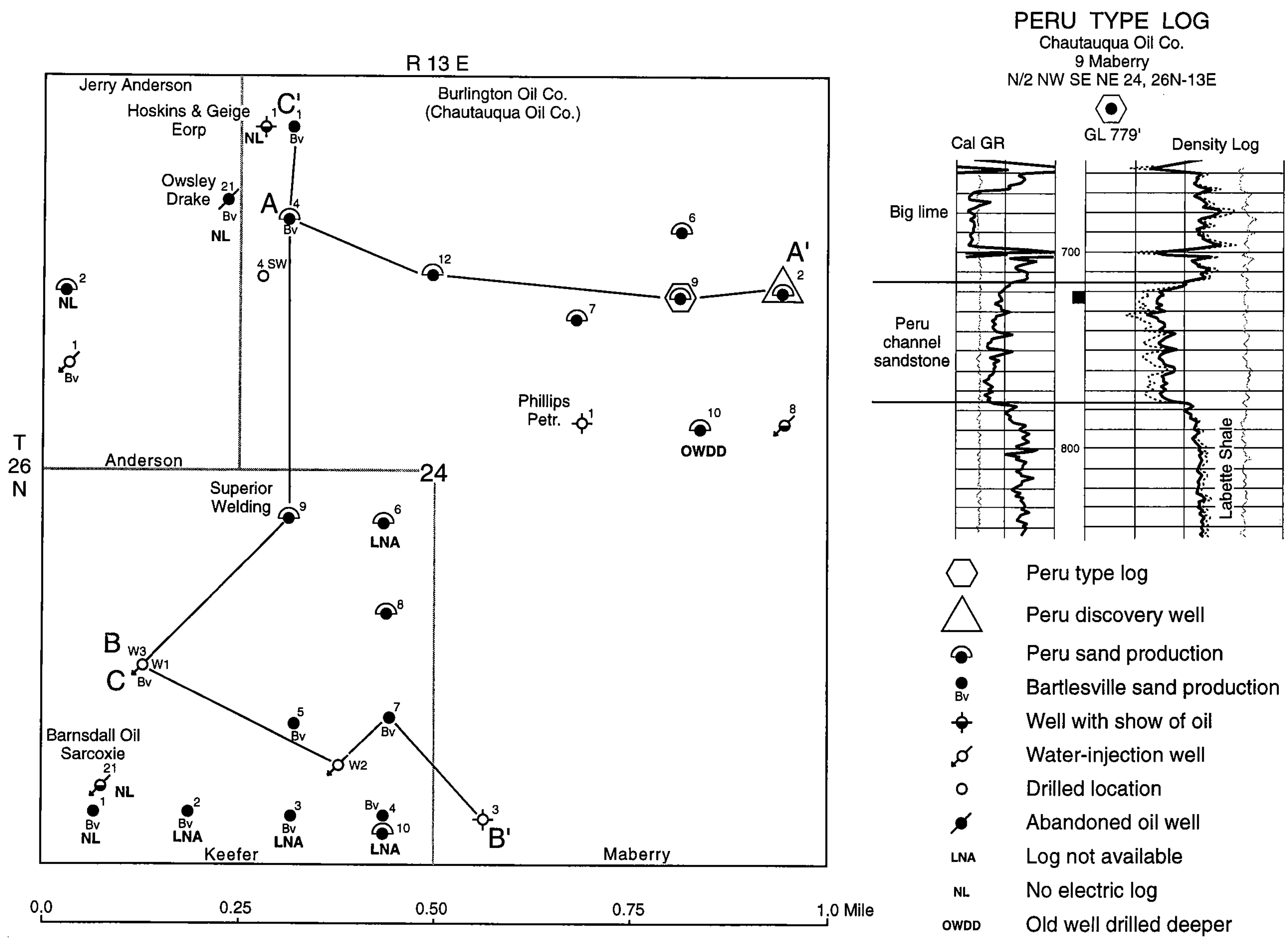


Figure 53. Well-information map, showing operators, lease names, well numbers, producing reservoirs, and lines of cross sections in the Peru study area, Hogshooter field. Cal = caliper; GR = gamma ray.

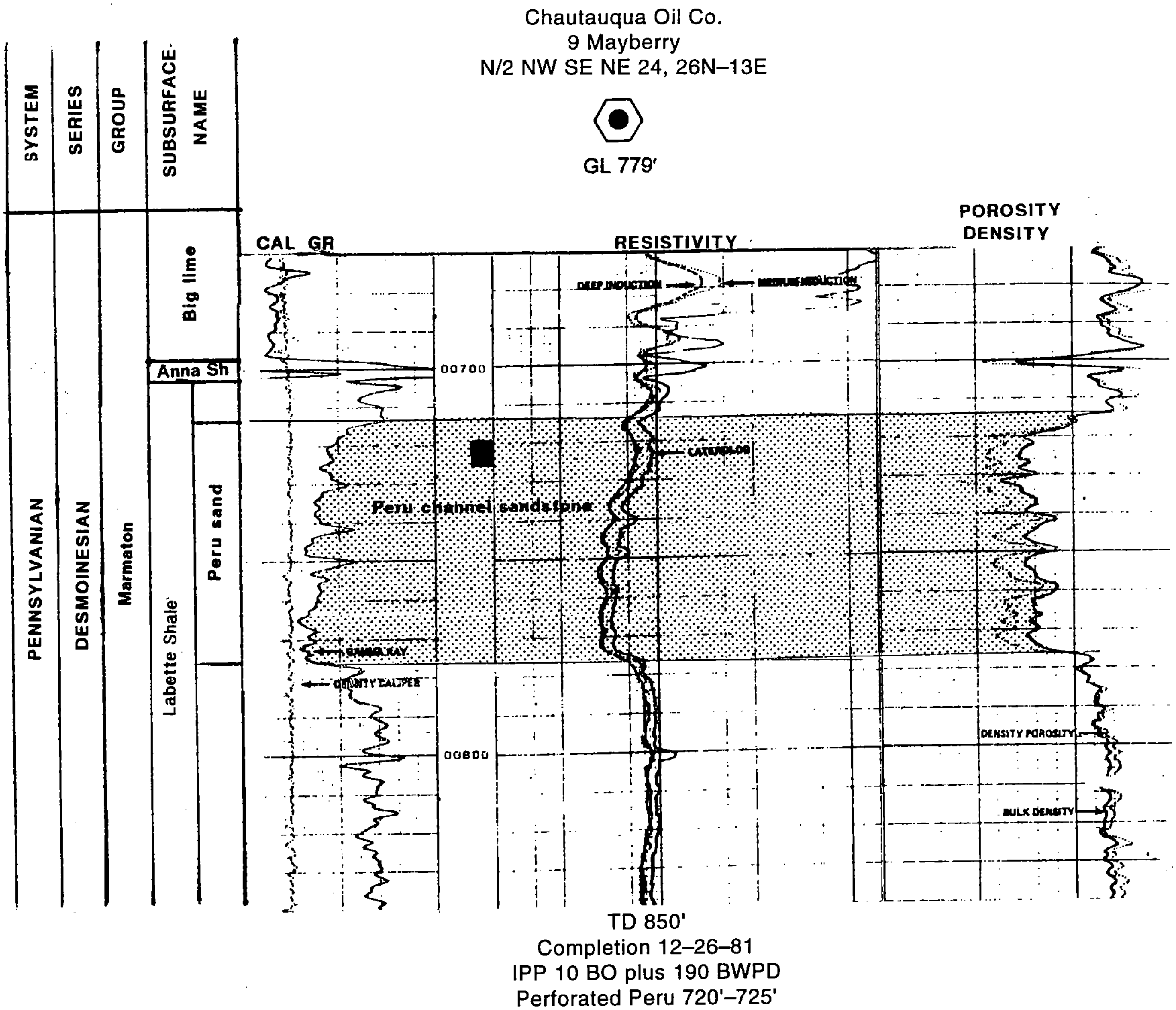


Figure 54. Type log for the Peru study area, showing stratigraphic nomenclature, markers, and typical log signatures, Hogshooter field. CAL = caliper; GR = gamma ray.

the No. 2 Maberry (N½NE¼SE¼NE¼) drilled by Chautauqua Oil, Inc. The Peru sand in the No. 2 Maberry was cored from 745 to 775 ft, beginning about 10 ft below the top of the sand. Mr. Tom Emerson of Burlington Oil, Inc., the operator that succeeded Chautauqua, supplied a copy of the core analysis and some of the core from the No. 2 Maberry. Table 14 shows the results of this core analysis. On the basis of oil-saturation data from the analysis, the oil–water contact in this well was determined to be at a depth of about 766 ft (40 ft below mean sea level). The oil saturation ranged from 8% to 15% in the upper 21 ft (745–766 ft) and from 0% to 5% in the lower 9 ft (766–775 ft). The upper part of the sandstone showed average values of 28 md permeability, 20% porosity, 10% oil saturation, and 56% water saturation. The lower part of the sand showed average values of 9 md permeability, 18.6% porosity, 2% oil saturation, and 68% water saturation. These values indicate a high water content in the formation. A summary of geological and petrophysical data for the reservoir is given in Table 15.

STRUCTURE

A structure map depicting the base of the Big lime (Fig. 59) shows a northwest dip of ~30 ft across the area of the Peru sand reservoir (datums are above sea level). This mapping datum was chosen because the Big lime is a distinctive unit that was generally recognized and reported by cable-tool drillers. A structural nose plunging to the northwest trends diagonally across the section. A small closure is interpreted in the southwest quarter section on the Keefer lease. The distribution of

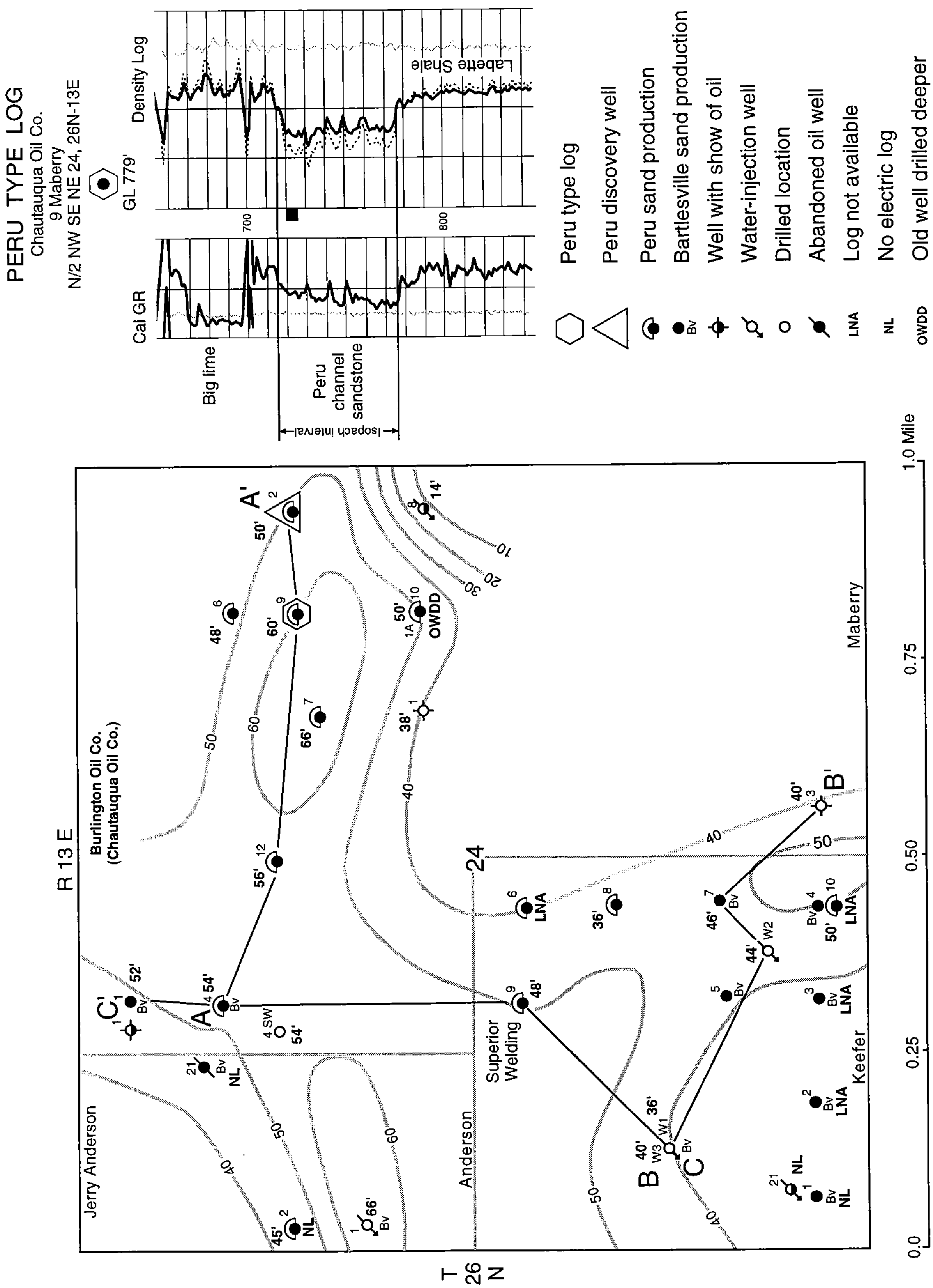


Figure 58. Isopach map of the Peru channel sand in the Peru study area, Hogshooter field. Contour interval, 10 ft.

TABLE 14. – Core Analysis of the Peru Sand in the Chautauqua Oil, Inc., No. 2 Maberry Well, N½NE¼SE¼NE¼ sec. 24, T. 26 N., R. 13 E., Washington County, Oklahoma

Depth (ft)	Permeability (md)	Porosity (%)	Core saturation (% pore space) Oil	Core saturation (% pore space) Water	Lithology
745–746	24	20.5	15	42	sand
746–747	26	20.5	14	51	sand
747–748	9.1	19.1	6	64	sand
748–749	19	19.8	11	53	sand
749–750	42	20.7	8	53	sand
750–751	4.7	18.6	10	64	sand
751–752	13	19.5	14	54	sand
752–753	9.3	18.8	2	69	sand
753–754	30	19.2	12	56	sand, shale laminae
754–755	21	19.8	9	57	sand, shale laminae
755–756	9.1	19.4	9	54	sand, shale laminae
756–757	31	21	11	52	sand
757–758	50	19.9	12	58	sand
758–759	not analyzed				
759–760	18	19.8	8	58	shaly sand, sand
760–761	34	20.8	11	55	sand
761–762	27	20.4	10	56	shaly sand, sand
762–763	29	21.7	10	50	sand
763–764	56	20.5	12	58	sand
764–765	37	20.1	10	53	sand
765–766	68	20.8	12	55	sand
766–767	9.1	16.5	5	74	shaly sand, shale
767–768	12	15.6	3	73	shaly sand
768–769	8.7	19.4	2	68	carb. sand
769–770	3.3	18.9	3	64	carb. sand
770–771	2.1	18.5	2	60	carb. sand
771–772	3.7	19.1	2	62	carb. sand
772–773	9.7	19.5	2	69	sand
773–774	14	19.6	1	63	sand
774–775	18	20.2	0	75	sand
		Averages			
745–766	28	20.0	10	56	Oil–water sand
766–775	9	18.6	2	68	Water sand

NOTE: Core began and ended in sand. Core analysis by Godsey–Earlougher, 5/26/81.

Peru oil wells does not appear to be closely related to the structure of the Big lime. Another structure map depicting the top of the Peru sand (Fig. 60) differs only slightly from the Big lime structure map (Fig. 59). The upper part of the Peru sand generally is porous throughout the study area, and therefore the top of the Peru sand coincides with the top of the Peru net sand. The amount of northwest dip of the Peru is a little less than that of the Big lime; the decrease in elevation from east to west is about 25 ft. The small structural closure in the southwest quarter is absent, but an area of structural closure is interpreted in the northwest quarter section. The configuration of the top of the Peru sand and the base of the Big lime is similar and does not reveal a strong correlation between structure and Peru oil production in the study area. The top of the Peru in productive wells ranges from 81 ft in the east (No. 10 Maberry, SW¼SE¼NE¼) to 57 ft in the west (No. 2 Anderson, NW¼SW¼NW¼). All the Peru wells in the study area produce low oil and high water volumes. No significant differences in oil-to-water-production ratios correlate with structural position (see Figs. 59–61). Figure 61 shows initial pumping potentials (IPP) per day, ground-level elevations (GL) in feet above mean sea level, total depths (TD) in feet below ground level, and dates of first production or completion in the Peru.

PERU FDD RESERVOIR AND PRODUCTION

A summary of geological and petrophysical data for the Peru oil reservoir in sec. 24, T. 13 N., R. 26 E., is given in Table 15. The reservoir is a local stratigraphic trap in a distributary-channel sandstone at the top of a progradational deltaic sequence. The Labette Shale–Peru channel-sandstone sequence corresponds to a platform delta sequence: prodelta shale, delta-front shale and sandstone, and then distributary-mouth-bar or distributary-channel sandstone (Fig. 8, Part I, this volume). Distributary-channel deposits extend beyond the study area to the northeast and southwest (see Fig. 58), but it is not known whether the reservoir extends beyond the study area. None of the wells adjacent to sec. 24 produce from the Peru (Fig. 51), and no wireline logs were available to evaluate the sand conditions.

A thin, dense, presumably tight bed is present in four wells in the N½ sec. 24. In the Burlington Oil, Inc., No. 12 Maberry well (C N½), the bed is about 3 ft thick, and the top lies at 710 ft (Fig. 55, cross section A–A'). This bed is also found in Chautauqua Oil, Inc., No. 1 Maberry (NW¼NE¼NW¼), No. 4 Maberry (SW¼NE¼NW¼) (Fig. 57, cross section C–C'), and No. 7 Maberry (NE¼SW¼NE¼). The Peru was perforated above the dense layer in the Nos. 4, 7, and 12 Maberry. The lithology of this dense, presumably tight, layer is unknown; no cores or samples of the interval are available for examination. However, on the basis of similarity in initial production rates reported for wells completed above

TABLE 15. – Geological/Engineering Data for the Peru Oil Reservoir, sec. 24, T. 26 N., R. 13 E., Hogshooter Field, Washington County, Oklahoma

Reservoir size	~230 acres
Well spacing (oil)	10 acres
Oil–water contact	~40 ft above mean sea level
Gas–oil contact	none
Average core porosity[a]	20%
Average core permeability[a]	28 md
Initial water saturation[a]	>56%
Average gross sand thickness	48 ft
Reservoir temperature	85°F
Oil gravity	35°API
Initial reservoir pressure	unknown
Initial formation-volume factor	unknown
Original oil in place (volumetric)	unknown
Cumulative primary production (Peru-only wells)	42,040 bbl (13 wells)
Recovery efficiency	unknown
Cumulative gas	no data

[a]Average measurements on the No. 2 Maberry core (Table 14).

TABLE 16. – Annual and Average Monthly Production (BO) for Leases in the Peru Study Area, sec. 24, T. 26 N., R. 13 E., Hogshooter Field, Washington County, Oklahoma, 1981–95

	Maberry lease		Keefer lease		Anderson lease	
Year	Annual	Mo. ave.	Annual	Mo. ave.	Annual	Mo. ave.
1981	2,512	209				
1982	13,635	1,136				
1983	5,038	420				
1984	2,693	224				
1985	2,747	229				
1986	6,830	569	4,063	339		
1987	3,759	313	4,432	369		
1988	3,167	264	5,164	430		
1989	3,533	294	2,773	231		
1990	3,498	292	1,938	162		
1991	2,518	210	1,551	129		
1992	2,447	204	1,253	104		
1993	1,536	128	1,100	92	310	26
1994	2,292	191	1,031	86	794	66
1995	1,540	128	892	74	389	32

SOURCE: Natural Resources Information System (NRIS) oil and gas production data base, Oklahoma Geological Survey.

and below the tight streak, the bed does not divide the sandstone into separate reservoir compartments.

The seal for this stratigraphic trap is formed in part by the Labette Shale, which surrounds the Peru channel sandstone. An updip seal within the channel sandstone is not defined by existing well control, and the reservoir may extend to the northeast. The surrounding marine shale is one logical source for the oil in this trap. Oil may also have migrated updip from the Arkoma basin. The uplift of the Ozark province to the east and regional westward tilting during Late Pennsylvanian time resulted in the final placement of hydrocarbons in this trap.

Drilling and Completion Practices

Many of the Peru wells in the study area were drilled with air. Surface holes are 7⅞ in. in diameter, with 7-in. surface casing cemented to the surface. A 6.25-in.-diameter hole is drilled to total depth, then 4.5-in. production casing is set to total depth and cemented to the surface. After the formation is perforated, it is acidized with either 7.5% or 15% hydrochloric acid (HCl); amounts range from 50 to 300 gal. The formation is then fracture treated with up to 12,000 lb of sand and 120–180 BW. A pumping unit is installed, and the well is put on production.

Production Data

Figure 61 is a production map for Peru wells in the study area. Production data by lease are shown in Figure 62. (Production data for wells plugged and abandoned before 1944 are not available.) Graph A shows monthly production from the two Maberry leases; data from two tank batteries on this lease were combined to produce the graph. Cumulative production from the lease was 32,953 BO (Sept. 1981–Oct. 1995: 14 years). The average production from the nine producing wells on the lease (including the Bartlesville well) was 3,661 BO.

Graph B shows monthly production from the Keefer lease: 4 Peru and 7 Bartlesville wells. Cumulative production from the lease was 24,952 BO. The average production from the 11 producing wells was 2,268 BO.

Graph C shows monthly production from the Anderson lease. Cumulative production from the lease (Oct. 1993–Dec. 1995) was 1,493 BO for the single Peru well. (The two Bartlesville wells on the lease did not produce during this period.)

Graph D shows combined annual production from all leases in the study area; cumulative production was 58,642 BO. The average cumulative production from the 21 producing wells was 2,792 BO.

The monthly lease-production graphs show the decline of production over time and the mature level of these wells. The annual and average monthly production by lease is shown in Table 16. The average monthly lease production in 1995 was: Maberry lease, 128 BO; Keefer lease, 74 BO; Anderson lease, 32 BO. Thus, the

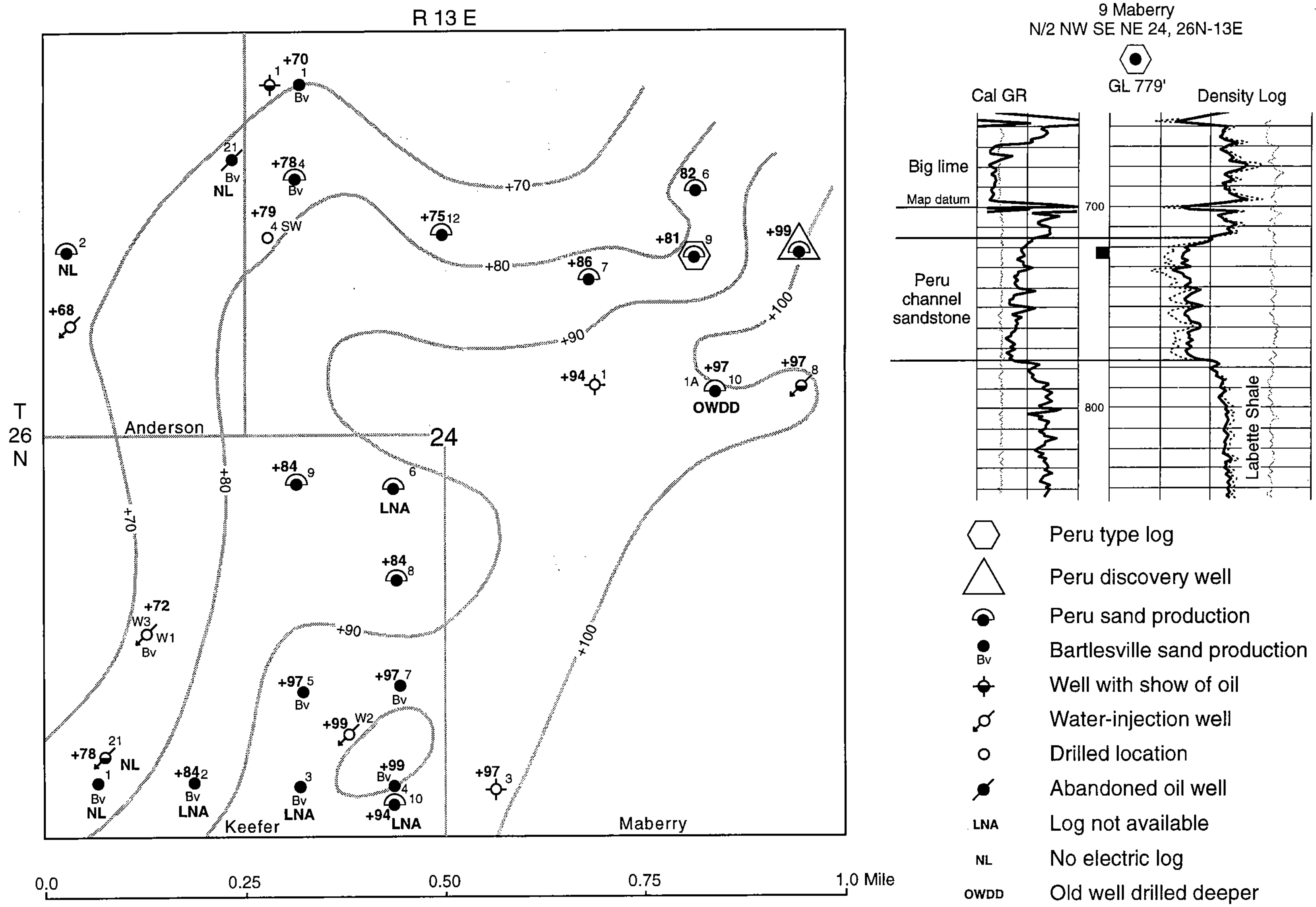


Figure 59. Structure map depicting the base of the Big lime in the Peru study area, Hogshooter field. Datum is above sea level. Contour interval, 10 ft.

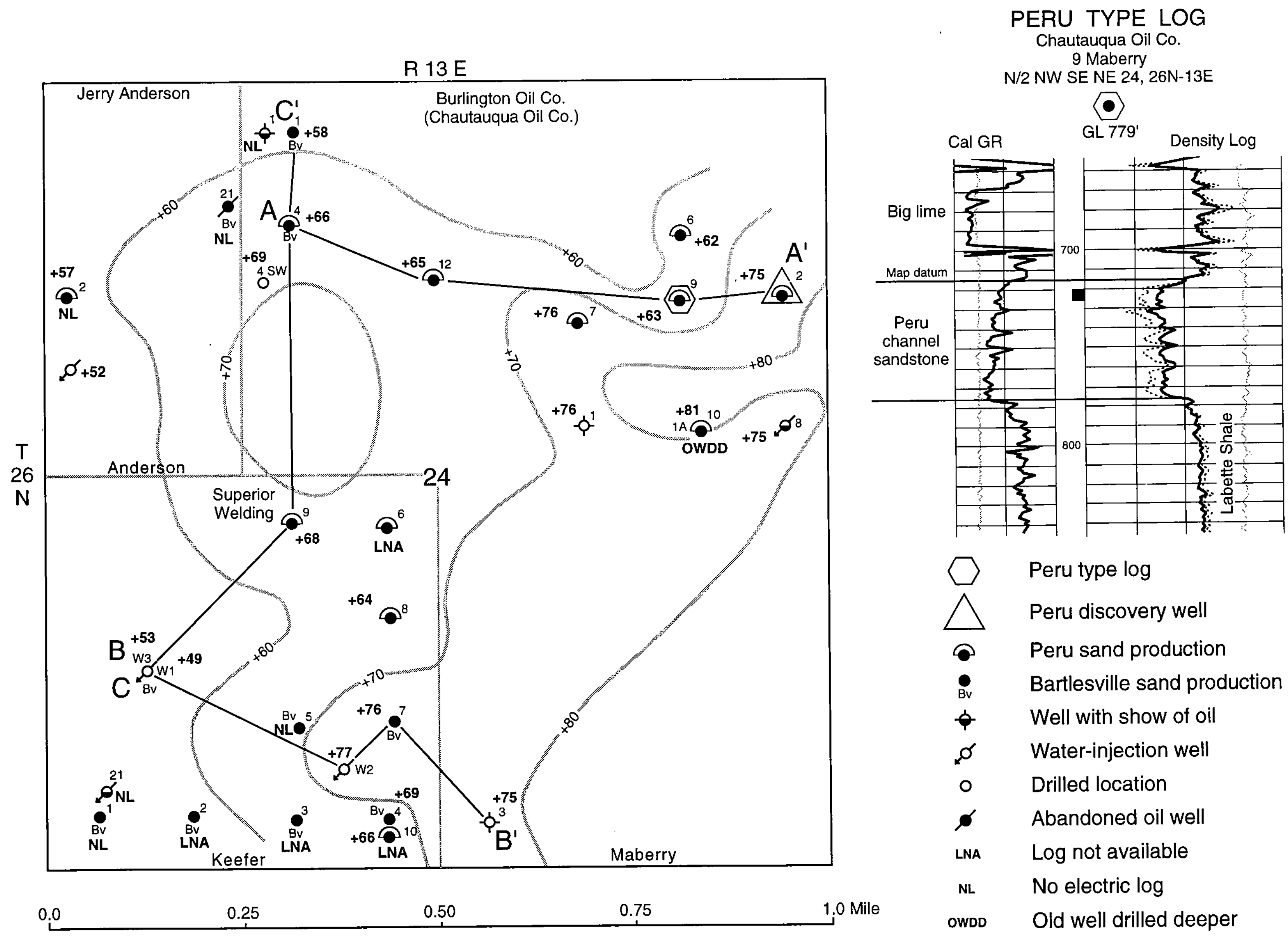


Figure 60. Structure map depicting the top of the Peru channel sand in the Peru study area, Hogshooter field. Datum is above sea level. Contour interval, 10 ft.

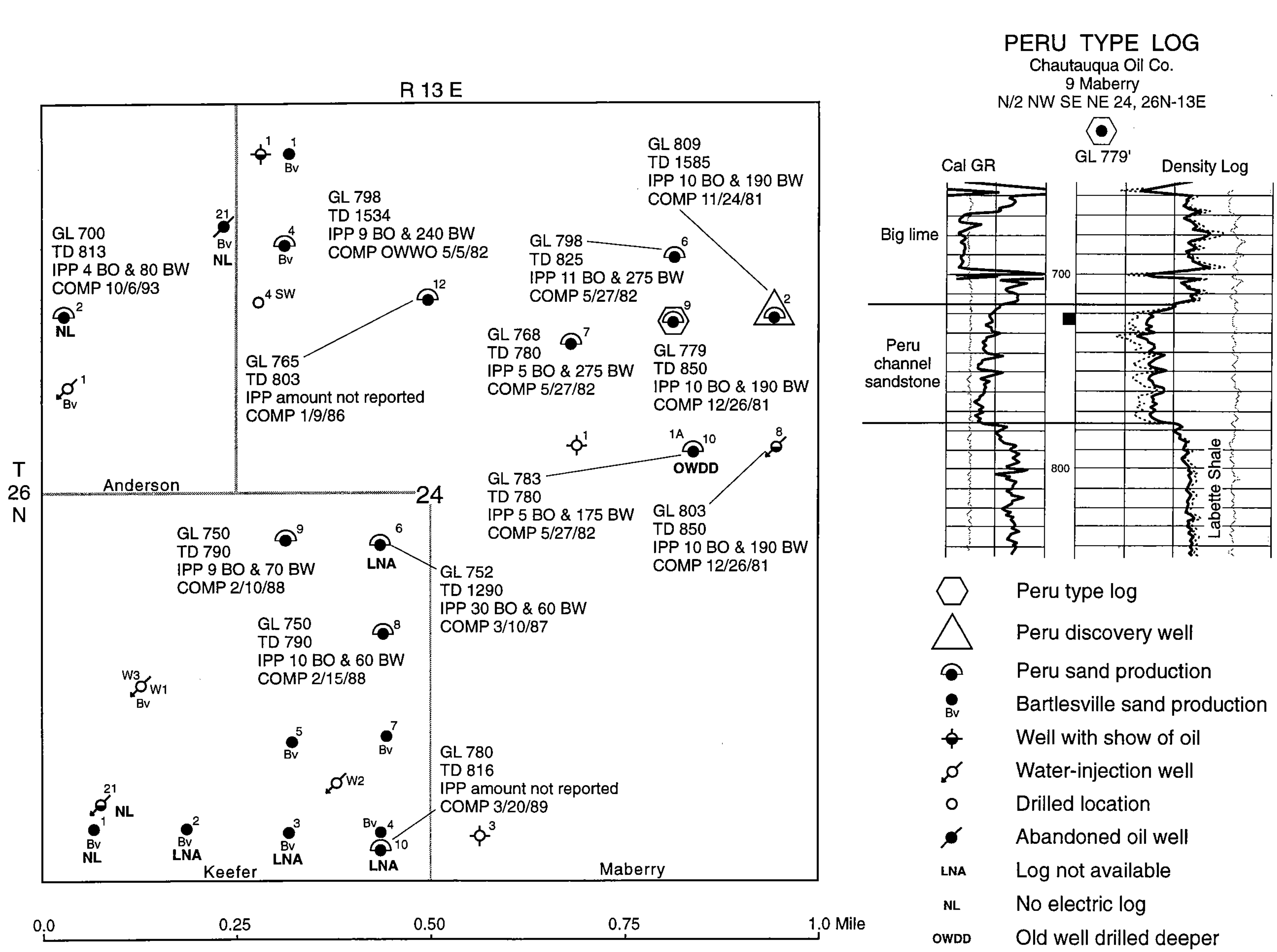


Figure 61. Peru sand initial-production data, sec. 24, T. 26 N., R. 13 E., Hogshooter field. Well-completion data include initial pumping potentials (IPP) per day, ground-level elevations (GL) in feet, total depths (TD) in feet; and dates of first production or completion (COMP). OWDD = oil well drilled deeper.

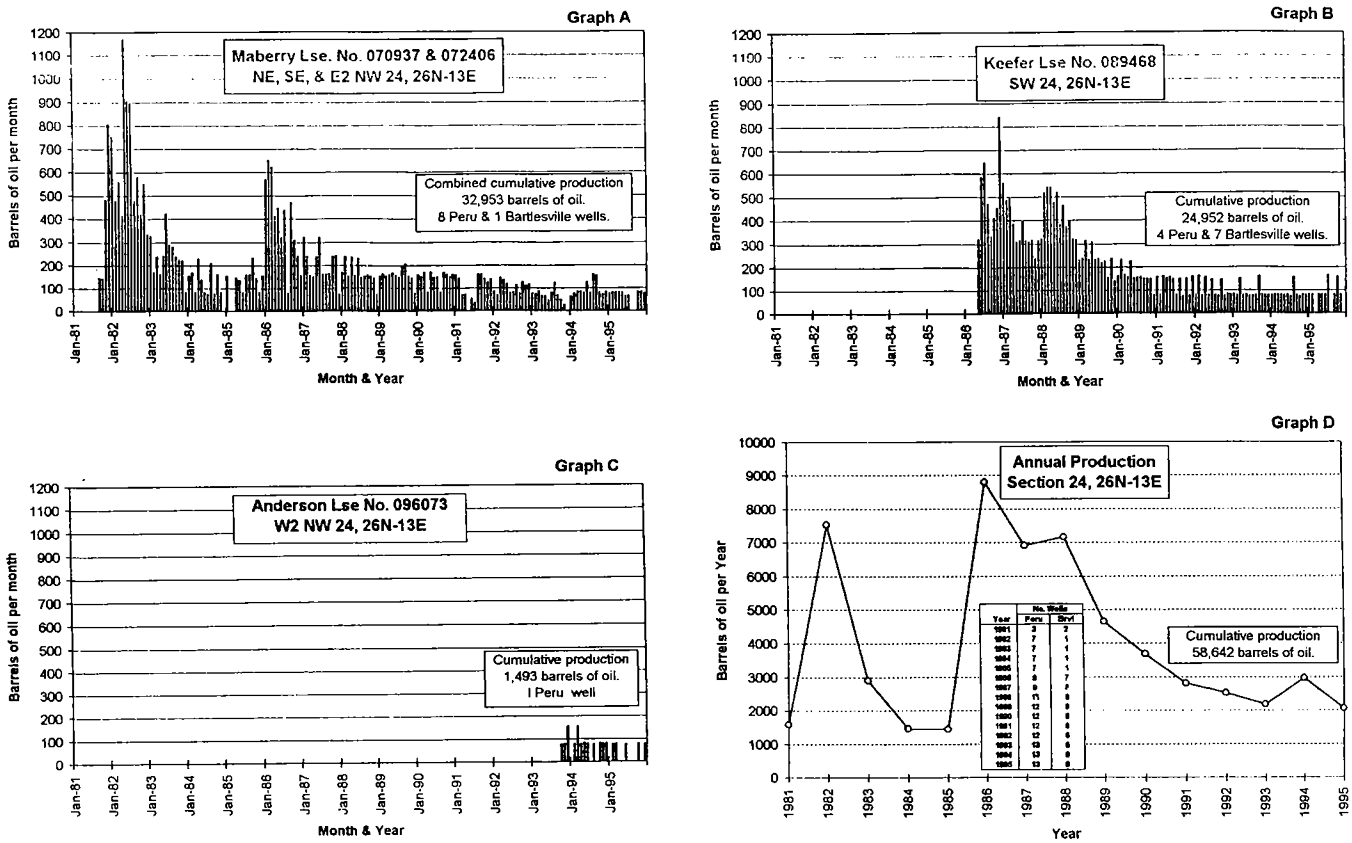


Figure 62. Graphs showing monthly oil production and total annual oil production from the leases in the Peru study area, Hogshooter field. (See Figure 53 for lease locations.) Graph A shows production from the combined Maberry leases (NE¼, E½NW¼, and SE¼). Graph B shows production from the Keefer lease; production from the Peru began in 1988. Graph C shows production from the Anderson lease. Chart D shows combined annual oil production from sec. 24.

average daily production from these leases was <10 BOPD. The amount of water produced and injected is not known. However, water production was undoubtedly substantial. The initial production from wells on the Maberry leases (NE¼ and E½NW¼ sec. 24) ranged from a low of 5 BO with 175 BW per day (No. 10 Maberry) to 12 BO with 275 BW per day (Nos. 6 and 7 Maberry) (Fig. 61).

Log Interpretation

by

Bruce Carpenter

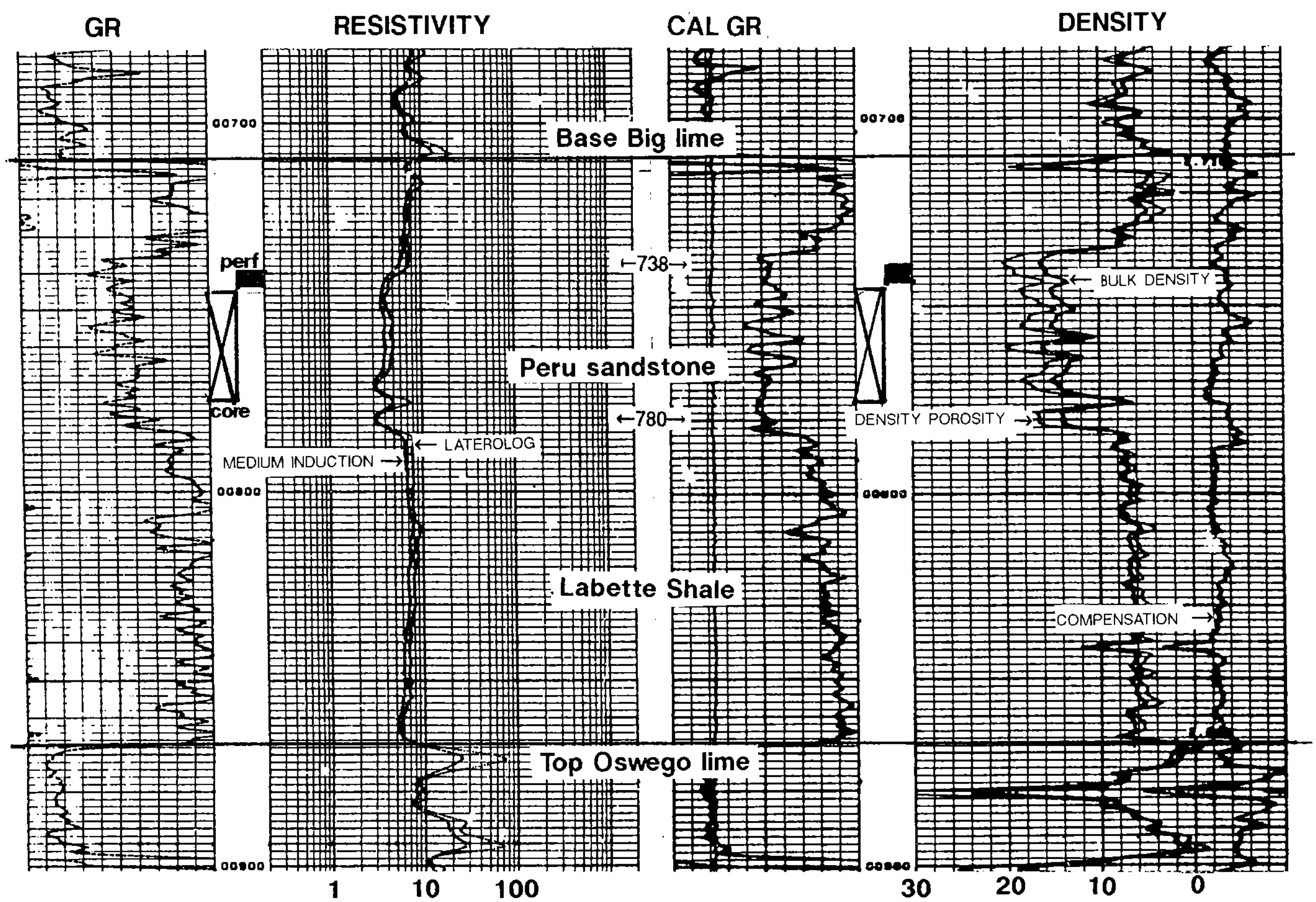
Log interpretation is always a challenge for researchers studying sandstones such as the Peru that have low resistivities and very little contrast in resistivity between wet and productive zones. These sandstones, which are sometimes referred to as *low-resistivity pay sands,* are common in Gulf Coast areas but are not common in Oklahoma. In order to understand log interpretation for these reservoirs, it is essential to calibrate wireline logs to lithology, porosity, permeability, and fluid saturations measured in core.

In the Hogshooter field study area (sec. 24, T. 26 N., R. 13 E.), modern logs and a core-analysis report were available for one well, the Chautauqua Oil, Inc., No. 2 Maberry. Dual induction–laterolog and compensated density logs for this well are shown in Figure 63; the density log is also included in cross section A–A′ (Fig. 55, in envelope). The core-analysis data (porosity, permeability, oil and water saturations, and lithology) are shown in Table 14.

Core Porosity Versus Density-Log Porosity

The computed density-log porosity, using 2.68 for the matrix density, ranges from about 10% to 20% in the interval that was cored in the No. 2 Maberry. The core porosity, on the other hand, ranges from 15.6% to 21.7% (Table 14). (No core-to-log depth correction is required.) The core porosity versus the corresponding density-log porosity is plotted in Figure 64, which shows that the density-log porosity is considerably lower than the corresponding core porosity. The difference between the two values ranges from <1 to 10 porosity units (Fig. 64). For intervals described as "shaly sand" or "sand with shale," the difference ranges from

Chautauqua Oil Co.
2 Maberry
N½ NE SE NE 24, 26N–13E
GL 809'



TD 1585'
Completion 11–24–81
IPP 10 BO plus 190 BWPD
Perforated Peru 739'–743'
Cored Peru 745'–775'

Figure 63. Dual induction–laterolog and compensated density logs, Chautauqua Oil, Inc., No. 2 Maberry (N½NE¼SE¼NE¼ sec. 24). GL = ground-level elevation; CAL = caliper; GR = gamma-ray; TD = total depth. Resistivity-log scale is in ohm-meters; density-log scale is for the porosity curve and is in percentages. The cored interval, marked in the depth track, is 745–775 ft. See core-analysis report in Table 14. No core-to-log depth correction is required.

0.5 to 2.4 porosity units; the average difference is only 1.5. For intervals described as "sand" in the core report (Table 14), the difference ranges from about 1 to 10 porosity units; the average difference is about 4 porosity units. Perhaps more noteworthy is that for intervals with density-log porosity ≥17%, the differences between the log and core porosity values are relatively small, 1–2.5 porosity units.

If the matrix density used in the density-log-porosity calculation is lower than the actual matrix density, the density-log porosity will be lower than the actual total porosity. On the No. 2 Maberry log, the average sandstone-matrix density (2.68 g/cm^3) was used to generate the density-log-porosity curve (Fig. 63). Using a higher matrix density would raise the calculated porosities. For example, using 2.71 g/cm^3 (the value used for logging formations that are dominantly limestone) raises the calculated porosity by roughly 1.5 porosity units. For some intervals, an increase of 1.5 porosity units would bring the log porosity very

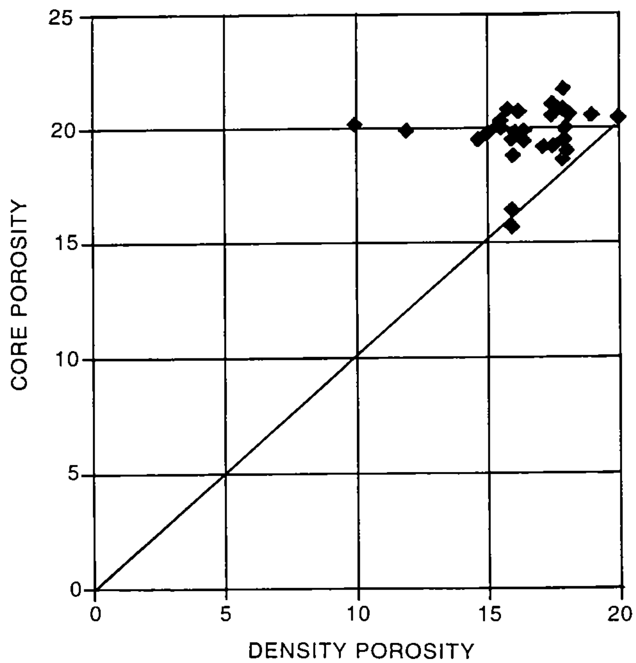


Figure 64. Core porosity–density-log porosity crossplot. Data are for the Peru sand (745–775 ft) in Chautauqua Oil, Inc., No. 2 Maberry. No core-to-log depth correction is required.

close to the core porosity measured in the core samples.

Density-log- and core-porosity values will also differ if there is a sizable difference between effective and total porosity, such as in sandstones that have abundant dispersed clay and microporosity associated with the clay. Core porosity is the porosity from which fluid can be extracted, and thus approximates effective porosity. Density-log porosity approximates total porosity if the rock's actual matrix density is close to the matrix density used in the log calculation. For highly clay-rich sandstones, total porosity is significantly greater than effective porosity, and therefore density-log porosity is generally greater than core porosity. The presence of ineffective porosity (i.e., microporosity and/or isolated pores) can be interpreted if the *grain density* reported for a sample is lower than the density expected for the mineralogy. Unfortunately, the No. 2 Maberry core report does not include grain densities, and so the mineralogy is not known.

The fact that the No. 2 Maberry density-log porosity (Fig. 63) is *less* than the core porosity does not preclude the presence of clay and ineffective porosity. Because the density of clay minerals ranges from about 2.2 to 3.0 g/cm^3, the actual total porosity can be either lower or higher than the porosity on the density log. For example, if a quartz sandstone with a bulk density of 2.35 g/cm^3 contains some calcite cement with a density of 2.71 g/cm^3, and 15% illite with a density of 3.0 g/cm^3, the porosity calculated would be 2 porosity units lower even than that indicated by the density-porosity curve. Another explanation is needed to explain the larger differences between the density-log and the core porosities.

In a common core analysis, testing is performed on a 1-in.-diameter plug selected from each foot of core. However, the density-log reading reflects the density of the rocks over a foot or more. Laboratories preferentially plug the "better looking" sandstone in intervals of mixed lithology. A 1-ft-thick interval that is a mix of shale and sandstone beds may be represented in a core report by measurements of the sandstone. The shale has ineffective porosity but is still more dense than the porous sandstone. Sampling bias, combined with the difference in sample size (1 in. for core samples versus ≥1 ft for the log), provides the most probable explanation for the large differences (>3 porosity units) between log and core porosities. Characteristics of other logs, and the initial production data, also suggest a significant amount of ineffective, water-filled porosity.

Quick-Look Method for Shaly-Sandstone Analysis

Conventional shaly-sand models assume that most of the clay occurs in only one of two possible modes: in shale that is (1) interlaminated with the sandstone or (2) dispersed throughout the sandstone. In cases of compromising circumstances, such as uncertainties about porosity (total porosity versus effective porosity), mineralogy (i.e., the presence or absence of conductive minerals), and formation-water resistivities, a simple method of interpreting resistivity logs is sometimes called for.

Recall that resistivity is a measure of water volume and that resistivity increases as water volume decreases. In a sandstone of uniform porosity, the total pore volume is constant, so an upward increase in resistivity can be attributed to the presence of hydrocarbons. To apply this method, compare resistivities in intervals that have the same density-log porosities. The interval with the lowest resistivity is presumed to be wet. If the resistivity increases upward, an upward decrease in water volume is indicated. Oil production with high water cuts can be expected from zones with resistivity as low as two times the wet resistivity. At three times the wet resistivity, fairly low water cuts are possible only if some of the water is immobile, as it is in sandstones with significant amounts of ineffective microporosity associated with dispersed clay. A formation with a low resistivity ratio can approach irreducible water saturation (i.e., produce water-free oil) only if most of the water is immobile. In the Peru, the low resistivity ratio of productive zones is caused by a combination of the water held in place by the ineffective porosity and producible water in the effective pore system.

To apply the simplified resistivity ratio method, assume that the interval with the lowest resistivity is wet. In the No. 2 Maberry well, the lowest resistivity, 3 ohm-m, is at a depth of 780 ft (Fig. 63). This assumption is supported by the observation that the oil saturation 5 ft higher is zero at the base of the core (774–775 ft). The density-log porosity at 780 ft is 16.5%. The density-log porosity is higher (18%) at 770 ft, but the resistivity is the same, indicating that at 770 ft at least 1.5 porosity units (18 minus 16.5) are occupied by hydrocarbons. The residual-oil saturation is 2% in the 770–771-ft core sample (Table 14). In the interval from about 760 to 762 ft, the porosity has increased to 20%, and the resistivity has increased from 3 to 4 ohm-m, indicating that >3.5 porosity units (20 minus 16.5) are full of hydrocarbons. The presence of hydrocarbons is supported by core analysis. The core oil saturation in the 761–762-ft sample is 10%, and the core porosity is 20.4%, which indicates that at least 2 porosity units (10% of 20.4%) are full of oil. From 740 to 738 ft, log porosity is 20%, and resistivity increases upward to ~6 ohm-m, twice the assumed wet resistivity value of 3 ohm-m, which is in a zone with considerably lower porosity (16.5%). Thus, hydrocarbons are present, perhaps in producible quantities. The sample from the top of the core (745–746 ft; 7 ft below) had 15% oil saturation in 20.5% porosity. The interval from 739 to 743 ft was perforated and pumped 10 BO with 190 BW. The fact that any oil was produced from a zone with resistivity only twice the wet resistivity value indicates that a considerable amount of the porosity is ineffective—i.e., contains immobile water and/or water bound by clay.

An even quicker "eyeball" approach is also applicable for this well. Overall, the porosity increases upward. Since the upward increase in porosity is accompanied by an upward increase in resistivity, hydrocarbons must be present.

Nonproductive Example

Resistivity that decreases with an upward increase in porosity indicates upward-increasing water volume. If hydrocarbons are present, they would have replaced some of the water, causing the resistivity to increase or at least to remain constant in spite of the upward increase in pore volume. The logs of the Chautauqua Oil, Inc., No. 3 Maberry well illustrate the relationship between the porosity and resistivity curves in a nonproductive well (Fig. 65). Note how the resistivity curves mimic the porosity curve. Upward, porosity decreases and resistivity increases from 784 to 776 ft and from 756 to 720 ft. The decrease in pore volume is accompanied by a decrease in water volume and a corresponding increase in resistivity. The porosity increases upward in the interval from 764 to 756 ft, and the resistivity for the same interval decreases slightly. As the pore volume increased, the resistivity decreased, indicating that the water volume also had increased, resulting in a lack of hydrocarbons. If hydrocarbons had decreased the water volume as porosity increased, the resistivity trend would be reversed or at least modified.

Significance of Stratigraphy

A shale interval from 742 to 750 ft is a potential barrier between two Peru sand zones in the Chautauqua Oil, Inc., No. 8 Maberry well (Fig. 66). The upper sand reaches a porosity of 18% between 732 and 738 ft. The porosity of the lower sand increases upward to 16% at the top. The resistivity of the upper sand reaches 8 ohm-m, and the resistivity of the lower sand drops to 3 ohm-m, resulting in a resistivity ratio of 2.67 and a good indication of hydrocarbons, considering that the upper sand also has more porosity (18%) than the lower sand (16%). The upper sand was perforated from 734 to 738 ft. The IPP was 10 BOPD plus 190 BWPD, or a 5% oil cut, which is typical, rather than better, for the wells in the study area. The 8-ft-thick vertical permeability barrier should at least prevent early water coning. Bad cement or a lack of isolation not withstanding, water coning is not the source of low oil cuts.

Clay Indicators

In the above examples, the gamma-ray (GR) curve decreases by only about two-thirds of the difference between the shale baseline levels (near the depth track) and the "clean" or shale-free levels (near the left edge of the log), as established by the limestones above and below the Labette Shale. GR levels this high are generally interpreted as evidence for very shaly sands, but radioactivity from other sources, such as potassium in feldspar, mica, phosphatic nodules, or uranium, attached to organic material can also cause high GR levels. A neutron log can usually aid in distinguishing between clay, which has a fairly high water content, and other sources of radioactivity. The neutron-log porosity is less than, but very close to, the density-log porosity in a clay-free sandstone. If both logs are run, assuming the matrix density of limestone (2.71g/cm^3), the neutron-log-porosity curve will "cross over" the density porosity curve in the sandstone-porosity profile.

Unfortunately, combination density-neutron logs were not run in most wells in the study area. One combination compensated density-neutron log was found and is shown in Figure 67. This log was run in the Anderson Oil Co. No. 1 Anderson well (W½SW¼NW¼ sec. 24). The neutron log is the dashed curve just to the right of the depth track. This particular neutron log is not presented in porosity units, but the curve in the tight limestones above and below the Labette Shale approximates the zero-porosity level. In contrast to the density log, which clearly shows the increase in porosity above the base of the sand at 812 ft, the neutron-log curve is not significantly different in the sand and in the underlying shale, thereby confirming that the sand has a very high clay content.

A cased-hole neutron log was also run in this well and is shown in the extreme right panel (Fig. 67). Note the collar-locator log (tick marks along the right side of the depth track show the locations of casing collars). Again, there is little difference in the neutron levels in the Peru sandstone (above 812 ft) and in the shale below. Porosity on the density log increases upward from the base of the sand to the top at 748 ft. Resistivity, which is very low in the lower 50 ft of the sand, begins increasing upward at 762 ft. It is interesting to note that from 762 ft upward, the cased-hole neutron curve decreases. (The decrease above 762 ft on the neutron curve of the density–neutron log is barely perceptible.) There is no shift in the gamma-ray curve at 762 ft. This increase in resistivity and decrease in the cased-hole neutron curve above 762 ft appear to correspond with the oil–water contact.

Reservoir Model

Log characteristics and initial-production data indicate that a considerable amount of water-filled porosity must be present in the Peru sandstone. The low ratios (2 to 3) between resistivity in wet and productive zones indicate a significant amount of ineffective porosity. High GR values of productive zones suggest a high clay content. The relatively small difference between the neutron-log readings in shale versus the Peru sand confirms the high clay content. A reasonable model for the Peru, in the absence of petrographic analysis, is to consider that a considerable amount, perhaps as much as half, of the intergranular space contains clay. Therefore, as much as half of the total porosity is ineffective, because it contains immobile water bound by clay minerals or trapped in clay microporosity.

Assuming a total porosity of 20%, half of it containing immobile water associated with clay, the effective porosity would be 10%. If hydrocarbons displaced half

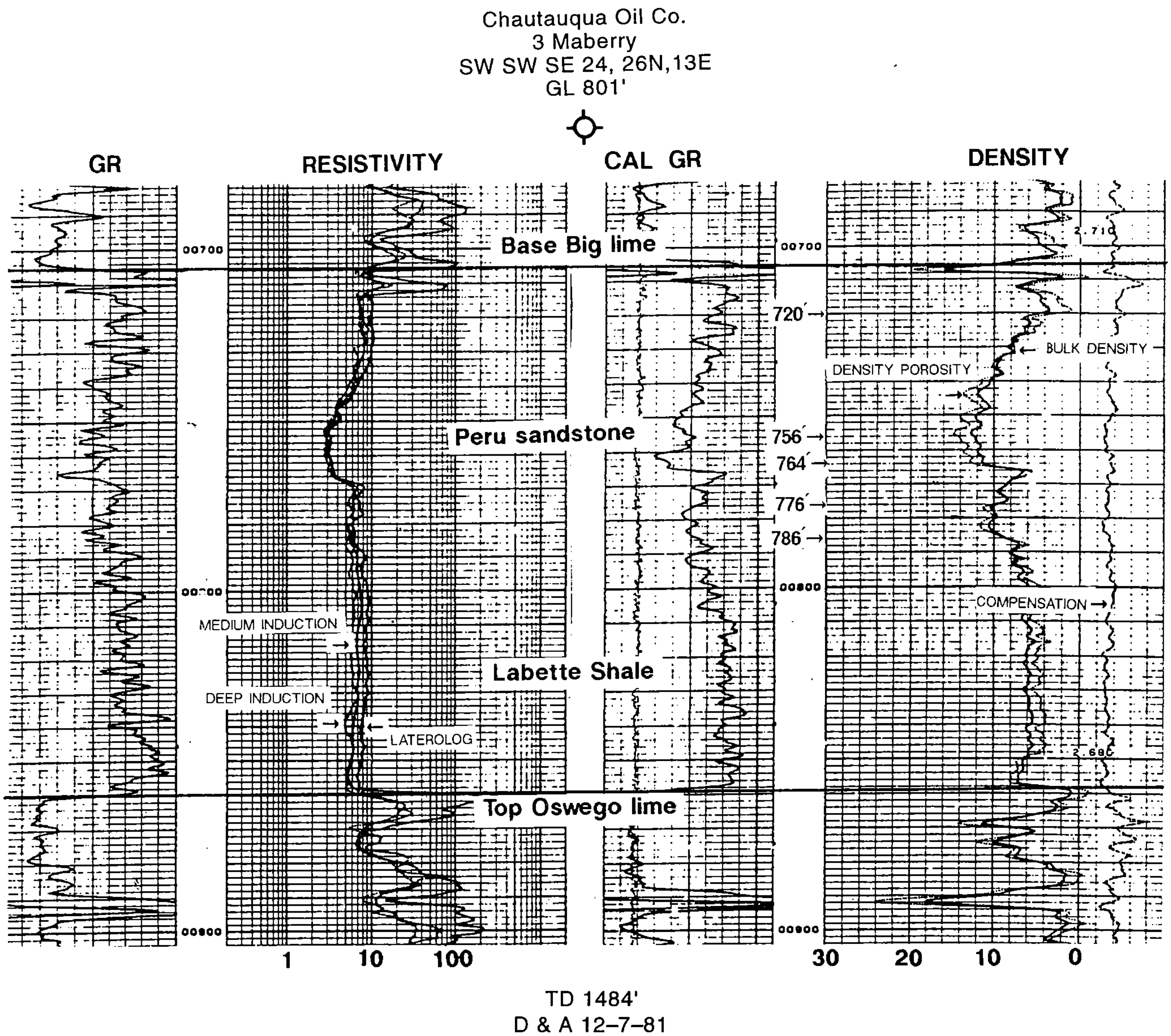


Figure 65. Dual induction–laterolog and compensated density logs, Chautauqua Oil, Inc., No. 3 Maberry (SW¼SW¼SE¼ sec. 24). GL = ground-level elevation; CAL = caliper; GR = gamma-ray; TD = total depth. Resistivity-log scale is in ohm-meters; density-log scale is for the porosity curve and is in percentages. The Peru was not tested, and the well was declared dry and abandoned (D & A).

the water in the effective pore system, the effective pore-system resistivity would increase by a factor of 4, but the total resistivity, which is controlled by both mobile and immobile water, would increase by a factor of only 1.6. If the wet resistivity is 3 ohm-m, an increase by a factor of 1.6 would be 4.8 ohm-m. If 75% of the total log porosity of 20% is effective, resistivity would slightly more than double if hydrocarbons displaced half the water in the effective pores. The water saturation calculated for a resistivity ratio of 2 is ~70%. This approximates the condition observed in the Peru wells in the study area.

Conventional shaly-sand models assume that the clay occurs either in shale interlaminated with sandstone or dispersed throughout the sandstone. The core-lithology notes indicate that laminated shale and dispersed clay are probably present, which makes the more complex shaly-sand log-analysis methods difficult to apply to the Peru. On the basis of correlations of production histories and resistivity-log characteristics, zones with a resistivity twice as high as the resistivity of a wet zone of comparable porosity should be tested. Water saturations are truly high (50%–75%), and high water cuts well over 50% are to be expected. Volumetric reservoir computations should consider that high water-saturation calculations are a fact, owing in part to high clay content and that both oil-in-place and recovery volumes will be lower than in better quality sands.

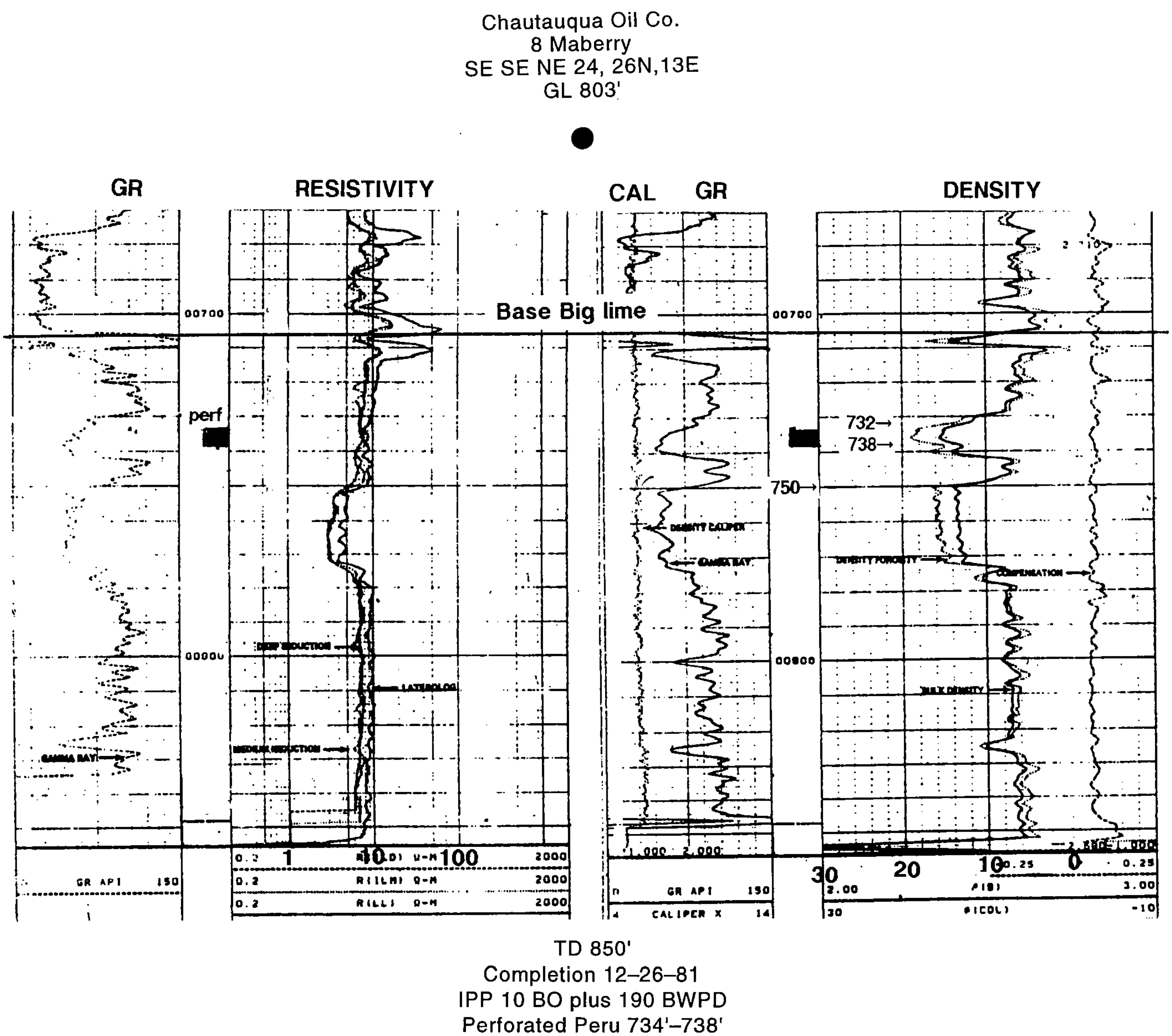


Figure 66. Dual induction–laterolog and compensated density logs, Chautauqua Oil, Inc., No. 8 Maberry (SE¼SE¼NE¼ sec. 24). GL = ground-level elevation; CAL = caliper; GR = gamma-ray; TD = total depth. Resistivity-log scale is in ohm-meters; density-log scale is for the porosity curve and is in percentages.

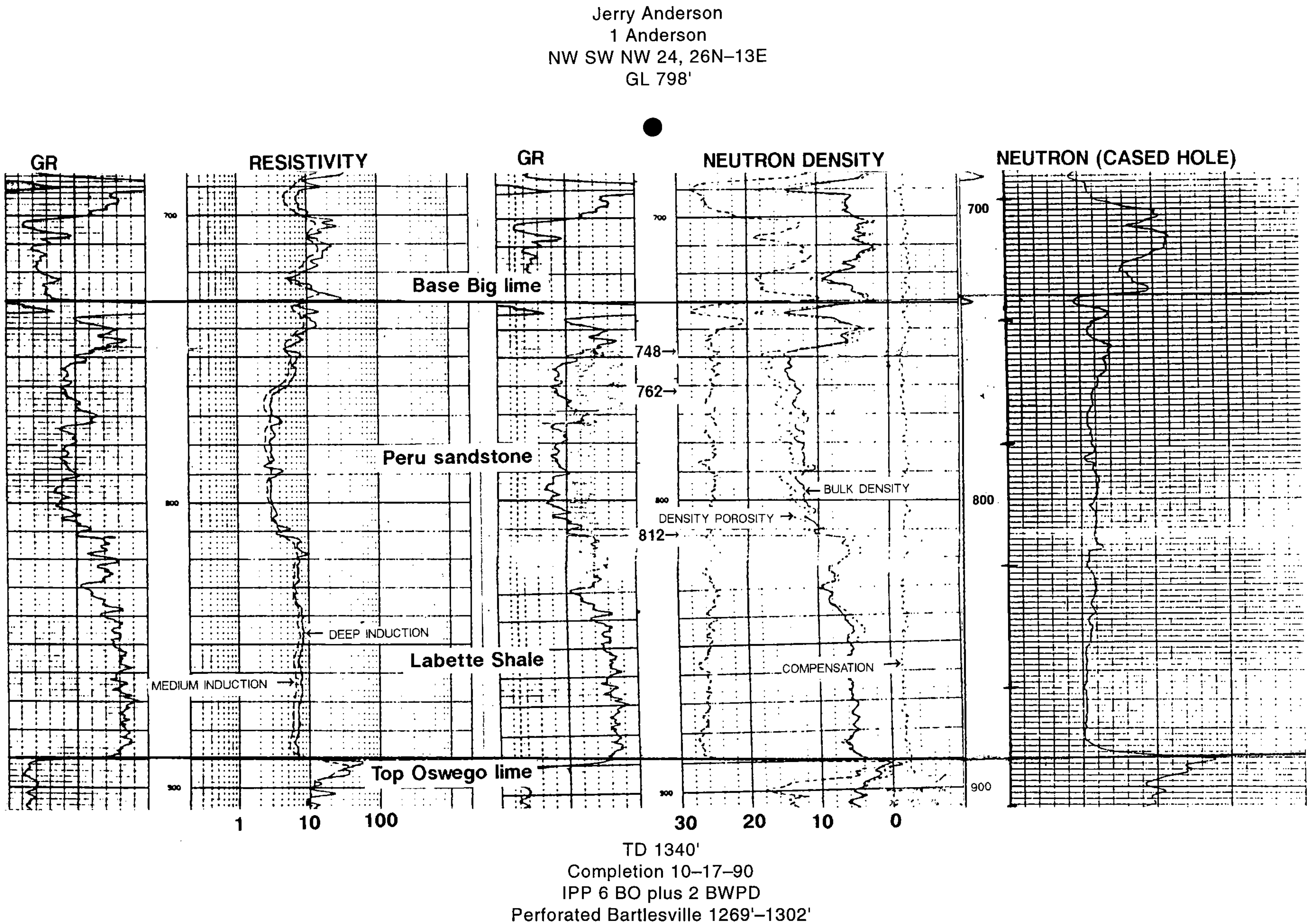


Figure 67. Dual induction and compensated density–neutron logs, Anderson Oil Co. No. 1 Anderson (W½SW¼NW¼ sec. 24). GL = ground-level elevation; CAL = caliper; GR = gamma ray; TD = total depth. Tick marks at the right edge of the depth track on the cased-hole neutron log show the locations of the casing collars. Resistivity-log scale is in ohm-meters; density-log scale is for the porosity curve and is in percentages.

Acknowlegments

Completion of this study would not have been possible without funding from the U.S. Department of Energy and the combined efforts of many people from the Oklahoma Geological Survey (OGS), Geo Information Systems (GeoSystems), and the OU School of Petroleum and Geological Engineering. The continuing effort of Rhonda Lindsey, Project Manager, Bartlesville Project Office of the U.S. Department of Energy, is greatly appreciated. Special recognition is given to Charles J. Mankin, director of the OGS, and Mary K. Banken, director of GeoSystems, who originated concepts for this program and provided overall leadership. Both the OGS and GeoSystems also provided funding for this cooperative project.

The investigators are most fortunate in having had the cooperation of Mr. W. B. Hoppes, Jr., operator of Pleasant Mound field, and of Mr. Wayne Storey of Advent Oil and Operating, Inc. We extend our abundant gratitude to Mr. Hoppes for having provided data supplemental to those in the public records for geologic description and reservoir modeling (Parts III and IV), and to Mr. Storey for the loan of the cored Cleveland sand interval from the No. 3-15 Cummins well.

Petroleum geologists who contributed greatly to this project by sharing their technical expertise with the authors are Richard Andrews, OGS; Kurt Rottmann, Oklahoma City consulting geologist; and Bruce Carpenter, Oklahoma City consulting geologist. Bruce Carpenter also prepared the work on the log-interpretation portion for the Peru sandstone study area in the Hogshooter field.

Much of the technical support for geologic- and computer-map preparation, core preparation, technical typing and editing, and computer graphics was completed by David Brown, GeoSystems technical project coordinator; Kathy Hines, GeoSystems programmer/analyst; Carlyle Hinshaw, GeoSystems petroleum geologist; Scott March, GeoSystems geotech; Betty Bellis, OGS technical typist; and Victoria French, student research assistant, OU School of Geology and Geophysics. Core examination was made possible by Walter Esry and Larry Austin of the OGS Core and Sample Library. Cartographic drafting, visual-aid preparation, and computer-assisted drafting (CAD) were completed by Wayne Furr, OGS manager of cartography; Jim Anderson and Charlotte Lloyd, cartographic drafting technicians; and Gary Leach and Greg Taylor, contract drafting technicians. Technical review and editing were completed by Charles J. Mankin, OGS director, and Dorothy L. Swindler, geologist/contract editor. Frances Young provided technical editing for the Cleveland sandstone portion of this report, and William D. Rose provided technical editing for the Peru sandstone portion. Christie Cooper, OGS editor, and Tracy Peeters, OGS associate editor, compiled the final manuscript for publication. Publication printing was made possible by Paul Smith and Richard Murray (OGS). Special recognition also is given to Michelle Summers, OGS technical project coordinator, for program organization and registration.

The authors are most appreciative of the technical reviews by Charles J. Mankin and Dorothy L. Swindler. Conversations with Rick Andrews, Greg Riepl, and LeRoy Hemish were most helpful; however, the authors alone are responsible for the interpretations and conclusions reached herein.

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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.—
				Cobbles
—64 mm—	−6			
		Gravel		—3 in.—
Pebbles		(Kies)		
				Gravel
—4 mm—	−2		Gravel	
				—4 mesh—
Granules				Coarse sand
—2 mm—	−1	—2 mm—	—2 mm—	—10 mesh—
Very coarse sand			Very coarse sand	
—1 mm—	0		—1 mm—	
Coarse sand		Sand	Coarse sand	Medium sand
—0.5 mm—	1		—0.5 mm—	
				—40 mesh—
Medium sand			Medium sand	
—0.25 mm—	2		—0.25 mm—	
Fine sand			Fine sand	Fine sand
—0.125 mm—	3		—0.10 mm—	
Very fine sand			Very fine sand	—200 mesh—
—0.0625 mm—	4	—0.0625 mm—		
			—0.05 mm—	
Silt		Silt		
			Silt	Fines
—0.0039 mm—	8			
		—0.002 mm—	—0.002 mm—	
Clay		Clay	Clay	
		(Ton)		

†Subdivisions of sand sizes omitted.
‡Mesh numbers are for U.S. Standard sieves: 4 mesh = 4.76 mm, 10 mesh = 2.00 mm, 40 mesh = 0.42 mm, 200 mesh = 0.074 mm.

APPENDIX 2

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

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

APPENDIX 3

Glossary of Terms

(as used in this volume)

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

allogenic—Formed or generated elsewhere.

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

authigenic—Formed or generated in place.

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

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

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

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

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

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

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

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

crevasse-splay deposit—See *splay.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

meteoric water—Pertaining to water of recent atmospheric origin.

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

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

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

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

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

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

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

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

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

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

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

ribbon sand—See: *shoestring sand.*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

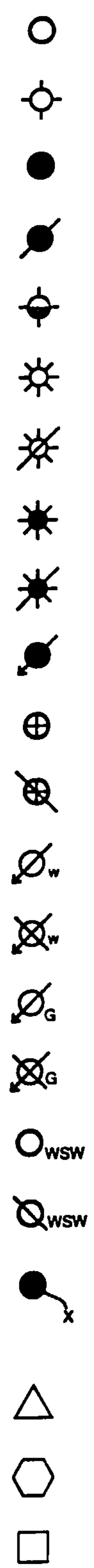
unitized—Consolidating the management of an entire oil or gas pool, regardless of property lines and lease boundaries, in the interest of efficient operation and maximum recovery.

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

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

APPENDIX 4

Well Symbols Used in Figures and Plates



Location

Dry hole

Oil well

Abandoned oil well

Dry hole, show of oil

Gas well

Abandoned gas well

Oil and gas well-dual completion

Abandoned oil and gas well

Oil well converted to injection well

Salt-water disposal well

Abandoned salt-water disposal well

Water injection (input) well

Abandoned water injection well

Gas injection (input) well

Abandoned gas injection well

Water supply well

Abandoned water supply well

Directionally drilled well
(Surface location shows well completion status. X indicates bottom hole location.)

Discovery well

Type or representative log well

Cored well

NDE- Not deep enough

DNP- Did not penetrate

ND- No well data

NL- No well log

APPENDIX 5

Supplemental Core Descriptions with Well Logs of Selected Intervals of Cleveland Sand:

1. **Gulf Oil Corporation No. 1 Schroeder**
   C SW¼NE¼ sec. 3, T. 12 N., R. 2 W.
   Cleveland sand, marine bar

2. **Jefferson-Williams Energy Corporation No. 1 Fagan**
   C NE¼NW¼NE¼ sec. 25, T. 17 N., R. 2 E.
   Cleveland sand, marine bar

3. **Fain-Porter Production Company No. 1 Ripley**
   SW¼SW¼SW¼ sec. 3, T. 20 N., R. 7 E.
   Cleveland sand, includes fluvial (distributary channel) and estuarine (tidal channel) environments of deposition

Gulf Oil Corporation
No. 1 Schroeder
C SW¼NE¼ sec. 3, T. 12 N., R. 2 W.
Oklahoma County
Core: 5,546–5,577 ft; recovered ~29 ft
Cleveland sand

Interval no.	Depth (feet)	Lithologies and depositional environments
1	5,546.0–5,547.7	Black shale with interbedded gray, silty, fine-grained sandstone. Slightly calcareous. Sandstone intervals bioturbated. Shallow marine deposition.
2	5,547.8–5,548.5	Limestone, sandy and silty. Fossil fragments very common. Marine deposition.
3	5,548.6–5,555.1	Sandstone, tan to greenish-tan, fine- to medium-grained. Bedding commonly indistinct, but locally marked by minor accumulations of organic matter. • Local small (up to 1.5 cm in longest exposure) clay rip-up clasts, 5,549.5 ft. • Bioturbation, 5,548.7–5,548.9 ft; 5,550.1–5,550.3 ft. • Soft-sediment deformation, 5,550.6–5,550.8 ft. • Vertical fracture, 5,553.2–5,553.6 ft. Shallow marine deposition, probably an offshore bar.
4	5,555.2–5,556.3	Core missing (1.1 ft).
5	5,556.4–5,562.5	Sandstone, as above (interval 3). • Local small (up to 1.75 cm in longest exposure) clay rip-up clasts, 5,560.6 ft. • Bioturbation, 5,560.4–5,561.6 ft. • Soft sediment deformation, 5,559.6–5,559.8 ft.
6	5,562.6–5,572.3	Sandstone, tan to greenish tan, fine- to medium-grained. Ripple-bedding common, and visually distinct as the result of organic matter, which is present in increasing amounts downward. Sandstone is present in decreasing amounts downward; becomes generally finer-grained and more thinly laminated. • Bioturbation, 5,565.1–5,565.2 ft; 5,566.0–5,566.4 ft; very common 5,566.6–5,572.4 ft. Shallow marine deposition, probably an offshore bar.
7	5,572.4–5,574.3	Black shale with interbedded, silty, fine-grained sandstone. Slightly calcareous locally. Similar to interval 1. • Extreme bioturbation, 5,572.4–5,573.1 ft. • Common bioturbation, 5,573.1–5,574.3 ft. Shallow marine deposition.

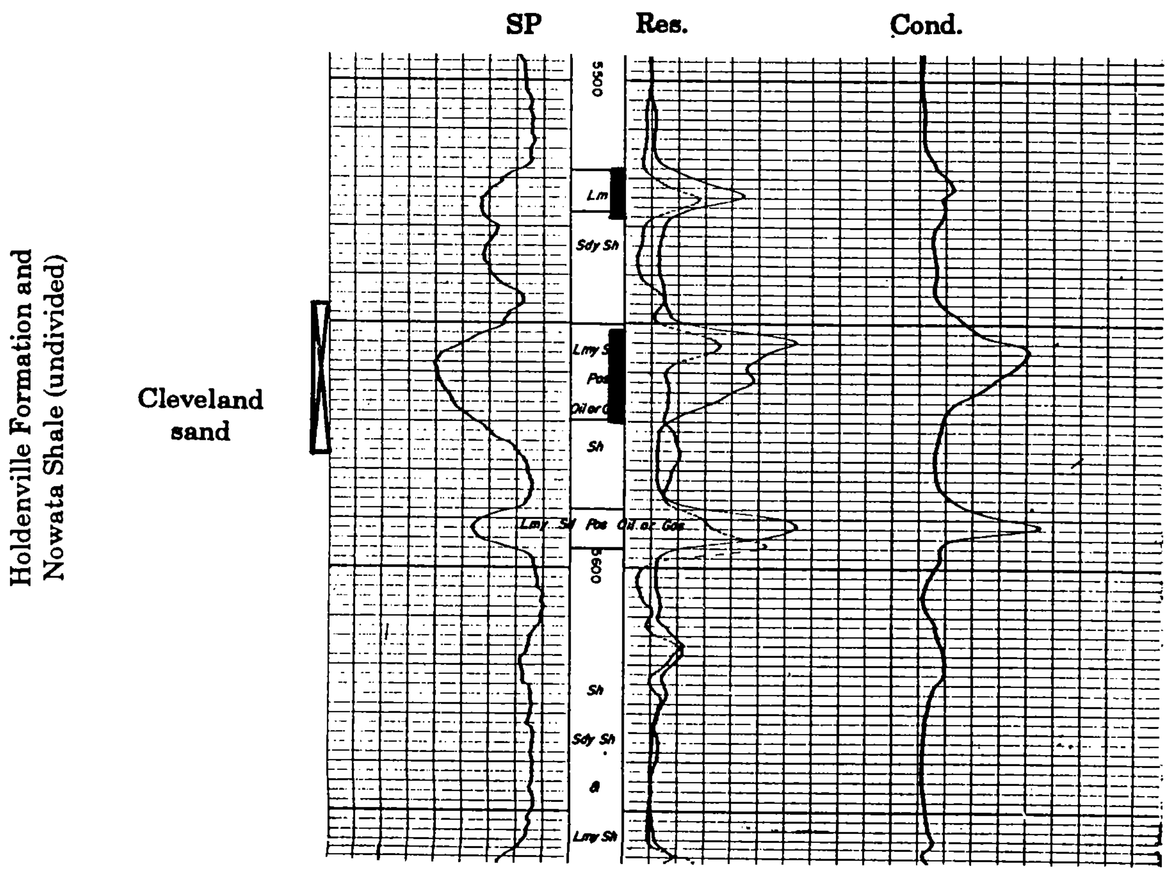
Missing core segments of less than 0.5 ft are not logged.

Core is about 2 ft high relative to gamma-ray log.

Gulf Oil Corporation
No. 1 Schroeder
C SW¼ NE¼ sec. 3, T. 12 N., R. 2 W.
Oklahoma County

TD 6,336 ft

Core: 5,546–5,577 ft; rec. approx. 29 ft



PBTD 5,632 ft (OWWO)
Completed: 5-13-52
Perforations: Cleveland, 5,518–5,128 ft; 5,551–5,570 ft
5,588–5,596 ft: flowed 1½ hours, est. 3½ MMCFGPD.
Shut in gas well.

Jefferson-Williams Energy Corporation

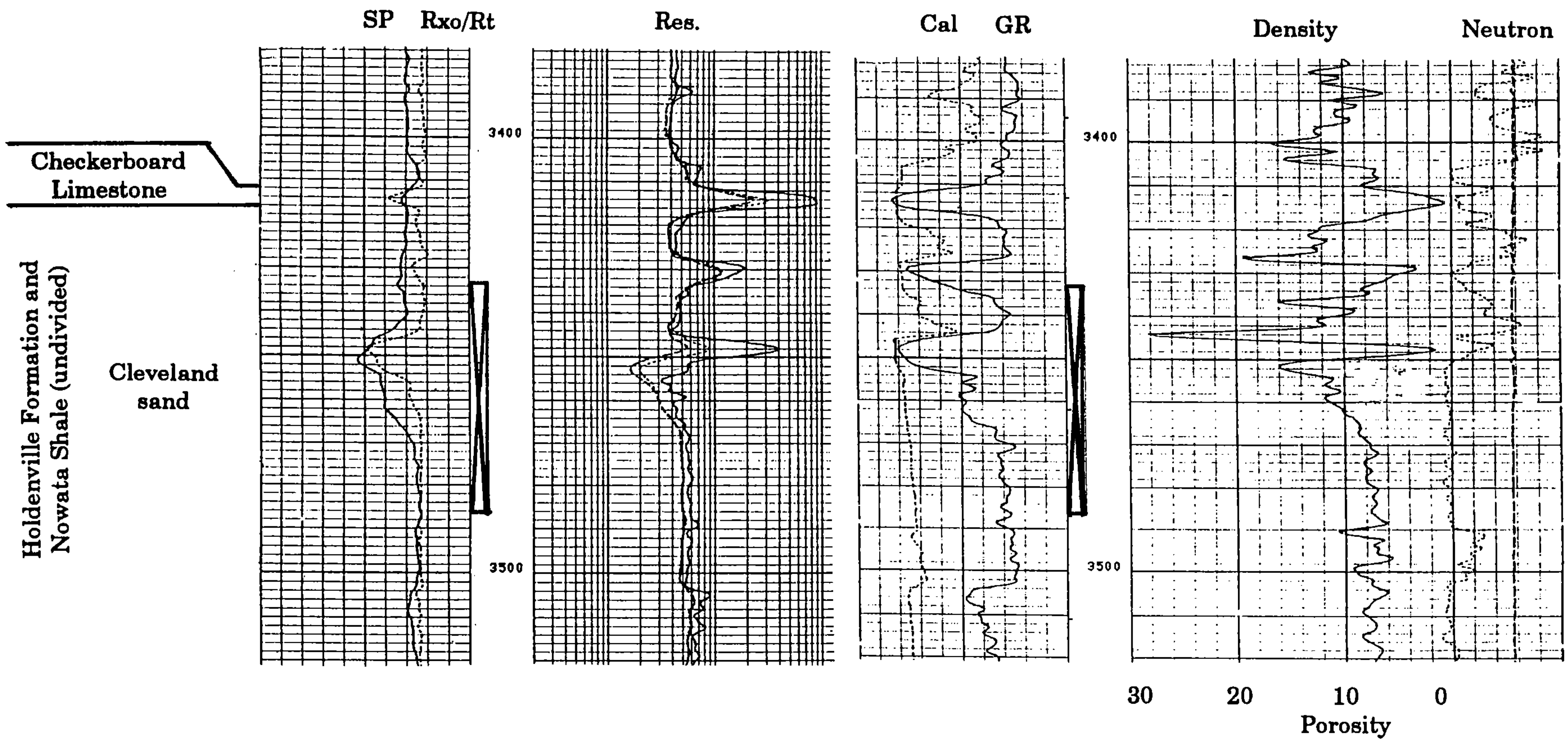
No. 1 Fagan
C NE¼NW¼NE¼ sec. 25, T, 17 N., R. 2 E.
Lincoln County
TD 4,776 ft
Core: 3,433–3,486 ft; rec. ~42 ft
Cleveland sand

Interval no.	Depth (feet)	Lithologies and depositional environments
1	3,433.0–3,434.1	Core missing (1.1 ft).
2	3,434.2–3,439.0	Black shale with partings of light gray, silty, fine-grained sandstone; locally calcareous. Bioturbation common, and locally intense. Shallow marine deposition.
3	3,429.1–3,441.9	Core missing (2.8 ft).
4	3,442.0–3,449.4	Sandstone, light tan to medium gray; slightly calcareous. Texture fine-grained; bedding mostly indistinct, but locally ripple-bedded, as marked by local partings of organic matter. • Bioturbation, 3,443.7–3,443.9 ft; 3,445.1–3,445.3 ft; 3,448.2–3,448.3 ft. • Minor clay clasts (up to 0.7 cm in longest exposure), 3,447.0 ft. Shallow marine deposition, probably an offshore bar.
5	3,449.5–3,453.0	Sandstone, light tan to medium gray; texture fine-grained, silty; with partings of black shale. Highly bioturbated. Shallow marine deposition, probably an offshore bar.
6	3,453.1–3,456.7	Core missing (3.6 ft).
7	3,456.8–3,463.1	Sandstone, light tan to medium gray; texture fine-grained, silty, with interbedded black shale; highly bioturbated. Shallow marine deposition.
8	3,463.2–3,482.2	Black shale with partings of light gray, silty, fine-grained sandstone. Bioturbated. Similar to interval 2. Shallow marine deposition.
9	3,482.3–3,486.0	Core missing (3.8 ft).
		Core is about 4 ft high relative to gamma-ray log. Original depths very poorly marked on core.

Jefferson–Williams Energy Corporation
No. 1 Fagan
C NE¼ NW¼ NE¼ sec. 25, T, 17 N., R. 2 E.
Lincoln County

TD 4,776 ft

Core: 3,433–3,486 ft; rec. approx 42 ft



Completed: 4-13-83
Perforations: Layton 3,158–3,162 ft
Treatment: Acid (no details reported)
IPP 41 BOPD; no other fluids reported

Fain-Porter Production Company
No. 1 Ripley
SW¼SW¼SW¼ sec. 3, T. 20 N., R. 7 E.
Pawnee County
Core: 2,131–2,190 ft; rec. ~54 ft
Cleveland sand

Interval no.	Depth (feet)	Lithologies and depositional environments
1	2,131.0–2,151.2	Black shale with local, thin (0.02 to 0.9 cm) intercalations of tan, silty fine grained sandstone. • Bioturbation, 2,135.0–2,135.6 ft; 2,144.9–2,145.1 ft; and locally elsewhere. • Soft-sediment deformation (including slump structures), 2,137.7–2,138.8 ft; 2,141.0–2,143.2 ft; 2,143.8–2,145.7 ft (probably includes bioturbation at 2,144.9–2,145 ft). • Sedimentary dip up to 20°, 2,137.7–2,138.2 ft (part of slump structure). Shallow marine deposition; or, may be accretionary bank associated with intertidal channel.
2	2,151.3–2,153.9	Sandstone, light tan to gray; fine-grained, silty. Interlaminated with black shale. Lamina commonly ripple-bedded, with thicknesses ranging from 0.05 to 2.5 cm ("tidal couplets"). Estuarine tidal-channel deposit.
3	2,154.0–2,155.1	Sandstone, light tan to gray; fine-grained, silty. Indistinctly ripple-bedded. • Clay rip-up clasts, 2,154.1 ft and 2,154.9 ft. Distributary channel deposit.
4	2,155.2–2,156.2	Sandstone and interlaminated black shale, as above (interval 2). Tidal channel deposit.
5	2,156.3–2,156.7	Sandstone, as above (interval 3). Distributary channel deposit.
6	2,156.8–2,158.7	Sandstone and interlaminated black shale, as above (intervals 2 and 4). Tidal channel deposit.
7	2,158.8–2,160.0	Sandstone, as above (intervals 3 and 5). • Clay rip-up clasts (up to 1.25 cm in maximum exposure), associated with inclined bedding (15° dip), 2,159.0–2,159.2 ft. • Cut-and-fill structure, 2,159.5 ft. • Black shale lamina, 2,159.5 ft and 2,159.7 ft. Distributary channel deposit.
8	2,160.1–2,162.4	Sandstone and interlaminated black shale, as above (intervals 2, 4, and 6). However, sandstone beds are as much as 10 cm thick. Tidal channel deposit.
9	2,162.5–2,186.4	Sandstone, light-tan to medium-brown; fine- to medium-grained. Bedding ranges from massive and indistinct to ripple-laminated. Minor amounts of organic matter locally associated with bedding planes. • Inclined bedding (from 5° to 16° dip), 2,164.8–2,165.6 ft; 2,170.7–2,171.2 ft; 2,184.4–2,185.4 ft. • Clay rip-up clasts, 2,164.5 ft; 2,166.2 ft; 2,861.1–2,861.2 ft; 2,169.4 ft; 2,172.0–2,172.2 ft; 2,173.8 ft; 2,174.9 ft; 2,181.3 ft; 2,188.2–2,188.4 ft; 2,189.6 ft. Distributary channel deposit.
10	2,186.5–2,186.8	Interlaminated fine-grained, silty sandstone and black shale (thickness range, 0.05–1.0 cm). Tidal channel deposit?
11	2,186.9–2,190.0	Sandstone, as above (interval 9). • Inclined bedding (dip up to 20°), with partings of micaceous organic matter, 2,188.2 ft. • Local small clay rip-up clasts (up to 0.4 cm maximum exposure), 2,189.0 ft; 2,189.6 ft). Distributary channel deposit.

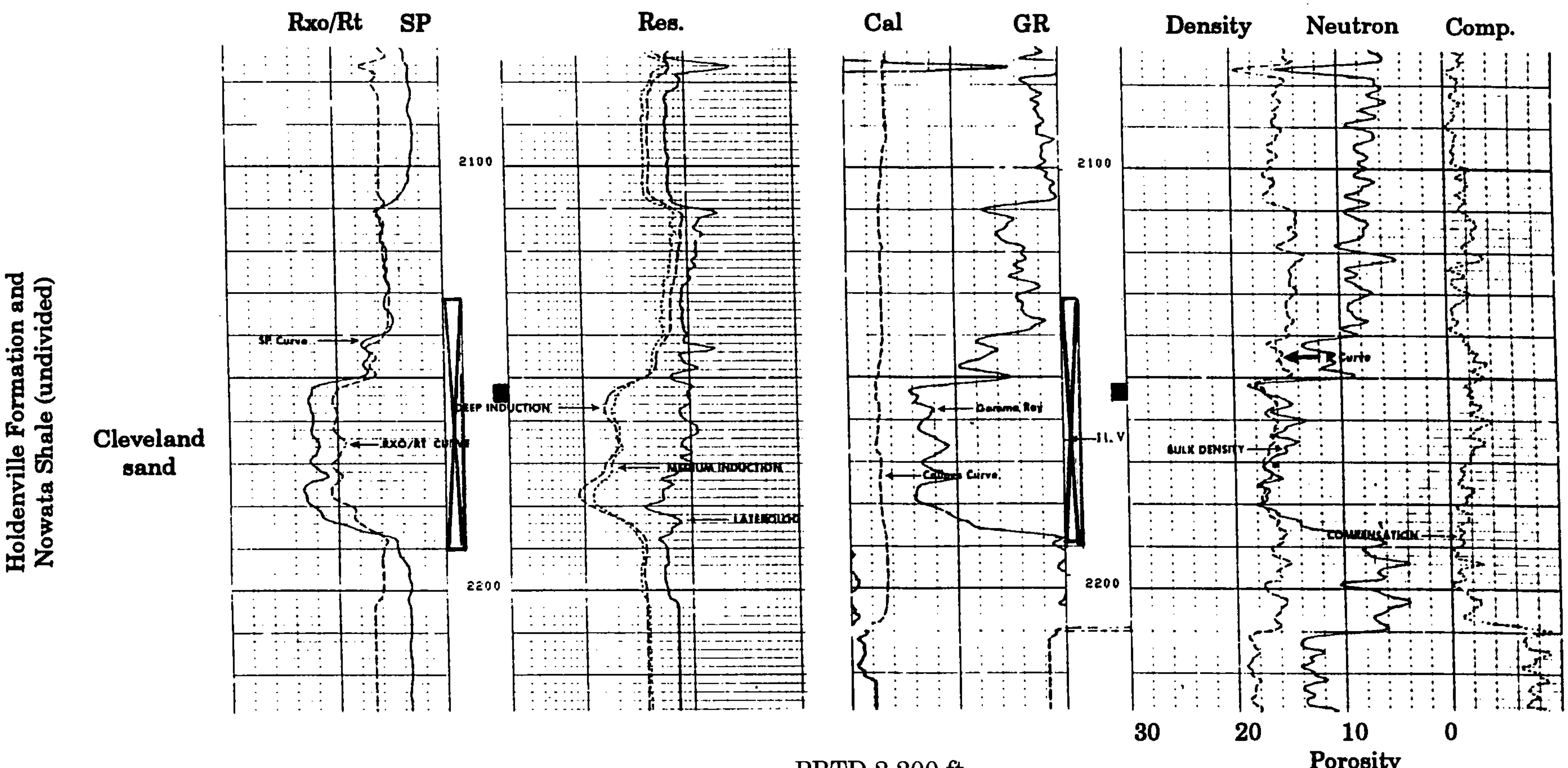
Missing core intervals sum to approximately 5 ft; all are 0.4 ft or less in thickness, and are not identified individually.

Core is approximately 10 ft low relative to gamma-ray log.

Fain-Porter Production Company
No. 1 Ripley
SW¼ SW¼ SW¼ sec. 3, T. 20 N., R. 7 E.
Pawnee County

TD 2,225 ft

Core: 2,131–2,190 ft; rec. approx. 54 ft



PBTD 2,200 ft
Completed: 9-11-78
Perforations: Cleveland, 2,151–2,155 ft
Treatment: Frac. 10,000 lb sand
and 10,000 gal gel water
IPP 17 BO, 170 BW (17 hrs)
Rate: 24 BOPD, 24 BWPD

Notes

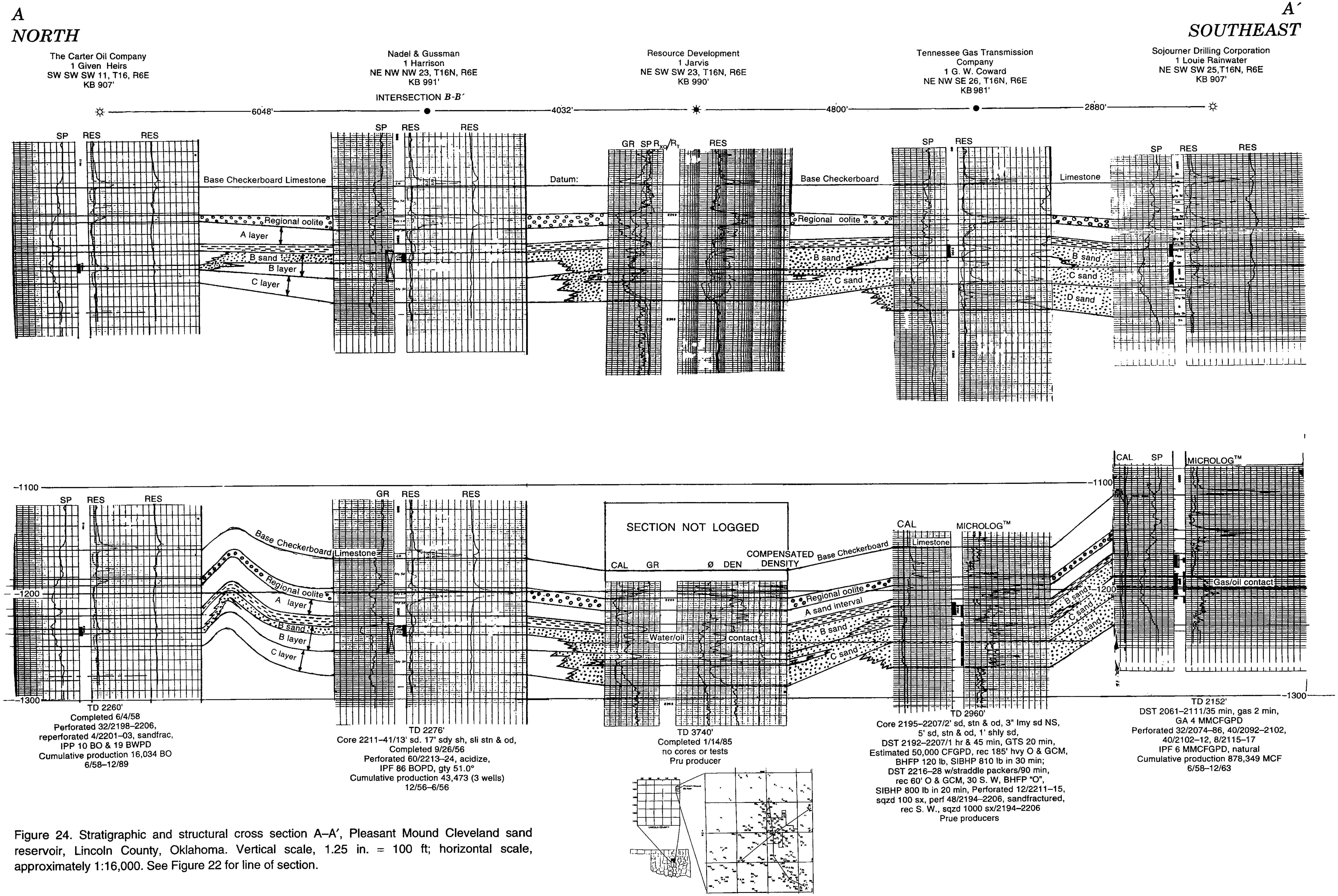


Figure 24. Stratigraphic and structural cross section A–A′, Pleasant Mound Cleveland sand reservoir, Lincoln County, Oklahoma. Vertical scale, 1.25 in. = 100 ft; horizontal scale, approximately 1:16,000. See Figure 22 for line of section.

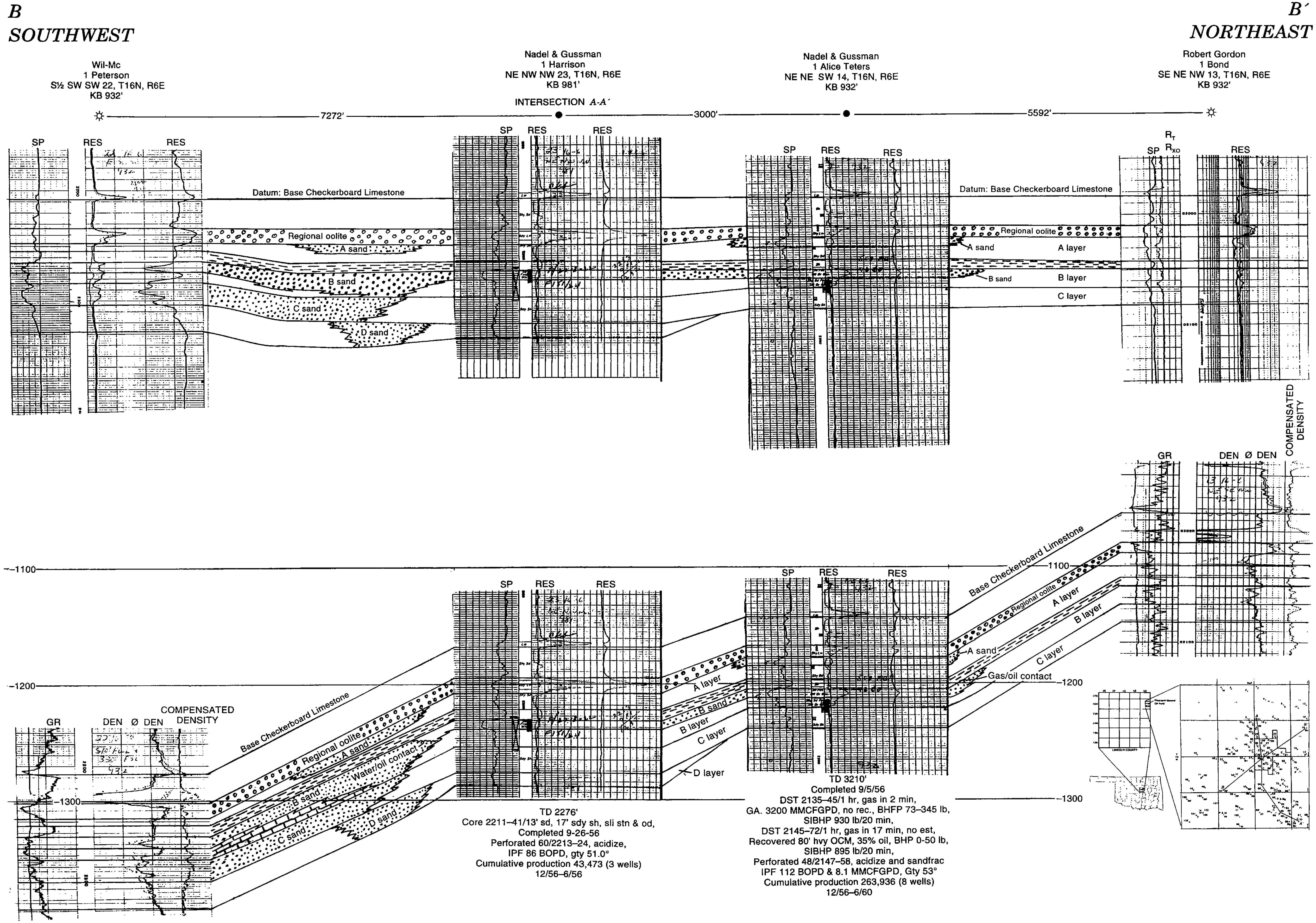


Figure 25. Structural and stratigraphic cross section B–B′, Pleasant Mound Cleveland sand reservoir, Lincoln County, Oklahoma. Vertical scale, 1.25 in. = 100 ft.; horizontal scale, approximately 1:16,000. See Figure 22 for line of section.

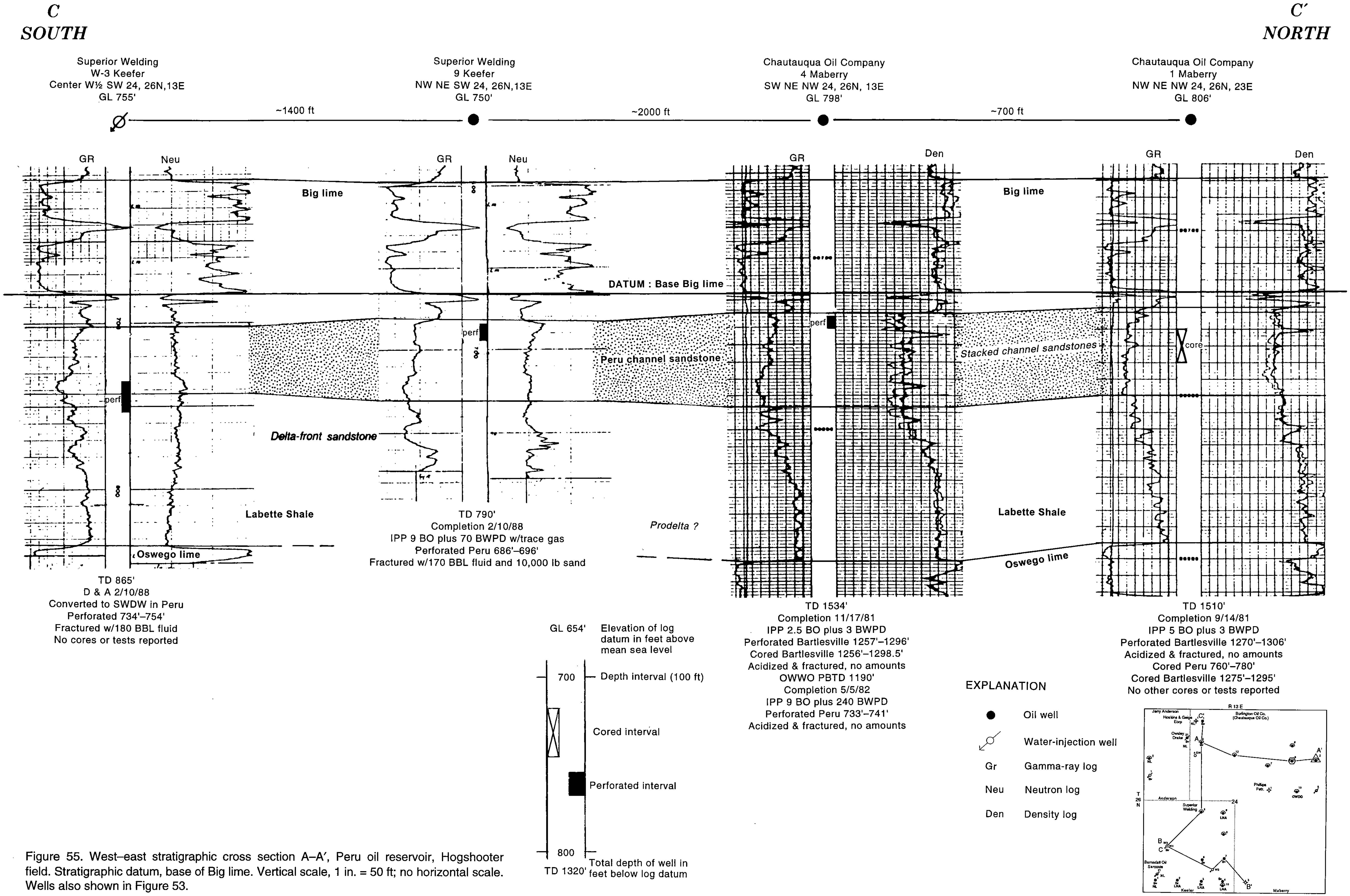


Figure 55. West–east stratigraphic cross section A–A′, Peru oil reservoir, Hogshooter field. Stratigraphic datum, base of Big lime. Vertical scale, 1 in. = 50 ft; no horizontal scale. Wells also shown in Figure 53.

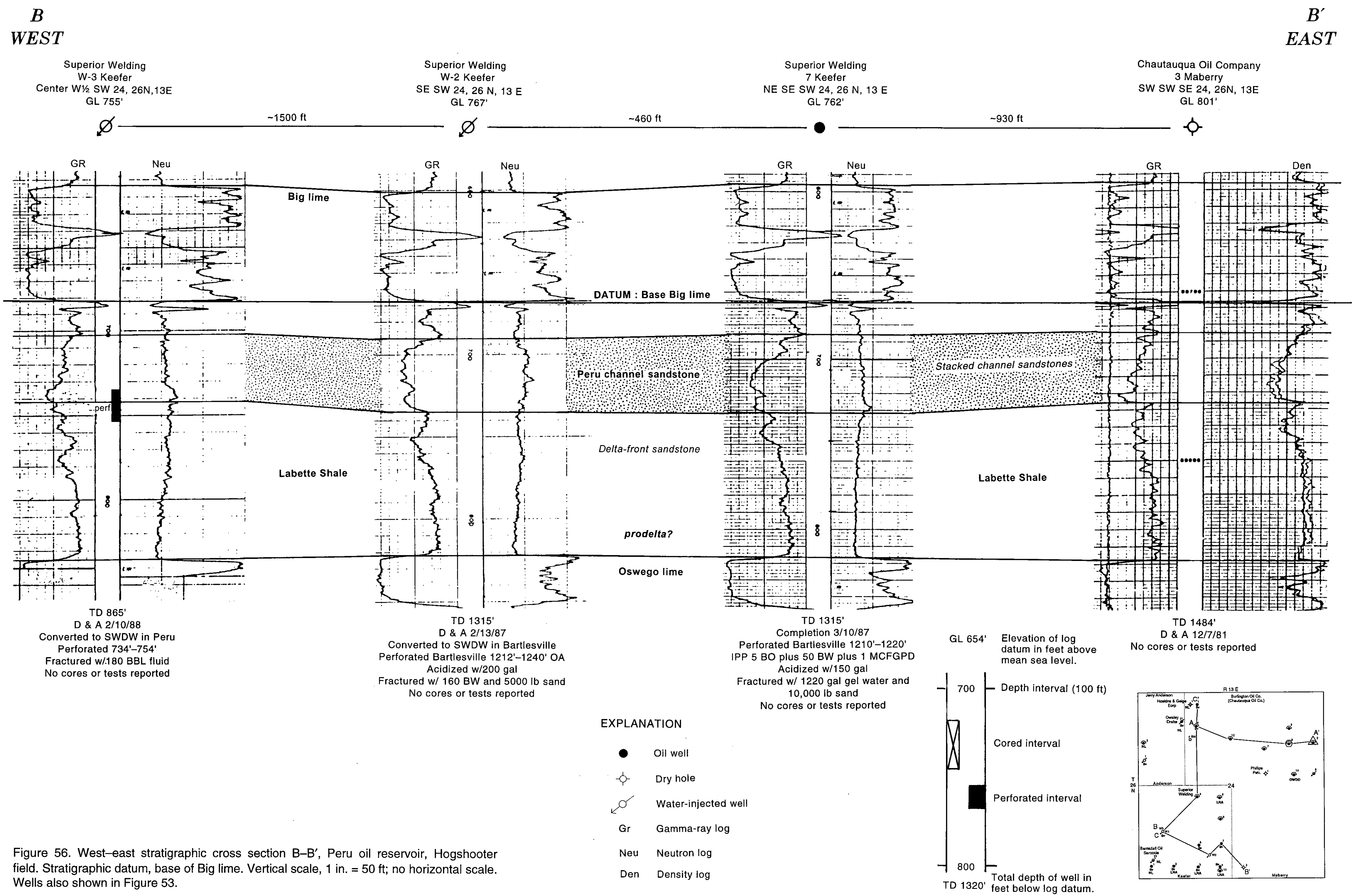


Figure 56. West–east stratigraphic cross section B–B′, Peru oil reservoir, Hogshooter field. Stratigraphic datum, base of Big lime. Vertical scale, 1 in. = 50 ft; no horizontal scale. Wells also shown in Figure 53.

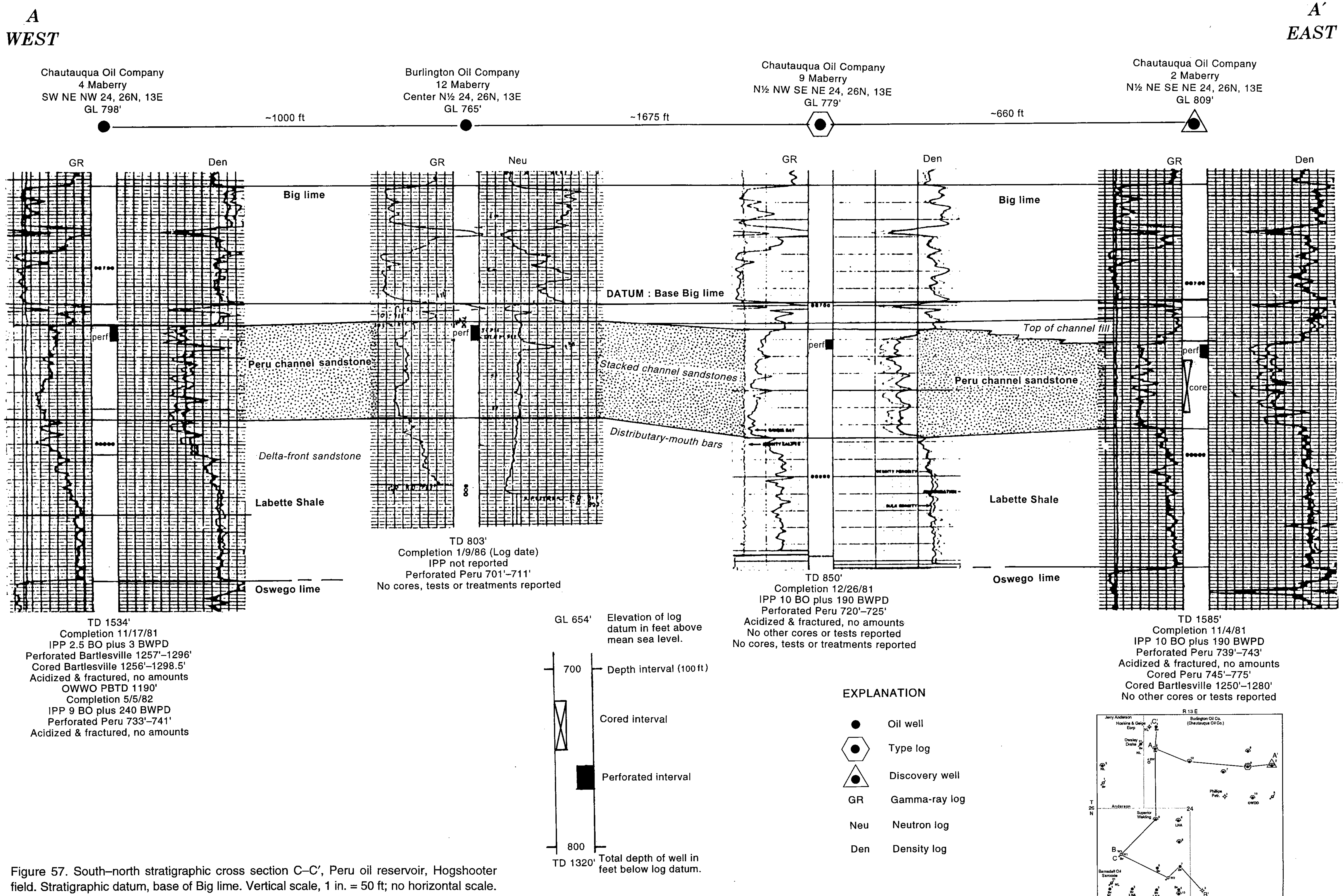


Figure 57. South–north stratigraphic cross section C–C′, Peru oil reservoir, Hogshooter field. Stratigraphic datum, base of Big lime. Vertical scale, 1 in. = 50 ft; no horizontal scale. Wells also shown in Figure 53.