02110465

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August 15 2005

Oil and Gas Conservation Commission
Weld County Colorado

Dears Sirs,

My name is Jon File, my address is 6255 Weld County rd. 3 ¼ I would like to request that I receive my two minutes and two minutes from Kenny Schell.

I am a land owner that will be affected by the proposal presented to you today. I am again surprised that the land owners affected by these changes were not notified in any manor by the OGCC or the proposing parties. However I come to offer a compromise, as both a supporter of the oil and gas companies rights to recover their reserves under our property and a landowner determined to protect our rights and preserve the original intent of the leases.

The original intent of most Landowners at the signing of the oil and gas lease, was to allow for the recovery of oil and gas while preserving the value and usability of the surface of the ground. Most leases state "this lease is subject to all Federal and State laws, rules etc… The problems start when we try to determine if that means the rules in place at the signing of the lease or as changed and modified from time to time.

The Oil companies have at least two main goals with this proposal, the first is establish new rights with interior infill wells and boundary wells.

Show Display:

There are 4 Sections shown on our exhibit with the quarter sections and quarter quarters also shown, Section 29 shows the number of wells allowed at the signing of most leases. Section 28 shows the current number of wells allowed, Section 32 shows the intended number of wells requested by today's proposal and Section 33 shows the number of wells allowed, under today's proposal or at least 160 wells per Section, if different zones are sold off to other parties as has historically been done with the Sussex and Shannon formations. The red dots are Sussex/Shannon wells and the blue dots are J Sands, Codell, Dakota and Niobrara wells, not counting if future discoveries are made and those zones are leased to additional parties. This drawing does not include roads and tank battery sites and is equal to at least one well for every 4 acres. The dot's are to scale with a 150' radius.

We are not asking the board to reduce the rights given to the oil and gas companies at the signing of the original leases, but to control the future taking of land as their rights are expanded. Directional drilling has been a well known art since the 1950's. The proposal today to directionally drill all interior infill wells and boundary wells is a smart way to protect the majority of the surface estate yet give the oil companies the right to recover a majority of their reserves. However in order to preserve the original intent of all O&G leases and make it easier for towns to control the development within them, any and all new wells drilled over and above those allowed by the rules and regulations in place at the date and time of the signing of the original lease should be clustered similar to what the local cities and counties are trying to do with homes. By adding wording to 318A.2 similar to "Any and all new wells to be drilled, above and beyond those allowed by the rules and regulations in place at the time of the signing of an oil and gas lease shall be directionally drilled from the center of each quarter section in clusters. Such clusters shall be laid out in rows 50' apart with spacing of 35' between each wellhead, unless permission is granted otherwise by the owner of the surface estate." This spacing is common in the oil and gas industry, we are currently working with one of the companies represented here today on a similar proposal. This would be a great compromise between the land owners and oil and gas companies to allow future development for both parties.

The second and much more dangerous issue which is buried in the words of the text, is the issue of changing the distance that wells can be located from each other. By removing 318A.c they have taken the requirement to locate wells as close as possible to existing wells, or 35' using sound engineering practices to allowing themselves at least 100' without any compensation to the surface owner. Also by eliminating the "Policy on staff administration of the greater wattenberg area special well location rule 318A dated April 26,1999, they have change the meaning of the drilling window (the 800' x 800' in the center of the quarter section and the 400' x 400' in the center of each quarter/quarter) from meaning the bottom hole location as described on page 3 and 4 of the staff policy to now mean a surface location. The original goal of the windows was to protect surrounding mineral holders from having their minerals taken by adjoining wells being too close to their neighbors and was not intended to give oil companies more surface location in which to drill. But that is how the oil companies interpreted it and they have convinced most surface owners that they have the right to use said drilling windows as surface locations, when the policy on staff made it very clear that they were bottomhole locations.

Therefore I propose the following changes as a compromise to allowing more well locations on the surface estate.

The following changes should be made:

as mentioned above:
318A.2 Any and all new wells to be drilled, above and beyond those allowed by the rules and regulations in place at the time of the signing of the oil and gas lease shall be directionally drilled from the center of each quarter section in clusters. Such clusters shall be laid out in rows 50' apart with spacing of 35' between each wellhead, unless permission is granted otherwise by the owner of the surface estate.

The new 318.A should have the new added word "surface" removed in "described SURFACE drilling locations to drill, twin, deepen etc.

The new 318A.a paragraph 4 should read These "<u>bottom hole</u>" locations, in stead of These "surface well" locations.

The old 318A.c should be reinstated.

The new 318G should be changed to The proposed surface well location shall "<u>meet</u>" the following criteria, not "shall be reviewed in accordance with"

The new 318G.1 should read <u>40'</u> not 100'

The new 318G.2 should also read <u>40'</u> instead of 100'

The new 318H.1 & 2 should include the "<u>surface owner</u>"

And the most important change is, a paragraph needs to be added that states that "Nothing in these OGCC Rules is intended to increase or deminish the rights of the lessee or lessor over and above the rights granted or intended to be granted at the signing of any oil and gas lease.

The Oil and Gas Companies and the OGCC says, it is not their intent to change the rights granted under the leases. By adding this paragraph it is a sure way for them to prove to the general public what their intent is.

Sincerely, Jon P. File

DATA FOR THE RULE 318A HEARING
NOVEMBER 17, 2005

City and County of Broomfield Open Lands: (Includes: Open Space, Parks, School Parks, Conservation Easement Acres) 3,900 acres

3,900 acres/160 acres = 24.3 Quarter Sections @160 acres

24.3 Quarter Sections x 5= 121 total well sites under the current rules

Number of Active Wells on Broomfield Open Lands 7

24.3 Quarter Sections x 3 new wells = 73 New Well Sites under the Proposed Rule 318A

Value of Land Impacted Proposed Rule 318A Additional Wells = $1.2 Million
73 new well sites x .4 acres of impacted site x $40,000 average price per acre = $1.2 Million

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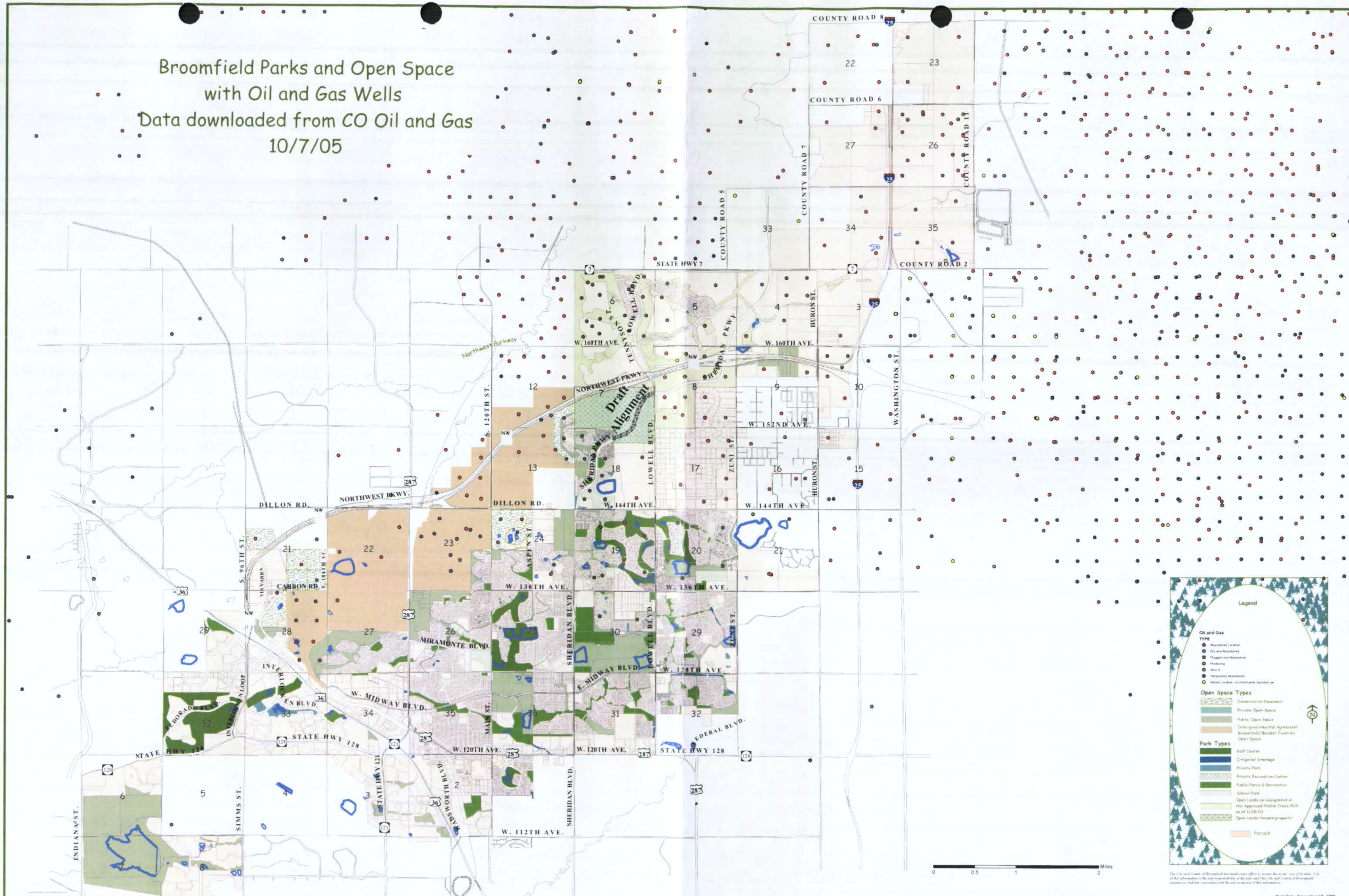
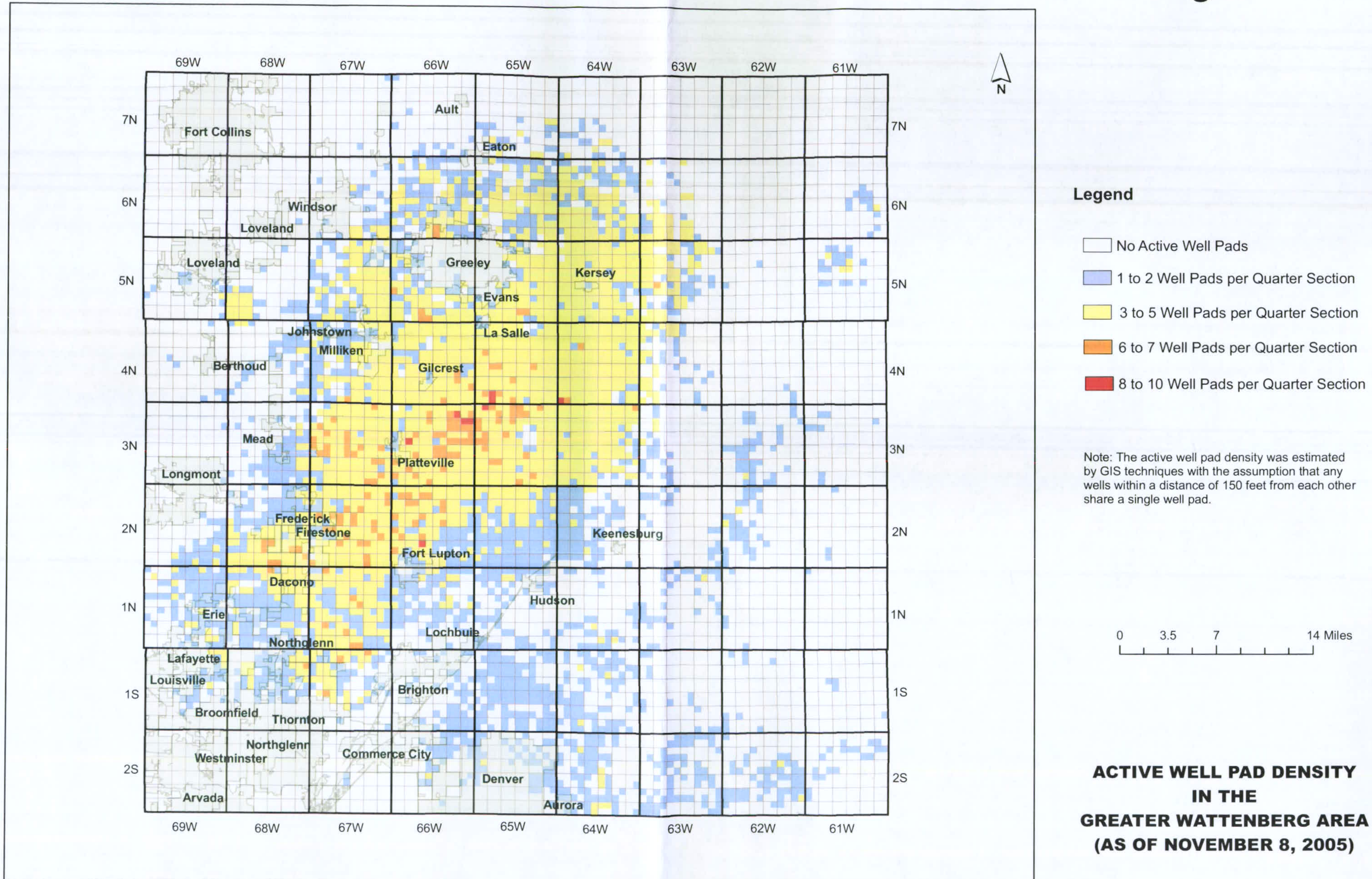
Total Acres in City and County of Broomfield 21,468.5 acres

Total Existing Active Wells in City and County of Broomfield 60 Wells

The City and County of Broomfield is in the following Townships and Ranges:
T1N, R68W
T1N, R69W
T1S, R68W
T1S, R69W
T2S, R68W
T2S, R69W
T2S, R70W (only a very small portion if any of our County is in this location)



Broomfield Parks and Open Space
with Oil and Gas Wells
Data downloaded from CO Oil and Gas
10/7/05
COUNTY ROAD 8
COUNTY ROAD 6
COUNTY ROAD 7
COUNTY ROAD 5
COUNTY ROAD 2
STATE HWY 7
W. 160TH AVE.
NORTHWEST PKWY.
Draft Alignment
W. 152ND AVE.
W. 144TH AVE.
DILLON RD.
NORTHWEST PKWY.
W. 136TH AVE.
CARBON RD.
MIRAMONTE BLVD.
E. MIDWAY BLVD.
W. 128TH AVE.
W. MIDWAY BLVD.
INTERLOCKEN BLVD.
STATE HWY 128
W. 120TH AVE.
W. 112TH AVE.
SHERIDAN BLVD.
LOWELL BLVD.
ZUNI ST.
HURON ST.
WASHINGTON ST.
S. 120TH ST.
S. 96TH ST.
INDIANA ST.
SIMMS ST.
MAIN ST.
FEDERAL BLVD.
Legend
Oil and Gas
TYPE
Abandoned Location
Dry and Abandoned
Plugged and Abandoned
Producing
Shut In
Temporarily Abandoned
Permit Location, no information reported yet
Open Space Types
Conservation Easement
Private Open Space
Public Open Space
Intergovernmental Agreement Broomfield/Boulder Counties Open Space
Park Types
Golf Course
Irrigated Drainage
Private Park
Private Recreation Center
Public Parks & Recreation
School Park
Open Lands as Designated in the Approved Preble Creek PUD as of 1/28/03
Open Lands Hooper property
Parcels
N
0 0.5 1 2 Miles
Print Date: November 18, 2005



ACTIVE WELL PAD DENSITY IN THE GREATER WATTENBERG AREA (AS OF NOVEMBER 8, 2005)

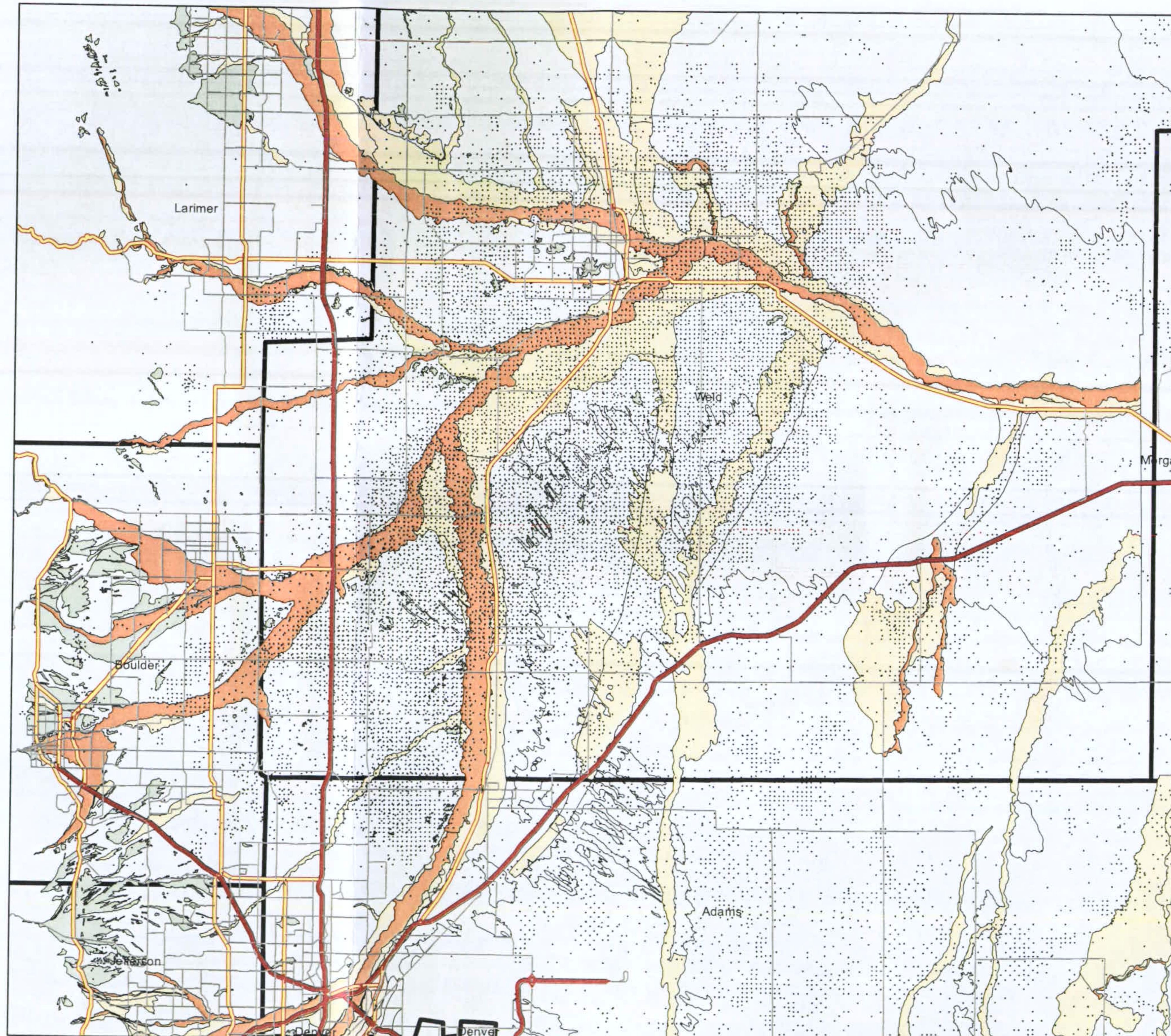
COGCC, November 16, 2005

Aggregate Resources
and
Oil and Gas Wells
in the
Greater Wattenberg Area

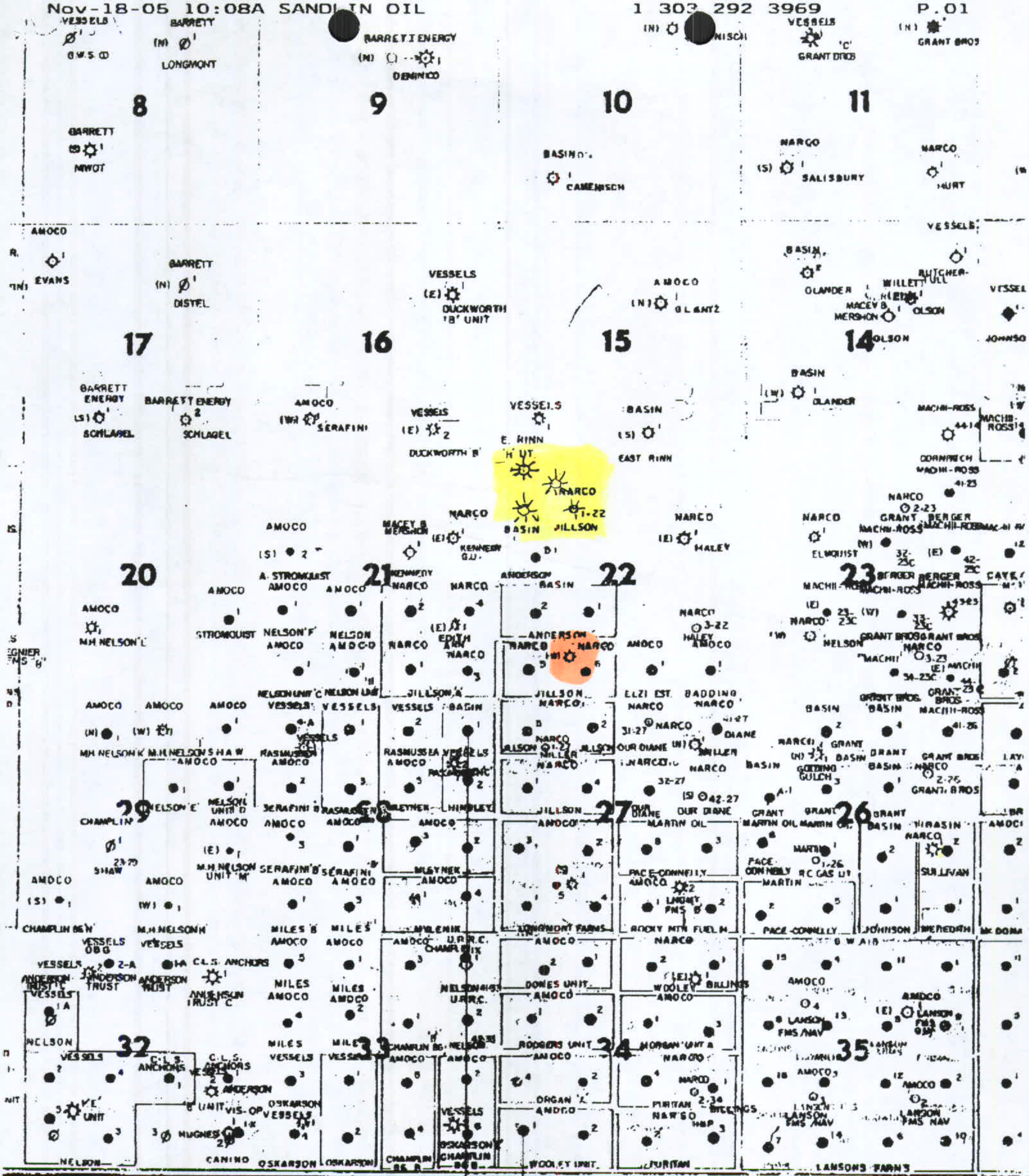
Aggregate Quality

- High
- Medium
- Low

· Petroleum well



Nov-18-05 10:08A SANDLIN OIL 1 303 292 3969 P.01



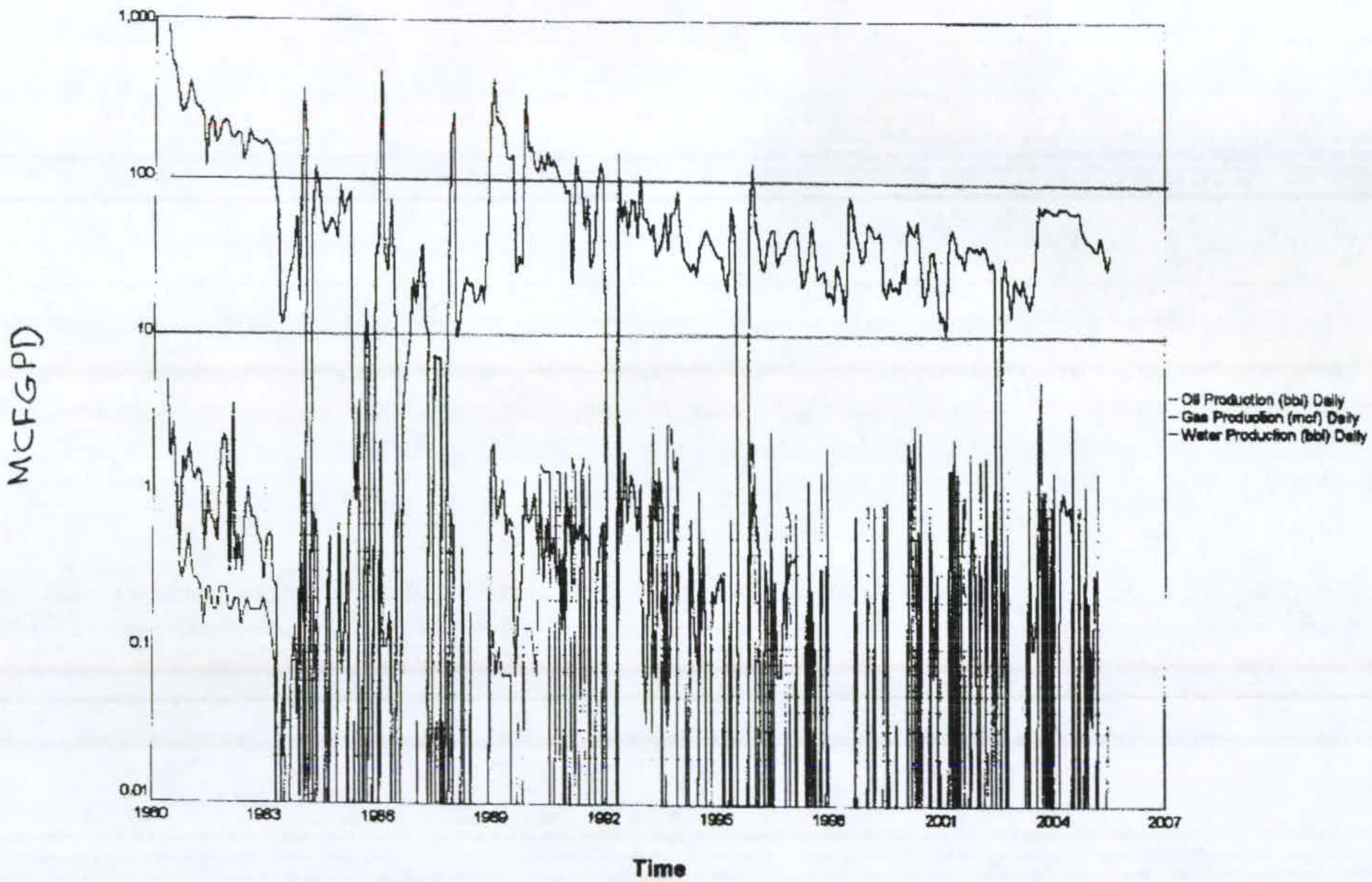
SOUTH

SN- 6810

BERG FIELD - Cause 232

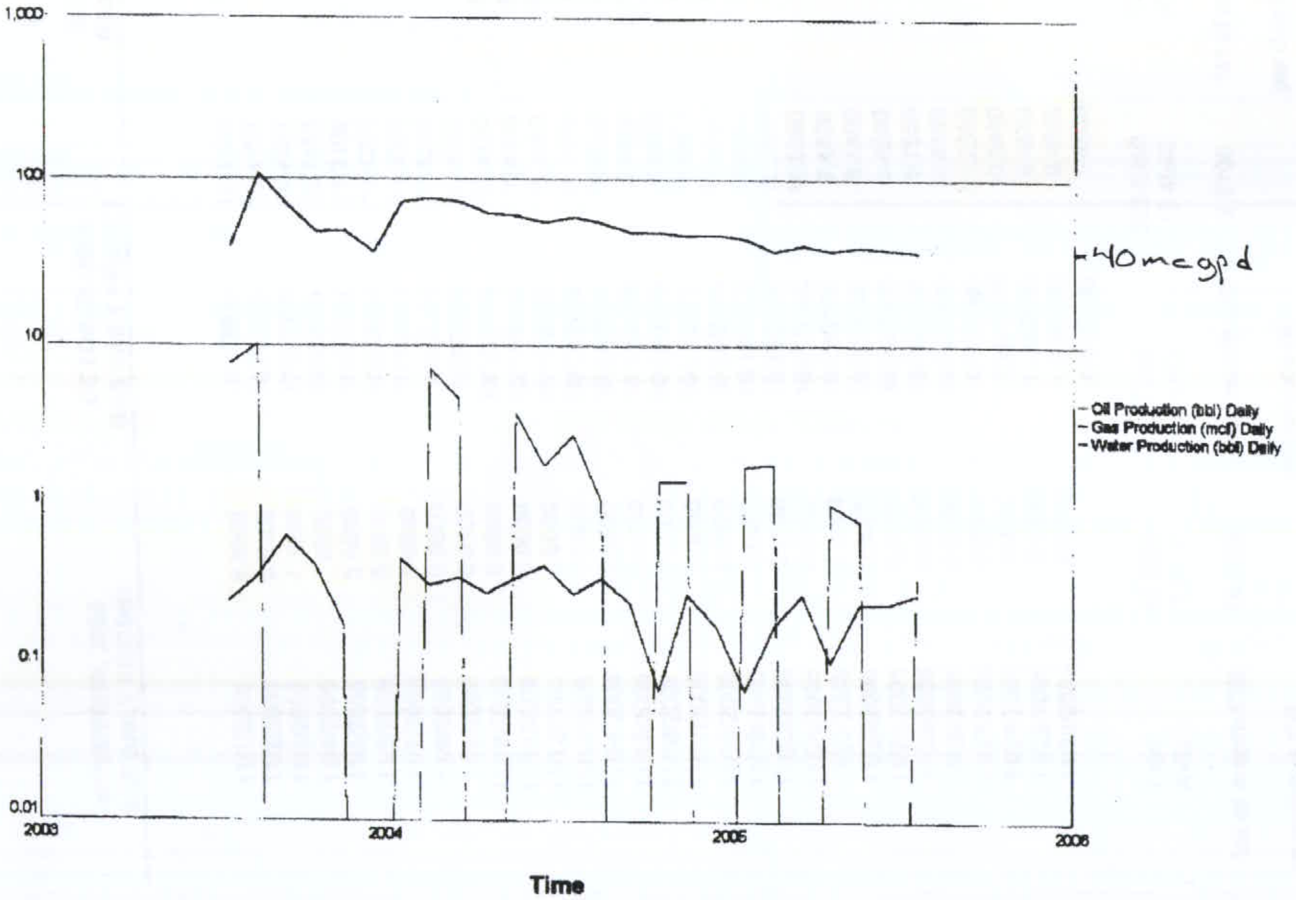
Lease Name: JILLSON GAS UNIT
County, State: WELD, CO
Operator: ENCANA OIL & GAS (USA) INCORPORATED
Field: WATTENBERG
Reservoir: J SAND
Location: 22 2N 66W NW SE SW

3,583 bbl 685,296 mcf 2,831 bbl



Lease Name: JILLSON 11-22
County, State: WELD, CO
Operator: ENCANA OIL & GAS (USA) INCORPORATED
Field: WATTENBERG
Reservoir: J SAND
Location: 22 2N 66W SE NW NW

194 bbl 39,293 mcf 1,326 bbl



34-60-114. Action for damages.

Nothing in this article, and no suit by or against the commission, and no violation charged or asserted against any person under any provisions of this article, or any rule, regulation, or order issued under this article, shall impair, abridge, or delay any cause of action for damages which any person may have or assert against any person violating any provision of this article, or any rule, regulation, or order issued under this article. Any person so damaged by the violation may sue for and recover such damages as he otherwise may be entitled to receive. In the event the commission fails to bring suit to enjoin any actual or threatened violation of this article, or of any rule, regulation, or order made under this article, then any person or party in interest adversely affected and who has notified the commission in writing of such violation or threat thereof and has requested the commission to sue, may, to prevent any or further violation, bring suit for that purpose in the district court of any county in which the commission could have brought suit. If, in such suit, the court holds that injunctive relief should be granted, then the commission shall be made a party and shall be substituted for the person who brought the suit, and the injunction shall be issued as if the commission had at all times been the complaining party.

34-60-115. Limitations on actions.

No action or other proceeding based upon a violation of this article or any rule, regulation, or order of the commission shall be commenced or maintained unless it has been commenced within one year from the date of the alleged violation.

34-60-116. Drilling units and pooling interest.

(1) To prevent or to assist in preventing waste, to avoid the drilling of unnecessary wells, or to protect correlative rights, the commission, upon its own motion or on a proper application of an interested party, but after notice and hearing as provided in this section, has the power to establish drilling units of specified and approximately uniform size and shape covering any pool.

(2) In establishing a drilling unit, the acreage to be embraced within each unit and the shape thereof shall be determined by the commission from the evidence introduced at the hearing, except that, when found to be necessary for any of the purposes mentioned in subsection (1) of this section, the commission is authorized to divide any pool into zones and establish drilling units for each zone, which units may differ in size and shape from those established in any other zone, so that the pool as a whole will be efficiently and economically developed, but no drilling unit shall be smaller than the maximum area that can be efficiently and economically drained by one well. If the commission is unable to determine, based on the evidence introduced at the hearing, the existence of a pool and the appropriate acreage to be embraced within a drilling unit and the shape thereof, the commission is authorized to establish exploratory drilling units for the purpose of obtaining evidence as to the existence of a pool and the appropriate size and shape of the drilling unit to be applied thereto. In establishing the size and shape of the exploratory drilling unit, the commission may consider, but is not limited to, the size and shape of drilling units previously established by the commission for the same formation in other areas of the same geologic basin. Any spacing regulation made by the commission shall apply to each individual pool separately and not to all units on a statewide basis.

(3) The order establishing drilling units shall permit only one well to be drilled and produced from the common source of supply on a drilling unit, and shall specify the location of the permitted well thereon, with such exception for the location of the permitted well as may be reasonably necessary for wells already drilled or where it is shown upon application, notice and hearing, and the commission finds, that the drilling unit is located partly outside the pool or field and adjacent to a producing unit, or, for some other reason, the requirement to drill the well at the authorized location on the unit would be inequitable or unreasonable. The commission shall take such action as will offset any advantage which the person securing the exception may have over other producers by reason of the drilling of the well as an exception, and include in the order suitable provisions to prevent the production from the drilling unit of more than its just and equitable share of the oil and gas in the pool.

Oklahoma Oil: Past, Present, and Future

Dan T. Boyd
Oklahoma Geological Survey

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

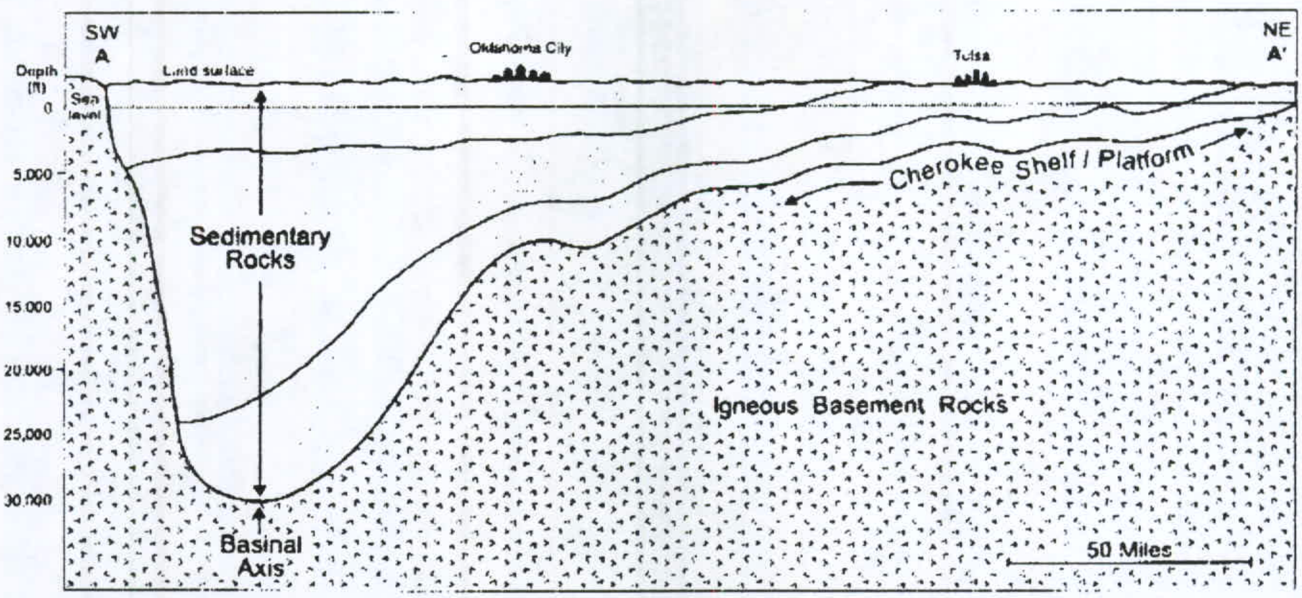


Figure 1. Cross-section of the Anadarko geologic basin. Modified from W. J. Witt and others (1971). Vertical exaggeration 14:1. See Figure 2 for base map.

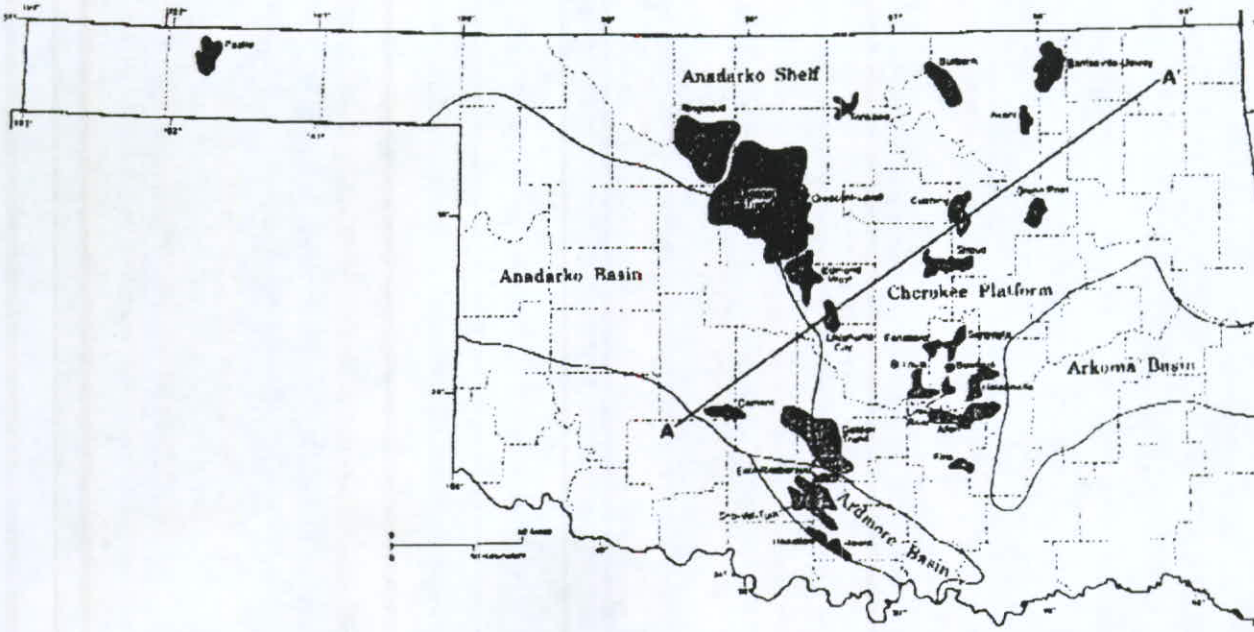


Figure 2. Petroleum provinces and major Oklahoma oil fields (>100 MMBO through January 2002). Modified from Robert A. Northcutt and Jock A. Campbell (1995) and Dan T. Boyd (in press).

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
		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 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

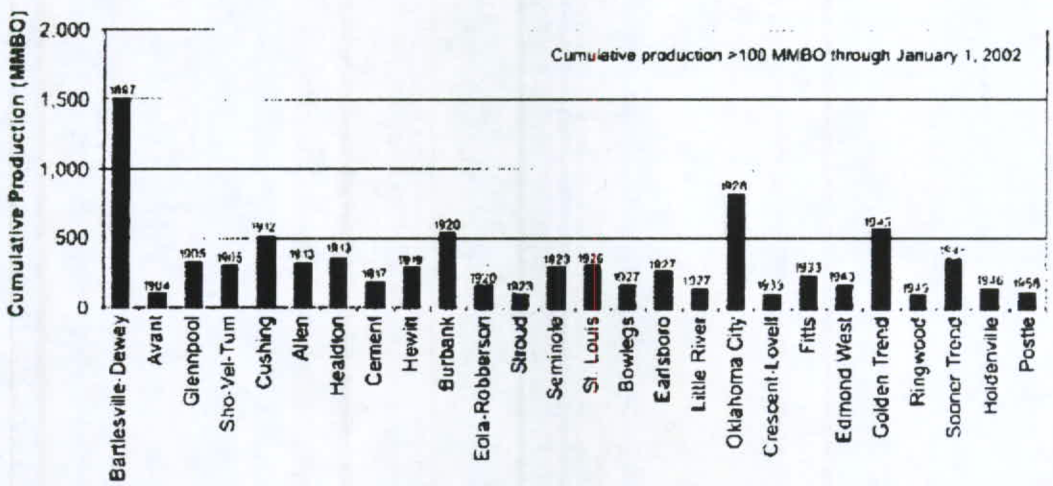


Figure 4. Major oil fields in Oklahoma; their cumulative production with discovery dates. From Lay (2001).

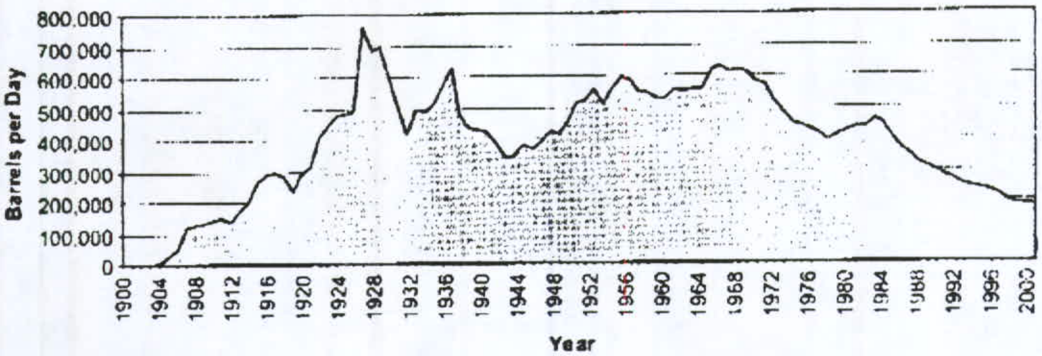


Figure 5. Historical oil and condensate production in Oklahoma. From Claxton (2001).

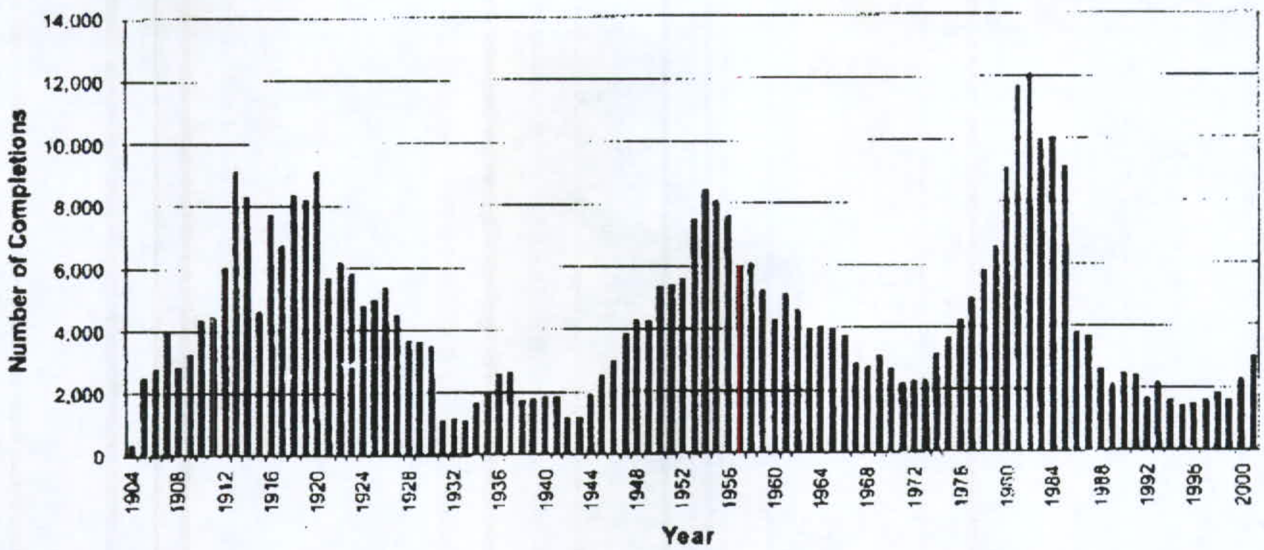


Figure 6. Oklahoma's well-completion history (producers and dry holes). From Claxton (2001).

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

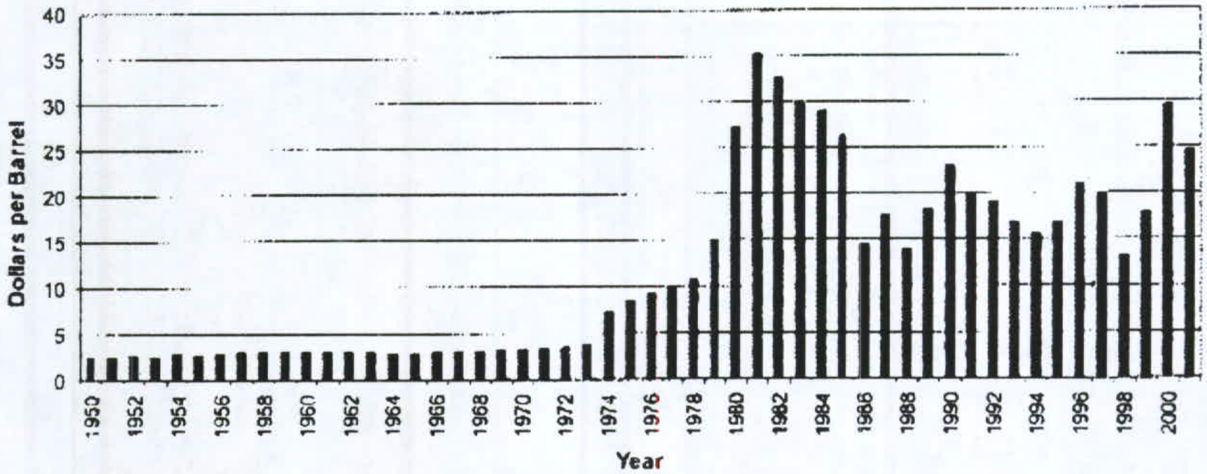


Figure 7. Average annual crude-oil price (unadjusted) in Oklahoma. From Claxton (2001).

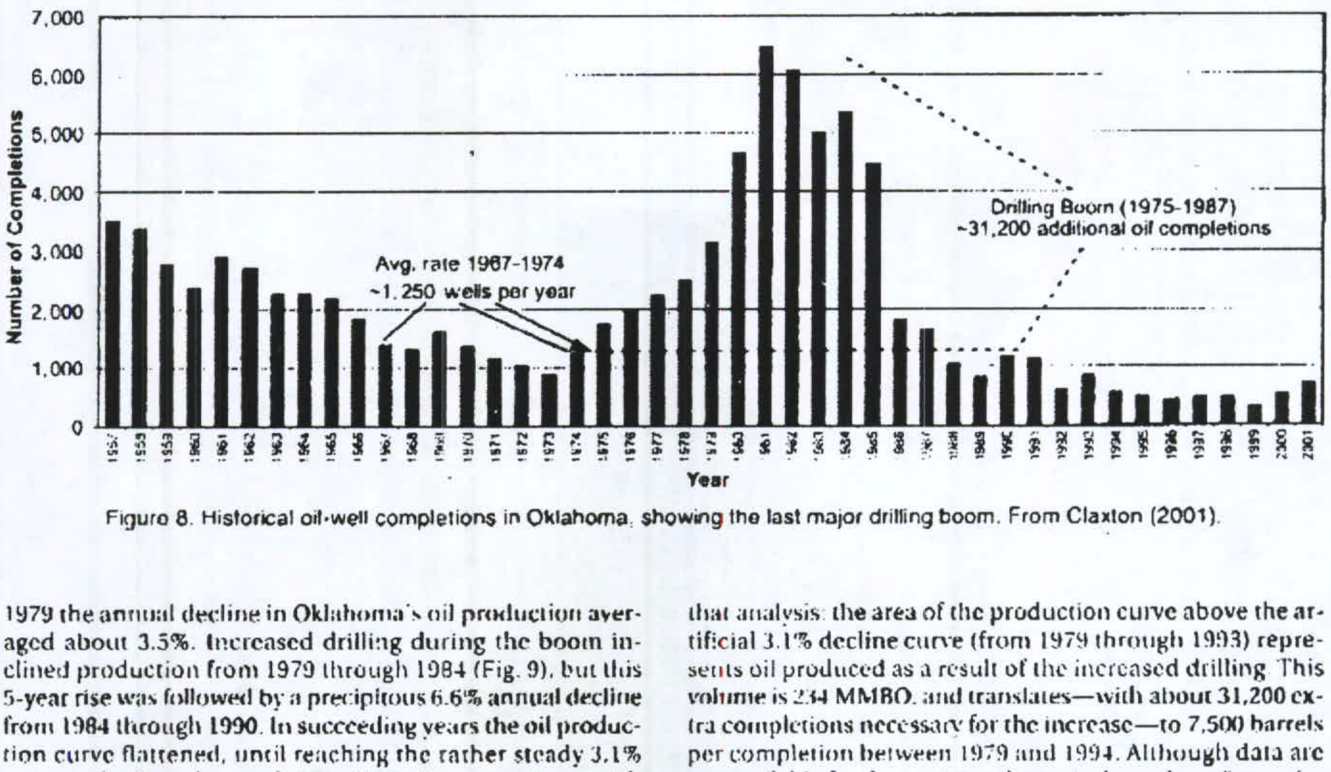


Figure 8. Historical oil-well completions in Oklahoma, showing the last major drilling boom. From Claxton (2001).

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.

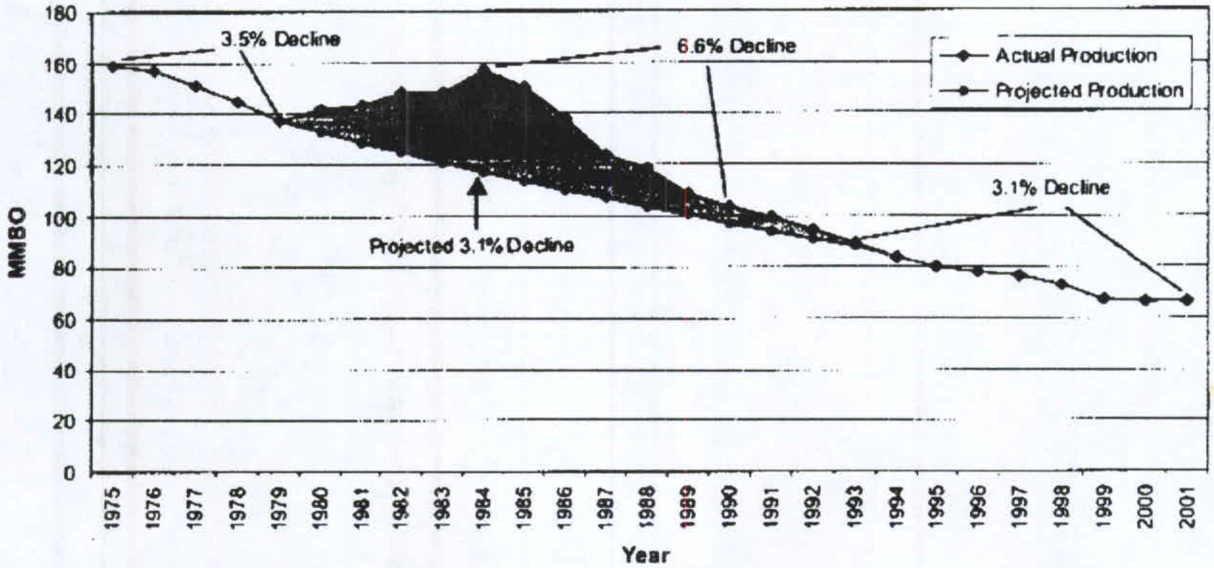


Figure 9. Annual oil production in Oklahoma, showing oil produced as a result of drilling boom. From Claxton (2001).

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

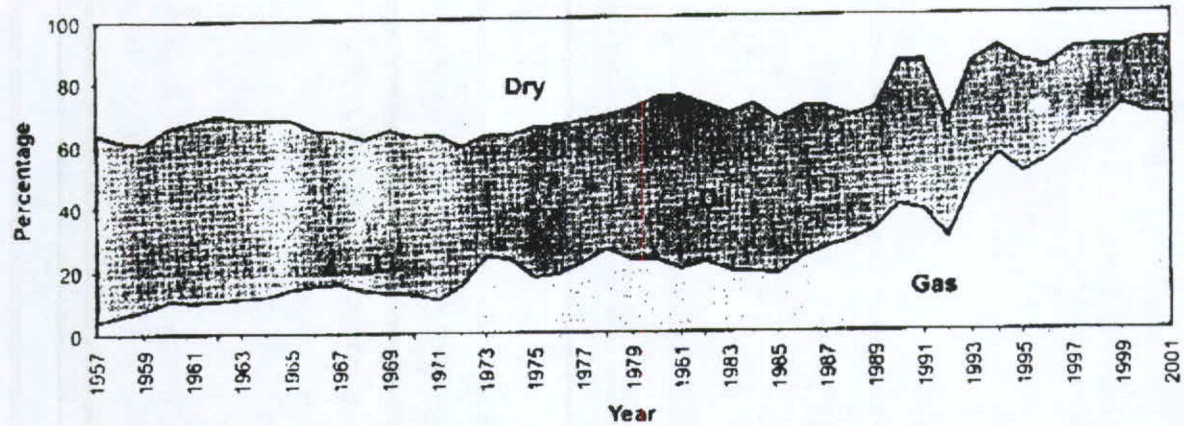


Figure 10. Oklahoma's well-completion history (all wells). From Claxton (2001).

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.

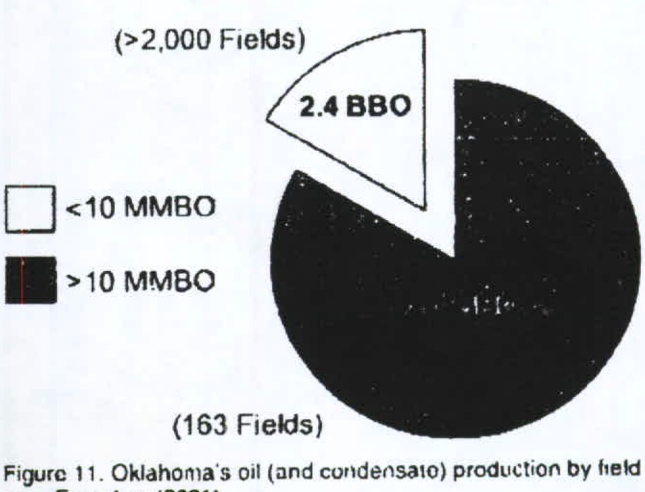


Figure 11. Oklahoma's oil (and condensate) production by field size. From Lay (2001).

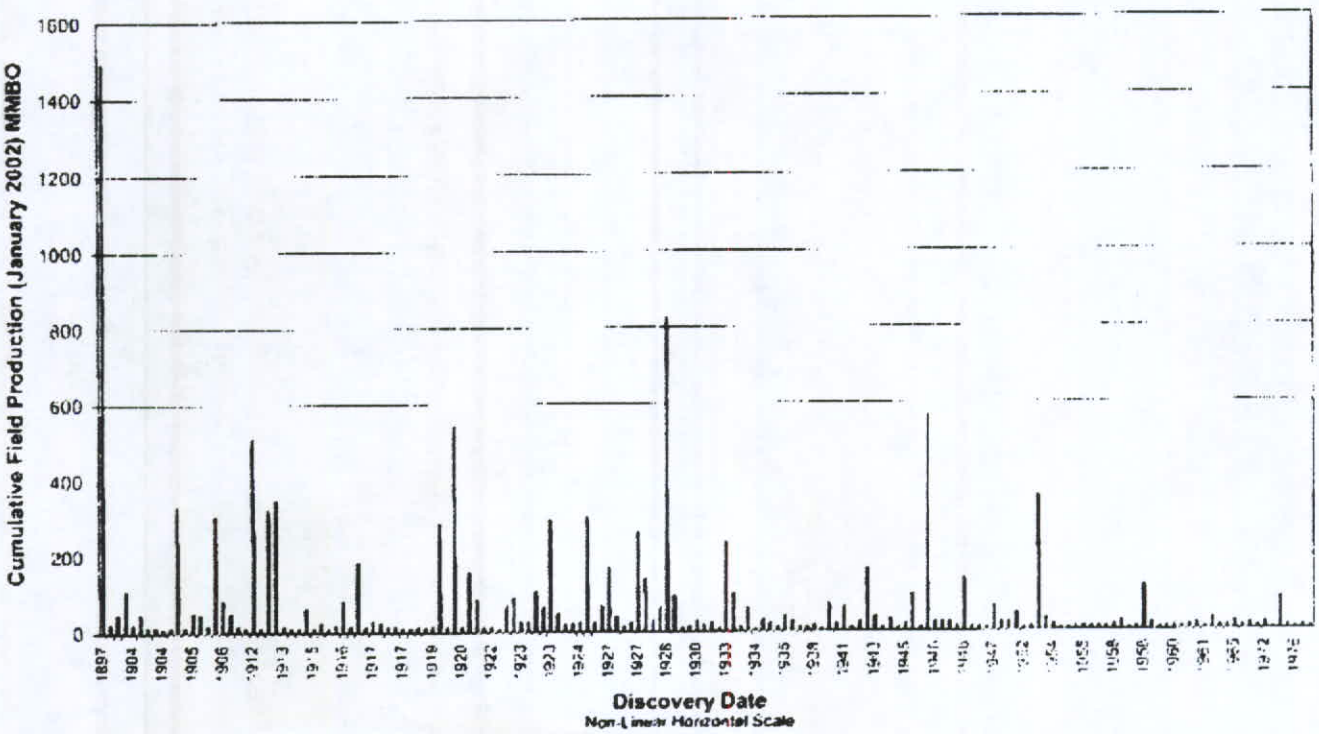


Figure 12. Oklahoma's oil-field discoveries by date (>10 MMBO cumulative recovery). From Lay (2001).

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-

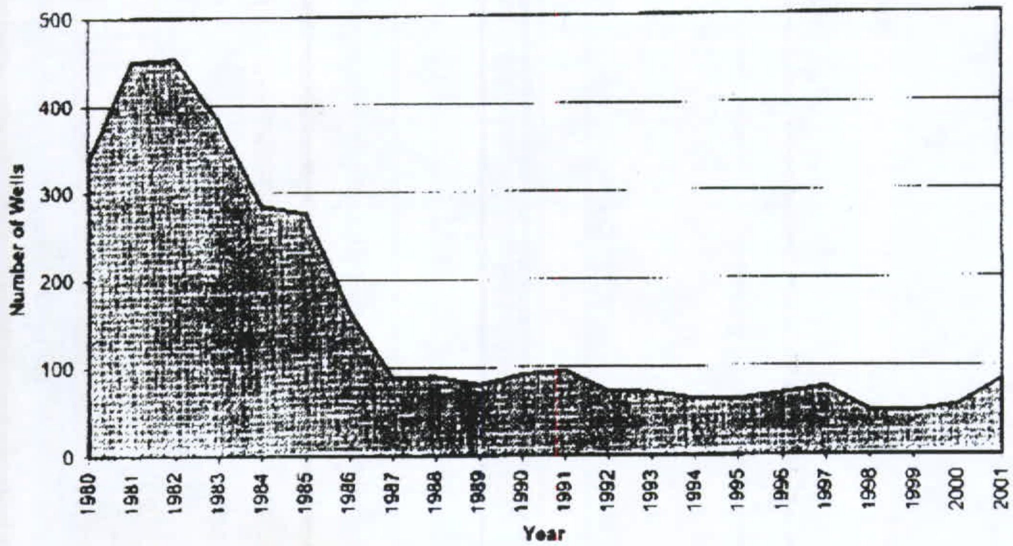


Figure 13. Historical new-field wildcat drilling in Oklahoma. From Claxton (2001).

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

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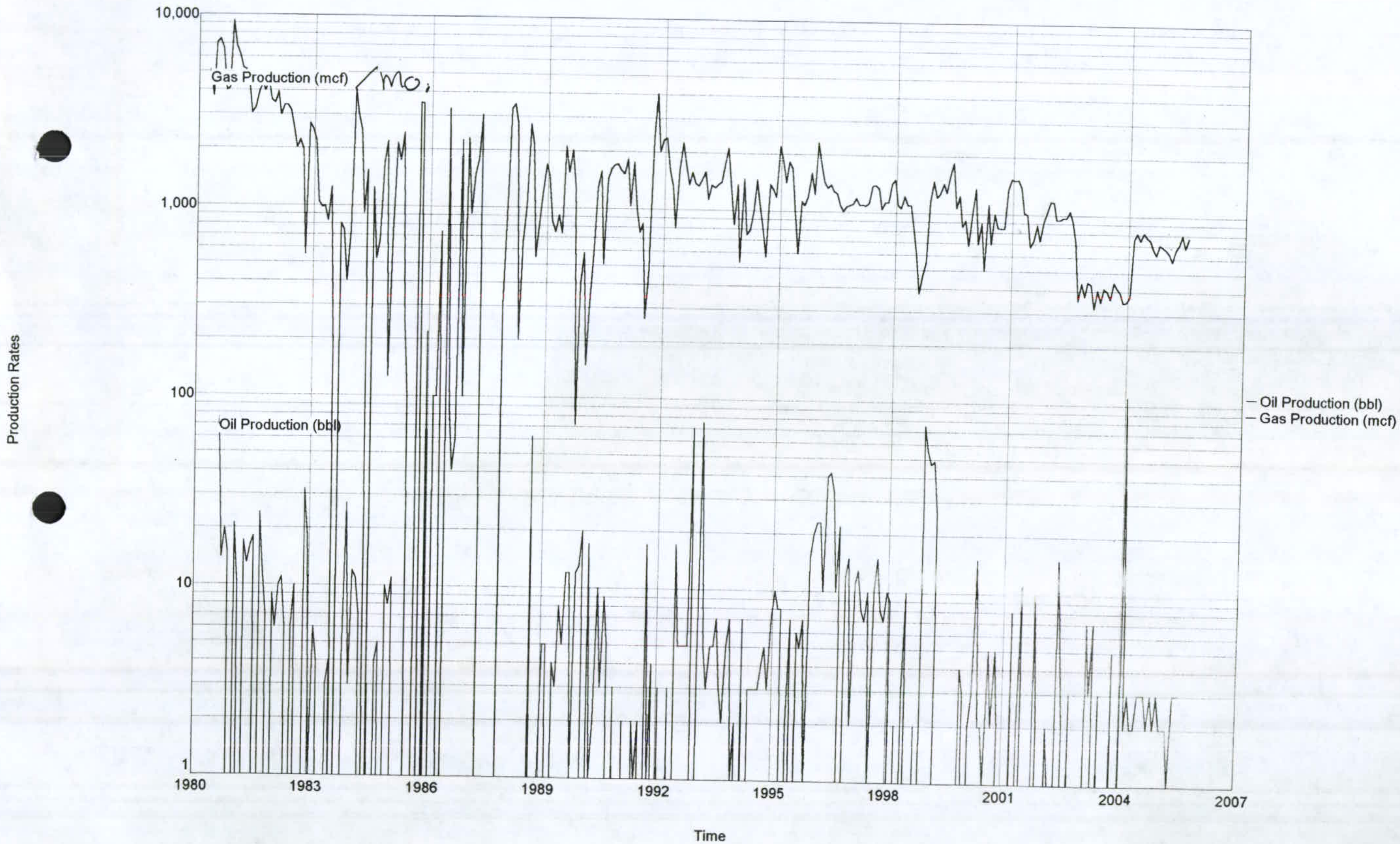
Lease Name: STUGART JERALD #2
County, State: WELD, CO
Operator: KERR-MCGEE ROCKY MOUNTAIN CORPORATIO
Field: WATTENBERG
Reservoir: J SAND
Location: 4 2N 65W NE SW SE

435,600 mcf 1,996 bbl



Lease Name: MOSER
County, State: WELD, CO
Operator: KERR-MCGEE ROCKY MOUNTAIN CORPORATIO
Field: WATTENBERG
Reservoir: J SAND
Location: 4 2N 65W NE NE SE

13,868 mcf 124 bbl