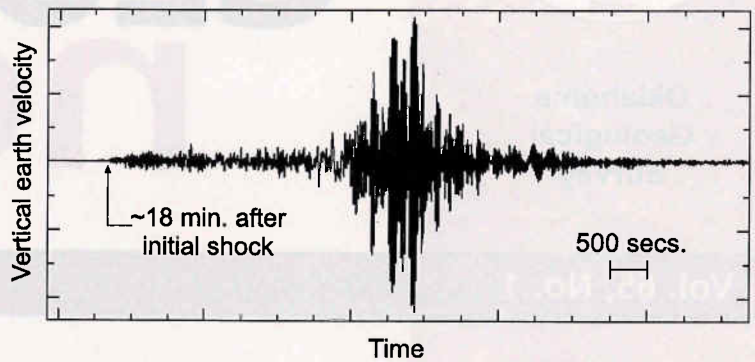
Oklahoma Geological Survey

OKLAHOMA GEOLOGY notes

Vol. 65, No. 1 Spring 2005

on the cover

9.3-Magnitude Earthquake in Indonesia "Unzips" Boundary along Tectonic Plates



The Sumatra-Andaman earthquake of December 26, 2004, off the west coast of Indonesia (cover map) was the second-greatest earthquake in instrumental history. It produced the most devastating tsunami ever known, killing more than 283,100 people and displacing 1,126,900 in 10 countries; 14,100 people are still missing.

A large area of the seafloor was uplifted several meters, displacing 30 km^3 (7.2 mi^3) of seawater, and ultimately raising global sea level about 0.1 mm. Along parts of the west coast of Sumatra, the tsunami's run-up height—the inundation height above sea level—was more than 30 m (98 ft). In Sri Lanka the wave was about 5–10 m (16.4–32.8 ft) high; along the east coast of India, 10 m (32.8 ft); and in the area of Phuket, Thailand, 3–5 m (9.8–16.4 ft). The tsunami also was detected in the United States: on the West Coast the height (peak to trough) was 13–60 cm (5.1–23.6 in.), and on the East Coast 22–34 cm (8.7–13.4 in.).

The inset figure above shows the seismogram from the Oklahoma Geological Survey's Geophysical Observatory. It shows the first three hours of vertical earth velocity as recorded by a broadband seismometer at the bottom of an 840-m (2,769-ft) borehole near Leonard, Oklahoma. The maximum vertical ground movement at Leonard was 42 mm (1.7 in.).

The earthquake occurred along 1,300 km (810 mi) of the boundary between the India-Australia tectonic plates and the Eurasian tectonic plate, which there consists of the Burma and Sunda subplates (see the cover map). The India-Australia plates are moving generally north-northeastward at 40–50 mm/yr (1.6–2.0 in./yr) relative to the Burma subplate; because the plate boundary there (marked by the Sunda trench) trends north-northwest, plate convergence is highly oblique. The oblique convergence is accommodated by slip partitioning: movement along the plate boundary (a megathrust fault plane), which dips gently east-northeast, is dominantly thrust faulting, and right-lateral strike-slip motion occurs along faults in the Burma and Sunda subplates and between them.

The Sumatra-Andaman earthquake has been described as an "8,050-km/hr, 10-minute . . . unzipping of the plate boundary" (Bilham, 2005, p. 1127). The energy released during the 9.3-magnitude earthquake was equivalent to that of a 100-gigaton hydrogen bomb, or about as much energy as the entire United States uses in six months. The initial shock occurred along a shallow-dipping (8°) fault plane at a depth of ~30 km (18.6 mi), but at first very little movement was apparent. About 50 seconds later, and lasting for about 3 minutes, the rupture propagated northward at ~2.3 km/sec (1.4 mi/sec)* and resulted in offset of 5–20 m (16.4–65.7 ft). (This is total offset along the fault plane, not the amount of surface rupture on the seafloor.) The sudden large movement caused the devastating tsunami. After the initial 4 minutes and lasting for the next 2 minutes, the rupture front moved northward at about 2.7 km/sec (1.7 mi/sec) and showed about 5 m (16.4 ft) of offset. From 6 to 10 minutes after the initial shock, the rupture front slowed to 1.2 km/sec (0.7 mi/sec) and resulted in <2 m (6.7 ft) of offset. As much as 5 m (16.4 ft) of movement continued along the middle and northern segments of the megathrust fault plane for more than 50 minutes after the initial "unzipping."

A series of aftershocks also occurred. Many resulted from continued thrust faulting along the subduction zone—the megathrust fault plane—and from strike-slip and normal faulting in the Burma and Sunda subplates. From January 27 to 30, more than 150 earthquakes of magnitude-5 and greater marked the strike-slip "adjustment."

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*NOTE: The speed of sound in air is about 330 m/sec (1,100 ft/sec). Thus, the rupture propagated at about seven times the speed of sound.

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Map courtesy U.S. Geological Survey
(modified by the Oklahoma Geological Survey)

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OKLAHOMA GEOLOGY notes

Vol. 65, No. 1 Spring 2005

Oklahoma Oil and Gas Production: Its Components and Long-Term Outlook

Dan T. Boyd
Oklahoma Geological Survey

INTRODUCTION

The outlook for Oklahoma's oil and gas industry has never been brighter. Rising global demand for oil, especially in developing countries, is reducing the world's spare production capacity and driving prices upward; for 5 years the average State price has been $30 per barrel, and recently much higher. Increasing demand for natural gas, combined with a flat production curve in the U.S., has kept the average price in Oklahoma above $4.00 per thousand cubic feet for the same period (Claxton, 2004). Volatility will persist and short-lived price slumps remain possible, but average prices for both oil and gas should remain high in the long term.

NOTE: Most data cited in this paper are from the IHS Energy Group, current through October 2004 (see IHS Energy, 2004). Total production reported for Oklahoma in the IHS database—including about 3 billion barrels of oil from "unknown" reservoirs—is 12.7 billion barrels; total gas production—including about 2 trillion cubic feet from "unknown" reservoirs—is 77 trillion cubic feet. Unfortunately, all databases have been affected by poor State records, especially for the industry's early years, and the totals above are roughly 2 billion barrels and 17 trillion cubic feet less than State tax records indicate as actual cumulative production (see Claxton, 2004). (All volumes combine condensate with oil and associated with non-associated gas.)

With higher prices come opportunities, and now the Oklahoma oil and gas industry must identify the opportunities. For oil, new discoveries with potential for a Statewide impact are unlikely, making the most promising course increased recovery in existing fields. For natural gas—now the State's largest energy resource—several options are open. Important discoveries are still being made, with the addition of new reservoirs in existing fields and infill drilling in low-permeability reservoirs being major components of new production. Of critical importance is continued development of myriad unconventional reservoirs, including deep and tight gas sands and shales, as well as the most active play in the State: coalbed methane.

For more than a century, Oklahoma has produced oil and natural gas as a fortuitous result of encompassing most of the Anadarko, Arkoma, and Ardmore-Marietta geologic basins and associated shelves (Fig. 1). Oil and gas are produced throughout most of the State, with the only large unproductive areas at the geographic corners: the tip of the Panhandle, the Ozark Uplift, the Ouachita Uplift, and the Wichita Uplift (Fig. 2).

In common practice, production is assigned to a major geologic province, based on the volumes reported by county. Although county lines seldom follow geologic boundaries,

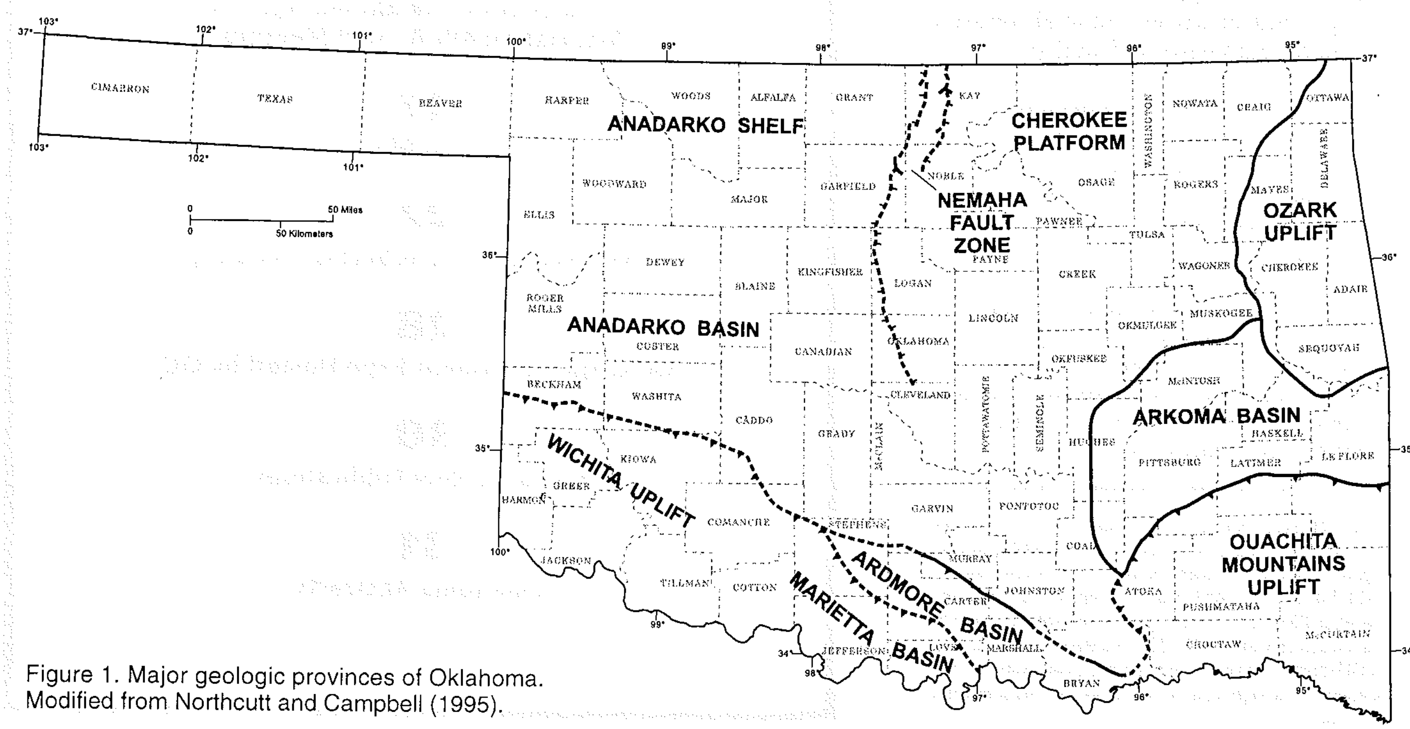


Figure 1. Major geologic provinces of Oklahoma. Modified from Northcutt and Campbell (1995).

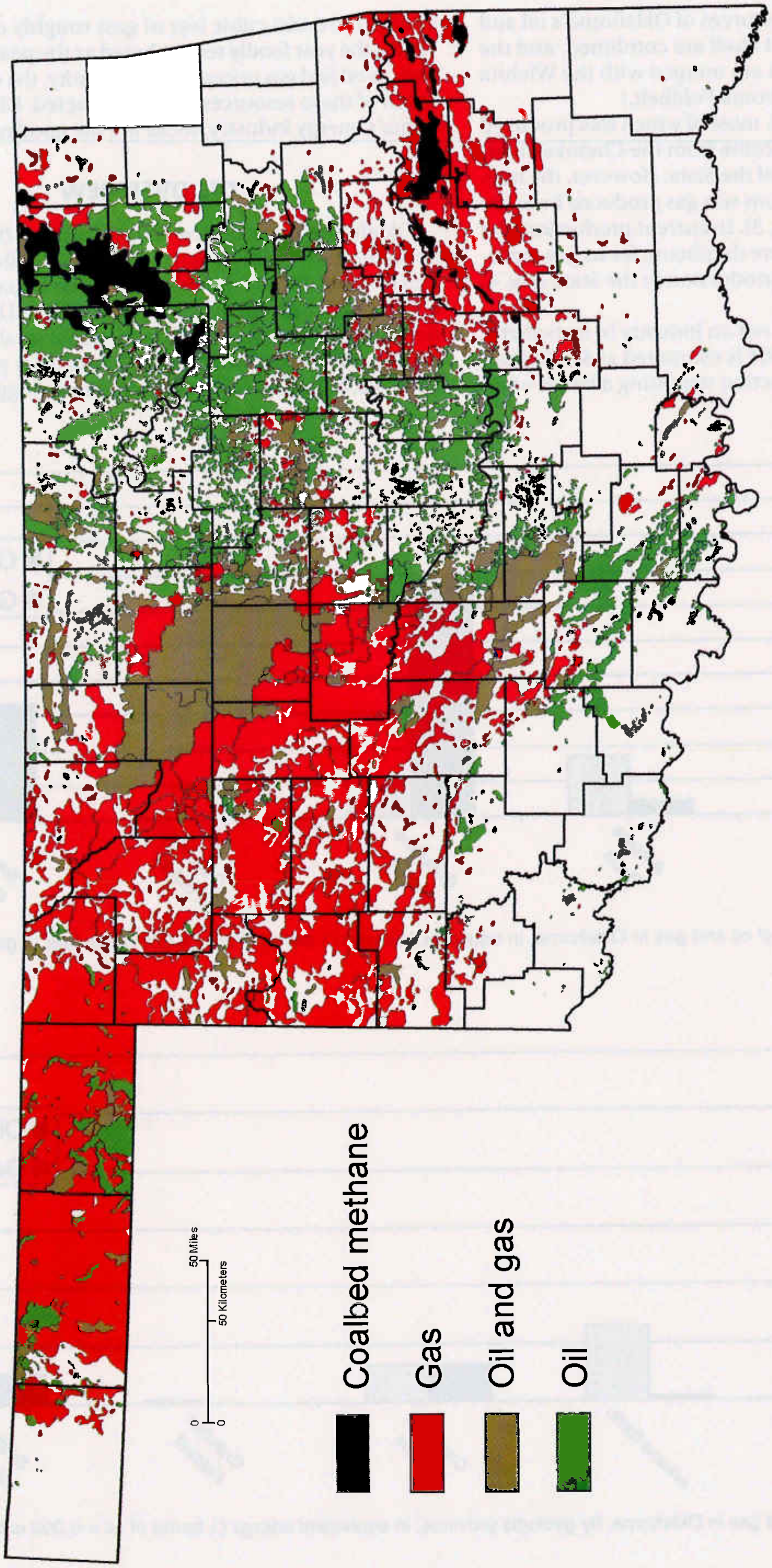


Figure 2. Oil and gas fields of Oklahoma. Map modified from Boyd (2002c).

county reports do help track sources of Oklahoma's oil and gas. (The Anadarko Basin and Shelf are combined, and the Ardmore and Marietta Basins are merged with the Wichita Uplift into the Southern Oklahoma Foldbelt.)

The bulk of Oklahoma's oil, most of which was produced early in the 20th century, has come from the Cherokee Platform in the northeastern part of the State. However, the largest single source of hydrocarbons was gas produced from the Anadarko Basin and Shelf (Fig. 3). In current production, the Anadarko province is even more dominant, for its gas represents 54% of all hydrocarbon production in the State (Fig. 4; IHS Energy, 2004).

Oil and gas in Oklahoma is not an industry in its twilight. Gross industry revenue for 2004 is estimated at $10 billion, with total hydrocarbon production (counting a barrel of oil as equal to 6,000 cubic feet of gas) roughly equal to that in 1927—the year fondly remembered as the peak of oil production. As oil and gas prices approach parity, the question is how much of these resources can be extracted. Clearly, for Oklahoma's energy industry, these are the good old days.

OIL OVERVIEW

Oklahoma's cumulative oil production (including condensate) is 14.6 billion barrels (Claxton, 2004). The current rate of about 177,000 barrels per day, or a quarter of the rate at the 1927 peak, places Oklahoma fifth in U.S. oil production and accounts for 3% of the national total (Energy Information Administration, 2003). Crude oil is produced from about 80,000 active wells (i.e., wells not plugged), averaging

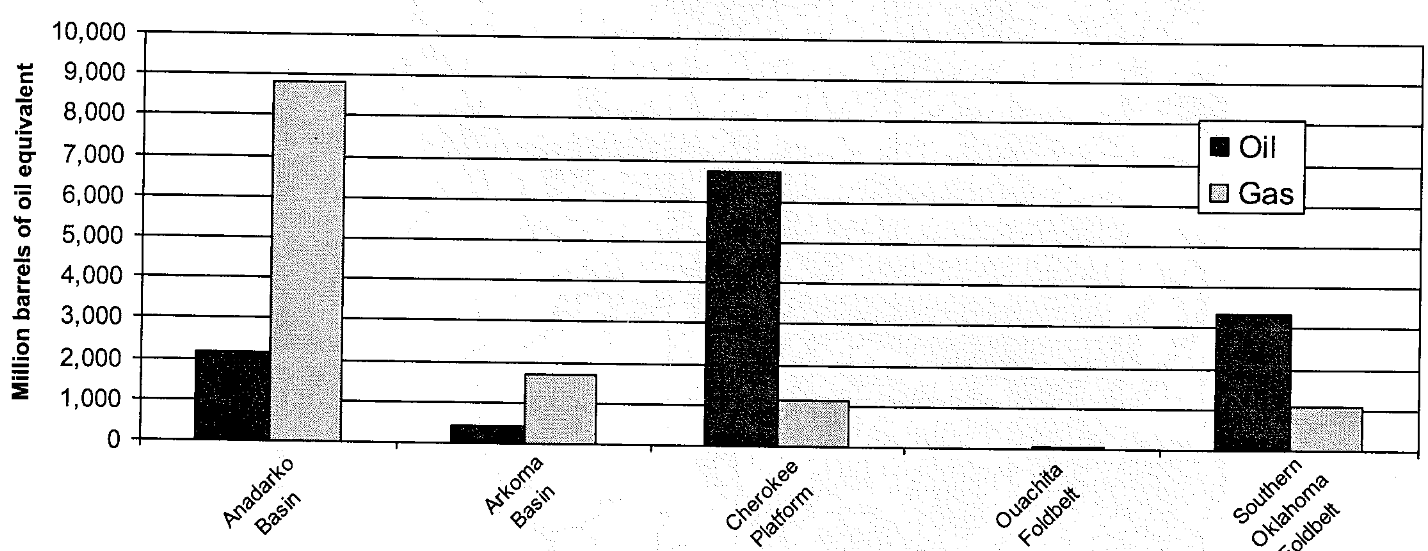


Figure 3. Cumulative production of oil and gas in Oklahoma, in equivalent energy (1 barrel of oil = 6,000 cubic feet of gas). IHS Energy (2004).

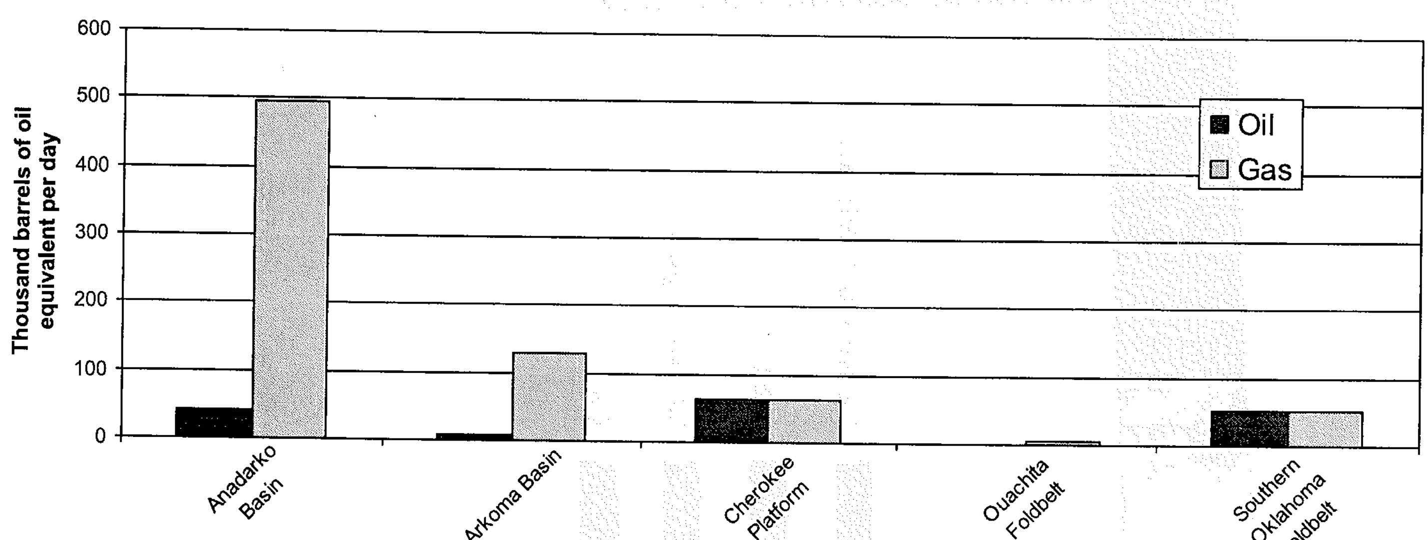


Figure 4. Production rates of oil and gas in Oklahoma, by geologic province, in equivalent energy (1 barrel of oil = 6,000 cubic feet of gas). From IHS Energy (2004).

2.2 barrels per day, in about 1,900 fields. Wells produce from thousands of named reservoirs, but fewer than 300 have 10 or more completed wells (Boyd, 2002a).

Over the last century Oklahoma's oil production has had many ups and downs. The last major increase came during the boom years of the late 1970s and early 1980s. Unfortunately, few discoveries of that period were significant, and none has recovered more than 15 million barrels (MMB). The bulk of the incremental oil produced during the boom was accelerated production—oil that would have been produced anyway (Boyd, 2002b). Since the last peak, in 1984, production has continuously declined. The decline was especially steep immediately after the boom, but over the last 10 years the curve has flattened to about 3.1% per year, for an annual loss of about 5,000 barrels per day since 1994 (Fig. 5).

Much of Oklahoma's oil has come from its 27 major oil fields, "major" defined here as having produced more than 100 MMB (Fig. 6). The median discovery date for the majors is 1923, with the latest (Postle) being found in 1958 (International Oil Scouts Association, 2001). Although major fields represent only 1% of the total, they account for almost two thirds of cumulative production (Fig. 7).

Bartlesville-Dewey Field, the largest and oldest of the major fields (discovered in 1897), illustrates the maturity of

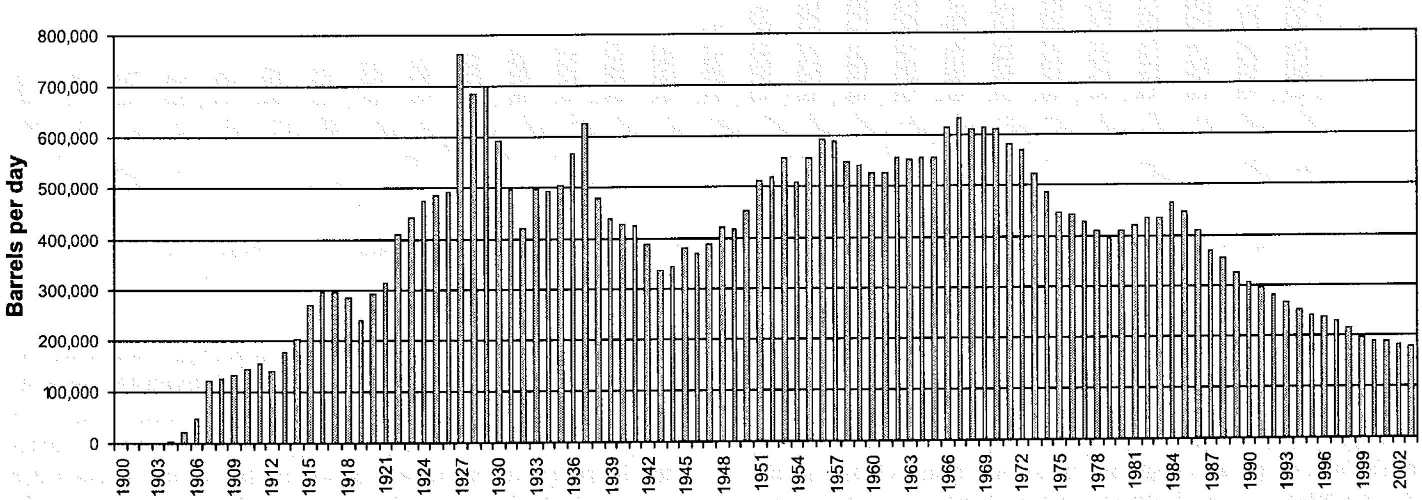


Figure 5. History of oil production (including condensate) in Oklahoma. From Claxton (2004).

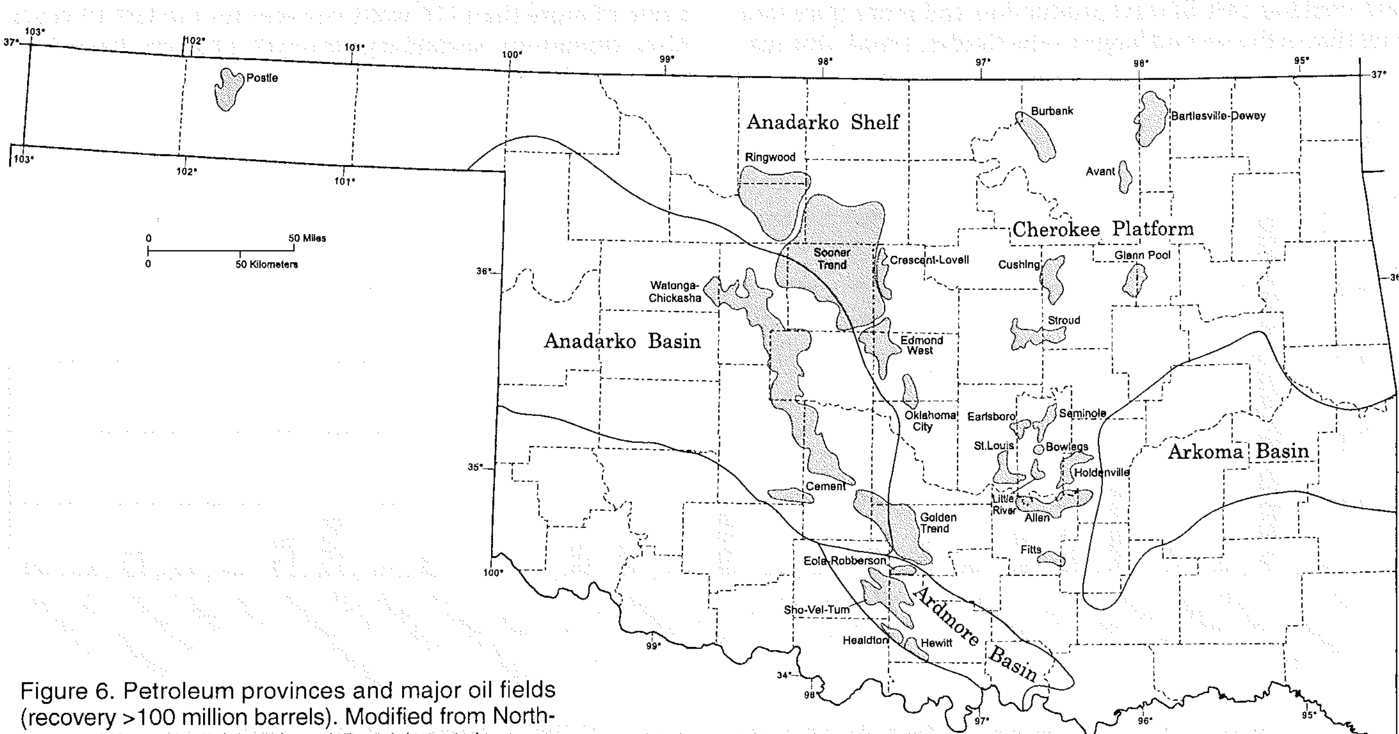


Figure 6. Petroleum provinces and major oil fields (recovery >100 million barrels). Modified from Northcutt and Campbell (1995) and Boyd (2002c).

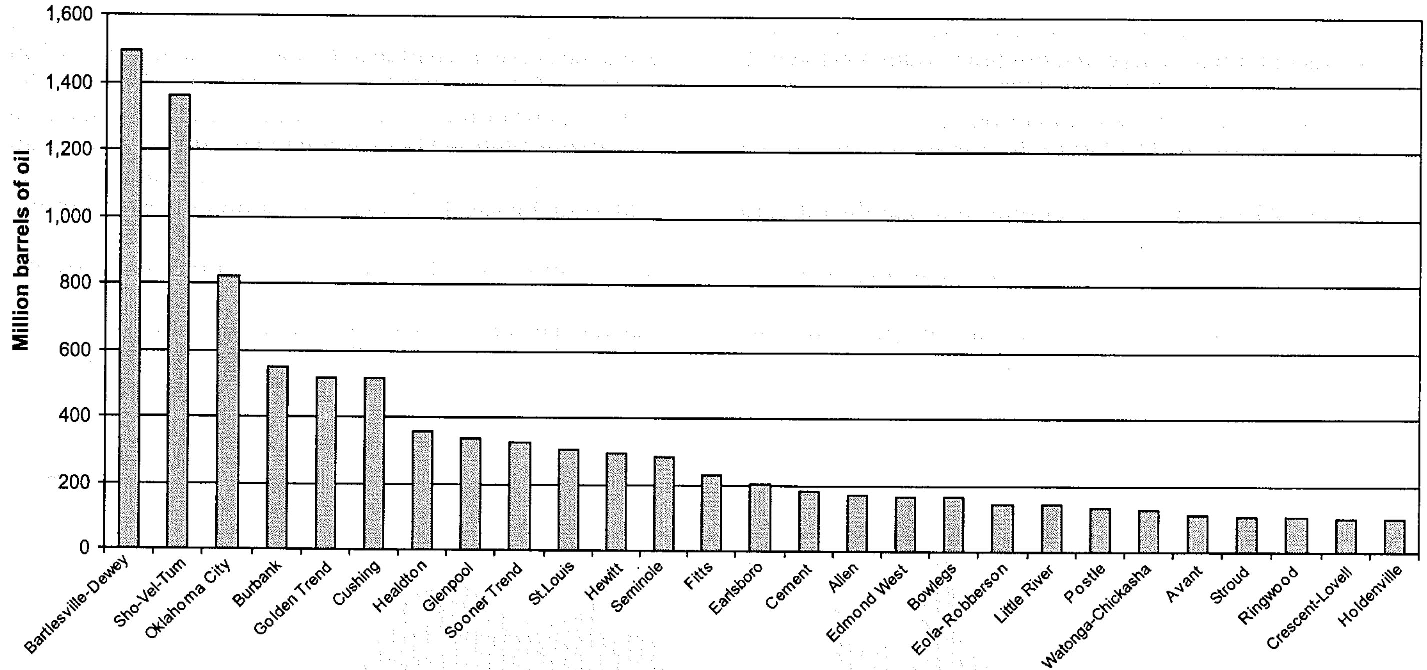


Figure 7. Cumulative oil production in Oklahoma (fields with recovery >100 million barrels). IHS Energy (2004).

Oklahoma's oil production. The field covers parts of nine townships and has produced 1.5 billion barrels of oil (BBO), but it is now producing only 700 barrels per day (Fig. 8; IHS Energy, 2004). Major fields still account for 41% of Oklahoma's daily oil production, but most now comes from numerous smaller accumulations scattered throughout the State (Fig. 2), and much of it through secondary-recovery projects (e.g., water-flooding).

The largest oil producer in the State is now Sho-Vel-Tum Field, making 14% of total production and more than four times that of the second largest—the Golden Trend. One reason for its rank is that in Oklahoma oil and gas fields are defined geographically. Sho-Vel-Tum is a consolidation of 42 previously defined fields producing from a large structural complex that has focused oil migration over a wide area. That helped form hundreds of structural-stratigraphic traps that are stacked in more than 60 named reservoirs at depths from 400 ft to >10,000 ft (IHS Energy, 2004).

The complexity of Sho-Vel-Tum and its wide variety of reservoirs and isolated traps has maintained development at a rate of more than 120 wells per year for the last 10 years. Also, numerous secondary-recovery projects have kept

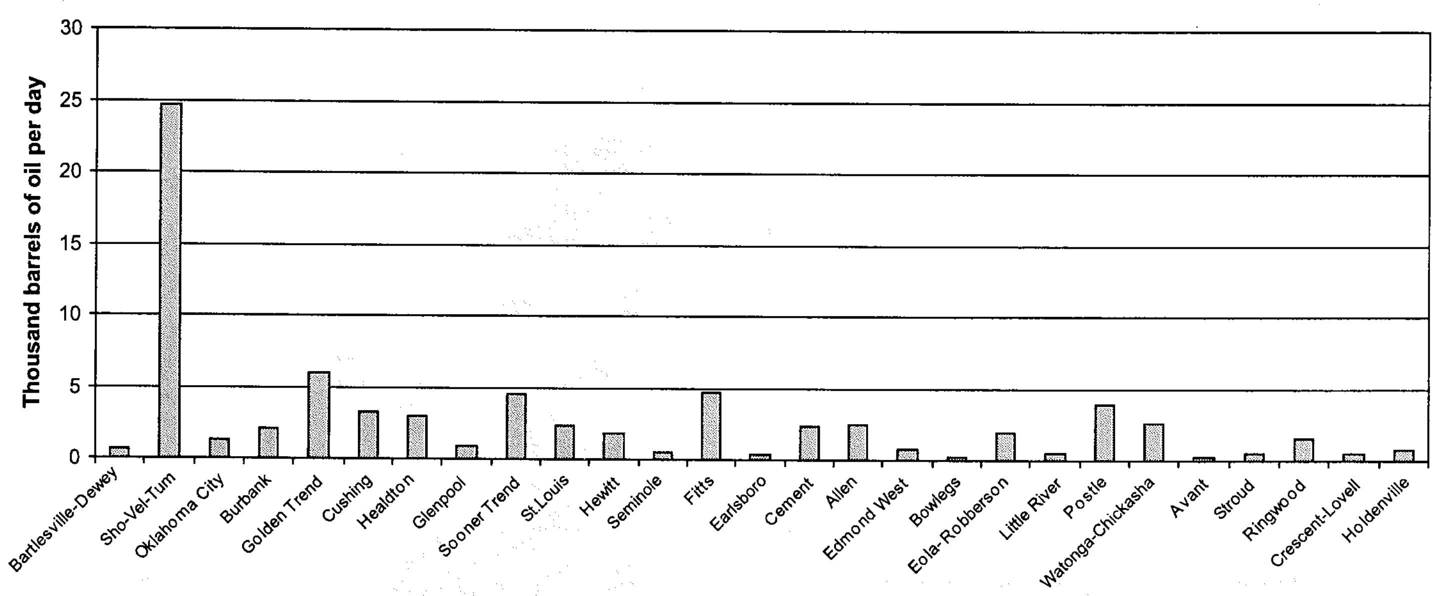


Figure 8. Daily oil production in Oklahoma fields with recovery >100 million barrels. From IHS Energy (2004).

many older wells active. Not coincidentally, Sho-Vel-Tum is both the largest producing field and also has the most active wells. Correlation of active-well numbers with production (Figs. 8, 9), although good, is imperfect due to differences in field age and the initiation of secondary-recovery programs.

An example is Postle Field, one of the State's smaller major fields, located in the Panhandle. It is the only major field that has markedly increased production over the last 10 years (Fig. 10). This is the result of an enhanced recovery project initiated by Mobil Oil involving the injection of carbon dioxide into Morrow-age reservoirs. The project began in 1996, and by 1999 had boosted average well production to 16 barrels a day (Southwell, 2004) and overall field production by 8,000 barrels per day (Fig. 11). In 2004 this made Postle the fifth largest oil-producing field in the State (IHS Energy, 2004). Since 1999, production has declined sharply, but the field is still producing at roughly double its rate of 10 years ago.

Of all the major fields, production from Sho-Vel-Tum has fallen the most over the last 10 years, but its 4.5% rate of de-

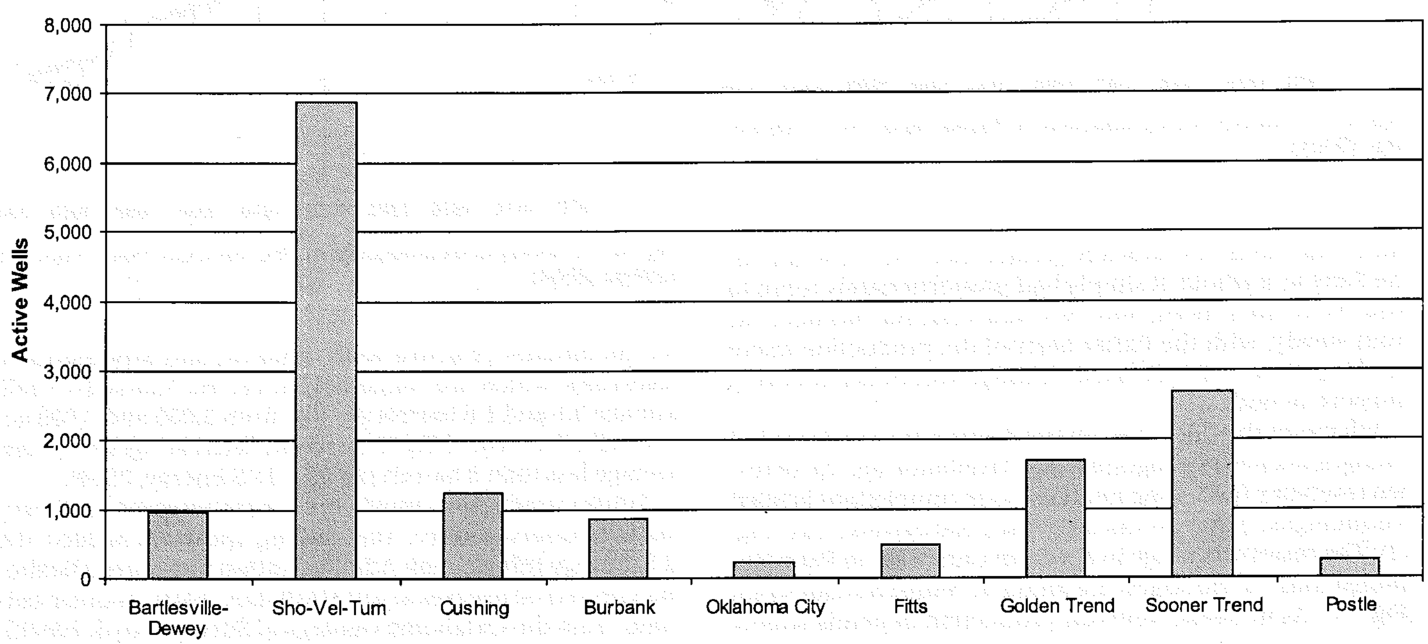


Figure 9. Active wells in nine Oklahoma oil fields with recovery >500 million barrels, or >4,000 barrels per day. From IHS Energy (2004). Compare with Figure 10.

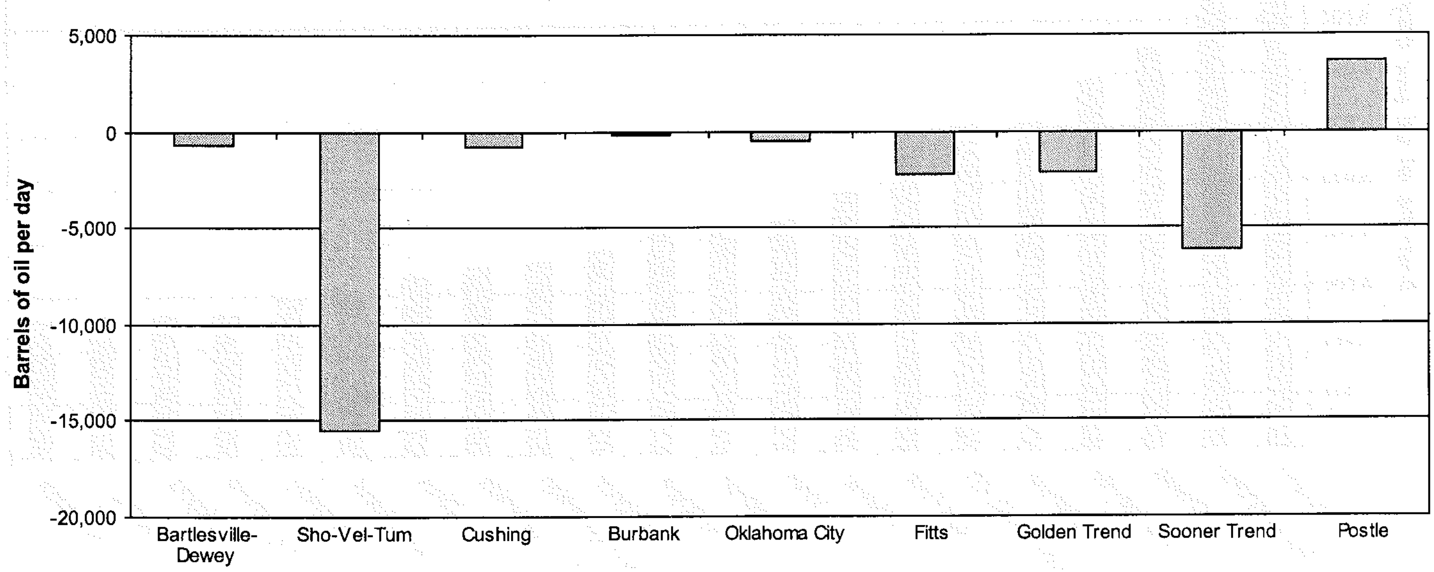


Figure 10. Changes in production rate in nine Oklahoma oil fields (recovery >500 million barrels, or >4,000 barrels per day) between 1994 and 2003. From IHS Energy (2004). Compare with Figure 9.

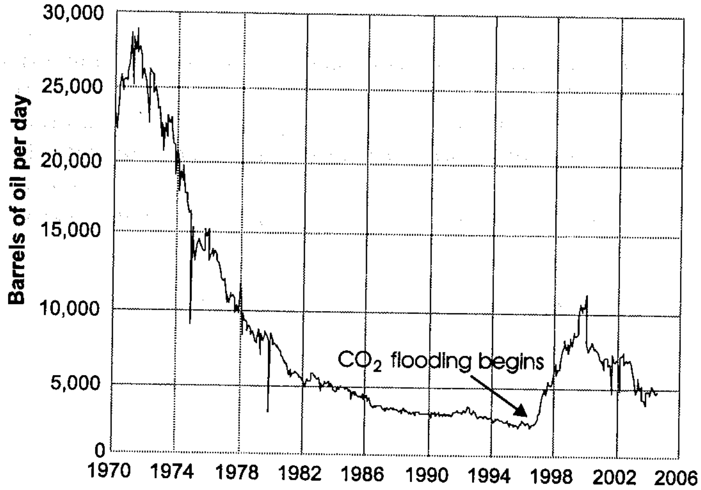


Figure 11. History of oil production in Postle Field. From IHS Energy (2004).

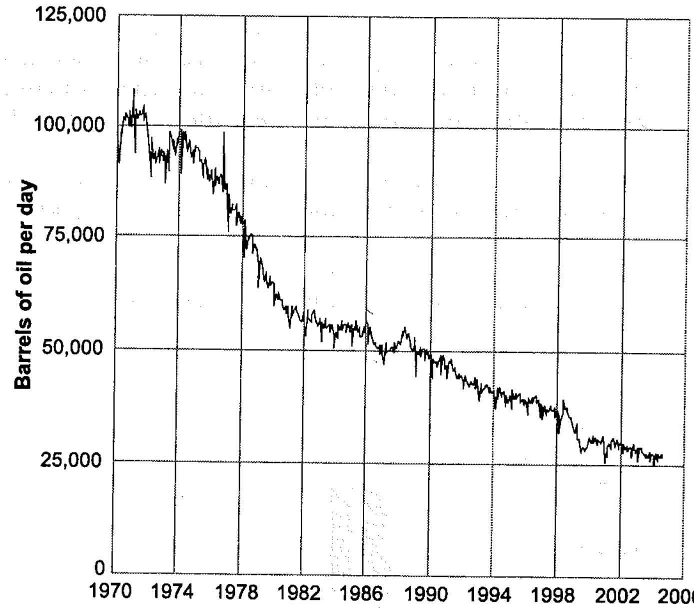


Figure 12. History of oil production in Sho-Vel-Tum Field. From IHS Energy (2004).

cline (Fig. 12) is not radically greater than the 3.1% rate for the State as a whole: it simply had proportionately more to lose. As in other fields, Sho-Vel-Tum's decline has been far from steady, with the flatter parts of the production curve marking times of increased drilling, secondary-recovery projects, or both.

Whatever the field size, oil production is as widespread stratigraphically as geographically. Oklahoma has 20 identified reservoirs (excluding multiple-zone completions labeled "commingled") that produce at least 2,500 barrels a day (Fig. 13). The reservoirs range in age from Cambrian to Permian, though most of the largest are found in Pennsylvanian strata (Fig. 14). As in fields, reservoir production depends largely on the number of active wells. Hunton and Mississippian reservoirs, which are concentrated on the Anadarko Shelf, average 3.1 and 1.6 barrels per day from 3,000 and 7,000 active wells. For most of the 20 reservoirs listed in Figure 14, wells average less than 3 barrels per day (IHS Energy, 2004).

Future production must come from reserves, and estimates of reserves differ. After polling operators in 2000, the U.S. Energy Information Administration estimated Oklahoma's proved oil reserves at 610 MMB (EIA, 2003). Another estimate, from the Oklahoma Geological Survey (Boyd, 2002b),

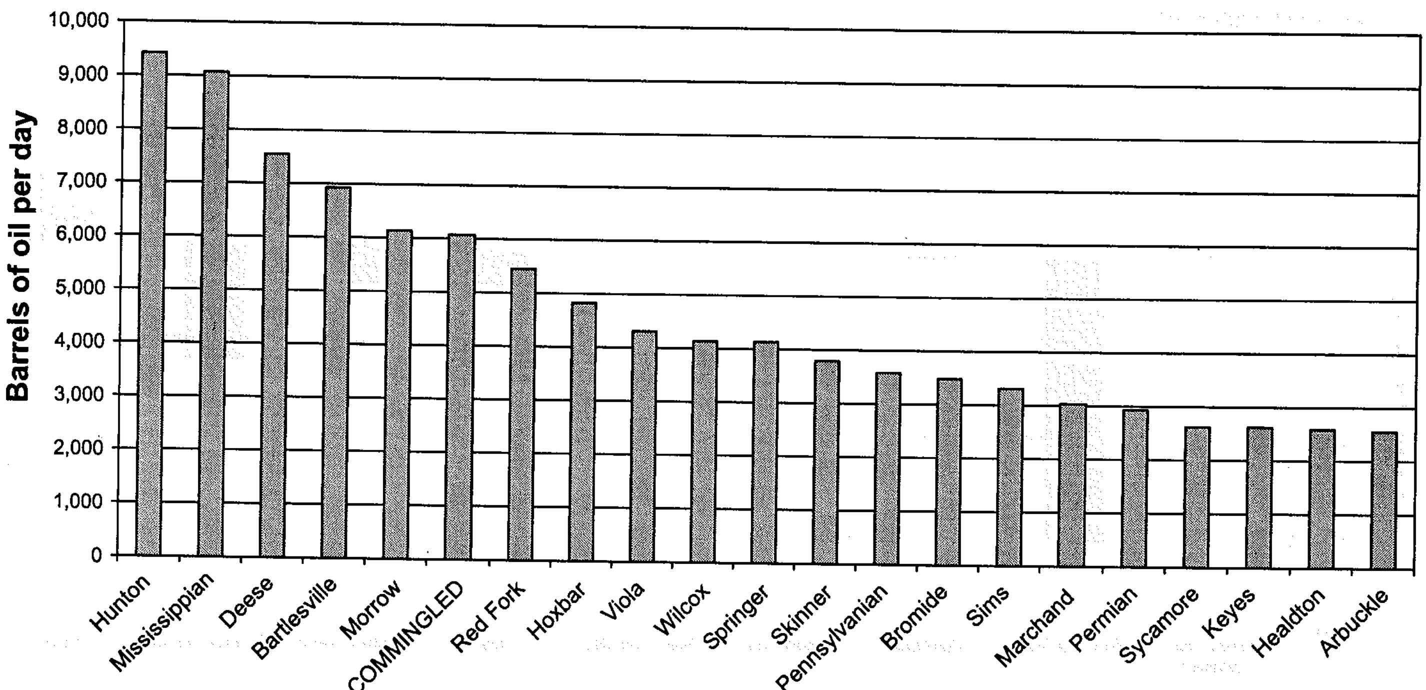


Figure 13. Daily oil production in Oklahoma reservoirs (>2,500 barrels per day). From IHS Energy (2004).

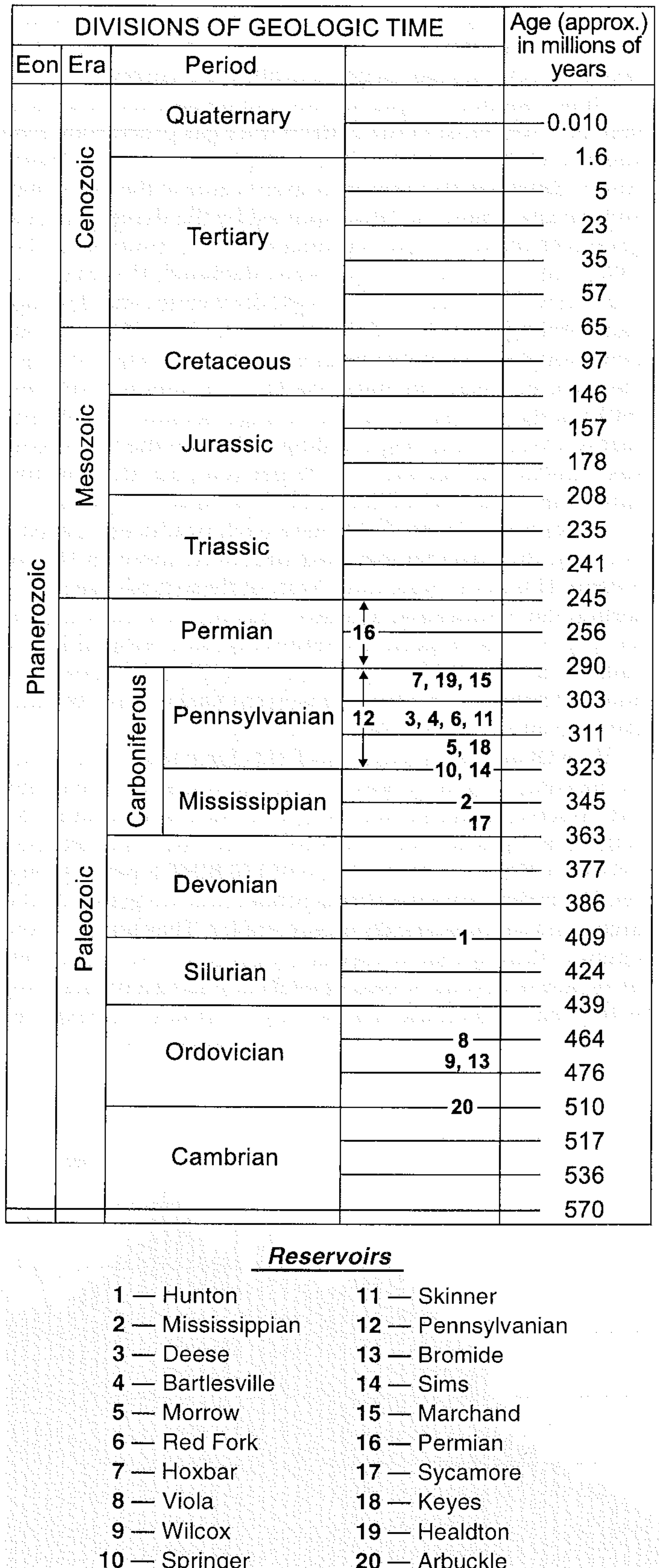


Figure 14. Stratigraphic location of oil-producing reservoirs in Oklahoma (those producing >2,500 barrels per day) ranked by production rate. Modified from Harland and others (1990) and Hansen (1991).

was based on the assumption that trends would continue in the decline of production and the abandonment of wells. Based on that, and assuming wells will remain active through an average rate of 0.5 barrels a day, it found that reserves in 2000 amounted to 1,080 MMB. Subtracting subsequent production, the first estimate says that in January 2004 2% of the State's ultimate oil recovery remained to be produced; the second, that 5% remained. Under such assumptions the good news is that (short of a price collapse) the chances are excellent that Oklahoma will produce far more oil than the EIA predicted. The bad news is that action must be taken soon—or the end is in sight.

No important fields or reservoirs have been added to the State's resources for decades—a primary reason for the long-term decline. After more than a hundred years of exploration and nearly 500,000 wells, the likelihood of a discovery that could reverse the decline has become vanishingly small. Even if prices and drilling remain high, as they are today, Oklahoma's oil production will continue to fall unless a systematic effort is undertaken to enhance recovery in existing fields.

To encourage enhancement operations, the Oklahoma Geological Survey is leading a study designed to bring as many oil accumulations as possible to their maximum economic recovery. The first step is to develop methods of identifying under-performing oil reservoirs and then determine the best technique(s) for increasing recovery. Techniques may include infill drilling, horizontal drilling, secondary-recovery operations (water-flooding or modified water-flooding), and a variety of enhanced recovery procedures. Among the factors that heavily influence economic viability are incremental oil volume, reservoir characteristics, age of wells and infrastructure, availability of data, land ownership, and surface issues. The goal is to determine which areas and reservoir types hold the most promise for enhanced recovery projects and whether these are sufficient to justify pilot projects and an in-depth evaluation of the entire State. The methodology for identification and the recommended enhancement techniques will be disseminated among operators, with results of pilot projects to determine the course of future work.

Optimal enhancement methods vary with the characteristics of the reservoirs concerned. Of Oklahoma's wide variety of reservoir types, those classified as fluvial-dominated deltaic (FDD) are the most important. These were deposited where delta systems feed into the marine environment, and a common characteristic of this group of reservoirs is their generally poor lateral and vertical continuity. Such reservoir heterogeneity complicates both primary drainage and water-flooding operations, with the net effect being a generally poor recovery of the original oil in place.

In play-based studies published by the Oklahoma Geological Survey, 21 FDD-type oil accumulations (mostly small) were analyzed. Their average ultimate recovery of only about 15% of the original oil in place had many causes. In addition to the physical nature of the reservoirs themselves, nearly all of the fields had multiple operators, development was rapid and haphazard, natural gas (which provides most of the reservoir energy) was produced with the oil, and water-flooding, if used at all, was not coordinated.

Because such problems are not restricted to FDD reservoirs, and because large fields are amalgamations of many smaller accumulations, the same problems and the same low recovery are likely common. As cumulative recovery approaches 15 billion barrels, using an optimistic average ultimate recovery of 33%, the total oil volume still residing in Oklahoma reservoirs is at least 30 billion barrels. Given that the recovery percentage in the fields studied was less than half this, the oil still in the ground is certainly very much more.

By any analysis the oil remaining in Oklahoma reservoirs is very large, and almost all of it has been mapped. The proportion that is theoretically recoverable will vary from field to field, but without doubt the total is in the billions of barrels. The only question is how much of this can be recovered economically, and where.

GAS OVERVIEW

Oklahoma's cumulative natural-gas production (including associated gas) at the end of 2004 was 93.8 trillion cubic ft (TCF). The current production rate, 4.3 billion cubic ft (BCF) per day, is 70% of the 1990 peak rate (Claxton, 2004). This places Oklahoma third (after Texas and Louisiana) in U.S. gas production, with an 8% share of the national total (Energy Information Administration, 2004). About 62,000 gas wells have been drilled in the State. Current production comes from 31,000 wells in about 1,400 fields and hundreds of named reservoirs (Boyd, 2002c; Claxton, 2004).

For lack of an early market, large-scale production of the State's natural gas began much later than for oil. Large discoveries and high demand made oil the primary exploratory objective in the State, with most operators viewing gas as a nuisance or a drilling hazard. Because oil almost always contains associated gas, in its earliest years the industry relied on small accumulations associated with shallow oil fields on the Cherokee Platform. Most of the largest gas fields were discovered in the first half of the 20th century, but none were close to a big city. As a result most of the fields were not fully developed, nor their size appreciated, until much later when demand grew and gas-targeted drilling increased.

Thus, Oklahoma's gas production peaked 63 years later than oil. Over most of the 20th century gas production rose steadily, with exploitation beginning in earnest after World War II. Especially strong growth spurts came in the early 1960s and the late 1980s, the latter spurred by the deregulation of gas prices (Boyd, 2002d). Production in the State peaked in 1990, and since then has generally declined. However—in contrast with the history of oil—gas discoveries and development drilling have slowed the decline, and in 1993 and 2000 even brought modest increases in production (Fig. 15). Since the peak in 1990, the State has lost 1.9 billion cubic feet (BCF) of daily capacity for an average decline of 2.8% per year (Claxton, 2004). High drilling activity in the last 3 years has reduced the decline to 1.2% per year, but the effective annual loss is still 50 million cubic feet (MMCF) per day.

In Oklahoma 16 gas fields have each produced at least 1 TCF (Fig. 16). Together they have produced about 39 TCF, or roughly 41% of the State total. Most of these fields are in and around the Arkoma and Anadarko Basins, especially the latter (Fig. 1). The largest, Guymon-Hugoton, located in the Panhandle, is part of a much larger complex that extends a hundred miles north into southwestern Kansas and the same distance into the Texas Panhandle (Fig. 17).

All of Oklahoma's major gas fields have been producing for decades, with most now producing well below their peak rate. Mocane-Laverne Field is typical, with peak production in the late 1960s at about 700 MMCF per day; it has declined 75% since then to a current rate of 170 MMCF per day (Fig. 18). Fields that continue strong production are generally the largest and stratigraphically most complex. They tend to show surges in drilling that are driven by gas price, by the discovery of new reservoirs or incompletely drained accumulations, by the need to increase well density in order to increase re-

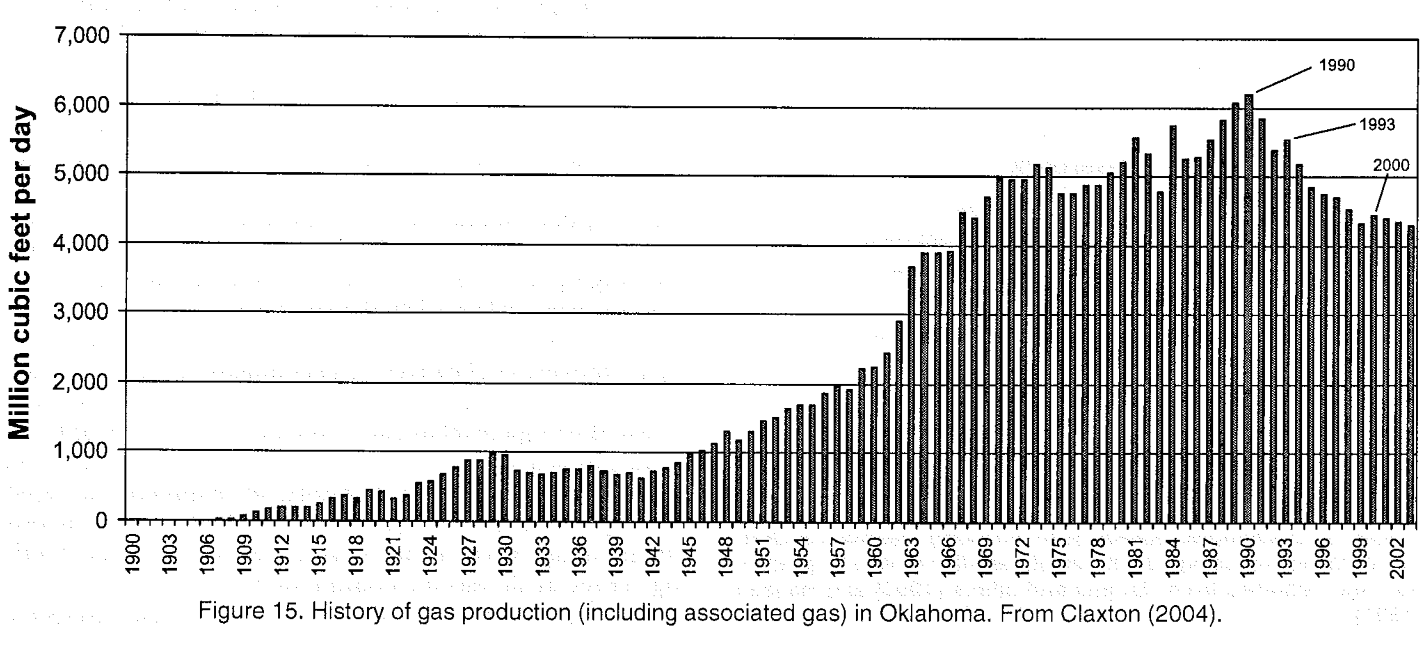


Figure 15. History of gas production (including associated gas) in Oklahoma. From Claxton (2004).

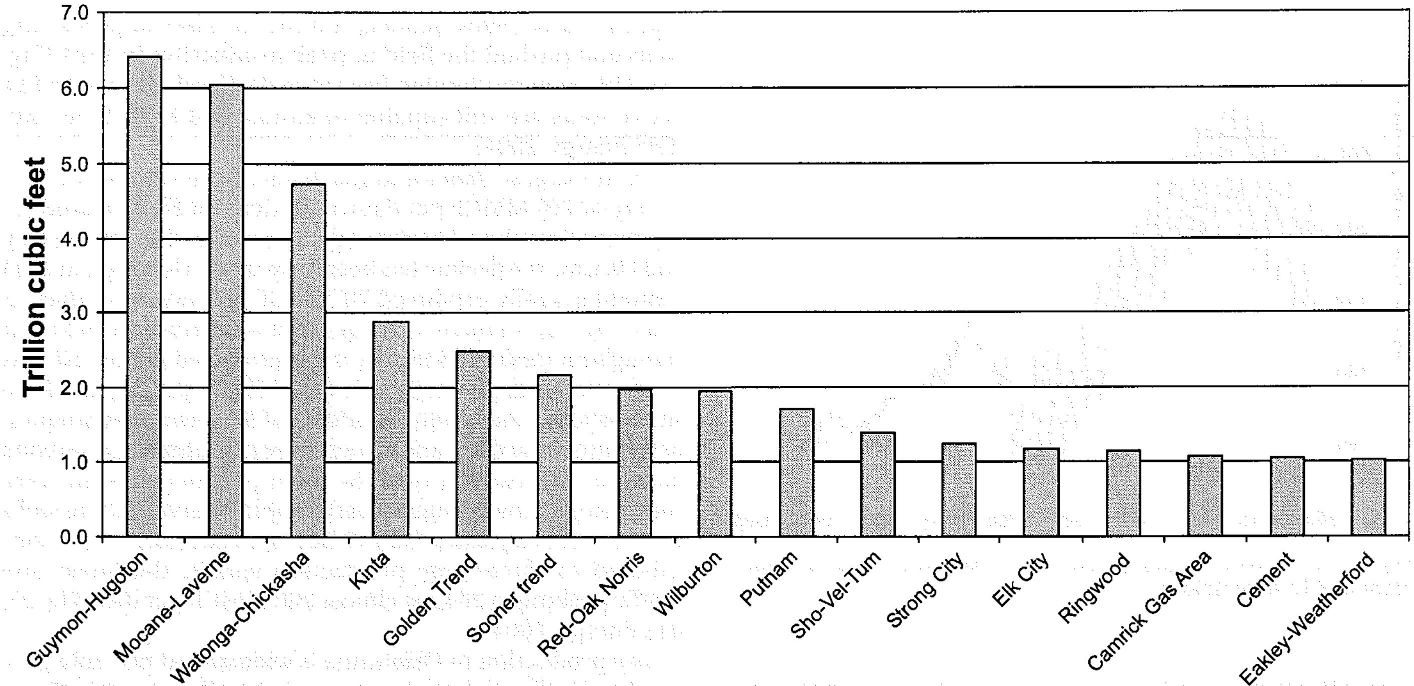


Figure 16. Cumulative production for major Oklahoma gas fields (>1 trillion cubic feet). Data from IHS Energy (2004). Compare with Figure 19.

covery efficiency, and by new techniques in drilling, completion, or stimulation that enable the drainage of less-permeable and/or deeper reservoirs.

In Figure 16, major Oklahoma gas fields are shown in order of cumulative recovery; Figure 19, showing the same fields in the same order, reveals that current production rates need not follow the same pattern. Examples are Red Oak–Norris, Strong City, and Cement Fields. Although Red Oak–Norris (in the Arkoma Basin) has been active since 1931, it is now the third largest gas producer because of concerted development of the Red Oak Sandstone that began in the late 1980s. It reached peak production in 1993, more than 60

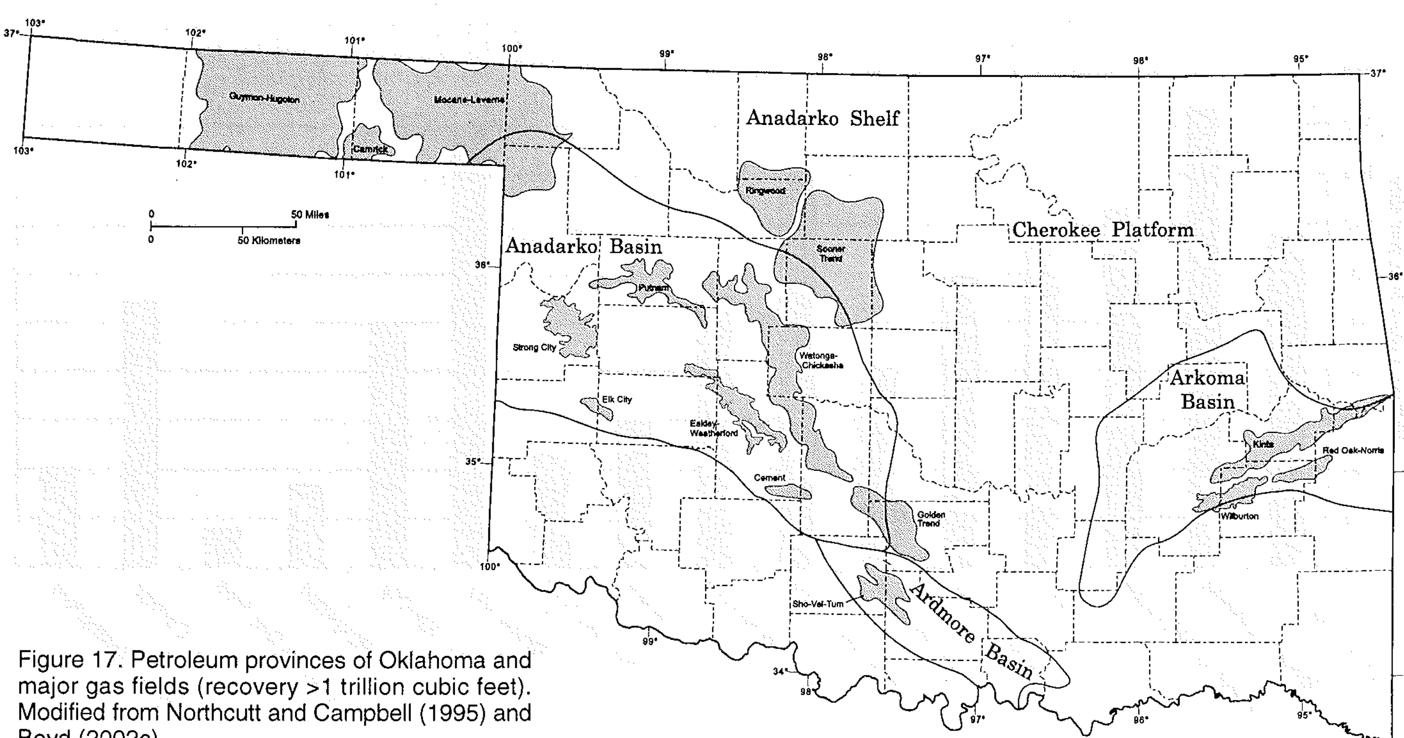


Figure 17. Petroleum provinces of Oklahoma and major gas fields (recovery >1 trillion cubic feet). Modified from Northcutt and Campbell (1995) and Boyd (2002c).

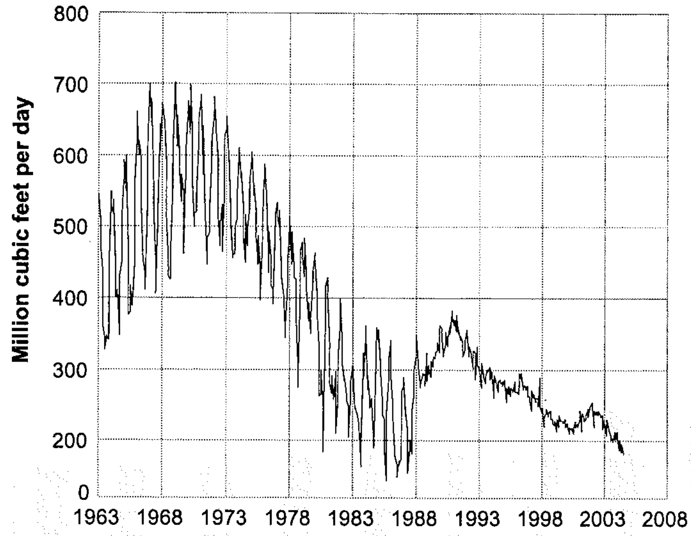


Figure 18. History of gas production in Mocane-Laverne Field. From IHS Energy (2004).

years after it first produced gas (Fig. 20). Today its 521 wells produce >150 MMCF per day, equaling its rate in 1970 (IHS Energy, 2004).

Strong City Field is also producing gas faster than might be expected from its cumulative recovery. The field—in the center of the Anadarko Basin and producing primarily from the Red Fork Sandstone—was discovered relatively late, in 1972. Active development began in the late 1970s on 640-acre well-spacing (one well per section), a spacing later determined, because of the generally low permeability of the sandstone, to be too wide for efficient drainage of the reservoir. Increasing the well spacing to 160 acres in the late 1980s and the early 1990s quadrupled the number of producing wells and pushed the field to peak production in 1994 (Fig. 21). Although production has since declined, the field's 814 active wells are still capable of almost 200 MMCF per day (IHS Energy, 2004).

Of the largest Oklahoma gas fields (those with >2 TCF recovery or 100 MMCF per day), only Cement Field is producing more now than 10 years ago. For some, like Strong City and Elk City, the decline has been very small. However, in 2003 Cement actually produced 70 MMCF per day more than in 1994 (Fig. 22). Cement's first gas well was drilled in 1920, but throughout most of its history it has produced mainly oil. Gas production was generally below 10 MMCF per day until the late 1980s, but then, with the advent of 3D seismic techniques, development of deep and structurally complex gas reservoirs began in earnest. Many of the most productive wells were completed in the Springer stratigraphic interval, where wells with recoveries greater than 10 BCF are common. These contributed to three large production spikes, the latest one briefly peaking in 2002 at almost 200 MMCF per day (Fig. 23; IHS Energy, 2004).

Gas production in Oklahoma is widespread not only geographically (Fig. 2) but also stratigraphically (Figs. 24, 25). In cumulative production, reservoirs identified as "Morrow" have been the most prolific producers. The Morrow, mainly in the Anadarko Basin and Shelf, has produced about 13.5 TCF in Oklahoma and 8 TCF in the Texas Panhandle. Its record dwarfs the production from the next largest Oklahoma reservoir, the Chase, which has produced 6.0 TCF. Other leading gas-producing reservoirs (IHS Energy, 2004) are the Hunton (5.5 TCF), Red Fork (4.7 TCF), and Chester (4.4 TCF).

In any setting, the exploitation of a resource may be active—or relatively inactive. If current reservoir production rates are plotted in the same order as their cumulative pro-

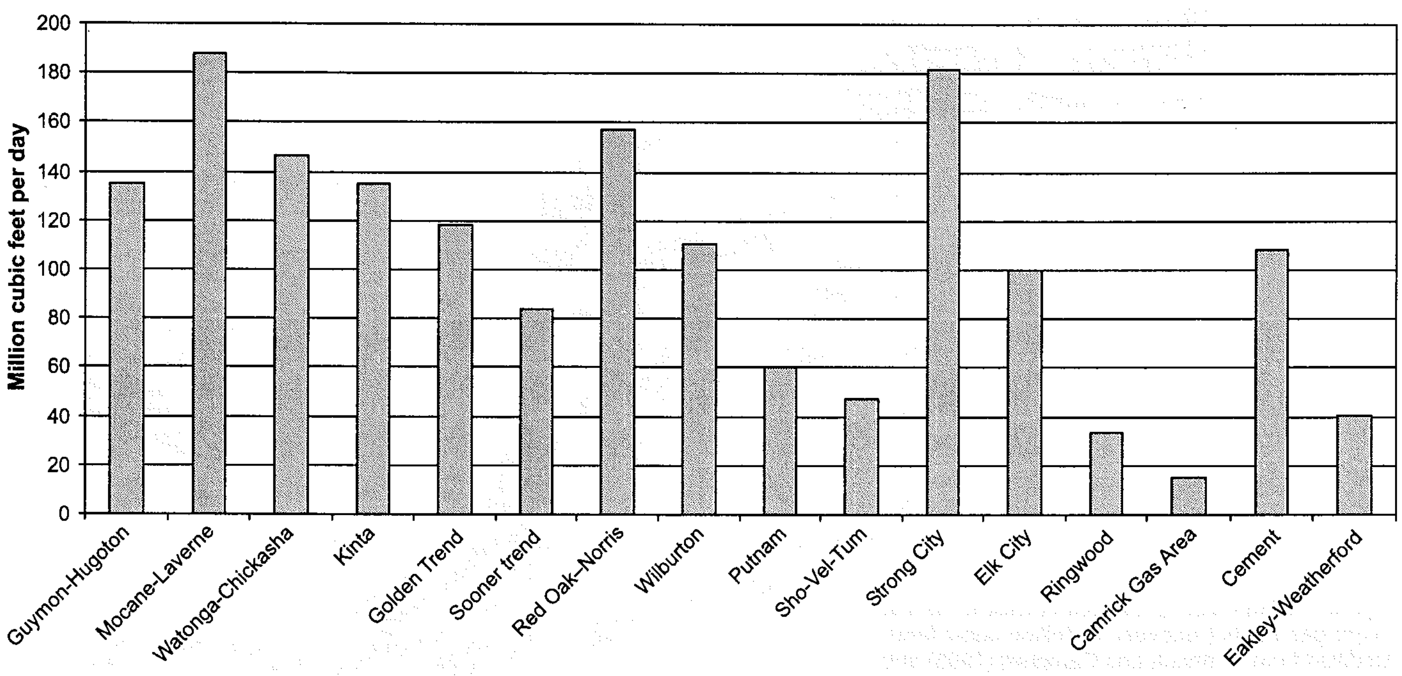


Figure 19. Daily production of major Oklahoma gas fields (recovery >1 trillion cubic feet). From IHS Energy (2004). Compare with Figure 16.

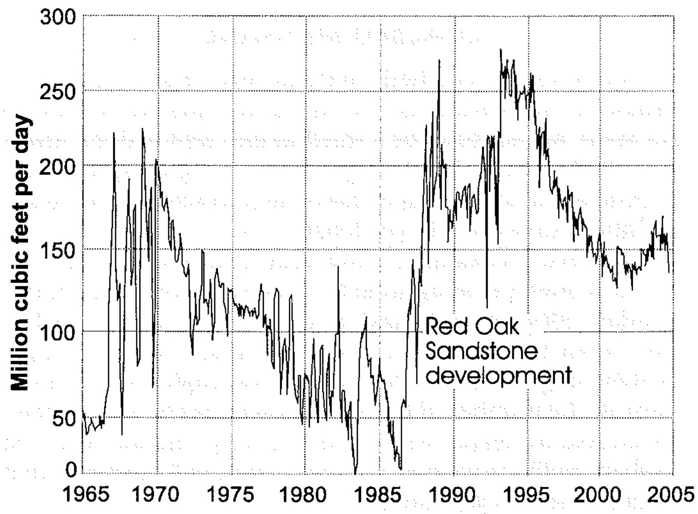


Figure 20. History of gas production in Red Oak–Norris Field. From IHS Energy (2004).

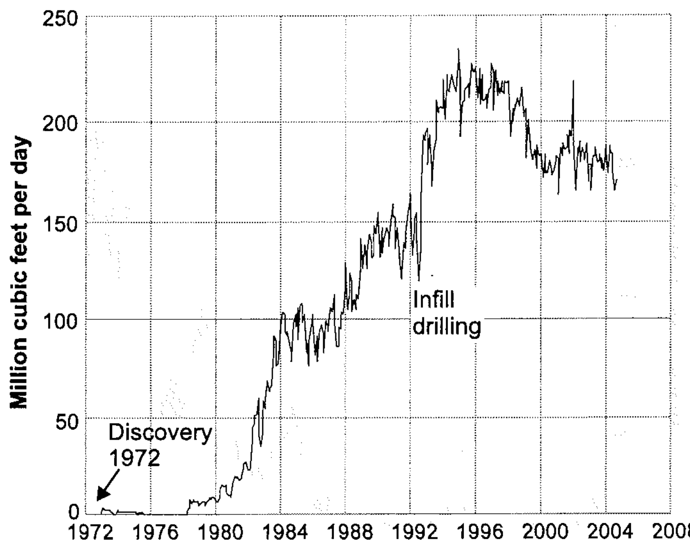


Figure 21. History of gas production in Strong City Field. From IHS Energy (2004).

duction (Fig. 24), it is possible to distinguish between reservoirs that are relatively inactive and those that are receiving more attention (Fig. 26). The Morrow, as the most active past and current producer, has a large lead in both categories. The Chase, which ranks second in cumulative production, is now near the bottom of the list of major reservoirs based on current production. The Chase was developed, mostly in Guymon-Hugoton Field, before the 1960s and since that time has been relatively inactive. In contrast, the Springer and Red Fork reservoirs, which owe much of their production to Cement and Strong City Fields—and to a lesser extent the Atoka and the Hartshorne—produce more than would be suggested by their ranking in cumulative recovery. The contrast indicates active development and their comparatively recent addition to the list of producers. Because average production per well for all reservoirs is low (100–300 MCF per day), reservoir production rates today depend mainly on the number of active wells (IHS Energy, 2004).

For oil, additions to production and reserves come almost exclusively from increased recovery from previously defined traps. For gas, the discovery of important new or incompletely drained reservoirs is still common. Recent activity in finding and producing natural gas continues to succeed in both conventional and unconventional settings.

An excellent example of a recent, significant, and conventional gas "discovery" is Potato Hills Field, which is located in a structurally complex area in southeastern Oklahoma. It was discovered in 1960 and was a marginal producer

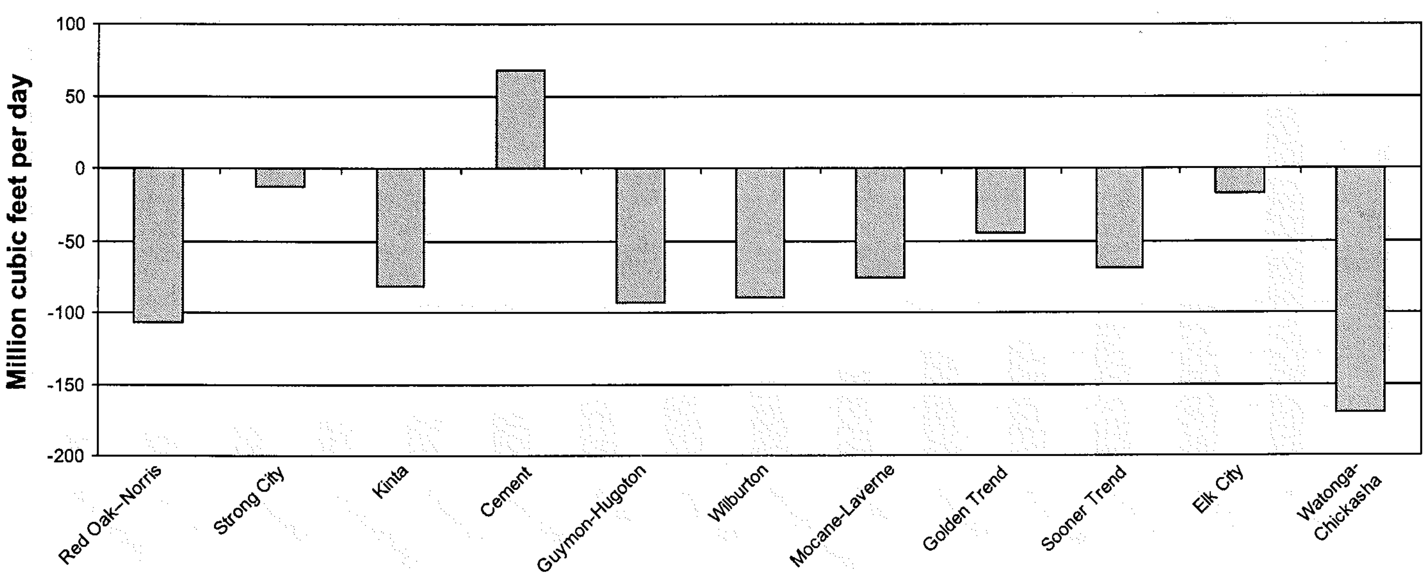


Figure 22. Changes in production rates in 11 Oklahoma gas fields (recovery >2 trillion cubic feet, or 100 million cubic feet per day) between 1994 and 2003. From IHS Energy (2004).

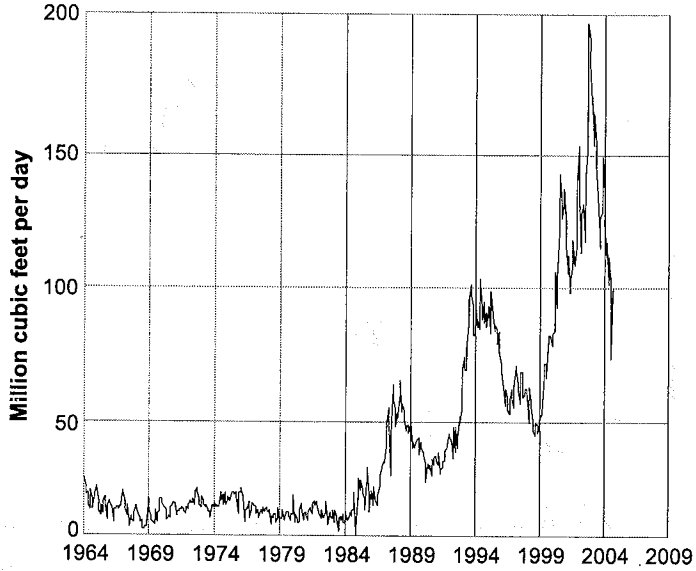


Figure 23. History of gas production in Cement Field. From IHS Energy (2004).

through January 1987, when it went off production after making less than 1 BCF of gas. The area was inactive until 1997, when a well drilled in the same section as a 1961 dry hole established production in the Jackfork Sandstone. Since returning to production in late 1998, the field has produced 146 BCF of gas (IHS Energy, 2004) and eventually is likely to produce 175–200 BCF. The production added from Potato Hills Field is among the most notable in decades, almost singlehandedly accounting for the rise in overall State production in 2000. Although notable discoveries have become increasingly rare, Potato Hills shows that Oklahoma's potential for gas, even in areas that have already seen considerable drilling, is still far from fully defined.

COALBED METHANE

Production of coalbed methane was first recorded in Oklahoma in 1989 and is now by far the most active play in the State, accounting for a third of gas-well drilling and a quarter of all wells (IHS Energy, 2004). As a gas resource it is considered unconventional, because coal acts as both reservoir and source rock (Boyd, 2002d).

Since first production, 3,500 wells have been completed, and new ones are being added at a rate of about two per day (Cardott, 2004). Its stabilized production rate is typically low (50–100 MCF per day), but coalbed-methane wells are noted for their long life and modest decline. Geologic risk is low because of the number of times the objective coals have been penetrated by deeper wells, and relatively shallow, low-cost coalbed-methane wells are suited to the small operators that predominate in Oklahoma.

The numerous thin coals of the Desmoinesian Series (Middle Pennsylvanian) are the primary objective of Oklahoma's coalbed-methane activity. Prospective areas are vast, with those already under production covering parts of 15 counties on the eastern margin of the Cherokee Platform and the northern half of the Arkoma Basin (Figs. 1, 2). At the end of 2003, cumulative production—two thirds from the Arkoma Basin—totaled 116 BCF. Annual production, which continues to rise sharply, should exceed 50 BCF in 2004 (Cardott, 2005; Fig. 27). Continued development ensures that coalbed methane's share of State hydrocarbon production will rise markedly in coming years.

GAS RESERVES

Whether gas is coalbed methane or conventional, defining a range of reserves is difficult. Gas can exist at greater depths than oil and can flow through lower-permeability rock than oil. Thus, wider stratigraphic intervals and larger geographic areas are open to gas exploration. Fluctuating prices, advances in technology, and a geologic understand-

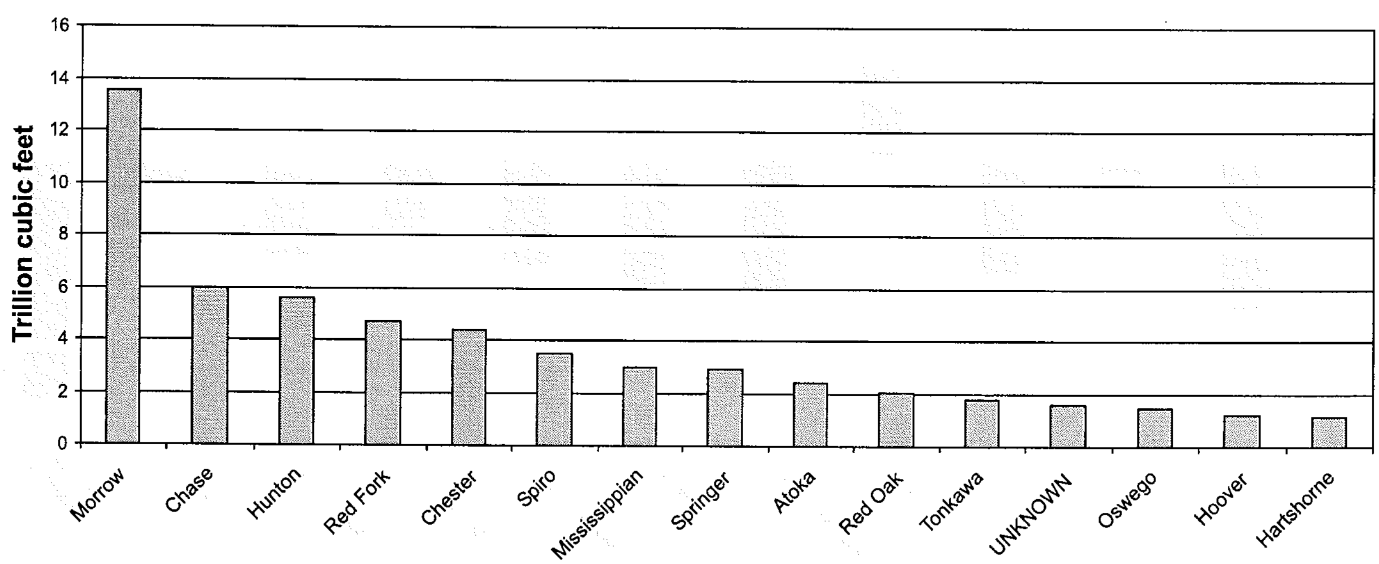
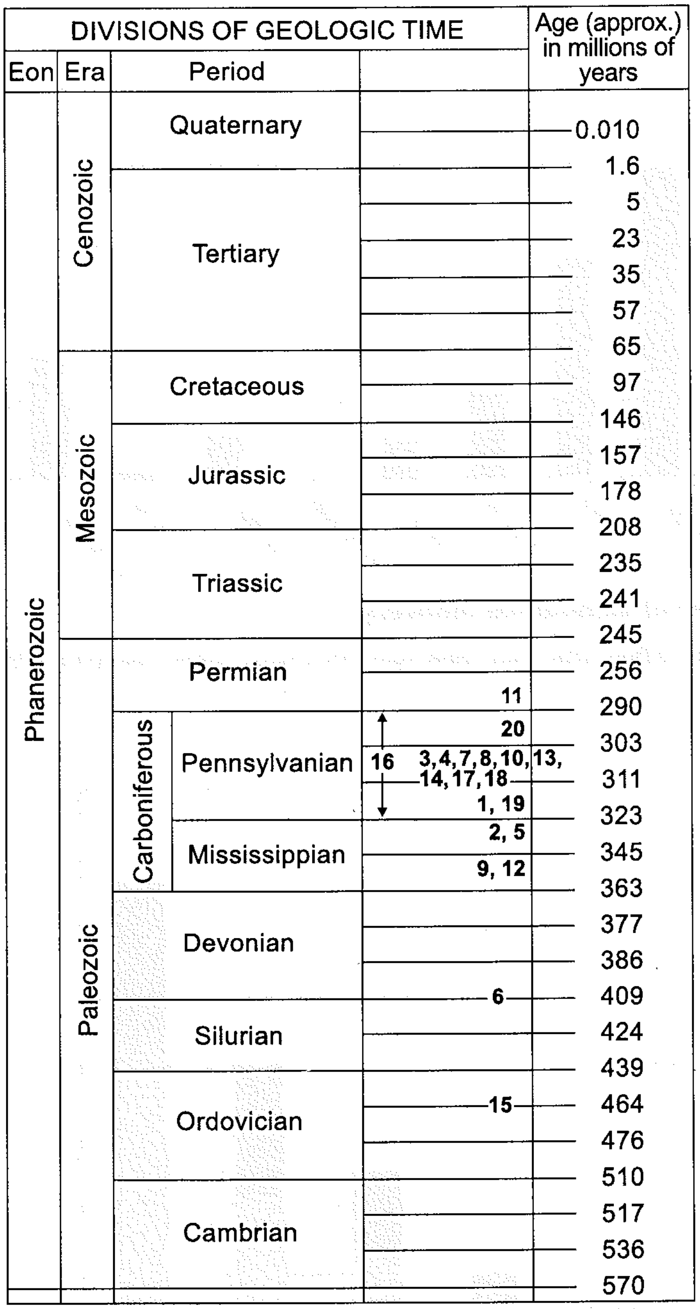


Figure 24. Cumulative production of leading gas reservoirs (recovery >1 trillion cubic feet). Data from IHS Energy (2004). Compare with Figure 26.



Reservoirs

1 — Morrow	11 — Chase
2 — Springer	12 — Sycamore
3 — Red Fork	13 — Cherokee
4 — Atoka	14 — Des Moines
5 — Chester	15 — Viola
6 — Hunton	16 — Granite Wash
7 — Hartshorne	17 — Skinner
8 — Spiro	18 — Oswego
9 — Mississippian	19 — Cromwell
10 — Red Oak	20 — Tonkawa

Figure 25. Stratigraphic location of 20 gas-producing reservoirs in Oklahoma (those producing >50 million cubic feet per day) ranked by production rate. Modified from Harland and others (1990) and Hansen (1991).

ing that continues to evolve—all contribute to uncertainty in determining gas reserves. The volume of gas in place, especially in unconventional settings, is enormous. This reduces its usefulness in determining how much gas may be recoverable in Oklahoma.

In 1946, Oklahoma's gas reserves were estimated at 10.1 TCF. This figure rose steadily to 18.3 TCF in 1962—a volume that is consistent with recent estimates (Hinton, 2001). Even so, since 1962 more than 72.5 TCF has been produced, a volume four times the 1962 reserve estimate.

Obviously, the gas resource from which reserves are derived is finite. However, with time, a combination of factors, including new discoveries, increased recovery efficiency, unconventional gas plays, and higher prices have repeatedly forced upward revisions of estimates. Future additions to reserves are impossible to quantify, but accepting the current production rate of 1.5 TCF per year, a 3% average annual decline, and no major economic surprises, one is led to the conclusion that easily 30–40 TCF remain to be produced.

LONG-TERM OUTLOOK

Prices

The continued vitality of Oklahoma's oil and gas industry depends on prices, which control drilling and production. Oil prices began rising in 1973 as the result of falling U.S. productive capacity combined with an oil embargo intended to influence U.S. policy in the Middle East. Then came the downfall of the Shah of Iran in 1979, and as energy prices rose to record highs the drilling boom began. Although prices declined afterward, since 2000 oil prices have remained well above their 20-year averages (Claxton, 2004; Fig. 28).

Although volatility will remain the norm, oil prices are expected to stay high—above $30 a barrel. They will stay high because declining production in giant fields worldwide has not been replaced by discoveries, and because demand for oil has been accelerated by the burgeoning economies of China and India. Meeting demand today requires all major suppliers to produce continuously at near capacity. Even a minor disruption in Venezuela, Nigeria, Russia, or the Middle East instantly sends prices higher. Upgrades of infrastructure in the former Soviet Union and OPEC countries, or a slowdown in world economic growth, could ease supply problems and reduce prices—but only temporarily.

Intersection of the world's oil supply and demand curves is inevitable; the question is when. OPEC's estimates of reserve volumes are deliberately nebulous, and there are many factors that might encourage overstating reserves rather than understating them. Optimists forecast that world oil demand will meet available supply in roughly 20 years; far more likely is that it will occur before the end of the present decade (Boyd, 2003). This event will not herald an end to oil consumption or price volatility, but to higher prices and the beginnings of serious conservation. It will also prompt fuel switching where feasible, and that will tend to link more closely the prices of all types of energy resources.

So far in Oklahoma, the price of natural gas has tended to follow the highs and lows in oil (Fig. 28, 29). However, the

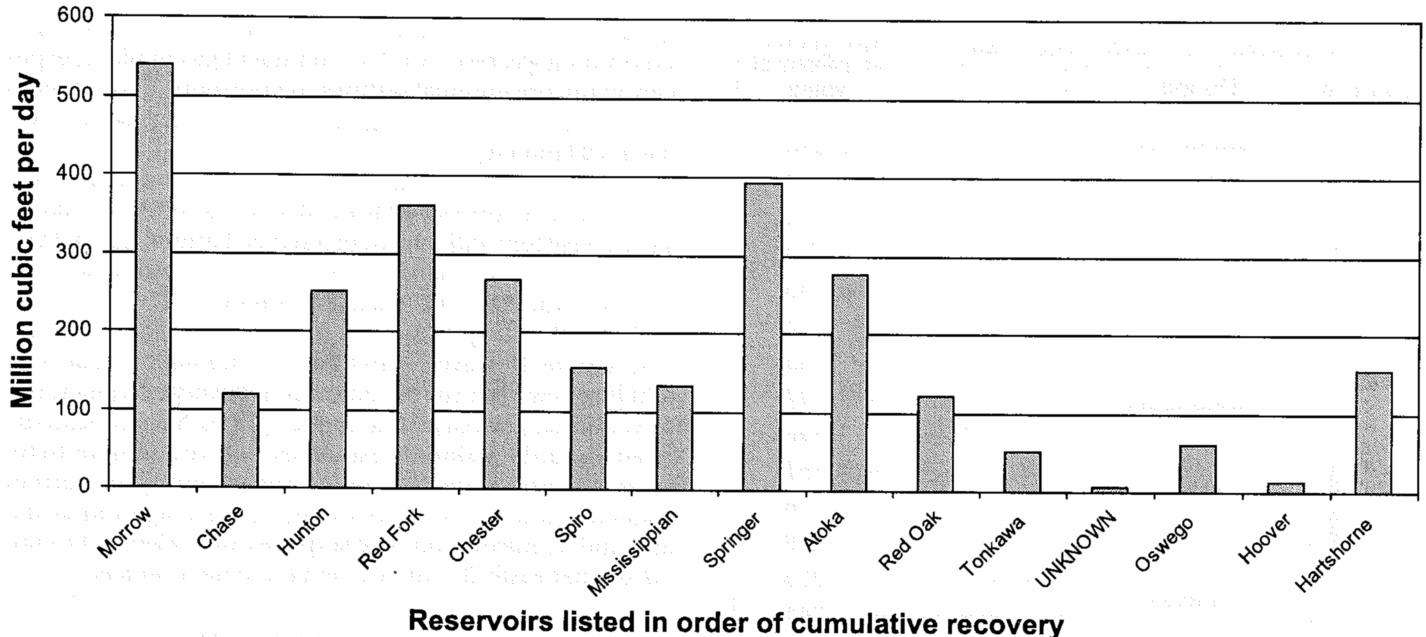


Figure 26. Daily gas production by reservoir (cumulative production >1 trillion cubic feet). Data from IHS Energy (2004). Compare with Figure 24.

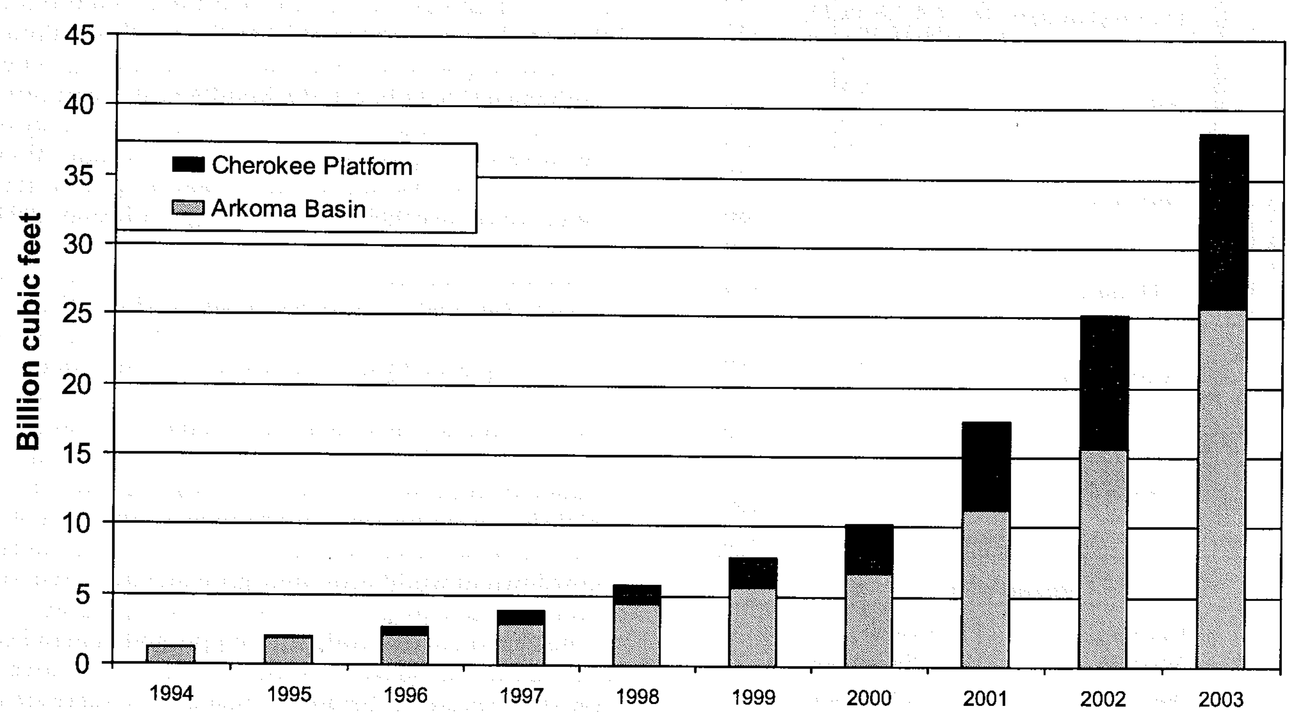


Figure 27. Production of Oklahoma coalbed methane. Data from Cardott (2005).

price of oil has been controlled by the global market for more than 30 years; in contrast, the gas market is restricted to North America. This isolation has been brought about by high levels of excess production capacity and by the high cost of importing large volumes of liquefied natural gas (LNG) into the U.S. from overseas. Thus, shortfalls in U.S. gas production have been met by imports, via pipeline, from Canada.

The current situation in natural gas is analogous to that for oil in the late 1960s, when the curves of supply and demand in the U.S. were about to meet. Differences include the seasonal nature of gas consumption and the dramatic effect winter weather can have on availability. Generally high gas prices in the last four years have spurred drilling, but only enough to slow the decline in production. A flat production

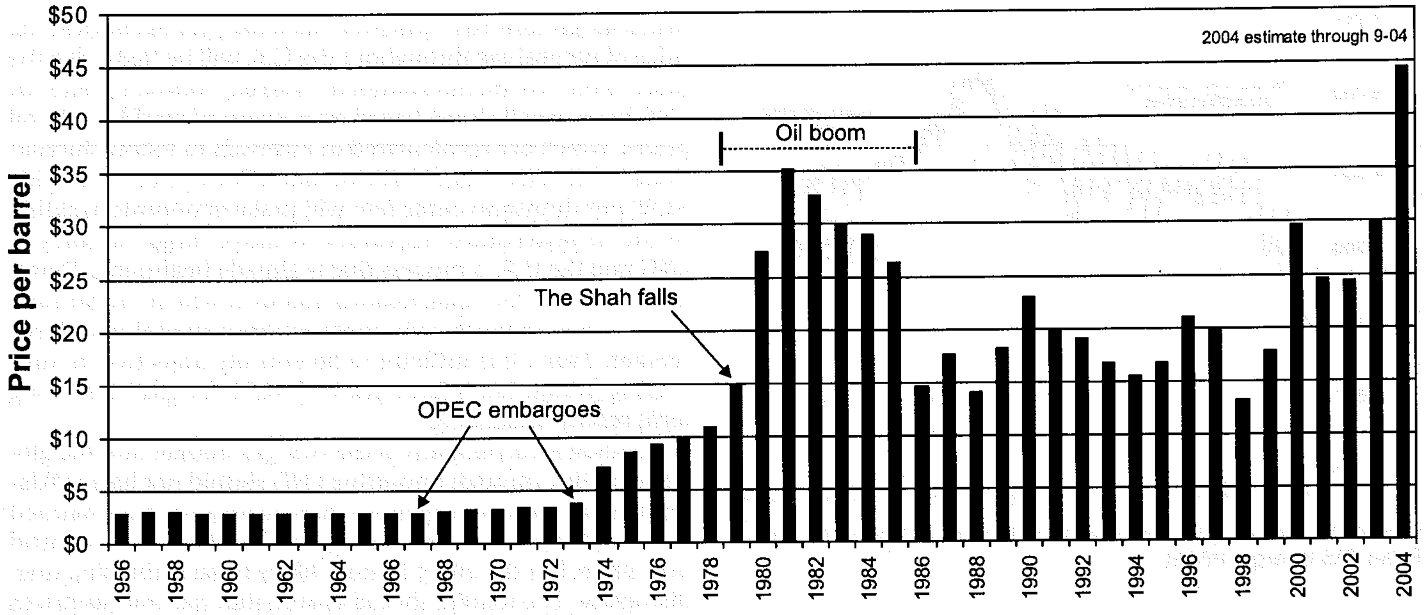


Figure 28. Average crude oil price (not adjusted for inflation) in Oklahoma. From Claxton (2004).

curve in the U.S. and Canada and rising demand have brought the market to the point where only warm winters have balanced supply and demand. This has been made possible by maintaining essentially maximum production year round, with the excess in summer going into storage for use in winter (Boyd, 2003).

The near equality of supply and demand is illustrated in Oklahoma by monthly gas production, two thirds of which is sent to other States. Production spikes in cold months were pronounced in the late 1980s, with seasonal demand varying as much as 2 BCF per day in a single annual cycle. Since the early 1990s these fluctations have been gradually reduced as the need for gas storage has forced maximum production almost year round (Fig. 30). Only since 1993 have the minor monthly spikes been apparent (they occurred in earlier years but were masked by much greater seasonal temperature changes then). Such spikes can be traced to the number of days in each month and are highlighted by a pronounced drop each February.

A consequence of the loss of excess productive capacity has been that the price of gas—in energy-equivalent units—now roughly equals that of oil. For decades, due to demand for oil and an oversupply of gas, gas has sold for a fraction of its heating value equivalent in oil. Through the 1950s oil was five to seven times as expensive as natural gas, and in the drilling boom of the late 1970s and early 1980s two to three

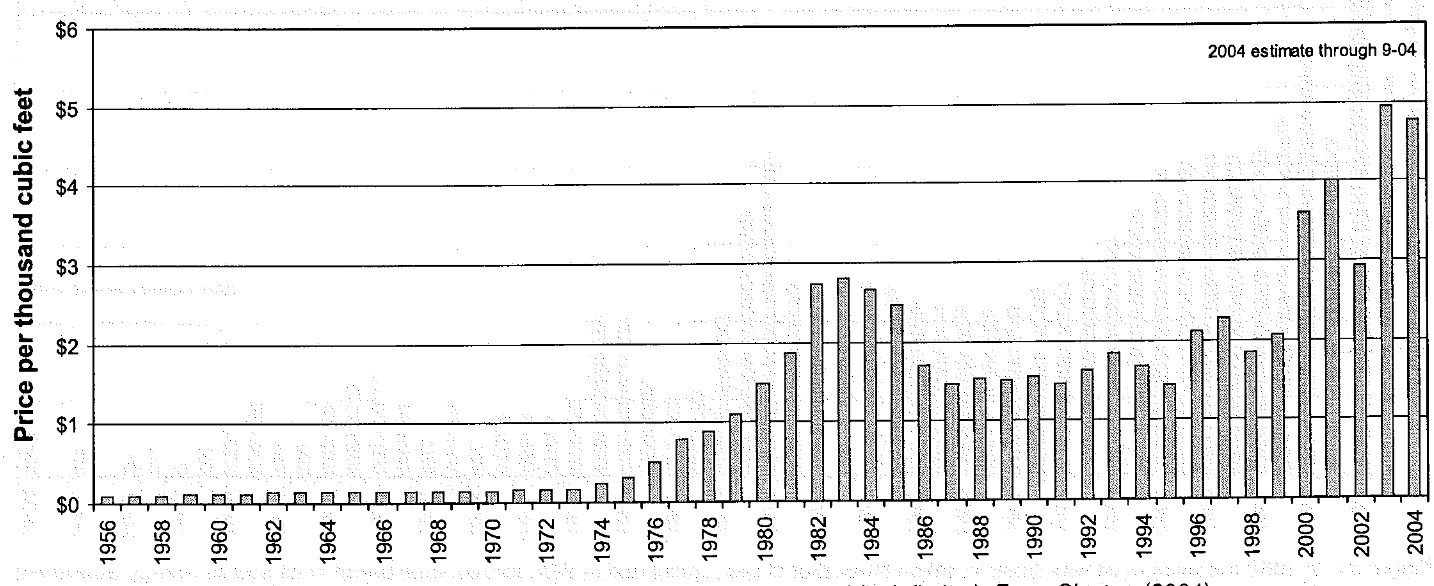


Figure 29. Average wellhead natural gas price (not adjusted for inflation). From Claxton (2004).

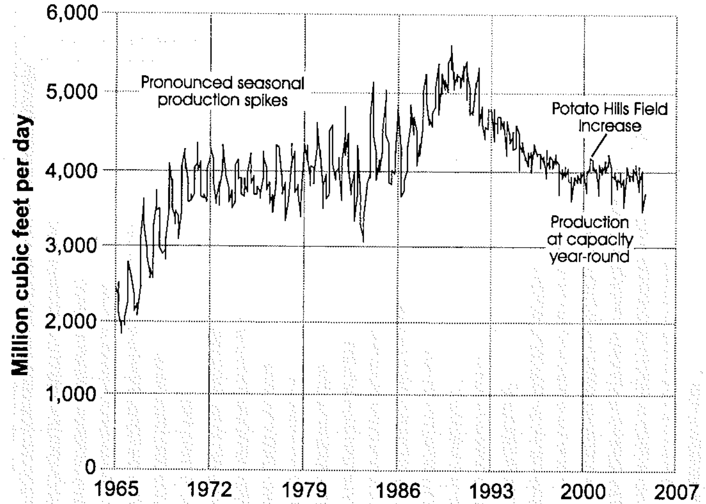


Figure 30. Natural gas production in Oklahoma (gas wells only). From IHS Energy (2004).

times as expensive (Fig. 31). However, as gas supply has lost ground to demand, oil's premium has nearly disappeared.

In the long term, imports of LNG will be necessary to meet increases in U.S. demand for natural gas. However, the country's inability to import large quantities of LNG from overseas means that for at least the next few years the gas supply should remain tight and average prices relatively high. Warm winters could cause short-term surpluses and reduce prices for a period of months, but equally possible are price surges during rapid storage drawdown in winter.

It will take years to build the port facilities and other infrastructure necessary to open the U.S. market to abundant overseas gas reserves. However, once the process begins, the price of natural gas throughout the U.S. will be tied—like the price of oil—to the international market. Contract prices for LNG have usually been based on a group of world crude-oil prices, which are recalculated at intervals to follow fluctuations in oil price. Many believe that a floor price of roughly $4.00 per thousand cubic feet will make economic building of the infrastructure necessary to move large volumes of LNG into the U.S., a process that is already beginning. That is also the price (for equal heating value) at which the burning of coal can economically meet environmental standards (Fisher, 2002). It is difficult to be entirely objective in forecasting prices, but a floor price of $4.00 for gas in the long term seems reasonable.

Gradual incorporation of the U.S. gas market into the global economy through importing LNG should not harm Oklahoma's gas industry any more than oil imports have harmed its oil industry. True, the change will reduce local control over price, but the effect is more likely to be stabilizing than disruptive. The market should ensure that natural gas prices do not rise (in the long term) above the price of clean-burning coal—which the U.S. has in abundance. Given that gas resources are widespread globally, producers must compete to preserve market share. Thus, supply disruptions great enough to reduce long-term demand should be rare.

Drilling

One effect of higher overall prices and the near parity of oil and gas has been a high level of drilling. Levels during the drilling boom (in the late 1970s and early 1980s) dwarf current drilling, but only because of a fundamental shift in the focus of drilling in Oklahoma. During the boom six to eight times as many new-field wildcats were drilled as are being drilled today, and ten times the number of dry holes.

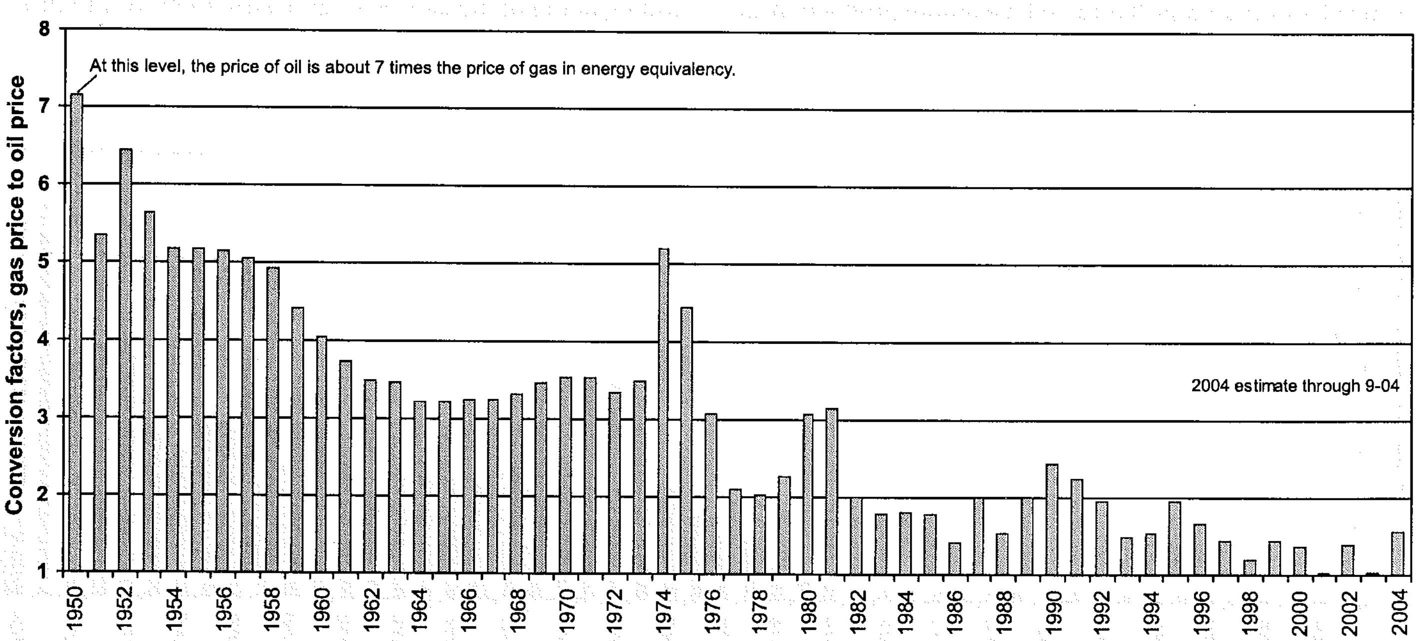


Figure 31. In 1950 the price of oil was close to seven times that of gas, calculated in BOE terms—one barrel of oil and its energy equivalent in gas (6,000 cubic feet). By 2003 the price ratio had fallen to near parity. Data from Claxton (2004).

This reflects the more conservative approach to drilling today, and also a gradual loss of areas for exploration. Since the boom years, the percentage of wells completed as dry holes has dropped markedly (Claxton, 2004). The 85% success rate for wells completed in 2003 shows the focus on development drilling today (Fig. 32).

In earlier times, premium oil prices made oil more attractive to the industry. In 1981, about 6,500 oil wells were completed in Oklahoma, accounting for more than half of all wells. By 2003 this number had dropped by 94%, to fewer than 400, reflecting a mere 18% of total drilling. In marked contrast, about 1,400 gas wells were completed in 2003, and more than 1,600 are projected for 2004. The current level of gas drilling is the highest ever, excepting 5 years at the peak of the drilling boom. Drilling for coalbed methane has augmented overall gas drilling from below 1,000 completions a year from 1989 through 2000 to an average of 1,439 a year since then (Claxton, 2004).

Continuous drilling activity is vital to maintaining production, especially for natural gas. Annual declines in oil and gas production in Oklahoma now average roughly 5,000 barrels and 50 MMCF per day. The numbers are large, but considering the volumes produced, the percentage declines are modest. According to a federal report, 22% of Oklahoma's gas production comes from wells less than 1 year old—an increase from 12% only 10 years ago (Energy Information Administration, 2004). Nearly a third of the State's gas comes from wells no more than 2 years old, and almost half from wells no more than 5 years old (IHS Energy, 2004). Oil production from new wells, although still significant, is only a quarter that of gas (Fig. 33).

Production

Prices drive drilling. Although a sustained drop in the price of either oil or gas is not expected, its effects through reduced drilling and accelerated well abandonments could devastate the petroleum industry. Barring a price collapse, what can be done to maintain production? In Oklahoma, as in the rest of the U.S., the industry's ability to increase production has been greatly diminished by a lack of major discoveries. The last major field (>1 TCF or >100 MMB) added in the State, Carpenter gas field, was discovered in the deep Anadarko Basin in 1970. With exploration unlikely to have a major impact on overall State production, lower risk and less-glamorous development projects are left to fill the gap.

Brightening the long-term prospects for oil in Oklahoma requires enhancing recovery in existing fields. The price of inaction is a continued decline in production. No one can say how the elevated prices seen since 2000 (Fig. 28) will affect industry thinking, but studies coordinated by the Oklahoma Geological Survey should uncover enough pilot projects to pique industry interest in identifying additional viable opportunities and pursuing them.

Oil remains important, but Oklahoma's energy future lies with natural gas. The State's geology is strongly favorable for gas, and because gas was developed later than oil its production will continue to be far stronger. Gas can be produced from greater depths and from rock with lower permeability than oil. As a result there are significant opportunities to add to reserves and production, both through development and exploration.

Economics and opportunity will always drive drilling, but maximizing gas production requires a combination approach. In the vast areas already producing, the effort to add new reservoirs in existing fields—especially deeper reservoirs—must continue. Infill drilling is also important in compartmentalized reservoirs or those with low permeability that are not being efficiently drained. Especially critical is the development of low-rate but long-lived unconventional reservoirs such as tight sandstones and shales, including areas with coalbed-methane potential. Finally, remote and geologically complex areas must be reevaluated—bearing in mind the example of

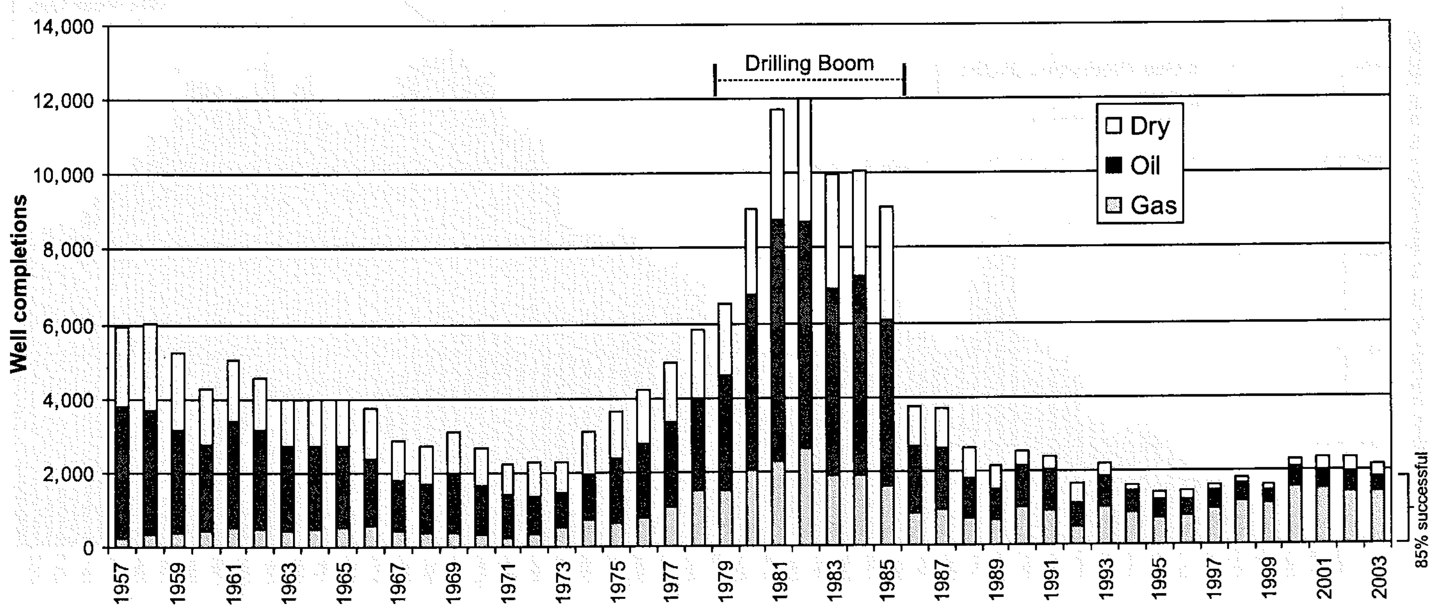


Figure 32. Well completions in Oklahoma—dry, oil, and gas. From Claxton (2004).

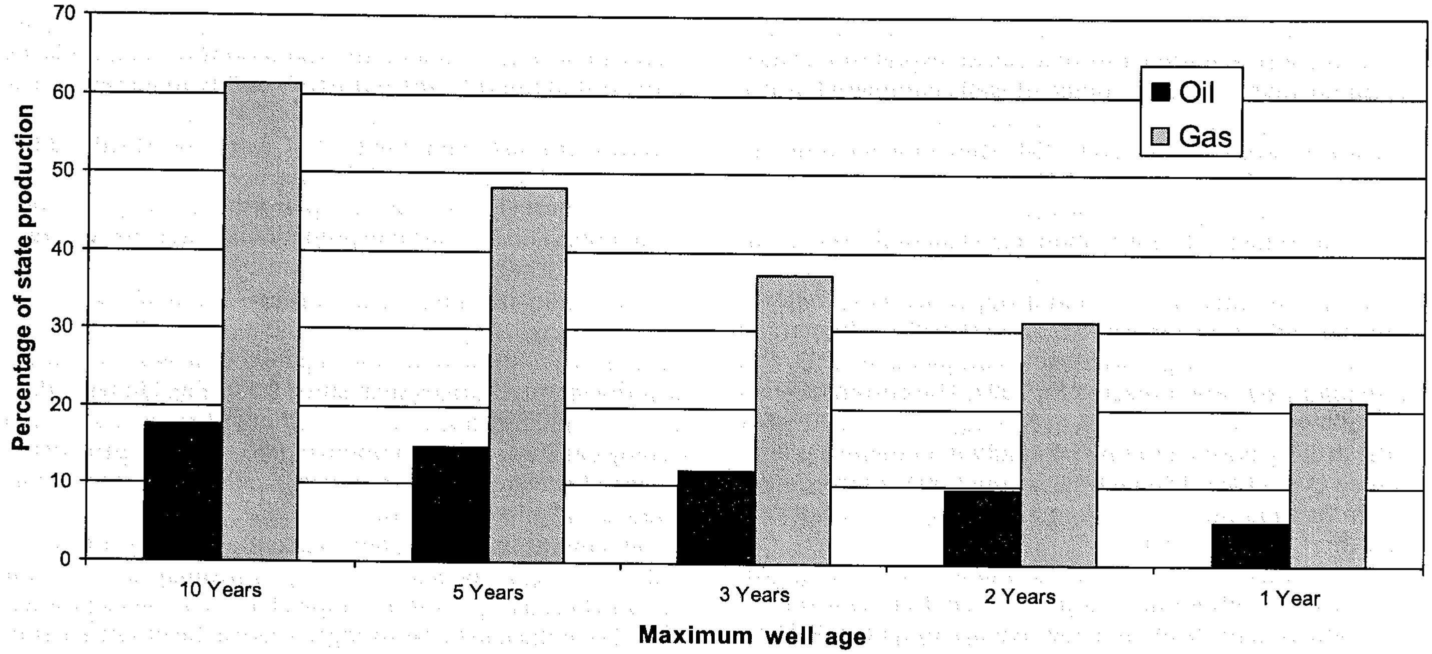


Figure 33. In 2003, wells less than 1 year old produced about 22% of Oklahoma's gas and 6% of its oil. Data from IHS Energy (2004).

Potato Hills Field. Such discoveries have the potential to reverse the decline in gas production, at least in the short term.

Rising prices have increased the economic viability of many formerly unattractive geologic plays, such as ultra-deep drilling in the Anadarko Basin and shallow coalbed-methane wells in the eastern half of the State. Wells with production rates that would have been unacceptably low 10 years ago are now being drilled by the thousand. As conventional gas opportunities and production decline, the industry will continue shifting its focus to less-permeable sands, shales, and coalbed methane. More than any other gas resource, unconventional reservoirs are the key to maintaining the long-term health of the industry.

Despite Oklahoma's image as an oil producer, natural gas has been its most important energy resource for decades, and today gas represents 80% of both drilling and total hydrocarbon production (Claxton, 2004). The State became primarily a gas producer (as measured by the standard

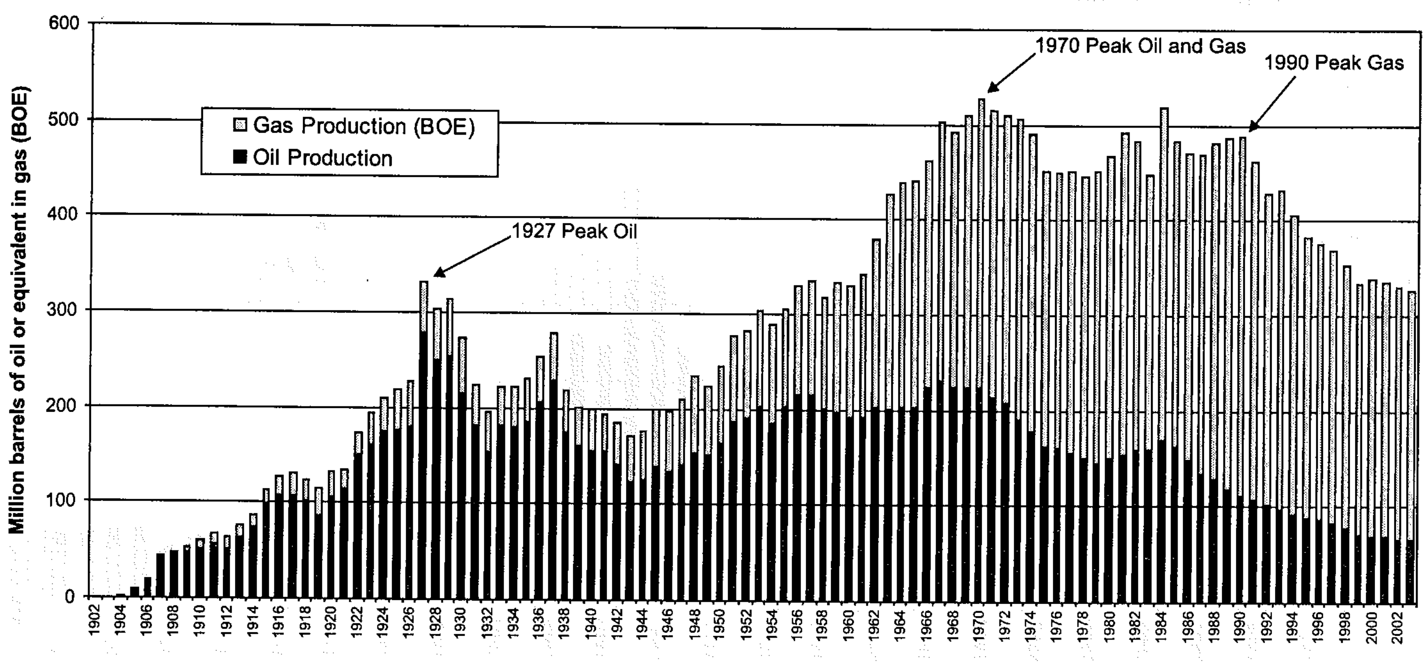


Figure 34. Total hydrocarbon production in Oklahoma (1 barrel of oil = 6,000 cubic feet of gas). From Claxton (2004).

equivalent energy) in 1963, and in 2000 cumulative gas production exceeded cumulative oil even though oil production began before statehood.

If oil and natural gas are combined (with the usual conversion, denoted as BOE for Barrels of Oil Equivalency), the 1927 peak in Oklahoma's oil production (333 MMBOE) is revealed as only an intermediate high in overall hydrocarbon production (Fig. 34). The all-time combined production high of 527 MMBOE came in 1970, a figure approached in 1984 with 518 MMBOE. From this perspective it is clear that the industry in Oklahoma is not in its twilight, but will remain very strong for decades.

Oil and gas satisfy the great bulk of energy demand in the U.S. and the rest of the world, and no alternative source is in sight which can change that (Boyd, 2003). Demand is rising with the growth of world economies, and the federal government has predicted that for the next 20 years petroleum's share of the global market will actually increase (Energy Information Administration, 2003). Use of oil will be capped when production reaches capacity, but global natural-gas reserves are enormous and remain largely untapped. In North America, the construction of facilities for importing LNG will enable overseas reserves to meet the growing U.S. demand for decades (Boyd, 2003). Meanwhile, an increasingly tight supply of world oil and domestic gas means that the long-term outlook for prices has never been stronger. As long as this situation continues, the economics for oil and gas projects will be excellent and activity will remain high. In Oklahoma, the challenge is to identify and exploit the myriad of oil and gas opportunities that have become economically viable in this environment.

ACKNOWLEDGMENTS

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• $12

Stratigraphic and Structural Evolution of the Ouachita Mountains and Arkoma Basin, Southeastern Oklahoma and West-Central Arkansas: Applications to Petroleum Exploration

Cooperative studies by state and federal geological surveys, universities, and industry have significantly improved our understanding of the geological history of the Ouachita fold-and-thrust belt and adjacent Arkoma foreland basin. Exploration for and development of natural gas and coalbed methane remain active, and new concepts in structural geology, stratigraphy, and sedimentology continue to be proposed and tested. This guidebook was prepared for field trips to west-central Arkansas and southeastern Oklahoma held as part of a three-day field symposium in October 2004 in Poteau, Oklahoma. Sixteen stops are described; the focus of the stops include interpretation of geophysical data for understanding large-scale structure, relation of surface exposures to well-log signatures and reservoir characteristics, significance of regional facies changes, interpretation of small-scale sedimentologic features for understanding depositional environments, among others. In addition to the stops, many of the natural gas and coalbed-methane fields crossed by the field-trip route are described.

OPEN-FILE REPORT 1-2005

• Neil H. Suneson and Richard D. Andrews

• 130 pages

• Photocopy

• $9

Guidebook to the Geology of the Cromwell Sandstone and Equivalent Units in the Lawrence Uplift, Arkoma Basin, Ouachita Mountains, and Ozark Uplift of Eastern Oklahoma

The Cromwell Sandstone is a highly productive petroleum reservoir in the Arkoma Basin and southeastern part of the Cherokee Platform. This publication was prepared for a field trip held in November 2003 in conjunction with a one-day workshop; it is a companion to OGS Special Publication 2003-2, *Cromwell Play in Southeastern Oklahoma* by Richard D. Andrews. This guidebook offers a detailed 231.1-mile road log covering eight stops, with discussion of geologic provinces crossed and a history of the complicated Morrowan stratigraphic nomenclature involved. Also described are oil and gas fields, old coal-mining districts, modern (now reclaimed) coal mines, active stone quarries, and historical sidelights along the field-trip route.

Circular 110, Guidebook 34, and OFR 1-2005 can be purchased by mail from the Survey at 100 E. Boyd, Room N-131, Norman, OK 73019; fax 405-325-7069. To mail order, add 20% to the cost for postage, with a minimum of $2 per order.

All OGS publications can be purchased over the counter at the OGS Publication Sales Office, 2020 Industrial Blvd., Norman; phone (405) 360-2886, fax 405-366-2882, e-mail ogssales@ou.edu. Request the OGS *List of Available Publications* for current listing and prices.

OGS Participates in Oklahoma Aggregates Association 4th Annual Meeting

The Oklahoma Aggregates Association (OKAA) held its 4th annual meeting February 8–9 at the Meridian Convention Center in Oklahoma City. Jim Rodriguez, executive director, announced that both producer and affiliate memberships had more than doubled since last year. James Kemp, chairman of the OKAA Board of Directors, honored past chairman James Allen "for his vision, drive, and inspiration" in the establishment and growth of the OKAA.

The 4th annual meeting was held in association with the Oklahoma Geological Survey. There were 201 attendees from industry, government, and business affiliates participating this year—an increase of 52% from last year. Activities included seminars, election of officers, and the OKAA Market Place trade show and exhibit. Seminar topics covered aggregates specifications and economics, aggregate base in highway construction, the environment, and health and safety.

A host of industry and government dignitaries participated in the meeting. Joy Wilson, president and CEO of the National Stone, Sand and Gravel Association, was the keynote speaker. In her address Wilson stressed society's dependence on the products of the aggregates industry saying that "aggregates make civilization possible." Aggregates are necessary for "helping to provide the basic necessities of life" such as water supplies, hydroelectric power, highways, and homes. She congratulated the OKAA for its "growth and efforts to educate the public and government officials about the aggregates industry."

Seminar speakers included Jan Kunze, chairman of the Oklahoma Mining Commission, who spoke about the common goals shared between the Oklahoma Department of Mines and the aggregates industry. Ed Lopez, district manager of the Mine Safety and Health Administration, spoke on the future of health and safety in the mining industry in the 21st century. Paul Zachary, deputy director of Public Works, City of Tulsa, spoke of how aggregates are used in public works projects.

The OKAA annual meeting field trip traveled to Mill Creek in Johnston County to view the U.S. Silica Company industrial sand quarry and processing plant, as well as the crushed stone operation of Texas Industries (TXI Operations, LP). The latter is a relatively new facility that started operation in 2002. The plant produces about 5,000,000 tons per year of crushed stone and manufactured sand. The majority is shipped to northern Texas aboard company-owned unit trains that make four trips south each day.

The OKAA sponsored an aggregates workshop the day after the annual meeting at the offices of Warren CAT. Rick Meininger from the Federal Highway Administration, best known for his monthly *Rock Products* column "Technically Speaking," presented a half-day classroom workshop on "Agg-base in Highway Construction." More than 50 scientists and engineers attended—one traveling more than 200 miles in order to participate.

On the following day, the OKAA hosted a barbecue luncheon at the State Capitol Rotunda for Oklahoma State legislators. More than 350 guests dined and heard presentations by James Kemp, Jim Rodriguez, and Senator Richard Lerblance (D, District 7), chairman of the Senate Committee on Energy and Environment. Six producer members had exhibits, along with the following government and industry affiliates: Oklahoma Department of Mines, Oklahoma Department of Transportation, Oklahoma Geological Survey, Oklahoma Miner Training Institute, Oklahomans for Safe Bridges and Roads, and Mine Safety and Health Administration.

The OKAA Market Place exhibits increased more than 50% from the 3rd annual meeting. Exhibitors included affiliate members and other companies supplying the aggregates industry with materiel, equipment, and expertise. Government agencies associated with the industry

Photos by Sue Crites

Participants examine the brilliant white sand in abundance at the U.S. Silica industrial sand quarry.

Photo by Jane Weber

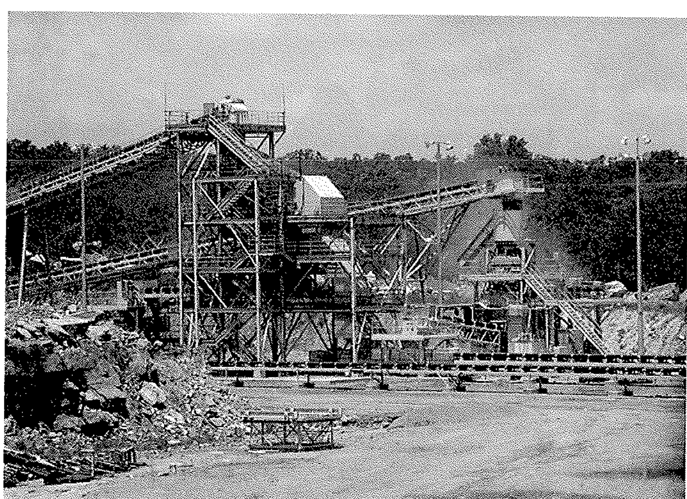
The award-winning Future City Team from St. Philip Neri School in Midwest City, Oklahoma, presented their exhibit at the OKAA Market Place. They brought home a 4th-place finish in the National Engineering Week Future City Finals, a nationwide event. Shown *(left to right)* are Thalia Nguyen, Alyssa Grossen, and Catherine Salazar.

also exhibited. An exhibit by the Future City Team from St. Philip Neri School in Midwest City was the highlight of the Market Place. The team, winners of the Statewide Future City Competition, represented Oklahoma at the national competition in Washington, D.C., during National Engineering Week Future City Finals and finished in 4th place.

The OKAA was first incorporated in July 2001. The Association was founded to provide information and assistance to producers and their associates in several critical areas, including product quality, specifications and requirements, safety issues, environmental concerns, and government regulations.

Today, the OKAA has 29 producer and 37 affiliate member companies with offices in Oklahoma City at 3500 North Lincoln Boulevard. There are two types of membership:

Photo by Russ Carter; courtesy *Rock Products*



TXI Operations, LP, Mill Creek crushed stone operation in Johnston County, Oklahoma, began shipping product in July 2002. This photograph shows a portion of the elaborate crushing and screening operation.

aggregate producers (29 members) and affiliate companies serving the aggregates industry (37 members). The Association continues to grow, and it plans to continue its membership drive in 2005.

Oklahoma produced nearly 75 million tons of aggregates in 2002 valued at more than $289 million. To put this figure in perspective, that's enough aggregate to construct a four-lane highway from Oklahoma City to Washington, D.C., 130,000 homes, and 3,500 schools and hospitals. According to the Oklahoma Geological Survey, Oklahoma ranks second in per capita aggregates production, supplying just over 13 tons per person. Aggregate producers directly provide 1,700 jobs for Oklahomans.

Aggregates include all types of crushed stone, gravel, and sand. They provide the basic materials upon which the building blocks of civilization rely. Most people are familiar with the role aggregates serve in asphalt and portland cement concretes; so wherever you see construction in progress—such as residential, commercial, industrial, or government sites—aggregates are being used. Highways, high-rise buildings, railroad beds, airport runways, houses, hospitals, schools, and shopping centers all contain aggregates. Each one of us requires more than 1.64 million pounds of stone, sand, and gravel over our lifetimes.

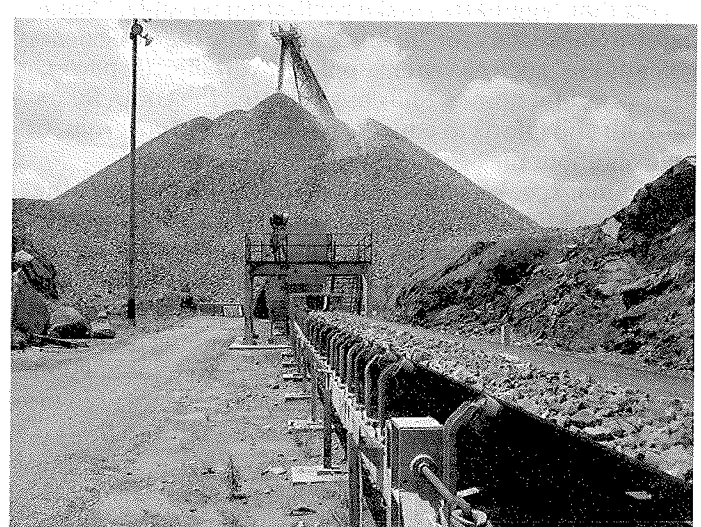


Photo by Russ Carter; courtesy *Rock Products*

Oklahoma minus-4-in. crushed stone is conveyed to the stock pile from beneath the primary crusher surge pile at the TXI Operations, LP, Mill Creek Operation in Johnston County, Oklahoma.

The OKAA is an associate member of the National Stone, Sand and Gravel Association; visit the Web site at **www.nssga.org** to learn more about aggregates and our reliance on them. More information about the Oklahoma Aggregates Association can be found at **www.okaa.org**. To learn more about the mineral resources of the State of Oklahoma visit the Oklahoma Geological Survey's Web site at **www. ogs.ou.edu.**

—*Stanley T. Krukowski*

upcoming meetings

JUNE

American Association of Petroleum Geologists, Annual Convention, "Exploring Energy Systems," June 19–22, 2005, Calgary, Alberta, Canada. Information: AAPG Convention Dept., P.O. Box 979, Tulsa, OK 74101; (888) 945-2274 ext. 617 (USA and Canada only) *or* (918) 560-2617; fax 918-560-2684; e-mail: convene@aapg.org. Web site: http://www.aapg.org/calgary/.

Rocky Mountain Association of Geologists & Petroleum Technology Transfer Council, Coalbed Methane Symposium, June 30, 2005, Denver, Colorado. Information: Rocky Mountain Association of Geologists, 820 16th St., Suite 505, Denver, CO 80202; (303) 573-8621; fax 303-628-0546; e-mail: admin@rmag.org. Web site: http://www.rmag.org/events.

AUGUST

Geological Society of America & Geological Association of Canada, "Earth System Processes 2," August 8–11, 2005, Calgary, Alberta, Canada. Information: Deborah Nelson, Geological Society of America, P.O. Box 9140, Boulder, CO 80301; (303) 357-1014; fax 303-357-1071; e-mail: dnelson@geosociety.org. Web site: http://www.geosociety.org/esp2.

SEPTEMBER

The Society for Organic Petrology (TSOP), Annual Meeting, September 11–14, 2005, Louisville, Kentucky. Information: Jim Hower, Center for Applied Energy Research, 2540 Research Park Dr., Lexington, KY 40511; (859) 257-0261; fax 859-257-0360; e-mail: hower@caer.uky.edu. Web site: http://www.tsop.org.

American Association of Petroleum Geologists, International Conference and Exposition, September 11–14, 2005, Paris, France. Information: AAPG Convention Dept., P.O. Box 979, Tulsa, OK 74101; (888) 945-2274 (USA and Canada only) *or* (918) 560-2679; fax 918-560-2684; e-mail: convene2@aapg.org. Web site: http://www.aapg.org/paris/.

Interstate Oil and Gas Compact Commission, Annual Meeting, September 18–20, 2005, Jackson Hole, Wyoming. Information: IOGCC, P.O. Box 53127, Oklahoma City, OK 73152; (405) 525-3556; fax 405-525-3592; e-mail: iogcc@iogcc.state.ok.us. Web site: http://www.iogcc.state.ok.us.

AAPG Mid-Continent Section Meeting

September 9–13, 2005

Oklahoma City, Oklahoma

Target the Hidden Potential in the Wild West

Hosted by the Oklahoma City Geological Society, Oklahoma City will be the host site for the 2005 Mid-Continent Section Meeting of the American Association of Petroleum Geologists.

The technical program will cover a wide range of topics that will guide the geoscience community to truly "Target the Hidden Potential in the Wild West." The event will be held in the Cox Business Services Center and the Renaissance Hotel, adjacent to the historical "Bricktown" area of downtown Oklahoma City.

Oral sessions, short courses, posters, and field trips will broaden the education of everyone in attendance. Topics that are expected to be presented include: Exploration in Mature Areas, Seismic Exploration, Shale Gas Plays, Unconventional Exploration Methods, New Plays, Production Techniques, Mineral Exploration, and Coalbed Methane Exploration.

Information:

Michael Root
TerraQuest Corp.
1015 Waterwood Pkwy., Suite J
Edmond, OK 73034
(405) 359-0773
fax 405-341-0115
e-mail: mroot@weatherbank.com
Web site: http://www.ocgs.org.

AAPG Spring Student Expo hosted by OU

The American Association of Petroleum Geologists held its fifth annual Spring Student Expo at the University of Oklahoma Sarkeys Energy Center on March 10–12, 2005. The Expo offers mutually beneficial opportunities for geoscience students interested in energy careers to showcase their work and to network with industry representatives who formally recruit on campus.

The 2005 Expo was attended by 166 students from 42 universities representing 22 states. Abstracts for poster presentations pertaining to Oklahoma geology are reproduced here.

Presented at the 2005 Student Expo:

Processing, Inversion, and Interpretation of a 3D Seismic Data Set from the Ouachita Mountains, Oklahoma

ABUDUWALI AIBAIDULA and *GEORGE A. McMECHAN*, University of Texas at Dallas

A data processing to obtain common angle stacks for simultaneous elastic impedance inversion is performed on a 3D land data set from the Ouachita frontal thrust zone in southeastern Oklahoma. To maintain true relative amplitudes, 3D spherical spreading corrections, surface consistent gain correction and a predictive deconvolution were applied. A 3D prestack time migration was performed to partly overlapped (0–12°, 10–22°, 20–32°) common angle gathers and provided a relatively true amplitude preservation data.

The simultaneous elastic impedance inversion is performed on the data. P-velocity (Vp), S-velocity (Vs), density logs, and seismic data are input to the inversion. The inversions produce P-wave and S-wave impedance sections (Ip and Is), from which Lamé parameter × density ($\lambda\rho$, and $\mu\rho$) sections are derived. The Ip, Is and $\mu\rho$ data provide a separation between the clastics and carbonates. Lithologies were also confirmed by using density (ρ) – porosity (φ) and gamma ray (GR) – porosity (φ) crossplots. Vp/Vs and $\lambda\rho$ data provide an estimate of hydrocarbon distribution within the target. These indicators all provide similar spatial patterns of areas of high gas potential and are consistent with the gas occurrence observed in a well.

Depositional Facies and Diagenesis of the Carlton Member (Kansas) and the Midco Member (Oklahoma) of the Wellington Formation (Sumner Group, Leonardian)

J. D. HALL and *S. J. MAZZULLO*, Wichita State University

Outcrops of the Carlton Limestone (Kansas) and the Midco Member (Oklahoma) exposed on the surface in Kansas (Sumner and Dickinson Counties) and Oklahoma (Noble and Kay Counties) were studied to determine their depositional and diagenetic history. This study combines paleontological evidence with sedimentology, stratigraphy, and diagenesis to propose a depositional environment and diagenetic history. Syndepositional diagenetic features observed in the dolomites such as desiccation cracks, fenestrae, meniscus calcite cement, and displacive halite hopper crystals indicate deposition in a shallow periodically emergent hypersaline environment. Fossils found such as *Myalinella meeki, Lingula, Paleolimulus, Permophorous,* and red algae suggest deposition in a marginal-marine environment. Previously the dolomites of the Carlton and the Midco were considered to be lacustrine sediments deposited in coastal freshwater ponds (Carlton — see Dunbar, 1924) or saline playas (Midco — see Carpenter, 1947) following the retreat of a regressing sea. These interpretations were based primarily on the presence of fossil assemblages normally associated with fresh water and terrestrial environments. However, faunal evidence combined with sedimentology and stratigraphy suggests a marginal-marine environment for several dolomites within the Carlton and the Midco.

The Mulberry Fault: Structure, Timing, and Influences on Natural Gas Production in the Arkoma Basin

ALEC LONG, University of Arkansas

The Mulberry fault is a major east-trending, down-to-the-south, fault zone that defines the northern margin of the Arkoma basin. This fault offsets many of the natural gas producing formations in the basin from the Cambro-Ordovician Arbuckle, through the Pennsylvanian Lower/Middle Atoka Formation. A three-phase study focusing on the fault's structural characteristics, its hydrocarbon-trapping tendencies, and the timing of movement along the fault are the goals of this investigation.

The Arkoma basin is an elongate foreland basin that extends as a surface feature from the Mississippi Embayment in central Arkansas to southeastern Oklahoma, where it is buried by Mesozoic strata. The Mulberry fault zone was a direct result of extensional tectonics beginning in the early Mississippian and continuing through the early/middle Atokan. The obduction of a southern landmass onto the North American craton margin resulted in a tensional stress field, which initiated flexural bending of the crust manifesting itself as the series of normal faults including the Mulberry.

Producing and non-producing wells are positioned both north and south of the Mulberry fault trace. The dip of the fault appears to vary along strike resulting in an undulating fault surface pattern. A greater understanding of the varying structural geometry is a major thrust of this investigation. Faults also have the ability to trap hydrocarbons due to favorable juxtaposition of stratigraphic layers as a result of movement along the fault. The Mulberry fault is generally considered to be a poor trap for hydrocarbons by those in the petroleum industry. An investigation into the production of wells directly influenced by the fault will hopefully lead to concrete conclusions on the fault's trapping characteristics. It is assumed that movement along the Mulberry fault occurred in one major pulse. However it is also possible that there were several pulses of movement that resulted in the Mulberry fault, as it is today. Identification of anomalous thickening trends throughout the Atokan section should allow for the validation of the single or multiple theories of movement.

Natural Brine Pump in the Tallgrass Prairie Preserve

SOPHIA RODRIGUEZ, NATHAN BUCHANAN, CAILEAN CARLBERG, JULIANA GENDRON, KATHLEEN McKEE, and *EMILY STARKE*, University of Tulsa

Surface and subsurface contamination by produced oilfield brines is an ongoing problem within the Tallgrass Prairie Preserve. In summer 2004, Geosciences Summer Undergraduate Research

Program (GSURP) students evaluated one of the oldest spills in Tall Grass, circa 1920, Site 3. We found evidence of permanent scaring due to the original surface spill at the site. We first characterized the site attempting to understand the lack of auto-remediation, and then we proposed a remediation plan.

The study included developing a stratigraphic cross-section, surface mapping (using DGPS), a field electrical-conductivity survey, and soil sampling for pH, x-ray diffraction, SEM, and IC (dissolved solids) analyses. During the investigation it became apparent that another source of brine contamination existed in conjunction with the original spill.

Field mapping indicates plant-kill zones corresponds to the base of sands and limes in the Upper Pennsylvanian strata. Conductivity mapping verifies the main subsurface transport for brine runs along fractures and sand/shale contacts. From the evidence, we conclude a continuous supply of brine runs along fractures in the subsurface with the original well as the source. The diffusion process functions as a "natural brine pump."

The brine pump models a simple one-dimensional diffusion equation; the "brine pump" hypothesis fits existing data in the Preserve and explains a perched brine layer in the area. We propose further modeling and field-testing of the hypothesis to determine whether bridge plugs in older wells might attenuate contamination and allow remediation of older scars and of near-surface brine contamination in the Preserve.

Presented at the 2004 Student Expo:

Geometry of Late Paleozoic Thrust Faulting in Southwestern Hartshorne Gas Field, Arkoma Basin, Southeast Oklahoma

OSMAN KALDIRIM, Oklahoma State University

The Arkoma Basin is classified as a foreland basin of early to middle Pennsylvanian Ouachita contractional Orogeny which formed the Ouachita Mountains of southeastern Oklahoma and eastern Arkansas. The Ouachita Mountains are characterized by tight folds and thrust faults whereas the Arkoma Basin is recognized by its broad to open folds.

This study is aimed to determine the structural geometry of the Pennsylvanian thrusting within the Hartshorne SW, Savanna, Ti, and Pittsburg quadrangle of the Frontal Ouachita–Arkoma Basin transition zone in southeastern Oklahoma. Within this study six balanced structural cross-sections are constructed to determine the geometry of the Late Paleozoic thrust system. The surface geologic information is obtained from the Oklahoma Geological Survey. The subsurface data are gathered from the wire-line logs that were obtained from the Oklahoma City Log Library along with completion reports and scout tickets.

To yield accurate geometry in the study area, the wire-line signatures for the Hartshorne, Fanshawe, Red Oak, Marker 'A, B, C, E, X', and the Spiro Sandstone were used. The Wapanucka Limestone is included in the Spiro Sandstone because of varying thickness of the limestone within the study area.

The cross-sections suggest the presence of a triangle zone between the Berlin Fault to the northwest and the Choctaw Fault to the southeast. The footwall of the Choctaw Fault zone contains duplex structures and associated horses above the Woodford and Springer detachments with the Lower Atokan Detachment as a roof thrust. The cross-sections are restored with using the Spiro as the keybed to determine the amount of shortening within the study area. The restorations show an average of 56% shortening within the area.

The Implications of Tectonic Activity on Hydrocarbon Migration, Cement Field, Cement, Oklahoma

H. JEROME MURPHY and *PAUL PHILP*, University of Oklahoma

Petroleum geochemistry is an important tool in the petroleum industry, through its applications in both the exploration and production phases of oil and gas field development. The focus of this project is to use geochemical, geological and petrophysical methods to assess the potential of the Cement Fault and Thrust as barriers to hydrocarbon flow or as migration pathways, as this could potentially improve production strategies for companies operating here. The Cement Oil Field has been producing hydrocarbons since 1916 and, as one might expect, its production has decreased as it has matured.

In this study, well logs were used in producing geologic structure maps on several horizons, to assess the location of the Cement Fault and Thrust throughout this study area. Several geochemical techniques were employed in the characterization of 13 oils that were collected from wells drilled in the resulting fault blocks. Ultimately, star diagrams were produced to determine whether or not the oils found in these reservoirs are communicating via these faults or are compartmentalized. If the star diagrams have similar values, then the faults may potentially be acting as conduits. However, if these values differ significantly, then the faults may be acting as seals. Thus, by combining these geochemical and geologic data, one is able to gain invaluable information about the migration scenario of these hydrocarbons.

Architectural Elements and Composition of Turbidite Deposits, Jackfork Group, Eastern Oklahoma

GLORIA A. ROMERO, University of Oklahoma

This poster presents the findings of a subsurface study of the Jackfork Group turbidites (early Pennsylvanian), Potato Hills, Oklahoma. The evaluation of these deposits is inaccurate because commonly bed thicknesses are below vertical resolution of the standard logging tools. In addition, structural complexity and turbidite facies lateral variability makes current correlations and interpretations of conventional subsurface data difficult. The goals of this study are to (1) determine the relationships between turbidite architectural elements, dipmeter trends and reservoir sand characteristics, to (2) establish criteria for developing a well-log based stratigraphic framework for sub-regional stratigraphic analysis, and to (3) recognize reservoir quality variations throughout the sequence and how this affect the gas production.

Two gas-producing wells have been studied in detail utilizing conventional logs, borehole images, dipmeter logs, and cuttings. These data provided a means to identify major faults through the Jackfork, and thus to subdivide the wells into discrete fault-bounded stratigraphic intervals. Sedimentary features that were not discernible on conventional well logs were identified from the borehole image and dipmeter patterns. Graphic techniques such as Cumulative Dip plots, Vector plots, Modify Fischer plots and Borehole image interpretation were used to identify dip trends and differentiate architectural elements. Based on macroscopic and microscopic cutting description three main sandstone types were identified: highly cemented, friable and siderite cemented sandstones. Bitumen is present in all sandstone types. Architectural elements differentiation associated with sandstone characterization guide us towards reliable reservoir quality and lateral continuity prediction, understanding the factors that control the gas production in the area.

notes on new publications

Hydrology and Ground-Water Quality in the Mine Workings within the Picher Mining District, Northeastern Oklahoma, 2002–03

USGS Scientific Investigations Report 2004-5043

In this 62-page report, authors Kelli L. DeHay, William J. Andrews, and Michael P. Sughru describe the hydrology of the mine workings and the ground-water quality in 2002–03 in the Picher mining district of northeastern Ottawa County, Oklahoma—a major site of mining for lead and zinc ores from about 1900 to the mid-1970s. The primary source of lead and zinc were sulfide minerals disseminated in the cherty limestones and dolomites of the Boone Formation, which comprises the Boone aquifer, an important aquifer in the region and the source of part of the base-flow to streams. Mining activities led to contamination of ground water and surface water by sulfate, iron, lead, zinc, and several other metals. The USGS, in cooperation with the Oklahoma Department of Environmental Quality, investigated hydrology and ground-water quality in the mine workings in the mining district as part of a process to aid water managers and planners in designing remediation measures that may restore the environmental quality of the district to pre-mining conditions. Several thousand people continue to live in the mining district and nearby areas. Recent cleanup of contaminated soils by the U.S. Environmental Protection Agency and public education campaigns by state and local governments have led to a 50% reduction in elevated blood-lead concentrations in local children.

Order SIR 2004-5043 from: U.S. Geological Survey, Water Resources Division, 202 N.W. 66th St., Bldg. 7, Oklahoma City, OK 73116; phone (405) 843-7570; fax 405-843-7712. A limited number of copies are available free of charge. This report is also available online at http://water.usgs.gov/pubs/sir/2004/5043/.

Chloride in Ground Water and Surface Water in the Vicinity of Selected Surface-Water Sampling Sites of the Beneficial Use Monitoring Program of Oklahoma, 2003

USGS Scientific Investigations Report 2004-5060

The Beneficial Use Monitoring Program (BUMP), under the direction of the Oklahoma Water Resources Board (OWRB), consists of sampling 100 surface-water sites 10 times annually. The program monitors whether concentrations of streams and lakes meet or exceed beneficial-use standards established by the State. The OWRB reported exceedances of beneficial-use standards for chloride at 11 surface-water sampling sites from January to October 2002. The U.S. Geological Survey, in cooperation with the Oklahoma Department of Environmental Quality (ODEQ), conducted a study to determine the chloride concentrations in ground water in the vicinity of BUMP surface-water sampling sites not meeting beneficial-use standards for chloride and compare chloride concentrations in ground water and surface water.

In this 35-page report, authors Shana L. Mashburn and Michael P. Sughru present chloride concentrations in local ground water adjacent to 11 chloride-impaired BUMP surface-water sampling sites and compare chloride concentrations of the ground-water sites to chloride concentrations of the BUMP surface-water sampling sites. The ground-water sampling sites were placed in proximity to the 11 surface-water sampling sites designated impaired by chloride by the OWRB. Two surface-water sampling sites were located on the Beaver River (headwaters of the North Canadian River), three sites on the Cimarron River, one site on Sandy Creek, one site on North Fork Red River, and four sites on the Red River.

Order SIR 2004-5060 from: U.S. Geological Survey, Water Resources Division (see contact information above). This report is also available online at http://water.usgs.gov/pubs/sir/2004/5060/.

Water Quality and Possible Sources of Nitrate in the Cimarron Terrace Aquifer, Oklahoma, 2003

USGS Scientific Investigations Report 2004-5221

Water from the Cimarron terrace aquifer in northwest Oklahoma commonly has nitrate concentrations that exceed the maximum contaminant level of 10 milligrams per liter of nitrite plus nitrate as nitrogen (referred to as nitrate) set by the U.S. Environmental Protection Agency for public drinking water supplies. Starting in July 2003, the U.S. Geological Survey, in cooperation with the Oklahoma Department of Environmental Quality, conducted a study in the Cimarron terrace aquifer to assess the water quality and possible sources of nitrate. This 60-page report, written by Jason Masoner and Shana L. Mashburn, describes the results of the study. Forty-five ground-water wells in the aquifer were randomly selected. Wells were grouped into two land-use categories: agricultural areas and grassland areas. Multiple lines of evidence from chemical analysis of nitrate, nitrogen isotopes in nitrate, pesticides (indicative of cropland fertilizer application), and wastewater compounds (indicative of animal and human wastewater) were used to indicate possible sources of nitrate in the aquifer.

Order SIR 2004-5221 from: U.S. Geological Survey, Water Resources Division (see contact information above). This report is also available online at http://water.usgs.gov/pubs/sir/2004/5221/.

Oklahoma abstracts

The Oklahoma Geological Survey thanks the American Association of Petroleum Geologists and the Geological Society of America for permission to reprint the following abstracts of interest to Oklahoma geologists.

Assessing Subeconomic Natural Gas Resources in the Anadarko and Uinta Basins

KELLY K. ROSE, ASHLEY S. B. DOUDS, JAMES A. PANCAKE, H. R. PRATT, and *RAY BOSWELL,* EG&G Technical Services, 3604 Collins Ferry Rd., Morgantown, WV 26505

Natural gas resource assessments are a commonly used tool by industry, academia, and government to understand the current and near-term recoverability of the nation's resource base. However, these resource assessments tend to be static pictures of a resource that is, in reality, highly dynamic. Assessment based on gas-in-place (GIP) analysis and iterative modeling of resource recoverability under a variety of technology/policy scenarios provide improved means to identify the most promising approaches to expanded resource recoverability.

This study collects detailed, spatially distributed, geologic and engineering information on key segments of the nation's under-utilized gas resource base. Phase one of this study, completed February 2003 for the DOE's National Energy Technology Laboratory, provided detailed GIP resource assessments for the Greater Green River and Wind River basins. Phase two of this effort focuses on the Tertiary and Cretaceous sections of the Uinta basin, and the mid-Pennsylvanian and older strata of the deep Anadarko basin.

Through the correlation and analysis of hundreds of log suites, and drilling & completion records, key geologic and engineering parameters including depth, potential pay thickness, porosity, pressure, water saturation, and temperature were determined and used to produce detailed characterizations of the GIP for each unit analyzed. In conjunction with DOE modeling efforts and permeability analyses, this study provides a detailed, disaggregated, geologic and engineering database for modeling the impact of different technology scenarios on the future of U.S. natural gas exploration, production, and supply.

Reprinted as published in the American Association of Petroleum Geologists *2004 Annual Convention Abstracts Volume,* v. 13, p. A120.

Increasing Compliance Among Small Independent Oil and Gas Producers for Remediation of Brine Spills: KISS and Cost

KERRY L. SUBLETTE, Dept. of Chemical Engineering, University of Tulsa, 600 South College Ave., Tulsa, OK 74104

In Oklahoma we have the cumulative equivalent of an Exxon-Valdez–size brine spill every two years based on reported spills. Many of these spills are poorly remediated, if they are remediated at all. The result is a significant loss of natural resources in terms of soil productivity and salt-impacted surface water and groundwater. At IPEC we have been asking why this is the case. In my experience most small producers want to do the right thing—they want to clean up the spill in a responsible manner. The problem is that they don't always know what to do. Some become immobilized, some become easy prey for snake oil salesmen, and some try to remediate the spill but are unsuccessful.

At IPEC we have developed remediation methods for brine spills that are easy to understand and low in cost. We have also developed tools to aid the small producer in monitoring the remediation process and protecting surface waters. These tools are distributed free-of-charge and IPEC holds free workshops throughout Oklahoma and Arkansas to teach small producers how to remediate these spills without busting their budgets. We believe that reducing the cost of regulatory compliance increases regulatory compliance, protecting our natural resources and keeping the producer in business. IPEC brine remediation methods and tools will be discussed in this presentation.

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Environmental Releases from E&P Operations in Oklahoma: Type, Volume, Causes and Prevention

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The 17,093 releases of fluids from exploration and production (E&P) operations in Oklahoma as reported to the Oklahoma Corporation Commission (OCC) for the ten-year period from 1993 to 2002, resulted from both preventable and non-preventable causes. The primary origin of oil and saltwater releases were line leaks (34.8%), tanks (32.7%), wellheads (12.9%), abandoned/unplugged wells (8.8%), purging wells (5.8%) and surface equipment (4.9%). Important causes of fluid releases were, in order of decreasing number, tank overflows, intentional dumping or illegal activity, storms, lightning strikes, third-party accidents, dike overflows, pit overflows and the actions of livestock or wildlife. Approximately 30% of all releases resulted in reported damage to surface water (15.3%), crops or livestock (11.6%), groundwater (2.8%), fish or wildlife (0.4%). For this period, 47.7% of all E&P complaints to OCC involved the release of fluids, and, on an annual basis, complaints involving the release of fluids comprised an essentially constant percentage of the total number of complaints (46.1% to 52.1% of total complaints received). Releases identified as involving oil and/or saltwater comprised 68.7% of all releases. Quantified releases of oil had a median volume of 10 bbls while quantified releases of saltwater had a median volume of 40 bbls. For those releases in which volume of both oil and saltwater were quantified, the volume of saltwater spilled was approximately 76% of the total volume of oil and saltwater released.

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2003 Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of USGS Province 045, Fort Worth and Hardeman Basins, Texas and Oklahoma

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Three total petroleum systems (TPS) are identified for the 2003 U.S. Geological Survey assessment of undiscovered, technically recoverable oil and gas resources of the Bend Arch–Fort Worth Basin Province: (1) Barnett–Paleozoic TPS, Fort Worth Basin and Bend arch; (2) Barnett–Hardeman Basin TPS, Hardeman Basin; and (3) Pennsylvanian Bend–Broken Bone Graben TPS that partly separates the Barnett–Paleozoic and Barnett–Hardeman TPS systems in the northwest part of the province. The Barnett Shale (Mississippian–Pennsylvanian) is the primary source rock for hydrocarbons in the Barnett–Paleozoic and Barnett–Hardeman TPS, whereas organic-rich shale of the Pennsylvanian-age Bend Group generated mainly gas from the Broken Bone graben.

Geologically defined units for assessment of mature conventional accumulations include the Mississippian Chappel Limestone pinnacle reefs and Waulsortian mounds, and the Pennsylvanian Bend Group conglomerates and Strawn Group sandstones. Assessment of the Bend Arch–Fort Worth Basin Province focuses on the continuous (unconventional) Barnett Shale accumulation where gas and some oil are sourced and reservoired in tight, organic-rich siliceous shale.

The Barnett continuous accumulation is expected to add the greatest volume of undiscovered, technically recoverable gas to reserves. Barnett gas will be assessed after determining areas of gas potential, and by estimating distributions of drainage areas of wells (cell size) and estimating ultimate recoverable gas volumes. The Greater Newark East area is considered a "sweet spot" within the Barnett where thick, organic-rich siliceous shale is within the gas window and overlain and underlain by impermeable limestone that confine induced fractures during completion and allow maximum gas recovery.

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These "Karst" Features in the Ellenburger Are Really Pull-Apart Basins

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The Ellenburger carbonates are an important fractured reservoir or aquifer in Texas, New Mexico and Oklahoma. We used seismic attributes based on a new method of vector dip computation by volumetric coherent energy correlation to investigate changes in fault, joint, and lineament orientations in a 3-D seismic data set from the Fort Worth Basin and to determine the structural and temporal framework for the development of collapse systems that extend vertically through the Ordovician Ellenburger carbonates and a 2300 ft (700 m) thick Mississippian–Pennsylvanian siliciclastic sequence to the Pennsylvanian Caddo Limestone. The collapse features developed during deposition of the overlying section and have a rounded, sinkhole-like appearance in this growth section. Such features have been called karst-collapse features. We find that in this area they cannot be Ellenburger karst because: (1) They developed after deposition of the overlying shales. (2) They affect too great a vertical thickness of section, i.e. the thickness of the collapse section is too great relative to the thickness of the Ellenburger. (3) The entire Ellenburger section is involved in the collapse. Tracing the features downwards in the seismic data reveals that in the pre-growth section they are sharply rombohedral pull-apart basins developed at stepovers between oblique-slip extensional faults that extend into the deep basement. The rounded shape in the growth section results from the geometry of syntectonic deposition and because the sediments collapsed prior to lithification.

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Intensive Groundwater Monitoring: A Good Thing? A Shallow Suburban Alluvial Soil Aquifer, North Central Oklahoma, Revisited

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Characterizing natural groundwater quality in shallow aquifers for the purpose of comparison against potentially contaminated water opens a Pandora's box of questions. Myriad physical, chemical, and biological processes impact groundwater chemistry and flow patterns in conflicting and reinforcing ways. Monitoring networks evolve as data needs change, conceptual models mature, and project budgets fluctuate. Scientists may become engaged in a public conversation to explain uncertainties and ambiguities that often result as a unintended byproduct of intensive data gathering efforts. Reexamination of historical data gathered from an intensively monitored field site in north central Oklahoma illustrates some of the issues involved in characterizing shallow alluvial aquifers.

The Ashport alluvial aquifer consists of 13.1 meters of surface soil and upper and lower buried paleosols overlying Permian shale in Payne County. Over a period of approximately four years, 41 wells, eight soil-water suction lysimeters, and four neutron access tubes were installed at the 2400-m^2 suburban site. Wells were typically installed in clusters of individual wells screened at discrete intervals between 2.0 m to 12.3 m below land surface. The site was monitored for precipitation, soil moisture content, water level, bulk water quality parameters, nitrate-N, chloride, bicarbonate, and major cations. Tracer tests and pumping well tests were performed to evaluate chemical transport parameters.

Horizontal hydraulic gradient and depth to the water table, two parameters integral to predicting groundwater transport, varied substantially over periods of months to days in response to local vegetative consumptive use and regional flow dynamics related to a nearby creek. Electrical conductivity of groundwater across the site varied from approximately 250 to 2000 micromhos/cm during one 11-month period. An order of magnitude change in nitrate-N was noted in one lysimeter following a recharge event. However, groundwater recharge and transport of chemicals to the aquifer during precipitation events depended on antecedent moisture conditions, so that amount of rainfall alone was not a good predictor of nitrate-N transport to the aquifer. These observations highlight the perennial challenge of characterizing alluvial aquifers.

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A Geological Framework for the Occurrence and Distribution of Naturally Occurring Arsenic in the Permian (Leonardian) Garber-Wellington Aquifer, Central Oklahoma

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The concentration of arsenic that occurs naturally in drinking water produced from portions of the central Oklahoma aquifer commonly exceeds EPA mandated standards (currently 50 ppb, falling to 10 ppb by 2006). In order to assist in development of remediation practices, we are working closely with EPA and USGS for the express purpose of providing a geological framework that can be used to better define the controls on the occurrence and distribution of arsenic in the aquifer system.

In south central Oklahoma, the Garber Sandstone and Wellington Formation are continental red beds that contain sandstone, mudstone, and rare intrabasinal conglomerate. Lithofacies, lithofacies associations, and analysis of bounding stratal surfaces from outcrops and cores suggest that the best-developed aquifer sandstones were deposited by braided-to-meandering fluvial systems that prograded from the east and south across a broad and muddy low relief alluvial plain. Correlation of stratal packages internal to the Garber-Wellington is difficult because of an absence of stratigraphic markers. Primitive soil structures and hardpans are common, though good evidence for flora and fauna is rare.

Integration of observations from outcrops, cores, and subsurface well logs with whole-rock geochemical data collected by the USGS indicate that arsenic is present in the sedimentary rocks that make up the aquifer. Moreover, the data demonstrate that the arsenic concentration in the red beds varies strongly with the lithology and grain size of the red beds; finer-grained lithofacies are enriched in arsenic while coarser-grained lithofacies contain much less arsenic. The enrichment of arsenic in the finer-grained lithofacies is because of the affinity of arsenic for iron oxide and clays, both of which are abundant in finer-grained lithofacies (such as mudstone).

In response to this finding, we have prepared maps of aquifer lithofacies (gross sand, net sand, shaley sand) and paleodepositional environments based on the outcrop, core, and well log data. These maps can be used to identify geographic areas where the potential for the occurrence of arsenic in the red beds is low. Based on the net-sand maps, we can identify several undrilled areas that appear to contain thick, well-developed sandstones with low arsenic potential.

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High Resolution Ground Penetrating Radar Mapping of the Permian Garber-Wellington Aquifer in Central Oklahoma

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The Garber Sandstone and the underlying Wellington Formation are important sources of drinking water in Oklahoma and Cleveland counties in central Oklahoma. The aquifer package consists of interbedded sandstone, shale, and siltstone deposited under fluvial conditions. The formations outcrop in central Oklahoma. Because of similar hydrological and petrophysical properties, the Garber Sandstone and the Wellington Formation are not easily distinguishable in outcrops. Previous geological work done on the Garber-Wellington aquifer suggests that water produced from sand bodies isolated by fine-grained sediments contains high levels of naturally occurring arsenic. Therefore, an understanding of the paleogeographic distribution and internal architecture of the sandstone bodies within the Garber-Wellington is critical to the placement of water wells.

This paper demonstrates the application of Ground Penetrating Radar (GPR) in imaging the Garber-Wellington. A PulseEkko100 GPR system with center frequencies of 50 MHz, 100 MHz, and 200 MHz is used to image outcrops of the Garber-Wellington. The 200 MHz data gives much better resolution than the 50 MHz or the 100 MHz data in identifying channelized features, resolving the basal erosional contact of the sandstone with the underlying shale, imaging faults, and defining the margins of the alluvial system. As expected, the 50 MHz data shows greater penetration. However, the depth of penetration of the GPR signal is limited in this area because of shales that underlie the imaged sandstones. Our preliminary conclusions from this work are that (1) GPR can be used to map and better define the external and internal architecture of the Garber-Wellington, (2) the Garber-Wellington is highly faulted which explains the isolated nature of some of the sand bodies, (3) a combination of antenna frequencies is desirable for better resolution and depth penetration in the Garber-Wellington, and (4) sand bodies that appear horizontally continuous are actually broken up into several smaller depositional units. This last finding is revealed only in GPR data acquired with a small transmitter-receiver step size.

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Conceptual Model Development and Identification of Groundwater Pathways for Monitoring System Design at a Nuclear Materials Processing Facility Using 3D Geospatial Models

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Knowledge of groundwater flow and transport pathways is essential for designing optimal monitoring systems, yet detailed pathway data are commonly not collected during initial site characterization and therefore not incorporated into early conceptual models. We present an approach for identifying site-specific groundwater pathways which involves construction of alternative conceptual 3D geohydrologic framework and property models using a former nuclear materials processing facility in Oklahoma as an example. The models formed a basis for monitoring system design at the site.

The geohydrologic framework model contains three hydrostratigrahic zones, corresponding to aquifer systems in which groundwater has been sampled since 1991. The terrace groundwater system (TGWS) aquifer (uppermost zone) is made up of terrace and alluvial deposits and a basal shale. A sandstone aquitard separates TGWS from the underlying shallow groundwater system (SGWS) aquifer (middle zone), composed of three shale units and two discontinuous sandstones. SGWS is separated from the underlying deep groundwater system (DGWS) aquifer (lowest zone) by another sandstone aquitard. Terrace and alluvial deposits form a perched aquifer and fractured shales are continuous water-bearing units.

TGWS and SGWS aquifers were contaminated during facility operation by spills and leaks of nitric acid processing solutions containing uranium ore constituents. Radioactive materials were also leached from discarded equipment and waste containers. Based on analysis of 3D models, site-specific groundwater pathways were identified. Lateral transport of uranium was indicated in TGWS along a buried erosional channel in bedrock trending south-southwest from the main processing building (MPB). Arsenic and nitrate greater than EPA MCLs also occur along this channel in TGWS and SGWS. Another pathway atop bedrock, trending west-northwest from the MPB, showed lateral migration of nitrate and arsenic in SGWS. Lateral movement of nitrate and arsenic in SGWS was indicated north and west from the largest holding pond at the site. As a result of delineation of these pathways, they were more carefully characterized by trenching and resistivity and new monitoring wells installed. The site conceptual model developed by hydrologic modelers was also modified.

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A New Method for Electrical Imaging of the Arbuckle-Simpson Aquifer, Oklahoma

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A new method for electrical imaging has been developed to help generate a conceptual model of the Arbuckle-Simpson aquifer in southern Oklahoma. This research is part of the Arbuckle-Simpson Hydrology Study to access ground water–surface water interactions in the approximately 800 meter thick aquifer. Data from electrical conductivity logs are limited to near borehole and data from multi-electrode resistivity arrays are limited to near surface. The limitations of these electrical imaging methods make them poorly suited for the task of generating 2D images of significant portions of the aquifer. The new method for electrical imaging combines these two techniques enabling a significantly greater coverage. A multi-electrode marine resistivity cable provides the capability to produce high resolution images to a depth of approximately 450 meters. The images will help determine the hydrostratigraphy of the aquifer and evaluate the flow properties of associated faults.

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Determination of Biodegradable Dissolved Organic Carbon (BDOC) in a Landfill Leachate-Contaminated Aquifer (Norman, OK)

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The potential for microbial degradation of dissolved organic carbon (DOC) was examined at an anoxic aquifer contaminated with landfill leachate in Norman, OK. Despite closure of the landfill in 1985, high amounts of DOC remain in the contaminant plume with concentrations of 225 mg/L at the landfill and >75 mg/L in the center of the plume. The persistence of DOC down-gradient suggests that much of the material is not biodegradable. Previous carbon fractionation work has confirmed that 65–70% of the DOC is comprised of the hydrophobic fraction. The availability of biodegradable carbon will exert a large control on microbial processes in the contaminant plume.

The goal of the current work was to develop a bioassay technique to examine the percentage of biodegradable DOC (BDOC) along the contaminant plume. A sulfate-reducing bacterial consortium (SRC) was enriched from the landfill and then inoculated into a subset of anoxic, filtered groundwater samples. In order to evaluate the potential for DOC consumption at the landfill, preliminary experiments were performed to evaluate the effect of the addition of (1) the SRC, (2) sulfate as an electron acceptor, (3) and nitrogen and phosphorus (N+P) as nutrients. The maximum amount of DOC consumption (9–10% in a 10-day period) occurred with the simultaneous addition of the SRC, sulfate, and N+P; 4% of the total DOC was consumed with the sole addition of the SRC. In contrast, indigenous bacteria only degraded DOC with additions of sulfate and N+P, consuming 4–5% of the total DOC.

In subsequent experiments, groundwater samples from 9 sites along the axis of the plume were amended with SRC, sulfate, and N+P. Relatively high amounts of BDOC (10–20%) were observed through the plume, including at sites furthest from the landfill. These results represent an estimate of biodegradation potential under non-limiting conditions of microbial biomass and electron acceptor availability. The in situ biodegradation may be overestimated using this approach, especially at sites where these factors may control carbon consumption. The use of bioassays to evaluate the potential for DOC consumption in contaminated aquifers will provide a useful tool for understanding the controls on microbial processes, many of which are tied to the natural attenuation of organic contaminants.

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Annual Changes in Biogeochemical Cycling at Surface Water–Porewater–Groundwater Mixing Interfaces in a Contaminated Aquifer-Wetland System

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Changes in chemical indicators of biogeochemical cycling were observed at mixing interfaces between surface water, wetland sediment porewater, and underlying aquifer groundwater in a wetland-aquifer system impacted by landfill leachate in Norman, Oklahoma. In subsurface systems, increased biogeochemical cycling is thought to occur at small-scale mixing interfaces where a gradient of electron acceptors and/or electron donors is present. These processes are controlled by the linked biological, geochemical and hydrological properties of the system. In this study, a vertical profile of water samples was collected using passive-diffusion equilibrators (peepers) to capture the surface water-wetland sediment interface and the wetland sediment-aquifer interface with a resolution of 0.5-cm to 1-cm. (Bio)geochemical indicators including alkalinity, Fe(II), S^{2-}, NH_4^+, NO_3^-, NO_2^-, Ca^{+2}, Mg^{+2}, Na^+, K^+, Cl^-, SO_4^{2-}, and organic acids such as, acetate, butyrate and propionate were measured in May 2003 and March 2004 during similar hydrologic conditions ("wet" spring seasons). Despite similar hydrologic conditions, differences in biogeochemical processes were observed. At the water-sediment interface sulfate reduction was the dominant process in both 2003 and 2004 but in 2003 higher sulfide was observed (~1000 uM vs. 16.58 uM in 2004) diffusing up into the water column. Lower S^{2-} in 2004 is likely attributed to reoxidation in the overlying surface water. In 2003 the surface water was covered with dense decaying vegetation and dissolved oxygen content of the surface water was low in contrast to 2004 when sparse vegetative growth and elevated dissolved oxygen was observed. Differences were also present at the sediment-aquifer interface in 2003 and 2004. Most notably, an accumulation of ammonium and organic acids (ex. 8770 uM acetate) was observed in 2003 but not in 2004. The absence of organic acids in 2004 is attributed to the presence of SO_4^{2-} in the underlying aquifer diffusing upward. The cm-scale sampling provides the ability to resolve sharp changes in biogeochemical indicators and thus quantify the enhanced biogeochemical cycling that occurs at mixing interfaces within the wetland-aquifer system.

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Kinetic Controls on Sulfate Reduction at an Experimentally Induced Mixing Interface in a Contaminated Wetland, Norman Landfill

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In situ push-pull tests were used to evaluate the rates of sulfate reduction at an interface between wetland sediment porewater and groundwater from underlying anaerobic aquifer sediments at the Norman Landfill research site, Norman, OK. Recent studies have indicated that small-scale mixing interfaces are zones of increased microbial activity and geochemical cycling and are therefore often the most dynamic portions of the system. Unfortunately, the complex interactions controlling the biogeochemistry of these zones are poorly studied due to the small transient nature of mixing interfaces. One such control requiring further study is the role of kinetics on biogeochemical cycling of electron acceptors and donors within these zones. This study was designed to evaluate kinetic controls on sulfate reduction through experimentally inducing small-scale mixing interfaces. This was accomplished using "mini" push-pull tests designed to simulate the exposure of a reduced zone, limited with respect to electron acceptor, to anaerobic groundwater containing abundant sulfate (~100 mg/L), thus simulating the aquifer-wetland interface. A uniform, porous sand lens within the wetland sediments was targeted using small-diameter (2.54 cm, O.D.) "drive-point" wells with a discrete, internally packed 4.5 cm well screen. Mini push-pull tests were then performed by using the wells to inject 10 L of aquifer water into the targeted zone. Sulfate-rich water used for the "push" phase of the tests was pumped from the anaerobic aquifer at the site and amended with 100 mg/L bromide (as NaBr) which served as a conservative tracer to track dilution from mixing, advection, and dispersion. The role of electron donor on sulfate reduction rates was also evaluated using push-pull tests by augmenting groundwater with additional electron donor (e.g. acetate). Mini push-pull tests appear to be an effective tool to quantitatively examine biogeochemical cycling in interface zones.

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Understanding Mixing and Annual Stratification of a Large Reservoir: Geochemistry of Lake Texoma, Texas-Oklahoma

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Lake Texoma is a large reservoir along the Texas-Oklahoma border, impounded in 1943, with a surface area of 360 km^2. The lake is a dynamic system, receiving input from two major river systems, the Red River and the Washita River. The Red River drains Permian evaporite and clastic sediments in west Texas and Oklahoma and, as a result, typically has elevated salinity (1200–2000 mg/L total dissolved solids, TDS, where it enters the lake and > seawater in some headwater reaches), making the Red River one of the saltiest major rivers in the world. In contrast, the Washita River drains west-central Oklahoma and typically has lower salinity than the Red (<500 mg/L TDS). Water from Lake Texoma has been collected during the spring, summer and fall over two years as part of an undergraduate class in geochemistry. We have sampled the lake at multiple sites and depths along the two influent arms, as well as at the deepest portion of the lake, proximal to the dam. Our data show that mixing between these two rivers results in horizontal chemical gradients. Near the Red River, Na concentrations are around 275–300 ppm but near the Washita River, Na concentrations are only 70–100 ppm. Near the dam, Na concentrations are at 200–240 ppm. There are also strong vertical chemical gradients generated in the main lake region during the development of a summer thermocline. At the deepest part of the lake (26 meter depth), near the dam, there is a boundary between the surface waters and the anoxic bottom waters at about 15–18 meter depth. The lake becomes well mixed some time during the fall, dependent on annual variation in rainfall and air temperature. During stratification, Dissolved Oxygen (DO) varies from 4 to 7 mg/L in surface waters, decreasing dramatically across the anoxia boundary to close to zero below 20 meter depth. Once the lake becomes mixed again, DO levels vary from 7 mg/L in the surface waters to 5 mg/L at 26 meters depth approaching zero only at the sediment-water interface. Similarly, during stratifi-

cation Fe concentrations vary from very low values to 5 ppb at the surface, and can increase to up to 70 ppb in anoxia waters while, once mixed, Fe concentrations are consistently 1–2 ppb at all levels. When stratified, Mn concentrations vary from <5 ppb at the surface to as much as 800 ppb in the deepest water, becoming around 1 ppb throughout once the lake becomes mixed.

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Fate and Interactions of Organic Compounds in Produced-Water Releases: Results from the Osper "A" Site, Osage County, OK

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About 20 billion bbl of formation water are currently co-produced annually in the USA with oil and natural gas. The large database on the geochemistry of this produced water shows salinities from ~3,000 to >350,000 mg/L TDS. Chloride, Na and Ca are generally the dominant ions, and concentrations of Fe, B, and NH_3 may be high. The concentrations of dissolved organics, including monocarboxylic (mainly, acetate and propionate) and dicarboxylic acid anions, BTEX, phenols and poly aromatic hydrocarbons (PAHs) can be very high (up to ~1,000 mg/L as DOC), especially in produced water obtained from young reservoir rocks at temperatures of 80° to 120°C. We are investigating the transport, fate, natural attenuation and ecosystem impacts of organic compounds, and inorganic salts present in releases of produced water and associated hydrocarbons at the Osage-Skiatook Petroleum Environmental Research (OSPER) sites, located in Osage County, OK. Data from nearby oil wells show that the produced water source is a Na-Ca-Cl brine (~150,000 mg/L TDS), with relatively high concentrations of Mg, Sr, and NH_4, but low SO_4 and H_2S. Dissolved organics, including, organic acid anions, BTEX, phenols and PAHs are relatively low. The source oils are paraffinic-naphthenic light crude, containing n-alkanes as the dominant components unimpacted by biodegradation. The surficial oil releases at the depleted OSPER "A" site are similar, but vary in stages of biodegradation. Repeated sampling of 44 wells from this site show a plume of high salinity water (2,000–30,000 mg/L TDS) at intermediate depths, that extends beyond the visibly impacted areas, and intersects the adjacent Skiatook Lake, a 4250-hectare potable water reservoir. No liquid petroleum was observed in this plume, but hydrocarbon gases, organic acid anions, BTEX and other VOCs are present. Microbial populations are degrading the crude oil and water-soluble organic compounds. The concentrations of the redox-sensitive inorganic and organic species and make-up of the microbial populations indicate that the system is poised at the level of iron reduction. Results show that significant amounts of salts from produced water and petroleum releases remain in the rocks of the impacted area after more than 65 years of natural attenuation.

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Transgressive Shoreface Erosion and Wave Ravinement on an Epeiric Shelf as Recorded by a Soil Nodule Conglomerate-Arenite in the Upper Pennsylvanian Oread Cyclothem, SE Kansas and NE Oklahoma

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The transgressive deposits of the Leavenworth-Heebner-Plattsmouth-Heumader minor cyclothem of the Oread Cyclothem overlie multi-story Calcisols and calcareous Vertisols and consist of basal Gleysol (10s cm), middle limestone conglomerate-arenite (5–25 cm), and upper fossiliferous shale and Leavenworth Limestone (1–2 m). The conglomerate-arenite was observed in 15 outcrop sections covering 100 km, and interpreted in 76 wells and cores in SE Kansas and NE Oklahoma. It is a single bed with conformable lower and upper contacts, composed of blackened clasts (80–95%), bedding-plane-parallel brachiopods, crinoids, and encrusting forams (5–20%), and rare coal fragments. Clasts are rounded, equant to elongate, coarse-sand-to-pebble size, and moderately sorted. They include micritic and radial-fibrous calcite grains, and pisoids. Micritic grains contain quartz silt, radiating and concentric spar-filled cracks, and rounded central molds filled with micrite or spars. Pisoids have micritic-clast cores and superficial micritic or ferruginous clay cortexes. Petrographically, the clasts have the same texture and composition as pebble-sized calcitic nodules, rhizoliths, and clasts of a channel-fill conglomerate in underlying paleosols and, thus, were probably derived from soil nodules.

Landward and upward shoreface translation during early transgression on a fluvial peneplain eroded the underlying calcareous paleosols and coeval early-transgressive deposits landward of the shoreline. The excavated soil nodules were reworked and transported to the inner shelf by storm return flows and were concentrated and deposited as a transgressive lag, i.e. the soil nodule conglomerate-arenite. The basal contact of the conglomerate-arenite is a wave ravinement surface, under which Gleysols formed by leaching and reworking of underlying paleosols by marine water. The persistent thickness and wide distribution of the conglomerate-arenite suggest extensive transgressive ravinement of the fluvial peneplain on the vast epeiric Kansas Shelf. The transgressive record is a typical T-C1 succession with a simple transgressive lag, composed of mixed carbonate and siliciclastic rocks.

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