Oklahoma Natural Gas: Past, Present, and Future

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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

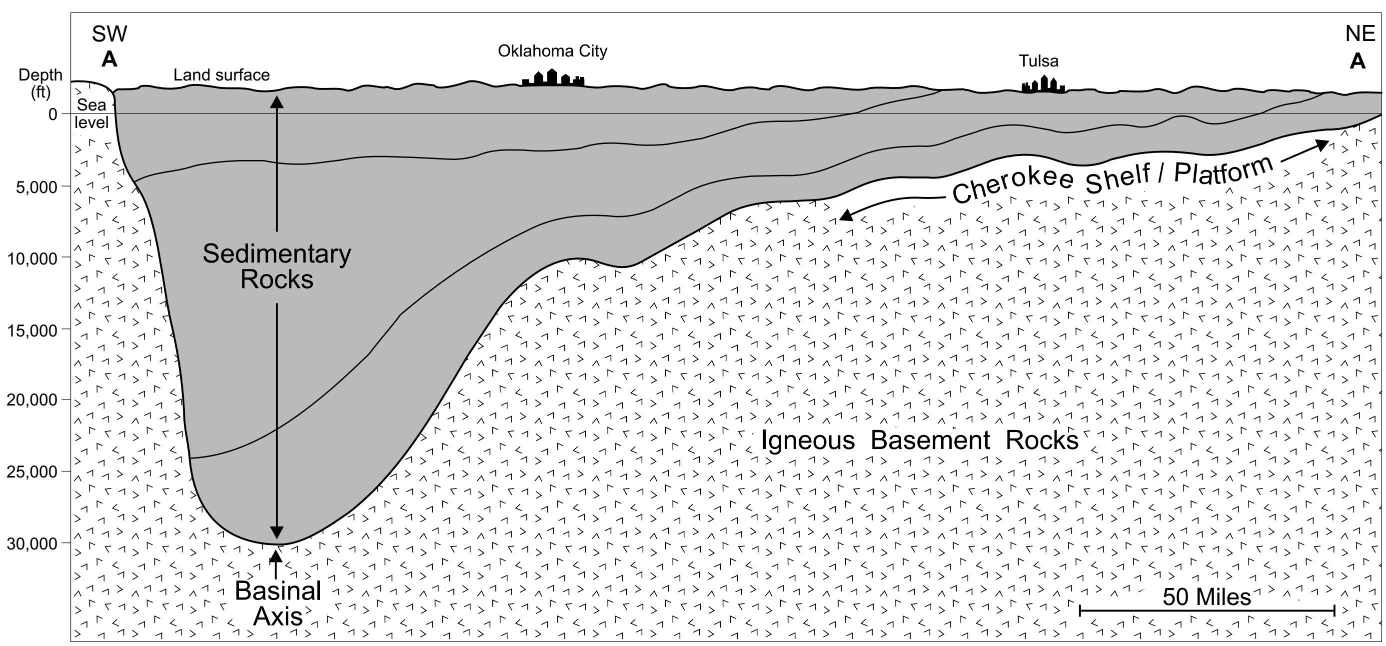

Figure 1. Cross section of the Anadarko geologic basin. Modified from Witt and others (1971). Vertical exaggeration 14:1. Figure 4 is the base map.

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

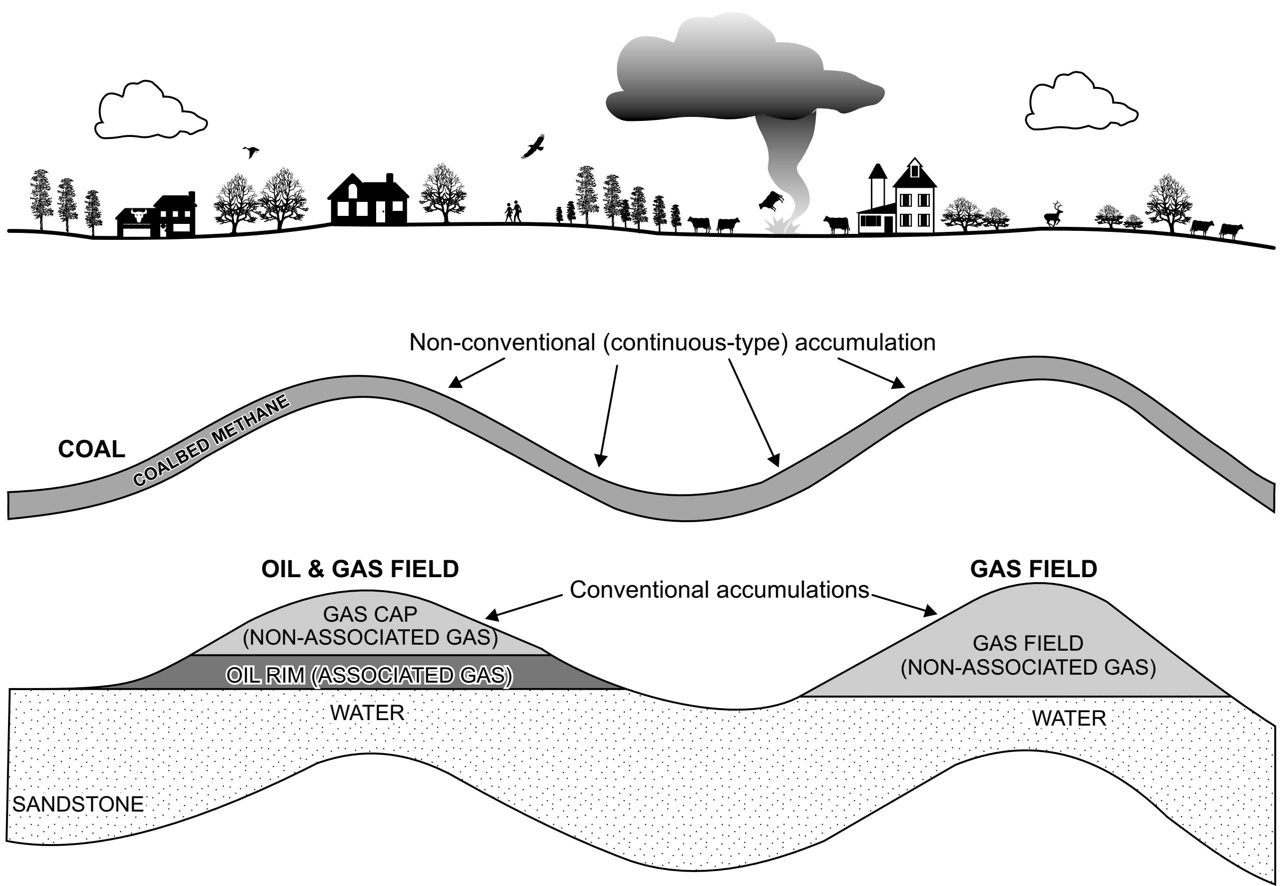

Figure 2. Some types of subsurface natural gas accumulation.

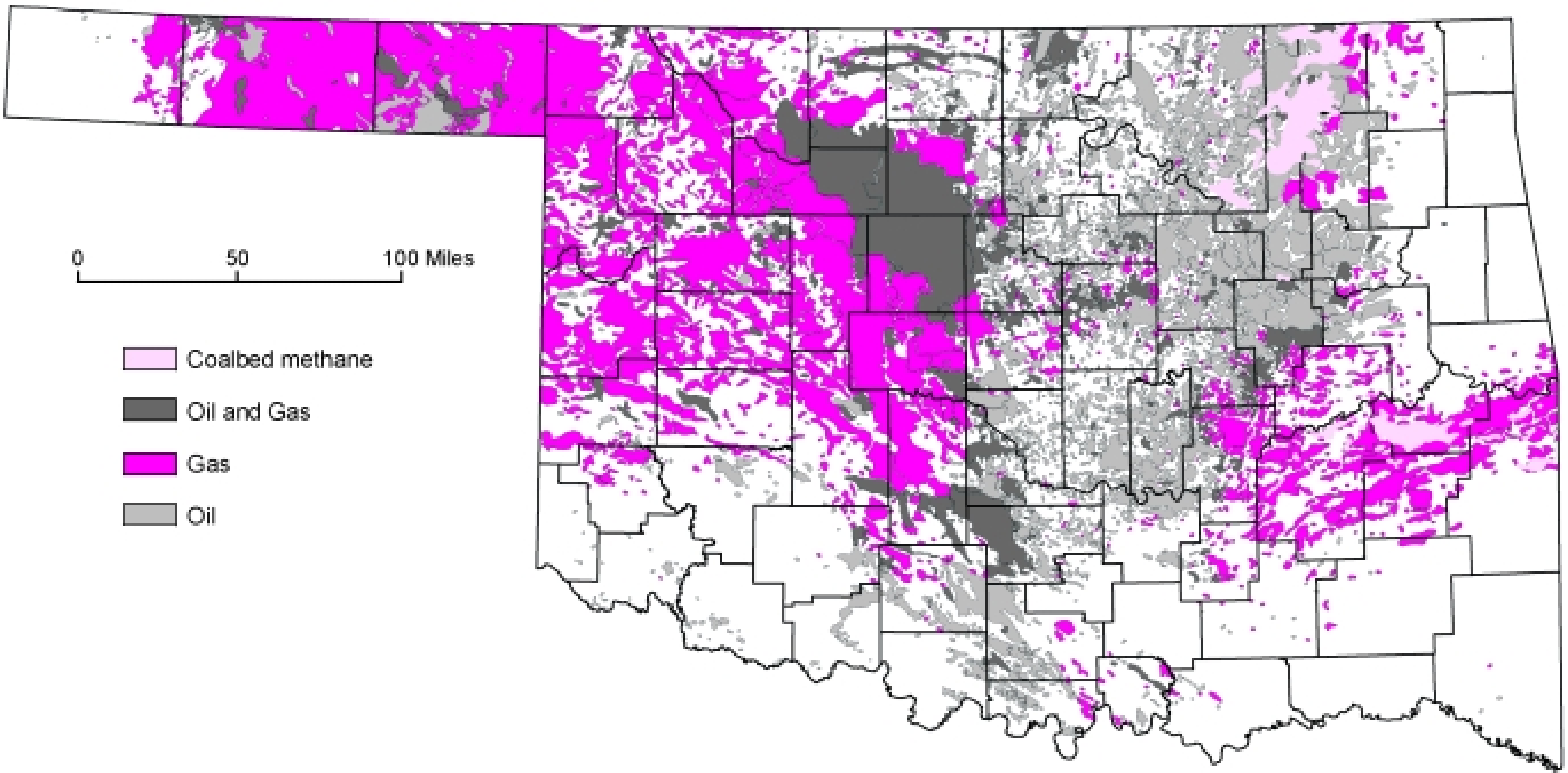

Figure 3. Oklahoma oil and gas fields distinguished by gas-oil ratio (G.O.R.) and conventional gas vs. coalbed methane. Modified from Boyd (2002b).

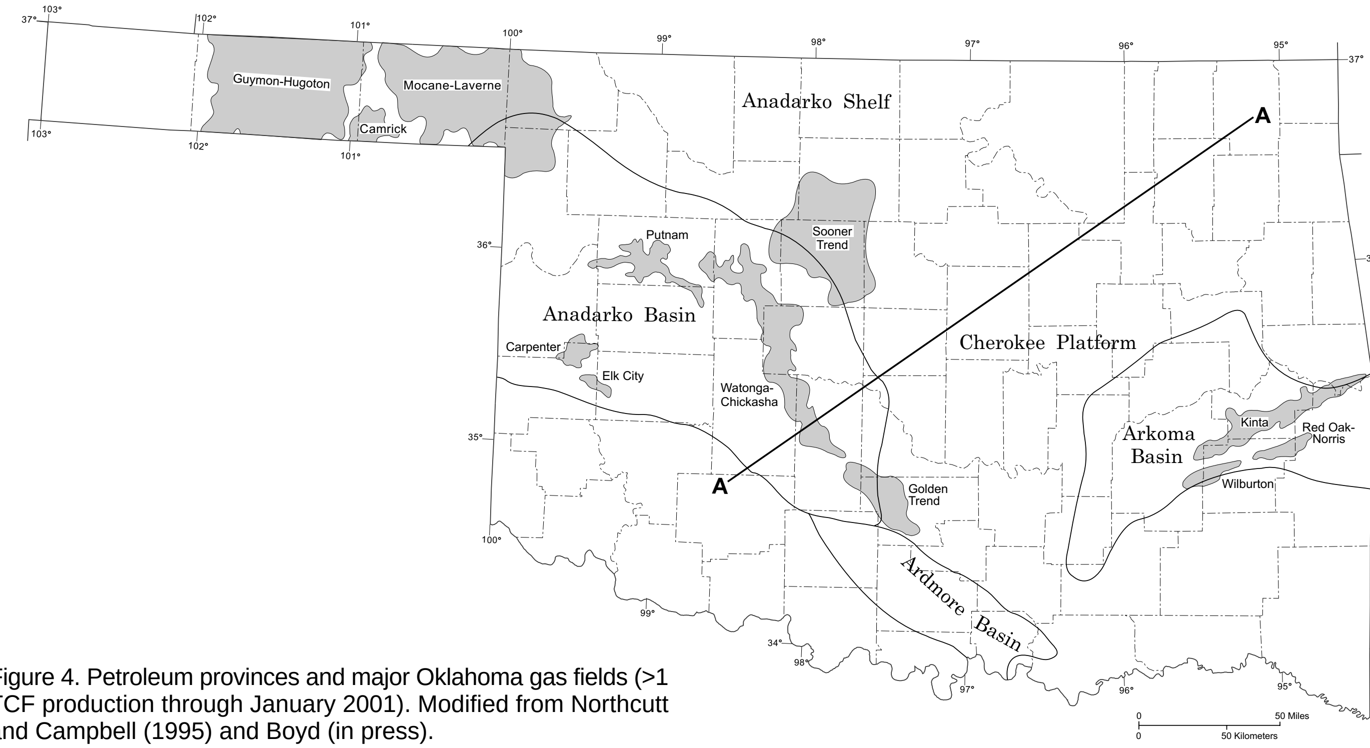

Figure 4. Petroleum provinces and major Oklahoma gas fields (>1 TCF production through January 2001). Modified from Northcutt and Campbell (1995) and Boyd (in press).

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
			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

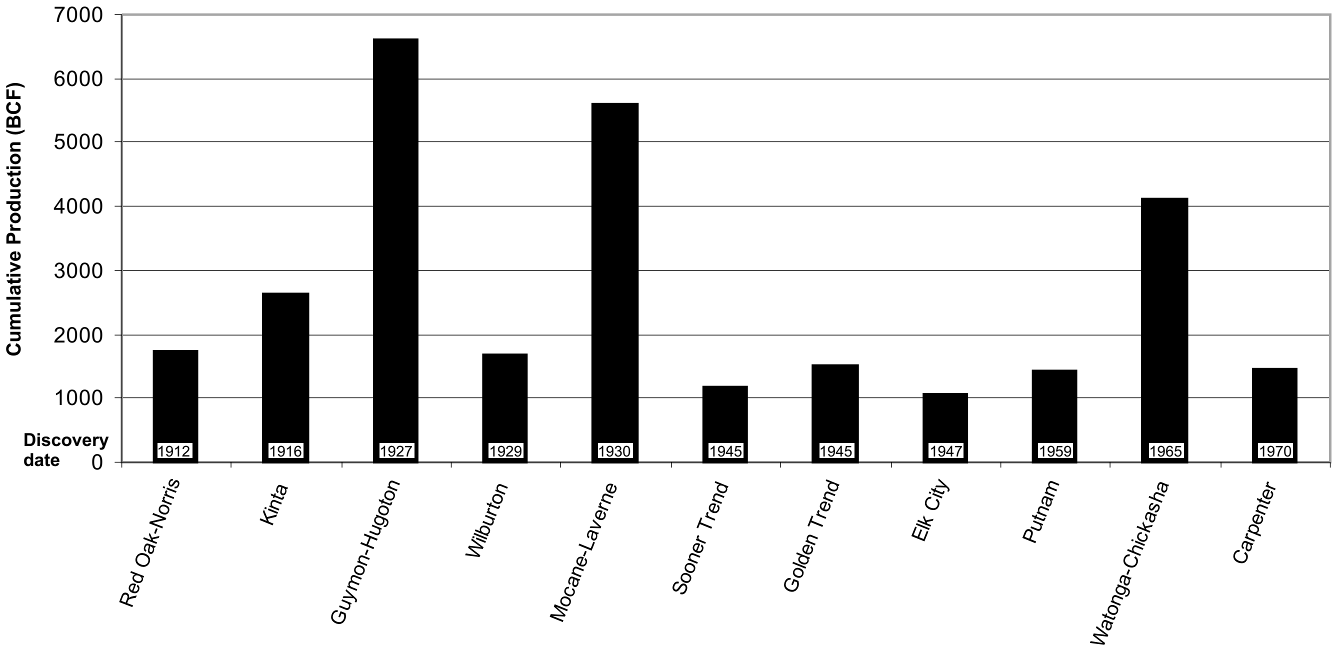

Figure 6. Major gas fields in Oklahoma: their cumulative production and discovery dates. Cumulative production >1 TCF through January 1, 2000. Data from Lay (2001).

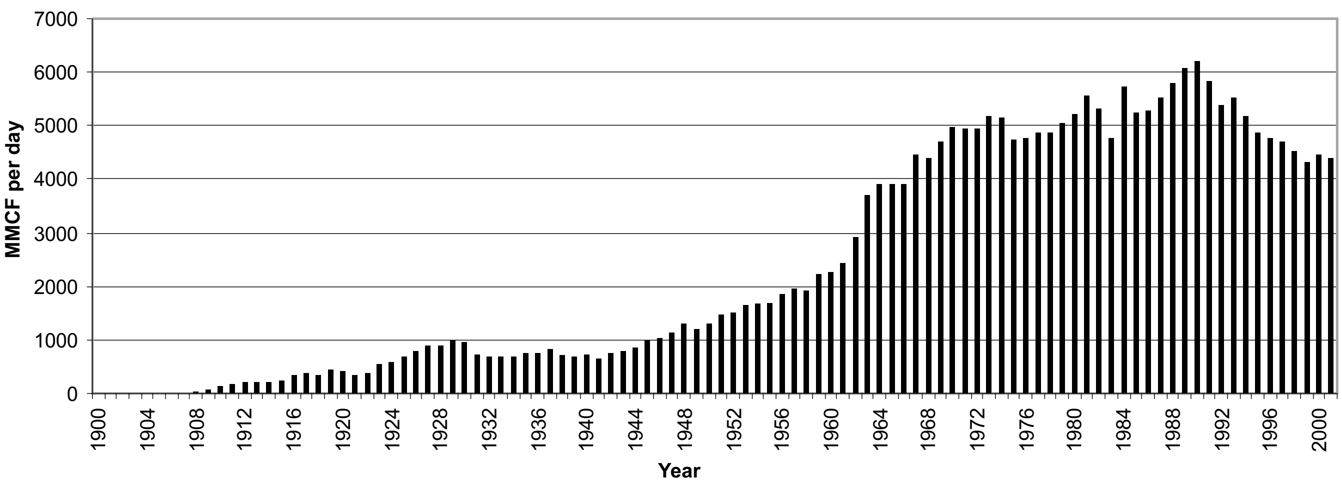

Figure 7. Natural-gas production in Oklahoma (1900–2001). Data from Claxton (2001).

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

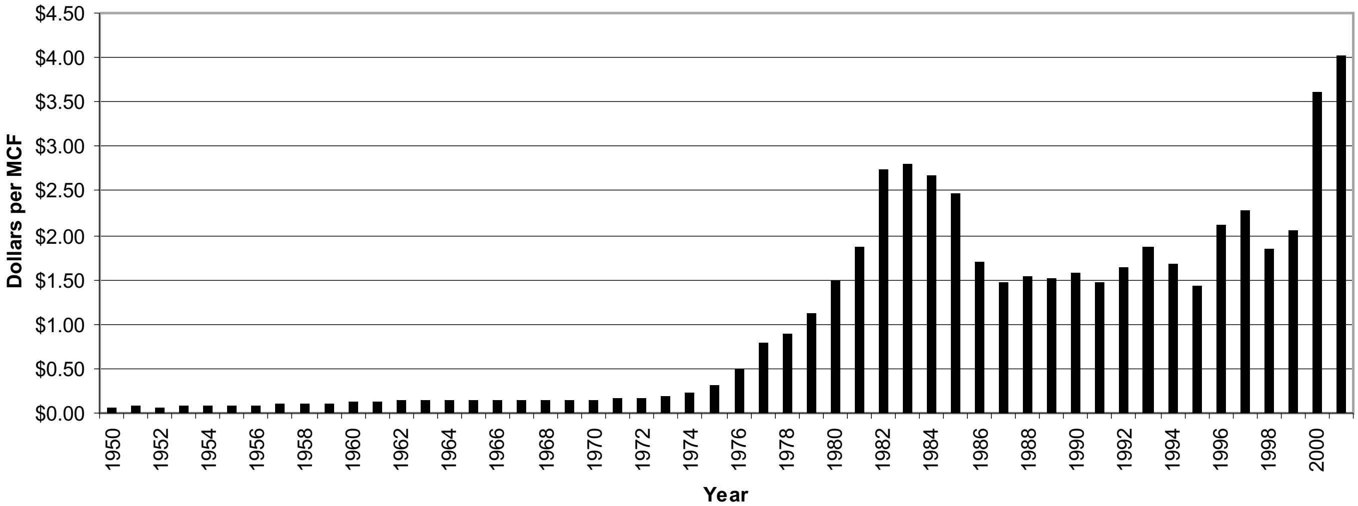

Figure 8. Average annual price of natural gas at the wellhead (unadjusted for inflation) in Oklahoma (1950–2001). Data from Claxton (2001).

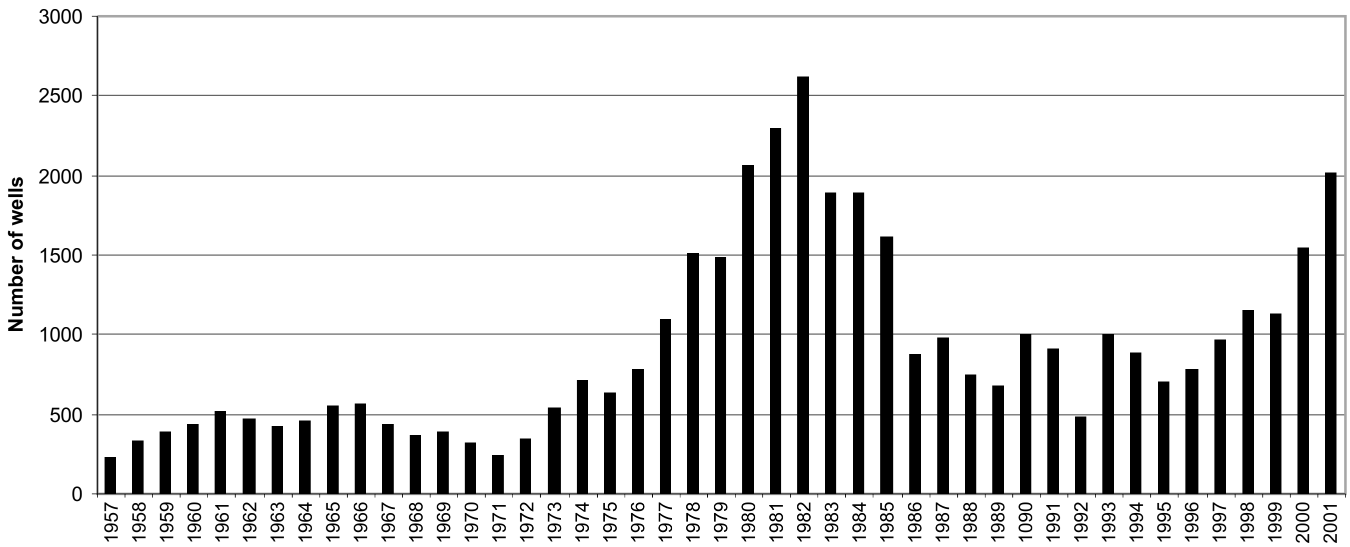

Figure 9. Gas-well completions in Oklahoma (1957–2001). Data from Claxton (2001).

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-

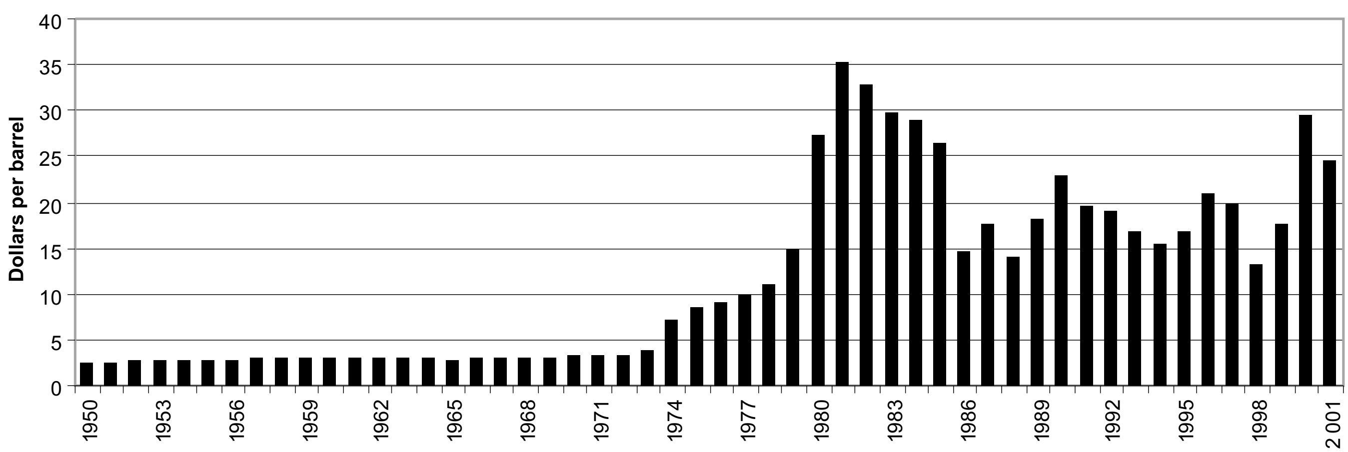

Figure 10. Average annual crude-oil price (unadjusted for inflation) in Oklahoma (1950–2001). Data from Claxton (2001).

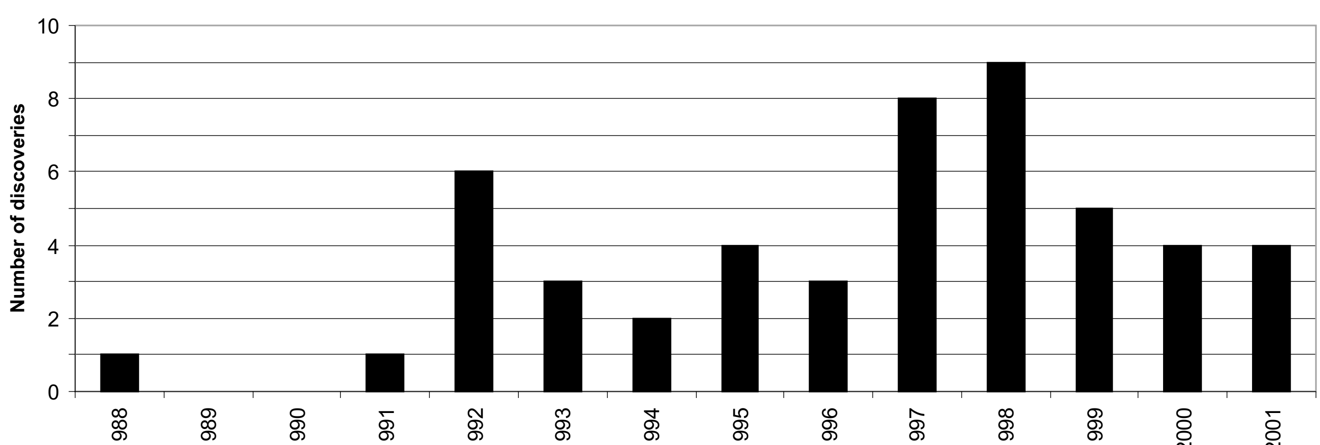

Figure 11. Provisional coalbed-methane fields in Oklahoma. From Boyd (2002b). Data from Cardott (2002).

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.

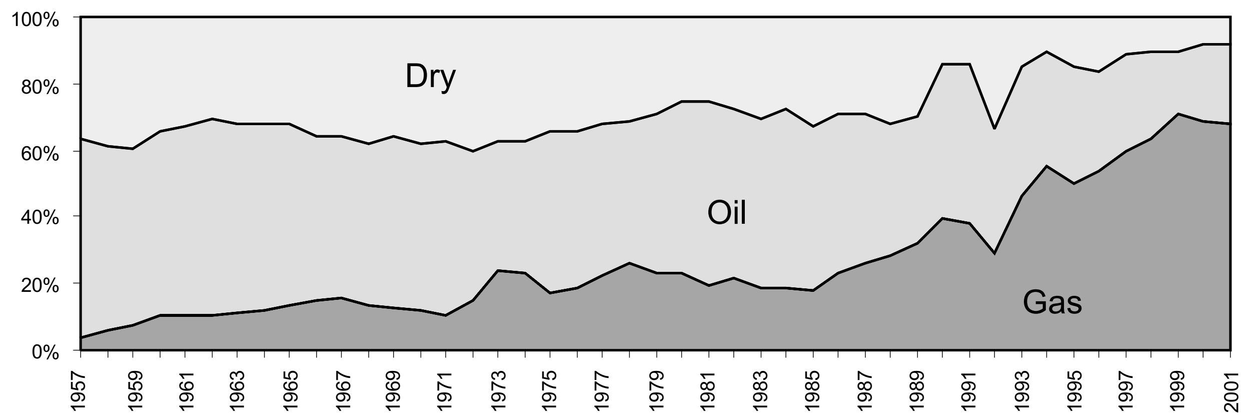

Figure 12. Oklahoma's well-completion history (all wells, 1957–2001). Data from Claxton (2001).

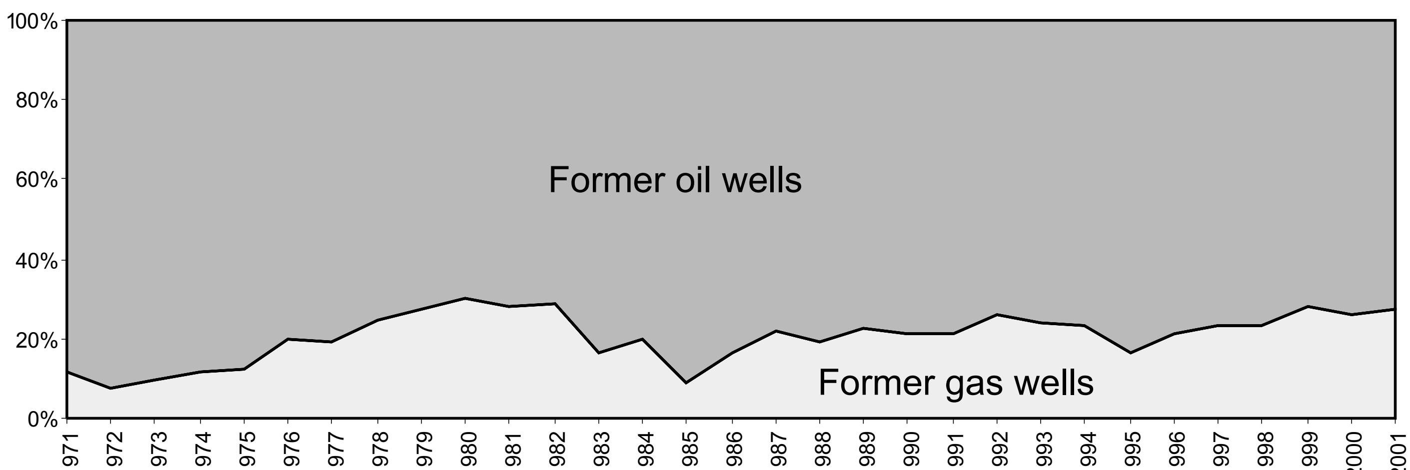

Figure 13. Well abandonments in Oklahoma (formerly productive wells). Data from Claxton (2001).

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

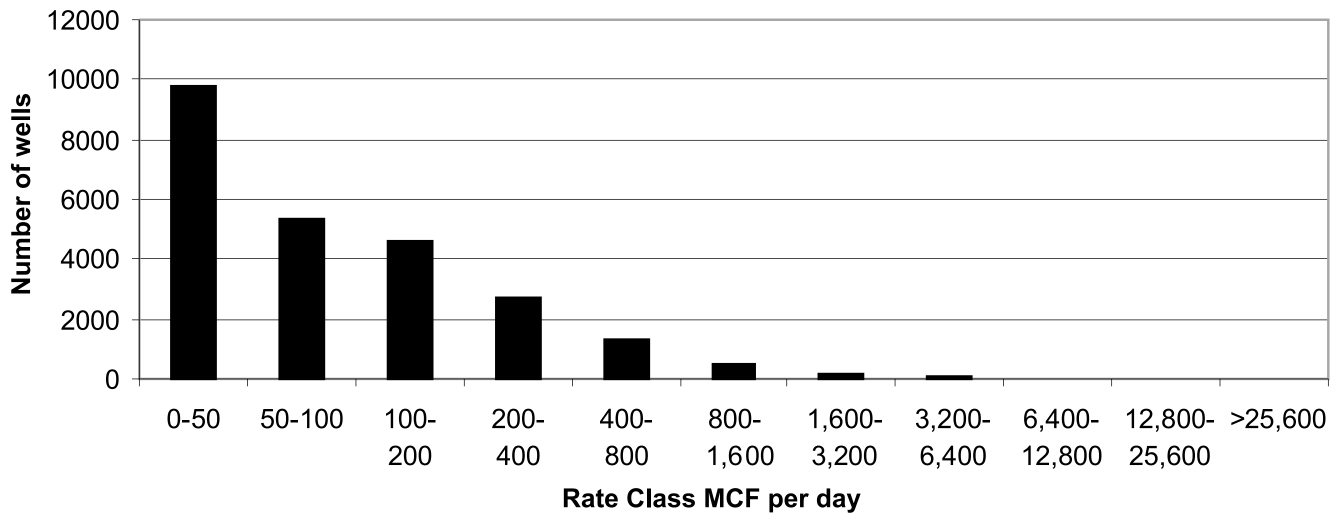

Figure 14. Gas-well production rates in Oklahoma (1999). Data from Hinton (2001).

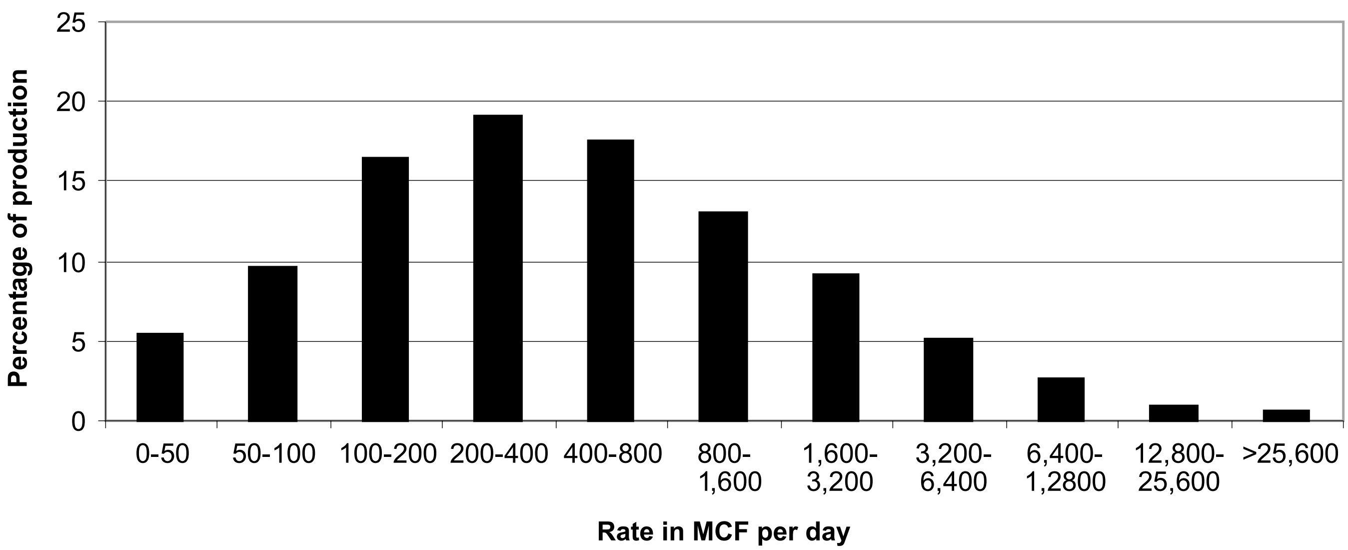

Figure 15. Oklahoma's gas production by rate class (1999). Data from Hinton (2001).

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-based 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 exist), 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

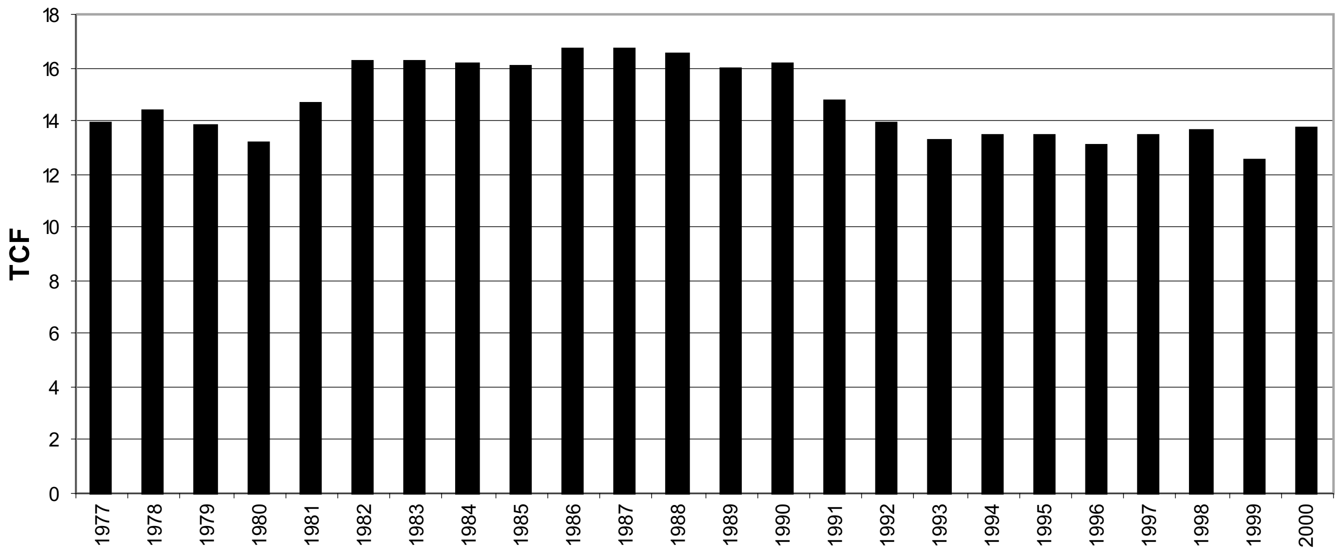

Figure 16. Proved gas reserves in Oklahoma (1977–2000). Data from Hinton (2001).

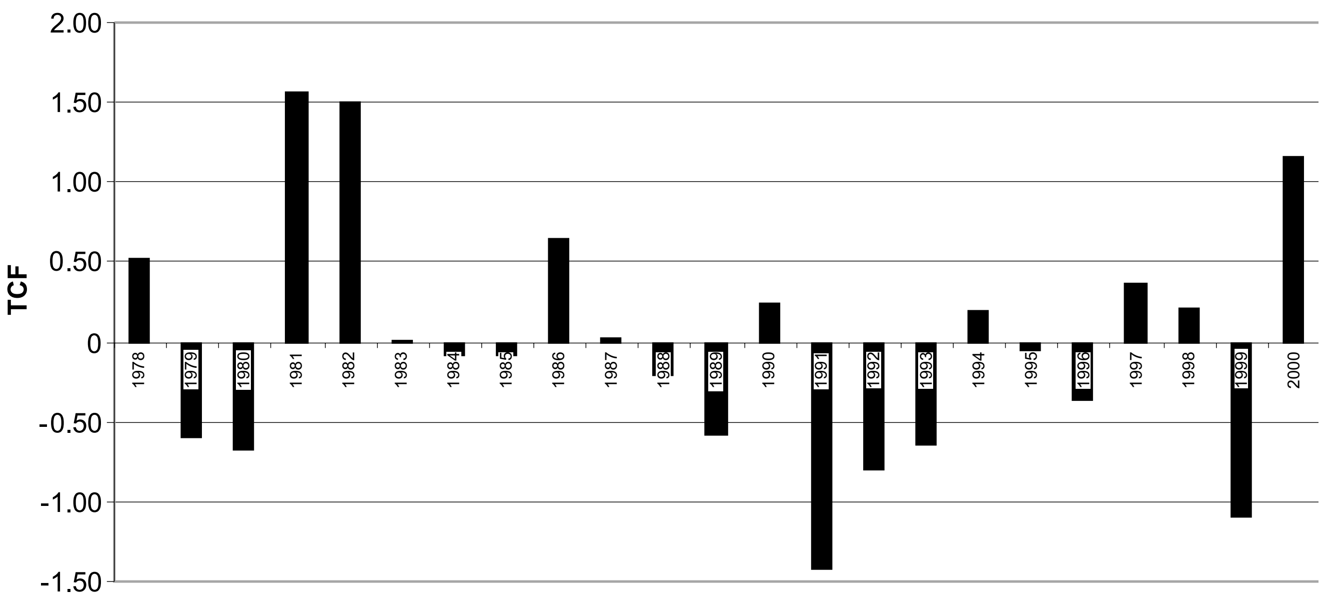

Figure 17. Changes in Oklahoma's net gas reserve (after production from the previous year). Data from Hinton (2001).

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.

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