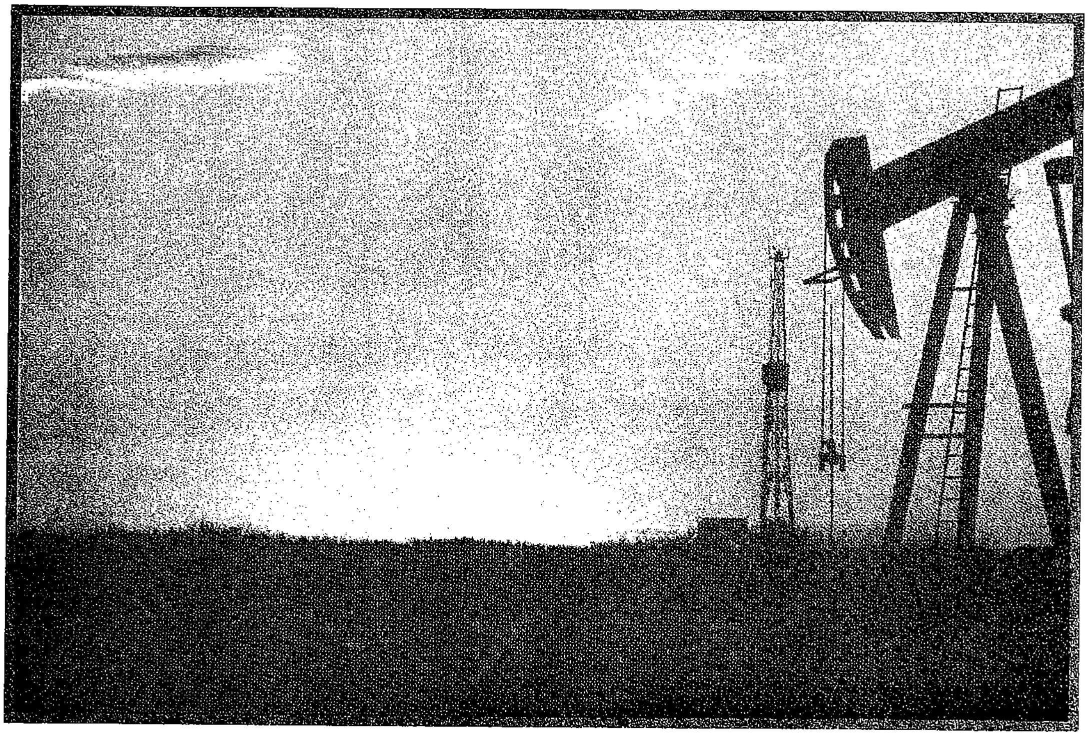
# Oklahoma Oil, Natural Gas, and Our Place in the Big Picture



## Information Series 10

Reprinted from *Oklahoma Geology Notes*, v. 62, no. 3, p. 97–106 (Fall 2002); v. 62, no. 4, p. 143–155 (Winter 2002); and v. 63, no. 1, p. 4–30 (Spring 2003).

Oklahoma Geological Survey
Norman, Oklahoma
2004

# Oklahoma Oil, Natural Gas, and Our Place in the Big Picture

## *Preface*

Although oil and natural gas have always been an integral part of the Oklahoma economy, few are aware of their history in the State, and fewer still are familiar with the underlying issues that ultimately control the industry's health. This publication is an effort to provide the tools necessary for a non-technical audience to understand these important topics. Using a reversal of the geological axiom that states "the present is the key to the past," knowledge of our energy past and how we arrived at our present situation is crucial to understanding what promises to be an unsettled energy future.

This publication is a compilation of three articles first published in *Oklahoma Geology Notes*. "Oklahoma Oil: Past, Present and Future" (Fall 2002 issue) and "Oklahoma Natural Gas: Past, Present and Future" (Winter 2002 issue) examined the evolution of the State's oil and natural gas industries through time and made broad predictions concerning their probable future course. "Oklahoma Oil and Natural Gas, Our Place in the Big Picture" (Spring 2003 issue) places our State into the larger, international energy landscape and shows that the forces shaping Oklahoma's energy industry apply equally to the world at large. Combined, these articles provide valuable insight into the forces affecting the local and global energy communities.

*— Dan T. Boyd*

This publication, printed by the Oklahoma Geological Survey, Norman, Oklahoma, is issued by the Oklahoma Geological Survey as authorized by Title 70, Oklahoma Statutes, 1981, Section 3310, and Title 74, Oklahoma Statutes, 1981, Sections 231–238. 500 copies have been prepared for distribution at a cost of $1,470 to the taxpayers of the State of Oklahoma.

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### Oklahoma Oil and Natural Gas: Our Place in the Big Picture

# Oklahoma Oil: Past, Present, and Future

*Dan T. Boyd*
Oklahoma Geological Survey

[Reprinted as published in *Oklahoma Geology Notes*, Fall 2002, v. 62, no. 3, p. 97–106.]

This is the first of three articles that will detail (1) Oklahoma oil, (2) Oklahoma natural gas, and (3) Oklahoma's place in the national and international energy picture. The series is geared for a non-technical audience; it will review the evolution of our petroleum industry through history and attempt broad predictions about where it's going.

## INTRODUCTION

The impact of fossil-fuel–derived energy on every aspect of American life, from the economy to politics and national security, is tremendous. The success of the oil industry in providing abundant cheap energy is one of the main reasons for the unprecedented prosperity enjoyed by the United States and the rest of the developed world. However, geological and political factors have gradually forced reliance on oil from unsettled areas of the world. We can no longer satisfy petroleum demand from domestic sources, not for lack of technology, nor because we have been cheated by Mother Nature, but because exploration and exploitation of our natural resources has continued for nearly one and a half centuries. For most of that time Oklahoma—first as a Territory and then as a State—has been one of the most rewarding areas to look for petroleum.

Oil and gas are formed by alteration of microscopic organisms that have been deposited with sediment that turns into sedimentary rock. Sediments and organic remains reach maximum thickness when they accumulate in large, gradually subsiding depressions called geologic basins (Fig. 1). With increasing temperature and pressure that result from increased burial depth, organic remains are converted through millions of years into oil and natural gas. These organic compounds consist dominantly of carbon and hydrogen, and so are called hydrocarbons. As oil and gas are less dense than the water in which the original sediment was deposited, where permeable rock makes it possible they migrate upward. Movement ends where blocked or sealed by impermeable rock. The seal is a major component of any hydrocarbon trap, and its extent helps define the size of the oil or gas field that develops.

Oklahoma's prominent place in the oil industry is fortuitous, a result of encompassing the bulk of the hydrocarbon-rich Anadarko, Arkoma, and Ardmore geologic basins and their associated shelves and platforms. Figure 2 shows the approximate outline of these basins and adjacent areas, and

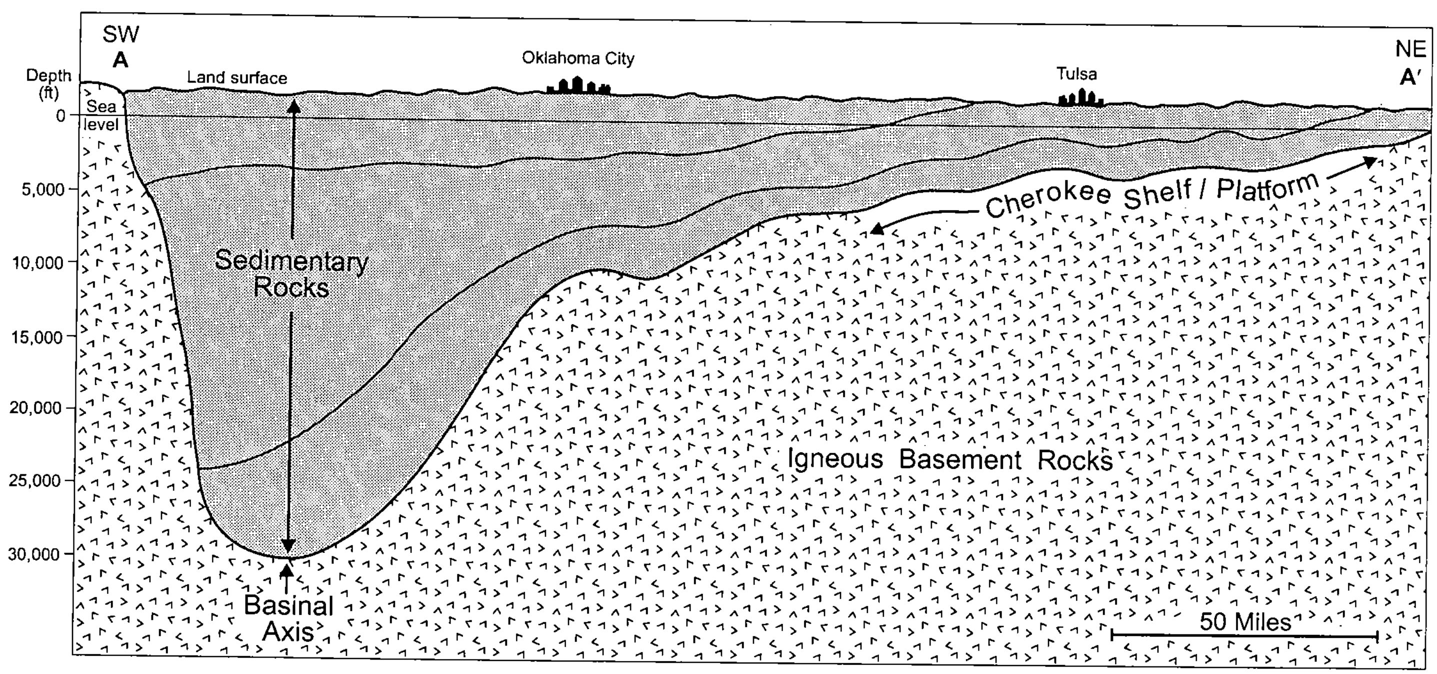


Figure 1. Cross-section of the Anadarko geologic basin. Modified from W. J. Witt and others (1971). Vertical exaggeration 14:1. See Figure 2 for base map.

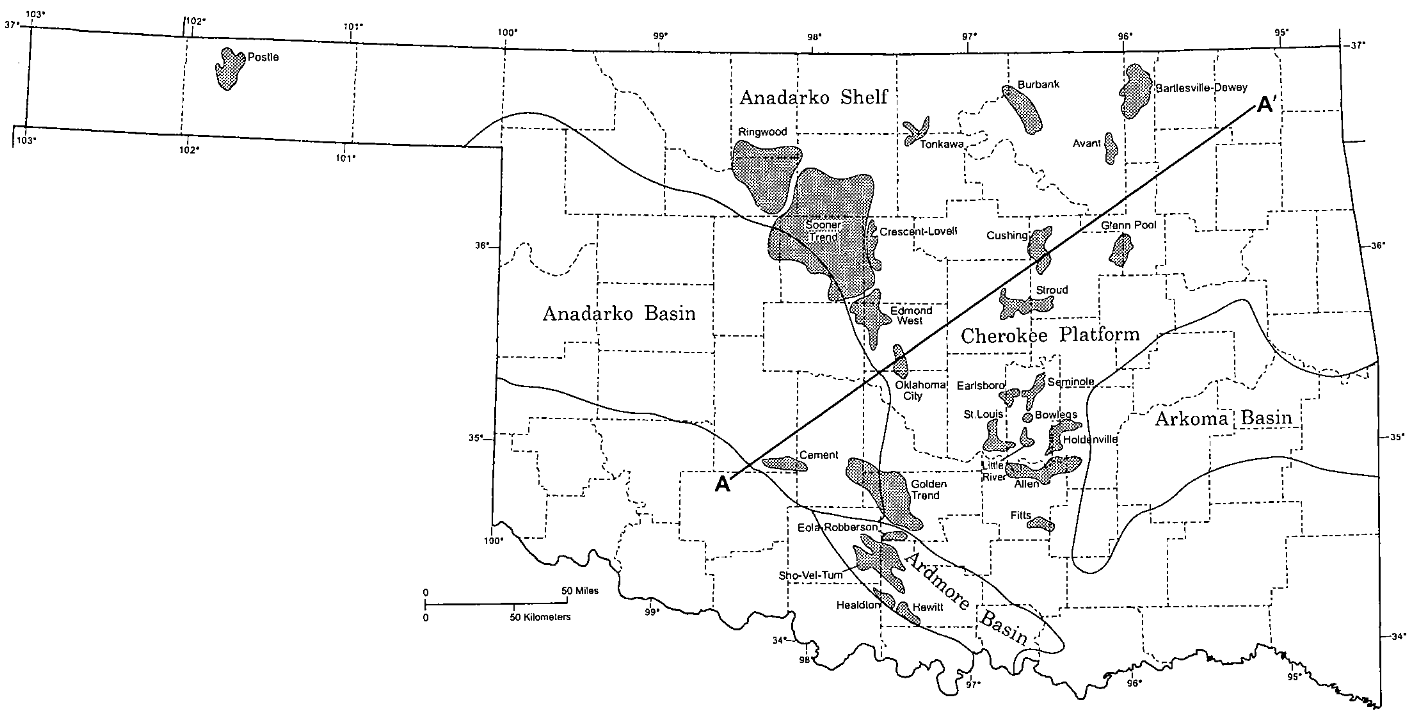


Figure 2. Petroleum provinces and major Oklahoma oil fields (>100 MMBO through January 2002). Modified from Robert A. Northcutt and Jock A. Campbell (1995) and Dan T. Boyd (in press).

also the State's major fields—those that have produced more than 100 million barrels of oil (MMBO). The sedimentary basins that have yielded the bulk of Oklahoma's oil production are mostly Pennsylvanian in age, but oil and gas reservoirs across the State range from Cambrian to Cretaceous (Fig. 3).

## EARLY HISTORY

Oil seeps were recognized in Oklahoma long before the arrival of European settlers, who mined some seeps for asphalt. The first subsurface oil was recovered by accident, in 1859, in a well drilled for salt near present-day Salina (in Mayes County); its small amount of oil was sold for use in lamps. The first intentional oil find came from a well drilled in 1889 in an area of seeps near Chelsea (Rogers County); the well produced a half barrel of oil per day, used as "dip oil" to treat cattle for ticks (Franks, 1980).

The first commercial paying well, the Nellie Johnstone No. 1, was drilled in 1896 near Bartlesville (Washington County). Completed in 1897 as the discovery well for the giant Bartlesville-Dewey Field, the well ushered in the oil era for Oklahoma Territory. Production there and in other areas rose rapidly thereafter, adding much impetus towards the granting of Statehood in 1907. In the 10 years between the first discovery well and Statehood, Oklahoma became the largest oil-producing entity in the world.

After the turn of the century, discoveries were made in rapid succession in areas that would eventually encompass many of the 26 major oil fields (Fig. 4). All but five of the majors were discovered before the end of World War II; the last of them, the Postle Field, was found in Texas County in 1958 (Northcutt, 1985). Although the 26 majors constitute only about 1% of the total number of fields, they account for 59% of the total oil produced (Lay, 2001).

Until overtaken by California in 1923, Oklahoma remained the leading producing state in the U.S. (Hinton, 2001). Peak annual production of 278 million barrels (762,000 bbls/day) was reached in 1927, with several intermediate highs and lows since then. The peaks and valleys result from changes in the number of wells drilled and completed as well as from the size of the fields being found.

The historical production figures cited in Figure 5 are from the Oklahoma Corporation Commission and are based on volumes on which taxes have been paid to the State (Claxton, 2001). These volumes include condensate, but this is estimated to represent only 3% of the liquid hydrocarbons produced. Totals are believed to be accurate, but allocation of production to specific fields and reservoirs is often difficult. State records carry cumulative production by field only through 1979, forcing cumulative field-production figures to come from the International Oil Scouts Association. Also, many fields have been combined into larger fields or trends; for example, the Sooner Trend encompasses more than 100 previously defined fields.

As can be seen from well-completion history (Fig. 6), Oklahoma has had three major drilling booms. The first occurred just after Statehood; it lasted through 1930, and was most active from 1913 through 1920. That spate of drilling brought Oklahoma into the club of major oil producers. The lull that followed lasted through most of WWII, and was followed by a second boom that reached its peak in the years 1953–1956. Then drilling gradually declined, reaching postwar lows in 1971–1973.

| DIVISIONS OF GEOLOGIC TIME | | | | | Age (approx.) in millions of years |
|---|---|---|---|---|---|
| Eon | Era | Period | | Epoch | |
| Phanerozoic | Cenozoic | Quaternary | | Holocene | 0.010 |
| | | | | Pleistocene | 1.6 |
| | | Tertiary | | Pliocene | 5 |
| | | | | Miocene | 23 |
| | | | | Oligocene | 35 |
| | | | | Eocene | 57 |
| | | | | Paleocene | 65 |
| | Mesozoic | Cretaceous | | Late | 97 |
| | | | | Early | 146 |
| | | Jurassic | | Late | 157 |
| | | | | Middle | 178 |
| | | | | Early | 208 |
| | | Triassic | | Late | 235 |
| | | | | Middle | 241 |
| | | | | Early | 245 |
| | Paleozoic | Permian | | Late | 256 |
| | | | | Early | 290 |
| | | Carboniferous | Pennsylvanian | Late | 303 |
| | | | | Middle | 311 |
| | | | | Early | 323 |
| | | | Mississippian | Late | 345 |
| | | | | Early | 363 |
| | | Devonian | | Late | 377 |
| | | | | Middle | 386 |
| | | | | Early | 409 |
| | | Silurian | | Late | 424 |
| | | | | Early | 439 |
| | | Ordovician | | Late | 464 |
| | | | | Middle | 476 |
| | | | | Early | 510 |
| | | Cambrian | | Late | 517 |
| | | | | Middle | 536 |
| | | | | Early | 570 |

Figure 3. Geologic time scale. From Harland and others (1990) and Hansen (1991).

The first drilling boom was driven by the number and size of discoveries made early in the 20th century. The second resulted from increased demand for petroleum products during conversion to a peacetime economy. (Both were caused by world and economic events that had little long-term impact on oil price.) The third and most recent boom resulted from increased oil prices arising from political tension in the Middle East (Fig. 7); however, its root cause was a gradual shift of the world's production capacity and reserves from consuming countries to less-developed areas represented by OPEC—the Organization of Petroleum Exporting Countries.

## ANATOMY OF A DRILLING BOOM

The decline in Oklahoma's oil production since 1967 (Fig. 5) mirrors that of the United States as a whole. By the late 1960s, exploration in most of the prospective petroleum provinces in the country—the North Slope of Alaska and the deeper-water Gulf of Mexico being prominent exceptions—had been underway for at least 50 years, and from an exploratory standpoint most of these provinces had matured. In any area, as the number of wells increases, understanding of the many factors affecting oil accumulation increases correspondingly. Eventually, nearly all significant reservoirs and their structural and stratigraphic trapping styles (called "geologic plays") are identified. The play types are exploited through a combination of random (or trend) drilling and prospecting driven by science and technology. As the process continues, the mean pre-drilling prospect size, which is based on historic discovery sizes, becomes progressively smaller. The trend of diminishing prospect size is a natural outgrowth of increased well density, and occurs simply because it is more difficult to hide large fields in the progressively smaller areas yet to be drilled.

Most geologic plays reach a point at which the potential reward no longer justifies the risk and expense of large-scale exploration, and activity moves elsewhere. For Oklahoma as a whole, that point was reached in the late 1960s (Fig. 6). The

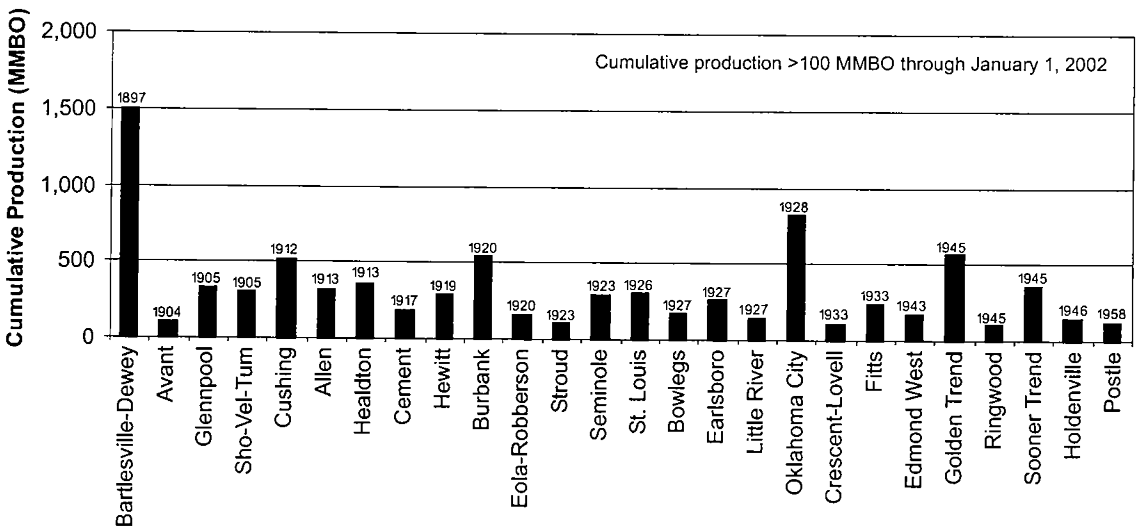


Figure 4. Major oil fields in Oklahoma; their cumulative production with discovery dates. From Lay (2001).

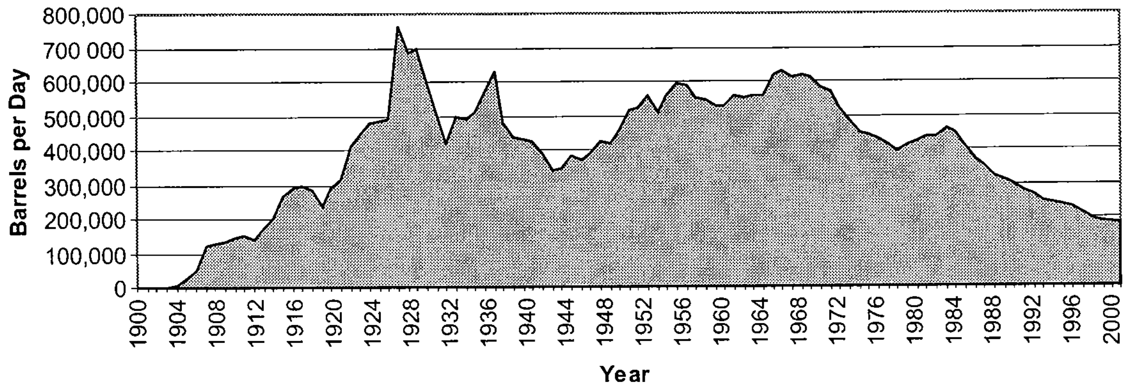


Figure 5. Historical oil and condensate production in Oklahoma. From Claxton (2001).

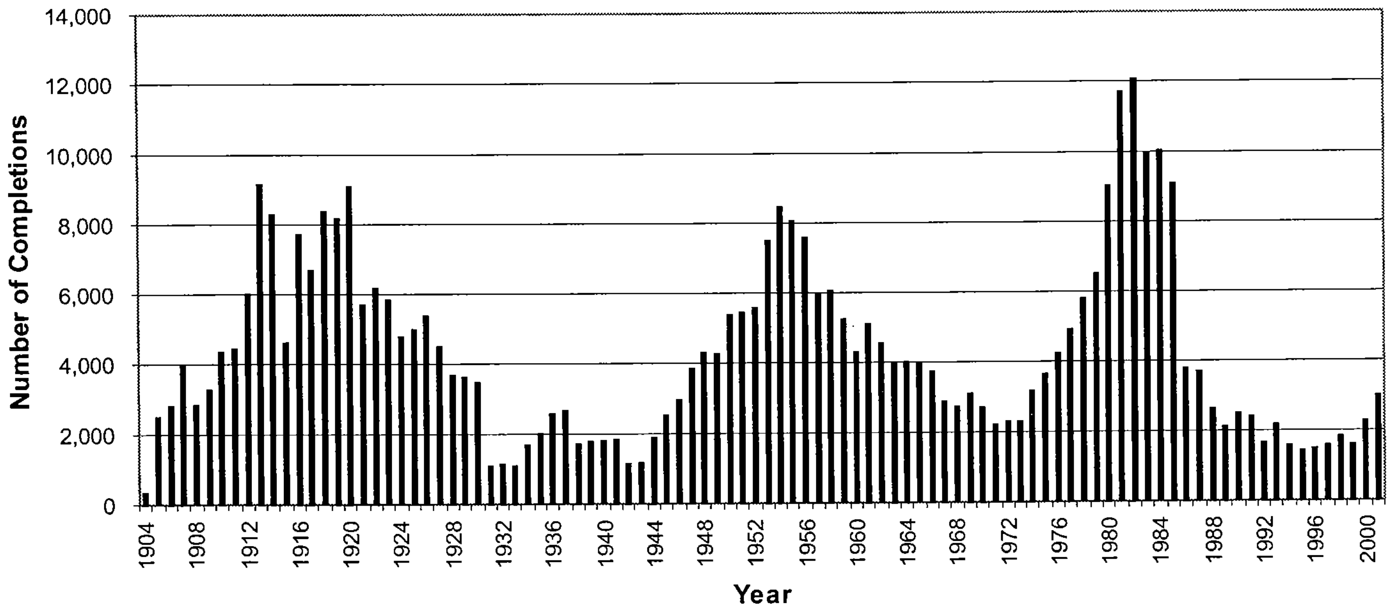


Figure 6. Oklahoma's well-completion history (producers and dry holes). From Claxton (2001).

price of crude oil had remained nearly flat for decades (Fig. 7), and discovery sizes no longer justified widespread exploration. This conclusion is inferred from the overall completion history and discovery rates, as the State did not record new-field wildcats until 1980. In 1967 oil production began a long downhill slide only briefly interrupted by the drilling boom discussed below. During the late 1960s the State's productive capacity was maintained by its older, larger, longer-lived fields. Here thousands of wells continued to produce, many in enhanced recovery projects involving water injection. Such larger fields take longer to drain, and lend themselves to recovery-enhancement techniques that usually continue for decades.

In that environment began the last major drilling boom in Oklahoma. In spite of weak drilling activity, oil production reached its second-highest peak in 1967, when about 231 MMB was produced (Claxton, 2001). A steep decline ensued between 1970 and 1975, averaging 6.1% per year (Fig. 5). Using the average number of oil completions from 1967 to 1974 (~1,250) as the pre-boom average: the drilling boom began slowly in 1975, peaked in 1981, and ended in 1987. (Figure 8 shows completions, which—because more than one oil reservoir may be stacked in a single well—only approximates actual drilling.) The jump in activity was caused not by the opening of a new geologic play, nor by a technological advance, but by a rapid increase in crude oil price beginning in 1974 (Fig. 7). From an economic standpoint the near doubling of Oklahoma crude prices—from \$3.78 per barrel in 1973 to \$7.18 in 1974—had the effect of doubling every oil well's production rate, as well as the value of its reserves in the ground. In one year the rise in price halved the reserves necessary for a well to make money. In addition, as the years passed and the expectation of continuing price increases was factored into economic analyses, progressively smaller well recoveries became attractive.

The State has separated oil and condensate production since 1975, which allows these statistics to apply to oil alone: after a period of steep (>6%) declines, from 1975 through

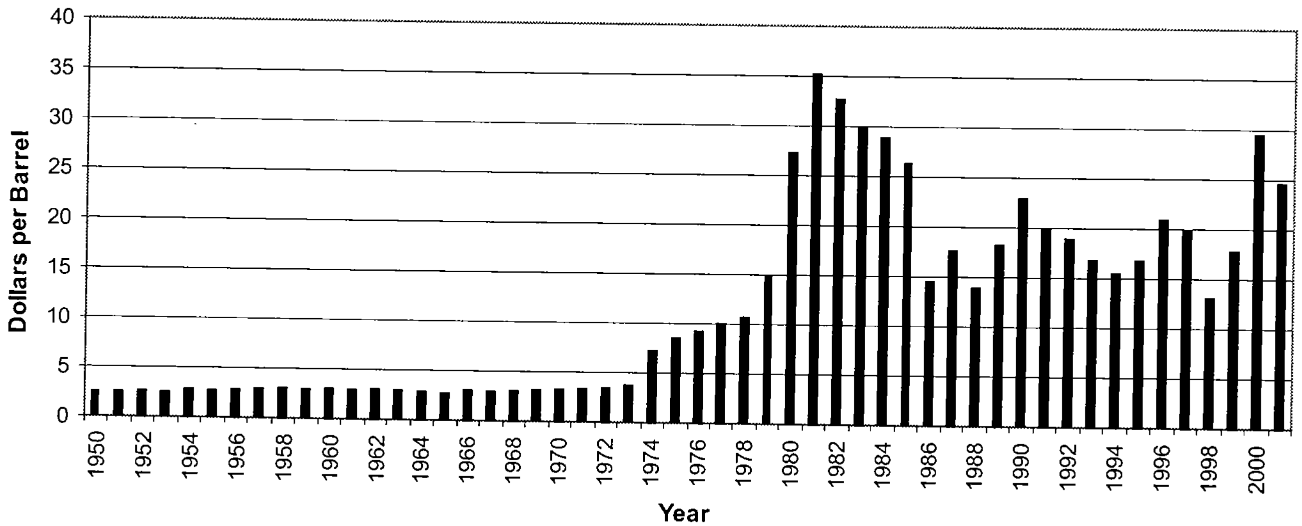


Figure 7. Average annual crude-oil price (unadjusted) in Oklahoma. From Claxton (2001).

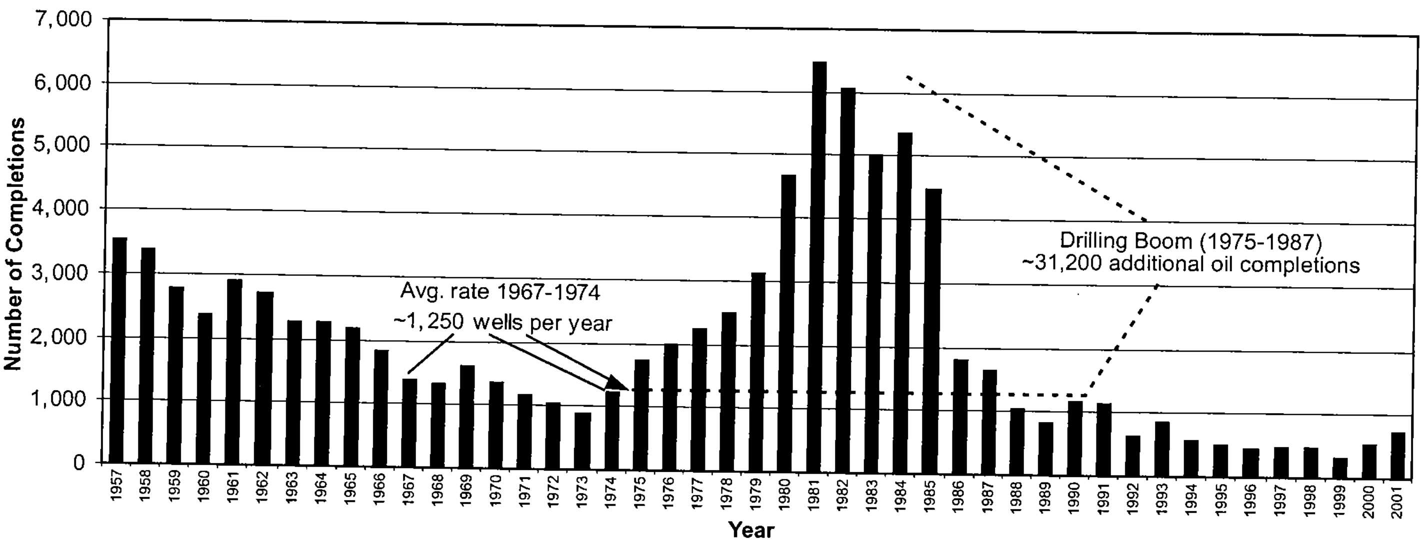


Figure 8. Historical oil-well completions in Oklahoma, showing the last major drilling boom. From Claxton (2001).

1979 the annual decline in Oklahoma's oil production averaged about 3.5%. Increased drilling during the boom inclined production from 1979 through 1984 (Fig. 9), but this 5-year rise was followed by a precipitous 6.6% annual decline from 1984 through 1990. In succeeding years the oil production curve flattened, until reaching the rather steady 3.1% average decline observed since 1993. By comparison, with large discoveries still being made in less mature areas, like the deep-water Gulf of Mexico, overall U.S. oil production for the same period (1993–2001) declined only 2.2%. Higher oil prices and the resultant increase in drilling for 2000 and 2001 have tended to flatten both the overall U.S. and Oklahoma production declines. However, with no significant new fields being added in Oklahoma, our long-term decline will probably remain significantly above the national rate.

On the Figure 9 graph, if we extend the line depicting the 3.1% decline since 1993 backwards through the boom years, it intersects the line for actual annual production in 1979. By that analysis: the area of the production curve above the artificial 3.1% decline curve (from 1979 through 1993) represents oil produced as a result of the increased drilling. This volume is 234 MMBO, and translates—with about 31,200 extra completions necessary for the increase—to 7,500 barrels per completion between 1979 and 1994. Although data are not available for determining the typical number of completions per well in Oklahoma, the average ultimate recovery for an oil well drilled during the boom is unlikely to be much more than 10,000 barrels.

Methods for calculating the volume of oil produced as a result of the drilling boom can vary, but probably not significantly from this analysis. In the six years after the end of the production boost (1993–1999) Oklahoma's oil decline averaged 4.5%. Given that this decline is significantly greater than the 3.5% before the boom, we can argue that the bulk of the 234 MMBO found was accelerated production—oil that would have eventually been produced from existing wells.

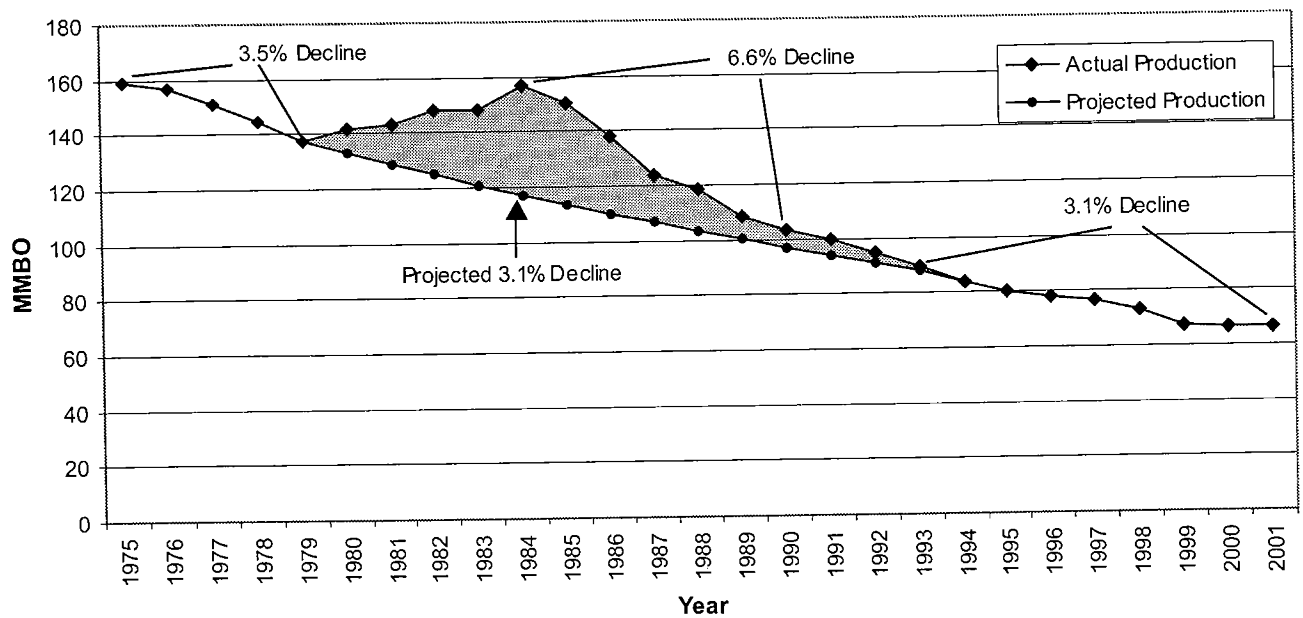


Figure 9. Annual oil production in Oklahoma, showing oil produced as a result of the last drilling boom. From Claxton (2001).

This contention that insubstantial new reserves were discovered is supported by the average success rate seen during the boom years of 1975 through 1987. The proportion of producers (non-dry holes) in that period has been shown by the Oklahoma Corporation Commission (Claxton, 2001) to range between 65% and 75% (Fig. 10). True wildcat success rates are far less than 65%, and the dry-hole percentage indicates that most drilling and completion activity during the boom was developmental. For the discoveries that were made, their small size is confirmed by their short-term impact on the State's production profile. Note the decreasing proportion of oil completions, relative to gas, that occurred after the drilling boom; it reflects both a percentage and an overall numeric reduction in oil-targeted drilling through time. The drilling boom nominally lasted through 1987. However, because of rapid declines and progressively less oil drilling, the divergence from the pre-boom production decline shrank dramatically after 1988, and was gone entirely by 1993—the year in which the positive effect of the drilling boom disappeared (Fig. 9).

From a Statewide perspective, except for the acceleration of tax revenues, another drilling boom has little long-term value to Oklahoma. It may be enjoyable as long as it lasts, but it would only hasten the end of meaningful oil production. Higher prices for oil would aid the State's oil industry, certainly in the short term. However, if the increased income is not used to initiate investment in enhanced recovery projects, the party will be very short. But more on this later.

## WHERE DO WE STAND NOW?

State tax records show that cumulative oil (and condensate) production from Oklahoma totals about 14.5 billion barrels. The State ranks fifth in crude oil produced and accounts for 3% of national production (Hinton, 2001). That's about a quarter of the peak rate reached in 1927, and is roughly equal to that of 1913. Although the volume is less than in the past, at $25 per barrel 2001's production was still worth $1.7 billion.

Apart from the boom years, Oklahoma's oil production has, since 1967, undergone a generally continuous decline. The drilling boom in the late 1970s and early 1980s temporarily reversed the trend, but since the late 1980s the general decline has been firmly reestablished. Up-ticks in oil price and drilling in 2000 and 2001 have tended to level production, but, at this writing, 2002 seems likely to restore our long-term 3.1% decline. Because of the large number of wells in both the oil-producing and potentially oil-producing regions of the State, it is unlikely that the overall decline will change markedly as a result of new discoveries. Some sparsely drilled areas with oil potential do exist, and some may eventually prove economically viable. However, even taken together they offer no reasonable hope of markedly changing the trend.

In the early days, drilling activity rose and fell with the number and size of exploratory successes. Today, Oklahoma's oil industry is mature, and oil production nationally is at 100% of capacity, so price is the key variable that affects activity. Because the U.S. consumes more than twice as much oil as it produces, price will remain beyond our control, as will other major factors affecting the health of the oil industry in the State. The bulk of the State's oil comes from low-rate, stripper wells (<10 barrels per day), mostly in large fields that have been producing for decades. The maturity of the industry is highlighted by the average production rate for an oil well in Oklahoma—about 2.2 barrels per day. Compare that with the national average, which is about 11 barrels per day.

At the beginning of 2002, Oklahoma had about 84,000 active oil wells, producing about 183,000 barrels per day. Such low-rate wells are more sensitive to oil price than higher volume wells because the income generated is often not much

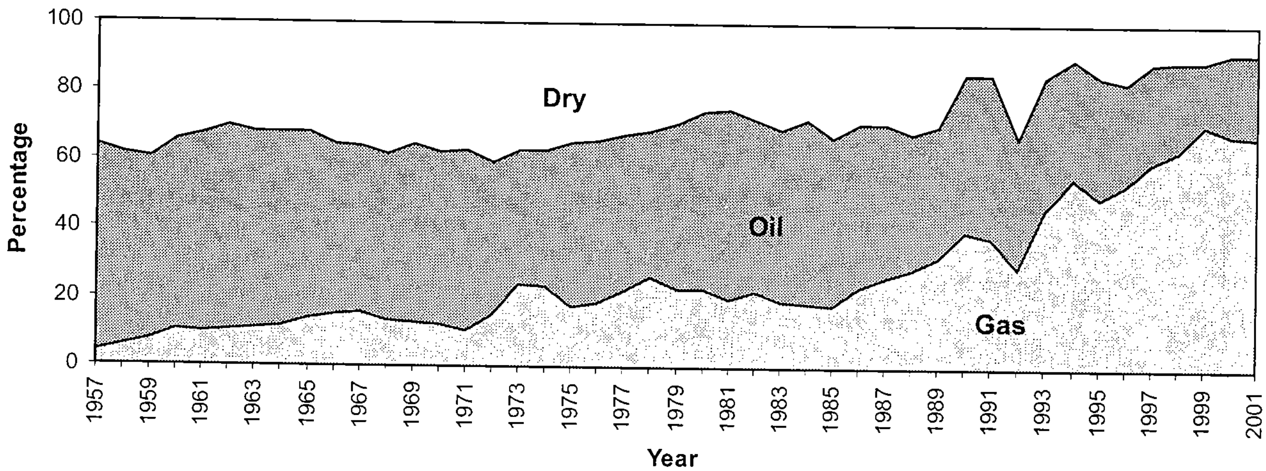


Figure 10. Oklahoma's well-completion history (all wells). From Claxton (2001).

more than the operating expense. The wells continue in production as long as maintenance is minimal and little more is required than simply collecting the oil. However, if mechanical failure requires significant expense, or if the oil price falls below an economic threshold, the well will go idle. The length of time between being shut-in and being plugged and abandoned (sometimes just abandoned) depends on the endurance of the operator and how long the price remains uneconomic. Once a well is plugged, production from its drainage area is usually lost forever. Even if the oil price rises, the prospect of another low-rate producer is likely to discourage reentry or workover of an existing well, much less drilling a new one.

Of approximately 100,000 wells producing in 1984—the last peak year of oil production—fewer than half are still producing (Claxton, 2001). This helps explain the steepness of the initial post-boom decline. It also points to the need to do as much as possible to keep stripper wells producing. In 1992 the Oklahoma Legislature created the Commission on Marginally Producing Oil and Gas Wells for the express purpose of helping operators manage marginally producing wells. The intent was to help operators weather the inevitable price dips, and keep the State production decline to a minimum. In addition, the Oklahoma Geological Survey offers low-cost, play-based workshops and a variety of other programs to aid operators. The programs help identify practical techniques and technology for finding new fields, as well as how to produce oil efficiently in existing fields.

## WHAT'S LEFT?

The simplest way to markedly increase long-term oil production is to discover large, long-lived fields. The size distribution in any petroleum province is the same, with larger, easier-to-find fields making up a disproportionate share of total production and reserves. Oklahoma is no exception: its 26 major oil fields account for 59% of the oil produced. Each of the next 137 fields (in order of size) has produced at least 10 MMB of oil. Together accounting for only 5% of the total number of oil fields in the State, these 163 fields account for over 83% of production (Fig. 11).

The mean discovery date for Oklahoma's major fields is 1925, and for those that have produced more than 10 MMBO, 1934 (Lay, 2001). The last field to be discovered with recovery of more than 10 MMBO was the Wheatland Field (in Oklahoma County), discovered in 1981 (Fig. 12). A handful of fields not on this list will eventually break the 10 MMBO hurdle, but none by much. In total approximately 3,100 fields with some oil component, many already abandoned, have been found thus far. In size they are strongly skewed toward the small end of the spectrum, the fields with less than 10 MMBO of recovery averaging only 800 MBO.

These facts have not been lost on the industry, and the bulk of oil drilling continues to be directed towards infilling, extending, and adding new reservoirs to existing fields. Some areas may be under-explored, an example being the part of the Ouachita Uplift in central Atoka County and southern Pittsburg County (Campbell and Suneson, 1990). However, these are all high-risk areas, and even the greatest optimist would find it difficult to assign speculative reserves amounting to as much as 1% of past production.

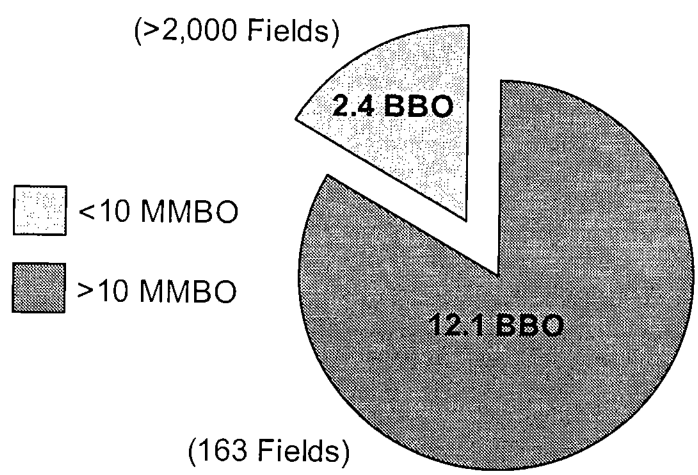


Figure 11. Oklahoma's oil (and condensate) production by field size. From Lay (2001).

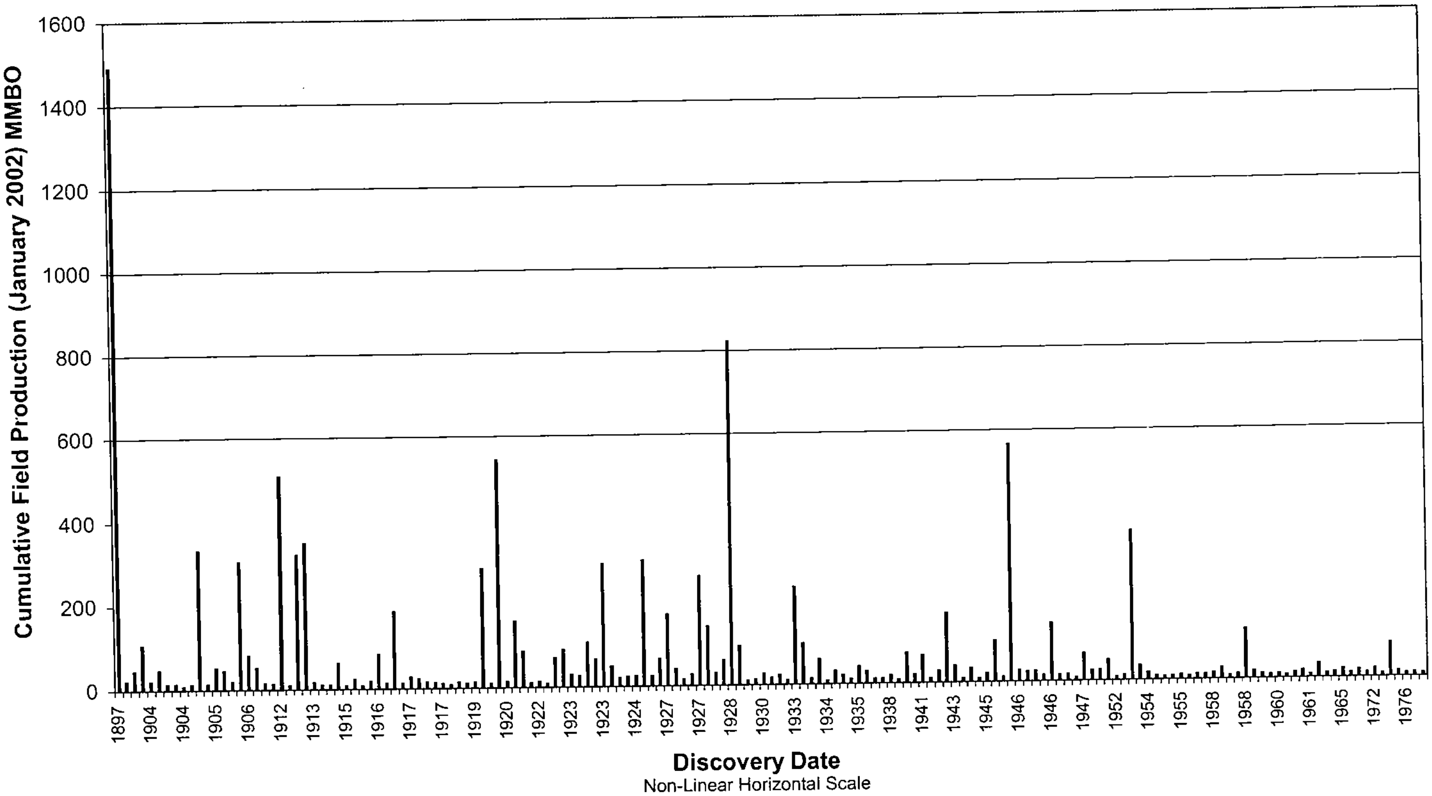


Figure 12. Oklahoma's oil-field discoveries by date (>10 MMBO cumulative recovery). From Lay (2001).

New-field wildcat numbers can be a measure of interest in exploration. In Oklahoma, fields are defined geographically, and to be declared a new-field wildcat a well must be located more than one mile from established production. Any well completed within a mile of production, whether producing from a different formation or from a disconnected reservoir compartment in the same formation, is defined as developmental. As nearly 500,000 wells have been drilled in the State, the feat of making a true discovery has become increasingly difficult. The Oklahoma Corporation Commission has kept data on the total number of wildcats drilled since 1980, shortly before the last drilling boom peaked (Fig. 13). Although these data include both oil and gas drilling, they accurately mirror the precipitous decline in overall exploratory activity through the middle and late 1980s (Fig. 8).

Because so many variables are involved, determination of remaining reserves is notoriously difficult. However, the situation in Oklahoma is somewhat more straightforward than in many other areas. Few new reservoirs are being added to the producing mix, and with 84,000 active wells scattered throughout 2,000 fields, the aggregate decline is well established. The primary source of uncertainty is, as always, the price of crude oil. A prolonged rise in price, as was seen in 2000 and 2001, can increase drilling and completions and thereby reduce the decline rate, at least in the short term. A prolonged fall in price can drop many wells beneath their economic threshold, causing large-scale abandonment and a corresponding increase in the rate of decline. For Oklahoma, changes in annual estimates of remaining reserves are based almost exclusively on accounting adjustments centered on new pricing assumptions, rather than on the addition of new reservoirs or fields.

In their last estimate at the beginning of 2000, the Energy Information Administration of the U.S. Department of Energy projected Oklahoma's proved oil reserves at 610 MMBO (Hinton, 2001). (The estimate was based on a poll of the State's thousands of operators.) Subtracting actual production through January 1, 2002, yields remaining reserves of 477 MMBO. Thus the EIA estimate leads to the conclusion that 97% of the State's ultimate oil recovery has already been produced.

Reserve estimates are meant to quantify bankable production, so they must take into account any factor that may have a negative impact on the oil actually reaching the market. Assuming that long-term oil prices remain stable—an unlikely event—the State's production decline should stay near the 3.1% rate that has prevailed for the last 9 years. If it does continue so, by 2010 the EIA reserve volume will have been produced. At this time the average well will be producing about 1.2 bbls per day, and Statewide production will still be more than 100,000 bbls per day. Economic production rates vary from area to area and well to well, but a large fraction of the State's production already comes from wells making less than 1 bbl per day. Given current trends in drilling and plugging, if the average abandonment rate for an oil well in Oklahoma is assumed to be 1 bbl per day, remaining reserves at the beginning of 2002 should be about 790 MMB. If this were reduced to 0.5 bbl per day, 1,080 MMBO would remain. Under such assumptions the good news is that (short of a pricing catastrophe) the chances are excellent that Okla-

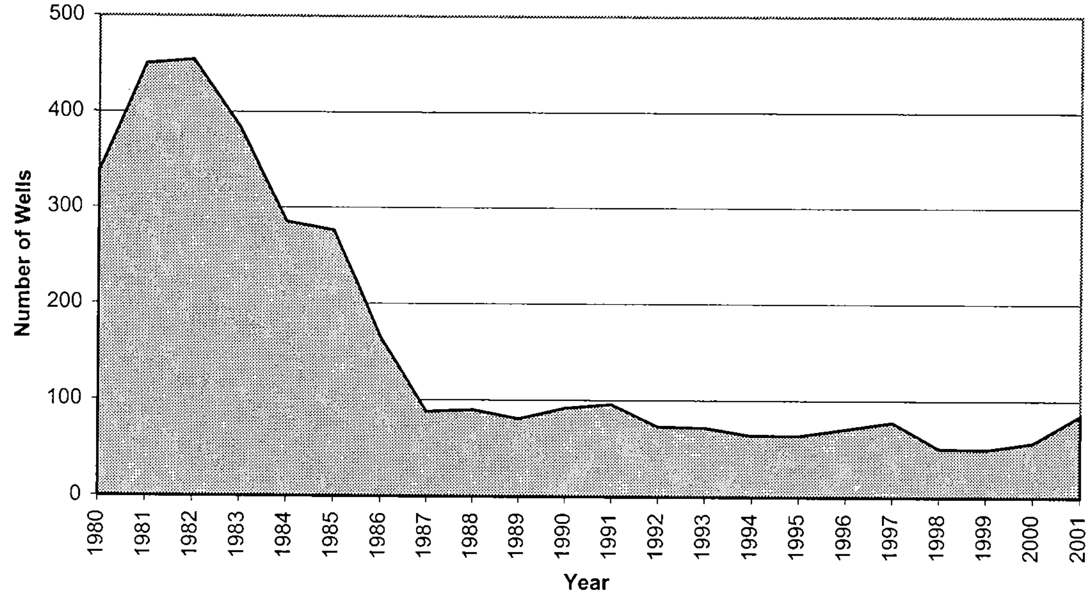


Figure 13. Historical new-field wildcat drilling in Oklahoma. From Claxton (2001).

homa will produce significantly more oil than the EIA now expects. The bad news is that the end is in sight.

The truth is that another price spike and drilling boom would bring only a short-lived respite to the long-term drop in Oklahoma's oil production. Worse, it would probably bring on an even sharper decline in succeeding years because the vast bulk of the increase would likely be in accelerated production. The likelihood of making one or more oil discoveries that would significantly change the State's long-term production curve has become vanishingly small. Therefore the only way to make a long-term, positive impact on the oil-production decline in Oklahoma is to enhance recovery in fields that have already been found.

Studies by the Oklahoma Geological Survey of fluvial-dominated deltaic reservoirs, from which a large fraction of the State's oil has come, indicate a current average recovery factor of about 15% of the original oil in place. Even if average recovery is stretched to 25%, three times as much oil as has already been produced is still in the ground. Cumulative oil recovery stands at more than 14 BBO. Regardless of how it is calculated, the volume of oil still residing in Oklahoma reservoirs is not less than 42 BBO, and could be as much as 93 BBO, and all of it has been mapped.

Even a small increase in the overall recovery percentage would yield huge rewards. The only way to markedly enhance the State's oil future is to systematically re-evaluate the means of increasing recovery in existing fields. The effort would be manpower intensive, requiring collaboration between engineers and geologists. Acquisition of data—pressure and production data especially—would take time and usually be incomplete. In spite of the State's forced unitization rules, land acquisition would be a major problem, but diverse ownership contributed to the haphazard field development that has left so much oil in the ground.

Much of the secondary and enhanced recovery work done thus far has been piecemeal. Except in the largest fields there has been little coordination between operators and undoubtedly little detailed, field-wide reservoir simulation work. A map of the waterflood unit boundaries maintained in the NRIS database (those active since 1979) shows an irregular patchwork of secondary recovery projects that overlay roughly half of the oil-producing leases in Oklahoma. Based on field studies by the OGS, many waterflood units have been subdivided into smaller areas that are operated in isolation and at cross-purposes with the management of adjacent units.

A necessity for increased oil recovery is regional mapping to show in detail the depositional environments of reservoirs. Such maps help define actual and expected reservoir geometry, and they can lead to the identification of areas with the greatest potential for undrained reservoir compartments. Combined with regional porosity and permeability trends, the maps can be used to assign provisional recovery factors for reservoirs with similar characteristics. This can then be compared with actual production to set practical recovery goals. (Such recovery factors would still be minimum values because they cannot take into account future technical improvements in drilling, completion, or recovery.) When actual recovery factors are applied to the volumetric estimates of the original oil in place, we can determine a realistic incremental recovery target using proved techniques. Analysis will not only highlight the most efficient techniques, but also reveal a practicable course of action for various types of reservoirs.

Many factors affect the capacity of a reservoir to produce oil, and their relative importance varies from place to place. Primary factors include porosity, permeability, thickness, and geometry—the reservoir's shape and connectivity. A reservoir classification scheme based on these four variables is adequate in identifying poorly drained areas and rank them by incremental oil recovery. The most attractive projects can be further evaluated based on other factors that affect recovery and economics. The additional factors include depth, well spacing, drilling and completion practice, reservoir pressure, drive mechanism, oil gravity, and gas saturation. The ranking of those projects with the greatest potential reward could be further refined on the basis of non-geologic criteria such as data availability, well condition, and ownership.

Much detailed work is necessary to determine the economic feasibility of such projects, but as most of the State's largest oil accumulations were discovered more than 70 years ago, and initial (often intermittent) waterflooding commenced 20–30 years after their discovery, there are undoubtedly many opportunities. Consider only the 163 fields that have each recovered more than 10 MMBO: every 1% of incremental recovery would add about 500 MMBO, or the equivalent of five major oil fields. With a series of long-lived, and potentially high-recovery projects, Oklahoma's oil production could actually experience a modest increase. Although an increase might be brief, the effort would certainly extend the life of the industry and the State's oil revenue for decades beyond current estimates.

We face no shortage of challenges associated with such an undertaking, but the potential rewards are great. Enhanced recovery is the only way that Oklahoma can add to its dwindling oil supply. Our biggest problem lies in forecasting the price of oil over the long term. That is especially true for projects that have substantial up-front costs and a long payout. However, once the initial investment is digested and production begins to respond, the economics for large enhanced-recovery projects usually become far more robust. A prudent strategy, in anticipation of the sustained oil price increase that must inevitably come, is to gather data and rank candidate fields now, while interest in such projects is relatively low.

## ACKNOWLEDGMENTS

Special thanks are owed to Charles J. Mankin, Robert A. Northcutt, Neil H. Suneson, Jock A. Campbell, and Richard D. Andrews: they read the manuscript and provided valuable input. Maxwell Tilford (Tilford Pinson Exploration LLC) carried out the formal review and made many useful suggestions; Wendell Cochran did the technical editing. The data used came primarily from the Oklahoma Corporation Commission, the Energy Information Administration of the U.S. Department of Energy, and the International Oil Scouts Association.

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# Oklahoma Natural Gas: Past, Present, and Future

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[Reprinted as published in *Oklahoma Geology Notes*, Winter 2002, v. 62, no. 4, p. 143–155.]

This is the second of three articles examining the oil and gas industry in Oklahoma. The first, "Oklahoma Oil: Past, Present, and Future," was published in the Fall 2002 issue of *Oklahoma Geology Notes*; it reviewed the history and projected future of oil in the State. This article does the same for natural gas. The final article, "Oklahoma Oil and Gas: Our Place in the Big Picture," will build on the first two and focus on Oklahoma's part in the bigger national and international energy landscape. These non-technical papers review the evolution and status of Oklahoma's oil and gas industry and attempt to predict its long-term future.

## INTRODUCTION

Oil put Oklahoma on the map. This is true both figuratively and literally, as in 1907 oil was the driving force behind turning the Oklahoma Territory into the State of Oklahoma. Industry's early success in finding abundant oil, and later natural gas, has made these our primary sources of energy. Relatively inexpensive energy is one of the largest factors responsible for the unprecedented levels of prosperity now enjoyed by the United States and the rest of the developed world. Although both U.S. and Oklahoma oil and gas production are past their peak, we continue to be a key producing state, ranking fifth nationally in oil and third in natural gas.

Natural gas is especially important to Oklahoma because it alone maintains a positive State energy budget that would otherwise be strongly negative. In spite of our national ranking, oil consumption in Oklahoma is about 50% higher than production, and local coal production accounts for less than 10% of State consumption. For oil, the possibility of discoveries that could significantly impact State production is very low, making enhanced recovery in existing fields the only way to meaningfully affect production declines (Boyd, 2002a). Coal in Oklahoma is another resource that has largely been defined, but in order to meet strict sulfur-emission requirements, the vast bulk of coal burned in the State now comes from Wyoming. In marked contrast, gas production is still three times the State's consumption, and Oklahoma continues to be an area where gas exploration and development can bring large rewards.

Oil and gas are formed by alteration of microscopic organisms that are deposited with the sediment that composes sedimentary rocks. The sediment and organic remains reach maximum thickness where they accumulate in large, gradually subsiding depressions called geologic basins (Fig. 1). With increasing temperature and pressure that result from

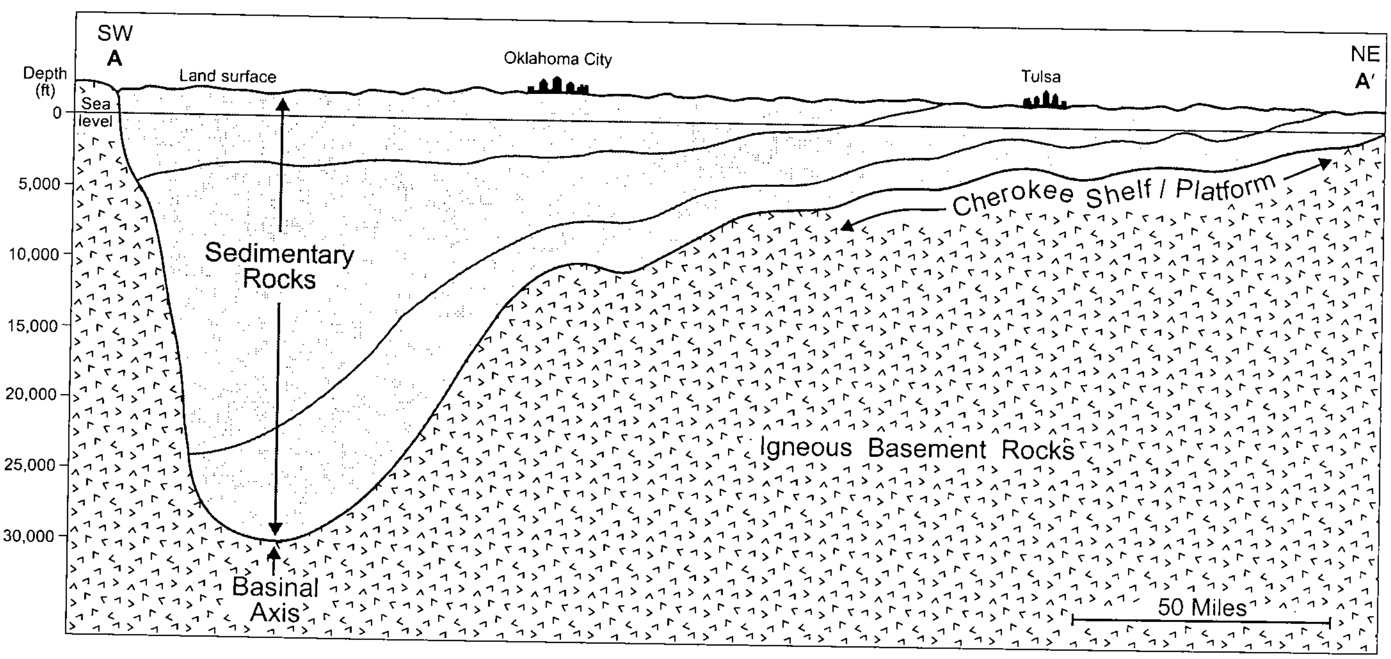


Figure 1. Cross section of the Anadarko geologic basin. Modified from Witt and others (1971). Vertical exaggeration 14:1. Figure 4 is the base map.

increased burial depth, organic remains slowly change into oil and natural gas. Those compounds consist dominantly of hydrogen and carbon, and hence are called hydrocarbons. As oil and gas are less dense than the water in which the sediment was deposited, where permeable rock permits they migrate upward. The upward movement ends where impermeable rock blocks the migration path, creating a seal that may form a hydrocarbon trap. A key factor in the size of the petroleum accumulation thus formed is the extent and sealing ability of the impermeable rock.

Gas is almost always associated with oil, as it represents the lighter chemical fraction (shorter molecular chain) formed when organic remains are converted into hydrocarbons. Therefore, in addition to being found underground as discrete gas reservoirs, much natural gas is also found dissolved in subsurface oil. As this oil is brought from reservoir conditions to the surface, and its pressure is reduced to the atmospheric level, dissolved gas comes out of solution much like carbonation from a soft drink when the cap is lifted.

Natural gas that comes from produced oil is classified as associated gas. When subsurface oil has been saturated with gas, any additional gas that migrates into the trap must exist as free gas; being less dense than oil, it occupies the top of the hydrocarbon trap and forms what is called a gas cap (Fig. 2). This gas, or any gas not directly associated with oil, is called non-associated gas.

The chemistry of certain types of organic matter (for example, those high in plant material) can make hydrocarbon source rock more likely to generate gas. A source rock is rock containing enough organic remains to generate an appreciable quantity of hydrocarbons—given adequate heat, pressure, and time. An example of a gas-prone source rock is coal, which in Oklahoma is important in mining and also in the rapidly expanding coalbed-methane industry.

Regardless of the type of source rock involved or the relative volumes of oil and gas that are initially generated, temperatures and pressures invariably rise with increasing burial depth. As the thermal energy in a subsurface system increases, the longer-chained hydrocarbons present in oil begin to break into progressively smaller pieces. Eventually a critical depth is reached below which liquid hydrocarbons are no longer stable. Although oil cannot exist anywhere below this critical depth, natural gas can still be present in large quantities. This is important for Oklahoma because many of the State's source rocks and reservoirs are, or were in the geologic past, located below the depth at which oil is stable. The combination of deep sedimentary basins and a source rock chemistry that is dominantly gas-prone has made large parts of Oklahoma almost exclusively gas producing (Fig. 3).

Oklahoma's prominent place in the oil and gas industry is a fortuitous result of its encompassing the bulk of the hydrocarbon-rich Anadarko, Arkoma, and Ardmore geologic basins and their associated platforms (also called shelves). A platform, unlike a basin, is a stable, relatively flat-lying area with a thinner blanket of sediment. Figure 4 shows the State's major basins and adjacent areas; it also shows the 11

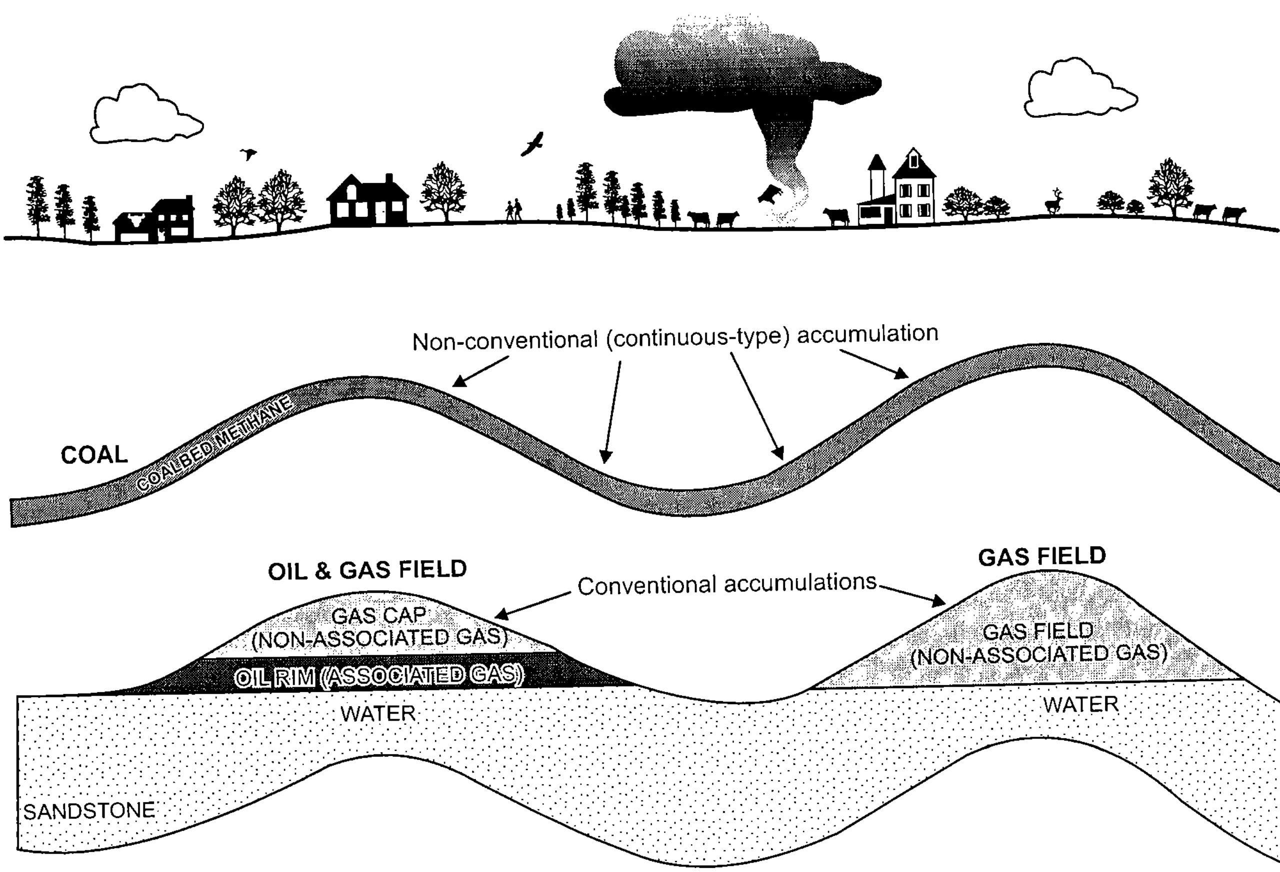


Figure 2. Some types of subsurface natural gas accumulation.

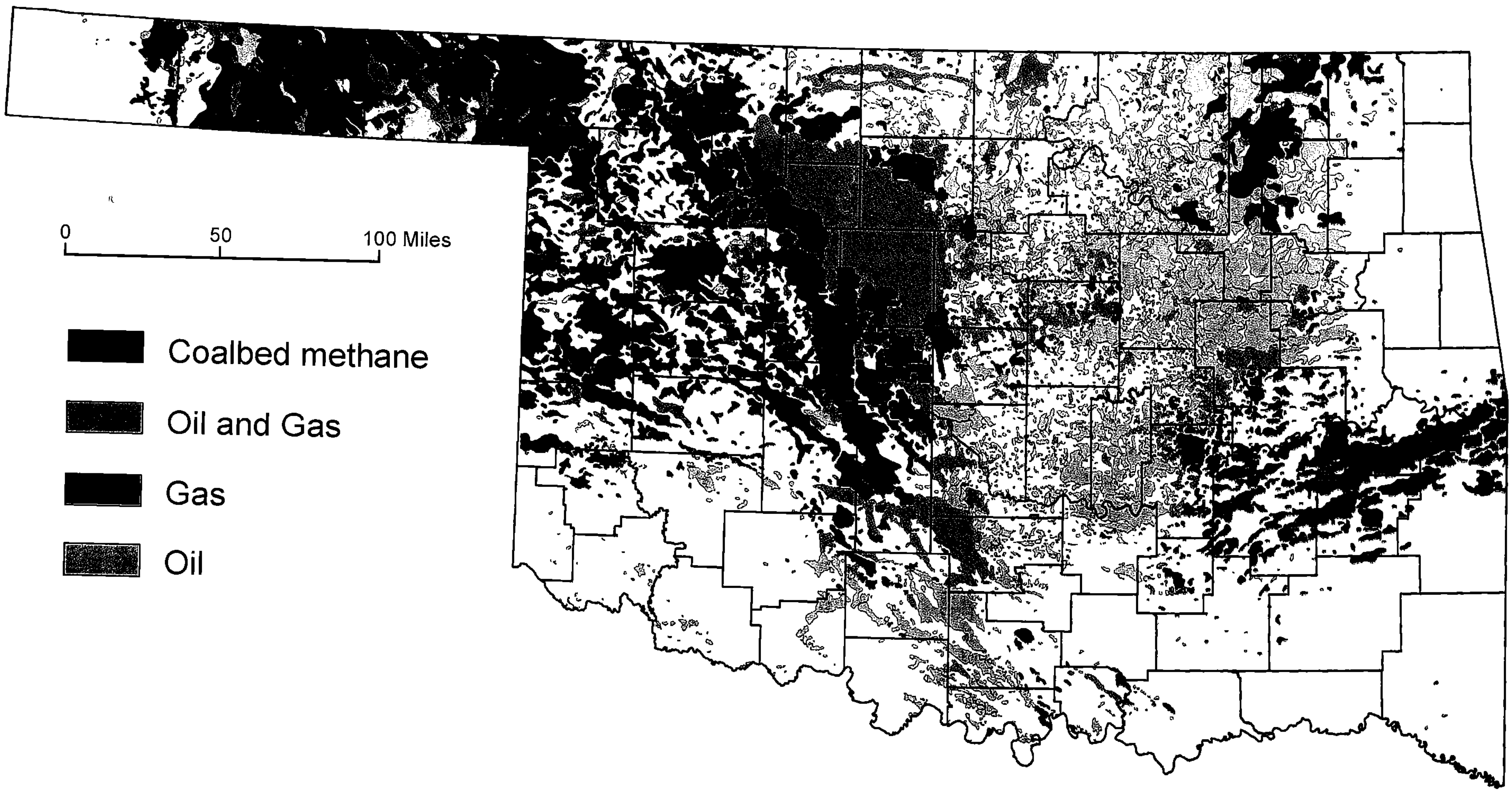


Figure 3. Here Oklahoma oil and gas field are distinguished by gas-oil ratio and conventional gas vs. coalbed methane. Modified from Boyd (2002b).

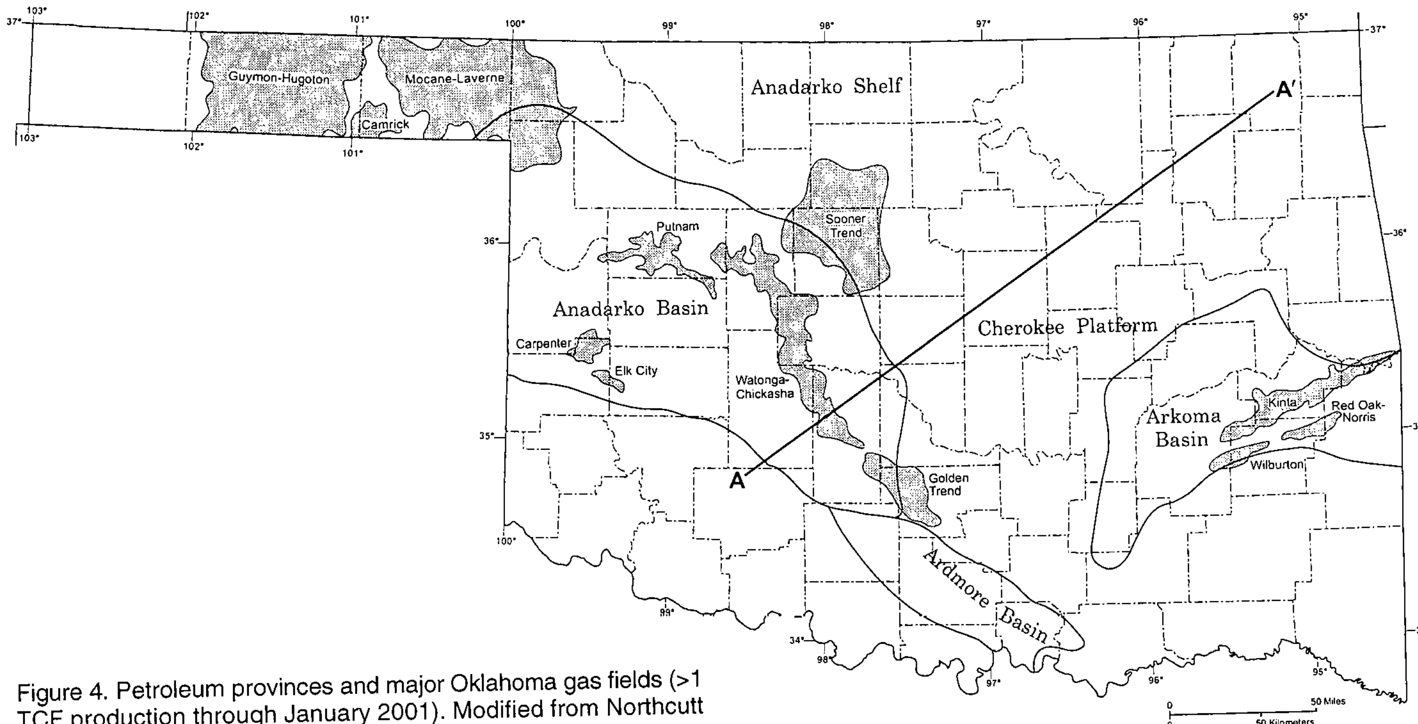


Figure 4. Petroleum provinces and major Oklahoma gas fields (>1 TCF production through January 2001). Modified from Northcutt and Campbell (1995) and Boyd (in press).

major gas fields—those that have produced more than one trillion cubic feet (TCF) of natural gas. The sedimentary rock from which the bulk of Oklahoma's gas production comes is largely Pennsylvanian in age (290 to 323 million years before the present; Fig. 5). However, oil and gas reservoirs across the State range in age from late Cambrian (about 517 million years ago) to early Cretaceous (about 100 million years ago).

## EARLY HISTORY

Natural gas has always been found in conjunction with oil exploration, which in Oklahoma began late in the 19th century. In the early days, gas was usually looked upon as a nuisance or a drilling hazard, and when encountered it was vented until it was determined whether oil lay below the gas (Fig. 2). If only gas was produced, the well was usually plugged and abandoned. (Plugging usually means placing cement in a borehole to keep subsurface fluid from moving to the surface or from one permeable rock layer to another.) Abandonment is the final act in the life of a well, and usually ensures that the well can never be used again. However, if the well eventually started producing oil as well as gas, it was treated as an oil well, with any associated gas either vented into the atmosphere or flared (i.e., burned). It is impossible to say how much gas was lost then, but Beebe (1962) has estimated the volume vented or flared in Oklahoma at 500 billion cubic feet (BCF).

Initial gas activity in Oklahoma was restricted to the northeastern part of the State. It began in 1894 when Cudahy Oil Company drilled two wells in the Muskogee area, each with commercial gas shows. Neither well produced gas, for no local market existed. However, in 1901 gas from two wells completed in the Red Fork sand was sold to a brick plant in Tulsa, marking the first commercial use of natural gas in Oklahoma. After this milestone, gas production was added in Bartlesville-Dewey Field (1904), Glenn Pool Field (1905), Hogshooter Field (1906), Boynton Field (1910), and Cushing Field (1912). Depew Field, which began producing gas in 1912, was converted to storage in 1951. With 63 BCF of capacity, it was the largest gas-storage facility in the United States (Koontz, 1962).

In 1906 the Oklahoma Natural Gas Company, today the State's dominant supplier, was formed to deliver gas to the Oklahoma City market (Moore, 1962). At the time, gas fields were near the towns they served, but, as demand climbed and nearby wells were depleted, the industry was forced to rely on more distant sources of supply. Despite a rapid increase in gas drilling and reserve additions due to a spate of discoveries in the late 1920s, it was not until the Anadarko and Arkoma basins and shelves (including the Panhandle) were exploited in the middle of the 20th century that reserves* began to grow exponentially.

The earliest years of the Oklahoma gas industry were sustained by small accumulations associated with shallow oil fields on the Cherokee Platform in the northeastern part of the State. Throughout most of Oklahoma's history an abundance of cheap oil made it the fuel of choice, keeping the

*Reserves are defined as the part of a resource base that is economically recoverable. In contrast, resources are defined as the total known volume, or gross supply, of a commodity. Resources are not recoverable from existing wells, and as such are less well defined than reserves. Reserves increase as the price of the commodity—in this case, natural gas—rises or technological advances make its recovery cheaper. Reserves decrease when the commodity is produced or its price drops.

| DIVISIONS OF GEOLOGIC TIME | | | | Age (approx.) in millions of years |
|---|---|---|---|---|
| Eon | Era | Period | Epoch | |
| Phanerozoic | Cenozoic | Quaternary | Holocene | 0.010 |
| | | | Pleistocene | 1.6 |
| | | Tertiary | Pliocene | 5 |
| | | | Miocene | 23 |
| | | | Oligocene | 35 |
| | | | Eocene | 57 |
| | | | Paleocene | 65 |
| | Mesozoic | Cretaceous | Late | 97 |
| | | | Early | 146 |
| | | Jurassic | Late | 157 |
| | | | Middle | 178 |
| | | | Early | 208 |
| | | Triassic | Late | 235 |
| | | | Middle | 241 |
| | | | Early | 245 |
| | Paleozoic | Permian | Late | 256 |
| | | | Early | 290 |
| | | Carboniferous: Pennsylvanian | Late | 303 |
| | | | Middle | 311 |
| | | | Early | 323 |
| | | Carboniferous: Mississippian | Late | 345 |
| | | | Early | 363 |
| | | Devonian | Late | 377 |
| | | | Middle | 386 |
| | | | Early | 409 |
| | | Silurian | Late | 424 |
| | | | Early | 439 |
| | | Ordovician | Late | 464 |
| | | | Middle | 476 |
| | | | Early | 510 |
| | | Cambrian | Late | 517 |
| | | | Middle | 536 |
| | | | Early | 570 |

Figure 5. Geologic time scale. From Harland and others (1990) and Hansen (1991).

demand for natural gas low, and thus its price and drilling activity. Another factor was the regulation of natural gas by the federal government through 1978, which kept prices low relative to oil. Also underlying low demand in the early days was a lack of pipelines. Although crude oil can be transported anywhere there are roads, gas requires a gathering system that usually entails huge up-front costs. In a classic Catch-22 scenario, the economic justification for a pipeline requires that a threshold of production rate and reserves be met, and that, in turn, means money must be spent in drilling wells. However, even if the wells justify the expenditure, they must remain shut-in (generating no cash flow) for a prolonged period during construction of the gathering system. Once this hurdle is overcome and pipelines are in place, drilling and production commonly increase exponentially. Drilling success then spurs expansion of the system, which in turn opens more-distant areas to exploration and development.

Despite early difficulties, all major gas fields in the greater Anadarko and Arkoma Basins were discovered before natural gas deregulation (Figs. 4, 6). Some of the fields were discovered quite early, but they were not close to main population centers. As a result they were usually not fully developed (or their size appreciated) until much later, when gas became a primary drilling objective rather than an unintended consequence of oil exploration.

## RECENT HISTORY

Although commercial gas production in Oklahoma began in 1901, annual production did not begin growing until the 1940s (Claxton, 2001). Growth continued through the early 1960s, with production rates more than doubling between 1960 and 1970 (Fig. 7). As measured by the standard average energy equivalence of 6 thousand cubic feet (MCF) per barrel (42 U.S. gallons) of oil, Oklahoma's primary production shifted in 1963 from oil to gas. The change occurred despite the fact that oil production in 1963 was still well over 500,000 barrels per day. In the year 2000, Oklahoma's cumulative production of gas (measured in sales) exceeded cumulative oil for the first time. Although these are important milestones, the critical point is that natural gas has been Oklahoma's primary energy resource for almost 40 years. In addition, because oil production has declined to one third of the level in 1963, and is still falling, the importance of gas in the State's energy mix continues to increase.

As is true of any commodity, the effort expended in the search for natural gas has increased as its value increased. The wellhead price (the price received by the operator) remained low and changed little during the first 73 years of commercial production in the State (Fig. 8). Then in 1974, for the first time, the price of natural gas began rising more than a penny per year. The change resulted from the deregulation of gas prices, which hitherto had been a part of an elaborate system that kept interstate below intrastate prices. This caused shortages to develop in gas-importing states, while surpluses were generated in major gas-producing states such as Oklahoma.

In response, the Natural Gas Policy Act was enacted in 1978 to deregulate the price that pipeline companies paid for gas, and the average annual price of gas rose from 23¢ per MCF in 1974 to $1.49 in 1980. The rapid increase is significant because it encouraged gas-targeted exploration and development and because the 1980 price has essentially remained the floor price for gas ever since. In the succeeding 21 years, the average annual wellhead price for Oklahoma natural gas was lowest in 1995. The value, $1.43 per MCF (unadjusted for inflation), is about the same as in 1980. Even in constant dollars this historic low still exceeds the price through most of the State's history (Fig. 8). However, it must be emphasized that the average annual price is not the net value realized by gas producers, and it in no way conveys the degree of volatility with which operators must contend. In any given year, the price low can be a fraction of the annual value shown. Although they average out in the long term, successful operators must be able to weather many short-term dips in price.

As we might expect, the number of wells drilled for gas has closely tracked the gas price (Figs. 9, 10). After the Arab

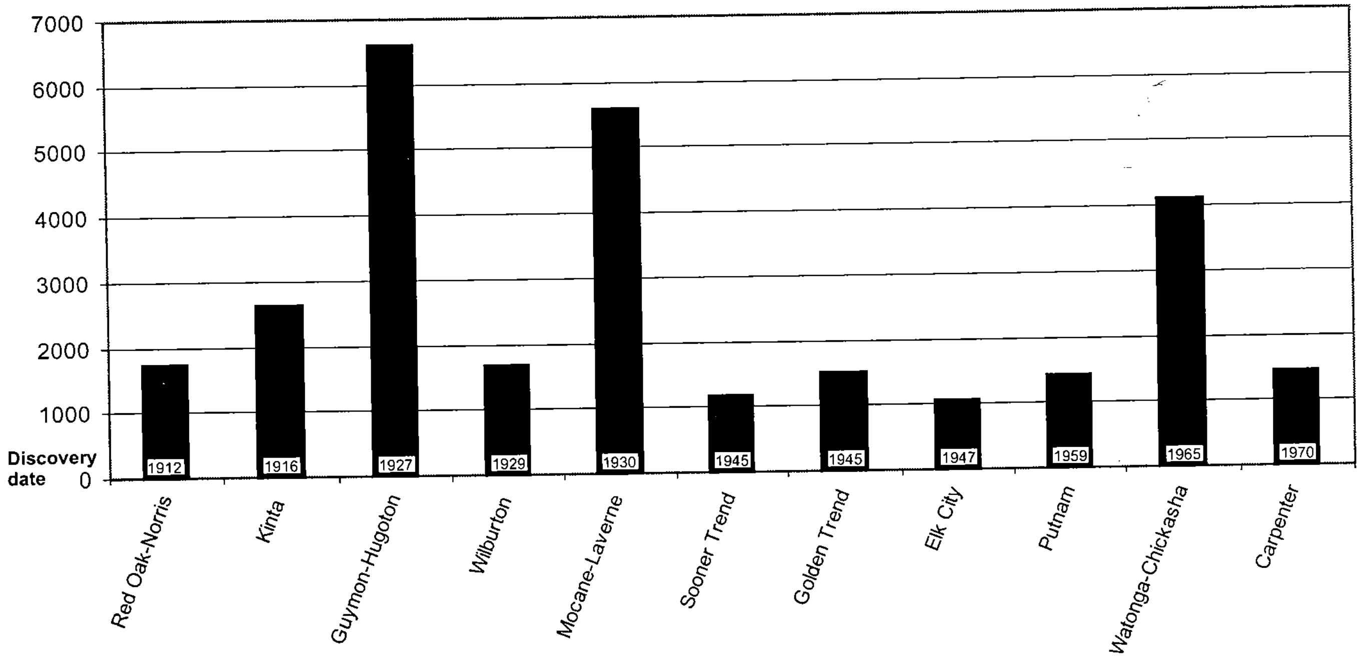


Figure 6. Major gas fields in Oklahoma: their cumulative production and discovery dates. Cumulative production >1 TCF through January 1, 2000. Data from Lay (2001).

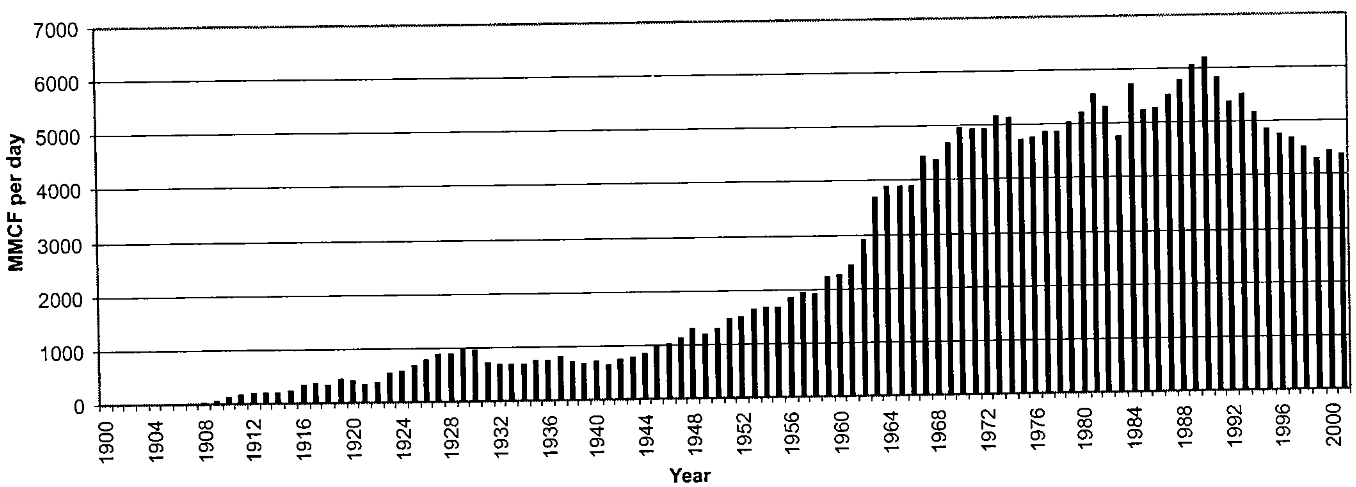


Figure 7. Natural-gas production in Oklahoma (1900–2001). Data from Claxton (2001).

oil embargo of 1973, which sent oil prices to record highs, the resulting increased demand for gas helped push prices higher for this commodity too. A combination of domestic deregulation and international politics precipitated a large increase in completions of gas wells from 1977 through 1985, a peak period in the last important drilling boom (Boyd, 2002a). However, with deregulation and eased political tension, market forces gradually have resumed control—resulting in moderate to low prices that suppressed gas drilling activity from 1986 through 1999.

Mirroring a dramatic rise in gas prices in 2000 (above $3.50 per MCF) and 2001 (above $4.00), the number of gas completions recorded for those complete calendar years was the highest in the State since the early 1980s. Many factors were responsible for this increase, primarily the markedly higher oil prices in the same period (Fig. 10). Upward pressure on the price of natural gas continued as the industry found itself unable to keep pace with peak seasonal demand. Because gas-storage facilities and their high delivery rates are key to meeting demand in winter, when storage levels drop significantly, concern for supply is heightened, and prices rise. Figures 8 and 10 show how closely the price trends for oil and gas have tracked through time.

In oil, additions to reserves in Oklahoma now come almost exclusively from improved recovery from previously defined traps: in gas, the discovery of new or incompletely drained reservoirs is still common. Recent activity directed toward finding and producing natural gas has succeeded in both conventional and non-conventional settings. Conventional accumulations occur in discrete reservoirs of limited

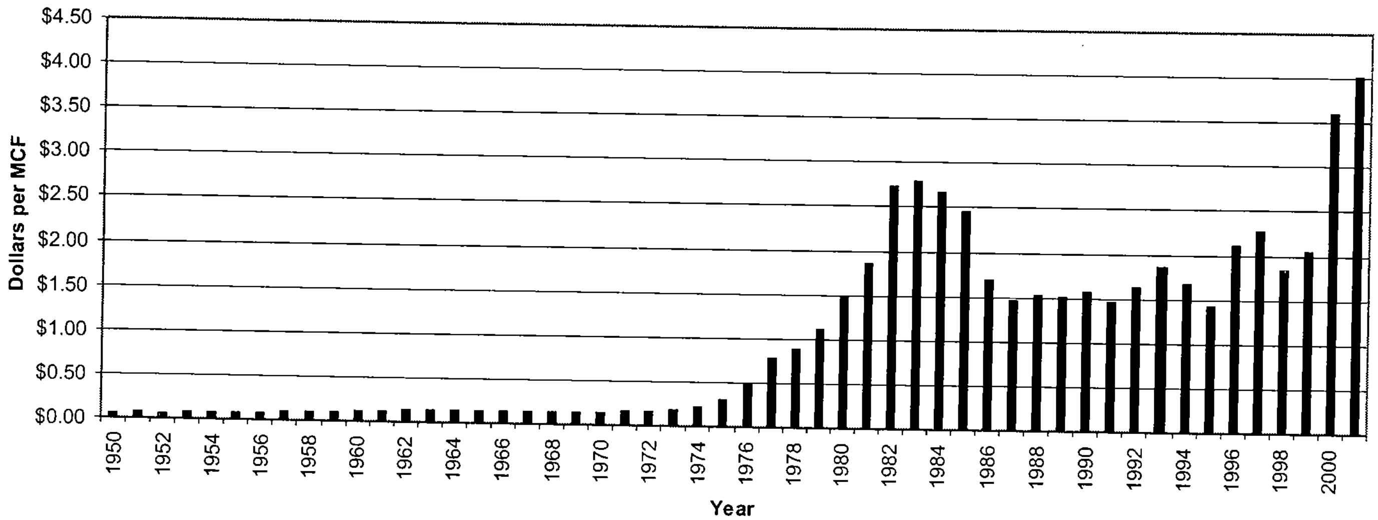


Figure 8. Average annual price of natural gas at the wellhead (unadjusted for inflation) in Oklahoma (1950–2001). Data from Claxton (2001).

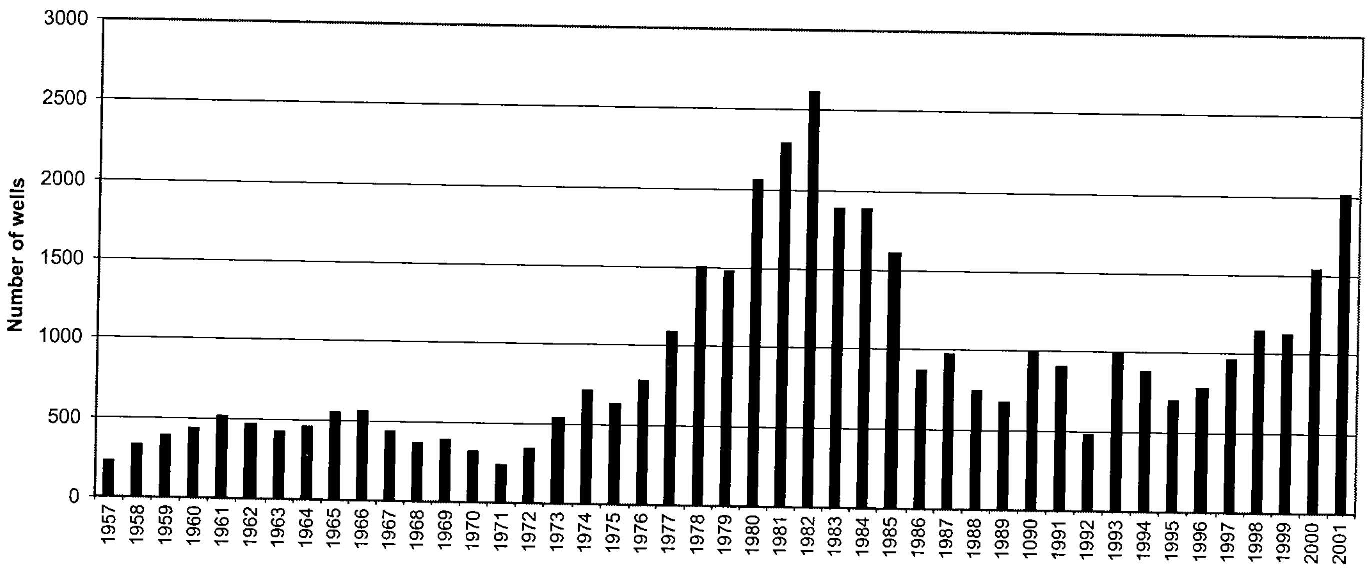


Figure 9. Gas-well completions in Oklahoma (1957–2001). Data from Claxton (2001).

aerial extent—mostly in sandstones, limestones, and dolomites, which are relatively permeable and represent the vast majority of Oklahoma's gas fields and reserves. Non-conventional accumulations, which are designated continuous-type by the U.S. Geological Survey (1995), do not occur in discrete reservoirs; they tend to cover large areas and include accumulations in coalbeds and in low-permeability (or tight) sandstones, shales, and chalks (Fig. 2).

An example of an important conventional gas discovery in Oklahoma is the Potato Hills Field, which is in a structurally complex area of southeastern Oklahoma. It was a marginal producer from its discovery in 1960 through January 1987, when it went off production after making less than 1 BCF of gas. There was no further activity in the area until 1997, when a well drilled in the same section as a dry hole drilled in 1961 established new gas production in the Jackfork Sandstone and initiated a spate of drilling that continues today. Since recently drilled wells went on line in late 1998, Potato Hills has produced more than 100 BCF of gas. Although production appears to be in decline, in the first 4 months of 2002 the field still produced an average of 61 million cubic feet (MMCF) per day.

The production added by Potato Hills Field is among the most significant in decades. As the State has nearly 500,000 wells, entirely new discoveries have become increasingly rare. However, this field shows that Oklahoma's gas potential, even in areas that have been drilled intensively, is still far from fully defined.

A non-conventional gas resource, coalbed methane, is a comparatively recent addition to Oklahoma's energy mix. As plant material is heated and compressed into what will eventually become coal, methane is released. The generation of methane turns coal into a source rock from which gas sometimes migrates into adjacent, permeable rock (such as sandstone) where the gas can be produced as in a conventional reservoir. More often, the gas has no way to escape and stays locked in the coalbed. Because coal is inherently impermeable, its quality as a reservoir depends on the spacing and interconnectivity of the fractures (cleats) that are formed during the coalification process. Where the cleats are pervasive and interconnected, it is possible to drill gas wells that are low-rate, but economic and long-lived. Production of coalbed methane is unusual because the coal acts as both source rock and reservoir, and rather than producing from reservoir pores, the gas is extracted from the coal itself.

The coalbed-methane play in Oklahoma is little more than 10 years old, and continues to be quite active. Because the productive coals have been penetrated many times by deeper wells targeting conventional oil and gas, the location, depth, and thickness of prospective coals are usually well established. The principal unknown is producibility—the rate at which gas will flow from the coal—but that cannot be ascertained until the well has been drilled and completed.

Because coalbed methane is considered non-conventional by regulators, its production is not merged with the existing, conventional field areas. However, by use of the same criterion as for conventional production (combining wells within ~1 mile of each other into one field), 50 coalbed-methane fields have been discovered thus far (Fig. 11). As these fields grow, many will be merged into larger fields or regional gas areas.

At mid-2002, about 2,000 coalbed-methane wells had been drilled in Oklahoma (Cardott, 2002), with new ones being added at a rate of about one per day. As coalbed methane is not distinguished from conventional gas, it is difficult to estimate its contribution to State production. However, if initial production is 60 MCF per well per day (Cardott, 2002), Oklahoma's production at the end of 2002 is about 120 MMCF per day, or about 44 BCF per year. Although this represents slightly less than 3% of the total gas production for the State, large prospective coalbed-methane areas remain undrilled or under-drilled. Consequently, coalbed methane's share of the State's natural gas production will undoubtedly continue to increase.

Shallow, low-cost coalbed-methane wells are suited to the small operators that dominate in Oklahoma. Although stabilized production rates are typically low (50–100 MCF per day), risk of a dry hole is low because the targeted coals are pervasive. In addition, coal acts as both reservoir and source rock, so areas with methane potential are vast. Another in-

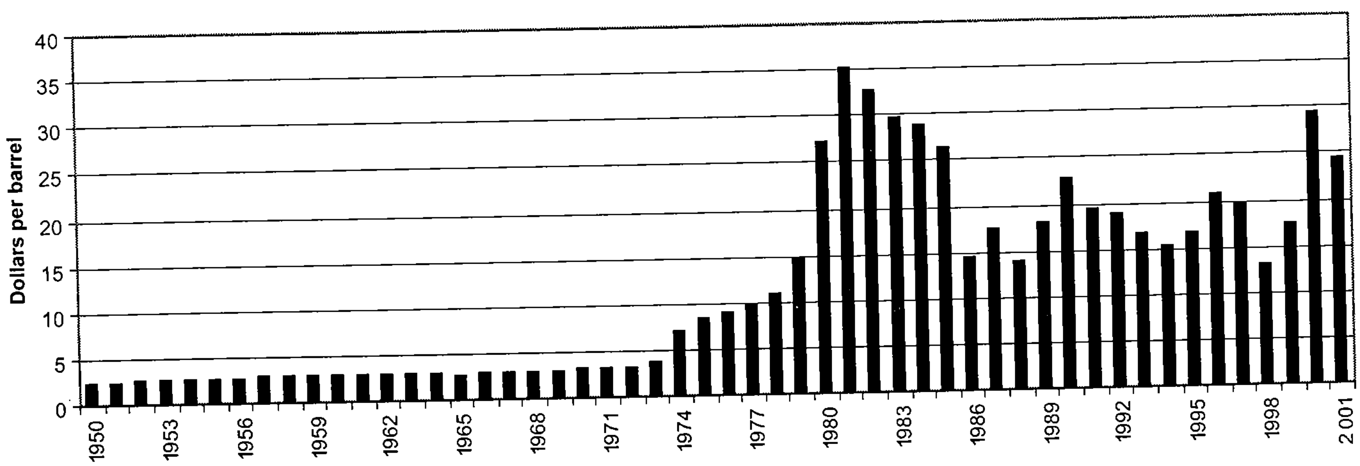


Figure 10. Average annual crude-oil price (unadjusted for inflation) in Oklahoma (1950–2001). Data from Claxton (2001).

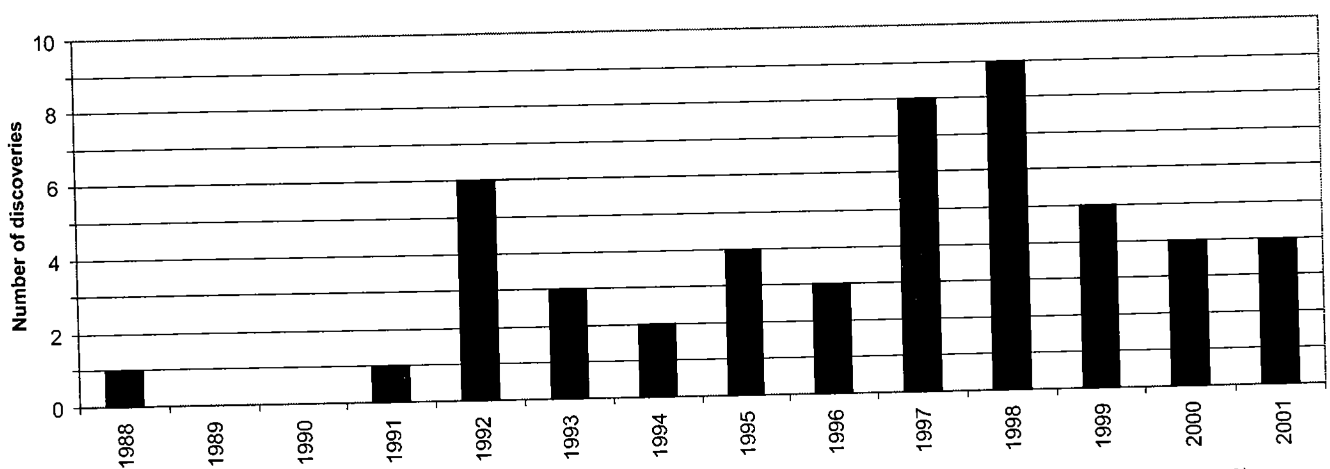


Figure 11. Provisional coalbed-methane fields in Oklahoma. From Boyd (2002b). Data from Cardott (2002).

centive for some operators is a federal tax credit applied to coalbed methane. As part of the Crude Oil Windfall Profits Tax Act of 1980, the credit (Section 29) was designed to encourage production of non-conventional fuels. These include shale oil, tar sands, tight gas, and coalbed methane.

Areas that produce coalbed methane in Oklahoma include parts of 15 counties on the eastern margin of the Cherokee Platform and the northern half of the Arkoma Basin (Figs. 3, 4). In 1995 the USGS estimated the mean, proved coalbed-methane reserves for the Cherokee Platform and Arkoma Basin at 4.6 TCF. Although these provinces (and reserves) are shared by Kansas and Arkansas, the estimate demonstrates the magnitude of the coalbed-methane play. Judging by experience in other basins, as drilling and production continue, estimates of coalbed-methane reserves will likely rise markedly.

Drilling and completion activity is an excellent indicator of the industry's focus on adding reserves. Changes in price, success rate, economics, tax incentives, and technology are all reflected in these data that show where the money has gone. In the last half century, the percentage of wells completed as dry holes in the State has fallen from almost 40% to under 10% (Fig. 12). This shows that as well density has increased and the number and size of productive fields has grown, dry-hole risk has fallen and drilling has become more developmental in nature.

We could infer from the current dry-hole percentage that the areas with the lowest risk have been drilled, and that risk-to-reward analyses make most of the undrilled areas unappealing. Exclusive of enhanced recovery projects, the reserve size of new oil prospects is almost universally low. However, because gas can exist at greater depths than oil and flow from less-permeable rock, it is still possible to find important new reserves of natural gas in densely drilled areas. Also, the value of gas, relative to oil, has increased, prompting the percentage of gas-well completions in the State to rise dramatically, from less than 5% in 1957 to nearly 70% today. Well-completion statistics clearly show that the industry in Oklahoma has undergone a pronounced change in focus, mostly in the last 15 years, from oil to gas (Fig. 12).

If completion marks the birth of a productive well, then abandonment marks its demise. From 1971 through 2001, former oil wells accounted for more than 80% of all abandonments (Fig. 13). In that period about 47,000 oil wells were plugged and abandoned, compared with about 11,000 gas wells. Not only are more gas wells being drilled each year in Oklahoma, but proportionately fewer are being abandoned.

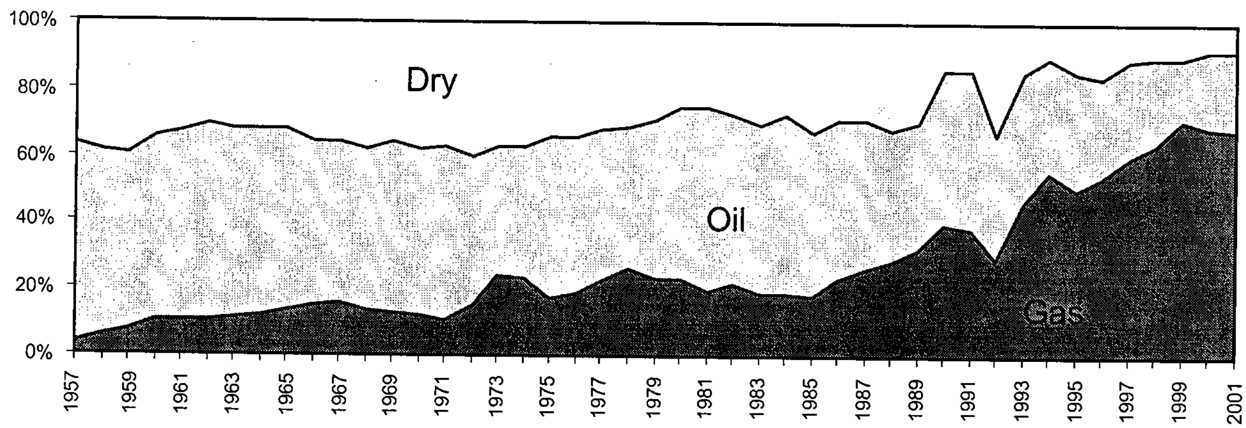


Figure 12. Oklahoma's well-completion history (all wells, 1957–2001). Data from Claxton (2001).

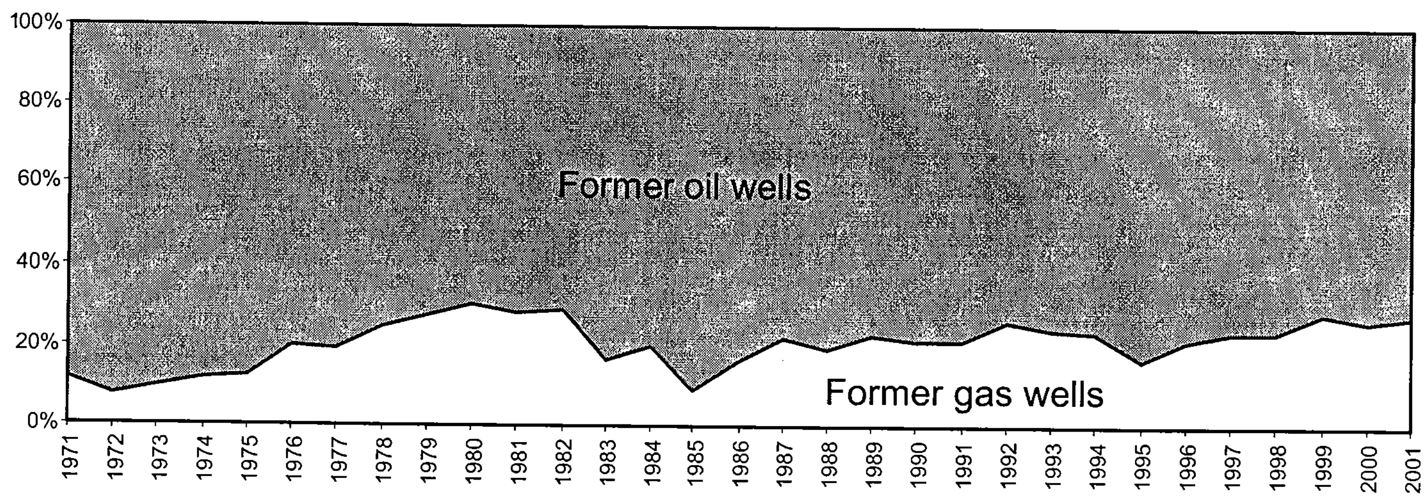


Figure 13. Well abandonments in Oklahoma (formerly productive wells). Data from Claxton (2001).

However, past drilling was so strongly directed toward oil that, despite recent activity, at the end of 2001 the ~84,000 active (unplugged) oil wells in the State still greatly outnumbered the ~33,000 active gas wells.

Of particular interest are the rate classes of wells that produce gas in Oklahoma. The Energy Information Administration (EIA) of the U.S. Department of Energy has classified the Oklahoma gas wells producing in 1999 by average production rate (Fig. 14), showing that 97% of the wells produced less than 800 MCF per day. In fact, about two thirds of the gas wells active in 1999 produced less than 100 MCF per day (Hinton, 2001). A review of the 11 well-production classes contributing to the 1999 State average of 4,356 MMCF per day shows that the class with 200–400 MCF per day contributed the most (~19%), followed closely by the 400–800 and 100–200 MCF per day classes (Fig. 15).

These data demonstrate that large numbers of low-rate wells produce most of Oklahoma's gas. As in oil (Boyd, 2002a), where the average well now produces only slightly more than 2 barrels per day, the average Oklahoma gas well in 1999 produced about 175 MCF per day. (This rate is undoubtedly quite close to today's gas wells.) Assuming that 6 MCF of gas yields energy equal to one barrel of oil, the average Oklahoma gas well, even at 175 MCF per day, still produces the equivalent of 29 barrels of oil per day. In terms of energy, this is more than 13 times the production of today's average oil well. This rate, unknown here since the mid-1960s, helps explain the dominance of gas in the State's energy production.

From a mechanical standpoint, maintaining a system of thousands of relatively low-rate producers is not as difficult or as expensive for gas as it is for oil. As oil wells are depleted, pumping equipment must be installed and maintained. As secondary recovery begins, water-injection wells must be drilled or converted from producers, and an elaborate pipeline system must be maintained to separate oil, associated

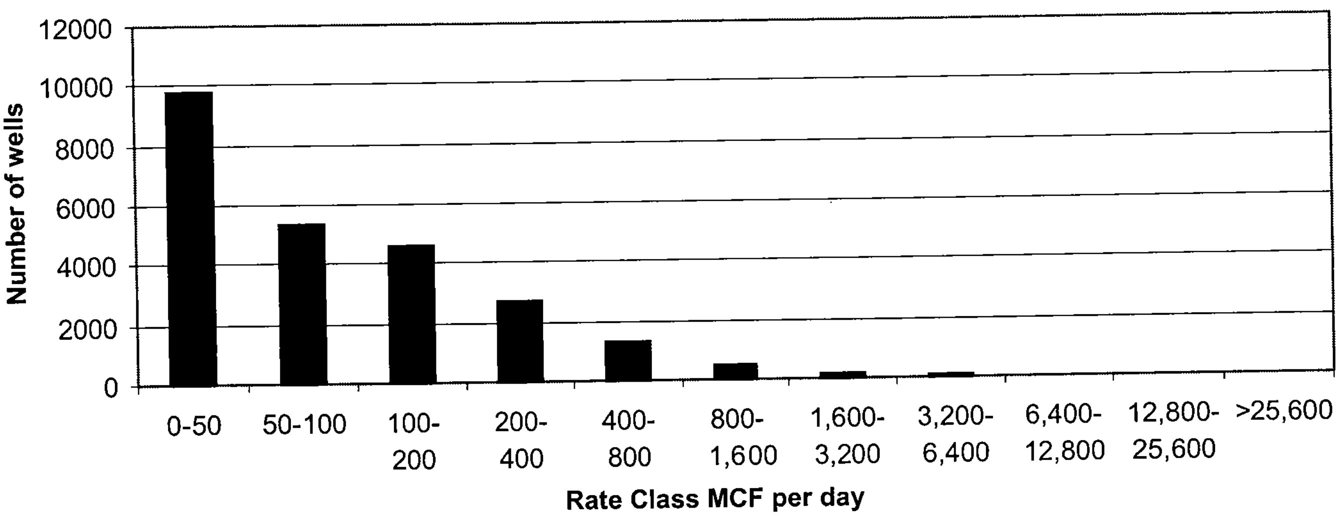


Figure 14. Gas-well production rates in Oklahoma (1999). Data from Hinton (2001).

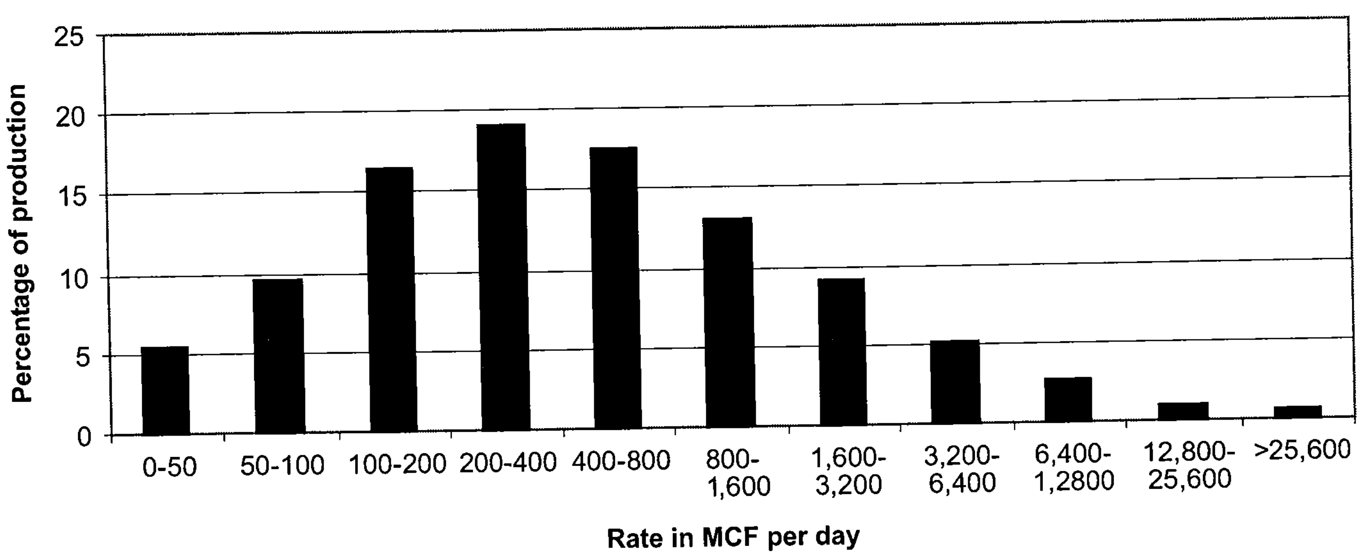


Figure 15. Oklahoma's gas production by rate class (1999). Data from Hinton (2001).

gas, produced water, and injected water. And equipment is subject to breakdown. Gas, which normally flows to the surface, requires less equipment. This ignores the need for compression, which arises when gas-pipeline pressure exceeds a well's surface flowing pressure, but a compressor usually serves multiple wells and so the maintenance expense is shared.

Clearly, in order to maintain production volume, wells must be kept active as long as possible. In 1992 the Oklahoma Legislature created the Oklahoma Commission on Marginally Producing Oil and Gas Wells for the express purpose of helping producers manage marginal oil and gas wells. The program was designed to help operators weather the inevitable price dips, and to minimize the long-term production decline. In addition, the Oklahoma Geological Survey offers low-cost geologic-play workshops and other programs to aid operators. Survey programs help identify practical techniques and technology for finding new fields, as well as means of efficient production in existing fields. They give local operators access to regional studies, technical insights, and resources usually available only to large companies. An example is the series of workshops coordinated by Brian Cardott designed to benefit Oklahoma's numerous small coalbed-methane operators.

## WHERE DO WE STAND NOW?

The bulk of Oklahoma's energy production and more than 70% of its drilling focus on natural gas. Drilling in the State today, especially exploratory, is dominated by wells with gas objectives. The result is that from 1901 through mid-2002 a staggering 90 TCF of natural gas was produced and sold. However, the health of the industry must be measured by the volume of hydrocarbons that remain to be produced—the remaining reserves. That leads to the question: How much is left?

Estimating ultimate remaining reserves is difficult because it requires accurate knowledge of resources in the ground, as well as long-term price forecasts. This requires foreknowledge of demand, technical innovation, political stability, and other factors that may affect economics and is why predictions of remaining reserves can change dramatically from year to year. This complexity has led the industry to use a tiered system of estimates designed to convey differing levels of uncertainty. Although names and definitions commonly vary from company to company (a variety of subcategories also exists), reserves commonly comprise three tiers.

The top tier is called proved reserves; it is the key volume because its low technical and economic risk allows it to be given a monetary value. Proved reserves are defined by the EIA as the volume that geological and engineering data demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic and operating conditions. Other reserve categories that may eventually be upgraded to proved are, in increasing degree of uncertainty, probable reserves and possible reserves. Because all reserve categories are defined by analog production and subsurface data, they are understood better than any of the statistically defined categories under the heading of resources.

Because of the volume and complexity of data involved in thoroughly analyzing the thousands of fields and hundreds of formations that produce gas in Oklahoma, the EIA calculates remaining reserves by simply asking operators for their reserve volumes and then totaling the numbers reported. Assuming that operators do not invoke unrealistic recovery assumptions or price forecasts, such an analysis should give the minimum volume recoverable based on wells producing from known reservoirs in a particular year. However, the estimate reveals nothing about the impact of new discoveries, increased drilling, higher recovery in low-permeability reservoirs, new technology (in drilling, completion, and production), non-conventional gas such as coalbed methane, or changing prices.

We must remember that remaining (proved) reserves, when added to cumulative production, are not meant to approximate ultimate recovery. All types of reserves change continuously, the only certain reserves being those that have already been produced. To give an example, in 1946 Oklahoma's estimate of proved gas reserves was 10.1 TCF, an estimate that rose steadily to 18.3 TCF in 1962. But since 1962 more than 72.5 TCF has been produced, four times the proved reserves estimated in 1962. Clearly, the gas resource volume from which reserves come is finite. However, from year to year a combination of factors including new discoveries, greater efficiency in recovery, and higher prices, has repeatedly forced upward revisions in estimates.

Historical estimates of gas reserves, compiled by the EIA for Oklahoma (Hinton, 2001), are shown in Figure 16. From 1977 through 2000, reserves ranged from 12.5 to 16.7 TCF, with peak years in the 1980s, during and just after the last major drilling boom. For the same period, gas production ranged from 1.6 to 2.3 TCF per year. Where proved reserves go up from one year to the next, the volume increase is in addition to that year's production. The actual swing in ultimate-recovery estimates from one year to another is much larger than the graph suggests. Although it is not obvious from Figure 16, throughout Oklahoma's history the estimates of ultimate gas recovery have always gone up. However, when estimates rise more slowly than production, proved reserves go down, and this is shown as a net negative year for the State (Fig. 17). For example, in calendar-year 1999 additions totaled 0.5 TCF. Because production for the year was 1.6 TCF, the net effect was a reduction in reserves of about 1.1 TCF. In the following year, reserve additions totaled 2.7 TCF; when offset by that year's production of about 1.6 TCF, the net-reserve addition was 1.1 TCF, essentially balancing the previous year's net-reserve loss.

A common measure of reserve life is a comparison of reserve volume to production rate, usually expressed as the R/P ratio. This is the length of time that proved reserves can sustain the current production rate with no decline. For example, a state with 10 TCF of reserves that is currently producing them at 1 TCF per year has an R/P ratio of 10. Since 1977 for Oklahoma the ratio has averaged 7.7 years, ranging from a high of 9.3 years in 1983 to a low of 6.6 years in 1993. Based on the most recent reserve estimate (year-end 2000), Oklahoma's R/P of 8.5 years is above the 25-year average. However, we certainly have no reason to become complacent, as the main factor keeping reserve life stable is the

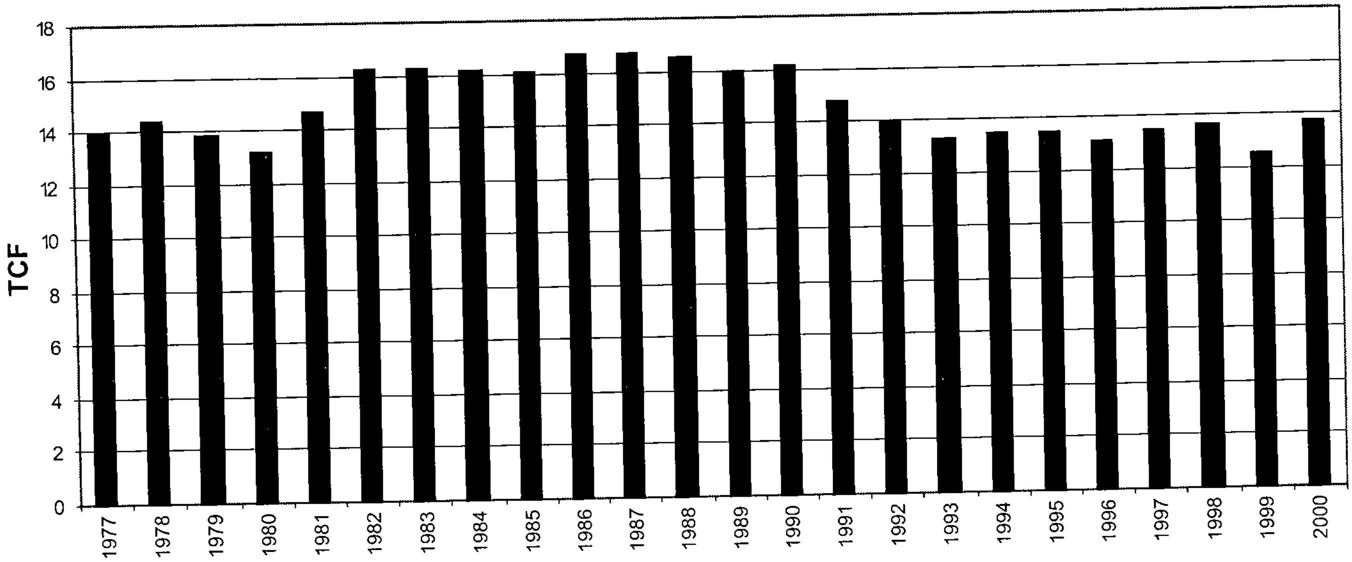


Figure 16. Proved gas reserves in Oklahoma (1977–2000). Data from Hinton (2001).

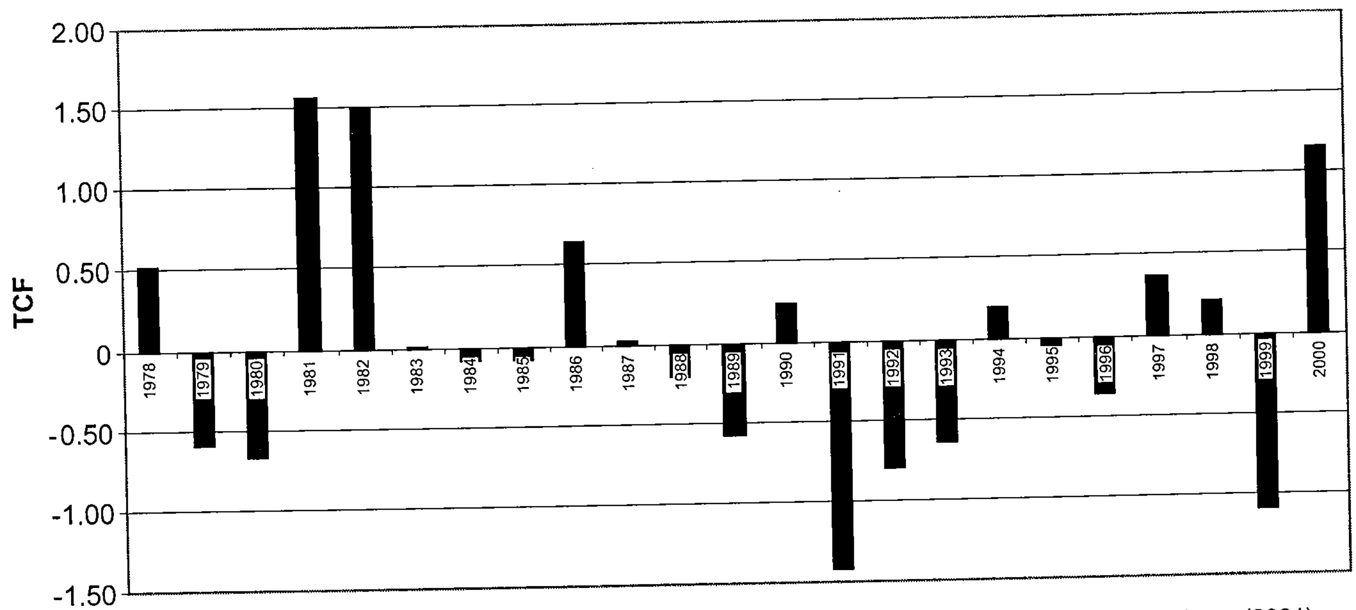


Figure 17. Changes in Oklahoma's net gas reserve (after production from the previous year). Data from Hinton (2001).

State's declining production rate. With production always at 100% of capacity, gas rates have slid from 1.9–2.3 TCF per year in the 1980s to 1.6–1.8 TCF per year since 1995.

Gas, unlike oil, has had no discernible long-term decline in annual estimates of the State's reserves (Fig. 16). Although Oklahoma's production rate is clearly declining in the long term, two years of increased prices and attendant higher drilling activity have, at least temporarily, slowed the decline (Fig. 7). How long current production rates can be maintained is impossible to determine, but if prices stay high, drilling should increase, and the inevitable long-term decline in production should be reduced. Price reductions do not usually cause gas wells to be shut-in, but they do slow the rate at which new wells are drilled. Because a new well typically has a steep initial production decline, less drilling invariably leads to lower gas deliverability. The resulting reduction in supply then pushes prices higher, usually dramatically so.

In 2001, Oklahoma's annual gas production of about 1.6 TCF (4,389 MMCF per day) was about two thirds of the peak rate in 1990, which was 2.3 TCF (6,200 MMCF per day). However, because the gas price in 2001 ($4.02 per MCF) was more than two and a half times that in 1990 ($1.57 per MCF), its gross value of $6.5 billion far exceeded 1990's $3.5 billion. Even inflated at the 2.79% rate calculated by the federal government for the period, 1990's record gas production was worth $1.9 billion less than 2001's production. This illustrates how the annual value of gas to the State of Oklahoma depends far more on its average price than on how much is produced. Much of the fall in State revenue for 2002 (relative to 2001) can be directly attributed to lower gas prices and proportionately lower tax revenues. The price of oil and gas, especially gas, is critical to Oklahoma's economic future.

## THE FUTURE

The continued vitality of Oklahoma's natural gas industry relative to oil is due to many factors. The initial large-scale exploitation of gas occurred more recently than for oil, so proportionately more gas is left. From a regional perspective the State has more gas- than oil-prone areas, and many areas where drilling is sparse also tend to be strongly favorable for gas. In addition, gas can exist at much greater depths and flow through less-permeable rock, so that even where drilling is dense there are large areas in which deeper reservoirs are incompletely evaluated. At shallow depths in the eastern part of the State are many productive coal seams that have been penetrated by thousands of wells with deeper objectives. Although once ignored, the coal has now added important reserves and production to our natural-gas mix.

The primary factor affecting the health of Oklahoma's gas industry will always be price. Although we have little control over the value of gas, we can influence how much we produce. The most direct way to increase gas production is to discover large, long-lived fields. As history has shown repeatedly, in the early stages of exploration in a hydrocarbon-rich state like Oklahoma new discoveries are not difficult. Then, as more wells are drilled, large discoveries become less frequent. But even now the industry is not so mature that large gas reserves cannot be added.

In some parts of the State, both productive and unproductive, reservoirs with gas potential remain under-explored or under-developed. Due to their geologic complexity and correspondingly high risk, they may be largely untested. Or they may require only proper techniques of drilling, completion, or production to become viable. Although the State's gas production and reserves are declining, both conventional and non-conventional additions continue to be made. The Potato Hills Field is an example of a large, conventional accumulation, recently identified. Coalbed-methane recovery is a non-conventional play that is adding important reserves.

So new reserves continue to be added. However, generally low production rates for individual wells and steep declines mean that high levels of drilling activity are necessary to sustain Oklahoma's gas production. When drilling declines, reserves and production rates drop, as they did after 1990. In 2001 the EIA estimated proved reserves for the entire Mid-continent at 58 TCF. Perhaps more important, the agency also estimated the technically recoverable gas resources (both conventional and non-conventional) in the same region at 250 TCF. Although not all if this can be assigned to Oklahoma, the estimate does suggest that our area has at least four times as much undiscovered, recoverable gas as proved reserves.

These facts are encouraging, but as with any other commodity the primary driving force in the Oklahoma gas industry is economics. Any forecast presupposes that the industry will not be hurt by a price reduction that suppresses drilling for an extended period of time. Increases in demand show no sign of abating, and national and State production, even when drilling activity is high, struggles to stay flat. Even if we disregard warm winters, global warming, and fluctuations in gas-storage volumes, a large long-term price drop seems unlikely. Although such an occurrence could devastate the gas industry, as well as the State's overall budget, the resource must be produced eventually. Gas is environmentally friendly, relatively abundant, and its infrastructure can support substantial growth in the market. Oklahoma's location, geology, resource estimates, pipeline system, and the energy industry's strong history, all ensure that gas will be a key component of the State's economic future well into the 21st century.

## ACKNOWLEDGMENTS

Charles Mankin, Robert Northcutt, Neil Suneson, and Brian Cardott read the manuscript and provided valuable input. Max Tilford (of Tilford Pinson Exploration LLC) carried out the formal review and made many useful suggestions. Wendell Cochran did the technical editing. Data used came primarily from the Oklahoma Corporation Commission, the Energy Information Administration of the U.S. Department of Energy, and the International Oil Scouts Association.

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# Oklahoma Oil and Natural Gas: Our Place in the Big Picture

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[Reprinted as published in *Oklahoma Geology Notes*, Spring 2003, v. 63, no. 1, p. 4–30.]

## INTRODUCTION

The Oklahoma energy landscape cannot be fully appreciated without an understanding of the larger, global issues that ultimately control it; hence the need to review the big picture. The conclusions in this article are predicated on a reversal of a geological axiom, "the present is the key to the past." Here, knowledge of our energy past and how we arrived at our present situation is crucial to understanding what promises to be an unsettled energy future.

This is the last of three articles examining the oil and gas industry in Oklahoma, written for non-technical readers interested in the petroleum industry. The first two, "Oklahoma Oil: Past, Present and Future" and "Oklahoma Natural Gas: Past, Present and Future," were published in the Fall and Winter 2002 issues of *Oklahoma Geology Notes*. Although each paper was written to stand alone, readers are encouraged to review the first two articles, as the principles that have shaped Oklahoma's energy history apply equally to the world at large. The articles can be purchased in hard copy from the Oklahoma Geological Survey Publications Office (405-360-2886), or accessed on the Oil and Gas page in the Fossil Fuels section of the Survey's Web site: **http://www.ogs.ou.edu/**.

The issue of energy is more critical today than ever before. Because the United States (like most of the developed world) is no longer energy-independent, issues involving domestic production, consumption, regulation, and prices must be examined against a backdrop of worldwide economic cycles and regional political stability. Security in our energy future is now inextricably linked to foreign policy and the ability to constructively interact with the governments of the producing nations on which we depend. For a nation that historically has prided itself on independence, the situation is sometimes uncomfortable. However, until consumption of fossil fuels diminishes, our long-term economic security will depend on the stability, good will, and economic interests of other nations.

Inexpensive energy in abundance is one of the greatest factors responsible for the unprecedented prosperity now enjoyed by the U.S. and the rest of the developed world. Though as history shows, dependence on oil and natural gas makes us sensitive to interruptions of supply. Whether these interruptions are short term or long, they inevitably result in higher prices that reduce economic growth; and any government that finds its economy at risk may be forced to neglect other national interests in an effort to maintain its energy supply. The precarious nature of this linchpin of the world economy, and the unforeseen consequences that securing its supply entail, will continue to rivet the attention of the world.

Much has been published about the world energy situation by the many organizations dedicated to its research. Critical variables, including size of the resource base, increases in future energy demand, and world productive capacity always will be in dispute. As a result, forecasts are often as much a function of the bias of authors as the data on which their predictions are based. Reasonable people can always disagree about the world's energy future. Even if the resource base were known precisely, and the infrastructure for moving oil and gas to the market always in place, we still would face economic, environmental, and political imponderables whose effect no one can predict. The only indisputable facts are that the world runs largely on oil and natural gas and the resource base for those commodities is finite.

As no viable alternative appears on the horizon, fossil fuels—especially oil and natural gas—will account for the vast bulk of world energy use for the foreseeable future. Although the oil and gas industry will remain an integral part of the Oklahoma economy, its health depends on price, and price is controlled by nations in the developing world where reserves and productive capacity are high but consumption is low. Thus the volume of Oklahoma oil and gas remaining in the ground is less important than how much will be economic to produce in a global market. In spite of Oklahoma's standing as a major producing state, we will experience at least as much price volatility in the future as in the past. A predicted rise in long-term energy prices will aid the State's energy industry, but the negative impact on other areas of the economy leaves the net effect uncertain.

Meanwhile, the world is producing (and consuming) more oil than is being discovered, and projections show that productive capacity will be overtaken by demand before the end of the decade. After that, prices will rise, demand will fall, and, where possible, consumers will switch to other fuels. Natural gas is the fastest growing component of world energy supply and has far more remaining reserves than oil, but major sources for both fuels tend to be concentrated in unstable areas of the world. In the U.S., demand for natural gas is met by domestic production and imports from Canada. However, North American resources can now barely meet demand, and rising consumption will depend increasingly on imports.

Despite pronouncements by ambitious politicians, U.S. energy independence in a world dominated by oil and natural gas is not possible. We can extend the life of domestic reserves by opening new areas to exploration and development, and conservation can reduce our vulnerability to shortages. However, neither the U.S. nor Oklahoma can ever reach old production highs, nor is a significant reduction in demand likely through voluntary conservation. With demand expected to increase substantially even as our domestic production declines, we will become increasingly dependent on external resources.

Even so, the future holds much promise. As our primary energy source has evolved from wood to coal, then oil, and eventually to natural gas, we have become increasingly efficient and less polluting in our energy consumption. Because energy resources are still vast, we have been able to rely mainly on the reserves that are most easily produced. The market forces of supply and demand ensure that we will never run out of energy from any source; it will simply become more expensive as the accumulations that are more difficult to produce are forced to satisfy a progressively larger share of demand.

## WORLD OIL: PAST AND PRESENT

During most of human history, wood was the principal energy source. Initially abundant, cheap, and easily obtainable, it carried many societies through their pre-industrial age. Unfortunately, the legacy of large-scale wood burning is a landscape marred by clear-cut forests. In the 1800s, as wood became increasingly scarce, the United States and world energy economies gradually converted to coal (Fig. 1). An unintended benefit of this conversion was that, as dirty as coal burning was, it allowed forests to re-establish themselves in areas not committed to agriculture (Fisher, 2002). Coal assumed the bulk of the energy load from the late 1800s through the early 1900s, and, although its use remains high, throughout the developed world it was overtaken by petroleum in the mid-1900s.

For thousands of years, oil seeps and associated tar sands and asphalt deposits have been used by mankind. They occur around the globe and in many of today's major petroleum-producing areas, including the Persian Gulf, the La Brea Tar Pits of Los Angeles, and seeps in Oklahoma. Oil, in the form of asphalt, has been used throughout human history, but mainly as an adhesive or sealant. This changed in the early 1800s when, as a result of spreading prosperity, large numbers of people had the money to substitute expensive whale oil for the vegetable oil or animal grease previously used in lamps. Increased demand decimated local whale populations, forcing whalers to hunt farther afield and pushing the price for premium sperm whale oil to over $2.50 per gallon (Yergin, 1992). High prices precipitated a search for alternatives, and in the late 1840s and early 1850s it was discovered that "rock oil," now better known as crude oil, made an excellent substitute for whale oil in lamps. Rock oil had the additional advantage that it made a high-quality lubricant for machines powering the industrial revolution.

It was against this backdrop that "Colonel" Edwin Drake drilled the first producing oil well in 1859 near Titusville, Pennsylvania. He showed that high-quality crude oil could be obtained from the Earth's subsurface and that wells could produce the oil in commercial quantities. As refining techniques improved and the variety of products made from crude oil grew, uses multiplied and demand increased substantially. A major increase in demand came with the advent of the internal-combustion engine and its need for gasoline. Technological advances and improvements in refining techniques added more products and uses for crude oil. In addition to a variety of transportation uses, heating and the generation of electricity also became major uses of crude oil.

A similar sequence of events occurred throughout the Western world, spawning a global market for petroleum. Prices rose and fell, often sharply, as supply and demand sought balance. The production side included many notable discoveries: 1873, Russia (Baku); 1885, Indonesia (Sumatra); 1897, Oklahoma (Bartlesville-Dewey); 1901, Texas (Spindletop); 1905, Oklahoma (Glenn Pool); 1908, Iran; 1910, Mexico (Golden Lane); 1912, Oklahoma (Cushing); 1920, Oklahoma (Burbank); 1922, Venezuela; 1930, Texas (East Texas); 1932, Bahrain; 1938, Kuwait and Saudi Arabia; 1956, Algeria and Nigeria; 1968, Alaska (Prudhoe Bay); 1969, North Sea. Because of the petroleum industry's success in finding oil, prices remained low and oil was able to fill a progressively larger share of the world's demand for energy. Between 1949 and 1972, world energy consumption tripled, but petroleum demand rose 5.5 times (Yergin, 1992).

Petroleum in the U.S. became prominent in the early 1900s, due largely to early discoveries in Oklahoma (Boyd, 2002a), and since then both demand and production have grown rapidly if somewhat irregularly (Fig. 1). To prevent catastrophic drops in crude-oil price that could result from over-production, a group of organizations in the U.S.—then the world's largest producer and consumer—curtailed production to help balance supply and demand. The cartel, sanctioned by the government, was the precursor of the Organization of Petroleum Exporting Countries (OPEC) and was led by the Texas Railroad Commission, the Oklahoma Corporation Commission, and the Louisiana Conservation Commission. Although not sounding as threatening to Americans as OPEC, which includes two charter members of the current "Axis of Evil," this cartel performed the same function. It maintained the price of crude oil at a level high enough to sustain the petroleum industry, yet low enough to keep demand robust.

Throughout most of the 20th century the productive capacity of the United States sufficed to make up for any sud-

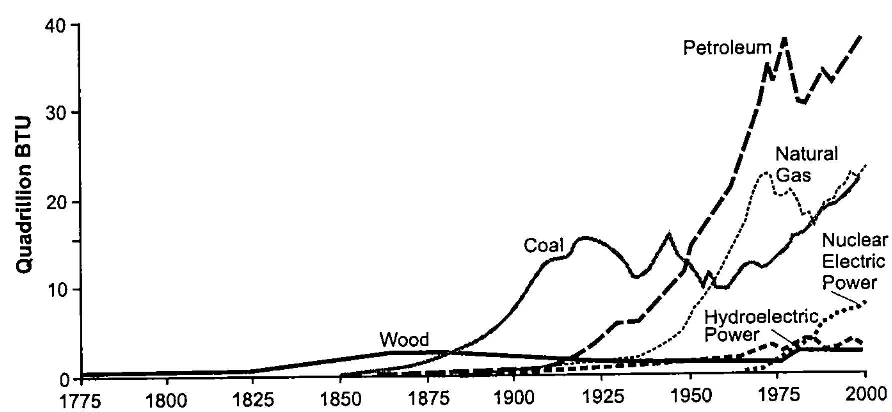


Figure 1. United States energy consumption by source, 1775–2000. From Energy Information Administration (2003).

den loss of imports. This permitted a balance of petroleum supply and demand that lasted through the early 1970s. The loss of some imports resulting from the 1967 war in the Middle East was the last major supply interruption to be overcome without a large increase in price. The shortage was made up largely by increased production in Ward and Winkler Counties in the Delaware Basin, authorized by the Texas Railroad Commission (Deffeyes, 2001). Similarly, in 2003, Saudi Arabia increased production to overcome U.S. shortages caused by strife in Venezuela. Because refineries are designed to process specific types of crude oil, this entailed the production of a crude (Arab Heavy) that matched the missing Venezuelan oil.

To reduce the negative effects from interrupted imports, the U.S. has stored about 550 million barrels of oil (MMBO) in the Strategic Petroleum Reserve. Storage is mostly in hollowed salt domes along the coast of the Gulf of Mexico. The reserve is meant to be a stopgap in the event of a major shortage; however, transporting large crude volumes from storage facilities to refineries has posed problems. In addition, the entire reserve represents only 52 days of petroleum imports, further reducing its effectiveness as a temporary source of supply.

The vulnerability of the U.S. to supply interruptions dramatically increased between the late 1950s, when excess capacity was about 4 million barrels per day (MMBOPD), and 1970, when this shrunk to 1 MMBOPD. The turning point came in March 1971 when, for the first time, Texas went to 100% allowable, placing all oil production in the country at 100% of capacity. Between 1967 and 1973, U.S. imports increased from 2.2 MMBOPD, or 19% of consumption, to 6.2 MMBOPD, or 36% of consumption (Fig. 2). That is why the 1967 embargo had no effect on supply, price, or consumption, but the embargo of 1973 (in the Yom Kippur War) led to drastically reduced supply and increased prices, and forced Americans for the first time to wait in line for gasoline. The Middle East war of 1973 disrupted the entire world economy by raising the price of a barrel of oil from $5.40 in October to $16 a month later (Yergin, 1992). This incremental price increase was followed by yet another in early 1979, when the Shah of Iran fell (Fig. 3).

For many decades the U.S. was by far the world's leading producer of oil, reaching its peak in 1970 (Fig. 4). Note: natural gas liquids are liquid hydrocarbons that condense from gas as it is produced and brought to atmospheric pressure; they are not added to the crude-oil volumes in Figure 4. Although Oklahoma's peak oil production came in the 1920s, it reached a lesser peak in the late 1960s, after which its production curve closely matches that of the United States as a whole (Boyd, 2002a). Both show a production drop in the early 1970s, a rise and secondary peak in the mid-1980s, and since then a nearly continuous decline.

In the international realm, Russian production has fallen from historic highs reached in the Soviet era, and Saudi Arabia—as the swing producer in OPEC—is believed to produce about 2.5 million barrels per day less than its capacity. As a result, in 2001 the U.S. was the world's leading producer of oil and natural gas liquids (Fig. 5; World Oil Magazine, 2002). However, the relative maturity of the U.S. oil industry is highlighted by the fact that its production in 2001 required more than 560,000 wells, while Saudi Arabia's production and much greater capacity required only 1,560 (Deffeyes, 2001).

## WORLD NATURAL GAS: PAST AND PRESENT

Throughout much of history, natural gas was an enigma. Where it seeped from the subsurface it was sometimes ignited by lightning and became a burning spring—a phenomenon perceived as evidence of supernatural forces. Often springs became religious centers, a famous example being the spring associated with the Oracle of Delphi in ancient Greece.

Humans were slow to make practical use of natural gas, but about 500 B.C. the Chinese harnessed the potential of burning springs. Where gas seeped to the surface, they constructed crude pipelines of bamboo and transported the gas to locations where it could be burned to boil sea water. This

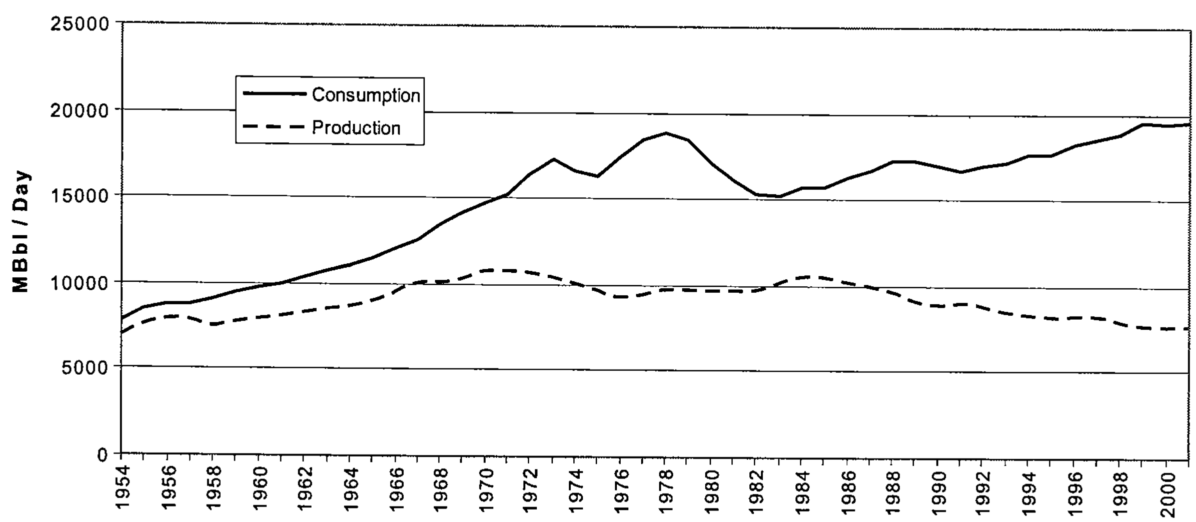


Figure 2. United States petroleum production vs. consumption, 1954–2001. From Energy Information Administration (2003).

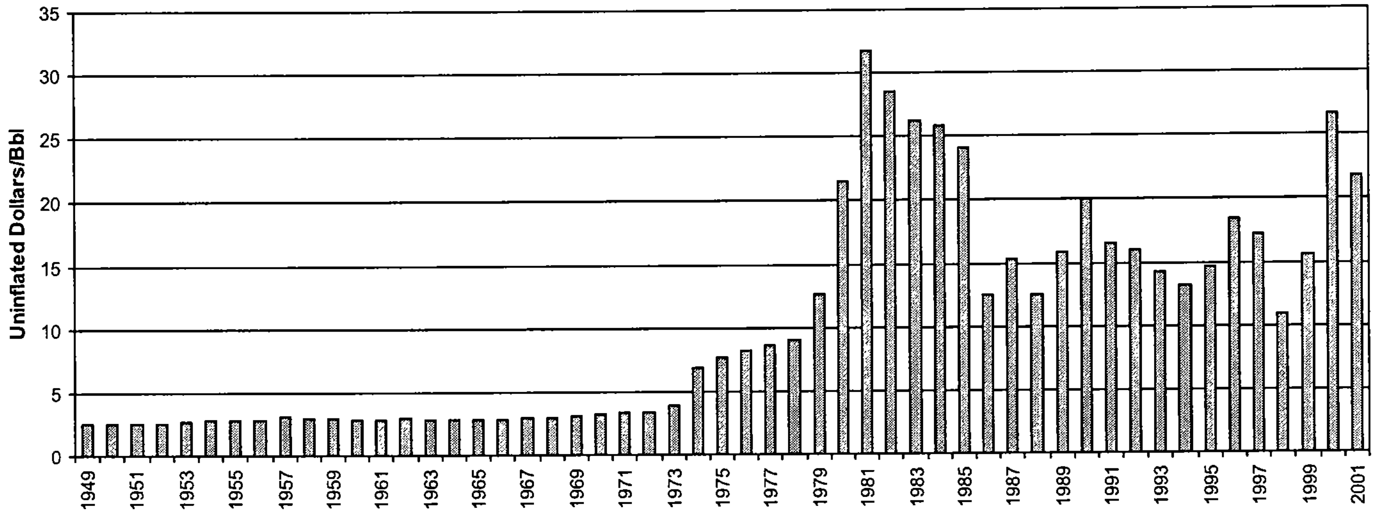


Figure 3. United States crude oil prices, 1949–2001. From Energy Information Administration (2003).

early distillation process removed salt from sea water, making it drinkable (NaturalGas.org, 2002).

Great Britain was the first country to commercialize use of natural gas, producing gas from coal in 1785 and using it for lighting. In North America, French explorers were the first to identify natural gas, observing natives in 1626 igniting seeps near Lake Erie. It was not until 1821 that the first well was dug with natural gas as the objective. In that year, William Hart (regarded by many as the father of natural gas in America) noticed gas bubbling to the surface of a creek at Fredonia, New York, and dug a 27-ft well to increase the flow (NaturalGas.org, 2002).

During most of the 19th century, natural gas was used almost exclusively for illumination in cities and businesses close to a source of supply. Demand remained low because, lacking pipelines, it was impossible to make gas widely available. Construction of large pipeline systems in the early 1900s led to a dramatic increase in demand. This led to the widespread home use of natural gas in heating and appliances, and its industrial use in manufacturing and processing plants (NaturalGas.org, 2002). Because gas is less expensive than oil as measured by equivalent heating capacity (or energy equivalence), it gradually replaced oil as a boiler fuel, and is now second only to coal in the generation of electricity.

Natural gas is found in conjunction with oil, and in the early days was usually considered a nuisance or a drilling hazard. Because gas had little value, when encountered it was commonly vented or flared until drillers determined whether oil was present in the reservoir below the gas (Boyd, 2002b). Difficulty of transport and the lack of local markets kept most early drilling focused on oil, and it was not until the late 1970s—with oil embargos, price deregulation, and the resulting increases in demand and price—that natural gas became a major exploration objective in many parts of the world.

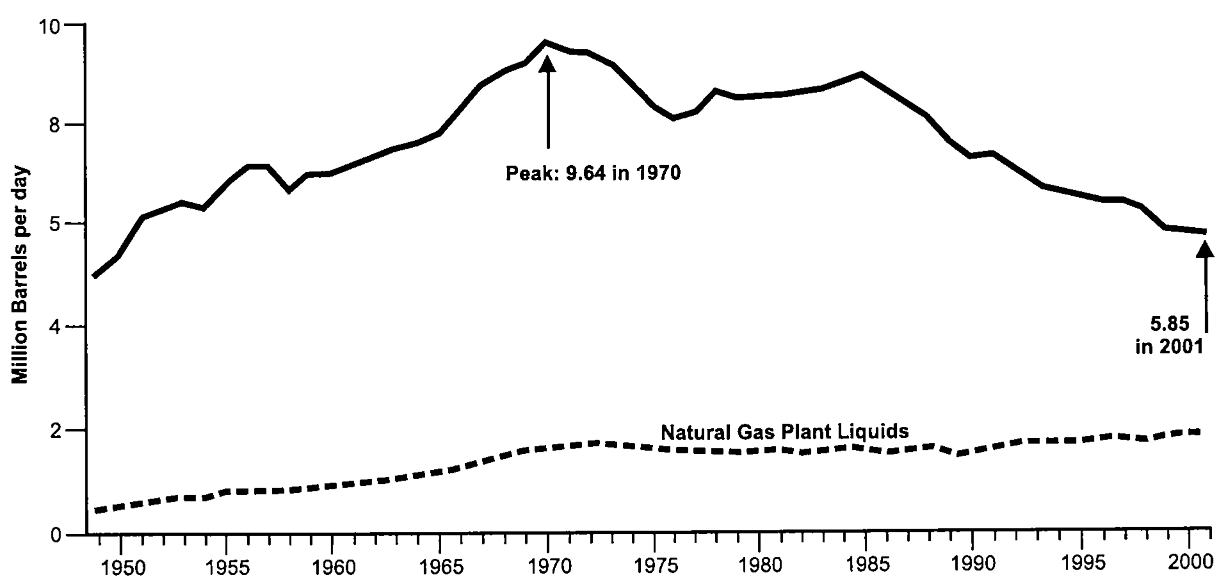


Figure 4. United States crude oil and natural gas liquids production, 1949–2001. From Energy Information Administration (2003).

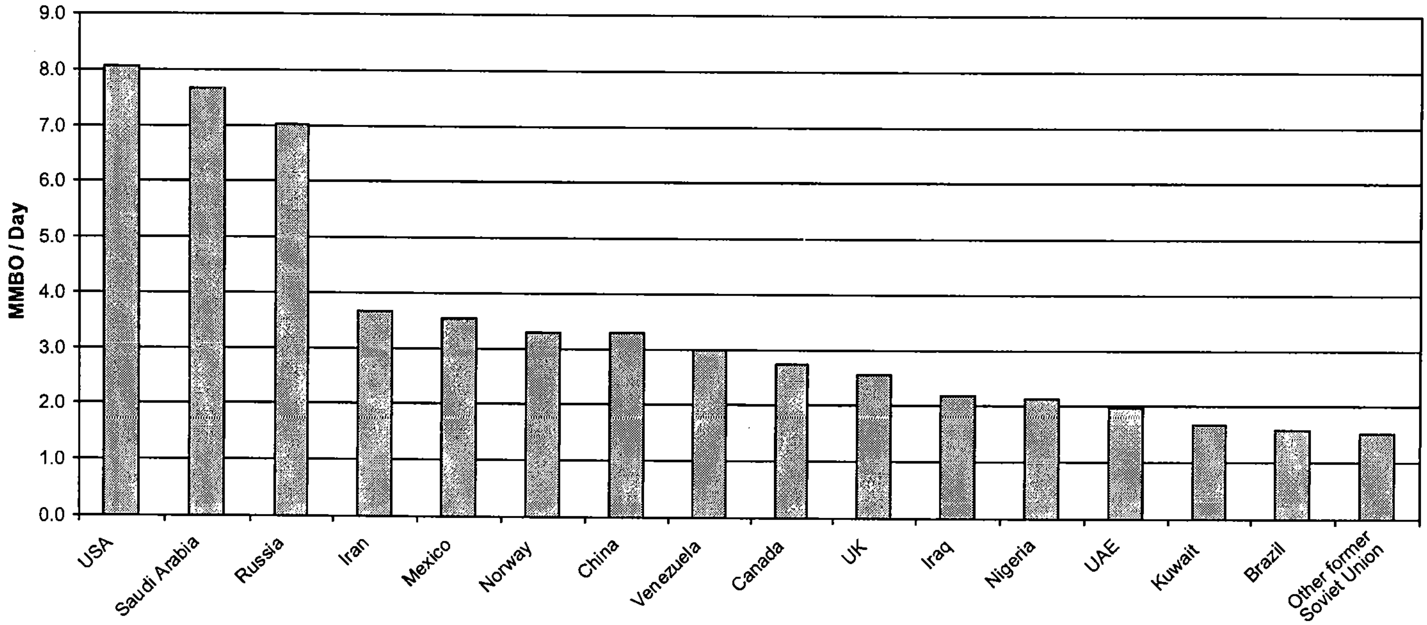


Figure 5. Daily national petroleum production (crude and natural gas liquids) for the top world producers. 2001 data from *World Oil*, from Energy Information Administration (2003).

In the same way that oil gradually supplanted coal in overall energy consumption, so natural gas began its rise to prominence 25–30 years later than oil. Although the uses of oil and gas differ, graphs of national consumption reveal parallel courses (Fig. 1), and with gas-price deregulation in the 1970s, the pattern is likely to continue. Deregulation has allowed the price to move with market demand; thus the correlation of oil and natural gas prices shown in Figures 3 and 6 (Boyd, 2002b). A similar parallel appears in graphs of U.S. production and consumption. Where the curves separate, imports begin rising rapidly. For oil the rise begins about 1967 (Fig. 2) and for gas 1986 (Fig. 7). Although it is not apparent in the figures, prior to 1958 the U.S. was a net gas exporter. The decline in production and consumption from 1972 through 1983 was due to rapid increases in gas price and the perception of a shortage, leading to government policies discouraging its use (U.S. Geological Survey, 2002).

The production of gas worldwide is—unlike oil—a function of access to a major market. Because the infrastructure for producing and transporting gas is expensive, long-term markets must be secured before development begins. If the market is overland, a pipeline system can be used to move the gas to market (for example, Russian gas exports to Europe via the Trans-Siberia Pipeline). If the market is overseas, the solution is usually shipment of liquefied natural gas (LNG) in the way that Indonesia supplies gas to Japan, South Korea, and Taiwan—from large LNG facilities in Sumatra and Kalimantan (Borneo). LNG is made by cooling natural gas until it liquifies. The supercooled liquid is then shipped in tankers that maintain the gas in a liquid state. Upon arrival at an off-loading facility, the LNG is allowed to warm and revert to a gaseous state, whereupon it is sent via pipeline to consumers.

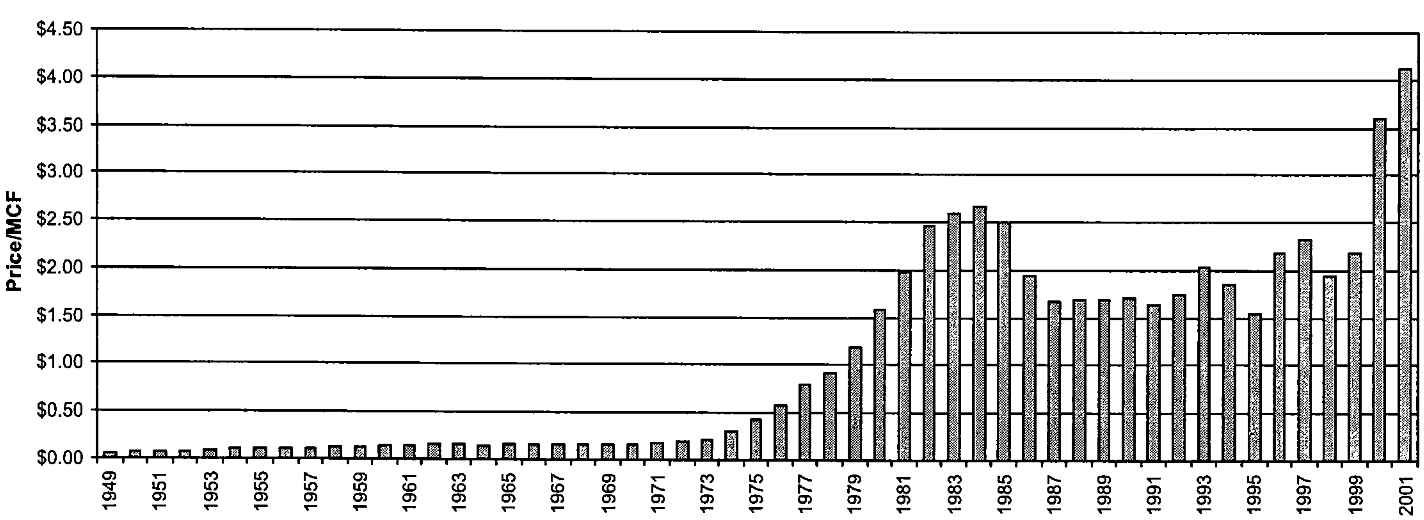


Figure 6. United States average wellhead natural gas price, 1949–2001. From Energy Information Administration (2003).

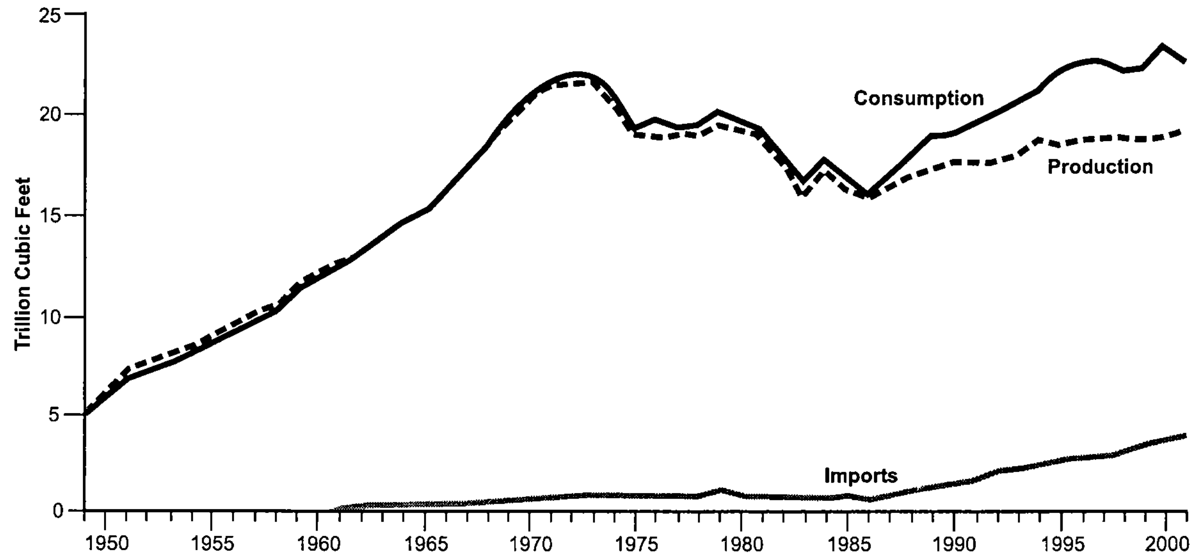


Figure 7. United States natural gas overview, 1949–2001. From Energy Information Administration (2003).

Because the up-front costs for both pipeline systems and LNG infrastructure are often measured in billions of dollars, the desire to insure that these investments are recouped is strong. To do so, a long-term gas market must be secured through contracts that are designed to protect both the buyer and seller. Under these the importer is committed to buy gas from the same facility for the life of the contract, but the price of the gas delivered is allowed to fluctuate with the market. (In most cases the gas price is based on a formula tied to the average world price of oil.) Because contracts are renewable and may span many years, large segments of the gas market are made unavailable to fields discovered in other areas. In addition, contracts are usually renewed until the seller no longer can meet demand, so the length of time that markets are dedicated is often measured in decades. Thus any gas inaccessible to existing gathering systems is stranded until additional demand justifies building another transportation system.

Countries that produced more than 2 trillion cubic feet (TCF) of gas in 1999 are shown in Figure 8 (Hinton, 2002). Russia and the U.S. continue to be the world's largest producers of natural gas. In Russia, gas development has paralleled both economic growth and the development of a large export market in Europe. In the U.S., where gas resources are smaller than in Russia, historically high demand has brought the development and production of gas much earlier than anywhere else. Gas production peaked in the U.S. in 1972 at 21.4 TCF (Fig. 7). Cumulative U.S. production is about 839 TCF (U.S. Geological Survey, 2002), of which Oklahoma has contributed 90 TCF, or 11% (Boyd, 2002b). Of the U.S. production total, about 64% was conventional, non-associated gas, 30% was gas associated with oil production, and about 6% was from non-conventional sources such as coalbed methane, shale gas, fractured reservoirs, and tight (low-permeability) reservoirs.

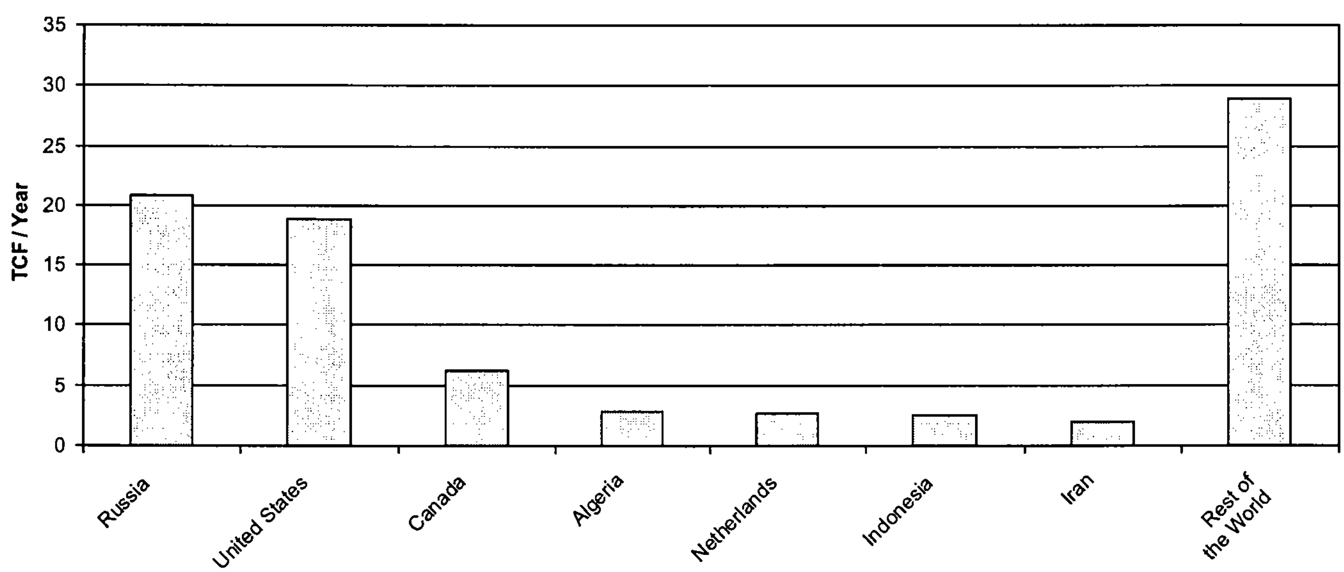


Figure 8. Countries producing >2 TCF of natural gas in 1999. From Energy Information Administration (2003).

## THE OUTLOOK FOR OIL

### Reserves

The most important variable in the analysis of any natural resource is proved reserves. For oil and gas, proved reserves are defined as the volume that geological and engineering data demonstrate, with reasonable certainty, to be recoverable from known reservoirs under existing economic and operating conditions. Their low technical and economic risk allows them to be assigned a monetary value. If reserves are divided by the annual rate of consumption (also known as the reserves to production or R/P ratio), one can estimate reserve life, which is the length of time that a given reserve volume can sustain the current rate of consumption (Boyd, 2002b). Reserve life is used as a yardstick in long-term planning, although it ignores future increases in demand resulting from economic growth.

It is convenient to categorize reserves by the world region in which they are found (Fig. 9). To clarify regional boundaries: (1) North America includes only Canada, the United States, and Mexico. (2) Asia/Oceania includes all countries east of Iran that are not former members of the U.S.S.R. (3) Greenland and Antarctica are assigned no reserves. The terms "developed country" and "developing country" refer to industrial development. In the broadest terms, developing countries are concentrated in the regions with the largest proved reserves of crude oil—the Middle East, Central and South America, and Africa. The industrialized countries are concentrated in North America, Western Europe, and Eastern Europe and the former U.S.S.R. Asia/Oceania comprises the developing economies of China, the Indian subcontinent, and Indonesia, as well as the industrial societies of Japan, South Korea, Australia, Taiwan, and Singapore.

Estimates of world oil reserves are relatively consistent. The value used here is the 2001 value of 1,028 billion barrels of oil (BBO), based on work by the *Oil and Gas Journal* (Fig. 10). As published by the Energy Information Association (EIA) of the U.S. Department of Energy (Hinton, 2001), it is very close to the value independently calculated by *World Oil Magazine* of 1,004 BBO for the same date, and is not far from a USGS estimate (based on 1996 data) of 891 BBO (U.S. Geological Survey, 2000). The similarity of these estimates reveals both a scarcity of the raw input data necessary to calculate reserves and a limited number of independent assessments for many of the countries involved. Note: oil's importance in the world economy has created conditions—in both developing and developed countries—in which political considerations commonly influence the size of reserve volumes reported.

As time passes, approximations of world oil reserves should converge. That does not mean that in a given economic environment there ever will be a precise and final estimate; rather, in a scheme in which 100 BBO has only a marginal effect, the range may be narrowing. The industry has matured, and the inventory of geologic basins that have been studied and explored has grown. In areas where exploration is allowed, the vast majority of promising basins have been evaluated. This is not to imply that they have been appraised to the level of many U.S. basins, but certainly large amounts of subsurface data have been acquired and the most promising areas have been drilled. Technology has advanced in the disciplines of well completion and evaluation, seismic acquisition and interpretation, and directional, horizontal, and deep-water drilling causing few prospective areas (in which drilling is permitted) to remain untested.

Because few frontier areas remain in the world, large future additions to reserves will be driven by technologies made economic through higher prices. One example is enhanced recovery operations in fields made after secondary (waterflood) recovery operations are completed. Another is in deep-water drilling (in more than 500 meters of water), where technological advances have made accessible large areas offshore. Deep-water discoveries account for an ever-increasing proportion of worldwide reserves, and have added roughly 21 BBO to the world total (Shirley, 2002b). In another realm, technological developments in producing oil from tar sands may greatly enhance proved reserves—as long as the long-term price of oil exceeds the cost of processing the tar. The tar sands in Canada (Athabasca) and Venezuela (Orinoco) will be the most important.

Except for the Middle East, the bulk of every region's reserves lie in one or two countries, each with at least 9 BBO of proved oil reserves. In North America, the U.S. and Mexico represent 91% of the region's total reserves; Venezuela contains 81% of the reserves in Central and South America; Norway, 54% of Western Europe; Russia, 83% of Eastern Europe and the former U.S.S.R.; Libya and Nigeria, 69% of Africa; and China, 55% of Asia/Oceania. In the Middle East, Saudi Arabia, Iraq, the United Arab Emirates (U.A.E.), Kuwait, and Iran each have at least 90 BBO reserves, and together account for 96% of the region's total. To complete the list of countries with more than 9 BBO of reserves, and to underscore the concentration of oil in the Middle East, the tiny nation of Qatar has reserves of 13.2 BBO. Qatar, whose land area is roughly the size of Connecticut, has reserves equal to 60% of the volume for the entire U.S.

One indication of disparity in the distribution of oil reserves around the globe is the two-tier system used by the American Association of Petroleum Geologists to classify fields as giants. In the Middle East, North Africa, and Asian Russia, a field must have an ultimate recovery of at least 500 MMB of oil or 3 TCF of gas to be considered a giant. For the rest of the world this hurdle drops to 100 MMB of oil or 1 TCF of gas (Fitzgerald, 1980). By the latter measure, Oklahoma has 26 oil fields (Boyd, 2002a) and 11 gas fields (Boyd, 2002b) classified as giants.

As one might expect, most of the world's future reserve additions probably will come from the areas with the bulk of today's proved reserves. Although analysts agree that OPEC countries still are the most promising areas for new reserves, some official estimates may be overstated, as member state's production quotas are determined in part by proved reserves. OPEC reserve estimates have risen dramatically in recent years, based largely on the expectation of higher recovery rates in existing fields. However, to be produced, much of these reserves will require huge capital investment (Sandrea, 2002).

Reserves are the part of a resource base (the total known supply) that is economically recoverable. As exploration around the world continues, the proportion of the resource

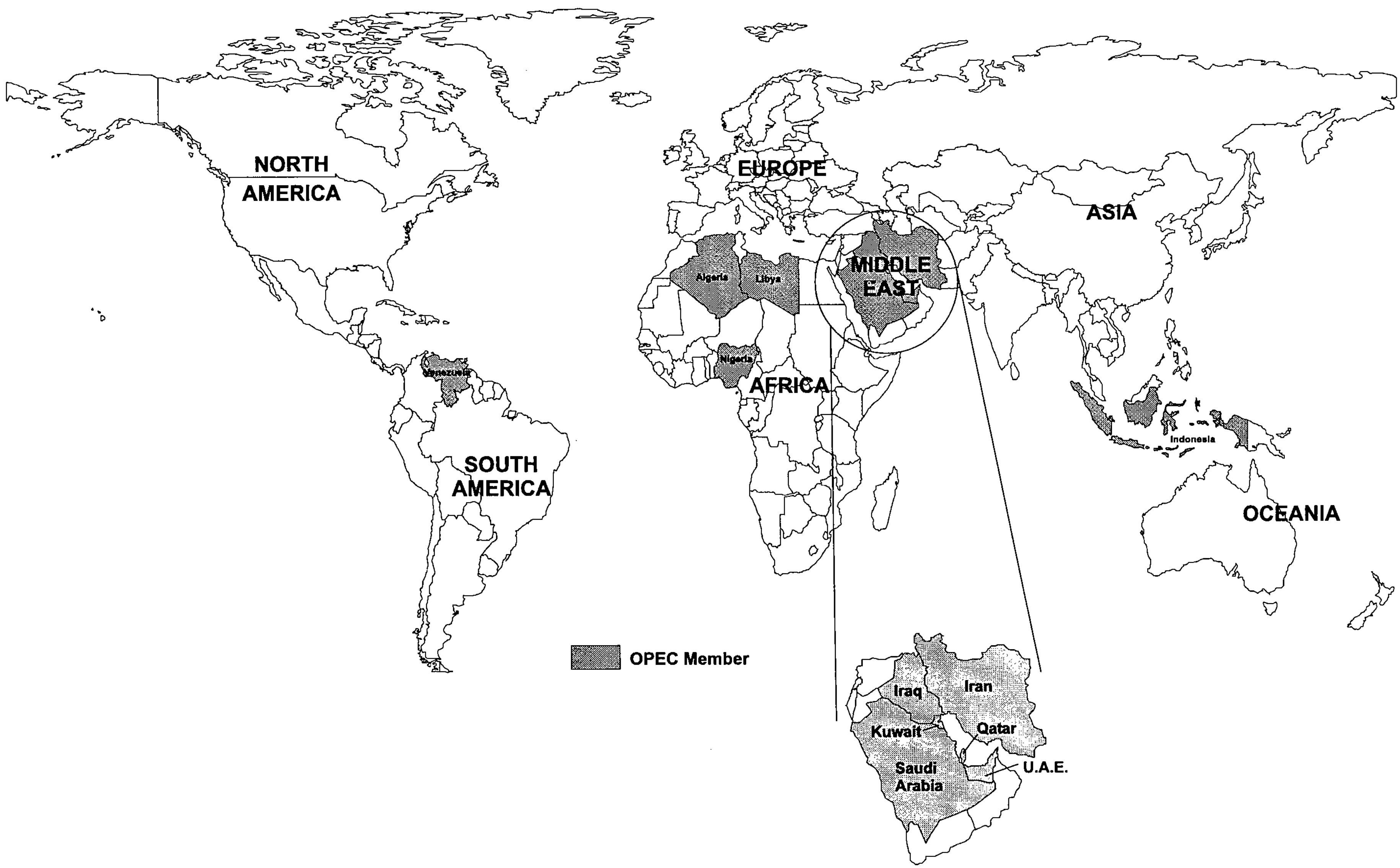


Figure 9. Map of world regions showing OPEC member states.

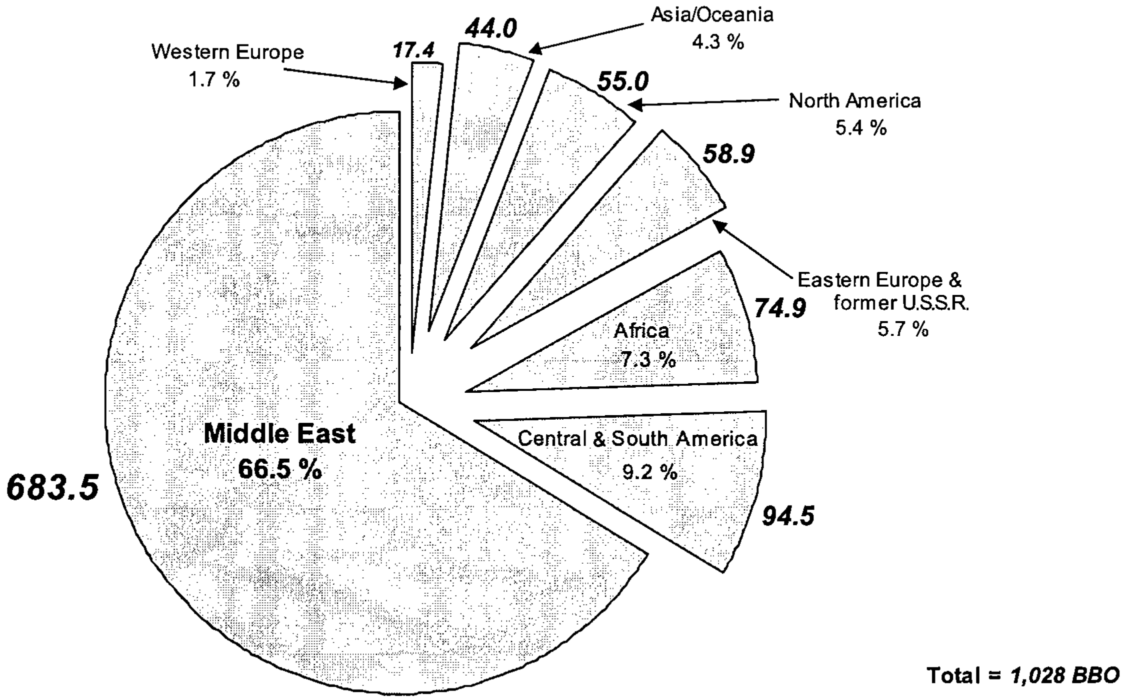


Figure 10. Proved oil reserves by world region (January 2001). Data from *Oil and Gas Journal*, from Energy Information Administration (2003).

base expected to be ultimately producible has grown. Historical reserve trends, advances in technology, and an ever-increasing volume of geological data have all been used to predict the size of additions to world reserves. Because these projected volumes are far less constrained than proved reserves, estimates can vary markedly. In order to avoid the problem of reserve volumes shifting categories through time (future reserves becoming proved reserves, and proved reserves being produced and becoming cumulative production), it is common to speak in terms of petroleum endowments. An endowment is the sum of all three categories (cumulative production, proved reserves, and future reserves) and is meant to represent the ultimate volume that will ever be produced.

Estimates of the world petroleum endowment range from about 1.8 trillion barrels of oil (Campbell, 1997) to 3.0 TBO (U.S. Geological Survey, 2000), with values clustering around 2.1 TBO (Deffeyes, 2001). Such calculations are not academic. The production curve for any large area tends to follow a bell-like shape, the peak of which can be determined, given enough historical data, based on ultimate recovery. Because much of the world's endowment has been produced, a realistic estimate of ultimate recovery should enable us to estimate a plausible date at which peak production will be reached. Because the world economy is based largely on petroleum, this prediction is very useful, as it marks the transition from a buyer's market to a seller's market.

## Consumption

Consider the world's approximately one trillion barrels of remaining proved oil reserves in light of annual consumption, which an EIA assessment for the year 2000 places at about 28 BBO (Fig. 11). Most consumption is by industrialized countries that, as a result of early and rapid domestic production of oil, now find themselves at the bottom of the list in terms of reserves (Fig. 10). The world's top consumers of crude oil are the U.S., Japan, China, Germany, and Russia (Fig. 12; data begin in 1992 because no earlier statistics for Russia are available.)

U.S. consumption, at nearly 20 MMBO per day, is greater than that of the next six countries. The price shocks that began in 1979 reduced U.S. petroleum consumption below the peak reached in 1978 (Fig. 2). However, higher energy costs were absorbed by the economy, and demand began recovering in 1983. Except for minor, short-term declines, demand for oil in the U.S. has increased continuously. Nor does oil stand alone at the peak; nearly every other major energy source (natural gas, coal, nuclear energy, and hydropower) including wood is now used at record levels in the U.S. and the rest of the world (Fig. 1).

If one divides a proved reserve volume of 1,028 BBO by annual consumption of 28 BBO, one finds that reserves can sustain consumption at the current rate for about 37 years. This statistic is useful, but potentially misleading because it rests on many assumptions. It assumes no change in world demand (either up or down), although in the U.S., despite an ailing economy, demand has risen about 14% in the last 10 years. It presupposes that the petroleum industry will produce the remaining reserves as rapidly as those already produced. It also takes for granted that the proved reserve volume will remain static, though long-term revisions of worldwide reserves have always risen (but usually not enough to replace consumption). Finally, it assumes that all reserves (and the equipment necessary to produce them) will be continuously available to support demand—but think of recent news from Nigeria, Venezuela, and Iraq.

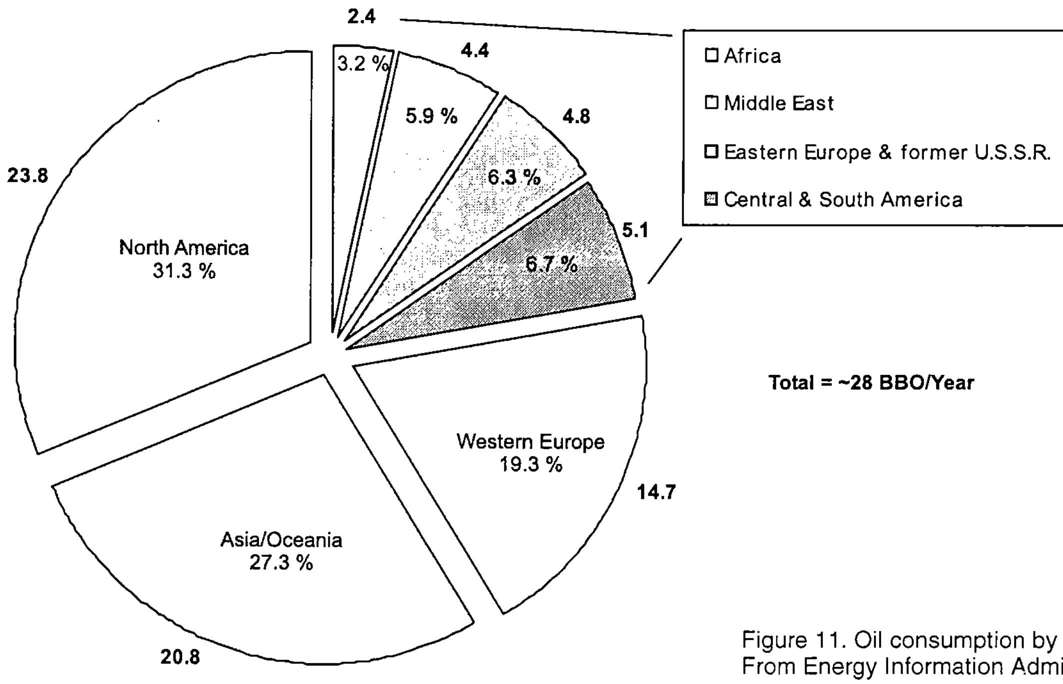


Figure 11. Oil consumption by world region (2000). From Energy Information Administration (2003).

Around the globe, as in the U.S., demand for energy is increasing continuously. Until recently this growth was confined almost exclusively to more developed and less populated regions. Now, industrialization has enlarged the proportion of world oil consumed in developing countries. Take China and India: their combined consumption in 2000 was a third that of the U.S.—but they had eight times the population. The point is not that our per capita use of energy is 24 times that of China and India; it is that in the last 10 years, while U.S. consumption was rising 14%, consumption in China and India rose 84% (Energy Information Administration, 2003). Their 2.2 billion people make up more than one third of the population of the planet. Although the developing world will never match per capita U.S. consumption, progressive industrialization will continue to push their energy demand higher.

The only factor that affects long-term oil consumption is price. Interruptions in supply are responsible for most major price increases, and, as a result, also the major drops in consumption. (These major supply interruptions are distinguished from those that are designed solely to keep oil within a price window that producers see as desirable.) Because the developed world has (by definition) an industrialized economy and the corresponding history of energy de-

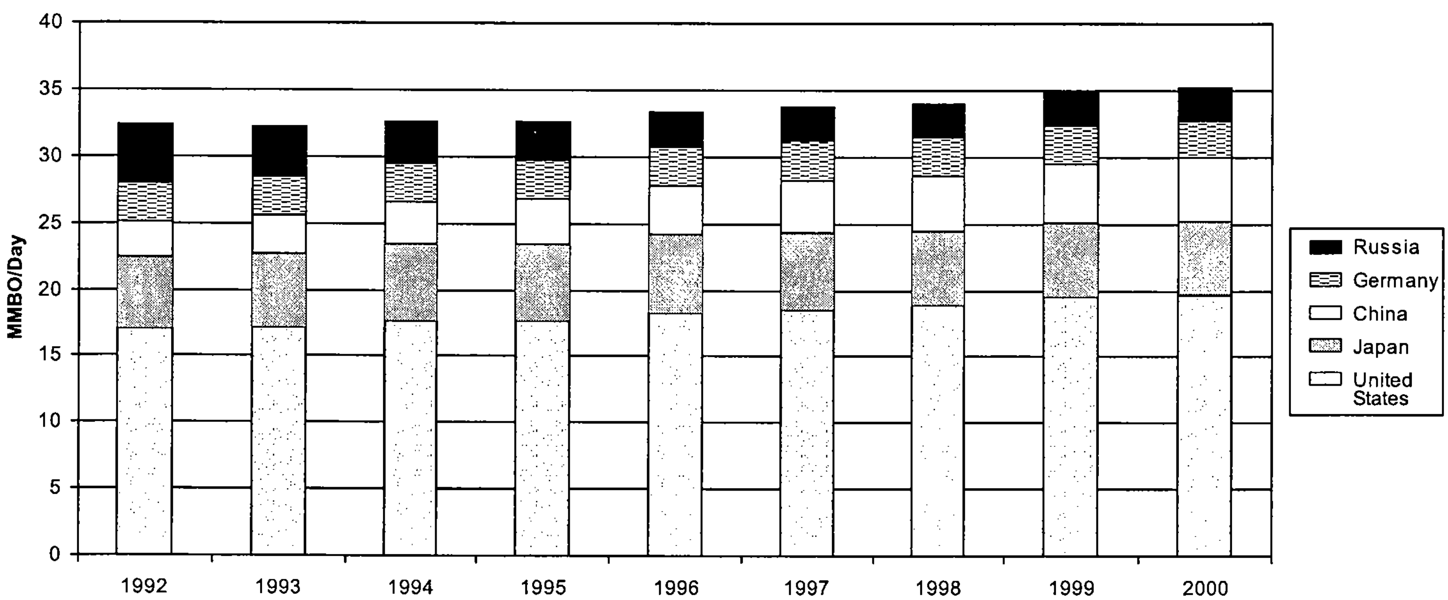


Figure 12. Countries consuming >2.5 MMBOPD (2000). From Energy Information Administration (2003).

mand, it has already produced the bulk of its oil reserves. As a result, an increasingly higher proportion of the remaining reserves reside in countries that have been slower to develop modern economies and the commodities that fuel them. Many developing countries are subject to all manner of internal and external disturbances that can disrupt their ability to produce oil. The world's excess production capacity is smaller than ever, so meeting today's demand requires sustained production from all major producers. In a precariously balanced market, a real or threatened interruption of supply anywhere inevitably leads to higher prices for everyone.

## Production

World oil production, except in the Middle East, is about equally divided among the seven world regions (Fig. 13). Their shares vary from about 9 to 16%, with the Middle East accounting for roughly a third of the world total. However, this analysis understates the leverage that Middle Eastern oil production exerts on the world market. North America, Asia/Oceania, and Western Europe use all of their own oil and import large volumes of crude. Eastern Europe and the former U.S.S.R., and Central and South America, produce significant amounts of oil, but they use most of it themselves. Thus Africa and the Middle East, with their tiny share of the consumption pie, remain the largest exporters of crude oil. The Middle East produces three times as much oil as Africa, and also contains most of the world's remaining excess productive capacity. This explains the enormous influence that news from this region has on world energy markets. The situation is unlikely to change, because in addition to proved reserves, projected future oil reserves are also concentrated in the Middle East.

In almost every petroleum province the distribution of field size is asymmetrical, with the larger and easier-to-find fields making up a disproportionate share of total production and reserves. Oklahoma follows the worldwide trend with 5% of the fields responsible for about 83% of the State's oil production and reserves (Boyd, 2002a). Because most of the largest fields are found early in the life of a petroleum province, initial production in a given region tends to increase rapidly. This increase continues until the first of the large fields peak and begin to decline. Early discovery of most of Oklahoma's largest fields led to the State's production peak in 1927 (Boyd, 2002a). If the decline in big fields cannot be overcome by production from later discoveries (which must be large to have much impact), the overall production curve begins to decline. Because even small percentage declines in large fields are large volumes, as more fields mature the overall effect snowballs. As average discovery sizes become progressively smaller, even concerted drilling programs usually can only reduce the rate of decline. Secondary and enhanced recovery operations combined with many smaller discoveries can extend the length of time that high production rates are maintained, which often leads to lesser, intermediate peaks. However, by this stage only the rate of the long-term decline can be affected.

The sequence just described creates a production curve conforming to a general bell-shape. Such a curve is seldom symmetrical, for peaks vary in duration, and intermediate highs are sometimes quite large. Lesser peaks may be caused by price fluctuations resulting from wars, embargoes, economic booms and busts, or anything that affects supply or demand. The opening of new areas to exploration late in the productive life of a given region also can generate bumps in the overall production curve. Such events can magnify intermediate highs, and if the timing is right they can extend the period of maximum production.

An example of both effects may be found in the U.S. oil production curve. It peaked in 1970, but production from the Prudhoe Bay Field and a nationwide drilling boom enabled it to stay near its maximum through the mid-1980s. (Note that Figure 14 shows only crude oil and not liquids derived from natural gas production, which do appear in Figure 5.) If production from Alaska is omitted, the 1970 peak is far more pronounced and the curve becomes far more bell-shaped.

Prudhoe Bay Field, the last supergiant (>10 BBO) found in North America, is the largest field in the U.S. Before the field's 1968 discovery the North Slope of Alaska had been drilled only sparsely. Its recognition was greatly facilitated by the use of early reflection seismology (Jamison, 1980).

Although the effect is not as dramatic, in recent years the decline in national production has been noticeably slowed by the addition of oil from deep-water fields in the Gulf of Mexico. Much of the oil in the Gulf had been out of industry's reach until new drilling technology enabled drilling in water depths of several thousand feet. This development has brought essentially all prospective offshore areas within reach of the drill bit.

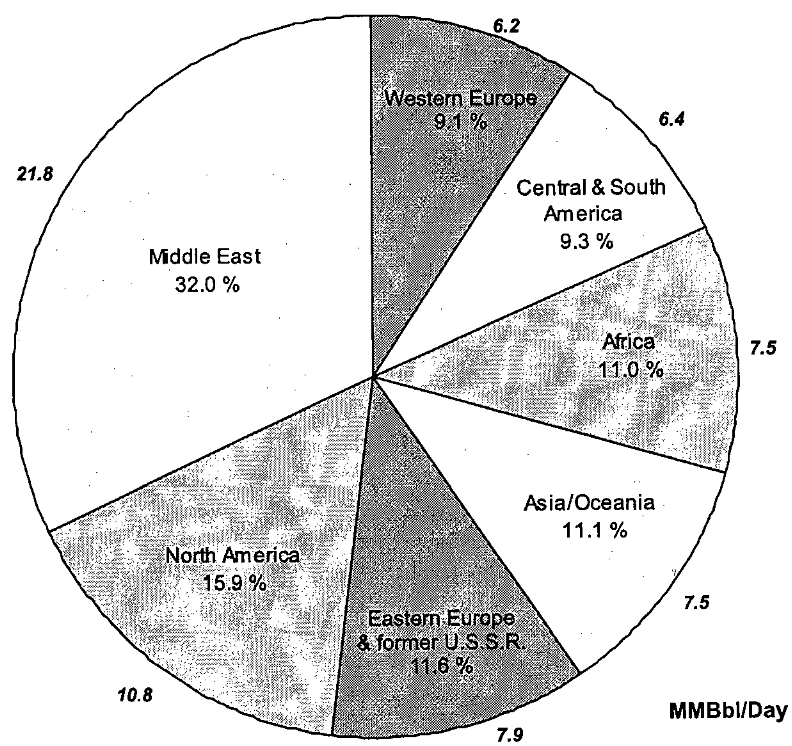


Figure 13. Oil production by world region (2000). From Energy Information Administration (2003).

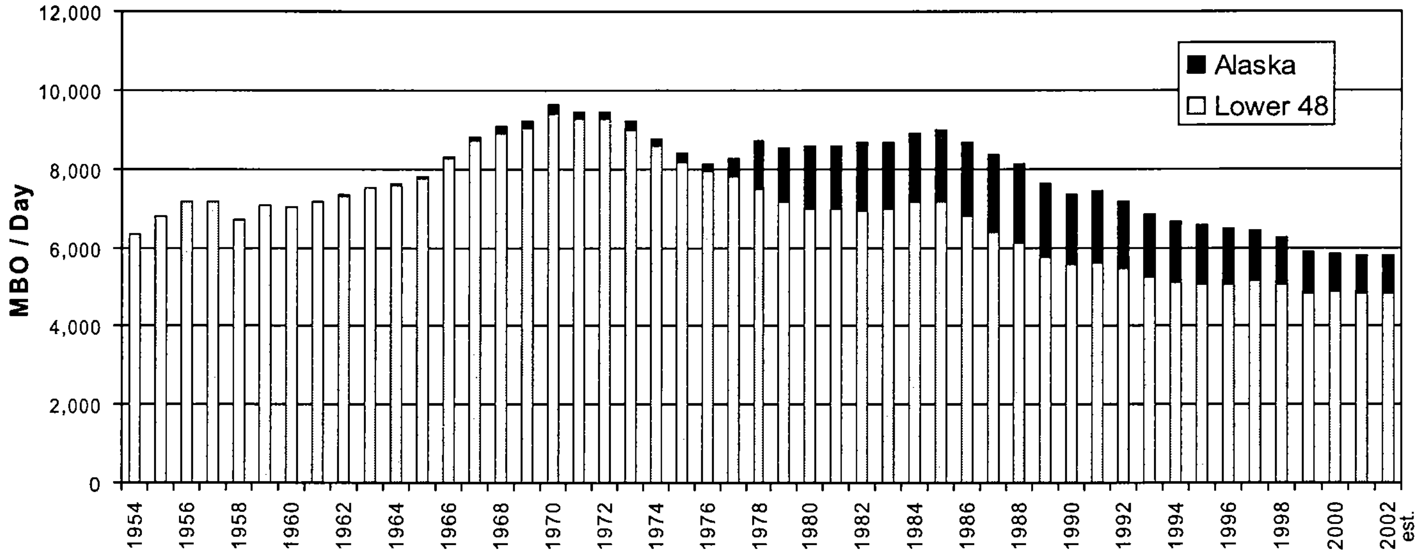


Figure 14. United States crude oil production, 1954–2002. From Energy Information Administration (2003).

Giant fields like Prudhoe Bay hold not only reserves, but also most of the world's capacity for oil production. The world has 583 giants (defined as having at least 500 MMBO of reserves plus production). The giants constitute 0.1% of all fields, but account for roughly 85% of global reserves (Fitzgerald, 1980). Not surprisingly, most of the largest oil giants were found early and have been producing for decades. Their increasing age is demonstrated by production rates: in 1986, 15 of the giants could produce more than 1 MMBO per day, but now only four can make this rate. The survivors are Ghawar in Saudi Arabia, Kirkuk in Iraq, Burgan in Kuwait, and Cantarell in Mexico (Petzet, 2001). Many other major producing fields are declining or soon will be, even in the Middle East. Two of Iran's four largest fields are in secondary recovery, and the U.A.E.'s two largest fields are about to begin secondary recovery operations. OPEC's overall peak production capacity of 40 MMBO per day was reached in the mid-1970s, when the largest fields were still young. Although massive spending on infrastructure could increase OPEC production, old highs are unlikely to be matched (Bakhtiari, 2002).

For Oklahoma and the U.S. as a whole, nothing can return production to historic highs. Oklahoma is 75% (573 MBO per day) below its peak rate, and the U.S. is down by 40% (4 MMBO per day). Although the declines in both have flattened in recent years, as a result of higher prices, their long-term slides continue (Boyd, 2002a). The U.S., unlike Oklahoma, has many promising areas off limits to exploration. They include the Arctic National Wildlife Refuge on the North Slope, the eastern Gulf of Mexico, offshore areas along the entire East Coast and most of the West Coast, and areas in the Rocky Mountains. However, even if all of these were opened today production still could not approach previous highs.

North Slope production remains by far the most important to be found in the U.S. in decades. At their peak, Prudhoe Bay and its satellite fields represented 25% of the national output and even now about 17% (Fig. 14). Without the North Slope, U.S. imports today would account for about 75% of consumption. Although Prudhoe Bay production peaked at about 2 MMBO per day, that was 20 years after the discovery well was drilled. The decline for Prudhoe Bay and its satellites alone in the next 20 years is estimated at 400 to 700 MBO per day (Energy Information Administration, 2001). Adding the concurrent loss in production that is expected in the rest of the country during the same period (2.0–3.5 MMB per day) makes apparent the difficulty in just maintaining today's production level. Even in the most optimistic outlook, the American "snowball" has gathered far too much momentum to ever be pushed back to the top of the hill.

Over a century of world oil production, and the realization that production graphs (in statistically large samples) tend to yield a bell curve, makes possible certain predictions. These include broad estimates of the peak production rate and when this peak will occur. Critical variables include ultimate recovery and the precise shape of the curve. In a given area production inclines and declines are often irregular and may be steep or gradual on either side of the peak. Economic factors and the addition of new sources of supply can affect the duration of production peaks (Fig. 14).

If the curve used to predict the peak of world oil production is roughly symmetrical and encompasses an ultimate recovery of about 1.8 TBO, the world could reach the peak this year, in 2003. Clearly we have not yet reached the peak, for although OPEC production capacity is kept secret most analysts believe that excess production capacity for the world is still 4 to 5 MMB per day (Toal, 2002). However, with current daily consumption at 76 MMBO and this increasing to more than 118 MMBO per day by 2020 (Energy Information Administration, 2003), it is clear that we are working with little cushion. The low level of excess capacity explains why even a small, brief interruption of supply can have a major impact on price.

If the ultimate recovery volume is increased by 300 BBO (or about half the cumulative production to date) to 2.1 TBO, world production should peak between 2005 and 2009 at an annual consumption rate of about 31 BBO (Fig. 15; Deffeyes, 2001). This is believed to be more realistic, and would show about 34% of the world's petroleum endowment as cumulative production, 42% as proved reserves, and 24% as future reserve growth. Different scenarios for reserve growth, discovery, infrastructure, and pricing could end with different dates and durations for peak production. However, even moderate economic growth leads to increases in world oil demand of 1–2 MMBO per day per year. So if the world's excess capacity is truly 4–5 MMBO per day, the supply-demand curves could easily cross in this decade.

An estimate by the U.S. Geological Survey (2000), of more than 3.0 TBO of ultimate recovery, has been used as evidence that peak oil production will not be seen for decades. However, this estimate is roughly 1 TBO higher than most others and requires a doubling of the current proved world oil reserves (Fig. 10). Some of this oil could come through improved recoveries in existing fields. However, most of it must come as a result of new discoveries. The discovery of so much economically producible oil so late in the life of worldwide oil exploration contradicts experience. Huge, prospective, and hitherto unexplored regions would have to be opened. Some areas of the world do remain sparsely explored, but unrealistic success rates also must be invoked in order to find the equivalent of 100 Prudhoe Bay fields. The worldwide field-size distribution (where 1/1000th of the fields represent 85% of reserves) and the trend in oil discovery size make it unlikely that ultimate recovery can be increased by a trillion barrels.

For reserves to significantly affect the date at which world oil production peaks, they must be found in large fields in reservoirs where high production rates can be established in the next few years. If they occur, for instance, in comparatively small pools in deep water, beneath Antarctic ice, or in low-permeability reservoirs that require intensive drilling to attain high production rates, they will not affect the point when demand exceeds supply. To delay the world's production peak much beyond the 2 to 6 years estimated requires bringing into production, every year, the equivalent of at least one field delivering 1–2 MMBO per day. Although nonconventional resources like tar sands and oil shale occur in very large volumes, they cannot approach such yields, and certainly not any time soon.

When demand is forced to match supply, the extreme price lows that prove ruinous to low-rate oil production (a situation dominant in Oklahoma) should become a thing of the past. Although volatility in price will undoubtedly persist, the lows will be higher than those of the recent past. Higher average prices will permit the use of new, more expensive recovery techniques in producing fields and will open to the world market some smaller accumulations now stranded by transportation costs. Exploration could become economic in less-hospitable environments, perhaps even in Greenland and the Antarctic. Many enhanced recovery projects with large up-front costs, which have been on hold for fear of prolonged periods of low prices, could become economically viable.

Higher oil prices also could make possible large-scale investment in extraction of oil from tar sands, in which potential reserves are huge but production and environmental costs are high. Processing tar sands requires great amounts of water as well as the disposal of up to 10 tons of solid waste per ton of oil produced (Energy Information Administration, 2002). Tar sands such as the Athabasca (in Alberta) and Orinoco (in Venezuela), although huge resources, will probably have little effect on when maximum world oil production will be reached. Their main value, like other sources that become economic in a high-cost environment, will be in providing a large (if expensive) source of petroleum for long-term demand.

The key point is that (transportation costs aside) similar types of oil sell for essentially the same price anywhere in the world, regardless of the political compatibility of buyer and seller. In this age of instant communication, the global market ensures that oil will be sold only to those who pay the going rate. When supply can no longer meet demand, prices will rise sharply until demand falls to a level that can be sup-

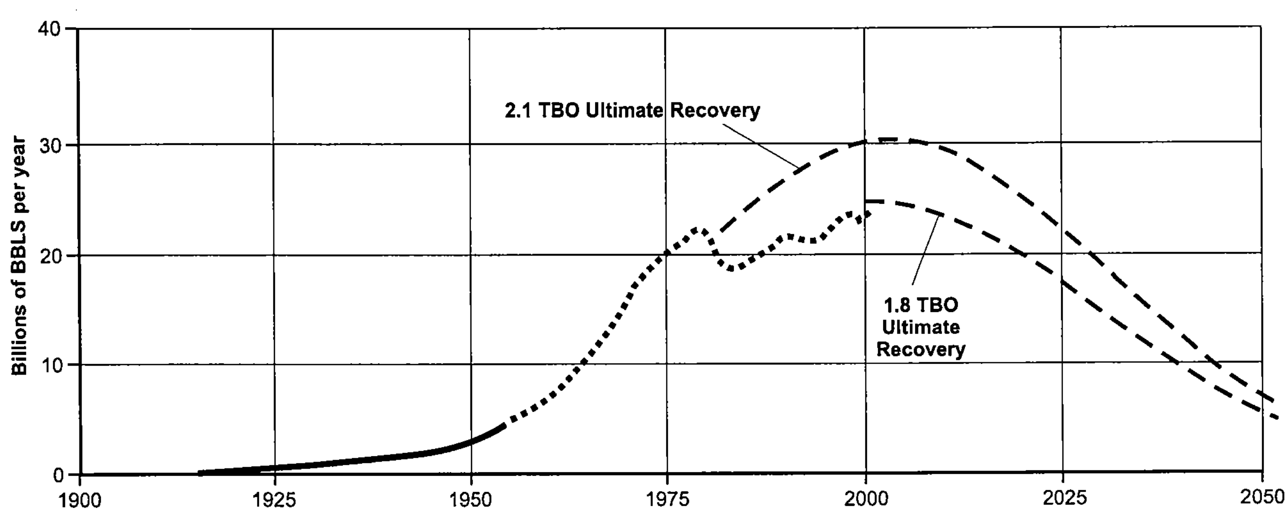


Figure 15. World oil production through 2000 (heavy dots) showing projected production through 2050 (dashed lines) for two possible ultimate recoveries. From Deffeyes (2001).

ported, usually through conservation and fuel switching. This relationship between supply and demand ensures that the world will never "run out" of oil.

## THE OUTLOOK FOR NATURAL GAS

### Reserves

There are many reasons to be optimistic about the long-term outlook for natural gas. Among them: (1) Gas remains a secondary target in many parts of the world, so it is comparatively under-explored. (2) When discovered in an area with no gas market, delineation wells (follow-up wells, to determine the size of the field) usually are not drilled, making reserve estimates cursory, and typically conservative. (3) If lacking a near-term market, an entire basin that is viewed as gas-prone may receive little attention from industry. (4) Gas can exist in deeper reservoirs than oil, and be produced from strata with much lower permeability than oil (Boyd, 2002b). (5) Many areas intensively drilled for oil have not been completely evaluated for deeper gas potential. (6) Non-conventional sources of natural gas, like gas hydrates, coalbed methane, and various types of low-permeability reservoirs, have huge resource potential; for them, even small changes in recovery estimates have a large impact on reserves. (7) In many areas of the world with large conventional gas reserves, little effort has been made to evaluate non-conventional resources.

Like oil, the world's proved reserves of natural gas are distributed unevenly (Fig. 16); Eastern Europe and the former U.S.S.R. and the Middle East contain nearly three-quarters of the world's proved reserves. On a national reserve basis, Russia has a large lead, but four of the top seven countries are in the Middle East (Fig. 17). A single huge accumulation in Qatar (the North Field) gives that tiny nation roughly three times the proved reserves of the U.S.

In the period from January 2000 to September 2002, according to IHS Energy (2002), 28 giant discoveries were made worldwide, with estimated reserves of more than 500 million barrels of oil equivalent (MMBOE). For gas, this is a reserve volume of at least 3 TCF (Fitzgerald, 1980). Two-thirds of these discoveries were gas, with all but one of the giant oil discoveries having a significant gas component. During the same period in North America, mirroring Oklahoma in recent years (Boyd, 2002b), 1,180 new fields were discovered. Most were small, but fully three-quarters were gas or coalbed methane (IHS Energy, 2002), indicating that industry's focus in North America has shifted strongly to natural gas. In the rest of the world, although oil may still be the primary objective, it is gas that is being found in the largest quantities.

Future additions to global reserves also are strongly skewed towards Eastern Europe and the former U.S.S.R. and the Middle East. Although the Northwest Shelf of Australia and offshore Norway hold promise, most new reserves are expected to come from Russia (Siberia, Barents, and Kara Sea) and the Middle East around the Persian Gulf (Ahlbrandt, 2002). These area's large conventional gas reserves have reduced the incentive to assess non-conventional resources, which are harder to produce and will not be needed for 60–100 years.

In North America, most easily produced gas already has been found, and large volumes of harder to produce gas are necessary to meet demand. Except for the many areas off limits to exploration, all possible sources of natural gas are being evaluated. Non-conventional sources such as coalbed methane and low-permeability reservoirs constitute a substantial part of both the resource base and daily production. For North America the resource volume of technically recoverable gas (proved reserves plus conventional and non-conventional resources) has been estimated at 2,500 TCF (Energy Information Administration, 2003).

Studies made in 1995–2001 of gas remaining in the U.S. (by private and federal organizations) project an average recoverable resource of 1,549 TCF—about nine times current

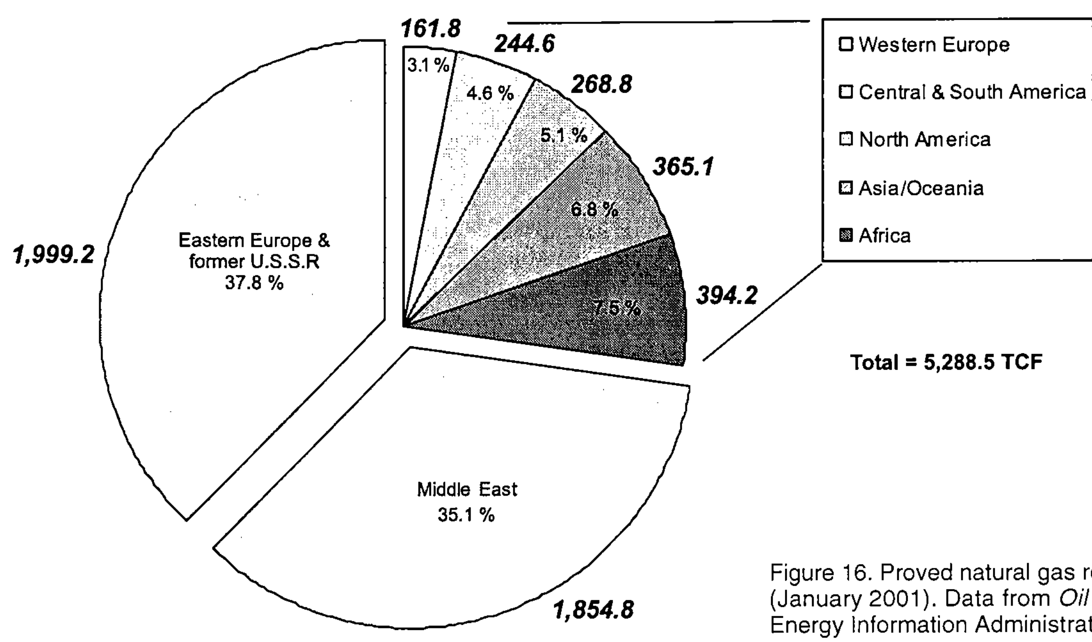


Figure 16. Proved natural gas reserves by world region (January 2001). Data from *Oil and Gas Journal*, from Energy Information Administration (2003).

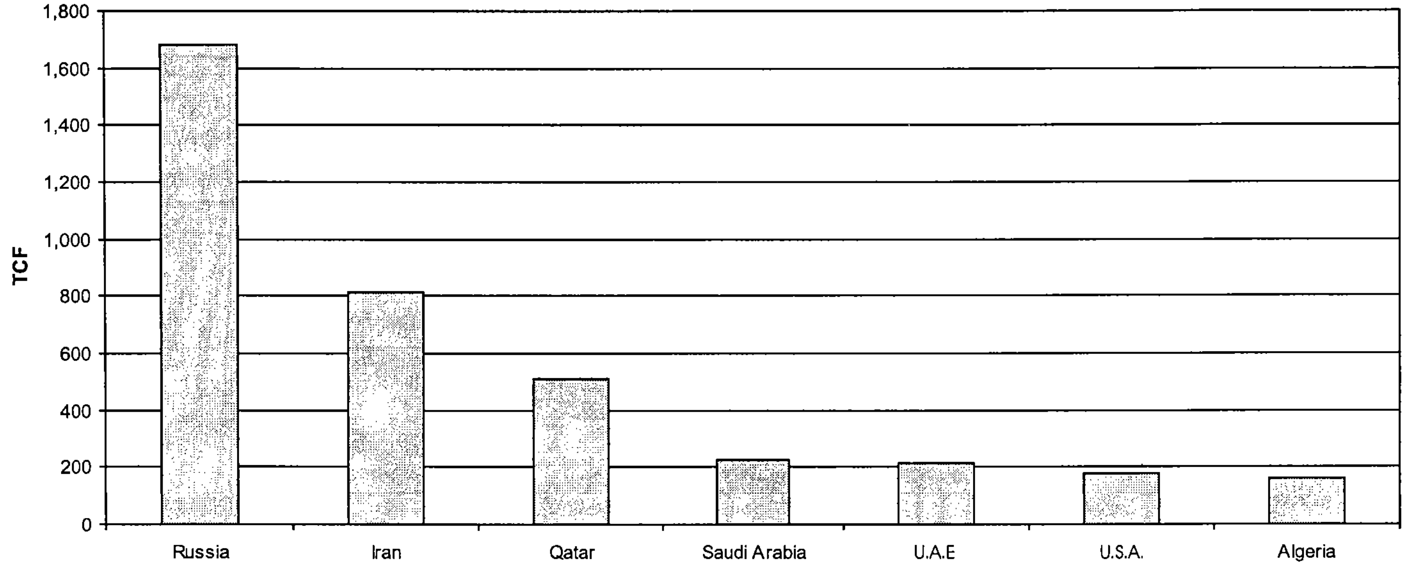


Figure 17. Proved natural gas reserves by nation (January 2002). Data from *Oil and Gas Journal*, from Energy Information Administration (2003).

proved reserves. This suggests that our reserve base can be greatly increased. The projected volume (assuming these resources all become reserves) amounts to a 67-year supply at the current rate of consumption. Non-conventional gas is a substantial component of the nation's resource base, so incremental improvements here could lead to large increases in reserves. For example, estimates of technically recoverable coalbed methane average 70 TCF, and for tight gas sands, 275 TCF. Although the non-conventional resource types are defined and assessed in different ways, and estimates vary considerably, the volume of potentially recoverable gas is clearly large (Curtis, 2002).

Proved gas reserves in the U.S. have remained fairly steady, averaging about 183 TCF over the last 25 years (Energy Information Administration, 2003), a volume equivalent to 8 years of current consumption. Year-end 2001 U.S. reserves were 183.5 TCF, but our ability to keep pace with production has not resulted from the discovery of large gas fields; in 2001, discoveries accounted for only 16% of additions to U.S. gas reserves. Most additions come from the expansion of old fields and upward revisions in recovery factors. Increasingly, additions are coming from non-conventional sources such as coalbed methane, tight gas, deep gas (>15,000 feet depth), shale gas, and offshore gas from deep water. These account for about 20% of U.S. reserves now, and this share is expected to grow to 50% by 2020. The coalbed methane component of gas reserves has grown since 1989 from less than 4 TCF to 18 TCF, or roughly 10% of total reserves (Energy Information Administration, 2003). In the Midcontinent (including Oklahoma) reserves are 16.9 TCF of recoverable tight gas, 5.8 TCF of coalbed methane, and 17.7 TCF of deep gas, mostly in the Anadarko Basin (Shirley, 2002a).

For gas, as for oil, endowments are the sum of cumulative production, proved reserves, and future reserves. They are meant to represent the ultimate volume of gas that will ever be produced and do not distinguish between associated and non-associated or conventional and non-conventional (Boyd, 2002b).

The USGS estimate of the world's natural gas endowment for the year 2000 is 15.4 quadrillion cubic feet (QCF), or 15,400 TCF. Of that endowment, 11% (~1,700 TCF) has been produced; 31% (~5,000 TCF) is proved reserves, and 58% (8,900 TCF) are reserves yet to be found. The volumes are huge, but in most parts of the world they include only conventional gas resources. Because this estimate could not include analyses for all prospective sedimentary basins, most consider the assessment conservative, despite its size (Ahlbrandt, 2002). In the last 20 years, as average prices have remained steady in real terms, consensus estimates of the world's remaining natural gas reserves have increased tenfold (Fisher, 2002), and discoveries and development show that this trend is likely to continue.

Any discussion of natural gas resources must include gas hydrates (also called methane hydrates). Hydrates are an enormous—but still uneconomic—non-conventional source of natural gas. They are solid, crystalline, ice-like substances composed of water, methane, and small amounts of other gases trapped in a water-ice lattice. Hydrates, which form at moderately high pressure at temperatures near the freezing point of water, are found in permafrost regions onshore and in ocean-bottom sediments in water depths below 450 meters (~1,500 feet). Some offshore hydrate deposits are exposed on the ocean bottom, but most are found in sediment beneath the seafloor. A growing body of evidence suggests that natural releases of methane from hydrates in the geological past have had major effects on the Earth's climate. How hydrate releases occur is not understood, but their production as an energy source could mitigate a long-term environmental hazard (Morehouse, 2001).

The volume of methane locked in natural gas hydrates around the world is staggering. Estimates vary widely, reflecting the early stage of research, but range from 35 QCF to >61,000 QCF. Compare these numbers to a resource estimate of 15.4 QCF for gas worldwide, and reserves of about 5.3 QCF. In terms of oil equivalence, Lubick (2002) estimates that worldwide methane hydrate resources total 137.5 TBOE (825 QCF), a volume that dwarfs a 2.1 TBO petroleum endowment. Although gas hydrate volumes are colossal, the percentage that may be economically recoverable is unknown and could be very small. No technology is available for making hydrates a practical fuel. However, in the U.S. alone, the gas hydrate resource has been estimated at 250 times the conventional gas volume and almost 2,000 times current reserves (Morehouse, 2001).

If only a small percentage of the world's gas hydrates can be produced commercially, they would still represent a huge source of energy. This gas could be used in conventional applications, such as a boiler fuel or in heating. However, looking much farther ahead, methane from hydrates could become a source of hydrogen for fuel cells, which many view as the energy of the future. Technology and economics will ultimately determine whether the world's hydrate resource can be widely exploited. Meanwhile, extensive research is under way in Japan, Russia, India, Norway, Germany, Canada, and the U.S.

## Consumption

In the year 2000, natural gas consumption worldwide was 87.4 TCF. As with other energy sources, gas consumption is at record levels and has increased 65% over the last 20 years (Fig. 18). However, in energy equivalence natural gas is still far behind that of oil (Fig. 1), mostly because its large-scale use started much later. The long-term share that gas takes of the world's energy budget will increase with time, and many variables will affect the rate of increase. However, fuel switching will be one of the most important, as global oil production peaks and prices rise accordingly.

Regional gas consumption resembles that of oil. The largest consuming region, North America, accounts for precisely the same share of the gas market as the oil—31.3% (Fig. 19). Natural gas reserves and infrastructure in Russia push Eastern Europe and the former U.S.S.R. into second place. Western Europe, with several moderate-size economies, is third. In gas, as with oil, the Middle East has the world's most favorable ratio of reserves to consumption, with 35.1% of gas reserves (Fig. 16), but only 7.7% of consumption.

Russia and the U.S. continue to be by far the world's largest consumers of natural gas (Fig. 20), together accounting for 42% of the world's consumption in 2000. Russia is self-sufficient in natural gas and a major exporter. The U.S. uses about 22 trillion cubic feet (TCF) of gas per year, produces about 18 TCF, and imports 4 TCF—nearly all from Canada. Production declines and the current level of imports (~18%) suggest that the U.S. gas market is roughly 25–30 years behind oil. Demand growth for gas parallels that of oil, forcing the U.S. to rely on ever-increasing gas imports. Although the import percentage for gas is still small relative to oil, the gap between production and consumption is headed in the same direction. Using these trends, Beims (2002) predicts that in 30 years the U.S. will import 50–60% of the gas it consumes.

The total North American gas endowment of 2,500 TCF (Energy Information Administration, 2003) can support current demand for more than 100 years, although it must use a great deal of non-conventional gas to do so. The challenge is that for these resources to be produced, they must be competitive with gas imports—ultimately meaning LNG. Hence, in North America what matters is not the size of the endowment but the economics of producing much of that endowment. Natural gas that does not eventually become economic to produce has no impact.

Analysts believe that prices approaching $4.00 per MCF will make economic the building of the infrastructure necessary to move large volumes of LNG into the U.S. market. Based on energy equivalency, this is also the same price at which the burning of coal can economically meet current environmental standards (Fisher, 2002). Natural gas prices will always be volatile, but when $4.00 per MCF is perceived to be the lower limit (or price floor), domestic gas production will face the same constraint as oil. This is a production cost competition in which hundreds or even thousands of U.S. wells are necessary to equal the production from a single well in an exporting country. Although the price of gas from

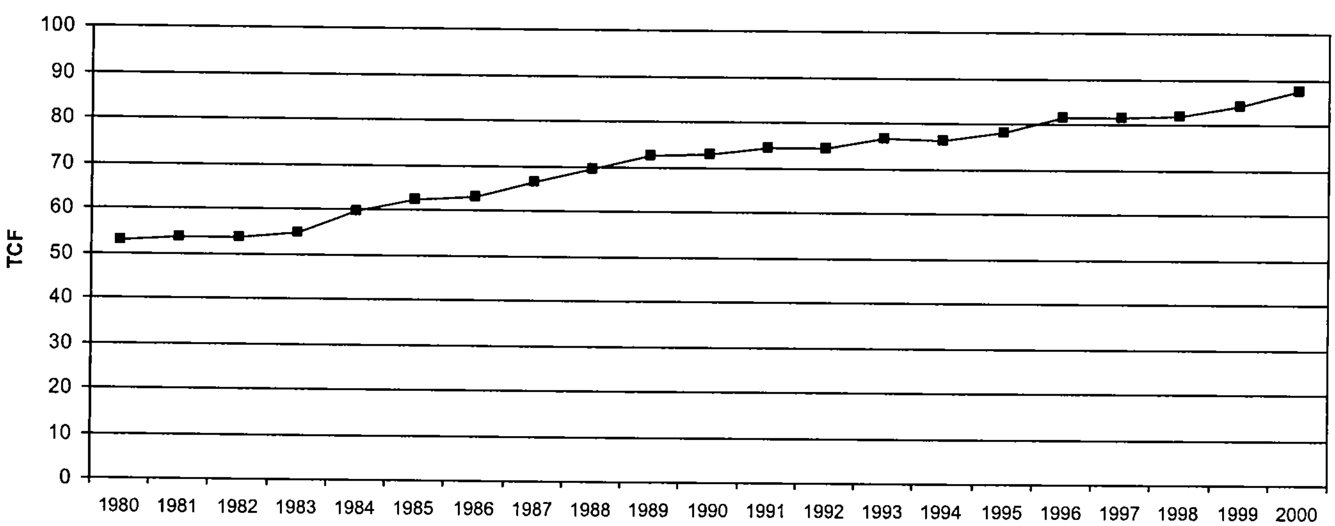


Figure 18. World natural gas consumption, 1980–2000. From Energy Information Administration (2003).

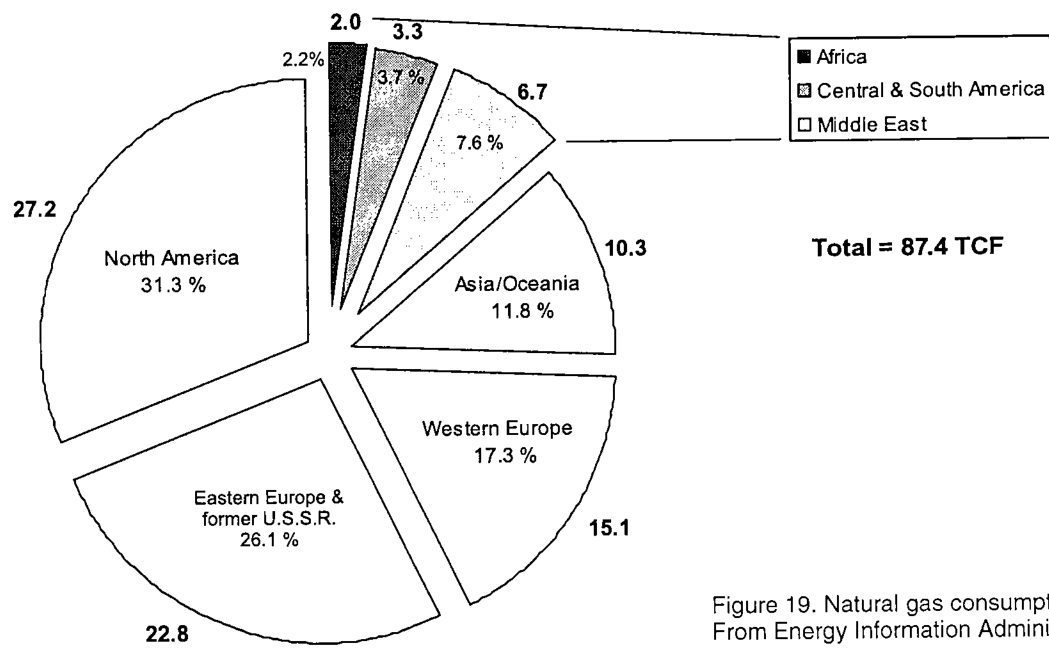


Figure 19. Natural gas consumption by world region (2000). From Energy Information Administration (2003).

an exporting country must include the cost of its conversion to LNG and transportation to our shores, this can be overcome by the disparity in production costs. Thus, when the infrastructure is in place to bring large volumes of LNG to the U.S. market, price will be beyond our control. Depending on where the global price settles, we could find a large part of our gas resource base inaccessible for the same reason that so much of our oil remains in the ground—namely, economics. Although various techniques can be used to produce more U.S. gas, it may cost more to produce than to buy from overseas. This could leave much of the North American gas endowment in the ground.

Gas prices have risen above $4.00 per MCF in the past, but only temporarily and usually during cold winters. To date, it is only the certainty that price lows would bring the average annual price well below winter highs that has kept international gas at bay. In fact, in the last 20 years the average price in the U.S. has been only $2.20 per MCF. Although the two most recent years of complete data (2000 and 2001) show record prices, averaging $3.60 and $4.12 per MCF, prices in the previous two years were only $1.94 and $2.17 (Fig. 6). The market for natural gas is delicately balanced, and a 2.5% change in supply or demand can lead to a 100%-plus rise in price. With a flat to declining production trend, price volatility is bound to remain high, but—barring a dramatic drop in demand (say in an economic depression) or an unexpected technological breakthrough—long-term prices seem sure to rise (Beims, 2002).

Natural gas has advantages over its major competitors, petroleum and coal. Gas is the most environmentally friendly of the three, and is so abundant that even conservative estimates show its reserves meeting increasing demand

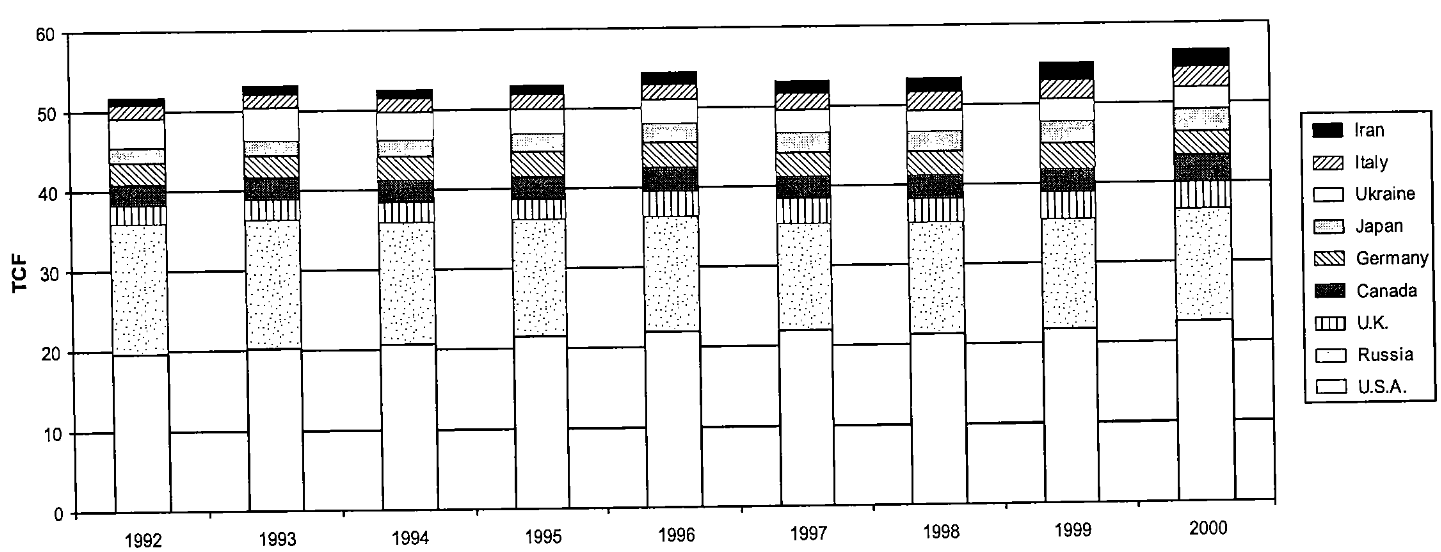


Figure 20. Countries consuming >2 TCF (2000). From Energy Information Administration (2003).

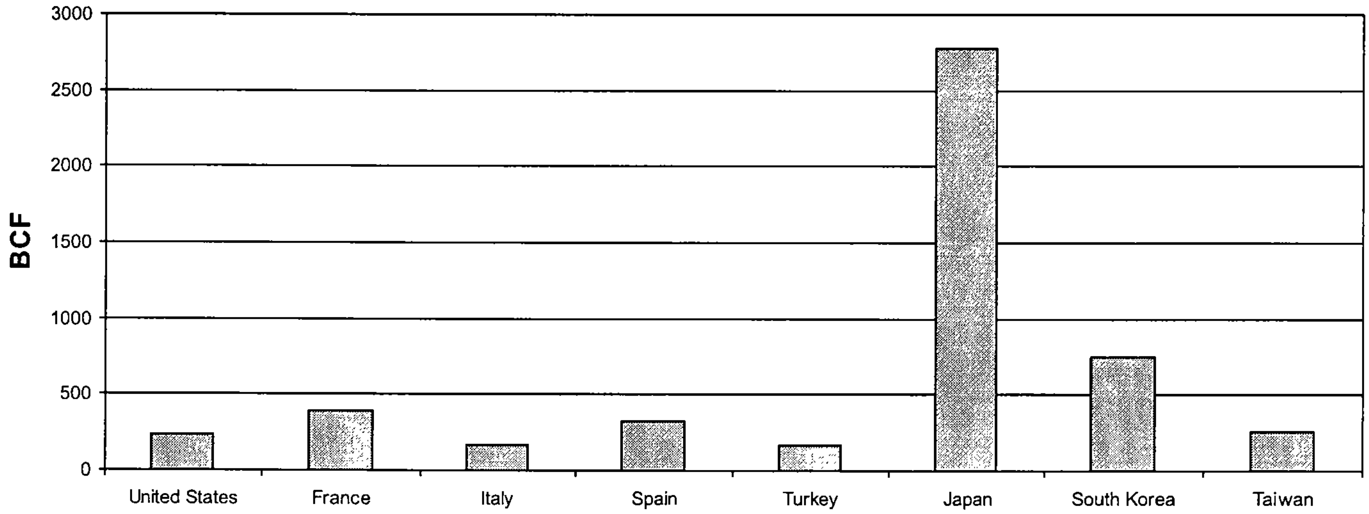


Figure 21. LNG importers of >100 BCF (2001). From Energy Information Administration (2003).

for several decades. The problem is that most of the reserves will be coming from the same regions as our imported oil. In addition, large imports will require a major investment in infrastructure and years of construction. This infrastructure will include a large number of LNG tankers, high-volume LNG off-loading and processing facilities, and pipelines for moving the gas inland. Today the largest LNG importers in the world are the hydrocarbon-poor nations of Japan and South Korea (Fig. 21). Only relatively minor volumes of LNG are consumed in other countries, including the U.S., but consumption is likely to increase substantially in the next few years.

The predicament for the U.S. is that much fuel-switching capability in the face of high oil prices involves increased use of natural gas. However, North America as a whole can barely keep pace with demand, and only when winters are mild. The point is illustrated by the abnormally cold winter of 2002–2003, when U.S. gas storage dropped to record lows, and prices increased four- to fivefold. If a problem with oil supply markedly increases gas demand, or if another cold winter comes, it is doubtful that enough gas will be available in the short term. Although this situation could starve some industries of energy so that homes could be heated, the problem is only temporary. A lasting solution will come when large-scale LNG imports are possible. Currently imported LNG meets only 1% of U.S. natural gas demand, and although this is a tenfold increase over 1995 LNG imports, maximum U.S. capacity for handling LNG is only about 4% of demand (Ziff Energy Group, 2001). If demand for natural gas grows faster than our capacity to import LNG, average prices should stay well above $4.00 per MCF until imported LNG can reach the market.

Despite North America's supply problems and high global consumption rates, the outlook for natural gas is good. Proved reserves and estimates of future additions are very large. Current proved reserves alone could support world demand for more than 60 years at current rates of use. If one adds the 8.9 QCF of future reserve additions predicted in 2000 by the USGS, consumption could be supported for a century more. A reserve life of 160 years, and the belief by most that even this estimate is conservative, explains why natural gas is seen as the bridge to sustainable energy sources.

## Production

World gas consumption is balanced by gas production (Fig. 22). Even for non-exporting regions that are self-sufficient (e.g., North America), these volumes rarely match (Fig. 19), with small differences between production and consumption reflecting additions or withdrawals from storage. The U.S. and Russia dominate production as they do con-

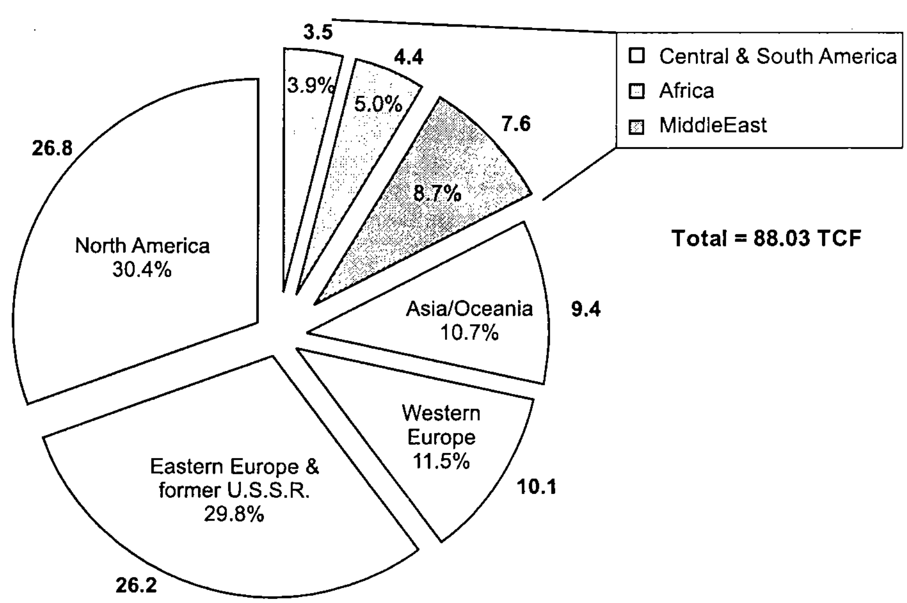


Figure 22. Natural gas production by world region (2000). From Energy Information Administration (2003).

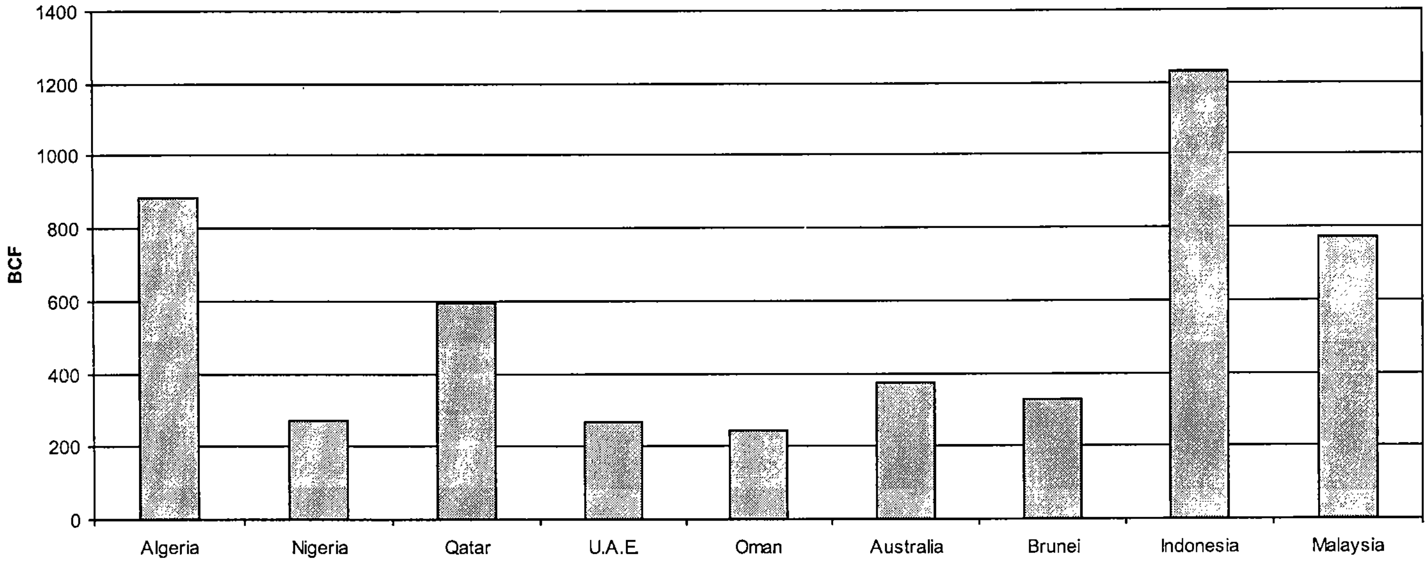


Figure 23. LNG exporters of >200 BCF (2001). From Energy Information Administration (2003).

sumption. However, production of gas (unlike oil) is not a direct indicator of the location of global reserves. It shows instead where reserves are connected to a market, which can be overland via pipeline or by seaborne LNG transport. Today only about 6% of the world's demand for natural gas is fed through LNG imports, but as reserves in the developed world are produced and consumption increases this percentage will grow markedly.

The largest LNG exporters are not the countries with the largest reserves but those that first met emerging demand from developed countries (Fig. 23). Many countries have larger gas reserves than Indonesia and Malaysia, but early drilling and reserve certification enabled them to obtain contracts with major Asian consumers—Japan, South Korea, and Taiwan (Fig. 21). Long-term contracts enabled them to build the infrastructure for shipping LNG to their markets, and later discoveries and additions to reserves have enabled the expansion of facilities to handle growing demand. Algeria's proximity to Western Europe has given it a decided advantage over other sources of LNG.

In the U.S., non-conventional resources such as tight gas and coalbed methane are taking a progressively larger share of production (Fig. 24), and conventional gas from deep water in the Gulf of Mexico and the U.S. and Canadian Arctic also will increase their contributions. However, the last three years in the U.S. have shown that even concerted gas drilling has not greatly increased our productive capacity. In fact, although demand continues to grow, we can barely maintain existing production levels. New volumes of conventional and non-conventional gas in North America are not large

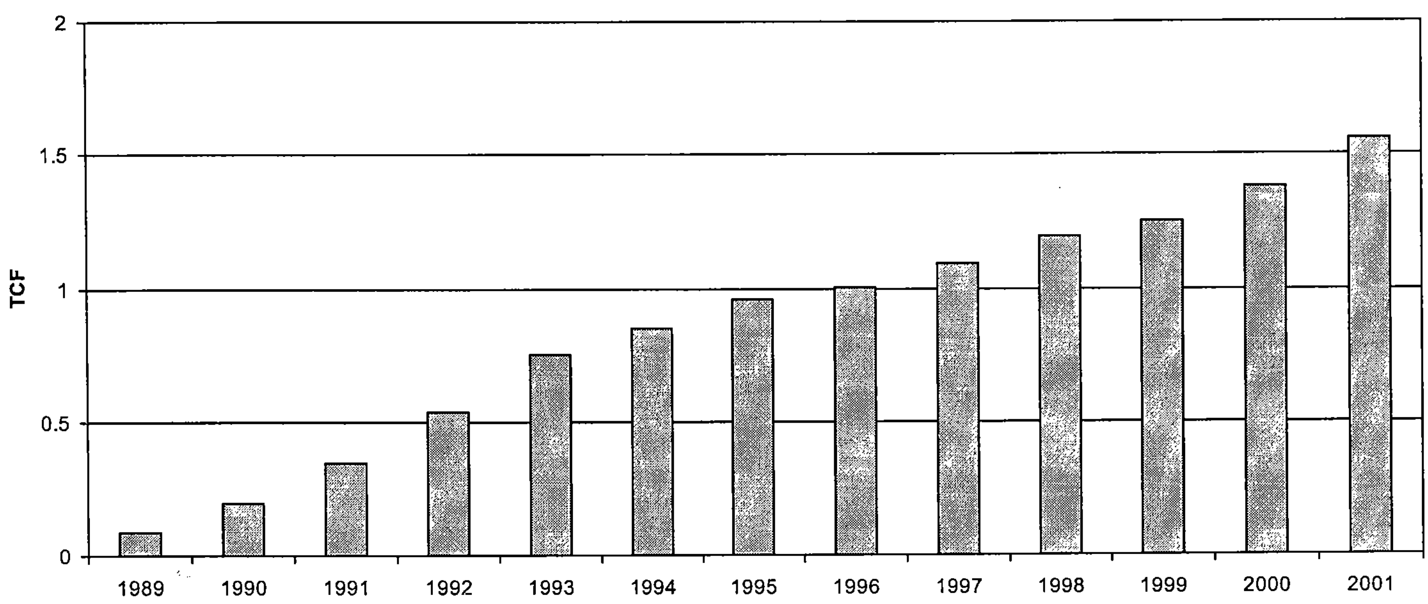


Figure 24. United States coalbed methane production, 1989–2001. From Energy Information Administration (2003).

enough, nor can they be produced fast enough, to prevent the need for large quantities of LNG in coming years. Although the U.S. is certain to be the largest emerging LNG market, of concern is the time needed to build the ships and facilities necessary to import it. With the delicate balance of supply and demand, it could take several years of progressively higher, roller-coaster prices before large volumes of LNG become available.

Ironically, many LNG facilities, which must be sited offshore and as close as possible to centers of demand, will be built over gas-prone basins that for political and environmental reasons are off limits to the petroleum industry. Examples include basins off the East Coast, adjacent to some of the nation's largest population centers.

The world's preoccupation with oil has often relegated natural gas to second-class status, especially in countries where oil is abundant. However, for both Oklahoma and the U.S. as a whole, it is gas that will largely be called upon to fill gaps left by reduced oil capacity. (A case in point is the conversion process of natural gas to liquid fuel, which will allow it to satisfy considerable oil demand.) The need for natural gas can only rise in the long run. Demand may temporarily fall as a result of conservation and fuel switching, but core demand—demand that remains whatever the price—will continue to increase. Core demand is being further augmented by gas-fired power plants built to meet increased electrical demand, most of which have no fuel-switching capability (Wright, 2002).

## THE GLOBAL ENERGY FUTURE

As the world economy becomes more integrated, analysis of any one region in isolation becomes impossible. Thus, to understand Oklahoma's oil, gas, and larger energy picture one must first take into account the principal global and national issues. The overriding reality is that fossil fuels (oil, natural gas, and coal) will continue to fill the great bulk of the world's energy needs for a long time to come. As a result, the primary matter in the short to medium term is the degree to which supply (production) can meet the demand (consumption) for these critical commodities.

From 1975 though 2000, the volume of oil discovered every 5 years has been decreasing, and in the period from 1995 to 2000 an annual average of 3 BBO was discovered—while 27 BBO was consumed (Magoon, 2000). Estimates of discovered oil vary, but all agree that the world is living in the red. Only the vast reserves and productive capacity of the Middle East have allowed this situation to continue, but as time passes dwindling reserves must eventually result in reductions in supply and corresponding reductions in demand.

The dominant economies of North America, Asia, and Western Europe consume the bulk (78%) of the world's oil production, but they control only 11% of the reserves. In fact, the disparity between their proved oil reserves and their consumption is growing. For example, North America and Western Europe account for about 50% of world consumption and 25% of production, but a paltry 7% of world reserves. Thus, in addition to having smaller proved reserve volumes, these regions are producing their reserves proportionately faster. Compare this to the Middle East, which accounts for 6% of world consumption, 32% of world production, and 67% of world reserves. The inequity between the "haves" and "have-nots" will continue to accelerate because predictions of where future discoveries will be made also are skewed strongly towards developing regions. In order of importance, these are the Middle East, the Siberian and Caspian Sea areas of the former U.S.S.R., and the Niger and Congo River deltas in western Africa (Ahlbrandt, 2002).

A similar disparity exists for natural gas. Nations in Eastern Europe and the former U.S.S.R. and in the Middle East contain almost three-quarters of world reserves, yet account for only about one-third of consumption. These regions are also projected to contain the greatest volume of future reserves. In contrast, North America and Western Europe possess only 8% of the world's gas reserves, but consume about half the world's production.

The key producing regions of Central and South America, Africa, and especially the Middle East, are mostly the remnants of dismembered colonial empires, and not surprisingly some have been politically unpredictable. The concentration of oil reserves in countries that have only recently gained independence or are perhaps fledgling democracies means that instability in oil supplies will remain the norm, not the exception. These regions account for 83% of world reserves, with a fraction of the Middle East alone possessing two-thirds of the planet's proved oil volume. The resulting reserve geography makes the Middle East's stability especially important to the world economy, so news-making events in even the smallest of its nations often have international implications.

Many of the political, economic, and military issues confronting us today can be traced directly to the distribution of the world's oil reserves (Fig. 10). This linkage has made possible what would have been unthinkable until recently: U.S. reliance on Russia and previous members of the U.S.S.R. (the former "Evil Empire") to provide a stable source of supply to reduce dependence on oil from the Middle East (the center of the current "Axis of Evil"). Politics changes, as do our perceptions of the world, but trying to determine the level of U.S. oil security by calculating (often to 2 decimal places) the percentage of imported oil coming from sources considered "unreliable" misses the point (Fig. 25). Whether oil is imported from a close ally or a potential enemy, the market for oil is *global*: so aside from transportation charges, a barrel of oil from Iraq costs a U.S. refinery the same as a barrel of oil from Oklahoma. Any production added to the world market, regardless of origin, will push prices lower. Conversely, if a producing area goes down for any reason, its customers will seek oil from another source, whether that oil is spoken for or not. This drives prices higher.

The U.S. government has predicted that nuclear and hydroelectric energy will remain flat, and that the use of other renewable sources will increase only slightly through 2025 (Fig. 26). Coal, natural gas, and especially petroleum demand (fossil fuels) are expected to increase dramatically. Even as a percentage of total energy consumption, the U.S. dependence on fossil fuels is expected to grow from its current 85% to 88% by 2025.

Of the nation's top energy resources, only coal can meet demand from exclusively domestic sources. Both coal and

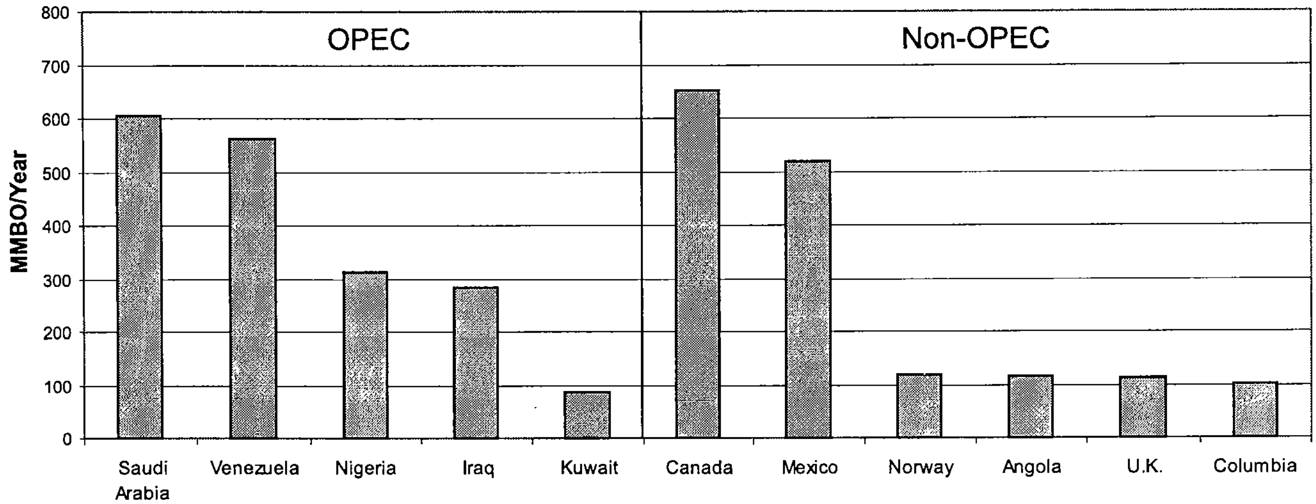


Figure 25. Major sources of United States crude oil imports (2001). From Energy Information Administration (2003).

nuclear energy, whose reserve lives (at current consumption rates) are 300 years and 100 years (Deffeyes, 2001), bear important environmental and political liabilities. As a result, it is unlikely that there will be a major shift in energy demand from oil into either of these. The fuel with the reserves and environmental qualities necessary to make up for any shortfalls in future oil supply is natural gas.

The peaking of world oil production, whenever it occurs, will lead to a considerable rise in price, and users that can shift to cheaper fuels will begin doing so. Coal, in which the U.S. is self-sufficient, is the least expensive, but on a Btu basis natural gas also has been cheaper historically than oil (Boyd, 2001). As fuel switching occurs, oil demand and prices will decline somewhat, but benefits from fuel switching are limited. Some petroleum products have no satisfactory substitutes. For example, about half of U.S. oil demand is in the form of gasoline and jet fuel, so for industries involved with transportation conversion may be too expensive or impossible.

Oil is America's number-one energy source, but a 50% increase in the current level of production and imports will be required to meet expected demand in 2025 (Energy Information Administration, 2003). As discussed previously, such an increase does not seem likely. In fact, under most scenarios, demand will exceed petroleum supply within years—not decades—and probably by 2009. When this occurs oil demand will be forced to match supply, with other energy sources taking up the slack. Whether demand exceeds production by one barrel or one million, the point where production and consumption curves cross will mark the beginning of the end of the age of oil.

Although market forces ensure that demand quickly balances supply, the range in which long-term oil prices will settle is impossible to predict. Price volatility probably will remain high, but the perception of scarcity should keep both price lows and average prices higher (in real terms) than they are today. The key to reducing turmoil is a gradual transition from an energy economy dominated by oil, to one in which a variety of long-lived resources can help shoulder the burden. To that end governments would be wise to plan for the long term, where possible using the most abundant domestic energy sources. Where economics dictate the use of less-expensive imported fuel, prudence demands formulating contingency plans involving fuel switching in favor of domestic resources. The goal is a smooth transition, with a minimum of price spikes. Reducing the speed at which prices rise is important, as it affords time to retool infrastructure and adapt to new economic constraints—an important task for developed and developing countries alike.

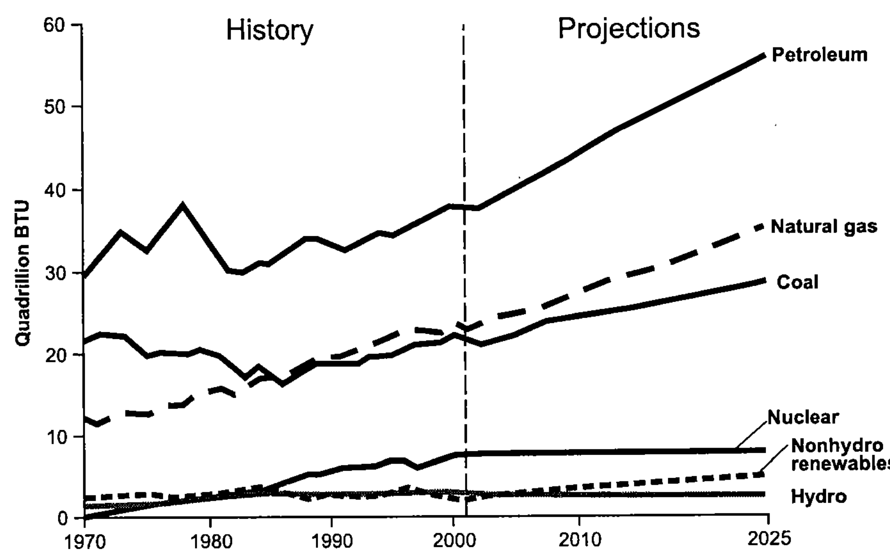


Figure 26. United States 2003 annual energy outlook—early release, 1970–2025. From Energy Information Administration (2003).

Apart from a decline between 1977 and 1982, resulting from sharply higher oil prices, U.S. consumption and dependence on imports have risen steadily. This trend will continue, as fully half of the 1.3 MMBO per day projected increase in worldwide demand in 2003 is expected to come from the U.S. (Wright, 2003a). A high level of national consumption is not surprising, as the American economy produces far more goods and services than any other country; however, we also have become more efficient in our energy usage. Between 1959 and 2001 the U.S. economy grew more than fourfold, but in 2001 we used half as much energy per dollar of gross domestic product as we did in 1959 (Radler, 2002).

The U.S. and the rest of the world depend on the free flow of oil and LNG from exporting countries. For their part, OPEC countries, excepting two embargoes intended to influence American policy in the Middle East, have provided oil in abundance. However, unforeseen events will continue to affect the flow of oil, forcing government planners to take precautions to ensure there are no interruptions. For instance, a primary mission of the U.S. Navy is to keep sea-lanes open to commerce, as our economic health, as well as that of the rest of the global community, depends on free access to energy supplies. The U.S. has fought one war over insuring access to oil and has recently completed another that, among other things, also will improve our long-term access to petroleum.

World events can lead to uncertainty in energy markets and create anxiety in the public mind. Our insecurity in energy matters is usually brought about by jumps in gasoline and natural gas prices. Complaints then become common, and conspiracies are alleged. However, with a myriad of uncontrollable factors that can affect prices, and an increasingly delicate balance between supply and demand, the wonder is that the average annual oil price has remained so steady in the $10–$20 per barrel range. Prices for oil (and gasoline) have, except for a jump in the early 1980s, remained nearly constant in real terms for 30 years (Fig. 27). Headlines may declare that the price of gasoline is the highest in history, but in constant dollars everything is more expensive. It is OPEC and the world's overcapacity in oil production that has largely kept energy prices independent of inflation. The price of natural gas in the U.S. has been proportionately more volatile than oil, but this is mostly because demand is more seasonal and we do not yet have large-scale access to overseas reserves. As a result, with the help of Canada, in natural gas we have been largely on our own.

What can America do to improve its lot? We are limited in our ability to maintain the uninterrupted flow of oil from producing countries, and for the same reason we have little control over price. Our options are to either reduce demand through some form of conservation, or enhance the supply of domestic oil and gas. Unfortunately, encouraging voluntary conservation of any kind is politically difficult, so only the supply side of the equation remains open. However, because of the maturity of our industry the only way to markedly increase long-term domestic oil and gas production is to open to leasing many areas that are now off limits. Popular sentiment also makes this course unlikely. For instance, gas-prone offshore areas (hence, with a minimal risk of oil spills) that are beyond sight of land have been placed off limits. (Bans have even been decreed retroactively through the denial of development permits after discoveries have been made.)

Although valid arguments exist both for drilling and for not drilling, it is important to understand that decisions to exclude areas from oil and gas exploration are as much philosophical as environmental. The industry's environmental track record is excellent, even in sensitive areas like the North Slope of Alaska where oil production has been under a microscope for more than 30 years. An environmental awareness that focuses on drilling restrictions tends to ignore the one element that would bring the greatest number of undeniable environmental benefits—reduced consumption. For example, 85% of the oil that enters North America's offshore environment (natural seepage excepted) results

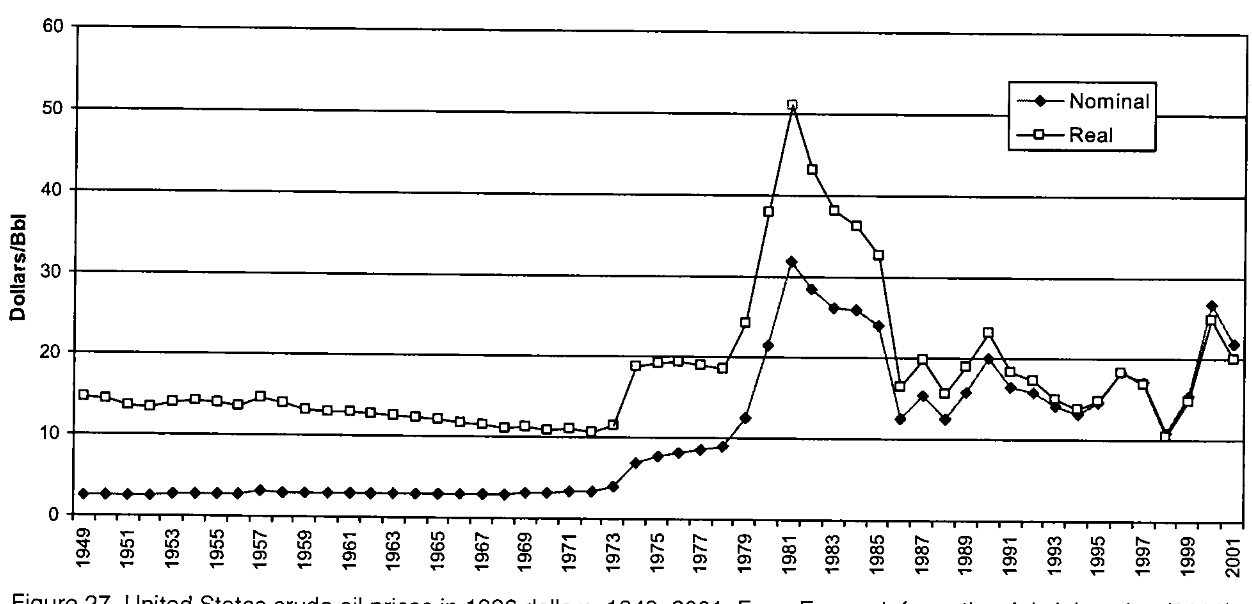


Figure 27. United States crude oil prices in 1996 dollars, 1949–2001. From Energy Information Administration (2003).

from consumption (runoff from urban areas and non-tanker shipping and boats). Transportation and refining account for an additional 11%, with only 4% entering the water through exploration and production activity (Wright, 2003b).

The irony is that increased domestic production would have not only economic benefits, but would also reduce the environmental hazards inherent in transport. Unfortunately, the environmental consciousness that finds it easy to reduce activity in areas that are tightly regulated has no problem in allowing the developing world, with far less stringent environmental regulations, to suffer greater risks satisfying our energy demand. The bulk of the negative environmental impact resulting from use of any fossil fuel comes not from activity devoted to its discovery, production, refinement, or transport, but from its consumption. Minimal conservation, combined with increased industrial efficiency and domestic production would generate many benefits. These include a reduced reliance on external energy sources and the level of insecurity that we feel with every unsettling event that occurs worldwide. National economics would benefit from an improved balance of payments. Environmental risks of all kinds could be mitigated, an important one being a reduction in the number of tankers plying the nation's and the world's waterways.

The world will never "run out" of energy supplies. They will only become more expensive. However, inexpensive energy encourages waste and speeds the day when supply will no longer meet demand. Fuel economy in the average U.S. motor vehicle today is lower than it was in 1980, and for 20 years American energy consumption per capita has been more than 40 times the world average (Cloud, 2003). Although many Americans can afford higher energy prices, many others many cannot. Look beyond our borders: for many countries, especially those in the developing world that are resource poor, increasing energy prices will retard many aspects of development. More than affecting the size or horsepower of the vehicles driven, or whether homes and shopping malls can be air-conditioned to 65°F, in a poor country expensive energy has a major effect on industrial growth, jobs, food production and distribution, and ultimately social and regional stability.

When world oil production peaks it will signal not that we are running out of energy, only energy in a very convenient form. Natural gas can be brought to the U.S. in vast quantities in the form of LNG. It and our own gas reserves can be converted to liquid fuels, but this comes at a price. Even our abundant coal reserves can be converted to liquid fuels, but again at a price. All agree that the next major shift in energy usage will increase demand for natural gas at the expense of oil, coal, and nuclear energy. However, this shift is simply one in a long line of gradual changes in the history of energy consumption. The progression is characterized by increased energy efficiency as hydrogen-to-carbon ratios have increased (Fisher, 2002). The transition from wood to coal to oil to natural gas has not only increased overall energy efficiency, but each step has reduced the number and intensity of harmful side effects, such as clear-cut forests, acid rain, and greenhouse gases. Unfortunately, we cannot take credit for directing this evolution, because market forces (supply and demand) drove the development of the technology that made such improvements possible.

As we become more proficient technologically, the use of pure hydrogen may become the next logical step. Hydrogen has many potential applications and, although not yet viable, it may play an important role in developing sustainable transportation in the U.S. It does not pollute and can be produced in virtually unlimited quantities using renewable or abundant resources. Pure hydrogen and hydrogen mixed with natural gas have been used effectively to power automobiles. However, hydrogen's real value rests in its potential in fuel-cell vehicles. Fuel cells are essentially batteries that, constantly being replenished with fuel, never lose their charge (Alternative Fuels Data Center, 2003).

Hydrogen is produced by two methods: (1) electrolysis and (2) synthesis gas production by steam reforming (partial oxidation). Both methods need large amounts of energy to produce pure hydrogen, which is a major technical hurdle that must be overcome. Electrolysis uses electrical energy to split water molecules into hydrogen and oxygen. It is not efficient in producing hydrogen, and the U.S. Department of Energy has concluded that it is unlikely to become the dominant method for generating hydrogen in large quantities. Steam reforming, which separates carbon from the hydrogen in natural gas, is the dominant method used to create hydrogen fuel. If this method becomes economically viable, a large share of future demand for natural gas could come from the creation of hydrogen fuel (Alternative Fuels Data Center, 2003).

It is possible that a technological breakthrough will fundamentally change the world's energy budget by providing abundant, environmentally friendly, inexpensive energy that could substitute for oil and gas. Although the economic, environmental, and political benefits would be enormous, the likelihood of such an event occurring in the near-term is remote. Research continues in many areas, but nothing on the horizon promises to end our dependence on fossil fuels for decades to come.

## OKLAHOMA'S OIL AND NATURAL GAS FUTURE

The energy future of Oklahoma, for both producers and consumers, is inextricably tied to the global marketplace. In that respect, our State is no different from any other. Its production of oil and especially natural gas is typified by large numbers of low-rate producers whose rates and long-term declines are tightly linked to drilling. Our reserves and production, although important nationally (Oklahoma ranks fifth in oil reserves and fourth in natural gas) are insufficient to affect, even in the slightest, the key variable influencing economics—world energy prices.

Price is especially important to Oklahoma's industry because our finding and development costs are higher, and production rates lower, than much of the rest of the world. This means when oil and gas prices slump, so do drilling and investment in infrastructure. In addition, during periods of low prices some wells become uneconomic to operate and, if low prices persist, many may be permanently abandoned (Boyd, 2002a).

The good news from a consumer's standpoint is that OPEC, like the state commissions before it, works hard to keep prices in a range that balances producers' income requirements with the world's economic interests. Unfortunately, this price range is barely enough to maintain Oklahoma's oil industry at a low level, and even this requires government programs designed to keep low-rate producers active (Boyd, 2002a). The relatively high cost of producing a barrel of Oklahoma oil is no one's fault, and there is no conspiracy to suppress U.S. drilling and production. The truth is that the oil price necessary to attract large investment (another drilling boom) in the State would also bring a global economic recession or depression. High prices would themselves soon reduce demand and bring on yet another round of falling prices. OPEC's balancing act is difficult, but must be judged as largely successful, for even as demand for oil has increased its price has remained reasonably stable. This factor, more than any other, has allowed the U.S. and other world economies to experience record growth.

World events make it all but impossible to entirely control energy prices, and short-term volatility will remain high. As long as the world's oil supply exceeds demand, the potential exists for prices to sink to levels ruinously low for Oklahoma's petroleum industry, although such drops should not last long. As demand continues to increase and oil production peaks—as is likely in the next few years—prices will rise. Then the balancing factor will cease to be the productive capacity of exporting countries, but the ability of consumers to reduce consumption. Volatility will continue, but both the peaks and valleys of price cycles should be higher than of those of the past. It is impossible to predict in what range oil prices will then move, but we can hope that the average will be high enough to encourage long-term investment in Oklahoma's oil industry. If so, it will be possible to concentrate on something that we can influence—how much oil is produced.

Any major increase in Oklahoma's oil reserves and production rate requires investment in concerted secondary and enhanced recovery work, especially in fields where recovery is substandard. The up-front costs are substantial for such projects, which require sustained higher prices in order to become economically attractive, but such prices could come in this decade. Regardless of how it is measured, the oil still residing in Oklahoma reservoirs is a staggering volume (44 to 82 BBO), all of which has already been mapped (Boyd, 2002a). Even a modest increase in the overall recovery factor for only the largest fields could yield huge rewards. A prudent strategy (in anticipation of the sustained oil price increase that seems inevitable) is to gather data and to rank candidate fields now, while interest in such projects is still relatively low.

Help could come as a result of studies (being sponsored by the U.S. Department of Energy) evaluating the feasibility of collecting carbon dioxide generated by industrial processes. The objective is to reduce greenhouse gases in the atmosphere, and this could be accomplished by pumping $CO_2$ into underground reservoirs from which it will never escape. The impact in this discussion is that $CO_2$ is very useful in enhancing oil recovery, and if the federal government decides that large-scale $CO_2$ sequestration is feasible, huge volumes of low-cost $CO_2$ could become available for enhancing oil recovery. If implemented, such a plan could dramatically increase ultimate oil recoveries in the eastern and southern parts of the State.

Higher oil prices will push natural gas demand and prices higher. However, unlike oil, the U.S. cannot yet import from overseas more than a tiny fraction (1–4%) of its gas requirements. Because our balance of supply and demand for gas is so tight, LNG capacity may be insufficient to satisfy all of the extra demand that may result from higher oil prices. Expensive oil, combined with a tight gas supply, could diminish our ability to reduce demand by switching fuels, and this may take prices for both to all-time highs. Higher prices would spur drilling, but there would certainly be negative repercussions for the overall State economy.

Drilling in Oklahoma is dominated by wells seeking gas. Nevertheless, major additions to gas reserves and production will require sustained drilling in areas that are still underdeveloped or underexplored. These include deep and low-permeability reservoirs that may be in areas of shallow, long-standing oil production. The continued development of coalbed methane resources also will remain critical to the State's gas industry. Oklahoma's location, geology, resource estimates, pipeline system, and the industry's strong history ensure that natural gas will be a key component of the State's economic future well into the 21st century. However, these strengths will avail us nothing without a steady stream of investment.

Petroleum products represent about a third (34%) of the State's energy consumption, nearly half of this as gasoline. Natural gas represents another 37% and coal 24%, bringing the total share for fossil fuels to 95%. The prices for all three tend to rise and fall together, but coal (as measured in Btu) is the cheapest and oil the most expensive. Unfortunately, coal use involves environmental issues that offset many of its advantages, and because most of Oklahoma's coal has high sulfur content, more than 90% of the coal burned here comes from Wyoming (Boyd, 2001).

Oklahoma's status as a major energy producer at the national level does not mean that the State's consumers are less affected by shortages or high prices. Even if we produced as much energy (oil, natural gas, and coal) as we use, prices in the global economy would remain beyond our control. (Local producers are obliged to maximize profits, and so cannot offer discounts to local consumers.) Ignoring taxes, transportation, and government subsidies, energy prices are the same everywhere on Earth. Oklahoma's production and nearby refineries reduce some transportation costs, but this price advantage is small and becomes less important as prices rise.

When prices for oil and gas swing widely, their value to the State depends far more on average price than on how much is produced (Boyd, 2002b). This is especially true for natural gas, which is the State's most abundant resource and its most important export. Two-thirds of Oklahoma's production of natural gas (roughly 1 TCF per year) is sold outside the State, and every dollar per MCF in gas price means \$1.5 billion in gross revenue (1.5 TCF × \$1.00/MCF). Building more gas-fired power plants will permit the conversion of some of these exports from gas to electricity, and the higher

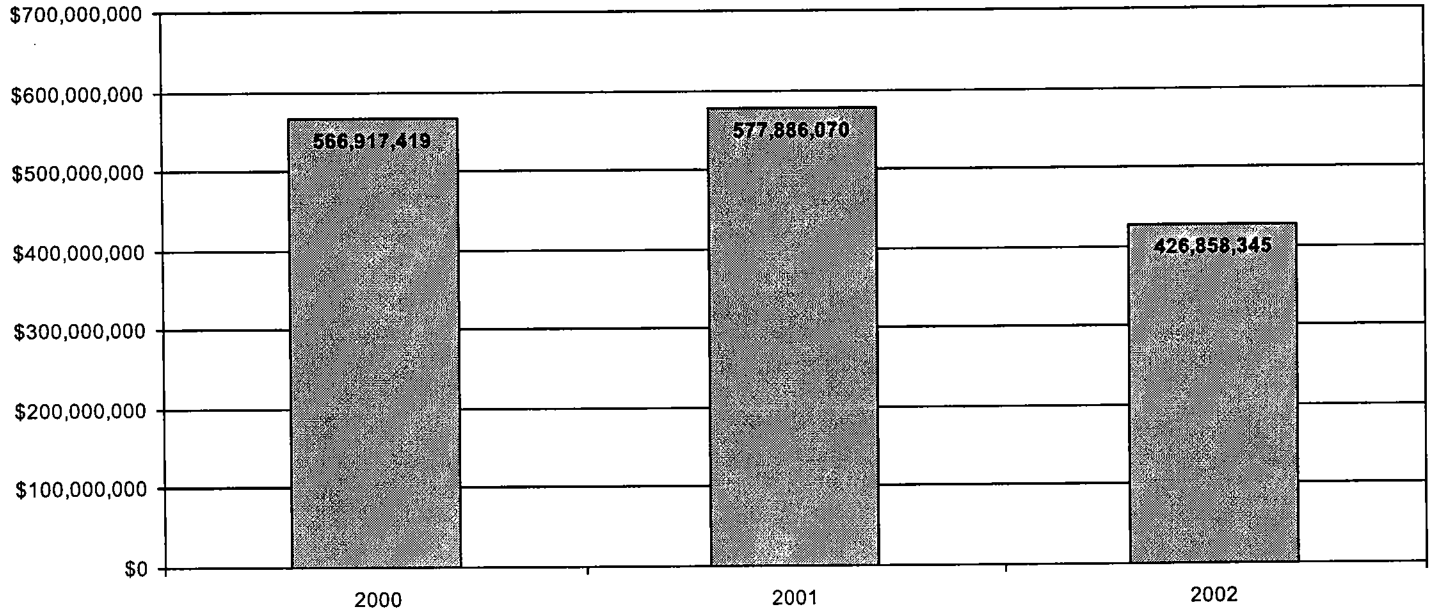


Figure 28. Oklahoma oil and gas tax revenues, 2000–2002. From Oklahoma Tax Commission.

price of electrical energy over raw natural gas should increase revenues to the State.

The annual decline in oil and gas production in Oklahoma has usually been less than 5%, but price can easily fluctuate 50–300% in a single year. This is why gross income and the resulting tax revenue to the State is so much more sensitive to price than the amount produced. Much of the shortfall in State revenue for 2002 can be directly attributed to lower prices for oil and gas—especially gas (Fig. 28). About three-quarters of the State's oil and gas tax revenue comes from gas production.

Oklahoma's Gross Production Tax has a sliding scale based on the average monthly price of oil and gas paid by the top three purchasers in the State. For oil the rate is 7% if the price is $17 per barrel or above, 4% from $14 to $16.99, and 1% if below $14. For gas the tax is 7% if the price is $2.10 per MCF or above, 4% from $1.75 to $2.09, and 1% if below $1.75 (Oklahoma Tax Commission, 2003). Such a variable tax is common among other States, but Oklahoma's scale is well below most others. For example, Kansas receives 8% of the revenue for oil and 15–17% for gas (Interstate Oil and Gas Compact Commission, 2003).

In light of recent tax shortfalls in Oklahoma, and the likelihood of substantially higher oil and gas prices in the future, an increase in our variable tax for prices well above $17 per barrel and $2.10 per MCF seems prudent. The negligible tax rate at low prices has done much to protect marginal producers, but State help given to producers in hard times should be balanced by higher rates when prices—and profits—are high. This is not a new idea, but it warrants consideration, especially as much of Oklahoma's royalty ownership is held by out-of-State residents (Dauffenbach, 2001).

Particularly important in the long term is the proportion of State resources that ultimately will become economic in an environment in which we cannot control price. How much of our oil and gas will be economically competitive with imports? Can we compete with LNG imported at $3.50 or $4.00 per MCF? Will long periods of low oil prices force abandonment of wells? Will new secondary and enhanced recovery projects become economic as world production plateaus and oil prices rise? In the more distant future, what proportion of reduced demand for oil will be met by natural gas? By coal? Hydrogen?

Our energy industry is important to the financial health of the State, and it certainly will benefit from higher energy prices. Higher prices will foster growth in energy-related businesses and increase State revenue, directly as production taxes and indirectly as a result of growth in the overall tax base through increased employment. However, because energy is an integral part of almost every business, the higher prices that help the oil and gas industry may not offset negative effects on other areas of the economy. No one can say whether the overall effect on Oklahoma will be positive or negative, but higher energy costs certainly will adversely affect much of the rest of the State's economy, and industries especially sensitive to energy prices will suffer disproportionately.

## CONCLUSIONS

Oklahomans have no reason to be apprehensive about the energy future. The world will never run out of any source of energy. The question is how smoothly an energy market dominated by oil can change to one in which no single source dominates. Scenarios range widely. One is a gradual, seamless shift in energy consumption in the different parts of the world in which changes in demand and production balance and the required infrastructure is always at hand. This utopian vision is as unlikely as the other extreme, a sudden collapse of the global economy resulting in numerous political and military confrontations.

Our future is far more likely to resemble the past, with supply disruptions continuing to cause volatile prices. A narrower gap between supply and demand will cause this volatility to increase in the long term and prices to spike more severely than in the past. It may take several years for this to happen, but as the world's excess productive capacity continues to shrink, flexibility of supply will be lost. The world will remain an unsettling place. The difference is that when there is no longer a Saudi Arabia that can quickly ratchet up production to cover supply shortages in Venezuela, West Africa, Kuwait, or Iraq, our sensitivity to supply interruptions will be magnified.

Society has progressed from a primary energy dependency on wood to one that is evolving to a combination of oil, natural gas, coal, and lesser resources. Although nothing on the horizon is capable of replacing fossil fuels, we still have plenty of time to prepare. The transition certainly will be bumpy, but the reserves remaining for each fuel are still large.

An individual can prepare for the coming transition and its uncertainties by factoring energy considerations into long-term decisions. A vehicle purchased today should last several years. However, if a 50% increase in gasoline prices in this timeframe is likely to be a financial burden, a reevaluation may be in order. In the same vein, a house 30 miles from the office may be appealing, but only if 300 miles of commuting per week with higher gasoline prices is not an economic strain. The same house also should be evaluated for its energy efficiency, because both the natural gas used to heat it in winter and the electricity used to cool it in summer are bound to become more expensive.

The American mindset tends to see any inducement designed to encourage conservation as restricting a basic freedom in our consumer society. As a result, we have arrived at this juncture sooner than was necessary. Only higher prices have ever led to appreciable conservation in the U.S., and as energy prices rise they will again curtail demand. It is impossible to predict exactly when prices will rise, or by how much, but energy inevitably will take an increasing share of everyone's budget. There are no guarantees concerning our energy future, but understanding the forces involved and taking simple precautions certainly will render us less vulnerable.

We have ample cause to be optimistic. The world economy and our average level of prosperity have grown dramatically, even as energy usage has become more efficient and less polluting. Although mankind will depend on fossil fuels for a very long time to come, history shows that we are adaptable. In spite of the many uncertainties that lie before us, the challenges ahead are no greater than those we already have overcome.

## ACKNOWLEDGMENTS

Charles J. Mankin, Robert Northcutt, and Neil Suneson read the manuscript and provided valuable input, and Max Tilford (Tilford Pinson Exploration, LLC) carried out the formal review. All had useful suggestions that were incorporated into this paper.

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*Oklahoma Geological Survey*

# Oil- and Gas-Related Publications

Listed below are the most popular oil- and gas-related publications available from the Oklahoma Geological Survey. A complete inventory, including those out of print, is available on the Survey website at www.ogs.ou.edu. These compilations are designed to quickly identify publications that have direct application to the State's oil and natural gas industry.

## CIRCULARS

**Circular 90.** — Anadarko Basin symposium, 1988 (Kenneth S. Johnson, editor). Proceedings of a symposium held April 5–6, 1988, in Norman, Oklahoma; cosponsored by the Oklahoma Geological Survey and the U.S. Geological Survey. 289 pages, 35 contributions. 1989; 2nd printing, 1991. Paperbound, $10.00.

**Circular 93.** — Source rocks in the southern Midcontinent, 1990 symposium (Kenneth S. Johnson and Brian J. Cardott, editors). Proceedings of a symposium held February 6–7, 1990, in Norman, Oklahoma; cosponsored by the Oklahoma Geological Survey and U.S. Department of Energy. 352 pages, 33 contributions. 1992. Paperbound, $12.00.

**Circular 95.** — Petroleum-reservoir geology in the southern Midcontinent, 1991 symposium (Kenneth S. Johnson and Jock A. Campbell, editors). Proceedings of a symposium held March 26–27, 1991, in Norman, Oklahoma; cosponsored by the Oklahoma Geological Survey and U.S. Department of Energy. 267 pages, 33 contributions. 1993. Paperbound, $10.00.

**Circular 98.** — Fluvial-dominated deltaic reservoirs in the southern Midcontinent, 1993 symposium (Kenneth S. Johnson, editor). Proceedings of a symposium held March 23–24, 1993, in Norman, Oklahoma; cosponsored by the Oklahoma Geological Survey and U.S. Department of Energy. 295 pages, 32 contributions. 1996. Paperbound, $10.00.

**Circular 100.** — Ames structure in northwest Oklahoma and similar features: origin and petroleum production (1995 symposium) (Kenneth S. Johnson and Jock A. Campbell editors). Proceedings of a symposium held March 28–29, 1995, in Norman, Oklahoma; cosponsored by the Oklahoma Geological Survey and U.S. Department of Energy. 396 pages, 41 contributions. 1997. Clothbound, $15.00.

**Circular 104.** — Pennsylvanian and Permian geology and petroleum in the southern Midcontinent, 1998 symposium (Kenneth S. Johnson, editor). Proceedings of a symposium held April 7–8, 1998, in Norman, Oklahoma; cosponsored by the Oklahoma Geological Survey and U.S. Department of Energy. 233 pages, 30 contributions. 2001. Paperbound, $15.00.

**Circular 106.** — Petroleum systems of sedimentary basins in the southern Midcontinent, 2000 symposium (Kenneth S. Johnson and Daniel F. Merriam, editors). Proceedings of a symposium held March 28–29, 2000, in Oklahoma City; cosponsored by the Oklahoma Geological Survey and the U.S. Department of Energy. 198 pages, 26 contributions. 2001. Paperbound, $13.00.

**Circular 107.** — Revisiting old and assessing new petroleum plays in the southern Midcontinent, 2001 symposium (Brian J. Cardott, editor). Proceedings of a symposium held May 8–9, 2001, in Oklahoma City; cosponsored by the Oklahoma Geological Survey and the U.S. Department of Energy. 183 pages, 20 contributions. 2002. Paperbound, $12.00.

**Circular 108.** — Finding and producing Cherokee reservoirs in the southern Midcontinent, 2002 symposium (Dan T. Boyd editor). Proceedings of a symposium held May 14–15, 2002, in Oklahoma City; cosponsored by the Oklahoma Geological Survey and the U.S. Department of Energy. 245 pages, 30 contributions. 2002. Paperbound, $13.00.

## SPECIAL PUBLICATIONS

**SP82-3.** — Determination of reserves of methane from coal beds for use in rural communities in eastern Oklahoma, by Samuel A. Friedman. 32 pages, 7 figures, 2 tables. 1982; 2nd printing, 1989. $4.00.

**SP86-3.** — Oil generation in the Anadarko basin, Oklahoma and Texas: modeling using Lopatin's method, by James W. Schmoker. 40 pages, 18 figures, 1 table. 1986. $3.00.

**SP95-1.** — Fluvial-dominated deltaic (FDD) oil reservoirs in Oklahoma: the Morrow play, by Richard D. Andrews and others. 67 pages, 53 figures, 9 tables, 6 plates. 1995. $6.00. (Also sold in set with OF9-97, $7.00.)

**SP95-3.** — Fluvial-dominated deltaic (FDD) oil reservoirs in Oklahoma: the Booch play, by Robert A. Northcutt and others. 67 pages, 58 figures, 8 tables, 5 plates. 1995. (Out of print; can be obtained for the cost of reproduction, $26.80.)

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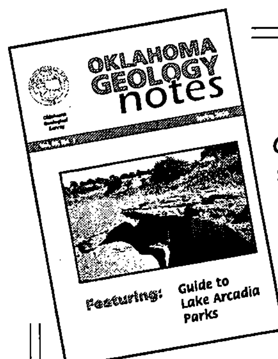


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