Oklahoma
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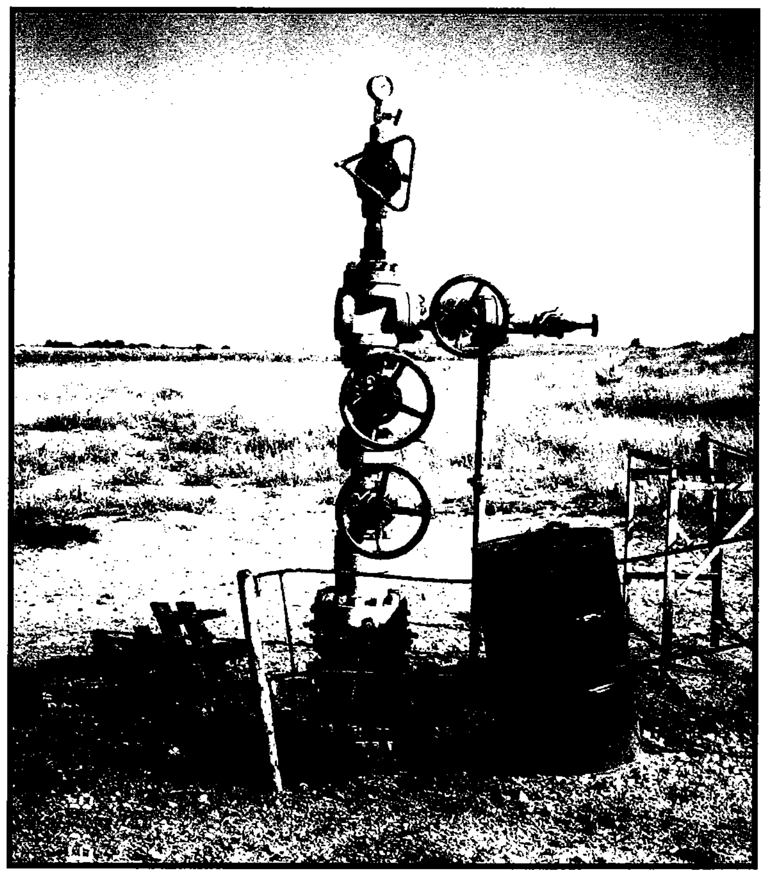
1999

Special Publication 99-4

Morrow Gas Play in the Anadarko Basin and Shelf of Oklahoma



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Oklahoma Geological Survey
and
Petroleum Technology Transfer Council

Oklahoma Geological Survey
Charles J. Mankin, *Director*

Special Publication 99-4
ISSN 0275-0929

Morrow Gas Play in the Anadarko Basin and Shelf of Oklahoma

PART I.—Morrow Gas Play in Western Oklahoma
by
Richard D. Andrews

PART II.—Milder Field
by
Richard D. Andrews

PART III.—Arapaho Field
by
Walter J. Hendrickson

PART IV.—Cheyenne West Field
by
Richard D. Andrews

Prepared for a one-day workshop, this volume is part of a continuing series that provides information and technical assistance to Oklahoma's oil and gas operators.

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The University of Oklahoma
Norman, Oklahoma
1999

SPECIAL PUBLICATION SERIES

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Front Cover

The Chain Ranch No. 26-1A well is located in eastern Dewey County just east of State Highway 3 in sec. 26, T. 18 N., R. 15 W. It was drilled by Brock Hydrocarbons Inc. in late 1981 and completed early the following year as an oil well producing from the lower Morrow (Primrose) sandstone. The Morrow was perforated between 9,402 and 9,448 ft and had initial production of 61 bbl oil (40° API gravity) and 125 MCF gas per day (GOR = 2,500). Although the Morrow is primarily know as a gas reservoir, the area in western Blaine and eastern Dewey Counties has a large proportion of Morrow wells completed as oil wells. Morrow sandstone in this general area was deposited mostly in fluvial and estuarine environments, and less commonly, in shallow marine delta-front environments. Cumulative production from this well as of April 1999 is 103,310 bbl oil and 221,870 MCF gas.

Photograph by Richard D. Andrews

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PART I

Morrow Gas Play in Western Oklahoma

Richard D. Andrews
Oklahoma Geological Survey

INTRODUCTION

This investigation is intended to be a companion to a study previously published by the Oklahoma Geological Survey—a fluvial-dominated-deltaic (FDD) study of the Morrow Formation (Andrews and others, 1995), which focused entirely on shallow Morrow sandstone reservoirs that were prone primarily to oil accumulation. The current study contains entirely new information and addresses Morrow sandstone reservoirs that are prone to gas accumulation in the deeper parts of the Anadarko basin and shelf. Morrow strata in these areas are characterized by shallow-marine delta-front and channel deposits. These environments are discussed in detail later. The general distribution of the major producing sandstone/conglomerate trends in the Morrow Formation is shown on Plate 1.

The Morrow Formation was first named in 1904 by Adams and Ulrich (USGS Professional Paper 24, p. 109) for the village of Morrow, Washington County, Arkansas (Jordan, 1957, p. 137). Morrow strata were first described about 25 mi southwest of Fayetteville, only a few miles east of the Oklahoma state line. The same strata are mapped in the Marble City–Tenkiller area in northern Sequoyah County and southeastern Cherokee County of northeast Oklahoma by Miser (1954). These sediments are eroded to the north but dip into the subsurface to the south. Equivalent rocks stratigraphically occur in the Arkoma basin of southeastern Oklahoma, where they are called the Cromwell sandstone. Morrow strata are discontinuous for an unknown distance west of the outcrop but reappear in the subsurface in western Oklahoma, where this study focuses. Within western Oklahoma, the Morrow is discontinuous to the east and northeast toward the Nemaha fault zone and thickens continuously to 4,000 to ~5,000 ft to the south at the base of the Wichita uplift but where it does not crop out. Therefore, nothing can be learned about this important gas- and oil-bearing formation from surface exposures, although numerous cores are available for study and interpretation. Five of these cores are described and selected visual images are shown in Appendix 4 of this publication.

The prominence of the Morrow play has always been due to the relatively large reserve base of fields and moderate drilling depths. Although extremely prolific gas production does occur in the very deep Anadarko basin, most Morrow production comes from wells shallower than about 12,000–13,000 ft. Morrow production in the extensive and prolific Mocane–Laverne field in northwestern Oklahoma and the Panhandle come from depths generally less than 8,000 ft. The Morrow Formation, regardless of facies, is primarily a gas reservoir, although significant amounts of oil and condensate are also produced. Figure 1 shows gas and oil production over the past 20 years from well completions in only the Morrow reservoir. This plot shows production declines of gas and oil from ~384 BCF and 7.2 MMBO in 1979 to present-day rates of ~183 BCF and 3.1 MMBO. Figure 2 shows gas and oil production from wells having Morrow production commingled with production from other reservoirs. A significant amount of this production is probably attributed to the Morrow. From Figures 1 and 2, it can be estimated that at least 7 TCF of gas has been produced from the Morrow during the last 20 years. Production data are given in Table 1. Many Morrow fields have been fully developed on increased-density drilling and location exceptions, while many other fields have significant development potential. A listing of Morrow fields is given in Appendix 5, which shows important reservoir and production information that can be used to characterize Morrow reservoirs throughout the Anadarko basin.

The Morrow Formation was a common objective in the early history of drilling in the Anadarko basin and shelf areas during the 1950s and early 1960s. During this time, high-volume gas wells were being discovered in the shallower Mocane–Laverne gas field in Beaver and Harper Counties of northwestern Oklahoma and the Panhandle. Production rapidly progressed into the deeper part of the basin to the south and southeast; the extensive Morrow–Springer high-pressure-gas-producing area was developed during the 1960s and 1970s in the Watonga–Chickasha trend. The Morrow FDD oil area in the Canton area was developed during the mid- to late 1970s. Primarily during the mid- to late 1970s and the 1980s, Morrow exploration activity was delineating the unusual upper Morrow chert-conglomerate fan-delta facies in the deepest part of the Anadarko basin north of the Wichita frontal fault zone. The over-

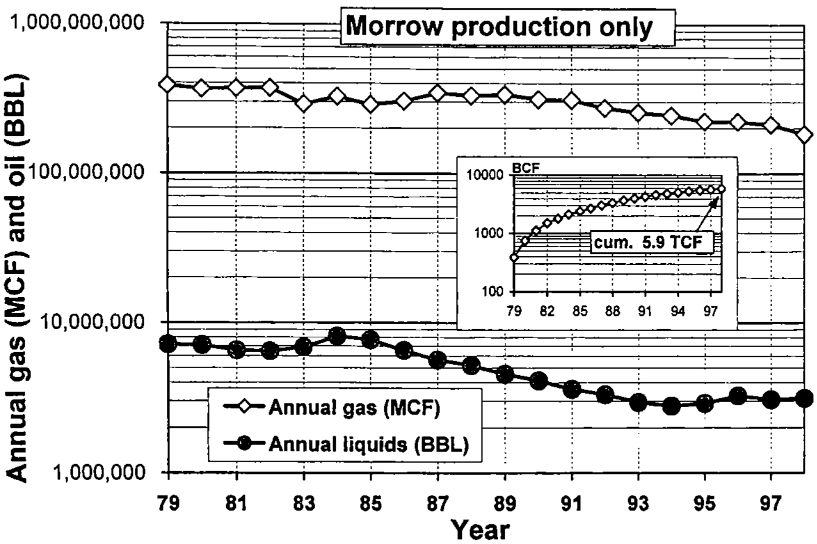


Figure 1. Annual gas and oil production from the Morrow Formation. Data from Natural Resources and Information System (NRIS), developed at the University of Oklahoma; data are current through 1998.

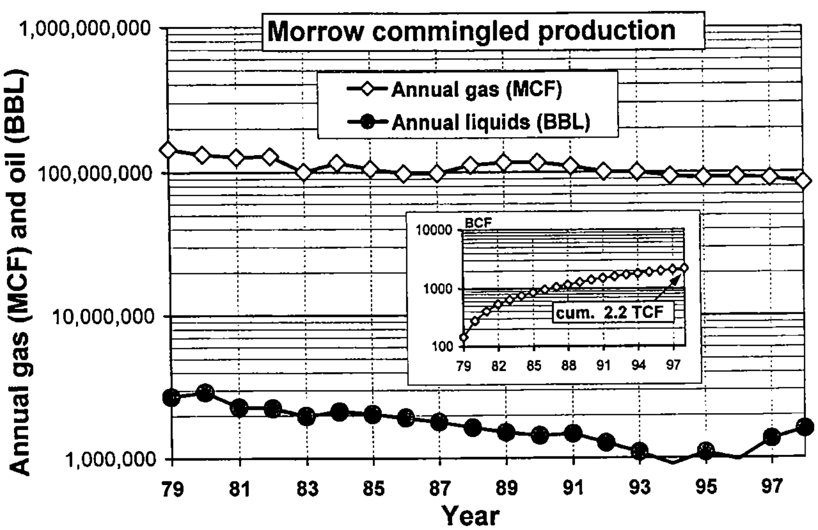


Figure 2. Annual gas and oil production from the Morrow Formation commingled with other reservoirs. Data from NRIS, current through 1998.

all Morrow drilling activity is plotted in Figure 3 and clearly shows the rapid rise and fall of Morrow completions during the past four decades.

However, the Morrow Formation is still highly prospective for gas and oil exploration and development, as Morrow sandstone bodies with excellent hydrocarbon potential are continually being found. This is illustrated in Figure 4, which shows the average ultimate recovery by date for Morrow wells and indicates that some current completions still have ultimate cumulative gas reserves of 2–4 BCF; even a 1-BCF well in some parts of the basin would be a good well. Another interesting representation of the current Morrow gas-production trend is shown in Figure 5, which is a plot relating pressure decline to date of first production. The vertical axis is MCF/psi, which is the total amount of gas from the date of first production divided by the pressure drawdown during the producing period. This figure shows a dramatic drop in production per psi during the 1970s, but surprisingly, the trend was reversed during the 1980s and 1990s.

Figure 6 is another plot illustrating pressure decline/psi versus ultimate recovery. In this plot, the Morrow has been divided into three zones, each having a general log-normal production distribution. One way to interpret this plot is to select an ultimate recovery—say, 1 BCF—and consider it to be applicable to all three Morrow zones. Tracing vertically along this axis, the first producing trend is the upper Morrow (gray triangles), corresponding to a value of ~100 MCF/psi; then the Primrose sands (black circles) of the basal lower Morrow, corresponding to a value of ~300 MCF/psi; and then the other lower Morrow sands (gray circles), corresponding to a value of ~600 MCF/psi. This means that for equivalent reserves, the upper Morrow has the greatest pressure drawdown (lowest MCF/psi) and that overall, the lower Morrow has the least amount of pressure drawdown, with the Primrose scattered between these two ranges. To some extent, these values are affected by reservoir depth and, therefore, permeability. The distribution of wells producing from these three zones is shown in the production-code map of Plate 2 (in envelope) and can be related to the regional structure of the Morrow on Plate 3 (in envelope).

Using these two regional plates can enable the reader to envision the depth relationship of the three Morrow reservoirs—namely, that production in the upper Morrow tends to be deeper than Primrose, and that Primrose production tends to be deeper than lower Morrow production.

Sandstone is the primary reservoir in the Morrow Formation, although some production is attributed to the "Squaw Belly," a limy interval in the middle part of the formation. Production is attributed to a variety of facies originating from many different depositional environments, both marine and nonmarine, which are discussed later in the text. Much oil has been produced from the shallower FDD facies of the upper Morrow in the Oklahoma Panhandle and of the lower Morrow in the Canton area. Elsewhere, production is primarily

TABLE 1. – Morrow and Commingled Morrow Production 1979–1998

Year	Annual liquids (BBL)	Cum liquids (BBL)	Annual gas (MCF)	Cum gas (MCF)
		Morrow production only		
1979	7,163,993	7,163,993	383,993,748	383,993,748
1980	7,089,886	14,253,879	363,623,682	747,617,430
1981	6,544,891	20,798,770	367,758,625	1,115,376,055
1982	6,447,268	27,246,038	369,618,838	1,484,994,893
1983	6,856,035	34,102,073	289,455,489	1,774,450,382
1984	8,111,605	42,213,678	326,299,689	2,100,750,071
1985	7,694,853	49,908,531	286,975,316	2,387,725,387
1986	6,530,066	56,438,597	303,070,023	2,690,795,410
1987	5,645,031	62,083,628	344,240,320	3,035,035,730
1988	5,197,191	67,280,819	330,417,983	3,365,453,713
1989	4,535,770	71,816,589	335,094,387	3,700,548,100
1990	4,119,298	75,935,887	312,222,928	4,012,771,028
1991	3,602,420	79,538,307	307,732,133	4,320,503,161
1992	3,324,863	82,863,170	273,193,934	4,593,697,095
1993	2,947,448	85,810,618	255,118,575	4,848,815,670
1994	2,780,875	88,591,493	242,930,176	5,091,745,846
1995	2,901,658	91,493,151	222,199,967	5,313,945,813
1996	3,254,237	94,747,388	220,989,780	5,534,935,593
1997	3,066,292	97,813,680	211,420,303	5,746,355,896
1998	3,125,633	100,939,313	182,507,999	5,928,863,895
		Commingled Morrow production		
1979	2,699,164	2,699,164	144,504,098	144,504,098
1980	2,907,649	5,606,813	132,694,876	277,198,974
1981	2,275,515	7,882,328	127,409,543	404,608,517
1982	2,238,449	10,120,777	129,178,696	533,787,213
1983	1,978,819	12,099,596	100,168,744	633,955,957
1984	2,125,210	14,224,806	115,747,474	749,703,431
1985	2,039,767	16,264,573	105,153,857	854,857,288
1986	1,921,542	18,186,115	97,552,163	952,409,451
1987	1,801,675	19,987,790	97,996,803	1,050,406,254
1988	1,643,352	21,631,142	111,724,163	1,162,130,417
1989	1,516,479	23,147,621	116,088,956	1,278,219,373
1990	1,437,271	24,584,892	116,436,674	1,394,656,047
1991	1,481,301	26,066,193	109,407,814	1,504,063,861
1992	1,274,374	27,340,567	100,085,757	1,604,149,618
1993	1,095,284	28,435,851	99,899,166	1,704,048,784
1994	906,583	29,342,434	93,528,494	1,797,577,278
1995	1,090,931	30,433,365	91,285,730	1,888,863,008
1996	973,492	31,406,857	93,261,384	1,982,124,392
1997	1,360,671	32,767,528	90,630,128	2,072,754,520
1998	1,594,933	34,362,461	83,946,859	2,156,701,379

gas with varying amounts of condensate. There is very little coal within the Morrow, although some has been recorded in association with the upper Morrow FDD facies in the Oklahoma Panhandle.

Regional changes in sea level and possibly local structural provinces affected the pattern of deposition in the Morrow Formation. Most sandstone accumulations appear to occur in northwest–southeast trends, although, upon closer examination of specific facies, many of the sandstone trends are at right angles to these trends and are oriented northeast–southwest. Identification of these facies from well logs usually reveals some sort of channel environment cutting across the otherwise predominant northwest sandstone trends. Detailed geological studies in Arapaho and Milder fields of this publication identified these patterns of deposition.

SEDIMENT-SOURCE AREAS (PROVENANCE)

Upper Morrow

The detrital-source areas for Morrow sandstones varied, depending on the tectonic evolution of bordering geologic provinces. The upper Morrow arkosic sandstone of the Oklahoma Panhandle and western Ellis County occurs largely in channel deposits that had their source to the northwest. Swanson (1979) discusses the provenance of these sediments in detail and believes that most of the upper Morrow coarse-grained material originated from northern Colorado and western Nebraska (Frontrangia–Siouxia), with a smaller component of detrital material coming from the Sierra Grande uplift of northeastern New Mexico and southeastern Colorado. The fine-grained marine deposits composing most of the upper Morrow in the southeastern part of the Anadarko basin in Custer, Washita, and Caddo Counties (Pl. 1) probably were deposited in a shallow-marine shelf environment. These sediments are not believed to be distal or basinward marine facies of the arkosic sedimentation previously mentioned. Additionally, no clear "trail" of sediment transport is recognized in the subsurface, because a fluvial facies in this sandstone sequence is not often discernible. It is likely that some of the major incised channel systems recognized in the lower Morrow (see following discussion) also contributed sediment to a marine environment during late (upper) Morrow time. The marine bars now recognized, then, may be the result of sandstone redistribution by marine energy in the form of tidal and longshore currents.

The upper Morrow chert-conglomerate sequences in the deepest part of the Anadarko basin in Roger Mills

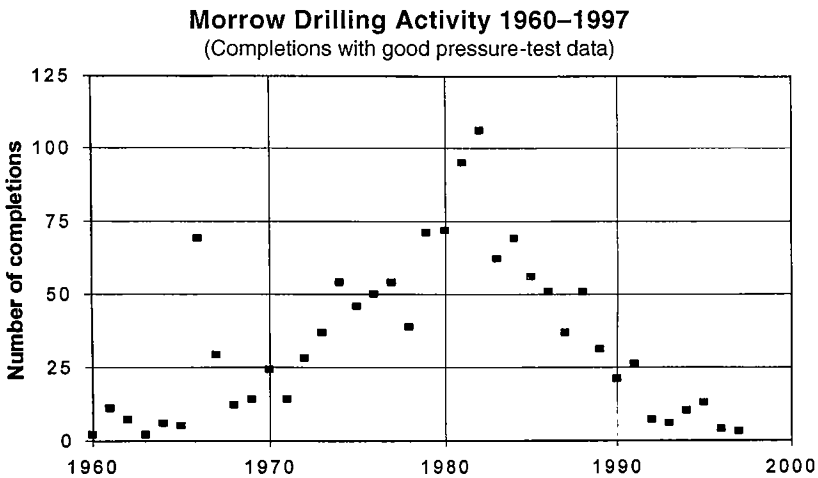


Figure 3. Morrow drilling activity from 1960 through 1997. From IHS Energy Group (1999).

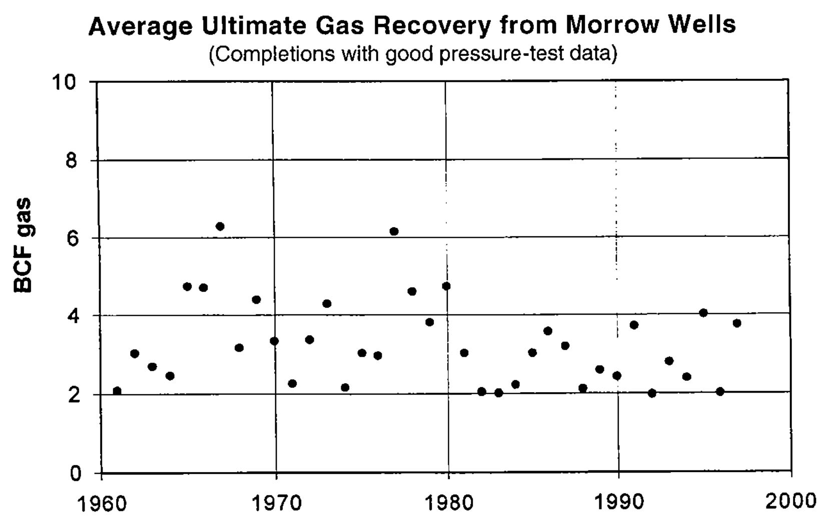


Figure 4. Average ultimate recovery of gas from Morrow wells having good pressure-test data, 1960 through 1997. From IHS Energy Group (1999).

and northern Beckham Counties had a direct source from the rising Wichita Mountains to the south. These coarse-grained-sandstone and chert-pebble-conglomerate sequences were deposited in a mountain-front fan-delta system and are distinct from the upper Morrow sediments previously described.

Lower Morrow

Detrital sediments composing the lower Morrow interval, including the Primrose sandstone sequence, appear to have originated from areas to the north and northeast (Central Kansas uplift), because specific corridors of sediment influx can be identified in the subsurface in the form of incised channels that trend in this direction. Additionally, distinctive progradational sequences can be identified in the subsurface that extend basinward to the south and southwest. The most important sediment corridors are the Woodward "trench," which extends northward from central Woodward and eastern Harper Counties. A parallel channel complex lies several miles to the west, as shown on Plate 1 and in regional cross section C–C′ (Pl. 6, well 2). An additional influx area for lower Morrow sediment lies in the Canton "embayment" area in eastern Dewey and western Blaine Counties. Arrows of depositional-transport direction (Pl. 1) show these sediment corridors. In a basinward direction, the environment of deposition appears to change from subaerial fluvial (flood plain) to estuarine–deltaic to delta-front marine. Well logs on regional cross sections illustrate this transition of environments to the south and southwest and are discussed in the section entitled "Regional Cross Sections."

STRATIGRAPHY

Morrow sediments are Early Pennsylvanian in age, and because they are not exposed in western Oklahoma, they have not been formally divided or named for that region. However, numerous informal subsurface names have been adopted by the geological community based upon well-log attributes or producing leases where significant hydrocarbon production was originally established. This nomenclature is shown in Figure 7. The Morrow Formation is almost always bounded unconformably by the overlying Thirteen Finger limestone of the Atoka Formation and by the underlying Springer Formation. The Springer–Morrow contact is also regarded to be unconformable regionally; therefore, the contact may be underlain by any one of the many informal units of the Springer as shown in the stratigraphic-nomenclature chart. In isolated areas along the subcrop belt, because of the unconformable relationship, the Morrow even may be underlain by the Mississippian Chester limestone or overlain by the middle Cherokee Inola Limestone (Smith, 1996). At many places, Morrow sands were deposited in deeply incised channels, the basal contacts of which cut into older Morrow strata but generally not into the underlying Springer Formation.

In this report, the Morrow Formation is divided into an upper and lower unit (Fig. 7). The division between the upper and lower Morrow is picked at the top of a series of regionally extensive limestone beds and/or limy sediments in the middle part of the formation that is called the "*Squaw Belly*." Above these strata, the upper Morrow is dominated by a thick (marine?) shale section. Most of the sandstone reservoirs in the upper Morrow occur above this thick shale sequence in the upper part of the upper Morrow, and their names are included in the stratigraphic chart (Fig. 7). The lower Morrow interval is usually dominated by sandstone comprising one or more separate sequences. Various informal names have also been used by industry; sometimes the nomenclature may simply be the A, B, C, etc., sands. One prominent Morrow sandstone stands out above the rest on a regional scale and is called the *Primrose*, the basal lower Morrow sandstone in the Anadarko basin. The Primrose is actually composed of one or more sandstone zones that thicken to the south in a basinward direction. It is differentiated in this report from other sandstones above it within the lower Morrow interval in that these other sandstones are simply referred to as "lower Morrow" sandstone (exclusive of the Primrose). To clarify the stratigraphic nomenclature used in this publication, then, the lower Morrow interval, in descending order, consists of the "Squaw Belly," the lower Morrow sandstone, and the Primrose sandstone.

The Morrow–Springer contact and age determination have always been a controversial topic. On well logs, this contact is usually picked from conductivity logs where there is a sharp *increase* in conductivity (a sharp *decrease* in resistivity) in the Springer shale. The Morrow–Springer contact is also commonly regarded as the Pennsylvanian–Mississippian boundary, but this assumption may not everywhere be the case, as shown in Figure 7. Peace (1989) reported the results of a core research study by Dr. Leonard R. Wilson, Professor Emeritus at the University of Oklahoma. The research was initiated to determine the position of the Mississippian–Pennsylvanian boundary on the basis of palynological evidence. A continuous core from 13,736 to 14,103 ft was recovered from the Apexco No. 1-A Buell well, which straddles the Springer–Morrow Formation boundary as picked from wireline logs (Fig. 8). The conductivity-log inflection point defining the boundary was picked at ~13,833 ft by Peace (1989), but an alternative pick by this author indicates the possible boundary to be 44 ft lower at ~13,877 ft. Ten samples were taken, as shown on the well log (Fig. 8), to determine whether or not the biostratigraphic Mississippian–Pennsylvanian systemic boundary closely coincides with the lithostratigraphic Springer–Morrow boundary. Peace (1989) indicated that Dr. Wilson determined that the overall palynomorph assemblage in the Buell core was more diagnostic of a Morrowan flora than a Chesterian one. This interpretation was highly influenced by the absence of diagnostic Mississippian microflora, although they may have been destroyed owing to the high degree of thermal maturity of the samples. Nevertheless, Peace concludes that the palynological systemic boundary in that part of the Anadarko basin where the Buell well was drilled is possibly not coincident with the lithostratigraphic top of the Springer.

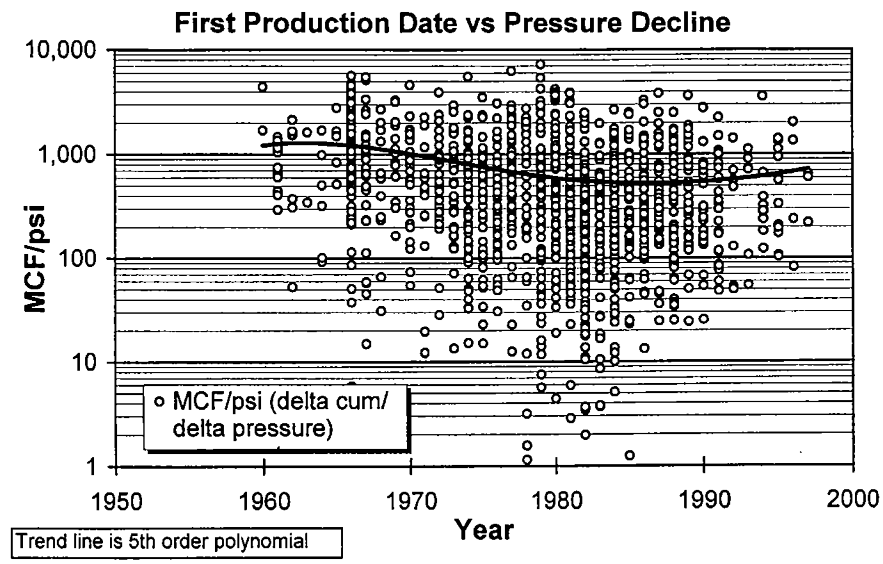


Figure 5. Plot showing Morrow first production date versus pressure decline. From IHS Energy Group (1999).

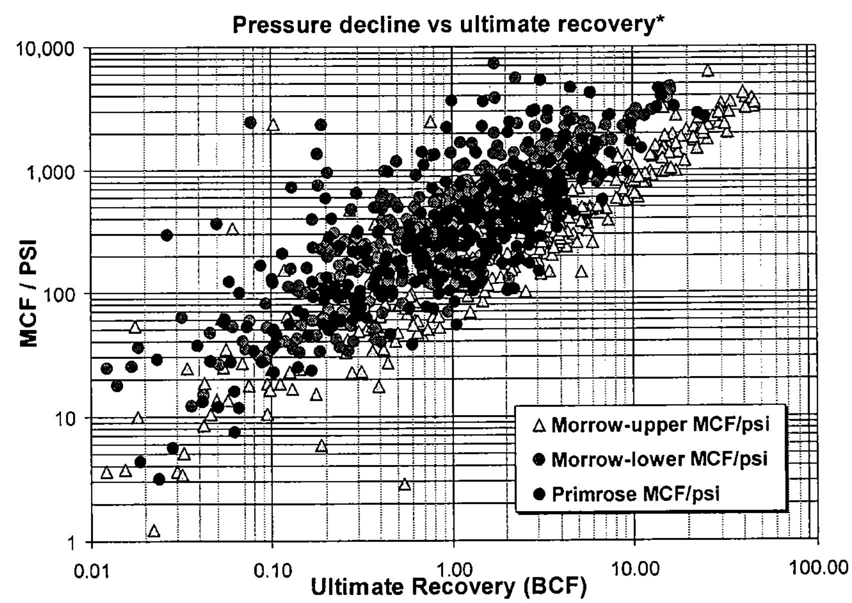


Figure 6. Plot showing Morrow pressure decline versus ultimate recovery. From IHS Energy Group (1999). See text for further explanation.

SYSTEM	SERIES	GROUP	FORMAL SURFACE NAMES (FORMATION)	INFORMAL SUBSURFACE NAMES	
PENNSYLVANIAN	Atokan	Atoka	Atoka (surface name where exposed in eastern Oklahoma)	"Granite wash"	Thirteen Finger lime
PENNSYLVANIAN	Morrowan	Morrow	Morrow (surface name where exposed in Arkansas) Kearny Formation (subsurface name used in Kansas)	Upper Morrow	Purvis, Puryear, Pierce, Bradstreet } Deep–basin chert conglomerates A, B, C, D, etc., sands
					"Squaw Belly" (limy sediments and limestone, sometimes called middle Morrow)
			Cromwell Sandstone of the Union Valley Formation in the Arkoma basin	Lower Morrow	Lower Morrow sands Mocane–Laverne sands A, B, C, D, etc., sands Primrose sands
MISSISSIPPIAN	Chesterian	Springer(?)	Springer (surface name where exposed in Carter co., south-central Oklahoma) Goddard (shale)		Cunningham sand Britt sand Britt carbonate Boatwright sand Boatwright carbonate Rod Club sand (southeast basin) Caney shale
		Chester	Pitkin Limestone (surface name where exposed in eastern Oklahoma) Fayetteville Shale Hindsville Limestone		Chester

Figure 7. Stratigraphic-nomenclature chart of the Morrow Formation in the Anadarko basin and northwestern Oklahoma. Modified from Jordan (1957) and Johnson (1989).

Although many studies were written about the Morrow Formation (see list of selected references), only a handful of contemporaneous studies were published or completed for academic requirements that accurately delineate spatially extensive subsurface mapping, facies recognition, and petrologic characterization of the Morrow Formation and its reservoir sandstones. Some significant investigations include (alphabetically listed) work by Al-Shaieb, Puckette, Ely, and Abdalla (1993) on upper Morrow fan-delta deposits; Al-Shaieb and Walker (1986) on evolution of secondary porosity in Morrow sandstones; Bentkowski (1985) on subsurface mapping and petrology of the Morrow in eastern Dewey County; Godard (1981) on subsurface mapping and petrology of the Morrow in Major and Woodward Counties; Harrison (1990) on subsurface mapping and petrology of the upper Morrow arkosic sandstone in Texas and Cimarron Counties; Hendrickson, Smith, Williams, and Woods (IHS Energy Group, 1997) on reallocation of production and correlation of the Morrow and Springer reservoirs; South (1983) on subsurface mapping and petrology of the Morrow in Blaine and Dewey Counties; and Walker (1986) in a regional study of the diagenetic and geochemical character of the Morrow.

TYPES OF SANDSTONE AND DETRITAL DEPOSITS

There are many specific classifications of sandstone in the Morrow Formation, but in general only about four main types characterize producing reservoirs. Numerous varieties of each rock type listed in this publication do occur, but they are simply specific classifications based upon a highly restrictive percentage of framework constituents (quartz, skeletal grains, rock or lithic fragments) and matrix composition. The main rock types in the Morrow Formation as determined by this study are as follows.

1. **Arenaceous sandstone** (quartz-rich), with minor lithic and/or skeletal fragments including "wacke" or dirty clay-rich sandstone, is the most common type of sandstone in the Morrow Formation. Framework constituents of these types of sandstone typically include ~85% quartz and smaller amounts of skeletal grains and rock fragments (Walker, 1986). Clastic grain size is usually fine, but some rocks are medium to coarse grained. Cementation in the high-quartz sandstones is usually dominated by quartz overgrowths and less commonly by authigenic carbonate cement. Matrix constituents usually include various amounts of clays in the form of illite, chlorite, and/or altered glauconite (Walker, 1986). These types of sandstone chiefly characterize the lower Morrow reservoirs, including the Primrose. Facies may include very clean, well-sorted channel sandstone or marine delta-front or shelf-bar

sandstone. Most marine sandstone facies (excluding the arkosic and chert sandstone/conglomerate facies) of the upper Morrow are also of this composition. This type of sandstone is described in all the cores of Appendix 4.

2. **Chert conglomerate** occurs only in the upper Morrow in the deep Anadarko basin. This lithology is discussed in the accompanying detailed geological study of the Puryear reservoir in Cheyenne West field (Part IV of this publication). It occurs in the basal zone of channel-sandstone sequences and in tabular beds of braided-channel sediments deposited in a fan delta plain. These types of deposits are unusual because of the conspicuous subangular chert clasts that commonly weather white. Their distribution is limited spatially to the southern part of the Anadarko basin of Roger Mills and northern Beckham Counties, adjacent to the Wichita uplift. On the basis of two samples analyzed by Alberta (1987), the chert-conglomerate and sandstone sequence is composed largely of medium- to coarse-grained quartz (<10% to 62%) and a large percentage of subangular chert fragments ranging in size from coarse grained to pebble and constituting <10% to at least 75% of the framework constituents. Feldspar fragments are also common, composing 5–15% of some rocks. An example of this rock type is described in Appendix 4 (Apache No. 2-31 Simmons well).

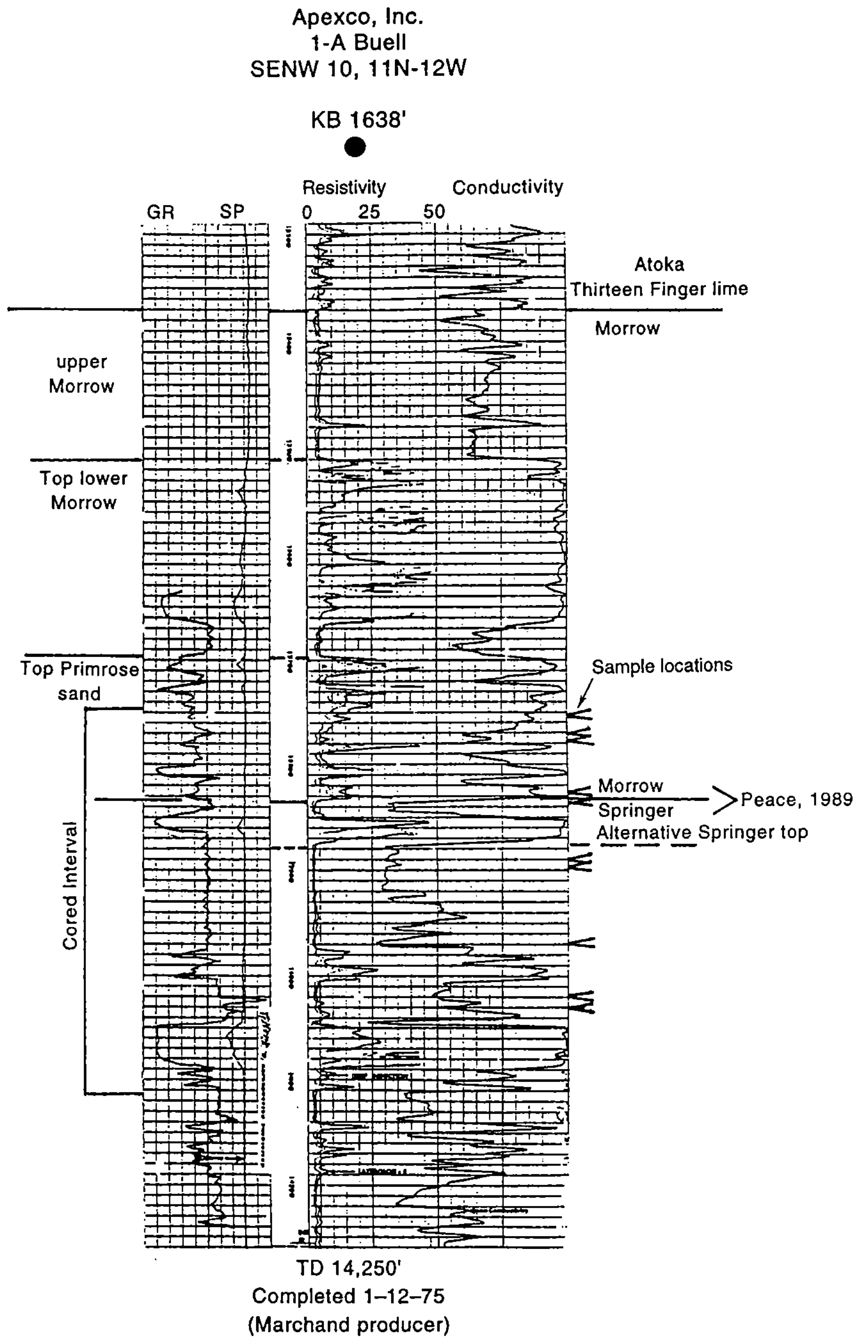


Figure 8. Cored interval and sample locations used to interpret Morrow–Springer contact in the Apexco No. 1-A Buell well. Modified from Peace (1989). *GR* = gamma ray; *SP* = spontaneous potential.

3. **Skeletal and lithic-pebble conglomerates** are commonly found throughout the Morrow play, primarily in the lower Morrow interval. Concentrations of specific detrital constituents have implications as to depositional origin. High concentrations of skeletal detrital material are usually indicative of marginal-marine environments such as tidal channels or estuarine environments. Skeletal material is commonly accompanied by lithic (rock) fragments, according to South (1983). Lithic pebble conglomerates commonly occur in terrestrial–deltaic channel environments and form layers in fluvial deposits otherwise composed of quartz-rich (arenaceous) sandstone. This type of lithology is described in Appendix 4 (Texas Pacific No. 4 Tidball well and Ladd Petroleum No. 5 Wills "A" well).

4. **Arkosic sandstone and conglomerate** constitute the predominant rock type in the FDD upper Morrow reservoirs of the shallow Anadarko shelf areas in the Oklahoma and Texas Panhandles. This lithology is prone to oil accumulation and is the main topic of discussion in the Morrow FDD reservoir series included in Oklahoma Geological Survey Special Publication 95-1 (Andrews and others, 1995). These rocks are mapped as upper Morrow sandstone in western Beaver County in this publication (Pl. 1) but are otherwise not discussed in this text (see SP 95-1 for additional information on these reservoirs). A core description of this rock type is provided in Appendix 4 (the Buzzard well) of this publication.

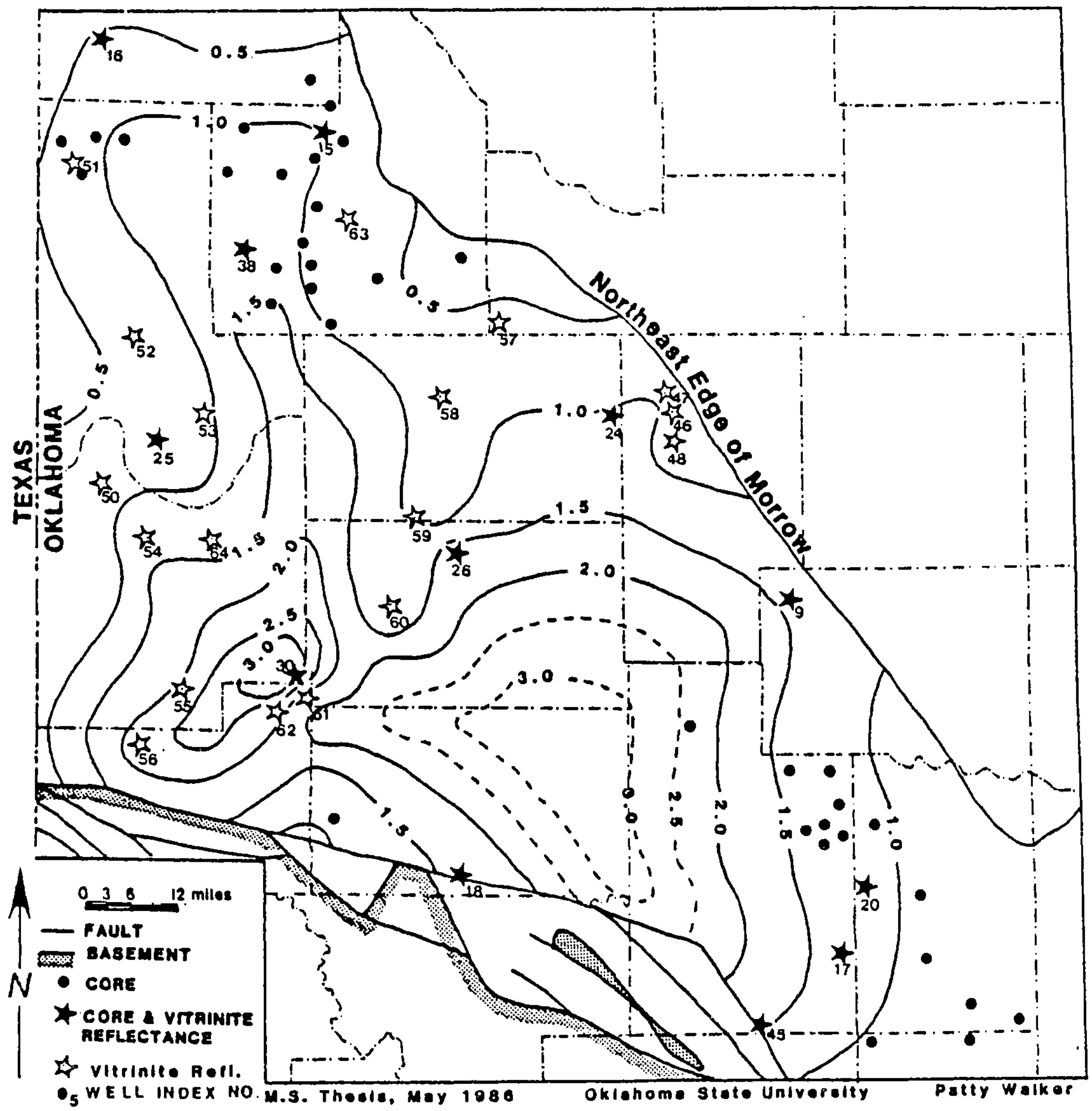


Figure 9. Map showing distribution of percentage of vitrinite reflectance of Morrow sediments in the Anadarko basin. Contour interval is 0.5% R_o. R_o is vitrinite reflectance measured in oil. Modified from Walker (1986).

5. **Skeletal grainstone/packstone (bioclastic limestone)** is a common component of most tidal-flat and/or lower delta-plain environments. This lithology is routinely seen in Morrow cores, as described in Appendix 4 (Texas Pacific No. 4 Tidball well and Ladd Petroleum No. 5 Wills "A" well). Although volumetrically insignificant, these rock types provide important clues to the depositional environment of other important hydrocarbon reservoirs previously described so that they can be mapped more accurately.

CHEMICAL PARAMETERS AND AUTHIGENIC CONSTITUENTS

Some of the most widely available and comprehensive information regarding chemical parameters and authigenic constituents of the Morrow Formation is included in two theses by Tsiris (1983) and Walker (1986). The following discussion is supported entirely by work of these two authors.

Although there can be no doubt about the thermal maturity of Morrow sediments in the Anadarko basin with regard to hydrocarbon generation, a knowledge of the degree of maturation on a regional scale is important to understand occurrences of oil, gas, and condensate throughout the basin. Figure 9 is a contour map showing the percentage of vitrinite reflectance, using a 0.5-R_o contour interval. Vitrinite is commonly expressed by reflectance in *oil*; thus, the units are expressed as R_o values. As expected, the highest R_o values are in the deepest part of the Anadarko basin, where they exceed 2.5% R_o. These high values of R_o are generally a function of depth, and on a log-normal scale this information plots as a straight line, as shown in Figure 10. These data can then be used to interpret the general distribution of hydrocarbon zones in the Anadarko ba-

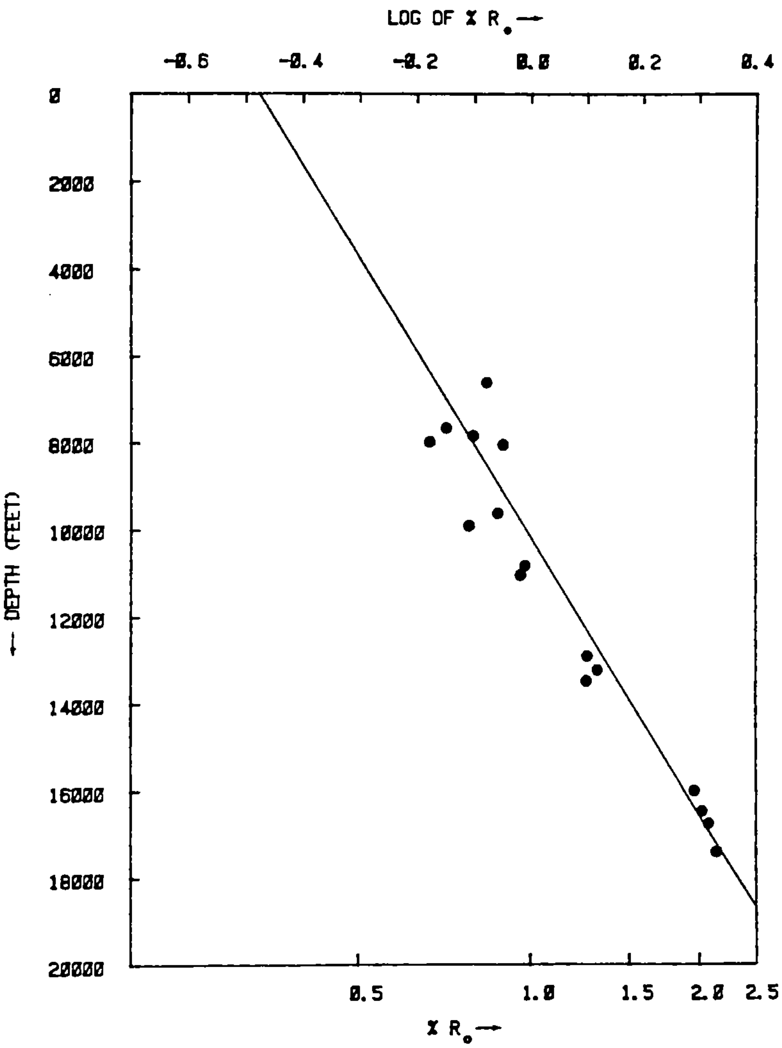


Figure 10. Plot showing relationship between present-day depth and vitrinite reflectance in oil (% R_o). R_o values are plotted on a logarithmic scale. Samples from upper Morrow shale interval. From Tsiris (1983).

sin, as shown in Figure 11. Areas in Figure 9 having the highest vitrinite reflectance contain the "driest" hydrocarbons and are plotted as an area of high-temperature methane in Figure 11. Areas having a vitrinite reflectance of less than about 1.5% R_o plot in the mature oil window, although it must be noted that considerable gas has also been generated and/or has migrated into these areas, too.

The distribution of organic carbon is shown in Figure 12 and indicates that the highest weight percentage occurs in the deepest part of the Anadarko basin. Sample locations on this map are considerably less dense than on the vitrinite-reflectance map, and this condition must be considered when making interpretations. The possible direction of sediment influx as shown by the amount of organic carbon indicates a southwestern source area, which is probably true for the upper Morrow system. However, data in the Woodward "trench" and Canton areas in eastern Harper, central Woodward, and eastern Dewey Counties (north-central and east-central parts of Fig. 12) are sparse, and these areas are interpreted to be sediment-influx areas on the basis of subsurface facies and sandstone mapping. Nevertheless, it is demonstrated that a relatively high percentage of organic carbon occurs in the deeper part of the Anadarko basin that may contribute to the hydrocarbon-source potential of the Morrow Formation in this part of the basin.

Authigenic carbonate cement (Fig. 13) is an important consideration when completing a well or in understanding porosity and permeability variations in reservoir rocks. Many parts of the Morrow play have very little carbonate cement (either calcite or dolomite) in quartz-dominated sandstone such as in the western part of the play. This may indicate that cementation is of a different type, such as quartz overgrowths. This is also true in the upper Morrow chert-conglomerate facies in northern Beckham and Roger Mills Counties in the southwestern part of the Morrow play and is substantiated by this map. Other areas also have little carbonate-matrix cement in arenaceous sandstones, such as in western Blaine County, where the Morrow is prone to oil rather than to gas accumulation. Most of Ellis County, shown in the northwestern part of the map of Figure 13, also has little calcite cement as matrix material in sandstones, and this area is coincident with a part of the prolific Mocane–Laverne gas field. A few areas contain >15% authigenic carbonate cement associated with Morrow sandstone strata, and these areas commonly have porosity impediments. Carbonate matrix is particularly common in skeletal grainstones rather than in arenaceous (quartz-rich) sandstones.

Authigenic kaolinite and chlorite (Fig. 14) are very fine clay particles that impede permeability in a sandstone reservoir when dislodged during fluid surges, or react harmfully during acid treatments commonly applied during well completions. Kaolinite in the form of booklets is often dislodged during drilling, completion, or production of a reservoir, causing a "logjam" of clay particles in pore throats near the wellbore. This damage is generally overcome by standard massive fracture treatments. Chlorite is probably the most harmful authigenic clay in the Morrow Formation and also the most abundant, according to Walker (1986). It is found mostly in sandstone, but it is also a common constituent in the clay matrix, where it occurs as an alteration of illite and brown glauconite. Walker indicates that the chlorite is high in iron and magnesium content, which means that when it is in contact with hydrochloric acid (HCl), an insoluble gel will result that can ruin the permeability of a reservoir. The general distribution of ka-

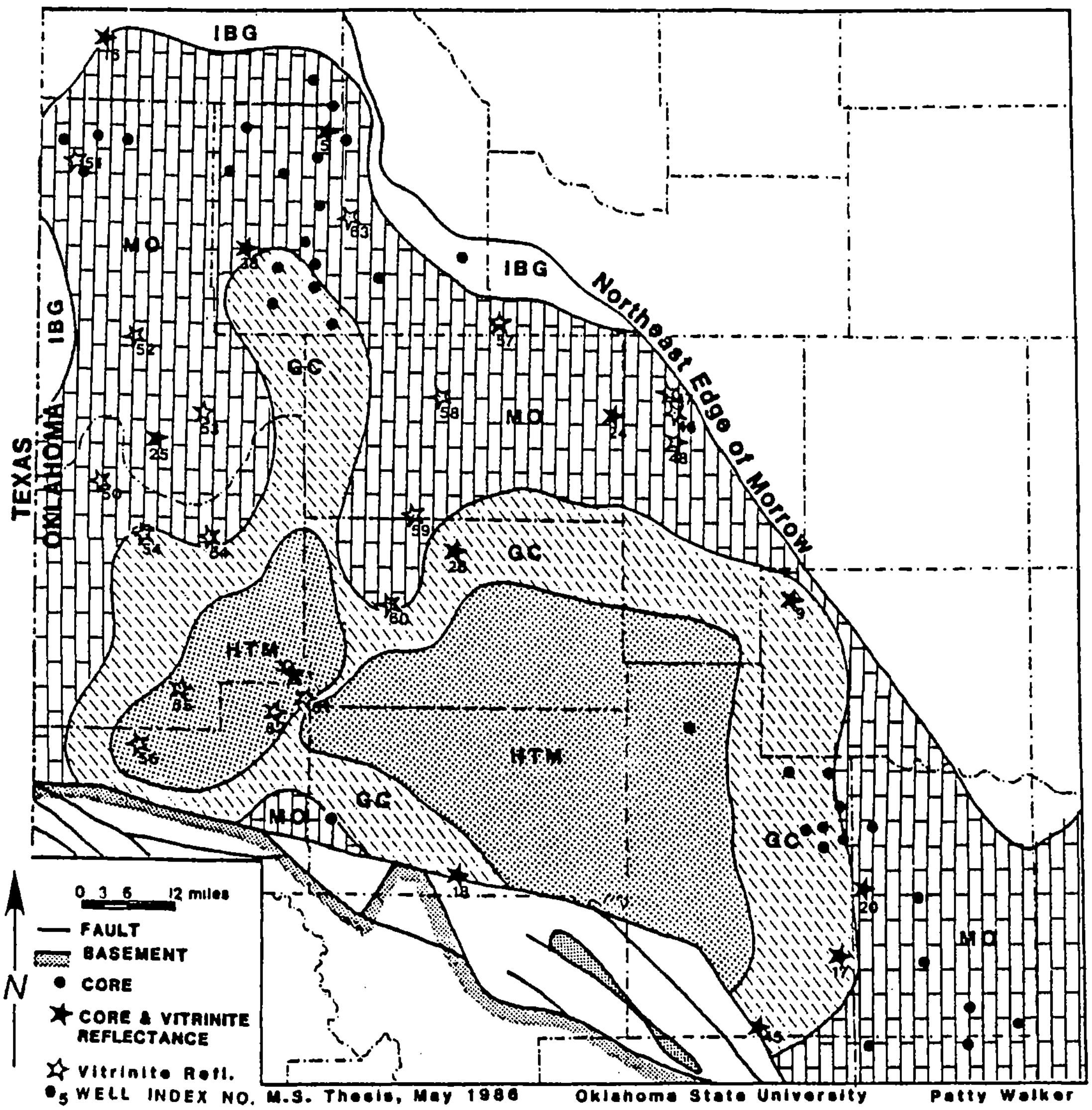


Figure 11. Map showing distribution of Morrow hydrocarbon zones in the Anadarko basin. *IBG* = immature biogenetic gas; *MO* = mature oil generation; *GC* = gas condensate; *HTM* = high-temperature methane. From Walker (1986).

olinite and chlorite is shown in Figure 14. Kaolinite is most common along the subcrop belt extending from the northern part of Mocane–Laverne field in Harper County to the southeast through the Watonga–Chickasha trend. Kaolinite decreases in content deeper into the Anadarko basin, whereas the amount of chlorite increases southward into the basin.

Illite is a major constituent of the detrital-clay matrix (Walker, 1986). Recrystallization of this matrix to chlorite commonly forms the greenish tint of many fine-grained Morrow samples. Illite is also the alteration product of brown glauconite, which in turn forms from the degeneration of green glauconite (Walker, 1986). Illite as an authigenic mineral occurs sporadically throughout the Morrow play in the Anadarko basin, as shown in Figure 15.

PRESSURE GRADIENTS AND GAS COMPRESSIBILITY

Gas reservoirs in the Morrow Formation are highly influenced by variable pressure conditions that greatly affect hydrocarbon reserves and drilling protocols. This discussion is not intended to compete with any reservoir-engineering text; rather, it is included to give the reader a general understanding of the subject. In the shallower parts of the Anadarko basin, the "normal" pressure gradient is ~0.465 psi/ft as plotted in Figure 16. However, deeper in the basin, the pressure gradient for the Morrow increases greatly to about 1.0 psi/ft, which is very high in comparison to formation pressures above and below the Morrow (Fig. 17). In areas where the Morrow has a very high pressure gradient,

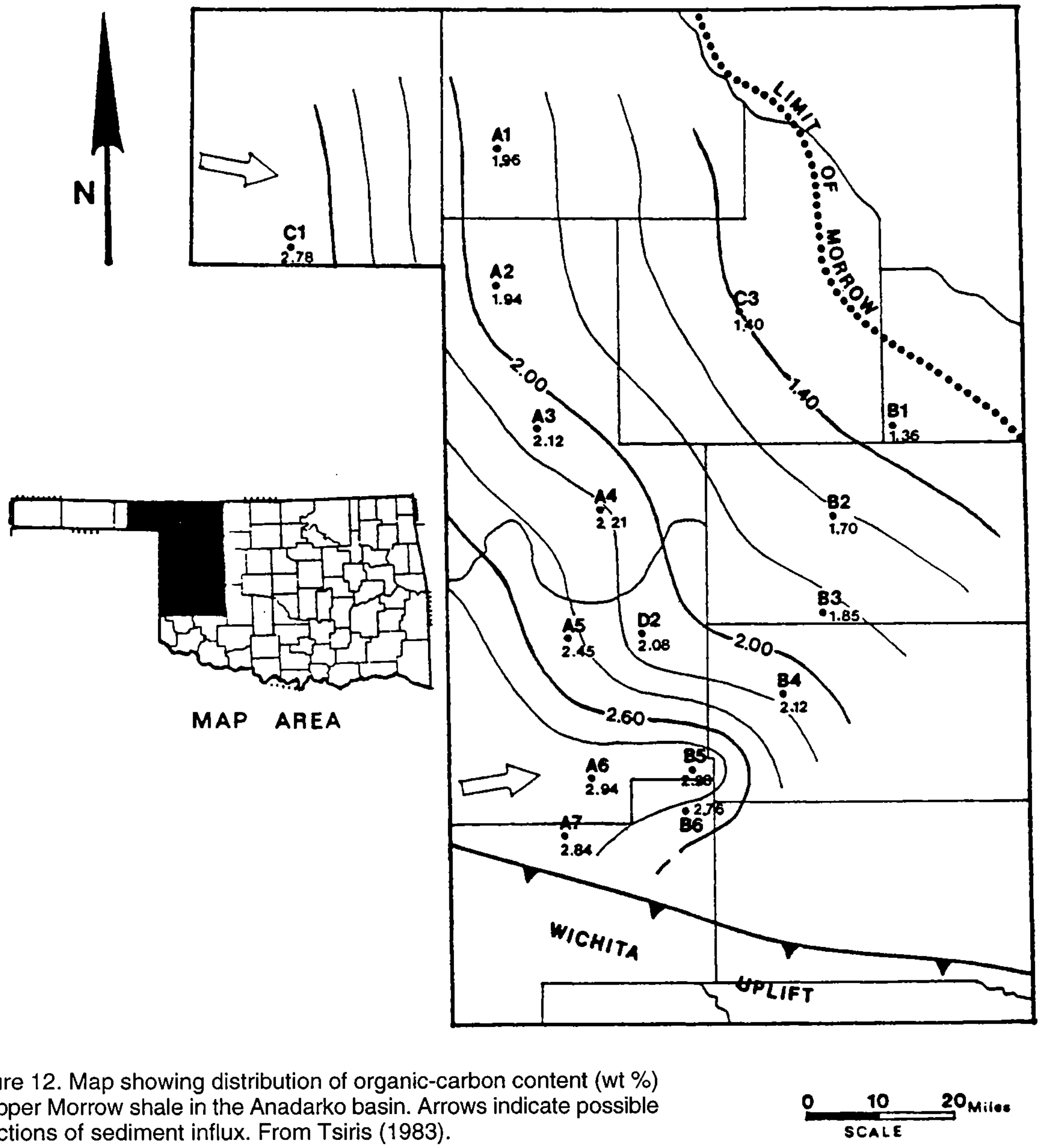


Figure 12. Map showing distribution of organic-carbon content (wt %) of upper Morrow shale in the Anadarko basin. Arrows indicate possible directions of sediment influx. From Tsiris (1983).

the situation is often called *overpressured*, and gas reserves are greatly enhanced per unit volume of reservoir because of the compressed nature of the gas. Overpressuring is generally recognized when the pressure gradient exceeds 0.6 to 0.7 psi/ft. In drilling, this elevated pressure also must be considered when encountering the Morrow in the deep basin, including "mudding up" to higher mud weights to prevent blowouts. This procedure is summarized in the discussion of the deep Puryear sandstone/conglomerate reservoir in Cheyenne West field (Part IV of this report). A map showing pressure gradients in the Anadarko basin is given in Figure 18. Overpressuring in the Morrow occurs only in the deep Anadarko basin, and as such is a product of depth and compartmentalization from shallower reservoirs.

In gas-reserve calculations, the volume of gas produced is affected not only by reservoir characteristics (porosity, permeability, and thickness) but also by the amount of gas contained per unit volume of reservoir at depth (herein referred to as *gas formation volume factor*, or B_g). So, a unit volume of reservoir at depth has more gas owing to compression in comparison to the equivalent reservoir volume at the surface. The initial gas formation volume factor (B_g) is largely responsible for the extremely large cumulative gas volumes reported for some deep Morrow wells, because this factor is multiplied directly by the gas-filled pore volume, which increases the surface volume of gas hundreds of times (see gas-in-place formulas in any reservoir-engineering field-summary table). In this publication, the gas formation volume factor (B_g) is represented in standard cubic feet per reservoir cubic feet. B_g is inversely proportional to the compressibility factor, or Z, which in turn is affected by the specific gravity of gas (gas composition), reservoir temperature, and reservoir pressure. Therefore, all calculations hinge upon the Z factor, which is the hardest to estimate. To some degree, the Z factor accounts for volumetric calculations of gas in place when the reservoir produces relatively small amounts of condensate.

At moderate depths in the Anadarko basin, Morrow gas has a relatively high density or specific gravity (>0.65 g/cm^3) owing to the amount of liquid or heavier hydrocarbons in the gas. In these situations (e.g., Milder field description, Part II of this report), the gas is called *wet*, and the gas-filled reservoir has tendencies to produce certain amounts of liquid (condensate) during pressure drawdown. In the deeper part of the Anadarko basin, the gravity of Morrow gas is less dense (<0.6 g/cm^3), and in these situations (e.g., Cheyenne West field description, Part IV of this report), the gas is called *dry*, and Morrow reservoirs produce little or no condensate. In the three reservoir studies in this publication, the gas formation volume factor (B_g) and compressibility factor (Z) range from ~235 and 0.9 in Milder field (depth, ~9,000 ft), to 480 and 1.6 in Cheyenne West field (depth, ~15,000 ft). Arapaho field has an estimated B_g ranging from ~400 to 490 standard cubic ft per reservoir cubic ft at a depth of ~14,000 ft, and a Z factor of ~1.

REGIONAL CROSS SECTIONS

Regional stratigraphy, depositional environments, and the character of the Morrow Formation are best shown on the three regional stratigraphic cross sections accompanying this report (A–A′, B–B′, C–C′, Pls. 4–6, in envelope).

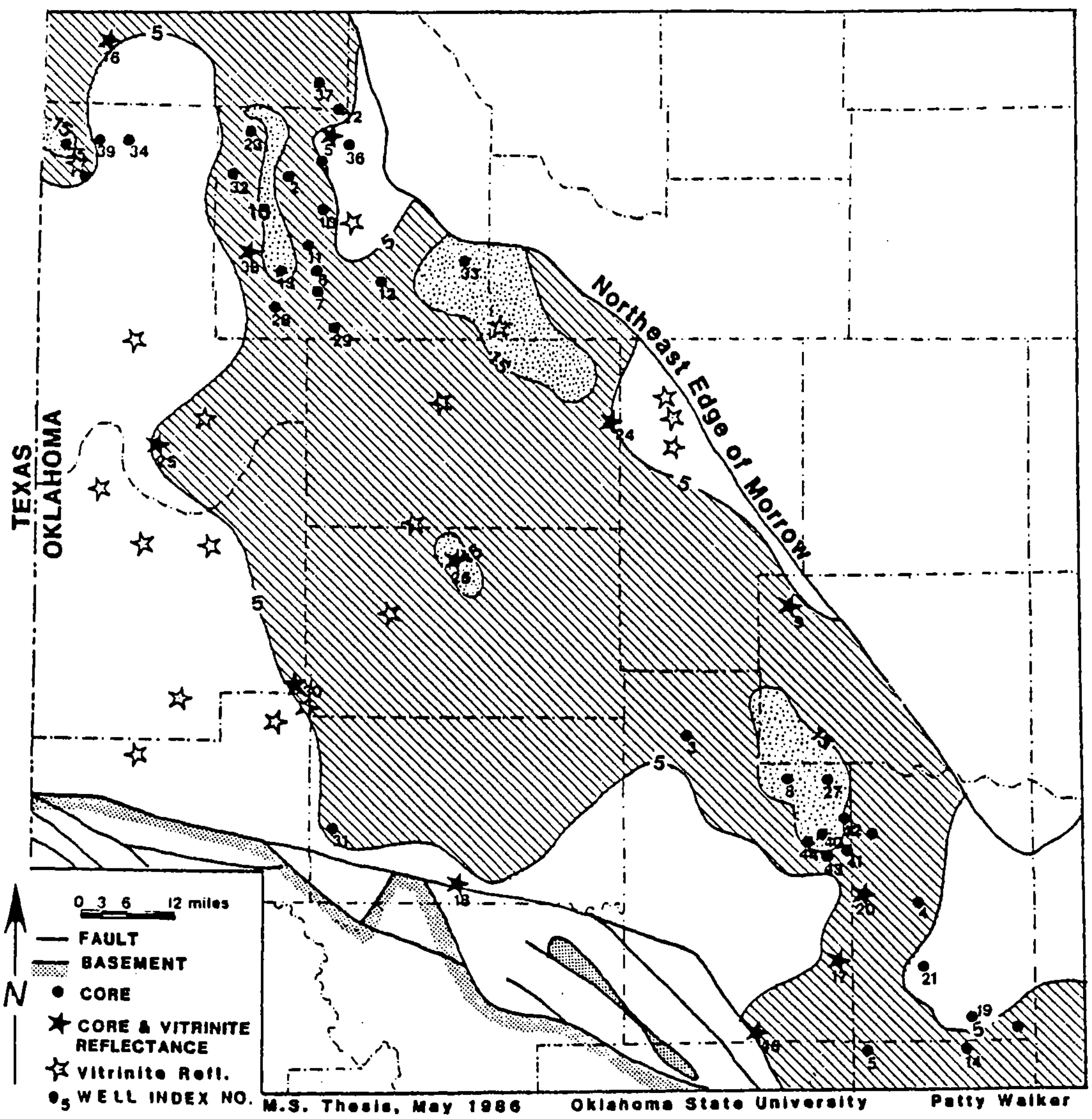


Figure 13. Map showing distribution of authigenic carbonate cement (greater than 5% and 15%). From Walker (1986).

Cross Section A–A′ (Plate 4)

Cross section A–A′ (Pl. 4, in envelope) is a dip section oriented north–south along the western margin of the study area. Representative wells were selected in areas where principal sandstone trends and hydrocarbon production occurs.

Starting along the southern limit of the play at well 1, the Morrow Formation is at least 3,000 ft thick, but only a part of the upper Morrow was penetrated by the well. The log shows several conglomerate/sandstone sequences attributed to a fan-delta clastic wedge shed from the proximal Wichita uplift to the south. Many of the clastic units have a blocky gamma-ray-log signature, and some are underlain by a clastic sequence having a coarsening-upward log signature. These units are probably the subaqueous-marine portion of the fan delta, and the more blocky units directly above represent fluvial deposits of a braided-river system. One of the best examples showing this type of progradational event occurs between 17,390 and 17,230 ft (well 1). The lower part of this sandstone sequence has a distinct coarsening-upward textural profile, whereas the upper part has a more blocky log appearance. Above 17,200 ft, Morrow sediments are probably all braided-channel deposits. With depth, the conglomerate/sandstone units become less common, and shale dominates the section. Upper Morrow strata beneath this log interval (below 19,000 ft) most likely would consist of marine shale. An abrupt "pinching out" of the chert-conglomerate facies in the fan-delta clastic wedge is interpreted to occur to the north, as illustrated between wells 1 and 2.

At well 2, the Morrow Formation is about 3,000 ft thick and is represented by two different wells very

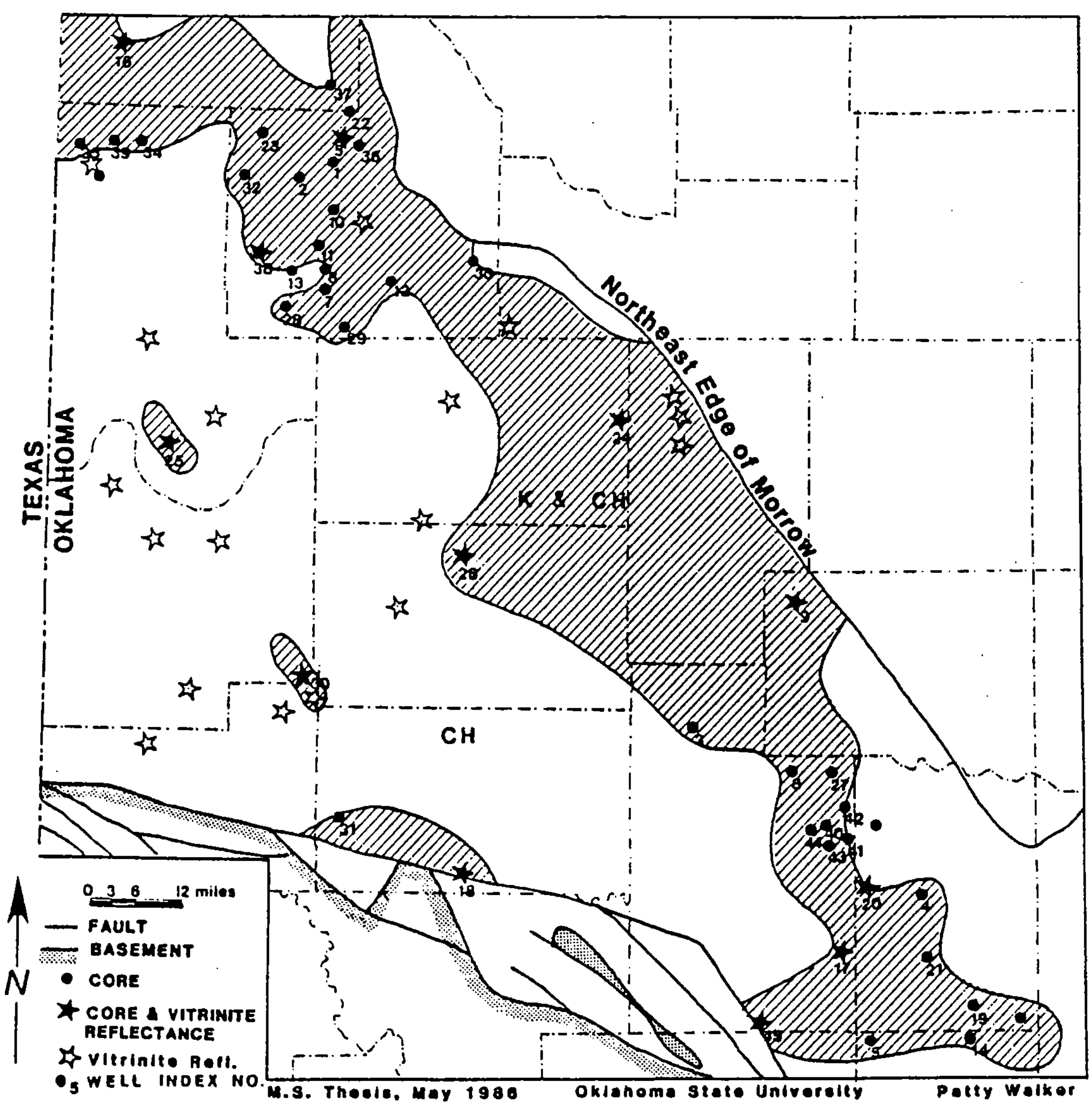


Figure 14. Map showing distribution of authigenic kaolinite-rich zones (*K & CH*). *CH* = predominantly chlorite-rich zone. From Walker (1986).

near one another. The upper part of the upper Morrow is represented by the Samson log (above 16,590 ft), and beneath this depth the El Paso log represents the remainder of the Morrow section. In the Samson log (well 2), the upper Morrow section consists mostly of shale with relatively thin detrital layers including the Puryear, Hollis, and Pierce chert-conglomerate facies. These are the principal producing reservoirs in the upper Morrow in the southwestern Anadarko basin and represent the mid- to distal-fan-delta facies illustrated in Figures 71 and 72 (Cheyenne West field study, discussed in Part IV). The Puryear chert conglomerate at about 15,910–15,965 ft shows a thick channel deposit that is productive throughout most of Cheyenne West field, but at this location it is wet. Because the Samson well did not completely penetrate the Morrow, the Samson log was spliced with the El Paso log to show all of the Morrow section at this general location. Beneath the upper Morrow chert-conglomerate sequences, a thick shale section >1,000 ft thick composes the lower part of the upper Morrow. A limy interval beginning at 17,090 ft is interpreted to be the "Squaw Belly" or the top of the lower Morrow interval. The lower Morrow section above the Primrose section is mostly shale, whereas the Primrose interval contains several sandstone zones that are tight and nonproductive. The Primrose section, between 18,500 and 18,200 ft, appears to represent a progradational sequence consisting of a sandstone interval having a coarsening-upward gamma-ray-log character, overlain by a sandstone having a sharp basal contact and a fining-upward log response.

About 21 mi farther north, at well 3, the Morrow Formation thins to ~2,370 ft. Only thin, distal facies of the upper Morrow fan-delta system are present at this location, as the upper Morrow is mostly shale. The lower Morrow section is identified again by limy sediments

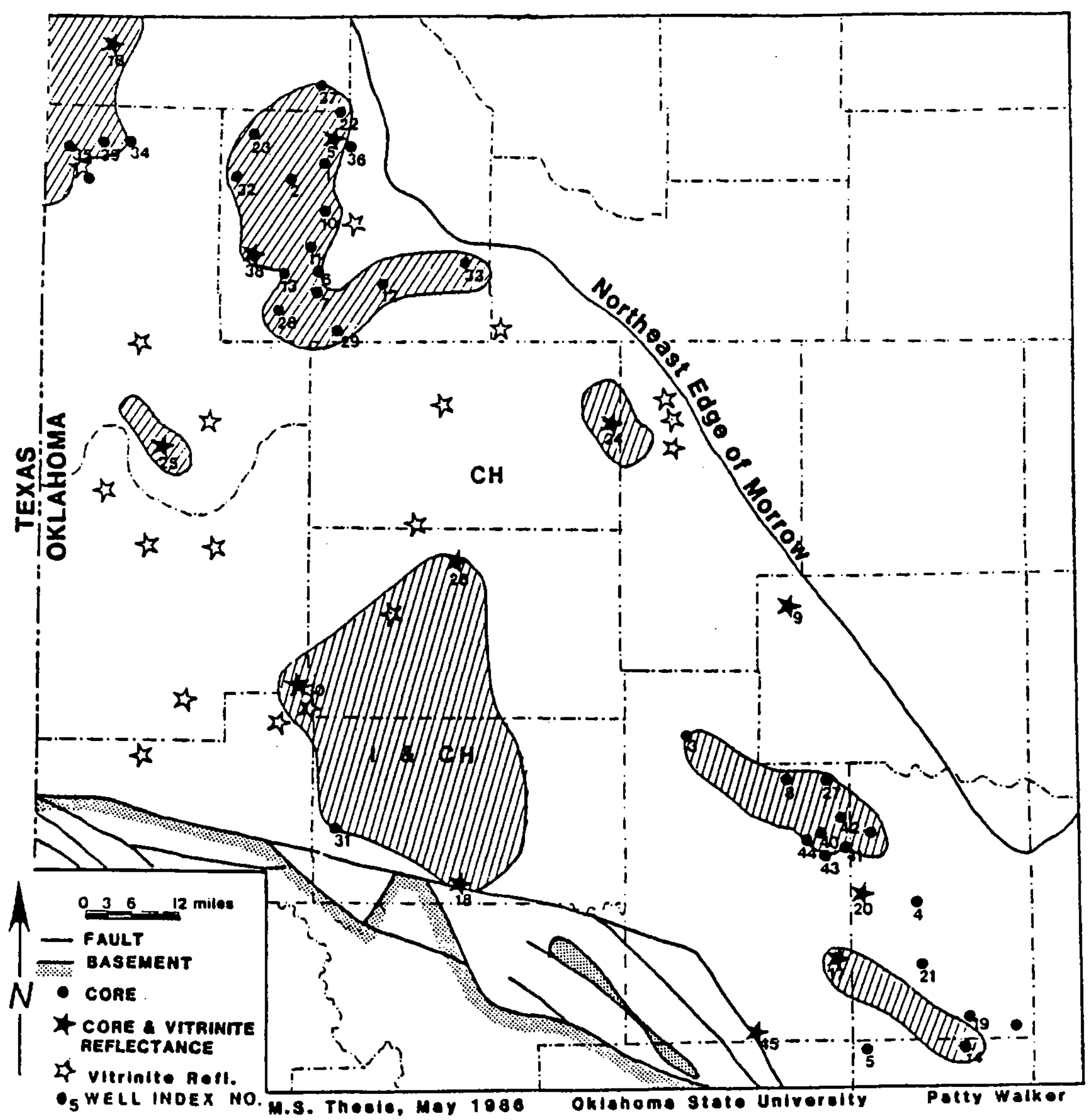


Figure 15. Map showing distribution of authigenic illite-rich zones (*I & CH*). *CH* = predominantly chlorite-rich zones. From Walker (1986).

interpreted to be those of the "Squaw Belly." Beneath this marker, the lower Morrow Primrose section is dominated by numerous sandstone sequences that also may represent progradational events. The base of the Morrow (top of the Springer) occurs at ~15,372 ft in well 3, where the conductivity abruptly increases (inflection to the left on log trace). The youngest sandstone occurring in the Springer in this log is interpreted to be the Cunningham (also for well 2).

At well 4, about 16 mi farther north, the Morrow Formation thins to ~1,500 ft. The upper part of the upper Morrow in this well has a significant sandstone buildup that is interpreted to be a marine-bar sequence, because the textural profile on the gamma-ray log shows an overall coarsening-upward profile. Mostly (marine?) shale defines the underlying upper Morrow interval down to the top of the "Squaw Belly," which reflects a very high resistivity owing to the limy nature of that unit. Both the upper part of the lower Morrow and the Primrose interval are dominated by sandstone sequences that are interpreted on the cross section to represent progradational sequences. Again, these depositional episodes are identified by sandstone beds with a coarsening-upward gamma-ray profile implying a marine delta-front (distributary-mouth-bar facies) overlain by sandstone interval(s) interpreted to be channel deposits (of the delta plain?). The top of the Springer in well 4 is defined by a sharp conductivity inflection in the shale above the Cunningham sandstone. The Cunningham sequence onlaps from the south and is absent farther to the north.

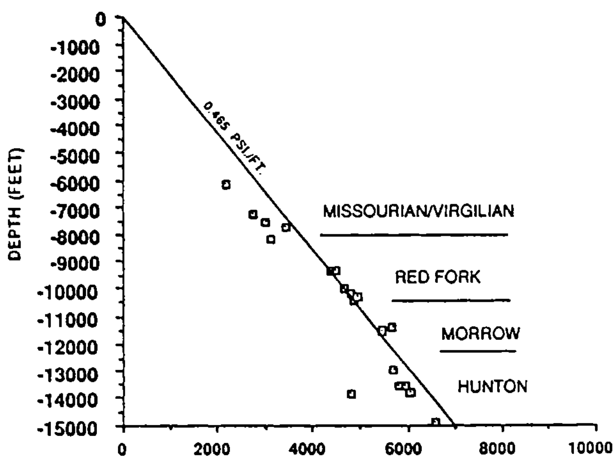


Figure 16. Pressure–depth profile from T. 17 N., R. 18 W., and T. 18 N., R. 18 W., of the shallow Anadarko basin. Note that all gradients plot along the projected 0.465 psi/ft "normal" gradient slope. From Al Shaieb and others (1992).

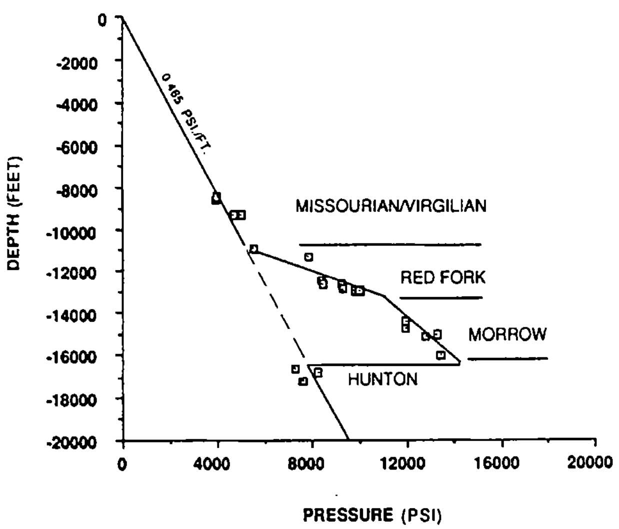


Figure 17. Pressure–depth profile in the deep Anadarko basin from Roger Mills County, Oklahoma. Deviation of curve to right (overpressuring) identifies the mega-compartment complex in the Red Fork and Morrow intervals. Hunton Group gradients cluster around the "normal" 0.465 psi/ft gradient. From Al Shaieb and others (1992).

At wells 5 and 6, the Morrow Formation thins to about 1,250 and 1,050 ft, respectively, about 10 and 17 mi north of well 4. The upper Morrow in both these wells is predominantly marine shale, whereas the lower Morrow and Primrose sections are dominated by prograding sandstone sequences. Also in both wells, the base of the Morrow lies on Britt shale and carbonate rocks as identified in the cross section. In well 6, the producing zone is a thin interval in the upper Morrow that may be correlative to FDD facies extending into western Oklahoma from the Texas Panhandle.

At well 7, the Morrow thins dramatically to only ~640 ft. This well is in the Milder field study area, described in Part II of this report. The shale-dominated upper Morrow interval has thinned significantly, as has the Primrose, which consists of only one progradational sandstone sequence. The lower Morrow above the Primrose is shown to thin only slightly and consists of two major progradational sandstone sequences. The productive interval in this well appears to be in the channel facies, where the SP curve exhibits an excellent deflection to the left, indicating permeability. The Springer contact is again represented by a sharp increase in conductivity.

Well 8, about 14 mi north of well 7, is near the Anadarko shelf hinge line. In this well, all Morrow zones have thinned appreciably, and the Morrow Formation is a little less than 400 ft thick. The producing Morrow sandstone is characterized by a good SP deflection and a deep resistivity of 10–20 ohm-m in what may be a delta-front facies.

In well 9, a thick channel appears to cut down through the lower part of the upper Morrow interval and is the only productive interval in the well. These types of deposits are occasionally identified in the subsurface and are not necessarily related to deltaic deposition, as no delta-front strata are associated with this specific type of channel deposit. Sandstone bodies such as this may represent estuarine or tidally dominated channels entering the Morrow sea from the north and may be one of several sediment-influx areas. In well 9, the Primrose section is almost absent and is truncated several miles farther north, as shown in well 10.

In well 10, the Morrow is only ~170 ft thick, and the only sandstone present is in the upper part of the lower Morrow interval. This sandstone appears to be some type of marine-bar sand, as are many in this area. The Morrow at well 10 rests directly on Britt carbonate strata that have been interpreted by many geologists as Chester.

The final well (well 11) has a Morrow section only ~60 ft thick that is mostly upper Morrow shale. A thin sandstone in the lower Morrow interval is tight, calcareous, and nonproductive.

Cross Section B–B′ (Plate 5)

Cross section B–B′ (Pl. 5, in envelope) is a true dip section that is oriented northeast–southwest. It identifies Morrow strata from the deep Anadarko basin just north of the Wichita frontal fault zone and correlates Morrow intervals through Arapaho field (geological study included in Part III of this report) into the oil-producing area referred to as the Canton "embayment."

The cross section begins in the deep Anadarko basin at well 1, where the Morrow Formation is ~4,000 ft thick. In order to show important sandstone intervals and to include the entire Morrow Formation at this location, logs from two wells were used. So as to accommodate the full length of the logs in one column, the shale interval between the upper and lower Morrow intervals was reduced. The upper part of the log above 17,960 ft belongs to the Dyco well, and the remainder of the section belongs to the Marathon well. The upper Morrow, as shown in the Dyco well log, consists of a fan-delta clastic wedge pinching out to the north in a manner similar to that shown in cross section A–A′ (Pl. 4). The lower part of the upper Morrow and the upper part of the lower Morrow (reduced section) are predominantly marine shale. In between lies a 60-ft-thick limy bed that is interpreted to be the "Squaw Belly." Because of the reduction in the size of the logs, the vertical scale is distorted between wells 1 and 2, which are about 19 mi apart. The lower Morrow section and underlying Primrose interval at well 1 contain sandstone intervals separated by thick shale zones. In the lower part of the Primrose section, a sandstone sequence is ~300 ft thick, but the depositional environment of this thick sandstone sequence is not entirely clear. The contact with the underlying Springer shows the resistivity to be very low (<5 ohm-m), and the conductivity log (not shown) shows a sharp inflection to the left at this horizon in a manner similar to the Morrow–Springer boundaries shown in cross section A–A′ (Pl. 4).

Northeastward, well 2 shows the Morrow Formation thinning to ~2,800 ft. Remnants of the chert-conglomerate facies can still be identified in the upper Morrow interval and represent the mid- to distal-fan-delta facies illustrated in Figures 71 and 72. Most of the remainder of the Morrow consists of shale except for the Primrose interval, where a 300-ft sandstone section is interpreted to be mostly a marine-bar sequence. The lowermost sandstone zone in this sequence (18,000–18,050 ft), however, has the log profile of a channel. The Springer contact in the shale directly below this sandstone shows a sharp increase in conductivity and very low resistivity. The sandstone below the Morrow in the deep basin is commonly the Cunningham, as shown in this section.

At well 3, about 9 mi farther northeast, the Morrow section thins considerably to ~1,500 ft. In this well, a marine-bar sequence occurs in the upper part of the upper Morrow interval that is locally productive in Arapaho field (described in Part III of this report). The Primrose interval in well 3 contains a thick incised channel-sandstone sequence between 14,900 and 14,600 ft that cuts through older marine-sandstone strata. Both facies are locally productive, as shown in the detailed field study of this area. In well 3, the Primrose overlies the Springer shale, which reflects the typical high-conductivity log response.

Coming out of the Anadarko basin another 9 mi, well 4 has a Morrow thickness of ~1,080 ft. The upper Morrow interval in this well is mostly shale, as there is little sandstone high in the section. However, the entire lower Morrow section is dominated by sandstone sequences that appear to be largely marine (delta-front?) bars.

Six miles to the north, in well 5, the lower Morrow and Primrose intervals appear to be composed mostly of prograding deltaic sequences, as noted in the space adjacent to the well logs in the cross section. Again, there are only a few thin, distinct sandstone beds in the upper Morrow interval, and the basal Morrow contact with the Springer is with the Cunningham sandstone interval.

Wells 6 and 7 contain mostly shale in the upper Morrow section. Sandstone in the lower Morrow and Primrose sections consists of progradational sequences that are generally tight. A good SP deflection and resistivity >10 ohm-m in the lower Primrose section of well 6 looks promising for gas potential, but the well was completed only in the deeper Springer Cunningham sandstone. A smaller SP response denotes a channel sandstone in well 7, but the very high resistivity may indicate the sandstone to be tightly cemented.

The Cunningham sandstone section in well 7 forms the basal contact with the Morrow but is absent several miles updip in well 8. In this well, the Morrow sits above the Britt zone, as shown in the cross section. The Primrose in well 8 consists of a single prograding sequence that is producing from the channel facies. A thicker sandstone in the lower Morrow section above the Primrose is also producing from a channel(?) sequence, and the good SP deflection and deep resistivity of 8–12 ohm-m are characteristic of a producing gas well.

Well 9 was completed in a lower Morrow channel sandstone as an oil well. In this well, the Primrose section is nearly absent, and the upper Morrow section is missing. The basal Morrow contact is with a thin Britt sandstone zone, which overlies a Boatwright sandstone and shale zone, which in turn overlies the Mississippian Chester limestone.

The Morrow Formation in well 10 is only ~100 ft thick and consists of interbedded channel sandstone and shale in the lower Morrow section. The upper Morrow is absent, and the Primrose occurs only as a thin remnant. This well was also completed as an oil well. Both wells 9 and 10 are part of a major lower Morrow oil-producing area referred to in this text as the Canton "embayment," because the subcrop pattern of the Morrow Formation is distinctly concave basinward in this area (see regional sand map, Pl. 1). The Morrow subcrop occurs about 12 mi northeast of well 10.

The absence of Morrow strata to the northeast is due in part to the unconformable relationship with the overlying Atoka and in part to depositional thinning. Thus, cross section B–B′ demonstrates this concept: the lower Morrow interval thickens in a basinward direction to the southwest in response to progradation. Depositional environments within the upper part of the lower Morrow are interpreted to be mostly flood plain (terrestrial) in the last three updip wells (8–10); basinward, the interval thickens in response to delta-front deposition in the marine distributary-mouth-bar facies in addition to thicker delta-plain sequences.

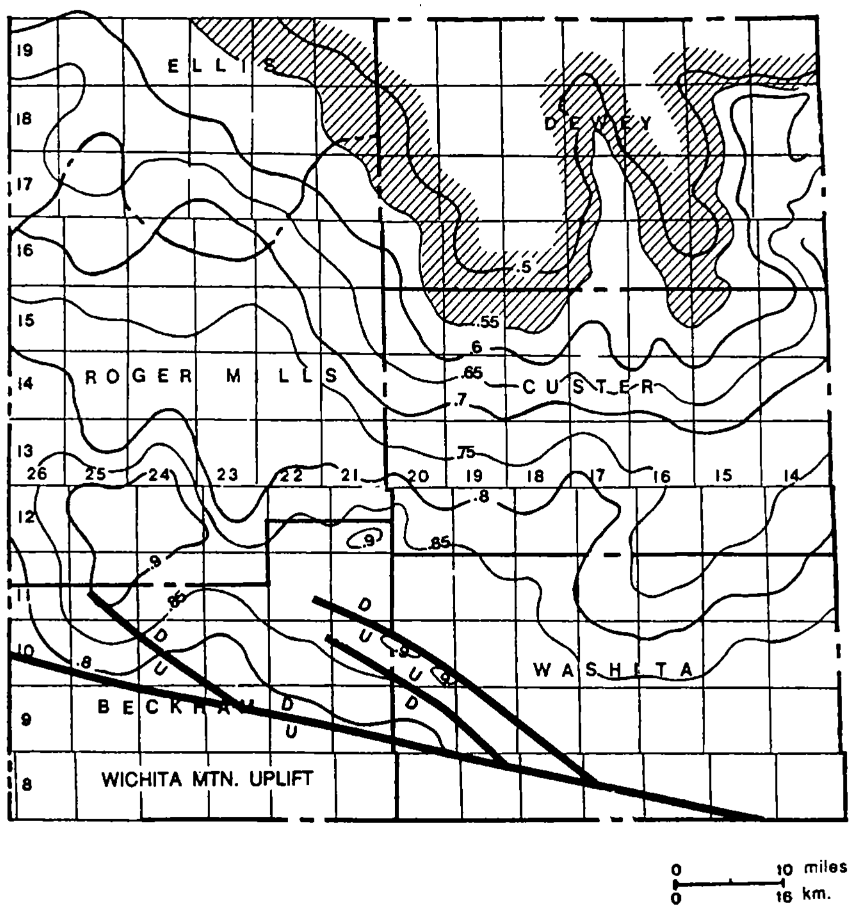


Figure 18. Pressure-gradient (psi/ft) contour map of the Morrow sandstone. Transition zone from normal-pressure regime to overpressuring is shaded. From Al Shaieb and others (1992).

Cross Section C–C′ (Plate 6)

Cross section C–C′ (Pl. 6, in envelope) is oriented oblique to strike in a northwest–southeast direction. It ties with cross section B–B′ (Pl. 5) between wells 5 and 6 and nearly ties with cross section A–A′ (Pl. 4) just west of well 1.

The first well in cross section C–C′ was drilled in the eastern part of the greater Mocane–Laverne gas area. In this well, the Morrow is only ~50 ft thick, as the well is near the northern subcrop, as shown in the regional sand map (Pl. 1). In well 1, the stratigraphic units of the Morrow are not completely certain, but upper and lower Morrow intervals are nevertheless indicated. The Morrow overlies the Boatwright carbonate unit of the Springer Formation, which is often called *Chester* in this area. Correlations by Dwights Energydata, LLC (1999) indicated that what has been called *Chester* is actually the carbonate facies of the Boatwright unit of the Springer.

Almost 10 mi to the southeast, well 2 encountered an unusual Morrow section consisting of a thick, incised channel-sandstone sequence. This excellent reservoir-quality sandstone has a pronounced SP log response, but the sandstone is wet, as indicated by a very low resistivity of <5 ohm-m. This channel complex can be traced for several miles to the north and south and is one of several channel systems that provided sediment to the Anadarko basin during Morrow time. This channel system parallels the much deeper and larger Woodward "trench" identified on the regional Morrow sand map of Plate 1.

Well 3, about 22 mi southeast, is producing from the lower Morrow, which sits unconformably on the Springer Boatwright carbonate sequence. This area is still north of the lower Morrow Primrose subcrop, which first appears at well 4, almost 12 mi to the southwest.

The expanded Morrow section in well 4 is ~390 ft thick and clearly shows the shale-dominated upper Morrow section. The lower Morrow section in well 4 has a well-developed prograding sequence, as indicated on the cross section.

About 34 mi to the southeast, the Morrow Formation thickens to ~520 ft in well 5 and to ~550 ft in well 6, 25 mi farther south. Note that the Springer Cunningham sandstone section emerges at well 5 and thickens considerably in well 6. The Morrow–Springer contact in the latter well is picked where the conductivity increases abruptly at 11,450 ft. It is always easier to make this pick on the conductivity log rather than on the resistivity log because of the greater sensitivity of the conductivity log.

In wells 7–11, the upper Morrow interval shows significant development of marine sandstone represented by sequences that have a coarsening-upward textural profile on gamma-ray logs. Also, in wells 7–9, the lower Morrow and Primrose sections contain some of the best examples of prograding sequences anywhere in the Anadarko basin. The interval between 13,650 and 13,380 ft in well 7 is one example of delta-plain(?) channel deposits overlying delta-front distributary-mouth-bar sequences. The same relationship is even better represented in well 8 between 15,000 and 14,800 ft. A similar prograding sequence is shown in well 9 between 15,100 and 14,800 ft. These log signatures clearly indicate the progradational nature of the lower Morrow and Primrose intervals into the Anadarko basin from the north–northeast. Well 10 displays an interesting lower Morrow section, with a thick incised channel sandstone in the Primrose interval. In adjacent well 11, the same interval has a typical prograding sandstone sequence, as seen in wells 7–9. It is likely that significant sea-level changes occurred during Morrow time, causing shorelines to shift and inducing fluvial-deltaic systems to form incised valleys in a basinward direction. Following these incised channel systems basinward in the subsurface should lead to marine delta-front sandstone sequences that may have additional gas potential.

The last well in cross section C–C′ (well 12) was drilled in the southeastern part of the Morrow play just north of Cement field. The condensed Morrow section is only about 350 ft thick in a manner similar to that of well 4 of this cross section. However, in well 12, the upper Morrow section is not clearly identifiable. The lower Morrow Primrose zone contains several sandstone sequences that are interpreted to represent delta-front deposits. The producing interval in this well has a good SP deflection and about 35-ohm-m resistivity in a sandstone that may be a channel deposit overlying a marine delta-front sequence.

STRUCTURE

The Morrow play of Oklahoma occurs mostly in the Anadarko basin of western Oklahoma but also extends into smaller "satellite" basins in the south-central part of the State, including the Cyril basin. These areas were excluded from detailed study even though they may contain excellent potential for hydrocarbons. Hydrocarbon accumulations in these latter areas are largely controlled by structures, and such accumulations will be exploited most often by detailed seismic interpretations on a localized basis. The value of this publication is largely in the stratigraphic and reservoir sense rather than in "bumpology." The base map used for regional mapping, including the regional structure map (Pl. 3, in envelope), is modified from a geologic-province map of Oklahoma (Northcutt and Campbell, 1995).

The regional structure map completed for this publication (Pl. 3) was made principally by using data from the Natural Resources and Information System (NRIS), a database developed at the University of Oklahoma. These data were supplemented locally by published information. A contour interval of 1,000 ft was used in the Anadarko basin areas to show the major structural configuration of the basin as well as the major structural elements within western Oklahoma. In the Anadarko shelf areas, a 500-ft contour interval was used because the dip is considerably less. The structure map was hand contoured and checked with well data where the three field studies (star symbols) were completed. Also shown on this map are locations of wells (solid squares) with Morrow core descriptions (Appendix 4). The lines of regional cross sections A–A′, B–B′, and C–C′ (Pls. 4–6) are also shown on the regional structure and sand maps.

As can be seen in the regional structure map of the Morrow Formation in western Oklahoma (Pl. 3), the regional dip throughout most of the Anadarko basin is only a few degrees to the south–southwest. In the Anadarko shelf areas of northwestern Oklahoma and the Panhandle, the regional dip is <1° to the south–southeast. Folding and faulting at Morrow time are uncommon in most of the shallow basin and shelf areas of this study but are intense in the extreme southern and southeastern parts of the Anadarko basin. Several large, elongated folds occur just north of the Wichita frontal fault zone in Washita and northern Beckham Counties. The most prominent of these folds are the Elk City and Cordell anticlines. The complex Cement and Chickasha fault systems in southern Caddo and Grady Counties essentially mark the extent of this study area in the southeastern part of the Anadarko basin. The Wichita uplift just south of the frontal fault zone is a broad area where pre-Pennsylvanian strata are missing, so the Morrow Formation does not crop out along the basin edges.

DEPOSITIONAL MODEL

Depositional patterns of Morrow sandstone sequences can be extrapolated by using a regional grid of subsurface cross sections and well logs. It is unfortunate that outcrops of the Morrow are not available in western Oklahoma to supplement interpretations that are based entirely on subsurface data.

The interpretation of the depositional origin of the Morrow sandstone, as outlined in this study, is considerably different than that of most previous investigators. The Morrow Formation appears to have been deposited during several prograding and transgressive periods that occurred primarily during early Morrow time. With the exception of the upper Morrow chert-conglomerate sequences in the southern part of the Anadarko basin, the Morrow Formation in Oklahoma overall becomes more terrestrial in a northeastward direction and more marine basinward. The following is a brief summary of the depositional environments of some of the principal Morrow strata as interpreted in this study.

Lower Morrow

Marine Sandstone Deposits

The lower Morrow is undoubtedly the most complex clastic depositional system in Oklahoma. As demonstrated on regional cross sections and on the detailed cross sections in the Arapaho and Milder field studies, the lower Morrow interval is composed of several sandstone sequences having a large spatial variation in thickness, log character, and depositional environment. Many early investigators believed that the Morrow was simply a series of offshore marine bars trending northwest–southeast. Although these facies are present, the distribution pattern and depositional origin of sandstone are much more complex. Well-log and core interpretations indicate that the basin contains numerous prograding depositional cycles consisting of marine distributary-mouth-bar (delta-front) sandstone in addition to several channel-form sandstone deposits.

The marine sandstone assemblages are probably mostly in the form of delta-front deposits instead of open-shelf "detached" bars. This interpretation is based on a sequence-stratigraphic relationship with other strata both above and below the marine deposits. The marine bars typically have some variation of a coarsening-upward textural profile as recorded on well logs and are commonly associated with overlying delta-plain deposits. The latter deposits include most notably the suspected channel deposits that are characterized by a sharp basal contact and a blocky to fining-upward textural profile as noted on gamma-ray and other wireline logs. The vertical assemblage of marine shale, overlain by marine delta-front bars, which in turn are overlain by channel deposits, defines a prograding sequence. This type of sequence occurs repeatedly in the Anadarko basin, not only in the upper part of the lower Morrow but also in the Primrose section of the lower Morrow. In the shallow Anadarko shelf areas where the Morrow Formation is relatively thin, marine sandstone assemblages in the lower Morrow section may be in the form of bars formed by tidal reworking, longshore currents, or small distributaries in a nearshore environment. Undoubtedly, some of the marine deposits are not associated with deltaic progradation and may simply be detached, nearshore bars formed by normal longshore or storm currents. However, their everywhere close association with deposits linked to tidal processes implies strongly that most marine sandstone deposits were formed in close proximity to the dynamic nearshore environment rather than in deep water. The erratic thickness and areal-distribution patterns support this interpretation. Deeper water marine-bar deposits are generally much more uniform and continuous over larger areas.

Channel Deposits

Numerous sandstone sequences have the typical log character of a channel by exhibiting a sharp basal contact (usually with shale), and a textural configuration, as determined from gamma-ray and other wireline logs, that shows a blocky to fining-upward profile. These log forms and interpretations are consistent with every other depositional system in the Cherokee Group of Oklahoma and conform to virtually every core or core description examined by the author. Therefore, these sandstone bodies are interpreted to be some form of channel deposit even though cores are not everywhere available to confirm this interpretation.

The channel deposits occur in two main geological circumstances: individually or stacked upon one another with *no* underlying representation of a delta-front sandstone. In these occurrences, the channel sandstones are believed to have been deposited as point bars or longitudinal bars in a flood or tidal plain. Numerous cores from the Canton "embayment" area, as described in Appendix 4 of this report and by South (1983) and Bentkowski (1985), support the channel concept. The channel deposits in the Canton area contain a variety of detrital constituents from pure quartz sand to fossiliferous grainstones. Many of these deposits contain at least a small amount of shell material and other marine constituents such as altered glauconite, indicating the close relationship of these deposits to a marine environment. Many channel deposits probably formed in marginal-marine environments such as tidal flats or estuarine channels. Yet, some channel deposits have no marine implications and were probably formed upstream from a tidal influence in a flood plain or an emerging delta plain.

Other suspected channel deposits occur in stratigraphic or spatial proximity to marine delta-front sandstone. These types of channels are interpreted to be distributary channels of a delta plain because of their relationship to a subaqueous marine delta-front environment. The entire sandstone sequence consisting of channels overlying marine delta-front deposits defines a prograding depositional system. These features are illustrated in cross sections of both the Milder and Arapaho field studies (discussed in Parts II and III) in addition to being identified on all three of the regional cross sections (Pls. 4–6). Some channel sandstone appears anomalously thick in proportion to the delta-front sandstone sequence or occupies an entire interval normally occupied by a distributary-mouth bar. In these cases, the channel environment is interpreted to be in an incised valley that was eroded as the result of falling sea level. The change in sea level causes fluvial systems to "chase" the shoreline in a basinward direction, ultimately ending in a marine environment where a lowstand delta front emerges. These types of depositional relationships are documented throughout the Cherokee Group of Oklahoma and therefore are not something new to the Morrow.

Upper Morrow

The upper Morrow interval is usually dominated by marine (prodelta?) shale. Strata of this type are useful in differentiating the stratigraphic components of the Morrow Formation. Some sandstone and conglomerate in the upper Morrow, however, were deposited in a unique environment. The most unusual are the coarse-grained chert-conglomerate sequences in the deep part of the Anadarko basin. As shown in regional cross sections A–A′ and B–B′ (Pls. 4, 5), they had their source to the south in the rising Wichita Mountains and form a series of fan deltas trending to the north. These coarse deposits are spatially limited to the southern part of the Anadarko basin and were laid down in a series of braided streams. The subaqueous and sandier parts of these systems were deposited in delta-front lobes of the prograding fan-delta system. Alternatively, the chert conglomerate sequences may be interpreted as turbidites.

Other coarse arenaceous and arkosic deposits in the study area occur in the Oklahoma Panhandle and extend into the far western part of Ellis County. These deposits are also fluvial in origin and are prone to oil accumulation. The areal-distribution pattern of these types of upper Morrow deposits is shown on Plate 1.

The most widespread occurrence of sandstone in the upper Morrow interval is in a broad belt extending northwest–southeast in the deeper, southeastern part of the Anadarko basin. These upper Morrow sandstone sequences contain numerous relatively thin sandstone beds with the characteristic coarsening-upward textural profile on well logs. The distribution pattern of these sandstones is parallel to the basin edge; stratigraphically, they occur just below the Thirteen Finger limestone of the Atoka Formation. Few, if any, logs represent prograding sequences—that is, channels overlying marine delta-front sandstones in these fine-grained deposits. Therefore, sandstone bodies may be part of an extensive, shallow-marine shelf or detached-bar depositional system. Several logs demonstrate these stratigraphic relationships on regional cross sections B–B′ and C–C′ (Pls. 5, 6). The areal-distribution pattern of these types of upper Morrow sandstone deposits is shown on Plate 1.

SUMMARY OF REGIONAL MORROW MAPPING

Regional distribution of the Morrow sandstone, and the interpretation of depositional facies, are shown on Plate 1. Also shown on this plate are the major geologic provinces in western Oklahoma, the subcrop limit of the Morrow Formation, field-study locations, core locations described in Appendix 4, and the lines of regional cross sections A–A′, B–B′, and C–C′ (Pls. 4–6). Plate 2 is a production-code map showing the allocation and reallocation of Morrow production based upon work by Petroleum Information/Dwights Energydata, LLC (1999). On this map, Morrow production is color coded in four different categories: upper Morrow, lower Morrow (exclusive of Primrose), Primrose, and commingled. Plate 3 is a regional structure map depicting the structure at the top of the Morrow Formation. Data used to construct this map were derived primarily from NRIS and supplemented locally by published structure maps and field studies of this publication. The regional structure map also gives supporting information as described for the regional sand map.

Plates 4–6 are regional cross sections (A–A′, B–B′, and C–C′) that illustrate the log character, facies relationships, and stratigraphy of the Morrow Formation. Correlations and log selection were based largely upon work by Petroleum Information/Dwights Energydata, LLC (1999).

Plate 7 (in envelope) is a map showing oil and gas fields with production from the Morrow Formation. Shaded areas on this map indicate areas where mostly oil is produced from the Morrow. Included with Plate 7 is an alphabetical listing of field names and their geographic locations. Field names were determined by the Oklahoma Stratigraphic Nomenclature Committee of the Mid-Continent Oil and Gas Association. In many cases, Morrow production is attributed to a general field boundary that has no geological relevance to sandstone in the Morrow Formation. In other cases, Morrow production is found outside the formal field boundaries. These vagaries occur because the effort to formally define and extend field boundaries lags behind the extension of producing areas.

All available sources of information were used in completing this study, including information in the private domain, theses, consultants, and personal investigations by the author. Approximately 2,000 well logs were used to construct the subsurface sandstone-trend maps of Plate 1.

Throughout this paper, references are made to various sand-size grades in the description of certain rock units; they are listed in Appendix 1. Similarly, various abbreviations and terms that are used in this paper are defined in Appendixes 2 and 3, respectively. Five cores are provided for examination by workshop attendees, and brief descriptions and facies interpretations are given, along with well logs and selected visual images, in Appendix 4. An alphabetical listing of Morrow fields, showing reservoir-data elements, production, and pressure data, is given in Appendix 5.

PART II

Milder Field

Lower Morrow and Primrose gas reservoir in northern two-thirds of T. 22 N., R. 25 W., and southern one-third of T. 23 N., R. 25 W., Ellis County, Oklahoma

Richard D. Andrews
Oklahoma Geological Survey

INTRODUCTION

Milder field is in northern Ellis County, northwestern Oklahoma (Fig. 19). The 56-section study area lies along the northern edge of the Anadarko basin about 24 mi west of Woodward (Pl. 1). As recognized by the Oklahoma Stratigraphic Nomenclature Committee of the Mid-Continent Oil and Gas Association, Milder field includes production from the younger Tonkawa sandstone (Pennsylvanian, Virgilian) in addition to several Morrow reservoirs. However, this project investigates only the two main lower Morrow reservoirs, which produce gas from nearshore-marine and possibly fluvial- and/or tidal-channel deposits. Field limits are not always well defined on the basis of log interpretations, although the general extent of the field is well established from surrounding dry holes. As a general rule, the Morrow Formation and its inclusive sandstone zones in Milder field thin to the north and become increasingly "wet" to the south within the limits of this study. Reservoirs are probably compartmentalized even within the same facies, although certain facies seem more prone to hydrocarbon accumulation than others. Sediments composing the lower Morrow in the study area probably were derived from the north and northeast, as indicated on the regional sandstone map (Pl. 1). Cumulative gas production to date for the two lower Morrow reservoirs evaluated in this study is about 36.2 BCF (24.9 BCF from the lower Morrow B sand and 11.3 BCF from the lower Morrow Primrose sand). Sandstone correlative with these units reaches a known gross thickness of 57 ft for the B sand and 79 ft for the Primrose. However, because of authigenic clays and cementation, the net reservoir sandstone is usually much thinner. These values can be compared on the gross- and net-sandstone isopach maps prepared for each reservoir. Based on log shapes and areal-distribution patterns of sandstone, the Primrose and Morrow B deposits have unique distribution patterns that seem to have been affected by tidal or nearshore depositional processes. A map identifying all wells in the study area is shown in Figure 20; the number adjacent to each well refers to well information and production data that is presented in Table 2.

Drilling first began in this study area during 1959 along the very northern and southern extents of the field. These first two wells tested dry, but the relationship between thick downdip, wet sandstone versus thin updip, tight sandstone set the stage for gas discoveries shortly thereafter. In 1961, the completion of the Pan Am No. 1 Purdum well in sec. 3, T. 22 N., R. 25 W., became the field opener. This well was completed in the lower Morrow A zone, which is highly calcareous and correlative with the "Squaw Belly." Because of limited production from this reservoir, it is considered inconsequential and is not mapped in this study. A few years later, in June 1963, the lower Morrow B sandstone reservoir was discovered, followed by discovery of gas in the Primrose sandstone only 3 months later. Together, these sandstone zones constitute the two principal gas/condensate reservoirs in the field. The field opener for the B zone was the Amoco No. 1 Fields in the SE¼NW¼ sec. 11. It had an initial production of 2.5 MMCFGPD from 17 ft of net pay (≥10% porosity, or ϕ) and had produced ~3.8 BCF and almost 18 MBO through December 1998. The field opener for the Primrose sandstone was the Shell No. 1 Walton in the SE¼ NW¼ sec. 8. This well had a calculated open-flow potential of 15.2 MMCFGPD from 12 ft of net pay (≥10% ϕ) and has produced about 4.3 BCF and 12 MBO.

Many of the initial wells in Milder field were drilled during the mid- to late 1960s on 640-acre spacing. These wells usually had a cumulative production of 1 to >4 BCFG per well and were the best wells in the field. Subsequent development drilling took place mostly during the mid- to late 1990s, with increased-density wells having been drilled on 320-acre spacing. These wells generally have a much poorer production history and reduced reservoir pressures, indicating partial depletion. As of July 1999, there were a total of 47 producing wells—13 productive from the Morrow A, 31 from the Morrow B, 8 from the Morrow C, and 15 from the Primrose. Many wells were multiple-zone completions in two or three of the four productive zones, making well-performance determinations of individual zones more difficult. Principal operators are or have been Pan Am, Amoco, Medallion, Reading & Bates, and

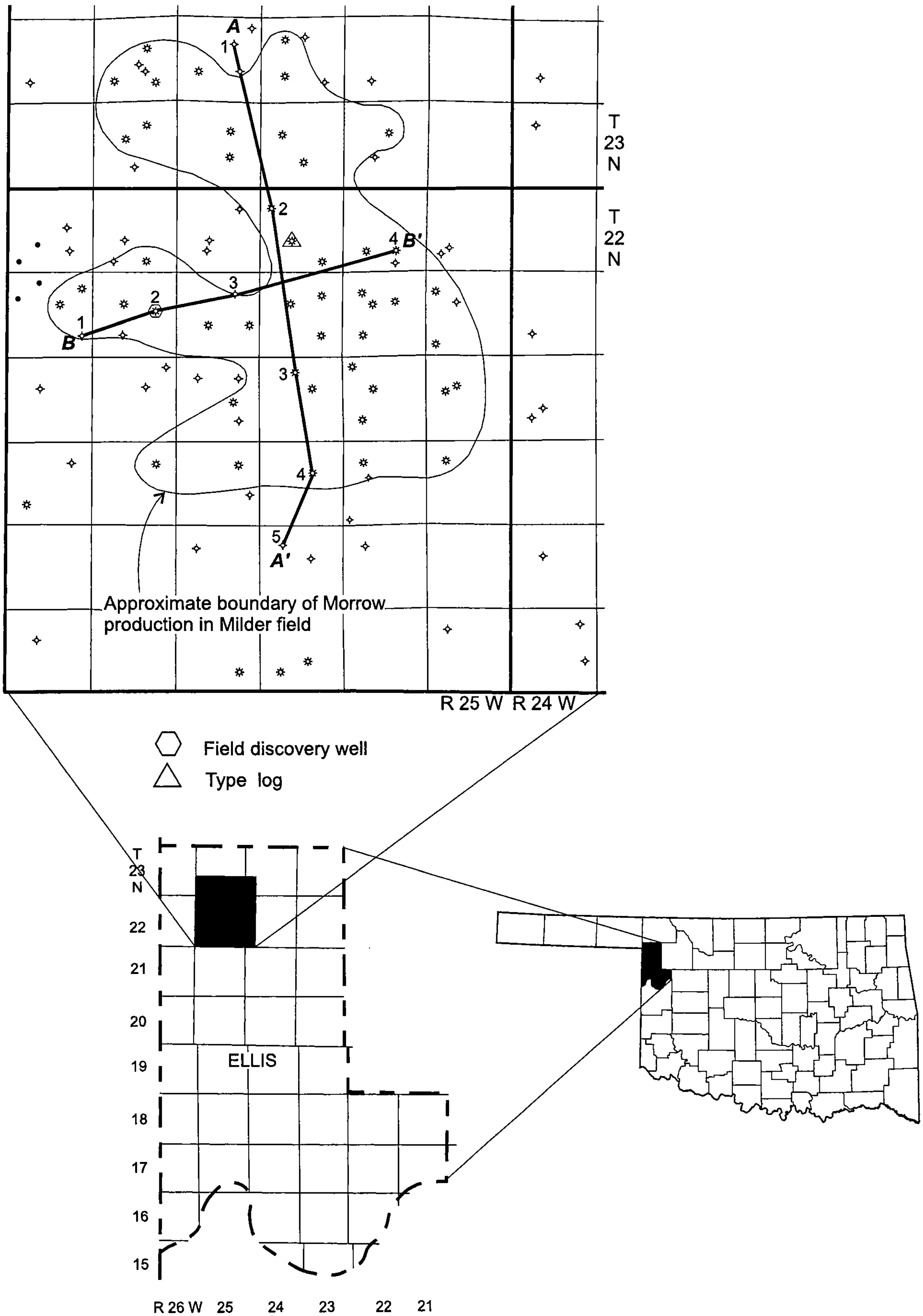


Figure 19. Generalized location map of Milder field in northern Ellis County, Oklahoma. Lines of cross sections A–A′ (Fig. 22) and B–B′ (Fig. 23) are shown.

Texaco. Most wells produced a significant amount of condensate, particularly the older wells; significant liquid production usually commenced a year or two after gas was initially produced. No significant amount of formation water is produced from any of the Morrow reservoirs. Several wells found additional pay above the

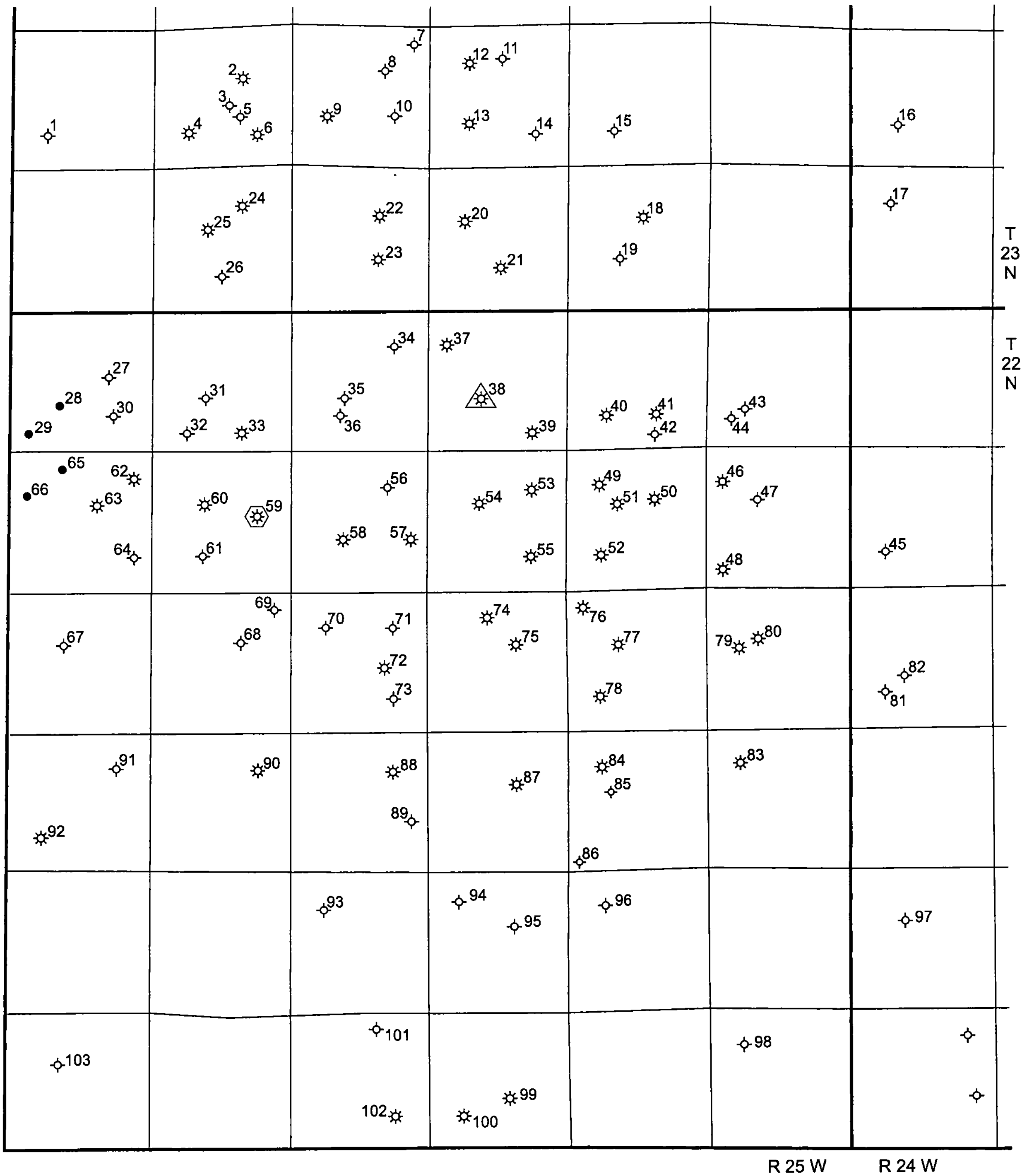


Figure 20. Map showing location and status of all wells in the Milder field study area. Numbers adjacent ot wells refer to well and production data tabulated in Table 2.

TABLE 2. – Well-Information Map and Tabulation Keyed to Figure 20, Showing Wells, Operators, Lease Names, Completion Data, Production Data, and Pressure Data for the Lower Morrow B Sandstone and Primrose Sandstone in Milder Field

Map no.	Operator	Well no.	Lease	Total depth	Completion date	Producing zone	Cumulative production Gas (MMCF)	Cumulative production Oil (BBL)	Date of first production	Initial Primrose production Gas (MCF)	Initial Primrose production Oil (BBL)	Initial Primrose production Water (BBL)	Initial L. Morrow "B" production Gas (MCF)	Initial L. Morrow "B" production Oil (BBL)	Initial L. Morrow "B" production Water (BBL)	Flowing tubing pressure	Shut in tubing pressure
1	Amoco	1	Peaster	9,200	Feb-78												
2	Allen & Parker recom. Unit Pet.	1	Lantelme	8,819	Aug-69	Morrow (C)[a]											
3	Pintex	1	Otter Cr.	6,440	Nov-87												
4	Cox	1	Peaster	9,020	May-82	Morrow (B[b] & C)	None reported	719 CM[c]	Apr-82 & Aug-83				49	4	7	NPD[d]	
5	Bradshaw	1	Lantelme	9,070	Mar-59												
6	Intercoast	1	Ellen	8,900	Mar-97	Morrow (B) & Primrose	35 (CM)		Mar-97	500	0	0	Commingled			980	1,300
7	Unit Petroleum	2	Romine	8,850	Mar-98												
8	Phillips Petroleum	1	Romine	9,000	Nov-96												
9	Unit Petroleum	1	Thompson	8,905	Aug-98	Primrose	34		Aug-98	440	0	1				900	1,350
10	HCM	1	Karn	8,950	May-75												
11	Amoco	2	Herman	8,785	Feb-97												
12	Crescendo	3	Herman	8,852	Nov-98	Morrow (A[e] & B)	No cum prod		Nov-98				4,332	0	0	1,150	1,250
13	Amoco	1	Herman	8,800	Sep-96	Morrow (B) & Primrose	2,013 (CM)[f]	9,423	Jul-96				2,267	25	0	1,831	2,039
14	E & V recom. Medallion	1	Nisler	8,900	Aug-81												
15	Phillips Petroleum	1	Richardson	8,950	Apr-97												
16	Cheyenne Pet.	1	Ruth	8,760	Feb-78												
17	Cheyenne Pet.	1	Simmon	8,800	Feb-76												
18	Oneok	1	Nine	9,100	Sep-89	Morrow (B) & Primrose	123 (CM)		Feb-90 & Feb-98	675	0	4	Commingled			220	?
19	Pan Am	1	Sill	9,002	Jan-63												
20	Amoco	2	Barrett	8,842	May-96	Morrow (A & B) & Primrose	775 (CM)[g]		May-96	1,400	0	0	Commingled			2,150	2,273
21	Pan Am	1	Barrett	9,050	Jun-62	Morrow (A) & Primrose	1,286 (CM)[h]	2,848	Nov-66	886	0	72				225	1,535
22	Phillips Petroleum	2-A	Hunter	9,000	May-97	Morrow (A & B)	27 (CM)		May-97				80	0	0	112	1,022
23	Pan Am	1	Hunter	9,065	Sep-66	Morrow (A)											
24	Intercoast	1	Lantelme	8,950	Mar-97	Morrow (B)	263	676	Nov-96				1,700	2	22	870	1,994
25	Burk	1	Bittman	9,060	Feb-81	Morrow (B)	434	3,700	Feb-81				——No IPF——				
26	Oneok	2	Bittman	9,080	Dec-89												
27	Shell	1	James	9,289	Jan-66												
28	Pintex	2	Gatsby	6,644	Jan-87	Tonkawa											
29	Pintex	1	Gatsby	6,666	Apr-85	Tonkawa											
30	Dunnavant	1	Jones	9,102	May-73												
31	Sunray	1	Suffield	9,197	Apr-64												
32	Medallion	1	Hamilton	9,236	Dec-88												
33	Cobra	1	Hunter	9,260	Jul-79	Morrow (B)	None reported	162	Nov-79 & Sep-80				450	15	10	NPD	
34	Champlin	1	Hunter	9,075	Jan-75												
35	Texaco	1	Hunter	9,155	Apr-64												
36	Benson-McCown	1	Hunter	9,150	Jun-89												
37	Amoco	1	Stevens	9,610	Jun-97	Morrow (A & B)	15 C-M		May-97				300	1	1	80	2,100
38	Pan Am	1	Purdum	9,200	Apr-61	Morrow (A) recom. Tonkawa	284		Nov-66 & Dec-85								
39	Medallion	1	Doris	9,125	Feb-88	Morrow (B)	1,291	4,194	Apr-88				1,100	10	5	1,704	2,114
40	H & L	1	Morgan	9,050	Nov-76	Morrow (B)	561	1,525	Mar-77				——No IPF——			?	2,710
41	Jones & Pellow	1	Shafer	9,030	Feb-74	Morrow (B & C) & Primrose	No cum prod		Feb-74	175	0	0	Commingled				NPD
42	Intercoast	2	Morgan	8,890	Nov-96												
43	Fisher-Webb Inc.	1	Stevens	8,904	Apr-82												
44	Kaiser-Francis	1	Fields	8,980	Dec-90												
45	Dyco	1	Rader	9,005	Nov-73												
46	H & L	1-A	Fields	9,020	Aug-97	Morrow (B)	111		Aug-97				581	0	0	81	954
47	Pan Am	1	Hardy	9,300	Aug-65												
48	TXO	1	Shafer	9,250	Feb-70	Morrow (B)	102	544	May-70 & May-73				3,613	?	?	NPD	
49	Amoco	3	Fields Unit	9,100	Jul-95	Morrow (C) & Primrose	No cum prod		Jul-95	26	0	0				NPD	

50	Amoco	4	Fields Unit	9,200	Oct-95	Morrow (B)	1,188	3,286	Sep-95				780	1	0	1,090	1,162
51	Amoco	1	Fields Unit	9,201	Jun-63	Morrow (B)	3,775	17,675	Oct-66 & Jun-95				2,500	0	0	780	2,710
52	Amoco	2	Fields Unit	9,268	Apr-91	Morrow (B & C) & Primrose	2,046 (CM)[f]		Apr-91				1,159	5	33	425	1,250
53	Amoco	3	Hunter	9,200	Apr-95	Morrow (A)											
54	Pan Am	1	Hunter	9,200	Sep-61	Morrow (A)											
55	Medallion	2	Hunter	9,220	Sep-88	Morrow (B)	1,075	2,443	Jan-89				967	0	3	190	1,625
56	Medallion	1	Jenkins	9,250	Aug-89												
57	Rig	1	Jenkins	9,250	May-83	Morrow (B)	None reported	1,143	May-83 & Nov-83				450	34	34	500	?
58	Pan Am	1	Jenkins	9,300	Jun-65	Morrow (B)	2,034	7,712	Dec-66 & Nov-80				No IPF			825	2,820
59	Amoco	2	Walton	9,376	May-94	Morrow (B & C) & Primrose	305 est.[h]	350	Jun-94	1,090	17	51				1,985	2,600
60	Shell	1	Walton	9,305	Sep-63	Morrow (C) & Primrose	4,300 est.[h]	12,000	Oct-64	15,200 CAOF						900	2,860
61	Intercoast	1	Herber	9,200	Nov-96												
62	Harken	1	Nicholson	9,300	Oct-88	Morrow (A)											
63	Pan Am	1	Nicholson	9,370	Oct-66	Morrow (C)											
64	TXO	1	Kuhlman	9,350	May-85												
65	Reading & Bates	2	Gatsby	6,650	Jun-85	Tonkawa											
66	Reading & Bates	1	Gatsby	6,650	Jul-85	Tonkawa											
67	Dyco	1	Redelsperger	9,364	Oct-73												
68	Shell	1	Kuhlman	9,350	Dec-64												
69	Search	1	Kuhlman	9,383	Sep-81												
70	OKM	1	State	9,193	Jan-75												
71	Western	1-A	State	9,185	Jul-71												
72	Western	1	State	9,196	Feb-70	Morrow (B)	18		May-70 & May-71				No IPF			?	2,671
73	Woods	1	Colo	9,242	Jun-73												
74	K-Stewart	1	Brown	9,200	Dec-91	Morrow (B)	357	113	Nov-91				598	0	80	190	1320
75	Western	1	Stevens	9,185	Jul-69	Morrow (B) & Primrose	4,853 (B) 1,714 (P) 37,271 (B)		Oct-69	No IPF			No IPF			1,835	2,875
76	Cross Timbers	3	Jontra	9,300	Apr-97	Morrow (A & B)	163 (CM)		Mar-97				625	0	0	250	1,050
77	Texaco	1	Jontra	9,195	May-64	Morrow (B)	4,408	26,795	Mar-67				1,300	8	2	2,047	2,537
78	Texaco	2	Jontra	9,232	Jul-82	Morrow (A)											
79	May Petroleum	1	State	9,300	Dec-81	Morrow (B)	118		Feb-83 & Dec-90				800	0	96	500	?
80	Duncan	1	State	9,150	Feb-70	Morrow (B)	89	243	Dec-70 & Apr-74				1,200	?	?	?	2,250
81	Basin Petroleum	1	Hardy	9,230	Apr-73												
82	Bradley	1	Hardy	6,481	Apr-79												
83	Woods	1	Haniotis	9,245	Dec-71	Morrow (A)											
84	Gussman	3	Weaver	9,310	Mar-73	Primrose	215	728	Sep-73 & May-74	No IPF						1,900	2,905
85	Western	2	Weaver	9,313	May-70												
86	Petroleum Inc.	1	Fields	9,442	Dec-70												
87	Western	1	Weaver	9,324	Feb-70	Primrose	2,831	18,133	Apr-70 & Jul-74	No IPF						2,419	2,942
88	Amarex	1	Fields	9,453	Feb-72	Primrose	285	920	May-72 & Apr-74	1,091	?	?				1,085	1,713
89	Reading & Bates	1	Fields	6,715	May-85												
90	Woods Petroleum	1	Herber	9,400	Jun-72	Morrow (B)	No cum prod		Jun-72				806	5	9	1,279	?
91	Arkla	1	Hein	9,490	Jul-74												
92	Geodyne	1	Hein	9,600	May-82	Morrow (A)											
93	Arkla	1	Tangney	9,575	Apr-74												
94	Petroleum Inc.	1	Ehrlich	9,455	Jun-71												
95[i]	Pan Am & Texaco	1	Emerson	9,658	Feb-59												
96	Ricks Expl	26A	MacKey	7,230	May-81												
97	Bonray	1	Shafer	9,335	Mar-83												
98	Texas Pacific	1	State	7,300	Jun-78												
99	Universal Res.	2	Walton	6,850	Jan-95	Tonkawa											
100	Moran Expl.	1	Walton	9,910	Jun-83	Tonkawa											
101	Flynn	33	Hagen	7,275	Oct-77												
102	Moran Expl.	1	Hagen	10,000	Apr-82	Morrow (A & B) & Primrose											
103	Pan Am	1	Baysinger	9,850	Jul-62												

[a]Morrow (C) = Lower part of lower Morrow.
[b]Morrow (B) = Middle part of lower Morrow.
[c](CM) = Commingled.
[d]NPD = No prssure data.
[e]Morrow (A) = Upper part of lower Morrow.
[f]Little contribution from the Primrose.
[g]Mostly Primrose and lower Morrow "B."
[h]Mostly Primrose.
[i]Map no. 95, twin well drilled to 7,230 ft in Oct. 1981; Ricks Exploration No. 27-A Hagen.

Note: Production is limited in the S½ of T. 22 N., R. 25 W., due to higher water saturation.

Morrow within the field: from the Tonkawa sandstone mostly, in sections 6 and 7. No deeper pool reservoirs are known in Milder field.

STRATIGRAPHY

A typical log from Milder field, and the stratigraphic nomenclature, are shown in Figure 21. In this well, the Morrow interval is about 650 ft thick and is informally divided into an upper and a lower unit. The lower Morrow is further subdivided, from oldest to youngest, into the Primrose sandstone, the C sandstone, the B sandstone, and the A zone. The A zone consists of sandstone grading upward into limestone that is correlative with the "Squaw Belly" zone. The extremely high resistivity of beds within the A zone corresponds with a photoelectric-log value (PE) of about 5 and is indicative of carbonate beds. Regionally, the top of the "Squaw Belly" defines the top of the lower Morrow. As a general rule, the upper member of the Morrow consists mostly of marine(?) shale, whereas the lower Morrow is predominantly sandstone with interbedded shale and lesser amounts of limestone. As stated previously, the main reservoir in Milder field includes the lower Morrow B and Primrose sandstone zones. The lower Morrow C sandstone is generally marginally productive in only eight wells, and the lower Morrow A sandstone produces from a few wells scattered throughout the field and may locally have produced 0.5–0.9 BCFG/well, although production is generally much less. Producing reservoirs within the Morrow Formation are identified in Table 2.

The top of the Morrow Formation in Milder field is recognized on logs by a "hot"-shale marker bed at the base of the Atoka Formation. Essentially, the base of the lowermost limestone in the Thirteen Finger limestone interval defines the Atoka–Morrow contact. This reference may vary through the field, as this contact may be unconformable. The base of the Morrow Formation is picked at the base of the Primrose interval; this is best identified on the conductivity log, as shown in Figure 21. This contact is commonly sharp where the conductivity is anomalously high (resistivity is very low) in the shale section that corresponds to the Springer Formation. The limestone beneath this shale interval has been identified as that of the Chester but which in this paper is correlated with the Springer Britt carbonate (IHS Energy Group, 1999).

Lower Morrow B Sandstone

The lower Morrow B sandstone occupies the middle part of the lower Morrow section and is the principal reservoir within Milder field. The total production from this reservoir is about 25 BCFG. The B sandstone has the best reservoir properties of any Morrow sandstone in the field and typically has about 14% cross-plot porosity (unadjusted for limestone matrix). In productive zones, the B sandstone has a significant SP deflection on logs.

As seen on gamma-ray logs, the sandstone usually has a sharp basal contact with shale (separating the B from the C interval) and has a blocky or slightly fining-upward textural profile (owing to an increase in clay content upward in the section). The B sandstone interval can consist of one apparently thick sandstone sequence but commonly is divided into two or more individual sandstone units in a stacked or amalgamated sequence. The lower part of the sand zone can be tightly cemented and calcareous, or it can have the best porosity of the interval. The limy nature at the base of some sandstone sections may be due to the presence of carbonate cementation in packstone-type strata common in tidal channels. The upper part of the sand zone typically grades upward into dirty sandstone or interbedded sandstone and shale and generally is too tight to be a reservoir, although porosity and production are attributed to the upper part where bedding is amalgamated. Some logs of the upper part of the B sand interval reflect a distinct coarsening-upward textural profile, just the opposite of the lower part of the B interval. Thus, B sandstone deposits in Milder field are typical of multiphase depositional cycles having both fluvial and marine origins. The sharp basal contact and overall fining-upward textural profile that usually characterize sandstone in the B interval could be attributable to a high-energy environment, such as in a channel. The overlying limestone of marine origin in the A interval and the underlying progradational deposits of the Primrose interval are evidence that deposition within the B cycle may have been tidally influenced or very nearshore marine in origin—essentially a depositional environment in between those of sediments above and beneath. The variation in log profile also indicates fluctuating depositional processes that characterize different depositional environments, as indicated previously.

Primrose Sandstone

The Primrose sandstone occupies the basal part of the lower Morrow interval and is a principal reservoir within Milder field but subordinate in gas reserves to the B sandstone. The total production from the Primrose sandstone reservoir in Milder field is about 11 BCFG. This sandstone is widely distributed over the study area and is locally thicker than any other sandstone unit in the field. However, porosity is only locally developed, which may be facies related. Much of the Primrose sandstone is tight, with porosity of <8%. Where productive, the Primrose sandstone typically has ~10% cross-plot porosity (unadjusted for limestone matrix). In productive zones, the Primrose sandstone has a moderate to weak SP-log deflection.

The Primrose interval commonly has a distinct progradational gamma-ray-log profile, consisting of an upper sandstone with a sharp basal contact and a blocky to fining-upward textural pattern overlying a lower sandstone sequence with a coarsening-upward textural pattern. The upper Primrose sandstone appears to have a downcutting relationship with under-

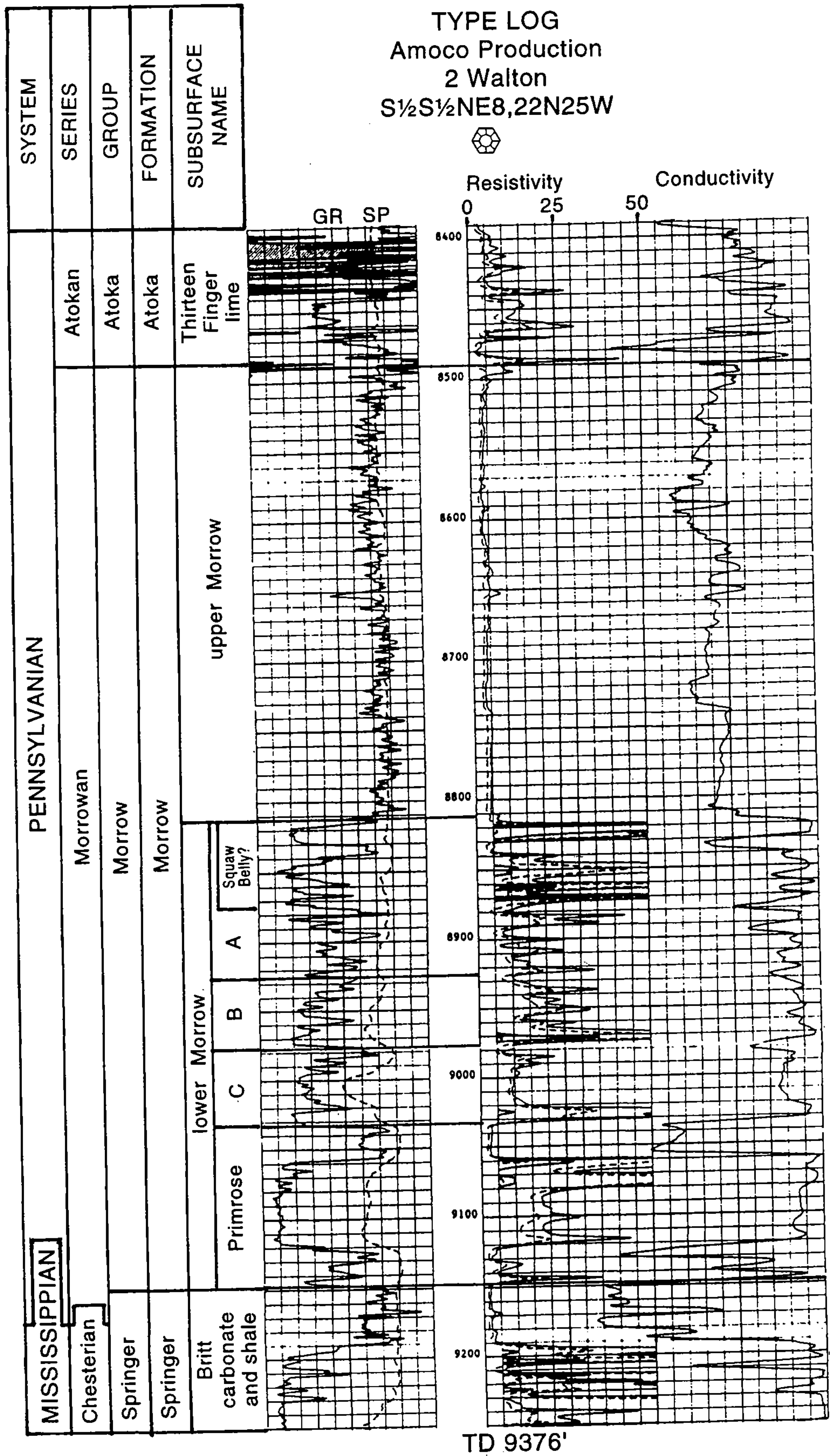


Figure 21. Type log for Milder field, showing formal and informal subsurface nomenclature of the Morrow Formation, as used in western Oklahoma. *GR* = gamma ray; *SP* = spontaneous potential.

lying strata, and its areal-distribution pattern is at right angles (north–south) to that of the lower Primrose sandstone (east–west). Primrose production is mostly attributed to the upper sandstone facies, which has attributes of a distributary or tidal channel. The underlying sandstone appears to be a distributary-mouth bar and is mostly tight and nonproductive throughout the field area.

CROSS SECTIONS

The stratigraphy of the Morrow Formation is best shown by two detailed stratigraphic cross sections constructed through Milder field. Section A–A′ is a dip section (Fig. 22, in envelope), and section B–B′ is a strike section (Fig. 23, in envelope). Both cross sections use a common datum: the top of the Primrose shale, just beneath the B sandstone interval.

Cross Section A–A′ (Figure 22)

This section lies along a north–south line that shows the updip limit of sandstone and the downdip water leg in each sandstone interval. Well 1 is a dry hole at the northern edge of the field. Here, the sandstone in the Primrose and in the B and C intervals is nearly absent.

Two miles to the south, well 2 produces from the B sandstone. The log shows the characteristic sharp basal contact, fining-upward textural profile, good SP deflection at the base of the B sand, and deep resistivity of about 6 ohm-m. The underlying Primrose interval shows a well-developed coarsening-upward textural profile characteristic of a delta-front sequence. The high resistivity in the Primrose sandstone is due to cementation, as the sand is tight and nonproductive.

Well 3, about 2 mi farther south, also produces from the B sandstone, but here the sandstone interval is composed of two distinct units in an amalgamated sequence. Only the lower half of the B interval produces, and the very bottom is tight. Again, this may be due to carbonate cementation in packstone strata (limy sediments) at the base of a channel. The cross-plot porosity of this reservoir is ~21%, although a small reduction may be necessary to account for the limestone matrix in which the log was run. The deep resistivity in the B reservoir is also ~6 ohm-m. The Primrose interval in this well reflects a considerably different log shape, whereas the upper sandstone has a very sharp basal contact above a shaly interval that separates it from the underlying Britt carbonate. This log character is typical of the producing facies of the Primrose. In this well, however, the Primrose sandstone is tight with only ~6% porosity (notice the absence of an SP response). Wells in Milder field never produce with much less than ~10% porosity.

A little more than 1 mi south of well 3, well 4 is productive from the Primrose. In this well, the B sandstone is about 54 ft thick, but despite porosity development the sandstone is not productive and calculates to be wet when considering the low resistivity in relationship to the porosity. The upper part of the Primrose interval, however, is productive from sandstone that is interpreted to be a distributary channel. This reservoir has a sharp basal contact, a good SP-log deflection, high resistivity (~72 ohm-m), and porosity (not shown) of ~16%. Sandstone underlying the productive interval has a coarsening-upward textural profile that is just the opposite of the producing sandstone unit above it. The gradual upward-coarsening profile is interpreted as lower delta-front in origin and actually extends from the Springer and continues into the lower Primrose section, thereby indicating a somewhat conformable relationship at this location.

Farthest to the south, at well 5, sandstones are present in all lower Morrow zones, but they are all wet. The B sandstone is stacked on top of the C sandstone and is differentiated only by the higher resistivity in the C zone. In the Primrose section, the characteristic progradational sequence is again evident, with delta-front sandstone having a coarsening-upward textural profile underlying a distributary-channel sandstone having a sharp basal contact. The Primrose is not productive in this well because the sandstone is tight and calculates to be wet despite the laterolog resistivty of ~11 ohm-m. A drillstem test (DST) in the Primrose sandstone interval recovered water.

Cross Section B–B′ (Figure 23)

This cross section is oriented east–west across the center of Milder field. The relationship of the Primrose delta-front marine sandstone to the incised distributary channels is shown and relates to the distribution pattern of hydrocarbon production in the field. In well 1, the Primrose interval consists entirely of distributary-mouth-bar deposits of the delta front. Two coarsening-upward cycles of sandstone deposition are evident, but in both the sandstone is tight and nonproductive. The overlying lower Morrow B sandstone tested wet from a DST. However, the sandstone in the bottom half of the B interval has cross-plot porosity >15% and a deep resistivity of 9–20 ohm-m, which should be sufficient for a gas well. Why this interval is not productive is unknown, but the log shape shows it to have a somewhat coarsening-upward textural profile rather than the "channel" type of log signature shown to be productive in all other wells where the B sandstone is productive.

At well 2, about 1 mi to the east, the Primrose interval is shown to have a thick incised distributary channel cut into the upper part of the distributary-mouth bar as illustrated in well 1. In well 2, the Primrose is productive from the channel facies, which is the principal reservoir. This reservoir has a little over 10% cross-plot porosity and about 15-ohm-m deep resistivity. Above the Primrose, the B interval is productive from a sandstone having a sharp basal contact (unlike that in well 1). Also, the C sandstone is productive from a marine-type sand body, as interpreted from the log shape.

At well 3, about 1 mi farther to the east, the Primrose still has the progradational characteristics of a distributary channel overlying the distributary-mouth bar (delta front). However, most of the Primrose channel sandstone is tight; a thin Primrose zone was perforated in the upper part of the sandstone interval, but a bridge plug was set to isolate this zone from the main channel sandstone directly below. The well was then completed in the lower Morrow B sandstone interval, consisting of stacked sandstone beds with each having a sharp basal contact. Typical reservoir parameters in the B sandstone include a cross-plot porosity of ~13% and a deep resistivity of ~10 ohm-m. Note that the lower part of the B sandstone is very tight, as in many other wells. Again, this may be due to calcite cementation in a packstone-type facies.

The channel facies within the Primrose interval is absent at well 4, which is at the eastern edge of the field ~2 mi east of well 3. In well 4, the Primrose consists entirely of marine delta-front sediments, and the coarsening-upward textural profile should be apparent from the gamma-ray log. This is one of a few wells completed in the Primrose where the sandstone is not a channel. However, this sandstone has marginal net porosity (very near or slightly less than 10% porosity). The overlying B sandstone thins considerably to the east and thins to <10 ft (gross), 0 ft (net), in sec. 1, only 1 mi away.

STRUCTURE

Milder field is on the northern edge of the Anadarko basin (Pl. 3), and the dip of the Morrow in the subsurface is to the south at about 1° (~110 ft/mi). A detailed structure map of the study area (Fig. 24) shows the configuration of the top of the shale that overlies the Primrose interval. As can be seen on this structure map, the highest position of the Morrow Formation within Milder field is just above –6,274 ft and occurs in the north-central part of the field in the W½ sec. 27, T. 23 N., R. 25 W. The south-central part of the field extends to about –6,800 ft in secs. 21 and 22, T. 22 N., R. 25 W. The vertical relief of the gas column, therefore, is about 526 ft.

A cursory view of the regional structural configuration of the top of the Morrow Formation in the Anadarko basin (Pl. 3) indicates that the Anadarko shelf and basin area surrounding Milder field is uncomplicated by faulting or folding. The relatively uniform structure-contour spacing (on a 50-ft contour interval), as shown in Figure 24, indicates a relatively uniform southerly dip with no major displacements. Hydrocarbon trapping, therefore, is strictly stratigraphic.

MORROW SANDSTONE DISTRIBUTION AND DEPOSITIONAL ENVIRONMENTS

The two principal reservoirs in Milder field are the lower Morrow B and Primrose sandstones. Isopach maps consisting of gross- and net-sandstone thicknesses for both these reservoirs are included in the study.

Lower Morrow B Sandstone

Figure 25 shows the gross thickness of the lower Morrow B sandstone for all the wells in the study area. The gross-sand thickness is the total thickness of sandstone regardless of porosity, as interpreted from gamma-ray logs (determined from the 50% sand/shale line). The 10-ft-thickness line is approximately the limit of clean sandstone that has porosity development. Within the mapped area, the isopach map never reaches a zero thickness, as thin, tight, dirty sandstone lenses that are not of reservoir quality (not having sufficient porosity, permeability, and thickness) persist over a large area. Areal-distribution patterns of the B sandstone show elongate trends to the northwest–southeast and an overall thickening to the south in a basinward direction.

The gross thickness of the B sandstone within the Milder study area ranges from <10 ft along the northern edge of the field to >50 ft in the southern part. Where productive, the gross sandstone is usually about 20–45 ft thick and averages ~37 ft. Thickness variations are not generally extreme over short distances except along the north edge of the field, where it thins abruptly to <10 ft.

The B sandstone interval almost always contains mostly sandstone rather than shale, and this observation is puzzling when considering depositional environments. Although many of the log signatures appear channel-like in having sharp basal contacts and fining-upward textural profiles as noted on gamma-ray logs (cross sections A–A′ and B–B′, Figs. 22, 23), no abandoned-channel or channel-margin facies are recognized, which would be present in most channel environments dominated by fine-grained sandstone. Therefore, the environment of deposition most likely incorporates a significant influence from marine sources, although the sandstone trends do not map or appear on logs to be shoreline sands, nor do they appear to be "typical" marine-bar (detached-shelf) deposits, as many geologists refer to them. The stacked arrangement of individual sandstone beds having different log shapes further supports the interpretation that deposition occurred during multiple events having different processes. A very shallow, nearshore environment with storm and tidal currents is the most likely depositional setting.

The net-sandstone isopach map of the lower Morrow B interval (Fig. 26) shows the thickness of sandstone in wells having porosity ≥10%, which was judged to be the approximate lower limit of porosity in producing wells within Milder field. Porosity values were determined by visually averaging the cross-plot porosity on density–neutron logs. No adjustments were made to account for logs recording porosity based on a limestone matrix (density of 2.71 g/cm^3), which is routinely used by logging companies. Density-porosity determinations in the absence of a neutron log were made by multiplying the observed density porosity by a factor of <1.0 (usually 0.7–0.8) to account for the gas effect on the density log. In producing Morrow wells, the net-sand thickness ranges from only a few feet to >30 ft.

Throughout the mapped extent of the field, the average thickness is ~16 ft. The net-sand isopach map (Fig.

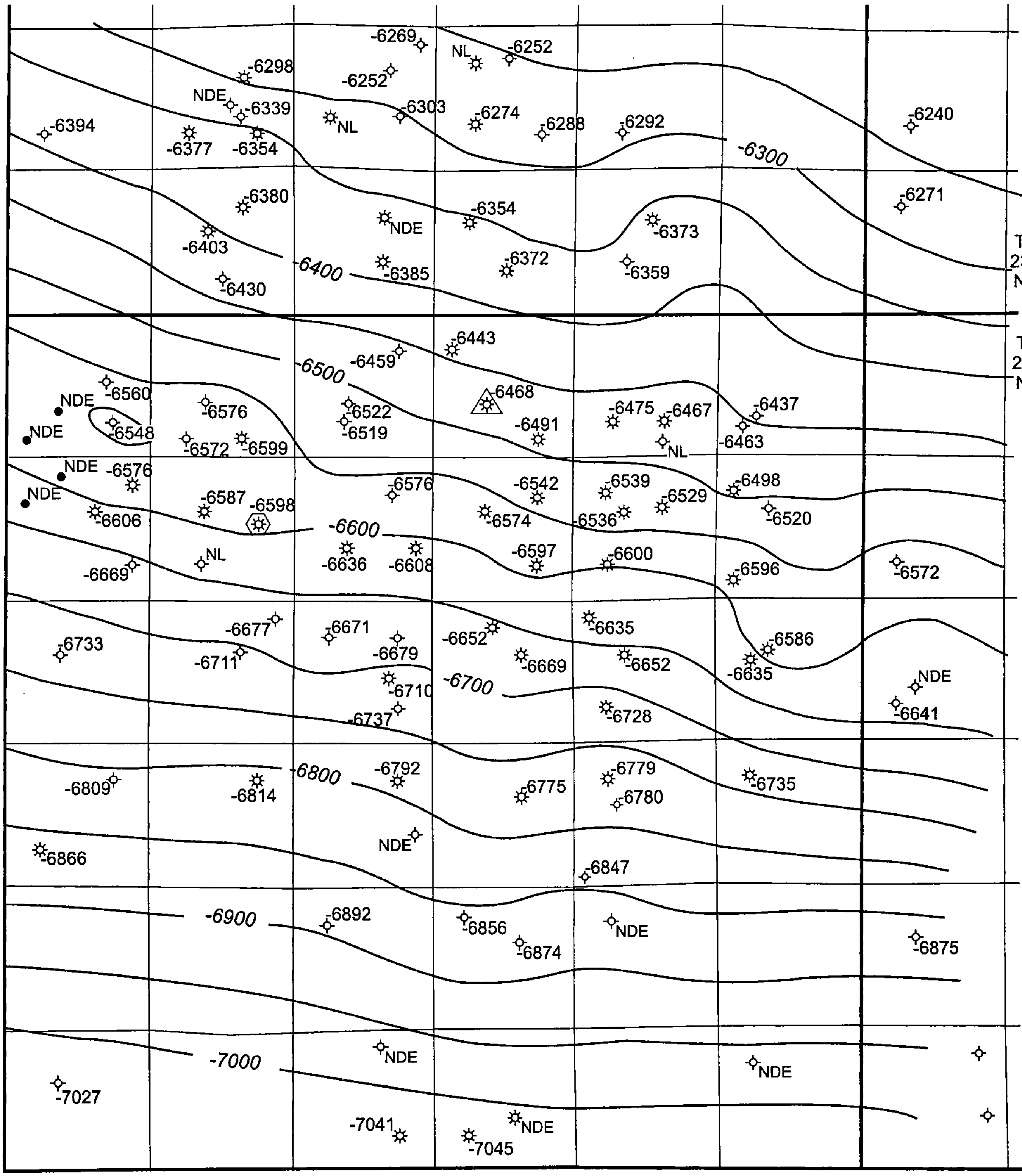


Figure 24. Structure map depicting the top of the shale marker bed above the lower Morrow Primrose sandstone, Milder field. Contour interval is 50 ft. Datum is mean sea level. See Table 2 for well names.

26) is similar in overall appearance to the gross-sand isopach map (Fig. 25), but with a significant reduction in sandstone thickness. This is due to clay-rich and tightly cemented zones within the lower Morrow interval that are included in the gross-sandstone thickness. The difference between the gross- and net-sandstone thickness is usually 10–30 ft for any given well; this constitutes a decrease by as much as 90% from the

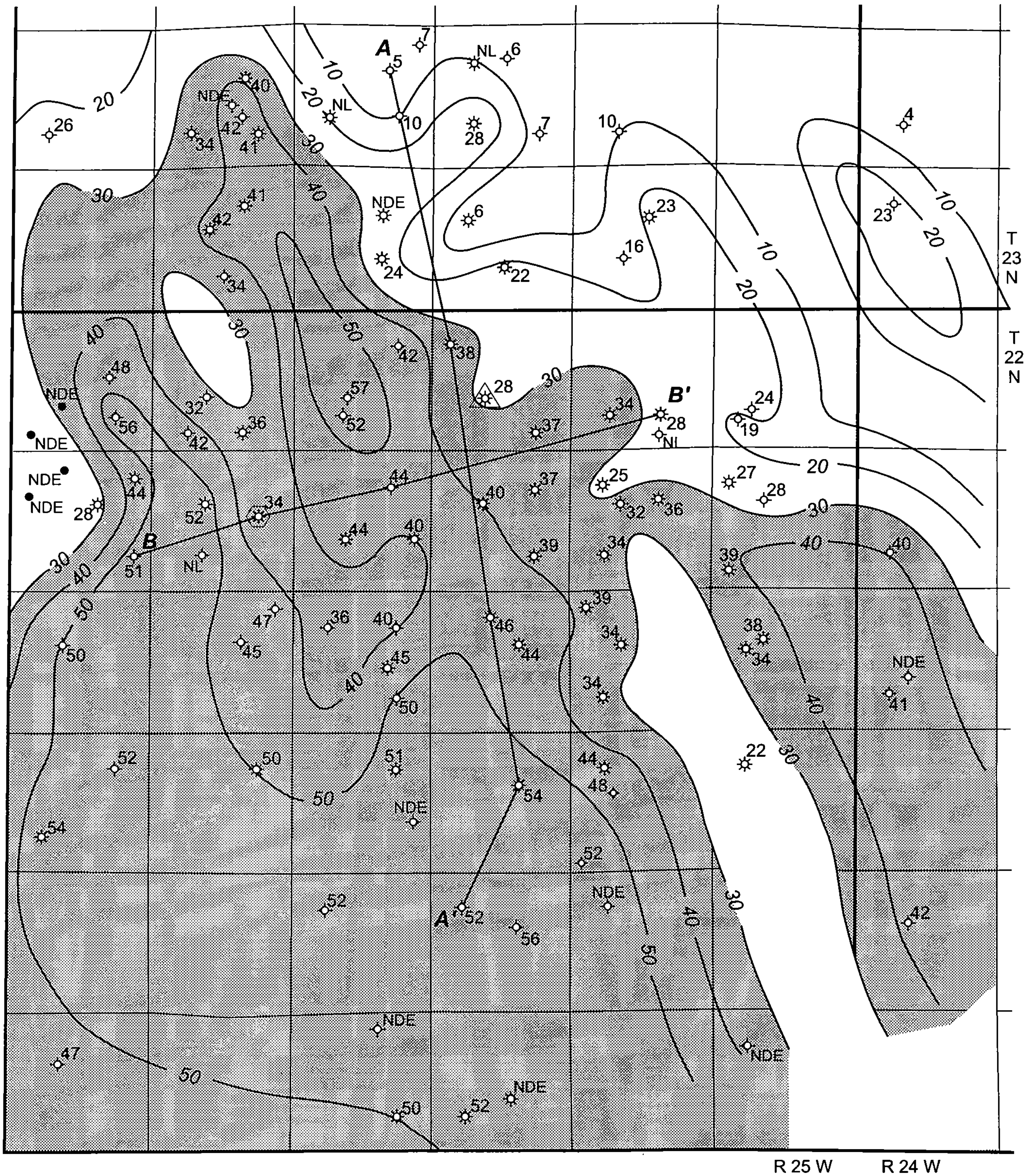


Figure 25. Gross-sandstone isopach map of the lower Morrow B sandstone in Milder field. Contour interval is 10 ft. See Table 2 for well names. Lines of cross sections A–A′ (Fig. 22) and B–B′ (Fig. 23) are shown.

original gross-sandstone thickness. A 50% reduction is more typical, and the net-versus-gross-sandstone relationship can easily be seen on any of the porosity logs shown in cross sections A–A′ and B–B′ (Figs. 22, 23). Most of the net sandstone has porosity in the range of 10–16%, some as high as 21%, but this is unusual. A higher porosity cutoff above 10% would have reduced the areal extent of the reservoir considerably.

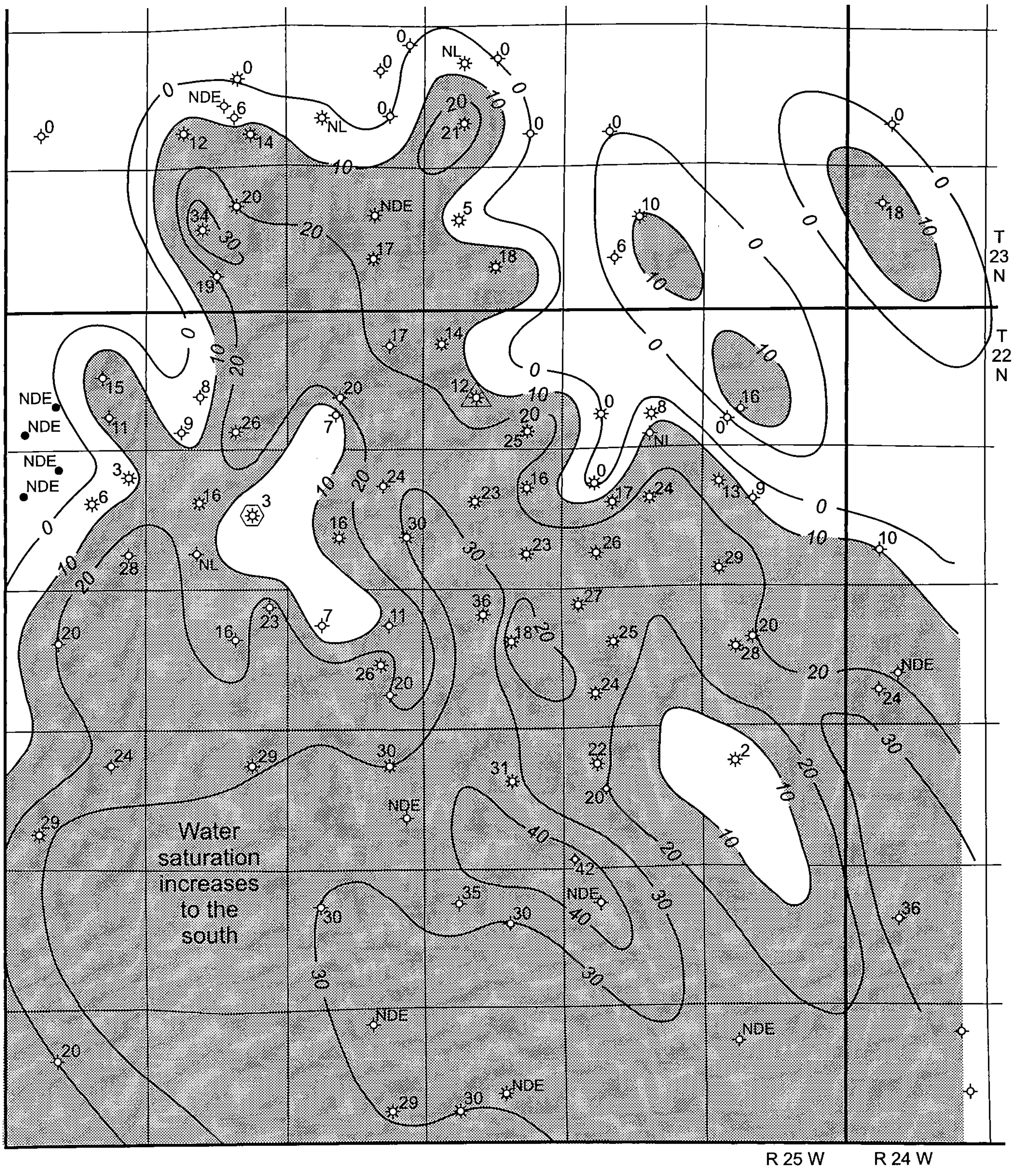


Figure 26. Net-sandstone isopach map of the lower Morrow B sandstone in Milder field. Net sandstone has log porosity of ≥10%. Contour interval is 10 ft. See Table 2 for well names.

There is no distinct and uniform gas–water contact within the B sandstone in Milder field, although all wells in the southern half of T. 22 N. are nonproductive or have minimal gas potential. In these areas, the sandstone usually calculates to be wet when considering porosity and true resistivity for individual wells. Therefore, the extent of the producing reservoir for the B sandstone was interpreted to include areas having net sandstone only in the north half of T. 22 N., excluding secs. 1, 2, 6, 7, 17, and 18; and in the south third of T. 23 N., excluding secs. 25 and 36.

Compartmentalization in the lower Morrow B sandstone does not seem to be prevalent when considering reservoir pressures, as all wells brought on-line—after the early 1960s wells were drilled—experienced significant pressure depletion. The net-sandstone isopach map supports this general concept in that nowhere in the field does the reservoir "zero out" even though individual sandstone beds vary considerably in thickness and lateral extent. However, when calculating water saturation, there seems to be a wide variation in values (explained later in the section "Formation Evaluation"), even in producing areas. This characteristic of Milder field is unnerving for development purposes, and the variation of water saturation in producing areas is not always supported by sandstone trends identified on the net-sand isopach map (Fig. 26).

Lower Morrow Primrose Sandstone

Figure 27 shows the gross thickness of the entire lower Morrow Primrose sandstone interval for all the wells in the study area. Gross sandstone in this reservoir study includes the total thickness of sandstone regardless of porosity, as interpreted from gamma-ray logs (determined from the 50% sand/shale line). The Primrose sandstone commonly consists of more than one sandstone sequence and is spatially extensive over most of the Anadarko basin. In the study area, the Primrose sandstone thins appreciably to the north in a shelf direction but persists locally for 10–20 mi farther north (Pl. 1). Areal-distribution patterns of the Primrose sandstone show elongate east–west trends and thin trends roughly at right angles. The erratic variations in gross Primrose sandstone thickness in the Milder study area is a strong indication that unique facies and depositional processes occur in the area.

Gross-sandstone thicknesses range from ~30 to almost 80 ft and average ~42 ft throughout the study area. The most conspicuous trend occurs along the border between T. 22 N. and T. 23 N., where a thick east–west sand "belt" occurs. In this area, the Primrose is about 50–70 ft thick. Thickness variations, however, can be great, particularly in the north-central part of T. 22 N., where the sandstone thins from 79 ft in the SE¼ sec. 9 to <20 to 30 ft directly to the south and east in secs. 16 and 10, respectively. The thinning of sandstone within the B interval is most apparent within a general trend extending in a north to southeast direction, cutting across the thick east–west sandstone "belt" described previously.

On the basis of well-log interpretations, particularly gamma-ray profiles, two distinct sandstone facies are recognized in Milder field. The most important facies—usually the only productive sandstone in the Primrose interval—is thought to be distributary channels. These channels are part of a progradational sequence and represent the shallowest deposition in what may be lower delta plain or estuarine in origin. The channel sandstone has a sharp basal contact, a blocky to fining-upward textural profile, and usually has the best porosity and permeability of any sandstone in the Primrose interval. Channel sandstone varies considerably in thickness, as shown in both field cross sections (Figs. 22, 23) and can be at least 60 ft thick with demonstrated downcutting (see well 2, Fig. 23). Underlying, or adjacent to, the distributary channels are subaqueous-marine distributary-mouth-bar (delta-front) deposits. These are best represented at wells 1 and 4 in cross section B–B′ (Fig. 23) and exhibit the characteristic coarsening-upward textural profile which is opposite that of the channels. The distributary channels cut down into the delta-front sandstones and therefore are younger, even though stratigraphically they may appear to be lower in the section (compare wells 1 and 2, Fig. 23).

Variations in gross Primrose sandstone thickness (Fig. 27) occur for a variety of reasons that are commonly facies related. At some wells, such as wells 1 and 2 in Figure 22, the Primrose interval contains relatively little sandstone because of poor bar development in the delta-front-margin environment. Much thicker sandstone accumulations do occur with the simultaneous occurrence of a thick distributary-channel sequence overlying delta-front sandstone, such as at wells 2 and 3 in Figure 23, or where delta-front deposits represent central-bar facies, such as at well 1 in Figure 23.

The net-sandstone isopach map of the lower Morrow Primrose interval (Fig. 28) shows the thickness of sandstone in wells having porosity ≥10%, again judged to be the approximate lower limit of porosity in producing wells within Milder field. Porosity values were determined by visually averaging the cross-plot porosity on density–neutron logs. No adjustments were made to account for logs recording porosity based on a limestone matrix (density of 2.71 g/cm^3), routinely used by logging companies. Density-porosity determinations in the absence of a neutron log were made by multiplying the observed density porosity by a factor <1.0 (usually 0.7–0.8) to account for the gas effect on the density log. In producing Morrow wells, the net-sand thickness ranges from only a few feet to >30 ft, although even thicker occurrences of net sandstone are noted in sec. 1 (46 ft), where the Primrose is nonproductive. Throughout the mapped extent of the study area, the average net-sandstone thickness is ~5 ft (including many places having gross sandstone but no net sandstone). However, the average net-sandstone thickness in wells having Primrose production is ~12 ft. The net-sandstone isopach map (Fig. 28) has no visual similarities to the gross-sandstone isopach map (Fig. 27), as the Primrose sandstone is generally tight. Only scattered areas have net porosity, which are almost always in the channel sandstones, as shown in cross sections A–A′ and B–B′ (Figs. 22, 23). The reduction of net-sandstone thickness versus gross-sandstone thickness may be due to clay-rich and tightly cemented zones. This interpretation can sometimes be made from resistivity logs, as the resistivity in tightly cemented zones is considerably

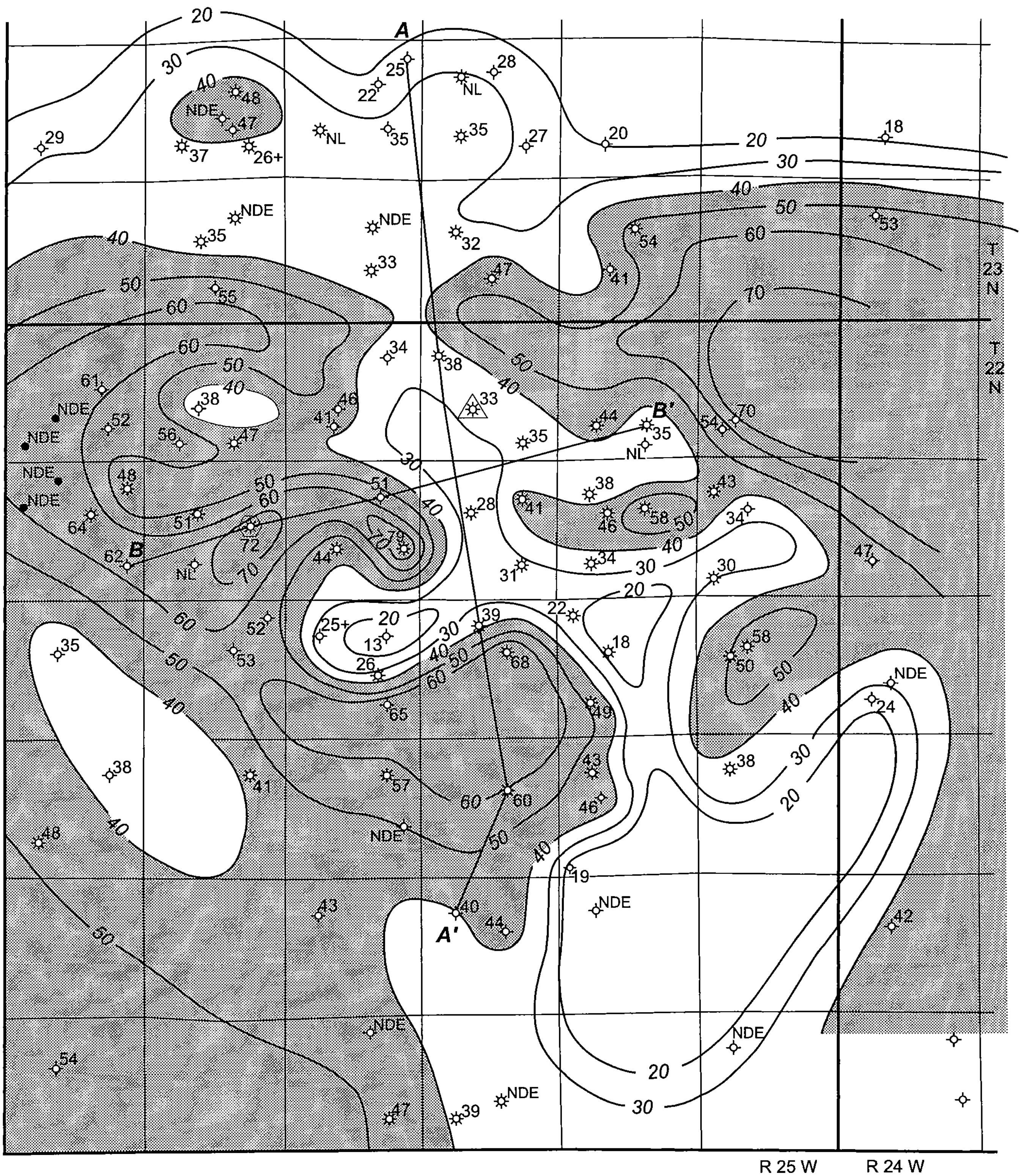


Figure 27. Gross-sandstone map of the lower Morrow Primrose sandstone in Milder field. Contour interval is 10 ft. See Table 2 for well names. Lines of cross sections A–A′ (Fig. 22) and B–B′ (Fig. 23) are shown.

higher than in porous zones. The differences between the gross- and net-sandstone thicknesses are much greater in the Primrose sandstone in comparison to the overlying Morrow B sandstone. Many wells with 30–40 ft of gross Primrose sandstone have no net sandstone, a decrease of 100%. Where productive, most of the net sandstone has porosity in the range of 10–14%, sometimes as high as 17%, but this is unusual. Overall, the

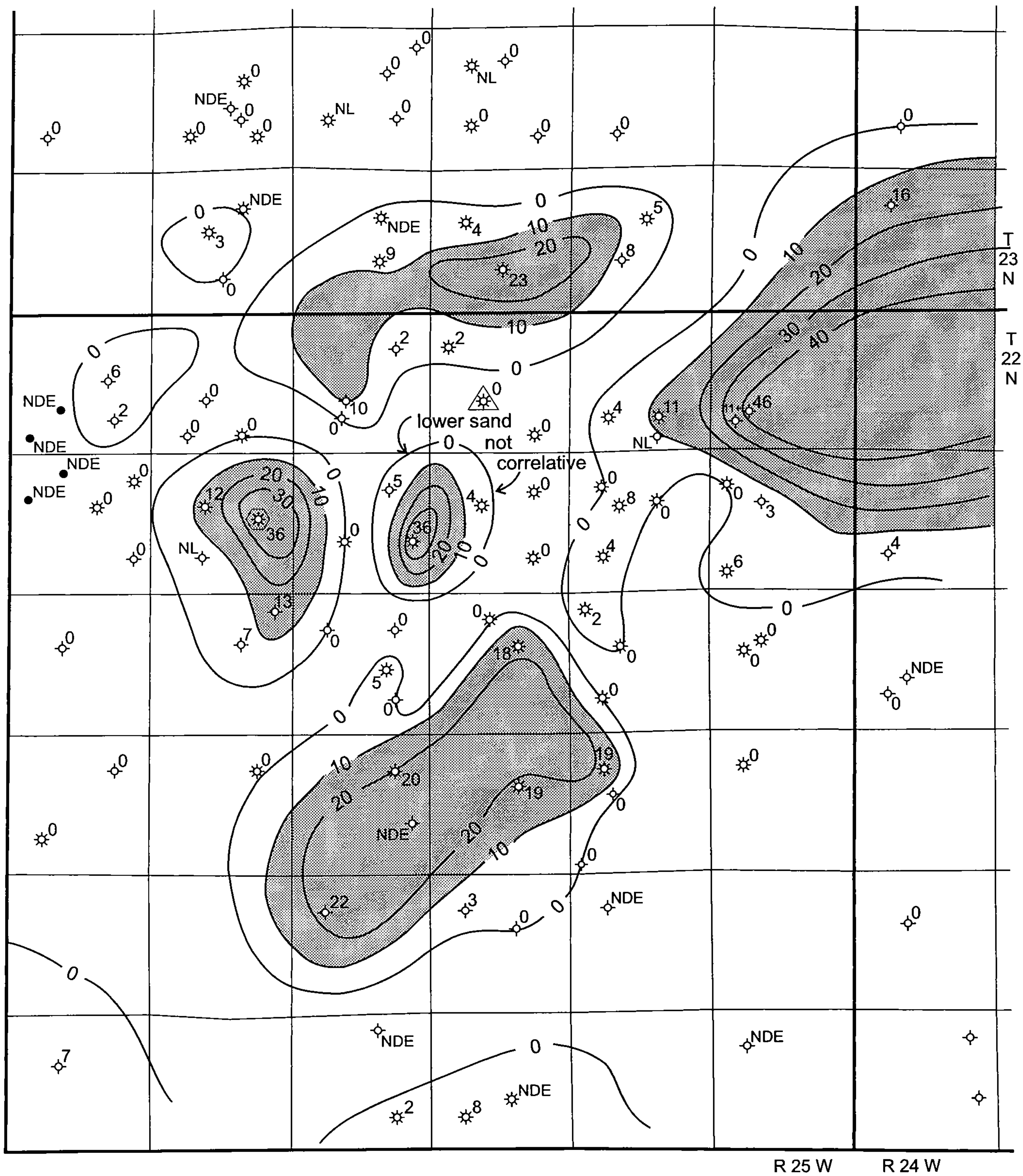


Figure 28. Net-sandstone isopach map of the lower Morrow Primrose sandstone in Milder field. Net sandstone has log porosity of ≥10%. Contour interval is 10 ft. See Table 2 for well names.

average porosity of the Primrose sandstone throughout the study area is ~9%. A higher porosity cutoff above 10% would have reduced the areal extent of the reservoir considerably.

Distribution patterns of net Primrose sandstone are seen in several isolated "pods," as shown in Figure 28. This is not to say that there is no sandstone between the pods, only that there is no sandstone having porosity >10% between the various pods. In other words, the porosity "zeros out," forming compartmentalization. Essentially only three of these pods are productive: the northern one straddling the T. 22 N.–T. 23 N. line, a middle pod centered in sec. 8, and another centered in secs. 15, 21, and 22. All three of these pods have net sandstone that originated predominantly from channel facies. Net Primrose sandstone occurs at two other places in the study area but is only marginally productive or nonproductive. The pod of net sandstone straddling secs. 9 and 10 has porosity development primarily in a sand body lower in the Primrose section with no show of gas. A channel sandstone slightly higher in the section at the same place is correlative with productive sandstone in sec. 8 but did not test gas despite favorable reservoir parameters—deep, or true, resistivity (R_t) >10, porosity >10%. The thick and areally extensive net Primrose sandstone in the northeastern part of the study area is entirely of marine origin (delta front) but tested dry or had only marginal Primrose gas production despite having reservoir characteristics similar to nearby Primrose wells producing from channel-sandstone reservoirs.

No distinct and uniform gas–water contact in the field applies to the Primrose interval. Productive wells have reservoirs that can generally be attributed to sandstone deposition in a channel environment versus a marine-delta-front origin. Even within pods of sandstone having similar facies, a clear distinction of water versus gas is hard to determine. As an example, the southern pod of net Primrose sandstone centered in secs. 15, 21, and 22 has four Primrose producers. Yet the well in sec. 28 did not test gas and is dry despite similar reservoir parameters. Obviously, water-saturation calculations must incorporate different values for water resistivity (R_w), and even calculations for deep formation resistivity (R_t) are suspect for having significant errors throughout the field because of clay problems. Nevertheless, in exploration or development drilling, it is important to target the channel facies preferentially, as they have the highest probability for production of commercial gas.

FACIES MAPPING OF SANDSTONE WITHIN THE PRIMROSE INTERVAL

Depositional environments were interpreted from wireline-log signatures in order to illustrate the generalized depositional setting of sandstone within the Primrose interval in the Milder field study area (Fig. 29). Logs from all wells in this area were used for interpretation, particularly gamma-ray and density–neutron logs. Two distinctly different depositional environments are interpreted for the mapped area, although the channel sandstone is the main producing reservoir of the Primrose interval in the field.

Distributary-Channel Deposits

The depositional environment of these sediments appears to be simple incised distributary channels originating within the lower delta plain. The distributary channels cut down into the underlying distributary-mouth-bar deposits and together formed a progradational sequence whereby succeeding younger sediments of the channel environment were deposited in areas previously occupied by deeper water sediments (delta-front environment). Within the distributary-channel facies, sediments consist predominantly of sandstone. On logs, the sequence has a blocky or fining-upward textural profile, which is caused by variations in abandonment stages. Blocky profiles are caused by more rapid abandonment, whereas typical fining-upward profiles indicate a more gradual abandonment process. Because of the morphology of channel sandstones (areal-distribution pattern and stratigraphic profile), they are interpreted to be a variation of a longitudinal bar (rather than a point bar). The reasons for this interpretation include (1) a sharp basal contact with shale, (2) an overall blocky or abruptly fining-upward textural profile on gamma-ray logs, and (3) an elongated map pattern, with some thinning and thickening.

The channel deposits appear to originate in the southern part of T. 23 N. and thicken over a wider areal extent to the south in a basinward direction (Fig. 29). This map pattern is also characteristic of tidal or estuarine channel deposits, and the effect of tidal currents during deposition of the upper Primrose channels may have been significant. A logical extension of this study would be to map the channel facies separately, which time did not permit. Because of the complex interfingering of sandstone bodies in the Primrose interval, it is difficult to distinguish channel-margin or abandoned-channel deposits.

Delta-Front (Distributary-Mouth-Bar) Deposits

Sandstone that is interpreted to have a coarsening-upward textural profile, as indicated on gamma-ray, resistivity, and porosity logs, is considered to originate from different depositional processes from those of distributary-channel deposits. Sandstones with these characteristics are not generally productive within Milder field but do occur throughout the entire study area. They are particularly extensive and thick in the north half of the study area (Fig. 27). Good examples of marine delta-front sandstone sequences are shown in wells 1 and 4, cross section B–B′ (Fig. 23). In wells 2 and 3 of the same cross section, the upper part of the delta-front sequence is truncated by downcutting of distribu-

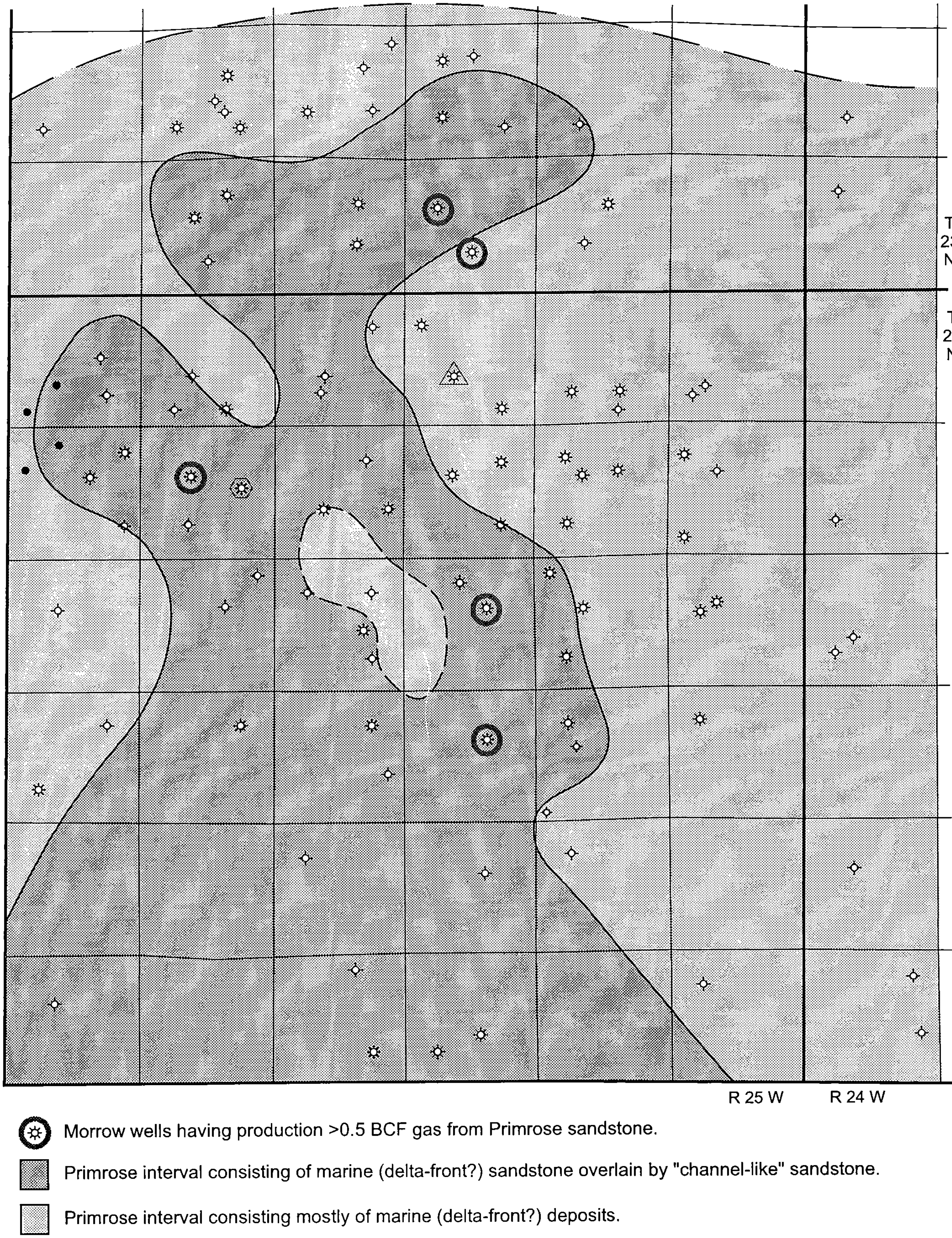


Figure 29. Depositional-facies map of the lower Morrow Primrose sandstone.

tary channels, which have a very different log shape. Again, the relationship of these different depositional processes (channeling versus subaqueous-marine deposition) indicates a progradational sequence—one that is shallowing vertically through the section—that can be interpreted entirely from logs without the aid of cores.

Although distributary-mouth bars can be good reservoirs, they are commonly clay-rich (distal-bar facies) or are extremely tight so that their potential as good reservoir rock is diminished. These two properties occur for several reasons, but notably because lower- or distal-bar facies contain a large percentage of interstitial clay and interbedded shale, and the "clean" upper-bar facies have no secondary porosity (the nearly pure quartz sandstone has few unstable constituents that alter to form secondary porosity).

It is difficult to differentiate between some fluvial and marine facies. The recognition of these two facies is important, however, and can be used effectively in exploration or step-out drilling in the development of fluvial-trend reservoirs, such as in Milder field.

CORE ANALYSIS

No core analyses of the Morrow sandstones in Milder field, or of similar nearby deposits, were available for study.

FORMATION EVALUATION

The correlation and evaluation of Morrow sandstone in Milder field is generally much more difficult than for any of the younger Cherokee Group deposits of Oklahoma. Correlations can be problematical, because sandstone usually occurs throughout a relatively thick interval and individual sandstone zones can be highly erratic in thickness and areal distribution. Additionally, individual sandstone intervals commonly have multiple depositional episodes whereby depositional environments are extremely variable and complicated. Yet it is not sufficient to merely map sandstone intervals as a single thick unit to adequately evaluate and characterize these sediments.

Morrow sandstone can be relatively "clean," but on a regional scale the formation has tendencies to contain certain amounts of secondary clays and minerals that may interfere with production, completion techniques, or formation evaluation. Distribution patterns of many of these secondary authigenic minerals are shown in Figures 13–15 in the regional discussion (Part I) of this play. The most problematical mineralization in the Primrose appears to be silica and calcite cementation, and chlorite. Chlorite reacts with hydrochloric acid (often used in well completions) and forms an insoluble gel that destroys permeability and production capabilities. Chlorite in combination with other clay types also skews the deep, or true, resistivity measured at the wellbore during logging and accentuates the gamma-ray response in sandstone. These effects on the reservoir make formation evaluation more difficult and have been suspected of interfering in the evaluation of sandstone in Milder field.

The deep, or true, resistivity (R_t) of producing sandstone in the Morrow Formation ranges from ~8 to 40 ohm-m and is usually in the range of 10–30 ohm-m. A deep resistivity of 3–6 ohm-m almost always indicates that the zone is wet. With a typical porosity of 10–14%, the Morrow probably won't produce significant gas with less than ~8 ohm-m of resistivity. On the other hand, when the deep resistivity surpasses ~70 ohm-m, the Morrow usually is tight because of cementation. Because of poor overall permeability, there is generally little separation between the deep- and shallow-resistivity curves. This indirect method of determining reservoir quality is based upon the assumption that the amount of invasion of drilling fluids is proportional to the porosity and permeability of the reservoir, and that the amount of separation between the shallow- and deep-resistivity curves is affected by the degree of invasion.

Porosity determinations using density–neutron logs were estimated by taking the cross-plot porosity of the two logs. By using this simple procedure, porosity values in the "cleanest" part of the sandstone interval ranged from 4% to 21% (average ~14%) for the Morrow B sandstone and 2% to 17% (average ~9%) for the Primrose sandstone. Most wells were logged by using the density–neutron combination, and a matrix density of 2.71 g/cm^3 (limestone) was routinely used by logging companies. Therefore, porosity determinations are theoretically a few percentage points higher than if a sandstone-matrix density of 2.68 g/cm^3 had been used. Porosity values used in this study were pessimistically estimated to take this variation into account but were not systematically reduced by 2–3% percentage points as some evaluators have done. Where only density porosity was available, values were attenuated by multiplying the indicated density porosity by a fraction, usually 0.7 or 0.8, so that the resulting porosity accounts for some of the normal gas effect (in producing wells) that causes the density porosity to be too high. The observed gas effect (crossover) in productive intervals may be 4–13 porosity units (see well 2, cross section B–B′, Fig. 23). In nonproducing or tighter zones, the gas effect is much less, and the multiplier should be higher (in the range of 0.8–0.9) (see well 1, cross section B–B′, Fig. 23).

In this study, water-saturation (S_w) calculations for the Morrow sandstone seem to be extremely variable and range from ~16% to >100% (which of course is not correct). Even in producing zones, some calculations were unrealistically high (>75%). No reliable and consistent S_w values were determined within the field. For many wells, the calculated S_w did not realistically reflect the actual well performance or well status (dry versus producing). Calculations were made by using the equation $S_w = \sqrt{F \times R_w / R_t}$. The value for formation-water resistivity (R_w) that proved to best fit reservoir conditions was assumed to be 0.09 ohm-m at formation temperature, although it is apparent that a variation of R_w values may better characterize individual wells. A modified Archie equation for formation factor ($F = 0.81/\phi^2$) was used, although the regular Archie equation ($F = 1/\phi^2$) was also used in an attempt to match well performance. However, the modified equation seemed to better characterize this particular type of reservoir (tightly cemented); use of the traditional Archie equation resulted in calculated S_w values that were even higher and more unrealistic. Values for true resistivity (R_t) were taken directly from the deep-resistivity logs, but the resistivities may have been suppressed for some reservoirs (clay problems?), causing S_w values to be too high. Porosity values were also taken directly from density–neutron, density, or sonic logs in a manner described above. Reservoir characteristics of the Morrow sandstone in Milder field are summarized in Table 3.

OIL AND GAS PRODUCTION

The estimated cumulative gas production from the Morrow Formation in Milder field is ~41 BCFG and 152,603 BO from October 1966 through December 1998. The lower Morrow B sandstone accounts for most of this production (~24.9 BCFG and 117,624 BO), followed by the lower Morrow Primrose sandstone (~11.3 BCFG and 34,979 BO). An additional ~3.7 BCFG was produced from the Morrow A zone and ~0.6 BCFG from the Morrow C sandstone. Table 2 shows cumulative gas and oil production, initial production, pressures, and dates of production are provided for the lower Morrow B sandstone and the Primrose sandstone. It can be seen from this table that wells completed earliest in the field's history (those drilled in the 1960s) are the largest producers. Also, liquid (condensate) production is mostly attributed to the earliest producing wells in the field. Condensate production occurred, therefore, in response to initial pressure drawdown in the reservoir; these liquids were originally in a gaseous state at reservoir conditions and during the early phases of gas production, so the decrease in pressure resulted in condensation of the gas to form light oil (condensate). Development wells drilled during the 1990s produced little if any hydrocarbon liquids, as the wells were pressure depleted beyond the critical pressure necessary to produce condensate. Commingling of the individual Morrow reservoirs is also shown. Commingling makes reserve allocations for individual zones difficult to determine and are often estimated.

On the basis of volumetric calculations, production from the lower Morrow B sandstone represents only ~23% of the original recoverable gas in place, which is estimated at 107 BCF (Table 3). The low recovery is probably due to the large areal extent measured for this reservoir and the fact that some wells in certain areas included in the reserve estimate were not completed or did not produce from the B sandstone. Because of such factors, there is considerable room for error in reserve calculations, as some areas included in the calculations may not have gas potential, thereby causing an exaggeration in calculated reserves. The estimated recovery with regard to current cumulative gas production is ~177 MCF/acre-ft for the Morrow B sandstone. Recovery will increase with time, of course, as the reservoir is being produced.

Production from the lower Morrow Primrose sandstone represents only ~30% of the original recoverable gas in place, which is estimated at 37.5 BCF (Table 2). The reasons for this low recovery are probably similar to those for the Morrow B sandstone previously discussed. The estimated recovery with regard to current cumulative gas production from the Primrose sandstone is ~161 MCF/acre-ft. Overall, the Primrose sandstone is tight, but where it is porous it makes an excellent reservoir.

The better wells in Milder field are generally in T. 22 N., R. 25 W., as both the Primrose and the lower Morrow B sandstone thin to the north. Nine wells completed in the B sandstone produced >1 BCFG, only one of which is in T. 23 N. Only four wells completed in the Primrose produced >1 BCFG, and only one of these is in T. 23 N. Regardless of the zone, the better wells in the field had initial-production rates of about 1–2 MMCFGPD, and even some of the more recent wells had initial-production rates of ~1 MMCFGPD. Initial shut-in tubing pressures (SITP) were generally between 2,800 and 2,900 psi for many of the early field wells. However, the pressure dropped significantly to <1,000 psi in many subsequent wells where the drilling density was greatest (NE¼ T. 22 N.). Flowing tubing pressure varied from only a few hundred psi to >2,000 psi, and many were in the range of 1,000–2,000 psi. The ratio of flowing pressure to shut-in pressure is extremely variable; for some wells, it is proportionally high regardless of completion date, and for other wells it is very low. This ratio can be quickly visualized by looking at the pressure data in Table 2 and can provide a good indication of reservoir conditions and completion effectiveness. The flowing pressure from really tight rocks or poorly completed zones is usually small in relation to the shut-in pressure.

PRODUCTION-DECLINE CURVES

Lower Morrow B Sandstone

Production-decline curves for three wells with production solely from the lower Morrow B sandstone in Milder field are shown in Figure 30. The upper plot (A) shows the production curve from the Pan Am No. 1 Jenkins well, NE¼SW¼ sec. 9, T. 22 N., R. 25 W. This well has 16 ft of net sandstone with about 10–15% porosity, although some zones within the sandstone interval have 8% porosity. The reservoir thickens abruptly in the eastern part of the section to 30 net ft of sandstone. This situation is often advantageous to the original operator when the first well does not encounter the "sweet spot," since drainage commonly extends for 1 mi or more, depleting volumetrically larger parts of the same reservoir even though the net pay in the

TABLE 3. – Reservoir/Engineering Data for Lower Morrow Sandstones in Milder Field, Ellis County, Oklahoma

	Morrow B sand	Morrow Primrose sand
Discovery date	6/4/63 (Amoco #1 Fields, SE¼NW¼ sec. 11, T. 22 N., R. 25 W.)	6/14/62 (Pan Am #1 Barrett, NW¼SE¼ sec. 34, T. 23 N., R. 25 W.)
Reservoir size (area within 0-ft net contour)	~9,000 acres (~14 mi²) S⅓ T. 23 N. and N½ T. 22 N. excluding secs. 1, 6, 7, 17, 18)	~6,000 acres (~9.4 mi²) (excluding sand in secs. 1, 2, 6, 11, 12, E½ sec. 9, W½ sec. 10, 31-36)
Reservoir volume	~165,000 acre-ft	~77,000 acre-ft
Depth	~8,500 to 9,100 ft	~8,600 to 9,300 ft
Spacing (gas)	640 with increased density to 320 acres	
Gas–water contact	variable, below about –6,600 ft	variable, below about –6,900 ft
Porosity (in "cleanest" part of sandstone)	about 4–21% (average ~14%)	about 2–17% (average ~9%)
Permeability	probably <1 md (no core data)	
Water saturation (S_w) in producing wells	Extremely variable, R_t may be suppressed by clays causing anomalously high values	
Calculated using R_w = 0.09 ohm-m	about 20–60%	about 20–60%
Thickness		
Net sandstone, ≥10% ϕ	0–42 ft, average ~15.6 ft	0–46 ft, average ~5 ft (~11.7 ft where produced)
Gross sandstone	4–57 ft, average ~37 ft	13–79 ft, average ~42 ft
Reservoir temperature	about 145–175°F	about 150–180°F
Gas density	0.60–0.75, average ~0.64	0.62–0.65, average ~0.63
Oil gravity (API degrees)	42–64, average ~55	50–63, average ~58
Z factor (compressibility)[a]	0.9 est.	0.9 est.
B_g (gas formation volume factor)[b]	~245 std cu ft per reservoir cu ft (est.)	~235 std cu ft per reservoir cu ft (est.)
Maximum well-head pressure	2,820 psi (max recorded SITP)	2,860 psi (max recorded SITP)
Maximum flowing pressure	1,831 psi (max recorded FTP)	2,150 psi (max recorded FTP)
Initial reservoir pressure (max. recorded DST)	~3,955 psi	~3,710 psi
Initial pressure gradient	~0.45 psi/ft	~0.40 psi/ft
Cumulative field condensate (est. to 12/98)	117,624 barrels	34,979 barrels
OGIP[c] (volumetric–field)	107 BCF	37.5 BCF
Cumulative field gas (est. to 12/98)	24.9 BCF	11.3 BCF
% gas recovery to date	23% (not including condensate)	30% (not including condensate)
Recovery MCF/ac-ft (field to date)	~177 MCF/ac-ft	~161 MCF/ac-ft

[a]Compressibility factor (Z) estimated from standard reservoir-engineering charts using T_{res} = 160°F and P_{res} = 3,955 psi (B sand) and 3,710 psi (Primose). T_{res} = reservoir temperature, P_{res} = reservoir pressure.

[b]B_g calculated using the formula: $B_g = \frac{35.4 \times P_{res}}{T_{res} \times Z}$ When T_{res} is in °Rankine (add 460° to the reservoir temperature measured in °F). The Z factor is stated above.

[c]Original gas in place (OGIP) determined from the following formula: Reserves (MCF) = 43.56 × area (acres) × sand thickness (ft) × porosity (%) × (1–S_w) × B_g.

producing well is not optimal. The Jenkins well essentially had no production competition from nearby wells during its producing life and was shut in or abandoned in 1980. The Jenkins well produced a little more than 2 BCFG and 7,712 BO over 14 years. The initial SITP was 2,820 psi, and the most current SITP was 670 psi. An offset well was drilled in 1983, but production and pressure details are not known.

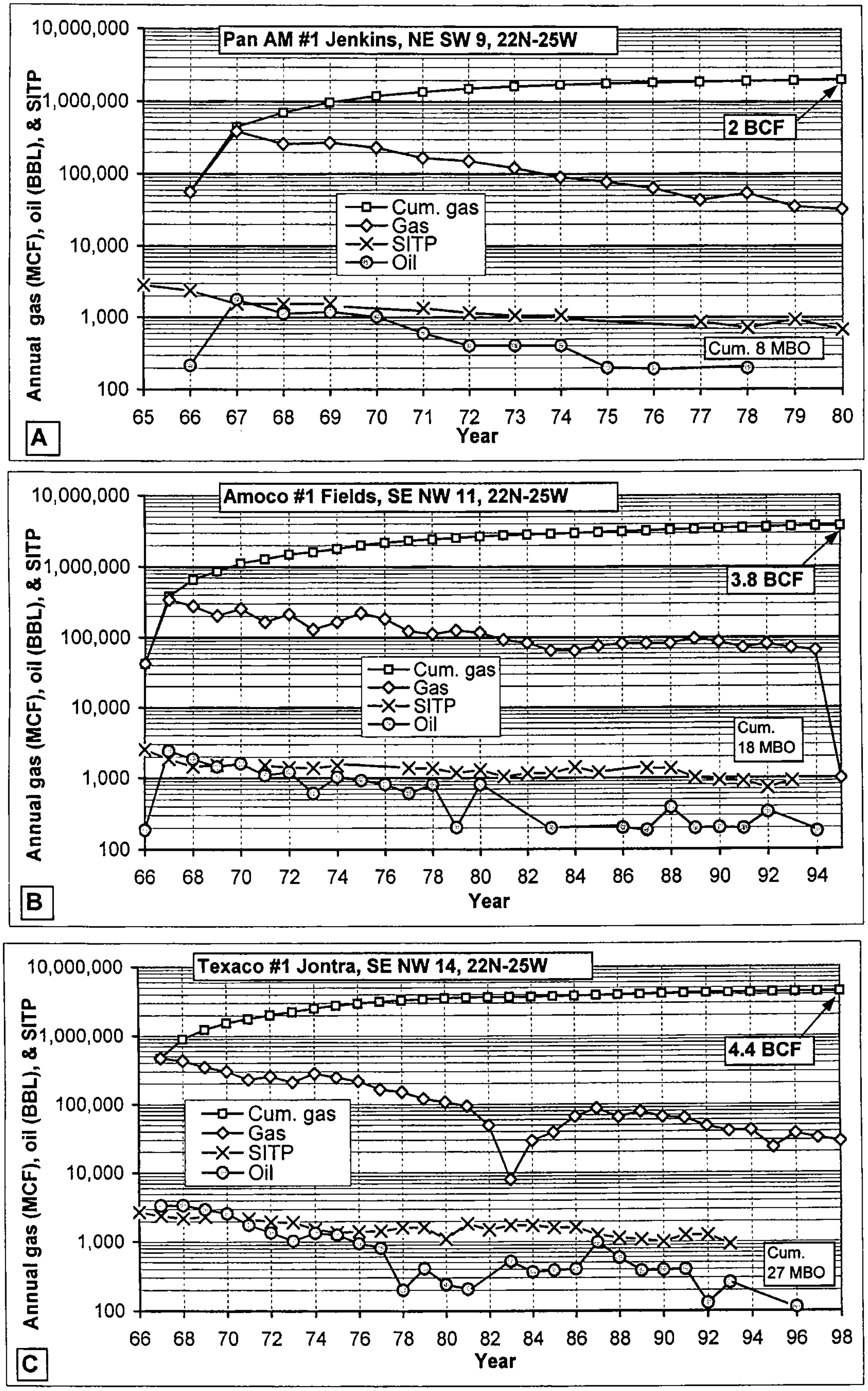


Figure 30. Production- and pressure-decline curves for three wells producing from the lower Morrow B sandstone in Milder field. Data are current through September 1998.

The production curve for the Amoco No. 1 Fields well in the SE¼NW¼ sec. 11, T. 22 N., R. 25 W., is shown in Figure 30B. This well produced ~3.8 BCFG and 17,675 BO over ~29 years before being shut in or abandoned in 1995. It was initially completed in 1963, but the first production was not until 1966. The well produced from 17 net ft of sandstone with about 12–20% porosity and had an initial SITP of 2,710 psi and abandonment pressure of ~900 psi (pressure dropped to ~700 psi 1 year before the last production). Amoco drilled an offset well in the SW¼NE¼ sec. 11 (No. 4 Shields) in 1995 and completed it in the B sandstone. The pressure depletion was severe in the offset well because the initial SITP was only 1,162 psi.

Shortly after the Amoco well was drilled, a south offset in the SE¼NW¼ sec. 14, T. 22 N., R. 25 W., was completed by Texaco in 1964, the production curve for which is shown in Figure 30C. Production from this well (No. 1 Jontra) began in 1967, and the well is still active. The Texaco well produces from 25 ft of net sandstone with porosity ranging from ~12% to 20%. It has produced ~4.4 BCFG and 26,795 BO over a 32-year period. The well had an initial SITP of 2,537 psi and a final pressure of 918 psi. An offset well drilled by Cross Timbers in the NW¼NW¼ sec. 14 was completed in 1997 and is severely pressure depleted (initial SITP of 1,050 psi).

The three production curves of wells producing from the lower Morrow B zone (Fig. 30) show that well-production performance is directly related to date of first production, reservoir quality, and thickness. All three wells were completed early in the history of the field. The moderate and uninterrupted production-decline rates also indicate that the wells had little or no interference from competing wells, as they were spaced far apart during most of their production history. The decline curves have all "plateaued," as shown by the cumulative-gas-production curves. The pressure data presented in Table 2 show that offset wells drilled in the past 10 years are severely depleted, indicating reservoir communication and continuity between the original wells and the increased-density wells completed in the general vicinity. This information in a general way indicates that the B sandstone reservoir is more depleted than the recovery percentage of original gas in place estimated at ~23% (Table 2). Additionally, wells are generally shut in or abandoned, once the SITP drops below about 900 psi (Fig. 30). This result may also contribute to the large amount of apparently unrecovered gas from this zone.

Pressure-decline curves for the three lower Morrow B wells are shown in Figure 31 and illustrate a common initial SITP but different decline rates over time. This may be due in part to different reservoir characteristics. Figure 32 is a graph relating SITP to cumulative production for the same three Morrow B wells. Trend lines have been inserted to clarify the trends. It is apparent that the three Morrow B reservoirs are producing very

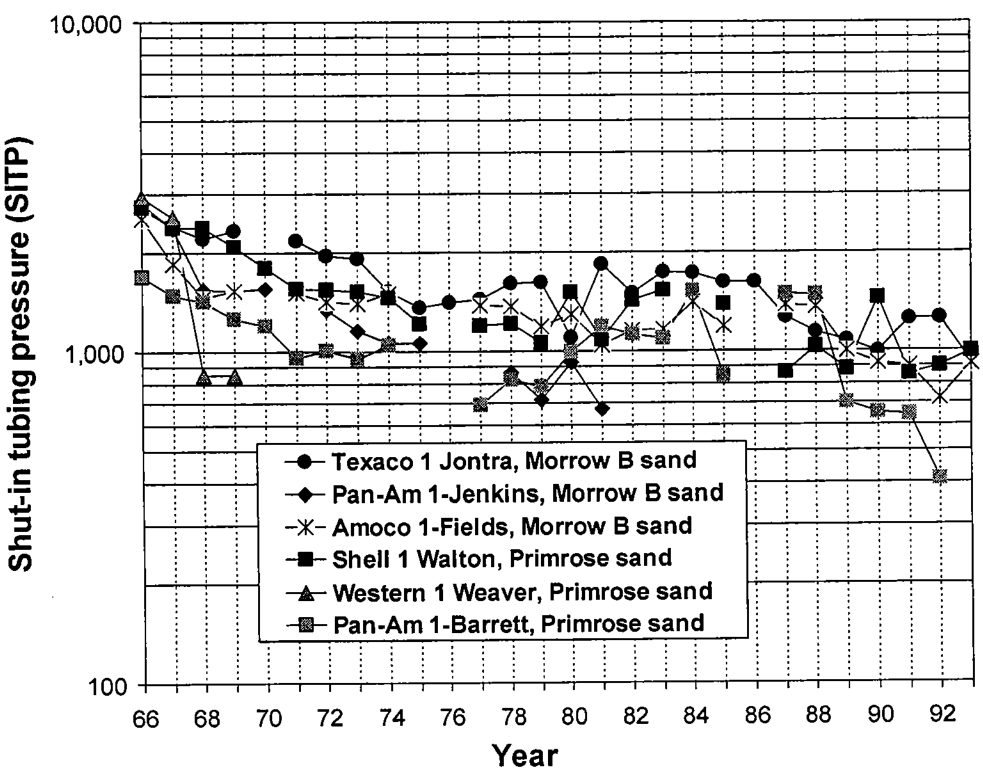


Figure 31. Graph showing relationship of pressure versus time for three wells producing from the lower Morrow B sandstone and three wells producing from the Primrose sandstone in Milder field.

differently, again illustrating the heterogeneity between reservoirs prior to increased well drilling.

Lower Morrow Primrose Sandstone

Production-decline curves for three wells producing primarily or solely from the Primrose sandstone in Milder field are shown in Figure 33. The upper plot (A) shows the production curve from the Pan Am No. 1 Barrett well in the NW¼SE¼ sec. 34, T. 23 N., R. 25 W. Here, the reservoir consists of about 23 ft of net sandstone with 10–20% porosity, although some zones within the sandstone interval have 9% porosity. The sandstone appears to be a distributary-mouth bar rather than a channel, but this interpretation is not clear-cut. Cumulative production of ~1.3 BCFG and 2,848 BO is commingled with that from the lower Morrow A zone, but log interpretations indicate that most of the production is attributable to the Primrose. The Pan Am well is still active; it was completed in 1962 but was not brought on-line until 1966. The initial SITP was recorded at 1,535 psi (questionable accuracy, unrealistically low), and the final SITP was 410 psi. It had no production competition from nearby surrounding wells until 1996, when Amoco completed a well in the SE¼ NW¼ sec. 34. Production from that well is commingled with that from three different Morrow reservoirs, so the performance of the Primrose alone is not known.

The production curve for the Shell No. 1 Walton well in the SE¼NW¼ sec. 8, T. 22 N., R. 25 W., is shown in Figure 33B. This well is currently active and has produced ~4.3 BCF gas and 12,000 BO over ~32 years. It was initially completed in 1963 and brought on-line in 1964. This well produces from a channel sandstone having 12 ft of net pay, although the full gross sandstone sequence of 51 ft has porosity ranging from ~6% to 14%. The well had an initial SITP of 2,860 psi and an abandonment pressure of ~900 psi. Production was commingled with that from the lower Morrow C sandstone, but most of the production from the well is attributed to the Primrose. An offset well in the SW¼ NE¼ sec. 11 was drilled and completed in the Primrose in 1994 by Amoco. This well encountered a thicker Primrose sandstone with 36 ft of net pay. Surprisingly, the well had a nearly virgin SITP of ~2,600 psi. The performance history of the Amoco well is not known.

During the early 1970s, the extreme southern part of Milder field was developed, with production mostly from the Primrose sandstone. The Western States Producing No. 1 Weaver well, in the SW¼NE¼ sec. 22, T. 22 N., R. 25 W., was one of the first wells to produce in this area. This well produced ~2.8 BCFG and 18,133 BO during a relatively short production history, ranging from 1970 to 1974. The 4-year production curve is shown in Figure 33C. The well produces from a channel sandstone with ~19 net ft of sandstone, with porosity ranging from ~14% to 17%. The well had an initial SITP of 2,942 psi and a final pressure of 850 psi. Offsets were drilled in sections both to the east and west a few

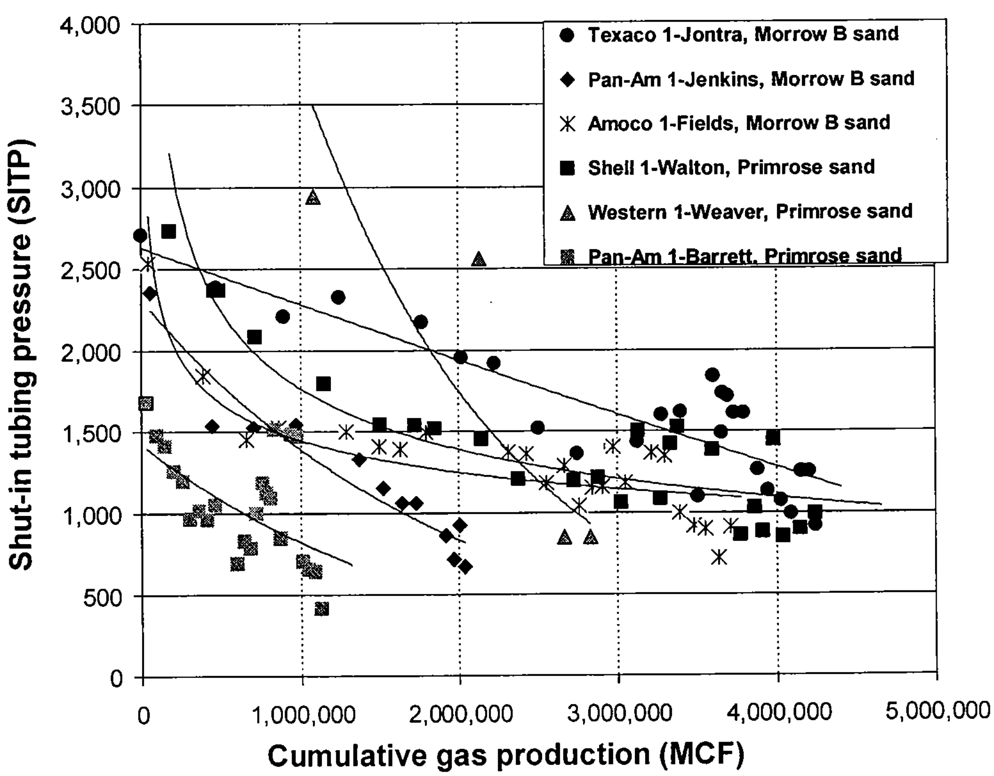


Figure 32. Graph showing relationship of pressure versus cumulative gas production for three wells producing from the lower Morrow B sandstone and three wells producing from the Primrose sandstone in Milder field.

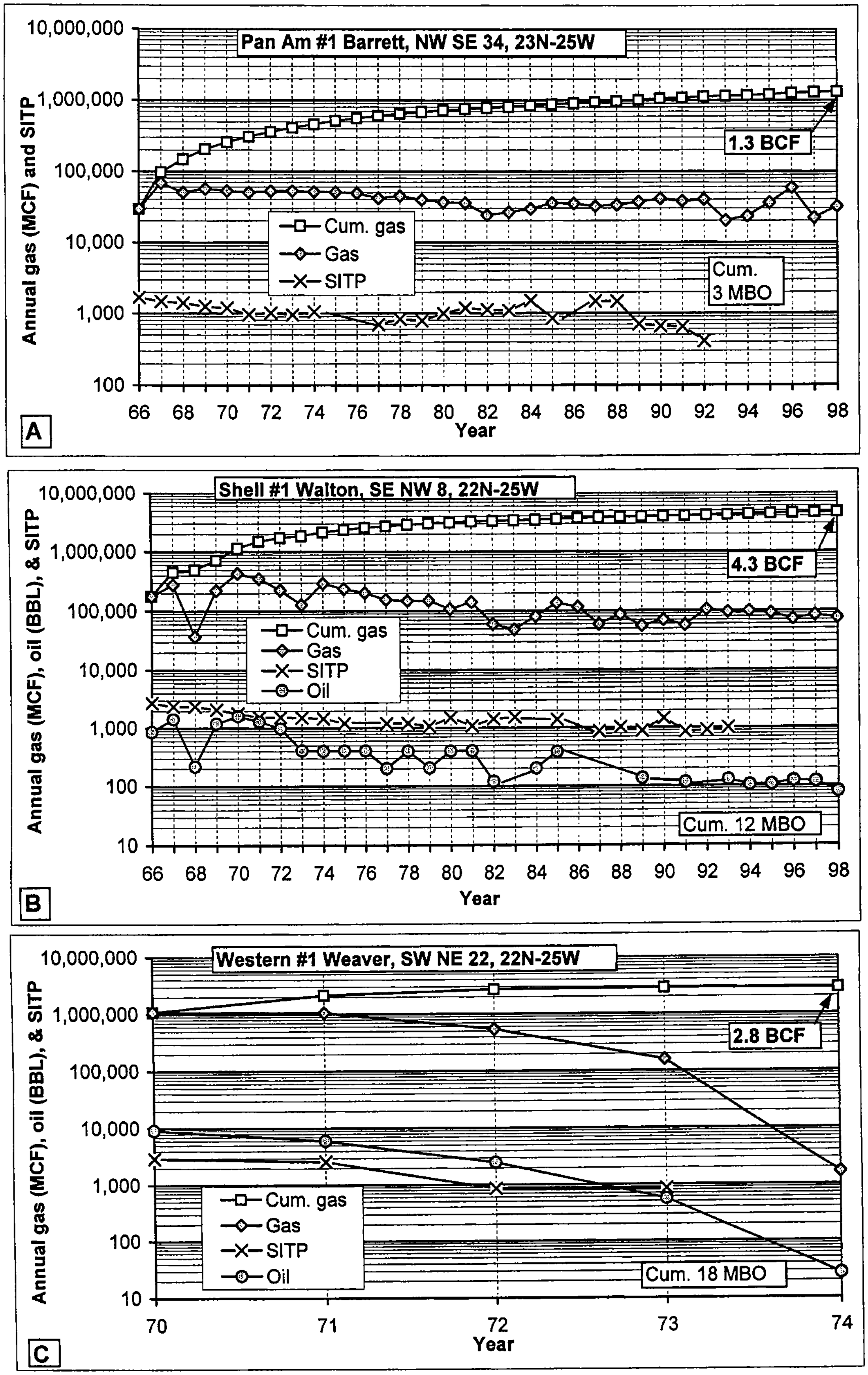


Figure 33. Production- and pressure-decline curves for three wells producing from the lower Morrow Primrose sandstone in Milder field. Data are current through September 1998.

years later, also establishing Primrose production. The east offset in sec. 23 had a virgin pressure of 2,905 psi, whereas the west offset in sec. 21 had partial pressure depletion, with an initial SITP of 1,713 psi.

Primrose production is scattered throughout Milder field and is often commingled with production from other Morrow reservoirs, making it difficult to differentiate. The first two production curves (Fig. 33A,B) show gradual depletion over a long period (32 years), whereas the Primrose well in the deeper, southern part of the field (Fig. 33C) produced for only about 4 years and had a rapid production-decline rate. This rapid decline was probably due to poorer reservoir properties rather than reservoir thickness, areal extent, or competition from nearby wells. As with the Morrow B reservoir, the Primrose wells are usually shut in or abandoned once the pressure drops below ~900 psi. This may be one of the reasons why the recovery of original gas in place is so low, which is estimated at ~30% (Table 2).

Pressure-decline curves for the three lower Morrow Primrose wells are illustrated in Figure 31 and show a common initial SITP but very different decline rates over time. This may be due in part to different reservoir characteristics. Figure 32 is a graph relating shut-in pressure to cumulative production for the same three Primrose wells. Trend lines have been inserted to clarify the trends and show that the three Primrose reservoirs are producing very differently, again illustrating the heterogeneity between reservoirs prior to increased well drilling.

WELL-DRILLING AND COMPLETION PRACTICES

Wells in Milder field are drilled with traditional water-based drilling fluids. The discussion of drilling techniques is beyond the scope of this study, but some important guidelines are noted for Morrow wells in this area. Wells vary in depth from ~9,000 ft in the northern part of the field to almost 10,000 ft in the southern mapped area. Operators usually set 8.5-in. surface casing to about 800–1,000 ft, then set 4.5-in. production casing at or very near the bottom of the hole. Completion reports indicate that many wells are acidized with 1,000–2,500 gal of 7.5% HCl. In all productive wells, the Morrow interval is stimulated with a fracture treatment consisting of various treated gels (commonly acid gel) or foam. Amounts ranged from ~30,000 to 60,000 gal plus about 20,000–100,000 lb of sand. Well-drilling costs for a conventional vertical well to a depth of ~9,500 ft having a single-zone completion are estimated at $400,000 for a dry hole and $610,000 for a completed well (estimated costs in August 1999).

PART III

Arapaho Field

Upper Morrow and lower Morrow Primrose gas production in T. 13 N., R. 17 W., Custer County, Oklahoma

Walter J. Hendrickson
IHS Energy Group
Oklahoma City, Oklahoma

INTRODUCTION

Arapaho field is in south-central Custer County, west-central Oklahoma (Fig. 34; Pl. 1). The field lies in the deep part of the Anadarko basin (Pl. 3) and produces predominantly gas from thin upper Morrow sandstones and relatively thick lower Morrow Primrose sandstones. Other zones of production are indicated by the field production map (Fig. 35).

Arapaho field was discovered in 1977 with the completion of the Harper Oil Co. No. 1 Meredith, flowing 800 MCFGPD from perforations in the Cunningham and Britt sandstones of the Springer Group. The original bottom-hole pressure (BHP) of the Meredith well was 11,768 psi. The well has a cumulative production of >8 BCFG and is still producing >800 MCFGPD. Additional cumulative production totaling ~7 BCFG has been derived from four other field wells that have produced from the Cunningham and/or Britt. However, these zones are not the dominant producers in the field.

The upper Morrow sandstone is the most prevalent productive zone in the field, having been discovered in 1979 by Harper Oil Co. with the completion of the No. 1 George in sec. 16, T. 13 N., R. 17 W. The George well was completed for 1,320 MCFGPD and 21.5 BOPD, with an initial BHP of 11,361 psi. After having produced >5 BCFG and nearly 44 MBO, the George well is currently producing ~12 MCFGPD. With 26 wells producing solely from the upper Morrow sandstone (Table 4), this zone has produced nearly 62 BCFG and >546 MBO, which indicates an average of 2.4 BCFG and 21 MBO/well.

The upper Morrow sandstone reservoir was originally developed on 640-acre spacing and occasionally has been the focus of in-field drilling, which has reduced some spacing to about 320-acre units. As can be noted on the type log for Arapaho field (Fig. 36), two units of upper Morrow are identified, which are hereinafter informally called the upper unit and the lower unit. There are possibly several independent reservoirs in the upper Morrow. Apparently, there is no downdip water leg in any of the upper Morrow reservoirs, so the drive mechanism is pressure depletion. Trapping is stratigraphic and is determined by the presence or absence of reservoir-quality sandstone.

The second major producing zone in the field is the Primrose sandstone of the lower Morrow Formation and was discovered in 1981 by the Gulf Oil Corp. No. 1A-3 Meacham well, sec. 3, T. 13 N., R. 17 W. This well was completed for 1,867 MCFGPD with an initial BHP of 11,086 psi and has produced nearly 2.5 BCFG; it is still producing ~150 MCFGPD. With 18 wells producing solely from this zone (Table 5), cumulative production amounts to >32 BCFG, with a per-well average of nearly 1.8 BCFG. The Primrose in this field can also be divided into two units, which are referred to informally as the upper unit and the lower unit, as indicated in Figure 36. The lower unit of the Primrose produces in Arapaho field and consists of a number of isolated or compartmentalized reservoirs. These reservoirs are stratigraphically controlled by the pinch-out of reservoir-quality sandstone updip and in both directions laterally, and by water levels and the degradation of reservoir quality downdip. The lower unit of the Primrose has been developed on 320- to 160-acre spacing, owing to reservoir heterogeneity.

The only other productive zone of significance in Arapaho field is the younger Skinner sandstone (Pennsylvanian, Desmoinesian), which produces in the southeast part of T. 13 N., R. 17 W., where it forms a pronounced northwest–southeast trend. There are 18 wells in Arapaho field that produce solely from the Skinner, with a total cumulative production of >12 BCFG and 408 MBO, with a per-well average of ~688 MMCFG and 23 MBO. The Skinner sandstone is outside the focus of this paper.

STRATIGRAPHY

The overall success of field development within Arapaho field has resulted in excellent well control and sufficient information to determine the geology controlling production within the field. A basis for placing Arapaho field within the proper geological context of the Anadarko basin was accomplished by using de-

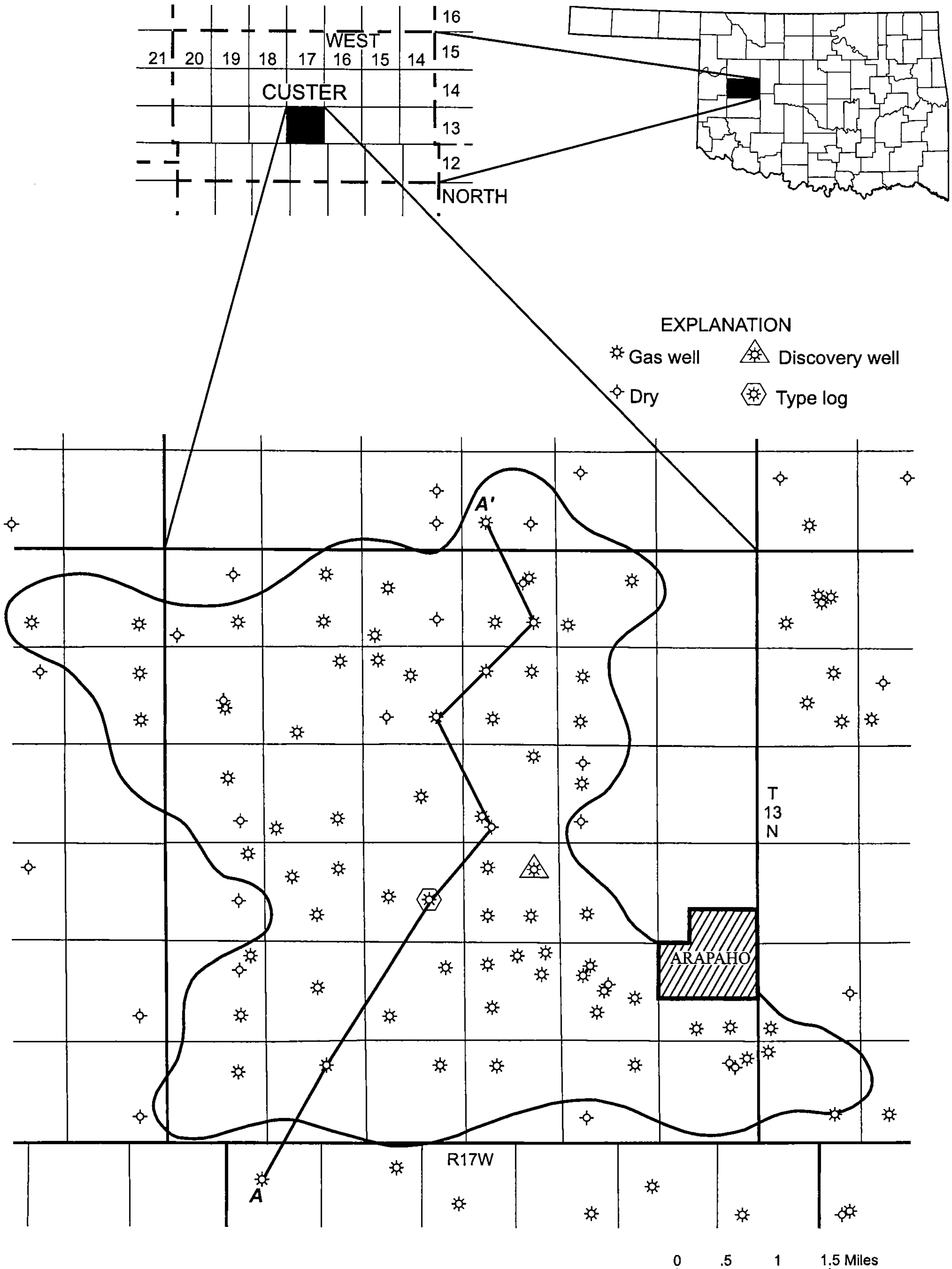


Figure 34. Generalized location map of Arapaho field, Custer County, Oklahoma. Line of a segment of regional cross section A–A′ (Fig. 38) is shown.

tailed studies conducted by the Reservoir Geology Division of IHS Energy Group. As part of a regional study covering essentially all the Anadarko basin and shelf of northwestern Oklahoma and the Panhandles of Oklahoma and Texas, the geologists of IHS Energy Group constructed many thousands of miles of contiguous cross sections to develop a stratigraphic-nomenclature system that could be used across the area with accuracy, detail, and consistency. Within the study area, the geologists compared every producing reservoir of each producing well with these cross sections and assigned the appropriate nomenclature. A contiguous framework of cross sections was drafted into finished form (Fig. 37). Custer County is indicated on this figure by a stippled pattern, and T. 13 N., R. 17 W., by a clear block within this pattern.

One of the regional cross sections produced during the IHS Energy Group study runs through the center of T. 13 N., R. 17 W., in essentially a north–south direction. Figure 38 (in envelope) shows a part (laterally and stratigraphically) of this cross section. The section uses the base of the Thirteen Finger limestone of the overlying Atoka Formation (top of the Morrow shale) as the datum. Directly subjacent to this datum and noted on

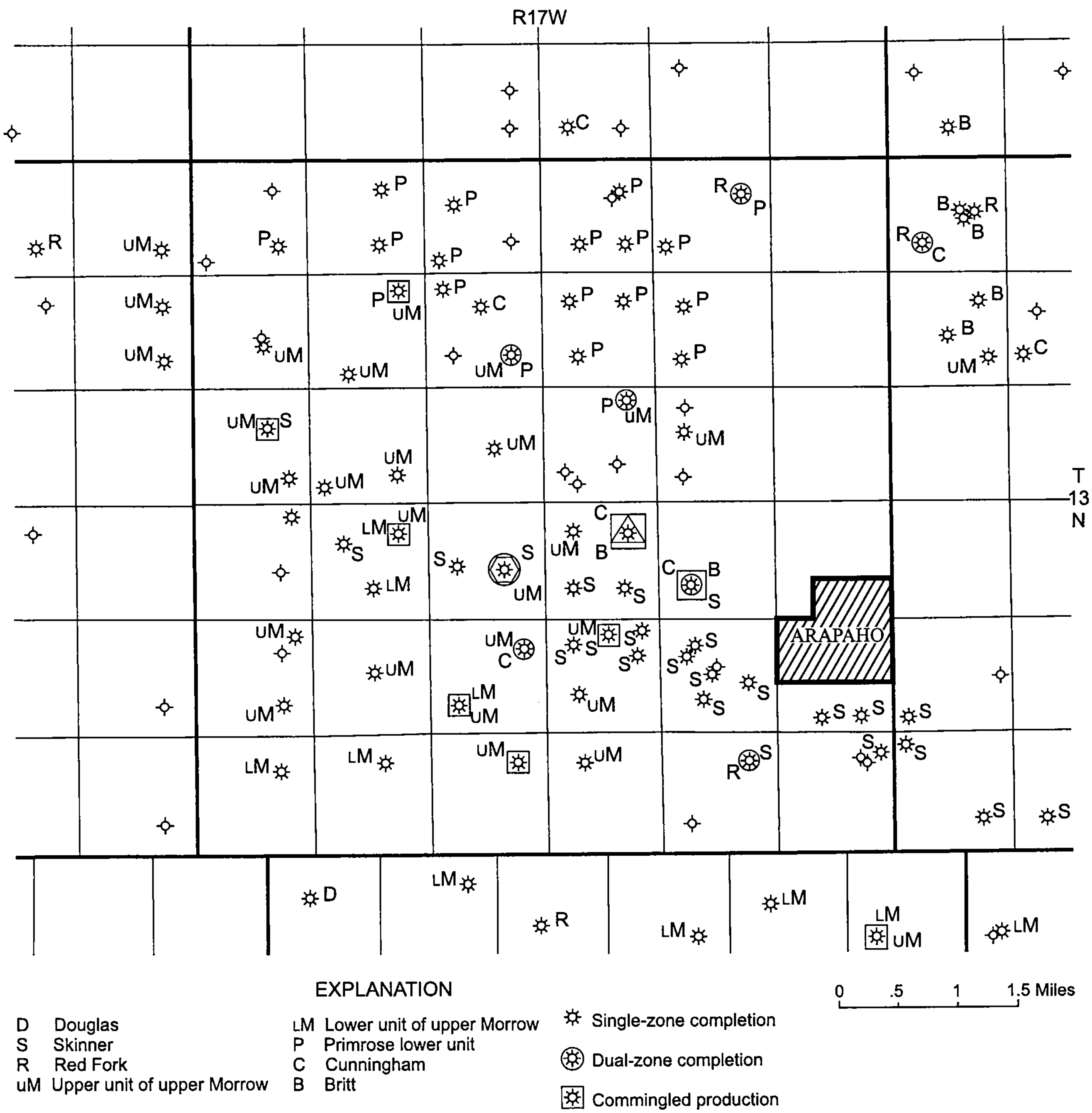


Figure 35. Map showing producing formations, Morrow producing zones, and types of completions in Arapaho field.

TABLE 4. – Upper Morrow Upper Unit and Lower Unit Producing Wells (Non-commingled), Arapaho Field, Custer County, Oklahoma

Location	Well lease name	Well no.	Field and producing formation	Operator	API no.	Status	Prod. code	Gas cum. (MCF)	Oil cum. (BO)
7 13N 17W	Roll #1-A	1-A	Arapaho (Morrow Upper)	Unit Petroleum Corp.	35-039-20788-00	Active	gas	1,160,206	10,382
8 13N 17W	Cox 8 #1	8-1	Arapaho (Morrow Upper)	Apache Corp	35-039-21196-00	Inactive	gas	2,551,376	18,413
9 13N 17W	Lockhart Curtis	1-9	Arapaho (Morrow Upper)	Questar Expl. & Prod.	35-039-20465-00	Active	gas	2,913,843	18,841
14 13N 17W	Palmer	1-14	Arapaho (Morrow Upper)	Arrow Oil & Gas Inc	35-039-21361-00	Active	gas	2,197,373	12,264
15 13N 17W	Parr	1	Arapaho (Morrow Upper)	Amoco Production Co.	35-039-21001-00	Inactive	gas	4,399,870	35,452
16 13N 17W	George	1	Arapaho (Morrow Upper)	U M C Petroleum Corp.	35-039-20264-00	Active	gas	5,012,504	43,540
17 13N 17W	Chrystal	1	Arapaho (Morrow Upper)	MidCon Central Expl. Co.	35-039-20417-00	P&A	gas	57,669	565
17 13N 17W	Wade	17-1	Arapaho (Morrow Upper)	Apache Corp	35-039-21077-00	Active	gas	2,382,577	17,842
18 13N 17W	Strong #2-18	2-18	Arapaho (Morrow Upper)	C E D LC	35-039-21284-00	Inactive	gas	758,045	6,220
20 13N 17W	Perry	1	Arapaho (Morrow Upper)	MidCon Central Expl. Co.	35-039-20304-00	P&A	gas	1,158,525	2,866
20 13N 17W	Perry	20-2	Arapaho (Morrow Upper)	Apache Corp	35-039-21132-00	Active	gas	3,526,559	47,836
21 13N 17W	Vera	1	Arapaho (Morrow Upper)	Apache Corp	35-039-20350-00	Inactive	gas	1,269,051	0
22 13N 17W	Coulson	1-22	Arapaho (Morrow Upper)	Apache Corp	35-039-21342-00	Inactive	gas	816,789	5,604
27 13N 17W	Schreiner	1	Arapaho (Morrow Upper)	Apache Corp	35-039-20321-00	Active	gas	1,177,394	5,203
28 13N 17W	Coulson	1	Arapaho (Morrow Upper)	Apache Corp	35-039-20235-00	Active	gas	2,865,674	20,566
28 13N 17W	Coulson	2-28	Arapaho (Morrow Upper)	Bristol Resources Corp.	35-039-20918-00	Active	gas	686,582	3,836
29 13N 17W	Stucker #1	1-29	Arapaho (Morrow Upper)	Apache Corp	35-039-30515-00	Active	gas	8,965,122	93,758
30 13N 17W	Donely	30-1	Arapaho (Morrow Upper)	Ward Petroleum Corp.	35-039-20760-00	P&A	gas	14,130	0
30 13N 17W	Stucker	1-30	Arapaho (Morrow Upper)	Ward Petroleum Corp.	35-039-21318-00	Inactive	gas	549,800	851
31 13N 17W	White Shield	1-31	Arapaho (Morrow Upper)	Sonat Expl. Inc.	35-039-20539-00	Inactive	gas	4,432,423	11,196
32 13N 17W	Miller	1-32	Arapaho (Morrow Upper)	Anadarko Basin Prod Serv	35-039-20656-00	Active	gas	833,464	0
33 13N 17W	Fransen	1	Arapaho (Morrow Upper)	S M R Property Mgmt Co.	35-039-20445-00	Active	gas	7,914,495	73,531
34 13N 17W	Hancock	1-34	Arapaho (Morrow Upper)	Apache Corp	35-039-20572-00	Active	gas	3,807,689	34,679
1 13N 18W	Shepard-Thompson	1-1	Arapaho (Morrow Upper)	Samson Resources Co.	35-039-20872-00	Inactive	gas	388,596	16,576
12 13N 18W	Huffstutter	1	Arapaho (Morrow Upper)	Samson Resources Co.	35-039-20934-00-	Inactive	gas	1,847,904	66,139
12 13N 18W	Roush #1-12	1	Arapaho (Morrow Upper)	Samson Resources Co.	35-039-21334-00	Inactive	gas	86,042	648
						TOTALS		61,773,702 MCF	546,808 BO
						Average (26 wells)		2,374,373 MCF	21,031 BO

TABLE 5. – Primrose Lower Unit Producing Wells (Non-commingled), Arapaho Field, Custer County, Oklahoma

Location	Well lease name	Well no.	Field and producing formation	Operator	API no.	Status	Prod. code	Gas cum. (MCF)	Oil cum. (BO)
2 13N 17W	Bozarth	1-2	Arapaho Primrose	Sanguine Ltd.	35-039-21209-00	Active	gas	2,021,438	542
2 13N 17W	Gardner	1-2	Arapaho Primrose	Sonat Expl. Inc.	35-039-21415-00	Active	gas	418,250	183
3 13N 17W	Bozarth Jack C SE	1-3	Arapaho Primrose	Questar Expl. & Prod.	35-039-21719-00	Active	gas	43,525	0
3 13N 17W	Meacham F	1A-3	Arapaho Primrose	Questar Expl. & Prod.	35-039-20416-00	Active	gas	2,456,619	0
3 13N 17W	Meacham	3-2	Arapaho Primrose	Sonat Expl. Inc.	35-039-21388-00	Active	gas	1,334,995	0
4 13N 17W	Denver	1-4	Arapaho Primrose	Chesapeake Operating	35-039-21932-00	Active	gas	1,241,043	0
4 13N 17W	Brown Colley #2-4	2-4	Arapaho Primrose	St. Mary Operating Co.	35-039-21623-00	Active	gas	808,459	0
5 13N 17W	Trigger	1-5	Arapaho Primrose	Chesapeake Operating	35-039-21406-00	Active	gas	409,772	0
5 13N 17W	Baker E E	1-5	Arapaho Primrose	Chesapeake Operating	35-039-20897-00	P&A	gas	4,321	0
6 13N 17W	Verna	1	Arapaho Primrose	Ward Petroleum Corp	35-039-21467-00	Inactive	gas	143,756	0
9 13N 17W	Lockhart Curtis	1-9	Arapaho Primrose	Questar Expl. & Prod.	35-039-20465-00	Inactive	gas	1,919,593	127
9 13N 17W	Lockhart	9-4	Arapaho Primrose	Sonat Expl. Inc.	35-039-21520-00	Active	gas	952,762	0
10 13N 17W	Baxter	1-10	Arapaho Primrose	Samedan Oil Corp.	35-039-20618-00	Active	gas	7,237,823	0
10 13N 17W	Lax	1-10	Arapaho Primrose	Samedan Oil Corp.	35-039-21362-00	Active	gas	6,173,502	0
10 13N 17W	Baxter	2-10	Arapaho Primrose	Samedan Oil Corp.	35-039-21518-00	Active	gas	2,605,249	0
11 13N 17W	B D Hggard 11-1	11-1	Arapaho Primrose	Amoco Production Co.	35-039-20949-00	Inactive	gas	2,159,627	82
11 13N 17W	Haggard 2-11	2-11	Arapaho Primrose	Parker & Parsley Prod.	35-039-21407-00	Active	gas	1,942,685	0
15 13N 17W	Parr	15-1	Arapaho Primrose	Santa Fe Minerals Inc.	35-039-21001-00	Inactive	gas	158,855	0
							TOTALS	32,032,274 MCF	934 BO
							Average (18 wells)	1,779,571 MCF	

the cross section are the upper and lower units of the upper Morrow sandstone. Within Arapaho field, both these units are very thin (usually <10 ft) and somewhat erratic in their deposition. The overall upper Morrow section in the field area is ~550 ft thick in the northern part of the field, gradually thickening to >650 ft in the south. The thickness of the upper Morrow sandstones does not appear to be affected by or related to the thickening of the overall upper Morrow interval.

The "Squaw Belly" zone divides the upper Morrow from the lower Morrow and is a relatively persistent "pick" across the region. The lower Morrow section, as herein defined (Fig. 38), thickens from ~350 ft in the north to 600 ft in the south. This is the greatest percent-

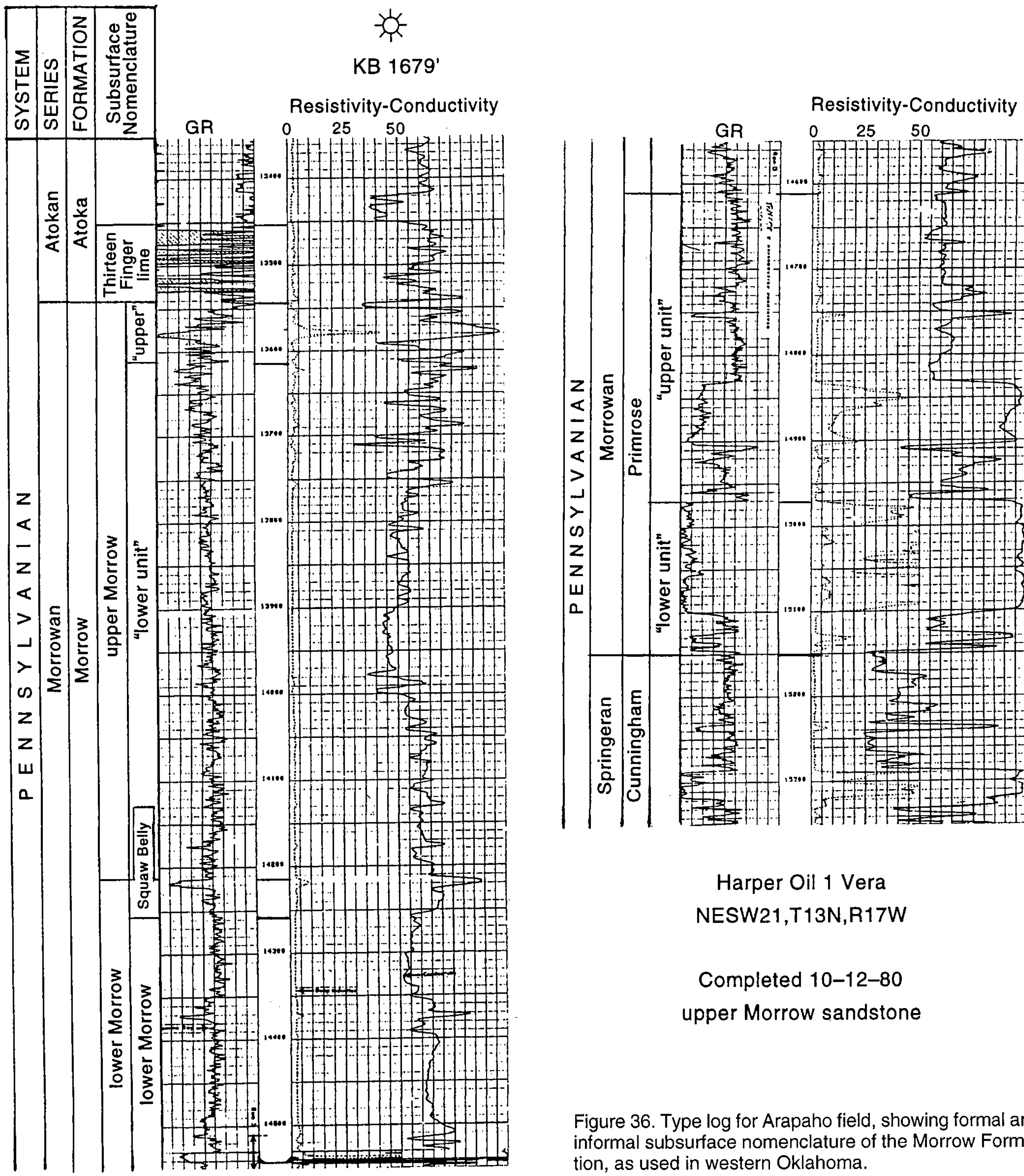


Figure 36. Type log for Arapaho field, showing formal and informal subsurface nomenclature of the Morrow Formation, as used in western Oklahoma.

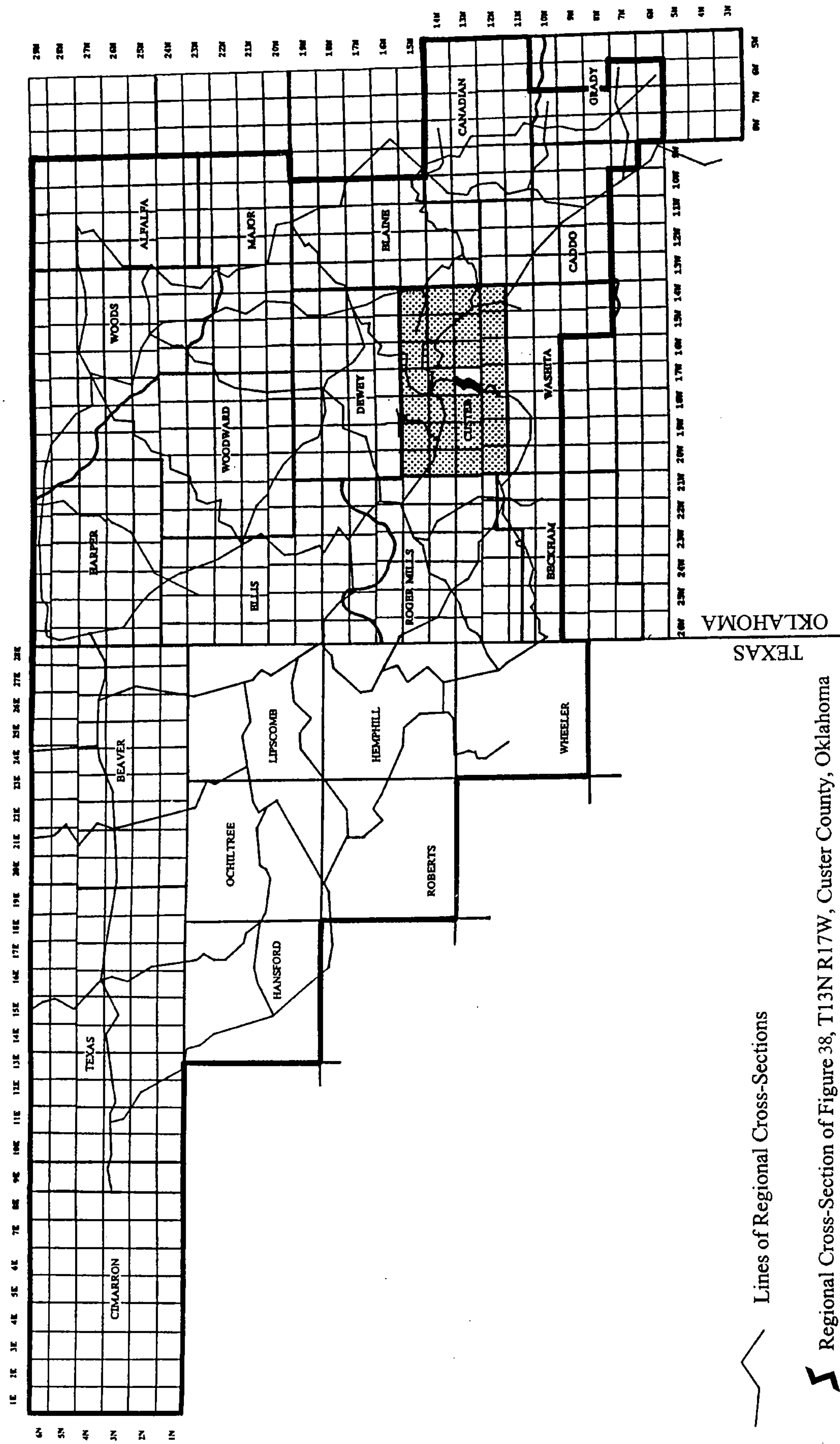


Figure 37. Generalized location map, showing grid of regional cross sections in western Oklahoma and part of Texas Panhandle completed by IHS Energy Group, and location of a segment of the regional cross section through Arapaho field in Custer County.

age increase in thickness of any of the intervals that are discussed. The lower Morrow interval contains very little sandstone in Arapaho field, and the sandstone that is present is generally shaly and tight and has not been found productive.

The top of the Primrose interval in the Arapaho field area is marked by a thick and highly correlative shale section that is ~200 ft thick throughout the entire area. The sandstones in the Primrose interval lie below this shale section and can be easily subdivided into an upper unit and a lower unit, with an intervening shale ~50 ft thick. This subdivision is indicated in Figure 38. Across the field, from north to south, the overall Primrose interval thickens from 400 to 550 ft.

The upper unit of the Primrose in Arapaho field extends across the area but generally is very shaly, tight, and calculates to be wet. Resistivities of the upper unit are noticeably lower than those of the lower unit and commonly are just 10–20 ohm-m. This lower resistivity is a function of the high clay content and associated bound water. When better porosity develops in the upper unit, the resistivity generally remains at low levels and continues to calculate as wet. One well in the field was perforated in the upper unit, and the production was commingled with that from the lower unit. With the exception of this one well, Primrose production in Arapaho field all comes from the lower unit. The interval from the top of the Primrose (shale) to the base of the upper unit is uniform across the field area with a thickness of ~350 ft.

The lower unit of the Primrose accounts for essentially all the thinning seen in the overall Primrose interval—550 ft from the south edge of the field down to 400 ft at the north edge. With the upper unit maintaining a thickness of 350 ft, the lower unit thins from 200 ft in the south, where the interval is largely sandstone, to 50 ft in the north, where the interval is largely very shaly sandstone or shale. This thinning and loss of reservoir quality constitute the trapping mechanism for the hydrocarbons in the lower unit of the Primrose in Arapaho field.

Generally, the Primrose lower unit rests conformably on the Springer Formation, which is represented by a shale in the field area. This shale at the top of the Springer thins from 120 ft in the south to 50 ft in the north. This thinning is depositional. Over most of the area there is no indication that the Primrose has eroded into and removed the top of the Springer shale. At some localized areas, thick sections of Primrose lower unit sandstone (channels) have apparently eroded some underlying shale, but most of those shales are in the Primrose interval. Thus, only a small amount of Springer shale, if any, would have been removed. For the northeastern limit of the field, however, several well logs indicate that the base of the Primrose is an erosional contact and that the upper part of the Springer shale has been removed. Specifically, logs of wells in the SE¼ sec. 34, T. 14 N., R. 17 W., and in the NE¼ sec. 2 and the NE¼ sec. 3, both in T. 13 N., R. 17 W., indicate this post-Springer erosion. This observation conforms with the interpretation (discussed later in this report) that indicates that the Primrose sands were transported into the Arapaho field area by way of a channel system.

Finally, multiple units of both the Cunningham and Britt sandstones of the upper Springer Formation are present in the field area. The discovery well of Arapaho field produced from both these sandstones, as did several other wells, but these zones are generally too tight to be productive. Indications are that the various Springer intervals thicken at approximately the same rate as most of the previously described intervals. For example, the Cunningham interval thickens from 300 ft in the north to 500 ft in the south. However, the focus of this paper is the Morrow, and thus a full analysis of Springer production is not included in this report.

STRUCTURE

A structure map depicting the base of the Thirteen Finger limestone (top of the Morrow shale) (Fig. 39) indicates a regional dip into the Anadarko basin at the rate of 250 ft/mi. Owing to the thickening of the Morrow section, it can be asserted that the base of the Morrow interval (base of the Primrose lower unit) dips at the rate of ~325 ft/mi. These rates of dip conform to the regional structural interpretation. The dip is to the west–southwest, and the strike is uniformly west–northwest. No unusual structural features have been identified in the Morrow section of Arapaho field; thus, the reservoirs produce as a result of stratigraphic traps.

UPPER MORROW SANDSTONE DISTRIBUTION AND DEPOSITIONAL ENVIRONMENT

Figure 40 is a map of west-central Oklahoma, with the upper Morrow producing wells indicated. Also indicated by arrows are two depositional trends. Most of the upper Morrow in far western Oklahoma is chert conglomerate that had its source on the Amarillo–Wichita uplift to the south and west. These chert conglomerates were shed off the Amarillo–Wichita mountain front into a fan delta to the north, which then prograded eastward into the slowly subsiding Anadarko basin.

The thin upper Morrow sandstones that produce in Arapaho field are interpreted to have a different source and depositional origin, as indicated in Figure 40. They likely originated as thin, tidally influenced fluvial-channel sandstones deposited in very slightly paleotopographically low areas of an estuary. The upper Morrow sandstones in this area indicate very little if any erosion at the basal contact; hence, the channels are interpreted to have followed topographically low areas. For the upper unit of the upper Morrow, tidal forces, and ultimately marine transgression, reworked these deposits into sheetlike deposits (see cross sections B–B′, C–C′—Figs. 41, 42, in envelope).

Isopach maps of the Morrow upper unit (Fig. 43) and lower unit (Fig. 44) clearly indicate the northeast–southwest trend of sandstone deposition. This trend

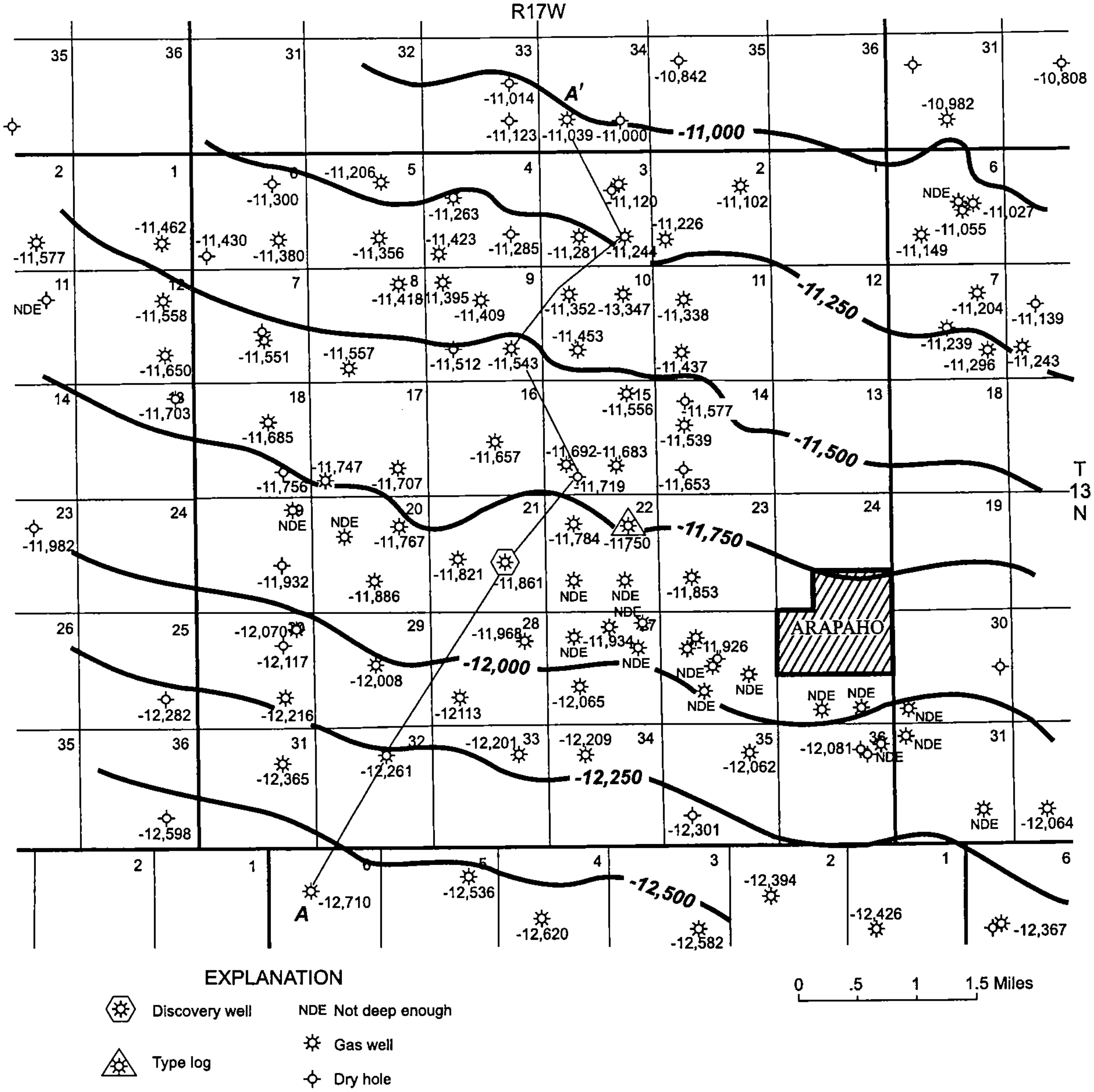


Figure 39. Structure map depicting the base of the Thirteen Finger limestone (top of Morrow shale) in Arapaho field. Contour interval is 250 ft. Datum is mean sea level. Line of cross section A–A′ (Fig. 38) is shown.

indicates that the channels headed into the basin and that an estuarine environment developed in the Arapaho field area where the upper Morrow sands were deposited. Figure 40 indicates that this was a localized occurrence. Therefore, these sandstones represent a tidally influenced fluvial–estuarine environment that was followed by a shallow-marine environment.

Additionally, sample descriptions from a number of mud logs within the field indicate that the upper Morrow is generally a clean to slightly argillaceous quartz sandstone that is clear to white, fine-grained, subangular, and friable to firm. In the sample descriptions there was no indication of chert, which is, of course, characteristic of the chert conglomerates of western Oklahoma. This observation supports the conclusion of a source other than the Amarillo–Wichita uplift.

Regionally, the stratigraphic section that incorporates the upper unit and lower unit of the upper Morrow sandstones in Arapaho field is truncated directly to the northeast of the field through erosion at the unconformity that marks the top of the Morrow and the base of the Atoka (Thirteen Finger limestone). Other, smaller areas of upper Morrow production have been established to the south and east of Arapaho field (Fig. 40) and may represent minor estuaries that developed at different standstills, or minor deposits of sandstones that represent sediments that were reworked in a shallow-marine environment.

UPPER MORROW FORMATION EVALUATION

The correlation of upper Morrow sandstones in Arapaho field is not difficult because they occur di-

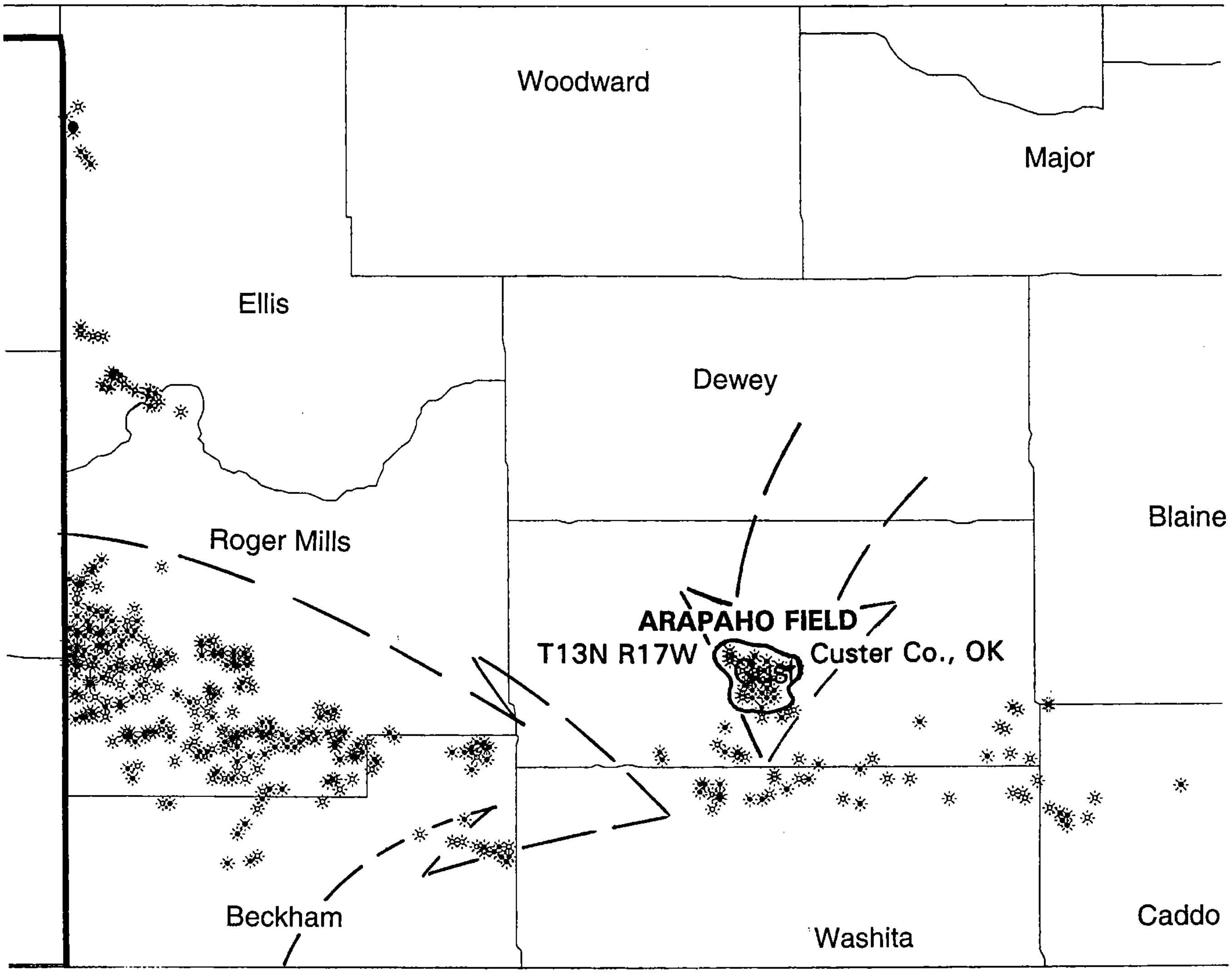


Figure 40. Map showing wells producing from the upper Morrow Formation in western Oklahoma and location of Arapaho field. Arrows indicate two depositional trends for Morrow sediments.

rectly subjacent to the easily identified Thirteen Finger section at the base of the Atoka Formation. The Thirteen Finger section in this area is represented by an approximately 75-ft-thick series of black shales sporadically interbedded with a few thin limestones, which can usually be identified while drilling. First, the black shales commonly exhibit a "drill-off" relative to the shales above and below. Second, these shales usually give up shale gas, which would be noted by a mud-logging unit. Third, the black shales are identified as black to dark gray, often described as sooty with a blocky fracture and highly carbonaceous. Therefore, these shales differ markedly from those above and below. Once logs are run, the correlation is even simpler. The black shales are readily identified by their high radiation, which is usually indicated as off-scale on the gamma-ray track.

Within Arapaho field, the upper unit of the upper Morrow sandstone, where present, is ~50 ft below the base of the Thirteen Finger section. In the southwestern part of the field, the lower unit of the upper Morrow, where present, is ~120 ft below the base of the Thirteen Finger section. As indicated by cross sections B–B′ and C–C′ (Figs. 41, 42), several good correlation points can be established on the logs to subdivide the overall upper Morrow and clearly identify the upper unit and lower unit.

The log analysis of the upper Morrow is relatively straightforward. In general, the sandstone is clean enough so that shale corrections are unnecessary and thick enough so that thin-bed corrections are likewise unnecessary. Generally, owing to the dates of development of this field (ca. 1980s), porosity logs usually include both density and neutron curves. Standard cross-plot techniques were utilized to arrive at porosities to use in analysis under these circumstances. Based on analysis of density–neutron logs available for Arapaho field, if only a density-porosity curve was available,

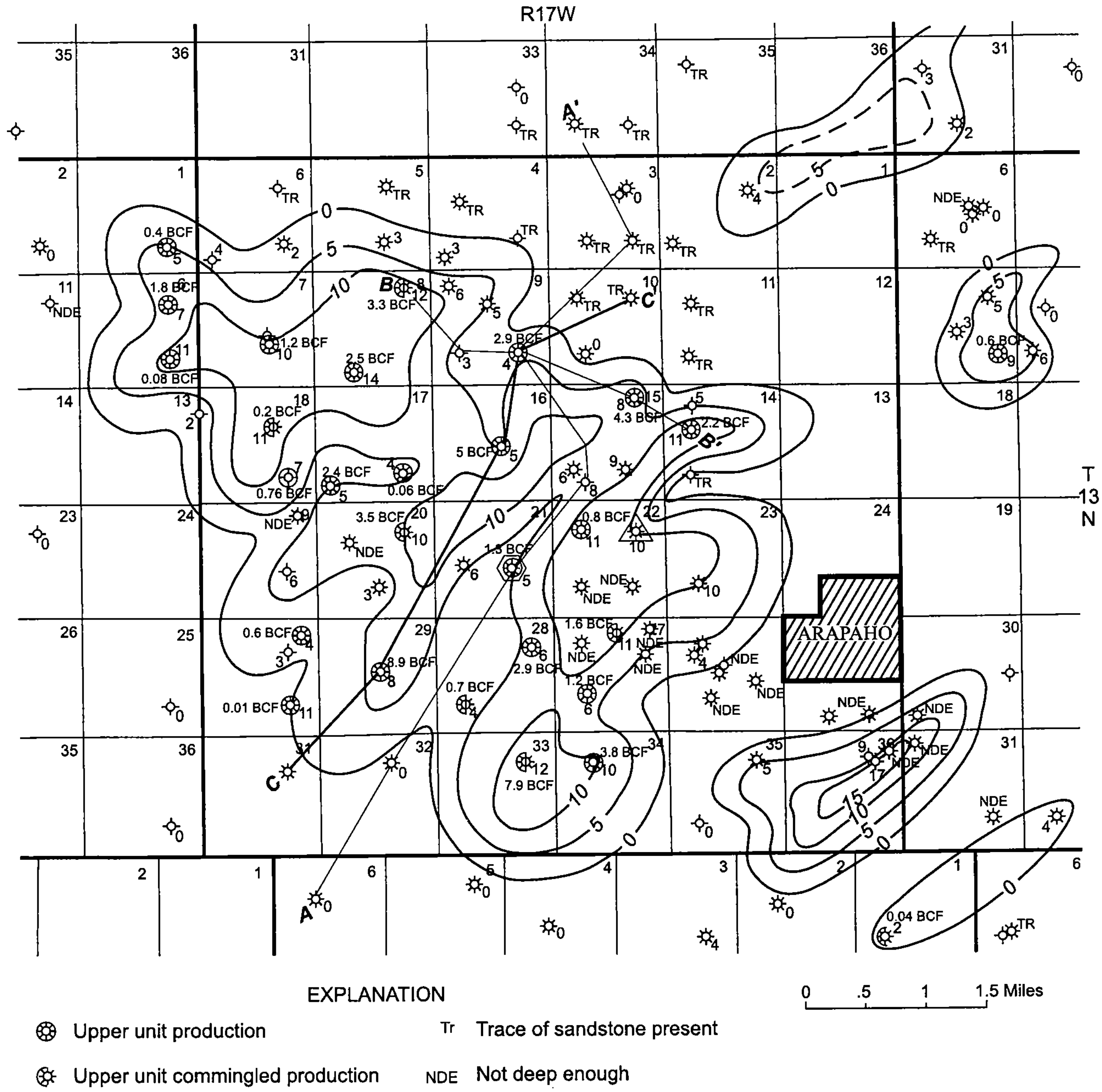


Figure 43. Gross-sandstone isopach map of the upper unit of the upper Morrow Formation in Arapaho field. Contour interval is 5 ft. Lines of cross sections A–A′ (Fig. 38), B–B′ (Fig. 41), and C–C′ (Fig. 42) are shown.

matrix corrections were made as well as a gas-effect correction. From the observed porosity on the density log, generally 3% was subtracted for the matrix (if the log was run on a limestone matrix of 2.71 g/cm^3), and an additional 2% was subtracted for gas effect. Therefore, subtracting 5% from density curves run on a limestone matrix usually arrived at a porosity that was reasonable and consistent with those arrived at through cross-plotting the density–neutron logs.

The only major obstacle in the analysis was a result of reservoir pressure and associated hole conditions. The upper Morrow of Arapaho field was originally overpressured. This fact created a host of problems in drilling and logging. In regard to logging, several wells were not logged over the upper Morrow section for fear of a blow-out. Many of the logs that were run through the upper Morrow exhibited serious problems with pulling and sticking of the logging tools, apparently because of heaving shales. At times, corrections and/or assumptions had to be made to arrive at values used in analysis. Overall, the frequency of these corrections/assumptions was low, and consequently the confidence level was high. Thus, the analyses are considered valid.

The results of the field analyses, including various log-analysis parameters, are given in Table 6. The values shown on the table were derived from well/reservoir records contained in the reservoir database of IHS Energy Group. These records were constructed from

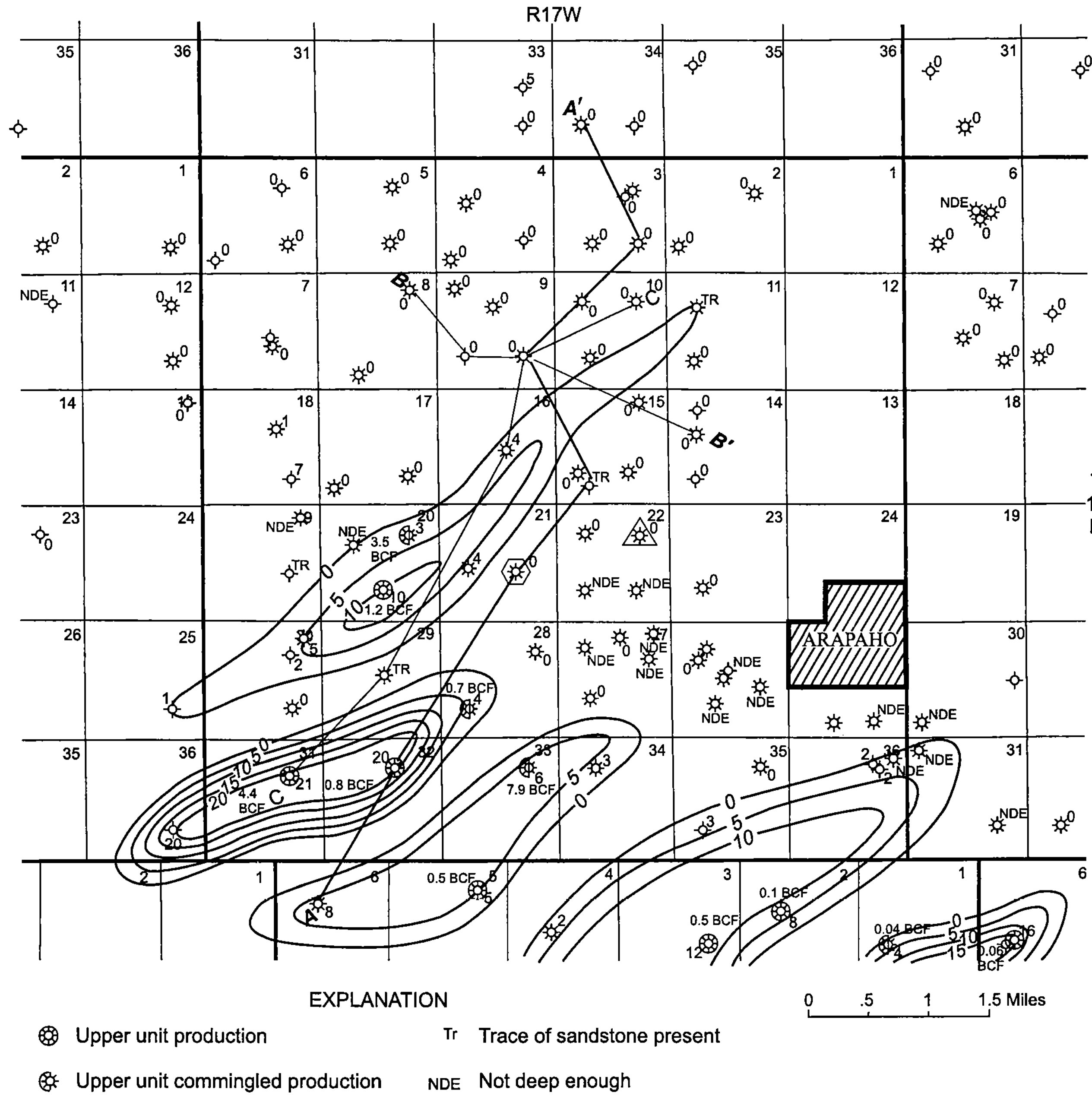


Figure 44. Gross-sandstone isopach map of the lower unit of the upper Morrow Formation in Arapaho field. Contour interval is 5 ft. Lines of cross sections A–A′ (Fig. 38), B–B′ (Fig. 41), and C–C′ (Fig. 42) are shown.

the interpretation of every well in the field. IHS Energy Group has an ongoing project designed to construct a database of reservoir records on a well-by-well, reservoir-by-reservoir basis. This database currently contains >10,000 well/reservoir evaluations within the Anadarko basin and shelf area.

UPPER MORROW PRODUCTION

An index map (Fig. 45) of wells producing from the upper unit of the upper Morrow in Arapaho field shows well names and numbers, dates of first production, and cumulative production of both gas and oil to September 1998. Production characteristics of the discovery well for the upper Morrow in Arapaho field, the Harper No. 1 George, are shown in Figure 46. The production history of the entire unit is indicated in Figure 47.

As indicated by the isopach map of this unit, the sandstone appears to be largely continuous across the field. BHP analysis supports this finding. Figure 48 is a composite plot of BHPs over time of the No. 1 George (the discovery well, near the center of sec. 16), the No. 1 Parr (near the N½NE¼ sec. 15), and the No. 1-14 Palmer (S½S½NW¼ sec. 14). This plot suggests communication between these wells. Additional plots and analyses of the various upper Morrow upper unit wells of Arapaho field indicate similar communication between most of the wells. While this unit is largely continuous across the field, inspection of the isopach map

TABLE 6. – Reservoir/Engineering Data for Upper Unit and Lower Unit of Upper Morrow Sandstone, Arapaho Field, Custer County, Oklahoma

Discovery date	10/5/79 (Harper Oil Co. #1 George, sec. 16, T. 13 N., R. 17 W.)
Reservoir size (saturated gross sandstone)	11,520 acres (~18 mi^2) upper unit and lower unit
Reservoir volume (saturated gross sandstone)	~80,640 acre-feet
Number of wells, including commingled	28
Average saturated/gross-sandstone thickness	7 ft
Reservoir depth	about 13,100–14,100 ft
Spacing	640 acre, occasionally 320 acre
Gas–water contact	None observed
Porosity	0–17%, average 7.2%
Water saturation in pay wells	12–42%, average 27%
Water resistivity	R_w = 0.034 at reservoir temperature
Reservoir temperature	185–225°F, average 212°F
Gas density	0.58–0.68, average 0.62
Z factor (compressibility)[a]	1.01 est.
B_g (gas formation volume factor)[b]	~590 std. cu ft per reservoir cu ft
Initial reservoir pressure (BHP)	11,406 psi
Initial pressure gradient	~0.85 psi/ft
OGIP (volumetric–field)[c]	106 BCF
Cumulative field gas to 9/98	64 BCF/gas equivalent (62 BCF + 548 MBO); for non-commingled wells only; 66± BCF, est., inclusive of commingled wells
% Recovery to 9/98	62%
Recovery MCF/ac-ft (field to 9/98)	818 MCF/ac-ft
Remaining reserves	6.5 BCF± remaining in upper Morrow wells, 10 BCF± behind pipe
Ultimate expected cumulative	82.5± BCF
Ultimate expected % recovery	78% with no additional wells drilled
Ultimate expected MCF/ac-ft	1,023 MCF/ac-ft
Average expected well cumulative	2.6 BCF/well

[a]Compressibility factor (Z) estimated from standard reservoir-engineering charts using T_{res} = 225°F and P_{res} = 11,511 psi. T_{res} = reservoir temperature, P_{res} = reservoir pressure.

[b]B_g calculated using the formula: $B_g = \frac{35.4 \times P_{res}}{T_{res} \times Z}$ When T_{res} is in °Rankine (add 460° to the reservoir temperature measured in °F). The Z factor is stated above.

[c]Original gas in place (OGIP) determined using the following formula: Reserves (MCF) = 43.56 × area (acres) × perforated sand thickness (ft) × porosity (%) × $(1–S_w)$ × B_g.

of this unit indicates thinning and thickening, which could create separate reservoirs. Indeed, there were situations where there appeared to be reservoir separation between certain wells indicated by BHP analysis, but, given time, these differences seemed to disappear. It is interpreted that reservoir characteristics (porosity and assumed permeability ranging from poor to good across the field) made communication between certain wells difficult. However, over time most wells appear to communicate.

An index map (Fig. 49) of wells producing from the lower unit of the upper Morrow sandstone in Arapaho field shows well names and numbers, dates of first production, and cumulative production of both gas and oil to September 1998. The production history of the lower unit wells is indicated in Figure 50. The isopach map of this unit indicated that several sandstone deposits were likely separated from one another. Figure 51 is a plot of BHPs over time for the three upper Morrow lower unit wells in the field. This plot supports the observations made from the isopach map. The No. 1-31 White Shield well (sec. 31) and the No. 1-32 Miller well (sec. 32) are ~1 mi apart and are indicated by the isopach map as producing from the same sandstone deposit. The plot of BHPs clearly indicates this to be the case. However, the No. 1 Perry in sec. 20 is indicated on the isopach map as having drilled a separate reservoir, and the plot of BHPs clearly agrees with this interpretation. Thus, as the upper unit seems to have a high degree of continuity, the lower unit has a high degree of discontinuity and is composed of several separate sandstones occupying the same stratigraphic interval.

Production data for these wells are shown in Table 4. Indications are that the average upper Morrow well in Arapaho field has produced 2.4 BCFG, with 21 MBO, with few reserves left. From data within the reservoir database of IHS Energy Group, an analysis can be made that readily generates a value for drainage area on a well-by-well basis, based on various parameters such as reservoir thickness, porosity, water saturation, and pressure. This type of analysis also indicates that the existing wells are largely in communication. A map plot of the various-size drainage areas of individual wells demonstrates that there is very little overlap of drainage areas and, most importantly, very few gaps in between. The overlaps and gaps can readily be eradicated by adjusting the shape of the drainage areas to something other than the standard representation of a circle surrounding the wellbore.

The upper Morrow reservoirs of Arapaho field appear to be well developed by the existing wells. Taking into account the future reserves expected to be recovered from the existing upper Morrow wells and the behind-pipe potential of the No. 1 Meredith (sec. 22) and the No. 1 Weidner (sec. 23), which currently produce from the Cunningham and Britt sandstones of the

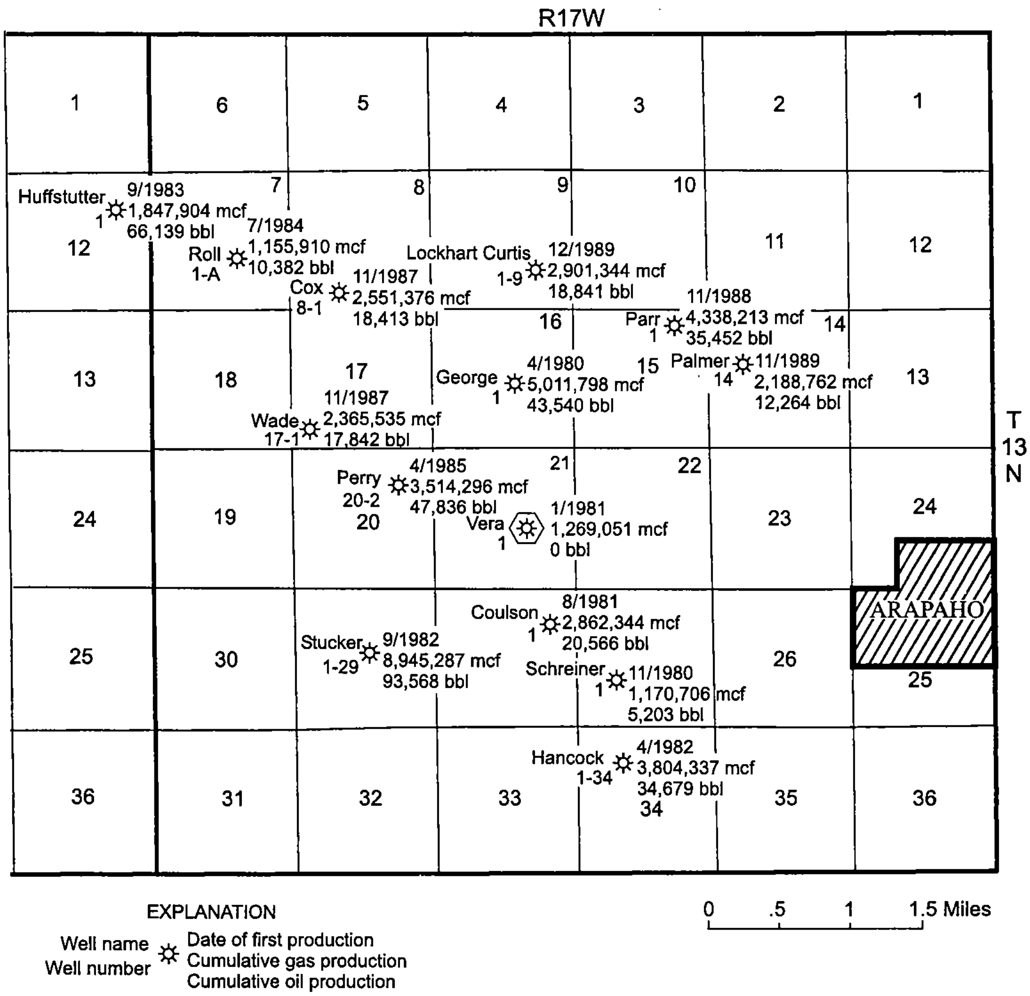


Figure 45. Well-information map, showing well names and numbers, dates of first production, and cumulative gas and oil production for wells producing from the upper unit of the upper Morrow Formation (non-commingled wells only), Arapaho field.

Springer Formation, this field should recover 78% of the calculated original gas in place (Table 6).

PRIMROSE SANDSTONE LOWER UNIT DISTRIBUTION AND DEPOSITIONAL ENVIRONMENT

An isopach map (Fig. 52) of the gross sandstone in the lower unit of the Primrose indicates that the Primrose sandstones that produce in Arapaho field are thickest in the southwestern part of T. 13 N., R. 17 W., and become progressively thinner to the point at which they essentially pinch out near the northern boundary of the township. Therefore, this map demonstrates the trapping mechanism for the Primrose in this field, a classic stratigraphic trap formed by the pinch-out of sandstone in an updip direction. Also shown on this map is an approximate water level based on the structure map of the base of the Thirteen Finger section (top of Morrow). The basis for interpreting this water level is discussed in the following section on formation evaluation of the Primrose lower unit.

This localized productive Primrose lower unit sandstone is interpreted to be deltaic in origin. The general geometry of the isopach map indicates that this is the case. Additionally, the regional production pattern of the Primrose lends credence to this interpretation. There is no Primrose production (from either of the units) to the southwest (basinward) of Arapaho field. Production from the lower unit is rare in Custer County outside this field, making Primrose production in the field a localized and unique occurrence. Directly northeast of the field, the lower unit pinches out. Farther to the northeast, sandstone in the upper unit of the Primrose pinches out, where hydrocarbon accumulations have been trapped and extensively produced.

Cross-sections were constructed within Arapaho field that demonstrate and support these conclusions. The cross-sections indicate deltaic deposits through the interpretation of log characteristics and by the spatial geometry of the deposits, both horizontal and vertical, which is consistent with a deltaic system.

Cross-section D–D′ (Fig. 53, in envelope) is a west–east strike section across the field. The log of the Woods No. 5-1 Baker, the well farthest west, exhibits a prodelta

Lease Name:	GEORGE (1)	Field Name:	ARAPAHO (MORROW UPPER)
County, ST:	CUSTER, OK	Operator:	U M C PETROLEUM CORP
Location:	13N-17W-16		

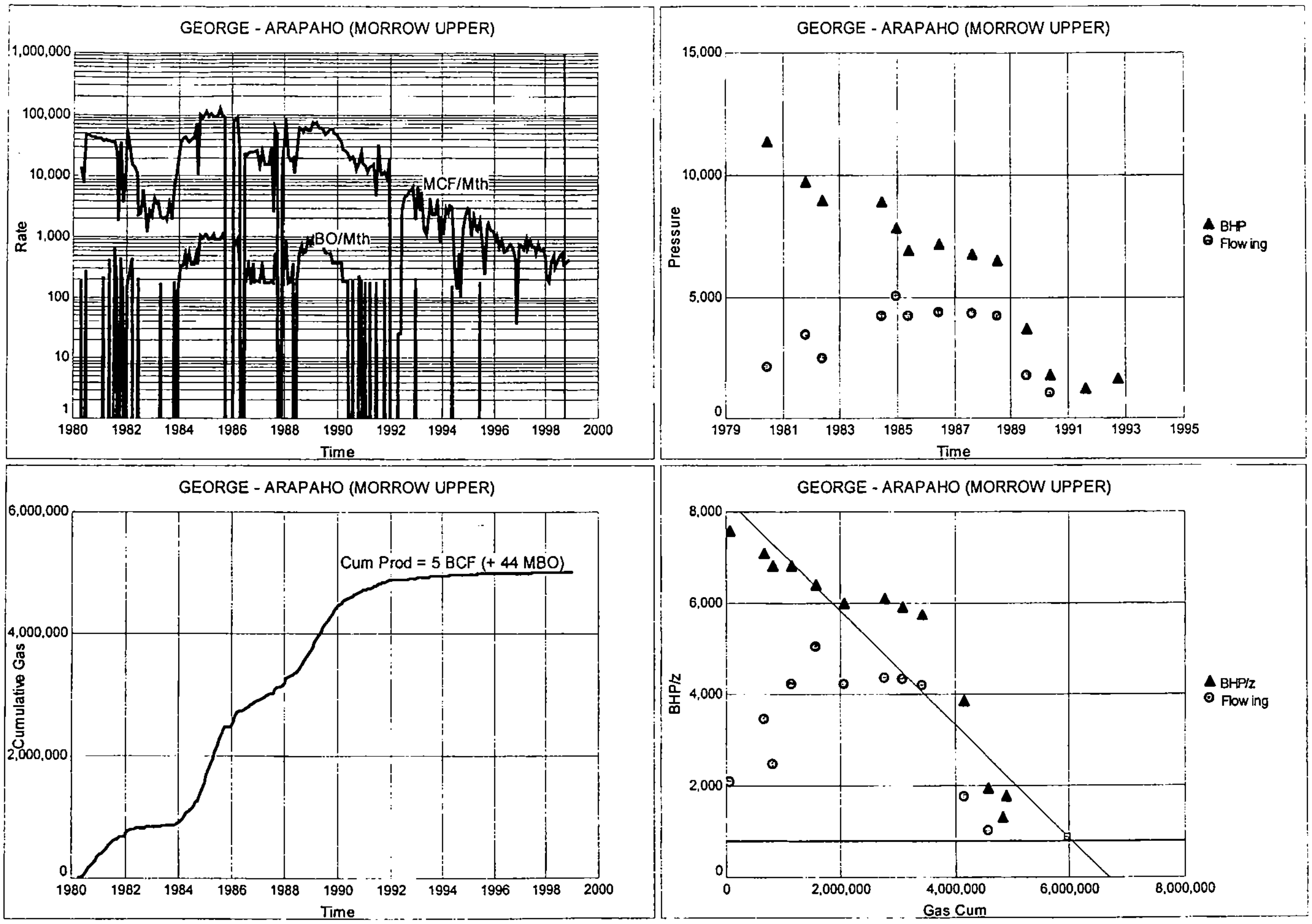
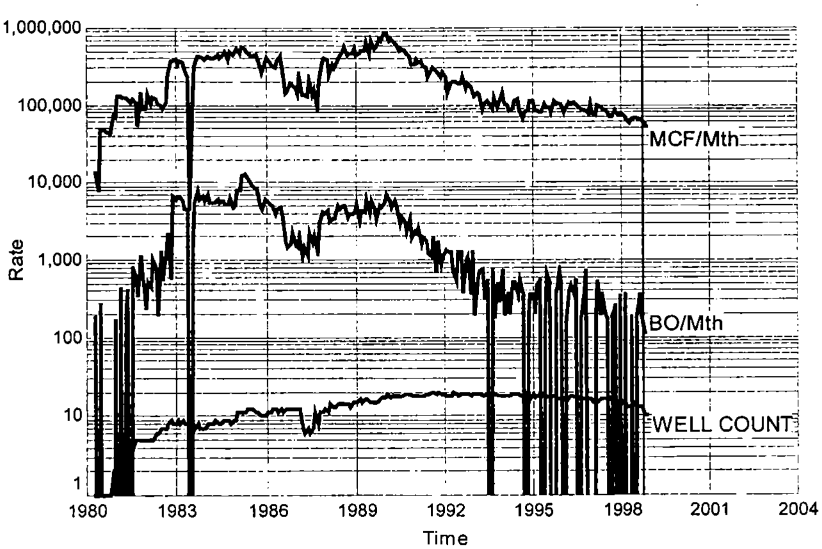


Figure 46. Production and pressure curves for the No. 1 George well, discovery well of the upper Morrow sandstone in Arapaho field.



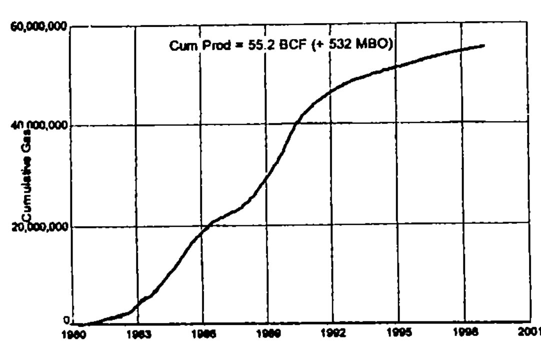


Figure 47. Production curve for the entire upper unit of the upper Morrow Formation in Arapaho field.

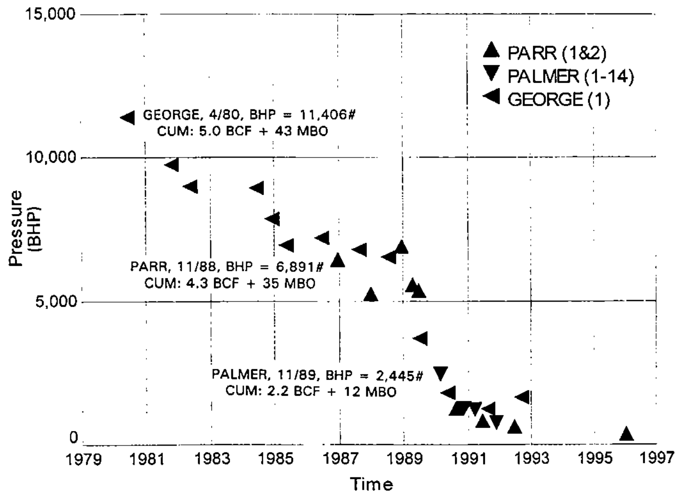


Figure 48. Pressure plots of three upper Morrow upper unit wells in Arapaho field, indicating communication.

sequence at the base of the lower unit of the Primrose, followed by a classic delta-front sequence through the rest of the unit. A mud log obtained for this well indicates the delta-front sequence to be a tan to dark gray, fine to very fine grained sandstone with abundant shale inclusions and abundant glauconite. The glauconite is an indicator of marine conditions. The Sonat No. 9-4 Lockhart, the next well, was drilled to the southeast. In this log, the lower unit appears to be a thick channel sandstone or possibly more than one sandstone superimposed on another. The distributary channels in this well have eroded down to and possibly slightly into the Springer shale. Unfortunately, there were no mud logs and thus no sample descriptions of wells that encountered these distributary-channel sandstones. Southeastward, in the log of the middle well, the Gulf No. 1-9 Lockart, the base of the Primrose appears to contain the same distributary channel. Above this channel in the Gulf well is the delta-front sequence that was seen in the westernmost well, the Woods No. 5-1 Baker. At this point it can be interpreted that a prodelta area existed, upon which a delta front developed, followed by a series of localized distributary channels that cut down through the area but left undisturbed delta-front deposits on either side. The other logs in this cross section indicate distributary channels resting on prodelta deposits that probably removed and replaced the delta-front sequence that was likely originally deposited in that area.

Cross section E–E′ (Fig. 54, in envelope) is a north–south dip section that starts in the north with a thin section of sandy shale that represents the lower unit of the Primrose. Moving southward, the next log indicates another major distributary channel resting on top of prodelta deposits, having likely removed and replaced any previous delta-front deposits. This log depicts the channel axis. Between the Samedan No. 1-10 Baxter well (the center log) and the Santa Fe No. 1-15 Parr well (the next log), which is depositionally downdip, a marked change in depositional character is evident. Whereas the No. 1-10 Baxter log generally depicts an upward-fining sequence characteristic of one or more distributary channels, the lower section of sandstone in the No. 1-15 Parr is the reverse. It is an upward-coarsening sequence representative of a distributary-mouth bar. In map view, this interpretation of log character and geometry is conformable with distributary channel(s) feeding in through secs. 3 and 10 and forming a more generalized distributary-mouth bar to the south, beginning at sec. 15. Similar characteristics were observed to occur with the distributary channels found in sec. 9, forming distributary-mouth bars to the south in

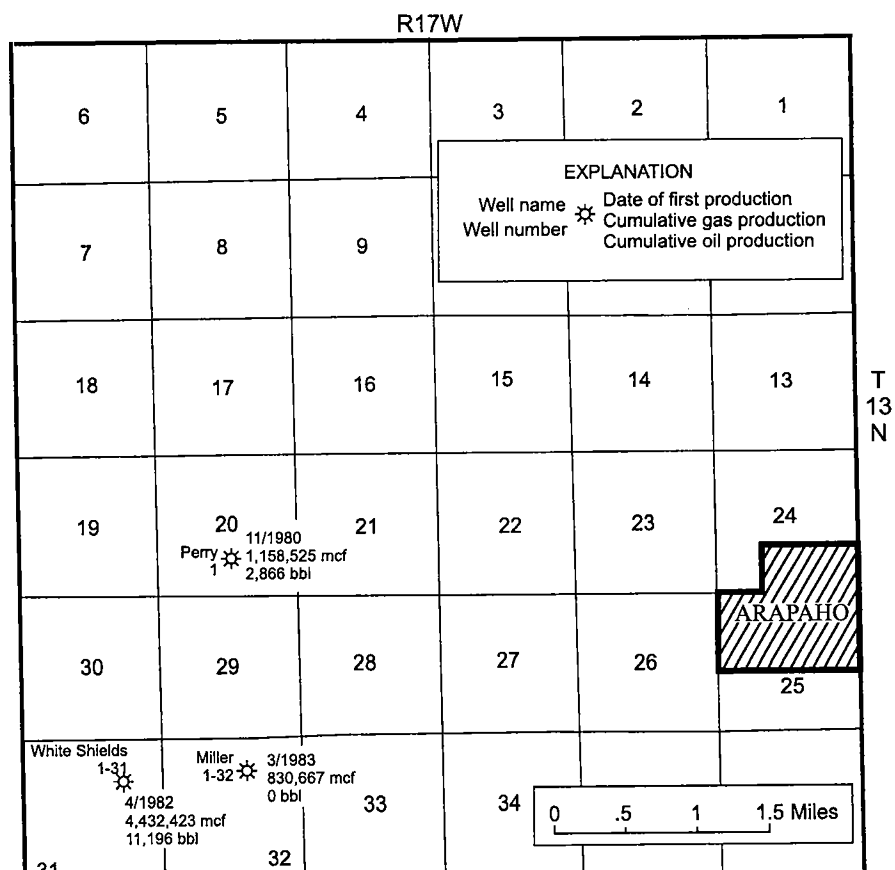
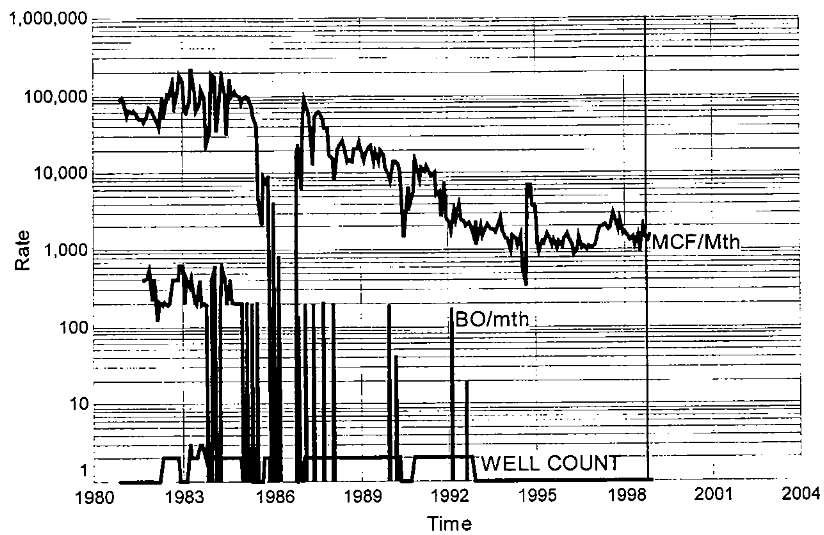


Figure 49. Well-information map, showing well names and numbers, dates of first production, and cumulative gas and oil production for wells producing from the lower unit of the upper Morrow Formation (non-commingled wells only), Arapaho field.



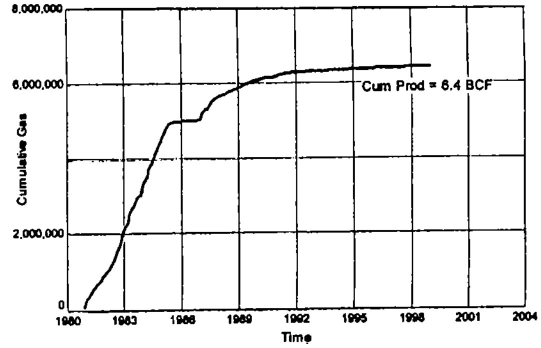


Figure 50. Production curve for the lower unit of the upper Morrow Formation in Arapaho field.

sec. 16. Sample descriptions from mud logs that indicate distributary-mouth-bar sequences describe the sandstone as clear to off-white, fine to medium grained, with only a trace of glauconite, which possibly indicates less of a marine influence than with the delta-front deposits. Finally, on the right side of the cross section can be seen another distributary channel that prograded over the distributary-mouth-bar sequence previously discussed.

The foregoing observations support the interpretation that the Primrose lower unit sandstones in the Arapaho field area are of deltaic origin. Essentially all the deltaic environments seem to be present and correctly related to one another spatially: prodelta shales overlain by delta-front deposits, which were eroded by distributary channels, which in turn built out distributary-mouth bars.

PRIMROSE LOWER UNIT FORMATION EVALUATION

The methodology for the formation evaluation of the Primrose was essentially identical to that which was discussed under a previous section for the upper Morrow. The Primrose contains more clay but generally not enough to warrant shaly-sandstone corrections. Fewer hole problems (pulling and sticking) were noted, but at times they were a factor. Unlike the upper Morrow, the Primrose in this field did exhibit a water level. A comparison of the log characteristics of a producing Primrose lower unit well to those of a well that is indicated to be wet is shown by Figure 55, in which porosity values are roughly the same in the two wells (6–9%), but resistivity values for the producer are 90–100 ohm-m and only 35 ohm-m for the wet well. These values indicate the producer to have salt-water concentrations of 52–70%, and the wet well a salt-water concentration of 100%.

Water calculations are complex, owing to the nature of the depositional environments of the individual reservoirs involved. It has been noted that the sandstones in this field are delatic in origin and as a result have a variety of genetic origins and resultant reservoir characteristics. Critical characteristics, such as clay content, porosity (and assumed permeability), and even water resistivity, vary with the different genetic units. For example, the distributary-mouth bars are believed to be finer grained, higher in clay content, and lower in porosity than the distributary channels. Most of these factors can be and were interpreted through log analysis. Predominantly, for two reasons, the distributary-mouth-bar deposits were found to be nonproductive in the field. First, owing to their genetic origin, these deposits were of poorer quality (shaly, with less porosity), and second, the developed porosity generally was in the water leg of the reservoir and therefore wet.

A thorough analysis of this type of depositional environment is complex but absolutely necessary for proper

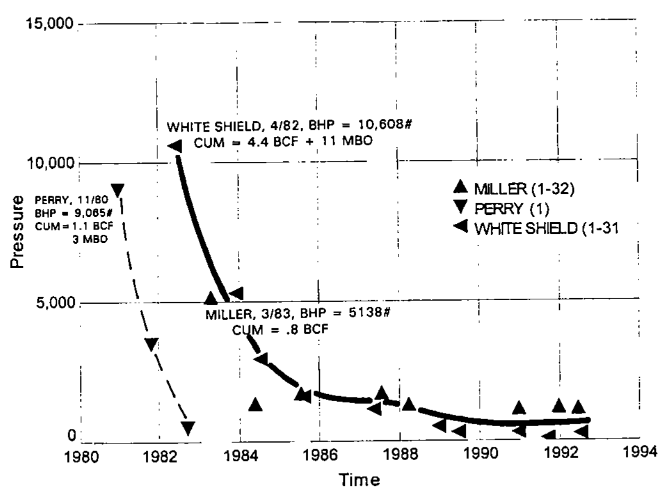


Figure 51. Pressure plots of three upper Morrow lower unit wells in Arapaho field, indicating communication between two wells that are not in communication with the third well.

understanding and successful exploration/exploitation. The results of the field analysis of this reservoir are given in Table 7. Several observations should be noted.

First, no single value for water resistivity (R_w) is necessarily considered to be valid for all the genetic units and thus for the reservoirs. Because of the complex depositional environment, it is not hard to imagine that a number of separate reservoirs are involved and that they could be expected to have varying water resistivities. This appears to be the case from log analysis, as no single value for water resistivity would work in all cases. A generalized value of R_w = 0.18 ohm-m at reservoir temperature was used, but producing zones were observed to have resultant water saturations of 13% (too low) to 100% (obviously too high). The value of 0.18 ohm-m for water resistivity was used because of general knowledge of the area and specific knowledge of produced Primrose lower unit water from the

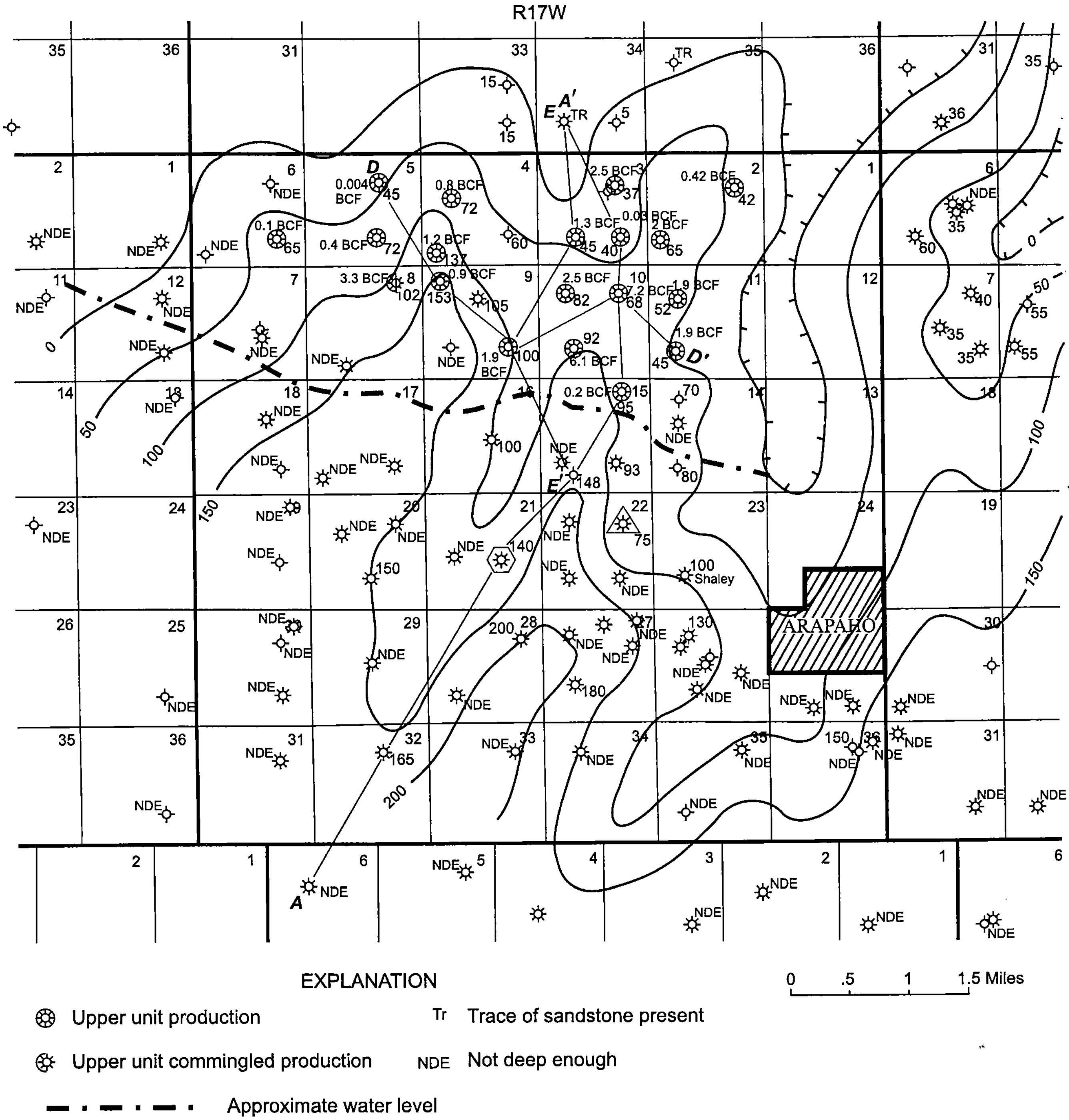


Figure 52. Gross-sandstone isopach map of the lower Primrose sandstone of the lower Morrow Formation in Arapaho field. Contour interval is 50 ft. Lines of cross sections A–A′ (Fig. 38), D–D′ (Fig. 53), and E–E′ (Fig. 54) are shown.

TABLE 7. – Reservoir/Engineering Data for Lower Unit of Primrose Sandstone, Arapaho Field, Custer County, Oklahoma

Discovery date	4/23/81 (Gulf Oil Corp. #1A-3 Meacham, NE¼SW¼NE¼ sec. 3, T. 13 N., R. 17 W.)
Reservoir size (using perforated sandstone)	4,480 acres (~7 mi^2)
Reservoir volume (using perforated sandstone)	~129,920 acre-ft
Number of wells, including commingled wells	20
Average perforated sandstone thickness	29 ft
Reservoir depth	about 14,105–14,616 ft
Spacing	320–160 acre
Gas–water contact	Variable and approximate, about –13,000 ft
Porosity	0–17%, average 6.9%
Water saturation in pay wells	13–100%, average 53%
Water resistivity	R_w = 0.18 at reservoir temperature, but variable owing to separate reservoirs
Reservoir temperature	202–246°F, average 225°F
Gas density	0.57–0.61, average 0.59
Z factor (compressibility)[a]	1.03 est.
B_g (gas formation volume factor)[b]	about 400–577 std cu ft per reservoir cu ft
Initial reservoir pressure (BHP)	Variable, 7,984–11,511 psi; separate reservoirs are apparent
Initial pressure gradient	about 0.6–0.8 psi/ft
OGIP (volumetric–field)[c]	89 BCF
Cumulative field gas to 9/98	31.5 BCF (non-commingled only); 33 BCF± (commingled)
% Recovery to 9/98	37%
Recovery MCF/ac-ft (field to 9/98)	255 MCF/ac-ft
Remaining reserves	13.5 BCF from present lower unit Primrose wells
Ultimate expected cumulative	45± BCF
Ultimate expected % recovery	51%
Ultimate expected MCF/ac-ft	346 MCF/ac-ft
Average expected well cumulative	2.25 BCF/well

[a]Compressibility factor (Z) estimated from standard reservoir-engineering charts using T_{res} = 225°F and P_{res} = 11,511 psi. T_{res} = reservoir temperature, P_{res} = reservoir pressure.

[b]B_g calculated using the formula: $B_g = \frac{35.4 \times P_{res}}{T_{res} \times Z}$ When T_{res} is in °Rankine (add 460° to the reservoir temperature measured in °F). The Z factor is stated above.

[c]Original gas in place (OGIP) determined using the following formula: Reserves (MCF) = 43.56 × area (acres) × perforated sand thickness (ft) × porosity (%) × (1–S_w) × B_g.

Bozarth well in the SW¼ sec. 2, T. 13 N., R. 17 W. The Bozarth well has produced >2 BCFG from this unit. Water-resistivity values may well need to be varied in accord with individual reservoirs.

Second, consideration needs to be given to variation in grain size, porosity, permeability, and clay content (and how clay is distributed in pore spaces) for the various genetic units. There is undoubtedly a relationship between the foregoing factors as to apparent water saturations and the relative percentages of reducible to irreducible reservoir waters.

CORE DATA

No core data were located covering the Primrose sandstones in Arapaho field. What follows are core data from the Springer sandstones in the field. It is hoped that these data will be useful in gaining a better understanding of the Primrose reservoirs.

Two cores were cut in the Arkansas Western No. 1-36 State, in sec. 36, T. 13 N., R. 17 W., within the confines of the field but were from the Cunningham and Britt sandstones (Springer), which produced in the Harper/Meredith (discovery well in sec. 22) and the Harper/Weidner (offset to the discovery well in sec. 23). When the State well was drilled in 1981, the Cunningham and Britt were considered the main Morrow/Springer targets in the area, as the discovery well for the Primrose lower unit sandstone was not drilled until that same year.

Early drilling within Arapaho field and the surrounding area had indicated a poor correlation between log characteristics and the characteristics of the production that might be obtained. Questions were raised as to the accuracy of the logs and/or their interpretation as well as the mineralogical properties of the potential reservoir rock. The decision to obtain core data on the State well was made in an effort to answer some of these questions.

The cores cut in the State well were from the same Cunningham and Britt units that were found productive in both the Meredith and Weidner wells. Data from these cores are given in Figure 56. Several observations can be made from these data. The core porosity has been plotted on the porosity log and indicates that in regard to log analysis, and in areas of reasonable porosity development, a standard cross-plot of the neutron-porosity value and density-porosity value would give values almost identical to those derived from the core. Additionally, a correction of the density-porosity value from 2.71 g/cm^3 (log calibrated to limestone matrix) to 2.68 g/cm^3 (log calibrated to sandstone matrix) would also result in a match with the core values. Therefore, it was felt that the logs correctly reflected the rock properties and that standard log interpretation was valid. Mineralogical and pore-geometry data were obtained from X-ray diffraction and scanning electron microscopy. These

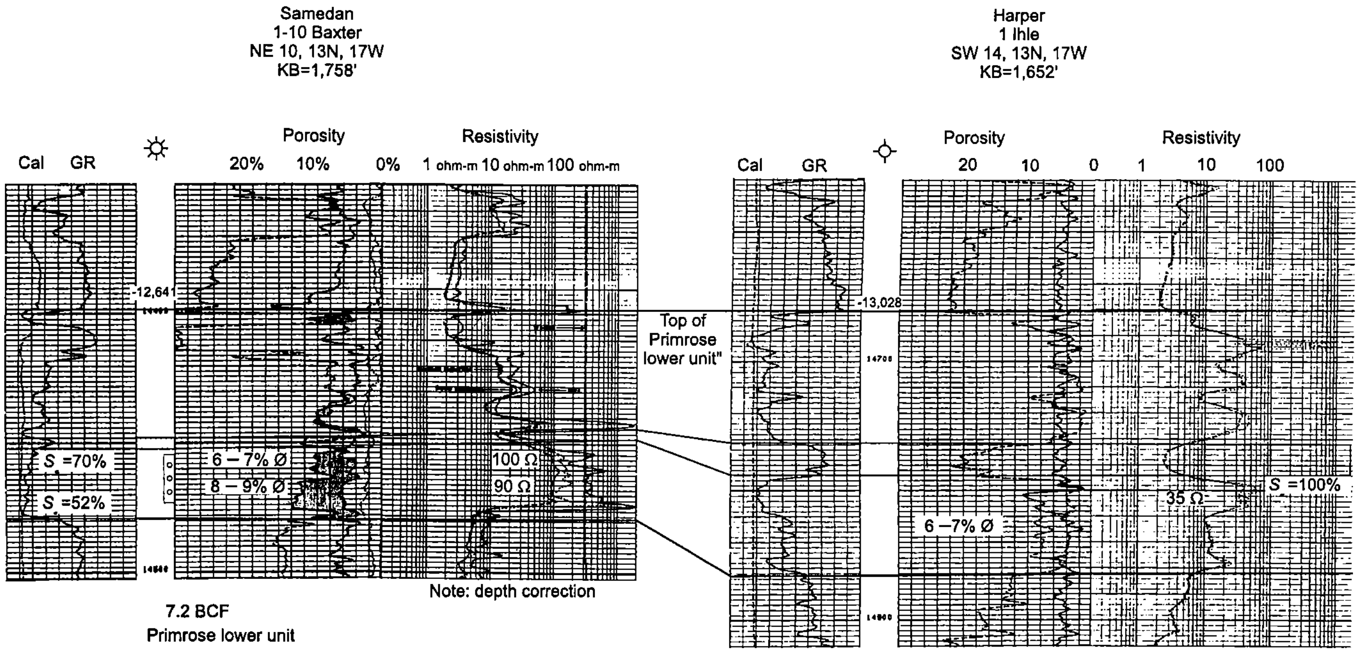


Figure 55. Comparison of productive versus "wet" log characteristics of the lower Primrose sandstone in Arapaho field. *Cal* = caliper; *GR* = gamma ray.

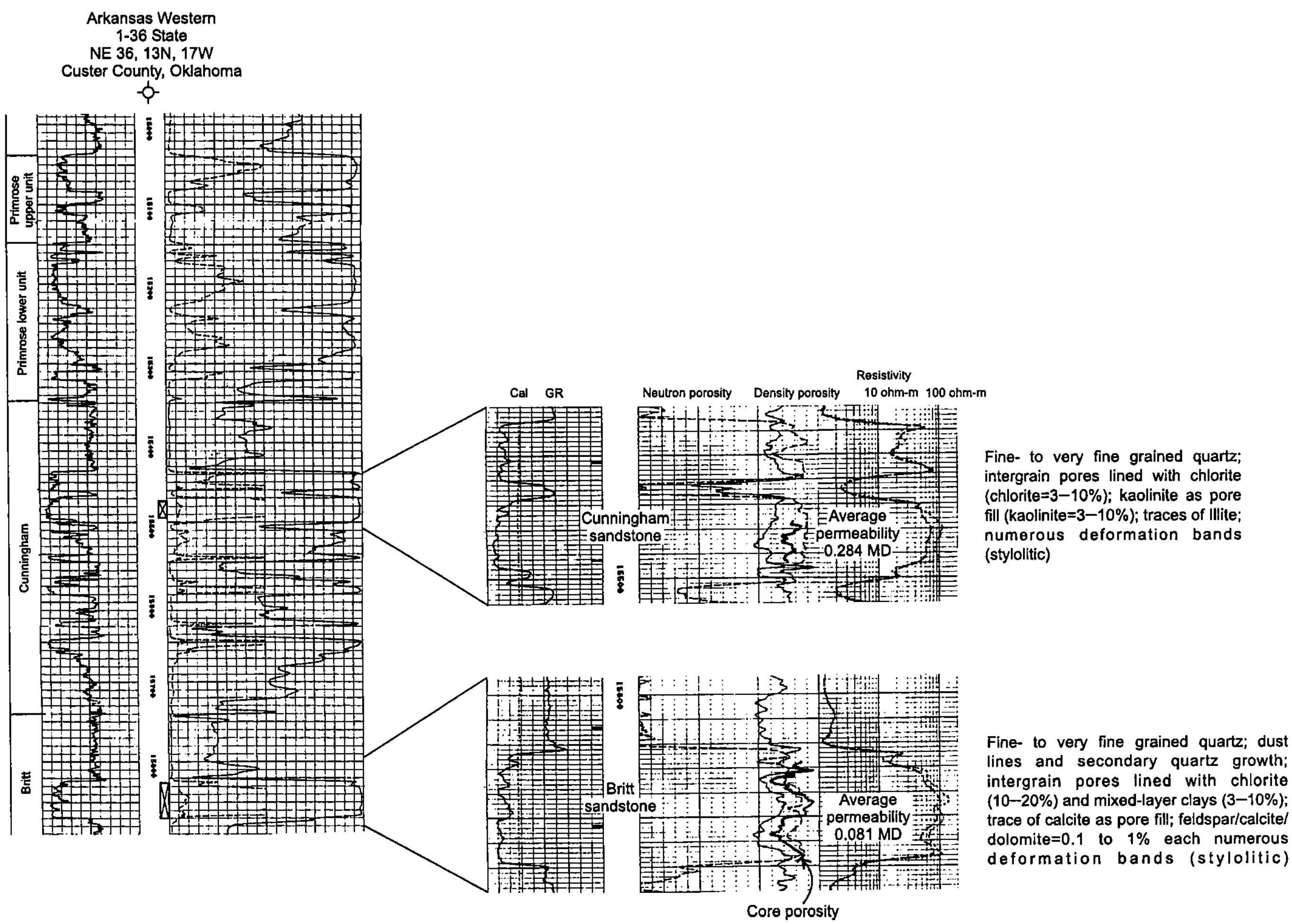


Figure 56. Core data for Cunningham and Britt sandstones (Springer Formation) in Arapaho field. *Cal* = caliper; *GR* = gamma ray.

analyses indicated that the reservoir rock is a very tight quartz sandstone with a notable assemblage of clay materials. Owing to the volume and types of clay minerals present, drilling and completion practices were reevaluated and at times altered.

Of final note is the evidence of substantial diagenetic alteration of the Britt sandstone. Numerous deformation (stylolitic) bands with what is assumed to be increased concentrations of heavy minerals were observed in the Britt core. Also noted was a substantial amount of secondary quartz overgrowth, as evidenced by dust lines. It is logical to conclude that the Britt underwent diagenetic processes in which rock material was dissolved and re-precipitated as quartz overgrowth with an associated loss of porosity.

PRIMROSE LOWER UNIT PRODUCTION

An index map (Fig. 57) of wells producing from the lower unit of the Primrose sandstone shows well names and numbers, dates of first production, and cumulative production of both gas and oil to September 1998. Production characteristics of the discovery well for the Primrose, the H S Resources (Gulf Oil) No. 1A-3 Meacham, are shown in Figure 58. As can be seen from the composite production curves in Figure 59, the production rate of the Primrose is consistent, and a low decline rate is the result of drilling additional wells.

A number of separate reservoirs are involved in the Primrose lower unit production. A plot of the BHPs of wells that have produced >1 BCFG from this unit is shown in Figure 60. This plot demonstrates that some wells are in communication and others are not. A truly definitive analysis of the different reservoirs is not possible, because separate reservoirs within the Primrose lower unit are often perforated and commingled in a single borehole. This situation is demonstrated on cross-section D–D′ (Fig. 53).

Well-level production data are shown in Table 7. The average Primrose lower unit well in Arapaho field has produced nearly 1.8 BCFG with little oil. From additional analysis of data within the IHS Energy Group well/reservoir database, indications are that this unit has produced only a little more than two-thirds of its ultimate per-well recovery. Additionally, analysis indicates that the present wells will recover only ~51% of the original gas in place. This is likely for a combination of reasons. Most important, the depositional environment is interpreted to include a number of separate reservoirs, thus retarding effective drainage. Second, the reservoir quality is only fair in most instances, re-

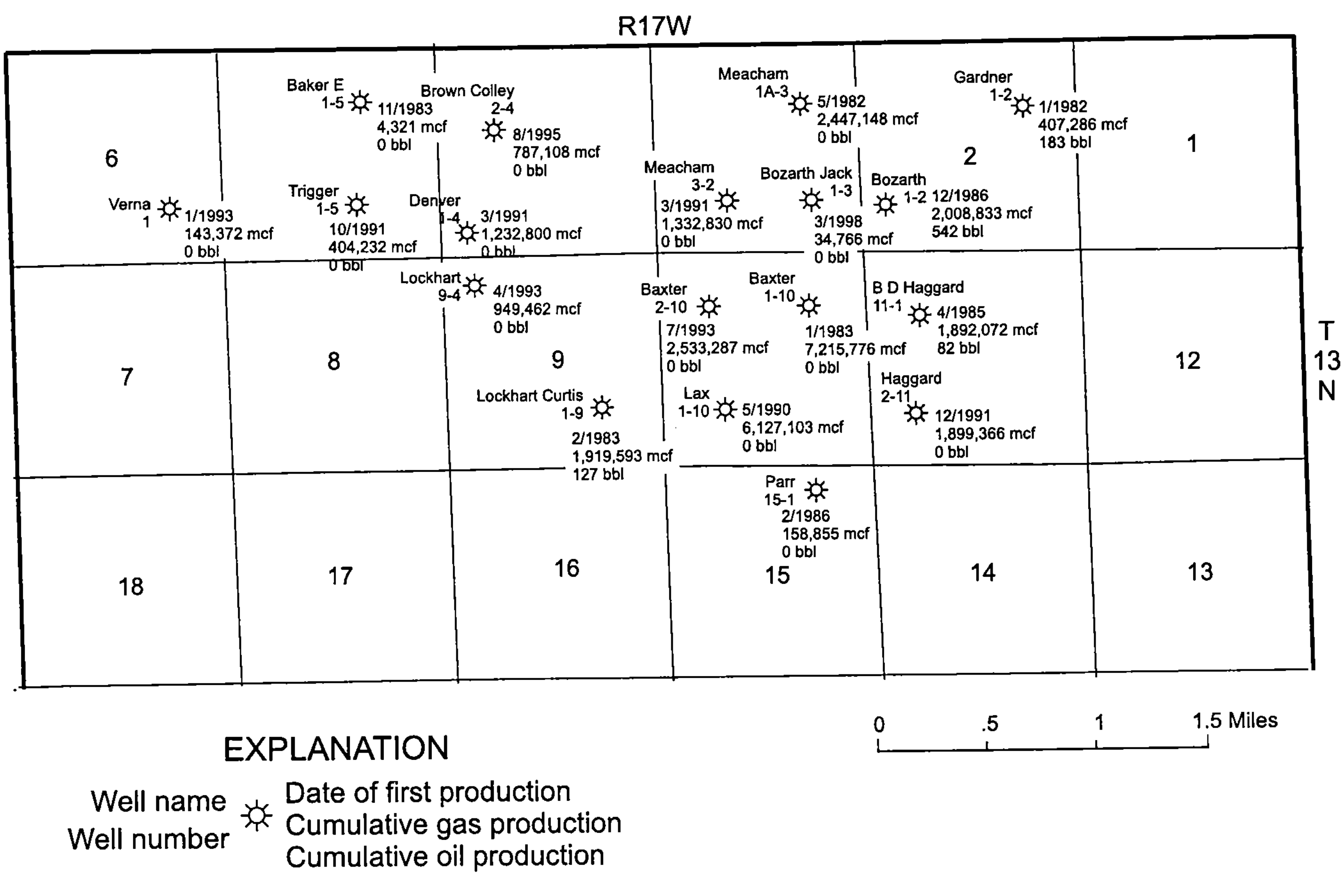


Figure 57. Well-information map, showing well names and numbers, dates of first production, and cumulative gas and oil production for wells producing from the lower unit of the Primrose sandstone of the lower Morrow Formation (non-commingled wells only), Arapaho field.

Lease Name:	MEACHAM F (1A-3)	Field Name:	ARAPAHO (PRIMROSE)
County, ST:	CUSTER, OK	Operator:	H S RESOURCES INC
Location:	13N-17W-3		

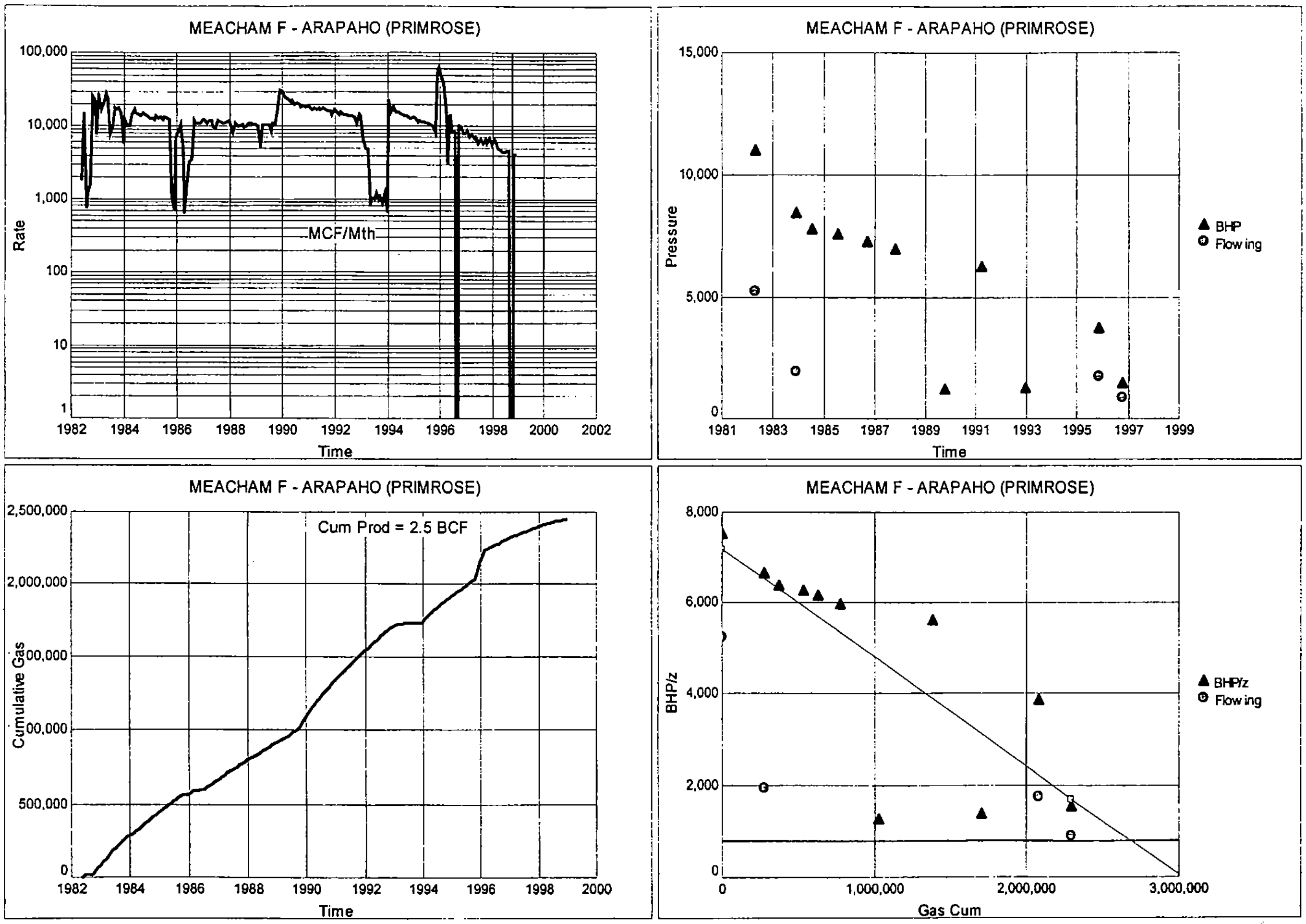
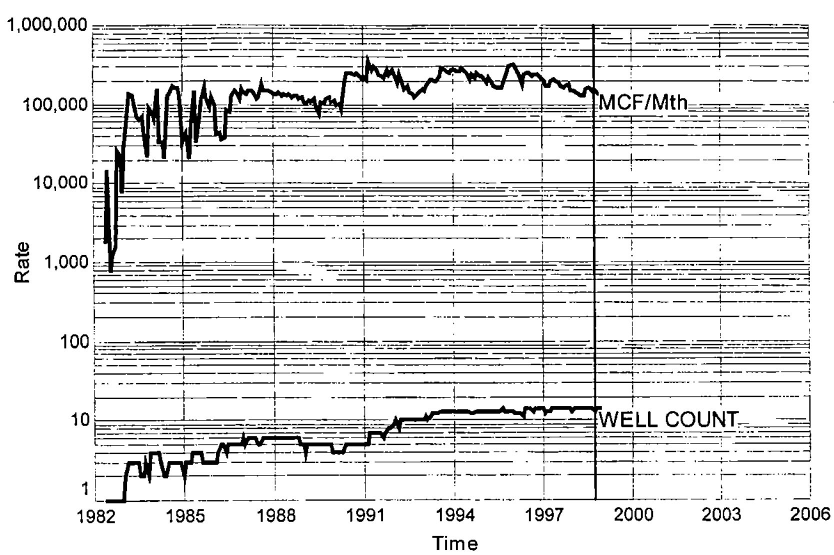


Figure 58. Production and pressure curves for the No. 1A-3 Meacham well, the discovery well of the lower unit of the lower Morrow Primrose sandstone in Arapaho field.



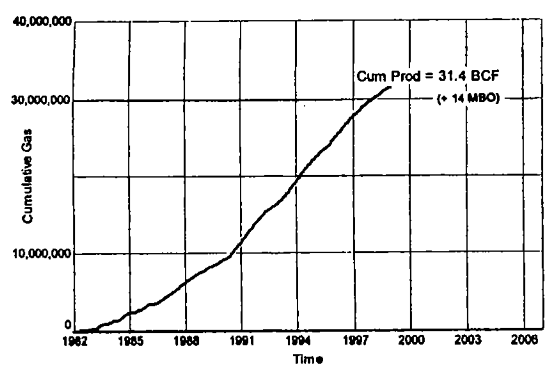


Figure 59. Production curve for the lower unit of the Primrose sandstone in Arapaho field.

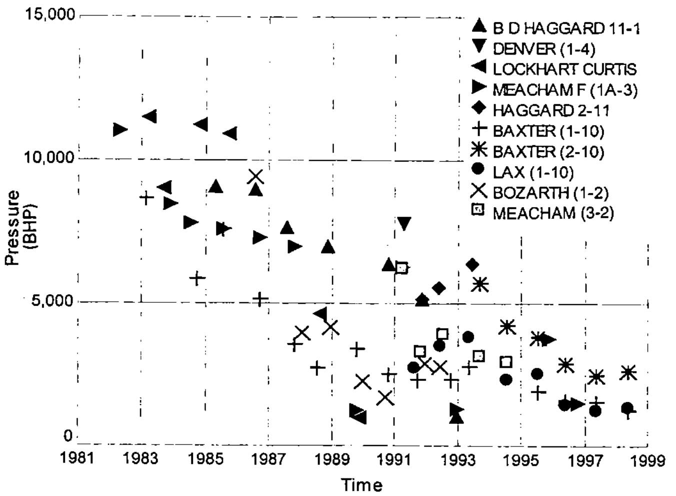


Figure 60. Pressure plots of Primrose lower unit wells (non-commingled) that have produced >1 BCFG in Arapaho field.

sulting in slow or incomplete drainage of very large areas. Last, the values used for calculations on a field-wide basis may be optimistic relative to the variability observed for the reservoirs. Only very detailed mapping and analysis could determine the relative importance of the preceding circumstances and, combined with an economic analysis, determine the future potential of the Primrose lower unit reservoir.

WELL-DRILLING AND COMPLETION PRACTICES

As stated previously, the upper Morrow sandstone in Arapaho field was an overpressured reservoir. The discovery well (1980) had an initial BHP of 11,361 psi at a reservoir depth of 13,422 ft. As a result, drilling practices were far from normal. Intermediate casing had to be set above the upper Morrow so that mud of a weight adequate to control the upper Morrow would not break down and be lost in shallower zones, creating the potential for a blowout. A number of wells in the area did experience blowouts. The problem was exacerbated when a well was scheduled to go to the lower Morrow/Primrose and Springer sections. This required that another string of casing be set through the upper Morrow so that the mud weight could be lowered to drill these deeper sections. Mud of adequate weight to control the upper Morrow would potentially break down the lower Morrow/Springer sandstones, thus emptying the hole to the point at which the upper Morrow could blow out a well. A typical casing and mud program for a Springer test is shown in Figure 61. If the well were just an upper Morrow test, the casing program could be stepped down by one step. That is, 7⅝-in. casing could be set above the upper Morrow, and 5-in. casing set through it.

Oil-based mud generally has been used to drill both the upper Morrow and lower Morrow/Primrose and Springer sections. This was due to the expected sensitivity of these formations to water-based drilling fluids. The average mud costs for a Springer test when these wells were being drilled was $336,000.

There is very little commonality in the treatments that were used in the wells within Arapaho field. The upper Morrow was generally completed naturally and only occasion-

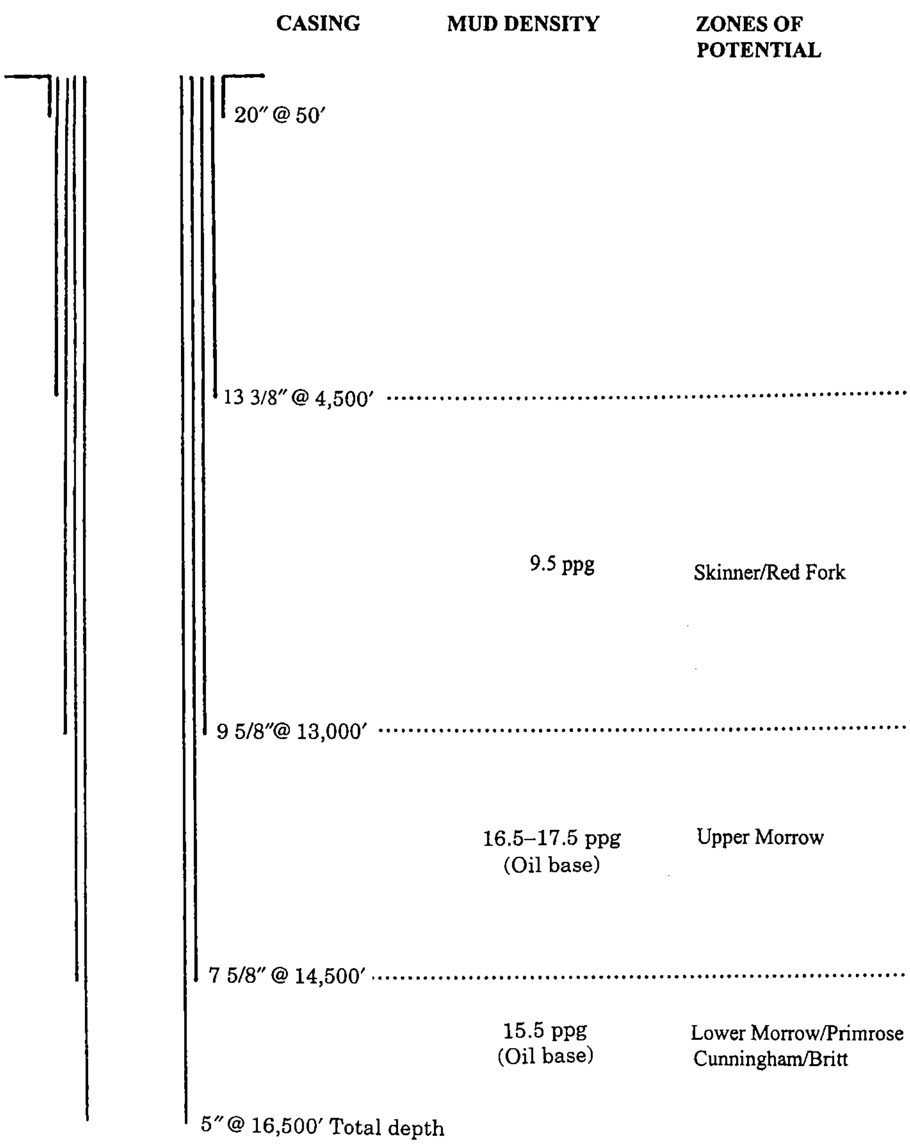


Figure 61. Typical casing program for wells completed in the Primrose sandstone or upper Springer sandstone in Arapaho field.

ally acidized and/or fracture treated. When it was acidized, it was usually with 2,000–5,000 gal of unspecified acid. When fracture treated, it was done with a wide range of 2,500–25,000 gal of fluid, usually CO_2, but once with water, and at times with 25,000–35,000 lb of sand. The lower unit of the Primrose was generally acidized and fracture treated because of its tight nature. The average treatment procedure, with wide variation, was ~6,000 gal of 7.5% acid, followed by a salt-water fracture treatment of 85,000 gal with 80,000 lb of sand. Because of the high variability of completion practices, no analysis of completion effectiveness was conducted.

PART IV

Cheyenne West Field

Upper Morrow chert-conglomerate gas reservoir in T. 13 N., R. 24 W., Roger Mills County, Oklahoma

Richard D. Andrews
Oklahoma Geological Survey

INTRODUCTION

Cheyenne West field is in south-central Roger Mills County, western Oklahoma (Fig. 62). The 64-section study area lies in the southern part of the Anadarko basin, or the "deep basin," as many people refer to it (Pls. 1, 3). The study area is about 25 mi northwest of Elk City, Oklahoma. The lithology of the Morrow reservoir is unusual, as it consists of coarse-grained sandstone and conglomerate. Typically, this clastic assemblage contains chert fragments—an indication of the predominant southerly source of sediments, which contrasts with most other Morrow clastics, having been derived from source areas to the north and northwest. As recognized by the Oklahoma Stratigraphic Nomenclature Committee of the Mid-Continent Oil and Gas Association, this field also produces from several younger Pennsylvanian reservoirs, including the Marmaton, Cherokee (Red Fork), and Atoka. However, the primary reservoir in the field is the upper Morrow Puryear sandstone/conglomerate. There is scattered production from other upper Morrow reservoirs in the general area as well as from the lower Morrow. All of this information is provided in Table 8, which is tabulated by assigned numbers adjacent to wells as shown

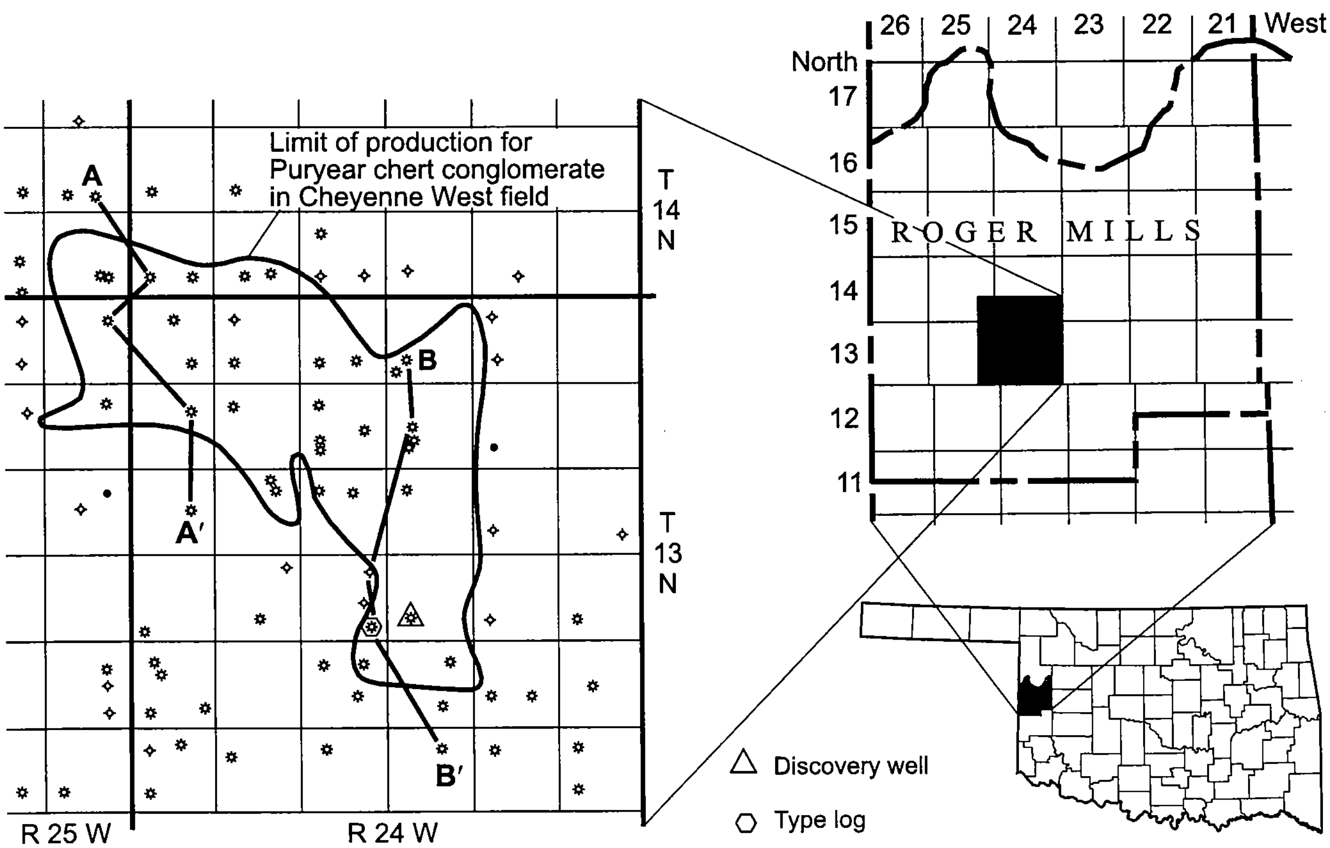


Figure 62. Generalized location map of Cheyenne West field in Roger Mills County, Oklahoma. Lines of cross sections A–A′ (Fig. 66) and B–B′ (Fig. 67) are shown.

TABLE 8. – Well-Information Map and Tabulation Keyed to Figure 63, Showing Wells, Operators, Lease Names, Completion Data, Production Data, and Pressure Data for the Upper Morrow Puryear Reservoir and Other Reservoirs in Cheyenne West Field

Map no.	Operator	Well no.	Lease	Total depth	Producing zone	Cumulative gas production (BCF)	Date of first production	Initial production: Gas (MCF)	Initial production: Oil (BBL)	Initial production: Water (BBL)	Initial production: Hrs of IP	Flowing tubing pressure	Shut in tubing pressure
1	Oryx	1	Tracy	16,000									
2	Trigg	1	Taylor	15,250	Atoka								
3	Grace Petroleum	1	Crawford	15,300	Cherokee[a]								
4	Grace Petroleum	1	Tracy	15,025	Atoka & Cherokee								
5	Wagner & Brown	1	Tracy	17,459	Cherokee								
6	Wagner & Brown	1	Tracy	17,250	Atoka & LMR[b]								
7	Wagner & Brown	1	Lovett	13,670	Marmaton								
8	Tenneco	1	Bradshaw	21,700	LMR								
9	Gas Anadarko	1	Cross	14,920									
10	Tenneco	1	Hawkins	14,664									
11	Tenneco	1	Lippencott	15,050									
12	Hoover & Bracken	1	Lippencott	14,870									
13	Hoover & Bracken	2	Lippencott	13,575	Cherokee								
14	Wagner & Brown	1	Tracy	14,777	Puryear[c]	9	Mar-79	9,401	0	18		?	3,742
15	Grace Petroleum	2	Tracy	13,738	Atoka & Cherokee								
16	Grace Petroleum	1	Tracy	14,675	Cherokee & Puryear	3.4	Jan-78	3,800	0	0			
17	Grace Petroleum	2	Tracy	15,000	Puryear	13.4	Dec-79	3,280	0	0		?	3,946
18	Hoover & Bracken	1	Tracy	15,016	Puryear	23.6	Mar-78	9,663	1	11		3,935	?
19	Grace Petroleum	2	Tracy	15,118	Cherokee								
20	Trigg	1	Burns	15,400	Cherokee								
21	Green River Exploration	1	Leland	13,600	Cherokee								
22	Anson	1	Berry										
23	El Paso	4	Berry										
24	El Paso	1	Berry		Puryear	13.9	Aug-78	10,260	0	18		7,492	8,904
25	Sanguine	1	Harrison	13,450	Cherokee								
26	El Paso	1	Berry	14,966	Puryear	26	Dec-77	14,823	0	5		8,792	11,050
27	Sanguine	1	Kass	13,330									
28	El Paso	1	Smith	14,920	Puryear	23	Jun-77	6,600	0	0		10,700	11,050
29	Hoover & Bracken	1-A	Lippencott	15,020	Puryear	25	Dec-77	5,500	0	0	18 hrs	?	9,500
30	Hoover & Bracken	1	Lippencott	15,400	Cherokee								
31	Anson	2	Lester	14,876	Puryear	5.3	Feb-80	2,560	0	0		3,000	5,132
32	Helmerich & Payne	1-A	Lester	15,015	Puryear	0.025	Dec-77	(CAOF 1710)	0	0		?	10,040
33	Grace Petroleum	1	Lester	15,100									
34	Davis Oil	1	Lester	15,300									
35	Helmerich & Payne	1	Bradshaw	15,386	Tonkawa								
36	Helmerich & Payne	1-A	State	15,055	Puryear	3.4	Oct-84	4,184	0	0		1,425	?
37	Helmerich & Payne	2	State	13,974	Atoka								
38	Helmerich & Payne	1	State	14,989	Puryear	28	Sep-76	27,330	0	40		4,950	?
39	Tenneco	2	Griffin	14,015	Atoka								
40	Helmerich & Payne	1-C	Lester	15,100	Puryear	2.1	Jan-89	1,296	0	0		220	2,300
41	Helmerich & Payne	1-B	Lester	12,397	Cherokee								
42	Helmerich & Payne	1	Lester	15,625	Puryear	16.5	Dec-76	10,400	0	0		8,550	10,777
43	Gas Anadarko	1	Berry	15,200	Puryear	30	Mar-77	7,050	0	0		10,249	11,306

44	Sun	1	Berry	15,163	Puryear	21	Oct-78	5,200	0	0		4,566	8,700
45	El Paso	2	Berry	15,270	Puryear	25.9	May-78	4,800	0	0	14 hrs	9,500	10,600
46	El Paso	3	State	15,800									
47	Coquina	1	Dempsey	16,038									
48	Trigg	1	Dempsey	9,500	Tonkawa								
49	El Paso	1	Purvis	16,000	Cherokee								
50	Braken	1	Morris	15,354	Puryear	0.4	Nov-87	725	0	0		100	2,450
51	Hoover & Bracken	1	Roark	15,835	Atoka & Puryear	1.8	Oct-76	2,420	0	0		2,500	9,600
52	Sun	1	Roark	15,500	Puryear	9.1	Feb-77	No IP				7,594	10,025
53	Sun	2	Roark	15,450	Puryear	2.4	May-85	2,378	0	10		2,371	2,487
54	El Paso	1	Barton	15,319	Puryear	23.6	Mar-77	6,000	0	0		?	10,030
55	El Paso	1	Haight	16,100									
56	Patrick Petroleum	1	Thurmond	16,065									
57	Sun	1	Thurmond	15,800	Atoka & Cherokee								
58	El Paso	2	Thurmond	19,153									
59	El Paso	1	Hunt-Cross	16,120	Cherokee & Puryear	8.4	Jun-76	10,000	0	0		9,000	12,200
60	Hoover & Bracken	1	Lester	16,000									
61	El Paso	1	McColgin	16,200									
62	Samson	1	McColgin	16,118	Puryear	3.5	Sep-82	5,200	0	0		2,180	2,677
63	Samson	1	Hostutler	15,728									
64	Gas Anadarko	1	McColgin	16,331	Cherokee								
65	MCNIC	1	Holley	16,060	Puryear								
66	Sanguine	1	Todd	16,325	Puryear								
67	Sanguine	1	Jason	16,150									
68	Ward	1	Dow	16,272									
69	Sanguine	1-X	Moore	15,860	Puryear								
70	Sanguine	1	Peggy	16,108	Puryear								
71	Sanguine	1	Coker	16,597	Puryear								
72	Apache	1	Coker	16,500	Puryear								
73	Ward Petroleum	2	Thurmond	13,750	Cherokee								
74	Ladd	1	Thurmond	15,900	Puryear	6.1	Sep-80	5,587	0	0		3,561	?
75	Ward Petroleum	1	Thurmond	13,833	Cherokee								
76	El Paso	1	Thurmond	15,858	Atoka & Puryear	7.4	Jan-77	No IP				8,000	9,490
77	Kaiser-Francis	2	Thurmond	13,760	Cherokee								
78	Apache	2	Thurmond	16,450	Cherokee								
79	Apache	3	Thurmond	13,800	Cherokee								
80	Texas O&G	1	Thurmond	16,000	Cherokee								
81	Apache	1	Thurmond	16,530	Cherokee								
82	Ward Petroleum	2	Thurmond	14,275	Cherokee								
83	El Paso	3	Thurmond	16,600	Atoka								
84	LPCX Corp.	4	Thurmond	16,361	Cherokee								
85	Lear Petroleum	1-A	Thurmond	16,259	Cherokee								
86	Sanguine	1	Sterling	16,476	Cherokee								
87	Sonat	2	Brown	16,300	Puryear								
88	Sanguine	1	Brown	16,666									
89	Anson	1	Perryman	16,835	Puryear								
90	Duncan	1	Thorton	17,032	Puryear								
91	Amarex	1	Hartman	16,900	UMR[d]								

[a]Cherokee, usually Red Fork.
[b]LMR, lower Morrow undifferentiated.
[c]Puryear, upper Morrow.
[d]UMR, upper Morrow, other than Puryear.

Note: Production data are current through September 1998.

in Figure 63. Field limits are generally accurately defined from logs of dry holes that surround the field. In a simplified explanation, the Morrow sandstone/conglomerate reservoir thins to the north and has an identifiable gas–water contact along the southern limit of the field. Compartmentalization does not appear to affect the reservoir, as pressure communication seems to occur over large areas. Cumulative gas production to date is ~332 BCFG. The producing reservoir reaches a known thickness of ~46 (gross) ft but thickens to >60 ft south of the field in the downdip water leg of the reservoir. There is relatively little reduction of thickness for the net reservoir sandstone in comparison to the gross thickness. On the basis of log profiles and areal-distribution patterns of sandstone, the reservoir appears to have been deposited in a fan-delta system. The spatial

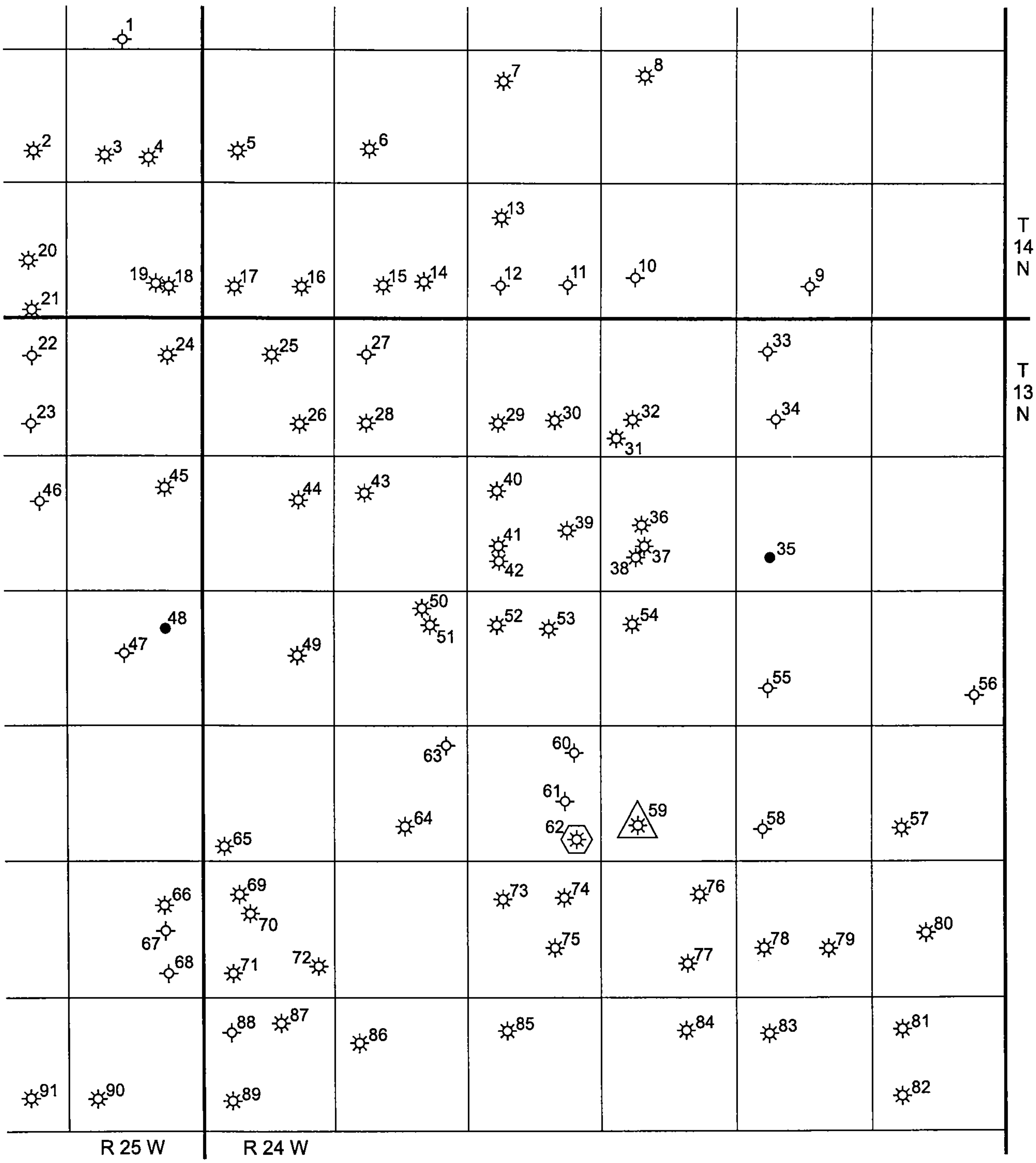


Figure 63. Map showing location and status of all wells in Cheyenne West field study area. Numbers adjacent to wells refer to well and production data tabulated in Table 8.

distribution of all Morrow chert conglomerates is the result of proximity to the Wichita uplift to the south. Uplifted and eroded Woodford (Devonian–Mississippian) strata probably provided the chert clasts that are so conspicuous in the upper Morrow in this part of Oklahoma.

Drilling began in the study area in 1973, with discovery of lower Morrow pay in sec. 27, T. 14 N., R. 24 W., just north of the present Cheyenne West field. Two years later, in June 1975, El Paso Natural Gas drilled the No. 1 Hunt/Cross well, which in this study is credited as the field discovery for the upper Morrow Puryear reservoir in this part of the field. Helmerich & Payne, El Paso Natural Gas, Sanguine, and Apache are the principal operators in the field, as shown in Table 8. The field was developed mostly in the mid- to late 1970s, and a few development wells were drilled during the 1980s.

The field opener for the upper Morrow Puryear reservoir, the No. 1 Hunt/Cross well, was drilled in the NE¼SW¼ sec. 22, T. 13 N., R. 24 W. This well had initial production of 10,000 MCFGPD from 28 ft of net pay (≥8% porosity, or ϕ) and had produced ~8.4 BCFG through December 1998. The well produced >4 MMCFGPD for the first 2 years. The flowing tubing pressure was measured at 9,000 psi, and shut-in tubing pressure was measured at 12,200 psi.

The original spacing of wells drilled in the 1970s was 640 acres, but increased-density wells were drilled on 320-acre patterns during the 1980s. Individual wells have cumulative gas production that varies greatly, from <1 BCF to ~30 BCF and averages >13 BCF/well. As of July 1999, 25 wells had been completed in the Puryear, with a maximum of 23 wells actually producing at any one time. The production history of the field is shown in Figure 64. Some wells are dual completions, usually with the overlying Atoka, but most wells are single-zone completions.

STRATIGRAPHY

A typical log from Cheyenne West field and the stratigraphic nomenclature are shown in Figure 65. In this area, the Morrow interval is ~3,400 ft thick, but only the upper part of the upper Morrow was penetrated in the Samson No. 1-21 McColgin well, as shown on the type log. Three sandstone zones are indicated: the Purvis, Puryear, and Pierce (Hollis?) zones. Locally, all three zones contain medium- to coarse-grained sandstone and chert conglomerate. The remainder of the upper Morrow section beneath the conglomerate zones is predominantly marine shale. The expanded section of the Puryear zone shows an upper, "clean" channel deposit overlying a shaly section that has an overall coarsening-upward textural profile as seen on the gamma-ray and resistivity logs.

The top of the Morrow Formation in Cheyenne West field is recognized on logs by a "hot"-shale marker bed or the lowermost persistent limestone bed at the base of the Atoka Formation, generally considered to be the Thirteen Finger limestone. This contact may vary throughout the field, as the Atoka–Morrow boundary may be unconformable. As in most parts of the Anadarko basin, the most commonly used datum to separate the upper and lower Morrow intervals is a limy sandstone or limestone section that is informally called the "Squaw Belly." The base of the Morrow Formation (not shown on the type log) is picked at the base of the Primrose interval, and this contact is best identified on conductivity logs as shown in various log traces in the regional cross sections (Pls. 4–6, in envelope). This contact is usually sharp where the conductivity is anomalously high (resistivity is very low) in the uppermost shale section of the Springer Formation. In the Cheyenne West field area, the youngest sandstone underlying the Morrow Formation in the Springer Formation is correlative with the Cunningham (IHS Energy Group, 1999).

Puryear Sandstone/Conglomerate

The upper Morrow Puryear clastic unit is the principal reservoir within the field and has produced ~332 BCFG. The Puryear sequence is composed largely of

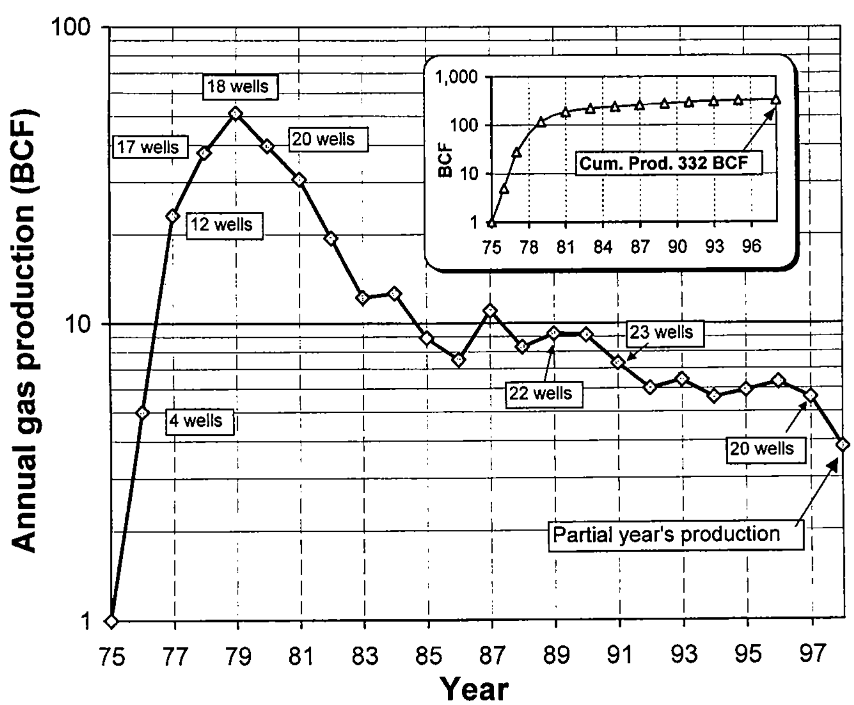


Figure 64. Production curve showing annual gas production from the upper Morrow Puryear chert sandstone/conglomerate reservoir in Cheyenne West field. Production is current through September 1998. Inset graph shows cumulative gas production.

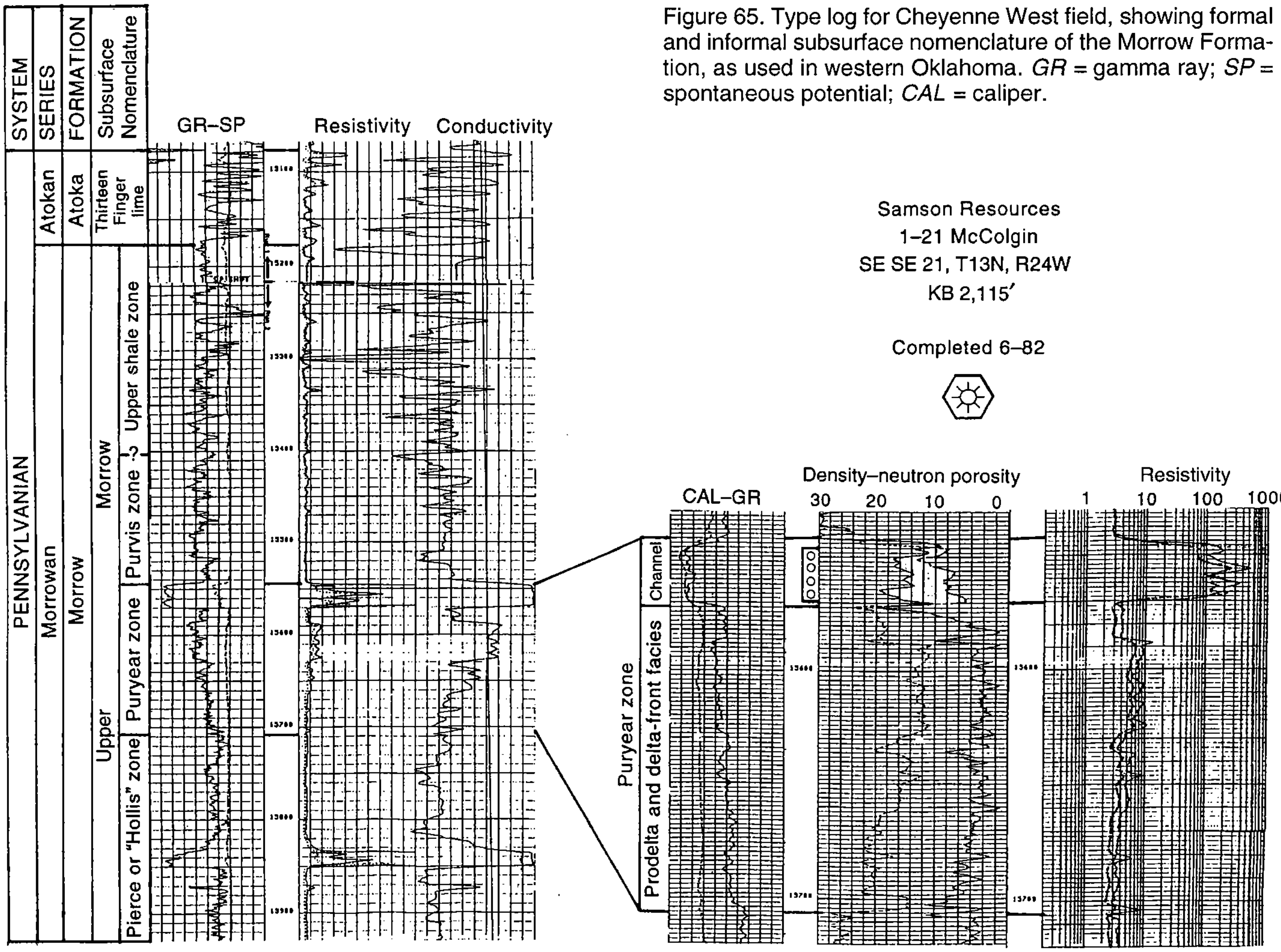


Figure 65. Type log for Cheyenne West field, showing formal and informal subsurface nomenclature of the Morrow Formation, as used in western Oklahoma. *GR* = gamma ray; *SP* = spontaneous potential; *CAL* = caliper.

medium- to coarse-grained quartz sandstone (24–62%) with a large percentage of chert ranging from <10% to ~60% of the framework constituents. Feldspar fragments are also common and can occupy 5–15% of the rock (Alberta, 1987). The coarse-grained sandstone and conglomerate reservoir typically has ~13% cross-plot porosity (unadjusted for limestone matrix). In productive zones, the reservoir has a moderate SP-log deflection and a weak mud-cake buildup, as shown by the SP–caliper log traces on the type log and on various logs in the cross sections through the field.

As seen on gamma-ray, resistivity, and porosity logs, the producing reservoir lies above a coarsening-upward, progradational sequence consisting of shaly sandstone and shale. The sandstone/conglomerate sequence occurs as a tabular body of variable thickness across the entire field, with thick trends oriented north and northwest. The reservoir has a sharp basal contact and a blocky or slightly fining-upward textural profile (owing to an increase in clay content). The Puryear sandstone usually consists of one apparently thick sandstone/conglomerate sequence but may actually consist of more than one depositional cycle in an amalgamated sequence. The extremely coarse-grained nature of the reservoir, sharp basal contact, blocky log signature, and proximity to the ancestral Wichita uplift to the south is evidence that the Puryear reservoir was deposited in a high-energy environment such as a braided-river complex.

CROSS SECTIONS

The stratigraphy of the Morrow interval is best shown by the detailed stratigraphic cross sections constructed through Cheyenne West field. Both sections A–A′ and B–B′ (Figs. 66, 67, in envelope) are predominantly dip sections and have a common datum, which is an upper Morrow marker bed.

Cross Section A–A′ (Figure 66)

This section lies along a north–south line in the western part of the field and shows the updip limit of the reservoir and the downdip water leg. Well 1 is just north of the production limit of the Puryear sandstone. Here, the Puryear channel is absent, and the correlative interval consists of subaqueous-marine delta-front deposits (equivalent to distributary-mouth-bar deposits) that are never productive in the field. Although the Morrow is not productive in this well, it was completed as a gas producer in the overlying Red Fork and Atoka sands.

A little more than 1 mi to the southeast, well 2 produces from the Puryear chert-conglomerate channel facies, and the log shows the characteristic sharp basal contact, the blocky to fining-upward textural profile on the gamma-ray log, good SP deflection throughout the entire interval, and deep resistivity of about 50–70 ohm-m. The underlying Puryear strata show two coarsening-upward sequences that are characteristic of the shaly delta-front marine deposits that underlie the subaerial(?) fan-delta–plain sediments.

At well 3, ~0.75 mi to the southwest, the Puryear thickens considerably to ~39 ft. The porosity log indicates a cross-plot porosity of about 15–16%, yet the caliper log indicates little if any mud-cake buildup. In this well, the Puryear appears to consist of just one main channel sequence. The underlying marine delta-front strata are similar to those in all other wells and consist of shaly sandstone grading downward into sandy shale and then prodelta shale.

A little more than 1 mi southeast of well 3, well 4 produces from the Puryear. In this well, the Puryear reservoir is only about 13 ft thick, yet the well produced >21 BCFG in comparison to ~14 BCFG in the much thicker reservoir of well 3. The maximum (deep) resistivity in well 4 is just under 100 ohm-m. The typical sharp basal contact and fining-upward textural profile are typical of the Puryear channel deposits. A little more than 1 mi to the south, well 5 penetrated 64 ft of Puryear sandstone and conglomerate, but the well is not productive from this zone, as it is entirely wet. The deep resistivity is generally <20 ohm-m (and usually <10 ohm-m), which calculates to be about 70–95% water saturation.

Cross Section B–B′ (Figure 67)

This section is oriented north–south in the eastern part of Cheyenne West field. The relationship of channel facies that overlie the subaqueous-marine delta-front facies is similarly represented on all logs. In well 1, the Puryear interval consists mostly of delta-front deposits overlain by a thin fan-delta channel. This well is very near the updip limit of the Puryear gas field, and the reservoir is only about 4 ft thick.

At well 2, ~0.75 mi to the south, the Puryear channel thickens abruptly to ~46 ft and appears to consist of just one depositional cycle. The porosity is about 16–18%, and the water saturation calculates to be about 15–30%, which is typical for this reservoir. The channel typically has a sharp basal contact and a blocky textural profile, as shown by the gamma-ray log. The caliper log shows little or no mud-cake buildup. This well has produced ~28 BCFG from this thick channel reservoir.

Well 3, ~1.75 mi farther to the south, is dry because the Puryear channel facies thins to just 2(?) net ft (9 gross ft) and is tight. A downcutting configuration of the channel between wells 1 and 3 is interpreted on the cross section.

At well 4, the channel facies within the Puryear interval thickens to about 26 ft. This well was selected as the type log for the field because of the excellent log representation of the Puryear zone, including the channel facies and underlying delta-front sequence. It has produced only 3.5 BCFG because of depletion from older nearby wells. The deep resistivity in this well is very high (between 70 and ~200 ohm-m) and the calculated S_w, based on 10–11% porosity, is 20–30%. About 250 ft beneath the Puryear reservoir is the Pierce or "Hollis" zone. The channel strata in this zone are tight and nonproductive in the field.

Well 5 drilled a relatively thick channel deposit, but the deep resistivity of generally <20 ohm-m indicates that it is wet. This well defines the downdip water leg in the field, where the S_w calculates >70%.

STRUCTURE

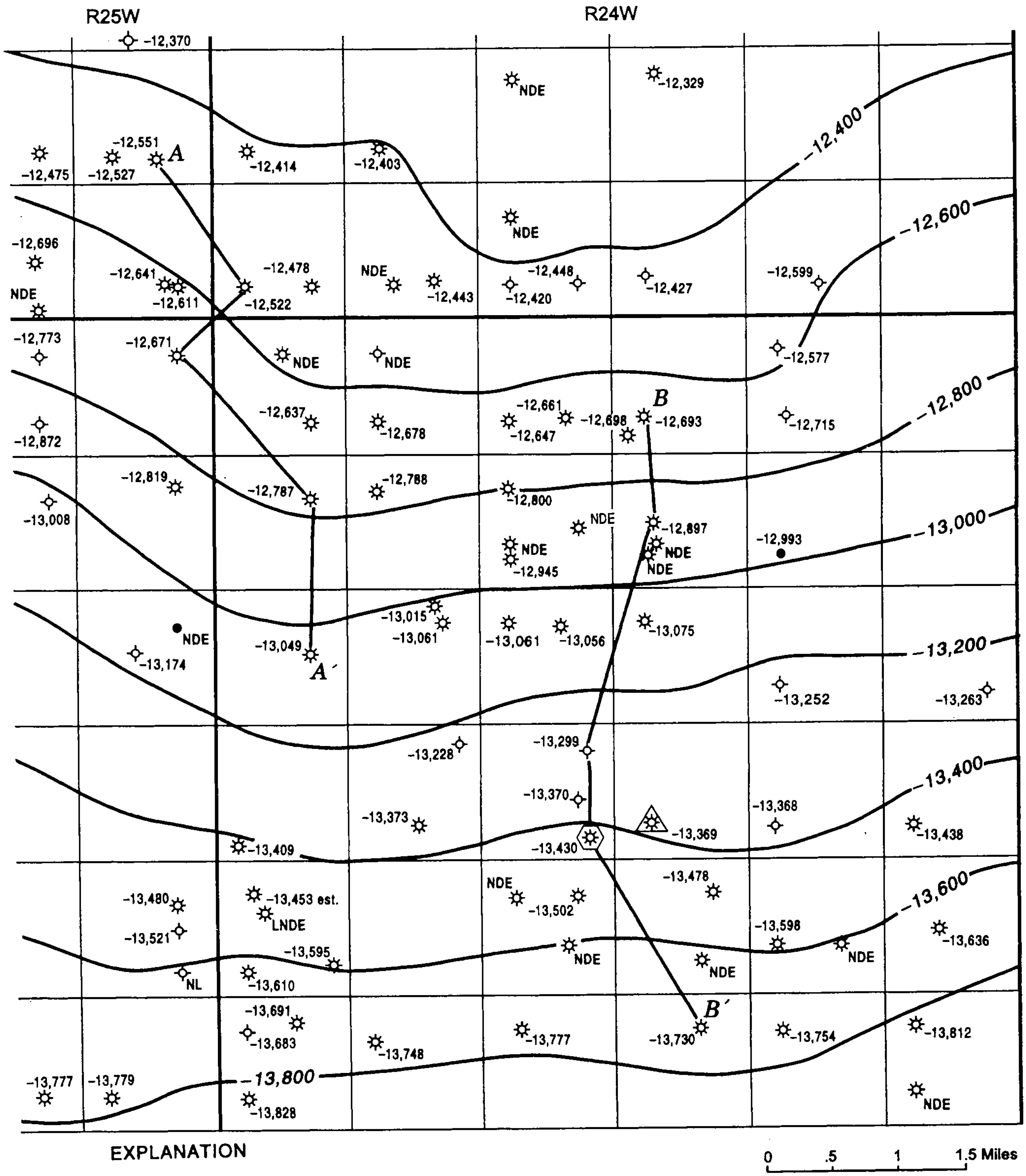
Cheyenne West field lies in the southern part of the Anadarko basin (Pl. 3), and here the Morrow Formation lies between −12,000 and −13,000 ft (below sea level). The subsurface dip of the Morrow is southward at ~2.6° (~250 ft/mi). A detailed structure map of the study area (Fig. 68) depicts the top of the Puryear interval, which is about 370 ft below the top of the Morrow–Atoka contact. As can be seen on this structure map, the highest position of the Puryear within Cheyenne West field is just above −12,443 ft in the north-central part of the field in the SE¼ sec. 32, T. 14 N., R. 24 W. The south-central part of the field extends to about −13,478 ft in the NE¼ sec. 27, T. 13 N., R. 24 W. The vertical relief of the gas column, therefore, is ~1,035 ft.

A cursory view of the regional structural configuration at the top of the Morrow Formation in the Arkoma basin (Pl. 3) indicates that the area surrounding Cheyenne West field is uncomplicated by faulting or folding. The field lies ~20 mi north of the Wichita frontal fault zone. The uniform structure-contour spacing as shown in Figure 68 (200-ft contour interval) indicates a relatively uniform southerly dip with no apparent displacements. Hydrocarbon trapping, therefore, is strictly stratigraphic.

MORROW SANDSTONE DISTRIBUTION AND DEPOSITIONAL ENVIRONMENTS

The upper Morrow Puryear section is the principal reservoir in Cheyenne West field. Isopach maps consisting of gross- and net-sandstone thicknesses for this reservoir are included in the study.

Figure 69 shows the gross thickness of the Puryear sandstone/conglomerate within the channel facies for all the wells in the study area. The gross thickness is the total thickness of sandstone/conglomerate regardless



EXPLANATION

△ Discovery well

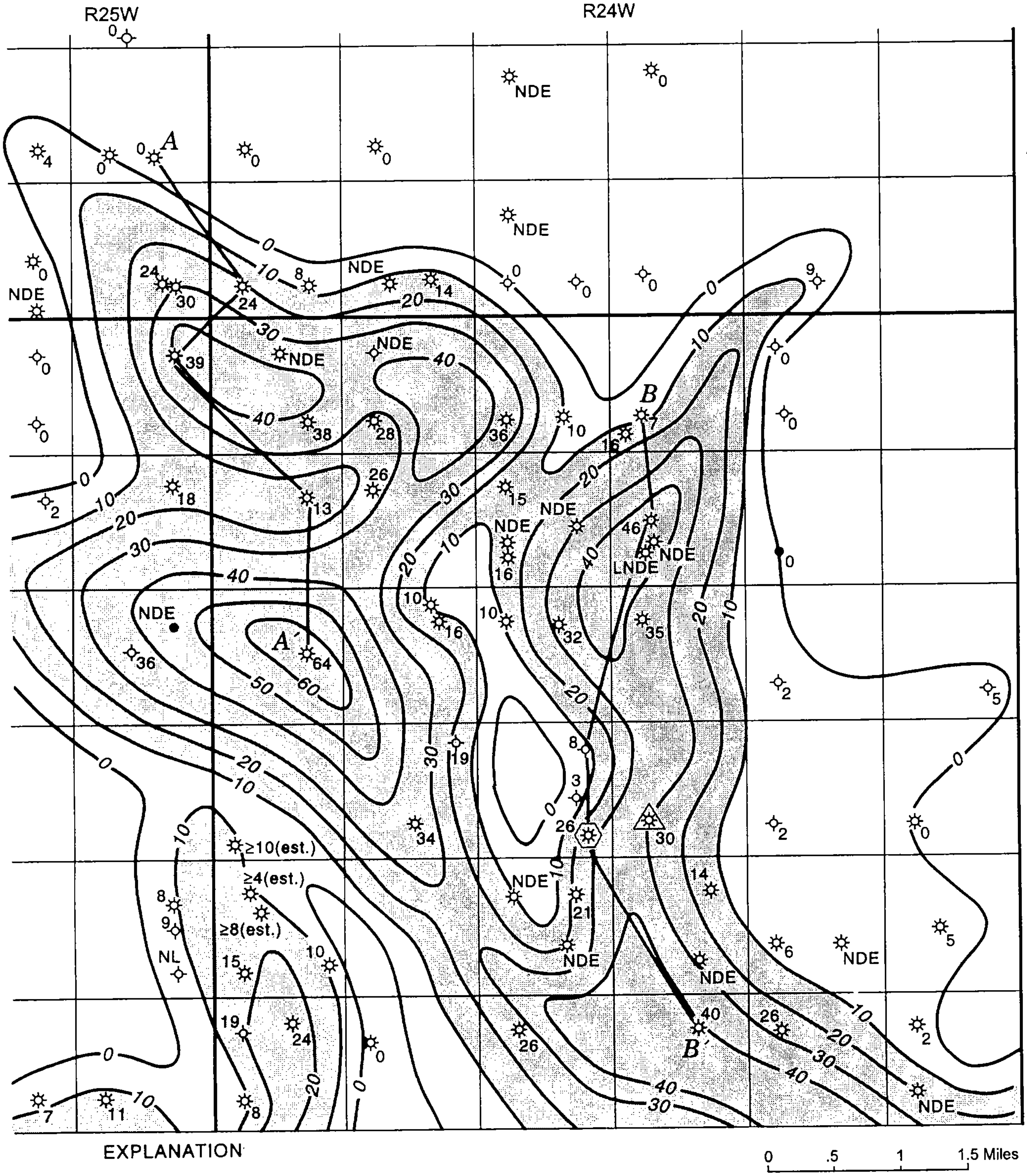
⬡ Type log

NL No log

NDE Not deep enough (well)

LNDE Log not deep enough

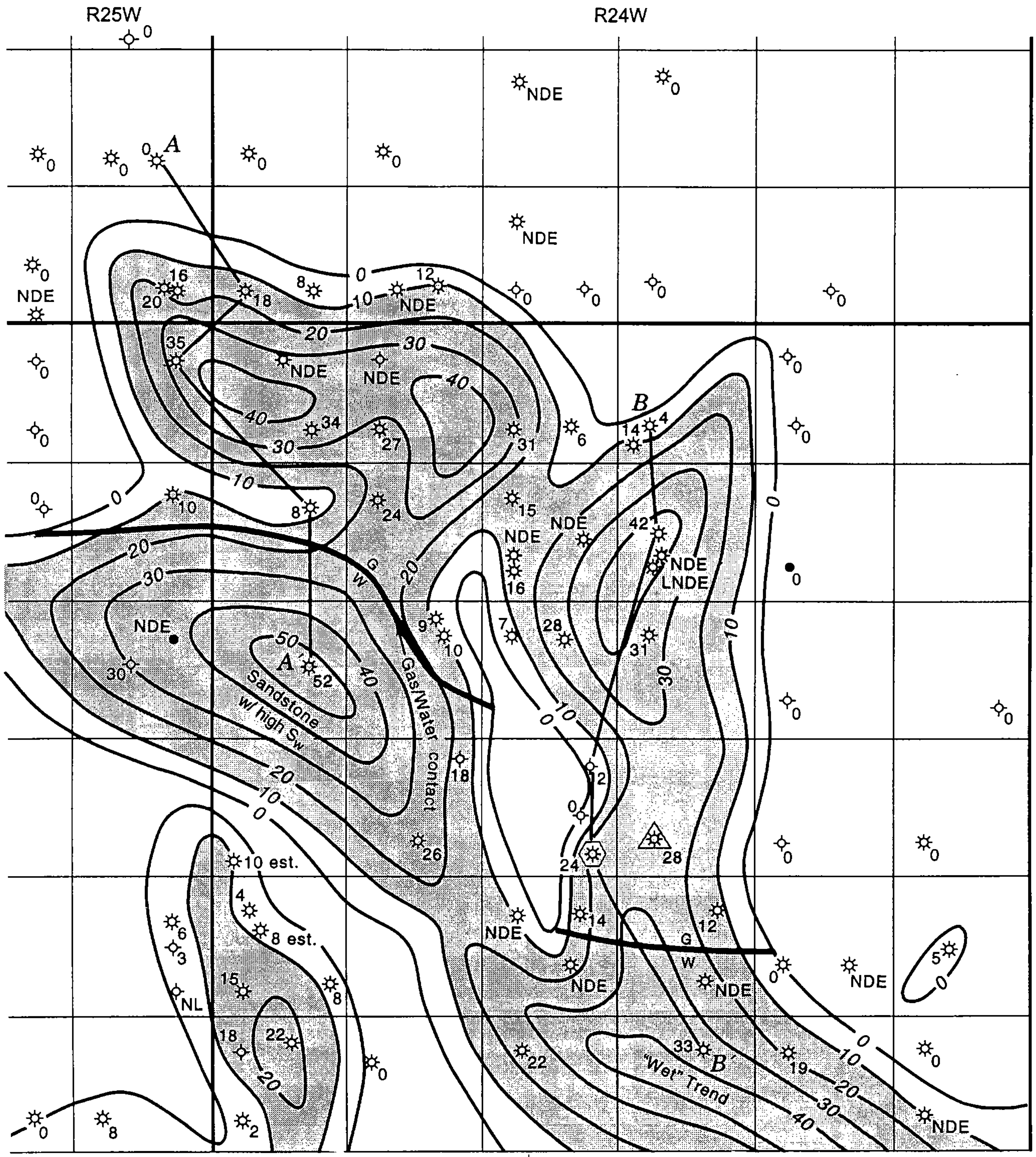
Figure 68. Structure map depicting the top of the Puryear sandstone/conglomerate (upper Morrow), Cheyenne West field. Contour interval is 200 ft. Datum is mean sea level. See Table 8 for well names.



EXPLANATION

- △ Discovery well
- ⬡ Type log
- NL No log
- NDE Not deep enough (well)
- LNDE Log not deep enough

Figure 69. Gross-sandstone isopach map of the Puryear sandstone/conglomerate in Cheyenne West field. Contour interval is 10 ft. See Table 8 for well names. Lines of cross sections A–A′ (Fig. 66) and B–B′ (Fig. 67) are shown.



0 .5 1 1.5 Miles

EXPLANATION

△ Discovery well

⬡ Type log

NL No log

NDE Not deep enough (well)

LNDE Log not deep enough

Figure 70. Net-sandstone isopach map of the Puryear sandstone/conglomerate in Cheyenne West field. Net sandstone has log porosity of ≥8%. Contour interval is 10 ft. See Table 8 for well names.

of porosity, as interpreted from gamma-ray logs (determined from the 50% sand/shale line). The zero-ft thickness line is approximately the limit of the fan-delta channel facies and is spatially a little larger than the limit of the actual reservoir, which is defined here by the net-sandstone/conglomerate isopach map (Fig. 70). Within the mapped area, the gross isopach map reaches a zero thickness in all directions except southward, which is the source direction. Areal-distribution patterns of the Puryear show elongate trends extending to the north and northwest.

The gross thickness of the channel sandstone/conglomerate within the Cheyenne West study area ranges from 0 ft along the north, east, and west edges of the field to >60 ft in the west-central part. Where productive, the gross channel thickness is usually about 25–40 ft. Thickness variations are not generally extreme over short distances, although a change of 20 ft over a third of a mile is common. A significant change in thickness, however, does not necessarily mean reservoir compartmentalization or segregation. The Puryear channel deposits are somewhat unusual in that abandoned-channel facies (i.e., shaly channel deposits) are not present or else not easily identified, which means that facies variations are limited. This condition is not typical of meandering mixed-load and suspended-load channel environments that characterize point-bar deposits. Because of the coarse-grained to conglomeratic nature of these sediments and their broad, sheetlike geometry and high width/thickness ratio, these deposits in Cheyenne West field are typical of bed-load braided-river sediments deposited in a broad, shallow, subaerial fan-delta plain such as those shown in Figure 71. Bar forms are probably longitudinal and map out in this fashion on isopach maps. Plan and cross-section views depicting fan morphology and terminology are shown in Figure 72. The gross-sandstone thickness of the Puryear interval below the fan channel facies is not included in the isopach map of Figure 69, as this facies consists of shale-rich sediments of the subaqueous fan-delta front, which are nonproductive.

The net-sandstone isopach map of the Puryear chert conglomerate (Fig. 70) shows the thickness of reservoir-quality channel sandstone in wells having porosity ≥8%. This was determined from cross-plot porosity on density–neutron logs, and no adjustments were made to account for porosity determinations that are based upon a limestone matrix density of 2.71, which is routinely used by logging companies (see reasons discussed in the section on "Formation Evaluation"). In producing Morrow wells, the net-reservoir thickness ranges from 0 to >40 ft. Throughout the mapped extent of the field, the average thickness is ~23 ft, and the isopach contour patterns are similar in overall appearance to those of the gross-sandstone isopach map (Fig. 69), but with a relatively small reduction in thickness values. The difference between the gross- and net-sandstone thicknesses is usually less than ~5 ft for any given well, and this constitutes a decrease of only about 10–15% from the original gross-sandstone thickness. The net- versus gross-thickness relationship can easily be seen on any of the porosity logs shown in cross sections A–A′ and B–B′ (Figs. 66, 67). Most of the net sandstone has porosity in the range of 10% to 16%, some as high as 18%, but this is unusual. The 8% net-sandstone cutoff was selected, as the Puryear generally was not productive with the porosity below this value.

A relatively distinct gas–water contact is present in two different parts of the field. These areas are shown on the net-sandstone isopach map (Fig. 70). The gas–water contact in the NW¼ T. 13 N., R. 24 W., is structurally higher by ~350 ft than the gas–water contact in the south-central part of the same township. This could indicate that gas production in the southern part of the field (in secs. 21 and 22) may be compartmentalized from the rest of the field farther to the north. Wet zones

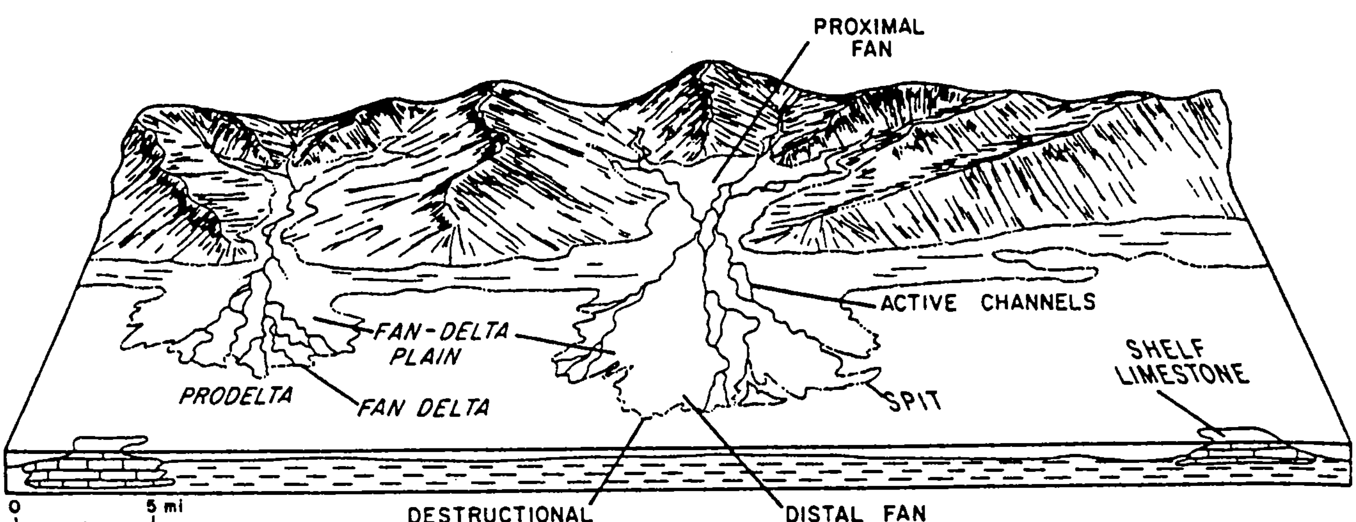


Figure 71. Schematic diagram of a fan-delta system. From Dutton (1982).

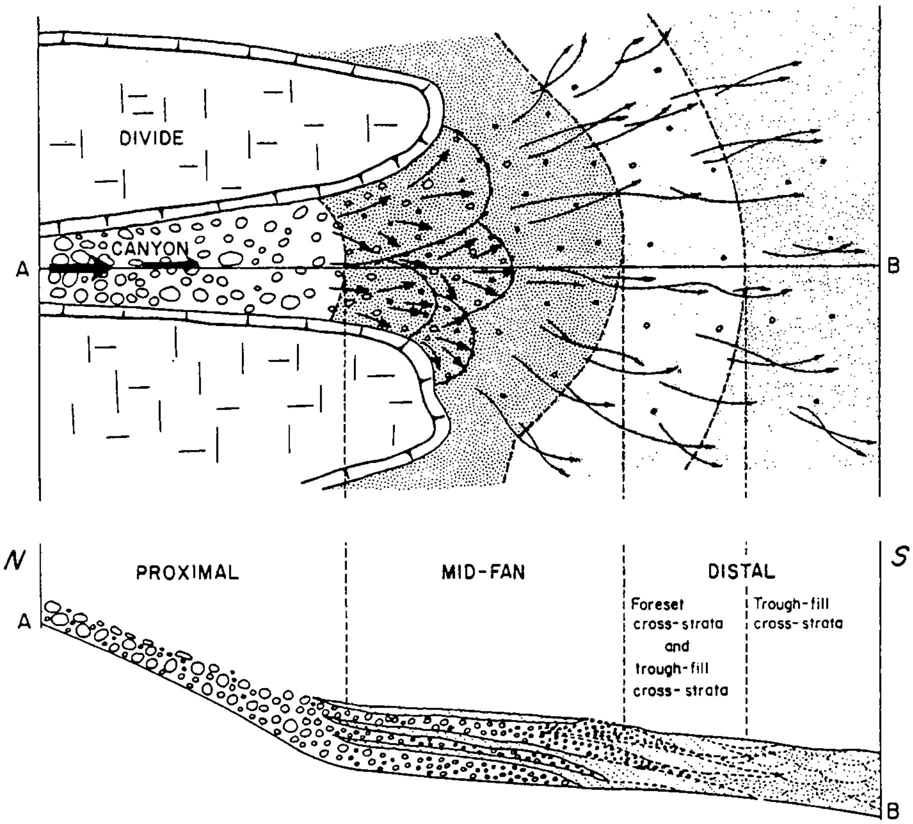


Figure 72. Plan and cross section of a single canyon fan, Van Horn Sandstone, Precambrian(?), Texas. Width of arrows in plan view indicates a relative intensity of fluvial processes. Cross section shows downfan decrease in slope and grain size and the following general north–south succession of stratification types: (1) proximal-massive gravel, (2) mid-fan alternating gravel and trough and foreset cross-bedded sand, and (3) distal trough and foreset cross-bedded sand. From Nilsen (1982).

are easily detected on the resistivity logs where the deep resistivity drops below ~35 ohm-m.

Although permeability is considered very low in these types of reservoirs at this depth, compartmentalization does not seem to be prevalent when considering reservoir pressures from competing wells. Pressure depletion is noted in all wells drilled in the 1980s as compared to the earlier wells drilled in the mid-1970s. The net-sandstone isopach map supports this general concept in that nowhere within the field boundaries does the net sandstone "zero out," even though individual sandstone beds vary considerably in thickness and lateral extent.

FACIES IDENTIFICATION WITHIN THE PURYEAR INTERVAL

Depositional environments were interpreted from wireline-log signatures in order to characterize the generalized depositional setting of sandstone within the Puryear interval in the Cheyenne West study area. However, because the productive zone within the Puryear interval consists of only one facies, there was no need to prepare a facies map. All the productive wells were completed in the fan-delta channel facies, having variable thickness but no differences in overall depositional origin. All strata underlying the channel deposits include delta-front deposits consisting of shale and shaly sandstone and are not productive, so no distinction is needed for these sediments, either. General descriptions of the two facies are given in this study, noting that only the channel facies is important as a reservoir.

Fan-Delta Channel Deposits

The depositional environment of these sediments appears to be a series of spatially related and interconnected braided rivers, probably within a flood plain that paralleled the ancient Wichita mountain-front fault zone. The fan channels were spread out over the marine delta front from south to north. The distal parts of the fan-delta–plain system show a gradual thinning of the channel deposits to the point at which they are absent. The overall areal distribution of the channel deposits is an elongate lobe, with thick trends defining the main channel areas. Downcutting into the underlying delta front is shown in the field cross sections (Figs. 66, 67). The stratigraphic position of the fan-delta channels above the marine delta-front facies is consistent with a progradational system. This type of depositional system is characterized by a vertical succession of strata having deposits of shallow-water or terrestrial origin overlying sediments of deeper water origin. Within the channel facies, sediments consist predominantly of coarse-grained sandstone and chert-pebble conglomerate. On logs, the channel sequence usually reflects a blocky textural profile rather than a gradual fining-upward profile. This is caused by rapid deposition and sudden abandonment, which is typical of high-energy braided-river environments. Gradual abandonment usually results in a gradual fining-upward textural profile typical of point bars.

Delta-Front–Fan (Distributary-Mouth-Bar) Deposits

Sandstone and shaly-sandstone sequences that have a coarsening-upward textural profile, as represented on gamma-ray, resistivity, and porosity logs, is considered to have originated from different depositional processes in comparison to the channel deposits. Sandstone sequences having these characteristics are not productive within Cheyenne West field, but they do occur throughout the entire study area. Good examples of marine delta-front deposits are shown on most of the well logs used in the field cross sections (Figs. 66, 67). Again, the relationship of the marine delta-front–fan deposits with the overlying channels indicates different depositional processes (channeling versus subaqueous-marine deposition) and is evidence of a progradational sequence, one that is shallowing vertically through the section, which can be interpreted entirely from logs without the aid of cores.

Although delta-front sandstone deposits can be good reservoirs where associated with fan deltas of the upper Morrow Formation, they are commonly clay-rich (distal bar facies) or extremely tight so that their potential as good reservoir rock is diminished.

CORE ANALYSIS

Two core analyses and one thin-section analysis were available from wells in Cheyenne West field. The core data were furnished by Stim-Lab, Inc. (Duncan, Oklahoma), and the thin-section data came from Alberta (1987). For each core analysis, the well log is provided for comparison of measured porosity with log porosity.

The core analysis from the GHK No. 2-27 Gregory well, C NW¼ sec. 27, T. 12 N., R. 21 W., shows a poorly defined log-normal relationship of porosity and permeability (Fig. 73A). Two trend lines were inserted to show this relationship. The best part of the reservoir, with porosity ≥8%, has permeability generally >0.1 md, whereas the sandstone having <8% porosity is extremely tight, with permeability <0.05 md. Well-log porosity (without adjusting sandstone porosity from logs using a limestone matrix) correlates well with core porosity. Porosity and permeability data for each depth interval are presented in Table 9.

The core analysis from the GHK No. 1-29 Gregory well, N½SE¼ sec. 29, T. 12 N., R. 21 W., shows a relatively good log-normal relationship of porosity and permeability in sandstone lithology (Fig. 73B). Shaly intervals have a consistent permeability of 0.1 md and a porosity of less than ~9%. Sandstone strata generally have permeabilities <0.4 md, although some intervals have permeabilities of 1–2.3 md. Log-to-core porosity does not correlate well in the more porous zones, because the core values are about 1–3 porosity units higher than the log values, even without taking into consideration a porosity correction (reduction) of the log porosity, which was calculated using a limestone matrix. Porosity and permeability data for each depth interval are presented in Table 9.

PETROGRAPHY

Alberta (1987) completed a thin-section analysis of the GHK No. 1-29 Gregory well, for which core data are plotted in Figure 73 and listed in Table 9. Alberta's thin-section data are summarized in Table 10. From these data, it can be seen that quartz is the largest framework constituent, which ranges from 24% to 62% and averages ~49% throughout the cored interval. Feldspars and chert are also obvious constituents and can readily be seen in hand samples, as described from cores (see Appendix 4). Feldspar ranges from ~6% to 15% and averages 11%, and chert ranges from 3% to 60% and averages ~13% throughout the cored interval (Alberta, 1987). Based upon these constituents, the Puryear zone in the GHK No. 1-29 Gregory is classified as a type of feldspathic litharenite or lithic arkose, depending upon local variations in chert, feldspar, and quartz content.

Authigenic minerals include quartz overgrowths and dolomite, which are the principal cementation agents in the rock. Hand samples exhibited slight effervescence with dilute hydrochloric acid (HCl), confirming this interpretation. Chlorite and illite are the principal clays and are present in the form of grain coatings and pore fillings (Alberta, 1987).

FORMATION EVALUATION

The identification and correlation of the upper Morrow Puryear sandstone/chert conglomerate in Cheyenne West field are generally easy. The channel facies is either present or absent. Variations in thickness occur throughout the study area, but the stratigraphic position of the Puryear interval is consistent. The reservoir facies that constitute the upper part of the Puryear interval appear to consist of a single massive unit on gamma-ray logs. However, erratic variations in porosity and resistivity as measured from well logs indicate that the internal structure of the reservoir is highly variable as if deposition had occurred during several episodes. Despite this heterogeneity within the reservoir, it is sufficient to map it as a single unit rather than trying to break up the sequence on the basis of internal variations in reservoir properties.

The Puryear sandstone/conglomerate is relatively "clean" in the sense of not containing much interstitial shale or secondary clay. This can be interpreted by the gamma-ray response, which typically has a low reading as seen in the field cross-section logs (Figs. 66, 67). Morrow sandstone can be relatively clean, but on a regional scale the formation tends to contain certain amounts of secondary minerals and clays that may interfere with production, completion techniques, or wireline-logging responses. The relative abundance of these clays does not seem to interfere with formation evaluation in the sense of getting a reliable deep resistivity measurement from well logs. Distribution patterns of many of these secondary authigenic minerals are shown in Figures 16–18 in the regional discussion (Part I) of this play. The most problematical mineralization is probably quartz and dolomite cementation, which is difficult to overcome in well stimulation during completion. Chlorite is also locally abundant and can have an adverse reaction with HCl (often used in well completions), as it forms an insoluble gel that destroys permeability and production capabilities.

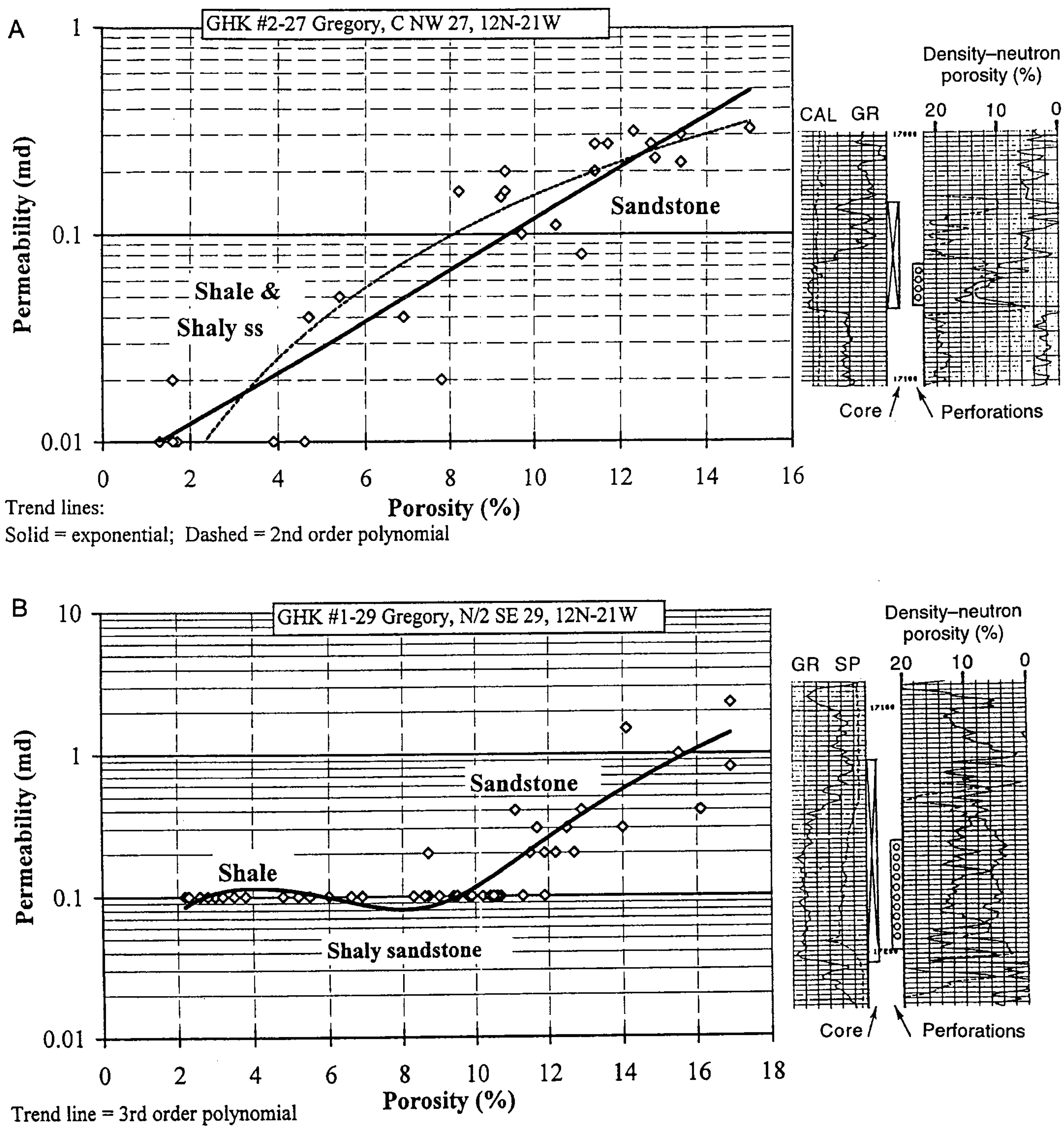


Figure 73. Core porosity and permeability data for two upper Morrow sandstone/chert-conglomerate reservoirs in Carpenter field, northeast Beckham County, Oklahoma. Information provided by Stim-Lab, Inc., Duncan, Oklahoma. *CAL* = caliper; *GR* = gamma ray; *SP* = spontaneous potential.

The deep, or true, resistivity (R_t) of producing intervals in the Puryear sandstone and chert conglomerate is usually in the range of 40–100 ohm-m. A deep resistivity of less than ~25 ohm-m in rocks having an average porosity of ~13% (described below) almost always indicates that the zone is wet. Because of poor overall permeability, there is generally little separation between the deep- and shallow-resistivity curves. This indirect method of determining reservoir quality is based upon the assumption that the amount of invasion by drilling fluids is proportional to the porosity and permeability of the reservoir and that the amount

TABLE 9. – Upper Morrow Chert-Conglomerate Core Data[a]

Core depth	Log depth	Porosity (%)	Permeability (md)	Interpreted strata
GHK–Apache 1-29 Gregory N½SE¼ sec. 29, T. 12 N., R. 21 W.				
17,120	17,121	2.8	0.1	shale
17,121	17,122	3	0.1	shale
17,122	17,123	3.5	0.1	shale
17,123	17,124	2.8	0.1	shale
17,124	17,125	2.6	0.1	shale
17,125	17,126	3.2	0.1	shale
17,126	17,128	2.2	0.1	shale
17,127	17,130	2.3	0.1	shale
17,128	17,132	5.2	0.1	shaly ss
17,129	17,133	6.9	0.1	shaly ss
17,130	17,134	6.6	0.1	shaly ss
17,131	17,136	9.4	0.1	shaly ss
17,132	17,138	9.8	0.1	shaly ss
17,133	17,140	9	0.1	shaly ss
17,134	17,142	9.9	0.1	shaly ss
17,135	17,144	8.7	0.1	shaly ss
17,136	17,146	8.3	0.1	shaly ss
17,137	17,148	9.4	0.1	sandstone
17,139	17,150	10.7	0.1	sandstone
17,140	17,152	10.2	0.1	sandstone
17,141	17,154	9.5	0.1	sandstone
17,142	17,156	9.9	0.1	sandstone
17,143	17,158	10.2	0.1	sandstone
17,144	17,160	10.4	0.1	sandstone
17,145	17,162	10.6	0.1	sandstone
17,146	17,164	10.5	0.1	sandstone
17,147	17,166	9	0.1	sandstone
17,148	17,169	11.3	0.1	sandstone
17,165	17,170	11.9	0.2	sandstone
17,166	17,171	11.1	0.4	sandstone
17,167	17,172	11.9	0.1	sandstone
17,168	17,173	12.9	0.4	sandstone
17,169	17,174	12.2	0.2	sandstone
17,170	17,175	11.7	0.3	sandstone
17,171	17,177	11.5	0.2	sandstone
17,172	17,179	12.5	0.3	sandstone
17,173	17,181	12.7	0.2	sandstone
17,174	17,183	14	0.3	sandstone
17,175	17,186	9.5	0.1	sandstone
(continued in next column)				
17,176	17,187	8.7	0.2	sandstone
17,177	17,189	8.6	0.1	sandstone
17,178	17,191	14.1	1.5	sandstone
17,179	17,192	15.5	1	sandstone
17,180	17,194	16.9	0.8	sandstone
17,181	17,195	16.1	0.4	sandstone
17,182	17,197	12.2	0.2	sandstone
17,183	17,198	16.9	2.3	sandstone
17,184	17,199	5.5	0.1	sandstone
17,185	17,200	6	0.1	shale
17,186	17,202	3.8	0.1	shale
17,187	17,203	4.8	0.1	shale
GHK 2-27 Gregory C NW¼ sec. 27, T. 12 N., R. 21 W.				
17,021	17,028	1.3	0.01	shale
17,022	17,030	1.6	0.02	shale
17,023	17,032	1.7	0.01	shale
17,024	17,033	4.7	0.04	shaly ss
17,042	17,049	1.6	0.01	shale
17,044	17,050	3.9	0.01	shaly ss
17,045	17,051	5.4	0.05	sandstone
17,046	17,052	6.9	0.04	sandstone
17,047	17,053	7.8	0.02	sandstone
17,048	17,054	8.2	0.16	sandstone
17,049	17,055	9.2	0.15	sandstone
17,050	17,056	4.6	0.01	sandstone
17,051	17,057	10.5	0.11	sandstone
17,052	17,058	11.1	0.08	sandstone
17,053	17,059	9.3	0.16	sandstone
17,054	17,060	9.3	0.2	sandstone
17,055	17,061	11.7	0.27	sandstone
17,056	17,062	12.8	0.23	sandstone
17,057	17,063	11.4	0.2	sandstone
17,058	17,064	13.4	0.3	sandstone
17,059	17,065	15	0.32	sandstone
17,060	17,066	11.4	0.27	sandstone
17,061	17,067	12.7	0.27	sandstone
17,062	17,068	12.3	0.31	sandstone
17,063	17,069	13.4	0.22	sandstone
17,064	17,070	9.7	0.1	sandstone

[a]Information provided by Stim-Lab, Inc., Duncan, Oklahoma. Core-depth determinations and inferred strata are interpreted by author to fit density log.

of separation between the shallow- and deep-resistivity curves is affected by the degree of invasion. Core analyses of the Puryear sandstone/conglomerate indicate that permeability is generally in the range of only 0.1–1 md, although some zones may have a permeability >2 md (Fig. 73; Table 9).

Porosity determinations using density–neutron logs were estimated by taking the cross-plot porosity of the two logs. Porosity values in producing zones range from 5% to 18% and average ~13%. Most if not all wells recorded density–neutron porosity simultaneously, using a matrix density of 2.71 g/cm^3 (limestone), which

TABLE 10. – Thin Section Data Showing Percentage of Detrital Constituents and Secondary Minerals for the GHK–Apache No. 1-29 Gregory Well[a]

Depth (ft)	Quartz		Feldspar	Chert	Plutonic	Detrital matrix	Other detrital	Over-growths	Dolomite	Chlorite	Illite	Porosity
	Mono	Poly										
17,124.5	41	3	7	27	2	3	tr	1		9	3	4
17,127.0	48	2	12	20	tr	1	2	2	2	1	10	tr
17,129.0	46	3	13	14	2	3	1	3	tr	4	8	2
17,130.0	52	1	15	11	tr	tr	1	3	tr	3	7	6
17,132.5	40	2	12	14	2	1	1	2	tr	5	5	15
17,135.0	51	3	11	9	2	1	tr	3		2	9	9
17,137.0	47	2	14	9	2	tr	1	2	1	5	4	13
17,138.5	61	1	9	4	tr	tr	tr	6	1	2	7	9
17,141.0	62	2	12	9	tr	tr	2	3	tr	2	3	5
17,141.0	56	3	14	3	3	tr	tr	4	1	5	2	9
17,143.5	57	4	13	7	2	tr	tr	3	1	2	2	9
17,146.0	60	5	9	15	tr		3	4	3	tr	1	tr
17,148.0	53	6	11	7	tr	tr	1	2	tr	1	4	13
17,166.0	60	4	12	3	tr	tr	3	3	tr	4	2	9
17,167.5	56	6	7	9	1	tr		4	3	7		7
17,171.0	50	5	15	14	tr		1	4	tr	3	2	6
17,173.0	54	7	9	6	10	1	tr	4		3		6
17,174.0	28	7	7	20	3	tr	1	2	2	14	6	10
17,176.0	41	4	11	8	8	tr	tr	3	tr	13	5	7
17,177.0	52	5	13	12			1	3	tr	tr	6	8
17,180.0	41	10	8	16	4	1	2	3	2	6		7
17,182.0	52	5	12	15	tr	1	tr	3	tr	1	5	6
17,184.0	42	5	11	5	5	tr	tr	3	16	6	tr	7
17,185.0	50	4	6	18	tr	tr	tr	7	7	7		1
17,186.5	24	3	tr	60	tr	1	tr	2	6	3	tr	1
Average %	49	4	11	13	2	tr	tr	3	2	4	4	7

[a]N½SE¼ sec. 29, T. 12 N., R. 21 W., northeast Beckham County, Oklahoma. Modified from Alberta (1987).

is routinely used by the logging industry. Porosity determinations, then, are theoretically a few percentage points higher than if using a sandstone-matrix density of 2.68 g/cm³. However, porosity values taken directly from logs appear to correlate better with the core data (Fig. 73; Table 9) than if log porosity is reduced a few percentage points to adjust for the limestone-matrix density of 2.71 g/cm³. The observed gas effect (crossover) in productive intervals can be 2–16 porosity units (see type log, Fig. 65; or well 2, cross section B–B′, Fig. 67). In nonproducing or tighter zones, the gas effect is much less or is not present.

In this study, water-saturation (S_w) calculations for the Puryear seem to be consistently realistic, using a formation-water resistivity (R_w) of 0.09 ohm-m and the regular Archie equation ($1/\phi^2$) to determine formation factor (F). Using the equation $S_w = \sqrt{F \times R_w / R_t}$, water saturation varied from ~13% to 42% and averaged ~24%. True resistivity (R_t) was taken directly from the deep-resistivity log; these values seem accurate, unlike the values recorded for the Milder field study area. Porosity values were also taken directly from density–neutron logs in a manner described above. Reservoir characteristics of the Morrow sandstone in Cheyenne West field are summarized in Table 11.

OIL AND GAS PRODUCTION

The estimated cumulative gas production from the upper Morrow Puryear reservoir in Cheyenne West field is ~332 BCF from June 1975 through December 1998. A tabulation showing cumulative gas production, initial production, pressures, and dates of first production is provided for the Puryear sandstone/conglomerate (Table 8). It can be seen from this table that the wells completed earliest in the field's history (those drilled in the 1970s) are the largest producers. Wells

TABLE 11. – Reservoir/Engineering Data for the Upper Morrow Chert Conglomerate in Cheyenne West Field (North Part), Roger Mills County, Oklahoma

Discovery date	6/16/75 (El Paso #1 Hunt-Cross)
Reservoir size (area within 0-ft gross contour)	~9,050 acres (~14 mi^2)
Reservoir volume	~208,000 acre-ft
Depth	~14,600 to 16,000 ft
Spacing (gas)	640 with increased density to 320 acres
Gas–water contact	variable, below about –13,050 ft
Porosity	about 5–18% (average ~13%)
Permeability[a] (see plot, Fig. 73)	about 0.1–2.3 md
Water saturation (S_w) in producing wells	about 13–42% (average ~24%); calculated using $R_w = 0.09$
Thickness (net productive sand, ≥8% ϕ)	4–42 ft, average ~23 ft
Reservoir temperature	about 210–260°F
Gas density	0.57–0.60
Z factor (compressibility)[b]	1.60 est.
B_g (gas formation volume factor)[c]	~480 std cu ft per reservoir cu ft (est.)
Maximum well-head pressure	12,200 psi (max recorded SITP)
Maximum flowing pressure	10,900 psi (max recorded FTP)
Initial reservoir pressure (calculated BHP)	~15,000 psi
Initial pressure gradient	~0.97 psi/ft
Cumulative field condensate (to 9/98)	574 barrels
OGIP[d] (volumetric–field)	435 BCF
Cumulative field gas (to 9/98)	332 BCF
% recovery to date	76%
Recovery MCF/ac-ft (field to date)	~ 1,600 MCF/ac-ft

[a]Data from Morrow core in GHK #1-29 Gregory, N½SE¼ sec. 29, T. 12 N., R. 21 W. (furnished by Stim-Lab, Inc.).

[b]Compressibility factor (Z) estimated from standard reservoir-engineering charts using $T_{res} = 225$°F and $P_{res} = 11{,}511$ psi. T_{res} = reservoir temperature, P_{res} = reservoir pressure.

[c]B_g calculated using the formula: $B_g = \frac{35.4 \times P_{res}}{T_{res} \times Z}$ When T_{res} is in °Rankine (add 460° to the reservoir temperature measured in °F). The Z factor is stated above.

[d]Original gas in place (OGIP) determined using the following formula: Reserves (MCF) = 43.56 × area (acres) × perforated sand thickness (ft) × porosity (%) × (1–S_w) × B_g.

drilled in the 1980s generally have considerably lower cumulative production and had pressure depletion.

Based on volumetric calculations, production from the Puryear represents ~76% of the gas in place, which is estimated at ~435 BCF (Table 11). The high recovery is due to one or more of three main factors: (1) the reservoir is largely drained; (2) initial bottom-hole pressure is inaccurate, causing errors in the calculation of the compressibility factor (Z) and the gas formation volume factor (B_g); or (3) an error has occurred in the determination of reservoir volume. However, as can be seen in Table 8, wells completed during the 1980s (W½ sec. 9 and NE¼ sec. 16), the Puryear was extremely pressure depleted, indicating near exhaustion of gas resources in these areas. Additionally, no new wells were drilled during the 1990s, indicating that the industry also thinks the field has little additional potential. The estimated recovery with regard to current cumulative gas production is ~1,600 MCF/acre-ft for the Puryear reservoir. Only 574 barrels of condensate was produced from the Morrow in the study area, so liquids are not a factor in gas-reserve calculations.

The better wells in Cheyenne West field were the wells completed early, during the 1970s. These wells typically produced about 10–30 BCFG. Subsequent wells completed during the 1980s had much lower cumulative production, usually less than ~4 BCFG. This information is tabulated in Table 8. As of July 1999, a total of 25 wells had been completed in the Puryear reservoir, with a maximum of 23 wells actually producing at any one time. On a per-well basis, the average cumulative production is ~13 BCFG/well.

Initial production rates of wells drilled during the 1970s varied from ~5 to 15 MMCFGPD. Wells completed during the 1980s had initial production rates much lower, at about 1–5 MMCFGPD. Initial shut-in tubing pressure (SITP) of the earlier wells was about 10,000–11,000 psi, and for later wells drilled during the 1980s the SITP was about 2,300–2,700 psi. Flowing tubing pressure of the early wells was generally between 5,000 and 10,000 psi, with a few wells recording much lower values. Wells drilled during the 1980s had flowing pressures considerably lower: about 100–2,400 psi. The ratio of flowing pressure to shut-in pressure is generally quite high, as this ratio can be quickly visualized by looking at the pressure data furnished in Table 8. This ratio can give a good general measurement of reservoir conditions and completion effectiveness. Considering the impermeable nature of the reservoir in Cheyenne West field, the ratio is surprisingly high. Usually, flowing pressure in really tight rocks or from poorly completed intervals is small in proportion to the shut-in pressure.

PRODUCTION-DECLINE CURVES

Production-decline curves for three wells in Cheyenne West field are shown in Figure 74. The upper plot (A) shows the production curve of the Gasanadarko No. 1-8 Berry well, C NW¼ sec. 8, T. 13 N., R. 24 W. This well produced ~30 BCFG since 1976 from 24 ft of net sandstone having about 14–15% porosity. This well is about 0.5 mi north of the gas–water contact and about

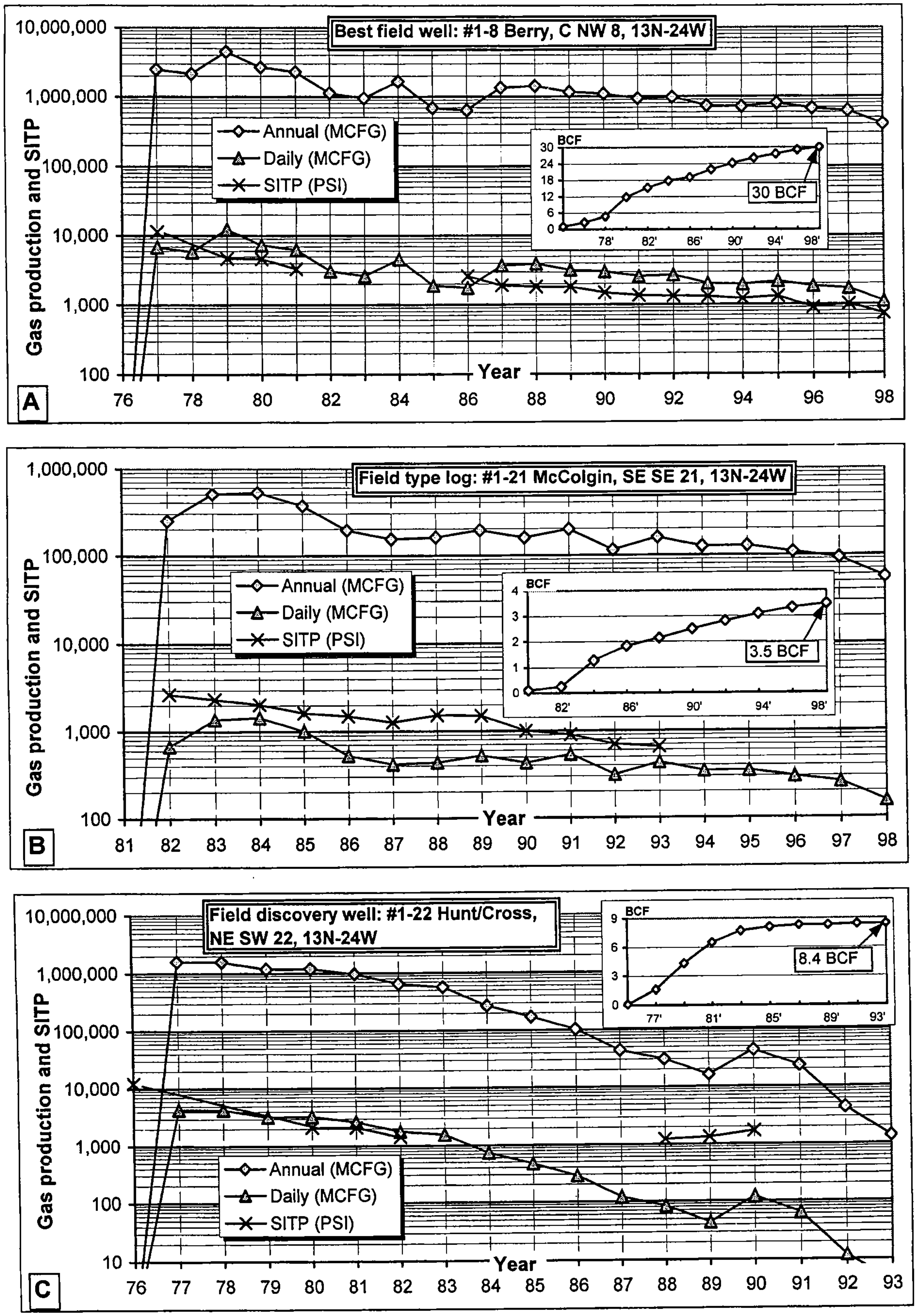


Figure 74. Production- and pressure-decline curves for three wells producing from the upper Morrow Puryear reservoir in Cheyenne West field. Inset graphs show plots of cumulative gas production. Data are current through September 1998.

TABLE 12. – Production Data for Three Wells in Cheyenne West Field, Showing Annual and Daily Gas Production and Shut-In Tubing Pressure (SITP)[a]

	Best well in field Gasanadarko #1-8 Berry C NW¼ sec. 8, T. 13 N., R. 24 W.			Field type log Samson Resources #1-21 McColgin SE¼SE¼ sec. 21, T. 13 N., R. 24 W.			Field discovery well El Paso Natural Gas #1-22 Hunt/Cross NE¼SW¼ sec. 22, T. 13 N., R. 24 W.		
Year	Annual gas (MCF)	Daily gas (MCF)	SITP	Annual gas (MCF)	Daily gas (MCF)	SITP	Annual gas (MCF)	Daily gas (MCF)	SITP
75									12,220
76							1,576,799	4,320	
77	2,489,017	6,819	11,292				1,573,424	4,311	
78	2,133,590	5,845					1,176,303	3,223	
79	4,488,335	12,297	4,715				1,188,866	3,257	2,104
80	2,660,776	7,290	4,628				960,336	2,631	2,102
81	2,279,905	6,246	3,327				643,723	1,764	1,402
82	1,128,716	3,092		245,498	673	2,677	565,898	1,550	
83	952,128	2,609		501,787	1,375	2,350	269,257	738	
84	1,660,867	4,550		525,818	1,441	2,050	171,775	471	
85	689,369	1,889		367,049	1,006	1,625	102,939	282	
86	639,238	1,751	2,581	192,148	526	1,500	43,595	119	
87	1,349,739	3,698	1,898	152,352	417	1,275	30,028	82	1,213
88	1,425,901	3,907	1,807	158,809	435	1,525	16,014	44	1,325
89	1,166,947	3,197	1,794	190,746	523	1,500	43,488	119	1,700
90	1,095,543	3,001	1,489	157,377	431	1,000	23,090	63	
91	935,887	2,564	1,347	195,936	537	900	4,331	12	
92	975,573	2,673	1,319	113,910	312	700	1,372	4	
93	737,859	2,022	1,293	158,276	434	650			
94	712,442	1,952	1,205	124,771	342				
95	795,358	2,179	1,311	126,767	347				
96	673,861	1,846	899	107,985	296				
97	620,560	1,700	1,003	93,390	256				
98	398,847	1,093	725	55,881	153				
Cumulative Production (MCF)									
	30,010,458			3,468,500			8,391,238		

[a]Data current through September 1998. Data graphed in Figure 74.

1 mi south of the thickest part of the reservoir that occurs to the north in secs. 1 and 2 (Fig. 70). The initial SITP was 11,292 psi, and the most current SITP was 725 psi. Following a relatively rapid pressure decline during the first few years of production, this well had a relatively small pressure decline over the past several years. Daily gas production continues to average >1 MMCFGPD. This information is given in Table 12.

The production curve for the Samson No. 1-21 McColgin well in the SE¼SE¼ sec. 21, T. 13 N., R. 24 W., is shown in Figure 74B. This well produced ~3.5 BCFG over about a 17-year period, starting in 1982, and is an east offset to the discovery well drilled in 1976 in the SW¼ sec. 22, about 0.5 mi to the east. The Samson well produces from 24 net ft of sandstone having about 12–13% porosity (see type log, Fig. 65) and had an initial SITP of only 2,677 psi and a flowing tubing pressure (FTP) of 2,180 psi (compare to pressures in the discovery well: SITP of 12,200 psi and FTP of 9,000 psi). The decline curve in Figure 74B, therefore, represents a pressure-depleted well drilled late in the production history of the field. Daily production from this well is now <200 MCFGPD, and the most current SITP (1993) was only 650 psi. This information is given in Table 12.

About 6 years prior to completion of the Samson well in sec. 21 (Fig. 74B), El Paso completed the No. 1-22 Hunt/Cross well in the SW¼ sec. 22 (Fig. 74C). This well produced ~8.4 BCFG, starting in 1976, but was shut in 17 years later, in 1992. The El Paso well has a net-pay thickness of 28 ft, with a porosity of about 15–

16%. It had an initial SITP of 12,200 psi, and a final pressure of 1,700 psi was recorded in 1989, 3 years before the well was shut in. Pressure data for the El Paso Hunt/Cross well and the Samson McColgin offset well can be compared in Table 12. The last 3 years of pressure data for the El Paso well are similar to those recorded in the Samson well to the west and demonstrate effective pressure communication between wells in adjacent sections. The earlier date of production (which precedes the McColgin well of Fig. 74B by ~6 years) relates to the much higher cumulative gas recovery in the El Paso Hunt/Cross well.

WELL-DRILLING AND COMPLETION PRACTICES

Because of the well depths in Cheyenne West field, drilling and setting casing are usually performed in several steps. A discussion of drilling techniques is beyond the scope of this study, but some important guidelines are noted for Morrow wells in this study area. Wells vary in depth from ~15,000 ft in the northern part of the field to almost 17,000 ft in the southern mapped area. Operators usually set 13⅜-in. casing to ~4,500 ft, then set either 7⅝-in., 9⅝-in., or 10¾-in. casing just below the Deese zone (Skinner equivalent, Pennsylvanian, Desmoinesian), which is just above the "Granite Wash" or Red Fork, at a depth of about 12,000–13,000 ft. A smaller diameter liner (varying from 7⅝ to 3½ in.) is then set to total depth. Wells of this depth take 40–50 days to drill, and if the deeper lower Morrow section is drilled, a 17,000-ft well would take 80–100+ days. Considering the lower potential of the lower Morrow in this area, the costs and time to drill only a few thousand more feet are dramatically increased.

Wells are drilled to ~12,000 ft with chemically treated water-based mud having a density of about 9.1–9.8 lb per gal. Well-log headers commonly indicate "FGM" or "fresh gel mud" as the fluid type used during this drilling stage. The mud weight is then increased to about 14–15 lb/gal, which is used in drilling to ~15,000 ft. Finally, an oil-based 18-lb mud is often used when drilling below 15,000 ft. If oil-based drilling fluids are used, such as invermul, wireline logs do not record SP or shallow resistivity in such intervals.

Completion reports indicate that many wells are acidized with 1,500–2,000 gal of 7.5% HCl. In most productive wells, the Morrow interval is stimulated with a fracture treatment consisting of various treated gels or foam. Treatments range from ~10,000 to 100,000 gal plus about 60,000–100,000 lb of sand. Well-drilling costs for a conventional vertical well to a depth of ~15,000 ft having a single-zone completion are estimated at $940,000 for a dry hole and $1,300,000 for a completed well (estimated costs in August 1999). Drilling time varies from 2 to 4 months.

ACKNOWLEDGMENTS

Completion of this study was accomplished largely through the efforts of many people, including the Oklahoma Geological Survey as a whole. Special recognition is given Dr. Charles Mankin, director of the Survey, for providing overall leadership and support in this cooperative project.

Several companies and consulting geologists contributed greatly to this project by providing technical information, field and well-log data, core data, and geological interpretations. Most important are the contributions by Petroleum Information/Dwights LLC for letting the OGS acquire certain data and publication rights and for providing technical support; Paul W. Smith (manager of reservoir geology, IHS, Oklahoma City) for overall assistance and being a guest lecturer on regional aspects of the Morrow; Walter Hendrickson (geologist, IHS, Oklahoma City) for preparing and presenting the Morrow Arapaho field study; Stan Dobler (Tres Management, Edmond, Oklahoma) for providing information and being a guest lecturer regarding Morrow drilling and completion practices; Kathy Fowler (Stim Lab, Inc., Duncan, Oklahoma) for providing core data for two wells in the Cheyenne field area; Dorothy Smith (OGS) for acquiring and photocopying well logs; and Dongwon Kim for assisting in making regional Morrow maps.

Core slabbing was completed by several part-time students working with the OGS under the supervision of Walter Esry and Larry Austin (OGS Core and Sample Library). Drafting and computer imaging were completed by Wayne Furr (OGS manager of cartography) and Jim Anderson and Charlotte Lloyd (OGS cartographic drafting technicians). Technical review, editing, and publication production were completed by William Rose (consulting geological editor), Charles J. Mankin (OGS director), Kenneth S. Johnson (OGS associate director), Christie Cooper (OGS editor), and Tracy Peeters (OGS associate editor). Publication printing was made possible by Paul Smith and Richard Murray (OGS). Program organization and registration for the workshop were coordinated by Michelle Summers (OGS technical project coordinator).

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APPENDIXES

APPENDIX 1

Various Size Grade Scales in Common Use

(from Blatt and others, 1980)

Udden–Wentworth	*ϕ values*	*German scale†* *(after Atterberg)*	*USDA and Soil Sci. Soc. Amer.*	*U.S. Corps Eng., Dept. Army and Bur. Reclamation‡*
		(Blockwerk)		
Cobbles		—200 mm—	Cobbles	Boulders
			—80 mm—	—10 in.—
—64 mm—	−6			Cobbles
Pebbles		Gravel		—3 in.—
		(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

ac	acre(s)
API	American Petroleum Institute
BBL, BBLS	barrel(s)
BCF	billion cubic feet (of gas)
BCFG	billion cubic feet of gas
B_g	gas formation volume factor
BHP	bottom-hole pressure
BO	barrels of oil
BOPD	barrels of oil per day
BW	barrels of water
BWPD	barrels of water per day
CAOF	calculated absolute open flow
CAL, Cal	caliper
cp	centipoise (a standard unit of viscosity)
DST	drillstem test
F	formation factor
frac	fracture or fractured
FTP	flowing tubing pressure
GOR	gas/oil ratio
GR	gamma ray
gty	gravity
GWC	gas–water contact
HCl	hydrochloric acid
IPF	initial production flowing
IPP	initial production pumping
KB	kelly bushing
LO	load oil
LW	load water
MBO	thousand barrels of oil
MCF	thousand cubic feet (of gas)
md	millidarcies, or 0.001 darcy
MMBO	million barrels of oil
MMCF	million cubic feet (of gas)
MMCFG	million cubic feet of gas
MMCFGPD	million cubic feet of gas per day
NRIS	Natural Resources and Information System (a database)
OGIP	original gas in place
OWC	oil–water contact
P&A	plugged and abandoned
perf	perforated, perforations
P_{res}	reservoir pressure
psi, PSI	pounds per square inch
psia	pounds per square inch, absolute
psig	pounds per square inch, gauge
PVT	pressure, volume, temperature
R_o	vitrinite reflectance in oil
R_t	deep, or true, resistivity
R_w	formation-water resistivity
R_{xo}	resistivity of flushed zone
SITP	shut-in tubing pressure
SP	spontaneous potential
SW	salt water
S_w	water saturation
TCF	trillion cubic feet (of gas)
TCFG	trillion cubic feet of gas
TD	total depth
T_{res}	reservoir temperature
Z	compressibility factor
ϕ	porosity

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).

absorption—Assimilation (e.g., gas molecules penetrate into a solid).

adsorption—Adherence of gas molecules, or of ions or molecules in solution, to the surface of solids with which they are in contact.

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.

desorption—Release of gas by a substance.

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.

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 systems 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.

longitudinal bar—A long, narrow ridge of sand or conglomerate developed in non-sinuous or relatively straight streams, oriented parallel with the direction of prevailing water flow such that bedding is either horizontal or inclined in a preferentially down-flow direction. See comparison with *point bar.*

lower delta plain—Depositional environment within a *delta* that 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 systems 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.

mixed load—Stream load consisting of both bed load and suspended load material.

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. Therefore, bedding is most often at right angles to the preferred orientation of the river system.

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.

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.

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.*

sorption—Includes both adsorption and absorption.

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.

suspended load—That part of the total stream load that is carried for a considerable time in suspension, free from contact with the stream bed; it consists mainly of clay, silt, and sand.

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 systems 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.

unitization—Consolidation of 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

Core Descriptions, Well Logs, and Digital Images of Selected Rock Intervals for the Following Wells:

1. **Cities Service Oil Co. No. 2 Buzzard "D"**
   C N½SE¼ sec. 23, T. 4 N., R. 12 ECM
   Upper Morrow (lithic or arkosic?) sandstone
   Incised fluvial channel
   Prepared cored interval: 6,030–6,056 ft

2. **Texas Pacific Co. No. 4 Tidball**
   NE¼NW¼ sec. 22, T. 18 N., R. 14 W.
   Lower Morrow (Primrose?) sandstone
   Tidal channel (point bar?) and intertidal deposits
   Prepared cored interval: 9,162–9,213 ft

3. **Ladd Petroleum No. 5 Wills "A"**
   NE¼SW¼ sec. 25, T. 18 N., R. 14 W.
   Lower Morrow (undifferentiated) sandstone
   Intertidal deposits and thin tidal channels
   Prepared cored interval: 9,018–9,086 ft

4. **Apache Corp. No. 2-31 Simmons**
   SW¼NE¼ sec. 31, T. 12 N., R. 22 W.
   Upper Morrow sandstone/chert conglomerate
   Braided-river fan-delta
   Prepared cored interval: 17,488–17,524 ft

5. **Shell Oil Co. No. 1-21 Blasdel**
   SW¼NE¼ sec. 21, T. 23 N., R. 22 W.
   Lower Morrow sandstone
   Tidal delta channel
   Prepared cored interval: 8,186–8,252 ft

Cities Service No. 2 Buzzard "D"

N½SE¼ sec. 23, T. 4 N., R. 12 ECM

Upper Morrow sandstone
Incised fluvial channel

Log depth: ~ Core depth ± a few feet

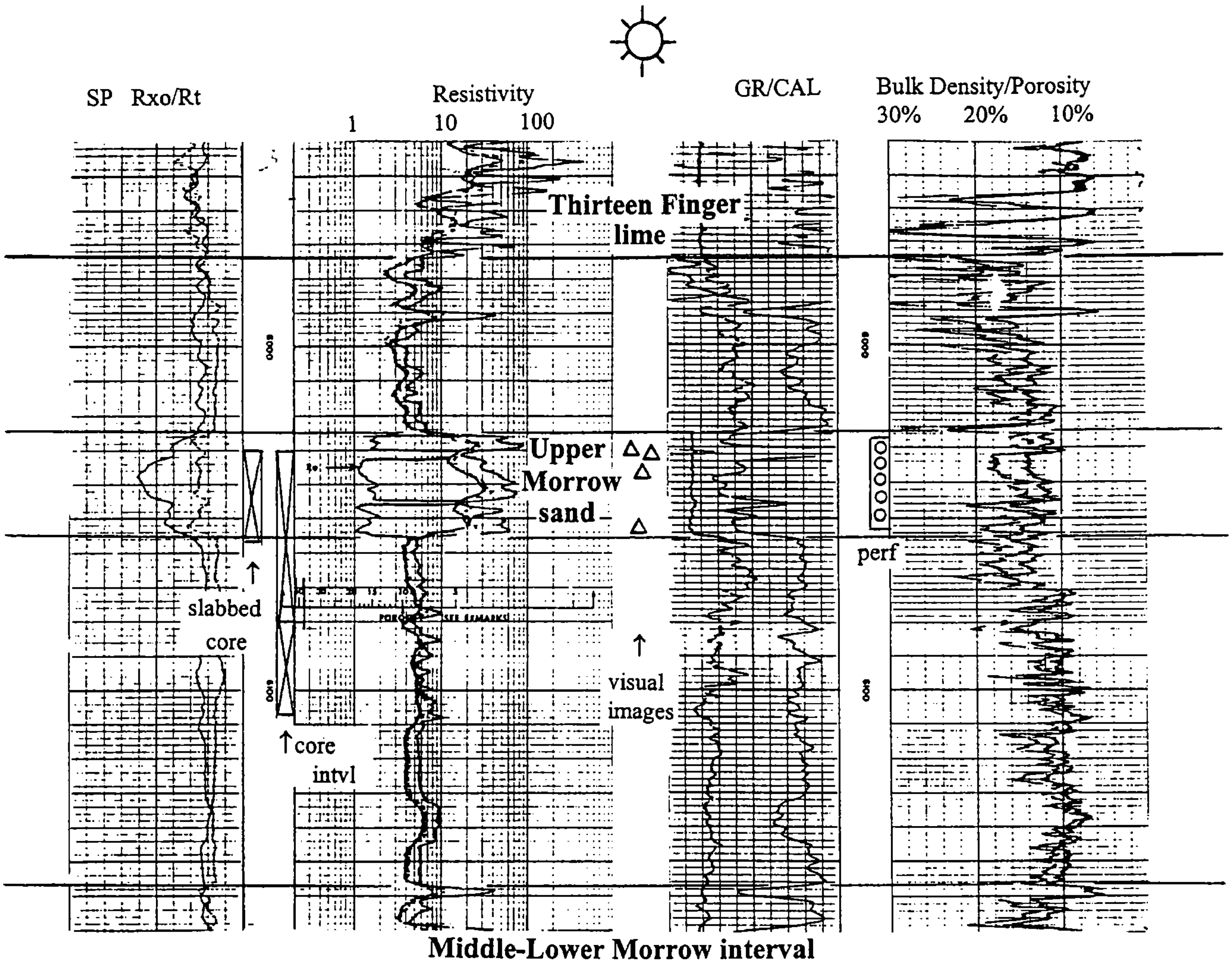
Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
6,030–6,031.9	Sandstone, medium to coarse grained, massive to highly inclined cross-bedding. Numerous carbonaceous shale or coaly laminations. Secondary quartz overgrowths (cement) is widespread. Porosity is mostly secondary and is generally good.
6,031.9–6,033.4	Sandstone, fine grained, with numerous shale laminations. Highly inclined bedding with microfaults in slumped section at 6,032 ft.
6,033.4–6,038.8	Sandstone, medium grained, relatively clean sand with few carbonaceous laminations. Bedding is mostly massive. Sandy rip-up mud clasts at 6,038.3–6,038.7 ft. Good secondary porosity with quartz overgrowths between framework constituents of quartz and rock fragments.
6,038.8–6,047	Sandstone, coarse grained, mostly massive bedding. Good secondary porosity with quartz overgrowths as above. Sandstone has numerous rock fragments, almost no partings, and appears granular.
6,047–6,048	Black shale with a few coarse grained sandstone interbeds. Shale is very fissile and carbonaceous. **Clay drape?**
6,048–6,050	Sandstone, coarse to very coarse grained with numerous rock fragments. Bedding is massive with a few scattered mud clasts and carbonaceous fragments.
6,050–6,054	Sandstone, as above, with numerous shale beds and laminations that are coalified. Sandstone has numerous rounded and elongated mud clasts. A sharp basal contact with the underlying black shale defines the **channel base**.
6,054–6,056	Shale, black, splintery, and coaly.

Cities Service No. 2 Buzzard "D" (N½SE¼ sec. 23, T. 4 N., R. 12 ECM)

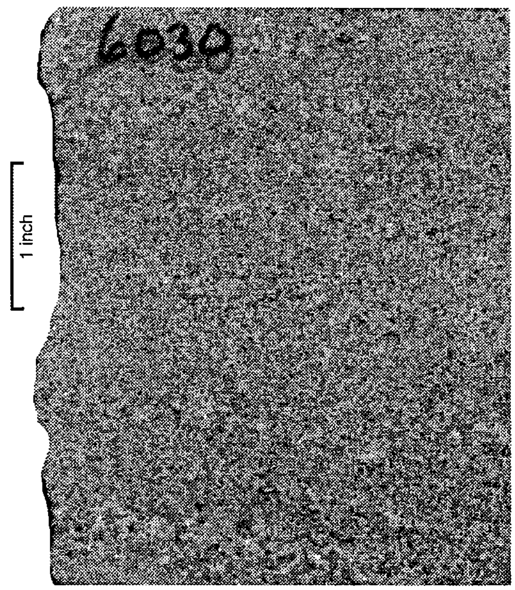
Reservoir: Upper Morrow sandstone
Depositional environment: Incised fluvial channel

Log depth: About 6,030–6,056 ft ± a few feet
Core depth: 6,030–6,056 ft



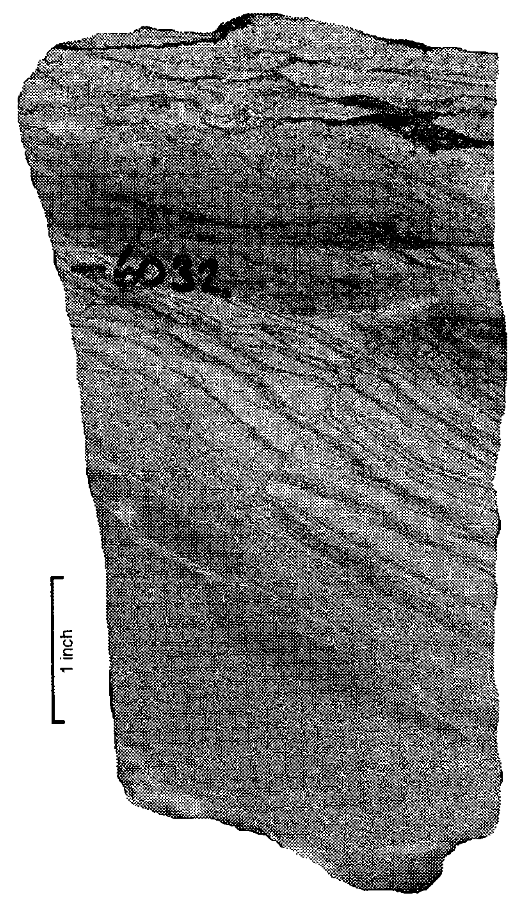
T.D.: 6,515 ft
Completion date: 3/9/76
Core #1; 6,030–6,080 ft, rec 50 ft (slabbed 6,030–6,056 ft)
Core #2; 6,080–6,107 ft, rec 27 ft
Perforated: 6,027–6,053 ft
Frac 21,500# sand, 11,000 gal acid
IPF (Morrow) 2,300 MCFGPD + 1BWPH

Cities Service No. 2 Buzzard "D" (N½SE¼ sec. 23, T. 4 N., R. 12 ECM)



Core depth: 6,030–6,030.3 ft
Log depth: about 6,030–6,030.3 ft

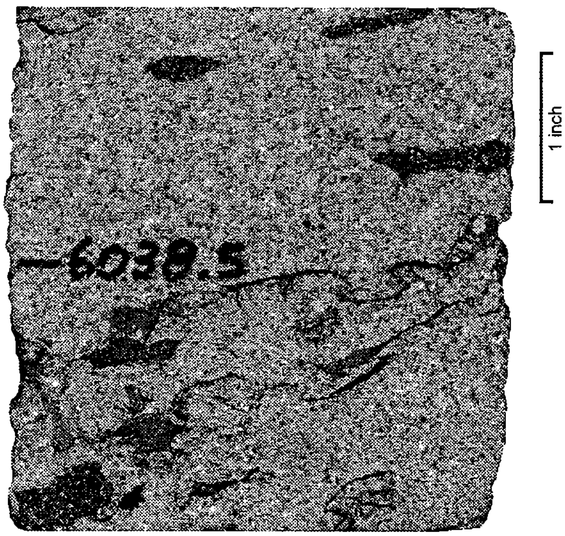
Massive to graded bedding in medium to coarse grained sandstone. With a hand lens, cementation can easily be determined as quartz overgrowths. The presence of dark fractions are rock fragments, and the conspicuous appearance of porosity is entirely due to secondary destruction of unstable rock constituents. Although this rock has good porosity (~12%), the permeability is only a few millidarcies.



Core depth: 6,031.9–6,032.3 ft
Log depth: about 6,031.9–6,032.3 ft

Slump structure or soft-sediment deformation in fine grained sandstone occurs below 6,032 ft. High-angle bedding with bed displacement is common in fluvial deposits such as this. Often, flowage (contorted bedding) accompanies such structures. The medium grained sandstone above the slump structure (above 6,032 ft) has interlaminations of highly carbonaceous shale. Commonly, such deformation is more apparent in finer grained deposits because of the conspicuous orientation of dark shale layers.

Cities Service No. 2 Buzzard "D" (N½SE¼ sec. 23, T. 4 N., R. 12 ECM)

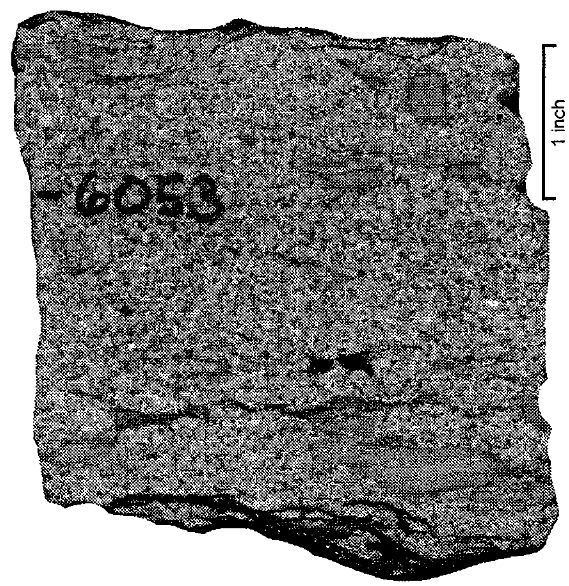


Core depth: 6,038.4–6,038.6 ft
Log depth: about 6,038.4–6,038.6 ft

Sandy mud clasts are floating within a medium grained sandstone. The dissolution of these rip-up clasts and other unstable rock constituents forms numerous voids that contribute greatly to the secondary porosity attributed to these rocks. Despite the presence of good secondary porosity, the permeability in this sample is only several millidarcies. The severe reduction in permeability is a big problem in the upper Morrow and is caused when aggregates of kaolinite plug up many of the pore throats. Kaolinite is a common alteration byproduct of rock fragments and feldspar, both of which are abundant in the Morrow.

Core depth: 6,052.9–6,053.2 ft
Log depth: about 6,052.9–6,053.2 ft

Coarse to medium grained sandstone with mudstone rip-up clasts is typical of the lower channel facies. This sample is bounded on the top and bottom by a thin coaly layer having plant imprints. As in all other sandstone zones within this channel sequence, secondary quartz overgrowths are the primary cementing agent. Less than a foot below this sample, the sandstone has a sharp basal contact with shale, which is typical of channel deposits.



Texaco Pacific Co. No. 4 Tidball

SW¼NE¼NW¼ sec. 22, T. 18 N., R. 14 W.

Lower Morrow sandstone

Tidal channel (point bar?), intertidal deposits

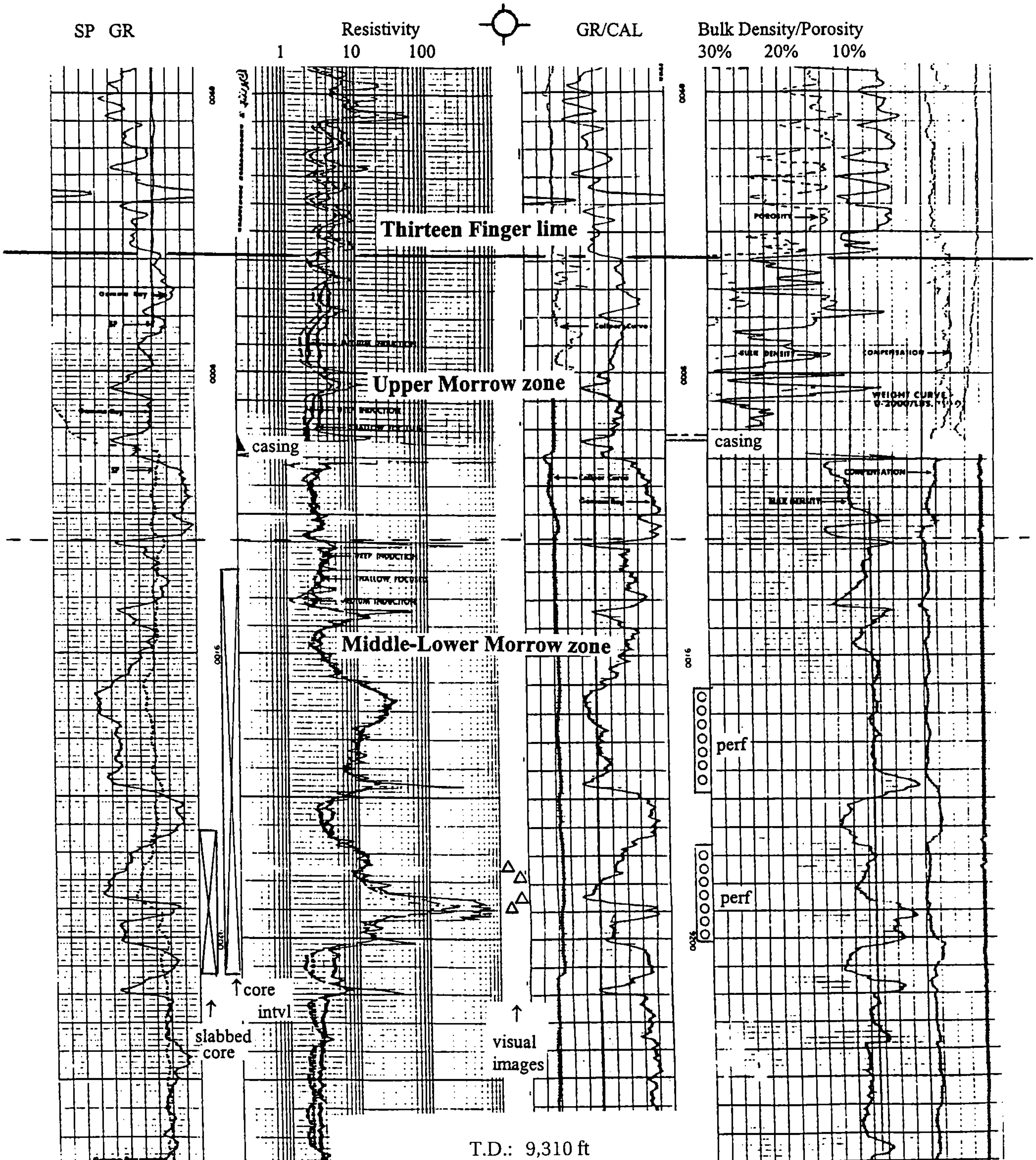
Log depth: ~ Core depth ± a few feet | Described by: Barbara Teichert and Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
9,162.0–9,163.9	Shale, dark gray to black, organic-rich, with coaly layers.
9,163.9–9,174.5	**Intertidal deposits** (tidal flat and/or upper tidal point-bar facies). Sandstone, fine to very fine grained, dark gray to greenish, with thin shale beds and laminations. Abundant plant debris and coaly layers. Possible rooting at 9,165.2 ft. At 9,167.3 ft: ~3 cm of mud clasts and fossil fragments. Slumping structures at 9,169.2–9,169.5 ft. Some bedding is indistinct or irregular (bioturbation at 9,168–9,169 ft), planar (9,171.7 ft), and in the form of tidal(?) couplets (thin distinct alternating beds of sandstone and shale) at 9,174–9,174.4 ft.
9,174.5–9,184.4	Sandstone, fine to very fine grained, medium gray, with locally abundant shale fragments and intercalations. Bioturbation intense at 9,174.5–9,174.8 ft. Slump structures with steeply dipping beds at 9,175.3–9,179.5 ft. Lenticular and ripple/flaser(?) bedding dominates at 9,180–9,183 ft. Tidal couplets(?) at 9,182.2 ft. Large coalified plant fragment at 9,182.3 ft.
9,184.4–9,187.4	Sandstone, fine grained, light gray to white, and tightly cemented with calcite. Rhythmic bedding consisting of alternating sandstone and highly carbonaceous shale is most common. Small-scale, medium-angle cross-bedding occurs at 9,185.8 ft. Shale laminations contain abundant small pieces of plant debris.
9,187.4–9,187.6	Sandstone, very fine grained, with soft-sediment deformation (i.e., slumping or flowage).
9,187.6–9,192.4	**Lower tidal channel facies** (subtidal?). Conglomeratic layers with interbedded sandy layers. Conglomerate: mostly mud clasts (3 cm max.) and some fossil fragments in calcareous matrix. Sandy layers: medium to fine grained, subrounded, light colored, calcareous, with abundant coalified organic material. Sharp basal contact with shale. **Channel base.**
9,192.4–9,202.2	**Muddy tidal flat or lagoonal beds(?).** Shale and very fine grained sandstone and siltstone, calcareous, dark gray to black. Bedding is faint but is either laminated or indistinct (bioturbated?). At 9,193.4 ft: 1-in. layer of bivalve shells.
9,202.2–9,213.0	Shale, dark gray to black. Top 3 ft is calcareous, diminishing with depth. Shale is increasingly more fissile in bottom of core. Several thin fossiliferous layers between 9,202.2 and 9,203 ft. Scattered bivalve(?) shells at 9,204.5–9,206 ft.

Texas Pacific Co. No. 4 Tidball (SW¼NE¼NW¼ sec. 22, T. 18 N., R. 14 W.)

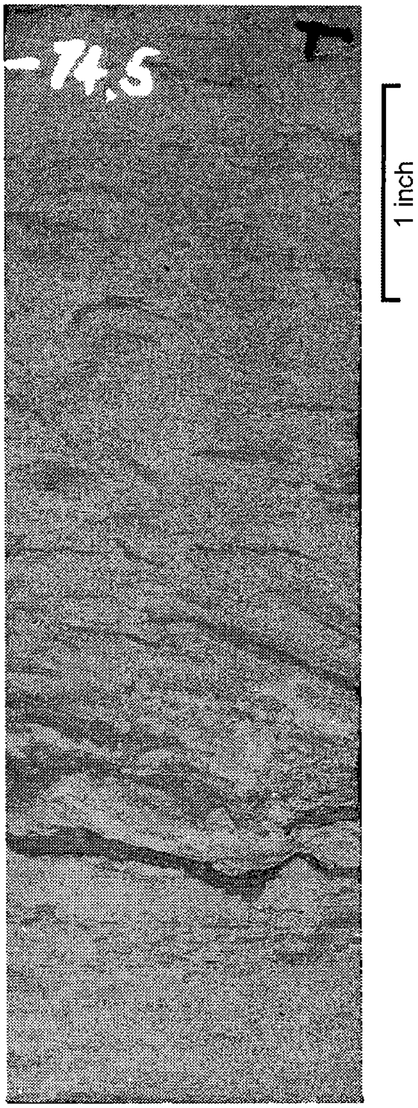
Reservoir: Lower Morrow sandstone (Primrose?)
Depositional environment: Tidal point bar

Log depth: About 9,162–9,213 ft
Core depth: 9,162–9,213 ft



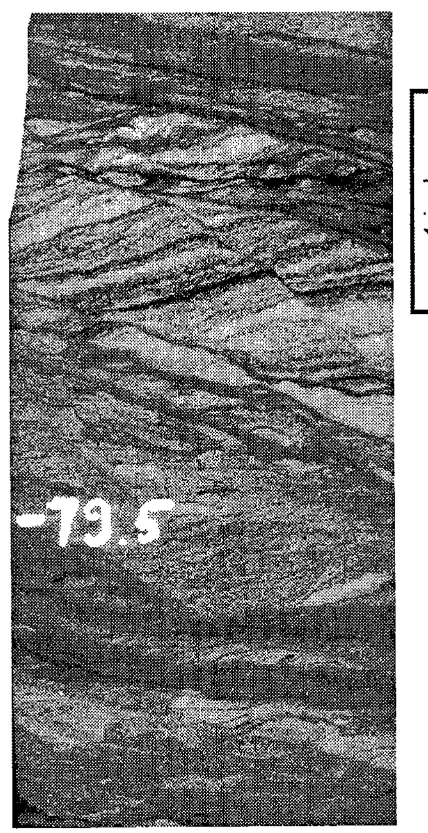
T.D.: 9,310 ft
P&A 8/9/77
Core: 9,070–9,213 ft (slabbed 9,162–9,213 ft)
Perforated: 9,111–9,147 and 9,166–9,201 ft
Frac 84,000# sand, 89,500 gal oil
F 76 BLO + 31 MCFGPD

Texas Pacific Co. No. 4 Tidball (SW¼NE¼NW¼ sec. 22, T. 18 N., R. 14 W.)



Core depth: 9,174.5–9,174.9 ft
Log depth: about 9,174.5–9,174.9 ft

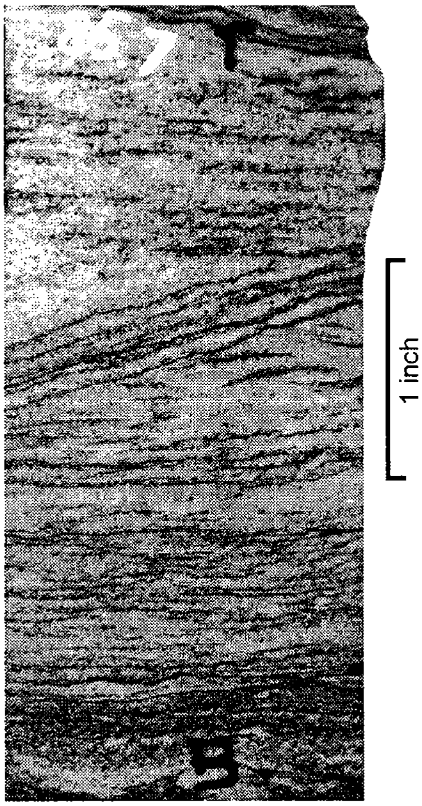
Bioturbated sandstone is very fine grained and contains numerous shale fragments. Bedding within the sandstone is amorphous but may have been ripple bedded prior to biogenic destruction of original bed forms. This type of post-depositional modification of sediments (diagenesis) is very common in tidal-flat environments and distinguishes it from upper point-bar facies deposited within a flood plain, which are not normally intensely bioturbated. In sandstone, bioturbation generally reduces porosity and permeability.



Core depth: 9,179.3–9,179.6 ft
Log depth: about 9,179.3–9,179.6 ft

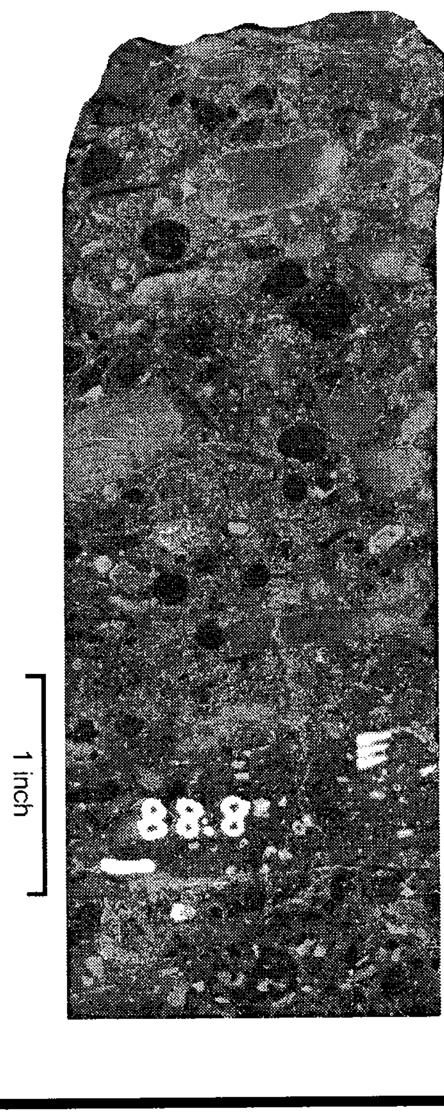
Slump structures or soft-sediment deformation occurs in any sedimentary environment where deposition is rapid. It is most common in distributary-mouth bars of the delta front but is also common in any type of channel bar. Therefore, this sedimentary structure is not diagnostic of a particular environment but rather of a depositional process.

Texas Pacific Co. No. 4 Tidball (SW¼NE¼NW¼ sec. 22, T. 18 N., R. 14 W.)



Core depth: 9,185.7–9,186.0 ft
Log depth: about 9,185.7–9,186.0 ft

Cross-bedding, small scale, medium angle, is common in the upper part of fluvial/tidal channel facies, whereas larger scale cross-bedding is typically found in the lower channel facies. This sandstone is fine grained and tightly cemented with calcite—a characteristic of many sands deposited in a marine or marginal-marine environment. However, the sandstone has numerous shale laminations containing abundant pieces of coalified plant material that are probably of terrestrial origin. These divergent rock characteristics are most commonly attributed to intertidal areas that are influenced both by the sea and by the land.



Core depth: 9,188.5–9,188.9 ft
Log depth: about 9,188.5–9,188.9 ft

Mud-clast conglomerate with sandy matrix is moderately calcareous. Mud clasts are rounded or elongated and randomly oriented and supported by a matrix of fine to medium grained sand. At 9,188.8 ft, a distinct layer of fine grained, fossiliferous sandstone is interbedded within the mud-clast conglomerate. Fossil debris in this 0.5-in.-thick zone consists mostly of crinoid fragments that may have been transported by flood tidal currents. Other distinct zones of interbedded sandstone similarly occur throughout the conglomeratic interval (9,187.6–9,192.4 ft) and may represent oscillatory currents in a tidal channel. The log response through the conglomerate may be confusing, as the gamma-ray log indicates shale and the resistivity log is anonymously high. This can easily be explained by the abundance of mud clasts (clay) that have been tightly cemented by calcite in a sandy matrix.

Ladd Petroleum No. 5 Wills "A"

C NE¼SW¼ sec. 25, T. 18 N., R. 14 W.

Lower Morrow sandstone

Intertidal deposits, possibly with thin tidal channels

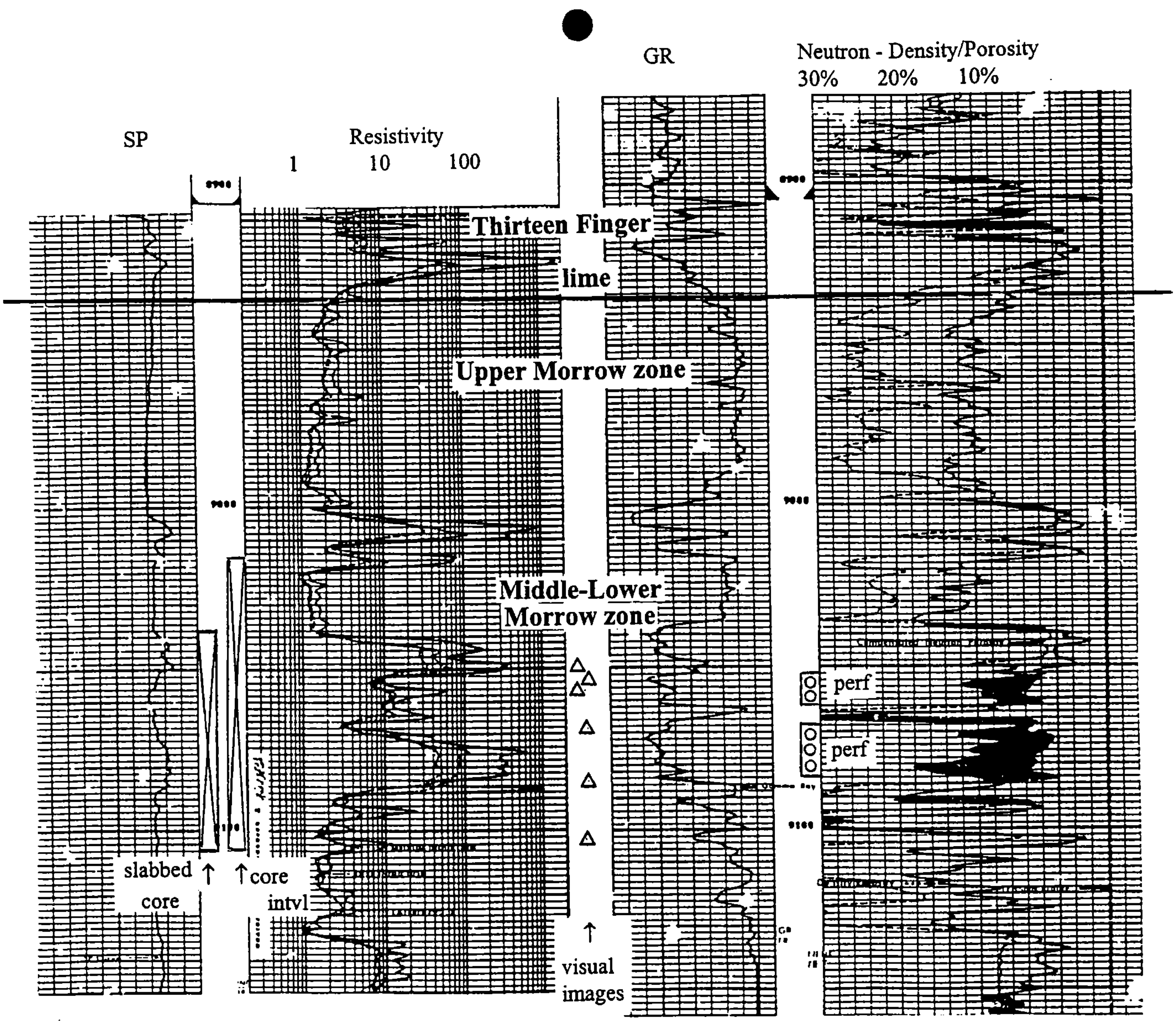
Log depth: ~20 ft lower than core depth | Described by: Barbara Teichert and Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
9,018–9,019.9	Shale, dark gray to black, fissile, with small amount of very fine grained mica.
9,019.9–9,027.0	**Top of tidal channel.** Bioclastic limestone (packstone) with fossil fragments consisting of bivalves, corals, crinoids, and ammonites mostly <2 mm (<0.1 in.) Numerous thin, black, shaly intercalations and flakes with very fine grained micas on bedding surfaces. Few mud clasts to 1 cm maximum (0.4 in.).
9,027.0–9,032.0	Limestone conglomerate (packstone), clast-supported fossil fragments (as above) and mud clasts with minor amounts of fine grained matrix sand. Calcareous mud clasts to 3 cm (1.2 in.) become larger and more abundant near base of this interval. Note the overall fining-upward texture from 9,032 to 9,020 ft. Sharp basal contact between conglomerate and underlying shale at 9,032 ft **(base of tidal channel).**
9,032.0–9,035.2	Sandstone, with interbedded black, carbonaceous shale lenses. Thin skeletal bed in shaly matrix at 9,032.7–9,033 ft.
9.035.2–9,045.0	**Intertidal deposits(?).** Sandstone, medium gray, very fine grained, with shale laminations. Some mica on bedding surfaces. The top 2 ft is mostly featureless, having indistinct bedding owing to bioturbation. The lower part may be relic ripple bedding in the aftermath of bioturbation, as it consists of irregular lenses of sand and mud. Possible water-escape structure at 9,039.15 ft.
9,045.0–9,048.0	Shale, black, thinly bedded, with some sandy intercalations.
9,048.0–9,060.0	**Top of tidal channel.** Sandstone, mostly quartz (arenite). Intercalation of dark gray sandstone with greenish and brownish sandstone. All sandstone is very fine grained, contains carbonized plant debris, and has abundant mica on bedding surfaces. Sandstone is tightly cemented but not calcareous (little or no "fizz" with acid). Contorted bedding (slumping structures) at 9,056.8 ft, 9,057.5 ft, and 9,058 ft. Bedding couplets (alternating sand and shale beds) or possibly flaser bedding (shaly material in ripple troughs) at 9,049.2–9,049.6 ft, 9,050.1–9,053 ft, and 9,055.6–9,056.2 ft.
9,060.0–9,065.0	Missing.
9.065.0–9,067.0	Sandstone, very fine grained, mostly quartz (arenite), tight, noncalcareous, flowage (contorted bedding) at 9,065.5 ft and 9,066.4 ft. Sharp basal contact with underlying shale at 9,067 ft. **Base of tidal channel.**
9,067.0–9,072.9	**Intertidal deposits(?).** Shale, dark gray, few micas, becoming increasingly interbedded with greenish sandy lenses with depth.
9,072.9–9,073.9	Sandstone, very fine grained, light gray, quartz arenite, interbedded with thin shale lenses in the upper 3 in. Some carbonaceous flakes, sharp basal contact with underlying shale.
9,073.9–9,076.1	Shale, dark gray, with thin, very fine grained sand lenses (tidal couplets?).
9,076.1–9,080.4	Shale, medium gray, organic-rich (carbonaceous plant debris).
9,080.4–9,083.0	Sandstone with interbedded fossiliferous limestone. Sandstone is very fine grained to silty, calcareous, mostly greenish with a few brown zones, lenticular to horizontal bedded, and bioturbated. Fossiliferous layers consist of clay-rich skeletal limestone (packstone) containing bivalves.
9,083.0–9,084.1	**Lagoonal or tidal-flat deposit(?).** Crinoidal–bivalve packstone–wackestone consists of fossil debris in a black, highly carbonaceous, noncalcareous shale matrix.
9,084.1–9,086.1	Shale, dark gray.

Ladd Petroleum No. 5 Wills "A" (C NE¼SW¼ sec. 25, T. 18 N., R. 14 W.)

Reservoir: Lower Morrow sandstone
Depositional environment: Intertidal deposits, possibly with thin tidal channel

Log depth: About 9,038–9,106 ft
Core depth: 9,018–9,086 ft

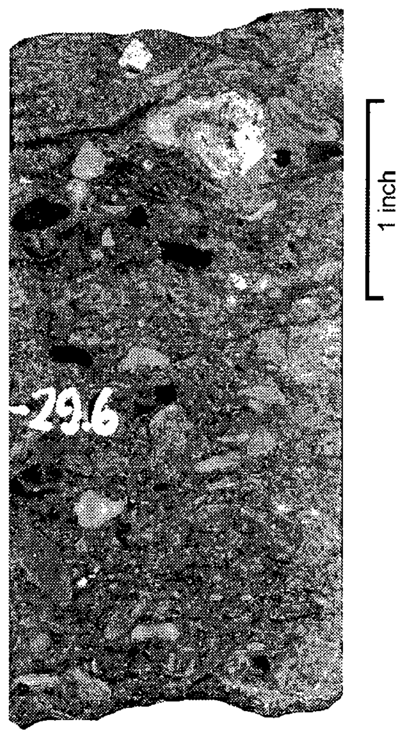


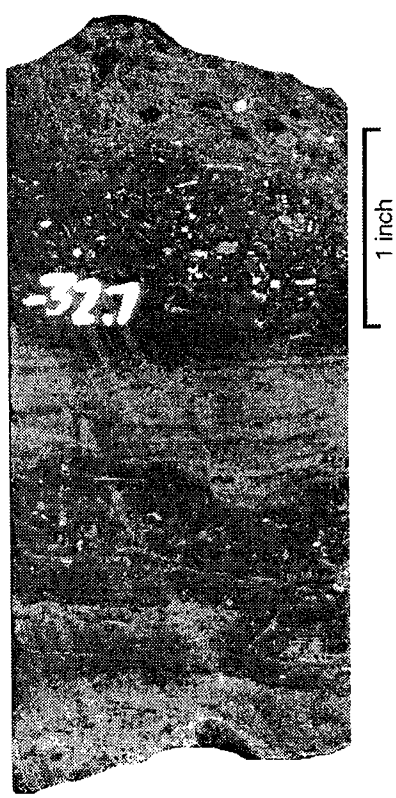
T.D.: 9,158 ft
Completion date: 10/15/78
Core: 8,995–9,086 ft, (slabbed 9,018–9,086 ft)
Perforated: 9,052–9,062 and 9,068–9,084 ft
Frac 165,000# sand + 115,000 gal gelled oil
IPF (Morrow) 10 BOPD + trace wtr, gty 39.3

Ladd Petroleum No. 5 Wills "A" (C NE¼SW¼ sec. 25, T. 18 N., R. 14 W.)

Core depth: 9,029.4–9,029.7 ft
Log depth: about 9,049.4–9,049.7 ft

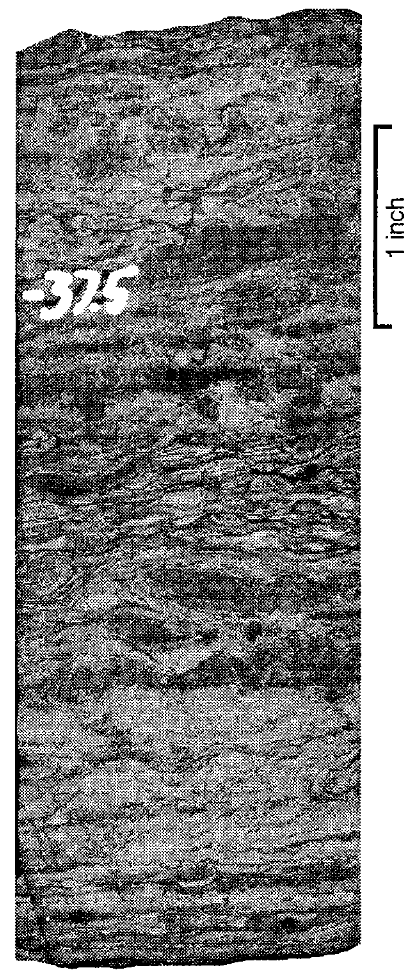
Limestone conglomerate (packstone) has numerous calcareous mud clasts with minor amounts of fine grained matrix sand. Fragments of crinoids, ammonites, and bivalves are present but more numerous directly above and below this sample. Zones consisting of predominantly mud clasts alternating with zones containing mostly fossil fragments may reflect ebb tides (seaward flowing) versus flood tides (landward flowing) in a tidal-channel (estuarine) environment.





Core depth: 9,032.6–9,032.9 ft
Log depth: about 9,052.6–9,052.9 ft

Alternating layers of black-shale lenses and skeletal packstone, and gray conglomeratic sandstone. The skeletal layers have abundant pieces of crinoids and small shell fragments, whereas the sandy layers have small mud clasts. As in the above sample, this may reflect oscillating currents: ebb tides (seaward flowing), forming conglomeratic sandstone, versus flood tides (landward flowing), forming skeletal layers.



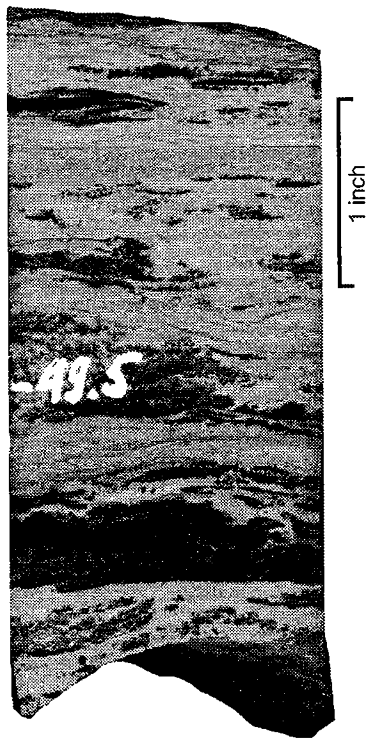
Core depth: 9,037.4–9,037.8 ft
Log depth: about 9,057.4–9,057.8 ft

Intertidal(?), bioturbated sandstone has amorphous distribution patterns of very fine grained sandstone and shale. The shale occurs as discontinuous lenses and laminations and is highly carbonaceous and slightly micaceous. Bioturbation in sandstones commonly reduces porosity and permeability. In this sample, bioturbation destroyed primary bedding features such as ripple marks. The importance of recognizing biogenic alterations in sandstone also serves in the interpretation of depositional environments. In this case, the effects of marine processes are evident and support the interpretation of an intertidal environment rather than a terrestrial flood plain.

Ladd Petroleum No. 5 Wills "A" (C NE¼SW¼ sec. 25, T. 18 N., R. 14 W.)

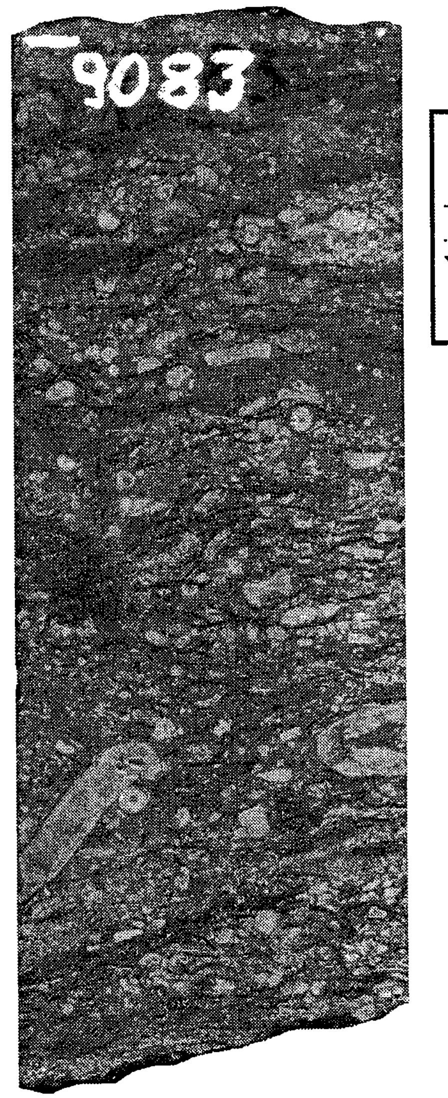
Core depth: 9,049.3–9,049.6 ft
Log depth: about 9,069.3–9,069.6 ft

Bedding couplets consisting of alternating sandstone and shale beds are common to tidal flats. The distribution patterns of shale and sandstone in this sample also show similarities to flaser bedding whereby shaly material accumulates within ripple troughs. This is somewhat hard to see, as the slab is not at the optimum orientation to see ripple bedding.



Core depth: 9,065.0–9,065.4 ft
Log depth: about 9,085.0–9,085.4 ft

Flowage or contorted bedding is evident by the near-vertical swirly pattern of darker colored material. This core sample is from the base of a 20-ft-thick sand bed and consists of very fine grained quartz. The sandstone is tightly cemented (probably quartz overgrowths) and is mostly noncalcareous. Although flowage occurs in a variety of depositional settings, in this sample it is more indicative of channel slumping rather than marine-bar slumping because it occurs at the very base of the sand bed.



Core depth: 9,083.0–9,083.4 ft
Log depth: about 9,103.0–9,103.4 ft

Lagoonal or muddy tidal-flat deposit (crinoidal–bivalve packstone–wackestone) consists of fossil debris in a shale matrix. Small bivalve and crinoid fragments are abundant in a very carbonaceous, black, noncalcareous shale matrix. This type of deposit is characteristic of marginal-marine environments affected by tidewater.

Apache Corp. No. 2-31 Simmons

SW¼NE¼ sec. 31, T. 12 N., R. 22 W.

Upper Morrow sandstone/chert-pebble conglomerate
Braided-river fan-delta deposit

Log depth: ~6.5 ft lower than core depth | Described by: Richard D. Andrews

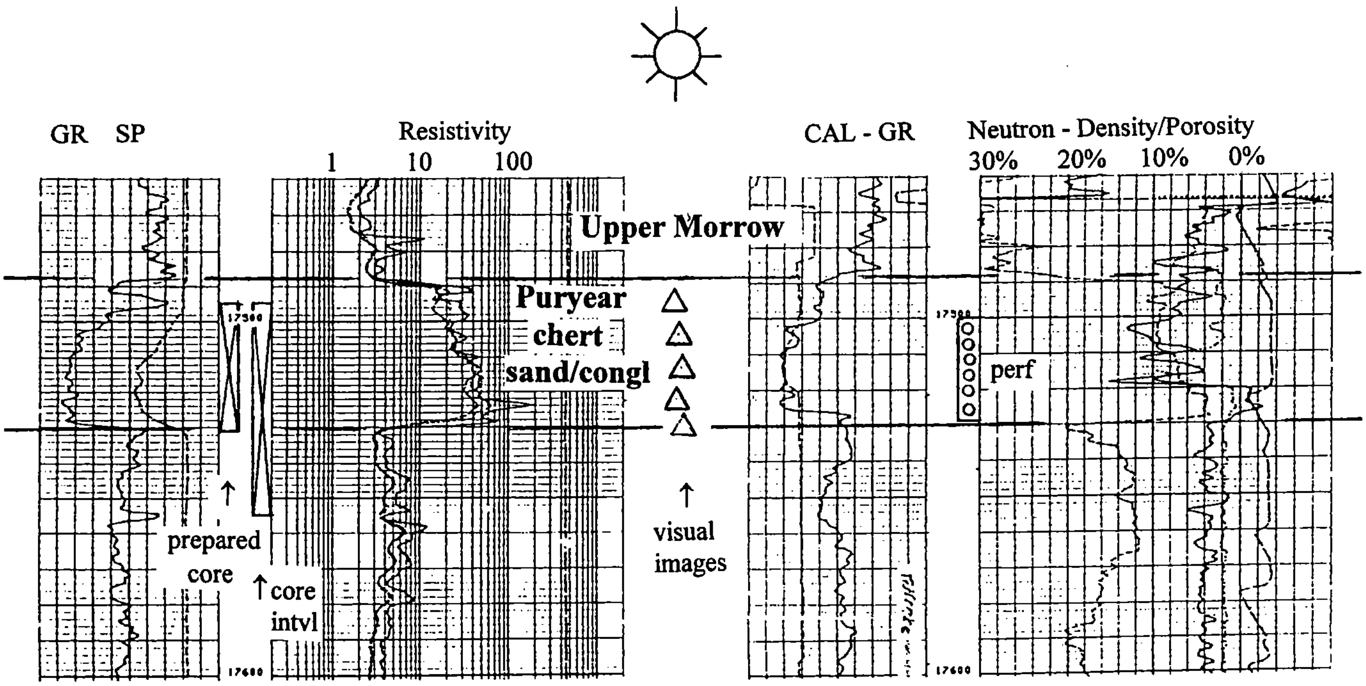
Core depth *(in feet)*	Lithology and sedimentary structures
17,488–17,502	**Upper channel facies** consists of sandstone, fine grained, light gray with darker organic-rich sandstone bands. Numerous micaceous- and carbonaceous-shale laminations and vertical fractures. Horizontal to medium-angle cross-bedding most common, with possibly ripple bedding in upper part of interval. A few rafted elongate shale rip-up clasts to 1.4 in. long are suspended in sandstone matrix. Grains are mostly quartz, with a small amount of indistinct altered chert fragments, minor rock, and feldspar(?). Sandstone is tightly cemented with silica. Minor carbonate cement.
17,502–17,506	Sandstone, medium to coarse grained, having salt-and-pepper appearance from white chert fragments. Detrital constituents consist of ~55% quartz, 35% chert. Dark, organic-rich sandstone bands apparent. Bedding is massive to low angle. Tightly cemented with silica, with minor carbonate cement.
17,506–17,512	**Lower channel facies** consists of coarse to very coarse grained sandstone and conglomerate. Detrital material is mostly quartz and chert, with abundant larger chert pebbles to 0.7 in. long. The chert clasts are white, subrounded to angular, and highly altered. Silica cement predominates, with minor amount of carbonate cement. Bedding is mostly indistinct to massive, with darker organic-rich bands and a few carbonaceous-shale laminations. Some laminations may be stylolitic.
17,512–17,520.5	Sandstone, light gray, with dark bands as above. Detrital material is medium to coarse grained, with abundant chert-pebble clasts rafted in the sandstone matrix. Some zones are darker from organic material. Bedding is mostly massive. Cementation is entirely silica. Carbonized wood fragment at 17,514.8 ft.
17,520.5–17,523.5	Conglomerate and very coarse grained sandstone, consisting of quartz and chert fragments. Chert pebbles to 0.7 in. long. Rounded shale rip-up clasts to 1.2 in. long at 17,523.5 ft. **Base of channel deposit.**
17,523.5–17,524	**Prodelta shale**, black, fissile, non-micaceous.

Note: Overall, this entire channel sequence represents graded bedding in a bed-load fluvial system.

Apache Corp. No. 2-31 Simmons (SW¼NE¼ sec. 31, T. 12 N., R. 22 W.)

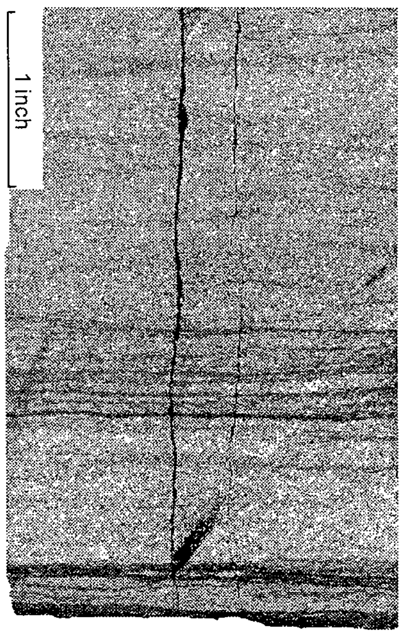
Reservoir: Upper Morrow chert sandstone/conglomerate
Depositional environment: Braided-river channel within fan-delta complex

Log depth: About 17,495–17,531 ft
Core depth: About 17,488–17,524 ft



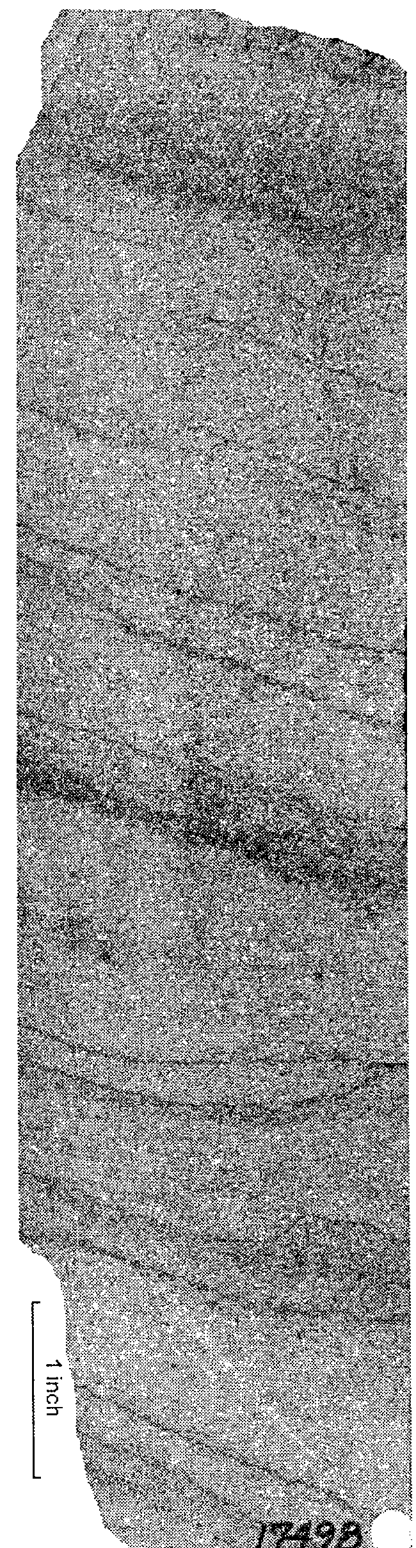
TD 18,073 ft
Completion 6/30/88
Core: 17,488–17,548 ft
17,495–17,555 ft (depth corrected)
Perforated 17,500–17,529 ft
IPF 3,662 MCFGPD + 91 BLW

Apache Corp. No. 2-31 Simmons (SW¼NE¼ sec. 31, T. 12 N., R. 22 W.)



Core depth: 17,488.2–17,488.5 ft
Log depth: about 17,494.7–17,495.0 ft

Upper channel facies, consisting of fine grained sandstone and interbedded shale laminations. Shale in the fluvial deposits is highly micaceous and carbonaceous. This is in contrast to the black prodelta shale that has little mica (see subsequent image of prodelta shale). Note vertical fractures.



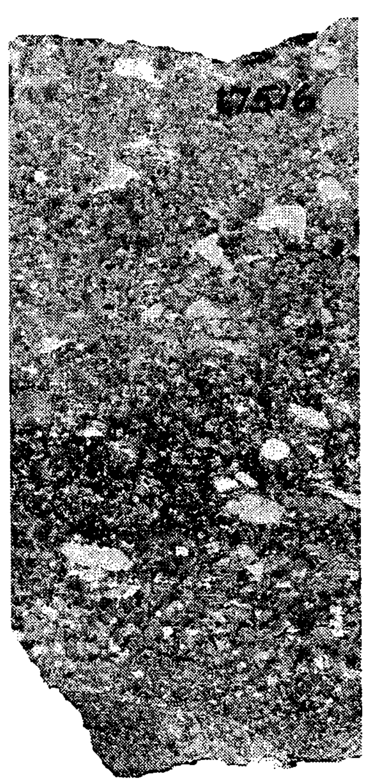
Core depth: 17,497.25–17,498 ft
Log depth: about 17,503.75–17,504.5 ft

Upper channel facies, consisting of fine to medium grained sandstone. Detrital material is mostly quartz with lesser amounts of chert. Note the medium-angle cross-bedding that is common in the upper part of longitudinal bars. Cementation is mostly silica with minor carbonate.

Apache Corp. No. 2-31 Simmons (SW¼NE¼ sec. 31, T. 12 N., R. 22 W.)

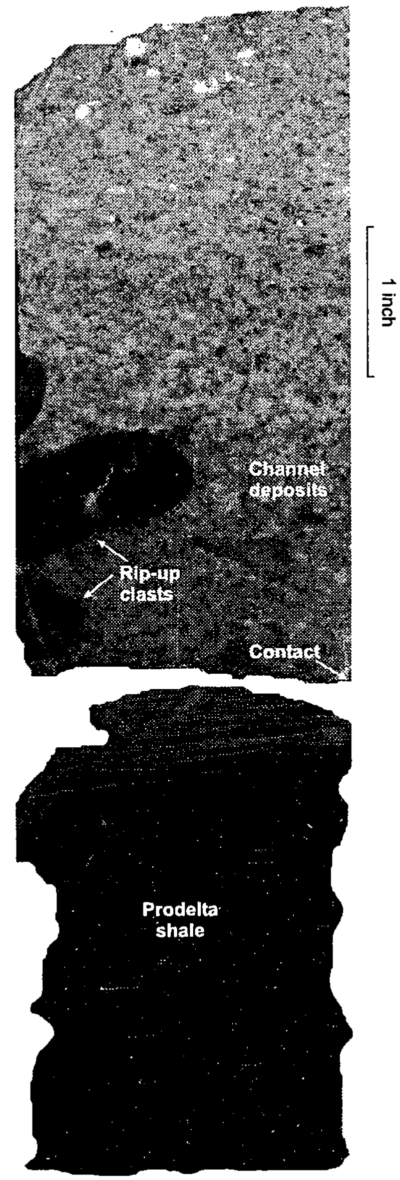
Core depth: 17,507–17,507.45 ft
Log depth: about 17,513.5–17,513.95 ft

Massive bedding in lower channel facies indicates very rapid deposition. In this sample, the detrital material consists of coarse to very coarse grained quartz and chert (white). As in all other samples in this core, porosity (and permeability) is entirely secondary and formed by the alteration and dissolution of the chert and rock fragments. Voids on the back side of the core more clearly show the dissolution effect.



Core depth: 17,516–17,516.4 ft
Log depth: about 17,522.5–17,522.9 ft

Lower channel facies consists of coarse to very coarse grained sandstone and chert-pebble conglomerate. Chert fragments (white) are up to 0.45 in. long in this image. Cementation in this zone is entirely silica, as the sample does not "fizz" with acid.



Core depth: 17,523.2–17,523.9 ft
Log depth: about 17,529.7–17,530.4 ft

Contact of channel and prodelta shale is sharp. This relationship is also seen on well logs (see accompanying logs of this cored interval). Note that the large, rounded shale rip-up clasts at the base of the channel appear to be the same as the underlying prodelta shale, indicating that the channel has cut into the older marine(?) shale. The prodelta shale is black and fissile, and lacks the conspicuous mica that characterizes interbedded shale beds in the fluvial deposits (see previous core image and description in this well). Channel facies consists mostly of quartz grains and lesser amounts of chert (white-colored clasts) and darker rock fragments.

Shell Oil Co. No. 1-21 Blasdel

SW¼NE¼ sec. 21, T. 23 N., R. 22 W.

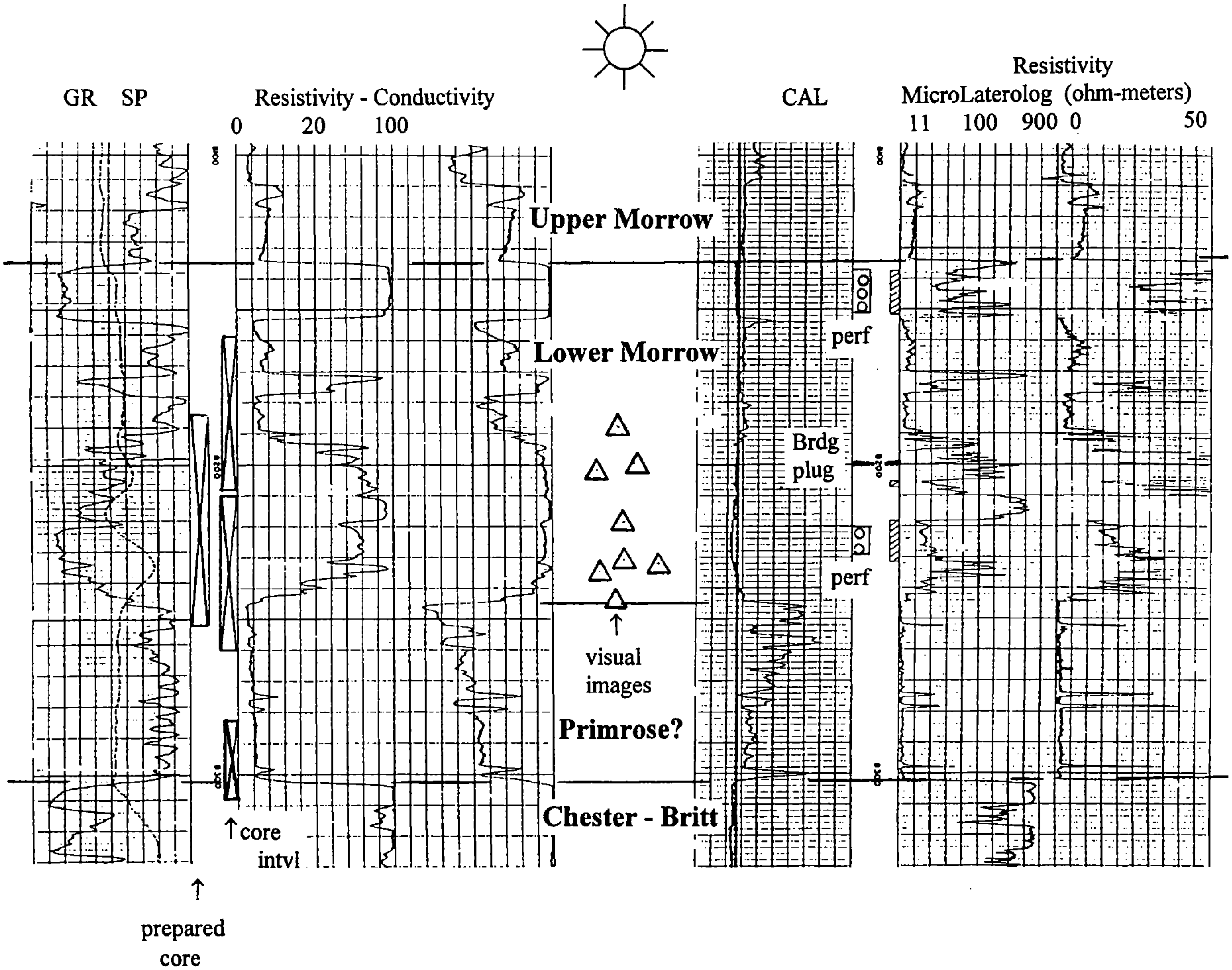
Lower Morrow sandstone

Tidal delta and channel complex including intertidal deposits

Log depth ≈ Core depth ± a few feet — Described by: Richard D. Andrews

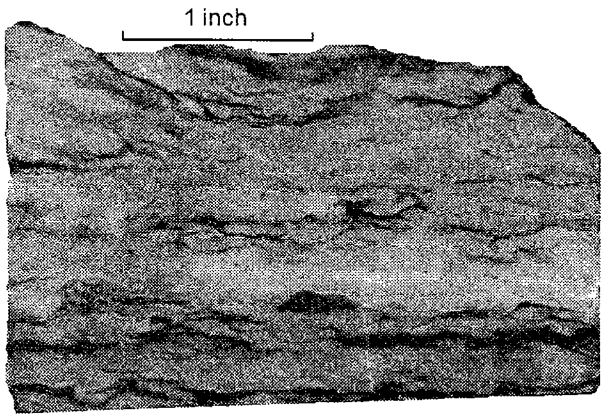
Core depth *(in feet)*	Lithology and sedimentary structures
8,186–8,189.3	**Marsh–marginal-marine shale**; dark gray to black, almost no mica, one isolated plant fossil at 8,187 ft. Sharp contact with sandy strata below.
8,189.3–8,193	**Tidal flat and marsh**; sandstone, very fine grained, greenish gray, interbedded with black-shale laminae and thin shale beds. Bedding is mostly irregular or indistinct, in places deformed and bioturbated, local flaser bedding. Vertical fractures.
8,193–8,199.7	**Tidal(?) creeks**; sandstone, fine to medium grained, light gray, indistinct to high-angle cross-bedding. Numerous elongate brown-shale rip-up clasts. Siderite(?) concretion at 8,193.5 ft. Highly calcareous. Shale laminae on some bedding surfaces.
8,199.7–8,200.6	**Tidal flat**; interbedded very fine grained sandstone and shale. Alternating thin beds of black shale and sandstone occur in a rhythmic-layering manner (tidal couplets?). Non-micaceous shale.
8,200.6–8,211	**Tidal creeks**; sandstone, fine to medium grained, light gray. Numerous rounded and elongate shale rip-up clasts ⅛ in.–2 in. that are black and orange-brown. Siderite/pyrite lens at 8,203 ft. Numerous carbonized organic clasts suspended in sandstone matrix or on bedding surfaces. A very large carbonized plant remnant at 8,202.5 ft. Sandstone is tightly cemented with silica, no carbonate cement. Bedding types include horizontal, ripple (8,202, 8,203 ft), and low-angle cross-bedding. Vertical fracturing.
8,211–8,218.5	**Upper tidal delta/channel sandstone**; sandstone, very fine grained, highly quartzose, uniform gray color except for shale laminations. Numerous olive-drab masses or nodules (sideritic?), some of which are altering to limonite. Numerous black, noncalcareous shale laminations have some stylolitic contacts. Bedding is horizontal to low angle, sometimes ripple and flaser bedded. Fractured vertically. Silica cementation.
8,218.5–8,230.8	**Lower tidal channel/delta facies**; sandstone, very fine to fine grained, increasing to medium grained at base of this interval. Composed of almost pure quartz with silica cement. Uniform light tan color. Bedding is massive to highly deformed, with flowage at 8,218.8, 8,223, 8,227, and 8,229.5 ft. Few shale laminations or flasers, no organic clasts or siderite nodules. Stylolitic contacts at 8,230.2 ft.
8,230.8–8,231.6	Sandstone and conglomerate. Sandstone is noncalcareous (silica cement), mostly medium grained. Large, flattened orangish mud clasts, some to 3 in. long, are suspended in sandstone matrix. Grain size of sand abruptly decreases to medium and then fine grained in the overlying sandstone interval. **Base of tidal channel.**
8,231.6–8,234	**Marsh and tidal flat?**; calcareous sandstone and packstone interval. Sandstone is very fine grained, highly calcareous, and grades downward into fossiliferous calcareous sandstone or sandy packstone. Numerous bivalve shell fragments and mud clasts are randomly oriented throughout this interval. Low- to medium-angle cross-bedding predominates, although bedding may be indistinct in certain intervals. Possible bidirectional cross-bedding (or scour and fill) at 8,231.8 ft.
8,234–8,236	Packstone, light gray, numerous bivalve shells and shale laminae. Tidal couplets(?) at 8,235.4 ft; strata for a few inches both above and below have ripple bedding.
8,236–8,236.3	Rip-up clasts, mostly rounded and elongate sideritic mudstone clasts reddish brown to grayish brown.
8,236.3–8,237	**Storm washover(?)**; sandstone, very fine grained, uniform light gray color and grain size. Horizontal bedding.
8,237–8,245	**Intertidal and marsh deposits**; consists of layers of broken crinoids and silty, calcareous shale. Numerous brachiopod(?) and other shell material contained in black shaly matrix.
8,245–8,252	**Prodelta(?)**; shale, black, fissile; no fossils, organic debris, or mica.

Shell Oil Co. No. 1-21 Blasdel (SW¼NE¼ sec. 21, T. 23 N., R. 22 W.)



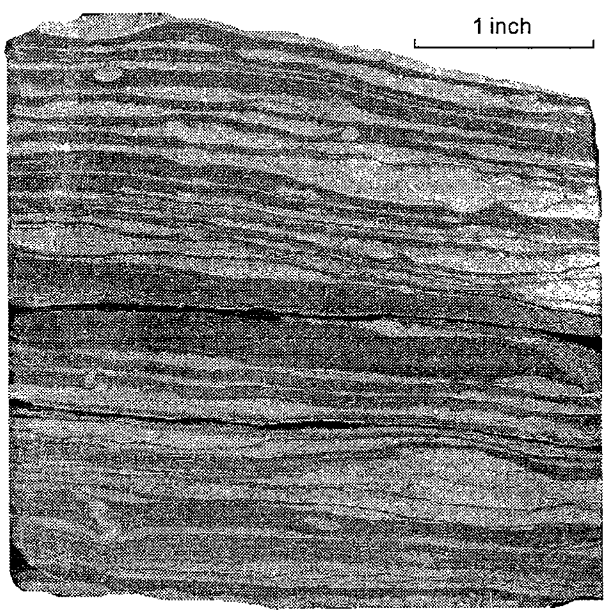
TD 8,525 ft
Completion 5/4/60
Core: 8,158–8,208 ft
8,210–8,260 ft
8,283–8,308 ft
Perforated 8,220–8,229 ft
Bridge plug at 8,200 ft
Perforated 8,137–8,151 ft
CAOF 5,850,000 CFGPD

Shell Oil Co. No. 1-21 Blasdel (SW¼NE¼ sec. 21, T. 23 N., R. 22 W.)



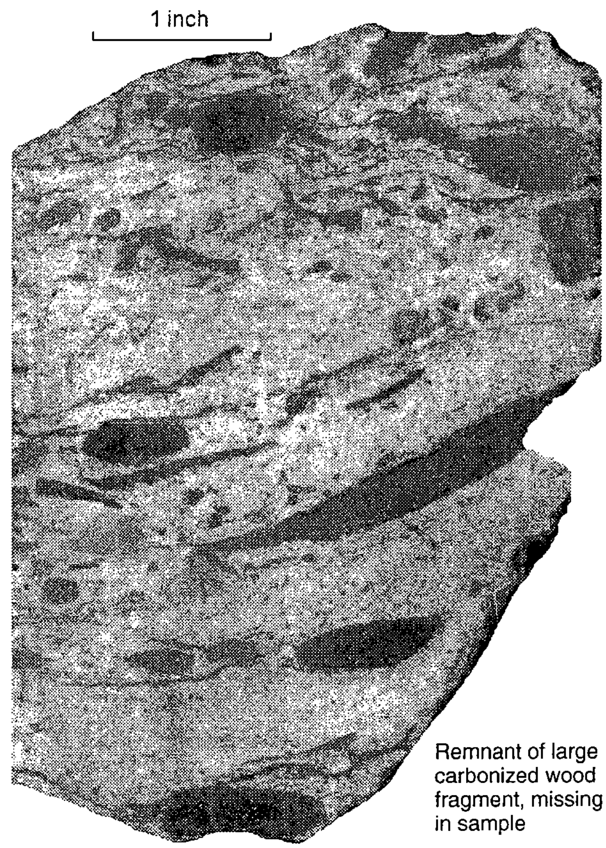
Core depth: 8,189.4–8,189.5 ft
Log depth: about 8,189.4–8,189.5 ft

Intertidal (tidal-flat) deposit, consisting of very fine grained sandstone having flaser bedding. The thin, irregular, discontinuous shale layers are "flasers." Indistinct bedding in sandstone is caused by bioturbation, although no burrows are visible.



Core depth: 8,200.2 – 8,200.5 ft
Log depth: ~8,200.2 – 8,200.5 ft

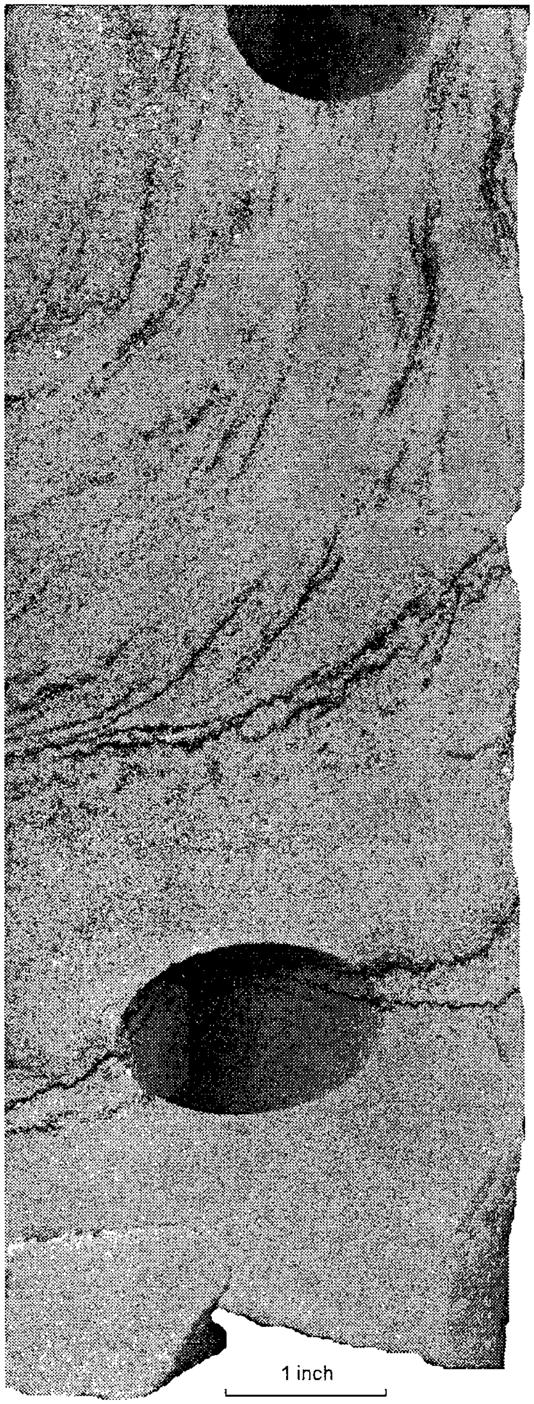
Tidal-flat deposits, consisting of alternating layers of shale and very fine grained sandstone in a rhythmic fashion. Also called tidal couplets, this type of bedding is wavy, lenticular, and rippled bedded.



Core depth: 8,202.2–8,202.5 ft
Log depth: about 8,202.2–8,202.5 ft

Conglomeratic lag deposit in a small channel or tidal creek. Many mud clasts are sideritic and alter to an orange-red color. The large void in the bottom right of image is a cast of a large carbonized wood fragment indicating terrestrial proximity.

Shell Oil Co. No. 1-21 Blasdel (SW¼NE¼ sec. 21, T. 23 N., R. 22 W.)



Core depth: 8,219–8,219.7 ft
Log depth: about 8,219–8,219.7 ft

Soft-sediment deformation (flowage) in very fine to fine grained sandstone. The light tan sandstone consists almost entirely of quartz grains and is well sorted. Dark laminations define contorted bedding that is common in both a channel environment and in the subaqueous distributary-mouth-bar environment and is caused by stratal instability from rapid deposition.

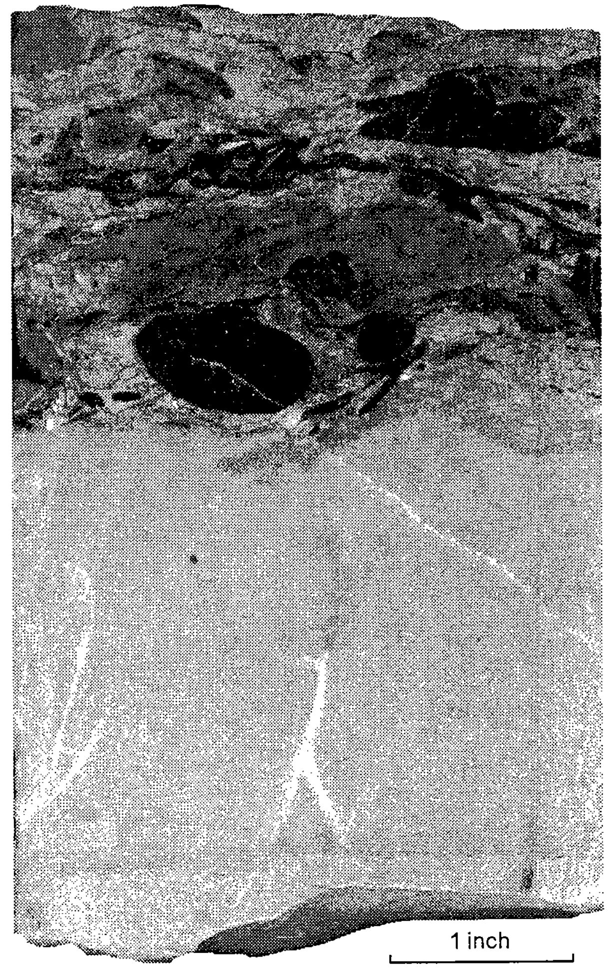
Core depth: 8,231–8,231.5 ft
Log depth: about 8,231–8,231.5 ft

Base of tidal channel; flat, elongate rip-up clasts (channel lag) are suspended in a medium grained sandstone matrix. Mud clasts are orange brown owing to oxidation of a sideritic core. Graded bedding is represented on a small scale in this image, as the grain size decreases upward from the conglomeratic lag to medium and fine grained sandstone. This change in texture is common in depositional environments dominated by fluvial currents.

Shell Oil Co. No. 1-21 Blasdel (SW¼NE¼ sec. 21, T. 23 N., R. 22 W.)

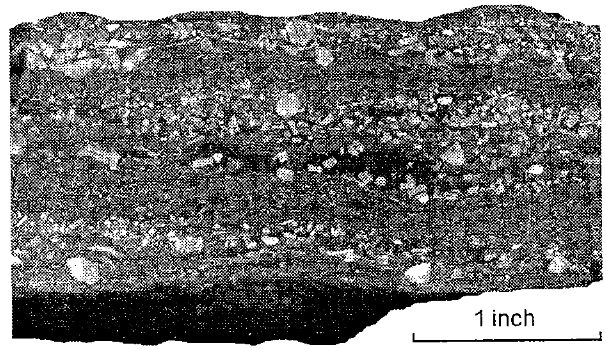
Core depth: 8,231.7–8,232.3 ft
Log depth: about 8,231.7–8,232.3 ft

Intertidal deposits, showing bi-directional cross-bedding(?) or scour and fill. Sandstone is very fine grained, highly calcareous, and fossiliferous (bivalves). Scattered mud clasts are medium grained to pebble in size and are orange brown owing to alteration of siderite.



Core depth: 8,235–8,235.5 ft
Log depth: about 8,235–8,235.5 ft

Intertidal rip-up clasts in a fine grained sandstone matrix. Rounded mud clasts are orange red owing to sideritic oxidation to limonite. The contact of the conglomerate with the underlying sandstone is sharp. The light-colored, very fine grained sandstone in the bottom half of the picture is part of an 8-in.-thick bed that is probably a storm-related deposit.



Core depth: 8,244.25–8,244.4 ft
Log depth: about 8,244.25–8,244.4 ft

Intertidal deposits, consisting of layers of broken crinoids and silty, organic-rich, calcareous shale. Numerous brachiopod and other shell material is contained in the black shale matrix, further indicating a brackish, marginal-marine depositional environment.

APPENDIX 5
Morrow Field Data Elements

Table A5-1. — Upper Morrow

Field	Well Count	Avg Depth ft	Avg Perf Thickness ft	Saturated Thickness Min (ft)	Saturated Thickness Max (ft)	Avg Perf Porosity %	Saturated Porosity Min (%)	Saturated Porosity Max (%)	Initial Pressure (PSI)[1] Min	Initial Pressure (PSI)[1] Avg	Initial Pressure (PSI)[1] Max
APACHE EAST	2	14,889	19.5	32	57	9.6	7.4	10.9	6,010	7,220	8,429
ARAPAHO	29	13,537	8.7	5	29	8.6	4.0	14.1	800	7,407	11,475
ARAPAHO NE	4	12,995	9.3	13	16	9.7	7.0	13.0	7,828	8,404	9,000
ARNETT	1	10,201	23.0	26	26	8.0	7.5	7.5	3,076	3,076	3,076
BESSIE EAST	2	15,851	12.0	13	15	7.8	7.6	8.0	1,782	5,453	9,124
BISHOP	4	11,589	22.5	14	38	6.8	5.0	7.8	4,090	4,463	4,800
BREATHWAITE	14	16,508	9.2	7	38	8.5	4.1	12.3	1,212	7,940	12,838
BURNS FLAT	5	15,104	22.2	18	39	9.4	5.5	12.0	1,830	6,306	9,714
CANUTE NORTH	2	18,395	7.0	7	8	4.3	2.6	5.5	11,646	11,646	11,646
CARPENTER	21	17,483	18.2	6	90	11.2	5.5	13.5	2,674	9,561	15,817
CHEYENNE WEST	61	16,445	15.6	6	72	13.1	1.5	20.0	1,225	10,084	16,765
CLINTON	10	14,850	18.3	2	42	6.3	4.0	9.5	2,359	8,638	13,325
CLINTON EAST	2	14,650	11.5	9	16	7.9	7.2	8.3	4,245	4,306	4,367
CLINTON NORTH	2	14,070	11.0	8	16	14.0	14.0	14.0	3,376	6,611	9,845
CLINTON SOUTH	6	15,601	16.3	8	39	10.3	7.0	11.0	9,189	10,440	11,415
CLOUDCHIEF NW	1	17,655	6.0	8	8	11.0	11.0	11.0	8,158	8,158	8,158
COLONY NW	6	14,850	8.3	8	26	10.4	5.1	12.8	3,000	8,413	11,742
CORN DISTRICT	1	15,382	4.0	4	4	7.0	7.0	7.0	7,145	7,145	7,145
CUSTER CITY SOUTH	2	12,799	6.0	8	8	7.0	6.0	8.0	7,504	8,305	9,106
DEMPSEY	42	17,096	16.7	4	120	11.2	3.0	18.0	1,136	10,172	16,705
DILL CITY	3	17,160	14.7	24	25	8.3	5.2	11.0	7,149	10,531	12,778
EAKLY-WEATHERFORD	33	14,290	11.9	5	30	8.2	6.0	10.5	2,100	7,180	11,411
ELK CITY	36	15,860	17.7	7	78	12.4	5.8	20.0	3,033	10,571	15,059
GOODWIN SOUTH	1	10,509	4.0	8	8	3.0	2.0	2.0	1,500	1,500	1,500
GRAND WEST	8	11,307	21.1	22	51	9.3	3.0	12.3	2,700	4,060	5,414
GRIMES	16	18,326	13.3	4	60	8.3	3.0	12.0	6,164	11,444	16,680
HIGGINS SOUTH	12	11,076	16.5	7	32	7.4	2.0	12.0	1,137	3,920	7,440
HYDRO WEST	2	12,501	7.0	5	17	9.3	6.0	11.4	3,213	6,368	9,522
INDIANAPOLIS	5	13,724	12.2	6	32	8.4	5.0	10.9	1,956	5,767	7,576
KIOWA FLATS NORTH	1	17,492	6.0	8	8	7.0	7.0	7.0	13,335	13,335	13,335
MILDER	2	8,526	10.0	10	12	9.9	9.3	10.5	1,771	1,774	1,776
NEW LIBERTY SOUTH	1	18,370	24.0	24	24	10.3	10.3	10.3	5,876	5,876	5,876
OAKWOOD SW	1	9,859	11.0	32	32	10.3	8.7	8.7	400	400	400
PEEK NE	2	11,050	9.0	8	10	13.8	11.5	16.0	1,528	2,598	3,667
PEEK SOUTH	2	11,389	6.5	4	12	11.5	11.0	12.0	226	3,508	6,790
RAINEY NE	1	10,611	8.0	9	9	14.0	13.0	13.0	550	550	550
REYDON	109	15,533	17.6	6	85	11.2	2.0	21.0	1,207	8,467	14,906
SEGER	3	15,456	12.3	10	44	7.0	3.0	6.3	5,493	11,014	13,976
SHATTUCK	2	9,794	7.5	7	8	11.0	8.0	14.0	1,050	1,075	1,100
SHATTUCK WEST	3	9,236	10.7	8	18	11.0	7.0	7.0	2,803	3,562	4,534
SICKLES NORTH	1	13,193	12.0	12	12	7.2	7.2	7.2	1,910	1,910	1,910
STAFFORD	2	15,708	14.0	12	18	7.2	6.5	7.4	9,600	11,143	12,685
SWEETWATER NW	9	17,374	24.1	12	90	9.3	5.5	12.0	3,403	9,991	14,852
TANGIER	1	9,352	12.0	12	12	6.0	6.0	6.0	976	976	976
TOUZALIN	5	8,905	11.2	6	21	12.6	6.7	15.0	662	3,094	4,311
WEATHERFORD	20	13,076	14.7	8	32	8.5	3.7	12.0	2,194	7,023	10,537
WEATHERFORD WEST	1	13,693	12.0	12	12	6.9	6.9	6.9	6,034	6,034	6,034
Grand Total	**499**	**15,213**	**15.3**	**2**	**120**	**10.4**	**1.5**	**21.0**	**226**	**8,443**	**16,765**

[1]Initial pressure data prioritized in this order: DST, BHP, SITP, FTP.

Source: Petroleum Information/Dwights LLC, ©1999. Data current to January 1999.

BCF Billion cubic feet
BCFE Billion cubic feet gas equivalent
PGIP Perforated gas in place
SGIP Saturated gas in place
VUGE Volume of ultimate gas equivalent

Field Data Elements

Observed Spacing		Cum	Cum	Last 12 Months		Ultimate recovery	SUM	SUM	Balance (BCF) note: (-) = minus	
Avg (ac)	Sum (ac)	Gas (BCF)	Oil (BBLS)	Gas (BCF)	Oil (BBLS)	(BCFE) = VUGE	PGIP (BCF)	SGIP (BCF)	PGIP - VUGE	SGIP - VUGE
640	1,280	2.35	3,397	0.123	142	3.334	31.253	54.986	27.919	51.653
270	7,840	62.60	593,286	1.073	2,985	72.668	61.614	69.121	-6.573	-3.547
640	2,560	1.54	37,030	0.046	539	2.007	33.125	53.180	31.118	51.173
640	640	0.27	59,999	0.000	0	0.326	4.706	4.987	4.379	4.661
640	1,280	2.17	0	0.115	0	3.075	9.125	10.734	6.049	7.659
400	800	0.50	261,297	0.000	0	0.866	0.807	0.856	-0.051	-0.009
640	8,960	14.58	1,086	0.526	0	18.741	62.034	79.609	45.469	60.868
640	3,200	5.15	1,281	0.217	587	6.874	70.642	80.352	63.768	73.478
640	1,280	2.05	0	0.728	0	7.806	1.861	1.862	-5.945	-5.944
579	12,160	69.89	5,530	3.114	2,755	94.520	352.568	504.737	260.851	410.217
611	37,280	515.52	23,608	14.872	862	633.103	1211.635	1605.532	642.979	972.429
480	4,800	29.44	2,465	0.354	0	32.249	47.608	52.409	28.722	20.160
640	1,280	1.09	14,029	0.030	588	1.350	7.980	8.667	6.630	7.316
480	960	0.15	0	0.000	0	0.148	4.010	4.010	3.973	3.862
560	3,360	3.52	319	0.060	0	4.003	53.305	72.237	49.641	68.234
640	640	1.08	234	0.018	0	1.219	4.966	6.621	3.747	5.402
640	3,840	7.99	1,007	0.158	0	9.237	39.164	50.808	29.927	41.571
640	640	0.15	0	0.015	0	0.269	1.297	1.297	1.028	1.028
400	800	1.57	71,191	0.036	0	2.053	4.760	6.347	2.707	4.294
625	26,240	196.43	15,561	8.894	1,243	266.750	748.275	1077.002	516.501	810.252
640	1,920	3.92	0	0.532	0	8.124	36.167	52.019	28.043	43.895
439	14,480	35.28	27,554	1.270	1,287	45.411	113.407	129.739	73.343	84.329
618	22,240	314.18	415,759	10.395	11,459	397.990	762.687	1155.926	429.664	757.935
640	640	0.05	14,695	0.000	195	0.059	0.059	0.078	0.000	0.020
320	640	3.53	591,971	0.154	41,175	5.967	8.913	10.510	2.946	4.543
580	9,280	30.58	194,745	1.109	2,689	39.918	121.134	151.253	81.856	111.335
291	3,200	7.37	333,594	0.344	1,221	10.379	22.945	24.146	14.373	13.767
80	160	2.23	45,375	0.216	1,463	4.089	0.105	0.121	-1.609	-3.968
640	3,200	1.45	1,148	0.079	0	2.076	37.346	47.847	35.270	45.771
640	640	0.32	357	0.016	0	0.449	5.093	6.791	4.644	6.342
480	960	0.76	5,244	0.044	0	1.119	3.108	3.251	1.990	2.132
640	640	0.74	0	0.013	0	0.846	20.135	20.135	19.289	19.289
320	320	0.00	24,695	0.000	0	0.003	0.253	0.622	0.250	0.619
640	1,280	0.57	78,310	0.017	2,879	0.758	10.457	10.457	9.699	9.699
640	1,280	1.65	20,046	0.009	0	1.764	3.447	3.507	1.683	1.743
640	640	0.03	10,457	0.000	104	0.033	0.547	0.571	0.514	0.538
609	66,400	718.25	648,735	16.942	12,206	854.111	1822.608	2221.493	1015.314	1367.382
640	1,920	4.98	0	0.039	0	5.290	15.235	21.784	9.944	16.494
640	1,280	0.06	6,171	0.000	0	0.062	1.679	1.679	1.617	1.617
480	1,440	6.85	35,584	0.092	523	7.633	0.755	1.922	-6.878	-5.711
320	320	0.49	26,868	0.028	1,860	0.729	0.886	0.886	0.157	0.157
160	320	13.81	760	0.665	0	19.065	5.182	5.434	-13.883	-13.631
640	5,760	19.69	12,574	0.713	0	25.370	194.287	205.187	168.917	179.817
160	160	0.00	179	0.001	179	0.011	0.137	0.137	0.126	0.126
320	1,600	3.27	109,872	1.046	3,826	11.564	18.401	21.183	8.006	9.618
272	5,440	36.78	412,298	1.445	8,327	49.533	50.379	69.013	18.997	19.480
640	640	0.25	512	0.248	512	2.217	4.552	4.552	2.335	2.335
544	**266,640**	**2,125.15**	**4,108,823**	**65.798**	**99,606**	**2,655.171**	**6,010.639**	**7,915.600**	**3,619.446**	**5,260.429**

NOTE: A minus (–) preceding production in the "Balance" columns indicates over-production in regard to volumetric reserve calculations. Positive numbers indicate under-production in regard to the particular field AND is an estimate of **POTENTIALLY REMAINING UNPRODUCED GAS RESERVES.**

Table A5-2. — Lower Morrow

Field	Well Count	Avg Depth ft	Avg Perf Thickness ft	Saturated Thickness		Avg Perf Porosity %	Saturated Porosity		Initial Pressure (PSI)[1]		
				Min (ft)	Max (ft)		Min (%)	Max (%)	Min	Avg	Max
ARNETT	2	10,869	22.5	22	99	8.8	5.0	8.2	2,721	4,131	5,540
ARNETT AIRPORT NE	2	10,593	19.5	18	42	9.9	9.2	10.0	3,886	3,886	3,886
ARNETT EAST	5	10,401	27.2	10	112	10.2	4.0	7.4	2,050	3,282	3,789
ARNETT SE	9	10,942	22.8	32	94	10.1	5.0	10.7	1,810	3,532	4,902
BISHOP	2	12,250	20.5	38	54	7.6	4.7	5.0	3,871	4,763	5,654
BOILING SPRINGS NORTH	21	7,232	12.2	5	42	15.8	9.3	22.0	720	2,399	3,396
CARLTON LAKE WEST	2	11,790	23.0	26	200	11.0	8.7	8.7	4,400	4,533	4,665
CARPENTER NE	1	17,485	18.0	37	37	3.8	3.4	3.4	13,936	13,936	13,936
CATEBY NORTH	2	8,128	18.0	17	30	14.5	10.9	15.0	2,171	2,171	2,171
CESTOS SW	4	10,106	13.5	20	36	14.9	7.0	15.0	4,056	4,389	4,649
CRANE SE	7	10,777	12.6	6	60	7.9	4.0	9.0	3,000	4,381	6,720
EAKLY-WEATHERFORD	2	15,551	57.0	65	95	1.8	1.8	1.8	1,714	4,815	7,915
ELM GROVE	3	11,935	10.3	18	32	12.0	6.0	9.0	4,876	6,019	7,161
FAY EAST	3	10,772	15.7	14	23	6.5	5.0	8.0	3,200	4,367	5,800
FORT SUPPLY EAST	2	7,528	18.0	13	30	9.2	7.8	9.1	1,735	1,994	2,253
FORT SUPPLY NE	6	7,281	12.2	16	34	12.7	8.0	17.3	1,338	2,116	3,436
FORT SUPPLY SE	1	7,856	12.0	18	18	15.0	13.1	13.1	2,090	2,090	2,090
FORT SUPPLY SOUTH	2	7,602	17.5	18	21	12.7	12.7	13.0	76	643	1,210
GAGE	116	8,605	15.8	7	109	10.6	3.0	21.0	660	2,420	6,200
GAGE NORTH	1	8,589	5.0	15	15	20.0	12.4	12.4	2,225	2,225	2,225
GAGE SE	11	9,554	23.7	9	87	11.3	4.6	11.0	1,567	2,750	3,945
GOODWIN SOUTH	3	10,744	17.0	10	70	8.2	5.1	7.6	3,350	3,794	4,478
GOODWIN WEST	1	10,186	21.0	52	52	9.0	5.1	5.1	300	300	300
GRAND WEST	29	11,919	20.3	8	161	7.8	3.0	10.0	550	3,768	5,811
HARMON EAST	57	10,243	22.4	10	74	11.5	2.9	17.0	900	3,099	5,895
HARMON NORTH	1	9,681	14.0	20	20	14.3	10.6	10.6	3,034	3,034	3,034
HARMON NW	3	10,574	38.7	34	70	10.2	7.8	11.2	2,347	2,747	3,535
HARMON SE	14	10,927	16.3	12	86	9.3	5.5	12.0	200	3,300	5,898
HIGGINS SOUTH	30	11,881	17.3	8	56	7.5	2.0	11.0	592	3,972	6,354
LEONEL SE	1	9,206	6.0	6	6	6.9	6.9	6.9	3,901	3,901	3,901
LOOKEBA	1	13,596	6.0	10	10	6.0	6.0	6.0	740	740	740
LOOKEBA EAST	6	12,643	15.5	4	50	8.7	5.7	11.5	6,465	7,448	9,198
MILDER	45	8,849	17.8	11	134	11.8	2.0	15.5	180	2,435	3,847
MILDER SW	1	9,345	107.0						700	700	700
MOCANE-LAVERNE	234	8,083	22.1	3	154	11.9	3.0	21.0	75	1,911	3,375
MOORELAND WEST	2	7,632	8.0	8	14	12.5	11.0	14.0	1,891	2,702	3,512
MUTUAL SW	2	10,025	18.0	19	26	14.0	10.7	13.0			
NOBSCOT NW	1	9,999	2.0	6	6	8.0	9.0	9.0	100	100	100
OAKWOOD NORTH	2	9,416	5.5	5	20	10.1	4.3	10.3	150	1,220	2,290
OAKWOOD SE	8	9,643	29.4	22	66	12.1	6.8	14.4	350	2,589	4,702
PACKSADDLE NW	1	13,318	20.0	22	22	3.6	3.3	3.3	7,743	7,743	7,743
PEEK NE	20	11,576	25.7	12	134	9.3	3.3	11.5	950	3,700	5,174
PEEK SOUTH	3	12,411	13.0	78	164	10.4	5.0	8.0	226	3,970	6,377
PUTNAM	3	10,718	8.3	8	20	9.3	8.6	9.0	940	3,231	4,416
SHARON NORTH	6	8,950	14.7	8	46	9.7	8.0	10.0	2,022	3,228	3,877
SHARON WEST	39	9,151	14.3	6	50	13.0	3.0	20.0	225	2,712	4,732
SHATTUCK	5	10,247	24.2	33	58	9.3	6.6	9.8	1,100	2,560	3,594
SHATTUCK NORTH	1	9,430	12.0	12	12	13.0	13.0	13.0	3,297	3,297	3,297
SHATTUCK WEST	6	9,505	33.0	35	75	9.3	4.6	7.0	2,059	3,288	4,385
TANGIER	106	8,989	16.7	6	112	10.7	2.5	19.0	70	2,329	4,877
TANGIER NW	1	10,138	6.0	24	24	18.0	8.0	8.0			
TOUZALIN	10	9,227	20.2	10	89	10.6	6.0	16.0	1,192	2,689	3,590
VICI	8	10,041	32.3	14	146	11.3	4.9	15.0	84	2,454	3,390
VICI NW	9	9,708	13.9	10	33	13.4	5.0	20.0	350	1,039	2,649
VICI SW	8	10,311	17.1	14	34	12.4	9.7	15.4	1,986	3,146	4,601
WATONGA-CHICKASHA	7	10,208	14.4	6	38	14.6	9.0	19.0	400	5,611	7,870
WOODWARD	7	8,305	15.0	13	28	13.8	7.9	19.0	400	2,672	3,720
WOODWARD NE	13	7,517	13.7	13	53	13.7	3.0	16.0	1,453	2,854	3,615
WOODWARD NORTH	26	7,736	10.5	6	38	14.5	3.5	22.0	25	2,240	4,646
WOODWARD NW	4	7,631	10.5	8	46	11.7	8.3	12.5	1,712	2,137	2,401
WOODWARD SE	6	8,217	13.2	15	52	11.8	6.0	12.7	883	2,974	4,085
WOODWARD SOUTH	15	8,678	16.7	6	66	16.5	6.0	23.0	500	3,005	3,844
Grand Total	**949**	**9,150**	**18.8**	**3**	**200**	**11.3**	**1.8**	**23.0**	**25**	**2,642**	**13,936**

[1]Initial pressure data prioritized in this order: DST, BHP, SITP, FTP.

Source: Petroleum Information/Dwights LLC, ©1999. Data current to January 1999.

BCF	Billion cubic feet
BCFE	Billion cubic feet gas equivalent
PGIP	Perforated gas in place
SGIP	Saturated gas in place
VUGE	Volume of ultimate gas equivalent

Field Data Elements

Observed Spacing Avg (ac)	Sum (ac)	Cum Gas (BCF)	Cum Oil (BBLS)	Last 12 Months Gas (BCF)	Oil (BBLS)	Ultimate recovery (BCFE) = VUGE	SUM PGIP (BCF)	SUM SGIP (BCF)	Balance (BCF) note: (-) =minus PGIP - VUGE	SGIP - VUGE
160	320	1.072	5,006	0.052	171	1.493	4.638	7.029	3.145	5.537
640	1,280	1.917	32,334	0.078	1,156	2.583	13.612	21.549	11.030	18.967
640	3,200	2.320	17,283	0.057	334	2.783	32.206	37.966	30.040	35.183
267	2,400	4.968	2,527	0.092	0	5.696	29.278	50.116	23.582	44.420
640	640	0.415	0	0.052	0	0.826	6.597	12.238	5.771	11.412
440	8,800	23.607	45,909	0.177	0	25.044	56.287	87.003	39.673	61.958
400	800	0.323	198	0.000	0	0.323	16.115	106.581	15.792	106.258
320	320	0.628	0	0.055	0	1.066	3.319	6.104	2.253	5.038
480	960	1.022	11,164	0.071	518	1.592	5.494	6.268	3.902	4.676
480	1,920	4.022	5,125	0.052	0	4.443	22.451	43.652	19.122	39.209
160	1,120	6.584	146,201	0.164	7,297	8.172	4.174	5.682	1.747	-2.490
400	800	4.185	11,218	0.172	525	5.577				
160	480	2.272	2,308	0.052	0	2.686	5.252	7.625	2.566	4.939
160	480	4.739	216,632	0.503	7,858	9.213	3.362	3.388	-5.851	-5.826
400	800	0.880	11,479	0.027	0	1.099	4.195	4.667	3.096	3.569
347	2,080	7.754	23,571	0.148	188	8.946	9.807	16.256	0.861	7.310
640	640	0.069	492	0.000	0	0.069	4.898	6.417	4.829	6.348
640	1,280	0.032	330	0.000	0	0.032	3.189	3.249	3.157	3.217
333	38,320	128.070	705,819	2.917	6,258	151.809	213.638	310.647	61.829	158.838
640	640	0.026	0	0.000	0	0.026	2.070	3.850	2.045	3.825
320	3,520	18.851	230,139	0.667	81	24.389	12.853	24.674	-11.501	0.284
280	840	1.530	1,281	0.104	507	2.354	3.831	6.392	1.477	4.038
640	640	0.311	29,947	0.000	359	0.318	0.367	0.509	0.049	0.192
429	6,440	21.146	96,494	0.829	539	27.826	62.393	123.731	34.568	95.905
295	16,240	80.180	2,058,801	3.465	59,826	110.154	166.004	213.369	55.850	103.215
640	640	1.021	47,045	0.000	0	1.067	5.895	6.249	4.829	5.182
640	1,920	0.348	12,275	0.000	0	0.359	40.908	65.791	40.550	65.432
314	4,400	14.252	228,822	0.328	4,077	17.111	35.684	51.079	18.573	33.968
212	6,140	52.674	178,840	1.084	1,680	61.510	40.435	52.789	-21.074	-8.721
320	320	2.079	27,666	0.004	0	2.144	0.593	0.593	-1.551	-1.551
160	160	0.550	0	0.002	0	0.564	0.052	0.086	-0.513	-0.478
587	3,520	7.536	4,180	0.324	56	10.106	54.235	64.912	44.129	54.805
339	14,560	42.382	85,541	2.432	268	61.663	64.799	110.195	4.253	48.532
640	640	0.892	3,477	0.016	0	1.022				
289	66,700	276.670	1,346,569	7.904	20,198	340.154	395.172	607.641	55.439	267.487
320	640	0.603	2,109	0.125	0	1.594	3.743	5.196	2.149	3.602
640	1,280	0.497	0	0.063	0	0.992				
640	640	0.000	5,242	0.000	0	0.000	0.017	0.059	0.017	0.059
160	320	1.656	24,525	0.045	333	2.033	0.392	0.501	-1.641	-1.532
130	1,040	11.281	545,354	0.057	576	12.378	18.970	21.058	7.621	8.680
640	640	0.298	0	0.016	0	0.422	4.670	4.663	4.248	4.241
303	5,760	15.056	34,277	0.401	125	18.273	66.480	150.441	48.206	132.167
373	1,120	1.774	0	0.106	0	2.613	3.622	63.850	1.009	61.237
640	1,920	1.229	33,950	0.000	0	1.253	8.939	10.995	7.686	9.742
280	1,120	6.949	38,004	0.023	0	7.174	3.312	4.047	-3.862	-3.126
424	15,680	84.932	1,430,438	1.117	12,745	95.298	167.249	211.749	73.206	116.451
640	3,200	0.531	11,723	0.000	0	0.540	30.047	45.201	29.507	44.661
640	640	0.700	3,855	0.000	0	0.704	6.121	6.121	5.417	5.417
320	1,920	2.646	7,964	0.121	322	3.609	7.252	10.307	4.230	6.698
420	43,280	119.578	1,823,646	2.691	54,500	142.511	321.137	426.234	189.961	283.724
640	640	0.005	2,837	0.000	0	0.005				
256	2,560	11.580	23,516	1.200	1,653	21.096	21.298	26.866	0.202	5.770
460	3,680	5.867	223,579	1.886	26,571	21.128	27.921	33.717	6.793	12.589
196	1,760	6.025	203,802	0.180	1,934	7.503	3.667	4.915	-2.861	-2.589
560	4,480	11.330	163,986	0.337	899	14.188	62.902	85.527	48.714	71.339
223	1,340	30.034	208,212	0.244	702	32.453	16.222	19.389	-12.944	-13.064
640	3,840	4.018	51,793	0.075	769	4.654	36.252	45.321	31.598	40.667
492	6,400	15.380	62,238	0.130	0	16.461	30.700	68.351	14.239	51.890
431	11,200	18.093	309,439	0.632	923	23.249	55.812	78.984	32.563	55.735
400	1,600	1.037	4,389	0.004	0	1.073	6.015	7.627	4.943	6.554
480	1,920	29.541	19,978	0.000	0	29.566	10.632	11.607	-18.934	-17.959
491	7,360	46.213	766,914	1.738	24,643	61.063	84.652	104.320	23.589	43.257
351	**319,940**	**1,142.177**	**11,590,443**	**33.017**	**238,591**	**1,416.051**	**2,321.829**	**3,515.343**	**948.299**	**2,099.291**

NOTE: A minus (–) preceding production in the "Balance" columns indicates over-production in regard to volumetric reserve calculations. Positive numbers indicate under-production in regard to the particular field AND is an estimate of POTENTIALLY REMAINING UNPRODUCED GAS RESERVES.

Table A5-3. — Morrowan (undifferentiated)

Field	Well Count	Avg Depth	Avg Perf Thickness ft	Saturated Thickness Min (ft)	Saturated Thickness Max (ft)	Avg Perf Porosity %	Saturated Porosity Min (%)	Saturated Porosity Max (%)	Initial Pressure (PSI)[1] Min	Initial Pressure (PSI)[1] Avg	Initial Pressure (PSI)[1] Max
ANTHON SE	1	12,540	10.0	10	10	3.0	3.0	3.0	2,593	2,593	2,593
APACHE NORTH	1	2,874	26.0	48	48	20.0	20.0	20.0	1,207	1,207	1,207
APACHE SE	2	7,729	55.0	84	111				3,511	3,560	3,609
BINGER NE	7	13,101	14.7	8	32	8.7	4.5	11.5	2,077	5,438	9,049
BINGER SOUTH	1	14,013	18.0	18	18	8.0	8.0	8.0	4,033	4,033	4,033
BOILING SPRINGS NORTH	15	6,938	12.9	8	56	15.8	11.0	20.0	813	2,454	3,394
BRIDGEPORT	5	12,150	9.8	5	22	6.9	3.3	11.5	1,401	3,759	6,500
CANTON NW	10	8,548	8.8	5	12	12.6	2.0	23.0	1,500	1,500	1,500
CEDARDALE NE	9	6,413	10.1	8	38	14.3	7.3	18.0	15	2,386	3,274
COOPER	4	8,314	14.5	8	36	11.7	9.4	14.0			
CRANE SE	1	10,408	21.0	22	22	9.1	9.0	9.0	5,337	5,337	5,337
CUSTER CITY EAST	1	11,736	12.0	24	24	7.5	6.0	6.0	6,526	6,526	6,526
CUSTER CITY NORTH	6	11,135	34.4	52	84	10.9	4.4	15.0	610	3,615	6,279
EAGLE CITY	11	9,048	11.1	10	31	14.7	7.3	18.0	3,183	3,745	4,702
EAGLE CITY SOUTH	1	9,546	8.0	8	8	7.0	7.0	7.0			
EAKLY-WEATHERFORD	1	15,182	76.0	88	88	2.5	0.0	0.0			
ELM GROVE	4	11,599	15.3	20	34	9.5	6.8	9.0	3,313	5,305	7,429
FAY EAST	10	10,526	13.9	4	24	4.5	0.5	9.0	2,806	5,690	8,066
FONDA SE	5	8,695	5.0	6	14	8.6	3.7	10.0	1,800	2,942	4,100
GREENFIELD NW	3	9,773	16.7	14	42	12.8	10.0	12.9	5	2,306	3,687
LEONEL SE	5	9,218	8.4	8	18	11.7	7.6	22.0	4,482	4,599	4,716
LONGDALE WEST	2	8,404	15.0	6	24	12.0	11.0	13.0	75	1,088	2,100
LOOKEBA EAST	3	13,384	13.7	16	20	11.3	10.0	11.0	5,357	6,718	7,835
OAKWOOD NORTH	4	9,217	25.7	17	45	10.0	10.0	10.0	500	1,928	3,100
OKEENE NW	12	7,888	13.9	6	25	15.9	3.5	21.0	1,100	2,820	4,500
SEGER	10	17,299	8.4	4	22	11.8	5.4	15.0	3,493	9,606	13,976
SENTINEL	4	11,600	62.7	62	190	9.7	5.4	11.0	707	2,502	3,900
SOONER TREND	2	7,887	7.0	6	8	12.5	12.0	13.0	2,715	3,481	4,246
VICI SW	2	10,269	13.0	22	26	14.5	8.0	17.5	4,619	4,735	4,850
WATONGA-CHICKASHA	433	9,104	13.6	1	80	12.1	1.5	22.0	25	3,753	9,139
WATONGA WEST	2	9,464	17.5	10	36	13.5	11.1	14.0	5,878	6,087	6,296
Grand Total	**577**	**9,301**	**14.0**	**1**	**190**	**12.0**	**0.5**	**23.0**	**5**	**3,830**	**13,976**

[1]Initial pressure data prioritized in this order: DST, BHP, SITP, FTP.

Source: Petroleum Information/Dwights LLC, ©1999.
Data current to January 1999.

BCF	Billion cubic feet
BCFE	Billion cubic feet gas equivalent
PGIP	Perforated gas in place
SGIP	Saturated gas in place
VUGE	Volume of ultimate gas equivalent

Field Data Elements

Observed Spacing Avg (ac)	Sum (ac)	Cum Gas (BCF)	Cum Oil (BBLS)	Last 12 Months Gas (BCF)	Oil (BBLS)	Ultimate recovery (BCFE) = VUGE	SUM PGIP (BCF)	SUM SGIP (BCF)	Balance (BCF) note: (-)=minus PGIP - VUGE	SGIP - VUGE
160	160	0.041	84	0.000	0	0.041	0.227	0.227	0.186	0.186
640	640	0.000	51,394	0.000	1,779	0.028	5.831	10.765	5.803	10.737
640	1,280	0.504	0	0.000	0	0.504				
229	1,600	2.947	109,030	0.018	0	3.307	17.041	19.525	13.733	16.218
640	640	0.521	0	0.000	0	0.521	5.725	5.725	5.204	5.204
160	2,400	17.520	72,635	0.152	878	18.797	15.577	24.524	-3.220	5.727
192	960	0.544	1,094	0.011	179	0.634	2.574	2.768	1.939	2.133
80	800	2.580	228,468	0.083	2,617	3.254	0.194	0.194	-0.980	-3.060
338	3,040	10.531	24,522	0.197	0	12.113	8.974	32.948	-3.139	20.835
520	2,080	0.300	29,017	0.026	1,859	0.504				
320	320	0.401	8,136	0.018	204	0.560	5.403	5.598	4.844	5.039
320	320	1.274	6,483	0.067	440	1.825	2.732	4.372	0.907	2.546
253	1,520	11.752	40,569	0.119	1,733	12.664	23.602	35.894	10.939	23.231
211	2,320	9.466	1,507,099	0.000	0	9.561	9.103	14.017	7.067	4.456
640	640	0.002	0	0.000	0	0.002				
160	160	0.502	19,219	0.024	536	0.689				
320	1,280	1.217	11,272	0.026	179	1.442	9.054	15.558	7.812	14.116
208	2,080	25.576	143,093	0.356	963	28.683	7.801	7.801	-19.955	-20.883
96	480	0.222	123,804	0.000	1,150	0.335	0.716	0.901	0.389	0.565
267	800	0.334	7,080	0.000	0	0.342	4.118	7.706	3.775	7.363
544	2,720	1.471	59,804	0.045	158	1.865	2.517	4.494	1.870	2.629
80	160	0.682	30,496	0.036	1,050	0.979	0.965	0.965	-0.014	-0.014
267	800	6.477	5,402	0.300	298	8.862	10.042	12.609	1.180	3.747
160	480	2.944	129,179	0.074	571	3.618	0.952	0.952	-2.665	-2.665
148	1,780	18.713	494,364	0.345	6,170	22.001	21.445	24.769	1.284	2.768
608	6,080	60.861	895	1.045	0	69.122	97.989	139.936	28.867	70.814
200	800	1.765	1,927	0.120	172	2.713	13.414	16.738	11.603	14.025
240	480	0.424	4,713	0.015	124	0.548	2.388	2.388	1.839	1.839
640	1,280	0.825	3,166	0.044	0	1.176	19.934	31.952	18.758	30.776
214	92,380	1,018.399	16,283,249	15.927	114,525	1160.926	1013.363	1449.524	-43.032	288.598
640	1,280	0.765	19,086	0.000	0	0.802	23.631	27.136	22.829	26.333
230	**131,760**	**1,199.561**	**19,415,280**	**19.048**	**135,585**	**1368.422**	**1,325.312**	**1,899.984**	**77.824**	**531.561**

NOTE: A minus (–) preceding production in the "Balance" columns indicates over-production in regard to volumetric reserve calculations. Positive numbers indicate under-production in regard to the particular field AND is an estimate of **POTENTIALLY REMAINING UNPRODUCED GAS RESERVES.**

Table A5-4. — Primrose

Field	Well Count	Avg Depth	Avg Perf Thickness ft	Saturated Thickness Min (ft)	Saturated Thickness Max (ft)	Avg Perf Porosity %	Saturated Porosity Min (%)	Saturated Porosity Max (%)	Initial Pressure (PSI)[1] Min	Initial Pressure (PSI)[1] Avg	Initial Pressure (PSI)[1] Max	Observed Spacing Avg (ac)	Observed Spacing Sum (ac)
ALEDO	2	12,412	26.0	24	32	10.8	9.9	9.9	2,150	3,971	5,791	640	1,280
ALEDO SE	1	12,952	8.0	8	8	8.6	8.6	8.6	4,262	4,262	4,262	640	640
ALEDO SOUTH	1	13,502	8.0	37	37	9.7	3.7	3.7	5,900	5,900	5,900	640	640
ALEDO WEST	1	12,355	187.0	0	0	4.0	0.0	0.0				640	640
ANTHON	5	12,704	16.4	16	40	9.3	4.2	10.7	1,036	4,201	6,382	352	1,760
ANTHON NE	4	12,147	18.0	13	72	7.5	4.0	8.0	3,381	4,789	5,531	320	1,280
ANTHON NW	5	11,757	17.6	23	56	7.3	2.7	8.0	1,963	3,755	5,781	512	2,560
ANTHON SE	1	12,843	8.0	18	18	9.0	6.0	6.0	5,023	5,023	5,023	160	160
ARAPAHO	20	14,393	33.9	8	136	7.3	2.7	10.7	4,000	7,724	12,268	224	4,480
ARAPAHO NE	2	14,309	19.5	18	28	7.4	5.8	9.5	9,117	9,364	9,611	400	800
ARNETT	1	11,102	40.0	135	135	10.1	6.5	6.5	2,721	2,721	2,721	640	640
ARNETT AIRPORT NE	1	10,932	7.0	20	20	8.0	6.3	6.3	3,886	3,886	3,886	640	640
ARNETT EAST	4	10,543	13.3	6	64	10.3	4.4	10.0	100	2,085	3,632	640	2,560
ARNETT SE	7	11,394	24.1	20	92	8.7	5.0	9.7	1,999	3,949	4,902	457	3,200
ARNETT SW	1	11,864	22.0	26	26	9.0	9.0	9.0	2,886	2,886	2,886	640	640
BINGER	1	13,938	6.0	6	6	11.0	11.0	11.0	7,151	7,151	7,151	160	160
BINGER NE	4	13,148	21.0	22	48	9.0	7.0	9.1	6,555	7,532	9,049	280	1,120
BINGER SOUTH	1	14,225	28.0	35	35	9.0	8.6	8.6	4,033	4,033	4,033	640	640
BISHOP	2	13,020	33.5	124	130	7.3	2.4	8.2	3,588	4,621	5,654	640	1,280
BRIDGEPORT	2	12,287	14.5	17	20	8.5	7.5	8.2	7,745	7,839	7,933	160	320
BROXTON NORTH	1	19,350	60.0	73	73	3.0	4.1	4.1	4,849	4,849	4,849	80	80
CAMARGO	1	11,066	27.0	30	30	6.8	7.2	7.2	1,669	1,669	1,669	320	320
CAMARGO NW	5	11,131	23.6	38	78	7.5	4.6	7.6	3,848	4,895	5,668	384	1,920
CANTON NW	33	8,600	18.5	6	38	11.6	5.0	15.6	20	1,075	4,894	78	2,560
CARLTON LAKE WEST	1	11,943	8.0	12	12				4,400	4,400	4,400	640	640
CEMENT	5	13,967	19.0	32	114	12.5	7.7	17.0	3,600	7,129	9,329	384	1,920
CESTOS	4	9,153	11.8	11	46	13.7	10.5	15.5	2,316	3,292	4,056	427	1,280
CESTOS SE	8	9,418	12.5	12	81	11.1	2.0	16.0	975	3,220	5,260	280	2,240
CESTOS SW	2	10,062	26.5	16	44	9.2	10.0	13.0	3,217	3,217	3,217	320	640
CHESTER WEST	1	7,961	11.0	11	11	19.0	19.0	19.0	312	312	312	160	160
CHEYENNE WEST	2	16,620	16.5	22	24	8.5	5.4	11.0	6,428	7,571	8,713	640	1,280
COLONY NW	16	15,856	16.6	12	66	9.6	3.0	13.0	2,650	9,301	12,904	560	8,960
CRANE SE	3	10,683	14.0	12	20	7.5	5.7	9.0	4,345	4,698	4,998	373	1,120
CRAWFORD NW	2	14,633	20.0	30	58	9.0	7.0	10.0	3,707	7,107	10,506	640	1,280
CUSTER CITY EAST	19	12,502	17.8	10	110	7.7	2.5	11.0	185	4,500	7,214	404	7,680
CUSTER CITY NORTH	3	11,710	31.7	10	54	6.5	5.0	6.9	4,000	5,010	5,996	160	480
CUSTER CITY SE	3	13,176	30.7	27	41	6.6	3.5	9.0	4,569	5,865	8,319	327	980
CUSTER CITY SOUTH	1	13,276	10.0	10	10	4.6	4.6	4.6	3,304	3,304	3,304	320	320
EAGLE CITY SOUTH	20	9,939	12.1	6	36	10.0	5.0	15.0	2,332	5,323	7,384	452	9,040
EAGLE CITY WEST	4	9,616	12.5	17	34	10.3	6.8	12.3	2,090	3,155	4,053	280	1,120
EAKLY-WEATHERFORD	13	15,710	39.5	18	135	8.4	3.8	11.0	3,100	7,234	14,358	388	5,040
ELK CITY	6	20,282	56.3	20	176	6.2	2.0	8.9	10,354	13,931	18,358	640	3,840
ELM GROVE	12	12,125	14.7	8	38	7.5	4.0	9.0	1,935	5,476	8,314	280	3,360
FAY EAST	52	10,584	20.8	4	76	8.4	3.0	15.0	1,000	5,238	8,066	249	12,960
FONDA NE	1	8,060	8.0	8	8	7.0	7.0	7.0				160	160
FONDA SE	28	8,704	19.3	7	84	11.0	6.0	17.0	75	1,798	4,861	83	2,240
FONDA SW	3	8,690	9.3	11	16	11.7	7.0	14.0	125	125	125	80	240
GAGE	81	8,787	19.9	3	114	9.2	3.0	18.0	450	2,297	4,281	412	32,560
GAGE SE	6	9,773	28.3	24	57	7.6	3.4	11.0	1,567	2,806	3,945	293	1,760
GEARY SW	1	11,405	4.0	28	28	7.4	5.3	5.3	2,387	2,387	2,387	160	160
GOODWIN SOUTH	13	11,284	28.4	8	104	6.8	4.0	10.9	1,762	3,139	4,821	234	3,040
GOODWIN WEST	2	10,487	16.0	20	28	7.0	5.0	5.0	300	300	300	640	1,280
GRAND WEST	9	12,397	20.8	7	100	9.7	3.0	16.0	600	4,112	6,480	560	3,360
GREENFIELD NW	5	9,986	18.2	3	54	8.6	6.5	10.9	5	3,960	7,790	184	920
GREENFIELD WEST	1	10,742	34.0	70	70	8.0	6.9	6.9	4,338	4,338	4,338	640	640
HAMMON EAST	9	15,021	45.2	15	138	6.6	3.9	10.0	3,263	7,180	9,666	196	1,760
HARMON EAST	13	10,299	13.2	6	104	8.4	2.0	15.0	850	2,833	4,582	507	6,080
HARMON NW	2	10,778	26.0	30	46	11.8	6.3	11.7	450	1,993	3,535	640	1,280
HARMON SE	3	11,317	30.7	37	252	8.5	4.6	6.8	1,500	3,073	4,831	427	1,280
HIGGINS SOUTH	4	12,371	17.5	26	51	8.7	6.0	9.8	3,372	4,154	5,650	640	2,560
HUCMAC	2	9,287	24.5	28	73	7.8	6.2	6.8	30	90	150	80	160
HUCMAC NORTH	15	9,029	17.3	8	44	10.6	5.3	16.0	25	244	1,150	80	1,200

Field Data Elements

Cum	Cum	Last 12 Months		Ultimate recovery	SUM	SUM	Balance (BCF) note: (-) =minus	
Gas (BCF)	Oil (BBLS)	Gas (BCF)	Oil (BBLS)	(BCFE) = VUGE	PGIP (BCF)	SGIP (BCF)	PGIP - VUGE	SGIP - VUGE
0.624	2,846	0.000	0	0.627	13.915	15.307	13.288	14.679
0.294	84	0.011	0	0.383	2.106	2.106	1.723	1.723
0.021	93	0.000	0	0.021	3.972	6.932	3.951	6.911
0.538	62,588	0.032	2,805	0.792				
2.577	382	0.323	0	5.125	13.350	16.986	9.935	11.861
2.445	5,031	0.021	0	2.615	13.257	20.237	10.642	17.621
2.009	230	0.045	0	2.363	30.191	45.954	27.827	43.591
1.226	1,026	0.056	0	1.667	0.968	1.453	-0.699	-0.214
35.159	21,414	2.521	0	55.119	85.964	113.066	32.765	57.947
2.256	375	0.222	0	4.010	19.082	25.969	15.072	21.959
0.441	0	0.028	0	0.660	10.685	23.101	10.025	22.441
0.958	16,167	0.039	578	1.291	1.734	3.870	0.443	2.579
1.181	326	0.037	0	1.477	7.487	10.655	6.010	9.178
5.343	6,797	0.107	0	6.195	31.255	64.569	25.061	58.374
0.266	0	0.000	0	0.266	6.250	7.387	5.984	7.120
0.003	0	0.000	0	0.003	1.215	1.215	1.212	1.212
2.688	107,997	0.282	0	5.131	17.379	27.711	14.469	22.580
0.521	0	0.000	0	0.521	10.838	12.945	10.316	12.424
0.261	0	0.000	0	0.261	19.271	48.482	19.009	48.220
7.392	243	0.118	0	8.325	4.891	5.868	-3.434	-2.457
0.812	91	0.032	0	1.068	0.795	1.316	-0.272	0.248
0.060	354	0.000	0	0.060	1.665	1.970	1.605	1.910
2.748	118,272	0.053	188	3.201	16.946	42.231	14.864	39.030
9.514	1,477,889	0.298	21,671	12.382	8.011	8.545	0.092	-3.837
0.152	0	0.000	0	0.152				
24.537	654,584	0.929	14,127	33.916	50.538	183.627	22.197	149.711
3.015	5,546	0.000	0	3.021	12.015	23.780	8.994	20.760
11.436	732,621	0.045	46,557	12.484	16.628	25.942	4.256	13.458
0.707	0	0.052	0	1.121	0.998	2.778	0.991	1.656
1.942	1,080	0.131	157	2.977	0.199	0.199	-2.777	-2.777
2.177	0	0.051	0	2.583	16.441	23.074	13.858	20.491
46.250	1,333	2.311	163	64.507	140.774	271.353	76.266	206.846
0.753	43,193	0.044	2,273	1.183	2.821	3.528	2.019	2.345
2.834	0	0.057	0	3.285	22.814	40.870	19.530	37.585
20.020	179,755	0.641	3,430	25.387	72.378	97.167	46.991	71.780
0.694	3,925	0.019	0	0.848	6.879	9.028	6.106	8.180
4.975	11,468	0.135	0	6.061	15.956	15.974	9.895	9.913
0.631	1,137	0.029	0	0.859	0.307	0.307	-0.552	-0.552
17.573	310,524	0.597	3,602	22.881	79.183	107.630	68.976	84.748
1.998	23,979	0.020	170	2.189	5.804	11.177	3.615	8.987
25.111	24,080	0.689	1,241	30.636	115.547	136.551	91.264	105.915
47.416	0	3.841	0	77.756	165.466	202.521	118.381	124.765
7.120	18,349	0.035	68	7.440	35.227	43.929	27.988	36.489
104.868	792,744	3.470	11,279	133.867	160.561	186.477	33.845	52.610
0.582	19,713	0.024	539	0.769				
4.529	967,467	0.167	14,177	6.058	6.523	7.260	3.134	1.202
0.240	209,115	0.009	6,316	0.314	0.015	0.048	-0.010	-0.266
47.757	182,726	1.339	2,492	58.509	161.355	314.308	102.846	255.798
12.324	101,243	0.601	0	17.202	12.261	18.596	-4.941	1.395
0.035	1,947	0.000	0	0.037	0.089	0.448	0.053	0.411
19.960	8,235	0.186	0	21.434	16.995	21.575	-4.439	0.141
0.622	59,894	0.001	718	0.635	0.580	0.658	-0.055	0.022
19.535	1,794	0.556	0	23.927	33.049	52.772	13.880	28.846
0.460	28,482	0.000	0	0.479	12.088	17.527	11.608	17.048
0.055	139	0.000	0	0.055	9.459	16.796	9.404	16.741
10.908	0	1.208	0	20.450	37.963	47.236	17.513	26.786
12.903	280,148	0.324	15,091	15.915	29.447	62.440	13.531	46.525
0.172	6,108	0.000	0	0.178	28.538	30.754	28.360	30.576
2.030	11,057	0.063	0	2.541	14.845	36.905	12.303	34.364
0.751	34,002	0.001	164	0.796	16.378	45.608	15.581	44.812
0.062	69,429	0.000	1,365	0.064	0.058	0.100	-0.007	0.036
0.930	1,279,552	0.021	2,179	1.205	0.398	0.500	-0.729	-0.705

(continued on next page)

Table A5-4. — Primrose

Field	Well Count	Avg Depth	Avg Perf Thickness ft	Saturated Thickness Min (ft)	Saturated Thickness Max (ft)	Avg Perf Porosity %	Saturated Porosity Min (%)	Saturated Porosity Max (%)	Initial Pressure (PSI)[1] Min	Initial Pressure (PSI)[1] Avg	Initial Pressure (PSI)[1] Max	Observed Spacing Avg (ac)	Observed Spacing Sum (ac)
HUCMAC NW	16	9,217	16.6	6	27	8.0	5.0	12.1	50	924	2,000	90	1,440
HUCMAC SE	3	9,694	6.3	6	14	7.4	4.0	8.7	1,600	2,767	3,350	320	960
HUCMAC SOUTH	11	9,567	18.1	12	55	9.4	5.0	15.9	1,100	1,800	2,500	131	1,440
HUCMAC SW	2	9,294	19.0	11	27	7.0	5.0	9.0	35	268	500	120	240
INDIANAPOLIS	1	14,308	8.0	18	18	12.0	8.0	8.0	8,380	8,380	8,380	640	640
LEONEL SE	3	9,332	11.0	12	16	12.1	8.7	11.8	1,800	2,934	3,901	373	1,120
LONGDALE WEST	1	8,448	14.0	14	14	13.5	13.5	13.5	2,100	2,100	2,100	80	80
LOOKEBA	7	13,807	29.4	7	100	7.3	3.6	9.0	3,174	6,386	9,643	274	1,920
LOOKEBA EAST	7	12,926	8.9	5	52	7.7	4.0	8.5	4,300	6,339	9,198	297	2,080
MACKIE	1	15,666	18.0	40	40	4.0	4.4	4.4	6,897	6,897	6,897	640	640
MAYFIELD NE	2	19,472	28.0	15	55	6.4	4.6	5.3	9,171	11,481	13,792	640	1,280
MILDER	15	9,060	19.3	10	62	8.3	3.0	11.9	1,626	2,770	4,100	427	6,400
MILDER SW	1	9,504	125.0	0	0				700	700	700	640	640
MOCANE-LAVERNE	46	8,434	12.3	5	43	8.4	2.0	12.4	600	1,934	3,018	388	17,440
MOORELAND SW	1	8,544	10.0	12	12	12.0	11.8	11.8	3,136	3,136	3,136	640	640
MOOREWOOD NE	2	14,302	37.5	32	116	7.1	3.9	9.4	4,483	5,179	5,874	480	960
MUTUAL SE	3	9,009	13.3	12	34	10.2	9.6	12.0	1,167	3,038	4,303	640	1,920
MUTUAL SW	4	9,917	92.8	8	160	10.9	9.0	9.8				640	2,560
MUTUAL WEST	6	9,111	7.7	5	20	10.6	6.1	15.0	3,050	3,497	3,850	213	1,280
NOBSCOT	1	9,956	29.0	32	32	11.2	11.2	11.2	1,164	1,164	1,164	160	160
NOBSCOT NE	2	10,007	11.0	12	30	7.9	5.9	6.3	50	1,600	3,150	640	1,280
NOBSCOT NW	24	10,301	13.1	6	42	8.4	3.6	13.0	10	2,565	5,212	340	8,160
OAKWOOD NORTH	93	9,381	18.7	7	76	10.5	3.3	18.0	20	2,609	5,466	167	15,400
OAKWOOD SE	5	9,677	15.2	10	62	11.4	7.3	13.9	350	2,691	4,388	112	560
OAKWOOD SW	5	9,905	15.0	16	42	9.0	6.2	9.1	270	724	1,950	128	640
OAKWOOD WEST	7	9,796	13.7	7	38	9.8	6.1	11.4	60	887	2,788	206	1,440
OKEENE NW	1	8,534	19.0	19	19	13.0	13.0	13.0	1,200	1,200	1,200	80	80
PEEK NE	7	11,854	23.9	10	120	8.1	2.9	10.3	500	3,590	5,134	549	3,840
PEEK SOUTH	2	13,388	49.5	161	165	7.3	5.3	7.2	3,579	3,586	3,592	640	1,280
PUTNAM	168	10,270	22.3	5	110	9.4	3.0	19.5	25	2,942	5,750	233	36,800
REYDON	1	15,450	20.0	60	60	4.0	3.0	3.0	7,231	7,231	7,231	640	640
SEILING NE	18	8,786	14.2	7	69	10.7	5.0	13.6	475	2,634	4,104	289	5,200
SEILING SW	6	9,317	10.7	6	35	9.8	5.6	15.4	2,293	3,118	3,911	400	2,400
SHARON NORTH	1	8,886	10.0	32	32	6.5	6.2	6.2	3,673	3,673	3,673	640	640
SHARON WEST	19	9,199	14.2	6	112	12.1	4.4	18.0	225	2,161	4,732	518	9,840
SHATTUCK	6	10,483	16.0	6	62	8.0	5.2	7.6	986	2,353	3,612	480	2,880
SHATTUCK WEST	5	9,814	26.4	8	57	7.0	3.0	10.0	280	2,504	4,534	640	2,560
SICKLES NORTH	2	13,535	18.5	35	49	8.3	5.8	7.5	2,681	5,724	8,766	240	480
SQUAW CREEK	10	11,655	14.8	8	72	10.9	4.7	15.0	2,744	5,594	7,580	528	5,280
STRONG CITY DISTRICT	3	14,987	33.3	12	102	10.7	6.3	17.0	2,264	5,127	8,569	640	1,920
TANGIER	49	8,945	19.0	7	84	10.2	2.0	16.0	275	2,435	4,038	473	22,720
THOMAS SOUTH	4	12,029	24.8	20	49	6.4	3.0	5.7	2,299	3,995	5,576	200	800
TOLAND NORTH	1	11,828	4.0	12	12	10.0	9.5	9.5	3,047	3,047	3,047	640	640
TOUZALIN	2	9,522	15.5	10	32	9.0	6.0	7.5	1,192	1,392	1,591	640	1,280
VERDEN	17	16,101	20.9	9	119	7.5	2.8	8.4	1,400	6,818	9,989	409	6,960
VICI NORTH	1	9,393	8.0	9	9	9.0	9.0	9.0	3,456	3,456	3,456	640	640
VICI SW	2	10,592	9.0	4	24	10.0	7.0	13.0	1,986	3,103	4,220	640	1,280
WASHITA CITY-CADDO	1	17,158	78.0	102	102	7.5	6.3	6.3	6,529	6,529	6,529	640	640
WATONGA-CHICKASHA	251	10,005	14.7	2	88	10.3	2.5	24.0	20	3,682	9,663	193	47,920
WATONGA WEST	2	9,351	8.0	8	10	14.6	11.0	17.0	6,296	6,296	6,296	640	1,280
WEATHERFORD	3	13,226	10.3	14	18	6.9	2.0	9.7	5,548	7,215	9,681	267	800
WOODWARD	7	8,409	20.9	12	48	9.6	5.0	12.0	950	2,295	3,040	549	3,840
WOODWARD NE	1	7,692	4.0	36	36	18.0	18.0	18.0	3,515	3,515	3,515	640	640
WOODWARD NORTH	10	7,813	15.3	10	46	12.8	8.0	19.0	200	2,572	4,646	576	5,760
WOODWARD SE	9	7,951	17.8	11	24	9.8	7.2	13.0	200	2,114	3,028	211	1,480
WOODWARD SOUTH	4	8,752	10.8	14	40	10.4	5.0	10.0	3,200	3,200	3,200	480	1,920
Grand Total	**1,364**	**10,362**	**19.1**	**2**	**252**	**9.5**	**2.0**	**24.0**	**5**	**3,580**	**18,358**	**298**	**398,620**

[1]Initial pressure data prioritized in this order: DST, BHP, SITP, FTP.

Source: Petroleum Information/Dwights LLC, ©1999. Data current to January 1999.

BCF	Billion cubic feet
BCFE	Billion cubic feet gas equivalent
PGIP	Perforated gas in place
SGIP	Saturated gas in place
VUGE	Volume of ultimate gas equivalent

Field Data Elements *(continued)*

Cum	Cum	Last 12 Months		Ultimate recovery	SUM	SUM	Balance (BCF) note: (-) =minus	
Gas (BCF)	Oil (BBLS)	Gas (BCF)	Oil (BBLS)	(BCFE) = VUGE	PGIP (BCF)	SGIP (BCF)	PGIP - VUGE	SGIP - VUGE
3.037	796,421	0.113	11,342	4.041	1.530	1.563	-0.243	-2.479
1.095	132,739	0.000	1,127	1.232	2.268	2.825	1.035	1.592
1.764	886,764	0.031	5,751	2.211	1.599	1.891	0.414	-0.320
0.046	152,065	0.000	7,494	0.060	0.172	0.172	0.111	0.111
0.962	0	0.041	0	1.283	6.269	9.404	4.986	8.121
2.924	55,480	0.327	0	5.560	6.482	7.704	0.921	2.144
0.619	19,161	0.033	512	0.895	0.579	0.579	-0.315	-0.315
2.885	42,990	0.056	1,410	3.338	9.878	13.258	6.550	9.920
6.029	8,997	0.285	298	8.297	5.797	8.884	-2.500	0.587
0.117	0	0.002	0	0.137	2.666	6.562	2.529	6.425
2.308	0	0.013	0	2.412	52.110	55.989	49.699	53.577
17.971	129,166	1.576	603	30.560	34.471	43.166	3.911	12.606
0.892	3,477	0.016	0	1.022				
48.493	317,366	2.184	6,701	65.989	43.651	61.090	-22.338	-4.900
0.103	2,664	0.000	0	0.105				
2.732	0	0.159	0	3.991	15.807	22.456	11.816	18.464
3.312	6,525	0.000	0	3.321	16.450	25.413	13.129	22.092
1.111	0	0.118	0	2.046				
4.928	42,941	0.016	0	5.107	2.381	3.212	-2.726	-1.895
0.000	83,110	0.000	0	0.031	0.999	1.102	0.968	1.071
0.003	34,913	0.000	780	0.010	2.963	5.508	2.953	5.498
17.024	447,572	0.148	1,919	18.548	27.679	41.804	9.131	23.256
101.192	3,513,180	2.244	22,155	122.700	110.443	144.585	-9.703	21.885
3.022	124,418	0.007	0	3.148	5.118	7.884	2.998	4.736
0.229	233,372	0.016	4,665	0.402	0.397	0.593	-0.004	0.191
0.160	214,969	0.000	1,221	0.173	3.016	3.837	2.843	3.664
0.638	38,449	0.026	1,925	0.863	0.435	0.435	-0.428	-0.428
4.366	35,226	0.052	0	4.800	33.100	56.112	28.451	51.311
2.208	0	0.059	0	2.677	21.419	60.483	18.741	57.806
376.861	3,833,252	9.851	62,601	457.789	369.051	489.521	-62.935	31.732
0.219	0	0.003	0	0.244	1.422	3.200	1.178	2.956
25.008	271,033	0.336	348	27.808	14.672	33.378	-13.001	5.570
1.609	34,535	0.000	0	1.631	16.315	30.098	14.684	28.467
0.029	1,354	0.000	0	0.030	1.692	5.163	1.661	5.133
17.636	425,901	0.396	5,704	21.146	48.157	61.939	27.140	40.793
1.720	5,204	0.003	0	1.747	9.575	18.698	7.828	16.951
7.767	41,254	0.098	692	8.605	12.473	15.578	3.869	6.973
4.805	213	0.037	0	5.095	5.128	8.938	0.034	3.844
10.091	16,827	0.286	0	12.387	67.678	100.967	56.064	88.579
2.823	603	0.133	0	3.874	25.288	30.977	21.413	27.102
25.764	727,469	0.618	12,503	31.162	135.073	203.888	103.917	172.727
3.935	60,714	0.723	326	9.742	3.256	4.538	-3.713	-5.204
0.114	1,051	0.000	0	0.115	0.844	2.404	0.728	2.289
0.372	710	0.098	0	1.143	3.786	4.471	2.642	3.328
25.625	79,813	2.413	3,570	44.907	113.878	232.154	69.849	187.247
0.298	0	0.000	0	0.298	2.738	3.080	2.440	2.783
4.939	88,397	0.101	360	5.859	3.709	4.902	-2.150	-0.957
0.298	155	0.007	0	0.352	36.873	40.633	36.522	40.281
473.172	9,391,883	8.848	51,940	549.522	473.358	718.954	-25.304	169.432
0.677	17,561	0.000	0	0.712	4.138	4.974	3.426	4.262
0.416	211	0.000	0	0.416	6.554	7.090	6.138	6.674
4.048	24,899	0.088	1,656	4.769	10.786	11.157	6.169	6.388
0.705	15,533	0.000	0	0.723	2.933	26.396	2.210	25.673
4.380	116,322	0.003	0	4.480	48.792	69.435	44.312	64.955
4.875	25,019	0.000	0	4.898	7.469	7.582	2.570	2.684
0.066	9,870	0.000	0	0.067	3.489	9.232	3.422	9.165
1,765.823	**30,400,042**	**53.384**	**358,953**	**2,211.772**	**3,458.608**	**5,303.175**	**1,422.527**	**3,091.404**

NOTE: A minus (–) preceding production in the "Balance" columns indicates over-production in regard to volumetric reserve calculations. Positive numbers indicate under-production in regard to the particular field AND is an estimate of **POTENTIALLY REMAINING UNPRODUCED GAS RESERVES.**

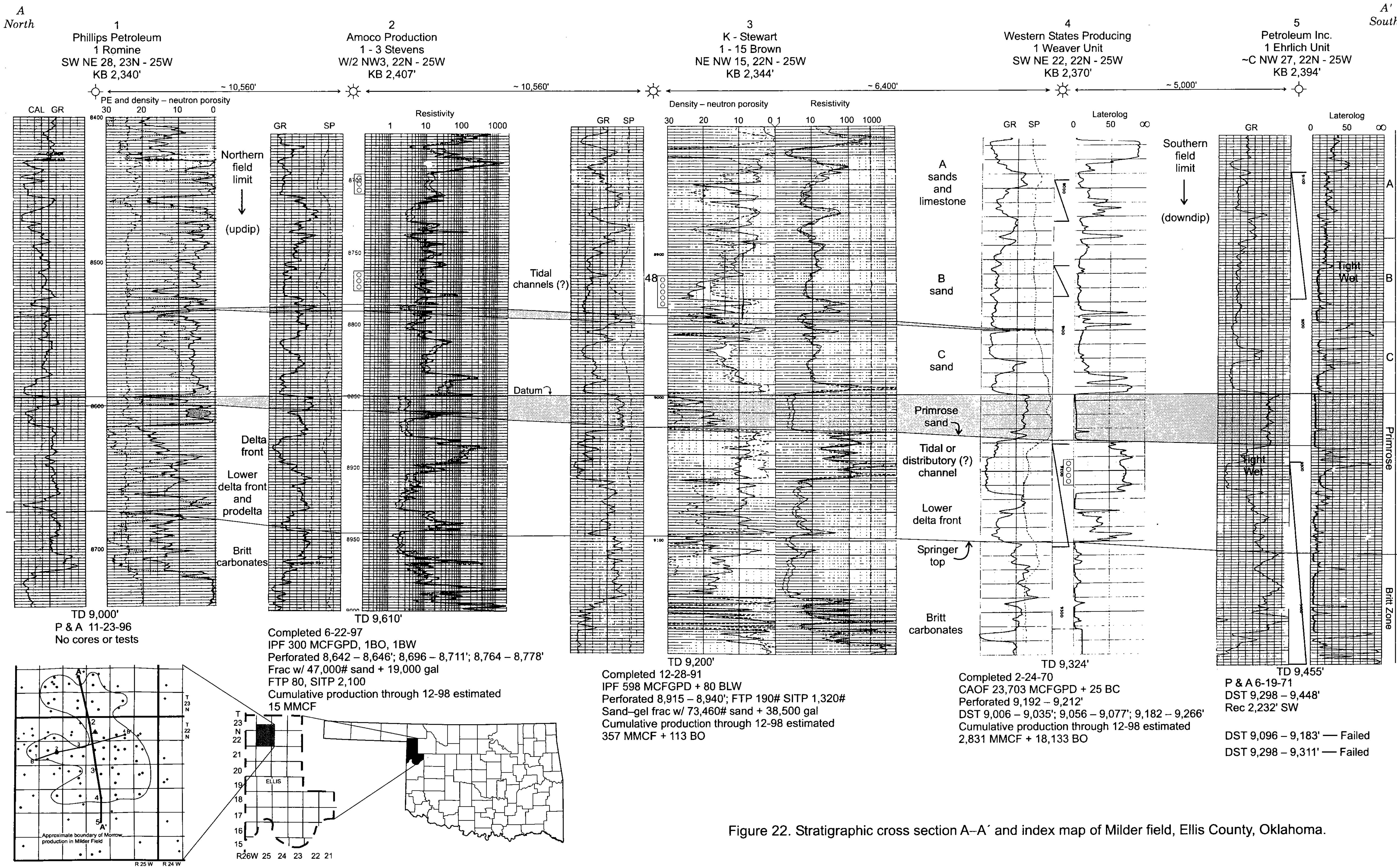
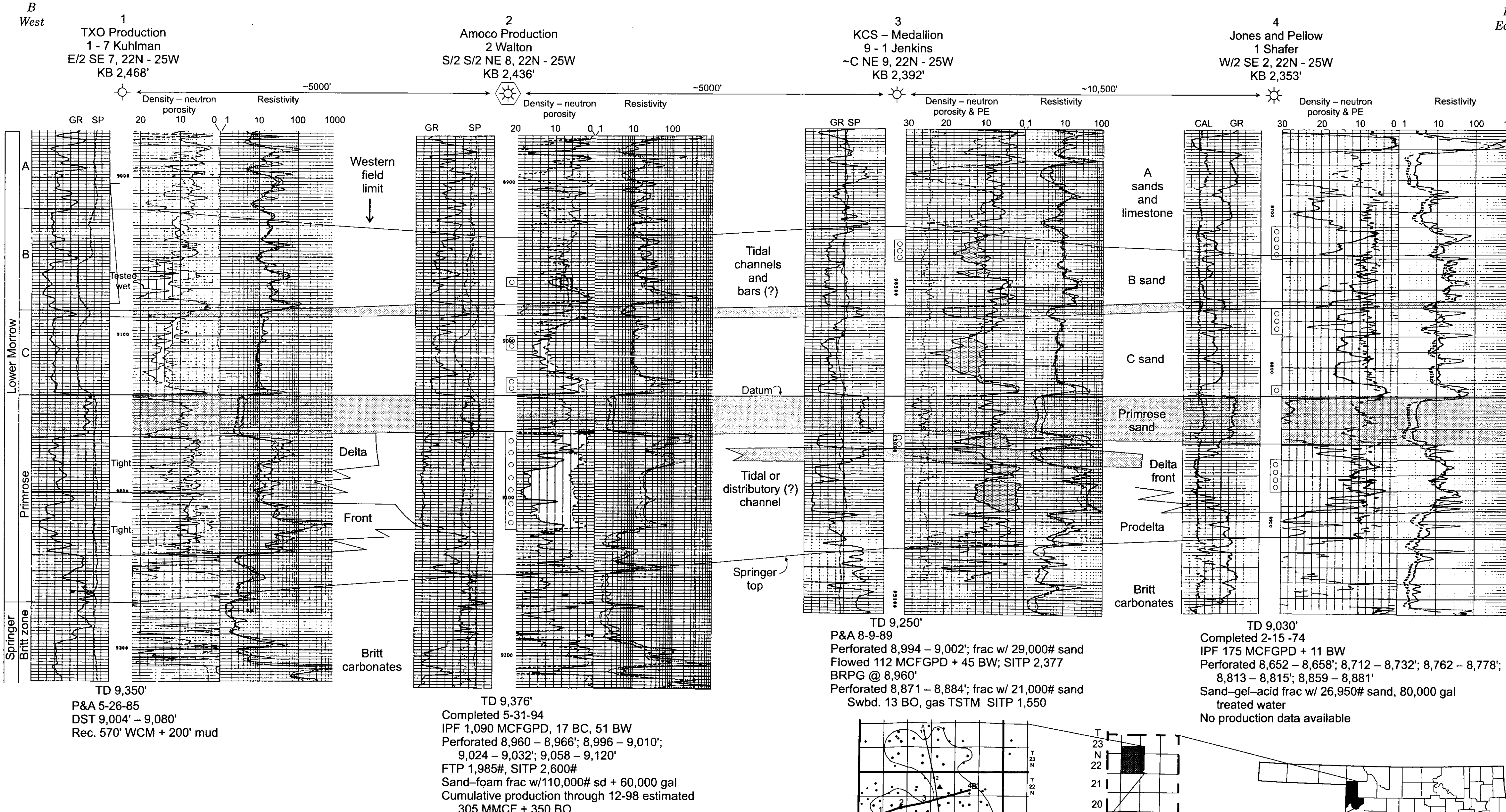


Figure 22. Stratigraphic cross section A–A′ and index map of Milder field, Ellis County, Oklahoma.



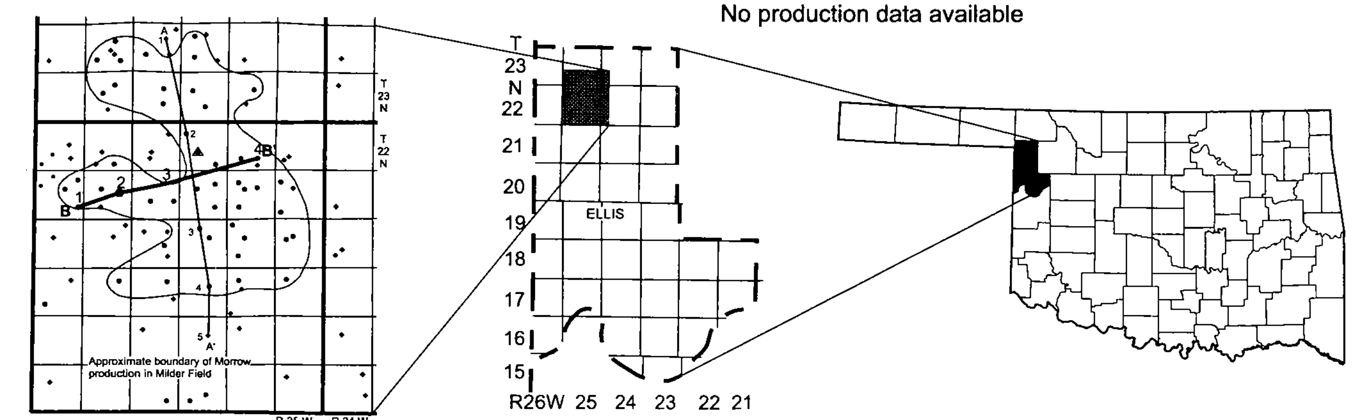


Figure 23. Stratigraphic cross section B–B′ and index map of Milder field, Ellis County, Oklahoma.

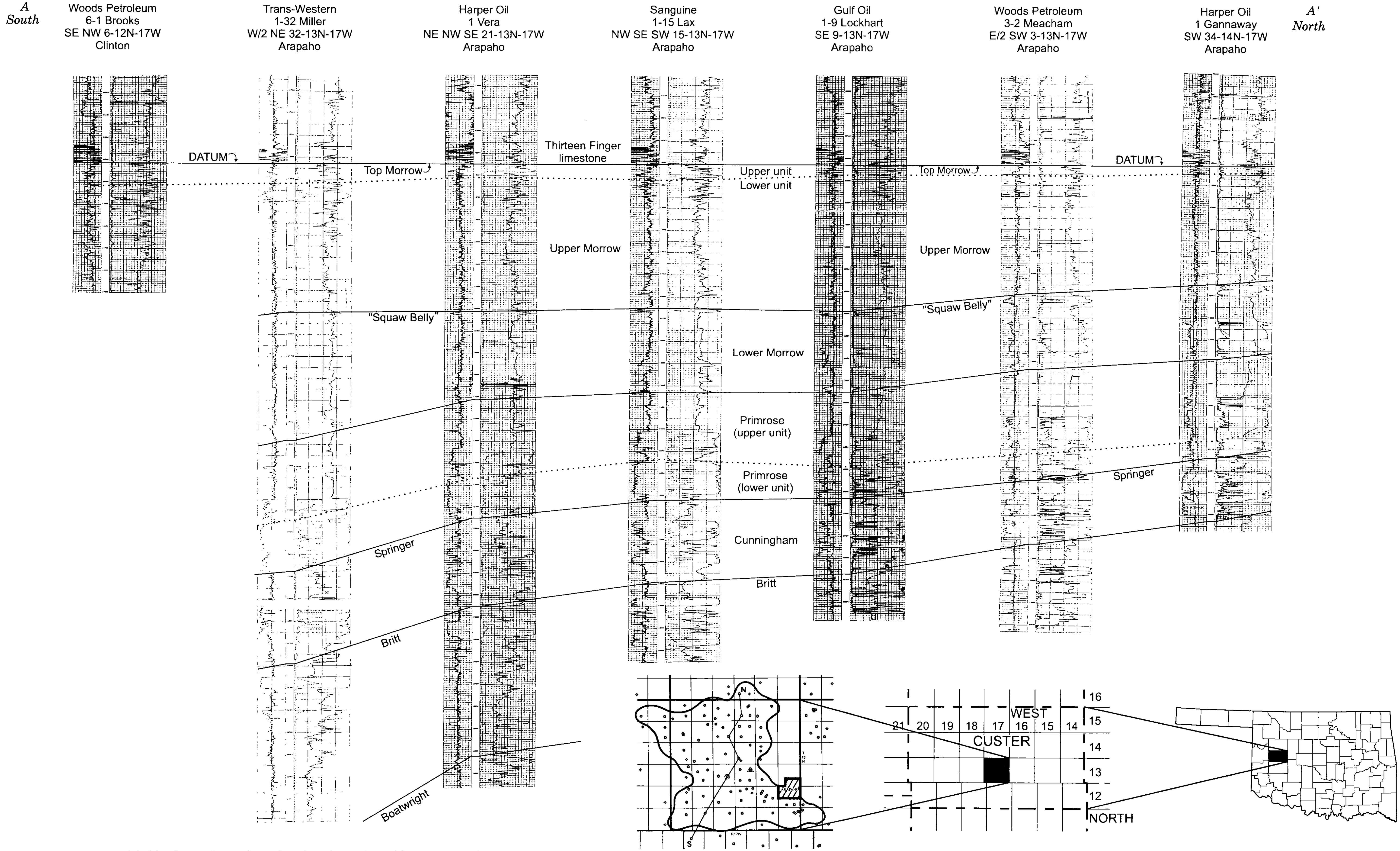
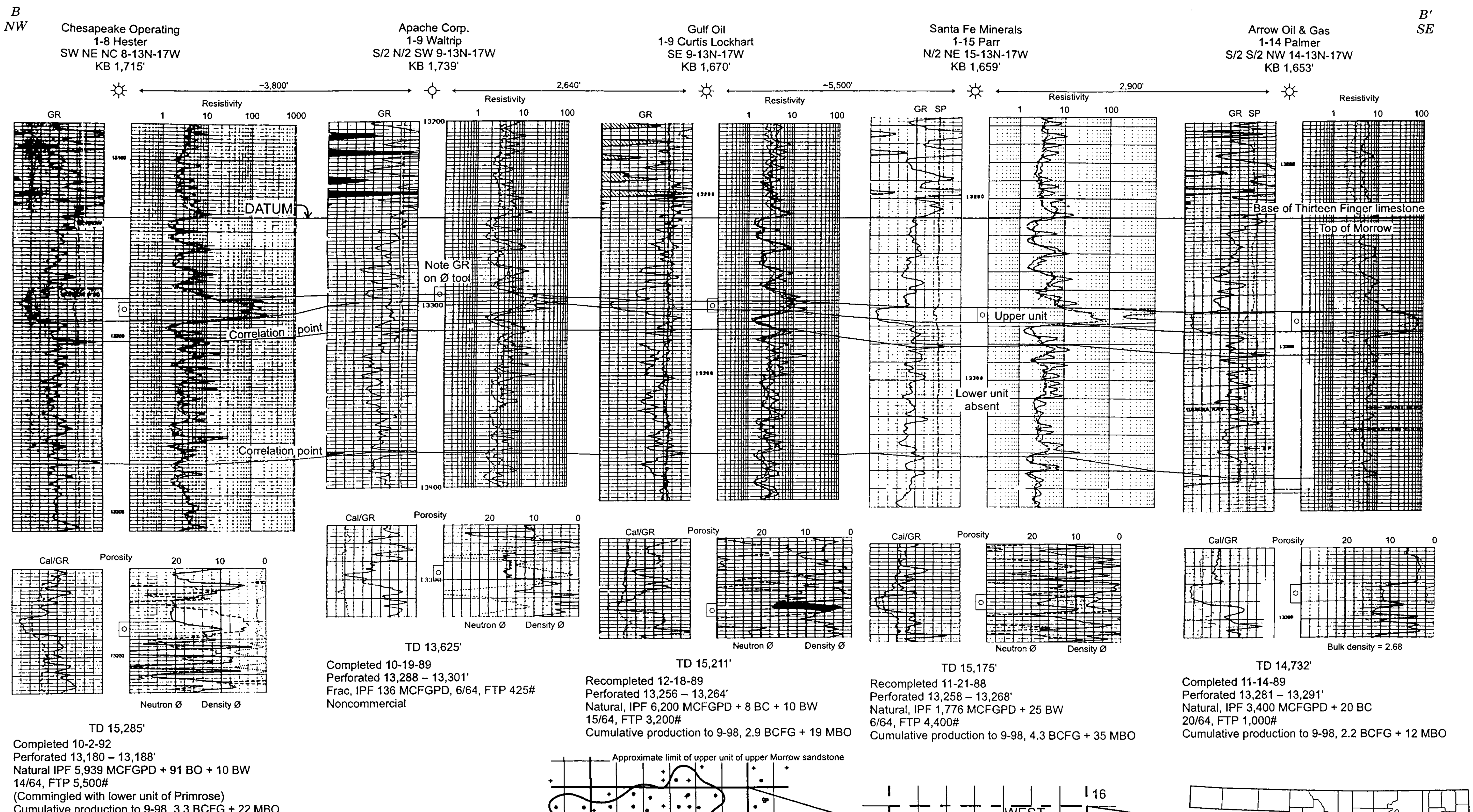


Figure 38. North-south portion of regional stratigraphic cross section A-A′ in Arapaho field and index map, Custer County, Oklahoma.



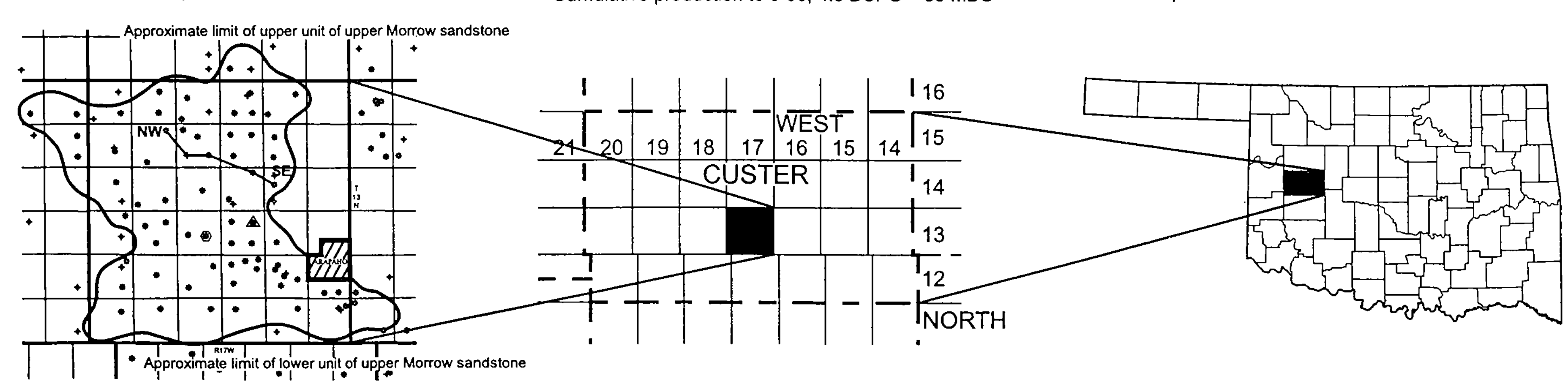


Figure 41. Stratigraphic cross section B–B′ (NW–SE), showing the upper Morrow interval and index map of Arapaho field, Custer County, Oklahoma

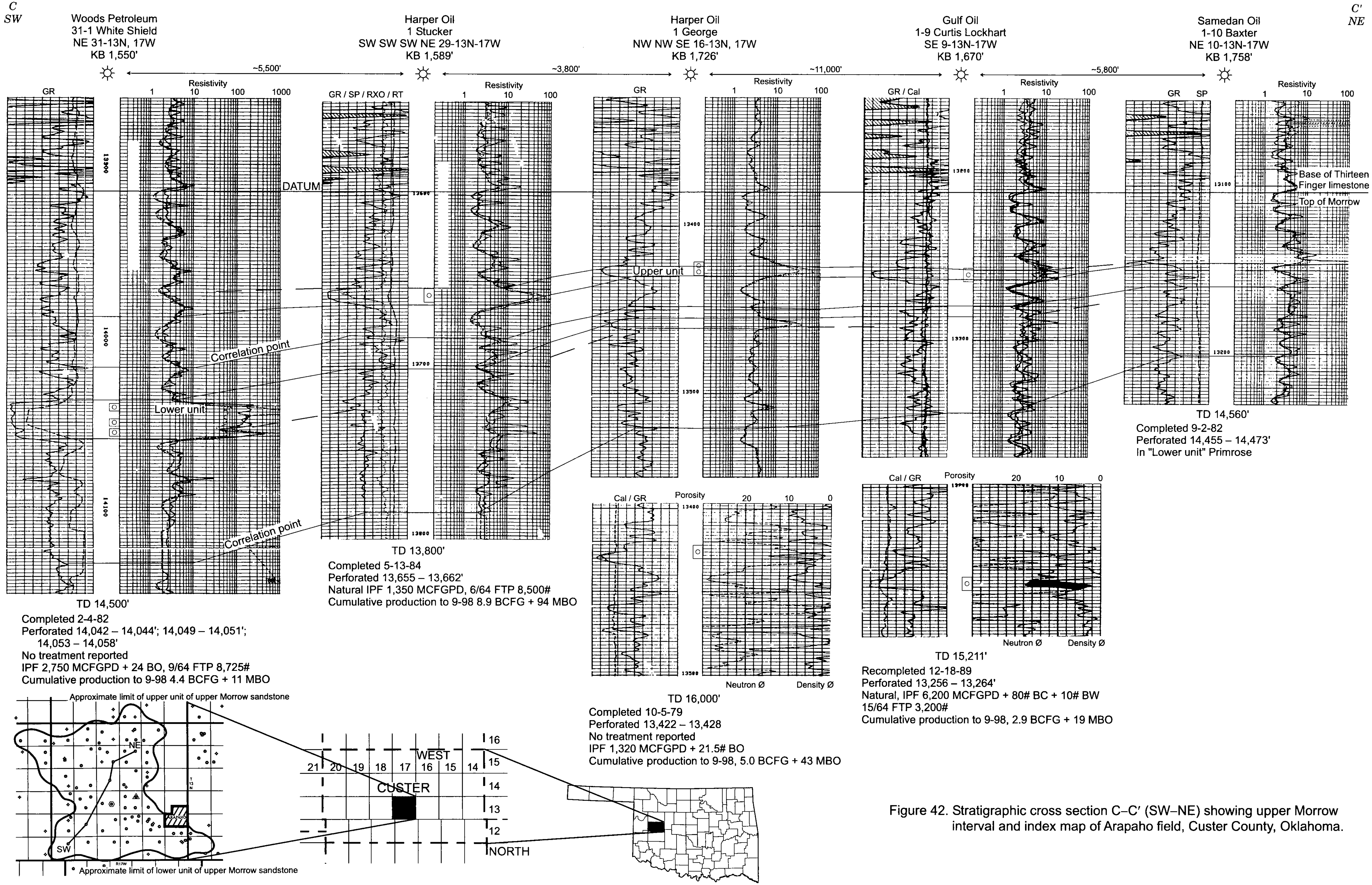


Figure 42. Stratigraphic cross section C–C′ (SW–NE) showing upper Morrow interval and index map of Arapaho field, Custer County, Oklahoma.

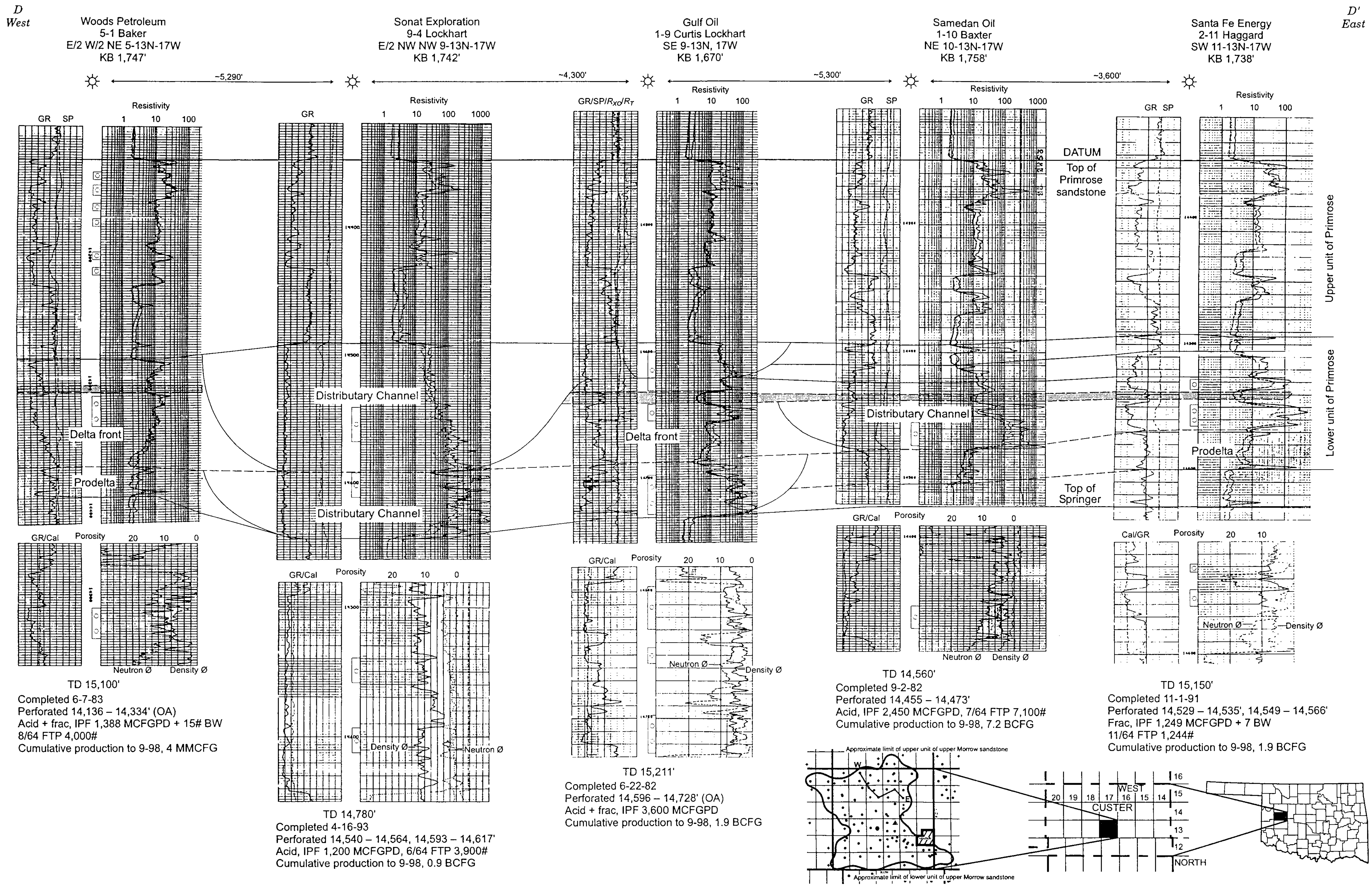


Figure 53. Stratigraphic cross section D–D′ showing the Primrose interval and index map of Arapaho field, Custer County, Oklahoma.

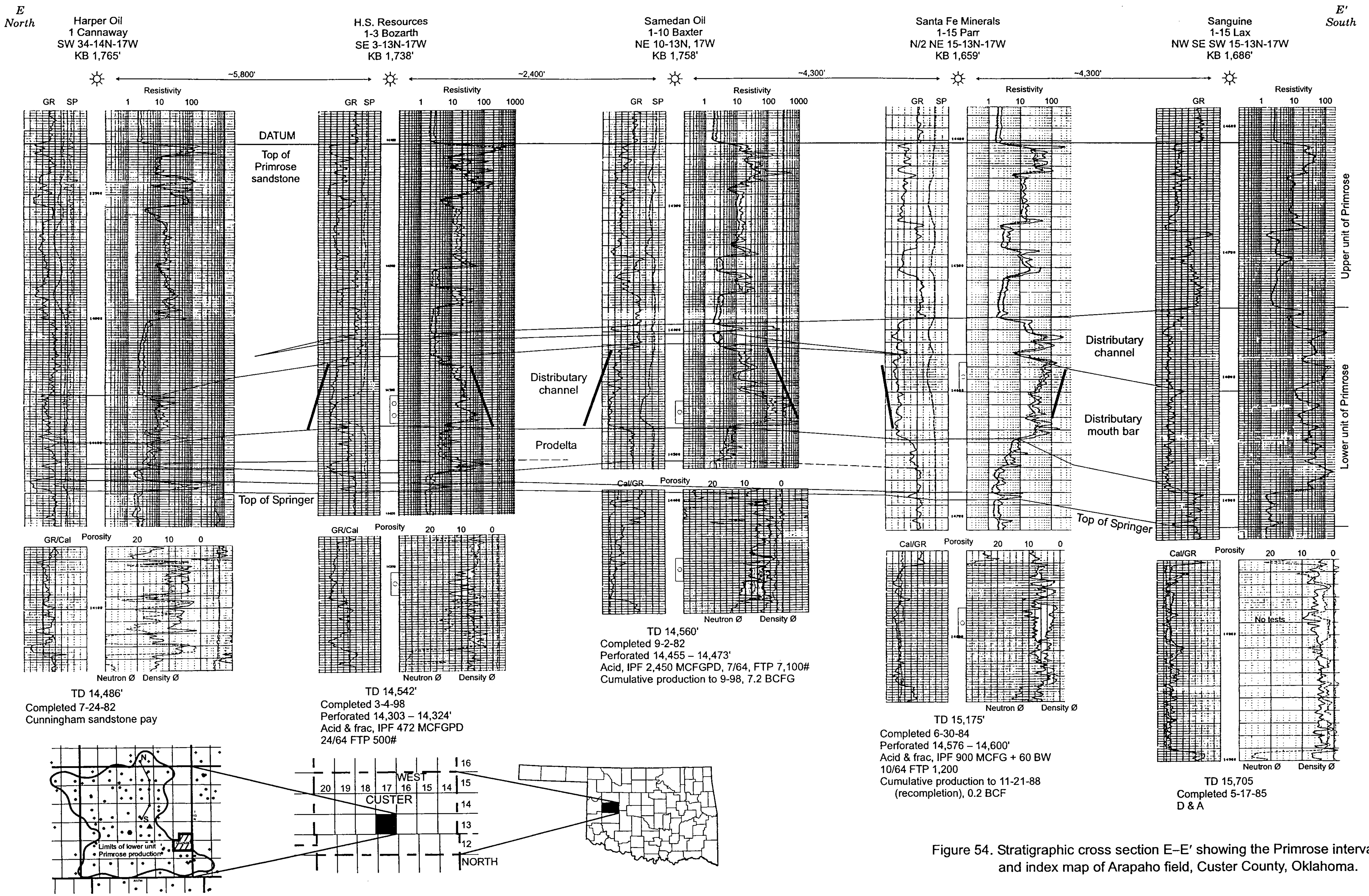
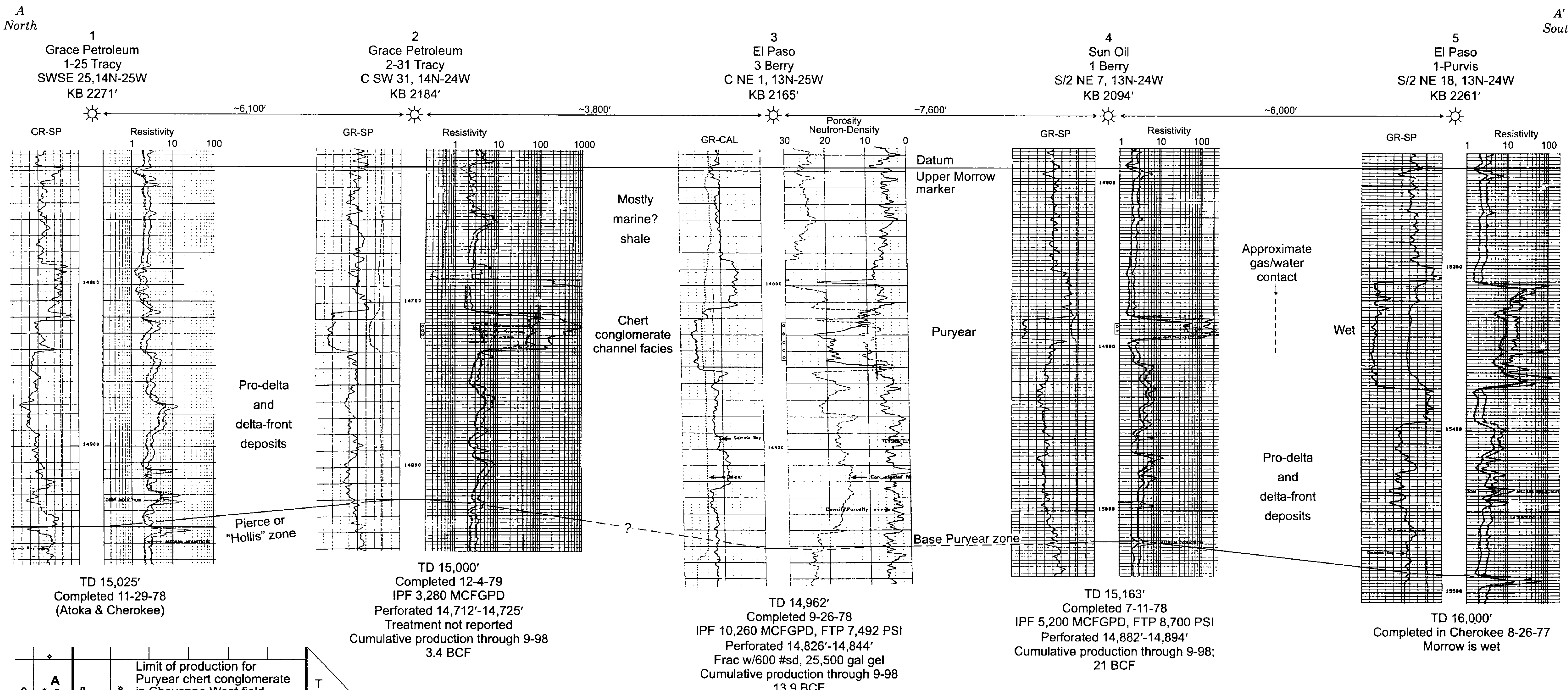


Figure 54. Stratigraphic cross section E–E′ showing the Primrose interval and index map of Arapaho field, Custer County, Oklahoma.



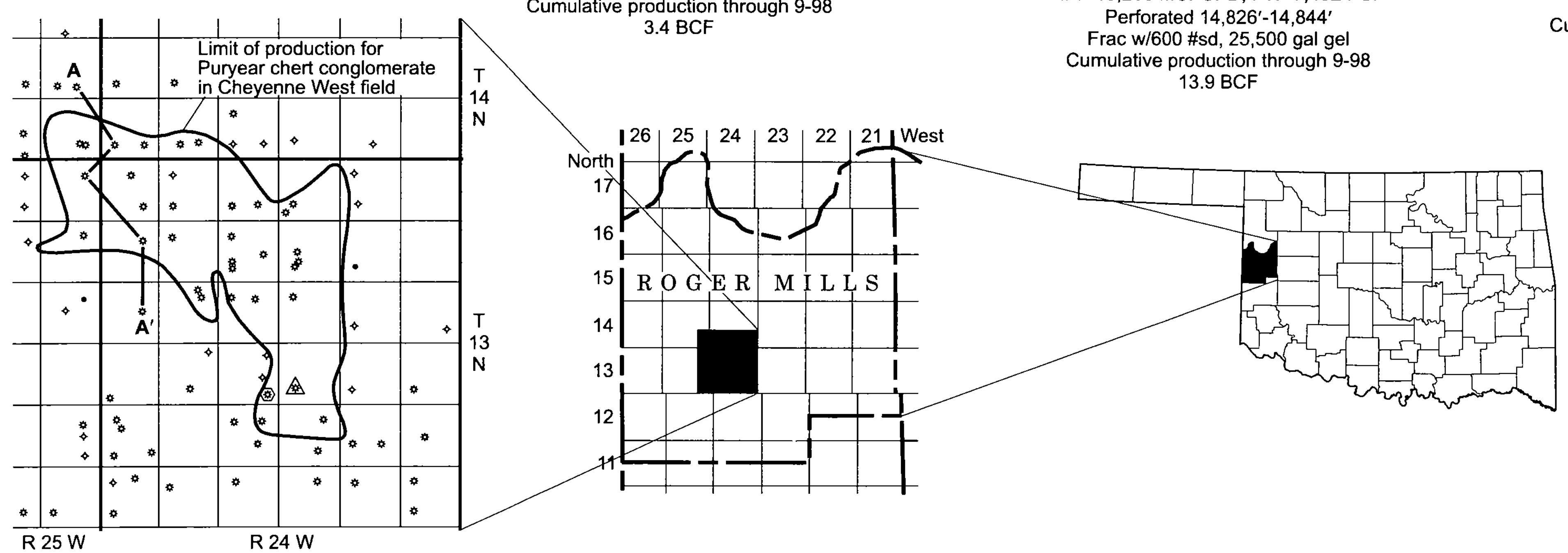


Figure 66. Stratigraphic cross section A–A′ and index map of Cheyenne West field, Roger Mills County, Oklahoma.

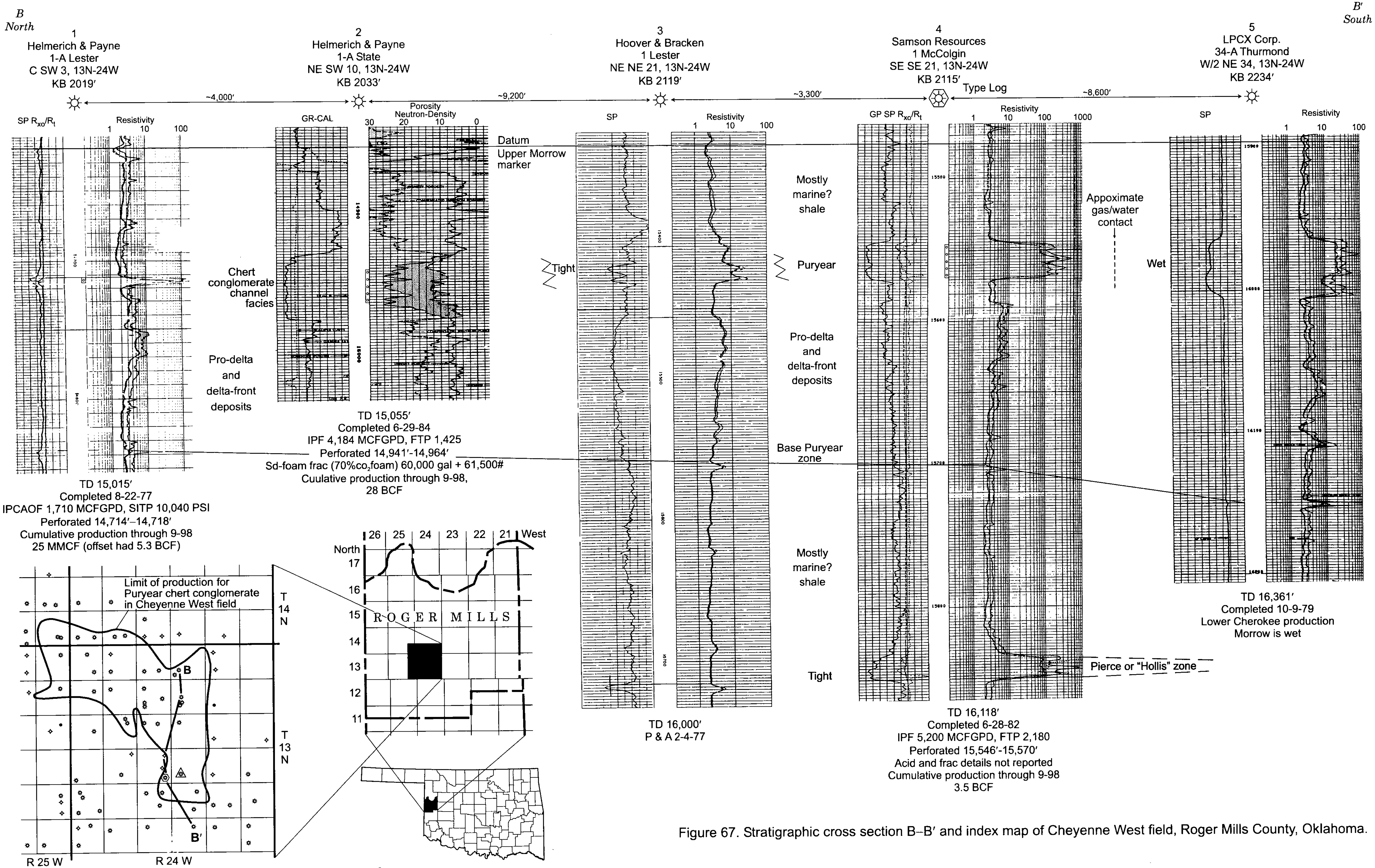


Figure 67. Stratigraphic cross section B–B′ and index map of Cheyenne West field, Roger Mills County, Oklahoma.