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

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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.

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,

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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.)

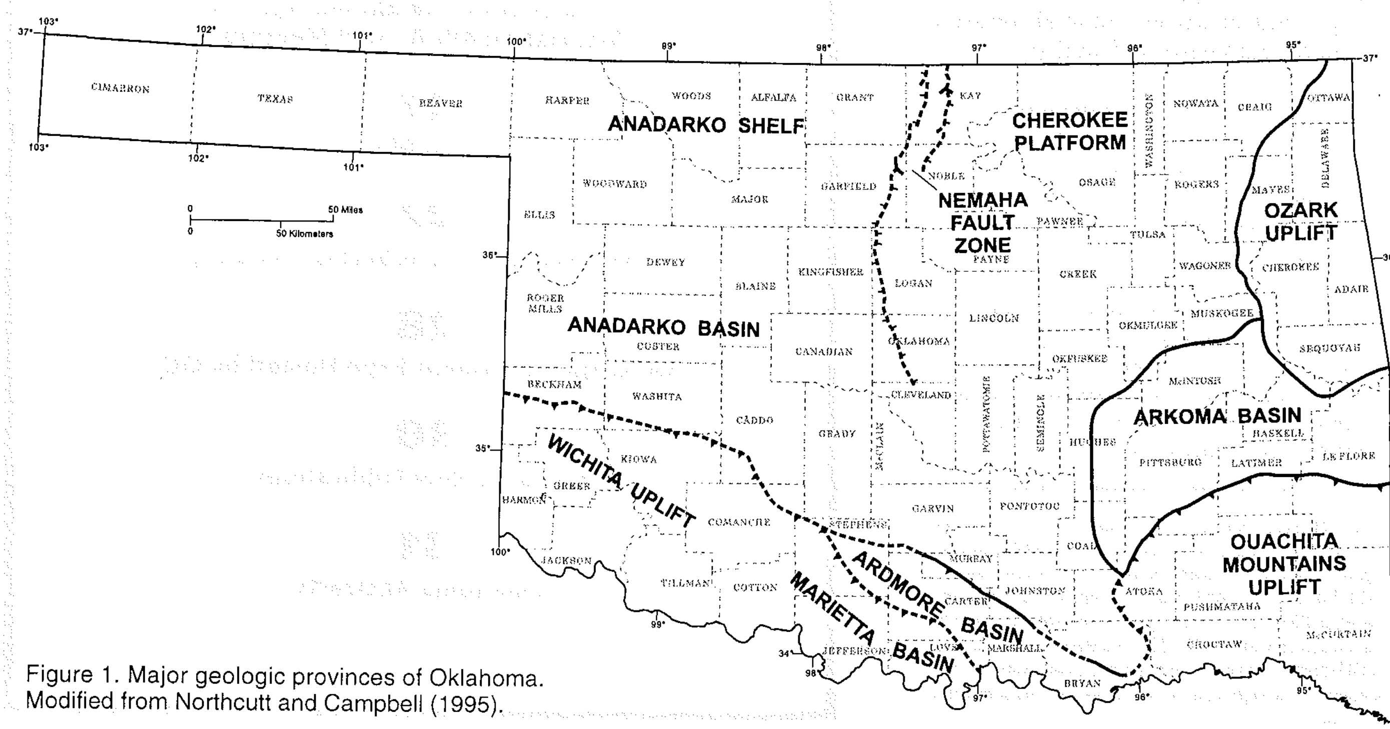


Figure 1. Major geologic provinces of Oklahoma. Modified from Northcutt and Campbell (1995).

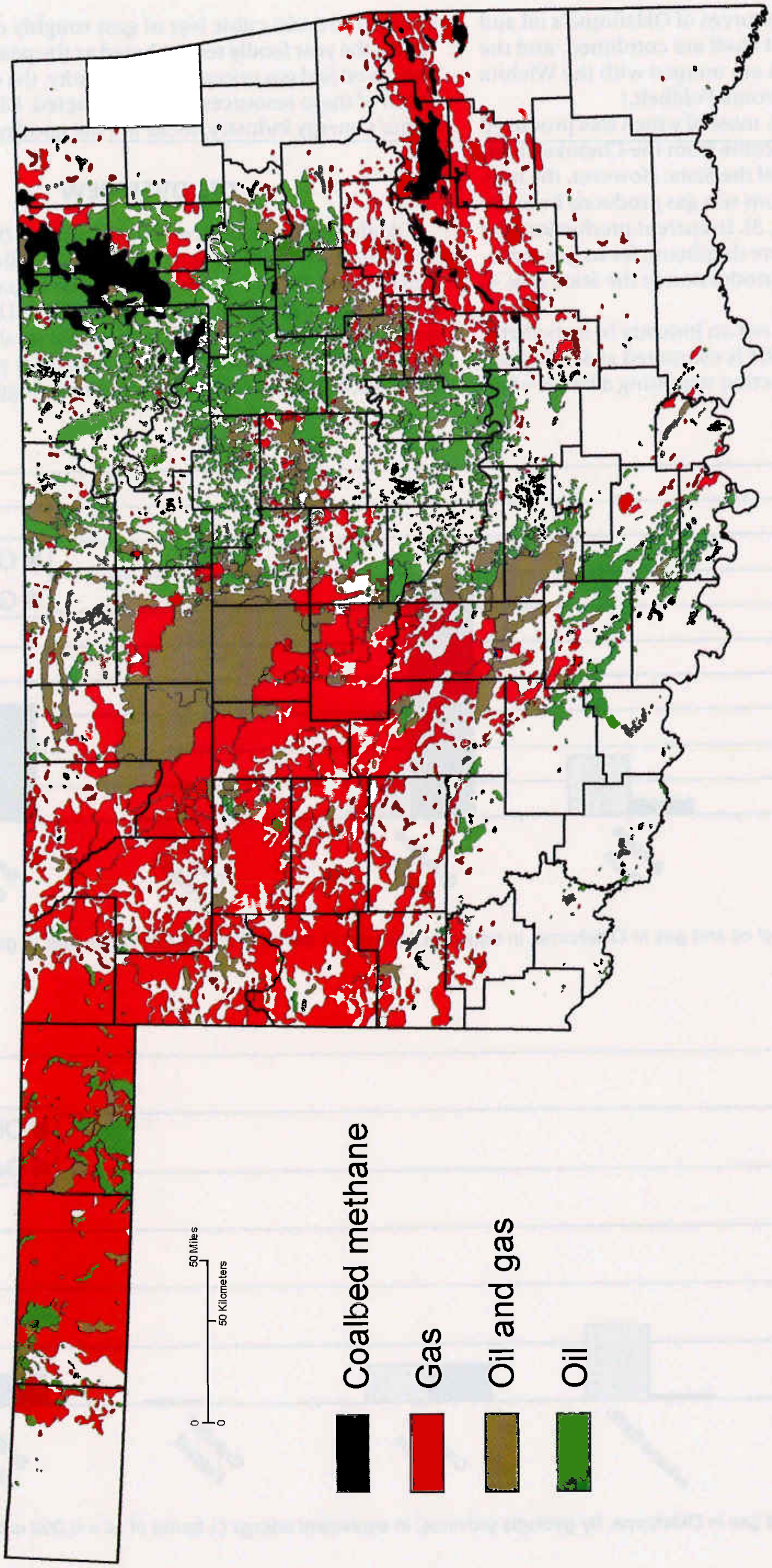


Figure 2. Oil and gas fields of Oklahoma. Map modified from Boyd (2002c).

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

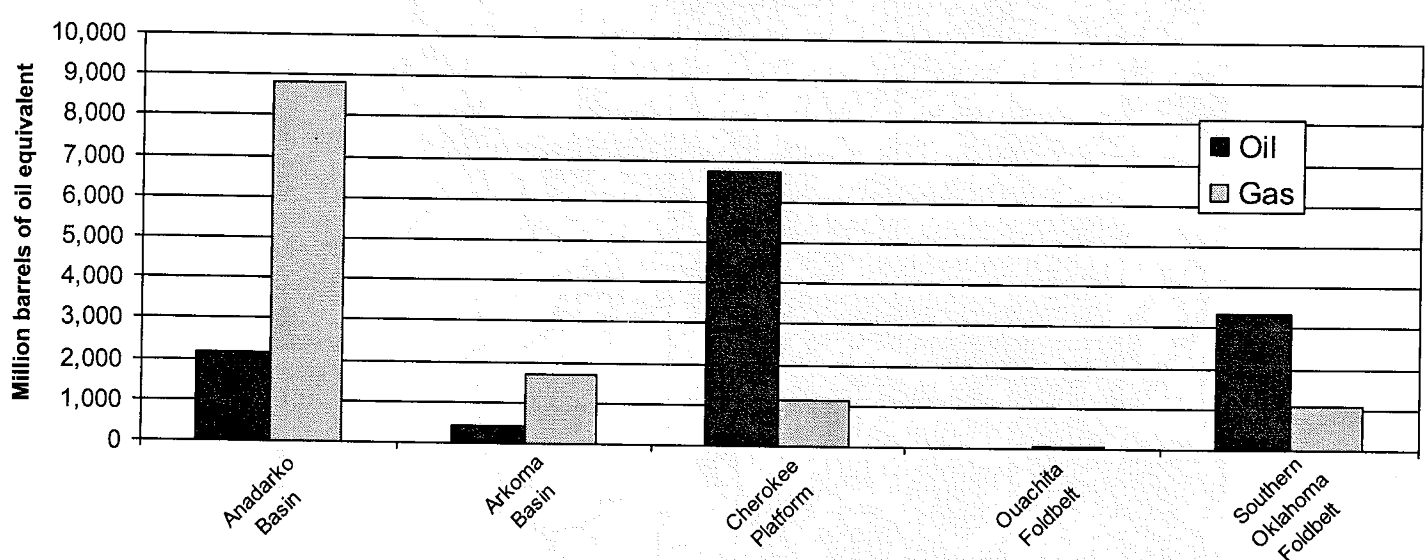


Figure 3. Cumulative production of oil and gas in Oklahoma, in equivalent energy (1 barrel of oil = 6,000 cubic feet of gas). IHS Energy (2004).

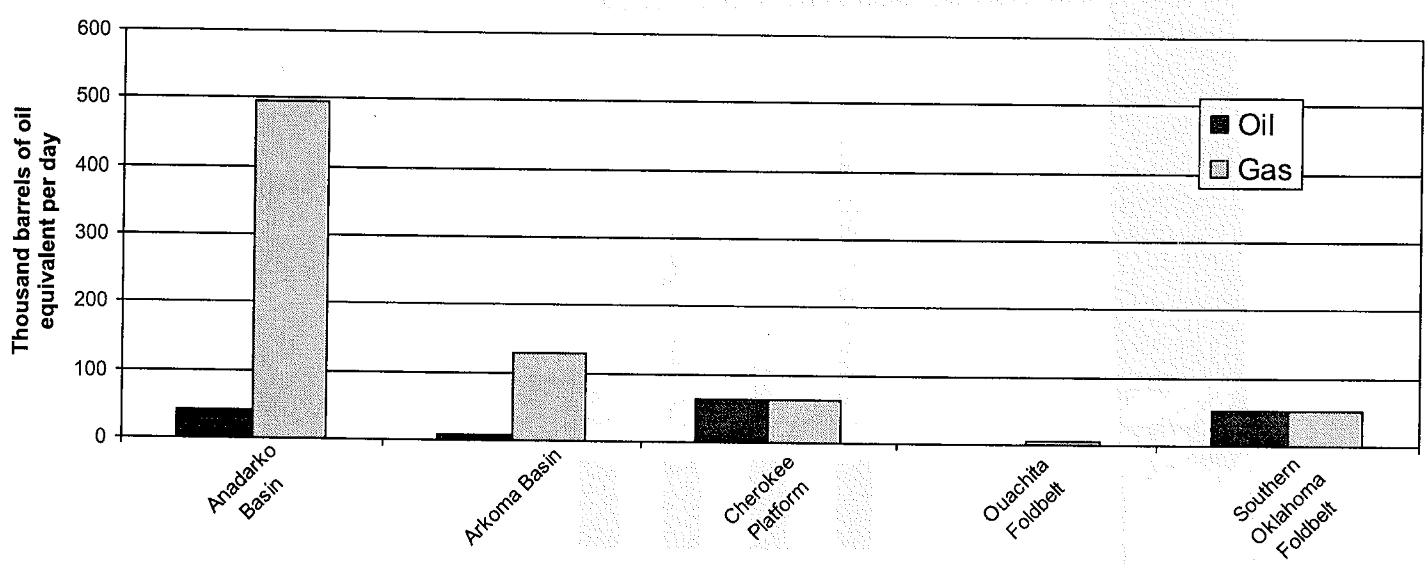


Figure 4. Production rates of oil and gas in Oklahoma, by geologic province, in equivalent energy (1 barrel of oil = 6,000 cubic feet of gas). From IHS Energy (2004).

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

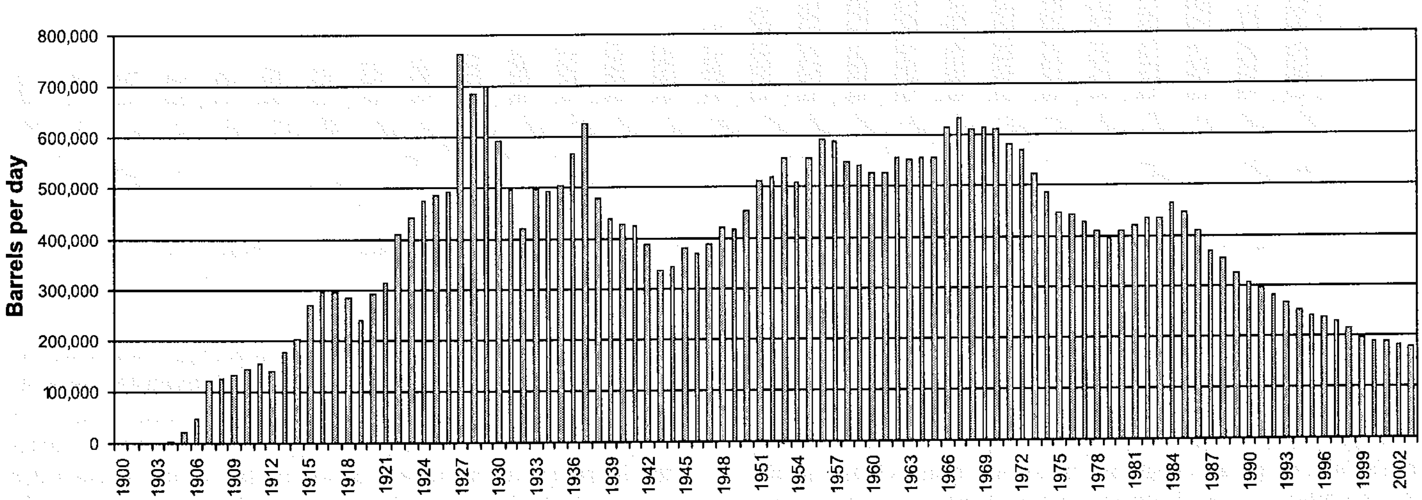


Figure 5. History of oil production (including condensate) in Oklahoma. From Claxton (2004).

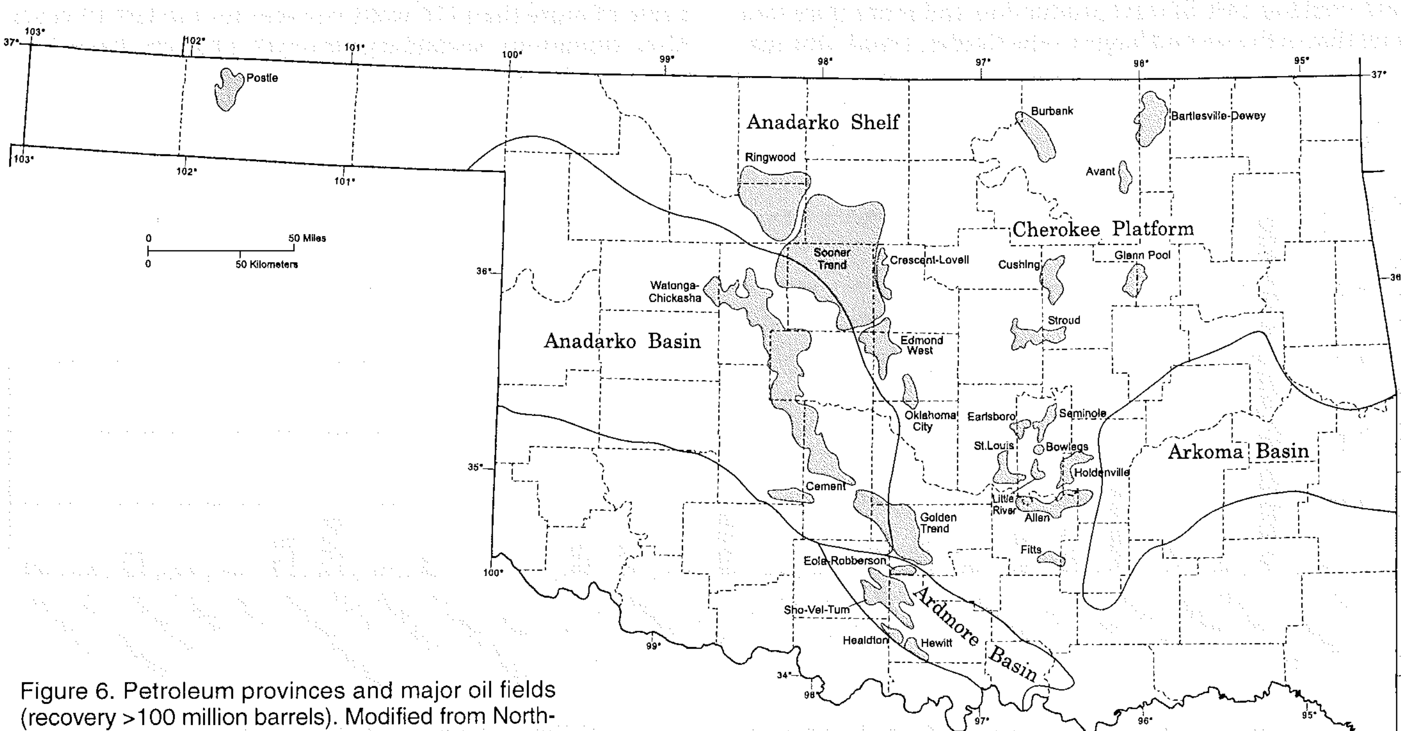


Figure 6. Petroleum provinces and major oil fields (recovery >100 million barrels). Modified from Northcutt and Campbell (1995) and Boyd (2002c).

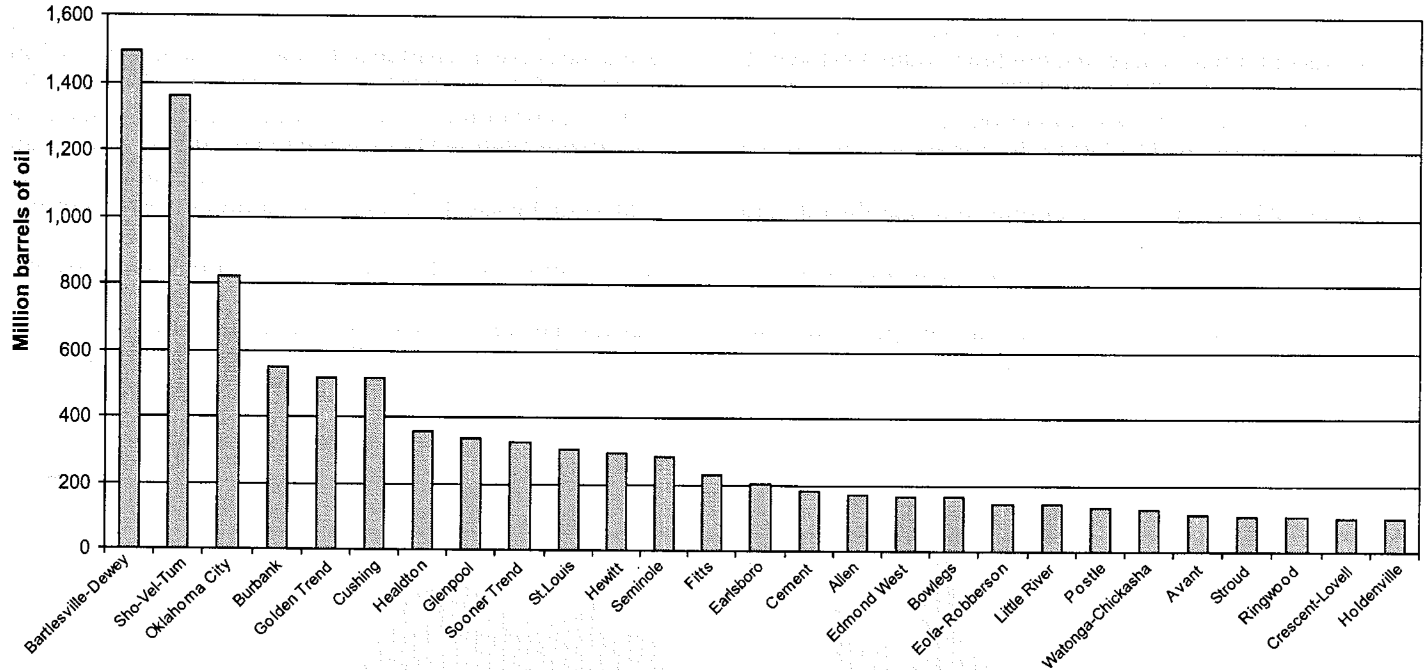


Figure 7. Cumulative oil production in Oklahoma (fields with recovery >100 million barrels). IHS Energy (2004).

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

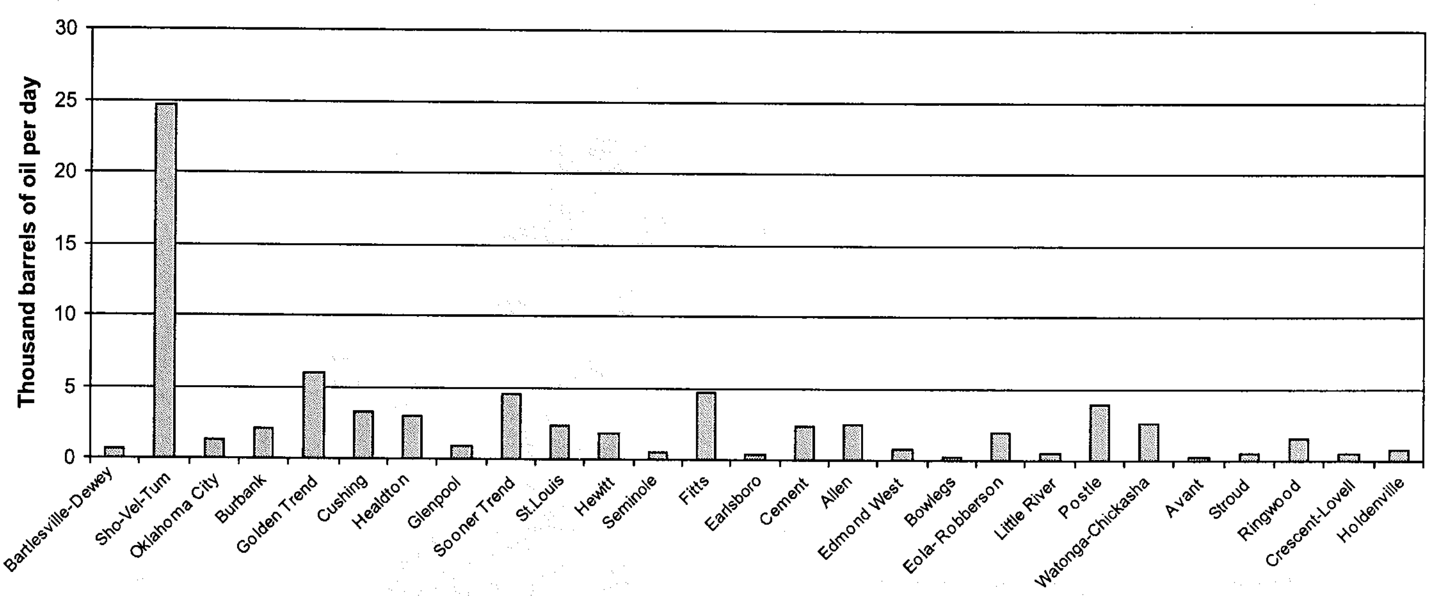


Figure 8. Daily oil production in Oklahoma fields with recovery >100 million barrels. From IHS Energy (2004).

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-

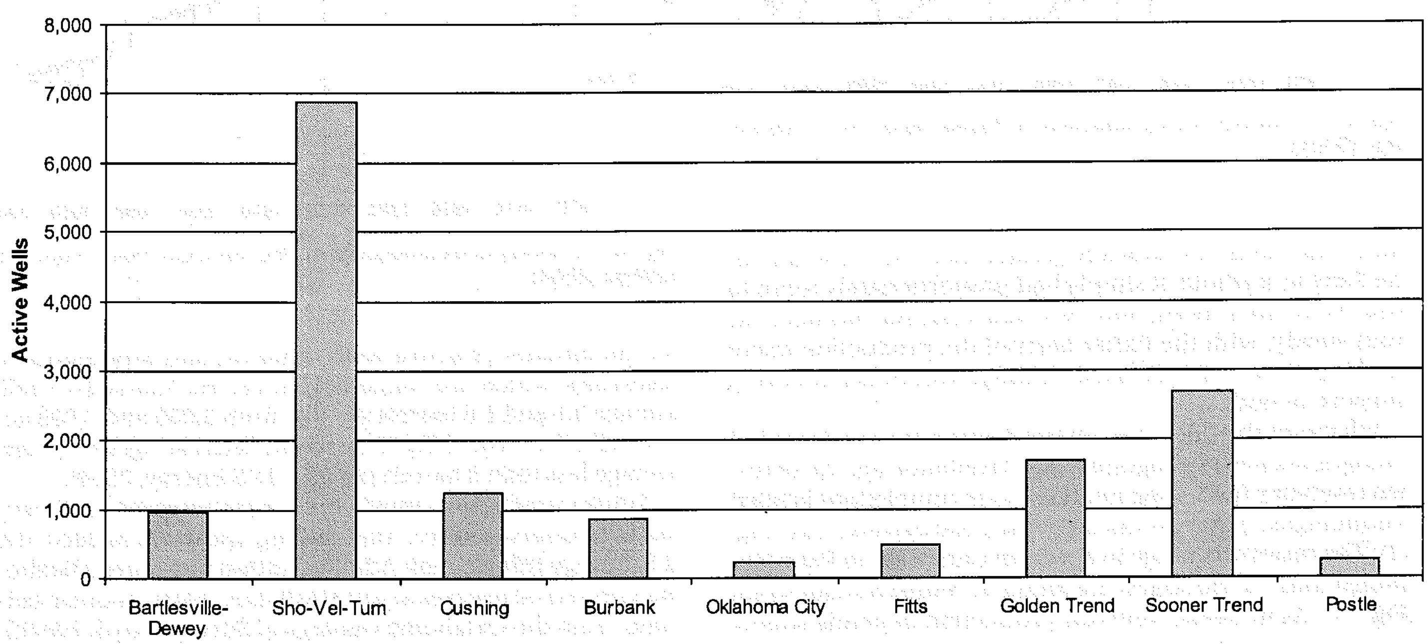


Figure 9. Active wells in nine Oklahoma oil fields with recovery >500 million barrels, or >4,000 barrels per day. From IHS Energy (2004). Compare with Figure 10.

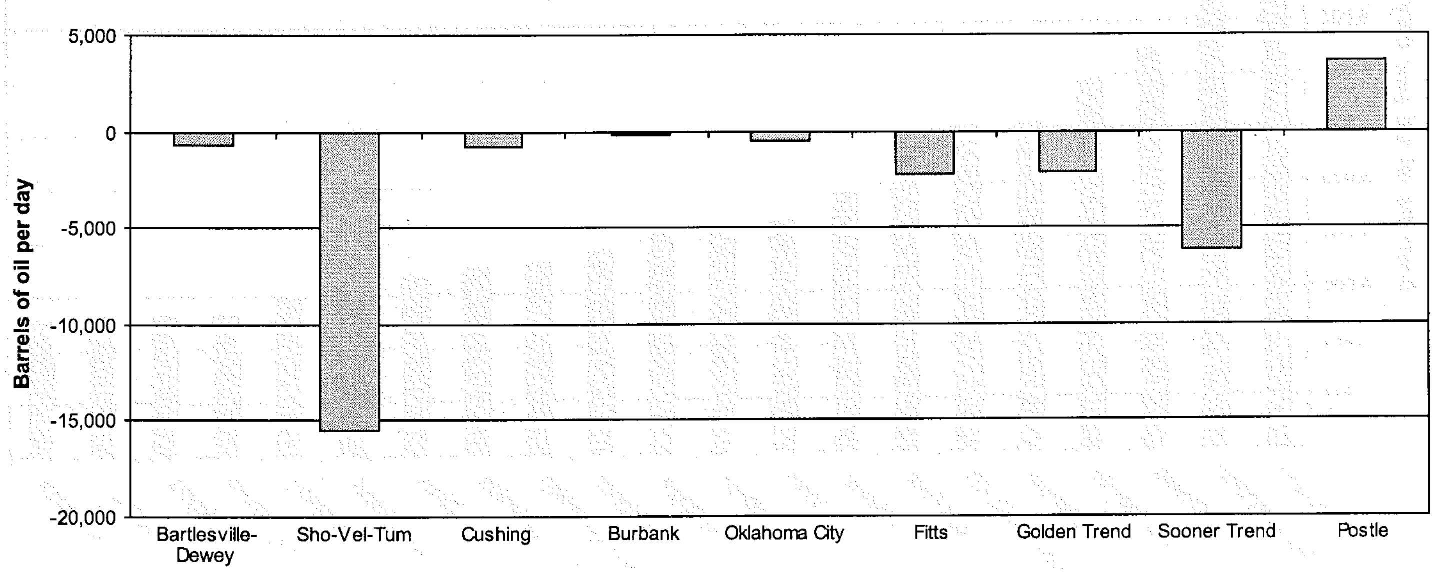


Figure 10. Changes in production rate in nine Oklahoma oil fields (recovery >500 million barrels, or >4,000 barrels per day) between 1994 and 2003. From IHS Energy (2004). Compare with Figure 9.

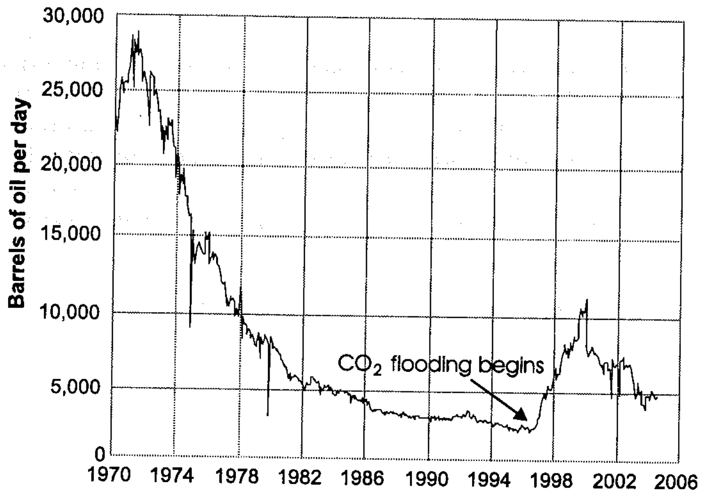


Figure 11. History of oil production in Postle Field. From IHS Energy (2004).

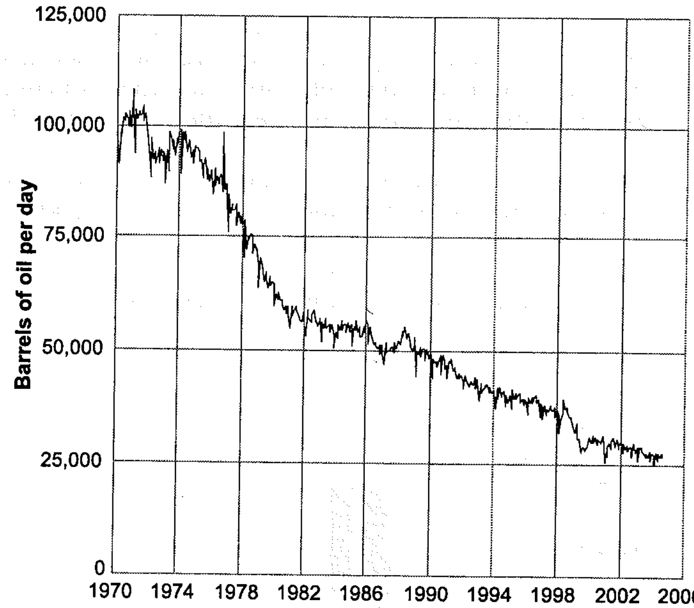


Figure 12. History of oil production in Sho-Vel-Tum Field. From IHS Energy (2004).

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),

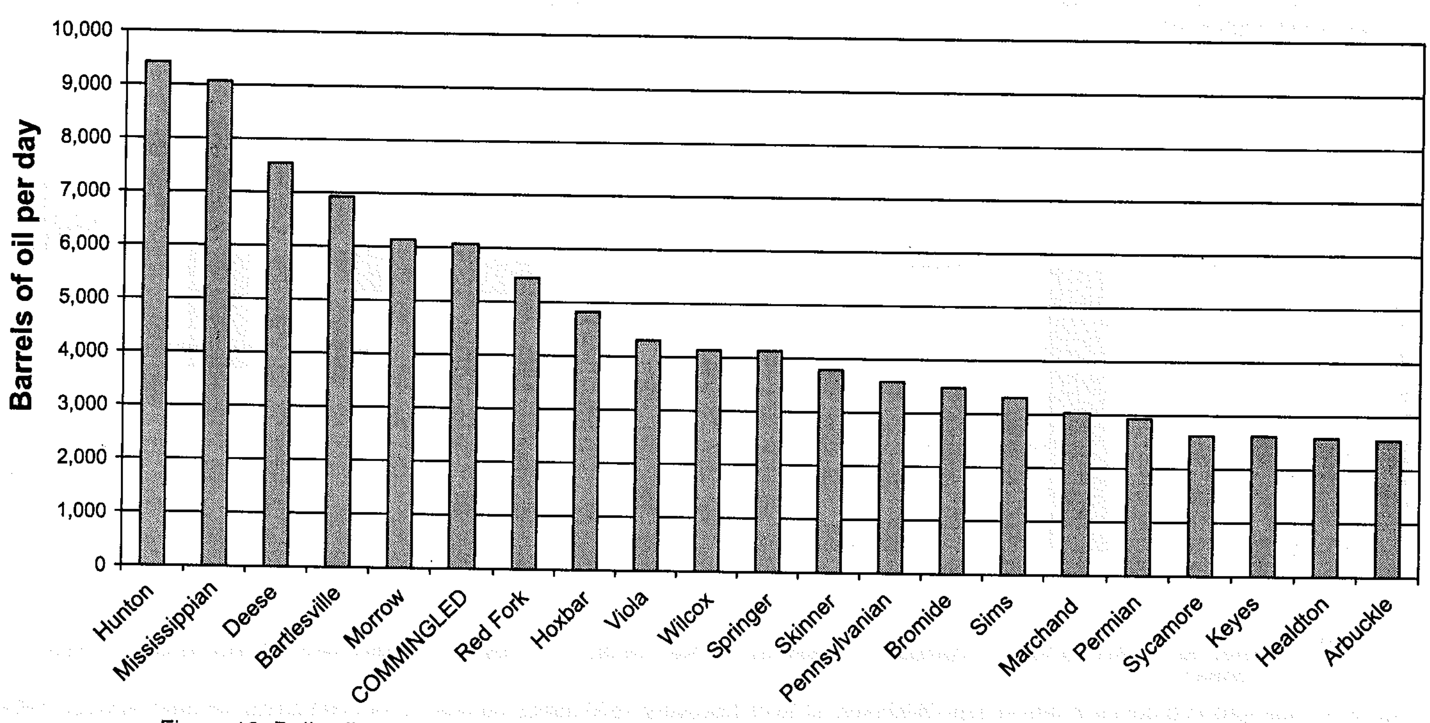
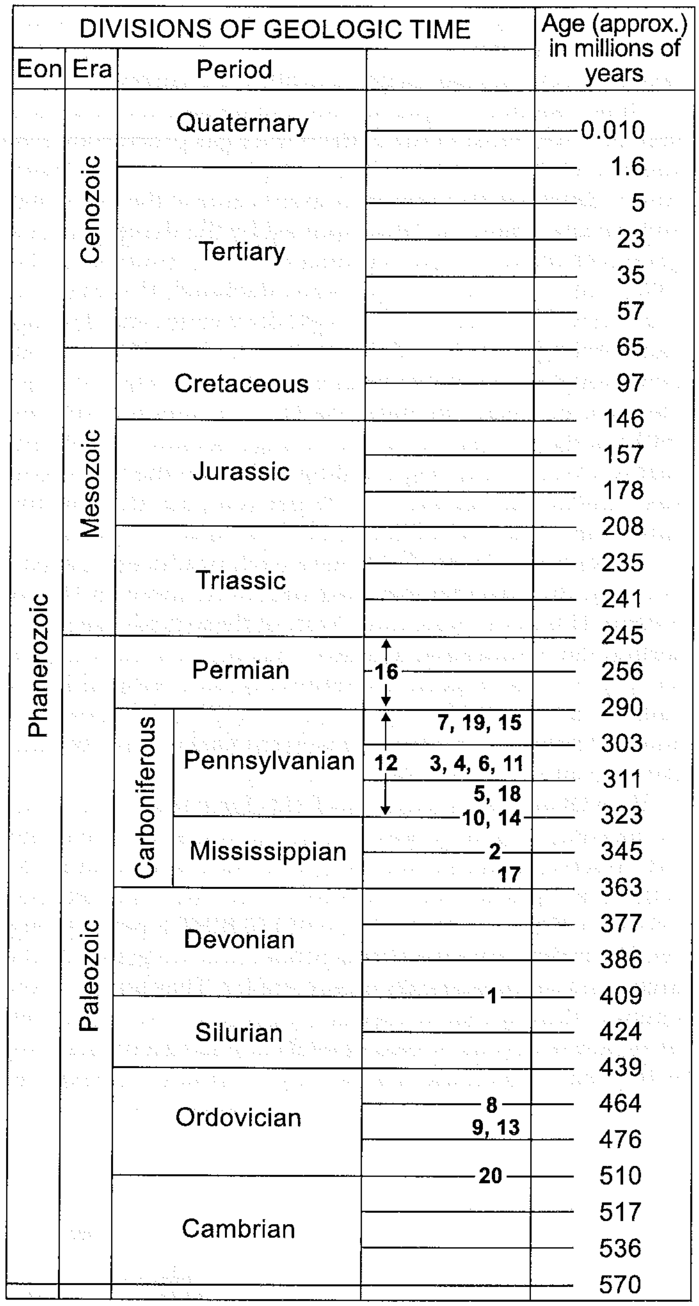


Figure 13. Daily oil production in Oklahoma reservoirs (>2,500 barrels per day). From IHS Energy (2004).



Reservoirs

1 — Hunton	11 — Skinner
2 — Mississippian	12 — Pennsylvanian
3 — Deese	13 — Bromide
4 — Bartlesville	14 — Sims
5 — Morrow	15 — Marchand
6 — Red Fork	16 — Permian
7 — Hoxbar	17 — Sycamore
8 — Viola	18 — Keyes
9 — Wilcox	19 — Healdton
10 — Springer	20 — Arbuckle

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-

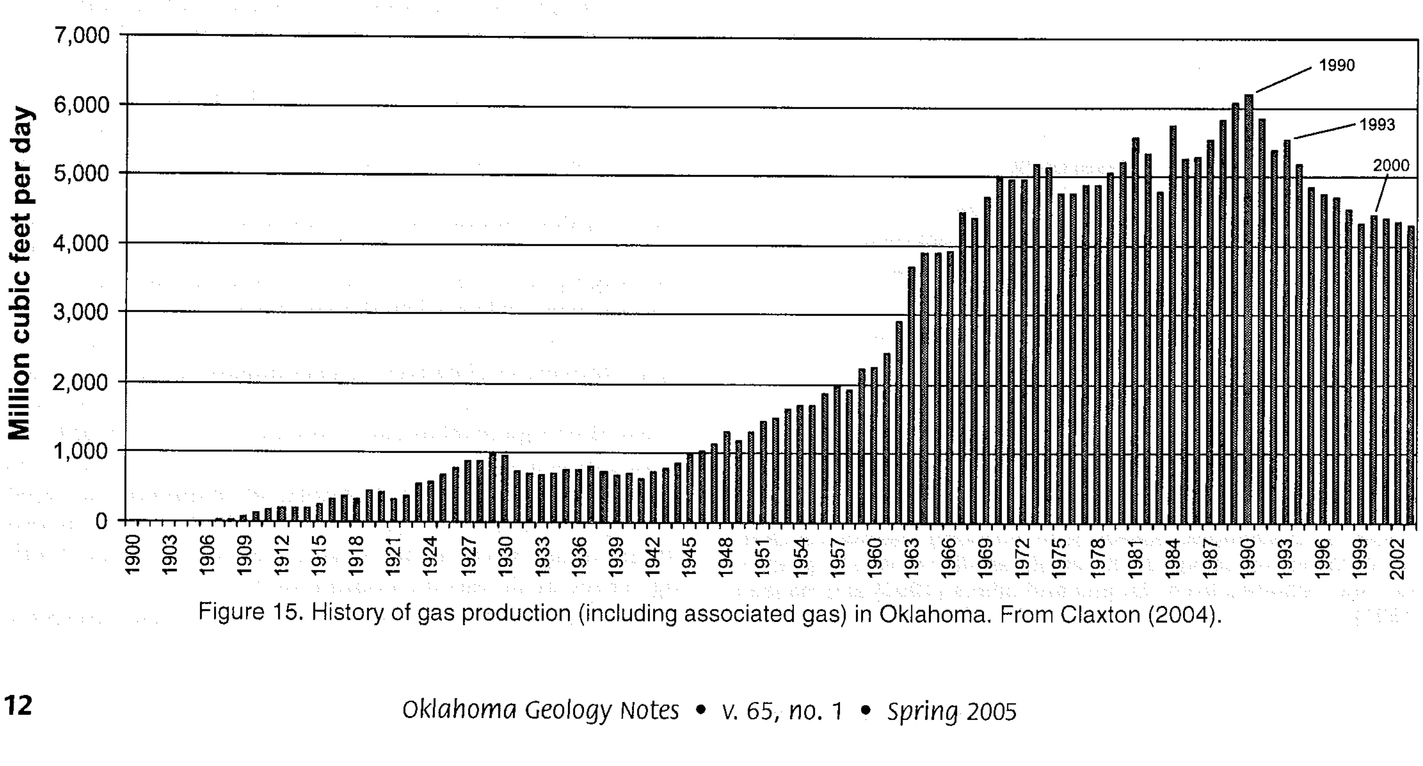


Figure 15. History of gas production (including associated gas) in Oklahoma. From Claxton (2004).

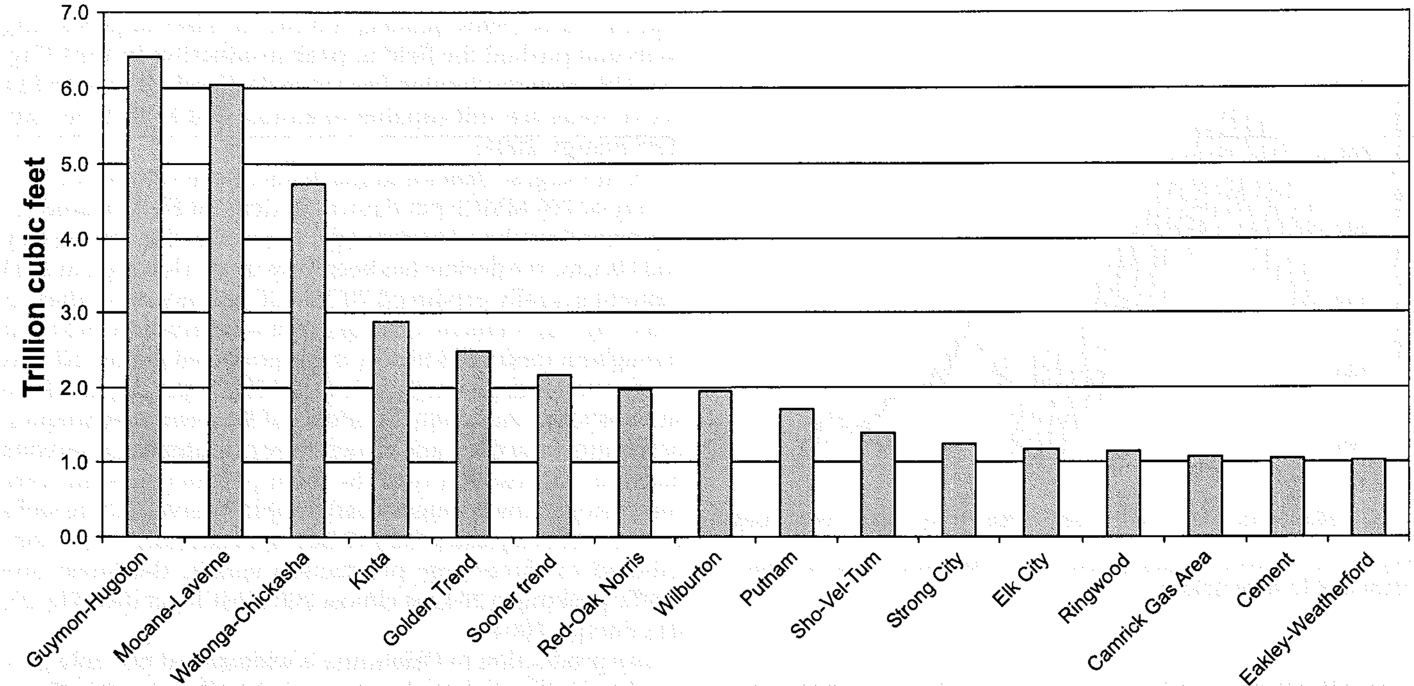


Figure 16. Cumulative production for major Oklahoma gas fields (>1 trillion cubic feet). Data from IHS Energy (2004). Compare with Figure 19.

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

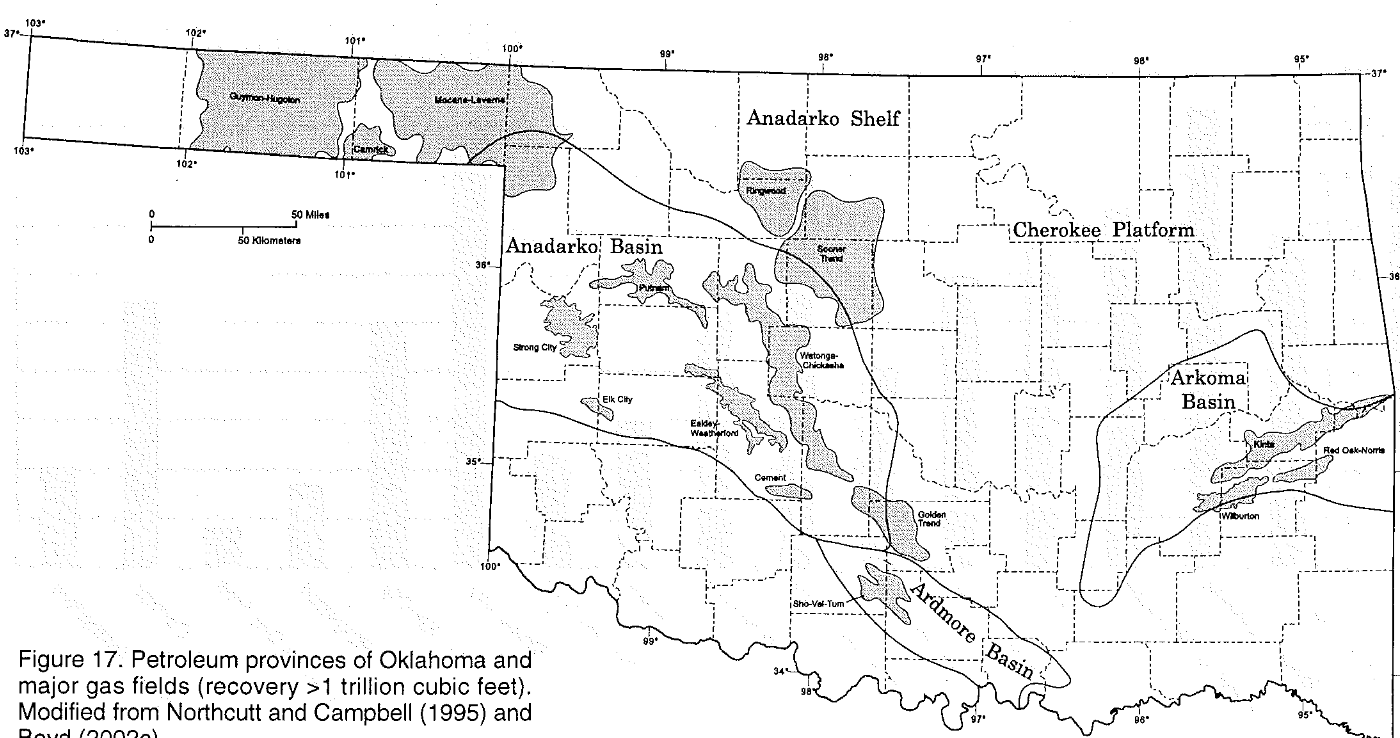


Figure 17. Petroleum provinces of Oklahoma and major gas fields (recovery >1 trillion cubic feet). Modified from Northcutt and Campbell (1995) and Boyd (2002c).

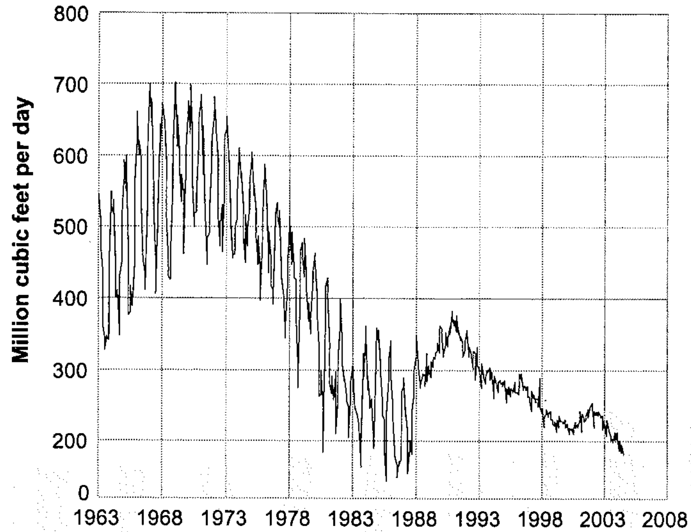


Figure 18. History of gas production in Mocane-Laverne Field. From IHS Energy (2004).

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-

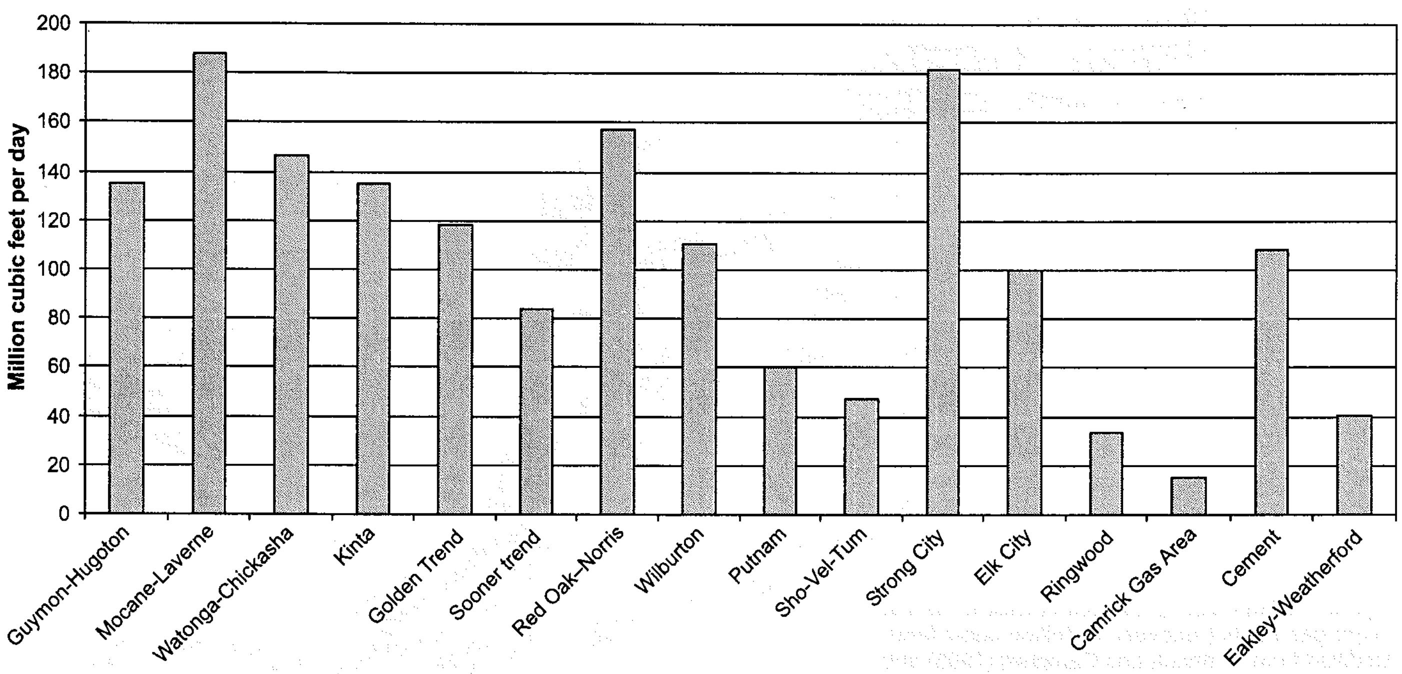


Figure 19. Daily production of major Oklahoma gas fields (recovery >1 trillion cubic feet). From IHS Energy (2004). Compare with Figure 16.

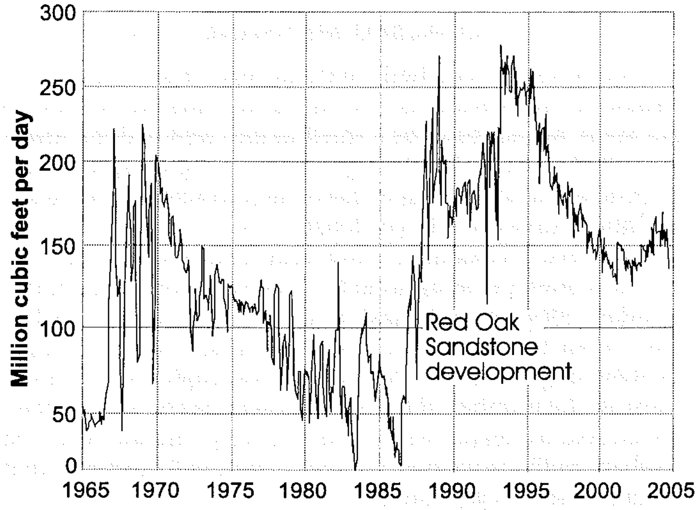


Figure 20. History of gas production in Red Oak–Norris Field. From IHS Energy (2004).

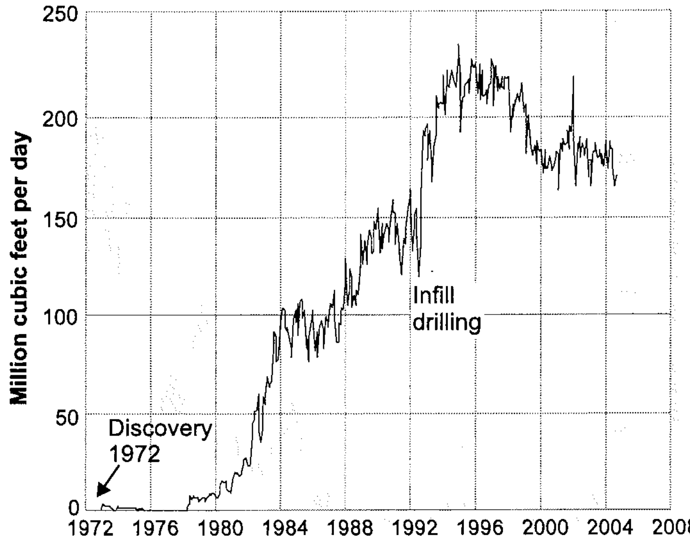


Figure 21. History of gas production in Strong City Field. From IHS Energy (2004).

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

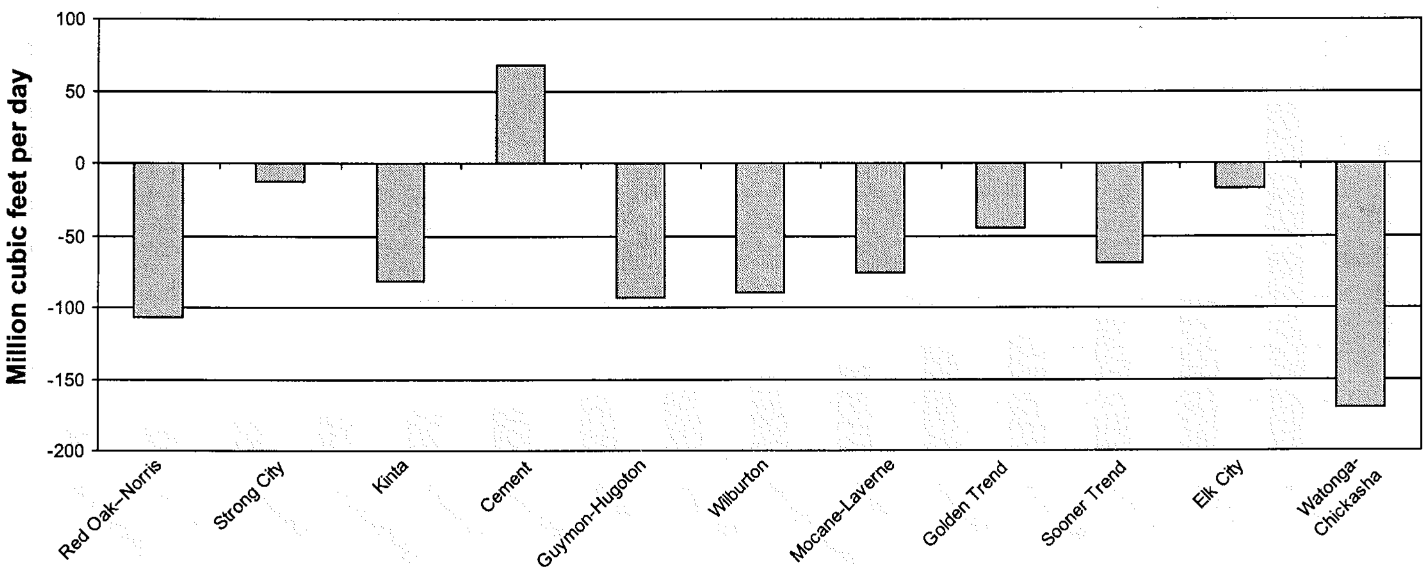


Figure 22. Changes in production rates in 11 Oklahoma gas fields (recovery >2 trillion cubic feet, or 100 million cubic feet per day) between 1994 and 2003. From IHS Energy (2004).

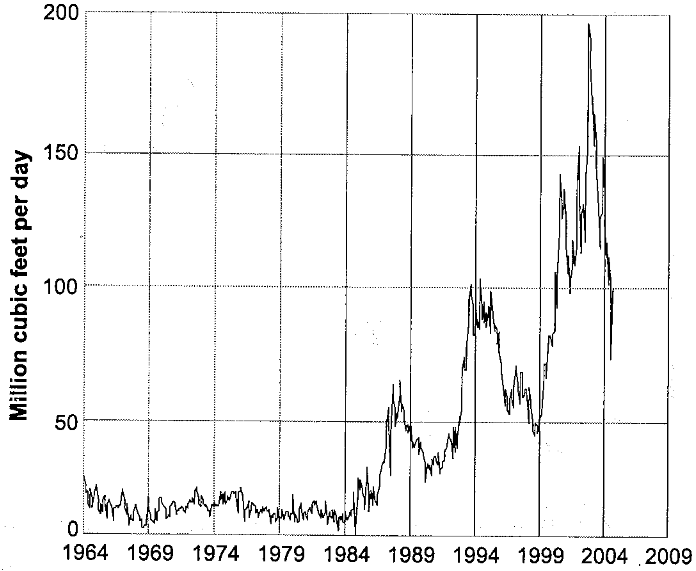


Figure 23. History of gas production in Cement Field. From IHS Energy (2004).

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-

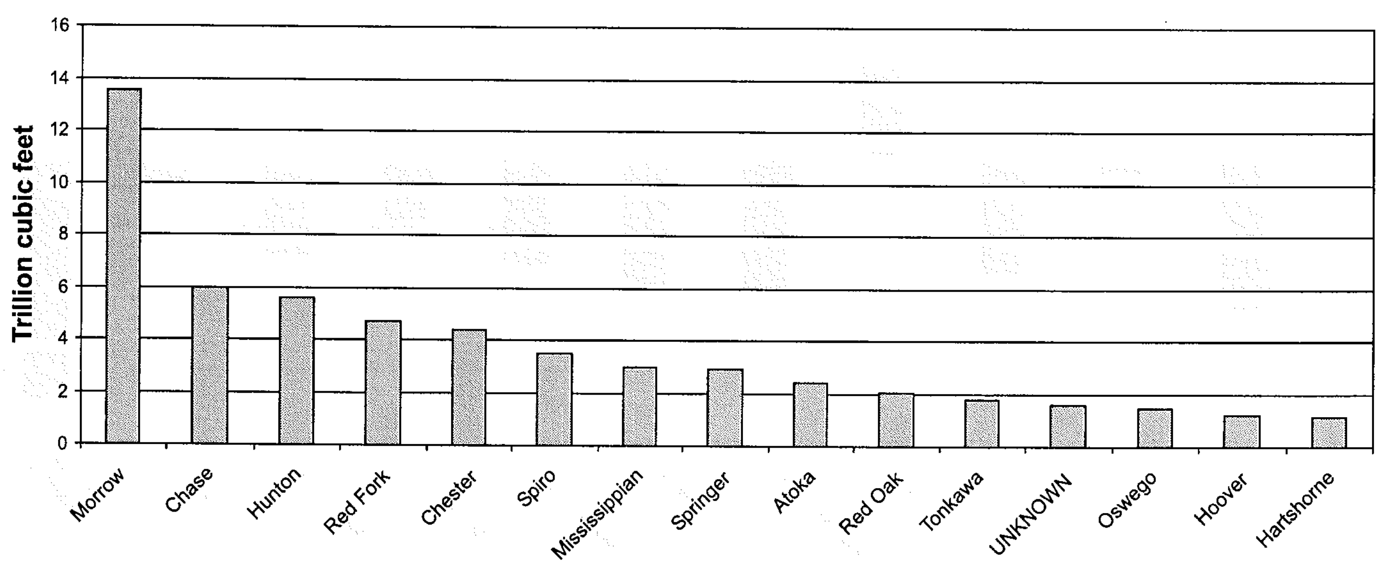
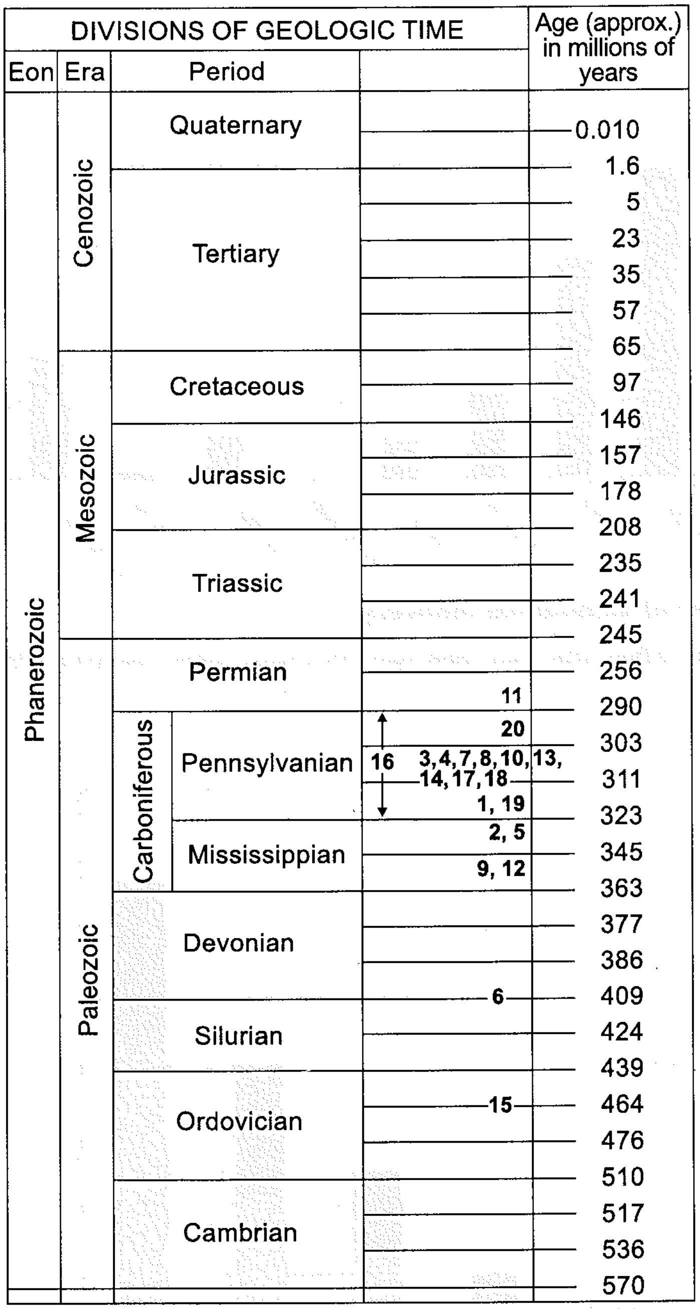


Figure 24. Cumulative production of leading gas reservoirs (recovery >1 trillion cubic feet). Data from IHS Energy (2004). Compare with Figure 26.



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

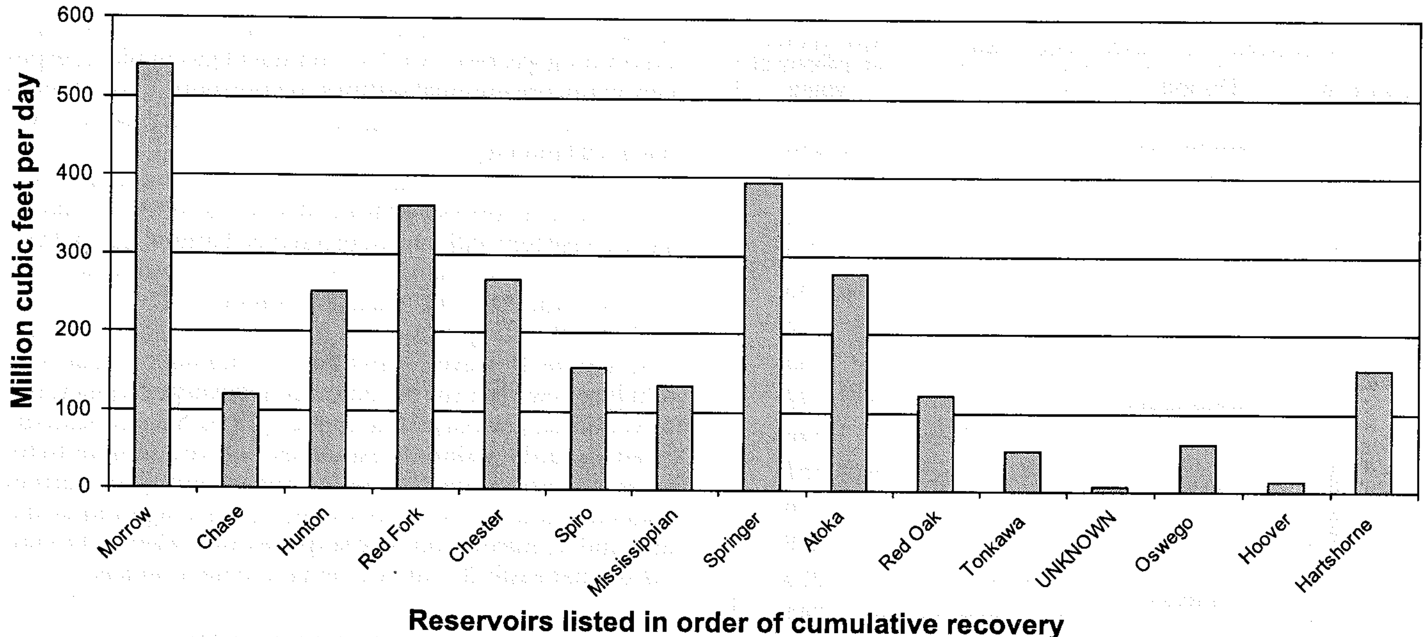


Figure 26. Daily gas production by reservoir (cumulative production >1 trillion cubic feet). Data from IHS Energy (2004). Compare with Figure 24.

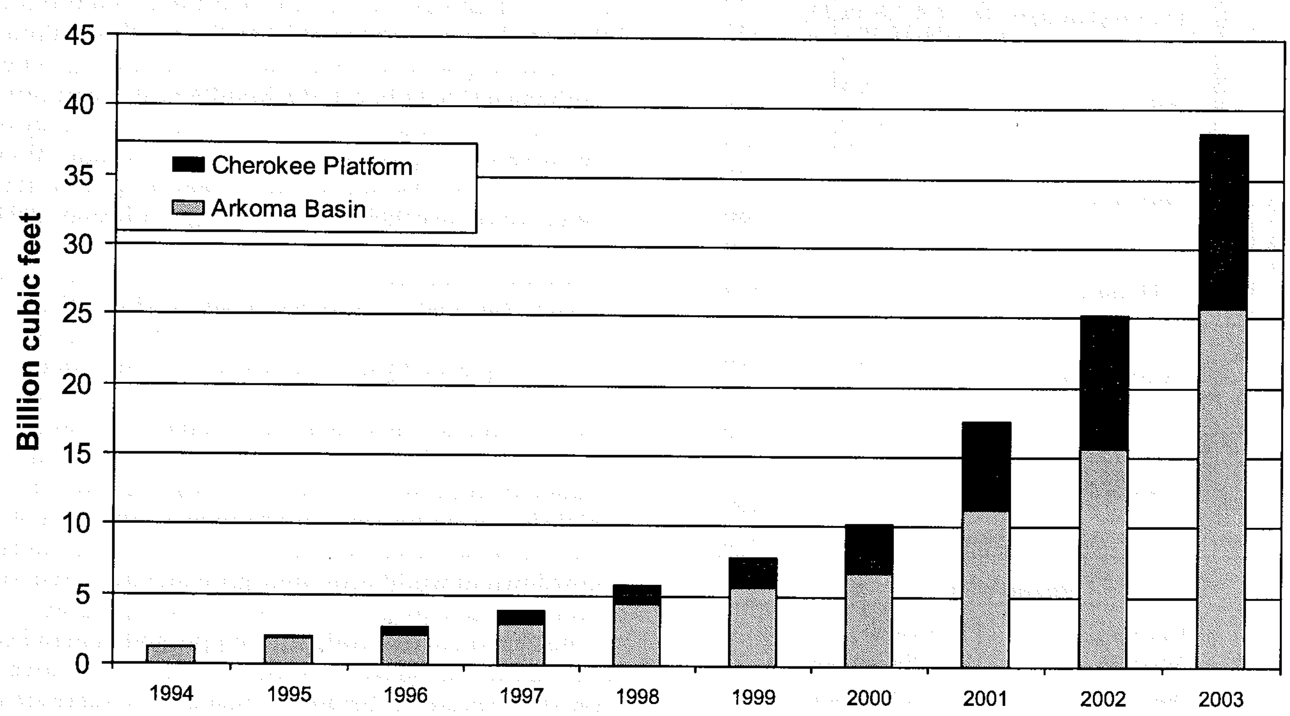


Figure 27. Production of Oklahoma coalbed methane. Data from Cardott (2005).

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

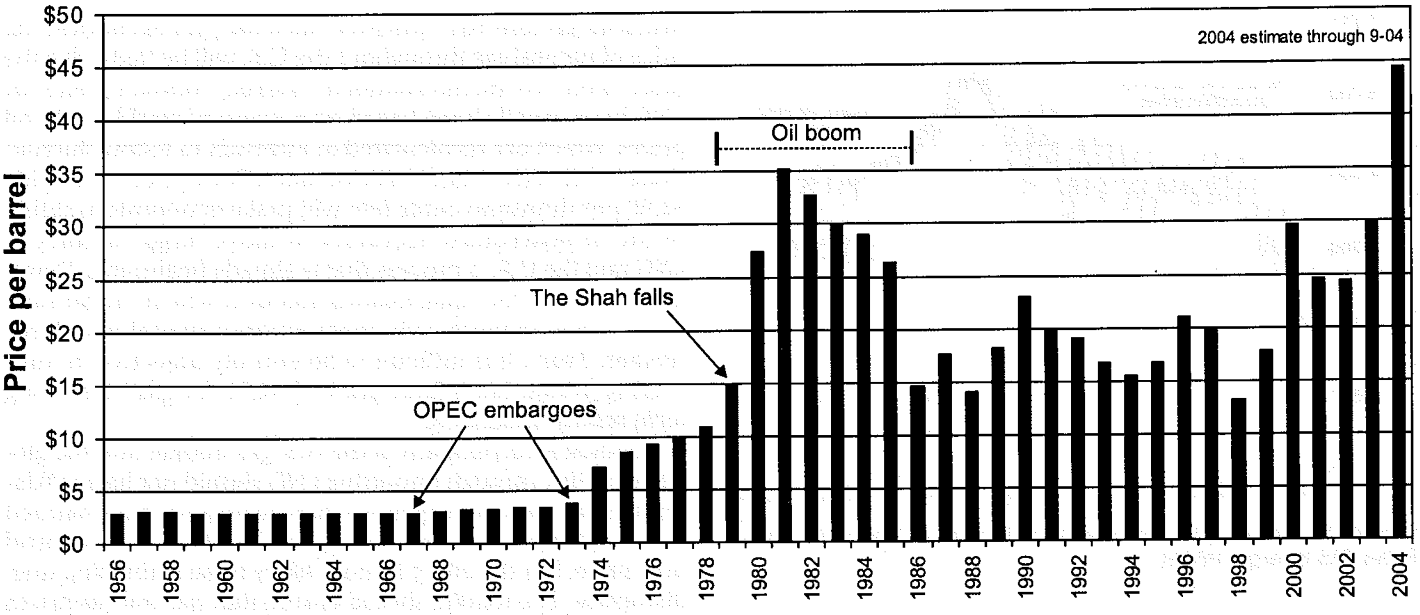


Figure 28. Average crude oil price (not adjusted for inflation) in Oklahoma. From Claxton (2004).

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 fluctuations 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

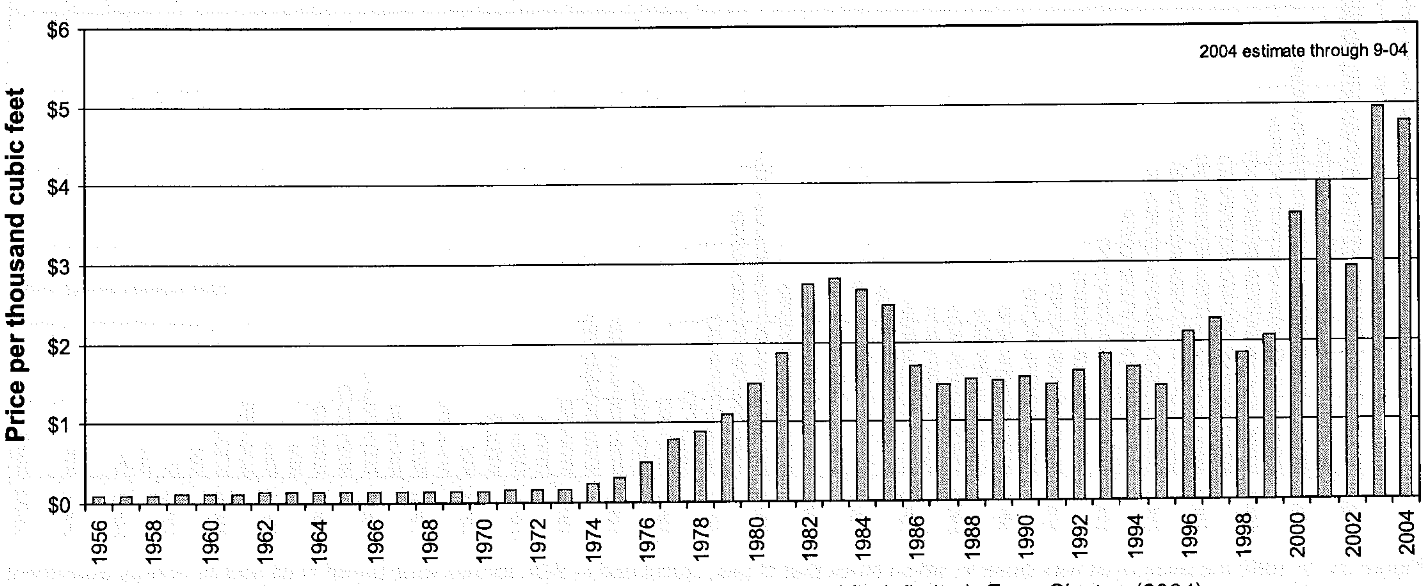


Figure 29. Average wellhead natural gas price (not adjusted for inflation). From Claxton (2004).

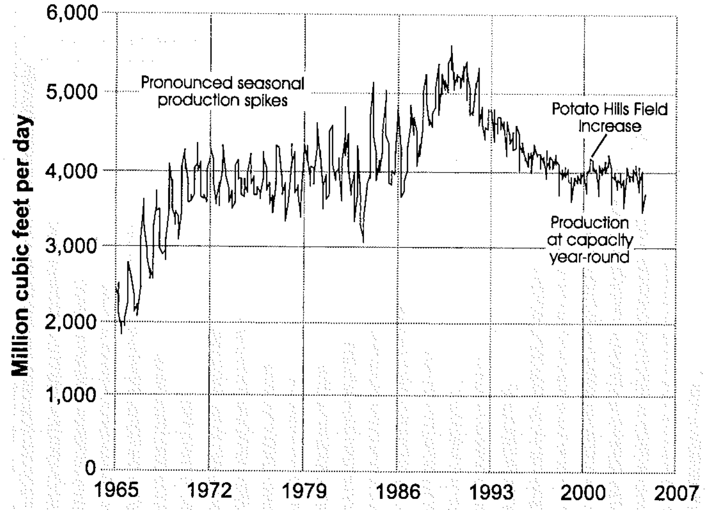


Figure 30. Natural gas production in Oklahoma (gas wells only). From IHS Energy (2004).

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.

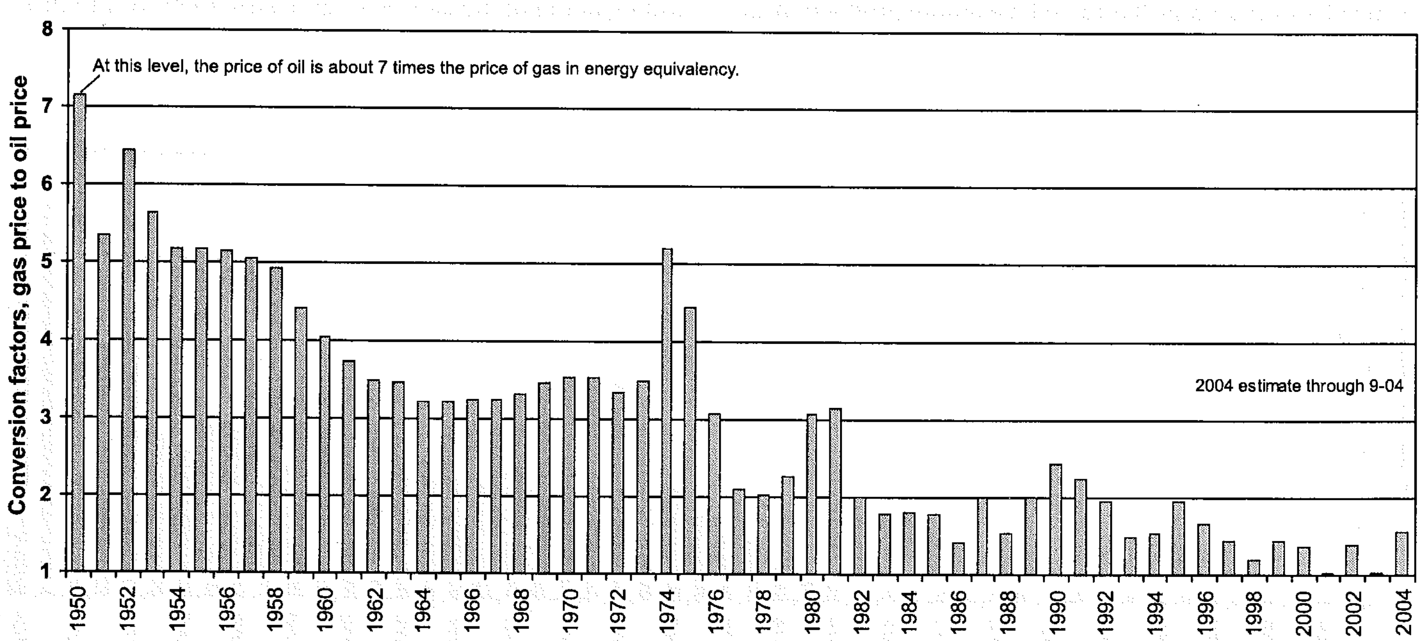


Figure 31. In 1950 the price of oil was close to seven times that of gas, calculated in BOE terms—one barrel of oil and its energy equivalent in gas (6,000 cubic feet). By 2003 the price ratio had fallen to near parity. Data from Claxton (2004).

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

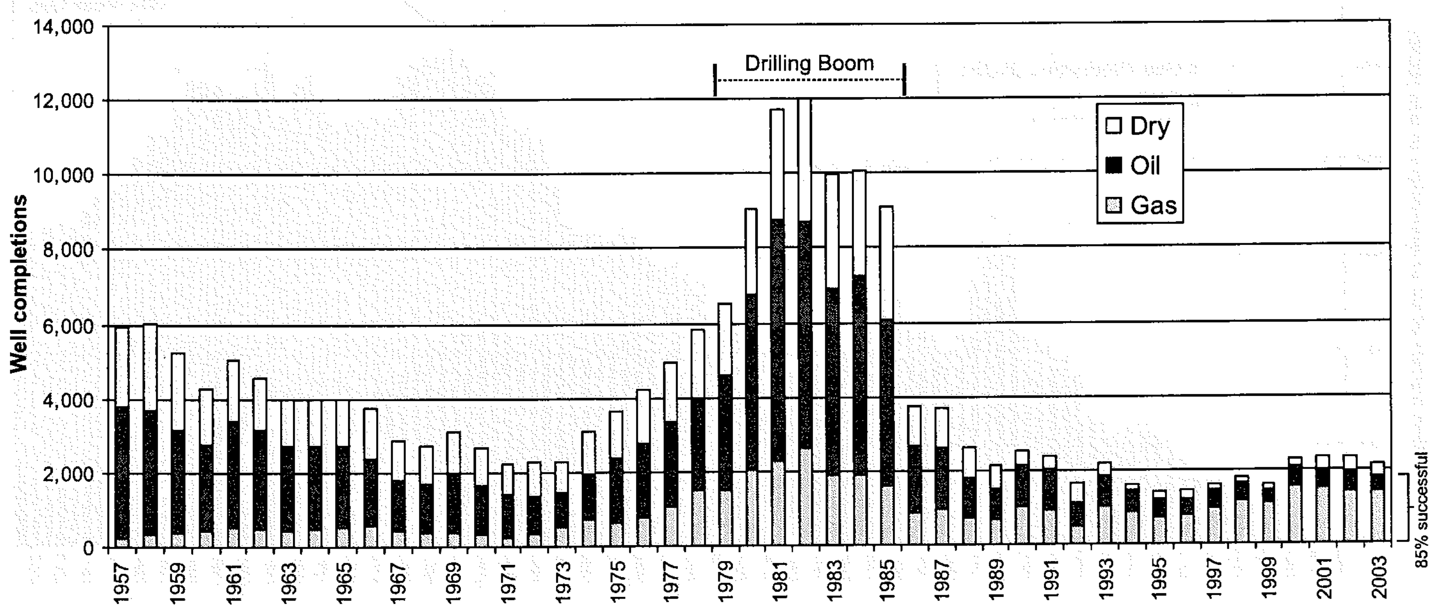


Figure 32. Well completions in Oklahoma—dry, oil, and gas. From Claxton (2004).

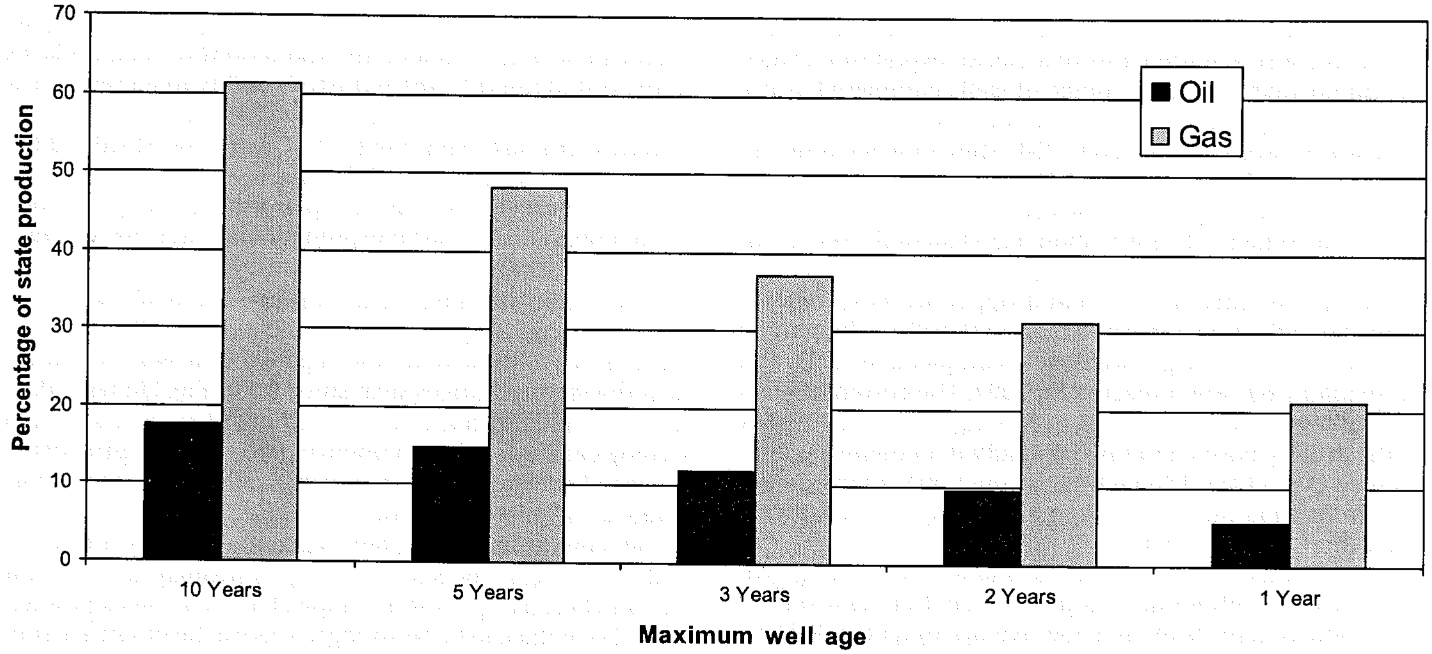


Figure 33. In 2003, wells less than 1 year old produced about 22% of Oklahoma's gas and 6% of its oil. Data from IHS Energy (2004).

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

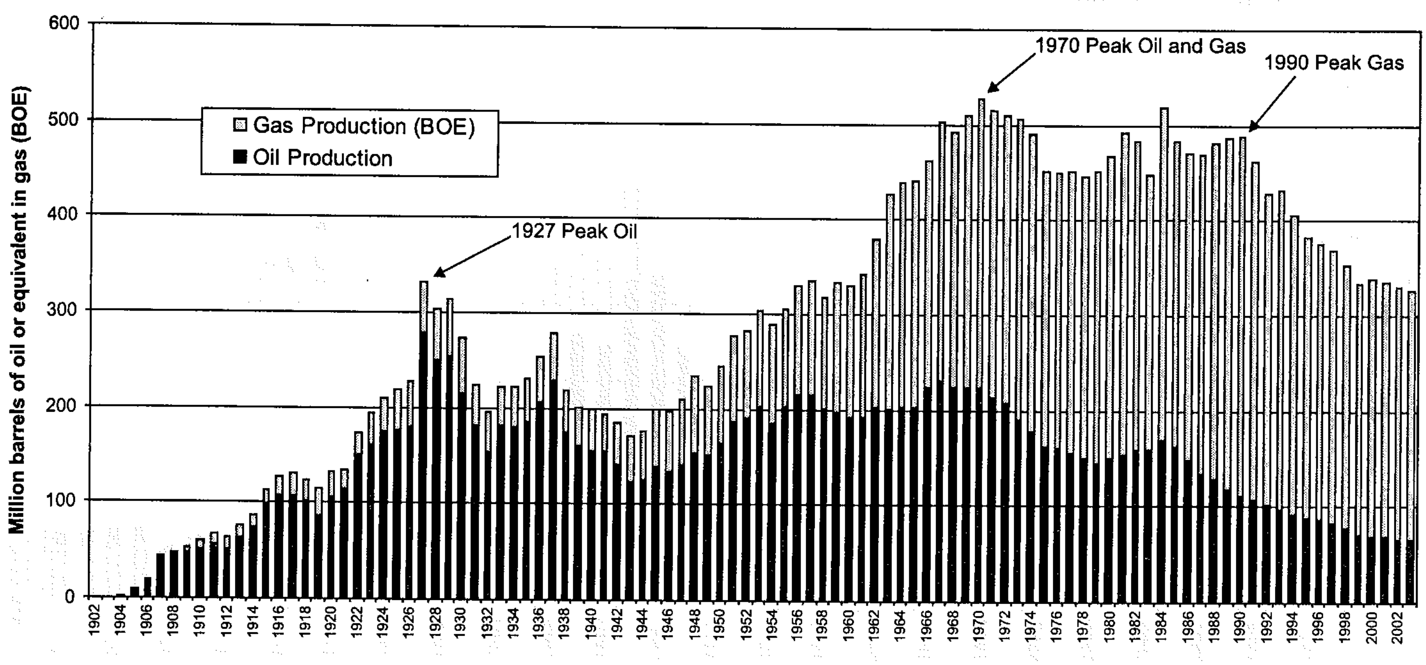


Figure 34. Total hydrocarbon production in Oklahoma (1 barrel of oil = 6,000 cubic feet of gas). From Claxton (2004).

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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Unconventional energy resources (coalbed methane, shale gas, tight gas) are considered the next energy frontier. Of importance to these resources has been the development of completion technology to economically recover gas from low permeability coals, shales, and sandstones. Petroleum exploration and development decisions are made based on technical information and data. To facilitate this technology transfer, the Oklahoma Geological Survey and the National Energy Technology Laboratory of the U.S. Department of Energy cosponsored a symposium dealing with successful practices for developing unconventional energy resources in the southern Midcontinent. The symposium was held in March 2004 in Oklahoma City, drawing about 345 representatives from industry, government, and academia. This volume contains the proceedings of that symposium. The 20 papers and abstracts in this book focus on case histories, best practices, characterization, development, resources, and potential of unconventional energy reservoirs in the southern Midcontinent.

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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.

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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.

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