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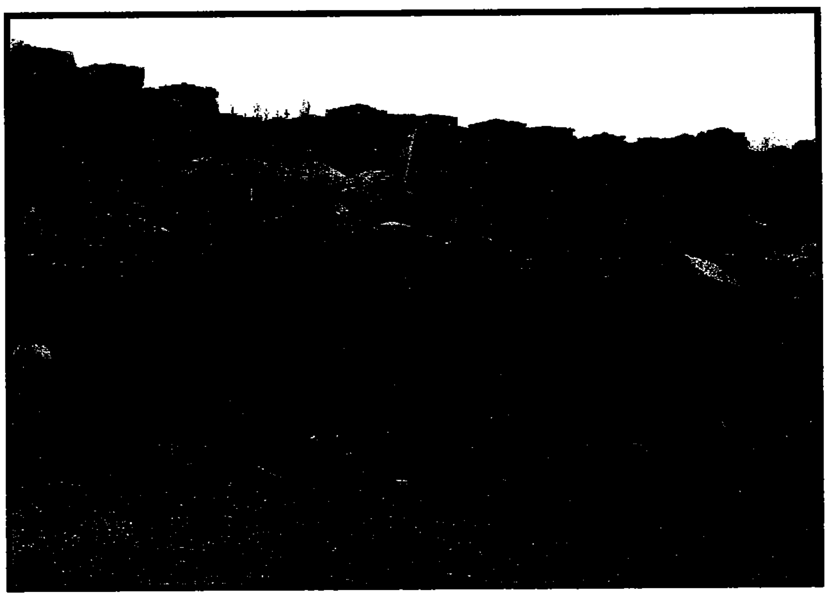
The Hartshorne Play in Southeastern Oklahoma: Regional and Detailed Sandstone Reservoir Analysis and Coalbed-Methane Resources



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Charles J. Mankin, *Director*

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The Hartshorne Play in Southeastern Oklahoma: Regional and Detailed Sandstone Reservoir Analysis and Coalbed-Methane Resources

PART I.—Overview of the Hartshorne Play in Oklahoma
by
Richard D. Andrews

PART II.—Coal as Gas-Source Rock and Reservoir, Hartshorne Formation, Oklahoma
by
Brian J. Cardott

PART III.—The Hartshorne Formation of Arkansas
by
Taylor Storm

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.

To complement the Hartshorne workshop, a two-day field trip was conducted in southeastern Oklahoma. The information presented during the field trip is contained in a companion publication, **Guidebook to the Geology of the Hartshorne Formation, Arkoma Basin, Oklahoma,** *by Neil H. Suneson (OGS Guidebook 31).*

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SPECIAL PUBLICATION SERIES

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

Front Cover

A distributary channel in the Hartshorne Formation cuts down into the underlying distributary mouth bar (delta front). The horizontal and uniformly bedded marine sandstone beds are being quarried for building stone, whereas the massive-bedded sandstone in the channel is of little commercial value.

The photograph was taken at the Green Country Stone Quarry near Rock Island in far eastern Oklahoma, on the south side of State Highway 120. This location is one of several stops included in the Hartshorne field trip that complements this study of the Hartshorne play (see OGS Guidebook 31, *Guidebook to the Geology of the Hartshorne Formation, Arkoma Basin, Oklahoma* [Suneson, 1998]).

Photograph by Neil H. Suneson

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PART I

Overview of the Hartshorne Play in Oklahoma

Richard D. Andrews
Oklahoma Geological Survey

INTRODUCTION

The Hartshorne (pronounced Harts´-horn) Formation was first named in 1899 by Taff from exposures of coal, sandstone, and shale near the town of Hartshorne, Oklahoma. This area gained attention geologically before statehood because of widespread coal deposits that were mined within parts of the Hartshorne–Kiowa syncline, which trends just north of the city of Hartshorne. Taff did not designate a type section in this area, even though the Hartshorne Formation is considerably thicker here than in all other places along the outcrop belt. This may be for the best, as there are much better exposures of the Hartshorne Formation elsewhere in the Arkoma basin. Many of these exposures are measured and described in OGS Guidebook 31, *Guidebook to the Geology of the Hartshorne Formation, Arkoma Basin, Oklahoma* (Suneson, 1998). The guidebook was prepared for a two-day field trip in southeastern Oklahoma conducted to complement this study of the Hartshorne play.

The prominence of the Hartshorne play has always been due to the relatively large gas reserve base of fields and shallow depth of production. Only a small amount of Hartshorne oil is produced in the extreme western part of the play area. Most gas fields have producing intervals considerably shallower than 3,500 ft, and many are less than 2,000 ft deep. The play was first recognized in 1910, when the Poteau–Gilmore field was discovered. This field alone produced an estimated 33 billion cubic feet of gas (BCFG) by 1934, nearly all of which came from the Hartshorne at depths ranging from 1,300 to 1,800 ft (Knechtel, 1949, p. 57). Other large Hartshorne sandstone gas reservoirs were found shortly thereafter, such as Quinton (1915) and Brooken, Centrahoma, and South Ashland (in the 1930s). Other large gas fields were discovered in the 1950s, '60s, and '70s, such as South Pine Hollow, Red Oak–Norris, Kinta, and Cameron (Summers, 1997). During the 1980s and '90s, many smaller Hartshorne fields were discovered that have reserves of several BCFG per field. Because of this, and the relative ease of drilling for the Hartshorne, this play has been an aggressive and competitive target for many small and large operators.

Sandstone has been the principal reservoir in the Hartshorne Formation, and production is attributed to a variety of facies originating from many different depositional environments, both marine and nonmarine. Additionally, coal is actively being pursued for coalbed methane in many parts of the basin, particularly in the eastern half of the play area. However, the best reservoirs within the Hartshorne Formation are the thick channel deposits; these are the main targets for many operators, since new wells commonly have reserves of 0.5 to >1.0 BCFG per well. The thinner marine-sandstone deposits are prospective in many of the periphery areas along the northern and western margins of the play, and they account for exploration/development targets having reserves generally less than 250 million cubic feet of gas (MMCFG) per well.

Hartshorne sandstone and coalbed-methane production accounts for a large part of the total hydrocarbon production in southeastern Oklahoma. It is estimated that over 675 BCFG was produced from the Hartshorne through 1997 (modified from Brown and Parham, 1994). Over the 87-year period (1910–97), this averages about 7.8 BCFG per year, but production was probably much greater during years when many of the big fields were producing at maximum rates. However, the trend in Hartshorne production since 1979 shows a relatively stable gas-production rate of about 2–3 BCFG per year (Fig. 1). Cumulative gas production from the Hartshorne from 1979 through 1997 is about 54 BCFG, according to production data from the Natural Resources and Information System (NRIS), developed by the Oklahoma Geological Survey and Geo Information Systems of the University of Oklahoma. During this same time period, Hartshorne oil production throughout the Arkoma basin was only a few thousand barrels per year. These data are compiled in Table 1.

The Hartshorne sandstone is one of the most widespread and commonly occurring gas reservoirs in the southern part of the Arkoma basin. Gas is produced in a large area extending north of the Choctaw fault (which parallels the Hartshorne outcrop) through T. 9 N. and from about R. 9 E. to R. 27 E. at the Arkansas state line (Fig. 2). The play is generally recognized by the presence of very thick, incised channel deposits (>200 ft thick), although many areas contain much thinner sandstone originating from marine environments. The formation can be traced in the subsurface and outcrop through T. 14 N., but in the very northern

TABLE 1. – Annual Gas- and Oil-Production Data for All Wells Producing from the Hartshorne Formation in Oklahoma from 1979 through September 1997

Year	Oil (bbl)	Gas (MCF)
1979	197	2,550,913
1980	651	2,947,773
1981	2,582	3,339,303
1982	4,313	2,933,510
1983	3,544	2,539,283
1984	3,022	2,359,390
1985	2,030	2,844,663
1986	2,196	2,371,594
1987	7,615	2,865,041
1988	6,141	3,071,164
1989	2,803	3,473,241
1990	2,199	3,322,474
1991	1,901	3,172,508
1992	1,455	2,891,099
1993	1,321	3,025,395
1994	2,142	3,194,693
1995	968	2,687,207
1996	728	2,591,112
1997	722	2,194,535
Total	46,530	54,374,898

extent of the play, the Hartshorne Formation is less than about 50 ft thick and is primarily marine shale. In Oklahoma, significant Hartshorne sandstone and subsurface coal are uncommon north of R. 10 N. The Hartshorne Formation also extends a considerable distance eastward into western Arkansas, where the outcrops are much more extensive (Fig. 2). Sandstone in this area is believed to be increasingly terrestrial in origin (fluvial channels), whereas in Oklahoma, the pattern of deposition comprises widespread marine facies and incised channel deposits.

Regional changes in sea level and possibly local structural provinces affected the pattern of deposition in the Hartshorne Formation. Most sediments occur in an east–west-trending belt north of the Choctaw fault. This area was approximately the ancient depocenter of the Arkoma basin during early Krebs (Cherokee) time. Distinct episodes of deposition are characterized by two progradational sequences, each terminating with the formation of a widespread coal bed. These clastic sequences are formally designated the Upper and Lower Hartshorne Members, and the regional sandstone trends that occur within each are shown on Plates 1 and 2 (in envelope). Along these sandstone trends, areas with Hartshorne gas (and oil) production, coalbed-methane production, and field names are shown on Plate 3 (in envelope).

Nearly all the sandstone trends mapped on these plates indicate that the Hartshorne had an eastern source area and was fluvially dominated with a westerly flow direction. Although the Ouachitas probably defined the southern edge of the Arkoma basin, they were mostly submergent during Hartshorne time. As a result, the Ouachita province is believed to have contributed little to the sandstone trends as mapped in this study, with one exception. In the southwest part of the outcrop belt, the chert-rich sandstone and chert-pebble conglomerate exposed near the town of Atoka (E½ Ts. 1 and 2 S., R. 11 E.) most certainly had a proximal source from an emergent structural uplift to the south, as shown on Plate 1. Therefore, the current extent of the Hartshorne Formation is probably close to its past maximum extent. Exposed thick channel deposits trending to the southwest (Red Oak Ridge, sec. 12, T. 5 N., R. 20 E., and Buzzards Roost, sec. 34, T. 6 N., R. 24 E.) indicate that they probably extended a short distance farther south of the outcrop belt (perhaps a mile or two) before ending in a marine environment such as a delta front. However, structural uplifts in the ancestral Ouachita Mountain complex probably created some form of submergent depositional barrier in

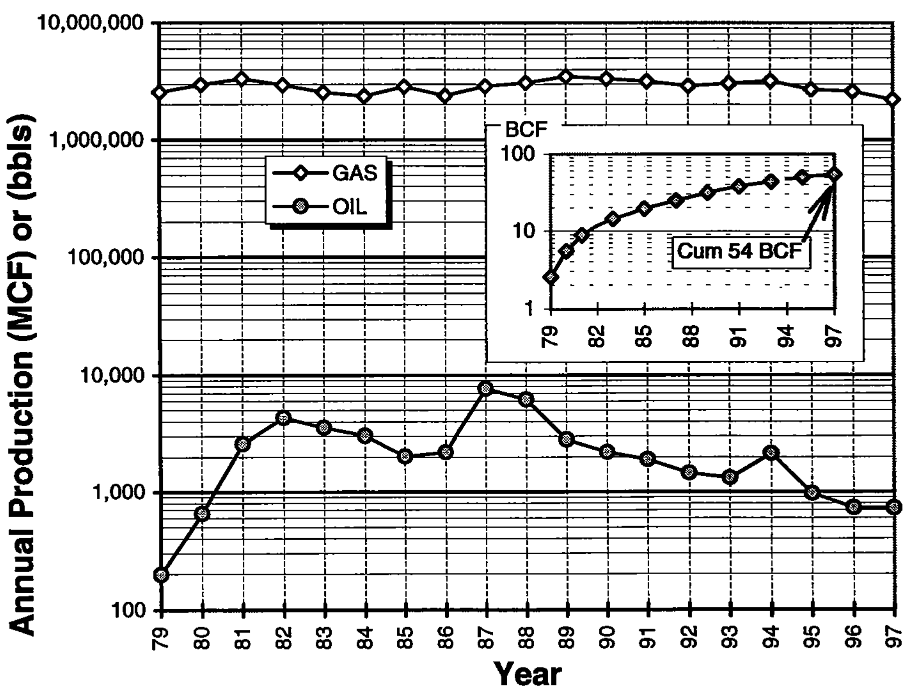


Figure 1. Production curve showing annual gas and oil production from the Hartshorne Formation in Oklahoma from 1979 through September 1997. Inset graph shows cumulative gas production.

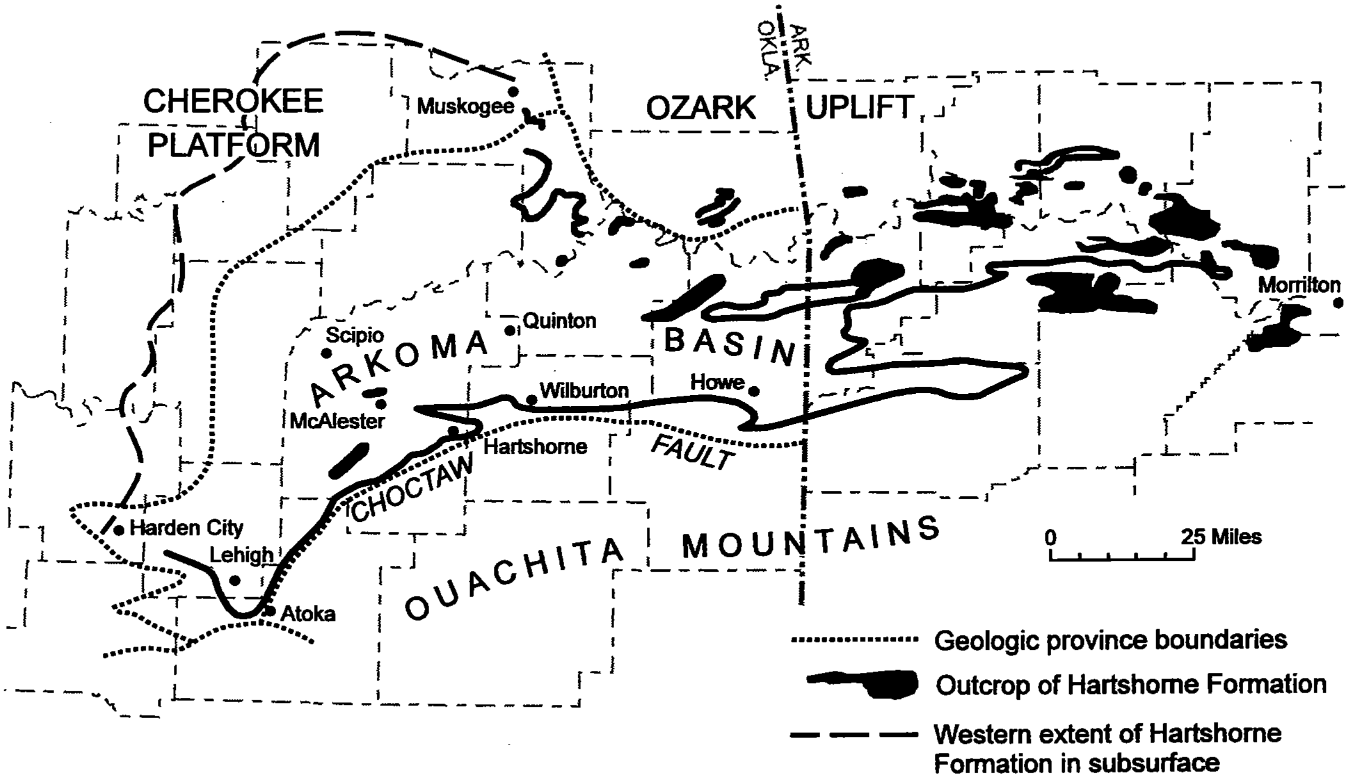


Figure 2. Map showing outcrop pattern of the Hartshorne Formation in Oklahoma and Arkansas. Dashed line is western extent of the Hartshorne Formation, based on well penetrations reported on Oklahoma Corporation Commission form 1002-A (NRIS data). Dotted lines are margins of major geologic provinces in Oklahoma, based on Northcutt and Campbell (1996). From Hemish and Suneson (1997).

far southeastern Oklahoma without being a major depositional source area (as from an emergent uplift). This situation may be analogous to the relationship between the emergence of the Nemaha uplift and development of the middle Cherokee fluvial-dominated deltaic (FDD) systems. In general, the Hartshorne depositional system had a major eastern source area with clastics advancing to the west, and a minor southern source area originating from locally emergent structural highs in the western part of the Ouachita Mountain uplift (Fig. 3).

STRATIGRAPHY

Hartshorne sediments are Middle Pennsylvanian in age and form the lowest formation within the Krebs Group, which includes (from oldest to youngest) the Hartshorne, McAlester, Savanna, and Boggy Formations (Fig. 4). The Hartshorne Formation is bounded conformably by the overlying McCurtain Shale Member of the McAlester Formation and by the underlying black shales of the Atoka Formation. In places where the Hartshorne was deposited in deeply incised channels, the basal contact with the underlying Atoka is sharp and undoubtedly unconformable (a disconformity).

The history of stratigraphic nomenclature used for sediments within the Hartshorne interval goes back more than 100 years. This nomenclature is covered in detail by Hemish and Suneson (1997) and is briefly covered in this text. Taff (1899) originally named the Hartshorne from deposits of coal and sandstone exposed in the McAlester and Lehigh coal fields, around the town of Hartshorne. However, the Hartshorne sandstone of Taff was first named by Chance (1890), who called the sandstone beneath the Hartshorne coal the Tobucksy sandstone. Taff abandoned this term, possibly because Chance had intended it to be relevant to sandstone exposures near McAlester (Branson, 1956a,b). In 1900, Taff and Adams realized that two distinct coal beds occurred above the Hartshorne (or Tobucksy) sandstone in the southern part of the Arkoma basin, and referred to them as the "upper" and "lower" coal beds. They believed that the "upper" coal was the basal unit of the overlying shale member of the McAlester Formation, but they retained the name *Hartshorne coal*. This confusing nomenclature was modified in 1948 by Oakes and Knechtel, who suggested that the Hartshorne Formation should include both coals, as they were interpreted to coalesce into one bed north of the principal outcrop belt that parallels the Choctaw fault. In 1956, Branson proposed that the term *Hartshorne sandstone* be elevated to formation status (Branson, 1956a,b). From interpretations of these last two investigations, McDaniel (1961) refined the terminology by proposing that the Hartshorne Formation be di-

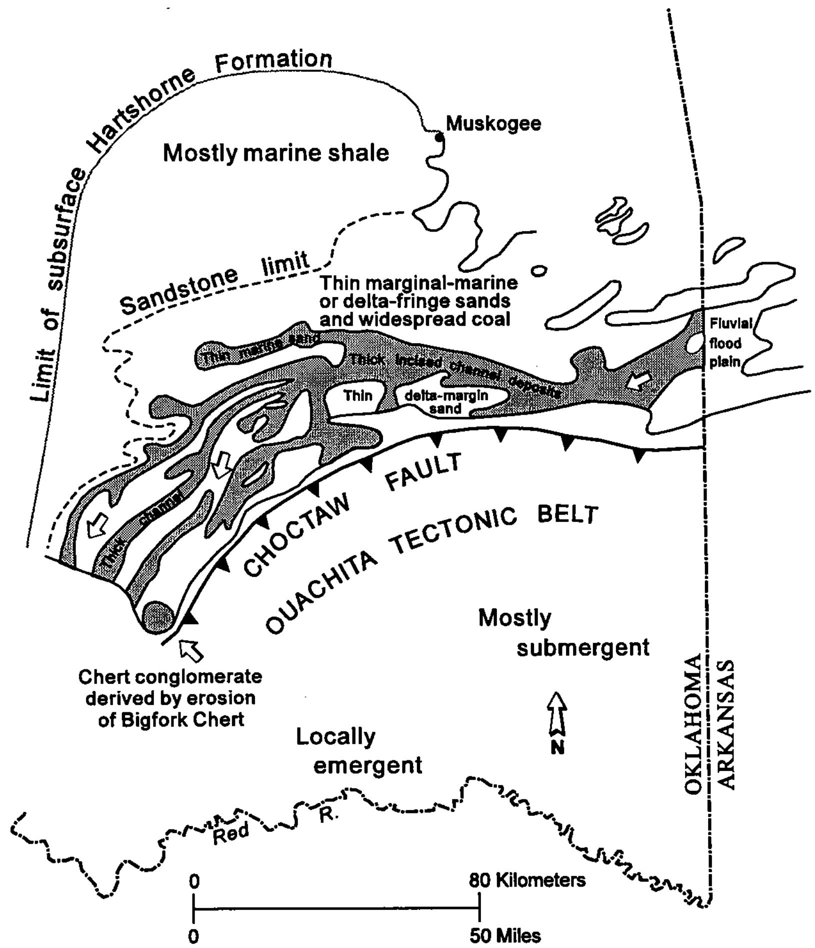


Figure 3. Generalized distribution and depositional environments of the Hartshorne Formation in southeastern Oklahoma.

vided into two members, as shown in Figure 5. A simplified schematic stratigraphic illustration showing the relationship of the Hartshorne sandstone and coal beds is shown in Figure 6. This classification is also used in this report. As shown in Figures 5 and 6, the Lower Hartshorne Member consists of the lower Hartshorne sandstone, shale, and the Lower Hartshorne coal. The Upper Hartshorne Member consists of the Upper Hartshorne coal plus all the sandstone and shale above the Lower Hartshorne coal. These relationships are shown on the type electric log (Fig. 7), which is typical for much of the Hartshorne play (south of the coal-split line). North of where the Upper and Lower Hartshorne coals coalesce (coal-split line; see Pls. 1,2), the Hartshorne Formation is undivided, and the coal is simply referred to as *Hartshorne coal.*

The Hartshorne Formation consists mostly of shale and sandstone with thin coal beds (usually just the Upper and Lower Hartshorne coals). Locally, however, additional thin coal beds can be identified on well logs, making correlations of the boundary between the Upper and Lower Member difficult. In subsurface, the Upper Hartshorne coal seems more persistent and can usually be found on well logs to identify the top of the Hartshorne Formation. The Lower Hartshorne coal is commonly absent where thick channel deposits are present. Coal in the Hartshorne Formation is only a few feet thick, but in places it is 6–8 ft thick. In areas where the Hartshorne coal is relative thick, it has been mined near the surface. But where it is more deeply buried (usually >500 ft deep), the coal has been exploited for coalbed methane. Figure 8 shows the principal areas where coalbed methane has been produced in addition to major structural folds within the Arkoma basin.

In gas-producing areas, the Hartshorne Formation is usually about 100–400 ft thick and typically contains two or more dominant sandstone sequences in any given area. The dominant sandstone units at some places contain more than one depositional unit or bed, thus forming a multistory sandstone body. Some stacked (or amalgamated) sandstone deposits thicken to occupy much of the Hartshorne interval, making stratigraphic distinction of individual beds difficult. Surface measurements of the Hartshorne Formation as reported by Knechtel (1937) show that the Hartshorne Formation is as thick as 500 ft in parts of Coal County. Near the town of Hartshorne, Hemish and Suneson (1997) indicate that the Hartshorne Formation is 1,083 ft thick, which is the thickest reported Hartshorne sequence in Oklahoma. Preliminary field work by the author indicates that most of the section east of Hartshorne (city) is of marine origin and consists largely of thin sandstone sequences, sandy shale, and shale. The measured section for this outcrop is included for stop 7 in OGS Guidebook 31 (Suneson, 1998).

In the southern part of the Arkoma basin, the Hartshorne Formation is directly overlain by a recognizable and mappable silty interval, referred to in this publication as the unnamed siltstone. Where present, this silty/shaly clastic sequence occurs in the lower part of the McCurtain Shale Member of the McAlester Formation (see regional type log, Fig. 7). It has a distinctive coarsening-upward textural profile on gamma-ray logs and is extremely variable in thickness. In the Kiowa field study area, this sequence varies in thickness from ~5 to almost 60 ft, which is typical throughout the area. Regionally, the unnamed siltstone thickens to the southeast, and it has a characteristic sharp inflection on gamma-ray and resistivity logs at its upper contact. This inflection on subsurface well logs is often incorrectly identified by many geologists as the top of the Hartshorne Formation.

Few studies have been published or completed for academic requirements (M.S. or Ph.D.) that reveal the detailed petrologic character of Hartshorne sandstone in the subsurface. Fields (1987), in his M.S. thesis (at Oklahoma State University), determined the detrital composition of upper Hartshorne sandstone from two cores. The lower Hartshorne sandstone interval from one of these cores is included in the core description in Appendix 4 of this report (Kerr McGee Corp. No. 1-24 Finch Unit core). The two cores represent channel and splay sandstone facies, and the petrologic results were combined into one compilation (Table 2).

Authigenic constituents of the upper Hartshorne sandstone were also determined by Fields and are summarized in Table 3. These data indicate that quartz is the dominant cementing agent, and that interstitial clays (particularly chlorite, which is reactive with typical acid treatments routinely used for the Hartshorne) are not a significant reservoir impediment, as they are in many of the Cherokee FDD reservoirs.

Based on obvious physical appearance, composition, bedding, texture, and sedimentary structures,

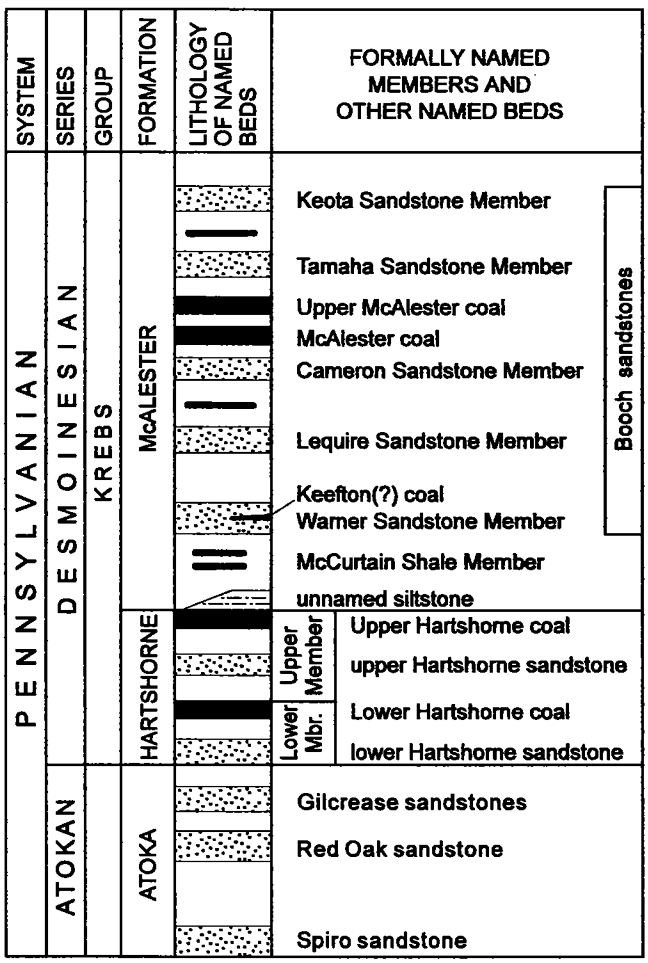


Figure 4. Generalized stratigraphic column of the lower Krebs Group and Atoka Formation in southeast Oklahoma. The relative position of formal members, coalbeds, and informal subsurface names are also shown. Modified from Hemish and Suneson (1997).

TABLE 2. – Average Detrital-Mineral Composition of the Upper Hartshorne Sandstone in Two Wells
(from Fields, 1987)

Constituent	Average percent (%)
Quartz	76.0
Rock fragments	8.0
Feldspar	1.5
Detrital matrix	2.0
Organic matter	<1.0
Muscovite	1.0
Tourmaline	trace
Zircon	trace

TABLE 3. – Average Authigenic-Mineral Composition of the Upper Hartshorne Sandstone in Two Wells
(from Fields, 1987)

Constituent	Average percent (%)
Quartz overgrowths	3.0
Siderite	2.0
Calcite	<1.0
Ferroan dolomite	<1.0
Kaolinite	2.0
Illite	1.0
Chlorite	<1.0
Hematite	trace
Pyrite	trace

the sandstone in the Hartshorne Formation can generally be grouped into three main types—marine, fluvial, and overbank (splay) deposits. All of these types of deposits were viewed in outcrops during the Hartshorne field trip and are described in OGS Guidebook 31 (see Suneson, 1998). The following brief discussions of these three facies are based on outcrop and core samples.

Marine Deposits

These sandstones have a traditional coarsening-upward textural profile. Mostly, this occurs gradually, but it can be abrupt over several feet. The marine deposits are generally very fine to fine grained, highly indurated with silica cement, very hard, and have low porosity and permeability. Flaggy bedding (discrete sandstone beds several inches thick separated by silty/shaly layers) with conspicuous ripple marks is most characteristic of these deposits. This characteristic makes them especially suitable for quarrying for use as building stone. In zones equivalent to the upper shoreface, high-angle cross-bedding is prevalent in the top part of marine-sandstone sequences. This facies commonly gives way to better porosity and per-

Figure 5. History of nomenclature and definitions of the Hartshorne Formation, 1890–1961. From Hemish and Suneson (1997). The current report uses subsurface regional markers shown on wireline logs to differentiate between the Atoka and overlying Hartshorne Formation, and we may differ from McDaniel (1961). See discussion on stratigraphy.

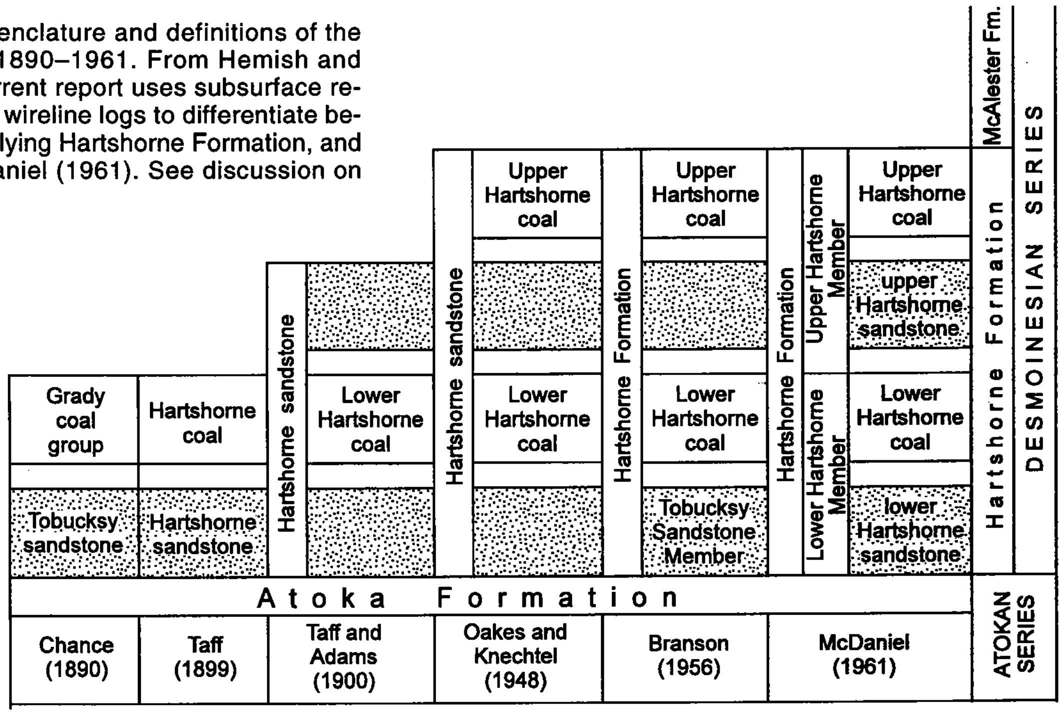
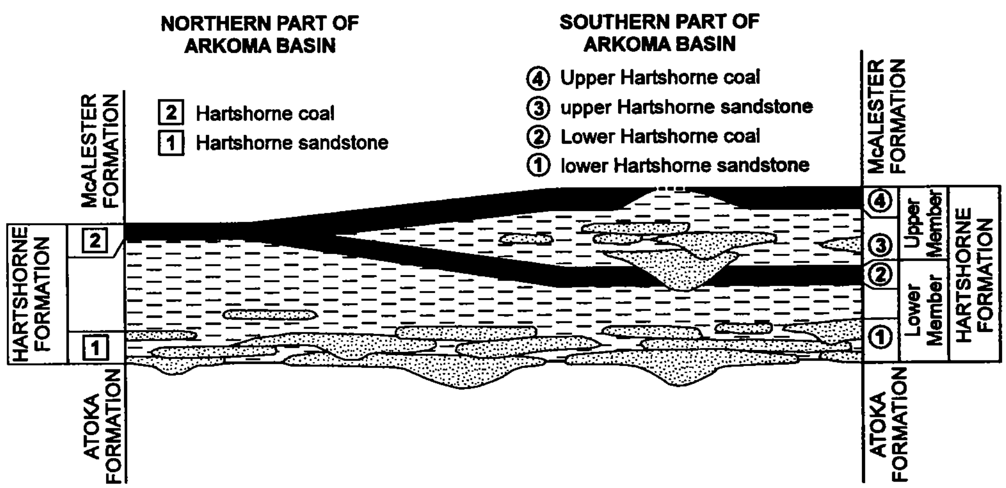


Figure 6. General relationship of different stratigraphic units (formal and informal) that constitute the Hartshorne Formation in the northern and southern part of the Arkoma basin in Oklahoma. Note that the Upper Hartshorne coal merges with the Lower Hartshorne coal in the northern part of the Arkoma basin, and that the Upper Member of the Hartshorne Formation appears to pinch out. From Hemish and Suneson (1997).



meability development. Most marine sandstones contain conspicuous amounts of interstitial and interbedded mica and organic debris. Storm rip-up clasts are also common within the marine sandstones, in a manner similar to those of fluvial deposits. These sedimentary features are described at stops 11 and 14 in OGS Guidebook 31 (Suneson, 1998). Occasionally, marine fossils, burrowing, and/or bioturbation are seen, particularly in cores (see cored images, both wells, Appendix 4). Marine-sandstone sequences are generally less than 25 ft thick, and commonly much less. They are often interpreted from well logs to be very shaly in the subsurface. Various types of marine deposits are described at stops 1, 2, 4, 5, 6, 7, 8, 9, 10A, 11, 14, 16, 17, and 18 in OGS Guidebook 31 (Suneson, 1998).

Fluvial (Channel) Deposits

These sandstones are generally fine to medium grained, poorly to moderately indurated (silica), and commonly have good to excellent porosity and permeability. The textural profile is usually blocky, and the beds have a sharp lower boundary with underlying sediments. Some channel deposits have an abrupt fining-upward profile. Bedding is commonly thick or massive, but sequences also are characterized by large- to moderate-scale high-angle cross-bedding. Rip-up clasts commonly occur at the base of channel beds, and rafted plant debris is also common. Interstitial mica is very common, whereas tiny rock particles are highly variable in minor quantities. Some channel de-

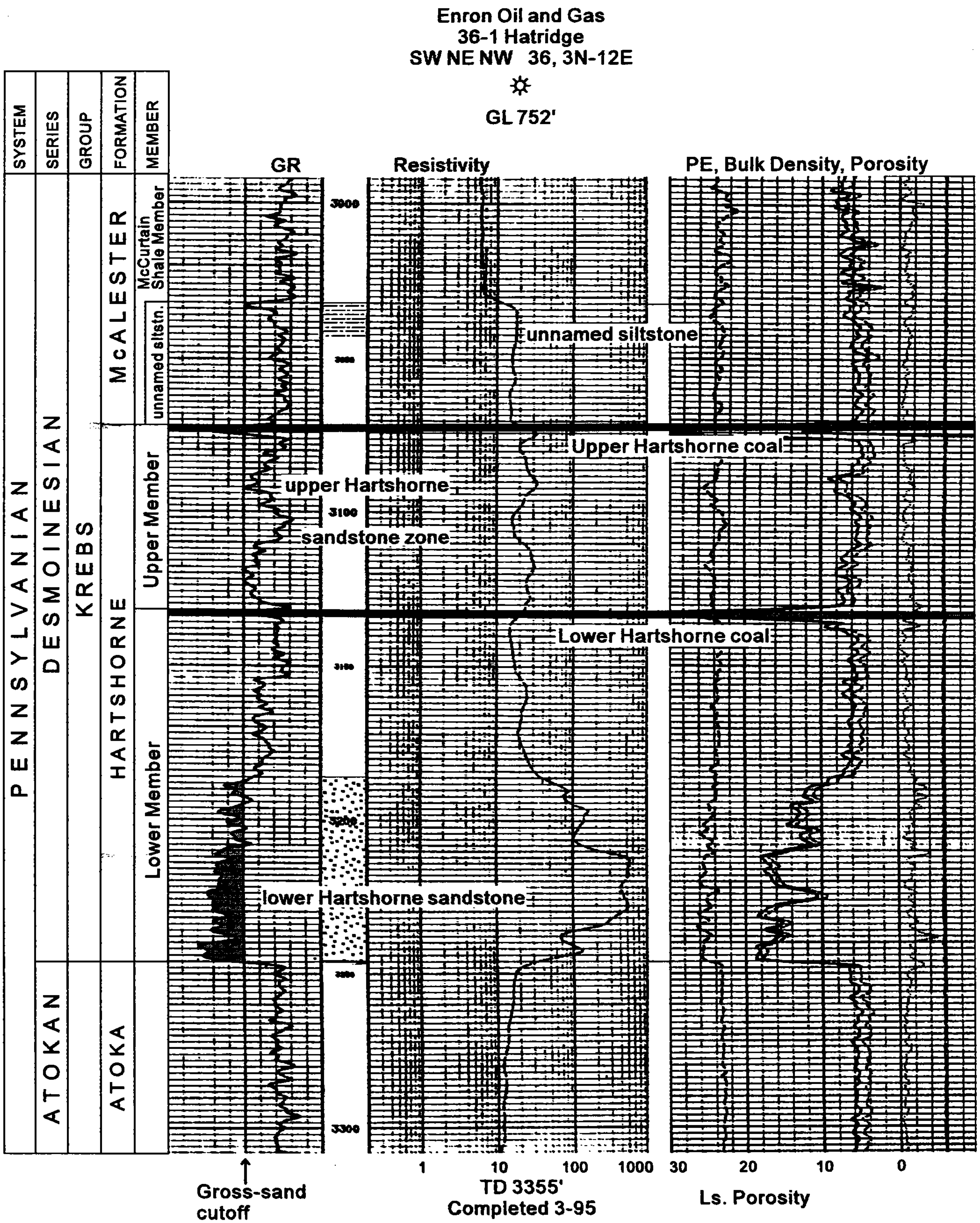


Figure 7. Hartshorne Formation type log showing formal and informal nomenclature.

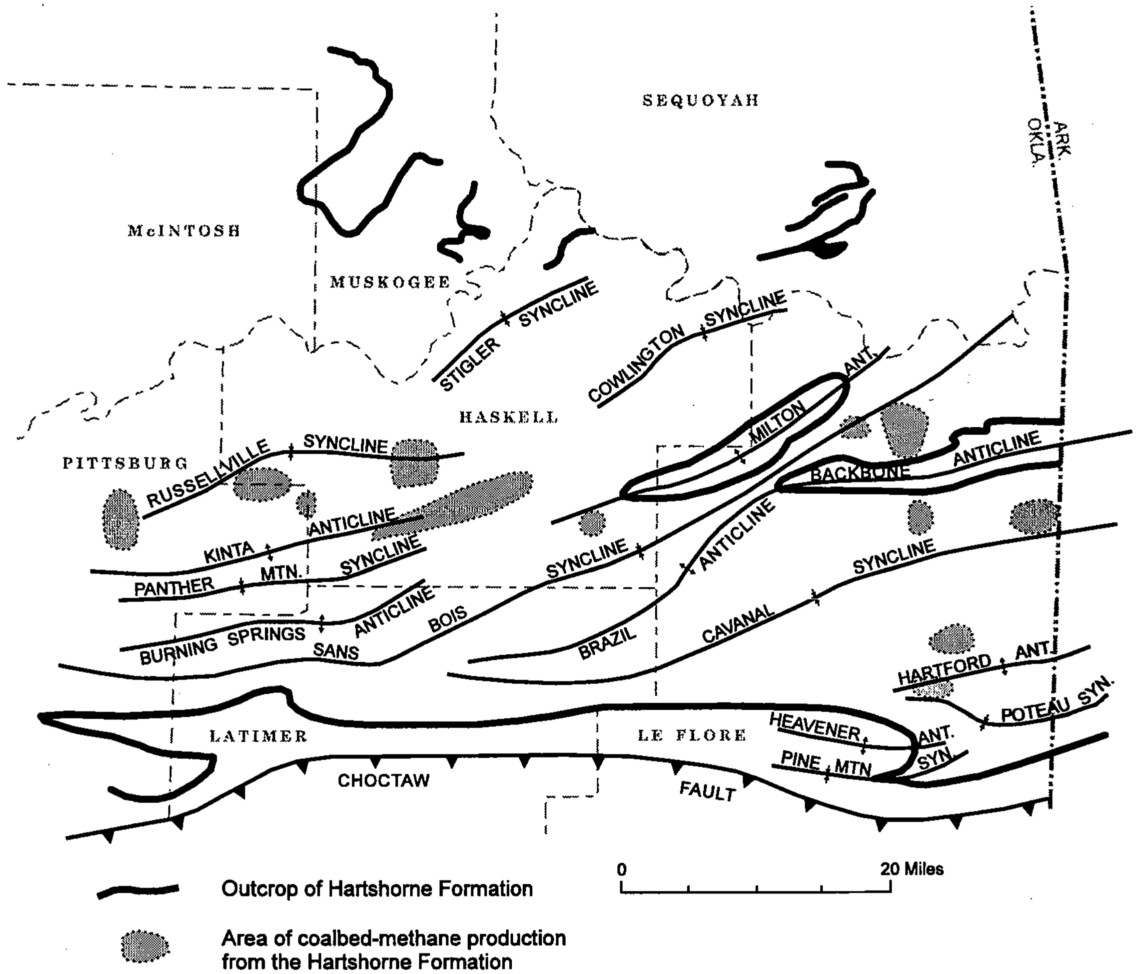


Figure 8. Map showing major surface folds and the locations (by pattern) of coalbed-methane production from the Hartshorne Formation. Also shown are surface exposures (heavy line) of the Hartshorne. Modified from Hemish and Suneson (1997).

posits appear remarkably clean, with few impurities, whereas many channel deposits are interpreted to be very shaly (from gamma-ray logs). Excellent exposures of various types of channel deposits are described in the sections on stops 3, 8, 10B, 12, 16, 17, and 19 of OGS Guidebook 31 (Suneson, 1998). The thickest channel deposits (usually >50 ft) occur in the form of falling-stage, incised channels. Thinner channel sands are often delta plain deposits in the form of distributary channels.

Overbank (Splay) Deposits

(See Kerr-McGee Corp. No. 1-24 Finch Unit well, Appendix 4)

These sandstones are usually diagnostic in the field, and often in core samples, by virtue of their internal sedimentary structures and stratigraphic association with other sedimentary units. One of the most characteristic features of this group of sandstone deposits is massive bedding and soft-sediment deformation (flowage) within the sand body. Cross-bedding is also common. Loading commonly occurs along lower bed boundaries, many of which are undulatory in attitude. Individual sand beds are somewhat tabular in nature in that the upper and lower boundaries with associated sediments (usually lagoonal shale) are sharp. Sometimes, an overall coarsening-upward profile is observed within the sandstone sequence. Plant impressions and *Calamites* (plant casts in living position) are numerous and commonly are oriented in one direction, thus indicating flow direction. The vertical textural profile is usually blocky, but some splay sequences show signs of coarsening upward. The sandstone is generally fine grained and can be relatively clean. Nevertheless, zones of rip-up clasts and organic particles are dispersed throughout the sand body in a manner similar to a channel (to which they are related). Field-trip stops 15 and 19 of OGS Guidebook 31 (Suneson, 1998) show good examples of these types of deposits.

REGIONAL CROSS SECTIONS

The regional stratigraphy of the Hartshorne Formation is best shown on the regional stratigraphic cross sections contained in this report. Cross section A–A′

(Pl. 4, in envelope) is oriented in an east–west direction, roughly parallel to the depositional trend of the play. Representative wells were selected in areas of principal sandstone trends. Starting along the western limit of the play at well 1, the Hartshorne Formation is only about 50 ft thick and is mostly shale. A sandy section occupies the upper 22 ft, and the Hartshorne coal defines the formation top. At well 2, the Hartshorne Formation thickens to about 85 ft, and the sandstone in the upper part of the formation is productive with development of porosity in a cleaner sand. Note the distinct response in the gamma-ray and SP curves on this log, and the deep resistivity, which is >40 ohm-m. Also shown on this log is the thick marine transition facies in the lower two-thirds of the section, which is gradational to the shale baseline, where an inflection is seen at about 3,096 ft. This horizon is commonly considered the Hartshorne–Atoka contact, and a slight gamma-ray response usually accompanies it. Well 3 shows the channel deposit that is productive at Cabaniss NW field of this project. The distinct sharp basal contact of the sandstone and the overall fining-upward textural profile are characteristic of a channel. The productive interval in well 3 exhibits very high resistivity, at some points >500 ohm-m. Directly beneath the channel sand, a thin part of the transition facies is believed present. At well 4, most of the Hartshorne Formation appears to be composed of channel sandstone. Several miles to the east, between wells 4 and 5, the coal-split line is encountered; farther east, in wells 5, 6, and 7, the Hartshorne is divided into Upper and Lower Members. In these three wells, the Lower Hartshorne coal is not represented on the logs but is projected to the correct stratigraphic interval by correlating nearby logs where the coal is present (but sandstone is absent). At some places, the position of the Lower Hartshorne coal correlates with a shale break (well 6), and at others, the Lower Hartshorne coal appears to have been truncated by channel erosion (wells 5 and 7). In wells 5–7, the Hartshorne is composed of amalgamated channel sandstones deeply incised into the Atoka shale. A similar channel sandstone is exposed a few miles south of these wells along the outcrop belt and is described at Red Oak Ridge, stop 10B in OGS Guidebook 31 (Suneson, 1998). A few miles northeast of well 7, the cross section again crosses the coal-split line between wells 7 and 8, and again between wells 8 and 9. At well 8, the Hartshorne Formation is essentially all shale except for the coal. In this occurrence, it is difficult to interpret the Atoka contact as shown. At well 9, the coal split is evident on the gamma-ray log; a relatively thick channel sand is present in the upper part of the Lower Hartshorne Member, whereas the lower part of the Lower Member is sandy/silty shale. The Upper Member in well 9 is only about 30 ft thick and, except for the coal, is entirely shale. At well 10, the Upper Member is about 110 ft thick and is composed mostly of sandstone. The Lower Member is mostly sandy/silty shale except for a thin marine-sand bed near the top. The identification of sandy sediments in the Lower Member in well 10 is assisted by the density–neutron log, which shows the "gas effect" in sandy zones throughout much of the upper part of the Lower Hartshorne Member. Both coals in wells 10 and 11 have the characteristic high-apparent-porosity deflection on the density–neutron log. In well 11, the Upper Hartshorne coal appears to split, and the underlying Upper Hartshorne Member is almost entirely marine shale. However, the Lower Member is composed almost entirely of channel sandstone (~140 ft). In well 12, which is very near the Arkansas border, the Hartshorne is composed almost entirely of channel sandstone that is part of a deeply incised river system.

Regional cross section B–B′ (Pl. 4, in envelope) is an important north–south line along the western part of the Hartshorne play. This section identifies the character of the Hartshorne Formation in the subsurface—from the northernmost townships where it can be recognized to exposures along the southwestern part of the outcrop belt (southern Coal County). The southern part of this section (well 1) shows a distinctive deltaic sequence consisting of a distributary channel overlying a delta front. This well is only about 0.3 mi north of the outcrop, where the section was measured for stop 2 in OGS Guidebook 31 (Suneson, 1998). Several miles to the east, and about 8 mi north of the outcrop, the Hartshorne Formation in well 2 exhibits an incised channel complex about 270 ft thick, most of which is channel sandstone. The first two wells are northwest of the coal-split line, and therefore their logs indicate only the Hartshorne coal bed at the top of the formation. Between wells 2 and 3, the Hartshorne coal splits, thereby accommodating the Upper Hartshorne Member. In well 3, the Lower Hartshorne Member still consists of an incised channel complex, whereas the Upper Member consists of shaly (channel?) sandstone. In well 4, the Lower Hartshorne is interpreted to consist of marine-delta-front and transition deposits, rather than an incised channel, and the lower contact with the underlying Atoka is gradational. In well 5, the Hartshorne again has a sharp basal contact with Atoka shale, and there is no coal in the section (as interpreted from the density logs). Based on correlations from nearby wells, an upper Hartshorne channel is believed to occur in the upper 65 ft of the section and to cut through the Lower Hartshorne coal. The boundary between the Upper and Lower Members is interpreted to be a shale break at about 3,714 ft. Beneath this depth, the lower Hartshorne sandstone in well 5 consists of a stacked channel sequence with interbedded shale. To the northwest, between wells 5 and 6, the cross section again crosses the coal-split line, and the Hartshorne Formation is undivided. At well 6, the Hartshorne Formation consists of sandstone deposited in an incised channel, as evidenced by the sharp basal contact of the sandstone sequence with Atoka shale and the numerous stacked sandstone beds. This Hartshorne section is similar to that which produces in the large South Pine

Hollow field, directly to the east. A short distance to the north at well 7, the Hartshorne is productive from marine facies typical of that in Stuart SW field. The downward gradational transition to the Atoka shale makes the interpretation of this formation boundary difficult. Some geologists make the pick 40 ft higher (at 3,172 rather than at 3,212 ft). The relationship, therefore, between the marine-delta-front facies in well 7 and that of a thick channel in well 6 appears to be incision caused by a forced regression (a fall in sea level). About 8 mi farther north, at well 8, the channel within Cabaniss NW field is shown and represents one of the westernmost channels in the northern part of the Hartshorne play. Eleven miles north of Cabaniss field, at well 9, the Hartshorne Formation appears to consist of a progradational sequence, as supported by the apparent presence of a distributary channel overlying a distributary mouth bar (delta front). Little sandstone occurs north of well 9, as shown in wells 10–12. Although the Hartshorne Formation is recognizable in these wells, it consists almost entirely of marine shale. At well 12, the Hartshorne is barely recognizable. In this general area, thin sandstone beds (some of which produce gas) are present in the Atoka section and are often miscorrelated with the Hartshorne Formation. These sandstones are called *Gilcrease sands* by many operators in the area.

Regional cross section C–C′ (Pl. 4, in envelope) is a north–south tie line illustrating stratigraphic changes that occur within the Hartshorne interval through the trough of the Arkoma basin; it extends almost to outcrops on opposing flanks of the basin. The first two wells in the southern part of the cross section show prograding sequences consisting of distributary mouth bars (delta front) overlain by distributary channels. This is identical to what is seen in the Green Country Quarry farther north in T. 8 N., R. 26 E., where the Hartshorne sandstone was measured for the Hartshorne field-trip publication (Suneson, 1998, stop 17). In wells 1 and 2, both Hartshorne members are present, and the coals have typical log responses on the gamma-ray and density logs. The subtle response on the resistivity log (well 1) is typical for coals in the Hartshorne, although higher resistivity readings are sometimes seen. In well 3 (the tie well for section A–A′), the Hartshorne is composed almost entirely of channel sandstone. In this well, the base of the upper sandstone and the position of the Lower Hartshorne coal are approximate and are based on correlations from nearby well logs. Although there is a lot of sandstone in well 4, the porosity log shows it to be tight; therefore, this well does not produce gas. In well 4, just south of Backbone anticline, the Hartshorne Formation is mostly shale with a thin marine, coarsening-upward sand sequence directly beneath the lower coal. The base of the Hartshorne Formation in this well is highly interpretive and may be placed above the resistivity marker as shown. Yet, the pick that is used to define the Atoka contact is characteristic of the Hartshorne base throughout the extent of the play. In the northern part of the cross section, at well 5, the Hartshorne section is similar to that at well 4; but the Upper and Lower Hartshorne coals have nearly coalesced, thereby reducing the thickness of the Upper Member (exclusive of the coal) to only a few feet. Well 5 is typical of the Hartshorne Formation in Spiro SE field, which produces coalbed methane (see Part II of this volume, p. 47). North of well 5, the coal completely merges but is interpreted to diverge again at well 6. It is uncertain if this is the divergence of the Upper and Lower Hartshorne coals, or if another coal has developed beneath the main Hartshorne coal bed. At well 7, the Hartshorne consists of several thin sandstone beds interpreted to be deltaic (or possibly flood plain) in origin.

STRUCTURE

Within the Arkoma basin, the Hartshorne Formation is highly affected by folding and faulting. These structural elements are roughly parallel to the east–west-trending Choctaw fault, which parallels the outcrop belt of the Hartshorne Formation as shown in Figure 8. Numerous other folds and smaller faults having hundreds of feet of displacement are present throughout the study area at different orientations. Some geologists refer to the structural configuration of the Hartshorne in the subsurface as a broken mirror, since fragments of strata have highly irregular structural dispositions. In fact, this characteristic provides one of the basic trapping mechanisms for hydrocarbons in the area. Almost every significant Hartshorne gas field has a trapping component related to folding and/or faulting. Natural fracturing that accompanies folding and faulting also appears to be associated with permeability and porosity enhancement in some gas fields (see Cabaniss NW field study in this report, p. 14).

Structural expressions of the Hartshorne Formation throughout the Arkoma basin are shown on Plate 5 (in envelope). This map depicts the top of the Hartshorne Formation and gives the locations and names of major folds and faults, with relative fault movement; subsea contour lines show the spatial geometry of the structure. Since dips in the area are locally very steep, some nearly vertical, a large contour interval of 500 ft was necessary to delineate the structural irregularities of the area. Although some areas may appear to be relatively undeformed, it is likely that displacements occur at least every few miles. Often, where structure contours are closely spaced, a significant fault can be interpreted in the area. The formation of all these structures postdates the deposition of sediments in the Hartshorne Formation; therefore, interval thickening is not conclusive.

Structural elements extend far to the north of the Ouachita Mountain uplift, which lies south of the Choctaw fault system. In the eastern part of the play, along Ts. 8 and 9 N., folding and faulting have exposed the Hartshorne Formation along the Backbone and Milton anticlines. Near the center of the play, northwest of

McAlester (T. 6 N., R. 14 E.), faulting also has brought the Hartshorne to the surface along the Penitentiary fault (Pl. 5). These exposures give geologists a good opportunity for examining the Hartshorne in the center of the Arkoma basin, and many of these localities were examined during the Hartshorne field trip (Suneson, 1998).

DEPOSITIONAL MODEL

Depositional patterns in the Hartshorne can be extrapolated by using a regional grid of subsurface well logs in addition to field work. This study incorporates both sources of data, and the conclusions regarding depositional environments and the origin of the Hartshorne play are identical. Field work also assists in subsurface interpretations, because outcrops that characterize certain depositional environments exhibit textural profiles that can be related to typical well logs in the subsurface.

The interpretation of the depositional origin of the Hartshorne sandstone, as outlined in this study, is considerably different than that of most previous investigators because an element of sequence stratigraphy is added (which accounts for relative sea-level changes). The Hartshorne Formation appears to have been deposited during a number of repeated depositonal events that occurred during both Lower (early) and Upper (late) Hartshorne time. Overall, the depositional environment was more terrestrial to the east (toward Arkansas) and more marine to the west, although fluvial processes still predominated in the deposition of the major sandstone trends.

Lower Hartshorne Member (HLM) and Undivided Hartshorne (HU) (Pl. 1)

The first phase of Hartshorne deposition (HLM and HU) was part of a widespread, but relatively thin, lobate delta system. Because of the extensive occurrence of storm rip-up clasts and eroded bedding surfaces in the bar face, the development of the delta was probably slightly destructive. Sediments accounting for the first phase of marine deposition are only about 100–150 ft thick in the main play area, but gradually they thin along the edges of the Arkoma basin to the north and west. The vast majority of sediment was transported in a east–west direction and was deposited in axial portions of the Arkoma basin. This was determined from sand-trend mapping, using both subsurface and surface control. Isolated highlands to the south in the Ouachita Mountain uplift also contributed a relatively small amount of sediment in the southwestern part of the play area. This is evident from the presence of chert in some of the sandstones and, more importantly, from the presence of chert-pebble conglomerate near the town of Atoka in the E½ Ts. 1 and 2 S., R. 11 E., stop 3 in OGS Guidebook 31 (Suneson, 1998). As these rocks are not known to be productive, or to extend very far northward into the basin, they are not discussed further in this report; they are significant more as a curiosity than for economic reasons.

As seen in the field and on well logs, the HLM and HU consist of marine deposits constituting the delta front, with some constituting the delta and flood plain (including associated splay deposits). The usual facies include a thin distributary mouth bar or marginal-marine bar, about 10–25 ft thick, underlain by a much thicker transition zone consisting of interbedded shale, sandstone, and siltstone (well 2, section A–A′, and wells 4 and 7, section B–B′, Pl. 4). In some places, a definite progradational sequence consisting of a distributary channel (delta plain) overlying a distributary mouth bar (delta front) occurs, as in wells 1 and 9, section B–B′, and well 1, section C–C′ (Pl. 4). Sometimes the initial phase of deposition resulted primarily in shale deposition in delta-fringe or distal-bar areas, such as in well 8, section A–A′, wells 10–12, section B–B′, and wells 5 and 6, section C–C′ (Pl. 4). In all these marine environments where sandstone is developed, storm-wave rip-up and eroded bedding surfaces are apparent throughout the Hartshorne outcrop belt. This indicates, on a regional scale, that the depositional environment was very shallow and that destructive wave action was significant in the development and modification of the marine sand (bar face). These marine sandstones also contain an abundance of detrital mica and carbonized plant material, indicating terrestrial proximity. The marine deposits thin to the north along the southern edge of the Cherokee platform, and to the west along the Seminole structure and Ada high, which define the limits of the Arkoma basin.

Following this initial progradational event, which basically defined the regional extent of the Hartshorne Formation, the most conspicuous sandstone bodies of the formation were deposited. These are the very thick channel deposits that seem to be unrelated in depositional origin to the predominantly marine deltaic event previously described. Primarily as a result of relative-sea-level lowering, fluvial systems originating in phase one were reactivated in a manner of forced regression. These sand bodies are clearly incised into the preexisting and older Hartshorne deltaic–marine deposits and are considerably thicker, usually 200–300 ft thick. These thick channel deposits were described by Houseknecht and others (1983) as distributary channels, but their interpretation in this study is clearly to the contrary. They are not distributary channels of a delta plain but rather are falling-stage sand deposits in incised valleys. The implications of this interpretation are enormous, because it means that marine delta-front-sandstone accumulations lie farther basinward. Modification of fluvial-sandstone deposits undoubtedly occurred by fluctuating sea level, but most of these types of deposits are clearly fluvial in nature and took place in a flood plain that was landward of baseline marine environments. The evidence that deposition by means other than fluvial channels occurred in the incised valleys is best shown in wells 5 and 6, section A–A′ (Pl. 4), for which a thin progradational sequence is interpreted within the valley-fill sequence. However, the incised fluvial nature of the typical valley-fill sequence of these sandstone bodies is clearly shown in wells 5, 6, 11, and 12, section A–A′, and in wells 2 and 5, section B–B′ (Pl. 4). Field observations also support this conclusion at the Craven Road and Red Oak Ridge field-trip stops in OGS Guidebook 31 (Suneson, 1998). At these localities, marine deposits of the Lower Hartshorne are incised by a thick, massive channel sandstone. The abrupt transition between these two facies can be seen from surface samples while walking from one exposure to another over a distance of only a few hundred feet. There are no marine facies within the incised channel complex at the Red Oak section. Additionally, tidal facies were not clearly recognized anywhere in the field.

Following, or even concurrent with, deposition of the deeply incised channel deposits, terrestrial-floodplain and delta-plain swamps provided conditions necessary for the formation of the Hartshorne coal (or Lower Hartshorne coal). This coal can be recognized in most areas where the Hartshorne Formation is present, except in areas north of T. 9 N. and west of R. 9 E. Because of fluvial deposition in channel areas, this coal may be locally absent in other areas as well. The Lower Hartshorne coal coalesces with the Upper Hartshorne coal north of the principal sand-trend areas. The location where these two coals merge (or separate) can be mapped and is shown on the regional sand maps (see coal-split line on Pls. 1 and 2). The trace of the coal-split line approximates the position of the basin margin (or depositional margin) that existed during Hartshorne time. North and west of this line, the merged coals are simply referred to as the Hartshorne coal. The Lower Hartshorne coal is usually only a few feet thick, but where it merges with the Upper Hartshorne coal, the coalesced thickness is as much as 7–8 ft. Density and gamma-ray logs are particularly helpful in delineating coal beds, whereas resistivity logs are not always useful for this purpose. Deposition of the Lower Hartshorne coal is the final sequence of the HLM, which may be described as an interrupted progradational sequence. The HLM represents the first and most significant progradational package of sediments in the Hartshorne Formation.

Upper Hartshorne Member (HUM) (Pl. 2)

The HUM represents the second and subordinate progradation package within the Hartshorne Formation. The regional distribution of the principal sand trends in this member is shown on Plate 2 and occurs south and east of the coal-split line. The HUM ranges in thickness from just a parting to about 120 ft. The HUM progressively thickens south and east of the coal-split line but is thickest where incised channel deposits are present. The depositional history of the HUM is similar to that of the HLM, except that prograding sequences are much thinner, more poorly developed, and more restricted spatially. The most apparent delta-front sequences lie in the eastern part of the mapped area, both at outcrop and in subsurface. Sediment dispersal in the HUM occurred in a westerly direction, and the principal channel systems occur in close proximity, or are redundant, with those in the HLM. In some cases, it is hard to determine the base of the upper Hartshorne sandstone and the top of the lower Hartshorne sandstone (see wells 5 and 12, section A–A′, and well 5, section B–B′, Pl. 4).

The first phase of the HUM began as a minor progradational event that resulted in thin delta-front deposits in the eastern half of the study area. These marine-sandstone sequences are identified in wells 1 and 4, section C–C′ (Pl. 4), and in the Panola measured section, E½ sec. 8, T. 5 N., R. 20 E. Delta-front sandstone in the HUM is generally less than about 20 ft thick. However, most of the HUM deposited during the first phase of deposition consists of shale, such as shown in wells 9 and 11, section A–A′, well 4, section B–B′, and well 2, section C–C′ (Pl. 4). This depositional phase defined the spatial limits of the HUM in a manner similar to the first phase of the HLM. The second phase of deposition during the HUM period occurred when minor fluvial systems originating in phase one were reactivated in response to relative-sea-level lowering. The slight change in flow gradient caused by sea-level lowering induced fluvial systems to flow basinward within incised valleys in a manner similar to that of the thick channels identified in the HLM. In places where the upper Hartshorne sandstone is abnormally thick, the incised channel cuts through the Lower Hartshorne coal. This is seen in wells 5, 7, and 12, section A–A′, and in well 5, section B–B′ (Pl. 4). In these wells, the upper Hartshorne sandstone is on the order of 60–100 ft thick. Following, or concurrent with, deposition of the thick upper Hartshorne channel sandstone, the Upper Hartshorne coal was formed. This marked the end of the second and last progradational event of the Hartshorne Formation. As in the HLM, the progradational package of sediments in the HUM appears to be interrupted by a forced regression that resulted in deposition of the thick, incised valley-fill channels.

The regional distribution pattern of major sand trends in the HUM (Pl. 2) is not entirely clear, because the nature of these (fluvial) trends is not certainly known as they persist to the southwest. The channels would be expected to terminate in a marine environment with the formation of delta front (distributary mouth bar) deposits. This has not been recognized in the subsurface in this study.

SUMMARY OF REGIONAL HARTSHORNE MAPPING

The regional distribution of the Hartshorne sandstone, and the interpretation of depositional facies, are shown on Plates 1 and 2. Plate 1 shows the thickness of the lower and undifferentiated Hartshorne sandstone. The thickest sand trends are largely fluvial in origin and trend to the west–southwest. Notations are also made regarding the nature of subsurface coal and characteristics of surface exposures. Plate 2 shows the thicknesses and locations of major sand trends attributable to the upper Hartshorne sandstone. The areal distribution of sandstone and sandstone thickness is considerably smaller than that of sandstone in the Lower Hartshorne Member. Both sand-trend maps show the Hartshorne outcrop belt in addition to some of the major bounding faults relevant to the play. The locations of regional cross sections A–A′, B–B′, and C–C′ (Pl. 4) are also shown on the regional sand-trend maps. As used throughout this paper, both marginal marine and delta-fringe designations imply nonfluvial deposition. Delta-fringe environments occur within the subaqueous distributary mouth bar, but in areas adjacent to the actual front of the delta. Marginal marine environments occur within the lower delta plain or in delta-fringe areas where deposition is accompanied by marine and freshwater currents such as in some bay-fill (splay) deposits. Reference to open-marine sand bodies or offshore bars designates detached sand bars originating in a shallow-marine shelf environment.

The Hartshorne produces hydrocarbons throughout much of the Arkoma basin in southeastern Oklahoma. This is illustrated on Plate 3, which is a map showing wells with Hartshorne gas and oil production and field names. Included with Plate 3 is an alphabetical listing of field names and their geographic locations. Field names were derived from the NRIS data base. Field names are consistent with field designations by the Oklahoma Nomenclature Committee of the Mid-Continent Oil and Gas Association. In many cases, Hartshorne production is attributed to a general field boundary that has no geological relevance to sandstone in the Hartshorne Formation. In other cases, Hartshorne production is found outside of formal field boundaries. This situation exists because the effort to formally define and extend field boundaries lags behind the extension of producing areas.

The basic stratigraphic framework and regional correlations of the Hartshorne Formation are included in regional cross sections A–A′, B–B′, and C–C′ (Pl. 4). The general structural characteristics of the study area, in addition to the identification and locations of major faults and folds, are included on Plate 5. Selected references used for subsurface sandstone mapping are listed alphabetically on Plate 6 (in envelope) and are designated with a numerical code that can be used to identify the area of geologic interpretation. A more complete list of references is included as part of this volume.

All available sources of information were used in completing this study, including theses, consultants, and personal investigations by the author. Approximately 3,000 well logs were used to construct the subsurface sandstone-trend maps of Plates 1 and 2.

Throughout this paper, references are made regarding various sand-size grades in the description of certain rock units. A listing is given in Appendix 1 of this report. Similarly, various abbreviations and terms that are used in this paper are defined in Appendixes 2 and 3, respectively. All well symbols used in geologic maps are consistent and are explained on the plates and in the figures. Two cores are provided for examination by workshop attendees. One core shows characteristics of a shallow-marine bar (distributary mouth bar?), and the other probably represents overbank-splay and lagoonal deposits. Brief core descriptions and facies interpretations are provided for these two wells, together with well logs and selected visual images, in Appendix 4.

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Regional base maps, regional structure maps, and regional production maps were prepared by Carlyle Hinshaw, consulting geologist for the OGS. Core slabbing was completed by Daniel Garbelmon with 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 by Jim Anderson and Charlotte Lloyd, cartographic drafting technicians. Technical review and publication editing were completed by Charles J. Mankin, OGS director; Kenneth S. Johnson, OGS associate director; Neil Suneson, OGS geologist; William D. Rose, geologist/contract editor; 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 were accomplished by Michelle Summers, OGS technical project coordinator.

CABANISS NW FIELD

(Hartshorne gas reservoir in secs. 12, 13, T. 6 N., R. 11 E., and secs. 7–9, 15–18, 20, 29, T. 6 N., R. 12 E., northwestern Pittsburg and eastern Hughes Counties, Oklahoma)

INTRODUCTION

Cabaniss NW field is located in northwestern Pittsburg and eastern Hughes Counties in southeastern Oklahoma (Fig. 9). The study area lies in the western trough of the Arkoma basin about 18 mi west of McAlester (Pl. 5). Cabaniss NW field produces gas from relatively thin channel sands, thin marine deposits, and possibly coal. The field area is north of the coal-split line, so the Hartshorne Formation is not divided into Upper and Lower Members. The fluvial trend that constitutes the main part of the field extends a few miles farther to the west, where it changes facies and gradually becomes entirely marine in origin (delta front). Fluvial facies probably extend another mile east of the field into sec. 21, which is the likely direction to pursue development drilling. Cabaniss NW field appears to be truncated on the east by a deeply incised fluvial-channel complex. In the study area, this major sand trend (see Pl. 1) contains over 80 ft of sandstone, but it is wet and not productive. Cumulative gas production to date from the field is about 3.6 BCF. The producing sandstone reservoir reaches a maximum known thickness of about 40 net ft, and the geometry of the reservoir appears to be some form of longitudinal bar with laterally adjacent marine-bar deposits and coal. A map identifying operators, well locations, well numbers, and principal leases within the field area is shown in Figure 10.

Within the Cabaniss NW field study area, drilling activity began in the early 1920s with three dry holes: sec. 23, T. 6 N., R. 11 E.; W½ sec. 29, T. 6 N., R. 12 E.; and NW¼NW¼ sec. 13, T. 6 N., R. 11 E. (Fig. 10). The latter well actually penetrated the western edge of the field and probably had commercial gas potential in the

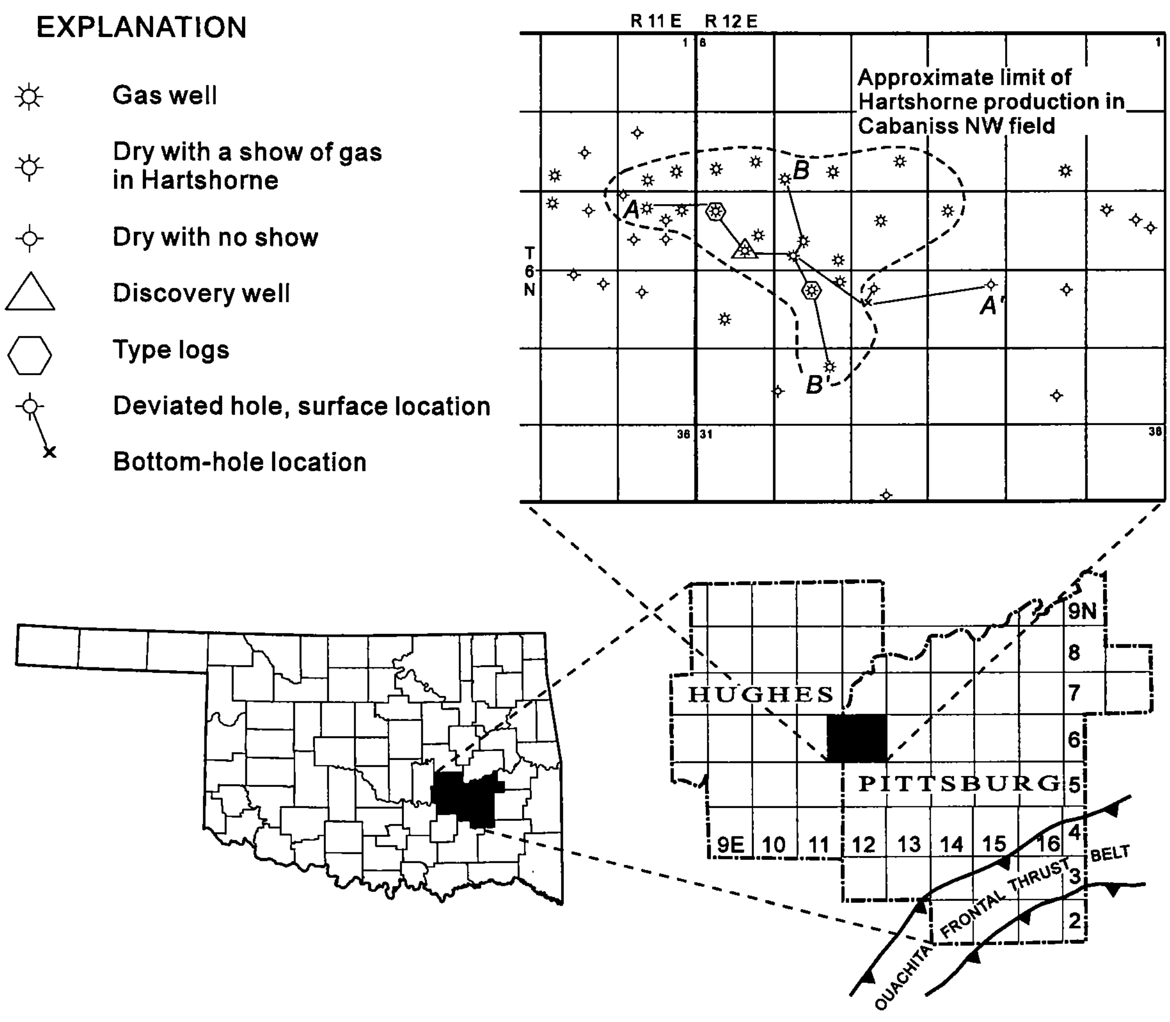

Figure 9. Generalized location map of the Cabaniss NW field study area in northwestern Pittsburg and eastern Hughes Counties, Oklahoma.

Hartshorne. Several more dry holes were drilled in the area during the 1960s and early 1970s. One of these, the No. 1 Hilseweck (NE¼ sec. 29, T. 6 N., R. 12 E.), was plugged and abandoned in 1973 but later recompleted by KWB Oil as a Hartshorne gas producer in July 1981 (7 years after the official field-discovery well).

Commercial gas was discovered in Cabaniss NW field in September 1974 with completion of the No. 1-18 Blevins, drilled by KWB Oil (sec. 18, T. 6 N., R. 12 E.). This well's initial production was 62 thousand cubic feet of gas per day (MCFGPD) plus 15 barrels of load water (BLW). In the Blevins well, the Hartshorne had about 11 ft of net sandstone (≥8% porosity), but the log profile is not conclusive regarding the exact depositional facies. Field development didn't occur until 2–3 years later, in 1977, when several additional wells were completed in the thin, tight marine facies, which occur predominantly in the northern part of the field. Production from these wells was delayed 2 years until 1979, probably because of pipeline delays. Operators at this time were unaware of the thicker channel reservoir that existed between the discovery well and development wells drilled in 1977 to the north. The best part of Cabaniss NW field wasn't discovered until the mid-1990s, when several wells penetrated a 20–40-ft-thick channel sandstone in the middle of the field. This reservoir proved to be the best commercial reservoir in the field, and wells completed in this facies are expected to produce >0.5 BCFG. Many of the wells drilled during the 1970s were completed by Regal Petroleum. Those completed in the mid-1990s were drilled largely by Gulf Oil. Around 1996, Tilford–Pinson Exploration acquired majority interests in these wells and continued developing the field.

The original spacing for the Hartshorne in Cabaniss NW field was 640 acres, but increased density and location exceptions have caused the field to be developed on 320- and 160-acre spacing. Currently, 21 wells produce from the Hartshorne. The field appears to be mostly developed, except possibly for the eastern edge, where an additional well or two might extend the known fluvial trend into sec. 21, T. 6 N, R. 12 E. The relationship of this field to the regional distribution of the upper and lower Hartshorne sandstone is shown on Plates 1 and 2.

STRATIGRAPHY

Two logs that are representative of Hartshorne stratigraphy in Cabaniss NW field, together with stratigraphic nomenclature, are shown in Figure 11. The log traces for the Blevins No. 2-18 well (type log on left) are characteristic of channel deposits in the field. In this

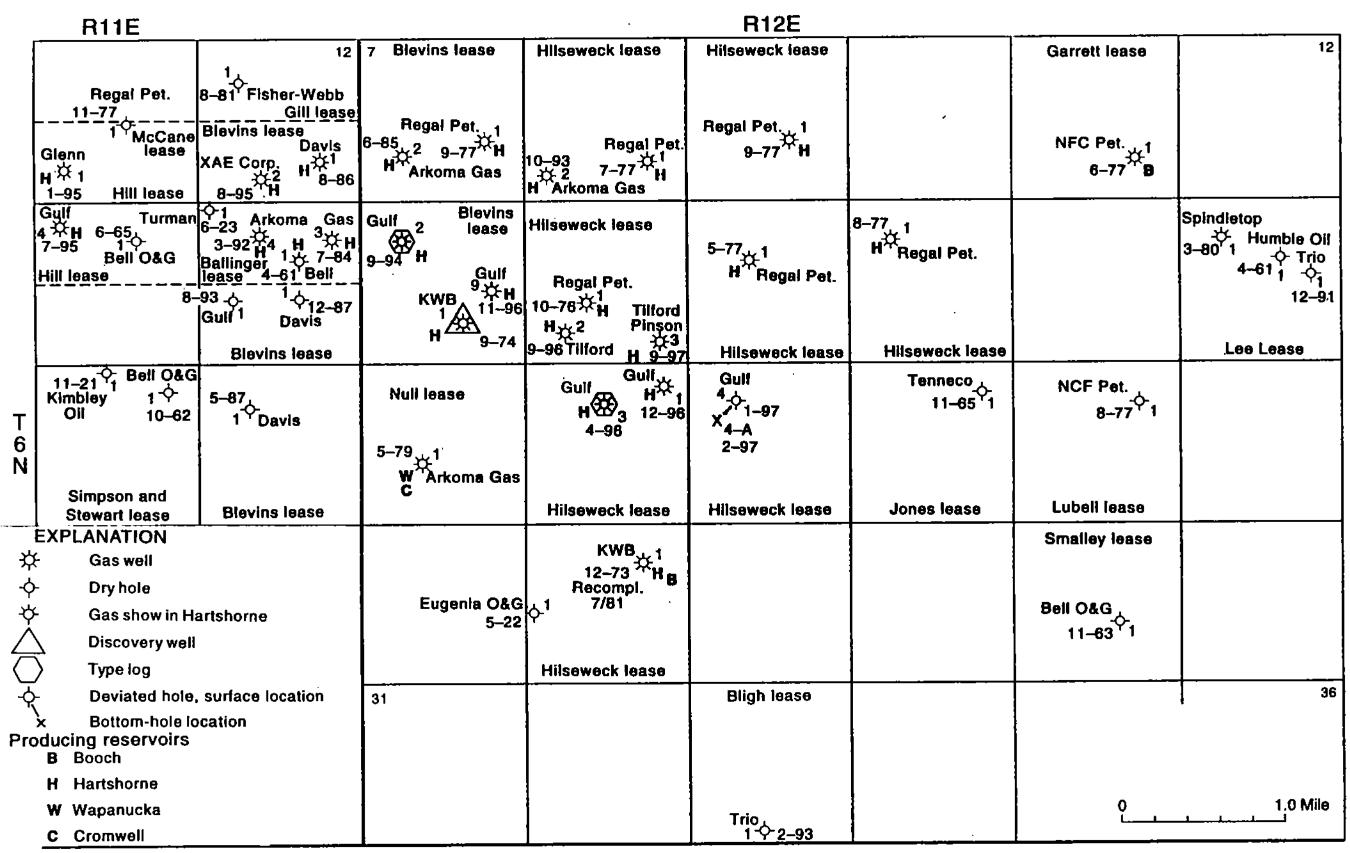

Figure 10. Well-information map showing operators, lease names, well numbers, completion dates, and producing reservoirs for wells in the Cabaniss NW field study area.

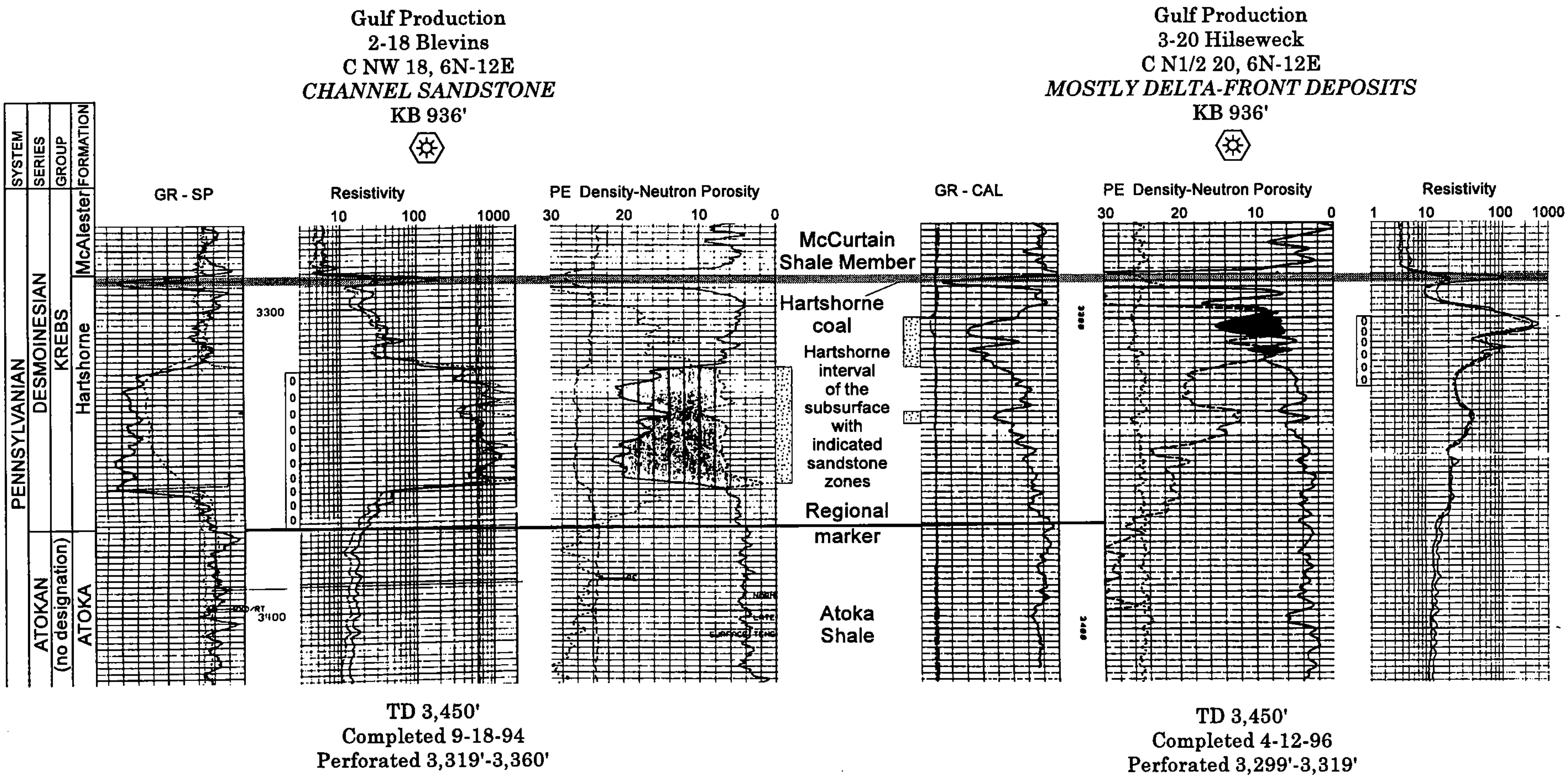

Figure 11. Type logs of the Hartshorne interval in the Cabaniss NW field. Two logs are presented to show typical log signatures of channel and nonchannel Hartshorne sandstones. The stratigraphic section and nomenclature above and beneath the Hartshorne are also shown. *GR* = gamma ray, *SP* = spontaneous potential, *PE* = photoelectric, *CAL* = caliper.

well, the sandstone has a sharp basal contact with shale and an overall fining-upward textural profile. The cross-plot porosity is about 12–14%, and the photoelectric (PE) log clearly deviates to the left of the shale baseline, indicating sandstone. Curiously, the spontaneous-potential (SP) log shows an upward-increasing deflection, which is sometimes correlative with porosity and permeability development. When interpreting depositional environments, it is important to note that the SP deflection is contrary to what is implied with all other log traces in this well. With the exception of the SP log, other logging measurements are indicative of a channel deposit. This may be due to the stacking of sandstone beds and permeability variations that do not occur in a log-normal distribution with porosity.

The log of the well on the right, the No. 3-20 Hilseweck, is characteristic of marine (delta-front?) deposits having an upward-coarsening textural profile. Additionally, a thin channel may overlie this marine sequence (uppermost sandstone bed). This stratigraphic assemblage is indicative of a progradational deltaic sequence, which is interpreted as the main depositional environment of the area. The deposition of thicker channel deposits, which appear to cut down into the delta front, may have been affected by sea-level changes, causing stream reactivation. The marine deposits generally exhibit the best porosity and the cleanest sandstone at the very top of the depositional cycle, whereas optimum sandstone development in the fluvial channels is stratigraphically lower in the section. Variations of this may be confusing, as in this type log, where the best sand in the Hilseweck well appears to be in a thin channel above the marine sequence. In this case, incision or downcutting has bypassed this area. The porosity in the marine sandstone is typically less than 8–10%, and the logs indicate that the sandstone is very shaly. At many places, the marine sand almost directly underlies the Hartshorne coal; where this is the case, some question exists regarding the amount of gas reserves contributed by the Hartshorne coal.

In both type logs, the Hartshorne interval is about 80 ft thick. There is only one coal bed, which defines the contact of the Hartshorne Formation with the overlying McCurtain Shale Member of the McAlester Formation. The Hartshorne coal is present everywhere within the field and in most places within the study area. The base of the Hartshorne Formation (upper Atokan contact) is considerably more difficult and controversial to identify. In the field study area, it is considered to be the base of an incised channel sandstone, or a downward-fining sandstone/shale sequence represented by a resistivity inflection below 10–30 ohm-m. On well logs, this resistivity-inflection point has a somewhat hot gamma-ray response. Below this inflection point, the resistivity response for both the shallow and deep log traces is generally uniform for 50–100 ft or more. These log characteristics are shown on log traces for the Gulf No. 3-20 Hilseweck well (Fig. 11). For comparison purposes, surface mapping places the base of the Hartshorne Formation at the base of the lowermost Hartshorne sandstone. Obviously, surface-mapping criteria used to identify the lower Hartshorne boundary become a problem in the subsurface where there is no sandstone below the Hartshorne coal, or in gradational marine sequences.

The stratigraphy of the Hartshorne interval is best shown by detailed stratigraphic cross sections A–A′ and B–B′ (Figs. 12,13, in envelope). In section A–A′, which is oriented west to east across the field, a variety of facies are represented. In well 1, the Hartshorne is productive from a marine-sandstone sequence directly beneath the Hartshorne coal. The sand sequence has a distinct coarsening-upward textural profile, and in outcrop these types of deposits are intensely ripple bedded. Note that the perforated (productive) interval generally has between 50 and 100 ohm-m resistivity. This log profile is considered representative of a distal distributary mouth bar (delta fringe?) because of the shaliness of the sandstone. The distinctive upper and lower formation boundaries are most evident in this well, including the resistivity inflection at the formation base as previously described. In well 2, the producing interval is interpreted to be an incised channel. The upper and lower boundaries of this sandstone sequence are sharp. Two distinct sand beds are present, as shown by porosity changes on the density–neutron log, which has a cross-plot porosity of about 12–13%. Farther to the east, the log of the discovery well (well 3) shows a relatively thin sandstone in the upper part of the Hartshorne section. The perforated portion of the sandstone has a resistivity of about 80–90 ohm-m, but the log profile is not conclusive regarding depositional origin. Beneath this sandstone, the gamma-ray and resistivity logs have a coarsening-upward profile in the lower part of the Hartshorne section, which indicates a marine origin for this part of the Hartshorne interval. In the center of the field, at well 4, the Hartshorne is again productive from a channel sandstone, and the sharp erosional base and fining-upward textural profile is unmistakable. Note that the deep resistivity is >100 ohm-m in the perforated interval. East of this location, at well 5, the Hartshorne is entirely shale. However, a small but distinctive gamma-ray and resistivity spike at 3,578 ft, and the overlying "ratty" gamma-ray response, are clear indications that this interval was deposited in an abandoned channel. The recognition of this facies is critical, because it identifies the continuation of the channel at this location and indicates that channel sands are probably not very far away. Continuing the section to the east 2 mi, at well 6, the Hartshorne Formation thickens considerably to about 160 ft. In this well, the Hartshorne is deeply incised into the underlying Atoka shale, and the channel sandstone is stratigraphically lower than any sandstone producing in Cabaniss NW field. The basal Hartshorne sandstone is wet at this location (note the low resistivity of <5 ohm-m) but is part of a regionally extensive, incised river complex that is productive at several other places along the trend (see Pls. 1,3). It is important to note that in all the producing wells along this line of section, the resistivity (where shown) is consistently more than 80–100 ohm-m.

Cross section B–B′ (Fig. 13) is oriented in a north–south direction across the center of the field. The end wells, 1 and 5, are typical of shaly marine deposits around the edges of the field. Note that the perforated interval in well 1 includes the coal that directly overlies the Hartshorne sandstone. Wells 2 and 3 are interpreted to constitute channel facies and are only 1,200 ft apart. In well 2, the cleanest and most porous sandstone is at the very base of the sandstone interval but is "ratty" throughout the rest of the section. Some of the thin sandy intervals above the thin basal sandstone appear to have a coarsening-upward texture, as seen on the gamma-ray log. These variations in log shapes are probably caused by changes in depositional processes in the adjacent channel-margin or flood-plain environment. Well 3 is distinctly a fluvial deposit, and the porosity (10–12%) is best developed in the lower part of the sandstone sequence. Two distinct sandstone cycles are indicated on the logs, and the shale partings at 3,484 and 3,490 ft may be clay drapes. Farther to the south, in well 4, the Hartshorne consists of a progradational deltaic sequence, as evidenced by the two coarsening-upward sandstone cycles overlain by a thin channel(?) sand. This log response is believed typical of the first phase of Hartshorne deposition, which occurred in this area prior to incision and channel deposition and which is illustrated in well 3. In well 5, the Hartshorne sandstone is barely discernible, although a small SP kick and a resistivity kick give some evidence of a very thin sandstone reservoir beneath the Hartshorne coal. This relationship is repeated regionally throughout the Hartshorne outcrop belt, and many of these thin marine-sandstone deposits contain conspicuous storm rip-up clasts.

Structure

Cabaniss NW field lies along a northwest–southeast-trending trough that is probably a western extension of the Talawanda syncline (Pl. 5). On a regional scale, the study area lies within a broad depression that defines the western axis of the Arkoma basin. As such, the subsurface dip of the Hartshorne Formation throughout most of the northern two-thirds of the field is to the south, dipping as much as 2.5° (~225 ft/mi). Along the southern one-third of the field, the subsurface dip is to the northeast. A detailed structure-contour map of the study area (Fig. 14) depicts the top of the Hartshorne Formation (Hartshorne coal). As can be seen in this figure, the highest position of the field is in the northwest, just north of the synclinal axis in the S½ sec. 7, T. 6 N., R. 12 E. Here, the Hartshorne lies at –2,355 ft. Most of the field lies between the –2,350-ft and –2,450-ft contours, although one well has a structural pick of –2,666 ft in the synclinal axis in the NE¼ sec. 29, T. 6 N., R. 12 E. The relief of the gas column in Cabaniss NW field, therefore, is about 300 ft.

The regional structural interpretation of the Hartshorne Formation in the Arkoma basin (Pl. 5) indicates widespread and locally intense deformation. Because of this, it is likely that some faulting occurs within the study area, even though no faults are identified on the field structure map (Fig. 14). However, the structure-contour spacing as interpreted in Figure 14 is not erratic, based on a 50-ft contour interval, which indicates that no major displacements have occurred. Available reservoir-pressure data do not conclusively indicate that compartmentalization has occurred because of structure.

Hartshorne Sandstone Distribution and Depositional Environments

Figure 15 shows the gross thickness of the Hartshorne sandstone for all the wells in the study area. The gross-sand thickness is the total thickness of sandstone in the Hartshorne Formation, regardless of porosity, as interpreted from gamma-ray logs (determined from the 50% sand–shale line). Two sand trends are mapped separately in this figure: undifferentiated Hartshorne sandstone that is productive within the field (trending northwest–southeast), and the regional incised channel (trending northeast–southwest). The depositional history of these two trends is unrelated, as mentioned in the regional summary.

The approximate production limit of Cabaniss NW field is interpreted to coincide with the 5-ft gross-sandstone contour line (Fig. 15). This boundary was selected because some wells have several feet of gross sandstone but no net sandstone having ≥8% porosity. Only a few areas within the entire study area actually have no sandstone within the Hartshorne interval, which is why the gross-sandstone isopach is not zero along the perimeter of the field. One place where there is no sandstone is in Gulf's No. 4-A deviated hole in the NW¼ sec. 21, T. 6 N., R. 12 E. In this well, abandoned-channel facies appear to consist entirely of shale. This information is still valuable because the location and orientation of the channel can be determined, and this might assist in development drilling.

The gross-isopach pattern is somewhat lobate over a 2-mi by 4-mi area, but the shape is not distinct. The thickest part of the sandstone occurs in a narrow, linear trend oriented to the northwest and is primarily composed of fluvial-channel deposits, whereas sandstone in the thinner areas adjacent to the channel is of shallow-marine origin. No distinction in the gross-isopach map is made with respect to sandstone facies. A separate map later in this report distinguishes facies. Channel deposits in Cabaniss NW field occupy an areal extent about 0.5–0.67 mi wide and >3 mi long. The gross sandstone has a maximum known net thickness of about 40 ft, and most of the sandstone within the channel facies is thicker than 20 ft. The marine facies is very thin and optimistically is only about 5–10 ft thick. Sandstone within the field is interpreted not to be continuous with sandstone contained in the deeply incised regional channel mapped in the southeastern part of

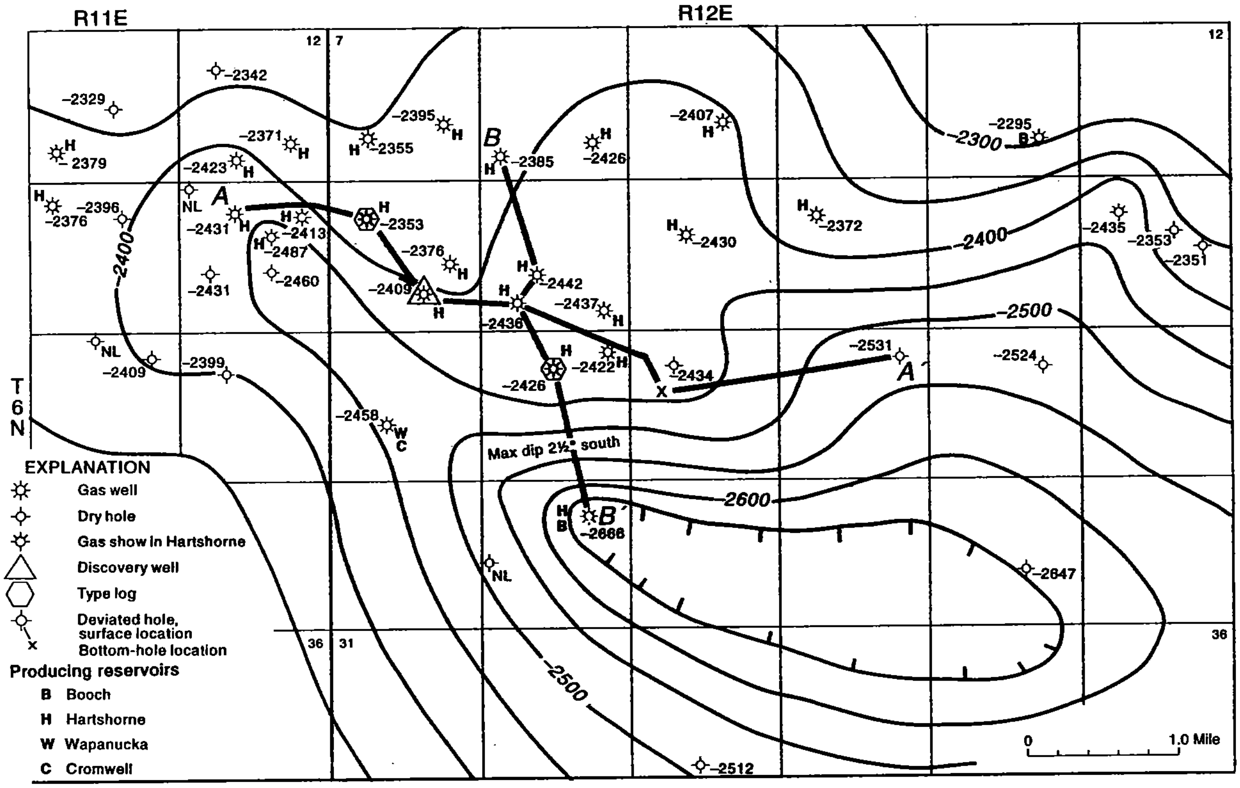

Figure 14. Structure map depicting the top of the Hartshorne Formation, Cabaniss NW field study area. Contour interval, 50 ft. Datum is mean sea level. See Figure 10 for well names. Lines of stratigraphic cross sections A–A′ and B–B′ are shown.

the study area. This channel complex has >80 ft of gross Hartshorne sandstone, but it is wet. In the very northwestern part of the study area, the productive trend of the Hartshorne continues farther to the west, where several additional gas fields are located (Pls. 1,3).

A net-sandstone isopach map (Fig. 16) shows the thickness of sandstone in the study area with ≥8% porosity. In producing Hartshorne wells, the net-sand thickness ranges from only a few feet to 40 ft. Throughout the mapped extent of the field, the average thickness is ~24 ft and is usually about 10–30 ft. The net-sand map (Fig. 16) is similar in overall appearance to the gross-sand map (Fig. 15), particularly in the center of the field where channel facies prevail. The most significant reduction in the thickness of net sand versus gross sand is in the adjacent marine facies, where most wells have little or no net sand within the gross-sand interval. Despite this, some of these wells produce significant amounts of gas, such as the Hartshorne wells in secs. 9 and 16, T. 6 N., R. 12 E. Each of these two wells has produced more than 250 MMCFG. In the absence of any significant sandstone reservoir, these wells and others like them may have gas-reserve contributions from the overlying coal, or else the reservoir may be extensively fractured. Because much of the shale in the Hartshorne interval has a baseline density porosity of about 4–5%, it is difficult to interpret porosity for such dirty sandstones. This situation is particularly evident in the marine facies where the gamma-ray response is minimal, making the distinction between sandstone versus shale unclear.

The approximate limit of the Hartshorne sandstone reservoir includes the entire area with >0 ft of net sand (Fig. 16). Most of the wells with no net sandstone are dry, yet significant gas production occurs outside this area in the northern part of the study area. This situation is somewhat puzzling and severely interferes with traditional gas-reservoir calculations, because reservoir thickness and areal extent are "wild cards" in the reserve formula (see superscript *e*, Table 4). Using the 5-ft gross-sandstone contour (which is considerably larger in areal extent than the zero net-sandstone contour) seems to contribute to a reasonable reserve calculation. Yet, by using the gross-sand limit rather than the net-sand limit, reserve calculations are probably compensating for inherent errors in the geologic understanding of this field.

The net-sandstone map (Fig. 16) indicates that the sandstone is more or less continuous within the thicker channel facies, which is where most of the net sandstone occurs. This undoubtedly is not the case, and large-scale bedding irregularities are expected. However, many of the variations in deposition (scour and fill, cross-bedding, thinning, and thickening) probably have a sand-on-sand relationship, which may create flow barriers but not complete

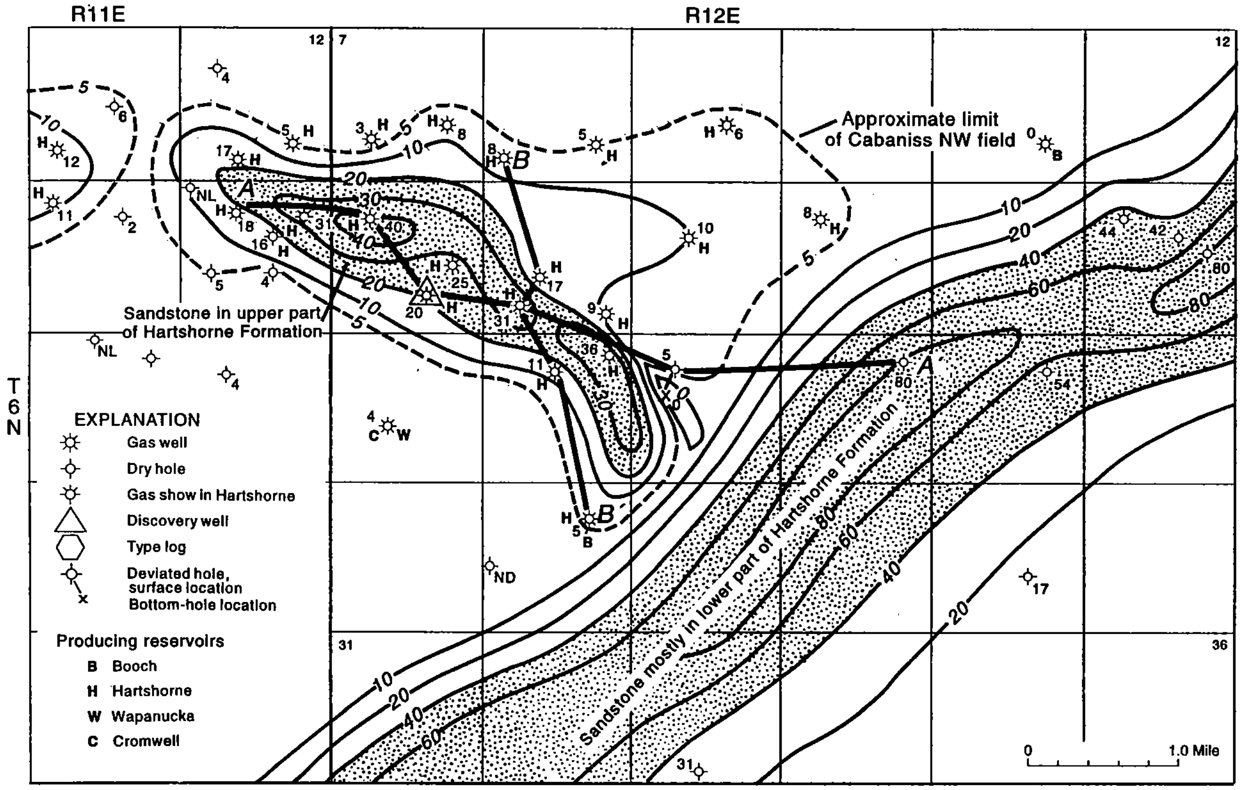

Figure 15. Gross-sand isopach map of the Hartshorne sandstone in Cabaniss NW field. Gross sand includes all sandstone in the Hartshorne Formation, regardless of porosity or facies. Contours in feet; interval is indicated. See Figure 10 for well names.

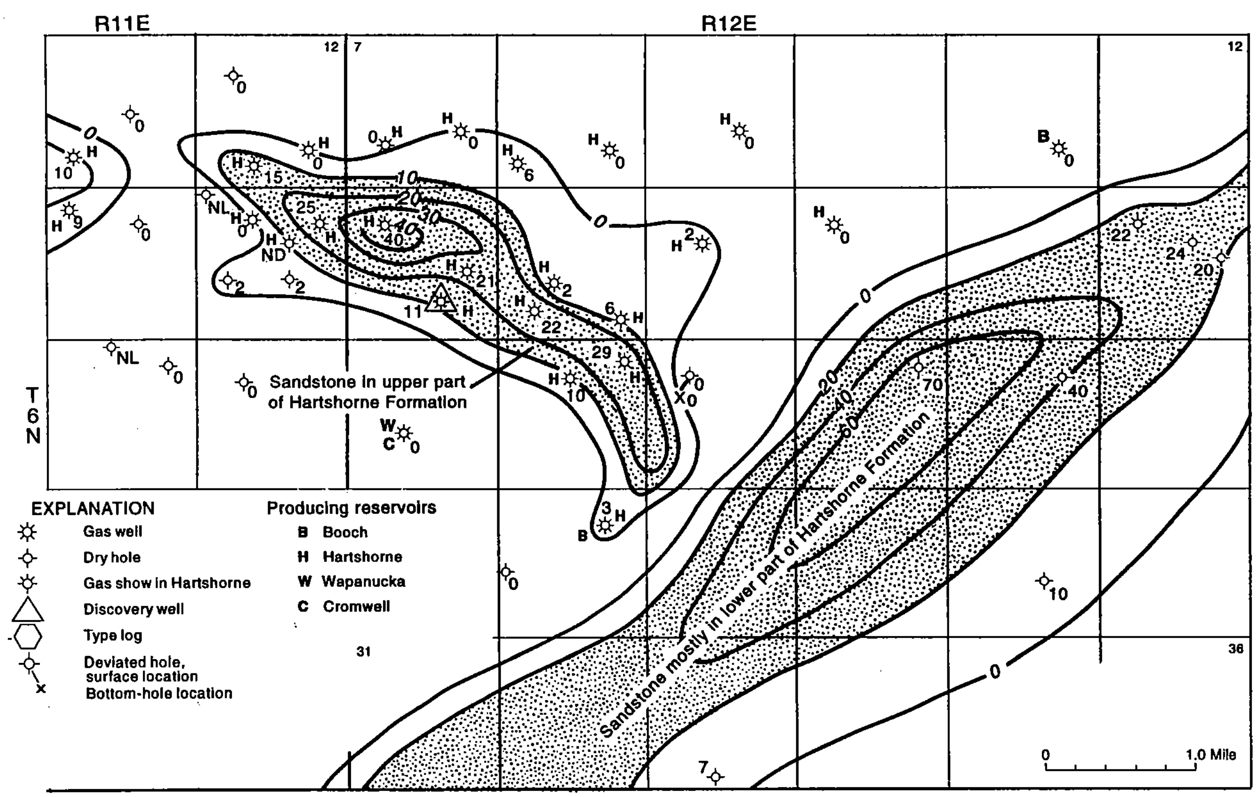

Figure 16. Net-sand isopach map of the Hartshorne sandstone in Cabaniss NW field. Net sand has log porosity ≥8%. Contours in feet; interval is indicated. See Figure 10 for well names.

compartmentalization of individual sandstone sequences. This is because individual sandstone beds are stacked one upon another and interfinger laterally so that the net isopach map does not "zero out" along the trend. Besides flow barriers in the net-sandstone distribution, the reservoir may have small-scale faulting that could facilitate compartmentalization. Reservoir-pressure data are inadequate to support this interpretation.

TABLE 4. – Reservoir-Engineering Data for the Hartshorne Sandstone in Cabaniss NW Field, Pittsburg and Hughes Counties, Oklahoma

Reservoir size (area within 5-ft gross contour)	~4,224 acres
Reservoir volume	~65,800 acre-ft
Depth	about 3,200–3,400 ft
Spacing (gas)	640 acres with increased density to 320 acres
Gas–water contact	None observed
Porosity (in producing wells)	5–14% (average ~8%)
channel	~10.5%
marine[a]	~7.4%
Permeability[b] (see plot, Fig. 18)	0.5–3 md
Water saturation (calculated using $R_w = 0.04$)	11–43% (average ~20%)
Thickness (gross sand, no ϕ cutoff)	Field average ~15.6 ft
channel	~24 ft
marine	~8 ft
Reservoir temperature	110°–115°F
Gas density	0.60–0.64
Z factor (compressibility)[c]	0.91 est.
B_g (gas formation volume factor)[d]	43 est.
Maximum wellhead pressure	580 PSI (max. recorded field ISIP)
Initial reservoir pressure (calculated bottom-hole)	630 PSI
OGIP[e] (volumetric-field)	8,181,000 MCF
Cumulative field gas production (to 9/97)	3,553,000 MCF
Recovery to date	43%
Recovery MCF/acre-ft (field)	~54 MCF/acre-ft

[a] Porosity values estimated from logs to be <8% (net-sand cutoff) were considered to be ~5% based on core data.

[b] Taken from Hartshorne core in the Regal No. 1 Hilseweck, NE¼SW¼ sec. 17, T. 6 N., R. 12 E. (furnished by Arkoma Gas). Permeability values in shaly intervals are always <0.5 md.

[c] Compressibility factor (Z) estimated from standard reservoir-engineering chart using $T_{res} = 115$°F and $P_{res} = 630$ PSI. T_{res} = reservoir temperature, P_{res} = reservoir pressure.

[d] 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.

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

Facies Mapping

Depositional environments were interpreted from wireline-log signatures in order to illustrate the generalized depositional setting within the study area (Fig. 17). Logs from all wells in the study area were used to make this interpretation, particularly gamma-ray, resistivity, and density logs. Two distinct facies are identified within the producing limits of Cabaniss NW field and include channel facies and marine-bar facies.

Channel Deposits

The depositional environment of these sediments appears to be part of the original lobate deltaic system that prevailed regionally. The channel sands commonly occur in a prograding stratigraphic sequence, because they overlie marine (distributary mouth bar deposits) of the delta front. In most cases, however, the channel deposits have a significant downcutting or incised character in that they are stratigraphically lower than marine sands but yet are probably younger. This situation is prevalent in falling-stage depositional systems, whereby fluvial systems are slightly reactivated by minor changes in sea level. The channel deposits in Cabaniss NW field are distinctly smaller in size and areal extent than the deeply incised regional valley-fill channel deposits mapped separately in the southeastern part of the study area. These latter channel deposits were caused by a major forced regression, owing to significant lowering of sea level.

Within the fluvial (channel) facies, sediments consist predominantly of sandstone and/or shale. Because of the morphology of the sandstone (areal distribution pattern and stratigraphic profile), the sandstone deposits are interpreted to be some variation of a longitudinal bar, although a few log profiles strongly resemble a traditional point bar. Log and map characteristics that support the interpretation of channel deposits include (1) a sharp basal contact of sandstone with shale, (2) an overall fining-upward textural profile on gamma-ray logs, (3) the presence of clay drapes interbedded with the sandstone, and (4) a very narrow, elongated distribution pattern with abrupt thinning and thickening of sandstone. Sediments deposited within the fluvial regime that are predominantly shale are

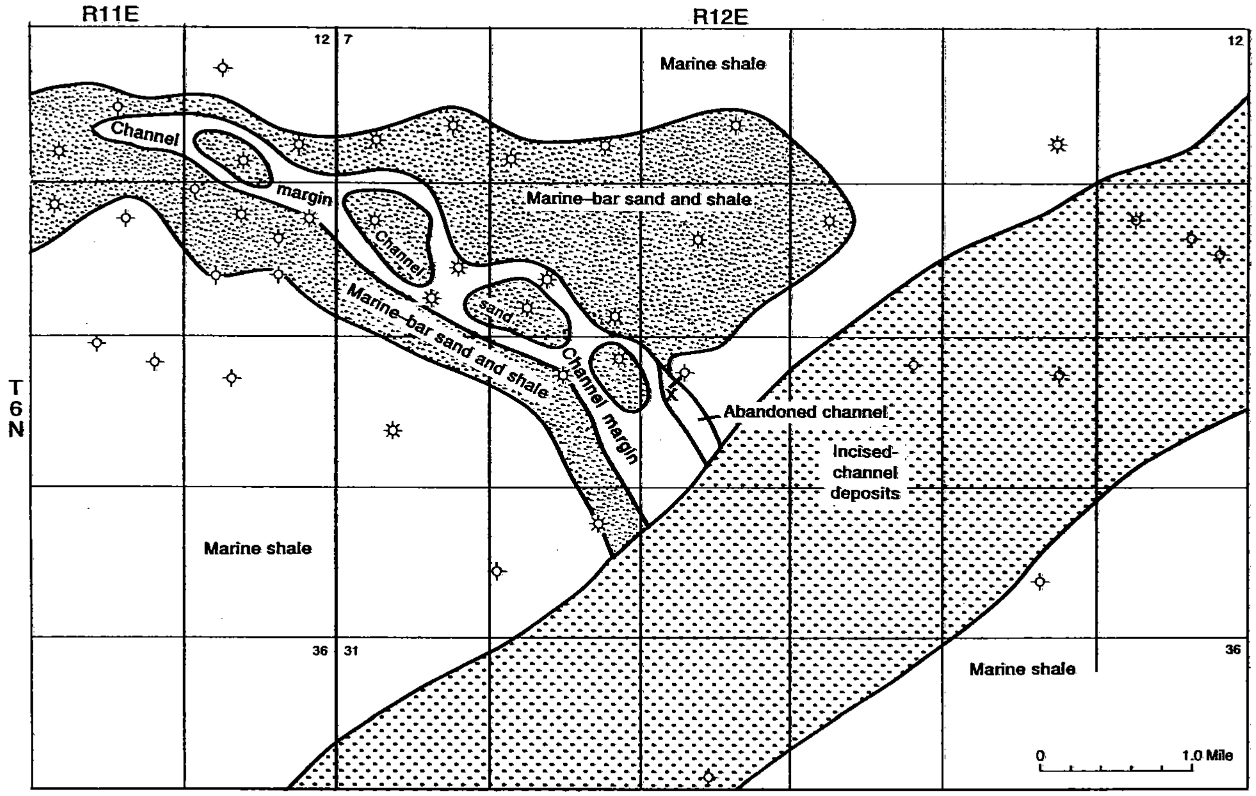

Figure 17. Depositional-facies map of the Hartshorne Formation in the Cabaniss NW field study area.

interpreted to be channel-margin, abandoned-channel, or flood-plain deposits and may not always be part of the reservoir. It is still necessary to be able to identify these types of sediments on well logs so they can be distinguished from the laterally adjacent marine facies.

Delta-Front (Distributary Mouth Bar?) Deposits

Sandstone that is interpreted to have a coarsening-upward textural profile, as indicated from gamma-ray, resistivity, and porosity logs, is considered to have originated from depositional processes other than those for fluvial-channel deposits. Sandstones having these characteristics are productive within Cabaniss NW field but occur primarily along the northern edge of the field. They are here loosely called *shallow-marine bars,* although this a highly generalized term and should not be routinely used unless clarified, as in this paper. A good example of the marine facies that is productive in this field is shown in well 1, cross section A–A′ (Fig. 12), and in wells 1, 4, and 5, cross section B–B′ (Fig. 13). These well logs show the Hartshorne sandstone to have a distinctly coarsening-upward textural profile.

Most marine bars (including distributary mouth bars) are normally good reservoirs. However, the thinness and lack of thick, clean sandstone in many of these types of deposits in the Hartshorne Formation reduce their potential as gas reservoirs. This occurs because the best part of the bar, in terms of reservoir quality (upper-bar facies), is usually poorly developed and thin. The lower-bar facies and transition zone contain more interstitial clay and/or interbedded shale, which is detrimental for a reservoir. Also, the thin shallow-marine (delta-front?) deposits in the Hartshorne Formation have a tendency to be highly cemented with silica, making them highly impermeable.

Core Analysis

One core was made available by Arkoma Gas in the study area. The Regal Petroleum No. 1-17 Hilseweck is interpreted to represent channel-margin facies and has produced >309 MMCFG since 1979. The log-normal plot (Fig. 18) shows no correlation of porosity versus permeability. The data for this plot are compiled in Table 5. Most of the sandstone in this core contains considerable interbedded and interstitial clay and is a poor reservoir by itself. The proximity of this well to a more porous sandstone interval (see net-sandstone isopach map, Fig. 16) may have contributed to the relatively good cumulative production, along with the help of a large fracture treatment. The highest recorded permeability is only 2.7 md at the base of the cored interval. The highest porosity was a little over 7%, recorded near the top of the cored interval. Unfortunately, these core data are not representative of a typical clean channel deposit, as seen in several wells in the field cross sections (Figs. 12,13).

TABLE 5. – Porosity and Permeability Data of the Hartshorne Interval in the Regal No. 1-17 Well, NE¼SW¼ sec. 17, T. 6 N., R. 12 E.[a]

Depth (ft)	Porosity	Permeability (md)
3,451	7.2	0.1
3,452	7.0	2.5
3,453	7.2	0.1
3,454	6.6	0.3
3,456	3.9	1.0
3,457	5.0	0.1
3,463	4.9	0.7
3,464	5.0	1.3
3,465	5.1	2.3
3,472	4.8	0.8
3,474	4.7	0.1
3,476	5.5	0.3
3,479	4.6	0.2
3,480	4.7	0.1
3,481	4.5	0.2
3,492	5.2	0.1
3,493	5.0	2.2
3,494	5.6	0.1
3,495	1.8	0.1
3,496	5.5	0.7
3,498	3.5	0.4
3,499	5.5	0.1
3,500	5.7	0.1
3,501	6.8	0.6
3,503	3.7	2.7

[a]This section of the Hartshorne is interpreted to be a shaly channel-margin deposit. Missing intervals are shale and were not analyzed. These data are plotted in Figure 18.

FORMATION EVALUATION

The identification and evaluation of Hartshorne sandstone in Cabaniss NW field can be somewhat complicated, mainly because many of the marine sandstones are very thin and shaly. In fact, many of these sand intervals contain no net sandstone, even with a 6%-porosity cutoff. Conversely, the interpretation and evaluation of channel sandstones is straightforward in that they generally have good reservoir properties (i.e., a clean gamma-ray profile, good porosity, and high resistivity). However, some of the early field wells were drilled with air, causing operators to run only density-porosity logs and resistivity logs with only the deep-induction recording. In the absence of a flushed zone created by a mud-based drilling procedure, shallow-recording resistivity logs, which are highly influenced by filtrate invading the flushed zone, are not run. Reservoir evaluations using these wireline logs are therefore less accurate but nevertheless can be reasonably interpreted. Reservoir characteristics of the Hartshorne sandstone in Cabaniss NW field are shown in Table 4.

The deep or "true" resistivity (R_t) of productive Hartshorne sandstone in Cabaniss NW field ranges from about 50 to >400 ohm-m and is usually in the range of 175–400 ohm-m. With an average porosity of 7–10%, the Hartshorne probably won't produce significant gas with a value less than about 30–50 ohm-m. Although a wide range in resistivity values exists within the field, there doesn't appear to be any specific area with anomalously high reservoir resistivity. Shaly reservoirs overall had lower apparent resistivities, which translated into higher calculated water-saturation (S_w) values. Because some wells were drilled with air and did not have the shallow formation resistivity recorded when logged, one of the traditional methods for detecting invasion (and therefore permeability and porosity) was not available for some wells. This indirect method for determining reservoir quality is based on the assumption that the amount of invasion is proportional to the porosity and permeability of the reservoir, and that the amount of separation between the shallow- and deep-resistivity curves was affected by the degree of invasion. Air drilling also produces no mud-cake buildup, so observations of this phenomenon were also unavailable to aid in estimating zones of invasion.

Porosity determinations by means of density logs were estimated, taking into account the normal "gas effect" that causes the density porosity to be too high (usually ~150% above actual porosity). Without the neutron log (which is used to determine cross-plot porosity), a simple method for attenuating the density porosity was used and involved the multiplication of indicated density porosity by a fraction, usually ranging from 0.7 to 0.6. The resulting porosity more closely approximates cross-plot porosity attained from traditional density–neutron logs. When density–neutron logs were available, the cross-plot porosity was used. Of significance is the observed gas effect (crossover), which may be 8–14 porosity units (see well 2, cross section A–A′, Fig. 12, or wells 3 and 5, cross section B–B′, Fig. 13). For many deeper reservoirs, this amount of crossover would be characteristic of gas depletion, but for the Hartshorne (which is generally an underpressured reservoir) this is not the case.

Water-saturation (S_w) calculations for the Hartshorne sandstone in the study area range from about 5% to 89%, the higher values being attributed to the sandstone in the large incised channel southeast of the field, which is nonproductive and wet. The S_w in most field wells was calculated at 5–34%, averaging ~20%. Shaly marine sands always calculated toward the high side of the S_w range. Calculations were made using the formula $S_w = \sqrt{F \times R_w / R_t}$. The formation-water resistivity (R_w) was assumed to be 0.04 ohm-m at formation temperature. Lowering the R_w, for instance, to 0.03 would have reduced the S_w to only a few percent, which is unreasonable. The Archie equation for formation factor ($F = 1/\phi^2$) was used, because S_w calculations seemed more reasonable in using this equation for this particular reservoir (tightly cemented). Using a modi-

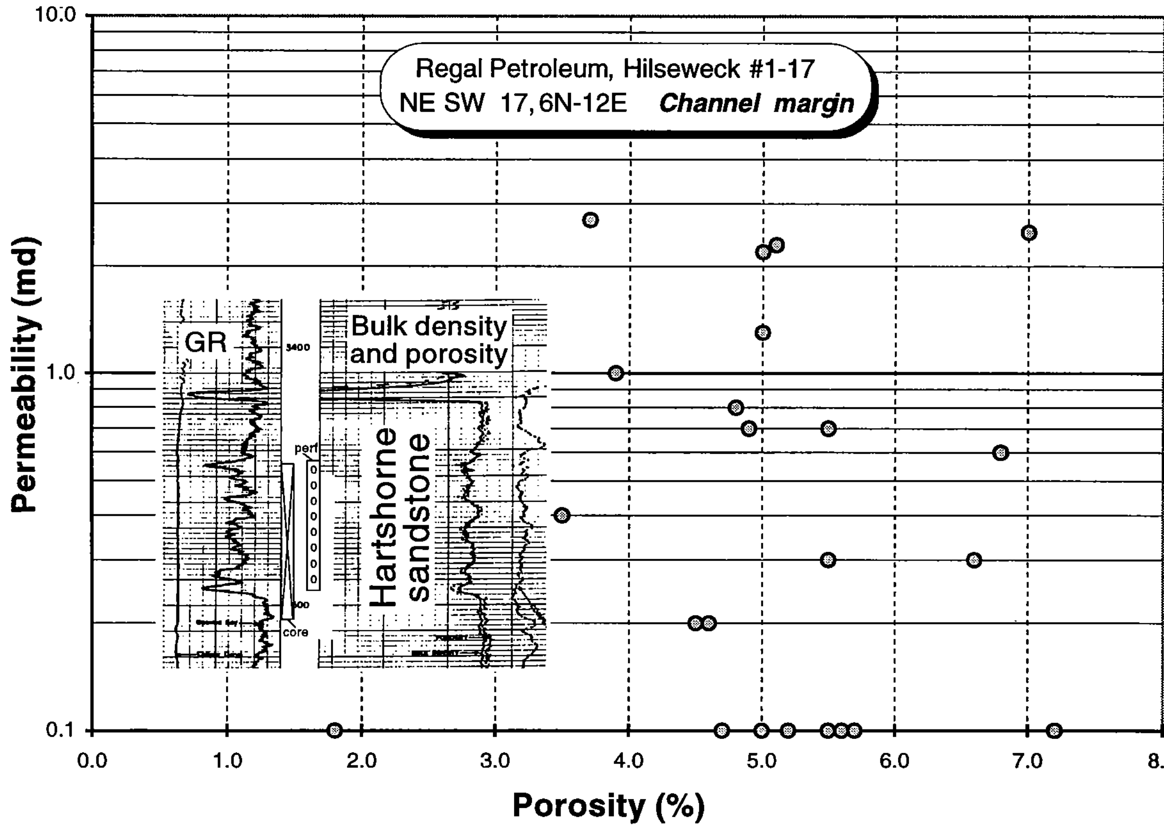

Figure 18. Core porosity and permeability data plotted from a Hartshorne shaly channel-margin sequence in Cabaniss NW field. No distinct trend line can be interpreted through these data points. Data are tabulated in Table 5.

fied *F* equation generally resulted in calculated S_w values that were unrealistically low, and, conversely, hydrocarbon-saturation determinations were too high. R_t, or "true" resistivity, was taken directly from the deep-resistivity log but may have been suppressed in shaly intervals. Porosity values were also taken directly from density logs, but, because of gas effect, they were reduced (see method described in previous paragraph) to reflect actual reservoir conditions. Neutron porosity was not used when unaccompanied by density porosity because of the highly variable clay content of the Hartshorne (clay causes the effective porosity to read high on neutron logs) and because of the severity of gas effect, which attenuates neutron porosity. Porosity determinations from most density logs were calculated by using a matrix density of 2.71 g/cm^3.

Oil and Gas Production

The estimated cumulative gas production from the Hartshorne in Cabaniss NW field from July 1979 through September 1997 was 3,553,000 MCF. This is believed to represent about 43% of the recoverable gas in place, which is estimated to be 8.18 BCF for the field (Table 4). The estimated recovery with regard to current cumulative gas production is 54 MCF/acre-ft. The recovery will, of course, increase with time as the reservoir is being produced. Because detailed pressure data were not generally available, the typical *P*/*Z* plots, or production-versus-pressure plots as used in gas-reservoir analysis, were impossible to construct.

Production-decline curves for three wells having different reservoir properties in Cabaniss NW field are shown in Figure 19. With each production-decline curve, an inset graph shows cumulative production over time, so some idea of ultimate recovery can be extrapolated. The plot in Figure 19A shows the production curve for a shaly marine-bar sand during the 19 years of 1978–97. The perforated interval in this well has no net sandstone and directly underlies the Hartshorne coal. Cumulative production was 259 MMCFG. The annual-production decline for the Regal No. 1 Hilseweck was small for several years (generally <5%), following a shut-in period in 1987. However, the decline rate accelerated in 1996 to 14% but then held flat over a projected 12-month period in 1997.

The Arkoma Gas No. 3 Ballinger well is the best producer in the field (848 MMCFG). The depositional environment of the Hartshorne sandstone in this well is difficult to interpret and may be, in part, a channel sandstone. The net-pay thickness is 25 ft. The annual production decline, shown in Figure 19B, was highly variable during the first 6 years and was shut in for about 2 years during 1990–91. The relatively erratic production

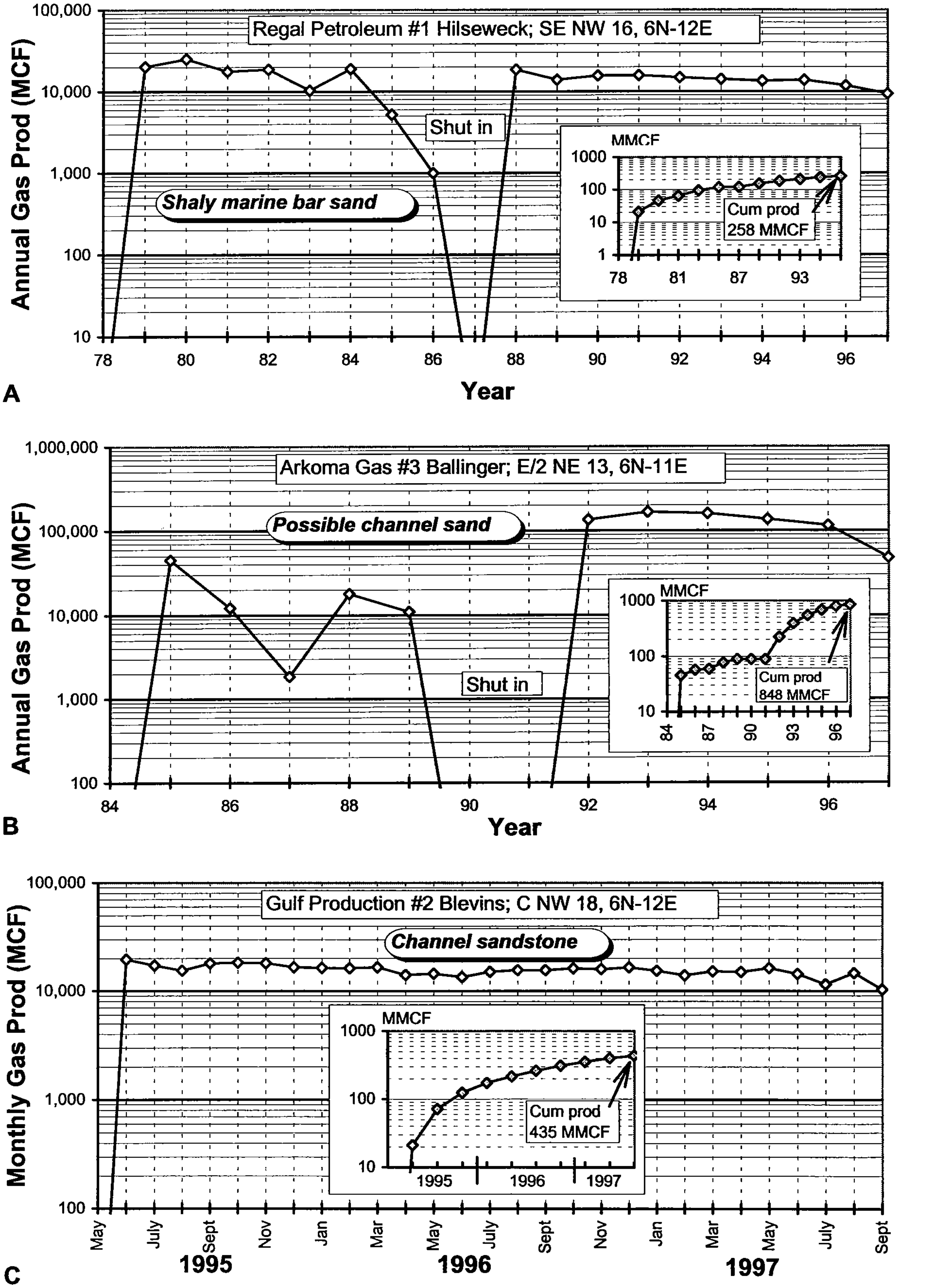

Figure 19. Production-decline curves for three wells in Cabaniss NW field. For the three wells, gas production from the Hartshorne sandstone is attributed to different facies as indicated. Inset graph shows cumulative gas production for that well. Production for 1997 is for only 9 months.

rate for the 7 years prior to 1992 was primarily due to gas-delivery problems (pipeline access). Thereafter, production increased greatly in 1992 and declined slowly for the next 3 years (3% in 1994). Starting in 1995, the decline rate increased dramatically to 15% in 1995–96 and to 45% projected for 1997. The sudden drop in production of the No. 3 Ballinger well, starting in 1995, coincides with completion of the No. 2 Blevins well (Fig. 19C), which is only about half a mile east.

The graph shown in Figure 19C represents production from a channel sandstone having 40 ft of net pay. The production decline for this well extends over a 2.3-year period, starting in May 1995 and ending in September 1997. The monthly production decline was generally negligible for the life of this well. The production decline for the only full year on-line (1996) was about 5%. This well produced 436 MMCFG and is still on a moderate incline of cumulative production (see inset graph). This well is probably in communication with the No. 3 Ballinger well (Fig. 19B), because the rate of decline dramatically increased for the No. 3 Ballinger well shortly after the No. 2 Blevins began production.

The three production curves illustrate that well-production performance is generally related to reservoir quality, as noted on the wireline logs. The first plot (Fig. 19A) is the exception, because there is no net-sand reservoir in that well. Consequently, gas production must be coming from other sources such as the adjacent Hartshorne coal bed or from a fractured shaly reservoir. The illustrated production-decline curves also indicate, in a general way, that a significant percentage of the original gas in place has already been produced (~43%). Some wells show a moderate decline in monthly or annual production and a slow incline in cumulative production. Other wells show a relatively small reduction in monthly gas production, even after 12–19 years of production. However, depletion in many parts of the field will begin to accelerate because of the number of competing wells currently producing from the Hartshorne reservoir.

A gas-production map (Fig. 20) shows cumulative Hartshorne production, the dates of first production, and various pressure data for each well in the field. Cumulative production does not always appear to be related to the date of first production (wells were completed over a 19-year time span) but rather to reservoir quality and thickness. Many recently completed high-volume wells are close to much older wells that have higher (or lower) cumulative gas production. This information supports the concept of drilling increased-density wells on 160-acre spacing (four wells per section) rather than the original concept of 640-acre spacing (one well per section). Facies irregularities and lateral changes in reservoir continuity and quality commonly make increased-density drilling necessary in order to expediently recover hydrocarbons, such as in this field.

Most of the better wells in Cabaniss NW field produce from channel sandstones. Exceptions are the three wells in secs. 9, 15, and 16, T. 6 N., R. 12 E., which produce from thin marine sands or the Hartshorne coal(?) (see cumulative production values, Fig. 20). Wells that were completed in channel reservoirs had a cumulative production of 175 to 848 MMCFG per well, and most of these wells were in service for only 2 to 4 years (from 1995). Nearly any well with at least 20 ft of net channel sandstone will produce at least 250 MMCFG, and often much more. The three best wells that produce from marine sandstone have a cumulative production of 161–257 MMCFG per well over 18 years. Most wells that produce from marine-sandstone reservoirs have a cumulative production of less than about 50 MMCFG per well.

Wells completed in the channel facies typically had initial gas production of 500–1,000 MCFGPD. The better wells completed in the marine-sandstone facies had similar initial-production values when compared with the channel-sand reservoirs, but most marine reservoirs produced much less gas initially. The initial shut-in tubing pressure (ISIP) for all wells, regardless of facies, was about 450–600 pounds per square inch (PSI), and the flowing tubing pressure (FTP) was generally about 150–300 PSI. A few wells (channel reservoirs) had FTPs >500 PSI, which is very high in comparison with the ISIP. Flowing tubing pressures that are relatively high in relation to the shut-in tubing pressure generally indicate good reservoir conditions. Flowing pressure in really tight rocks is considerably smaller in proportion to the shut-in pressure.

Well-Drilling and Well-Completion Practices

Wells in the Cabaniss NW field area have been drilled by means of both mud and air. The deciding criterion is usually depth, because water invasion into the wellbore limits the use of air. The discussion of drilling techniques is beyond the scope of this study, but some important guidelines are noted for Hartshorne wells in the study area. Most wells targeting the Hartshorne are less than 3,500 ft deep. Using the procedures commonly employed by most Hartshorne operators, air drilling usually encounters water problems below 3,000 ft. Therefore, the choice of drilling techniques is mandated by depth, or becomes problematical when drilling deeper. Air drilling can accommodate a certain amount of water, and the process develops a mist when formation water is encountered. The high pressures used in air drilling can usually overcome a fair amount of water encroachment during the drilling process. The problem arises when air drilling is shut down during the night, at which time water drains into the wellbore, making it difficult or impossible to resume air drilling the next day. Because air drilling utilizes no mud or blowout protectors for wellbore-pressure maintenance, a safety hazard occurs from natural gas leaking from the wellbore. Because of this, air drilling normally is not conducted at night, and water seeping into the bottom of the wellbore overnight can kill an air-drilling attempt. Therefore, operators tend to prefer mud-

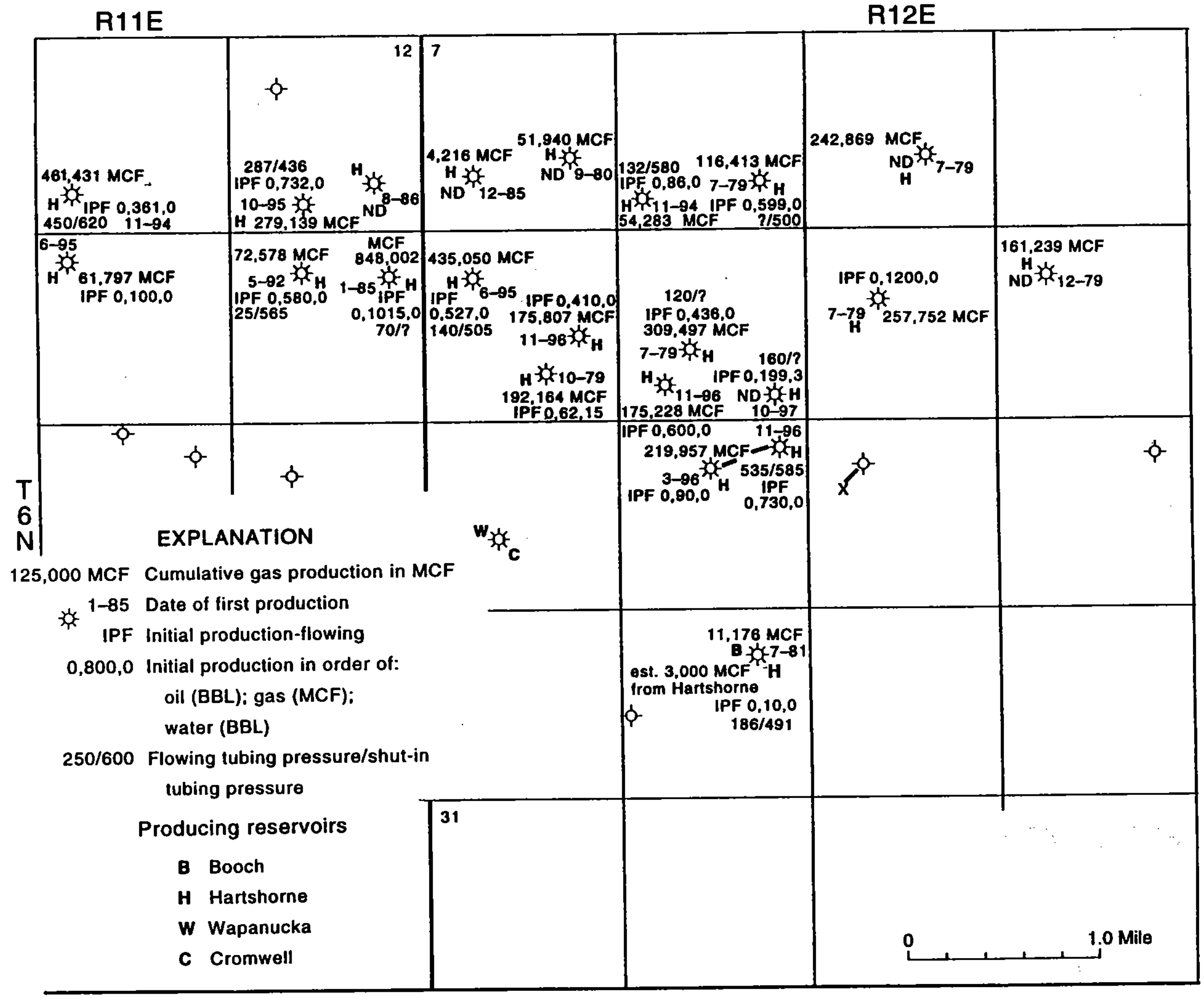

Figure 20. Map showing cumulative Hartshorne gas production, date of first production, flowing tubing pressure (FTP), shut-in tubing pressure (SITP), and initial production flowing (IPF) for wells in Cabaniss NW field. See Figure 10 for well names. Production tabulated through September 1997.

based drilling systems when drilling wells where water encroachment or depth limitations are expected.

When wells are shallow enough, air drilling is considerably quicker and less expensive compared with mud-based procedures. Air drilling is acceptable as long as water is not encountered; otherwise, drilling is converted to a water–mud system using a conventional rotary bit. Several drawbacks are encountered when completing an air-drilled well. First, wireline logs generally record only the deep (induction) resistivity; a shallow recording is redundant or unnecessary, because a flushed zone is not created during drilling. Second, there is no mud-cake buildup adjacent to permeable zones, as there is no invasion of drilling fluids when using air. Consequently, the caliper log has less significance in reservoir zones. And third, most operators only run density logs in air-drilled wells. In the absence of the neutron log, porosity determinations are more difficult, owing to gas effect. Density–neutron logs, which are commonly run in water/mud-filled holes, are characterized by a conspicuous crossover effect in gas zones, which makes cross-plot porosity determinations easy.

In the Cabaniss NW field area, operators usually set 250–400 ft of 8.5-in. surface casing, and then 4.5-in. production casing at or very near the bottom of the hole. In all productive wells, the Hartshorne interval was perforated where the sandstone had high resistivity (usually ≥50 ohm-m, but also as low as 30 ohm-m) and relatively good porosity (usually corrected density porosity ≥8–10%), or where density–neutron crossover porosity was evident. The wells are acidized with 1,000–2,000 gal of 7.5% hydrochloric acid (HCl), and then stimulated with a fracture treatment. Because there is no water leg in this field, any porous sand was perforated (and sometimes a lot more!). Fracture treatments used anywhere from 18,000 to 66,000 gal and about 25,000–66,000 lb of sand. A conventional vertical hole drilled with mud having a single-zone completion would cost about $150,000–$155,000 (in 1998). Dry-hole costs would be about half this amount, or about $65,000.

KIOWA NW FIELD

(Hartshorne gas reservoir in secs. 25, 26, 34, 35, 36, T. 3 N., R. 12 E., and secs. 19, 20, 30, T. 3 N., R. 13 E., Pittsburg County, Oklahoma)

INTRODUCTION

The Kiowa NW field study area is located in southwestern Pittsburg County in southeastern Oklahoma (Fig. 21). The 15-section study area is in the Arkoma basin about 21 mi southwest of McAlester and about 5 mi northwest of the Choctaw fault (Pl. 1). As recognized by the Oklahoma Stratigraphic Nomenclature Committee, this study area encompasses only a part of the Kiowa NW field, which formally includes production from several reservoirs over a much larger area. The mapping for this project is limited to the Lower Hartshorne Member, which produces gas from incised fluvial-channel deposits. The production limits of this reservoir are still open-ended on both sides of the sand trend. Cumulative gas production to date is about 4 BCF. The producing reservoir reaches a maximum known thickness of about 100 net ft, and the geometry of the reservoir appears to be some form of longitudinal bar rather than a point bar. A map identifying operators, well locations, well numbers, and principal leases within the field area is shown in Figure 22.

Gas production was first established in the Kiowa NW field study area in 1977, with the completion of two wells northwest of the field in secs. 22 and 26, T. 3 N., R. 12 E. These wells were completed in the older Cromwell sand and Wapanucka Limestone. The Hartshorne sandstone in these two wells lies in a parallel channel complex, but the sand was wet. About 4 years later, in November 1981, Texland drilled the No. 1 Shields well (NE¼SW¼NE¼ sec. 25, T. 3 N., R. 12 E.) and discovered the Hartshorne gas reservoir. It is probable that this test well originally targeted the deeper Cromwell and Wapanucka zones and was dually completed in the Atoka and Wapanucka zones. In this well, the Hartshorne had a calculated absolute open-flow (CAOF) of 283 MCFGPD from 42 ft of net Hartshorne sandstone with a porosity ≥8%. Although the Hartshorne in the Texland well had a clear-channel log signature, the Hartshorne trend was not developed by Texland, possibly because of the relatively poor initial production in comparison with the deeper reservoirs.

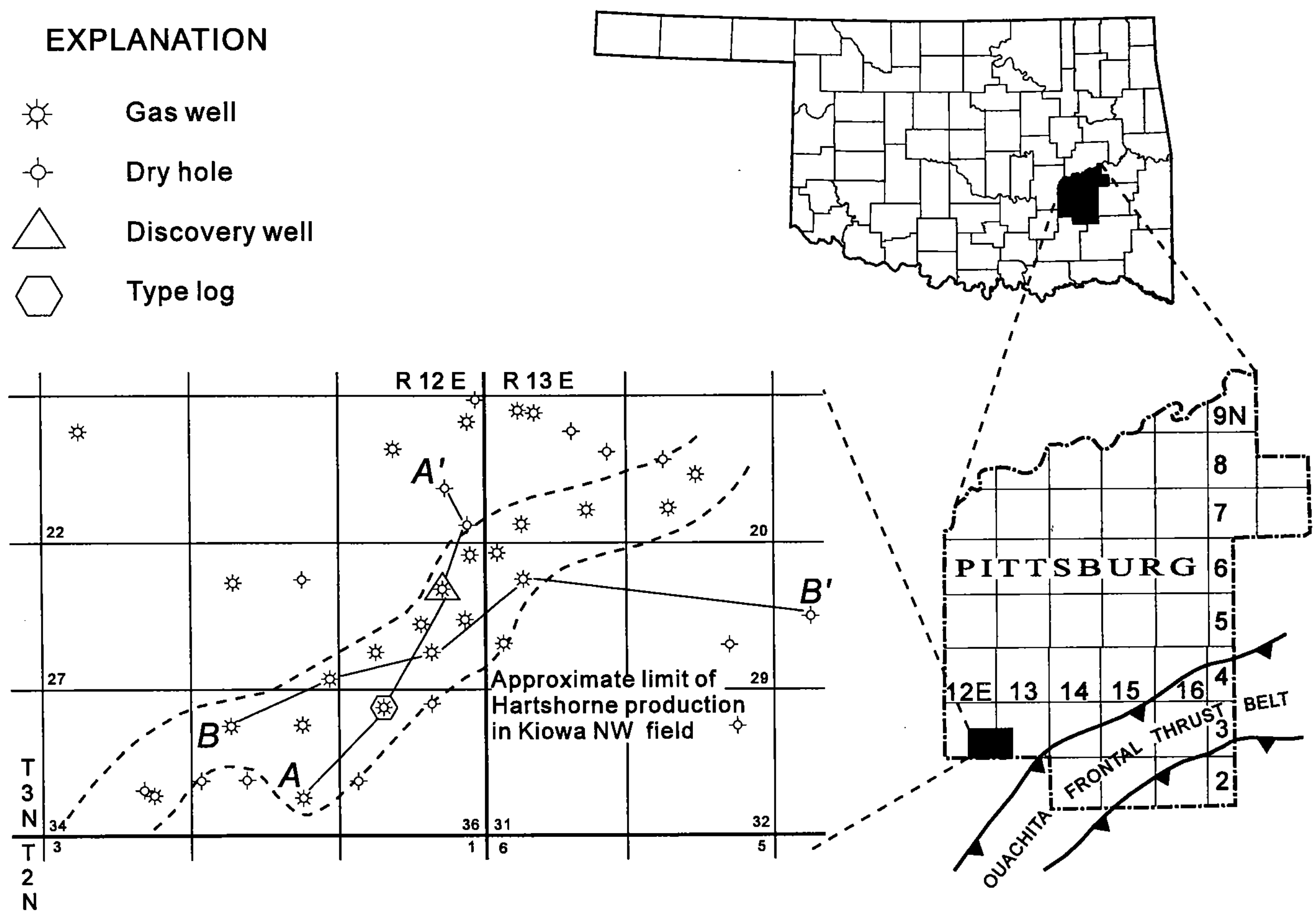

Figure 21. Generalized location map of the Kiowa NW field study area in southwestern Pittsburg County, Oklahoma.

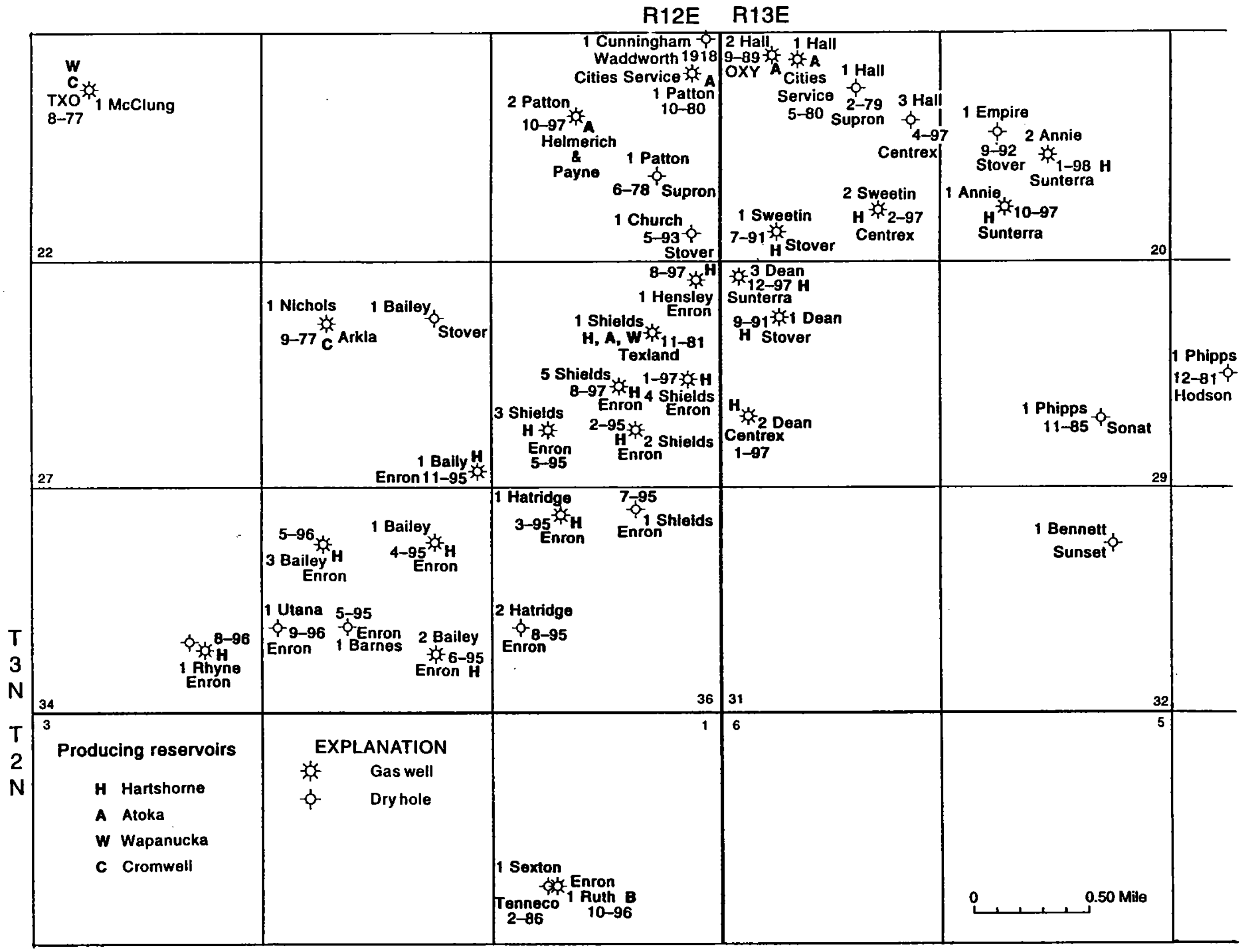

Figure 22. Well-information map showing operators, lease names, well numbers, completion dates, and producing reservoirs for wells in the Kiowa NW field study area.

The area remained inactive for 14 years until Enron "rediscovered" the Hartshorne with the No. 2 Shields well in the W½SE¼ sec. 25, T. 3 N., R. 12 E. This well penetrated the thickest part of the Hartshorne channel and had an initial production of 2,782 MCFGPD. Field development was relatively quick thereafter, with five more producing wells drilled by Enron in 1995, two in 1996, and three in 1997. The Enron wells extended the field about 2 mi to the southwest and 1 mi north of Enron's original well. Other operators (Sunterra, Stover, and Centrex) joined the search northeast of Enron's activity and extended the field into the west half of sec. 20, T. 3 N., R. 13 E. A total of 19 wells were completed in the Hartshorne through April 1997. No oil and no significant amounts of formation water are produced from the Hartshorne reservoir. Only one well found additional pay below the Hartshorne within the field: the original discovery well, as mentioned above, which was a triple completion with the Atoka and Wapanucka.

The original spacing for the Hartshorne in Kiowa NW field was 640 acres, but increased density and location exceptions have caused the field to be developed on 320- and 160-acre spacing. All of the 19 Hartshorne wells are still producing. Sunterra is attempting to expand the northeastern limits of the field into the eastern half of sec. 20. The southwestern limits of the field are not being developed at this time. The relationship of this incised channel trend to the regional distribution of the upper and lower Hartshorne sandstones is shown on Plates 1 and 2.

STRATIGRAPHY

A typical log from the Kiowa NW field and the stratigraphic nomenclature are shown in Figure 23. In this well, the Hartshorne interval is about 175 ft thick and is

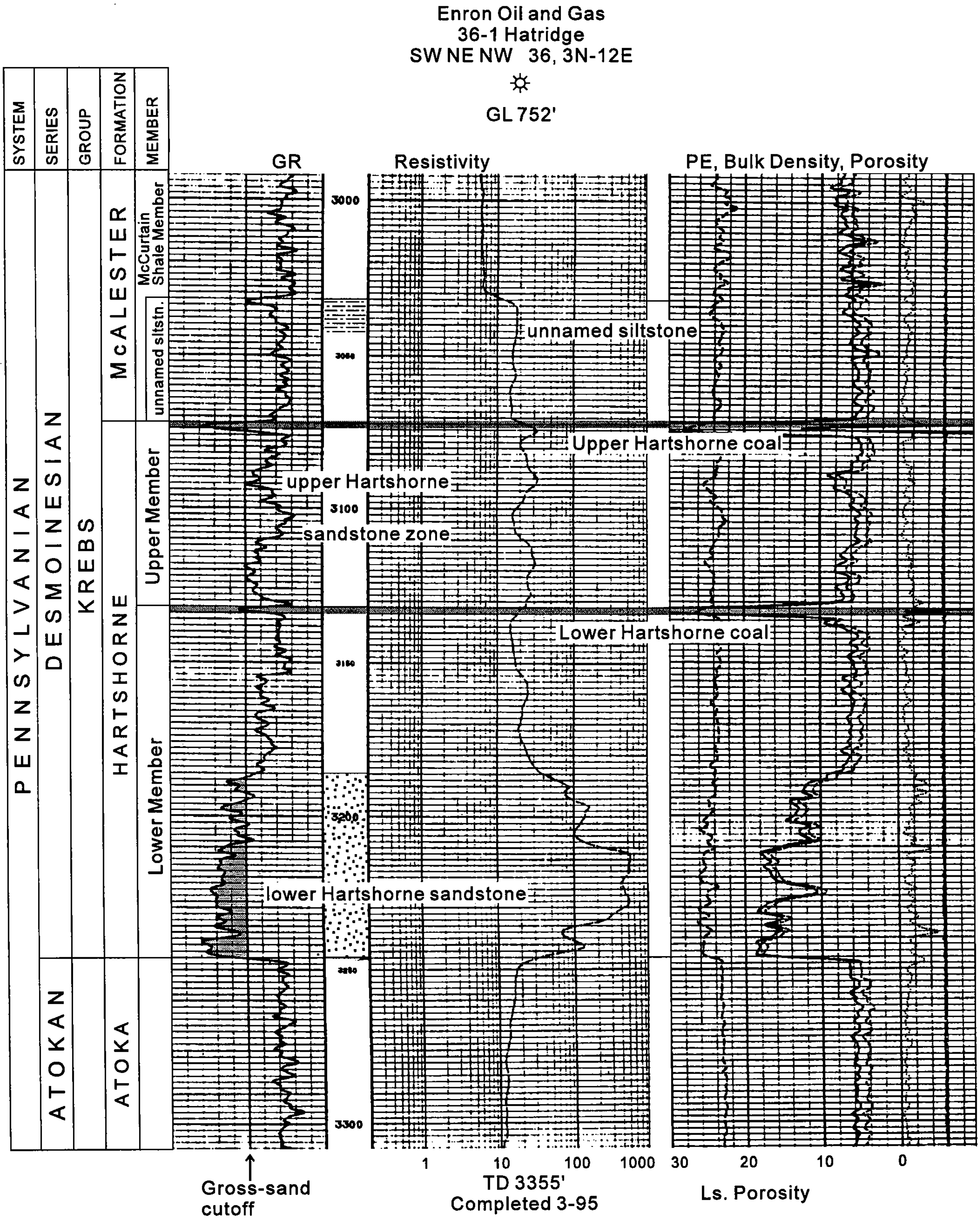

Figure 23. Type log of the Hartshorne interval in the Kiowa NW field. The stratigraphic section and nomenclature above and beneath the Hartshorne are also shown. *GR* = gamma ray, *PE* = photoelectric.

divided into an Upper Member and a Lower Member. In this figure, each member is bounded at the top by a thin, persistent coal bed. Where either coal bed is absent, a correlative shale break can usually be identified for partitioning the two members. In general, the Upper Member is thinner than the Lower Member and contains little sandstone within the field. The main reservoir in the field consists of channel sandstone deposited in the lower part of the Lower Member.

The top of the Hartshorne Formation in Kiowa NW field is defined as the top of the Upper Hartshorne coal, which lies directly beneath the unnamed siltstone of the McCurtain Shale (see later discussion). The base of the Hartshorne Formation is considerably more difficult and controversial to identify. In the field study area, the base is considered to be the base of an incised channel sandstone, or a downward-fining sandstone–shale sequence represented by a resistivity inflection below 20–30 ohm-m. On well logs, this resistivity-inflection point has a relatively "hot" gamma-ray response. Below the inflection point, the response for both the shallow and deep resistivity is generally uniform for 50–100 ft or more. These log characteristics are shown on various log traces in cross sections of the field (discussed later). For comparison purposes, surface mapping places the base of the Hartshorne Formation at the base of the lowermost Hartshorne sandstone. Obviously, surface-mapping criteria used to identify the lower Hartshorne boundary become a problem in the subsurface such as (1) in gradational marine sequences in which sandstone occurs only in the Upper Member with no sandstone below the Lower Hartshorne coal, or (2) where there is no sandstone within what is recognized as the Hartshorne interval.

Within the study area, the Hartshorne Formation is directly overlain by a recognizable silty interval, referred to informally in this report as the unnamed siltstone. This highly recognizable clastic sequence has a distinctive coarsening-upward textural profile on gamma-ray logs and is extremely variable in thickness, varying from ~5 to almost 60 ft in the study area. This sequence appears to be nothing more than a unique clastic facies in the lower part of the McCurtain Shale Member of the McAlester Formation. The unnamed siltstone thickens to the southeast and has a characteristic sharp inflection on the gamma-ray and resistivity logs at its upper contact. This inflection on well logs is often incorrectly identified by many geologists as the top of the Hartshorne Formation. Beneath the Hartshorne Formation, black marine shale of the Atoka Formation generally has a relatively uniform resistivity- and density-log response.

The lower Hartshorne sandstone, which occupies only a part of the Lower Member, is the principal reservoir within the field. As seen from gamma-ray and density logs, the sandstone usually has a sharp basal contact with shale (of the Atoka) and an overall upward-fining textural profile (owing to an increase in clay content). However, the net- and gross-sandstone thickness almost always is composed of several individual sandstone beds in a stacked or amalgamated sequence. The upper part of the sand zone typically consists of dirty sandstone or interbedded sandstone and shale, and generally is too tight to be a reservoir. Thus, sandstone deposits in Kiowa NW field are typical of multiphase fluvial cycles. The fining-upward tendency of most channel deposits in this field does not necessarily represent a point bar but rather is an indication of gradual abandonment of a fluvial channel.

The stratigraphy of the Hartshorne interval is best shown by detailed stratigraphic cross sections A–A′ and B–B′ (Figs. 24,25, in envelope). Wells 1–3, cross-section A–A′ (Fig. 24), produce gas from the lower Hartshorne sandstone, which constitutes part of an incised-valley channel deposit. The southwestern limit of the field and the channel edge are represented by well 1. At this location, the lower part of the Lower Member is mostly shale except for the basal 12 ft, which is sandstone. The relative thinness of this sandstone bed, in addition to the sharp basal contact with Atoka shale and the abrupt upper contact with Hartshorne shale, indicates that this sandstone may be the basal part of an abandoned channel deposit. Farther to the northeast, the Hartshorne channel sandstone thickens to about 56 gross ft at well 2 and then to about 60 gross ft at well 3. These two wells are near the center of the incised channel and appear to be composed of several sand packages in a stacked or amalgamated sequence (particularly in well 3, the field-discovery well). The northern edge of the field is defined at well 4, which is just outside the limits of the field. Well 4 contains mostly shale with some interbedded sandstone in the lower part of the Lower Member. There is no net sandstone (having ≥8% porosity) in well 4. The depositional environment and facies recognition of Hartshorne sediments in well 4 are difficult to determine. The basal part of the Lower Member in well 4 is correlative with channel facies in other nearby wells, so these deposits may be channel-margin deposits in the same channel complex. A short distance north, at well 5, the Hartshorne Formation thickens to about 260 ft in what appears to be a deeply incised channel deposit. In this well, the Hartshorne Formation is mostly shale except for the basal 51 ft, which appears to be a channel sandstone. This sandstone is probably within a different, noncorrelative channel complex, because it is distinctly lower stratigraphically than sandstone in Kiowa NW field. The log analysis of the sandstone in well 5 indicates that it is wet, with a possible gas–water contact at 2,472 ft as shown.

The Upper Member of the Hartshorne in cross section A–A′ (Fig. 24) is easily identified as the stratigraphic sequence between the top of the Upper and Lower Hartshorne coals. In the field study area, this interval consists mostly of shale and thin, dirty sandstone. A few wells have produced a small amount of gas, attributable to these thin sandstone beds, as shown by the perforated intervals in well 1 (Fig. 24) and in well 3 (Fig. 25). In cross section A–A′ (Fig. 24), the two coals are split farther apart to the south, where, in well 1, the Upper Member is about 70 ft thick. At other places in the Arkoma basin, the Upper Member is a little thicker than 100 ft and may be composed entirely of (channel) sandstone. In well 5 (Fig. 24), the Lower Hartshorne coal is absent. This is probably due to the presence of the deeply incised channel complex in the Lower Member, which may have eroded the coal or inhibited the formation of coal in a channel environment.

Cross section B–B′ (Fig. 25) is oriented in an east–west direction across the center of the field. Incised channel-fill deposits constitute the entire Lower Member of the Hartshorne in wells 1–4. In these wells, the Lower Member is composed entirely of interbedded sandstone and shale, and the basal contact with the underlying Atoka shale is sharp. Wells 1 and 2 are very shaly, and the corresponding gas production was attenuated because of the poor reservoir condition. Note that only the high-resistivity zones have been perforated. Well 3 has nearly 100 ft of reservoir sandstone, which is the most sandstone recorded in any of the Hartshorne wells in the field. This well produced nearly 600 MMCFG and has considerably fewer shale breaks than other wells. Well 4 is near the eastern edge of the incised channel. Here, the sandstone thins to about 44 gross ft, and a considerable amount of interbedded shale is included within the Lower Member interval. Within a short distance to the east, the Lower Member changes facies, as shown at well 5. Here, the Lower Member is interpreted to be composed of a deltaic sequence characterized by a coarsening-upward delta-front sandstone overlain by a thin distributary channel. Both of these facies are tight and nonproductive east of Kiowa NW field, but similar sandstone facies in other parts of the Hartshorne play are often productive.

The lower Hartshorne sandstone sequences in wells 1 and 2 (Fig. 25) are probably shaly channel-margin deposits. This interpretation is based on the sharp basal contact of the lower sandstone with the underlying shale, the low resistivity, the relatively high gamma-ray values, and the "ratty" nature of the interbedded sandstone and shale sequence. The relatively small departure of the gamma-ray log from the shale baseline in the sandy zones also is a direct indication that the Hartshorne interval in wells 1 and 2 is shaly. The gamma-ray response in the first two wells can be compared with the incised channel-sandstone sequence shown in well 3, which is considerably cleaner. Well 3 contains less interstitial clay and fewer shale partings. Additionally, the overall fining-upward textural profile is consistent with fluvial systems that gradually "fill up and become abandoned," but it is not necessarily indicative of a point bar. The log profile of the lower Hartshorne channel sandstone in well 3 contrasts sharply with that of the channel-margin deposits interpreted in wells 1 and 2, and the delta-front (marine) facies in well 5.

The Upper Member of the Hartshorne is also easily identified on cross section B–B′ (Fig. 25), but it is mostly shale. In wells 1–4, this member is about 40–55 ft thick, and it thickens to the east in well 5, where it is about 95 ft thick and is composed of marine delta-front sandstone and delta-plain deposits. In all wells, the Upper and Lower Hartshorne coals are present and exhibit typical log responses, which include low density (high apparent porosity), low gamma-ray values, and some high resistivities.

Structure

Kiowa NW field is on the southwest flank of the Savanna anticline (Pl. 5), and the subsurface dip of the Hartshorne is southward at about 9° (~850 ft/mi). A detailed structure-contour map of the study area (Fig. 26) depicts the top of the Hartshorne Formation (Upper Hartshorne coal). As can be seen on this map, the highest position of the Hartshorne Formation within Kiowa NW field is just above –1,620 ft and occurs in the north-central part of the field in the SW¼ sec. 19, T. 3 N., R. 13 E. The southwestern part of the field, which appears to be in the same channel trend, extends below –2,700 ft in the S½ secs. 34 and 35, T. 3 N., R.12 E. The relief of the gas column, therefore, is about 1,100 ft.

A cursory view of the regional structural configuration in the Arkoma basin, as shown for the top of the Hartshorne Formation (Pl. 5), indicates widespread and locally intense structural deformation. Because of this, it is likely that the incised channel system, as mapped in this report, is faulted to some degree, even if no faults are indicated on the field structure map in Figure 26. However, the relatively uniform structure-contour spacing, based on a 200-ft contour interval, indicates no major displacements. Additionally, some geologists think that a fault separates the water-saturated channel sandstone in sec. 24, T. 3 N., R. 12 E., from the productive-sand trend. This interpretation seems unnecessary because of the different facies that separate the two channel trends.

Hartshorne Sandstone Distribution and Depositional Environments

Figure 27 shows the gross thickness of the Hartshorne sandstone for all the wells in the study area. The gross-sand thickness is the total thickness of sandstone in the Lower Member of the Hartshorne Formation, regardless of porosity, as interpreted from gamma-ray logs (determined from the 50% sand–shale line). The zero-thickness line is the limit of sand deposition within the channel and generally includes a larger area than the limits of the actual reservoir or net sandstone. In some areas, such as the southeast corner of sec. 24, T. 3 N., R. 12 E., the isopach map does not reach a zero thickness because of the lateral distribution of interfingering sand beds. The spatial limits of the incised valley may be somewhat larger than the gross-sandstone distribution, because areas within the channel

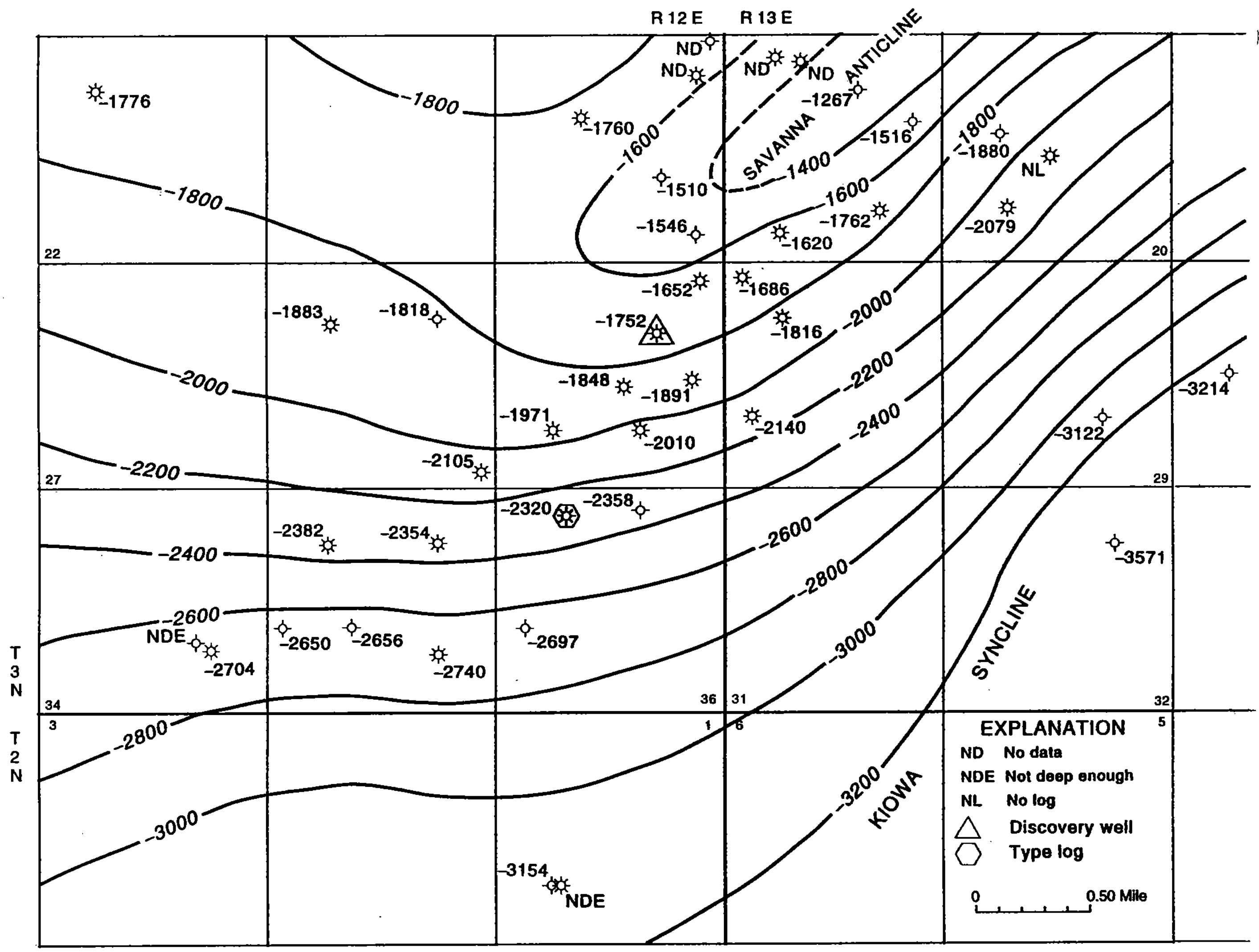

Figure 26. Structure map depicting the top of the Hartshorne Formation, Kiowa NW field study area. Contour interval, 200 ft. Datum is mean sea level. See Figure 22 for well names.

may not contain sandstone. Based on this isopach map, the channel is about 0.7–1.1 mi wide. Within the general area, the course of the channel is fairly straight and extends beyond the area mapped to the northeast and southwest for miles. Along this trend, the lower Hartshorne sandstone reaches a maximum thickness of almost 100 ft, although it is considerably thinner in most places. The discovery of this incised channel is relatively recent, and the sandstone trend is under-explored. This combination of circumstances should lead to field extensions or additional new fields.

The gross thickness of the channel sandstone within the Kiowa NW study area ranges from about 9 to 97 ft, but it is usually about 40–70 ft. However, thick sandstone does not occur everywhere within the channel. At many places, such as the southwest part of the field (SE¼ sec. 35 and SW¼ sec. 36, T. 3 N., R. 12 E.), channel deposits consist predominantly of shale rather than sand because they occur along the channel margin or in places within the channel where little sand was deposited (abandoned-channel environment). Such shaly intervals form stratigraphic barriers that isolate hydrocarbons along the courses of these types of channel deposits. The Hartshorne sandstone east of the incised channel complex is part of a regionally extensive marine delta-front sequence that existed prior to deposition of the incised channel-fill deposits. These marine sandstones locally produce gas but are commonly tightly cemented with silica, especially where the upper-bar facies is relatively thin. The marine sandstone was not contoured, but thicknesses are reported on the isopach map (Fig. 27).

A net-sandstone isopach map (Fig. 28) shows the thickness of sandstone in wells having porosity ≥8%. In producing Hartshorne wells, the net-sand thickness ranges from only a few feet to 94 ft. Throughout the mapped extent of the field, the average thickness is ~26 ft, even though many wells have reported thicknesses

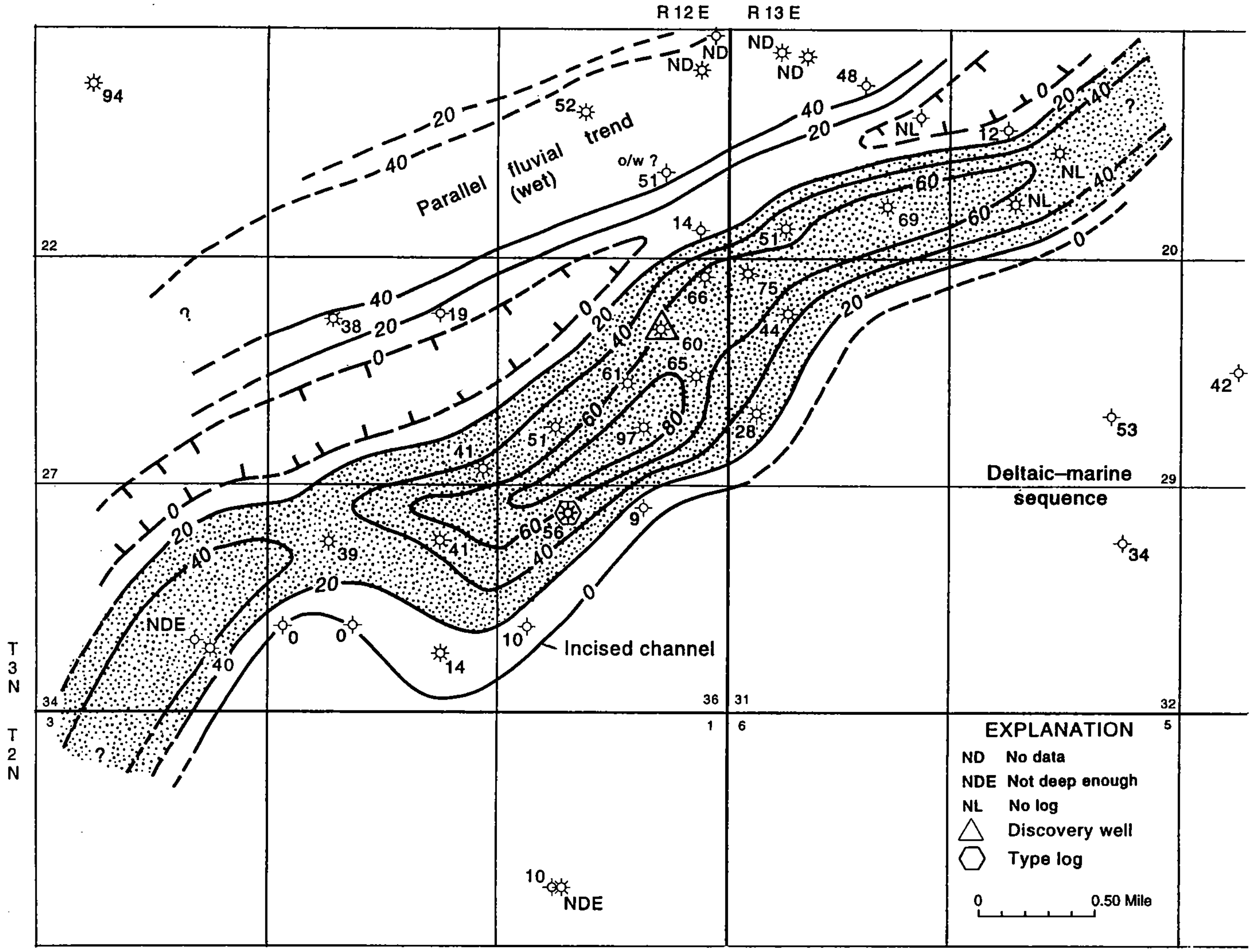

Figure 27. Gross-sand isopach map of the Hartshorne sandstone in Kiowa NW field. Gross sand includes all sandstone in the Lower Member of the Hartshorne, regardless of porosity or facies. Contour interval, 20 ft. See Figure 22 for well names.

of about 20–40 net ft. The net-sand map (Fig. 28) is similar in overall appearance to the gross-sand map (Fig. 27), but with a significant reduction in sandstone thickness. This is due to clay-rich and tightly cemented zones within the Lower Hartshorne interval that are included in the gross-sandstone thickness. The differences between the gross- and net-sandstone thicknesses is usually 10–40 ft for any given well, but this constitutes a decrease by as much as 90% from the original gross-sandstone thickness. Most of the net sandstone has porosity in the range of 9–11%; some is as high as 16%, but this is unusual. A higher porosity cutoff above 8% would have reduced the areal extent of the reservoir considerably. Because much of the shale in the Hartshorne interval has a baseline density porosity of about 4–5%, it is difficult to interpret porosity in dirty sandstones. This situation exists when the gamma-ray response is minimal, making the distinction between sandstone versus shale unclear.

There is no water leg in the field, so the reservoir includes the entire area having more than zero feet of net sand (Fig. 28). The field contains at least three areas where the net sandstone is considerably thicker than in other locations within the channel. This situation may facilitate compartmentalization, as could small-scale faulting. The reservoir pressure shows significant local variations, but this may simply indicate partial depletion, even though the field was developed relatively quickly. Overall, the northeastern part of the field had higher initial reservoir pressures than the southwestern part.

Facies Mapping

Depositional environments were interpreted from wireline-log signatures in order to illustrate the generalized depositional setting within the study area (Fig. 29). Logs from all wells were used to make this interpretation, particularly the gamma-ray, resistivity, and

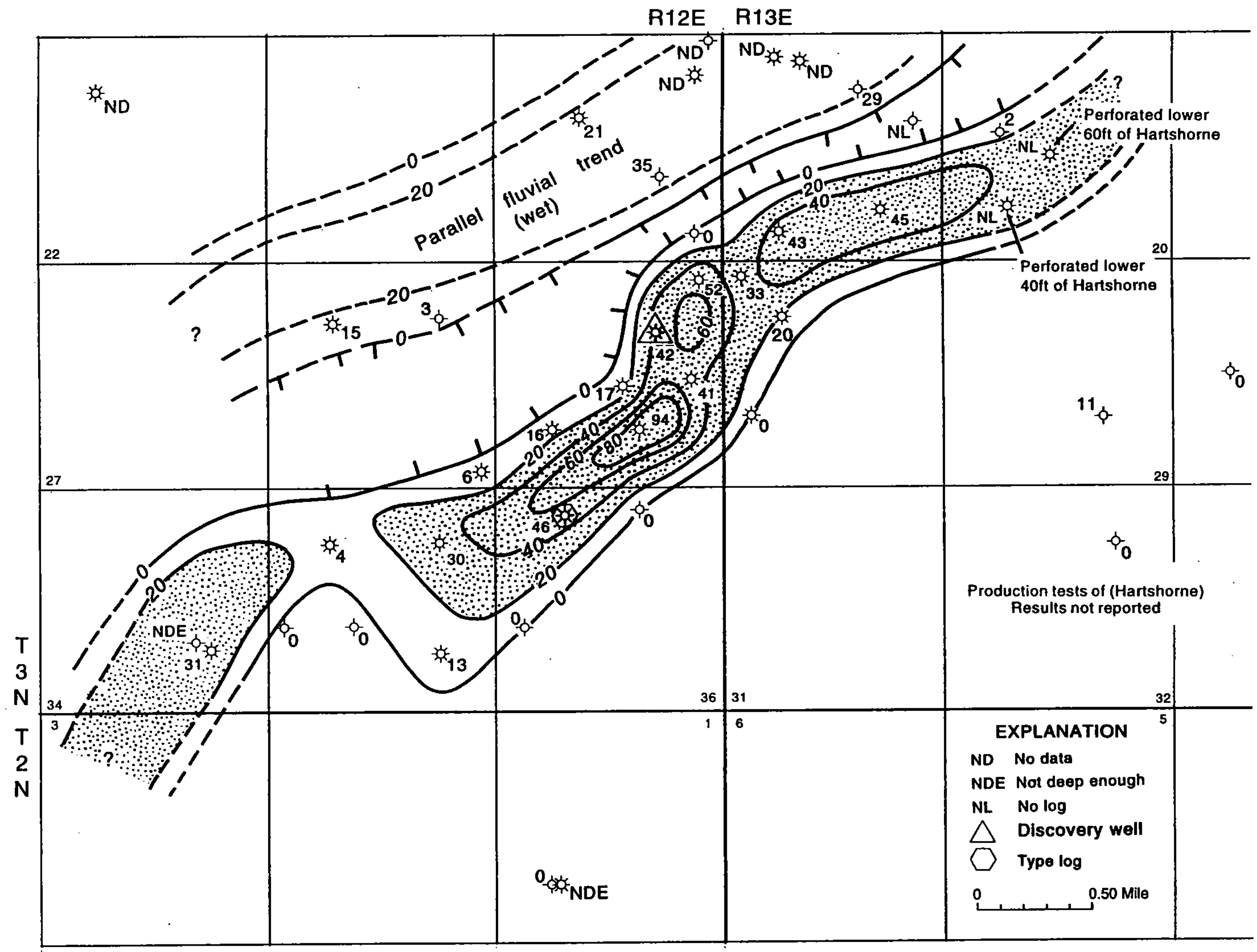

Figure 28. Net-sand isopach map of the lower Hartshorne sandstone in Kiowa NW field. Net sand has log porosity ≥8%. Contour interval, 20 ft. See Figure 22 for well names.

density records. Two distinctly different depositional environments are interpreted in the mapped area, although only the fluvial Hartshorne facies is productive in Kiowa NW field.

Incised Channel-Fill Deposits

The depositional environment of these sediments appears to be a simple incised valley containing fluvial deposits originating within a flood plain (rather than a delta plain). This distinction is important for exploration purposes, because there is no delta front underlying the channel facies and, therefore, no progradation—i.e., no deposition extending basinward into a marine environment (definition of a delta!). Within the fluvial (channel) facies, sediments consist predominantly of sandstone and/or shale. Because of the morphology of the sandstone (areal-distribution pattern and stratigraphic profile), the sandstone deposits are interpreted to be some 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 fining-upward textural profile on gamma-ray logs, and (3) a highly elongated map pattern, with some thinning and thickening. Sediments deposited within the fluvial regime that are predominantly shale are interpreted to be channel-margin, abandoned-channel, or flood-plain deposits, and might not always be part of the reservoir. It is still necessary to be able to identify these types of sediments on well logs so they can be distinguished from the laterally adjacent deltaic–marine facies.

Delta-Front (Distributary Mouth Bar) Deposits

Sandstone that is interpreted to have a coarsening-upward textural profile, as indicated from gamma-ray, resistivity, and porosity logs, is considered to originate from different depositional processes than those for fluvial-incised channel deposits. Sandstones with these characteristics are not productive within Kiowa NW

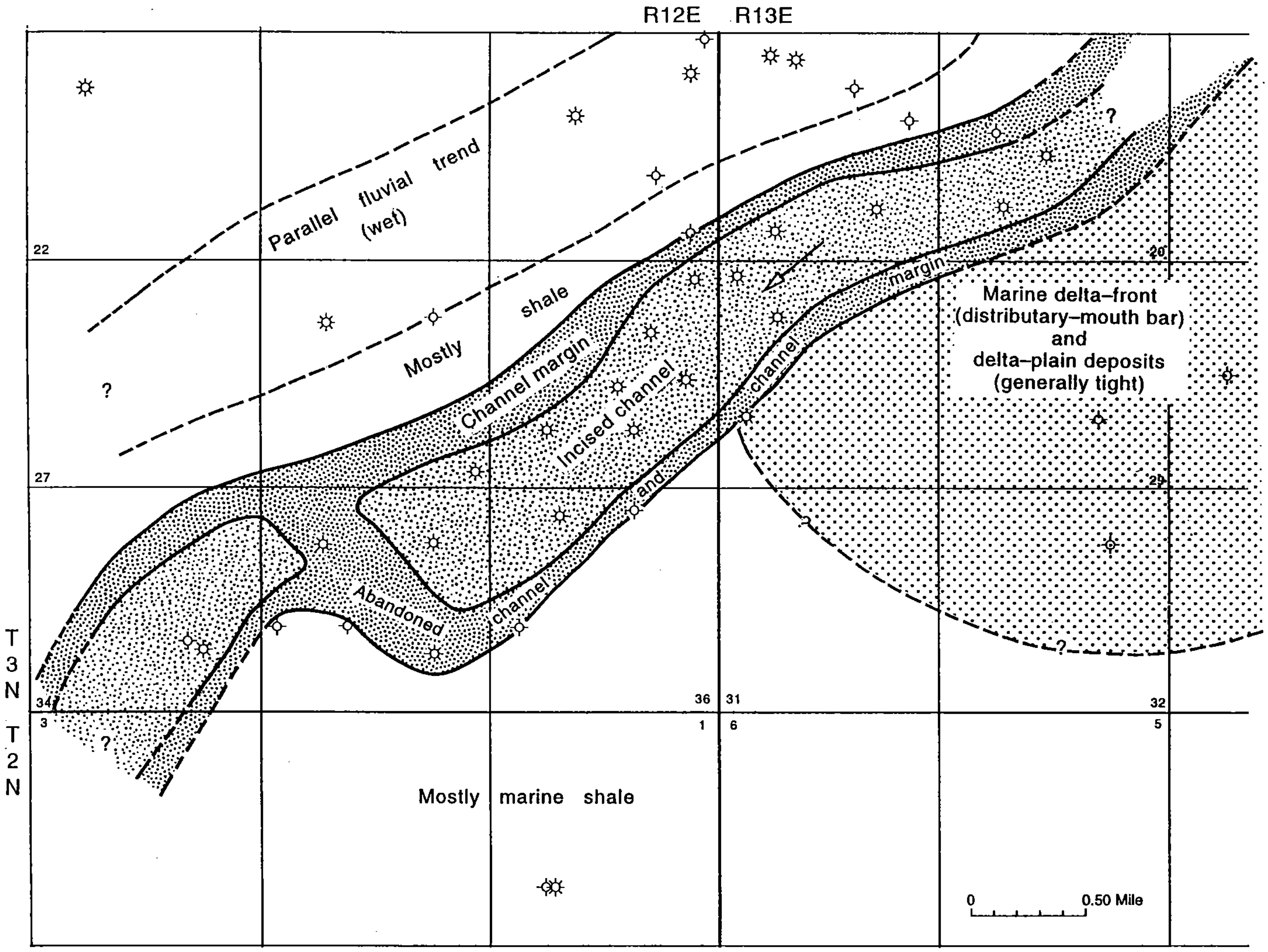

Figure 29. Depositional-facies map of the Hartshorne Formation in the Kiowa NW field study area.

field but occur along the eastern part of the study area adjacent to this field (Fig. 29). A good example of the marine delta-front facies is shown in well 5, cross section B–B′ (Fig. 25). In this well, the lower Hartshorne sandstone has a distinct coarsening-upward textural profile, as indicated on the gamma-ray, SP, and resistivity logs. A thin (~10-ft-thick) sand bed lies just above the delta-front sequence and is interpreted to be a distributary channel. Above the channel is the Lower Hartshorne coal. This stratigraphic interval clearly indicates a progradational sequence—one that is shallowing vertically through the section—and it can be interpreted entirely from logs without the aid of cores. A similar sandstone sequence in the Upper Member in this same well exhibits a coarsening-upward textural profile and is likely to be another distributary mouth bar of another depositional cycle in the Hartshorne Formation.

Although distributary mouth bars are normally good reservoirs, the thinness of many of these types of deposits in the Hartshorne Formation reduces their potential as gas reservoirs. The reason for this is because the best part of the bar, in terms of reservoir quality (upper-bar facies), is usually poorly developed and thin. The lower-bar facies and transition zone contain more interstitial clay and/or interbedded shale, which is detrimental for a reservoir. Also, the thinner delta-front deposits in the Hartshorne Formation have a tendency to be highly cemented with silica, making them impermeable.

Even though it is difficult in some cases to differentiate between fluvial and marine facies, the recognition of these two facies is important. This skill can be used effectively in exploration or step-out drilling in the development of fluvial trends such as those in Kiowa NW field.

Core Analysis

No core analyses of this or similar nearby channel deposits were available.

FORMATION EVALUATION

The identification and evaluation of Hartshorne sandstone in Kiowa NW field is somewhat complicated, owing to the local shaliness of the reservoir and limited log sweeps. The productive sandstone can be relatively clean, but it usually contains a large amount of interstitial and interbedded clay. This condition suppresses the deep or "true" resistivity and accentuates the gamma-ray response in sandstone. Additionally, many of the wells are drilled with air, causing most operators to run only density-porosity logs and deep-induction–resistivity logs. In the absence of a flushed zone created by a mud-based drilling procedure, shallow-resistivity logs, which are highly influenced by filtrate invading the flushed zone, are not run. Additionally, some deep wells have intermediate casing through the Hartshorne interval, permitting only neutron logs to be run. Reservoir evaluations using these wireline logs are therefore much less accurate but nevertheless can be reasonably interpreted. Reservoir characteristics of the Hartshorne sandstone in Kiowa NW field are shown in Table 6.

The deep or "true" resistivity (R_t) of producing sandstone intervals in the Hartshorne Formation ranges from about 75 to over 400 ohm-m and is usually in the range of 150–300 ohm-m. With an average porosity of 10–11%, the Hartshorne probably won't produce significant gas with a value less than about 75 ohm-m. Although a wide range of resistivity values exists in the reservoir sandstone, there doesn't appear to be any specific area within the field with anomalously high reservoir resistivity. As many logs did not record shallow-formation resistivity, one of the traditional methods for detecting invasion (and therefore permeability and porosity) was not available for some wells. This indirect method for determining reservoir quality is based on the assumption that the amount of invasion is proportional to the porosity and permeability of the reservoir, and that the amount of separation between the shallow- and deep-resistivity curves was affected by the degree of invasion. Air drilling also produces no mudcake buildup, so this phenomenon could not always be observed for estimating zones of invasion.

Porosity determinations by the use of density logs were estimated, taking into account the normal "gas effect" that causes the density porosity to be too high (usually about 150% above actual porosity). Without the neutron log (which is used to determine cross-plot porosity), a simple method for attenuating the density porosity was used and involved the multiplication of indicated density porosity by a fraction, usually ranging from 0.7 to 0.6. The resulting porosity more closely approximates cross-plot porosity attained from traditional density–neutron logs. When density–neutron logs were available, the cross-plot porosity was used. Of significance is the observed gas effect (crossover), which may be 10–16 porosity units (see well 3, cross section B–B′, Fig. 25). For many deeper reservoirs, the amount of crossover would be characteristic of gas

TABLE 6. – Reservoir-Engineering Data for the Hartshorne Sandstone in Kiowa NW Field, Southwest Pittsburg County, Oklahoma

Reservoir size (area within 5-ft gross contour)	~2,066 acres (current field extent)
Reservoir volume	~54,100 acre-ft (current field extent)
Depth	about 2,300–3,400 ft (dip ~9½° to south)
Spacing (gas)	640 acres, with increased density to 160 acres and location exceptions
Gas–water contact	None observed
Porosity (in producing wells)	5–16% (usually about 9–11%)
Permeability	Not available; probably several md at best
Water saturation (calculated using R_w = 0.04)	8–33% (usually about 14–16%)
Thickness (net sand, ϕ ≥8% cutoff)	Field average ~26 ft
Reservoir temperature	96°–115°F
Gas density	0.63–0.72, (average ~0.66 g/cm^3)
Z factor (compressibility)[a]	0.85 est.
B_g (gas formation volume factor)[b]	80 est.
Maximum wellhead pressure	1,050 PSI (max. recorded field ISIP)
Initial reservoir pressure (calculated bottom-hole)	1,120 PSI
OGIP[c] (volumetric-field)	14,076,000 MCF
Cumulative gas production of field (through 12/97)	4,061,000 MCF
Recovery to date	29%
Recovery MCF/acre-ft (field)	~75 MCF/acre-ft

[a]Compressibility factor (Z) estimated from standard reservoir-engineering chart using T_{res} = 110°F and P_{res} = 1,120 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 from the following formula: Reserves (MCF) = 43.56 × area (acres) × sand thickness (ft) × porosity (%) × (1–S_w) × B_g.

depletion, but for the Hartshorne (which is generally an underpressured reservoir), this is not so.

Water-saturation (S_w) calculations for the Hartshorne sandstone range from about 8% to 76%, the higher values being attributed to water-wet trends northwest of Kiowa NW field. The S_w in the lower Hartshorne sandstone within the field was calculated at 8–33%, averaging about 15%. Calculations were made using the formula $S_w = \sqrt{F \times R_w / R_t}$. The formation-water resistivity (R_w) was assumed to be 0.04 ohm-m at formation temperature. Lowering the R_w, for instance, to 0.03 would have reduced the S_w to only a few percent, which is unreasonable. The Archie equation for formation factor ($F = 1/\phi^2$) was used, because S_w calculations seemed more reasonable in using this equation for this particular reservoir (tightly cemented). Using a modified F equation generally resulted in calculated S_w values that were unrealistically low, and, conversely, hydrocarbon-saturation determinations were too high. R_t, or "true" resistivity, was taken directly from the deep-resistivity log but may have been suppressed in shaly intervals. Porosity values were also taken directly from density logs, but, because of gas effect, they were reduced (see method described in previous paragraph) to reflect actual reservoir conditions. Neutron porosity was not used when unaccompanied by density porosity because of the highly variable clay content of the Hartshorne (clay causes the effective porosity to read high on neutron logs) and because of the severity of gas effect, which attenuates neutron porosity. Porosity determinations from most density logs were calculated by using a matrix density of 2.71 g/cm^3.

Oil and Gas Production

The estimated cumulative gas production from the Hartshorne Formation in Kiowa NW field from June 1982 through December 1997 was 4,061,000 MCF. This is believed to represent about 29% of the recoverable gas in place, which is estimated to be 14.1 BCF for the current field extent (Table 6). The estimated recovery with regard to current cumulative gas production is 75 MCF/acre-ft. The recovery will, of course, increase with time as the reservoir is being produced. Because detailed pressure data were not generally available, the typical P/Z plots, or production-versus-pressure plots as used in gas-reservoir analysis, were impossible to construct.

Production-decline curves for three wells having different reservoir properties in Kiowa NW field are shown in Figure 30. With each production-decline curve, an inset graph shows cumulative production over time, so some idea of ultimate recovery can be extrapolated. The plot in Figure 30A shows the production curve of a very thick channel-sandstone sequence during the 3 years of 1995–97 for the Enron No. 2 Shields well. Cumulative production was nearly 0.6 BCFG. The production decline for this well was about 69% for 1995, 30% for 1996, and 36% for 1997. The well drilled 94 net ft of sandstone, which is the best sandstone reservoir within the field.

The production curve for a well interpreted to represent a shaly channel-margin deposit is shown by the plot in Figure 30B. This graph includes gas production from the Enron No. 3 Bailey well for about 1.5 years through 1997. The decline in production for 7 months in 1996 was about 57%, and for 1997, about 32%. Note that this well was shut in during August 1996 and again during April 1997. The total cumulative gas production for the well was 240 MMCF. During a similar time period, the thick channel-sand reservoir in Figure 30A produced over 407 MMCFG.

The graph shown in Figure 30C represents production from a channel sandstone of intermediate thickness (about 46 ft of net sand). The production decline for this well, the No. 1 Hatridge drilled by Enron, extends over a 3-year period, from March 1995 through 1997. The production decline was 63% for the first 10 months of 1995, 34% for 1996, and 31% for 1997. This well produced 329 MMCFG, as compared with 580 MMCFG for the thicker channel deposit in the No. 2 Shields well (Fig. 30A).

The three production curves illustrate that the well-production performance is directly related to reservoir quality and thickness. The moderate decline in production rates also indicates that the wells are in the early stages of depletion. The decline curves support, in a general way, the estimated recovery percentage of the original gas in place (~29%). The production-decline curves also show the relatively small monthly reduction in gas production, even after 3 years.

A gas-production map (Fig. 31) shows cumulative Hartshorne gas production, the dates of first production, and various pressure data for each well in the field. Cumulative production does not appear to be related to the date of first production (wells were completed mostly over a 3-year time span) but rather to reservoir quality and thickness. This information supports the concept of drilling increased-density wells on 160-acre spacing (four wells per section) rather than the original concept of 640-acre spacing (one well per section).

The better wells in Kiowa NW field had initial-production rates of 750 MCFGPD to almost 3 MMCFGPD. Thin or dirty sandstone reservoirs came in for a lot less. Nearly any well with at least 20 ft of net sand will produce at least 250 MMCFG, and usually much more. Wells with thicker than average sand will ultimately produce at least 1 BCFG. Currently, three wells have produced >0.5 BCFG per well after only 3 years. Initial shut-in tubing pressure for most wells ranges from about 500 to 600 PSI. A few wells along the northeastern part of the field (secs. 19 and 30, T. 3 N., R. 13 E.) had significantly higher initial pressures of 700–1,000 PSI, which may indicate a compartmentalized reservoir or that these wells were completed in another sandstone trend. Flowing tubing pressure varied from about 200 to >500 PSI throughout the field. The

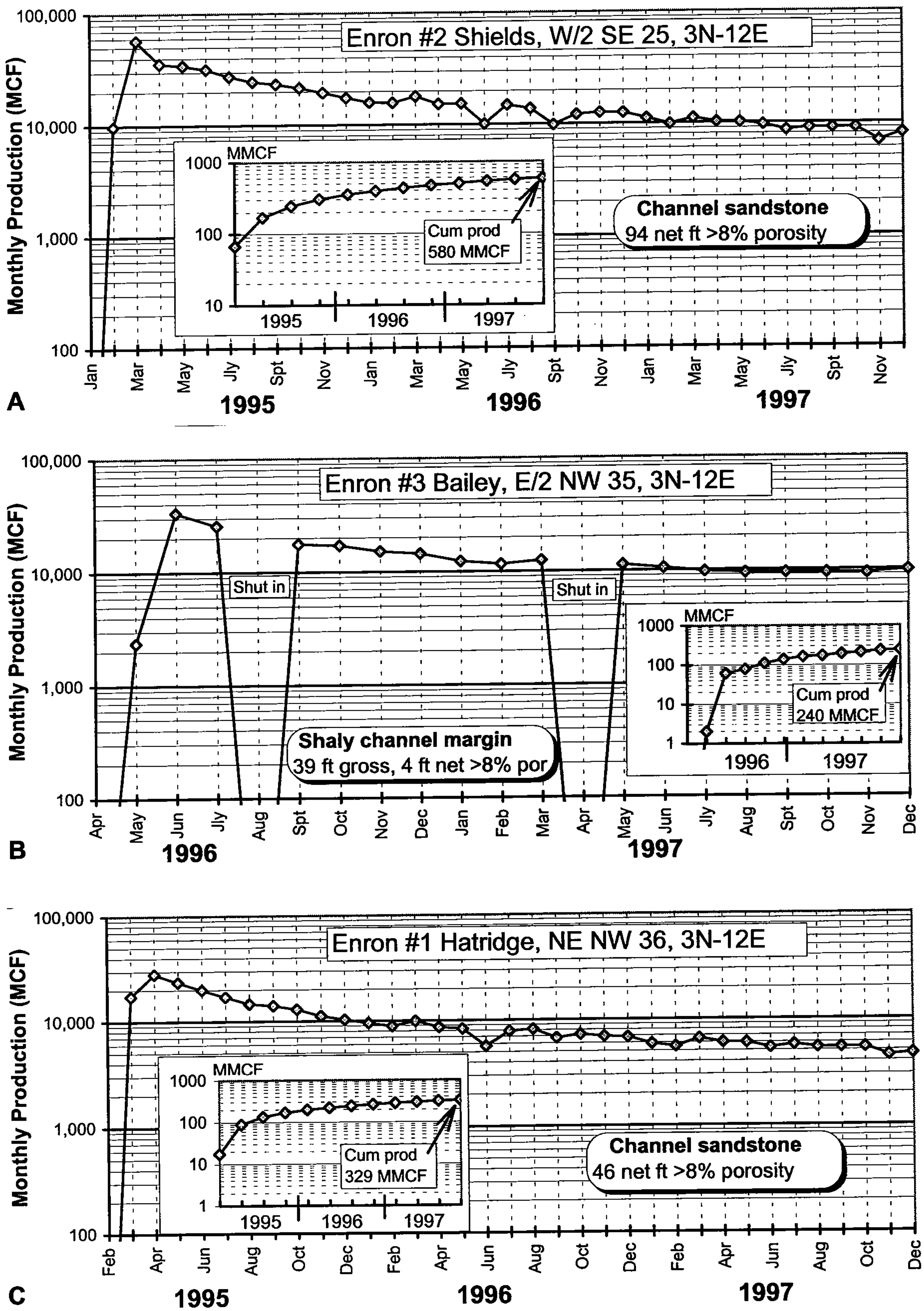

Figure 30. Production-decline curves for three wells in Kiowa NW field. For the three wells, gas production from the Hartshorne sandstone is attributed to different fluvial facies and net-sandstone thicknesses, as indicated. Inset graph shows cumulative gas production for that well. Production is current through 1997.

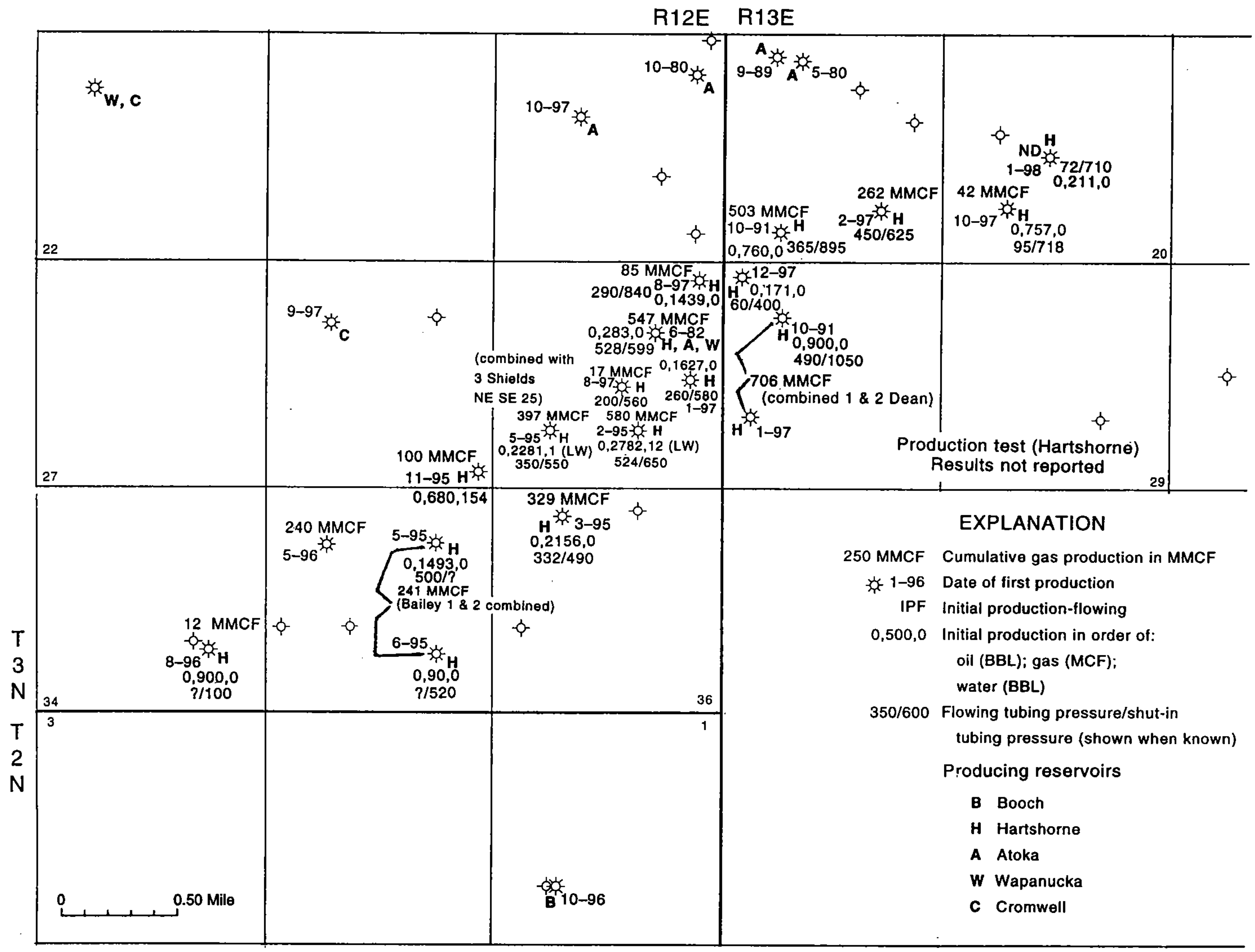

Figure 31. Map showing cumulative Hartshorne gas production, date of first production, flowing tubing pressure (FTP), shut-in tubing pressure (SITP), and initial production flowing (IPF) for wells in Kiowa NW field. See Figure 22 for well names. Production tabulated through December 1997.

flowing pressure is proportionally high in comparison with the shut-in pressure, indicating relatively good reservoir conditions. Flowing pressure in really tight rocks is usually small in proportion to the shut-in pressure.

Well-Drilling and Well-Completion Practices

Wells in the Kiowa NW field area have been drilled by means of both mud and air. As in the Cabaniss study area, the deciding criterion is usually depth, because water invasion into the wellbore limits the use of air. Most wells targeting the Hartshorne in this field are less than 3,500 ft deep, similar to those in Cabaniss NW field. Therefore, guidelines regarding drilling and logging considerations are similar to those discussed under the same heading in that field, and the reader is referred to that earlier discussion for much of the information.

Operators in Kiowa NW field usually set 750–1,400 ft of 7-in. surface casing, then set 4.5-in. production casing at or very near the bottom of the hole. In all producing wells, only the Hartshorne zones having high resistivity (≥75 ohm-m) and relatively good porosity (corrected density porosity ≥8–10%), or zones having density–neutron crossover porosity, were perforated and fractured. The wells were acidized with 1,000–2,000 gal of 7.5% HCl and then stimulated with a fracture treatment. Most fracture treatments used about 48,000 gal (of foam?) as the mobilizing agent and about 60,000–100,000 lb of sand.

PART II

Coal as Gas-Source Rock and Reservoir, Hartshorne Formation, Oklahoma

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INTRODUCTION

Coal is a major source of energy, contributing importantly to the generation of electricity and process heat in the industrial sector. But, coal also can be both a source rock and a reservoir for natural gas (methane). This unique property of coal makes it an exploration target under a selected set of conditions. Understanding those conditions and the particular characteristics of coal beds as natural gas reservoirs is essential to the successful development of methane production from these strata.

Coal is a "black combustible sedimentary rock composed principally of consolidated and chemically altered plant remains," according to the American Society for Testing and Materials (ASTM, 1992). Schopf (1956, p. 525–526) defined coal as having "less than 50 percent mineral matter by weight, and more than 70 percent carbonaceous matter by volume." Coal is classified further into humic (banded) and sapropelic (nonbanded) coal types. Middle Pennsylvanian coals in Oklahoma are humic and contain more than 75% vitrinite (Cardott, 1989, 1990). Vitrinite (a coal maceral derived from woody tissues) is a type III kerogen and is primarily gas generative. Humic bituminous coals in Oklahoma are the source of, and reservoir for, some natural gas.

Methane is stored in coal in three primary ways: (1) molecular storage (matrix porosity), adsorbed on the organic surfaces or absorbed within the molecular structure of the coal; (2) pore storage (fracture porosity), free gas in micropores and cleats (natural fractures in the coal); and (3) dissolved gas in formation water, also occurring in the cleat (Rightmire, 1984). Coal can store more methane than a conventional reservoir because of the sorptive capacity of coal. Most of the gas is sorbed on the molecular structure of the coal; only minor amounts of gas are stored elsewhere. Fracture storage occurs when the coal is supersaturated with methane. In general, gas content increases with increasing rank, depth, and reservoir pressure (Kim, 1977; Scott and others, 1995; Rice, 1996). Adsorptive capacity increases with increasing rank from high-volatile-bituminous- to semi-anthracite-rank coals (Fails, 1996). A high moisture content reduces a coal's capacity to adsorb methane (Kim, 1977). Methane generation peaks at low-volatile-bituminous-rank coal. Gas-storage capacity decreases with increasing rank (Rice, 1993). By medium-volatile-bituminous rank, coals may generate more methane than can be stored; gas is expelled into adjacent strata (Rice, 1993, p. 162; Fails, 1996). High-volatile- to low-volatile-bituminous-rank coals are the most favorable coalbed-methane reservoirs owing to maximum thermogenic methane generation and high brittleness, which favor fracture formation (Jones and others, 1988; Das and others, 1991).

Kissell (1972) recognized an increase in permeability (methane flow) with time from loss of water. The drop in hydrostatic pressure on removal of produced water initiates methane desorption and emission from coal.

LITERATURE REVIEW ON OKLAHOMA COALBED METHANE

Oklahoma coals are well known for their gassiness. Many underground-coal-mine disasters recorded from 1885 to 1945 were attributed to gas explosions (Humphrey, 1959, p. 203; Oklahoma Department of Mines, 1993). The U.S. Bureau of Mines (USBM) conducted numerous studies to reduce hazards and mine explosions as part of the Coal Mine Health and Safety research program (1964–79) and the methane-control program (McCulloch and others, 1975; Diamond, 1979; Iannacchione and Puglio, 1979; Diamond and others, 1986; Deul and Kim, 1988). Even though the economic potential of coalbed-methane resources was considered (e.g., Kim, 1977, 1978; Diamond, 1979), the primary objective was finding ways to vent or drain the gas in advance of underground mining.

Howe Mine

Irani and others (1972) reported that the low-volatile-bituminous Lower Hartshorne coal (averaging 39 in. thick and 350 ft deep) in the Howe Coal Co. Howe No. 1 mine in Le Flore County (NW¼ sec. 7, T. 5 N., R. 26 E.; operating 1967–71) emitted an average of 1.6 million cubic feet of gas per day (MMCFGPD) in 1971 (an average of 2,191 cubic feet per short ton [CF/ton]). Kissell (1972) described a U.S. Bureau of Mines study of coal-bed permeability and methane-sorption capacity from the Pittsburgh coal (West Virginia), the Pocahontas No. 3 coal (Virginia and West Virginia), and the Hartshorne coal (Oklahoma; Howe No. 1 mine). The gas pressure in the Hartshorne coal increased with horizontal-hole distance to a maximum of 138 PSIG (gauge pressure) at 110 ft (hole 11), with a range of 25–95 PSIG at a distance of 50 ft. The permeability of the Hartshorne coal ranged from 0.08 to 1 md (assuming the sorption capacity to be 0.5). The overburden (thickness of the sedimentary deposit from the surface) was 285 and 700 ft. Kissell (p. 18) concluded that "the values of permeability shown...are for coalbeds that have already been influenced by the mining process and that the permeability of the virgin coalbed was much lower." The Hartshorne coal in Haskell and Le Flore Counties was described as friable and highly fractured, with closely spaced cleats (the numerical value was not indicated). Iannacchione and Puglio (1979, p. 9) concluded that "the friability of the Hartshorne coalbed is due to close spacing of cleat and the frequent occurrence of shear fractures with dips of 45° to 55° within the coalbed." McCulloch and others (1975) reported that friable coals emit more gas during desorption than do blocky coals.

Kissell and others (1973) compared the average gas-emission data from Irani and others (1972) from the Hartshorne coal in the Howe No. 1 mine (2,191 CF/ton) with the gas content of nearby exploration coal-core samples determined by the direct method. The amount of methane from the Hartshorne coal within 1 mi of the Howe mine was 11.1 cm^3/g (355 CF/ton) measured by the direct method (see Diamond and Levine, 1981; Mavor and others, 1995), 10.5 cm^3/g (336 CF/ton) determined by the indirect method, and 11.8 cm^3/g (378 CF/ton) calculated from adsorption data (Kim, 1977). Of seven coals studied by Kissell and others (1973), the ratio (mine emission/direct amount) varied between 6 and 9, with higher emissions from older mines than from newer mines.

Iannacchione and others (1983) reported that the gas production from a five-hole vertical methane-drainage project totaled 5 MMCFG and 101,000 gallons of water from 500–600 ft deep in the Howe mine over a 3-year period.

Choctaw Mine

Irani and others (1972, 1974) and Friedman (1982a) reported that the medium-volatile bituminous Hartshorne coal (36–61 in., averaging 4 ft thick at 1,200–1,400-ft depth) in the Kerr-McGee Corp. Choctaw mine in Haskell County (SW¼ sec. 1, T. 8 N., R. 21 E.; operating 1968–75) emitted 300 MCFGPD in 1971 and 400 MCFGPD in 1973. Iannacchione and others (1983) reported that gas production from several horizontal boreholes in the Choctaw mine reached a high of 1 MMCFGPD in 1977 and decreased to 400 MCFGPD in 1978.

Hildebrand (1981) reported the chemistry of Hartshorne coal samples from the Choctaw mine (sec. 6, T. 8 N., R. 22 E.; sample D176848 in Table 8).

Regional

The most detailed coalbed-methane study of the Hartshorne coals in Haskell and Le Flore Counties was by Iannacchione and Puglio (1979). Structure, isopach, and overburden maps were constructed from approximately 900 data points. Cleat directions were measured from surface mines and exposures. Gas content primarily is a function of depth, thickness, rank, and post-deposition geologic history. Gas content, determined by the direct method from 16 coal-core desorption samples, ranged from an average of 211 CF/ton at 0–500-ft depth to an average of 672 CF/ton at 2,000–3,000-ft depth.

Diamond and Levine (1981) determined gas content by the direct method from 1 Upper Hartshorne and 14 Lower Hartshorne coal samples from Le Flore County. The total gas content ranged from 2.5 to 17.1 cm^3/g (80–547 CF/ton) from depths of 175 to 1,440 ft.

Rieke and Kirr (1984) estimated the methane content of all coal beds to be 73–211 CF/ton in the northwest subshelf area of the Arkoma basin, and 200–700 CF/ton, increasing west to east, in the central trough of the Arkoma basin.

Diamond and others (1986) summarized the gas-content data of 27 samples from Le Flore and Pittsburg Counties, Oklahoma, from the U.S. Bureau of Mines coalbed-methane database. The total-gas-content data for the Hartshorne coals are as follows: 3 samples of low-volatile-bituminous Hartshorne coal from Le Flore County, 9.9–16.8 cm^3/g (317–538 CF/ton); 17 samples of low-volatile-bituminous Lower Hartshorne coal from Le Flore County, 2.5–17.1 cm^3/g (80–547 CF/ton); 4 samples of high-volatile-A-bituminous Lower Hartshorne coal from Pittsburg County, 5.4–10.1 cm^3/g (173–323 CF/ton); and 2 samples of high-volatile-A-bituminous Upper Hartshorne coal from Pittsburg County, 9.0–9.2 cm^3/g (288–294 CF/ton). Locations for 19 samples are in Iannacchione and others (1983), of which 14 samples correlate by depth with Diamond and others (1986).

Diamond and others (1988) reported the results of 16 desorption samples from the Hartshorne coals in Haskell and Le Flore Counties, with a methane-content range of 350–570 CF/ton by the direct method.

Available Oklahoma coal-core desorption analyses of 34 samples are summarized in Table 7. The gas content ranges from 2.2 to 17.5 cm^3/g (70–560 CF/ton) from a depth range of 175 to 3,651 ft. The gas-content data are plotted against depth in Figure 32; the locations of the samples are plotted in Figure 33. In general, gas content increases with increasing depth and increasing rank from west to east in the Arkoma basin. The four deepest samples (ID 1, 30–32; 1,905–3,651 ft) are from three coal beds (McAlester, Keefton, Upper Hartshorne) in the Barringer and Brown Estate wells in

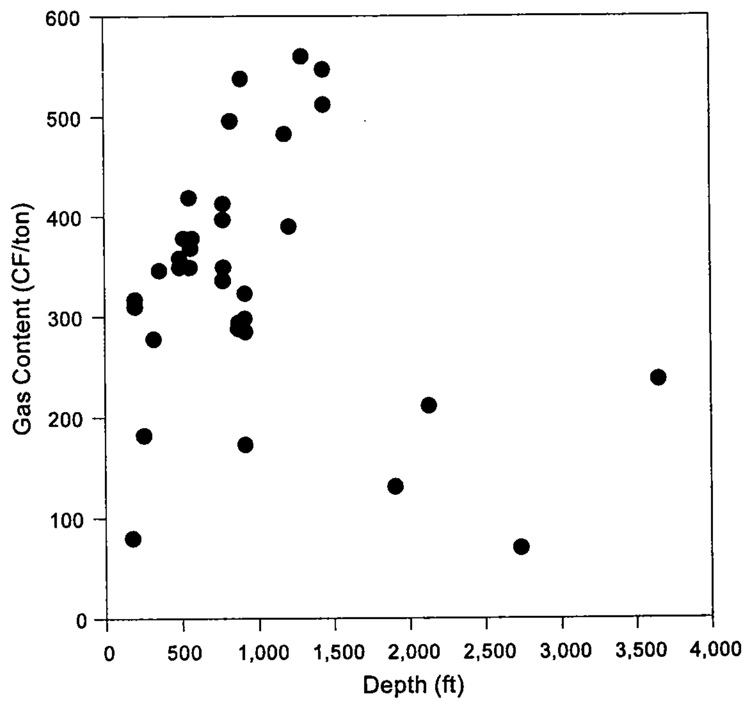


Figure 32. Oklahoma coal-gas content versus depth.

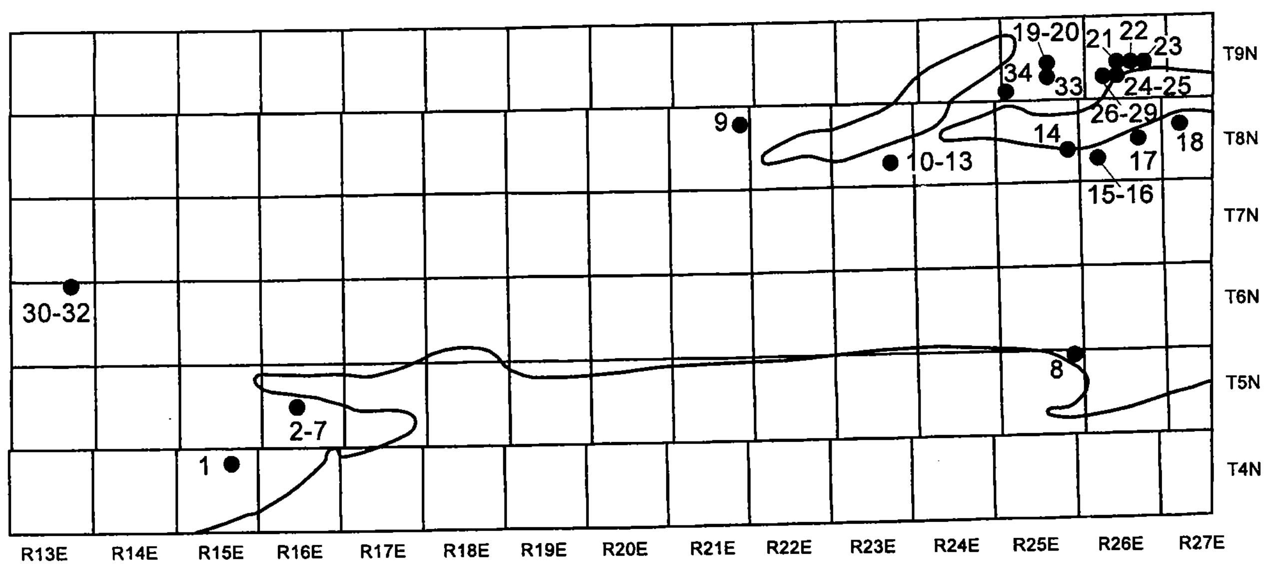


Figure 33. Map showing location of Oklahoma coal-core desorption samples and outline of Hartshorne coal outcrop. Refer to Table 7 for desorption analyses.

Pittsburg County. The low gas contents (70–237 CF/ton) of these deep samples may be due to low rank, thin coal, and sampling or analytical errors. See Iannacchione and Puglio (1979, fig. 10) for a similar scatter plot of gas content versus depth that excludes these four deep samples. Other samples from Pittsburg County (ID 2–7) contained 173–323 CF/ton from depths of 869–916 ft. The low gas content (80 CF/ton) of the shallowest sample (175 ft) is due to near-surface gas emission. High-volatile-bituminous-coal samples have 2.2–10.1 cm^3/g (70–323 CF/ton), a medium-volatile-bituminous-coal sample had 17.5 cm^3/g (560 CF/ton), and low-volatile-bituminous-coal samples have 2.5–17.1 cm^3/g (80–547 CF/ton).

Forgotson and Friedman (1993) estimated that the gas content from Hartshorne coals in the Oklahoma Arkoma basin increases from 300 CF/ton in high-volatile-C-bituminous coals in the west to 600 CF/ton in low-volatile-bituminous coals in the east, at depths of 800–2,000 ft.

Gas Composition

Kim (1973, 1978; Kim and Deul, 1988) reported the gas composition of two samples of the Lower Harts-

TABLE 7. – Summary of Oklahoma Coal-Core Desorption Analyses

Sample ID	Coal bed	Location[a]	County	Depth, meters (ft)	Lost gas, cm^3/g	Desorbed gas, cm^3/g	Residual gas, cm^3/g	Total gas[b], cm^3/g (ft^3/ton)	Rank[c]	Source[d]
1	Keefton(?)	C,NW 11-4N-15E	Pittsburg	1,113 (3,651)	0.9	5.6	0.9	7.4 (237)	hvAb	1 (USBM ID 1059); 3 (Barringer 1-11 well)
2	Upper Hartshorne	NE 21-5N-16E	Pittsburg	265 (869)	0.4	7.6	1.0	9.0 (288)	hvAb	1 (USBM ID 1725); 2 (Sample 18)
3	Upper Hartshorne	NE 21-5N-16E	Pittsburg	265 (870)	0.4	7.9	0.9	9.2 (294)	hvAb	1 (USBM ID 1724)
4	Lower Hartshorne	NE 21-5N-16E	Pittsburg	278 (912)	0.4	8.2	0.8	9.3 (298)	hvAb	1 (USBM ID 1726); 2 (Sample 19)
5	Lower Hartshorne	NE 21-5N-16E	Pittsburg	278 (913)	0.5	4.3	0.6	5.4 (173)	hvAb	1 (USBM ID 1727)
6	Lower Hartshorne	NE 21-5N-16E	Pittsburg	279 (914)	0.4	9.1	0.5	10.1 (323)	hvAb	1 (USBM ID 1728)
7	Lower Hartshorne	NE 21-5N-16E	Pittsburg	279 (916)	0.4	7.7	0.9	8.9 (285)	hvAb	1 (USBM ID 1729)
8	Lower Hartshorne	1-5N-25E	Le Flore	169 (553)	1.6	11.2	0.3	13.1 (419)	lvb	1 (USBM ID 33); 2 (Sample 13)
9	Hartshorne	12-8N-21E	Haskell	395 (1,296)	NA	NA	NA	17.5 (560)	mvb	2 (Sample 11)
10	Lower Hartshorne	26-8N-23E	Le Flore	235 (771)	0.4	9.4	0.7	10.5 (336)	lvb	1 (USBM ID 1699)
11	Lower Hartshorne	26-8N-23E	Le Flore	235 (772)	0.4	11.2	0.7	12.4 (397)	lvb	1 (USBM ID 1700)
12	Lower Hartshorne	26-8N-23E	Le Flore	236 (773)	0.5	11.9	0.4	12.9 (413)	lvb	1 (USBM ID 1701)
13	Lower Hartshorne	26-8N-23E	Le Flore	236 (774)	0.5	10.0	0.4	10.9 (349)	lvb	1 (USBM ID 1702); 2 (Sample 17)
14	Lower Hartshorne	SE,SW 24-8N-25E	Le Flore	97 (318)	0.7	7.2	0.7	8.7 (278)	lvb	1 (USBM ID 20); 2 (Sample 1)
15	Upper Hartshorne	29-8N-26E	Le Flore	251 (823)	1.3	13.6	0.6	15.5 (496)	lvb	1 (USBM ID 217); 2 (Sample 15)
16	Lower Hartshorne	29-8N-26E	Le Flore	272 (892)	3.9	12.1	0.8	16.8 (538)	lvb	1 (USBM ID 216); 2 (Sample 14)
17	Upper Hartshorne	14-8N-26E	Le Flore	60 (196)	0.3	8.4	1.2	9.9 (317)	lvb	1 (USBM ID 1060); 3 (DH-A17 well)
18	Lower Hartshorne	8-8N-27E	Le Flore	60 (196)	NA	NA	NA	9.7 (310)	lvb	2 (Sample 16)
19	Hartshorne	22-9N-25E	Le Flore	439 (1,439)	3.2	13.2	0.8	17.1 (547)	lvb	1 (USBM ID 31)
20	Hartshorne	22-9N-25E	Le Flore	439 (1,440)	3.0	12.2	0.9	16.0 (512)	lvb	1 (USBM ID 32); 2 (Sample 12)
21	Hartshorne	21-9N-26E	Le Flore	149 (489)	1.0	9.2	0.7	10.9 (349)	lvb	1 (USBM ID 25); 2 (Sample 6)
22	Hartshorne	22-9N-26E	Le Flore	169 (556)	0.6	9.6	0.7	10.9 (349)	lvb	1 (USBM ID 28); 2 (Sample 9)

(continued on facing page)

TABLE 7. – *Continued.*

Sample ID	Coal bed	Location[a]	County	Depth, meters (ft)	Lost gas, cm^3/g	Desorbed gas, cm^3/g	Residual gas, cm^3/g	Total gas[b], cm^3/g (ft^3/ton)	Rank[c]	Source[d]
23	Hartshorne	23-9N-26E	Le Flore	109 (356)	0.4	9.7	0.7	10.8 (346)	lvb	1 (USBM ID 29); 2 (Sample 10)
24	Hartshorne	28-9N-26E	Le Flore	53 (175)	0.0	2.2	0.2	2.5 (80)	lvb	1 (USBM ID 27); 2 (Sample 8)
25	Hartshorne	28-9N-26E	Le Flore	174 (571)	0.5	10.6	0.8	11.8 (378)	lvb	1 (USBM ID 24); 2 (Sample 5)
26	Hartshorne	29-9N-26E	Le Flore	77 (252)	0.1	4.7	0.9	5.7 (182)	lvb	1 (USBM ID 26); 2 (Sample 7)
27	Hartshorne	29-9N-26E	Le Flore	149 (488)	1.1	9.4	0.7	11.2 (358)	lvb	1 (USBM ID 21); 2 (Sample 2)
28	Hartshorne	29-9N-26E	Le Flore	157 (516)	0.8	10.3	0.7	11.8 (378)	lvb	1 (USBM ID 22); 2 (Sample 3)
29	Hartshorne	29-9N-26E	Le Flore	171 (561)	0.7	10.0	0.7	11.5 (368)	lvb	1 (USBM ID 23); 2 (Sample 4)
30	McAlester(?)	2-6N-13E	Pittsburg	581 (1,905)	1.4	2.7	0.0	4.1 (131)	hvAb	3 (Brown Estate 1-2 well)
31	Keefton(?)	2-6N-13E	Pittsburg	649 (2,130)	3.5	3.1	0.0	6.6 (211)	hvAb	3 (Brown Estate 1-2 well)
32	Upper Hartshorne	2-6N-13E	Pittsburg	833 (2,733)	0.6	1.6	0.0	2.2 (70)	hvAb	3 (Brown Estate 1-2 well)
33	Upper + Lower Hartshorne	27-9N-25E	Le Flore	360 (1,182)	4.3	10.8	NA	15.1 (483)	lvb	4 (27-9 Eagleton well)
34	Upper + Lower Hartshorne	31-9N-25E	Le Flore	369 (1,209)	3.0	9.2	NA	12.2 (390)	lvb	4 (31-8 Stiles well)

[a]Quarter section(s), Section, Township, Range.
[b]Total gas may not equal the combined total owing to independent rounding of "lost gas + desorbed gas."
[c]hvAb = high-volatile A bituminous; mvb = medium-volatile bituminous; lvb = low-volatile bituminous.
[d]1 = Diamond and others (1986, p. 69); 2 = Iannacchione and others (1983, p. 8); 3 = Rieke and Kirr (1984, p. 156); 4 = OGP Operating.

horne coal from a depth of 350 ft in the Howe mine. The average gas composition, analyzed by gas chromatography, was 99.22% methane, 0.01% ethane, 0.66% inert gases (nitrogen, carbon dioxide), and 0.10% oxygen.

Iannacchione and Puglio (1985; also in Diamond and others, 1988) reported the gas composition from the Hartshorne coal (medium-volatile-bituminous rank) in eight horizontal degasification holes in the Choctaw mine and from the Lower Hartshorne coal (low-volatile-bituminous rank) in two coal cores from Le Flore County. The gas content from seven samples in the Choctaw mine (collected from production holes drilled 3 to 14 months before sampling) ranged from 97.35% to 97.85% methane, 0.49% to 0.86% heavier hydrocarbons (ethane, propane, butane), 1.2% to 1.6% carbon dioxide, and 0.18% to 0.44% oxygen plus nitrogen. The methane content in the low-volatile-bituminous-rank Lower Hartshorne coal in Le Flore County was higher (98.5–99.25%).

The gas composition of eight Hartshorne coal samples from Haskell, Le Flore, and Pittsburg Counties ranged from 58.27% to 99.25% methane (Iannacchione and others, 1983). The lower value of 58.27% may be due to sampling or analytical error (e.g., air contamination). The ratio of methane to total hydrocarbons (C_1/C_{1-4}) is >99%.

Rice (1996) indicated that "gases from horizontal degasification wells and desorbed core from the Hartshorne coal bed are composed mostly of methane with minor amounts of CO_2 (<1.6%) and heavier hydrocarbon gases (generally <1%). On the basis of isotopic analyses, the gases are interpreted to be mainly of thermogenic origin, although probable mixing of biogenic gas has occurred, which was generated relatively recently in association with groundwater flow."

Coalbed-Methane Resources

Murrie (1977) estimated that the Lower Hartshorne coal in a 600-mi^2 area in Haskell and Le Flore Counties, Oklahoma, contains at least 1 TCF of methane from coal resources of 2.0 billion tons (>12 in. thick, <2,000 ft deep). The gas content measured by the direct method ranged from 80 CF/ton at a depth of 175 ft to 545 CF/ton at 1,500 ft.

Iannacchione and Puglio (1979, p. 13) calculated that 1.1–1.5 TCF of methane is present in 2.4–3.2 billion short tons (from 0 to 3,000 ft deep) of the Hartshorne coal in a 1,500-mi^2 area in Haskell and Le Flore Counties, Oklahoma. Most (858 BCF) of the methane was estimated to occur at depths from 500 to 1,500 ft.

Iannacchione and others (1983) estimated that 325 BCF of methane is present in 1.1 billion short tons of the Hartshorne coal (>14 in. thick, <3,000 ft deep) in Atoka, Coal, Hughes, and Pittsburg Counties, Oklahoma. Most (201 BCF) of the methane was estimated to occur at depths from 2,000 to 3,000 ft. The gas content, estimated for high-volatile-A-bituminous Hartshorne coal, ranged from an average of 227 CF/ton at depths of 0–1,000 ft to an average of 362 CF/ton at depths of 2,000–3,000 ft.

Rieke and Kirr (1984) estimated that nine coal-bearing counties in the Oklahoma portion of the Arkoma basin contain 1.22–2.76 TCF of methane resources (based on an average gas content of 200–450 CF/ton) from 10 coals (500–3,000-ft depth). Gas in place from three coal beds in the Brown Estate No. 1-2 well (sec. 2, T. 6 N., R. 13 E.; samples 30–32 in Table 7) was estimated to be 1.4 BCF/640 acres. A drillstem test of the Hartshorne coal showed a flow of 9 BWPD at a shut-in pressure of 716 PSIG.

Friedman (1989) estimated that about 3 TCF of methane resources are present in 12 coal beds from 500 to 7,000 ft deep in Haskell, Latimer, and Le Flore Counties.

Gossling (1994) calculated 3.1–3.5 TCF of methane resources from 8.01 billion tons of the Hartshorne coal beds (>1 ft thick, 250 to >3,000 ft deep) in 65 townships in parts of Haskell, Latimer, Le Flore, McIntosh, and Pittsburg Counties. This should be considered a maximum range, as the current estimate by the Oklahoma Geological Survey of remaining identified bituminous-coal resources in 19 counties of Oklahoma is 8.09 billion tons (>10 in. thick, 0–100 ft deep; >14 in. thick, 100–3,000 ft deep; and >28 in. thick, >3,000 ft deep).

Hartshorne Coal Chemistry

Table 8 summarizes the chemistry of Hartshorne coal samples for which exact locations are given. Hartshorne coals are generally medium-sulfur (average of 1.5% from 55 samples; range of 0.5–4.2%) and low-to-medium-ash coals (average of 7.7% from 55 samples; range of 2.6–27.1%) (classification based on ranges from Wood and others, 1983). Additional reports of Hartshorne coal chemical analyses with imprecise location information include Shannon and others (1926), Fieldner and others (1928), Moose and Searle (1929), Shead and others (1929), Hendricks (1937a, 1939), Davis and others (1944), Oakes and Knechtel (1948), Knechtel (1949), Walker and Hartner (1966), and Swanson and others (1976). Major-, minor-, and trace-element data for the Hartshorne coal are in Zubovic and others (1967), Boerngen and others (1975), Swanson and others (1976), Hildebrand (1981), and Bragg and others (1998).

A number of reports describe the rank of Oklahoma coals (White, 1915; Fuller, 1920; Croneis, 1927; Miser, 1934; Thom, 1934; Hendricks, 1935; Wilson, 1971; Burgess, 1974; Friedman, 1974; Iannacchione and others, 1983; Rieke and Kirr, 1984; Diamond and others, 1988; and Houseknecht and others, 1992). Figure 34 is a generalized coal-rank map of the eastern Arkoma basin in Oklahoma, based on unpublished vitrinite-reflectance data and earlier published maps, showing the boundaries of high-, medium-, and low-volatile-bituminous rank. Rank increases from high-volatile bituminous in the west to low-volatile bituminous in the east. The classification of coals by rank is given in Appendix 5.

Oklahoma Coal Cleats

Cleats are natural, opening-mode fractures in coal. Two orthogonal sets, perpendicular to bedding, are the *face cleat* (primary, well developed; extends across bedding planes of the coal) and the *butt cleat* (secondary, discontinuous; terminates against face cleat). Cleats control the directional permeability of coal beds and are therefore important in methane production from coals. McCulloch and others (1974), Ting (1977), Close (1993), Scott (1997), and Laubach and others (1998) discuss the origin and occurrence of cleats in coal. Cleats are the result of dehydration, devolatilization, and tectonic stress during coalification, initially developed as early as the peat–lignite transition. Cleat spacing (frequency) varies by several factors, such as rank, coal type (banded versus nonbanded), coal lithotype (layers in banded coals), ash (mineral-matter) content, bed thickness, and geologic history. Ting (1977), Close (1993), and Law (1993) indicated that cleat spacing (frequency) increases (more frequent) with increasing rank: spacing of 2–15 cm in subbituminous coals, 0.3–2 cm in high-volatile-bituminous coals, and <1 cm in medium- and low-volatile-bituminous coals. Gossling (1994) reported a cleat spacing of 0.21–0.25 cm for the medium-volatile-bituminous Lower Hartshorne coal exposed along Highway 59 (sec. 36, T. 5 N., R. 25 E.). A cleat may be annealed at any rank (Levine, 1993). In addition to rank, cleat development also is related to petrographic composition, with greater frequency in bright (vitrinite-rich) coals than in dull (inertinite- and liptinite-rich) coals (Ting, 1977). Oklahoma coals are vitrinite rich, with a dominance of vitrain and clarain lithotypes.

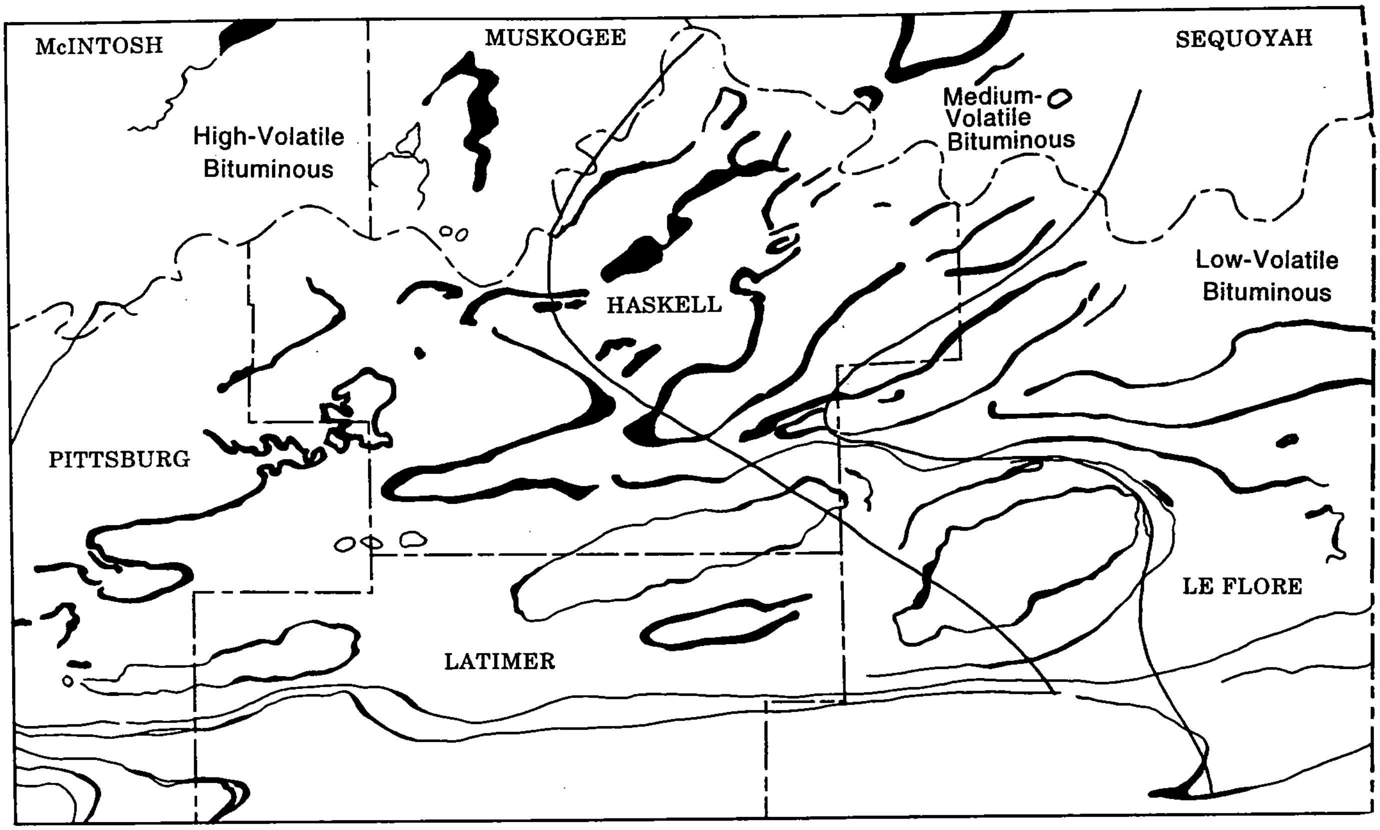


Figure 34. Coal-rank map of eastern Arkoma basin, Oklahoma. (Base map showing coal outcrop from Friedman, 1982b.)

As McCulloch and others (1974, p. 19) summarized, "The face cleats tend to be perpendicular to the axial trend of the folds and probably formed as extension fractures. The butt cleats tend to be parallel to the axial trend and formed after compressive forces were released." Ting (1977) also indicated that unloading of burial pressure by erosion may cause an abnormal increase in cleats in low-volatile-bituminous coals (as has probably occurred in Oklahoma).

Secondary mineralization (e.g., precipitation of authigenic cements) of cleats will lower the porosity and permeability of coal. Clay, carbonate, quartz, and sulfide minerals are common cleat-filling minerals (Close, 1993; Gamson and others, 1996). A detailed study of cleat-filling minerals in Oklahoma coals has not been reported.

Several reports describe the cleat directions in Oklahoma coals. Hemish (1986, 1989, 1990a, 1994, 1998) described the cleat directions of coals in the northeast Oklahoma shelf, with an average face-cleat range of N. 39° W.–N. 47° W. and an average butt-cleat range of N. 46° E.–N. 56° E. Face-cleat directions in the Hartshorne coal beds are N. 15° W.–N. 32° W.; butt-cleat directions are N. 52° E.–N. 77° E. (Iannacchione and Puglio, 1979; Diamond and others, 1988, p. 67; Trevits and others, 1988, p. 117). McCulloch and others (1974) described the cleat directions of the Hartshorne coal in the Howe mine as follows: face cleat, N. 15° W. (parallel to the axis of compression), butt cleat, N. 74° E. (subparallel to fold axes).

HARTSHORNE COALBED METHANE IN SPIRO SE GAS FIELD

More than 200 coalbed-methane wells have been completed in the Hartshorne coals (Hartshorne, Upper Hartshorne, Lower Hartshorne) in the Arkoma basin of Oklahoma from 1988 to 1998 (Fig. 35; based on data from the Coalbed-Methane Completions Table in the Oklahoma Geological Survey Coal Database). The Spiro SE gas field (secs. 25, 26, 27, 34, 35, and 36, T. 9 N., R. 25 E.) was selected for the Hartshorne coalbed-methane (CBM) field study because of the concentration of CBM wells in the field, the high-initial-potential gas rates in the low-volatile-bituminous-rank Hartshorne coal, and the availability of data. The field is north of the Backbone anticline in northern Le Flore County, eastern Oklahoma. Friedman (1982a) determined that the town of Spiro and vicinity was the recommended primary site (of three sites identified) for developing CBM from demonstrated coal resources of 77 million short tons. Friedman (1982a, p. 29) indicated that "Spiro and vicinity contain 39.6 billion cubic feet of identified, remaining, demonstrated coal-bed methane, of which a conservative estimate of 20 billion cubic feet is recoverable reserves."

TABLE 8. – Chemical Analyses of Hartshorne Coals
(all analyses are on an as-received basis, unless specified otherwise)

Coal bed	Sec.-Twp.-Rge.	County	Moisture (%)	Ash (%)	Volatile matter (%)	Fixed carbon (%)	Total sulfur (%)	Calorific value (BTU/LB)	Rank	Data source	Notes
Hartshorne	3-5N-25E	Le Flore	0.41	4.83	18.23	76.53	1.06	ND	mvb	Shannon et al., 1926	Sample 127
Hartshorne	3-5N-25E	Le Flore	0.45	9.80	20.89	68.86	0.69	ND	mvb	Shannon et al., 1926	Sample 128
Hartshorne	28-5N-26E	Le Flore	0.48	6.21	22.03	71.28	1.13	ND	mvb	Shannon et al., 1926	Sample 129
Lower Hartshorne	11-5N-19E	Latimer	3.9	6.6	34.8	54.7	2.3	ND	hvb	Fieldner et al., 1928	Sample 1818
Lower Hartshorne	8-5N-19E	Latimer	3.4	5.4	37.8	53.4	1.8	ND	hvb	Fieldner et al., 1928	Sample 1771
Upper Hartshorne	8-5N-19E	Latimer	3.0	5.1	36.0	55.9	1.1	ND	hvb	Fieldner et al., 1928	Sample 1770
Upper Hartshorne	10-5N-19E	Latimer	2.8	5.2	36.5	65.5	0.9	ND	hvb	Fieldner et al., 1928	Sample 1769
Lower Hartshorne	4-5N-22E	Le Flore	4.0	3.6	29.0	63.4	1.1	14,310	hvb	Fieldner et al., 1928	Sample 1816
Lower Hartshorne	6-5N-16E	Pittsburg	3.2	4.6	33.3	58.9	0.5	ND	hvb	Fieldner et al., 1928	Sample 1735
Lower Hartshorne	16-4N-14E	Pittsburg	2.6	9.4	33.5	54.5	1.3	12,980	hvb	Fieldner et al., 1928	Sample 5921
Hartshorne	15-8N-22E	Haskell	3.9	5.0	22.2	68.9	1.3	14,170	mvb	Oakes & Knechtel, 1948	Sample B88030; composite of 3 samples
Hartshorne	26-9N-24E	Le Flore	1.4	7.8	17.2	73.6	1.5	13,890	lvb	Knechtel, 1949	Sample B66263
Hartshorne	26-9N-24E	Le Flore	1.8	7.5	16.6	74.1	1.3	14,020	lvb	Knechtel, 1949	Sample B66264
Hartshorne	ND	Haskell	3.1	6.7	22.0	68.2	0.9	13,960	mvb	Trumbull, 1957	Average of 23 samples
Lower Hartshorne	ND	Latimer	4.7	5.6	35.9	53.5	1.4	13,450	hvb	Trumbull, 1957	Average of 21 samples
Upper Hartshorne	ND	Latimer	3.4	5.3	37.1	55.0	1.0	13,590	hvb	Trumbull, 1957	Average of 11 samples
Hartshorne	ND	Le Flore	2.4	5.6	20.6	71.4	1.0	14,190	mvb	Trumbull, 1957	Average of 5 samples
Lower Hartshorne	ND	Le Flore	2.9	7.1	17.8	72.3	0.8	14,000	lvb	Trumbull, 1957	Average of 23 samples
Upper Hartshorne	ND	Le Flore	2.5	10.1	21.3	66.3	4.1	13,700	mvb	Trumbull, 1957	Average of 2 samples
Lower Hartshorne	ND	Pittsburg	3.6	6.5	37.2	52.8	1.5	13,490	hvb	Trumbull, 1957	Average of 39 samples
Upper Hartshorne	ND	Pittsburg	4.5	6.5	35.4	53.7	1.5	13,230	hvb	Trumbull, 1957	Average of 6 samples
Hartshorne	ND	Sequoyah	5.3	5.5	16.8	72.4	1.7	13,980	lvb	Trumbull, 1957	1 sample
Lower Hartshorne	ND	Coal	5.9	7.9	35.7	50.5	1.4	12,782	hvb	Friedman, 1974	USGS data; 1 sample
Hartshorne	ND	Haskell	Dry basis	8.6	22.3	69.1	1.8	14,346	mvb	Friedman, 1974	Company data; average of 64 samples
Lower Hartshorne	ND	Haskell	0.2	6.4	21.3	72.1	0.8	14,233	mvb	Friedman, 1974	USGS data; 1 sample
Upper Hartshorne	ND	Haskell	0.04	7.0	21.0	71.9	1.3	13,969	mvb	Friedman, 1974	USGS data; 1 sample
Lower Hartshorne	ND	Le Flore	Dry basis	9.1	17.3	73.5	0.8	ND	lvb	Friedman, 1974	Company data; average of 47 samples
Lower Hartshorne	13-8N-22E	Haskell	2.8	3.5	19.6	74.1	0.5	14,560	mvb	Hildebrand, 1981	Sample D176853

Upper Hartshorne	13-8N-22E	Haskell	1.0	3.2	21.4	74.4	0.5	14,930	mvb	Hildebrand, 1981	Sample D176851
Upper Hartshorne	13-8N-22E	Haskell	1.6	2.6	20.3	75.5	0.7	14,960	mvb	Hildebrand, 1981	Sample D179907
Lower Hartshorne	22-8N-22E	Haskell	1.2	3.5	20.4	74.9	0.8	14,860	mvb	Hildebrand, 1981	Sample D179902
Hartshorne	6-8N-22E	Haskell	1.2	5.6	19.3	73.9	0.8	14,320	mvb	Hildebrand, 1981	Sample D176848
Hartshorne	10-8N-27E	Le Flore	2.5	13.3	16.5	67.7	1.8	12,850	lvb	Hildebrand, 1981	Sample D176250
Lower Hartshorne	16-8N-24E	Le Flore	3.5	8.3	18.1	70.1	1.1	13,400	lvb	Hildebrand, 1981	Sample D176165
Upper Hartshorne	16-8N-24E	Le Flore	4.9	11.6	20.7	62.8	1.9	12,590	mvb	Hildebrand, 1981	Sample D176244
Lower Hartshorne	20-8N-23E	Le Flore	2.9	4.9	18.7	73.5	2.2	14,130	lvb	Hildebrand, 1981	Sample D176249
Upper Hartshorne	20-8N-23E	Le Flore	3.0	6.1	18.4	72.5	2.7	13,880	lvb	Hildebrand, 1981	Sample D176248
Upper Hartshorne	25-5N-25E	Le Flore	1.0	8.5	22.0	68.5	1.0	14,140	mvb	Hildebrand, 1981	Sample D183431
Lower Hartshorne	18-6N-26E	Le Flore	1.2	16.4	18.0	64.4	1.3	12,730	lvb	Hildebrand, 1981	Sample D223851
Lower Hartshorne	14-6N-27E	Le Flore	1.3	11.8	17.9	69.0	1.6	13,500	lvb	Hildebrand, 1981	Sample D223852
Upper Hartshorne	9-6N-26E	Le Flore	1.7	27.1	15.3	55.9	1.1	10,700	lvb	Hildebrand, 1981	Sample D223849
Lower Hartshorne	16-5N-16E	Pittsburg	2.6	9.7	32.1	55.6	1.6	12,970	hvb	Hildebrand, 1981	Sample D179905
Upper Hartshorne	16-5N-16E	Pittsburg	2.9	22.8	29.5	44.8	2.0	10,660	hvb	Hildebrand, 1981	Sample D179904
Hartshorne	ND	Haskell	1.0	6.8	20.2	72.1	0.9	14,090	mvb	Friedman, 1997	OGS & USBM data; average of 4 samples
Hartshorne	35-12N-20E	Muskogee	1.6	2.6	26.0	69.8	0.9	14,863	mvb	Hemish, 1998	Sample 82C39H
Upper Hartshorne	14-8N-22E	Haskell	1.4	7.8	21.0	69.8	0.5	14,030	mvb	OGS	Sample 83C4F
Hartshorne	29-9N-21E	Haskell	0.4	8.5	26.4	64.7	2.5	13,961	mvb	OGS	Sample 88C1F
Hartshorne	33-9N-21E	Haskell	1.6	9.4	24.4	64.6	4.1	13,676	mvb	OGS	Samples 83C1F–83C3F; average of 3 samples
Hartshorne	33-9N-21E	Haskell	2.3	7.2	24.2	66.3	2.9	14,133	mvb	OGS	Samples 84C63H–84C65H; average of 3 samples
Hartshorne	36-9N-23E	Haskell	2.1	10.3	20.0	67.6	3.6	13,476	mvb	OGS	Samples 84C20H–84C22H; average of 3 samples
Lower Hartshorne	25-5N-17E	Latimer	6.4	3.2	38.4	52.0	1.7	13,514	hvb	OGS	Samples 84C1F–84C2F; average of 2 samples
Lower Hartshorne	12-5N-20E	Latimer	4.6	8.8	34.5	52.1	2.0	12,862	hvb	OGS	Samples 84C23H–84C24H; average of 2 samples
Lower Hartshorne	28-5N-25E	Le Flore	4.6	8.3	22.4	64.7	0.8	13,644	mvb	OGS	Samples 86C5F–86C6F; average of 2 samples
Hartshorne	24-9N-24E	Le Flore	0.8	4.9	16.9	77.4	1.3	14,616	lvb	OGS	Samples 88C2F–88C5F; 1 analysis

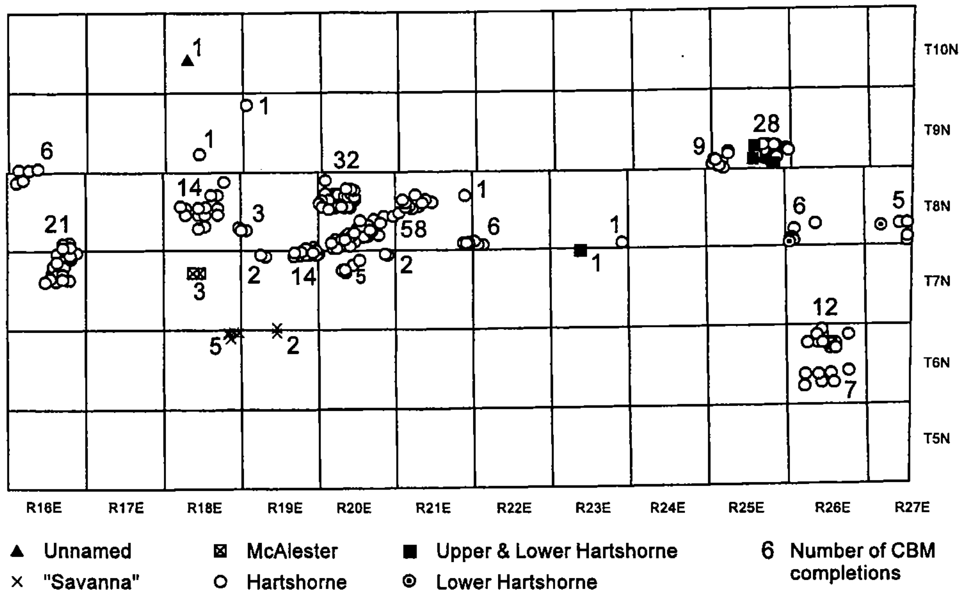


Figure 35. Coalbed-methane (CBM) well completions in the Arkoma basin, Oklahoma.

The extent of this study would not have been possible without the generosity of OGP Operating, Inc., the operator of all the CBM wells in the field, in providing the data. CWF Associates/Energy drilled 15 wells for Hartshorne CBM in T. 9 N., R. 25 E., during 1991–94. OGP Operating bought the CWF CBM wells in 1994 and drilled an additional 22 wells for Hartshorne CBM in T. 9 N., R. 25 E., during 1995–97. The CBM wells were drilled originally on 80-acre spacing. More recently, infill drilling on 40-acre spacing was granted.

The discovery well of the Spiro SE gas field was the Sunray DX Oil Co. No. 1 Craig well (C NW¼ sec. 31, T. 9 N., R. 26 E., completed in December 1962), with Atoka and Spiro production. The discovery CBM well of the Spiro SE gas field was the CWF Associates No. 27-9 G. W. Eagleton well (NE¼SE¼ sec. 27, T. 9 N., R. 25 E.), completed in April 1991. This well had an initial production of 90 thousand cubic feet of gas per day (MCFGPD) and 2 barrels of water per day (BWPD) from a 5-ft net thickness of the Upper and Lower Hartshorne coals. A 4-in.-diameter core of the Hartshorne coals was taken from this well. CWF Associates/Energy drilled 11 CBM wells, and OGP Operating drilled 17 wells in the Spiro SE gas field. The 9 CBM wells in secs. 29 and 31, T. 9 N., R. 25 E., are within the Kinta gas field. Table 9 and Figures 36–38 summarize the well information for the 28 CBM wells in the Spiro SE field. Initial gas-production rates ranged from 45 to 185 MCFGPD. Initial produced-water rates ranged from 0 to 37 BWPD. Initial shut-in pressures were 50–535 PSIG. Flowing tubing pressures were 5–15 PSIG. Hartshone coals are underpressured to normally pressured (Kemp and others, 1993).

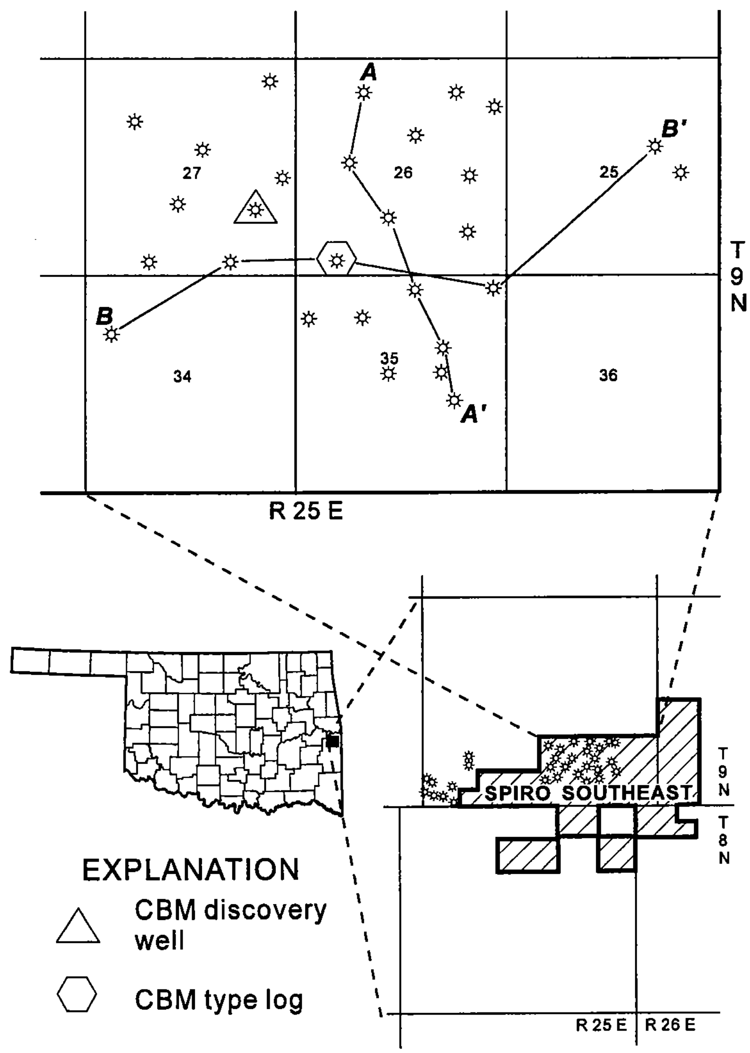


Figure 36. Generalized location map of Hartshorne coalbed-methane (CBM) field study in Spiro SE gas field.

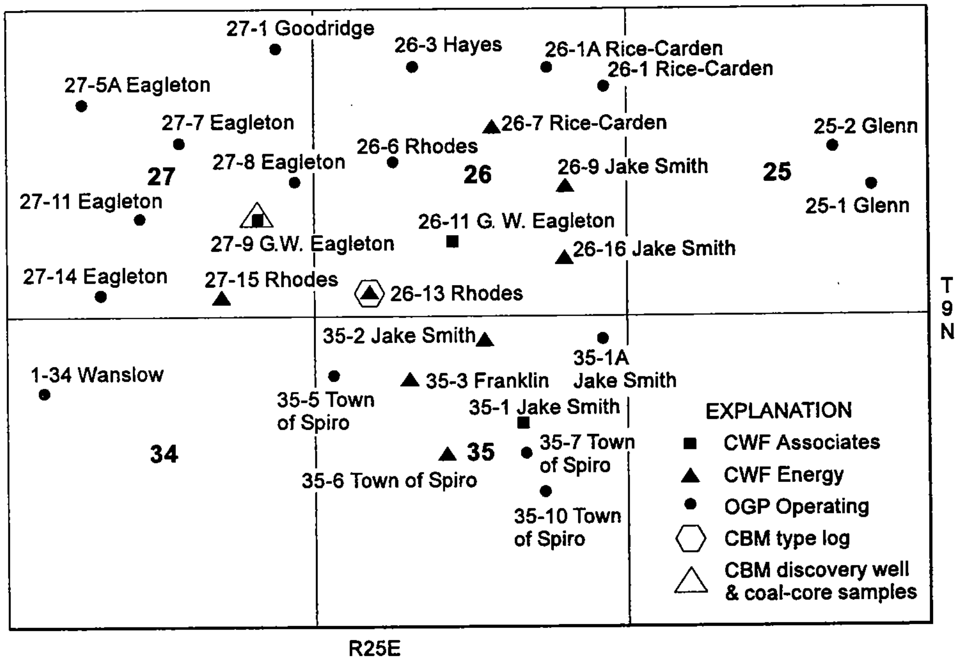


Figure 37. Well-location map showing operators, lease names, and well numbers in Spiro SE gas field.

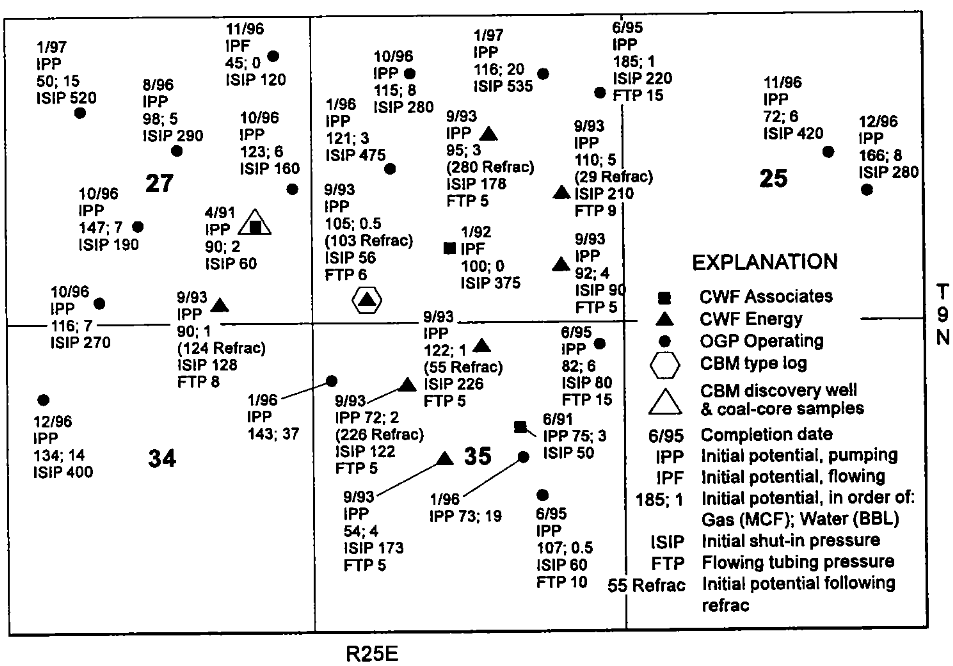


Figure 38. Map showing initial potentials, pressure data, and completion dates in Spiro SE gas field.

Coal has a natural gamma-ray response of <70 API units (Hollub and Schafer, 1992, p. 3–11). Thickness estimates of the Hartshorne coal were conservative on the basis of a rule of one-third (one-third of the minimum peak response), primarily from minimum gamma-ray and bulk-density values. The only coal core available in the study area is from the CWF Associates No. 27-9 G. W. Eagleton, the discovery CBM well of the field. The log indicated coal at 1,185–1,187 ft and 1,188–1,191 ft, separated by 1 ft of shale. Coal bulk-density data (provided by OGP Operating, current operator of the well; Table 10) indicate coal (using a cutoff of 1.40 g/cm^3) at 1,182–1,184 ft and 1,185–1,188 ft, separated by 1 ft of shale. The coal thickness determined from the core corresponds to the thickness from the logs, although there is a 3-ft discrepancy between coal depths measured during drilling and during logging (Table 9).

The Hartshorne coal (undivided) contains a thin claystone parting (Friedman, 1982a, p. 11). The coal is divided into the Upper and Lower Hartshorne coals where the parting is greater than 1 ft (Iannacchione and Puglio, 1979; Friedman, 1982a; Diamond and others, 1988). The interval between the Upper and Lower Hartshorne coal beds increases to the southeast, with a maximum thickness of 120 ft (Friedman, 1978; Iannacchione and Puglio, 1979, 1985). Iannacchione and Puglio (1979) presented an isopach map of the interval between the Upper and Lower Hartshorne coal beds (fig. 4) and a generalized stratigraphic cross section (fig. 7) showing the increase in thickness of the Hartshorne Formation and the separation of the Upper and Lower Hartshorne coal beds from northwest to southeast. A slight bimodal peak in electric logs noted in this study was interpreted to be the shale parting in the Hartshorne coal (undivided), whereas a significant bimodal peak was inter-

The thickness of the Hartshorne coal was determined from available geophysical well logs. Ayers and others (1994) indicated that coal has a low natural gamma content, low density, high neutron and density porosities, low sonic velocity, and a low neutron content. Scott and others (1995, p. 1321) indicated that "coal thickness commonly is determined from bulk density geophysical logs using a density cutoff of 1.40 g/cm^3."

TABLE 9. – Hartshorne Coalbed-Methane

Operator	Well name	Completion date	Location[a]	Latitude	Longitude	Hartshorne coal	Coal interval (ft)
OGP Operating	25-1 Glenn	12/14/1996	NW¼NE¼ SE¼ sec. 25	35.222855	–94.605244	Undivided	1,061–1,066
OGP Operating	25-2 Glenn	11/29/1996	SE¼SW¼ NE¼ sec. 25	35.224662	–94.607456	Undivided	1,163–1,170
CWF Associates	26-11 G.W. Eagleton	1/25/1992	E½E½SW¼ sec. 26	35.220238	–94.629566	Upper & Lower	1,173–1,175; 1,176–1,179
CWF Energy	26-9 Jake Smith	9/20/1993	NW¼NW¼NE¼ SE¼ sec. 26	35.222949	–94.622929	Undivided	1,189–1,195
CWF Energy	26-7 Rice-Carden	9/23/1993	NE¼SW¼SW¼ NE¼ sec. 26	35.225660	–94.627354	Undivided	1,286–1,292
CWF Energy	26-13 Rhodes	9/15/1993	SE¼SE¼SW¼ SW¼ sec. 26	35.217528	–94.633990	Upper & Lower	1,086–1,088; 1,089–1,092
CWF Energy	26-16 Jake Smith	9/11/1993	NW¼NW¼SE¼ SE¼ sec. 26	35.219335	–94.622929	Undivided	1,166–1,172
OGP Operating	26-1 Rice-Carden	6/19/1995	E½E½NE¼ sec. 26	35.227467	–94.620717	Undivided	1,352–1,358
OGP Operating	26-6 Rhodes	1/4/1996	C W½ sec. 26	35.223852	–94.632884	Undivided	1,244–1,250
OGP Operating	26-3 Hayes	8/13/1996	SW¼NE¼NW¼ sec. 26	35.228370	–94.631778	Undivided	1,465–1,470
OGP Operating	26-1A Rice-Carden	1/1/1997	S½N½NE¼ sec. 26	35.228370	–94.624036	Undivided	1,390–1,395
OGP Operating	27-7 Eagleton	8/15/1996	SW¼SW¼NE¼ sec. 27	35.224680	–94.645123	Undivided	1,407–1,412
OGP Operating	27-8 Eagleton	10/14/1996	NE¼NE¼SE¼ sec. 27	35.222873	–94.638486	Undivided	1,278–1,284
OGP Operating	27-11 Eagleton	10/12/1996	SE¼NE¼SW¼ sec. 27	35.221066	–94.647335	Upper & Lower	1,258–1,260; 1,261–1,266
OGP Operating	27-14 Eagleton	10/18/1996	SW¼SE¼SW¼ sec. 27	35.217452	–94.649547	Undivided	1,159–1,166
CWF Energy	27-15 Rhodes	9/18/1993	NW¼SE¼SW¼ SE¼ sec. 27	35.217452	–94.642910	Upper & Lower	1,151–1,153; 1,155–1,158
CWF Associates	27-9 G.W. Eagleton	4/21/1991	SE¼SW¼NE¼ SE¼ sec. 27	35.221066	–94.640698	Upper & Lower	1,185–1,187; 1,188–1,191
OGP Operating	27-1 Goodridge	11/2/1996	C NE¼NE¼ sec. 27	35.229198	–94.639592	Undivided	1,524–1,531
OGP Operating	27-5A Eagleton	1/4/1997	N½S½NW¼ sec. 27	35.226487	–94.650653	Upper & Lower	1,430–1,432; 1,433–1,436
OGP Operating	1-34 Wanslow	12/10/1996	C W½NW¼ sec. 34	35.212850	–94.652753	Upper & Lower	1,104–1,107; 1,109–1,112
CWF Energy	35-2 Jake Smith	9/6/1993	NW¼NW¼NW¼ NE¼ sec. 35	35.215560	–94.627389	Undivided	1,067–1,072
CWF Associates	35-1 Jake Smith	6/29/1991	NE¼SW¼NE¼ sec. 35	35.211946	–94.625177	Undivided	1,082–1,087
CWF Energy	35-6 Town of Spiro	9/3/1993	NE¼SE¼SE¼ NW¼ sec. 35	35.210139	–94.629601	Undivided	1,111–1,116
CWF Energy	35-3 Franklin	9/9/1993	SW¼SW¼NE¼ NW¼ sec. 35	35.213753	–94.631813	Upper & Lower	1,086–1,089; 1,092–1,096
OGP Operating	35-7 Town of Spiro	1/3/1996	SE¼SW¼NE¼ sec. 35	35.210139	–94.625177	Undivided	1,124–1,130
OGP Operating	35-1A Jake Smith	6/21/1995	NE¼NE¼NE¼ sec. 35	35.215560	–94.620754	Undivided	1,038–1,043
OGP Operating	35-10 Town of Spiro	6/29/1995	S½N½N½ SE¼ sec. 35	35.208332	–94.624071	Upper & Lower	1,198–1,201; 1,203–1,205
OGP Operating	35-5 Town of Spiro	1/5/1996	SW¼NW¼NW¼ sec. 35	35.213753	–94.636236	Upper & Lower	1,066–1,068; 1,070–1,074

[a]All wells are in T. 9 N., R. 25 E., Le Flore County, Oklahoma. [b]Refrac = refracture treatment. [c]ISIP = initial shut-in pressure.

Play Well Information

Net thickness (ft)	Elevation Kelly bushing	Elevation Ground level	Subsea elevation (Hartshorne coal) Top	Subsea elevation (Hartshorne coal) Bottom	Producing interval (ft)	Initial potential (Refrac)[b] (MCFGPD)	Water (Refrac) (BWPD)	ISIP[c]	FTP[d]
5		535	–526	–531	1,060–1,066	166 P[e]	8	280	
7	570		–593	–600	1,162–1,167	72 P	6	420	
5		520	–653; –656	–655; –659	1,172–1,180	100 F[f]	0	375	
6		501	–688	–694	1,188–1,195	110 (29) P	5 (2)	210 SITP[g]	9
6		520	–766	–772	1,286–1,293	95 (280) P	3 (3)	178	5
5		440	–646; –649	–648; –652	1,085–1,093	105 (103) P	0.5 (10)	56 SITP	6
6		559	–607	–613	1,165–1,172	92 P	4	90 SITP	5
6		501	–851	–857	1,351–1,359	185 P	1	220 SITP	15
6		467	–777	–783	1,243–1,251	121 P	3	475	
5		464	–1,001	–1,006	1,464–1,472	115 P	8	280	
5		485	–905	–910	1,390–1,394	116 P	20	535	
5		448	–959	–964	1,409–1,411	98 P	5	290	
4		461	–817	–823	1,279–1,281	123 P	6	160	
7		466	–792; –795	–794; –800	1,258–1,266	147 P	7	190	
7		474	–685	–692	1,158–1,166	116 P	7	270	
5		452	–699; –703	–701; –706	1,150–1,158	90 (124) P	1 (0)	128	8
5		450	–735; –738	–737; –741	1,184–1,192	90 P	2	60 SITP	
7		477	–1,047	–1,054	1,524–1,530	45 F	0	120 SITP	
5		491	–939; –942	–941; –945	1,431–1,435	50 P	15	520 SITP	
6		467	–637; –642	–640; –645	1,104–1,112	134 P	14	400	
5		459	–608	–613	1,067–1,074	122 (55) P	1 (0.5)	226	5
5		452	–630	–635	1,082–1,088	75 P	3	50 SITP	
5		428	–683	–688	1,111–1,116	54 P	4	173	5
7		451	–635; –641	–638; –645	1,086–1,095	72 (226) P	2 (7)	122 SITP	5
6		442	–682	–688	1,123–1,131	73 P	19		
5		466	–572	–577	1,037–1,045	82 P	6	80 SITP	15
5		436	–762; –767	–765; –769	1,192–1,208	107 P	0.5	60 SITP	10
6		435	–631; –635	–633; –639	1,066–1,074	143 P	37		

[d]FTP = flowing tubing pressure. [e]P = pumping. [f]F = flowing. [g]SITP = shut-in tubing pressure.

TABLE 10. – CWF Associates 27-9 G. W. Eagleton Core Bulk Density

Sample number	Depth (ft)	Bulk density (g/cm³)
1	1,182.0–82.6	1.34
2	1,182.6–82.8	1.35
3	1,182.8–83.1	1.53
4	1,183.1–83.5	1.30
5	1,183.5–84.0	1.30
6	1,184.0–84.6	1.77
7	1,184.6–84.7	1.66
8	1,184.7–85.0	1.65
9	1,185.0–86.0	1.36
10	1,186.0–86.4	1.34
11	1,186.4–86.7	1.37
12	1,186.7–87.3	1.30
13	1,187.3–88.0	1.34
14	1,188.0–88.7	1.45
15	1,188.7–88.8	1.69

preted to be the shale split separating the Upper and Lower Hartshorne coal beds.

Figure 39 shows the Hartshorne coal type log from the CWF Energy No. 26-13 Rhodes well. The base of the McAlester Formation includes an unnamed siltstone (16 ft thick). The top of the Upper Hartshorne coal is the top of the Hartshorne Formation. A 1-ft-thick shale separates the Upper and Lower Hartshorne coals in this well. The Hartshorne Formation is 100 ft thick (depth of 1,086–1,186 ft); the Hartshorne–Atoka formation boundary is imprecise and may alternatively be interpreted at 1,134 ft instead of 1,186 ft.

North–south and west–east stratigraphic cross sections are shown in Figures 40 and 41 (in envelope). Section A–A′ shows the Hartshorne coal splitting into Upper and Lower Hartshorne coals in wells 3 and 6 on the basis of the gamma-ray logs. The coal in well 5 (No. 35-1 Jake Smith) was interpreted to have a parting <1 ft thick in the detailed copy of the log; however, the peak separation could have been interpreted as a 1-ft shale separating the Upper and Lower Hartshorne coals. Other wells, not shown in the cross sections, interpreted as having a parting rather than a shale split are the Nos. 26-9 Jake Smith, 27-1 Goodridge, and 35-6 Town of Spiro.

Section B–B′ shows the change from the Upper and Lower Hartshorne coals in the west to the Hartshorne coal in the east. Shale separating the Upper and Lower Hartshorne coal beds is 2 ft thick in wells 1 and 2. A shale parting in the Hartshorne coal is not evident in the logs of wells 4 and 5. The Hartshorne–Atoka formation boundary is imprecise and was picked at the contact between the coarsening-upward sandstone interval above and the shale sequence below. Friedman (1982a, p. 14–15) illustrated a west–east stratigraphic cross section through the field study area, showing the stratigraphy from land surface to the Hartshorne coal.

A structure map depicting the top of the Hartshorne coal (Fig. 42) shows that most of the CBM wells in the field are on the northwestern limb of an anticline (Spiro anticline? of Iannacchione and Puglio, 1979). The depth to the top of the coal ranges from 1,038 to 1,524 ft (Table 9). Figure 43 is an isopach map of net Hartshorne coal (including the thickness of the Upper and Lower Hartshorne coals combined). This net-coal thickness ranges from 4 to 7 ft. The dashed line represents the coal-split line separating the Hartshorne coal on the north and east into the Upper and Lower Hartshorne coals on the south and west.

CWF Associates extracted Hartshorne coal cores from two wells in T. 9 N., R. 25 E.—the No. 27-9 G. W.

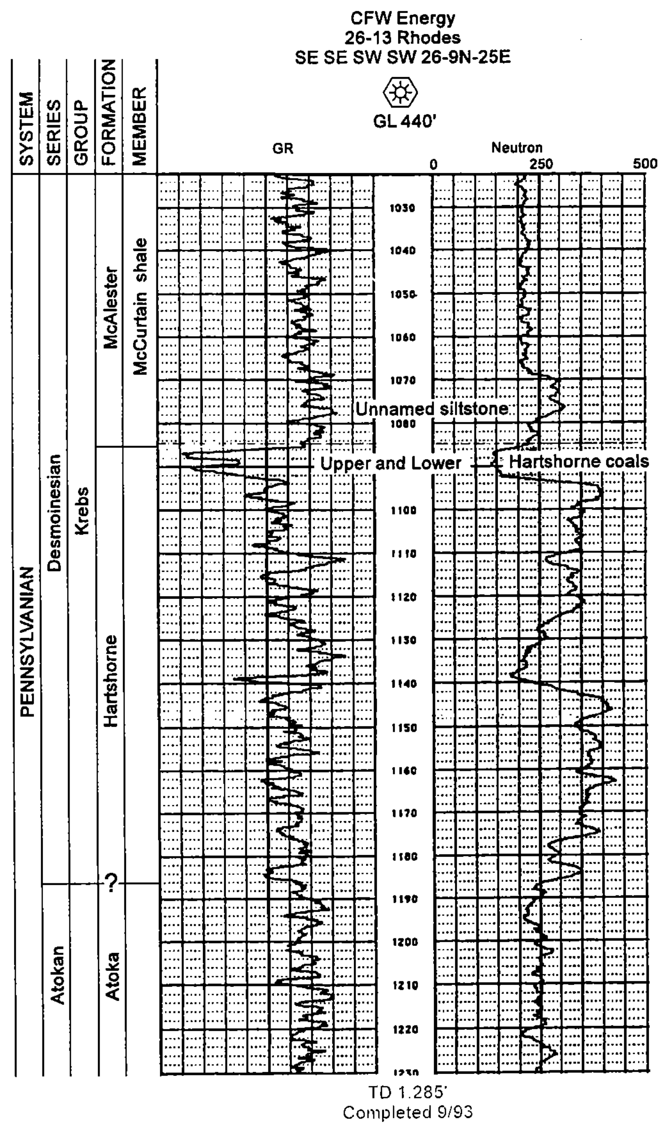


Figure 39. Hartshorne coal type log, Spiro SE gas field. *GR* = gamma ray.

Eagleton (sec. 27) and the No. 31-8 L. W. Stiles (sec. 31). The coal-core desorption data are given in Table 7 (samples 33 and 34, total gas contents of 483 and 390 CF/ton, respectively). Figure 44 illustrates the gas-storage capacities determined from adsorption isotherm testing and the gas contents measured during canister desorption testing. A report provided by OGP Operating indicated that "three of the four canister data points suggest an initial undersaturated condition in the coal seam since the gas contents are less than gas storage capacities at the same pressure level. If the coal seam was undersaturated, depletion through water production would have to occur for gas desorption and production to take place. However, actual production performance (i.e., gas was produced initially on all wells) indicates a saturated system at initial conditions." Therefore, the cleat system is saturated with gas, with a minor amount of mobile water. Additional coal-core data are in Table 11. The rank of the Hartshorne coals is low-volatile bituminous, on the basis of mean random vitrinite reflectances of 1.62% and 1.61%, respectively (average of three samples each). The gas composition is mostly methane with minor amounts of impurities. This is consistent with the gas-composition data summarized above. Additional gas-analysis data from the No. 27-9 Eagleton core indicated a nitrogen content of as much as 36.57%, which probably represents air contamination. The heating value (dry) of the gas was 1,004 Btu/CF. CWF Associates commissioned a cleat analysis of the Hartshorne coal in the Eagleton well by The Western Co. The report, provided by OGP Operating, indicated that the face cleat is spaced about 3–5 mm apart and has an aperture thickness of about 0.2 mm at surface conditions. Cleat-filling minerals in the coal core and cuttings were dominated by kaolinite and calcite. The Hartshorne coals in the No. 31-8 L. W. Stiles had a porosity (helium) of 1.1–3.5%, a permeability of 1.8–4.4 md, an initial pressure of 550 PSI, and a gas-in-place estimate of 8.075 MMCF/acre.

Most CWF wells were fractured, using a cross-linked gel and sand treatment, and had poor initial results. Wells that were restimulated, using fresh-

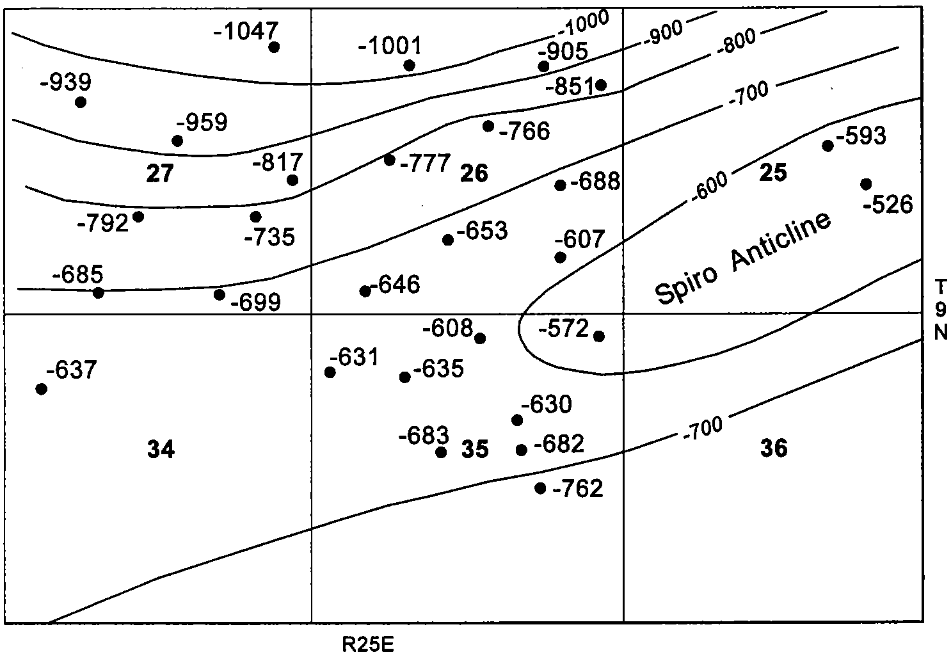


Figure 42. Structure-contour map depicting top of Hartshorne coal, Spiro SE gas field. Contour interval, 100 ft. Datum is mean sea level. See Figure 37 for well names.

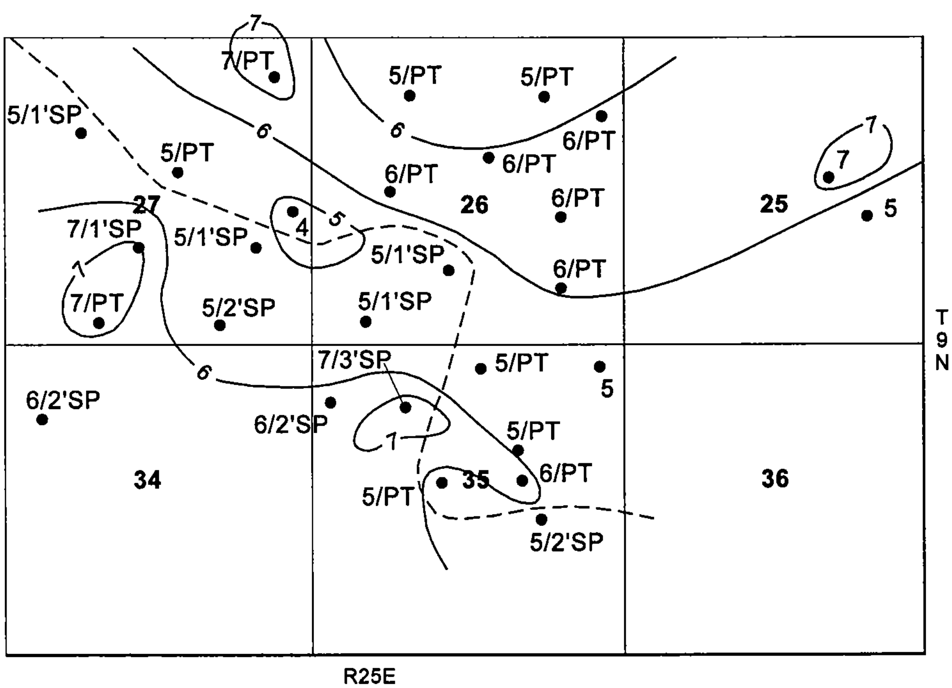


Figure 43. Isopach map of net Hartshorne coal, Spiro SE gas field. Contour interval, 1 ft. *PT* = shale parting within Hartshorne coal, *SP* = thickness of split separating Upper and Lower Hartshorne coal beds, dashed line = coal-split line.

TABLE 11. – Upper and Lower Hartshorne Coal-Core Data from CWF Associates No. 27-9 G. W. Eagleton (SE¼ sec. 27, T. 9 N., R. 25 E.) and No. 31-8 L. W. Stiles (NE¼ sec. 31, T. 9 N., R. 25 E.) Wells[a]

	27-9 G. W. Eagleton				31-8 L. W. Stiles			
Analysis	Depth (1,182.7 ft)	Depth (1,183.5 ft)	Depth (1,186.5 ft)	Average	Depth (1,208–1,209 ft)	Depth (1,212–1,213 ft)	Depth (1,214–1,215 ft)	Average
VR_o (%)[b]	1.62	1.60	1.65	1.62	1.64	1.59	1.61	1.61
Moisture (%)[c]	1.44	1.50	1.36	1.43	2.46	10.49	6.74	6.56
Ash (%)[c]	6.58	2.79	7.50	5.62	9.32	19.07	5.27	11.22
Volatile matter (%)[c]	15.90	15.26	16.96	16.04	17.89	13.26	12.63	14.59
Fixed carbon (%)[c]	76.08	80.45	74.18	76.91	70.33	57.18	75.36	67.63
BTU/LB[c]	14,400	15,063	13,991	14,485	13,474	10,535	13,624	12,544
Sulfur (%)[c]	0.60	0.68	0.63	0.64	0.87	0.68	0.72	0.76

GAS ANALYSIS (Mole %)[d]:

Well	Carbon dioxide	Nitrogen	Methane	Ethane	Propane	Iso-butane	N-butane	Iso-pentane	N-pentane	Hexanes
Eagleton	0.41	0.12	99.43	0.04	0.00	0.00	0.00	0.00	0.00	0.00
Stiles	0.56	0.12	99.27	0.05	0.00	0.00	0.00	0.00	0.00	0.00

[a] Analyses reported by Core Laboratories, Inc. Data provided by OGP Operating, Inc.
[b] Mean random vitrinite reflectance (oil immersion; based on 100 readings for Eagleton well and 103 readings for Stiles well).
[c] As-received basis. Analyses performed by Standard Laboratories, Inc.
[d] Analyses performed by Shamrock Gas Analysis. Data provided by OGP Operating, Inc.

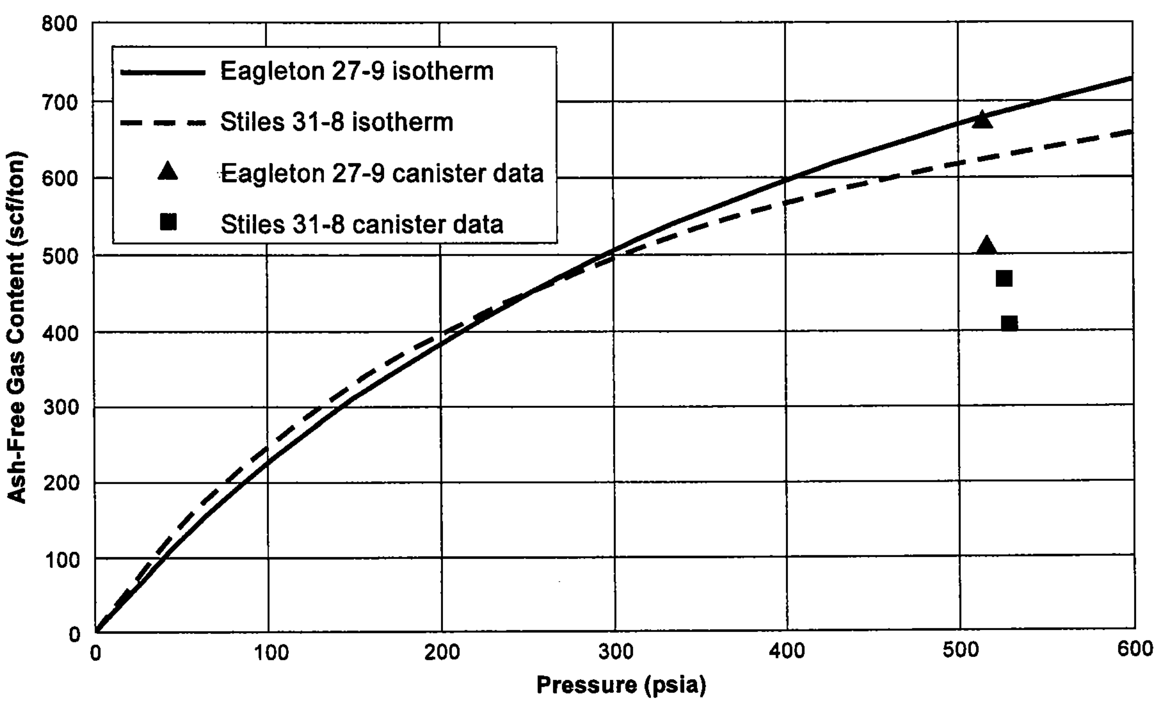


Figure 44. Adsorption isotherms and canister desorption data for Nos. 27-9 Eagleton and 31-8 Stiles wells; *scf* = standard cubic feet (of gas).

water and sand, resulted in improved production. Most of the OGP wells were fractured, using freshwater and sand treatments (Table 12). Wells treated with nitrogen foam (80%) and sand were not as effective as the freshwater and sand treatments. A report from OGP Operating indicated that "the wells produce one-half to one barrel of water per day aided by conventional downhole pumps and pump jacks with electric motors on timers. The water is separated and run in tanks for occasional pick-up and disposal. The average operating

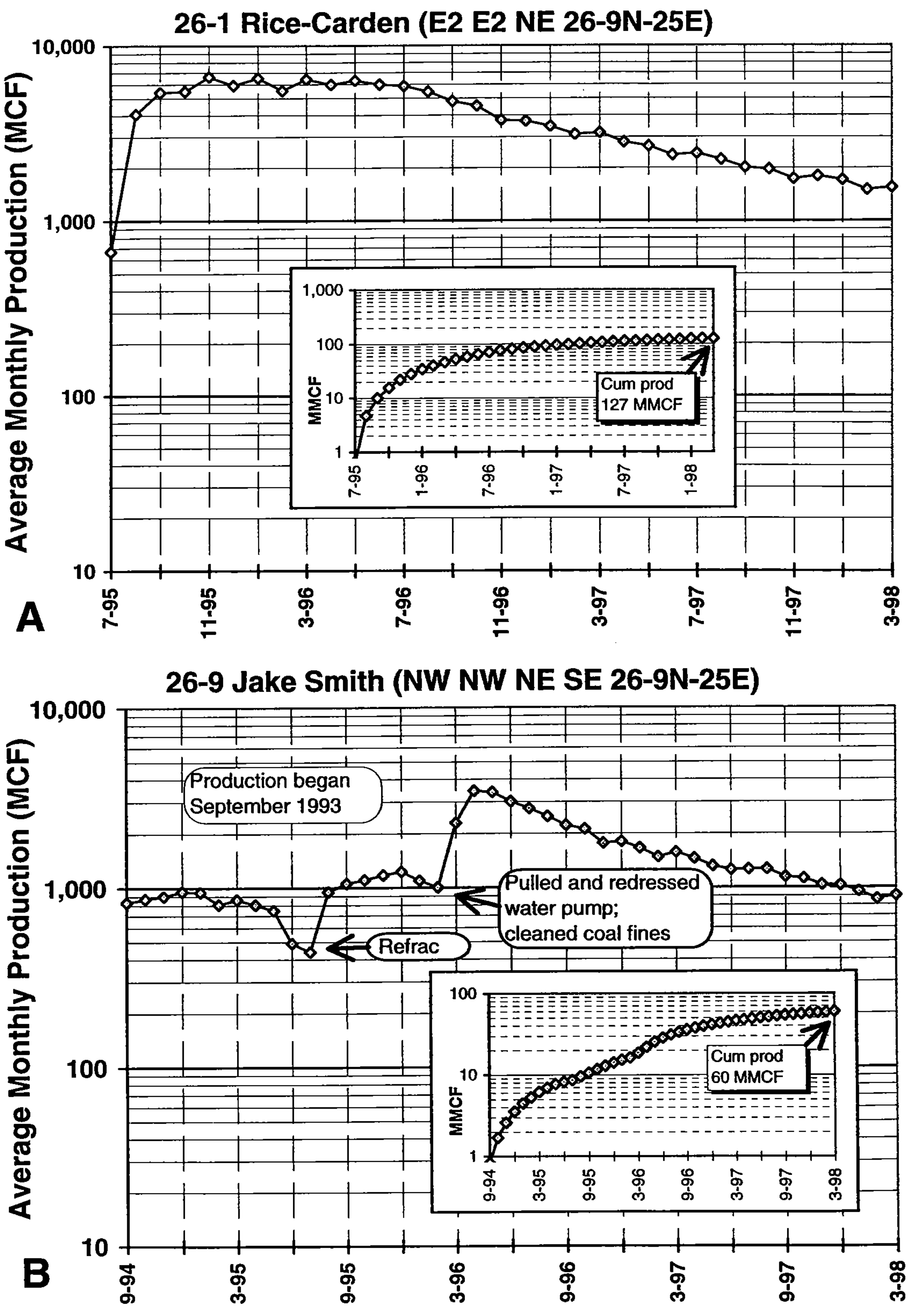


Figure 45. Gas-production-decline curves. (A) No. 26-1 Rice-Carden well. (B) No. 26-9 Jake Smith well.

cost per well per month, including G & A, is approximately $450.00."

Figures 45–47 illustrate gas-production-decline curves from six CBM wells, three from sec. 26 and three from sec. 35, using monthly production data. The No. 26-1 Rice-Carden well (Fig. 45A) has the best monthly production of all the CBM wells in the field, peaking at 6,631 MCF in November 1995 (fifth month of production). The curve follows the typical decline curve for CBM wells: the gas rate increases initially during the dewatering

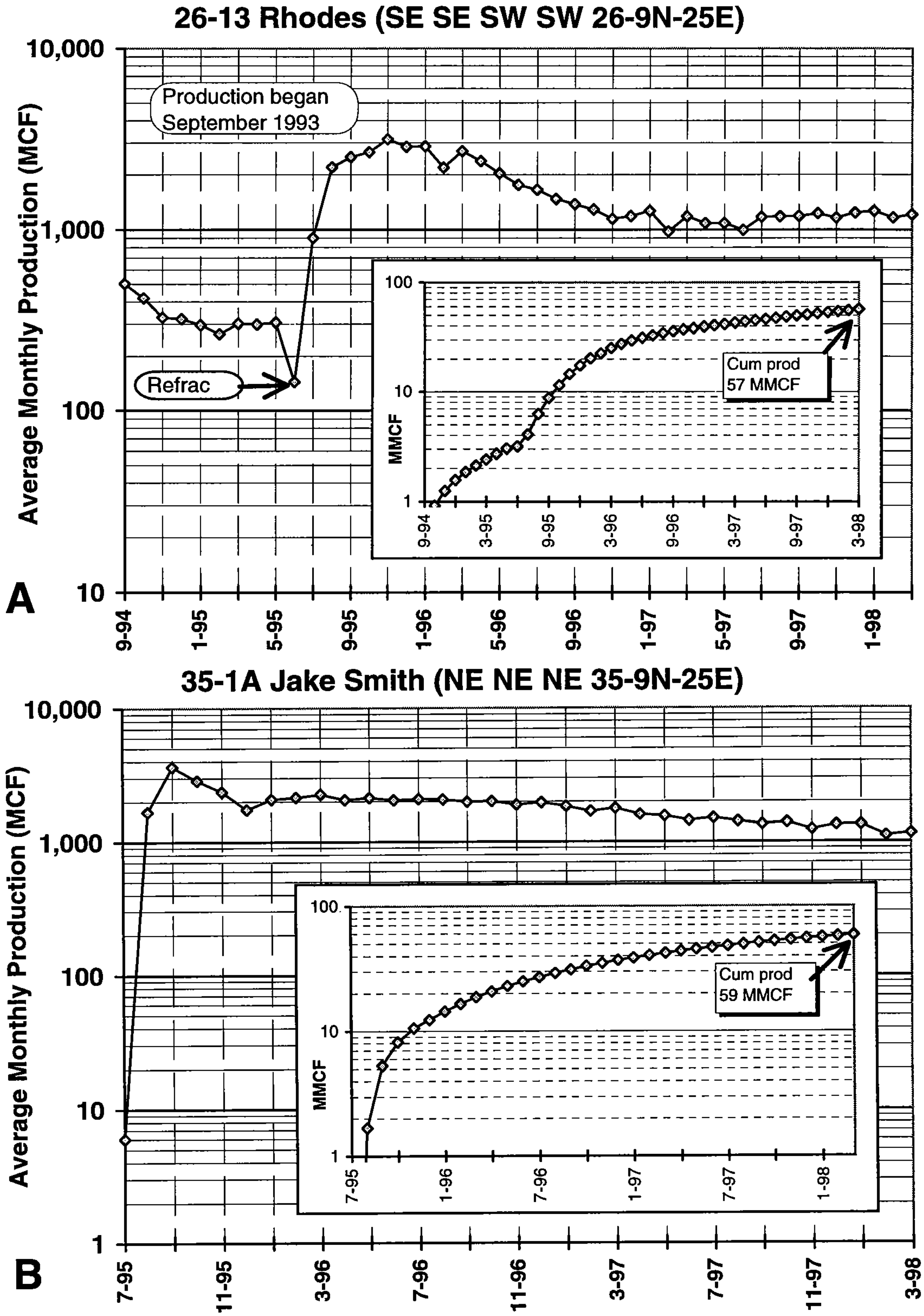
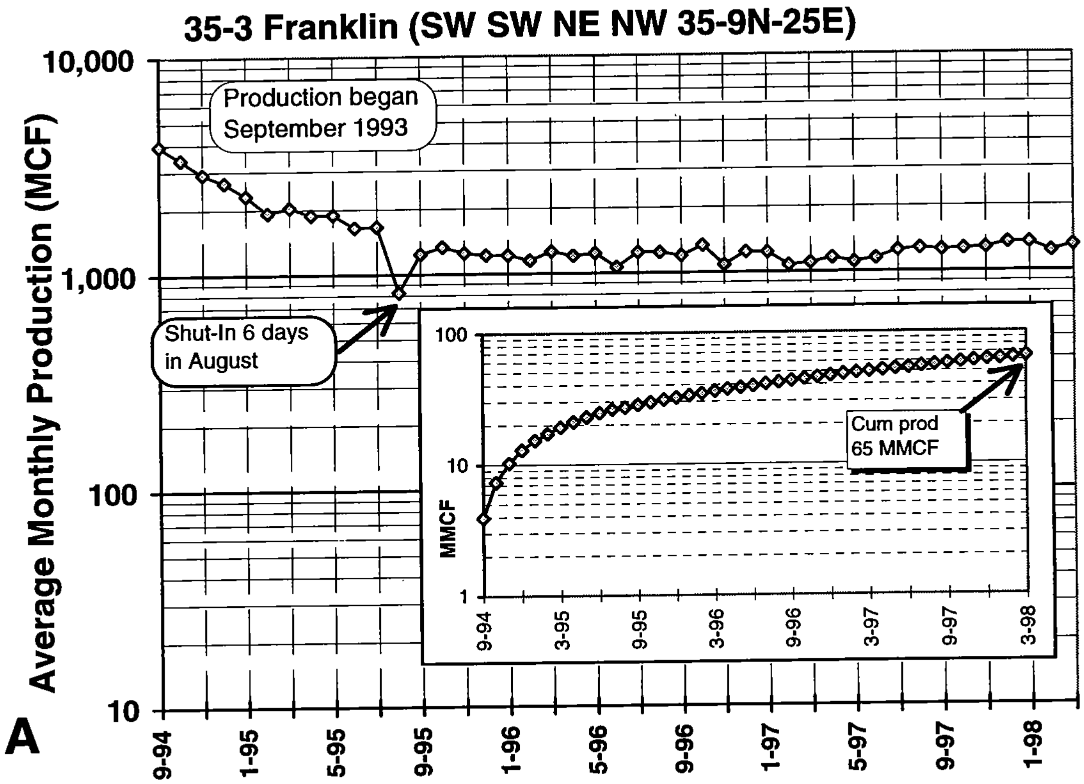


Figure 46. Gas-production-decline curves. (A) No. 26-13 Rhodes well. (B) No. 35-1A Jake Smith well.

stage, then comes peak production in the stable-production stage, followed by the decline stage (Boyer, 1989; Schraufnagel, 1993). Cumulative gas production for this well is 127 MMCF from July 1995 through March 1998 (33 months).

The production-decline curve for the No. 26-9 Jake Smith well (Fig. 45B) shows the effect of a refracture treatment in June 1995 and a water-pump cleaning in February 1996. The well was refractured (see stimulation data in Table 12) when monthly gas production



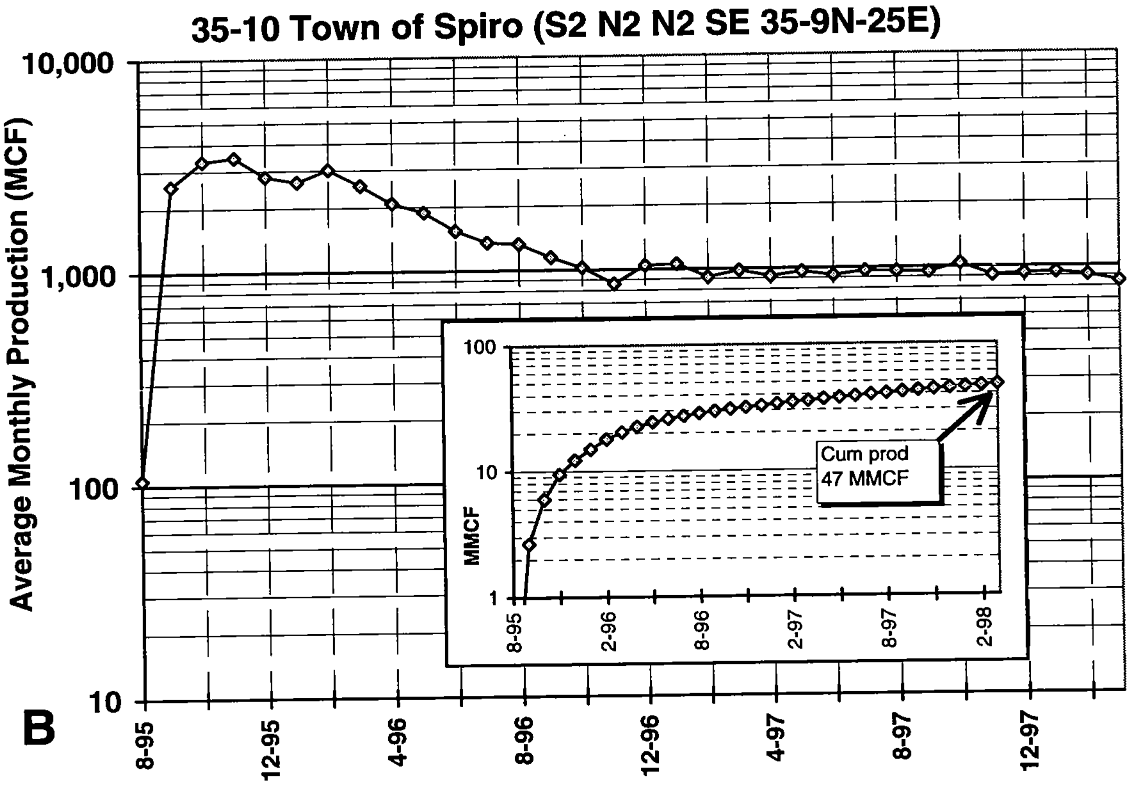


Figure 47. Gas-production-decline curves. (A) No. 35-3 Franklin well. (B) No. 35-10 Town of Spiro well.

TABLE 12. – Well-Stimulation Data for CBM Wells in Spiro SE Field

Well name	Perforations (ft)	Date	Base fluid Type	Base fluid Volume	Total proppant (lb)	100 mesh (lb)	20/40 mesh (lb)	16/30 mesh (lb)	12/20 mesh (lb)	Treating pressure Min. (PSI)	Treating pressure Max. (PSI)	Treating pressure Avg. (PSI)	Avg. inj. rate (BPM)	Initial potential (MCF)	Initial potential (BW)	Initial potential Date	Current prod. (as of 3/19/97) (MCF)	Current prod. (as of 3/19/97) (BW)	Comments
25-1 Glenn	1,060–1,066	12/14/96	Fw	2,331 Bbl	50,320	0	0	0	50,320	1,750	2,100	1,840	40.5	166	8	2/19/97	111	3	
25-2 Glenn	1,162–1,170	10/17/96	Fw	2,245 Bbl	48,000	0	0	0	48,000	1,830	2,520	2,150	41.5	72	6	11/29/96	96	0	
26-3 Hayes	1,464–1,472	9/5/96	N_2 Foam	550,000 Scf	30,740	0	0	0	30,740	1,610	1,990	1,740	40	115	8	10/13/96	76	2	
26-1 Rice-Carden	1,351–1,359	6/21/95	Fw	4,294 Bbl	109,210	0	88,000	0	21,210	2,100	3,130	2,650	40.5	185	1	10/27/95	99	0	
26-7 Rice-Carden	1,286–1,293	11/9/93	N_2 Foam	306,000 Scf	47,000	0	0	47,000	0	1,810	2,300	1,980	29	95	3	12/24/94	—	—	Bailed out with 1,000 gal 7½% HCl
26-7 Rice-Carden	1,286–1,293	2/15/94	Fw	3,702 Bbl	91,000	11,000	60,000	20,000	0	2,000	3,200	2,200	42	280	3	3/21/94	37	1	Refrac
26-6 Rhodes	1,243–1,251	2/5/96	Fw	1,479 Bbl	37,500	0	37,500	0	0	2,940	4,600	3,200	37	121	3	3/4/96	53	0	1,000 PSI @ 3 min.
26-9 Jake Smith	1,188–1,195	10/27/93	N_2 Foam	316,500 Scf	64,000	0	0	64,000	0	1,800	2,400	2,050	30	110	5	12/23/93	—	—	
26-9 Jake Smith	1,188–1,195	6/23/95	Fw	3,964 Bbl	91,000	0	81,000	0	10,000	2,064	2,700	2,350	40	29	2	9/30/95	49	1	Refrac
26-11 G.W. Eagleton	1,172–1,180	3/1/94	Fw	3,777 Bbl	83,500	12,000	71,500	0	0	1,780	2,400	2,100	40	100	0	12/23/93	45	0	
26-16 Jake Smith	1,165–1,172	11/1/93	N_2 Foam	258,000 Scf	60,000	0	0	60,000	0	1,650	2,000	1,800	28	92	4	12/23/93	33	0	Bailed out with 1,000 gal 7½% HCl
26-13 Rhodes	1,085–1,093	10/14/93	N_2 Foam	28,000 Scf	41,500	0	41,500	0	0	1,640	2,550	2,000	31	105	0.5	12/23/93	—	—	Bailed out with 1,000 gal 7½% HCl
26-13 Rhodes	1,085–1,093	6/9/95	Fw	3,990 Bbl	105,840	0	88,160	0	17,860	1,880	2,300	2,000	40.5	103	10	8/30/95	35	2	880 PSI @ 20 min.; refrac
27-1 Goodridge	1,524–1,530	10/17/96	N_2 Foam	549,000 Scf	50,460	0	0	0	50,460	1,020	1,100	1,060	45.8	45	0	11/2/96	5	0	
27-7 Eagleton	1,409–1,411	10/1/96	N_2 Foam	525,000 Scf	46,100	0	0	0	46,100	2,070	2,460	2,250	43	98	5	10/23/96	22	0.5	
27-8 Eagleton	1,279–1,281	9/11/96	N_2 Foam	603,000 Scf	46,060	0	0	0	46,060	1,960	2,270	2,180	44	123	6	10/14/96	52	0	
27-9 G.W. Eagleton	1,183–1,190	6/27/91	Fw	2,848 Bbl	89,320	8,100	70,000	0	11,200	1,300	1,580	1,400	33	90	2	12/23/93	30	1	1,090 PSI @ 20 min.
27-11 Eagleton	1,258–1,266	9/11/96	N_2 Foam	250,000 Scf	5,200	0	0	0	5,200	2,320	3,000	2,400	39	147	7	10/12/96	25	1	
27-14 Eagleton	1,158–1,166	10/1/96	N_2 Foam	740,000 Scf	40,000	0	0	0	40,000	2,090	2,480	2,250	47.5	116	7	10/18/96	28	0	
27-15 Rhodes	1,150–1,158	11/8/94	N_2 Foam	271,000 Scf	37,000	0	0	37,000	0	1,550	2,500	1,600	29	90	1	12/23/93	—	—	
27-15 Rhodes	1,150–1,158	3/28/94	Fw	3,980 Bbl	118,640	13,100	105,540	0	0	1,750	2,300	2,000	41	124	0	4/24/94	22	1	Refrac
1-34 Wanslow	1,104–1,112	11/7/96	Fw	2,183 Bbl	51,860	0	0	0	51,860	1,940	2,480	2,200	40	134	14	12/10/96	73	1	
35-2 Jake Smith	1,067–1,074	10/18/93	N_2 Foam	112,946 Scf	4,100	0	0	4,100	0	1,900	2,950	1,900	27	(See below)			—	—	Bailed out with 1,000 gal 7½% HCl
35-2 Jake Smith	1,067–1,074	10/25/93	N_2 Foam	304,000 Scf	61,400	0	0	61,400	0	1,780	2,850	1,850	29	122	1	12/23/93	—	—	
35-2 Jake Smith	1,067–1,074	1/15/94	Fw	3,109 Bbl	72,300	0	51,700	6,800	13,800	2,000	2,900	2,400	40	55	0.5	1/11/94	25	1	
35-1A Jake Smith	1,037–1,045	6/29/95	Fw	3,956 Bbl	99,560	0	9,000	40,560	50,000	1,990	2,800	2,300	40	82	6	10/8/95	56	2	
35-5 Town of Spiro	1,066–1,074	2/23/96	Fw	1,965 Bbl	70,600	0	15,000	0	55,600	2,290	2,950	2,620	37	143	37	3/22/96	37	0	
35-3 Franklin	1,086–1,095	10/18/93	N_2 Foam	269,377 Scf	39,000	0	0	39,000	0	1,600	1,800	1,650	30	72	2	12/23/94	—	—	
35-3 Franklin	1,086–1,095	6/6/94	Fw	4,729 Bbl	110,000	10,000	100,000	0	0	1,580	2,400	1,700	40.7	226	7	7/15/94	40	1	Refrac
35-1 Jake Smith	1,082–1,088	7/12/91	Fw	1,472 Bbl	55,000	12,000	43,000	0	0	1,450	3,700	2,000	32.8	75	3	12/23/93	—	—	Screened out
35-1 Jake Smith	1,082–1,088	10/29/96	Fw	1,345 Bbl	8,100	0	0	0	8,100	1,370	1,580	1,500	40				14	1	Refrac: recovering load water
35-6 Town of Spiro	1,111–1,116	10/14/93	N_2 Foam	350,000 Scf	60,700	0	0	60,700	0	1,640	2,100	1,900	28	54	4	12/23/93	—	—	Bailed out with 1,000 gal 7½% HCl
35-6 Town of Spiro	1,111–1,116	4/22/94	Fw	3,252 Bbl	102,000	12,000	90,000	0	0	1,850	2,900	2,150	41	118	3	6/4/94	—	—	1,400 PSI @ 21 min.
35-6 Town of Spiro	1,111–1,116	10/29/96	Fw	1,454 Bbl	22,000	0	0	0	22,000	1,940	2,560	2,150	37.5				36	2	Refrac: recovering load fluid
35-7 Town of Spiro	1,123–1,131	2/21/96	Fw	1,921 Bbl	67,640	0	25,500	0	42,140	2,150	2,800	2,350	40	73	19	3/21/96	57	0	
35-10 Town of Spiro	1,196–1,208	8/2/95	Fw	2,670 Bbl	90,240	0	48,560	0	41,680	1,925	2,800	2,500	40	107	0.5	11/23/95	32	0	

TABLE 13. – Annual Gas Production from the Hartshorne Coal Beds for Wells in Spiro SE Field (T. 9 N., R. 25 E.)

Sec.	Well name	Date of first production	Annual gas production (MCF)[a] 1994[b]	1995	1996	1997	1998[c]	Average daily production (MCF)[c]	Cumulative production (MCF)[c]
25	25-1 Glenn	2/97	—	—	—	35,984	8,644	105	44,628
25	25-2 Glenn	11/96	—	—	2,826	35,522	8,982	91	47,330
26	26-3 Hayes	9/96	—	—	8,394	22,394	3,933	60	34,721
26	26-1A Rice-Carden	5/97	—	—	—	23,911	8,133	96	32,044
26	26-1 Rice-Carden	7/95	—	28,148	64,769	29,694	4,749	127	127,360
26	26-7 Rice-Carden	12/93	6,716	14,354	13,934	13,103	3,074	39	51,181
26	26-6 Rhodes	3/96	—	—	29,472	14,258	2,017	60	45,747
26	26-9 Jake Smith	12/93	3,551	10,619	27,413	15,623	2,713	46	59,919
26	26-11 G.W. Eagleton	1/92	8,752	21,725	17,701	15,587	3,293	51	67,058
26	26-16 Jake Smith	12/93	7,071	16,847	12,441	12,074	3,099	39	51,532
26	26-13 Rhodes	12/93	1,564	15,882	22,047	13,770	3,649	43	56,912
27	27-1 Goodridge	10/96	—	—	1,144	1,771	238	6	3,153
27	27-5A Eagleton	4/97	—	—	—	10,526	2,886	37	13,412
27	27-7 Eagleton	10/96	—	—	4,102	5,591	910	19	10,603
27	27-8 Eagleton	9/96	—	—	6,897	15,965	2,585	44	25,447
27	27-9 G.W. Eagleton	9/91	4,990	13,592	11,961	9,335	2,073	32	41,951
27	27-11 Eagleton	10/96	—	—	5,533	7,398	1,762	27	14,693
27	27-14 Eagleton	10/96	—	—	6,456	7,679	2,116	30	16,251
27	27-15 Rhodes	12/93	4,704	12,061	10,039	7,385	1,533	27	35,722
34	1-34 Wanslow	11/96	—	—	2,811	21,760	3,418	54	27,989
35	35-2 Jake Smith	12/93	6,813	13,977	10,160	9,612	2,473	33	43,035
35	35-1A Jake Smith	7/95	—	12,275	24,696	18,156	3,615	58	58,742
35	35-5 Town of Spiro	3/96	—	—	18,502	12,514	2,883	44	33,899
35	35-3 Franklin	12/93	12,923	19,222	14,453	14,473	3,890	50	64,961
35	35-1 Jake Smith	9/91	2,530	9,088	6,487	7,917	2,285	22	28,307
35	35-6 Town of Spiro	12/93	6,898	11,822	9,385	13,487	3,278	34	44,870
35	35-7 Town of Spiro	3/96	—	—	26,609	19,589	3,837	66	50,035
35	35-10 Town of Spiro	8/95	—	12,229	20,452	11,494	2,695	48	46,870

[a]Includes wells having only a partial year's production.
[b]Production from September through December 1994.
[c]Production from January through March 1998.

TABLE 14. – Gas-Production Statistics for the Hartshorne Coal Beds in Spiro SE Field, Le Flore County, Oklahoma

Year	Number of wells	Annual production[a] (MCF)	Average monthly production per well (MCF)	Average daily production per well (MCF)	Cumulative production (MCF)
1994[b]	11	66,512	1,512	50	66,512
1995	14	211,841	1,603	53	278,353
1996	25	378,684	1,680	55	657,037
1997	28	426,572	1,325	43	1,083,609
1998[c]	28	94,763	1,128	37	1,178,372

[a]Includes wells having only a partial year's production.
[b]Production from September through December 1994.
[c]Production from January through March 1998.

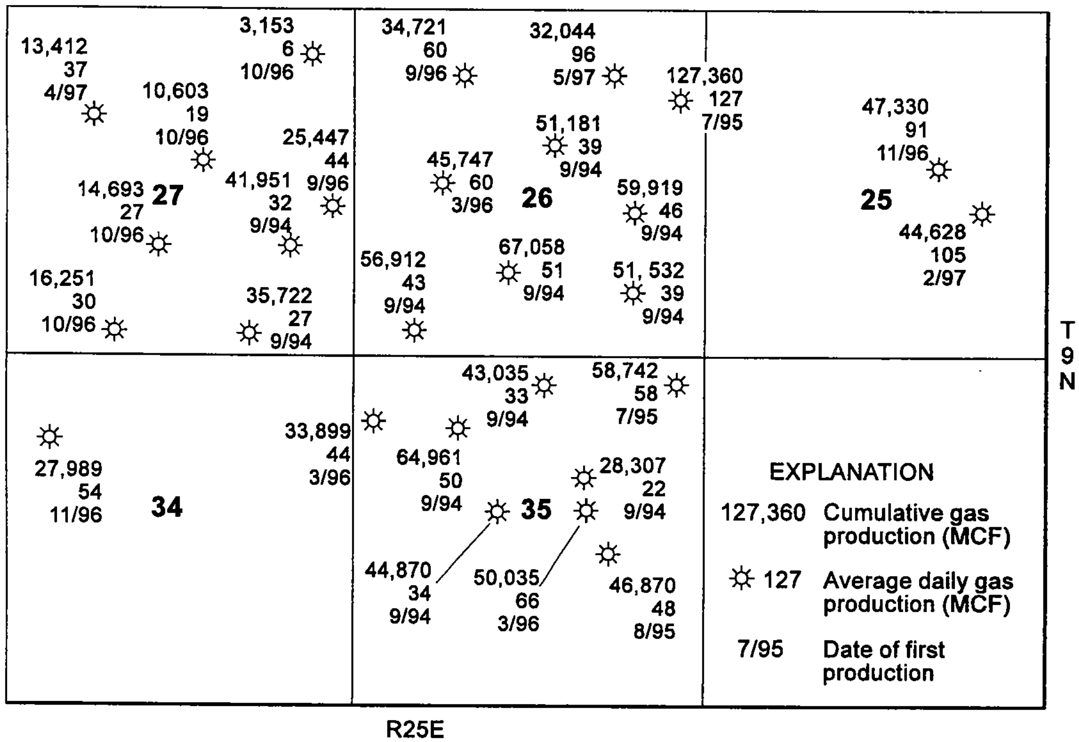


Figure 48. Map of Spiro SE gas field showing cumulative gas production (MCF), average daily gas production (MCF), and date of first production (9/94 indicates CWF wells with starting date of available gas-production figures).

was 440 MCF; gas production increased to 1,231 MCF by December 1995. By pulling the water pump and cleaning out the coal fines, gas production increased from 1,005 MCF in February 1996 to a maximum of 3,447 MCF in April 1996. Cumulative gas production from September 1994 through March 1998 (the period of available data) was 60 MMCF (43 months).

The No. 26-13 Rhodes well (Fig. 46A) was refractured in June 1995, when monthly gas production was 144 MCF (see stimulation data in Table 12). Following refracturing, gas production increased to a maximum of 3,145 MCF in November 1995. Cumulative gas production from September 1994 through March 1998 (the period of available data) was 57 MMCF (43 months).

The first full month of gas production in the No. 35-1A Jake Smith well (Fig. 46B) was 1,674 MCF in August 1995. The peak gas production was 3,633 MCF in September 1995, followed by a gentle decline to a minimum of 1,111 MCF in February 1998. Cumulative gas production from July 1995 through March 1998 was 59 MMCF (33 months).

Figure 47A illustrates the decline stage of the No. 35-3 Franklin well. The slope of the curve flattens to 1,063–1,351 MCF (average of 1,221 MCF) for September 1995 to March 1998 (31 months). Cumulative gas production from September 1994 through March 1998 (the period of available data) was 65 MMCF (43 months).

The first full month of gas production in the No. 35-10 Town of Spiro well (Fig. 47B) was 2,540 MCF in September 1995. The peak gas production was 3,455 MCF in November 1995, followed by a gentle decline to a minimum of 849 MCF in March 1998. Cumulative gas production from August 1995 through March 1998 was 47 MMCF (32 months).

Cumulative gas production from September 1994 through March 1998 for the 28 Hartshorne coalbed-methane wells in the Spiro SE gas field is given in Figure 48 and Tables 13 and 14. The No. 26-1 Rice-Carden well had the highest cumulative gas production (127,360 MCF) and highest average daily gas production (127 MCFGPD). The average daily gas production per well ranged from 6 to 127 MCFGPD, with an average of 50 MCFGPD. Gas production from all 28 wells was about 1,400 MCFGPD. The annual gas production from the 11 CWF wells for 4 months during 1994 was 66,512 MCF. The peak annual gas production was 426,572 MCF from 28 wells in 1997. Cumulative gas production from September 1994 through March 1998 was 1,178,372 MCF.

PART III

The Hartshorne Formation of Arkansas

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INTRODUCTION

The Hartshorne Formation is an upper Middle Pennsylvanian (Desmoinesian) unit in the Arkoma basin of western Arkansas and eastern Oklahoma. Although predominantly sandstone, it has long been known to contain minable coal reserves. It is also a gas reservoir, particularly in Oklahoma, where the Hartshorne began producing natural gas before well-spacing and production regulations were imposed in the 1930s. Because Oklahoma elected to retain relatively small production units for the formation, development of the reservoir continues to the present. In Arkansas, however, Hartshorne gas was not exploited prior to the 1930s and came to be placed under restrictive field-spacing regulations that limited wells to one per 640-acre section for each producing zone. As the reservoirs in Arkansas tend to be of low pressure and low production, this limit made the Hartshorne Formation of little commercial interest. Most producers drilled through it, seeking deeper zones with higher production. In 1995, a petition by Grubbs Energy Co., Inc., resulted in the change of field-spacing rules to allow 40-acre production units. Smaller production units allowed wells to be clustered for efficient, cost-effective compression. This regulatory change has stimulated interest in drilling the Hartshorne by some of the independent producers in western Arkansas.

LOCATION AND GEOLOGY

The Arkoma basin is an arcuate foreland basin that developed during the late Paleozoic Ouachita orogeny, when the crustal plates of North America and Gondwana collided. Located between the present-day Ouachita Mountains to the south and the Ozark Plateau in Arkansas and the Cherokee platform in Oklahoma, the basin stretches from Little Rock, Arkansas, westward to the Arbuckle Mountains in south-central Oklahoma. Its length of arc is nearly 300 mi, whereas the maximum width is about 50 mi (Fig. 49).

The present structure of the Arkoma basin represents a transition in styles between the folding and thrust faulting of the Ouachita orogen and the predominantly horizontal strata of the Ozark plateau. The structure within the basin itself consists of broad, open folds that become compressed on the southern margin (Houseknecht and Kacena, 1983). Some limbs of the anticlines and synclines are nearly vertical in tightly folded areas. Faulting within the basin is common. Normal faulting predominates, especially on the northern side of the basin, but reverse faults are also present (Lumbert and Stone, 1992).

In Arkansas, the Hartshorne Formation is found mainly in the subsurface (usually <4,500 ft below the surface in the eastern region), but it crops out along the northern and southern basin margins (Fig. 50). Outcrops also occur in synclinal remnants and anticlines within the basin. The formation consists mostly of sandstone, with some siltstone and interbedded shale, and ranges in thickness from a feather edge on the northern fringe to nearly 400 ft in the central axis of the basin (Haley, 1961). Coal beds are also associated with the sandstone; these tend to become both more extensive and thicker in the western region of the basin. In Arkansas, these coals vary in thickness from a few inches to >9 ft (Bush and Colton, 1983).

It must be noted that a difference in terminology exists between Arkansas and Oklahoma concerning the boundaries of the Hartshorne and the placement of the coals. Over much of the western half of the Arkoma basin, the Hartshorne consists of an Upper Member and a Lower Member, each of which contains a sandstone and an overlying coal bed. The Upper Member is generally less than 100 ft thick, whereas the Lower Member is up to several hundred feet thick. However, the lower coal bed is absent at some places, making the distinction between the two members difficult to determine. In Arkansas, however, only one sandstone normally occurs, which seems to correlate with the Lower Member of the Hartshorne of Oklahoma, whereas the coal beds appear to merge into a single unit that is assigned to the overlying McAlester Formation (Fig. 51) (Hemish and Suneson, 1997). This coal thins progressively eastward, eventually disappearing.

The McAlester Formation is predominantly shale, and the contact between the Hartshorne and the McAlester is typically gradational. At a few locations, though, such as the spillway at Horsehead Lake in

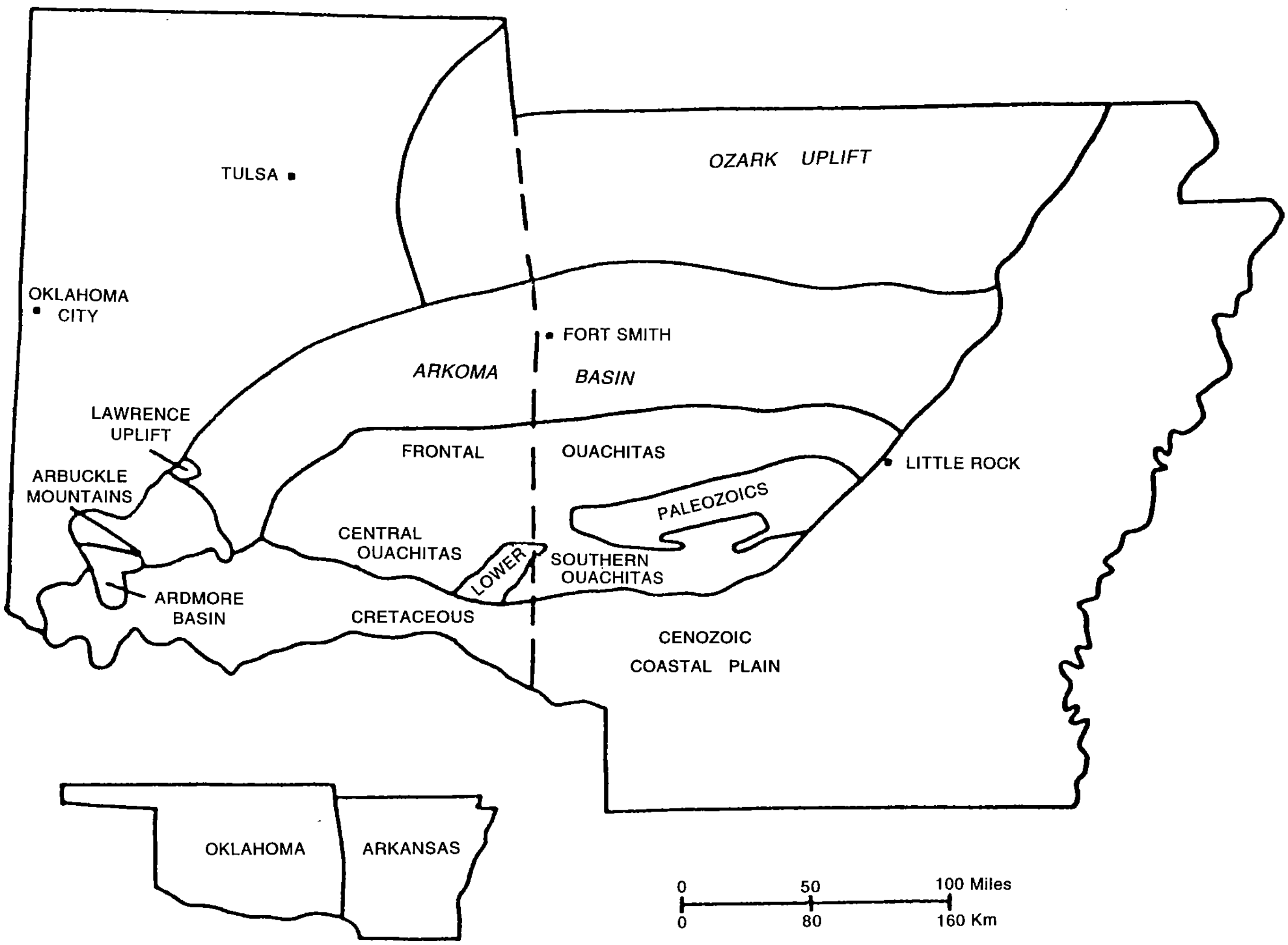


Figure 49. Location map for Arkoma basin. From Houseknecht and Kacena (1983).

Johnson County (Fig. 50), the stratigraphic sequence appears to be slightly different. Only the top part of the Hartshorne is exposed in the spillway. A 6–8-in.-thick coal bed lies at the base of the McAlester Formation and rests atop ≥40 in. of gray clay underlain by 30 ft of bedded sandstone that consists largely of tabular, fine- to medium-grained sandstones ≤18 in. thick, with a few beds as thick as 5 ft. The sandstone in turn overlies another coal bed whose thickness is 24 in. and is underlain by 30–36 in. of gray clay. Below the second clay is more bedded sandstone. This stratigraphic sequence appears to be restricted to the Horsehead Lake area, but, like the rest of the Hartshorne Formation in Arkansas, it probably does not contain the Upper Member, despite the presence of two coal beds.

The Atoka Formation underlies the Hartshorne Formation. This sequence of mostly marine shale, interspersed with sandstone, is generally divided into upper, middle, and lower units. The thickness of the Atoka Formation dramatically increases to the south across a series of faults. Some of the faults resulted from fracturing of the North American continental margin during the collision that resulted in formation of the Ouachita orogen. Other faults are growth faults that formed during deposition, particularly those of the middle part of the Atoka, which displays the greatest thickening of the three units (Fig. 52). Discrete sandstone units and scattered rare coals occur within the Atoka Formation; many of the sandstones are gas bearing and are targets of most of the wells that penetrate the Hartshorne. Some of the sandstones in the upper Atoka have deltaic origins, whereas those in the middle and lower Atoka were deposited in submarine fans or as turbidites (Thomas, 1989). Other thin sandstones in the upper Atoka occur as tabular beds; in outcrop, some of these thin sandstones are rich in shallow-marine fossils.

The nature of the contact between the Hartshorne and Atoka Formations is somewhat problematical. Some geologists—most notably, those with the Arkansas Geological Commission—believe that the contact is unconformable, at least in the eastern half of the basin (Haley and others, 1979; Lumbert and Stone, 1992). Others believe that the contact is gradational, with

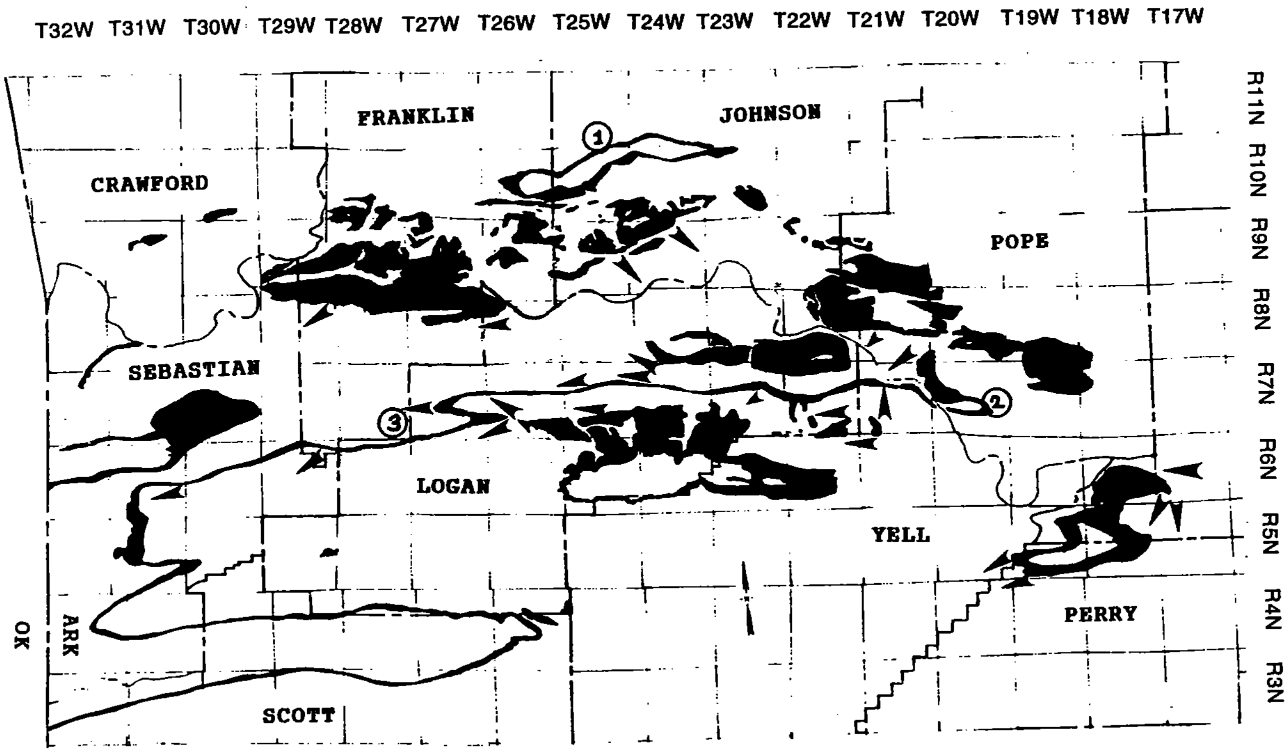


Figure 50. Outcrop map of Hartshorne Formation in Arkansas. Outcrop 1 is Horsehead Lake spillway. Outcrop 2 is Duffield Quarry near Russellville. Arrows indicate paleocurrent direction, based on data from Yeakel (1966). Outcrop 3 shows location of Philmon No. 2 well. Easternmost outcrop near Mayflower in Faulkner County lies off map to east.

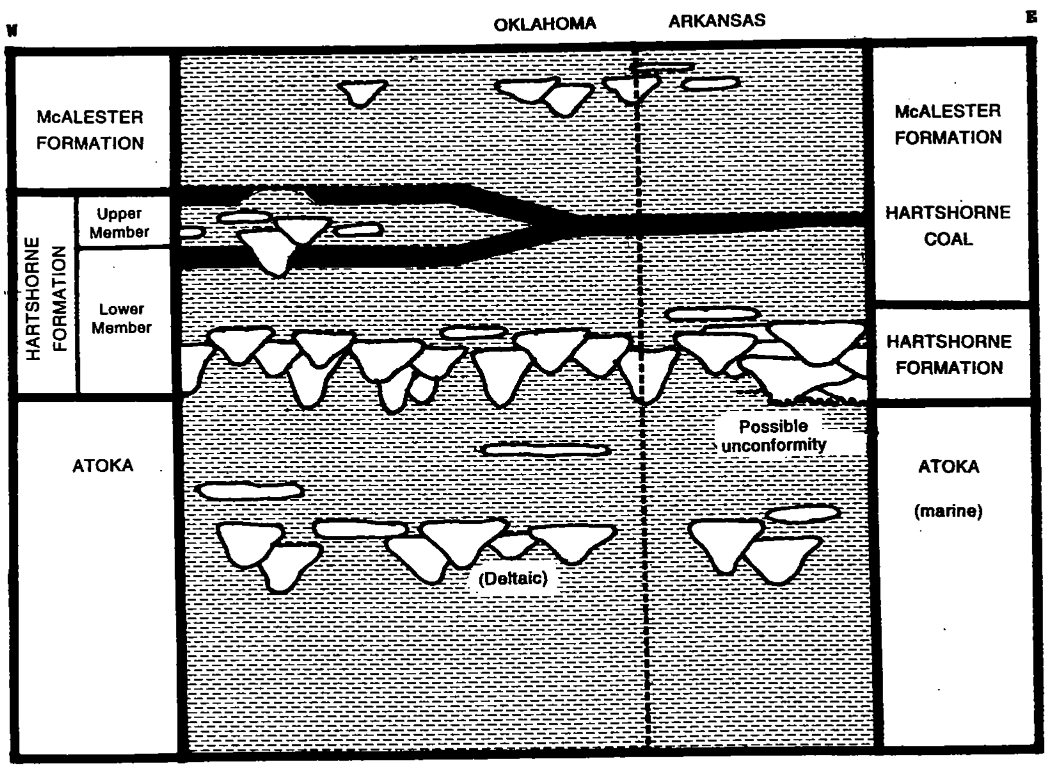


Figure 51. Diagram illustrating nomenclature problem between Oklahoma and Arkansas usage. The Upper Member of the Hartshorne Formation does not appear to have been deposited in the Arkansas part of the Arkoma basin. In addition, a regional unconformity between the Hartshorne and Atoka Formations may be present in the eastern part of the basin in Arkansas.

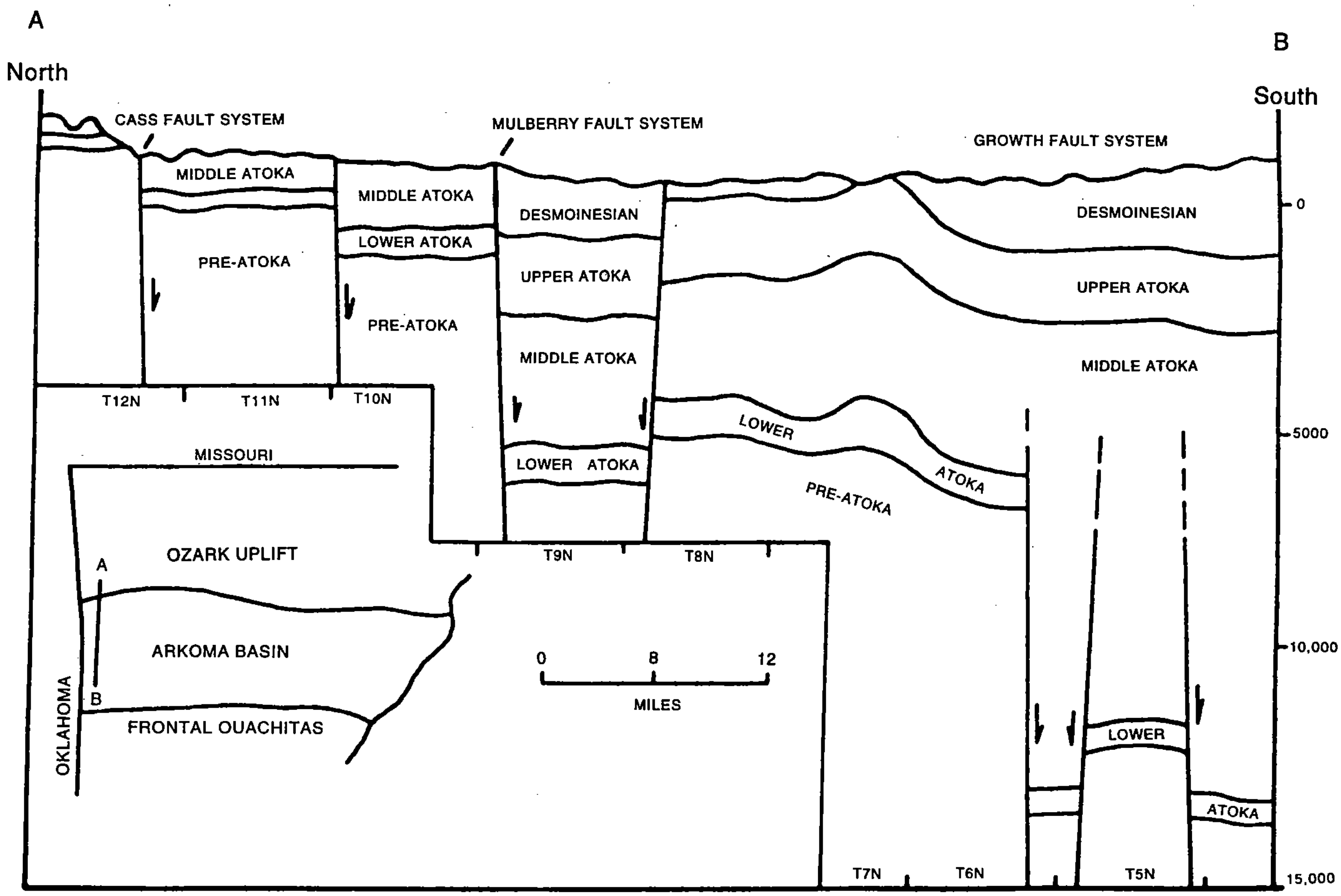


Figure 52. Generalized structural cross section of the Arkoma basin, showing major normal-fault systems. From Houseknecht and Kacena (1983).

channel scouring (Houseknecht and Kacena, 1983). This disagreement has existed for many years, and both views are reflected in the literature on the eastern part of the Arkoma basin (Bush and Gilbreath, 1978; Stone and McFarland, 1981).

PREVIOUS LITERATURE

Early writers who mention the Hartshorne Formation include A. J. Collier, whose 1907 volume, *The Arkansas Coal Field,* was published by the U.S. Geological Survey. He was, however, more interested in the coal fields of the area than in the origin of the sandstone.

The next notable publication was by Carey Croneis in 1930, *Geology of the Arkansas Paleozoic Area.* Although this was the most comprehensive reference of the time, he also did not discuss the origin of the sandstone.

The next in-depth studies were theses by two students at the University of Arkansas, Charles Piles (1955) and James Sherman (1955), who analyzed heavy minerals from the Hartshorne.

The most comprehensive work on the Hartshorne was done by Boyd Haley, W. V. Bush, and Charles Stone, who are or have been geologists with the Arkansas Geological Commission. Jointly and separately, they have published numerous circulars, guidebooks, and maps for the Arkansas Commission, as well as numerous articles in various geologic publications. Of this group, Boyd Haley has spent the most time investigating the Hartshorne and has written the most about it. He is the chief proponent for a regional unconformity at the base of the Hartshorne Formation, believing that the entire eastern half of the Arkoma basin was subaerially exposed and eroded before deposition of the fluvial and deltaic sediments that make up the Hartshorne (Bush and others, 1978).

During the 1960s, geologists from many major oil companies extensively studied the Hartshorne Formation. Most of this work remains unavailable in closed files, but Shell Oil Co. did make part of this information available to the Arkansas Geological Commission for their library. The bulk of the data released was compiled by the late L. S. Yeakel, along with work by Rufus Le Blanc. Yeakel considered the Hartshorne Formation to have been a delta deposit, which was succeeded by a fluvial system that eroded much of the deltaic sediments, particularly in Pope County and eastward.

Yeakel's idealized sequence for the fluvial deposits begins at the base of the Hartshorne with an erosional scour and a subsequent channel-lag deposit consisting of plant debris, shale pebbles, and coarse sand that is festoon bedded (trough bedded) on a medium scale. The grain size decreases upward but retains the festoon bedding. The smallest grain size is at the top of the sequence, where the bedding changes from festoon to horizontal. The interpreted fluvial deposits extend westward into eastern Oklahoma, but Yeakel did not believe that the underlying delta had been entirely removed and that distributary-channel and delta-fringe deposits are preserved west of Perry County. It appears that he believed any unconformity to be local. Although he used the modern Mississippi delta as an analog, he did state in his writings that the river that deposited the Hartshorne sand appeared to be considerably less sinuous and meandering than the Mississippi. He found the general paleocurrent direction to have been from east to west, with some outcrops along the northern fringe of the Arkoma basin having a southerly paleocurrent component (Fig. 50). His interpretation of the Hartshorne was for a narrow (~12-mi-wide), elongate deposit of distributary to fluvial sandstone surrounded on the flanks by fringe sediments (Yeakel, 1966).

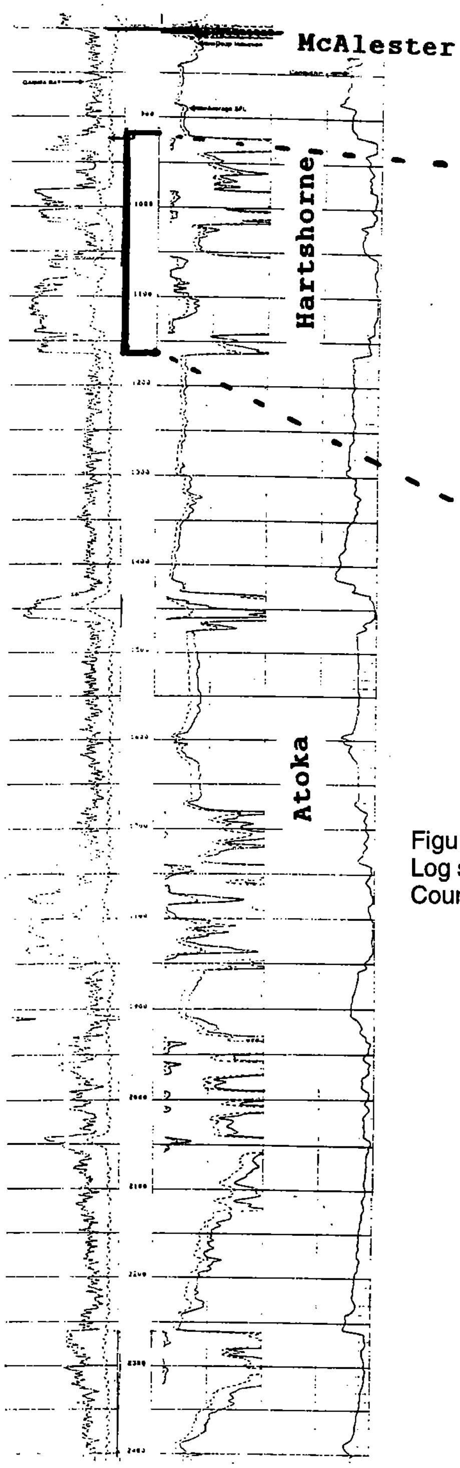
In the early 1980s, three graduate students from the University of Missouri at Columbia completed master's theses on Hartshorne Formation outcrops fringing the Arkoma basin (Zaengle, 1980; Kuhn, 1981; Steyaert, 1980). Their work concentrated on the petrology and diagenesis of the sandstones. In 1983, Dr. David Houseknecht, who was their thesis advisor, published (with J. A. Kacena) *Tectonic–Sedimentary Evolution of the Arkoma Foreland Basin,* which summarized much of their work and added to it. They interpreted the thickest sandstone outcrops as distributary channels with scoured basal contacts between the Hartshorne and Atoka Formations. Transitional contacts were interpreted to be deltaic in origin. This contrasts with Haley's interpretation of a regional unconformity and Yeakel's fluvial replacement in the eastern occurrences of the Hartshorne.

My preliminary work in the Arkansas portion of the Arkoma basin suggests that an unconformity could be present, although its extent is still unclear. Many Hartshorne outcrops show a scoured basal contact with the underlying Atoka shale, but the shale is truncated against the sandstone and does not show any signs of soft-sediment deposition, which would be expected if a heavy deposit of sand accumulated rapidly on unconsolidated mud of a delta front; rather, the appearance of the shale seems to indicate that it was already lithified sufficiently to withstand the added burden of sand. As a result, many outcrops in the eastern exposures of the Hartshorne have a sharp contact between shale and sandstone. Additionally, most of the logs from >400 wells in the east-central part of the basin (Logan, Franklin, and Johnson Counties; Fig. 50) show the same relationship between the two formations (Fig. 53). The grain size of the sandstones ranges from coarse to fine, with a general fining-upward trend. Many channels contain lag deposits at the base; these usually contain shale pebbles and large quantities of plant debris. Examination of the logs indicates that the main belt of thick sandstone down the axis of the basin may be at least twice as wide as Yeakel (1966) postulated.

Some outcrops appear to have features characteristic of deltas, such as the Duffield Quarry in Russellville, Pope County, Arkansas. Conversations with Charles Stone and Boyd Haley at the Arkansas Geological Commission indicate that their current interpretation for these sediments is a freshwater lacustrine delta. Their detailed examination of these sediments has found no evidence to indicate a marine environment, and much to suggest otherwise. No marine fossils are present, and much plant debris is common. The thick sandstone throughout much of the eastern half of the Hartshorne Formation is absent; rather, shale, siltstone, and smaller sandstone deposits are present that are interpreted to be mouth bars, crevasse splays, and crevasse lobes. Deposits near the Oklahoma border, however, are interpreted to be deltaic deposits in a shoreline/marine setting. Thus, it appears that the eastern environs of the Hartshorne Formation represent more of a fluvial setting than do the western environs. Whether this eastern depositional environment is a paleovalley fill or a prograded delta with (1) some accommodation space, or (2) little or no accommodation space, has yet to be determined.

It should be noted, however, that the change in facies from the Atoka to the Hartshorne indicates a fundamental change in the depositional environment of the Arkoma basin as a whole. Mostly marine deposits were replaced by sediments more terrestrial in character. The trend of deposition also appears to have shifted. The small deltas in the upper Atoka had northerly and northeasterly sources off the craton (Stone and McFarland, 1981). The Hartshorne, on the other hand, appears to have been supplied predominantly from the east and northeast (Yeakel, 1966). The formations above the Hartshorne and the McAlester repeat the sequence of deltaic/fluvial sandstone, shale, and coal. Growth faulting appears to be absent in the Desmoinesian strata, at least in the eastern part of the basin. This change could indicate that this part of the basin had filled, with a resulting loss of accommodation space. When the basin filled, small changes in sea level would have resulted in dramatic shifts of the shoreline from east to west and could have been the origin of the cyclic nature of the Desmoinesian deposits.

The entrapment of natural gas within parts of the Hartshorne Formation was the result of stratigraphic or structural mechanisms, or a combination of both. The source of the gas was either the associated coal beds or the underlying Atoka Formation. Although the composition of the Hartshorne gas has been analyzed only



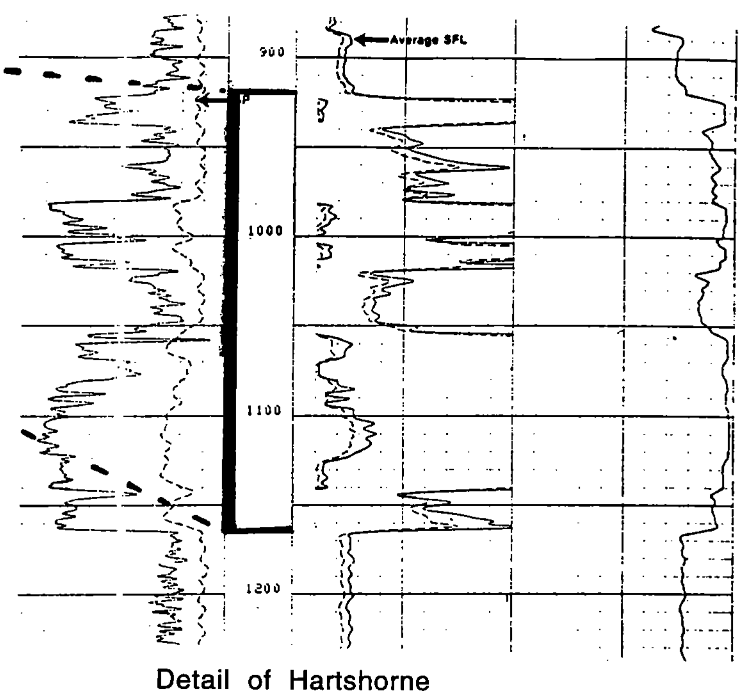


Figure 53. Typical log from east-central part of Arkoma basin in Arkansas. Log shown is from Philmon No. 2 well, sec. 36, T. 7 N., R. 28 W., in Franklin County.

sparsely, there is some indication from the few Hartshorne wells that have produced in Arkansas that the Btu content of the natural gas is higher than that of gas produced from other formations. This makes a coal-bed origin for at least some of the Hartshorne gas highly probable.

Regardless of the source, the best production potential appears to lie within the belt of thick fluvial or distributary-channel deposits. Again, these are low-volume and low-production reservoirs, but with 40-acre spacing, a single compressor can serve multiple wells. This fact, combined with the shallow depth of the Hartshorne Formation, makes exploitation of Hartshorne natural gas more economically feasible than in the past.

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

†Subdivisions of sand sizes omitted.

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

APPENDIX 2

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

API	American Petroleum Institute
BCF	billion cubic feet (of gas)
BCFG	billion cubic feet of gas
BO	barrels of oil
BOPD	barrels of oil per day
BHP	bottom-hole pressure
Bw	barrels of water
BWPD	barrels of water per day
cp	centipoise (a standard unit of viscosity)
DST	drill stem test
Fw	freshwater
GOR	gas to oil ratio
gty	gravity
IPF	initial production flowing
IPP	initial production pumping
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
MMSTB	million stock tank barrels
MSTB	thousand stock tank barrels
OGIP	original gas in place
OOIP	original oil in place
OWC	oil-water contact
OWWO	oil well worked over
PSI	pounds per square inch
PSIA	pounds force per square inch, absolute
PSIG	pounds per square inch, gauge
PVT	pressure volume temperature
RB	reservoir barrels (unit of measurement of oil in the subsurface where the oil contains dissolved gas); see STB or STBO
RB/STB	reservoir barrels per stock tank barrels
Scf	standard cubic feet
STB or STBO	stock tank barrels of oil (unit of measurement for oil at the surface in a gas-free state rather than in the subsurface reservoir where the oil contains dissolved gas); see RB
STB/DAY	stock tank barrels (of oil) per day
TCF	trillion cubic feet (of gas)
TSTM	too small to measure

APPENDIX 3
Glossary of Terms
(as used in this volume)

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

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.

bituminous (coal)— Class of rank consisting of high-volatile bituminous coal, medium-volatile bituminous coal, and low-volatile bituminous coal. Bituminous coal ranks between subbituminous coal and anthracite and contains >14% volatile matter (on a dry, ash-free basis) and has a calorific value of >11,500 BTU/lb (moist, mineral-matter-free) or >10,500 BTU/lb if agglomerating (ASTM, 1992).

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.

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

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

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

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

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

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

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

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

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

humic (banded) coal—Coal that is megascopically heterogeneous in composition, being composed of layers called lithotypes (vitrain, clarain, durain, fusain). Humic coals were derived mainly from the decomposed remains of terrestrial plants deposited as peat in swamps.

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.

kerogen— Organic matter insoluble in organic solvents.

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

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

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

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

maceral—Microscopically distinguishable organic component of coal. There are three maceral groups: vitrinite, liptinite (or exinite), and inertinite.

macropores—Secondary porosity from cleat (natural fractures in coal).

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.

micropores— Primary porosity in coal matrix (average pore diameter of 5 to 50 Å).

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

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

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

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

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

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

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

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

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

rank (coal)—Classification of coals according to their degree of very low-grade metamorphism in the natural series from lignite to anthracite.

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).

reserves (coal)—The part of coal resources that can be economically extracted, considering environmental, legal, and technologic constraints.

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

resources (coal)—Naturally occurring deposits of coal whose extent and thickness are known or estimated from specific geologic evidence.

ribbon sand—See: *shoestring sand.*

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

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

sapropelic (nonbanded) coal—Fine-granular coal lacking megascopic layers. Sapropelic coals were derived from macerated organic debris deposited as subaquatic muds in an anaerobic environment on the shallow bottoms of lakes.

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

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

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.

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

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

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

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

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

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

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

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

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

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

APPENDIX 4

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

1. **Regal Petroleum No. 1-35 Hilseweck**
   C NW¼ sec. 15, T. 6 N., R. 12 E.
   Hartshorne sandstone, shallow-marine bar, possibly small distal(?) distributary mouth bar
   Cored interval: 3,353–3,370 ft

2. **Kerr McGee Corp. No. 1-24 Finch Unit**
   C SW¼ sec. 24, T. 8 N., R. 17 E.
   Hartshorne sandstone, interdistributary deposits (lower-delta-plain-splay and lagoonal deposits) or storm-modified delta margin
   Cored interval: 2,259.5–2,294.0 ft

Regal Petroleum No. 1-35 Hilseweck

C NW¼ sec. 15, T. 6 N., R. 12 E.

Hartshorne sandstone core

Shallow-marine bar, possibly a small, distal(?) distributary mouth bar

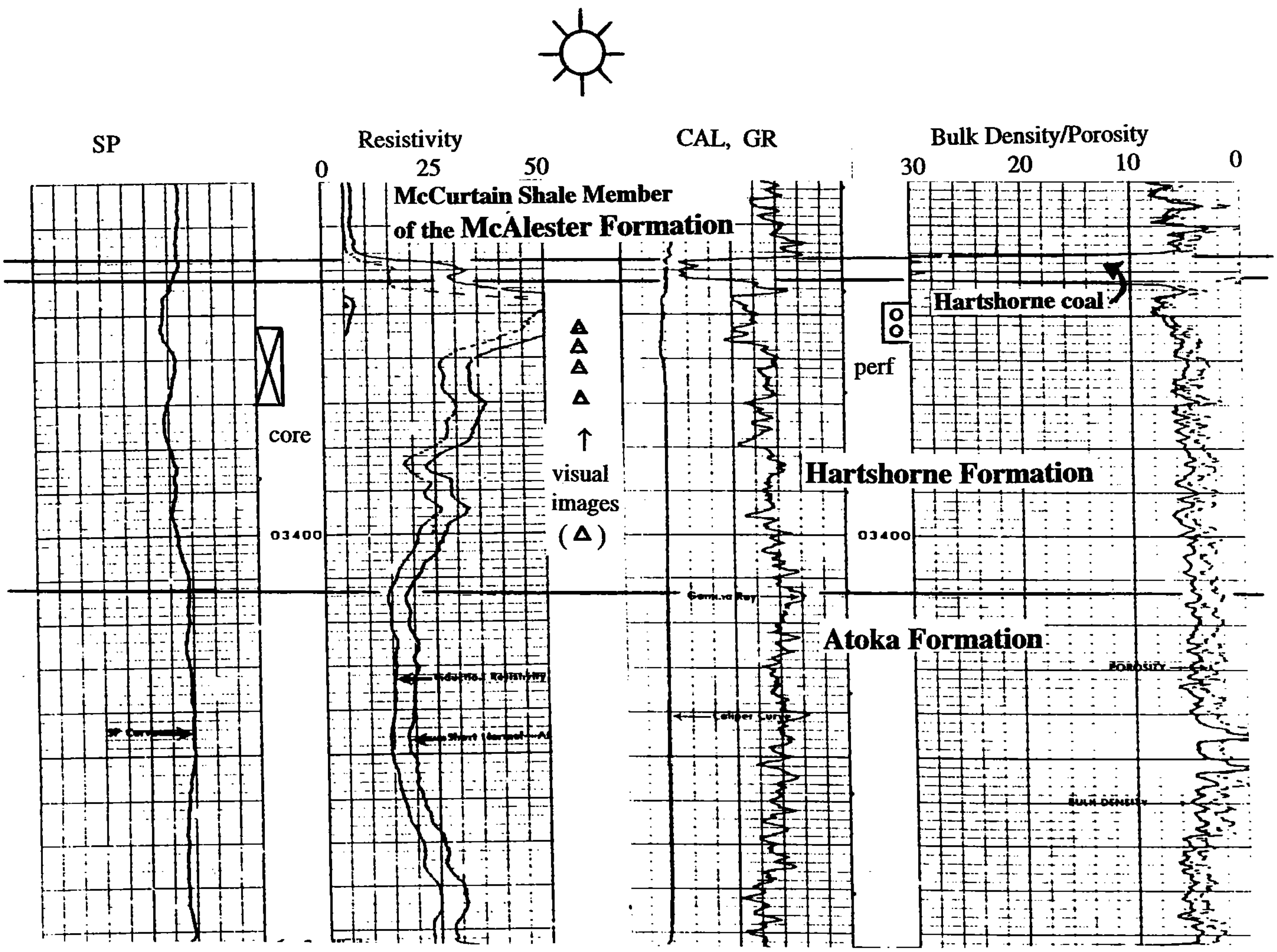
Log depth ~ core depth — Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
LOWER BAR FACIES	(Very little shale; sedimentary structures indicate low to moderate current energy—i.e., ripple bedding rather than large-scale, high-angle cross-bedding.)
3,353.0–3,353.2	Sandstone with interbedded shale laminae. Horizontal bedding.
3,353.2–3,355.3	Sandstone, very fine grained, mostly quartz, well-cemented (quartz), with small-scale cross-bedding and ripple bedding. Numerous interbedded shale laminations are highly micaceous and carbonaceous.
3,355.3–3,355.6	Laminations of shale and sandstone.
3,355.6–3,356	Sandstone, very fine grained, with faint ripple bedding.
3,356–3,357	Sandstone with interbedded shale laminations. Sandstone is very fine grained and mostly ripple bedded. Shale is moderately micaceous on bedding surfaces.
3,357–3,357.7	Sandstone, very fine grained, with small-scale cross-bedding and ripple bedding. Faint shale laminations are moderately to highly micaceous and carbonaceous.
TRANSITION ZONE	(First significant presence of shale.)
3,357.7–3,358.5	Laminations and thin beds of interbedded sandstone and shale. Possible small burrows at 3,358.5 ft penetrate thin shale beds.
3,358.5–3,359.2	Sandstone, very fine grained; faint ripple bedding.
3,359.2–3,360.5	Interbedded sandstone and shale. Thin sandstone beds have ripple and small- scale, low-angle cross-bedding. Thin shale beds and laminations are interbedded within the sandstone.
3,360.5–3,361	Sandstone, very fine grained; wavy and small-scale cross-bedding with possible deformation (flowage) at top (see back side of core). Faint shale laminations are discontinuous.
3,361–3,364	Interbedded sandstone and shale. Sandstone is very fine grained and occurs in laminations or thin beds up to 2 ft thick. Bedding is mostly parallel or subparallel but in places is low-angle cross-bedding (3,362 ft). Shale is moderately to highly micaceous and moderately carbonaceous, and has parallel to subparallel bedding that is laminated or in thin beds up to 0.5 in. thick.
PRODELTA(?)	(Mostly shale.)
3,364–3,370	Shale with interbedded sand–siltstone lenses. Shale is black, slightly micaceous, and has parallel to subparallel laminated bedding with interbedded elongate or isolated sand–siltstone lenses rarely thicker than 0.1 in. This contrasting lithology is persistent with depth and has a sharp overlying contact with the sandstone–shale sequence previously described.

Regal Petroleum No. 1-35 Hilseweck (C NW¼ sec. 15, T. 6 N., R. 12 E.)

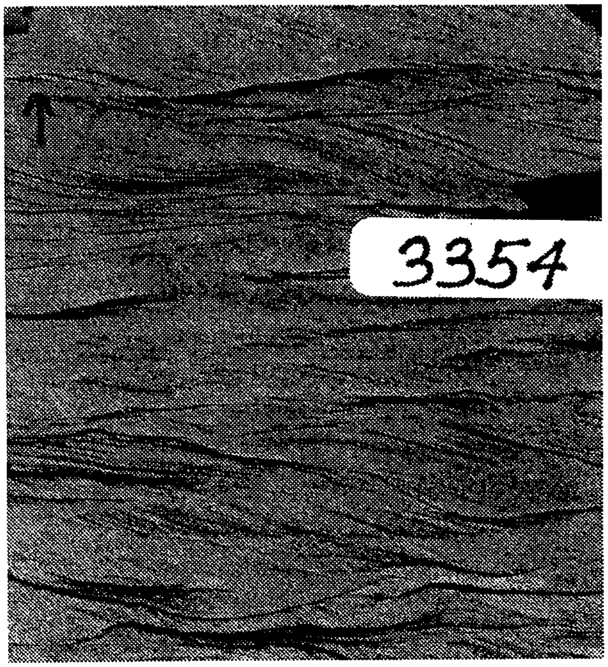
Reservoir: Hartshorne sandstone
Depositional environment: Marine bar, possibly a distal(?) distributary mouth bar

Log depth: 3,353–3,370 ft ± a few ft
Core depth: 3,353–3,370 ft



T.D.: 3,500 ft
Completion date: 8-77
Perforated: 3,347–3,348 ft, 3,353–3,354 ft, 3,355–3,356 ft
Frac 18,900 lb sand, 607 BW, 1,000 gal acid
IP test not taken

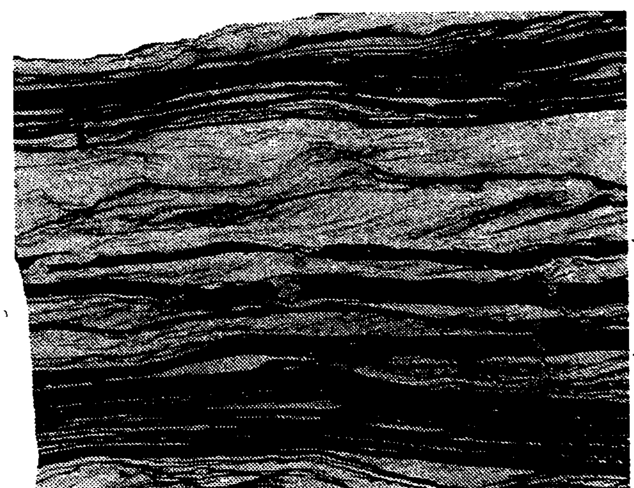
Regal Petroleum No. 1-35 Hilseweck (C NW¼ sec. 15, T. 6 N., R. 12 E.)



1 inch

Core depth: 3,353.9–3,354.2 ft
Log depth: about 3,353.9–3,354.2 ft

Lower-marine-bar facies, consisting of unidirectional, small-scale cross-bedding and ripple bedding in very fine grained sandstone. Numerous shale laminations occur on bedding surfaces and are generally highly micaceous and carbonaceous. Bed sets are horizontal. Considering the absence of large-scale, high-angle cross-bedding and the lack of shale, this interval is interpreted to have been deposited in the lower part of a marine bar (slightly deeper water below wave-breaker zone but probably in less than 50 ft of water). This zone is commonly characterized by oscillatory wave currents (shoaling wave zone). The large amounts of mica and organic debris found throughout this core indicate terrestrial proximity rather than detachment far away from shore. Additionally, the vertical association of coal above this bar sequence (not cored but shown on the well log) indicates the presence of a subaerial delta plain (coal marsh). Therefore, this cored sequence may be part of a delta-front complex, forming a widespread gas reservoir.



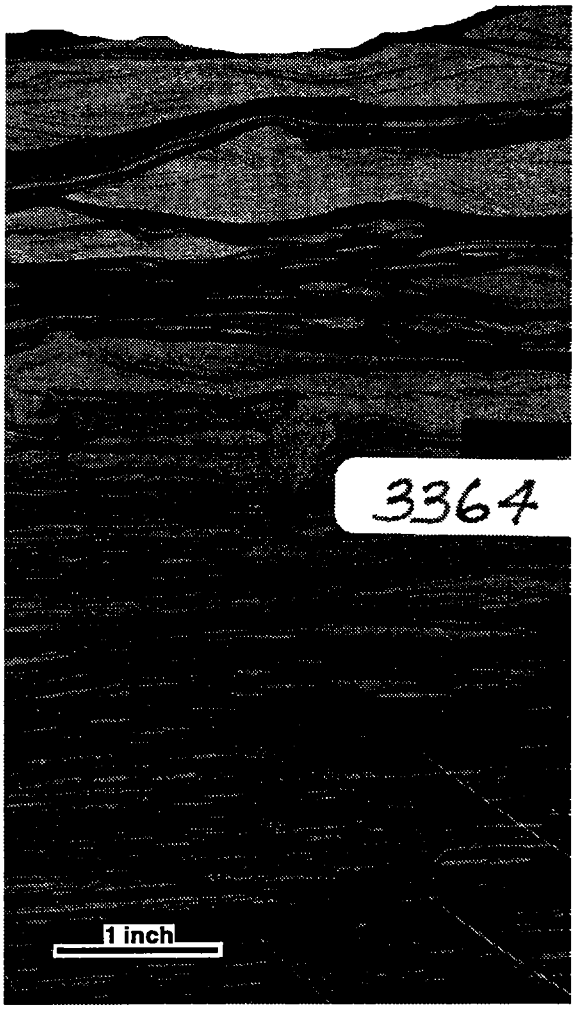
Burrow zone

1 inch

Core depth: 3,358.3–3,358.5 ft
Log depth: about 3,358.3–3,358.5 ft

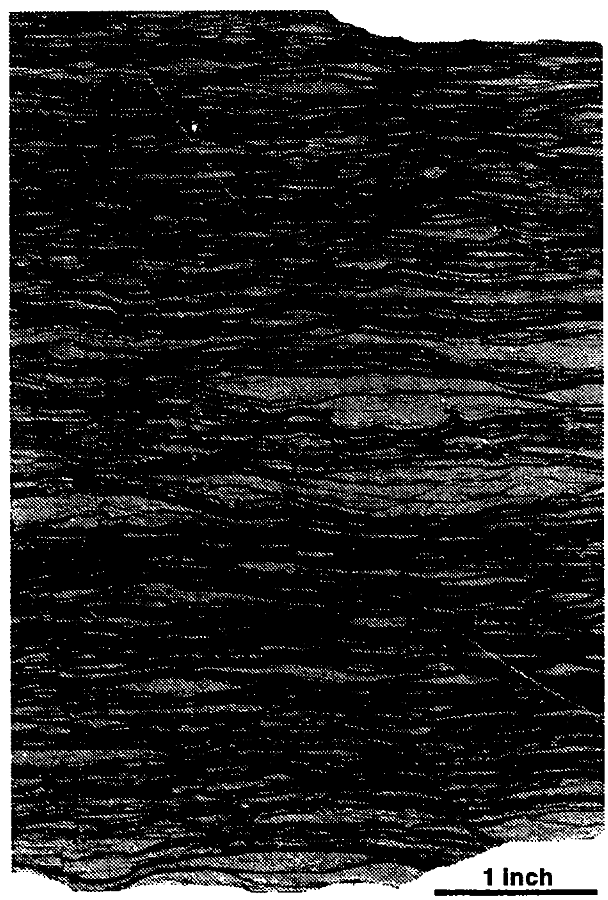
Bar-transition zone, consisting of alternating thin beds and laminations of very fine grained sandstone and shale. The conspicuous presence of shale in this zone distinguishes it from the cleaner lower-bar facies stratigraphically higher as shown in the previous photo. Small burrows penetrate a thin shale layer in the center and may be interpreted as marine trace fossils.

Regal Petroleum No. 1-35 Hilseweck (C NW¼ sec. 15, T. 6 N., R. 12 E.)



Core depth: 3,363.8–3,364.4 ft
Log depth: about 3,363.8–3,364.4 ft

Contact between bar-transition zone and underlying prodelta facies occurs at 3,364 ft. An amorphous burrow trace fossil also occurs at this depth. The monotonous sequence interpreted as prodelta consists mostly of marine shale with numerous siltstone laminations (light-colored layers). No appreciable sand occurs below this contact, and the amount of mica and organic debris is reduced considerably, indicating the distal terrestrial depositional relationship of this shale unit.



Core depth: 3,369.3–3,369.75 ft
Log depth: about 3,369.3–3,369.75 ft

Prodelta shale containing interbedded laminae and lenses of siltstone and extremely fine grained sandstone is a common lithology encountered in well drilling. Modern well logs can be used to adequately interpret this type of lithology, but old resistivity logs can be highly misleading when trying to determine the amount of gross sandstone for isopach-mapping purposes. A problem occurs because the lower transition zone and upper prodelta (and similar lithologies) have relatively high resistivity, commonly >25 ohm-m (see included well log). In these situations, the section might sometimes be interpreted to be relatively clean sandstone (which it obviously is not).

Kerr McGee Corp. No. 1-24 Finch Unit

C SW¼ sec. 24, T. 8 N., R. 17 E.

Hartshorne sandstone core

Interdistributary deposits (lower-delta-plain-splay and lagoonal deposits) or storm-modified delta margin

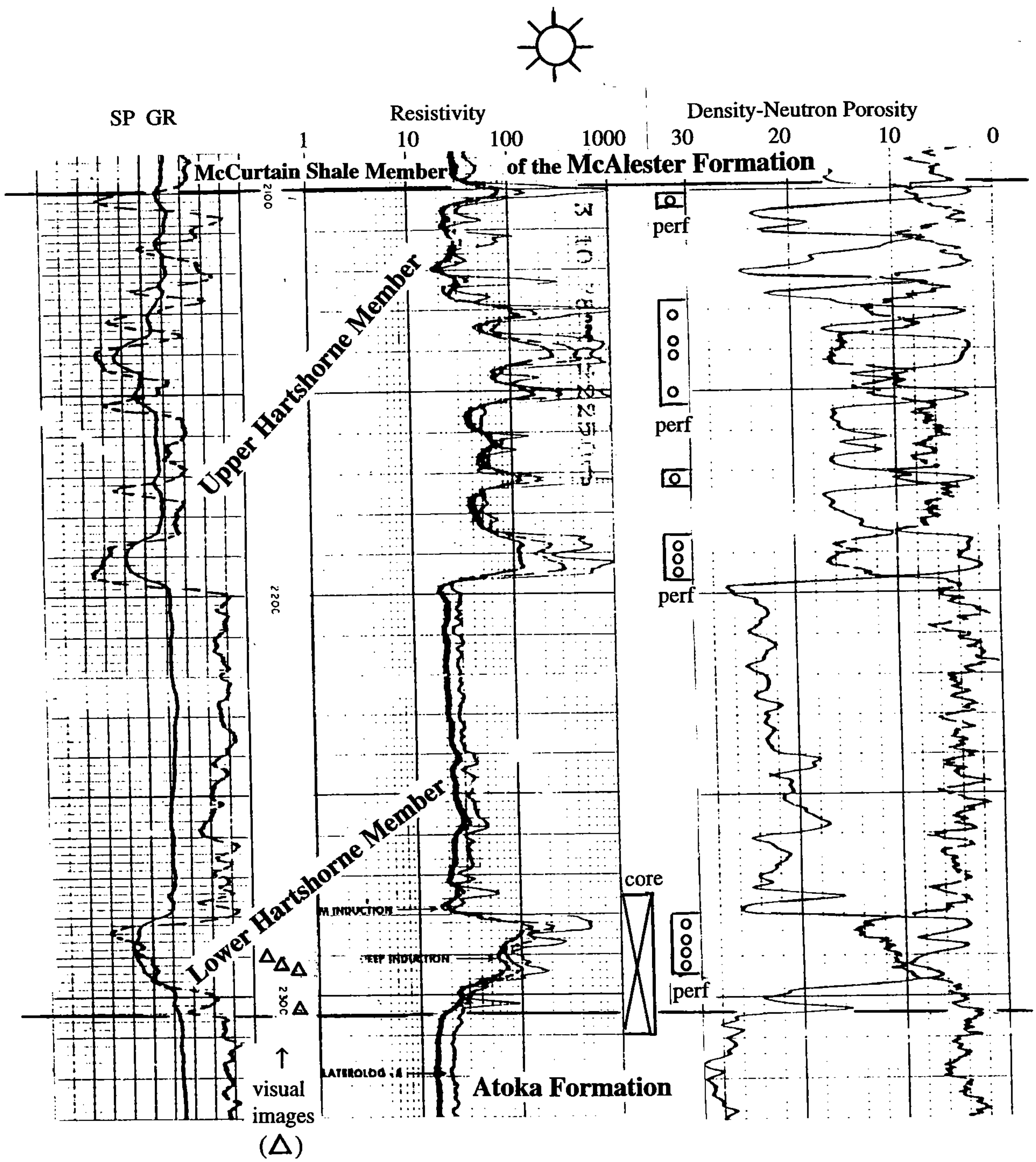
Log depth ~16 ft lower than core depth — Described by: Richard D. Andrews

Core depth *(in feet)*	Lithology and sedimentary structures
2,259.5–2,261	Sandstone, very fine grained; bedding is mostly indistinct from bioturbation but in places is horizontal and parallel.
2,261–2,265	Shale, dark gray, uniformly laminated, with scattered thin lenses of siltstone and one thin sandstone bed 1 in. thick. In places, minor organic debris is present, but little mica occurs on bedding surfaces. No fossils were observed.
TOP OF INTERDISTRIBUTARY SAND BAR	
2,265–2,270	Sandstone, very fine grained, massive, but in places bedding is horizontal. Sharp upper contact with shale. Small, randomly oriented mud clasts (<0.5 in.) and small carbonaceous particles occur sparingly within the sandstone. The sand is tightly cemented with silica, as there is little or no reaction to HCl. Very few interbedded shale partings are present.
2,270–2,270.5	Sandstone, very fine grained, with numerous rounded mud clasts and elongated carbonaceous, coaly shale rip-up clasts **(storm rip-up?)**. Bedding surfaces are highly micaceous. One mud clast is 3 in. in diameter. Bedding is mostly indistinct.
2,270.5–2,270.55	Thin coal bed or coalified plant debris.
2,270.55–2,271	Sandstone, very fine grained; indistinct bedding from bioturbation and soft-sediment deformation(?).
2,271–2,272	Sandstone, very fine grained, massive; numerous randomly oriented, elongated carbonaceous plant fragments.
2,272–2,276.4	Sandstone, very fine grained, tightly cemented (silica); mostly massive bedding with scattered zones of faint shale laminae. Intense bioturbation at 2,274.9–2,275.5 ft; shale clasts at 2,275.6–2,276 ft. Flame or water-escape structure at 2,273.9 ft indicates rapid deposition and possible current effects.
2,276.4–2,277	Sandstone, very fine grained, with zones of subparallel shale laminations at top, shale and mud rip-up clasts **(storm rip-up?)** in center, and bioturbation at base of interval. Coalified plant remains with conspicuous vitrinite are present in layers up to 0.125 in. thick.
2,277–2,277.7	Sandstone, very fine grained; massive bedding.
2,277.7–2,278.3	Sandstone, very fine grained, bioturbated, with numerous irregularly shaped large pieces of carbonaceous shale rip-up clasts 1–2 in. long. Bedding possibly deformed.
2,278.3–2,282.1	Sandstone, very fine grained; bedding possibly deformed to 2,279 ft; thereafter, bedding is parallel-horizontal to massive. Numerous subparallel carbonaceous and micaceous shale laminations are present. Possible deformed bedding at 2,280.5–2,281 ft, where large shale rip-up clasts are grain supported by fine-grained sandstone. **Base of interdistributary sand bar.**
TOP OF LAGOONAL–BAY-FILL SEQUENCE	
2,282.1–2,283.3	Shale, slightly micaceous on parting surfaces, interbedded with siltstone laminations.
2,283.3–2,283.8	Sandstone, very fine grained; numerous carbonaceous laminations and thin coalified layers. Bioturbated.
2,283.8–2,287	**Soft-sediment deformation.** Shale, fractured, slightly micaceous, highly deformed, with overturned flowage at 2,286.5 ft.
2,287.1–2,287.15	Thin coal bed or coalified plant debris.
2,287.15–2,288.2	Sandstone, very fine grained; massive–subparallel bedding; minor bioturbation at 2,287.4 ft; shale and rounded mud **rip-up** clasts to 0.75 in. in diameter at 2,287.5 and 2,288 ft. Sharp basal contact with underlying shale (eroded?). **Base of bay-fill sequence.**
TOP OF MARINE(?) SHALE SEQUENCE	
2,288.2–2,294	Shale, dark gray; little mica; uniform textural appearance; no conspicuous fossils or organic debris.

Kerr McGee Corp. No. 1-24 Finch Unit (C SW¼ sec. 24, T. 8 N., R. 17 E..)

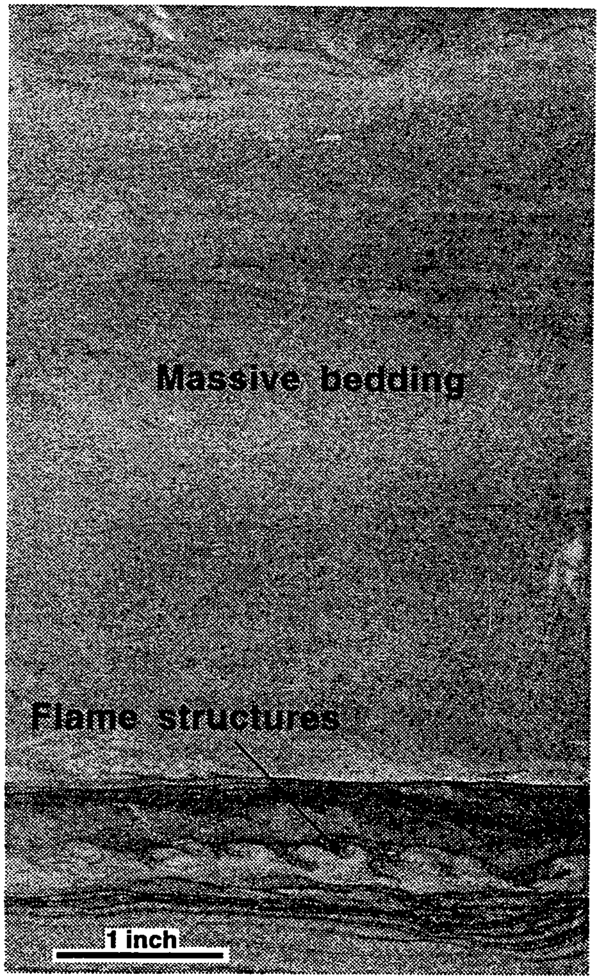
Reservoir: Lower Hartshorne sandstone
Depositional environment: Storm-modified delta margin or splay–lagoonal deposits

Log depth: 2,275.5–2,310 ft ± a few ft
Core depth: 2,259.5–2,294 ft



T.D.: 2,416 ft
Completion date: 2-15-78
Perforated: 2,101–2,295 ft (gross)
IPF 837 MCFGPD, no wtr
Frac 47,650 lb sand, 54,400 gas KCl wtr

Kerr McGee Corp. No. 1-24 Finch Unit (C SW¼ sec. 24, T. 8 N., R. 17 E..)

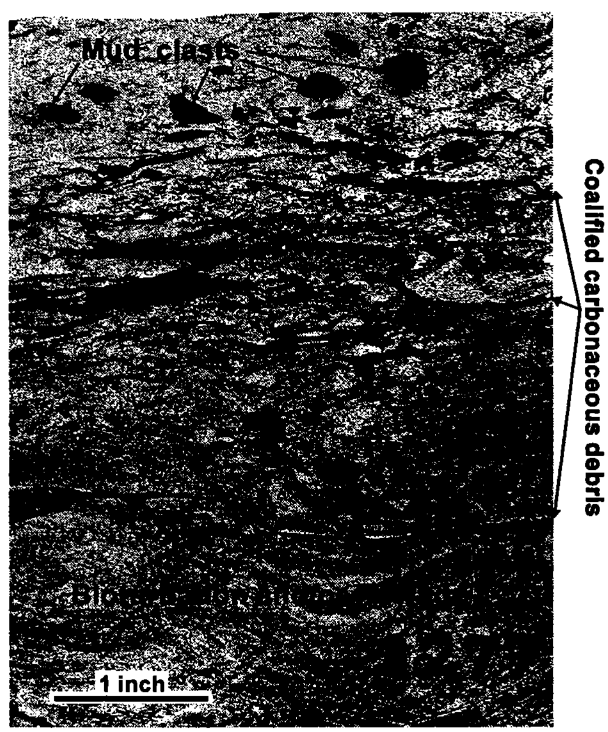


Core depth: 2,273.5–2,274 ft
Log depth: about 2,289.5–2,290 ft

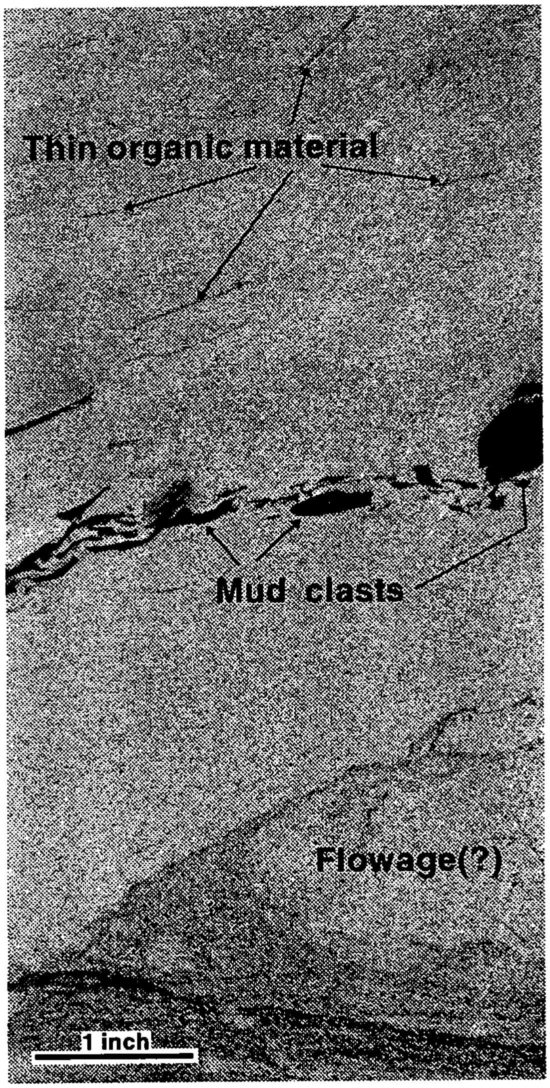
Flame or water-escape structures and massive bedding often indicate very rapid deposition. Massive bedding can be highly advantageous in a reservoir, because there are fewer bedding surfaces that may impede hydrocarbon flow. In the upper part of this sample, horizontal bedding is somewhat distinguishable, but it may be destroyed by bioturbation. In the center part of this sample, bedding is massive with no distinguishing features. Near the very bottom, amorphous patterns of sediment protrude upward and to the left. These are flame structures, which occur during dewatering in the aftermath of very rapid deposition. In considering the entire cored interval, this sequence appears to be part of a deltaic sequence. The environment must have been in proximity to an aggressive sandstone-distribution system (channel?) that was influenced both by marine processes and terrestrial habitats. Other succeeding photos will show storm-wave rip-up (nonfluvial), coalified layers, and deformation.

Core depth: 2,276.6–2,277 ft
Log depth: about 2,392.6–2,293 ft

Mud clasts, carbonaceous debris, soft-sediment deformation, and bioturbation occur throughout this sample. The rounded mud clasts, elongated shale fragments, and coalified carbonaceous debris are grain-supported and randomly oriented throughout the upper half of this sample and may be due to the effects of storm-current reworking(?). Obviously, these sediments are part of a rapid depositional event in proximity to a terrestrial environment. Bedding in the lower half of this sample is indistinct, possibly because of soft-sediment deformation or bioturbation. Some of the longer carbonaceous layers are coalified and show distinct vitrinite reflectance. These are probably coalified remains of large plant fragments washed into the sand bar. For obvious reasons, this part of the sand sequence would make a poorer reservoir than that in the massive sandstone shown above.

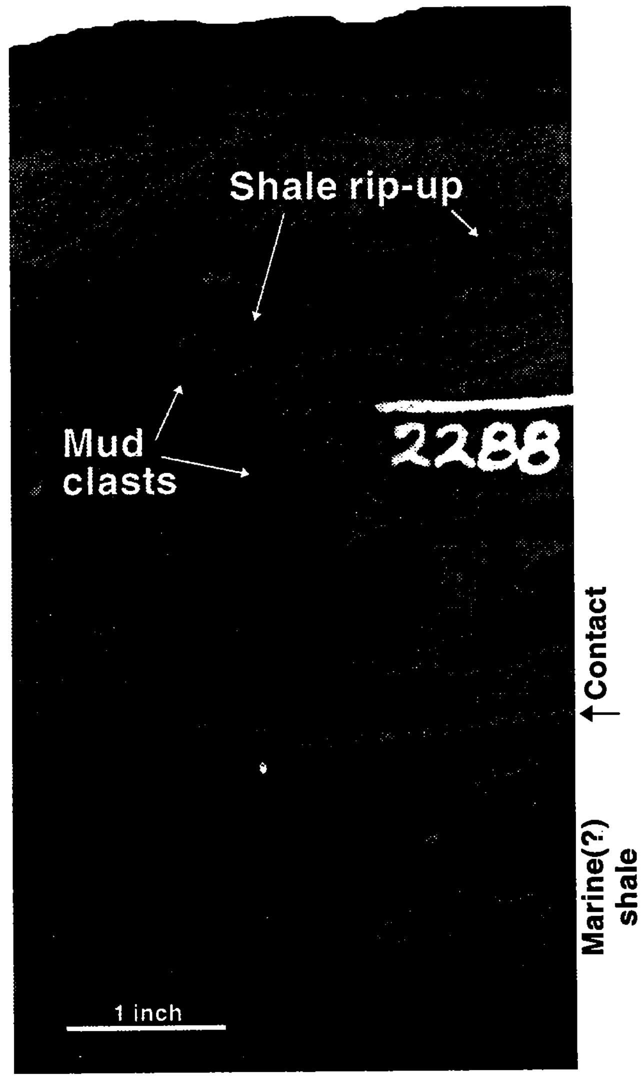


Kerr McGee Corp. No. 1-24 Finch Unit (C SW¼ sec. 24, T. 8 N., R. 17 E..)



Core depth: 2,278.3–2,278.8 ft
Log depth: about 2,294.3–2,294.8 ft

Lower part of the sand sequence shows no changes in textural differences in comparison with the top of the bar. The sandstone is still very fine grained, tightly cemented, and lacking well-developed bedding. This sample shows apparent inclined bedding dipping to the left, as defined by the inclination of mud clasts in the center of the core. A color contrast made obvious by tiny bits of organic material indicates an even steeper dip in the bottom part of the photo, but this may be due to soft-sediment deformation (flowage) rather than to depositional bedding. The mottled appearance of the sand along the very bottom of the core may be due to bioturbation. Scattered elongated pieces of coalified plant material are present throughout the core, at least in minor quantities. The massive bedding characteristic of this sample is typical of the Hartshorne reservoir in this core.



Core depth: 2,287.8–2,288.3 ft
Log depth: about 2,303.8–2,304.3 ft

Contact of thin splay or storm(?) deposit with underlying marine(?) shale is defined by a thin zone of mud clasts and shale rip-up clasts in the center part of the sample. A sharp contact with the underlying black shale is probably erosional. The marine(?) shale sequence is similar in texture to the prodelta sequence interpreted in the Hilseweck core. Although this sample has no reservoir potential, it is important in helping to identify the overall depositional environment of the Hartshorne sequence, as similar depositional patterns that look identical to this on well logs occur throughout the Hartshorne play.

APPENDIX 5

Classification of Coals by Rank[A]

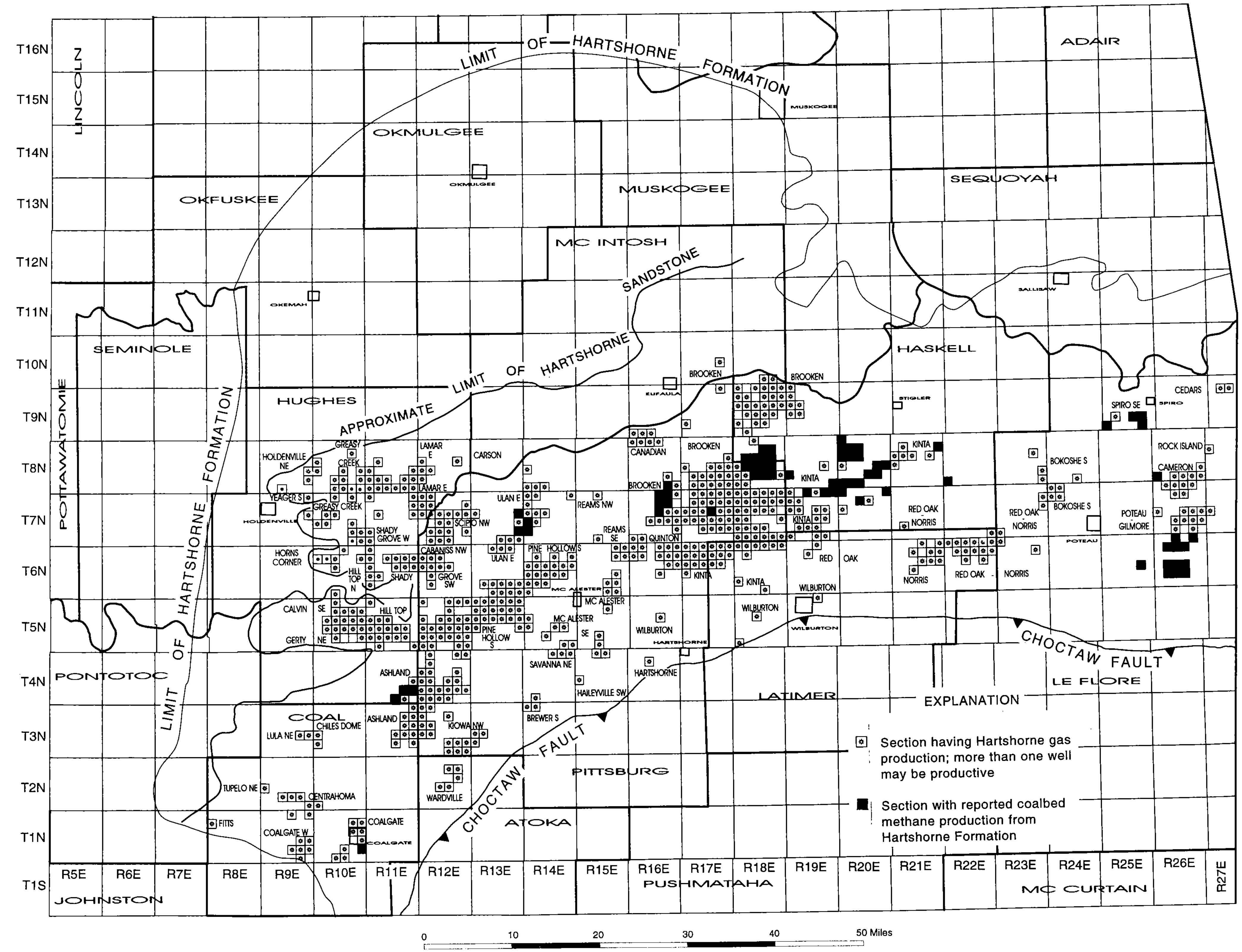
(from ASTM, 1992, standard D 388, table 1)

Class/Group	Fixed Carbon Limits (Dry, Mineral-Matter-Free Basis), %		Volatile Matter Limits (Dry, Mineral-Matter-Free Basis), %		Gross Calorific Value Limits (Moist,[B] Mineral-Matter-Free Basis)				Agglomerating Character
					Btu/lb		Mj/kg[C]		
	Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	Equal or Greater Than	Less Than	
Anthracitic:									
Meta-anthracite	98	...	...	2	...	...	...	...	
Anthracite	92	98	2	8	...	...	...	...	nonagglomerating
Semianthracite[D]	86	92	8	14	...	...	...	...	
Bituminous:									
Low volatile bituminous coal	78	86	14	22	...	...	...	...	
Medium volatile bituminous coal	69	78	22	31	...	...	...	...	
High volatile *A* bituminous coal	...	69	31	...	14 000[E]	...	32.6	...	commonly agglomerating[F]
High volatile *B* bituminous coal	...	...	...	...	13 000[E]	14 000	30.2	32.6	
High volatile *C* bituminous coal	...	...	...	...	11 500	13 000	26.7	30.2	
					10 500	11 500	24.4	26.7	agglomerating
Subbituminous:									
Subbituminous *A* coal	...	...	...	...	10 500	11 500	24.4	26.7	
Subbituminous *B* coal	...	...	...	...	9 500	10 500	22.1	24.4	
Subbituminous *C* coal	...	...	...	...	8 300	9 500	19.3	22.1	nonagglomerating
Lignitic:									
Lignite *A*	...	...	...	...	6 600	8 300	14.7	19.3	
Lignite *B*	...	...	...	...	...	6 300	...	14.7	

[A] This classification does not apply to certain coals.
[B] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.
[C] Megajoules per kilogram. To convert British thermal units per pound to megajoules per kilogram, multiply by 0.002326.
[D] If agglomerating, classify in low-volatile group of the bituminous class.
[E] Coals having 69 % or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of gross calorific value.
[F] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and that there are notable exceptions in the high volatile *C* bituminous group.

OKLAHOMA GEOLOGICAL SURVEY
Charles J. Mankin, *Director*

FIELD	TWP	RGE	SECTIONS
ASHLAND	03N	11E	1,11,12,14,22-25, 27
	03N	12E	6,7,17,18,19,20,
	04N	11E	24,25,26,34,35
	04N	12E	5,8,14,17-20,22,24,26-34
BOKOSHE S	07N	24E	5,6,7,8,
	08N	23E	14,25,36
	08N	24E	34
BREWER S	03N	14E	5,6
	04N	14E	32
BROOKEN	08N	16E	26,35,36
	08N	17E	13-16,19,21-29,32-36
	08N	18E	4,10,11,14-17,19-22,25-32
	08N	19E	23
	09N	17E	2,30
	09N	18E	1-4,6,7,8,10-18,20-22,26-28,30,32
	09N	19E	6,7,17,18,19,20
	10N	17E	23
	10N	18E	34,35
BROOKEN - QUINTON	07N	16E	1,2,3,10,11,13,14,15,21,24-26
	07N	17E	1-5,8-24
	07N	18E	1-11,14-18
CABANISS NW	06N	11E	1,12,13
	06N	12E	7,15,17,18,20
CALVIN SE	05N	10E	4,9-17,20,21,22
	05N	11E	6
	06N	10E	33
CAMERON	07N	26E	2,3,4,5,9,10
	08N	26E	18,25,31,33,34,35,36
CANADIAN	08N	16E	3,4,5,6
	09N	16E	31,32,33
CARSON	08N	12E	14
CEDARS	09N	27E	8,9
CENTRAHOMA	01N	09E	1,3
	02N	09E	26,27,28,36
	02N	10E	31
CHILES DOME	03N	09E	24
	03N	10E	19,30
COALGATE	01N	10E	11,12,13,14,24,27,33,34
COALGATE WEST	01N	09E	23,24,25,26,27,35
FITTS	01N	08E	7
GERTY NE	05N	10E	23,24,25,26,27,28
GREASY CREEK	07N	09E	13
	07N	10E	2,4,16,17,19,20
	07N	11E	6
	08N	10E	11,22,24,25,27,28,33-36
	08N	11E	17,19,28-36
HAILEYVILLE SW	04N	15E	19
HARTSHORNE	04N	16E	9
HILL TOP	05N	11E	16-19,23,26-32,36
HILL TOP N	06N	11E	18,19,20,30
HOLDENVILLE NE	08N	09E	24,25,33
	08N	10E	18,19
HORNS CORNER	06N	10E	3,7,8,9,16
KINTA	06N	16E	1,2,3,10-14,22
	06N	17E	1-12,14-19
	06N	18E	1-6,8,30,34
	07N	17E	25,26,27,28
	07N	18E	19,20,24,27-35
	07N	19E	1-4,6-8,14,15,17,18,22,23,27-29,31,34,35
	07N	20E	6,9,10,18
	08N	22E	31,36
	08N	19E	30,36
	08N	20E	7-9,16-19,24,26,27,31,32,33
	08N	21E	8,14,16,17,18,19
KIOWA NW	03N	12E	10,25,26,27,34,35,36
	03N	13E	19,20,30
LAMAR E	07N	11E	1,12,13
	07N	12E	5,6,7,8
	08N	11E	24,25,26
	08N	12E	18,19,20,30
LULA NE	03N	09E	23
MC ALESTER SE	04N	15E	3,4
	05N	15E	28,33
	06N	15E	23,26,27,34,35
MCALESTER	05N	14E	7,8,19,22,23,
MCALESTER	05N	14E	8,18,19,22,23,28,35,36
PINE HOLLOW S	04N	12E	1,2
	05N	12E	1,2,3,6,10,13-16,18,20-32,35,36
	05N	12E	1-19,24
	06N	13E	25-29,33,35,36
	06N	14E	10-20,22,23,28,29,30,31
POTEAU-GILMORE	06N	26E	4,9,10
	07N	26E	19,22-28,33,35
	07N	27E	19
REAMS NW	06N	14E	8
	06N	15E	12,11,12
	06N	16E	6,7,8
	07N	15E	4,33
	07N	16E	31,32
RED OAK-NORRIS	06N	19E	3,9
	06N	21E	9,11,12,13,14,15,21
	06N	22E	1-6,8-12,14,16
	06N	23E	6,11
	07N	21E	29
	07N	22E	36
	07N	23E	12,13,31
ROCK ISLAND	08N	27E	18
SAVANNA NE	04N	14E	1,2,3
SCIPIO NW	07N	12E	12-18,21,22,24,27-29,32-34
	07N	13E	18
SHADY GROVE SW	06N	11E	9,10,14,15
	06N	12E	8,9,16,29
SHADY GROVE W	06N	10E	12
	06N	11E	6,7
SHADY GROVE WEST	07N	10E	23,25,26,35,36
	07N	11E	17,30,31
SPIRO SE	09N	25E	26,27,29,31,35
TUPELO NE	02N	09E	19
ULAN E	06N	13E	2,3,4,
	07N	13E	13,24,25,34,35
	07N	14E	1,5-7,16-20,30
	08N	14E	19,31,32,33
WARDVILLE	02N	12E	10,11,14,21,22
WETUMKA E	09N	10E	11
WILBURTON	05N	16E	15
	05N	18E	16,31
	05N	19E	3
YEAGER S	07N	09E	1



MAP SHOWING AREAS OF HARTSHORNE GAS AND OIL PRODUCTION, WITH FIELD NAMES

Compiled by
G. C. Hinshaw and R. D. Andrews
1998

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12. McQueen, K. C., 1982, Subsurface stratigraphy and depositional systems of the Hartshorne Formation, Arkoma basin, Oklahoma: University of Arkansas unpublished M.S. thesis, 70 p.
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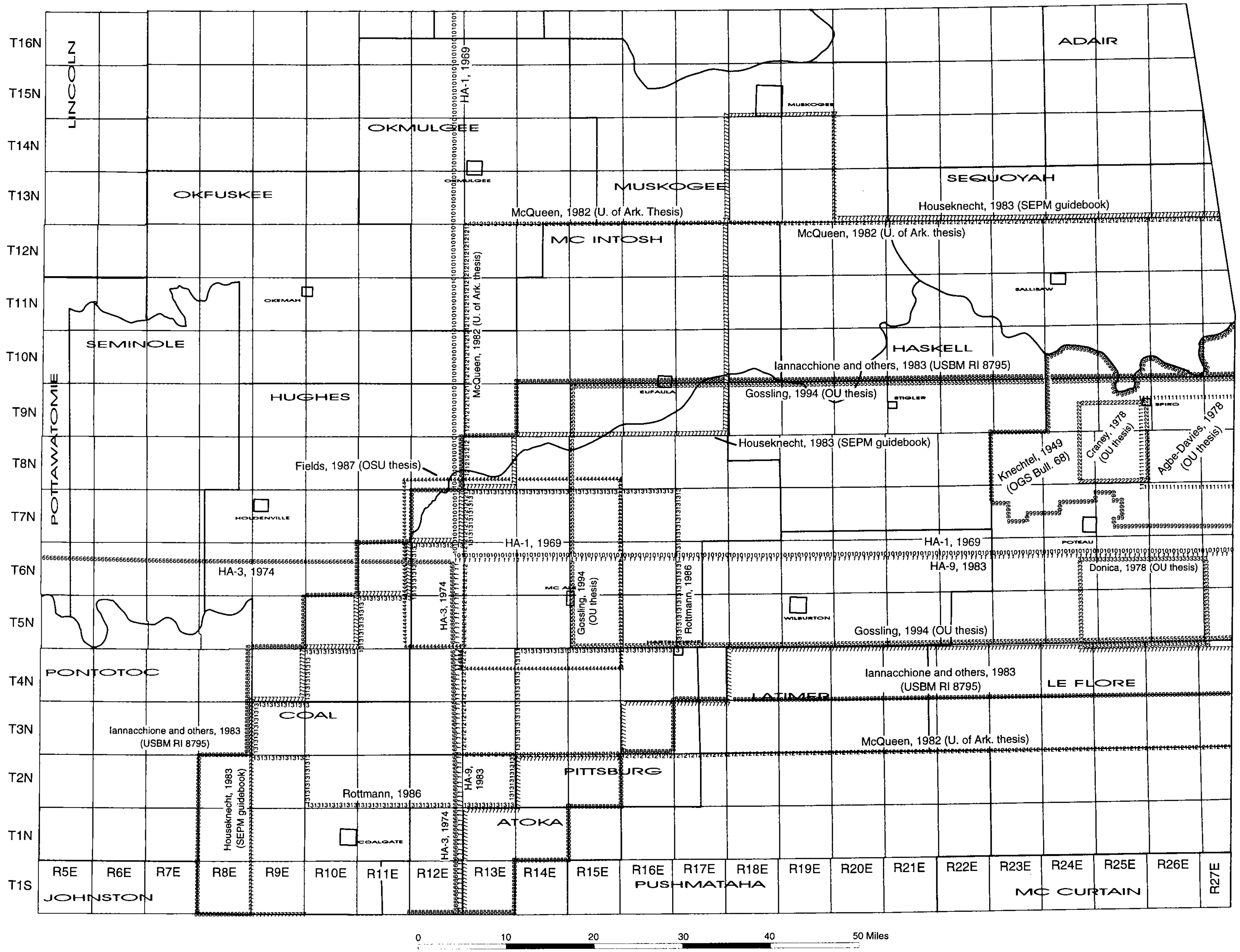
13. Rottmann, Kurt, 1986, Net and gross sandstone thickness map of the Hartshorne Formation: Unpublished work map.

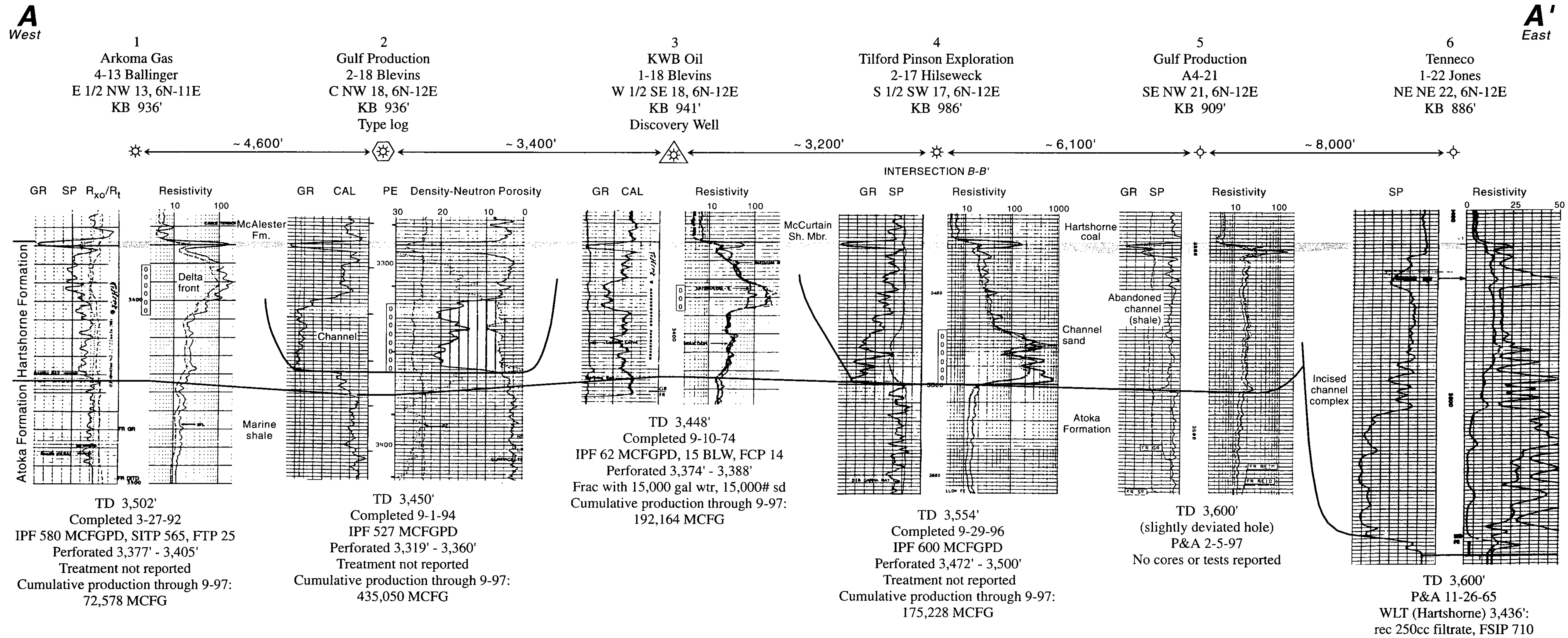


INDEX TO SELECTED REFERENCES USED FOR HARTSHORNE SURFACE AND SUBSURFACE SANDSTONE MAPPING

By

R. D. Andrews

1998



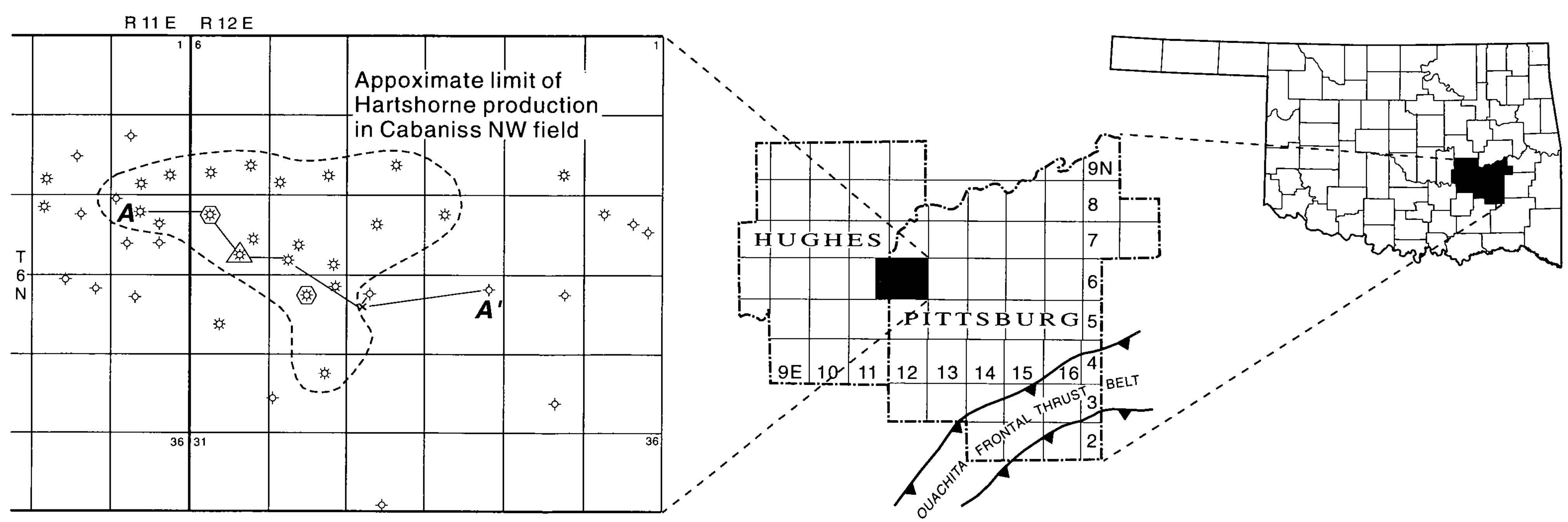
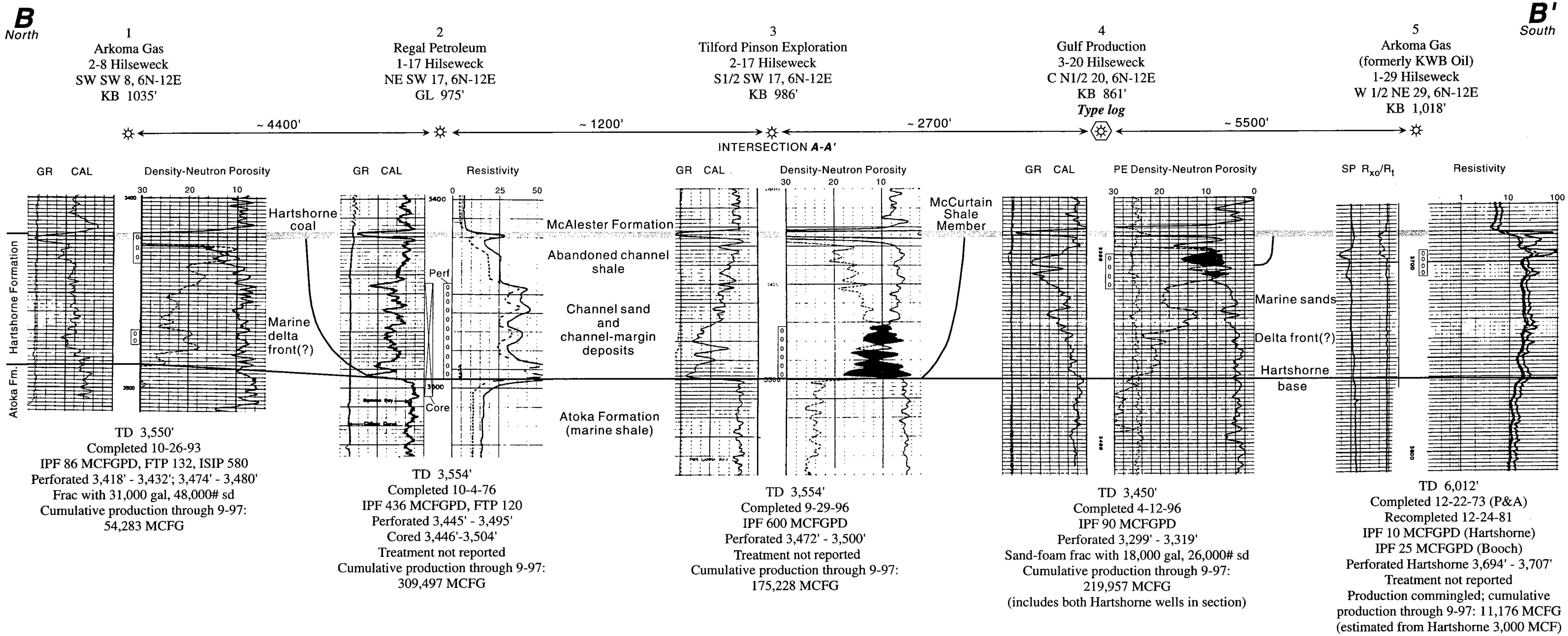


Figure 12. Stratigraphic cross section *A-A´* and index map, Cabaniss NW field, Pittsburg and Hughes Counties, Oklahoma. Datum: top of Hartshorne coal. Vertical scale, 1 in. = 60 ft; no horizontal scale. GR = gamma ray, SP = spontaneous potential, R_{xo} = resistivity of flushed zone, R_t = resistivity of uninvaded zone ("true" resistivity), CAL = caliper, PE = photoelectric.



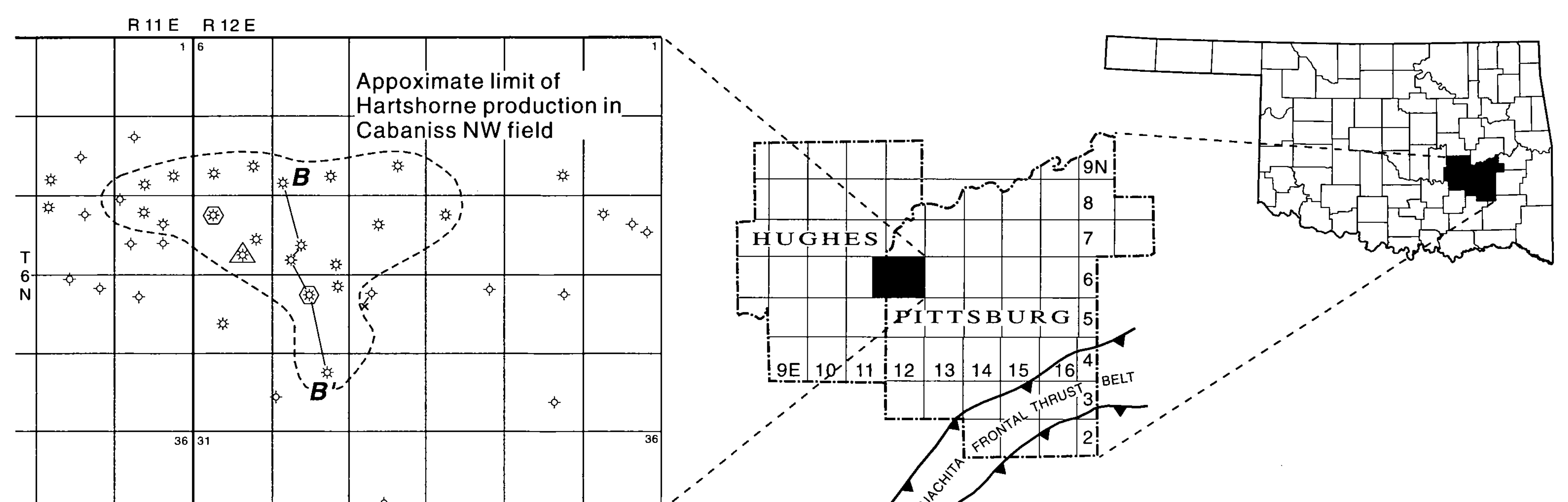


Figure 13. Stratigraphic cross section *B-B´* and index map, Cabaniss NW field, Pittsburg and Hughes Counties, Oklahoma. Datum: top of Hartshorne coal. Vertical scale, 1 in. = 50 ft; no horizontal scale. GR = gamma ray, SP = spontaneous potential, R_{xo} = resistivity of flushed zone, R_t = resistivity of uninvaded zone ("true" resistivity), CAL = caliper, PE = photoelectric.

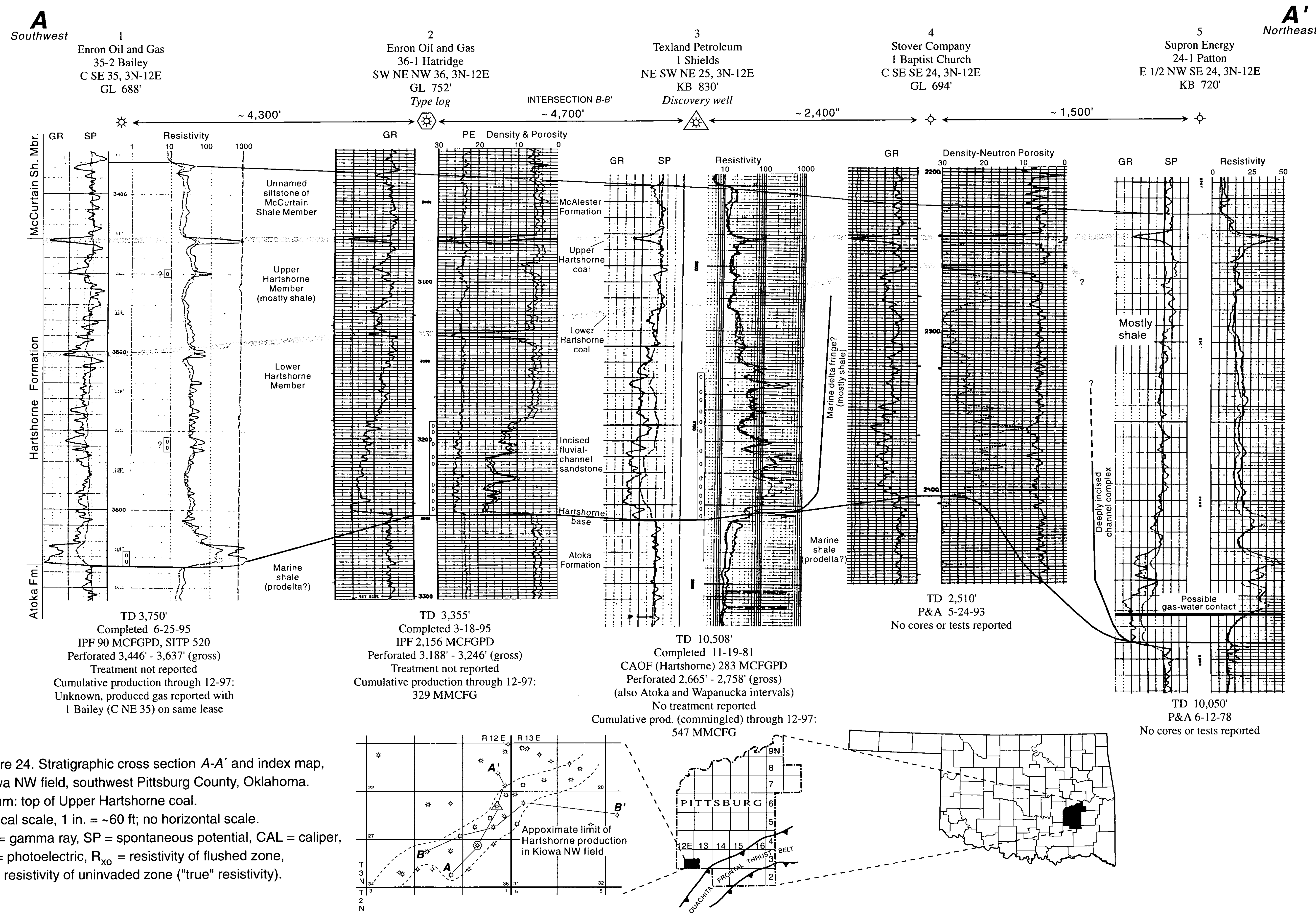
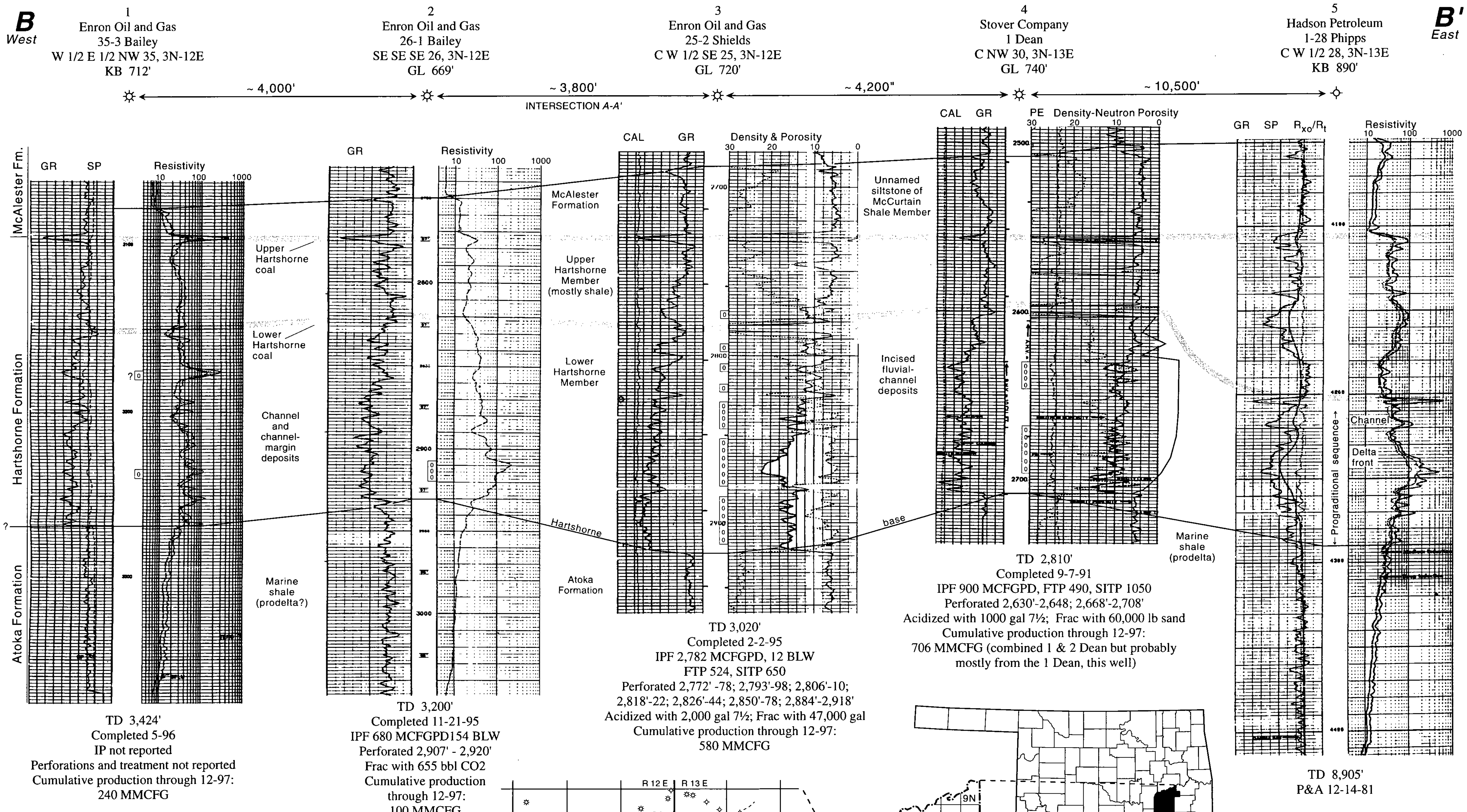


Figure 24. Stratigraphic cross section *A-A´* and index map, Kiowa NW field, southwest Pittsburg County, Oklahoma. Datum: top of Upper Hartshorne coal. Vertical scale, 1 in. = ~60 ft; no horizontal scale. GR = gamma ray, SP = spontaneous potential, CAL = caliper, PE = photoelectric, R_{xo} = resistivity of flushed zone, R_t = resistivity of uninvaded zone ("true" resistivity).



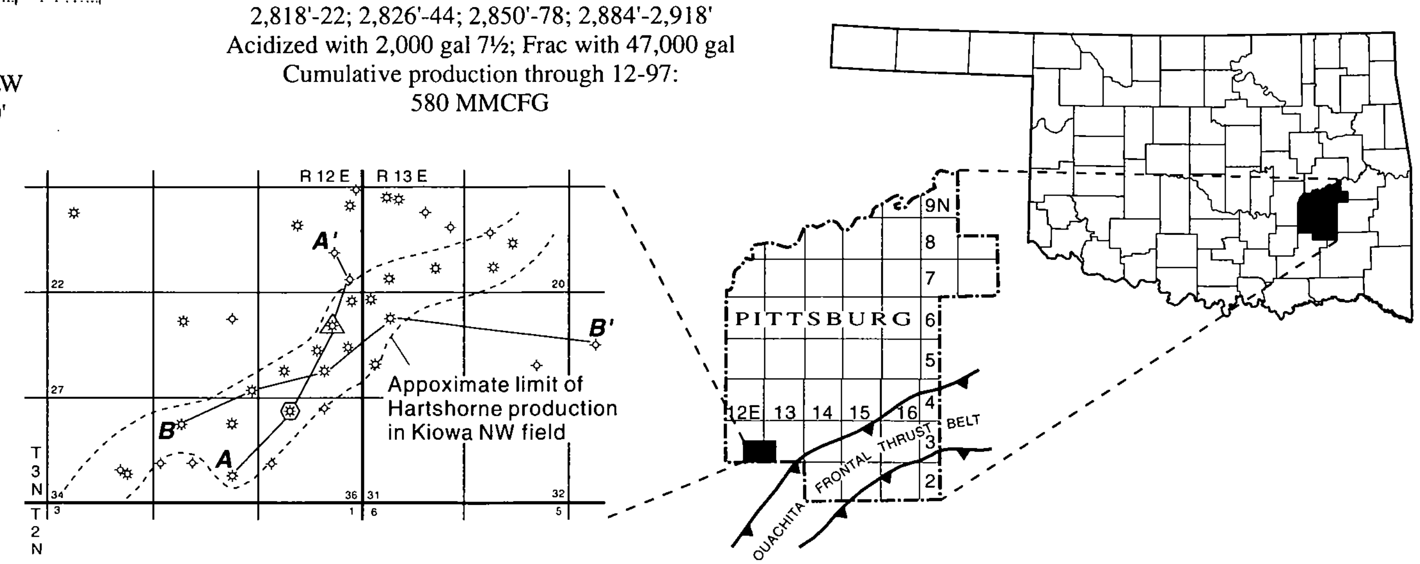


Figure 25. Stratigraphic cross section B-B´ and index map, Kiowa NW field, southwest Pittsburg County, Oklahoma.
Datum: top of Upper Hartshorne coal.
Vertical scale, 1 in. = ~60 ft; no horizontal scale.
GR = gamma ray, SP = spontaneous potential, CAL = caliper,
PE = photoelectric, R_{xo} = resistivity of flushed zone,
R_t = resistivity of uninvaded zone ("true" resistivity).

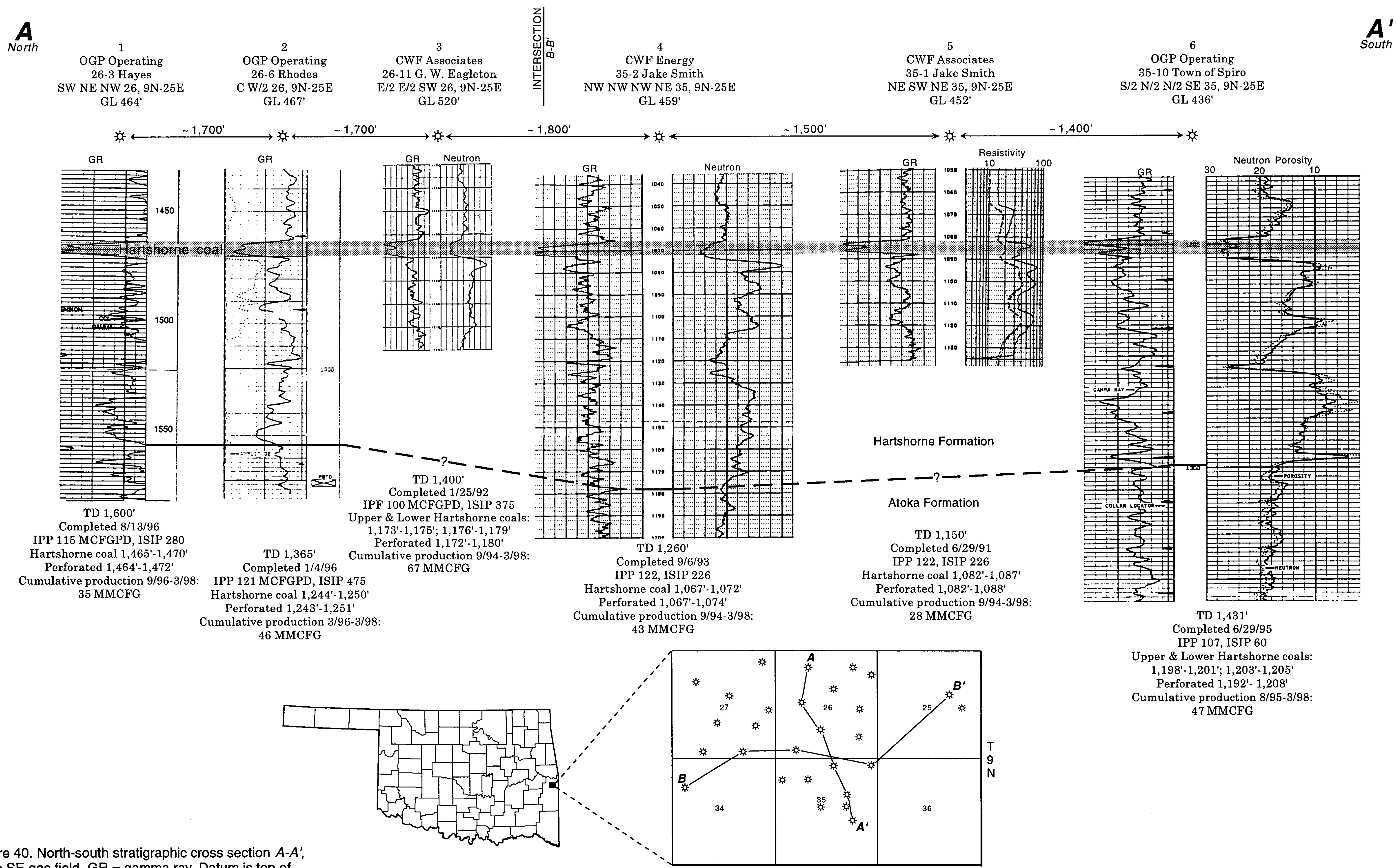


Figure 40. North-south stratigraphic cross section *A-A'*, Spiro SE gas field. GR = gamma ray. Datum is top of Hartshorne Formation.

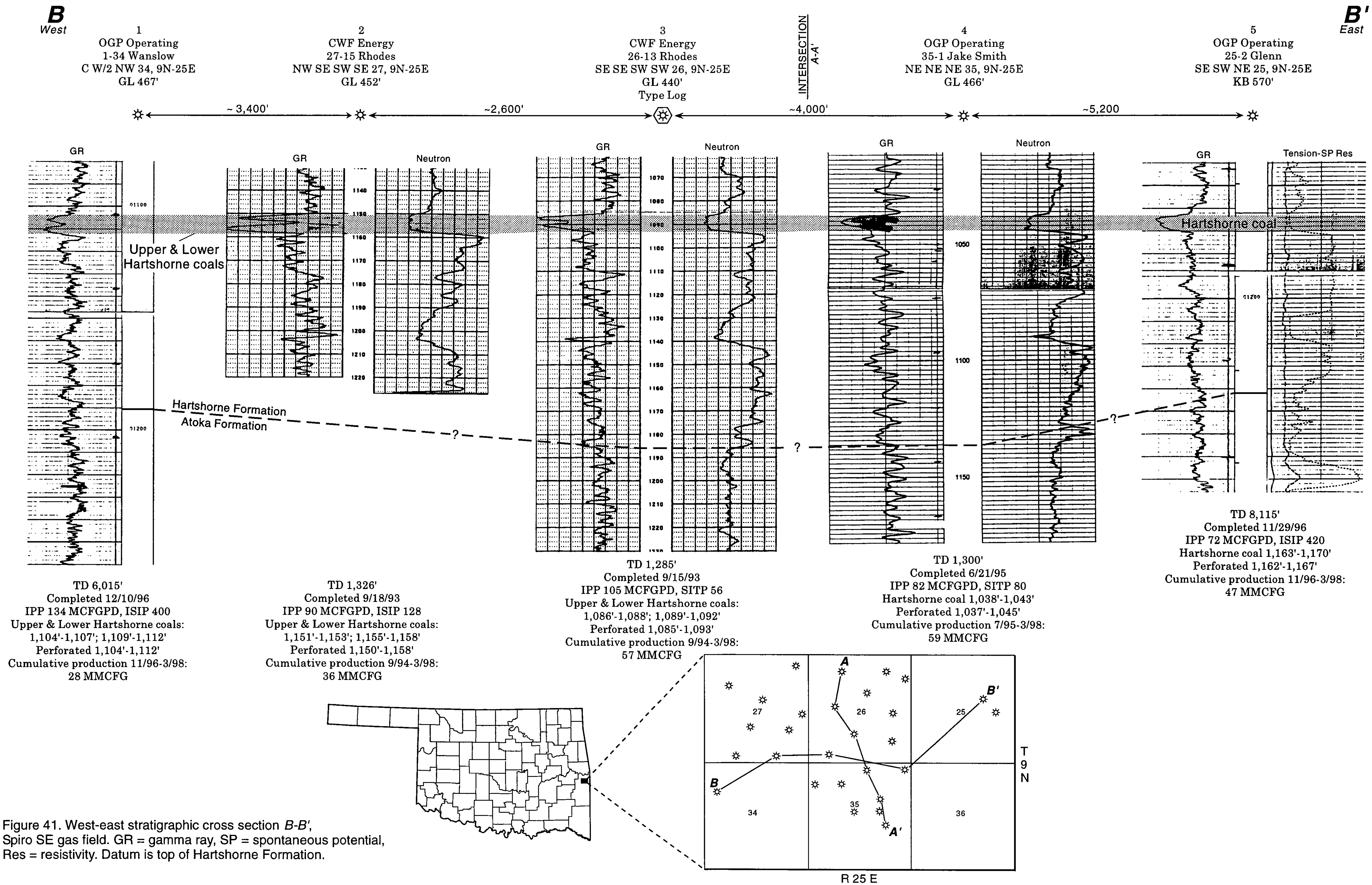


Figure 41. West-east stratigraphic cross section *B-B'*, Spiro SE gas field. GR = gamma ray, SP = spontaneous potential, Res = resistivity. Datum is top of Hartshorne Formation.