Bureau of Mines
Report of Investigations 4917

PETROLEUM-ENGINEERING STUDY OF HEALDTON OIL FIELD, CARTER COUNTY, OKLA.

BY C. H. RIGGS, JOHN E. WEY, EDWARD SANABRIA, JR.,
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UNITED STATES DEPARTMENT OF THE INTERIOR
Douglas McKay, Secretary
BUREAU OF MINES
J. J. Forbes, Director

The work upon which this report is based was done under a cooperative agreement between the Bureau of Mines, United States Department of the Interior, and the State of Oklahoma.

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by

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INTRODUCTION AND SUMMARY

This petroleum-engineering study of the Healdton oil field in Carter County, Okla., describes the geology and production history of that field and estimates the oil reserves that could be produced by efficient secondary-recovery methods.

The Healdton field, in western Carter County approximately 20 miles west of Ardmore, Okla., was discovered in 1913 and was one of the early important oil-producing areas in the State. Although the volume of oil recovered from the Healdton sands has been comparatively high, studies show that a large reserve remains in the pressure-depleted sand, which can be recovered by efficient water-flood operations.

In making this study of the Healdton-sand reservoir, the writers utilized many data already available in company and Government offices. Most of the fluid samples were collected by Bureau of Mines personnel and analyzed in the Bureau's laboratories at Bartlesville, Okla.; but other data, including logs, core analyses, and production records, were obtained from outside sources. These data were examined critically but were not verified, and possible errors in the original data may be reflected in the conclusions.

In this study, attempts were made to consider only those aspects of the available information that would contribute to a clear and concise engineering report on the Healdton-sand reservoir. Other phases of the data, as well as those concerning associated reservoirs, were eliminated from consideration as being irrelevant to the particular problem. Cores and drill cuttings of the Healdton sands were analyzed and studied to determine the nature of the reservoir rocks. Analyses of samples of produced oil, water, and gas were studied to fix the different types, the limits of their occurrence, and the suitability of different waters for injection into the Healdton sands. Records of oil, gas, and water produced and of gas and water injected were studied to interpret the production behavior of the field and of certain individual leases. Theoretical calculations were made to predict the probable water-flood behavior and oil recovery, at constant water-injection rates, for individual sands on two leases.

Table 1 summarizes data pertinent to the Healdton field.

Oil is produced from discontinuous and lenticular Healdton sands of late Pennsylvanian age, which range in depth between 700 and 1,400 feet. Apparently these sands were deposited unconformably around and over a topographic high of the eroded Ordovician surface. During Mesozoic time, the area was folded and faulted to form a modified anticlinal structure.

TABLE 1. - Field and reservoir data, Healdton sands, Healdton oil field, Carter County, Okla.

GENERAL	
Date of discovery	Aug. 14, 1913
Depth of wells ... ft.	700 to 1,400
Total productive area ... acres	7,142
Total wells drilled to Nov. 1, 1951	2,590
Wells producing as of Nov. 1, 1951	1,863
Stock tank gravity of oil ... A.P.I.°	26 to 35
Viscosity of typical stock-tank oil of 31° A.P.I., at 80° F ... Cps.	13.3
RESERVOIR DATA	
Average effective thickness ... ft.	72
Average porosity ... percent	21.6
Average permeability ... md.	330
Average connate water content ... percent	18.2
Average original reservoir pressure (est.) ... p.s.i.g.	270
Average formation temperature (est.) ... °F.	80
Gas in solution in reservoir oil per barrel of stock tank oil (est.) ... cu. ft.	85
Formation volume factor, (est.)	1.044
Original mobile oil reserves ... bbl.	422,000,000
Total stock tank oil originally in reservoir ... do.	674,195,000
PRODUCTION DATA	
Average initial oil production between 1913 and 1917, per well per day ... bbl.	270
Maximum yearly oil production, 1917 ... do.	22,036,000
Yearly oil production, 1950 ... do.	2,263,000
Average daily oil production, 1950 ... do.	6,200
Average daily water production, 1950 ... do.	14,600
Average specific gravity of produced gas (est.)	0.88
Gasoline content of produced gas as of Jan. 1, 1951, per M c.f. ... gal.	0.31 to 3.95
RECOVERY	
Cumulative oil production to Jan. 1, 1951 ... bbl.	211,179,000
Oil recovery to Jan. 1, 1951, field average per acre ... do.	29,570
Oil recovery to Jan. 1, 1951, field average ... barrels per acre foot	410

In this study the Healdton sands are considered to belong to four zones, the uppermost of which is termed the "first-sand zone" and the lowermost, the "fourth-sand zone." The first sand, the most nearly depleted, is the thickest and most extensive and should lend itself best to water-flood development. The character of this sand and the proposed methods of water-flood development are described in the sections on Reservoir Conditions and Water Flooding. The second and third sands are extremely lenticular, with alternating beds of sand and limestone of high and low permeability. The fourth sand covers a relatively smaller area and is more uniform in character, but it differs from the other sands in that natural water drive is the important production mechanism. The history of the natural water drive in the fourth sand for the field and for certain representative leases is discussed under Production Mechanisms.

Approximately 2,600 wells have been drilled in the Healdton field, as shown on the development map (fig. 1.), and over 211 million barrels of oil have been recovered from the several Healdton sands underlying the 7,142 oil-productive acres in the field. The comparatively high oil production obtained from "infill" wells drilled between old producers substantially raised the rate of oil production following three infill-drilling periods during the life of the field. The increased recovery from the field as a whole and from three leases in particular is given careful attention in the report under Infill Drilling.

Air and gas injection to increase oil production or to store gas for future use has been tried on a limited scale but with comparatively little success. The results obtained on several projects are discussed in detail both as to the accompanying increases in oil recovery and as to the indications they give of the continuity of the oil sands.

The study indicates that, in the Healdton sands, many millions of barrels of oil will not be recovered by present operating methods. Much of this oil can be flushed from the sands and forced to producing wells by water injected through specially equipped and properly spaced input wells. Introducing water into the several sands and controlling its movements through the oil-bearing pore spaces between the sand grains will present many problems to the water-flood engineer, but possible recovery of millions of barrels of oil will be an adequate reward. Methods of water-flood development and associated problems are discussed under Water Flooding.

ACKNOWLEDGMENTS

This engineering study of the Healdton oil field, Carter County, Okla., was conducted by the Bureau of Mines under a cooperative agreement with the State of Oklahoma. The investigation was carried on under the general supervision of R. A. Cattell, chief, Petroleum and Natural Gas Branch, Bureau of Mines, Washington, D. C., and H. C. Fowler, superintendent, Petroleum Experiment Station, Bureau of Mines, Bartlesville, Okla., and under the direct supervision of D. B. Taliaferro, chief, Secondary Recovery Branch, Petroleum Experiment Station, Bureau of Mines, Bartlesville, Okla.

The writers wish to extend their sincere appreciation to the following companies, who by furnishing production data and other pertinent information regarding their properties in the Healdton oil field have made this report possible:

Shell Oil Co., Inc., Oklahoma City, Okla.
Sinclair Oil & Gas Co., Tulsa, Okla.
The Pure Oil Co., Tulsa, Okla.
Magnolia Petroleum Co., Oklahoma City and Healdton, Okla.
Schermerhorn Oil Co., Tulsa, Okla.
Kewanee Oil Co., Tulsa, Okla.
The Texas Co., Tulsa, Okla.
Harry Ells, Inc., Tulsa, Okla.

Cities Service Oil Co., Bartlesville, Okla., and Shell Oil Co., Inc., Oklahoma City, made available early reports of oil purchased in the field. The completeness of oil-production data for many individual leases largely is due to their cooperation. Recent data concerning pipeline runs from individual leases made available by Bell Oil & Gas Co., Tulsa, Okla., and Shell Pipe Line Co., Tulsa, Okla., helped immeasurably.

Sincere thanks are extended to C. W. Tomlinson, Ardmore, Okla.; S. W. Hamner, Schermerhorn Oil Co., Healdton, Okla.; I. B. Stitt, Magnolia Petroleum Co., Healdton, Okla.; and S. H. Rockwood, Shell Oil Co., Inc., Oklahoma City, Okla., for their aid in many phases of this study. The cooperation and assistance of the personnel of operating companies in the field is gratefully acknowledged also.

Samples of drill cutting were obtained for study through the cooperation of Elbert King, Ardmore Sample Cut, Ardmore, Okla.

Data from unpublished reports on the Healdton oil field by Bureau of Mines personnel, A. A. Hammer, R. A. Cattell (1),4/ C. F. McCarroll (2), and C. R. Bopp were especially helpful.

GENERAL GEOLOGY

Location and Topography

The Healdton oil field is located in the western part of Carter County, Okla., about 20 miles west of Ardmore and 30 miles southeast of Duncan, Okla. (see fig. 2). The major portion of the field lies in T. 4 S., R. 3 W. (Indian meridian), although portions of the field extend into T. 3 S., Rs. 3 and 4 W., and T. 4 S., Rs. 2 and 4 W. The communities of Healdton, Wirt, and Dundee (McMan) are wholely or partly within the field limits.

The land is flat or gently rolling, with elevations ranging from about 885 to 1,070 feet above sea level. The topsoil consists of red and yellow clay and sand. Blackjack oak and low bushes comprise the natural vegetation, and very little of the land in the field is now cultivated. The area is drained by Whiskey and Walnut Creeks, small tributaries flowing southeast to the Red River.

In the immediate area the principal industries are associated with producing, transporting, and refining petroleum; a few cattle are grazed along the edges of the field. A branch of the Gulf, Colorado, & Santa Fe Railroad runs from Ardmore to Ringling, with a spur to Healdton. U. S. Highway 70 from Ardmore to Waurika passes south of the field. State Highway 76 passes through Healdton along the east side of the field.

Regional Geology

Stratigraphy

Figure 2 shows the geography, areal geology, and principal structural features in southern Oklahoma. In Carter County surface formations range in age from Ordovician, which outcrops on the Criner Hills, to Cretaceous beds in the Marietta syncline. Tomlinson (3) gives the following general section for Carter County, Okla.:

Recent	Alluvium and gravel
Cretaceous	Goodland limestone Trinity sand
Permian	Red Beds
Pennsylvanian	Pontotoc series Hoxbar formation Deese formation.(Healdton sands?) Dornich Hills formation (Hewitt sands?) Springer formation

4/ Underlined numbers in parentheses refer to references at end of this report.

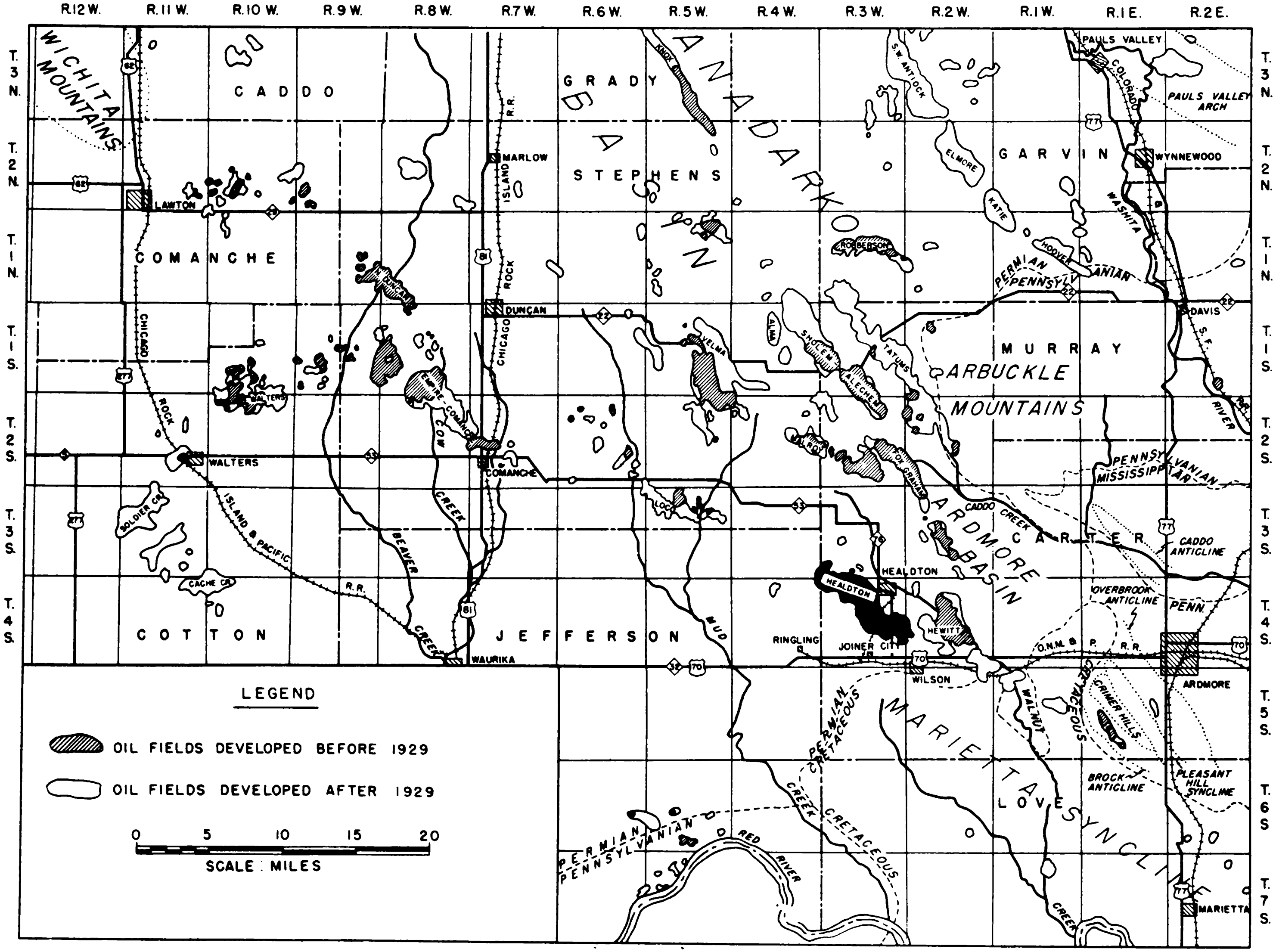


Figure 2. - Location of Healdton oil field in relation to other oil fields and structural features in Southern Oklahoma.

Mississippian	Caney shale Sycamore limestone Woodford chert	
Devonian	Hunton formation	Bois d'Arc limestone Haragan shale
Silurian	Hunton formation	Henryhouse shale Chimney Hill limestone
Ordovician	Sylvan shale Viola limestone Simpson formation Arbuckle limestone	

Many of these formations are exposed in the highly folded area immediately southwest of Ardmore, which includes the Criner Hills and the Overbrook anticline. Permian "Red Beds" cover most of the county west of the Indian meridian, including the area of the Healdton field.

Geological History of Structure

The known structural history of this area begins in late Pennsylvanian time with deposition of the Dornick Hills formation (4). A major diastropic movement, which formed the Wichita, Arbuckle, and Ouachita Mountains, also formed smaller parallel folds running northwest and southeast. Many of these smaller folds influenced oil accumulations in the Healdton, Velma, Loco, Fox-Graham, Sholem-Alechem, and Tatums fields. In the erosion period that followed this diastrophism, the lower Pennsylvanian and older formations were removed from the crest of the Healdton and Criner Hills. Gradual subsidence followed, beginning in the Marietta syncline and Ardmore Basin and progressing northwest. During the early stages of this subsidence and deposition the Healdton and Criner Hills stood out as islands with steep limestone cliffs facing the sea (5). Sand bars and shale beds were deposited, reworked, and redeposited around the base of the Healdton Island. As the land continued to subside, lenticular sand and shale beds were deposited over the top of the Healdton Island. In the Healdton area there is little apparent break between these Healdton sands and the overlying Permian Red Beds, although further to the east a discomformity is apparent (6).

Following Hoxbar deposition the area was again folded and faulted along the former trends and raised above sea level. In early Cretaceous time Gulf seas again invaded the continent, spreading over Oklahoma and Kansas. Probably Cretaceous sediments originally were deposited over the entire area, although a small patch in the Marietta syncline is all that remains in Carter County of the sediments deposited by these seas. After Cretaceous time the area was again uplifted, and the seas receded to form the off-lap deposits of the coastal areas of Texas and Louisiana. During the present emergence, all of the Cretaceous and much of the Permian sediments have been removed from the Healdton Hills by erosion (7) (8).

DEVELOPMENT

Discovery

Early in the 1890's a prospector named Palmer used a springpole rig to drill a well near an oil seep on what was Indian land and is now the Shell Oil Co., Inc., C. L. McClure lease in sec. 5, T. 4 S., R. 3 W. (9). At 425 feet in depth oil "oozed and slopped" over the top of the hole. Palmer capped the well, hoping to obtain the necessary leases before the news spread about the oil strike. However, before the Atoka Agreement in 1897, a Federal treaty with the Chickasaw and Choctaw Indians prohibited development of Indian lands for oil, and Palmer died without profiting from his discovery.

Substantial "oil shows" were found in water wells drilled several years later on the Apple, Franklin, and Smith properties in secs. 5 and 8, T. 4 S., R. 3 W. These indications, together with the fact that oil was still oozing from the capped Palmer well, prompted Roy Johnson, Edward Galt, Wirt Franklin, and Lon Apple to lease 4,000 acres of land in the Healdton area and organize the Plains Development Co. and the Red River Oil Co.

The first commercial oil well in the field was drilled by the Red River Oil Co. and was completed August 4, 1913, on what is now the Shell Oil Co., Inc., Wirt Franklin lease, NE1/4 sec. 8, T. 4 S., R. 3 W. Oil was found at a depth of approximately 900 feet, and the initial production was 80 barrels daily, from a sand about 20 feet thick. The second well, drilled on what is now the Shell Oil Co., Inc., C. L McClure lease northwest of the discovery well, initially produced 300 barrels of oil per day.

Development of other leases followed, and by the end of the year 15 oil wells had been drilled (10). Originally, independent operators held 90 percent of the leases. By November 1, 1913, 14 oil companies were operating in the field. The Sun Oil Co. obtained 1,000 acres from the Crystal Oil Co. (formerly the Plains Development Co.) in October 1913.

Intensive drilling in a southeast extension, including all or parts of secs. 13, 14, 15, 22, 23, 24, and 25, T. 4 S., R. 3 W. and secs. 18 and 19, T. 4 S., R. 2 W., was begun in 1916 and continued through 1917. Table 2 shows a summary of the development history during the first 3 years.

TABLE 2. - Early development history, Healdton oil field, Carter County, Okla.

Year	Completed wells				Oil production, bbl.			Gas production, M c.f.	
					Initial daily		(Yearly)	Initial daily	
	Total	Oil	Gas	Dry	Total	Average	total	Total	Average
1913............	23	15	3	5	844	56	36,250	50,000	17,000
1914............	392	340	9	43	106,171	312	7,784,000	150,000	16,000
1915............	335	290	14	31	86,010	297	6,412,500	191,000	13,600

Figure 3 shows the oil-production history, average price paid for crude oil, and number of producing wells in the Healdton oil field from 1913 through 1950.

Transportation and Oil Sales

During the early development of the field, equipment and supplies were hauled from Ardmore by mule teams over poor, muddy roads. Construction of the Ringling Railroad (now Gulf, Colorado & Santa Fe) was begun in May 1913, and by December of that year the railroad had reached a point 3 miles south of the field. Wilson and Joiner City became transportation headquarters for hauling supplies to the field and oil to the railroad by mule teams. Later, a spur track (Oil Field Railroad) was laid into Healdton, and oil was shipped out in tank cars.

By January 1914 oil production averaged 1,600 barrels daily. In February 1914 Magnolia Pipe Line Co., the principal purchaser of crude oil in the Healdton field, announced an increase in the price for crude oil from $1.00 to $1.03 per barrel. A 55,000-barrel storage tank was completed that month, and shortly thereafter the first oil was run through a newly laid 6-inch line to Addington, Okla., and thence through the main pipeline to the Magnolia Petroleum Co. refinery at Fort Worth, Tex.

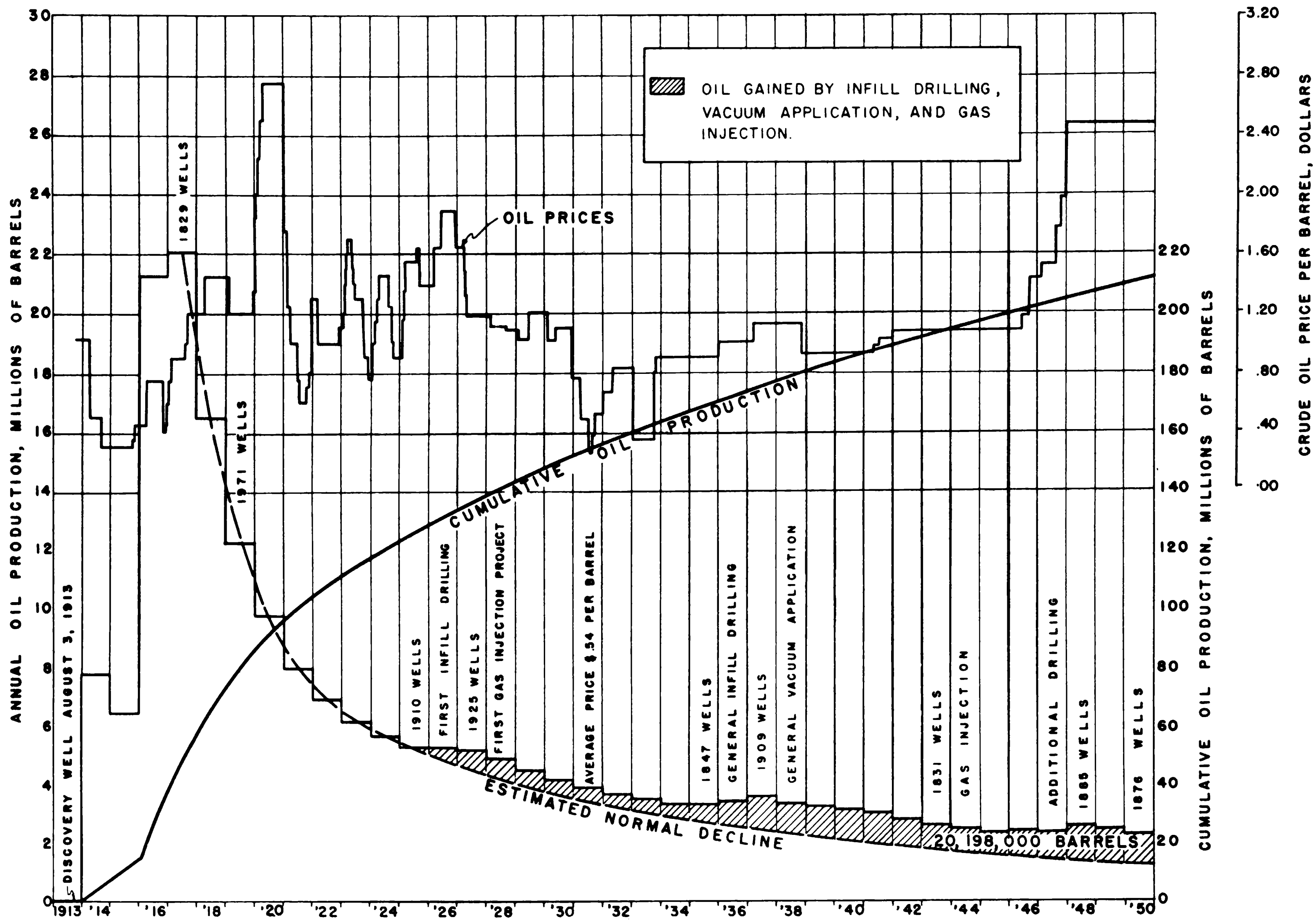


Figure 3. - Oil production history and crude oil prices (Healdton sand zone only), Healdton oil field, Carter County, Okla.

Comparatively low drilling costs and high initial-production rates (100 to 1,000 barrels daily (9)), contributed to rapid development of the field early in 1914. Fear of underground drainage led to competitive production, which soon filled all available storage.

Earthen pits were hastily constructed to store the oil, but heavy rains and fire started by electrical storms caused much loss and damage. McPhail & Corbett constructed a small dam across a creek and skimmed much lost oil off the top of the water. Oil prices dropped to 70 cents.

By August 1914, after 1 year of operation, 208 wells on 74 leases were producing over 50,000 barrels of oil daily. Oklahoma Corporation Commission Order 846 restricted oil production from wells to the amount that could be sold for 65 cents or more per barrel. In October the Magnolia Pipe Line Co. reduced the price to 40 cents per barrel, and the Oklahoma Corporation Commission (Order 847) prohibited production of any oil that could not be sold for 50 cents or more per barrel. Oil stored in earthen pits became unsalable at quoted market prices because of included water and the decrease in gravity, so the Oklahoma Corporation Commission (Order 878, issued November 10, 1914) permitted sale of this oil below the market price, provided that the amount sold was charged against the prorated allowable on the basis of the value received therefor. The Oklahoma Corporation Commission Order 920 (issued June 5, 1915) prohibited storage of oil in earthen pits.

Late in 1914 the Ardmore Refining Co. completed the first 1,000-barrel refining unit at Ardmore, and the Producers Refining Co. began to construct an 8-inch line to Gainesville, Tex.

Because of inadequate markets and low prices for crude, development was virtually at a standstill during late 1914 and early 1915. Oil prices dropped to 30 cents per barrel, and the pipeline companies purchased only currently produced oil and would accept none from storage. Activity increased late in 1915, and in October of that year the Producers Refining Co. 8-inch line to Gainesville, Tex., was completed. The independent operators in the Healdton field contracted to furnish 15,000 barrels of oil daily to the pipeline at 30 cents a barrel. By the end of 1915 750 wells had been drilled, and daily oil production averaged 75,000 barrels.

Oil prices gradually increased from 35 cents per barrel in October 1915 to 75 cents per barrel in December 1916. (See fig. 3.)

By February 1917, six pipelines with a daily handling capacity of 73,000 barrels of oil had been constructed. Since then oil-transportation facilities have been adequate. By December 1917, 1,825 oil wells had been completed, and yearly oil production (as illustrated in figure 3) reached a peak of 22 million barrels in 1917 (11). During 1918 and 1919, 150 wells were drilled, but their comparatively low rates of production could not stay the sharply declining field rate of production. The initial drilling campaign in the Healdton field came to a close in 1919, and since that time there has been little change in the productive limits of the field. In 1919 and 1920, 1,971 oil wells were producing in the field. At no time since have there been as many.

Table 3 lists the 11 pipelines that, in the early 1920's, transported oil from the field to refineries in cities as near as Wilson, Okla., and as far away as Wood River, Ill.

TABLE 3. - Pipeline companies and refineries serving Healdton oil field in the early 1920's, Healdton oil field, Carter County, Okla.

Pipeline company	Size of line	Con-nected leases	Refinery name	Refinery location	Refinery capacity, bbl.
Pure Pipe Line Co.	6-inch	18	Pure Oil Co.	Ardmore, Okla.	7,000
Magnolia Pipe Line Co.	Two 6-inch	34	Magnolia Refining Co.	Fort Worth, Tex.	20,000
Sinclair Pipe Line Co.	8-inch	20	Sinclair Refining Co.	do.	10,000
Chickasaw Pipe Line Co. (Coline Oil Co.)	4-inch	8	Chickasaw Refining Co.	Ardmore, Okla.	5,000
Cameron Pipe Line Co. (Ardmore Refining Co.)	6-inch	5	Cameron Refining Co.	do.	3,500
Empire Pipe Line Co. (Producers Refining Co.)	8-inch	16	Producers Refining Co.	Gainesville, Tex.	6,000
Imperial Refining Co.	4-inch	7	Imperial Refining Co.	Ardmore, Okla.	7,000
Nyanza Refining Co. (J. Howard Pugh)	3-inch	1	Nyanza Refining Co.	Wilson, Okla.	3,000
Yarhola Pipe Line Co.	6-inch	13	Shell Oil Co.	Wood River, Ill.	Unknown
Texas Pipe Line Co. of Okla.	8-inch	10	Unknown	Unknown	Do.
Pierce Pipe Line Co.	do.		Pierce Refining Co.	Fort Worth, Tex.	8,000

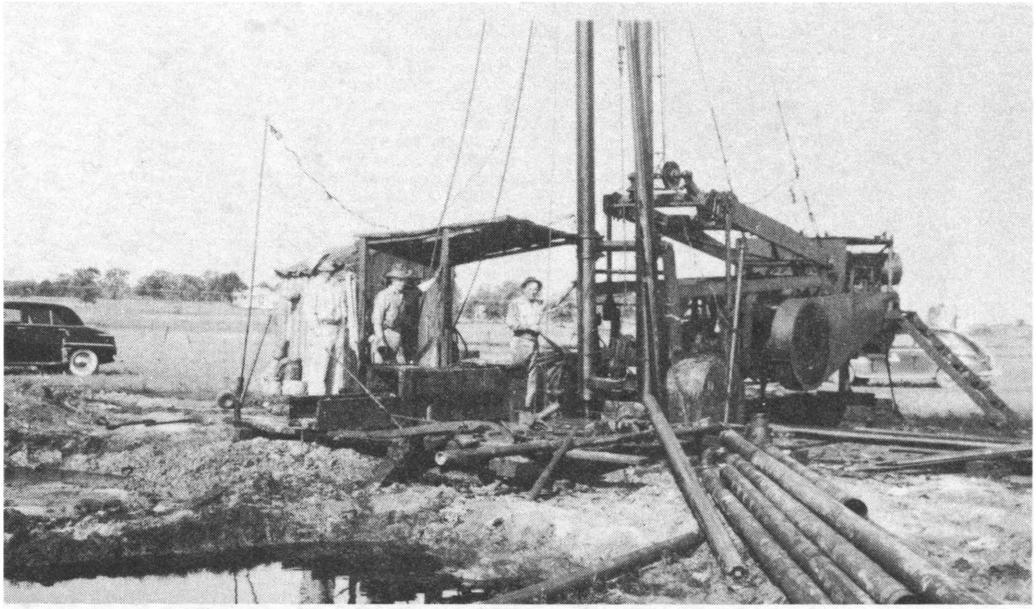
In 1920 the demand for crude oil increased sharply, and the price increased steadily to a peak of $2.75 per barrel in March of that year. Shortly thereafter, imports of foreign crude, chiefly from Mexico, decreased the price to a low of 60 cents per barrel. After 1922 most oil was sold on a gravity basis, but until 1925 the price paid for Healdton crude was 20 cents per barrel less than for other crudes of comparable gravity.

In 1926 the first infill-drilling program began, and during the next few years 38 new wells were drilled. Oil prices for 31° A.P.I. gravity oil declined from a high of $1.89 per barrel in 1926 to a low of 25 cents per barrel in 1931.

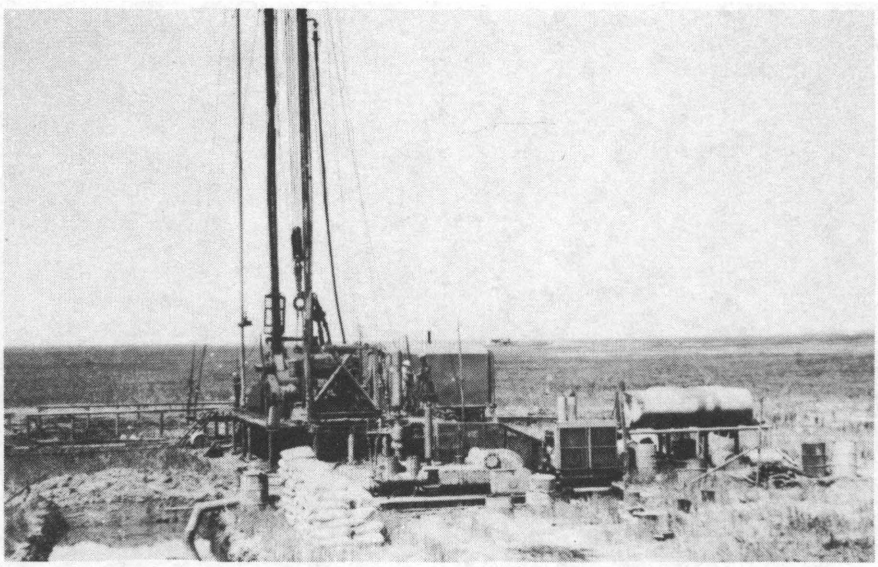
In November 1930 State-wide proration limited oil production to 5 barrels of oil per well per day, plus 50 percent of the difference between this and the potential daily oil production of the well. The proration base was raised to 10 barrels per well per day in January 1931 and to 20 barrels in May 1931.

By 1933 the economic depression forced many small refineries in the Healdton area to discontinue operations, and the plants were shut down or dismantled. However, two refineries still were operating in Ardmore and processing Healdton crude oil, and Shell Pipe Line Co., Magnolia Pipe Line Co., and Pierce Pipe Line Co. were transporting oil to refineries in Wood River, Ill., and Fort Worth, Tex. The average daily oil production from the fields was approximately 9,500 barrels.

The second infill-drilling campaign, beginning in 1935, and general application of vacuum, beginning in 1938, increased and maintained the yearly oil production at 3 to 3 1/2 million barrels per year until 1941.



Cable tool drilling rig



Rotary drilling rig

Figure 4. - Portable cable tool and rotary drilling rigs used in the Healdton oil field, Carter County, Okla. (1951).

Healdton crude-oil prices were stabilized at $1.07 per barrel during World War II (1941-45). After price restrictions were removed, the price for oils of gravities between 31 and 31.9° A.P.I. rose steadily to $2.47 per barrel in 1948.

A third infill-drilling and extension program began in 1946 and continued through 1950, with the drilling of 114 new wells.

In 1950 oil from the Healdton field was purchased at $2.47 per barrel by the Bell Oil & Gas Co. for refining in Ardmore, Okla., and by the Shell Pipe Line Co. and the Magnolia Pipe Line Co. for refining at Wood River, Ill., and Fort Worth, Tex. During this year, 1,876 wells produced 2,260,000 barrels of oil, or about 6,200 barrels daily.

Drilling and Completion Practices

Most of the wells in the Healdton field were drilled with cable tools (see fig. 4), probably because of the lower cost during development. Drilling time for these cable-tool wells was 10 to 20 days, and costs averaged $3,000 to $4,000 per well. During early development, rotary tools were used to drill a few wells to oil-productive formations below the Healdton sands.

The only logs for wells drilled before the late 1930's were those kept by the drillers. During the infill-drilling period beginning in 1935, several electric logs were made, and cores of the formation were cut. More recently, radioactivity logs have been made in several of the old wells, as well as in some recently drilled.

When the field was being developed, the usual practice was to use three strings of casing - 10-inch at about 300 feet, 8-1/4-inch at 400 to 600 feet, and 6-5/8-inch at about 800 feet. In some instances the 10-inch casing was pulled. A 5-3/16-inch slotted liner was set on bottom extending approximately 20 feet up into the 6-5/8-inch casing. This casing program usually was adequate; but, in some instances, more strings of casing were used to exclude upper formation waters.

Many of the earlier wells were shot with 1 quart of nitroglycerin per foot of oil sand. Today the same practice is followed on some new wells, but others are completed without shooting. Indiscriminate shooting sometimes damaged the casing seat for the producing string and permitted an influx of water from the upper water sands. Several instances where this occurred in wells drilled in 1917 in the southeast extension have been recorded by Bureau of Mines engineers, who studied water production in that area of the Healdton field (1).

Because of the caving nature of the Healdton sands, work-over and clean-out jobs were necessary on many early wells to sustain the rate of production. Drillers' logs show that many of the old wells drilled originally to the first Healdton sand were deepened later to produce oil from the lower Healdton sands. When these wells were deepened, it was necessary to pull and reset the liner. Often a new string of casing had to be run inside the original production string, or the production string was pulled and reset at a lower depth. Many wells were plugged back with lead wool, rocks, or limit plugs to exclude bottom water, but some of these plug backs were not successful.

A majority of the recent wells have been drilled with a combination of rotary and cable tools. A portable rotary rig (fig. 4) is used to drill to the top of the oil sand where the production string is set and cemented with about 250 sacks of cement, and then a cable-tool rig is used to drill into the producing sand. If rotary tools were used to complete the wells, the water-base mud might penetrate and seal off the pressure-depleted Healdton oil sands, which would result in poor or non-productive wells. A few recent wells were completed with rotary, using oil-base mud.

Table 4 shows the estimated cost of drilling and completing a well in the Healdton field in 1951, using the combination rotary- and cable-tool methods described above.

TABLE 4. - Estimated cost of completing a well in the Healdton sand, 1951, Healdton oil field, Carter Coutny, Okla.

	Item	Total
Drilling - Depth 1,200 feet		
Cost per foot includes fuel, water, rigging up, pits, etc.		
900 ft. drilled with rotary tools at $2.00 per ft.	$1,800	
300 ft. drilled with cable tools at $3.00 per ft.	900	
Total cost of drilling		$2,700
Casing and tubing		
80 ft. of 10-3/4-in. o.d., 32-3/4 lb. per ft.	208	
900 ft. of 7-in. o.d., 24 lb. per ft.	1,746	
320 ft. of 5-3/16-in. o.d. liner	352	
1,190 ft. of 2-3/8-in. o.d. tubing	488	
Total cost of casing and tubing		2,794
Equipment		
Rods, 1,200 ft.	125	
Pump (includes pumping jack)	300	
Flow line, 500 ft.	350	
Miscellaneous	75	
Total cost of equipment		850
Material		
Cement, 300 sacks	180	
Mud	270	
Total cost of material		450
Completion costs		
Services of cable tool rig for completion (2 days at $175 per day)	350	
Cementing service		
10-3/4-in. casing with 50 sacks and 7-in. casing with 250 sacks	296	
Trucking, labor, miscellaneous	100	
Total cost for completion		846
Total cost for drilling and completing well		$7,640

RESERVOIR CONDITIONS

Structure and Stratigraphy

Most authorities agree that Healdton sands of Pennsylvanian age were unconformably deposited around and over folded and eroded Ordovician hills. Subsurface studies made in preparation for this report support this concept of Healdton-sand deposition on an irregular Ordovician surface. The irregularity of this depositional surface affected the thickness and extent of the Healdton sands.

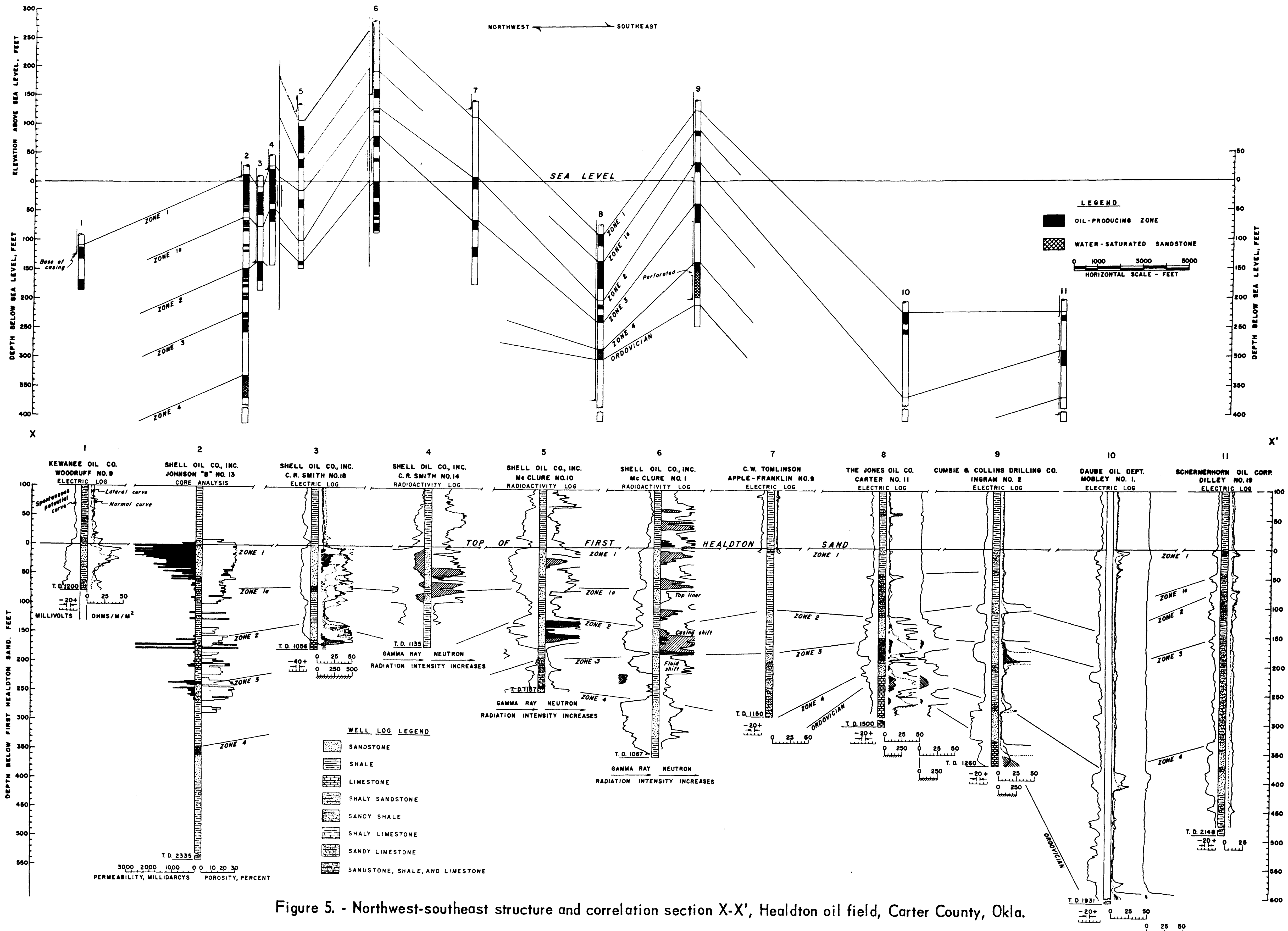


Figure 5. - Northwest-southeast structure and correlation section X-X', Healdton oil field, Carter County, Okla.

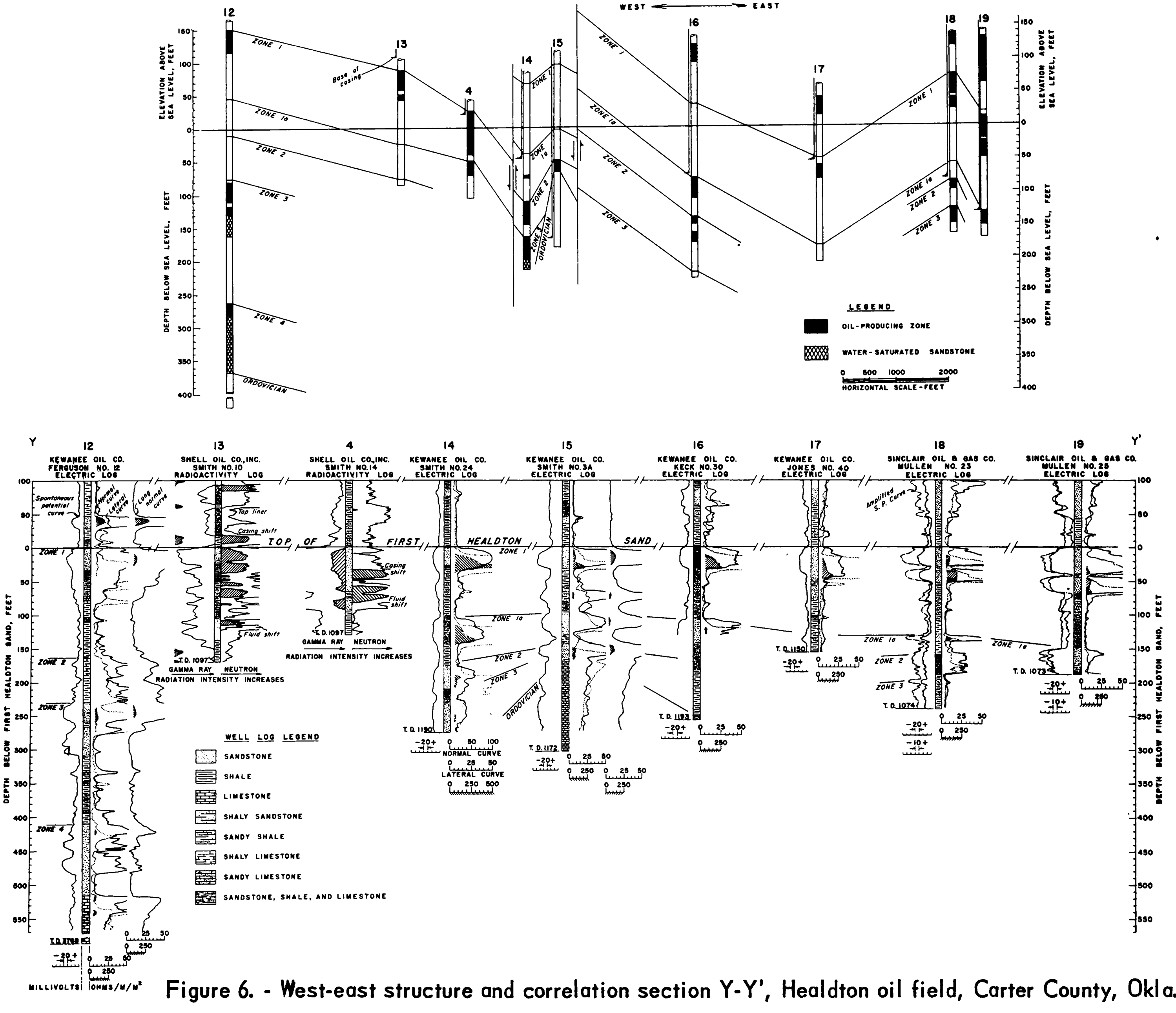


Figure 6. - West-east structure and correlation section Y-Y', Healdton oil field, Carter County, Okla.

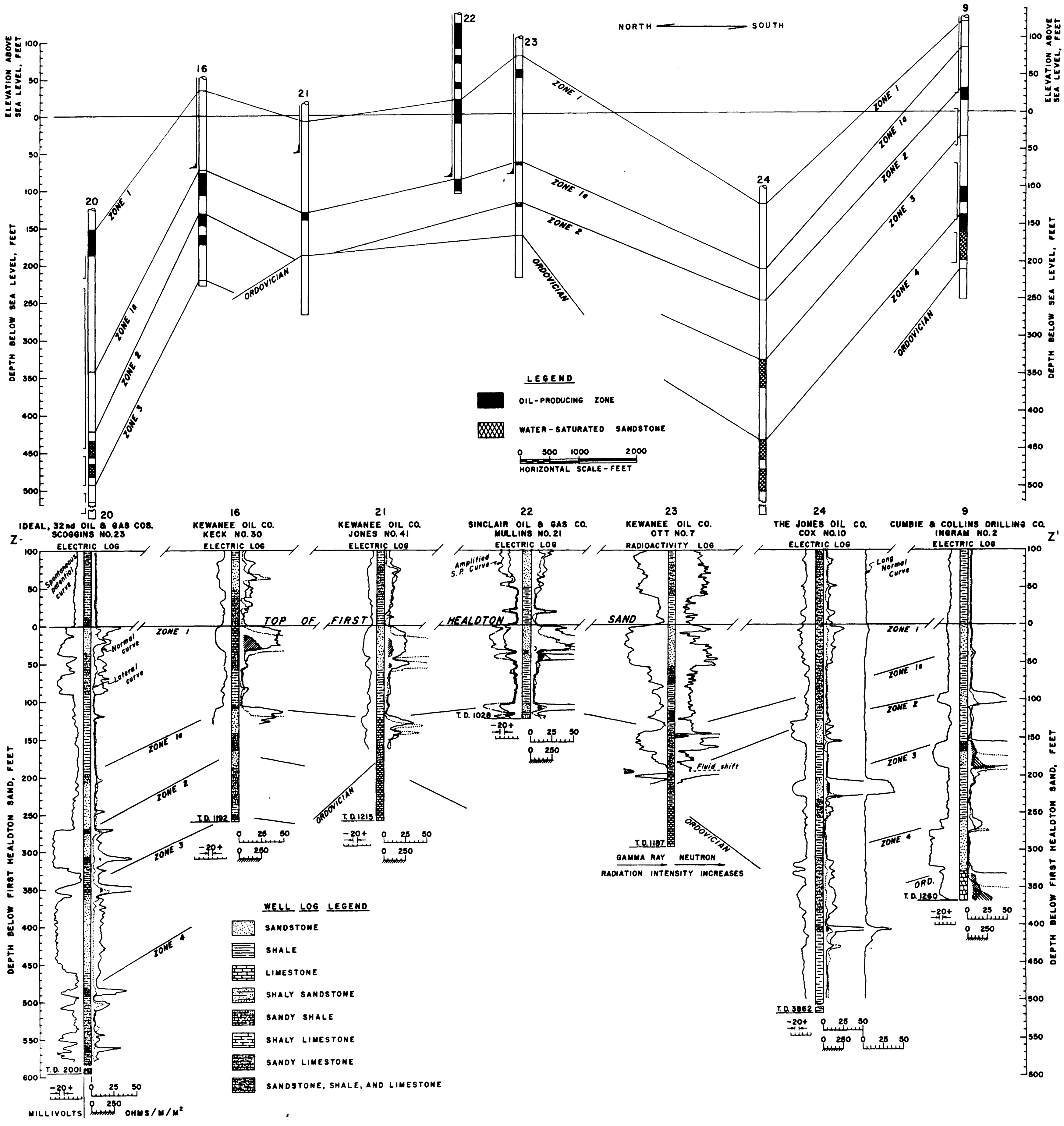


Figure 7. - North-south structure and correlation section Z-Z', Healdton oil field, Carter County, Okla.

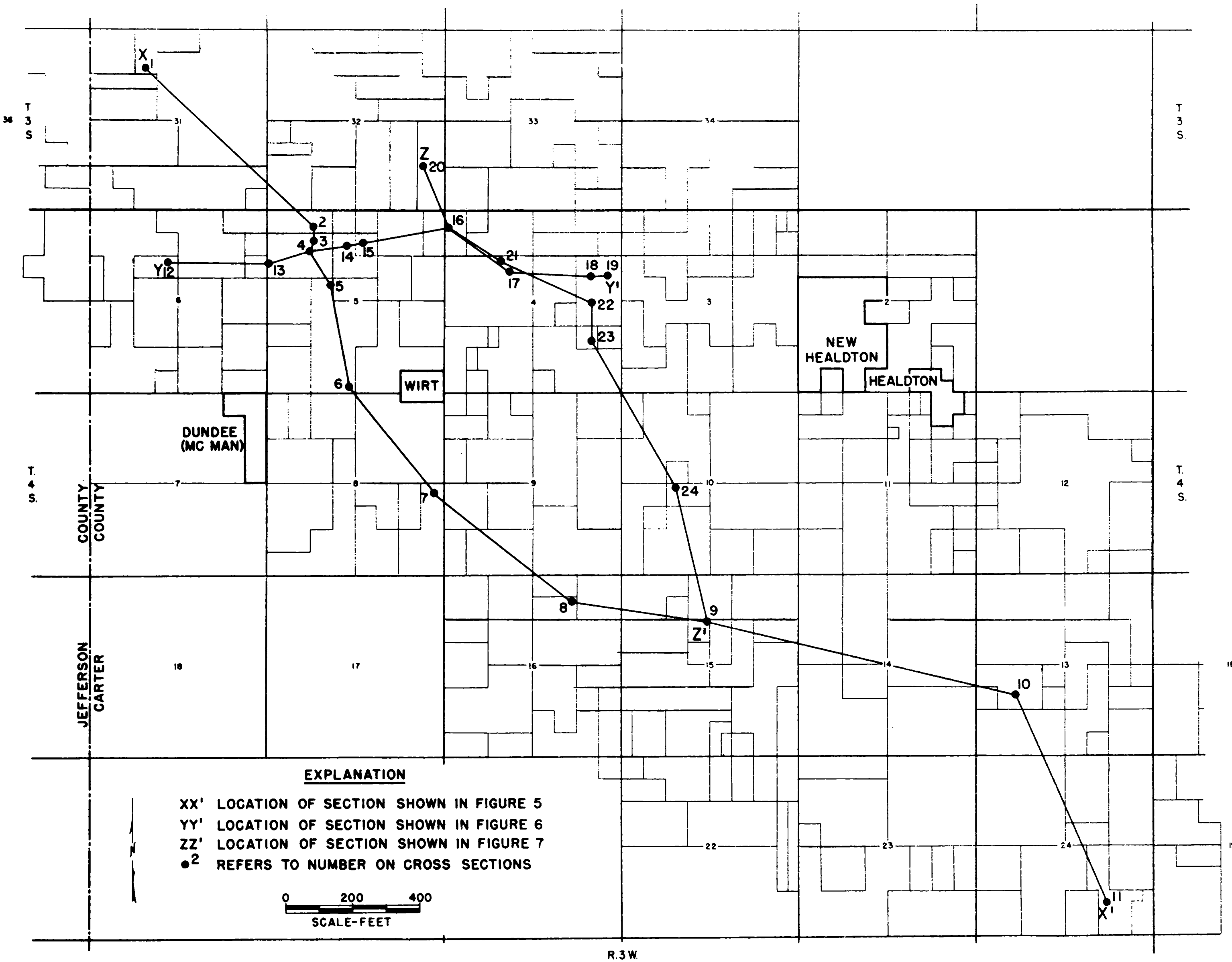


Figure 8. - Location of structure and correlation sections, Healdton oil field, Carter County, Okla.

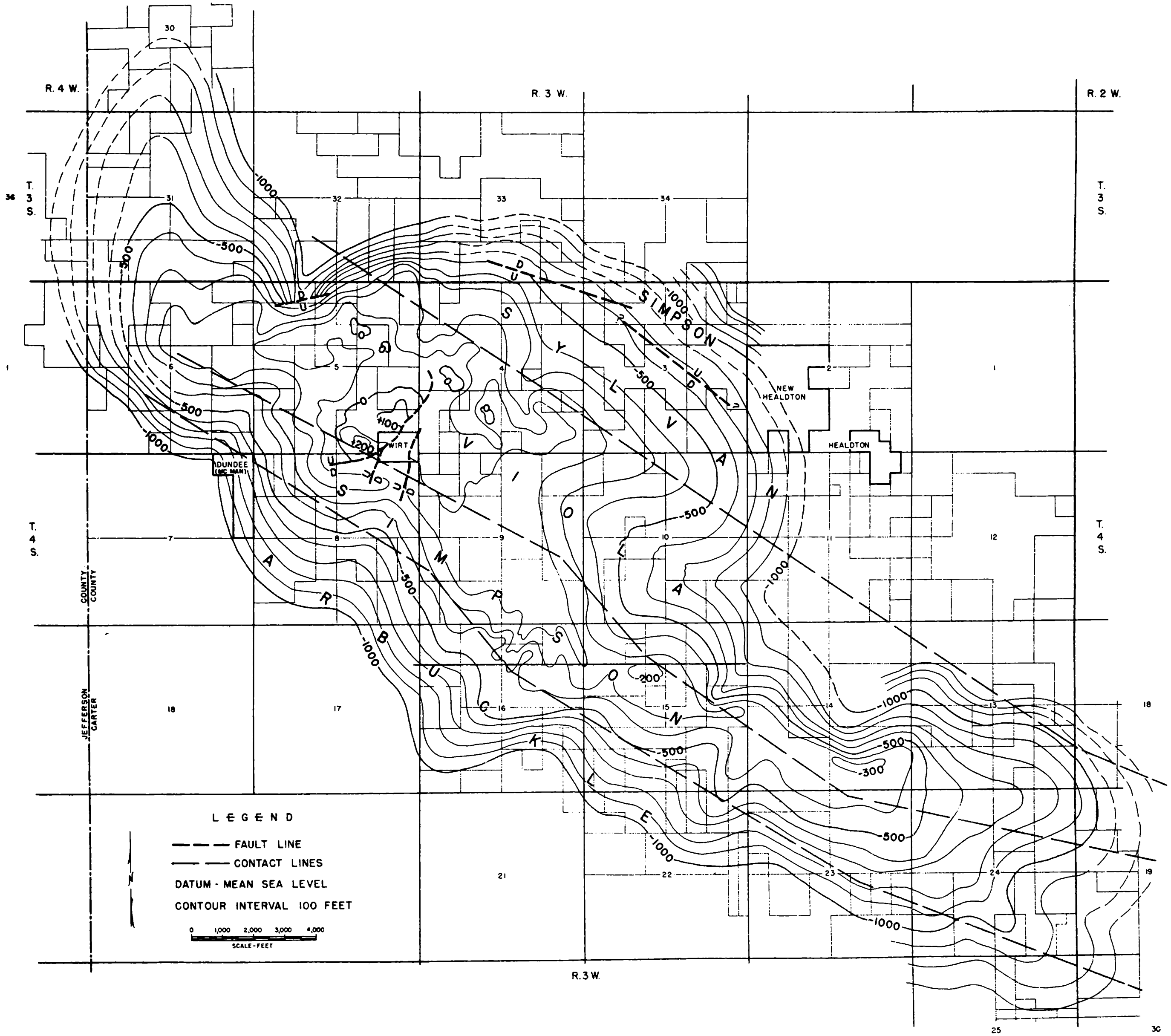


Figure 9. - Structure and geologic map of pre-Pennsylvanian surface, Healdton oil field, Carter County, Okla.

By 1950 about 2,600 wells had been drilled in the Healdton field, and drillers' logs, many of questionable accuracy, of approximately 2,500 of these wells were available for study. Complete or partial electric logs of 132 wells and radioactivity logs of 32 wells were studied. Drill cuttings from 33 wells and analyses of cores from 49 wells were used to interpret reservoir conditions in the Healdton sands. Most of these data were concentrated in the north and central areas of the field, although electric logs and drill cuttings were available for several wells in the eastern and southeastern areas. More data were available for the first than for lower sands, although several wells were electrically logged and cored through all Healdton sands.

The structure and extent of the fourth and other Healdton sands has been studied in 57 cross sections. Figures 5, 6, and 7 are structure and correlation sections across the field northwest to southeast, west to east, and north to south, based upon electric and radioactivity log studies. The locations of cross sections (figs. 5, 6, and 7) are shown on figure 8. Zones 1, 1-A, 2, 3, and 4 have been identified and correlated as separate members, but these correlations picture a simplicity that actually does not exist in the reservoir. Individual sands are lenticular and grade laterally and vertically into shale. In the north-central and northwestern part of the field, several oil-productive stray sands lie stratigraphically above the first Healdton sand.

A core-analysis profile of a well in sec. 5, T. 4 S., R. 3 W., is shown as well 2 in figure 5. The porosities of the sands range between 10 and 33 percent, and the permeabilities between 0 and 3,800 millidarcys.

Figure 9, a structure map with contours drawn on top of the Ordovician, shows the present attitude of the pre-Pennsylvanian surface. Many irregularities shown were present at the time of the Healdton-sand deposition, but others result from post-Hoxbar folding and faulting. This figure also shows, in a general way, the areal geology of the pre-Pennsylvanian surface. Cuttings from deep wells in this area show that the Arbuckle limestone immediately underlies the Pennsylvanian sands in a belt parallel to and southwest of the field. Progressing northeast across the structure, successively younger Ordovician sediments (Simpson, Viola, and Sylvan) are directly overlain by the Pennsylvanian formations. Subsurface investigation in the Healdton area did not include a study of the structure of the Ordovician sediments, except that truncated sections of successively older beds to the southwest indicate that the axis of any such structure would lie considerably southwest of the anticline, as indicated in figure 9. Presumably, the Viola limestone was the resistand member that capped the Healdton hills during the late Pennsylvanian time.

Deep wells on C. W. Tomlinson's Bell and Schermerhorn leases in sec. 3, T. 4 S., R. 3 W., penetrated Simpson formations and not Sylvan shale immediately under the Healdton sands. Apparently a pre-Pennsylvanian fault in this area lifted the older sediments and permitted erosion of the Sylvan and Viola formations before Healdton-sand deposition.

A series of oil-bearing sands overlies the Ordovician beds at the southeast end of the field at depths between 1,200 and 2,000 feet but is not present over the main part of the field. These sands include the "Jackson" sand in sec. 15, T. 4 S., R. 3 W., the "Pugh" sand in sec. 18, T. 4 S., R. 2 W., and the "Westheimer" sands in secs. 24 and 25, T. 4 S., R. 3 W. These sands, which represent a separate oil reservoir, are not included in this study of the Healdton sands.

Fourth Sand

Above the Pugh and Westheimer sands in the southeast extension, and immediately overlying the Ordovician throughout the central part of the field, is a Healdton sand and sandy lime zone, usually separated from the Healdton sands above by 10 to 30 feet of waxy shale. This zone, which is included with the "Simpson" Sand in some localities, can be identified and traced throughout much of the field. In this report it is considered to be the fourth Healdton-sand zone. Usually the top of the zone is marked by thin sandy limestone beds, often glauconitic with small calcareous oolites 0.3 to 5 mm. in diameter, which were formed around subangular quartz grains. A representative section of this fourth sand, penetrated in the Shell Oil Co., Inc., C. L. McClure well 38, sec. 5, T. 4 S., R. 3 W., is described as follows:

	Thickness, feet	Top depth, feet
Limestone, light-gray, sandy, and oolitic..................	4	1,010
Sand, gray grains 0.2 to 0.4 mm. in diameter, rounded and subangular..	14	1,014
Sand, as above, with thin streaks of dark-gray shale........	34	1,028
Sand, gray, as above with little white chert................	4	1,062
Shale, gray sandy, with many crinoid stem fragments and pelecypod shells..	11	1,066
Limestone, gray and light-buff, sandy.......................	18	1,077
Sand, very fine, light-buff.................................	11	1,095
Limestone, gray, sandy......................................	5	1,106
Sandstone, fine-grained, calcareous.........................	6	1,111
Sand, gray, calcareous and fossiliferous....................	27	1,117
Sand, very fine...	7	1,144
Limestone, light-gray with some gray shale..................	15	1,151
Shale, light-gray, calcareous...............................	17	1,166
Limestone, light-gray, sandy and shaly......................	2	1,183
--------------------(Unconformity)--------------------		
Limestone, white, dense (Ordovician)........................	-	1,185

For the purposes of this report, the fourth Healdton zone is considered as a separate reservoir, differing from the upper Healdton sands above in that it is under the influence of a rather definite water drive. The extent and effect of this water drive on oil production is discussed under Production.

The top of the fourth Healdton sand ranges from 150 feet above sea level in the northwestern part of the field to 600 feet below sea level at the southeastern edge.

Logs of early wells record water in the fourth sand at depths ranging from 470 feet below sea level in the southeast extension to 180 feet below sea level along the northeast and southwest edges in the main part of the field. Only those wells drilled before 1920 were used to establish the original oil-water contact in the different areas of the field.

Figure 10, an isopachous map of the effective oil-productive thickness of the fourth Healdton sand above the water level, was constructed using the oil-water contact levels in various parts of the field and a structure map of the top of the fourth sand. In general, the thickness of oil-productive beds in the fourth sand zone, as recorded in drillers' logs, compared closely with those shown by electric logs through the section. The fourth sand is absent in large areas (including 750 acres) of secs. 4, 5, 6, and 9, T. 4 S., R. 3 W., where the top of the Ordovician surface is structurally high.

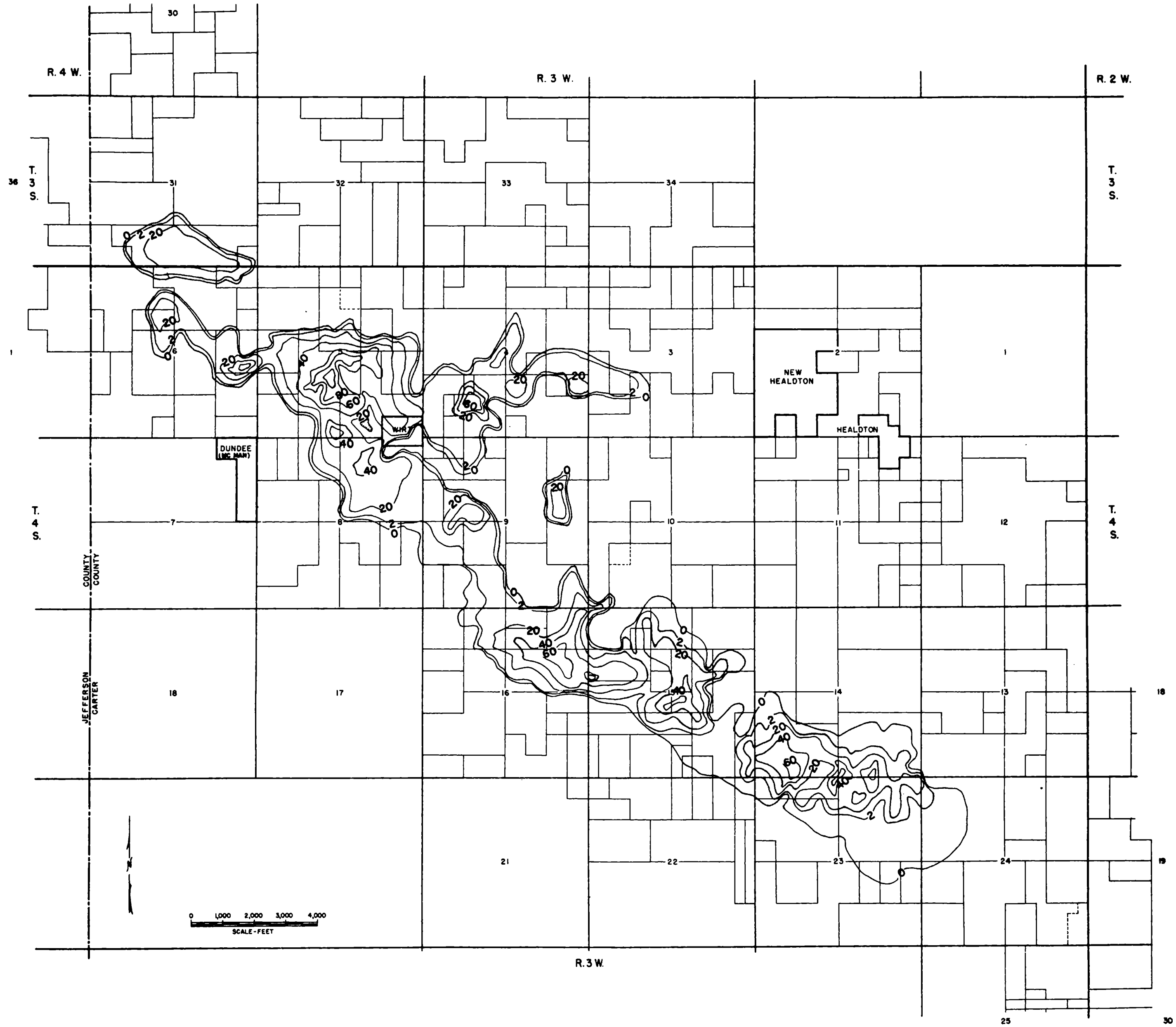


Figure 10. - Effective thickness of fourth Healdton sand, Healdton oil field, Carter County, Okla., 1951.

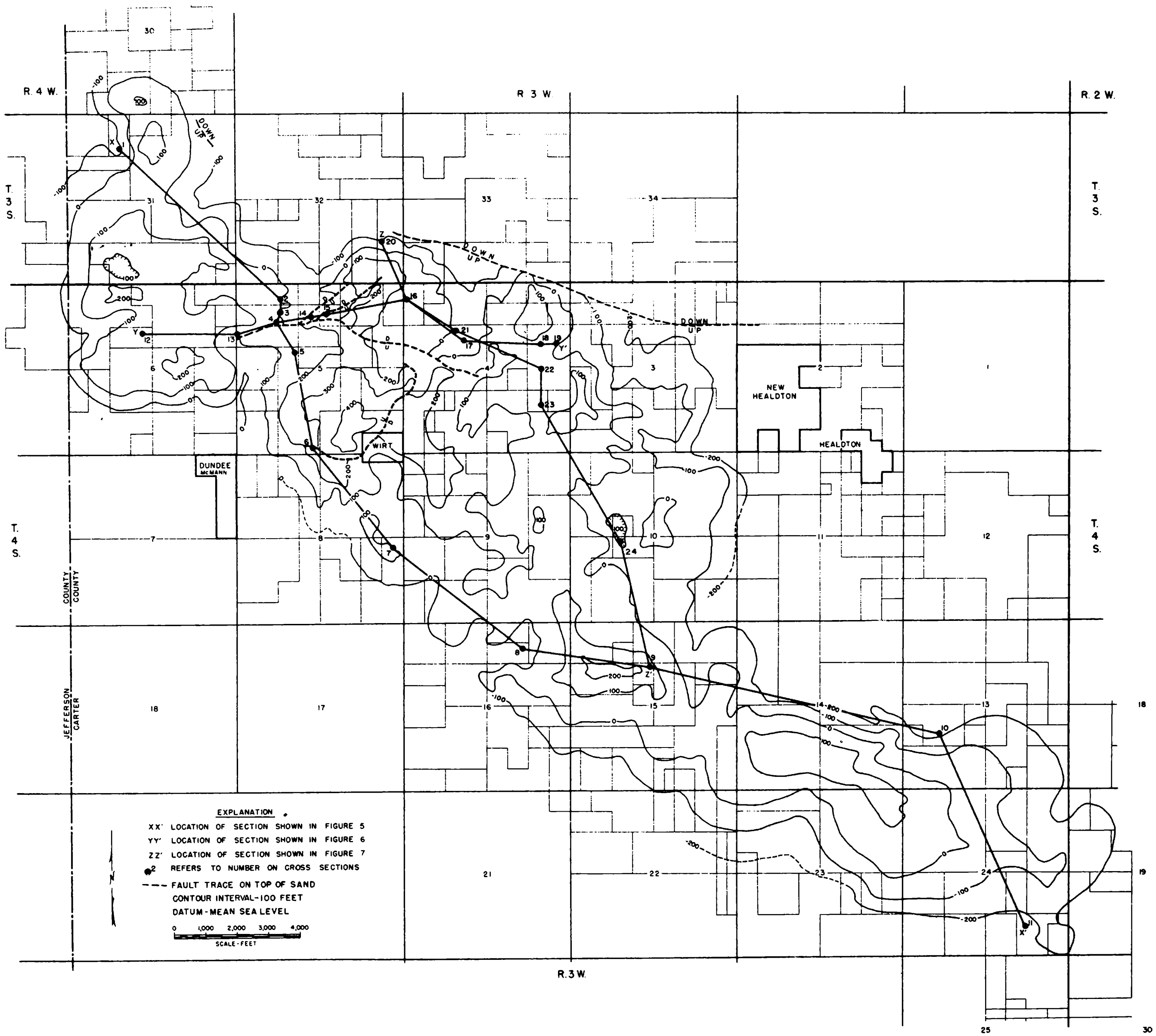


Figure 11. - Structure of the top of first Healdton sand, Healdton oil field, Carter County, Okla., 1951.

The study of well logs and oil-production history of the fourth sand indicates that the actual economically oil-productive area of the fourth sand is substantially less, particularly at the southeast end of the field, than that within the designated oil-water contact line. Actually the oil-water contact is not horizontal but, to a large extent, follows the structure, so that, in an area along the edge of the structure, the water level is close to, although not at the top of, the sand zone. Wells drilled in these areas recorded a thin oil sand, not economically productive, above bottom-hole water. In figure 10 a 2-foot contour line has been drawn inside the oil-water contact line to illustrate the large area where the oil-water contact is near the top of the sand. For practical purposes, only those areas within this 2-foot contour line have been considered as economically oil-productive in estimating reserves in the fourth sand.

The original oil-productive area of the fourth sand covered 1,960 acres. Total thickness ranged from 50 to 75 feet, and the total volume of oil-productive sand was 45,080 acre-feet.

Upper Sands

A contour map (fig. 11) was prepared, with the aid of cross sections, to show the structural attitude of the top of the first Healdton-sand zone. The structure is an anticline 8 miles long and 1 to 3 miles wide, with several local high areas throughout the field and with steep dips on the northwest flank. The total closure is about 500 feet. A study of records of wells in sec. 33, T. 3 S., R. 3 W., and sec. 3, T. 4 S., R. 3 W., indicates a major normal fault along the northeast edge of the field, with a displacement on the north side of approximately 300 feet. In sec. 5, T. 4 S., R. 3 W., a series of faults surround a central upthrown block. Some of these faults may have been caused by differential settling owing to compaction of sediments around topographic highs of the Ordovician surface, but others are the results of deep-seated faulting, which cut the Ordovician limestone. (See figs. 9 and 11.)

Because identification and correlation of individual sand members in wells have been very difficult, all beds above the fourth sand, except for some stray sands in the northwestern part of the field, have been treated as belonging to a common reservoir. Results of infill drilling and gas injection have proved that often shaly zones with little horizontal or vertical permeability separate the productive beds, so that this treatment as a common reservoir, although practical, does not represent all the actual conditions.

The total oil-productive area of the upper sands, as determined from a study of well logs and production records, includes 7,016 of the 7,142 productive acres in the Healdton field. In several structurally high areas of the field upper sands are barren, and oil production was obtained from the fourth sand only.

Throughout most of the field, the top of the fourth sand was taken as the base of the upper sand section, but where the fourth sand was absent the top of the Ordovician limestone was used as the lower limit. A few structurally low wells penetrated bottom water at depths ranging from 142 to 440 feet below sea level and in these areas the water-saturated sand was used as the base of the productive upper sand section.

The upper oil-productive sands were studied in a series of 50-foot zones, beginning at the top of the sand, as indicated in figure 11. All wells penetrated the first 50-foot zone, fewer wells the second, and progressively fewer each succeeding zone. It is assumed that sands not penetrated in one well yielded gas and some oil to adjacent wells in the immediate vicinity, and, as such, the sand should be considered as a part of the entire reservoir. Many of the wells, particularly the early wells, did not penetrate the complete section. The relatively lower initial production rates of most of the later wells, which penetrated the full section, leads to the general conclusion that most of these unpenetrated sands were depleted of pressure and some oil by the earlier wells. Notable exceptions are those later wells with initial-production rates higher than those of the original wells on the lease.

Six deep wells in the northwestern part of the field penetrated seven 50-foot zones, whereas, in the southeastern part of the field, there were oil-productive sands in only two or three such zones.

Several wells were cored and electrically logged through the upper sands, and comparisons between core analyses and electric logs showed that indentations in the SP and normal resistivity curves represented thin shale beds in the sand section, which should be eliminated from the net oil-productive thickness. Comparison between drillers' logs and electric logs on the same wells showed that beds reported by the drillers as oil sands often contained such shale partings and nonproductive tight streaks. By comparing the electric and drillers' logs, a correction factor of 0.841 was developed, which was applied to the thickness of oil sands recorded in the drillers' logs to estimate the net effective thickness of oil-producing sands in the main part of the field. In the southeastern part of the field, fewer electric logs of wells were available, but drill cuttings were examined microscopically, and the results were used with these electric logs to develop a correction factor of 0.816, which was applied to the thickness of the oil sand in the drillers' logs to estimate the net productive thickness.

Using the net effective thickness of oil sands in those wells that were drilled through each 50-foot zone, net isopachous maps were prepared for each of seven 50-foot zones. From these maps the probable net thickness of unpenetrated sand at each well was read and tabulated. The total net oil-productive thickness at each well was then plotted on a map and contoured.

The total thickness of the upper Healdton beds, which included the oil-productive sands above the fourth sand, ranges from 120 feet on top of the structure to over 500 feet along the flanks of the north end of the field. The total volume of oil-productive upper sands in the entire field is approximately 454,000 acre-feet.

Stray Sands

In certain areas of the Healdton field, oil sands were penetrated at depths above those that generally have been designated as the first Healdton sand. In the northwestern part of the field, it appears from correlation studies that these oil-productive sands are continuous, but in other areas they are discontinuous or absent entirely. During the early development many of these stray sands were cased off by a producing string run to the more productive Healdton sands at greater depths. When a stray sand did appear to be commercially oil-productive, it was left open to production. Studies show that the productive area of the stray sands included approximately 1,420 acres.

The original reserves in two of these productive sands were calculated. Electric and radioactivity logs of the sands showed that what the drillers described as a solid section of productive oil sand, actually contained a large number of shale and limestone partings. From these comparisons the correction factor of 0.841, as described

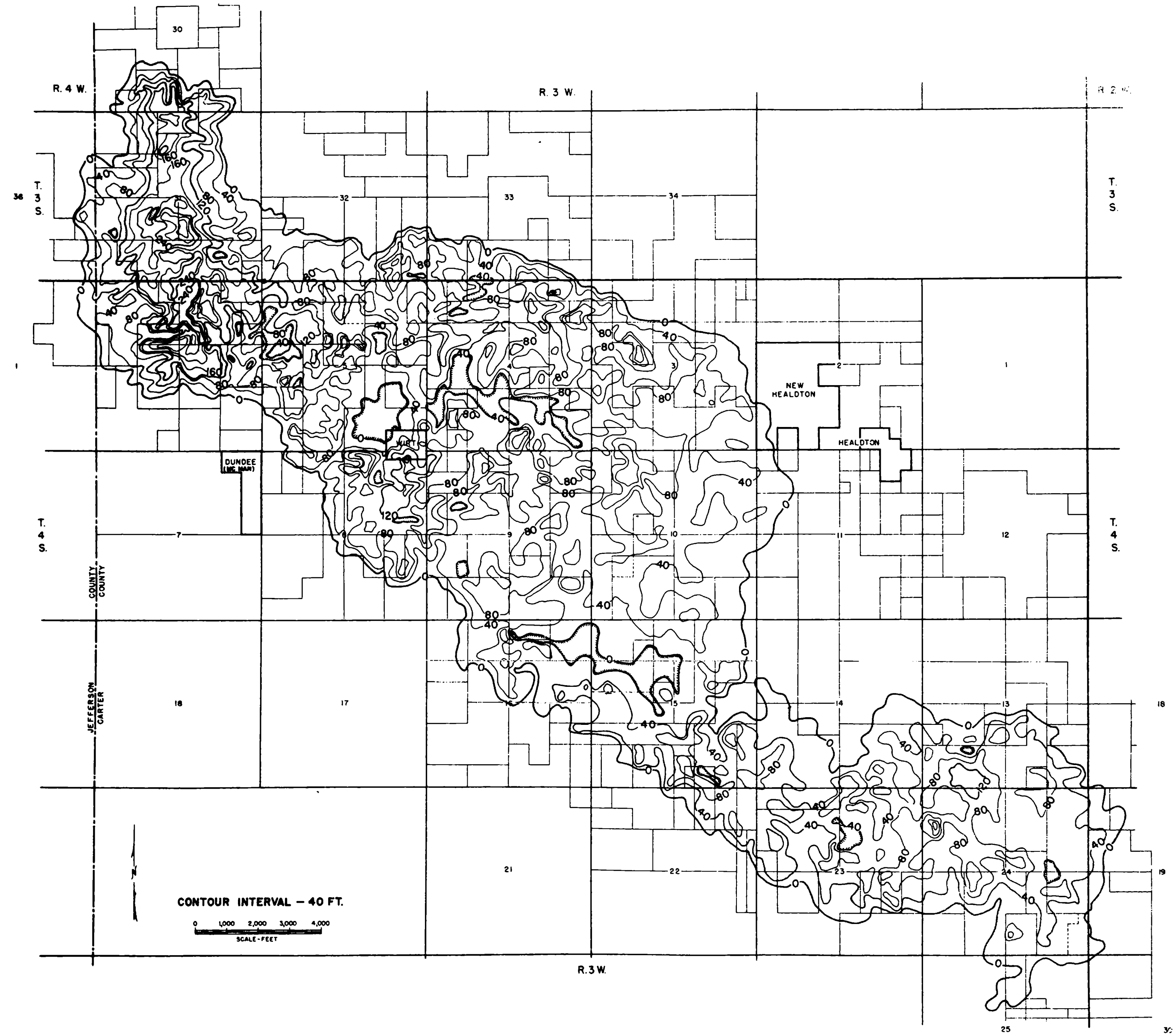
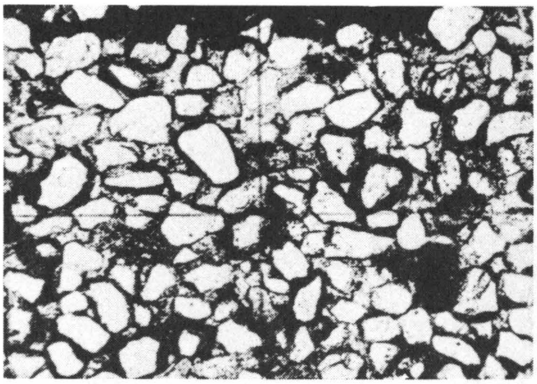
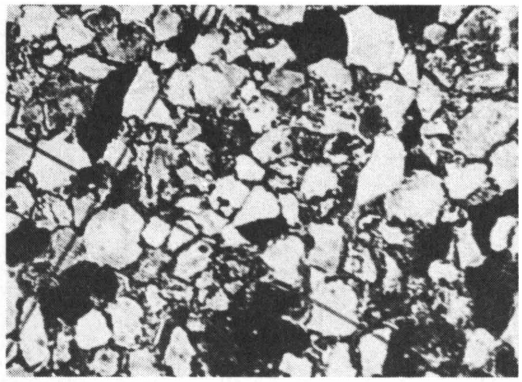


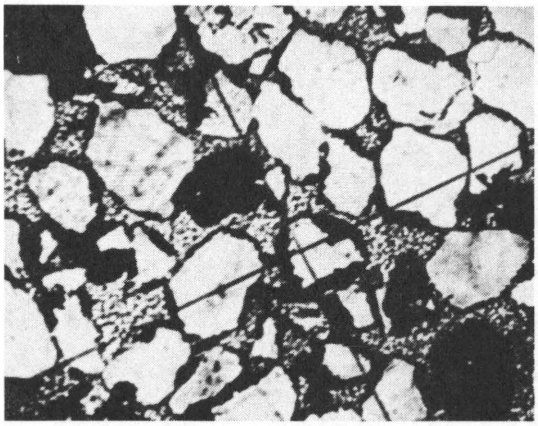
Figure 12. - Effective thickness of oil-productive sands above the fourth Healdton sand, Healdton oil field, Carter County, Okla., 1951.



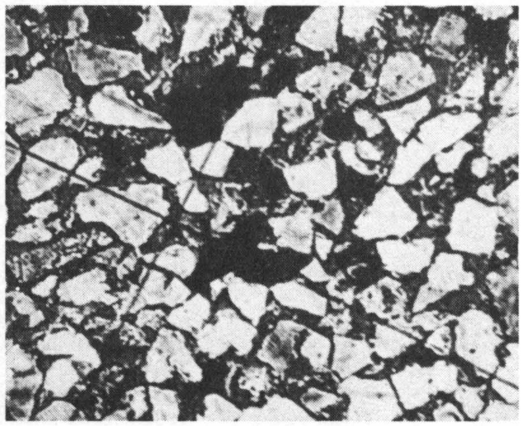
No. 12. Porosity 6.9 pct., Perm. 110 Md. Limestone 34.2 pct., Clay 5.5 pct. Average grain size .241 mm.



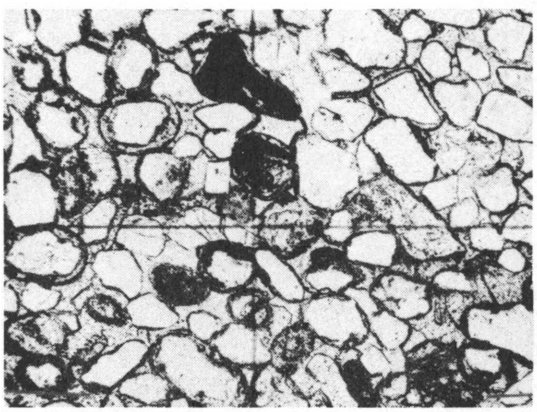
No. 7. Porosity 27.0 pct., Perm. 530 Md. Limestone 3.6 pct., Clay 13.4 pct. Average grain size .151 mm.



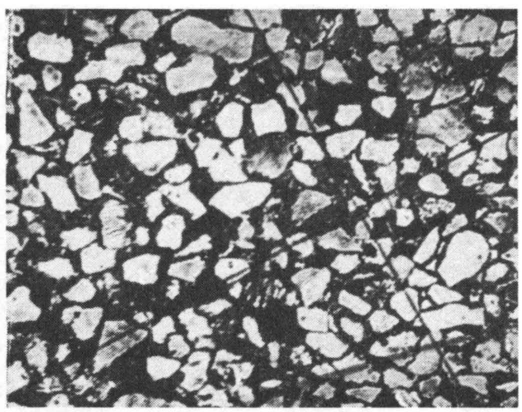
No. 41. Porosity 10.5 pct., Perm. 14 Md. Limestone 33.2 pct., Clay 4.5 pct.



No. 40. Porosity 30.1 pct., Perm. 2900 Md. Limestone Trace, Clay 16.5 pct. Average grain size .255 mm.



No. 34. Porosity 8.7 pct., Perm. 7.1 Md. Limestone 37.1 pct., Clay 4.1 pct. Average grain size .181 mm.



No. 31. Porosity 29.1 pct., Perm. 740 Md. Limestone 7.6 pct., Clay 2.2 pct. Average grain size .166 mm.

Figure 13. - Plastic-impregnated core samples of Healdton sands.

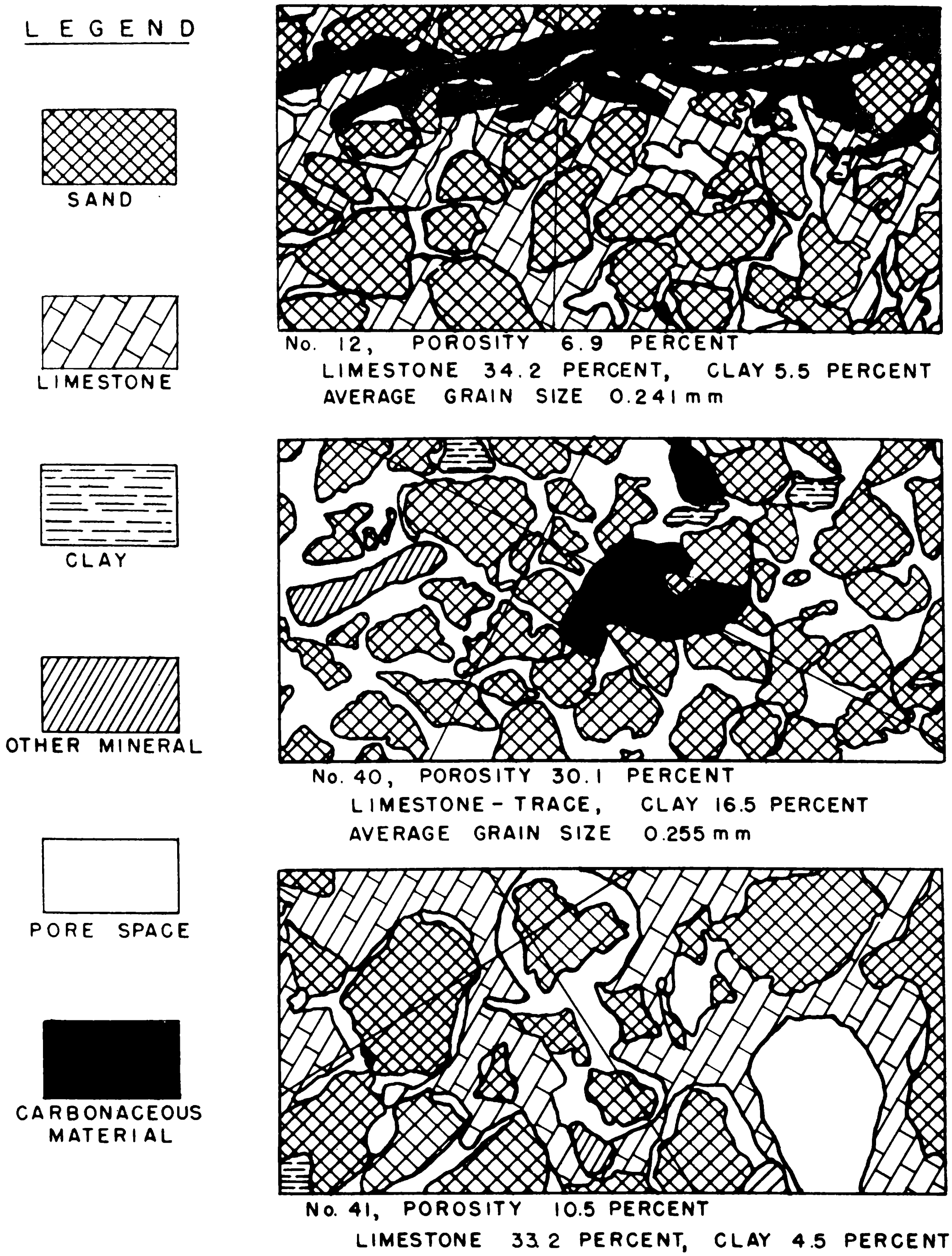


Figure 13A. - Arrangement of mineral grains and pore spaces in Healdton oil sands, Carter County, Okla.

earlier, was applied to recorded thicknesses in the drillers' logs. Total thickness of stray sands ranged up to 70 feet. Calculations indicate that the total oil-productive portion of the stray sands is about 18,900 acre-feet.

Figure 12 is an isopachous map, which shows the total net effective thickness of all oil-productive sands above the fourth sand, including upper sands and stray sands, which range in thickness up to 320 feet. The thicker sands occur throughout the north-central part of the field, and the thinner sands lie along the edges and in the southeast extension. For individual leases, the net average effective thickness of all oil-productive sands above the fourth sand ranged from 4 to 177 feet.

Lithology

In general, the first sand zone includes fine-grained, loosely cemented sand and shaly sand, whereas the lower sand zones contain more limestone. Several core samples from these sands were analyzed in the Bureau of Mines laboratories, and the results of measurements on these cores are summarized in table 5. Clean cores were saturated under vacuum with formation brine, but in most instances the cores could not be saturated to 100 percent of the pore volume as determined by gas expansion. The fraction of the total pore volume thus saturated with brine ranged from 0.57 to 1.0 and appears in column 4 of the table. The resistivity of the brine-saturated core to the flow of an electrical current of approximately 30 milliamperes was determined, and the ratio between this resistivity and that of the brine alone at the same temperature (about 78° F.) is shown in column 5 as Formation factor. The saturating brine was displaced (restored-state method) from the cores with nitrogen at pressures up to 50 p.s.i., and the water remaining in the core is assumed to be representative of the connate water.5/ The percentage of the pore volume, ranging from 4.3 to 71.7, that remained filled with this connate water is shown in column 6. The clay and limestone content of the core samples, as shown in columns 7 and 8, was determined by sodium peroxide and acid separation; and the average size of the remaining sand grains, as shown in column 9, was determined by sieve analysis and microscopic measurements. A litho-logic description of the core is shown in column 10.

In addition to the routine laboratory measurements on consolidated core samples, the sedimentation method was used to determine the porosities of unconsolidated, or loosely consolidated sands, which make up a large percent of the Healdton sands. In this method, described by Rockwood (12), clay and limestone are removed from the sample, and the clean sand is sedimented in water. Corrections of the observed porosity are then made, depending on the percentage of clay and limestone. The "sedimented porosity" of five samples ranged between 26 and 30 percent and is related to grain-size distribution and clay and limestone content.

Fifteen core samples were impregnatad with plastic by a method outlined by Lockwood (13), and thin sections were prepared for microscopic study. Photomicrographs of six of these plastic-impregnated core samples are shown in figure 13. Figure 13a is a drawing of three enlarged photomicrographs, cores 12, 40, and 41, showing the composition and the relation of pore spaces to sand grains and cementing material.

5/ As used in this report the term "connate water" is defined as minimum water saturation; that quantity of water coexisting with oil in a water-wet reservoir rock at initiation of exploitation and maintained by capillary forces that equal or exceed displacing gravitational forces.

TABLE 5.--Laboratory measurements on Healdton sand core samples, Healdton field, Carter County, Okla.

Core No.	Porosity, percent	Permeability, millidarcys	Maximum brine saturation,[1] fraction of pore space	Formation factor[2]	Connate water, percent of pore space[3]	Clay, volume percent	Limestone, volume percent	Average grain size, mm.	Core description
1	2	3	4	5	6	7	8	9	10
						First sand			
1	27.6	260	0.88	8.93	27.8	14.3	5.0	-	Fine, hd. sd. - sh. stk. - mod. to well-cem.
2	20.1	210	.74	11.07	36.7	13.3	6.9	-	Very shy. sd. - mod. to well-cem.
3	17.1	73	.78	14.55	38.4	14.8	11.8	-	-
4	18.5	-	-	15.16	-	-	-	-	-
5	29.0	4,200	.76	6.24	11.3	8.4	3.2	0.326	Fine sd. - loosely cem.
6	27.6	-	.92	5.77	24.7	-	-	.176	Do.
7	27.0	530	.77	8.53	15.4	13.4	3.6	.151	Fine sd. - mod. to well cem.
8	21.6	-	.80	6.37	28.1	24.8	6.6	.159	Fine sd. - sh. stk., - fri., loosely cem.
9	27.8	1,300	.67	11.44	16.8	9.9	4.3	.184	Fine sd. - sh. stk., mod. cem.
10	20.8	-	.78	9.45	43.6	29.8	6.5	-	Laminated sh. and sd.
11	19.1	21	.00	13.10	18.6	20.1	4.2	.134	Shy. sd. - mod. cem.
12	6.9	110	.94	45.41	34.3	5.5	34.2	.241	Hd. sd. - (limestone?) very dense.
13	2.3	.1	.81	192.25	71.7	3.2	42.9	-	Hd. limestone.
14	30.5	-	.89	6.24	10.2	5.0	1.8	-	Sd. - loosely cem.
15	27.2	770	.81	9.47	14.2	10.5	10.7	-	Fine sd. - mod. cem.
16	29.5	-	.88	6.54	11.9	8.3	5.8	-	Fine sd. - little sh. stk. - very loosely cem.
17	30.3	-	.91	9.56	10.4	6.5	2.9	-	Fine sd. - loosely cem.
18	30.1	3,500	.87	6.28	12.9	7.1	3.2	-	Fine sd. - very fri. - loosely cem.
19	30.6	1,100	.91	6.64	11.3	5.7	3.7	-	Fine sd. - few sh. inclusions - loosely cem.
20	28.3	3,200	.96	6.53	10.9	5.3	3.5	-	Fine sd. - thin sh. stks. - loosely cem.
21	29.9	-	.88	5.47	11.7	6.0	3.7	-	Fine sd. - very fri., - very loosely cem.
22	29.8	1,700	.91	6.52	11.9	7.4	3.7	-	Fine sd. - fri., - loosely cem.
23	29.2	-	.83	8.72	11.7	8.7	5.4	-	Fine sd. - very loosely cem.
24	25.7	-	.90	7.28	9.7	7.1	4.3	-	Fine sd. - loosely cem.
25	28.4	1,900	.93	4.98	11.3	7.6	4.7	-	Fine sd. - very loosely cem.
26	25.3	600	.76	8.10	13.6	9.8	10.0	-	Sdy. sh. - stk. of sd. in sh. - loosely cem.
27	13.2	18	.95	34.94	5.7	-	-	-	Fine to med. sd. - mod. to well-cem.
28	28.3	1,600	.93	7.77	11.5	-	-	-	-
						Second sand			
29	24.9	760	1.00	7.71	15.2	4.2	7.6	-	Hd., fine sd. - mod. to well-cem.
30	28.6	270	.73	12.50	14.4	11.3	2.4	-	Fine sd. - well-cem.
31	29.1	740	.72	11.52	7.1	2.2	7.6	0.166	Fine sd. - mod. to well-cem.
32	11.9	3.7	.95	34.83	23.8	3.5	31.2	-	Sd., - dense , - well cem.
33	20.7	170	.79	9.55	6.1	4.6	21.2	.153	-
34	8.7	7.1	.97	45.72	24.2	4.1	37.1	.181	Hd., dense, fine sd. - well cem.
35	14.0	-	.63	14.46	16.5	3.4	86.8	-	Fine sd. - very loosely cem.
36	8.8	.3	.57	106.53	54.4	17.4	67.3	-	Fine sd. - well cem.
						Third sand			
37	27.1	450	0.77	10.09	14.8	8.8	2.5	-	Fine to med. sd. - mod. to well-cem.
38	27.4	-	.77	9.07	12.3	12.5	2.6	-	Fine to med. sd. - thin sh stk. - mod. cem.
39	27.1	2,600	.89	6.81	13.2	6.9	21.3	0.246	-
40	30.1	2,900	.94	6.27	8.1	16.5	0	.255	Med. sd. - loosely cem.
						Fourth sand			
41	10.5	0.4	0.62	71.40	56.2	4.5	33.2	-	Tight cal. ss.
42	27.3	870	.81	7.00	11.9	9.2	6.5	0.200	Fine to med. sd. - mod. to well cem.
43	30.1	620	.83	12.60	7.0	-	-	-	-
44	27.7	525	.87	9.90	7.8	-	-	-	Coarse sd. - sh. laminations.
45	25.8	630	.91	10.16	16.3	-	-	-	Coarse sd.
46	28.7	1,200	.90	8.10	10.0	-	-	-	Med. sd. - very little sh. - some mica.
47	27.9	520	.89	8.90	14.4	-	-	-	Fine to med. sd. - some limestone.
48	8.5	2	1.00	65.60	32.4	-	-	-	Dense ss. with included limestone.
49	9.8	9	.96	56.30	34.3	-	-	-	Dense ss. - many cal. fossil fragments.
50	15.1	12	.94	35.90	21.0	-	-	-	Coarse cal. ss. - some oolites.
51	25.7	500	.89	11.20	15.2	-	-	-	Hard, cal., fine to med. ss. - some mica.
52	29.5	1,350	.84	8.60	4.3	-	-	-	-
53	32.5	1,450	.79	8.10	11.9	-	-	-	-
54	31.8	640	.86	8.90	11.0	-	-	-	Very fri. ss.
55	26.8	640	.87	12.30	11.0	-	-	-	Cal. ss., coarse.
56	27.9	1,050	.88	10.00	8.3	-	-	-	Fine rounded ss. - very little sh. or mica.
57	28.2	700	.90	12.50	13.6	-	-	-	Med. to coarse sd. - fri., loosely cem.
58	26.6	350	.84	12.80	16.3	-	-	-	Dark, fine grained sh. ss. - micaceous, loosely cem.

1/ Saturated in laboratory under vacuum.

2/ $\text{Formation Factor} = \frac{\text{Resistivity of core at maximum brine saturation}}{\text{Resistivity of brine}}$

3/ By Restored State method, displacement at 50 p.s.i.

Explanation of abbreviations

cal. - calcareous	dn. - dense	hd. - hard	mod. - moderate	sdy. - sandy	shy. - shaly
cem. - cemented	fri.- friable	med.- medium	sd. - sand	sh. - shale	ss. - sandstone
					stk. - streaks

Core 12, taken from the first Healdton sand, shows streaks of carbonaceous material in the oil sand that was not removed by toluene extraction of the core. The core contains a large percentage of limestone, which surrounds the sand grains and appears in the photograph as dark areas or lines surrounding the individual sand grains. Most of the interstitial spaces are filled with limestone cementing material. A few scattered particles of clay are present, but almost no clay cementing material.

Core 7 shows a more porous and permeable sandstone containing comparatively little limestone. Although the grains vary considerably in size, average grain size is somewhat less than in the former core. Core 7 contains a large percentage of clay, which appears brown under the microscope but black in the photograph. Pore spaces between the sand grains appear as speckled areas.

Core 41 shows large sand grains with considerable limestone cementing material between the grains. In the photograph the pore spaces appear as dark areas, whereas the mottled area between the grains is limestone cementing material. The pore spaces are almost entirely in areas surrounding individual grains. In the lower right corner is a large pore space that may have been the result of the removal of a sand grain during grinding.

Little cementing material is present in core 40, and most of the space between the grains is filled with plastic. One of the dark areas near the center of the photograph is carbonaceous material; the other is an unidentified dark mineral. Shale appears as dark spots scattered throughout the photograph. Core 34 is a dense, calcareous sand with a few isolated pore spaces surrounding the sand grains. Some oolites are present. Core 31 is a fine-grained sand with angular, well-sorted grains and large, interconnected pore spaces.

These thin sections and the physical measurements shown in table 5 illustrate the wide range in character of the Healdton sands. Core 40 has large, open pore spaces, permitting a comparatively low connate-water saturation, whereas, in core 41, the pore spaces surrounding the individual grains are small and disconnected, resulting in a much higher connate-water saturation.

Porosity

Cores from 49 wells in several areas of the Healdton oil field have been analyzed. These core analyses show that the porosity of the oil sand ranges from 12 to 35 percent. Many of the later wells have been electrically logged. For a few wells, core analyses and electric logs through the same producing sands were available, so that the electrical properties of the sands could be compared with laboratory measurements on the cores. Attempts to calculate porosity from log resistivity by Archie's formulas (14) proved unsatisfactory. (See Appendix.) However, electric logs did give some qualitative idea as to the nature of the producing sand and, with certain limitations, were used for porosity estimates.

From many indications the porosity of the fourth sand is more consistent than that of the upper sands. Core analyses through this sand in three wells show average porosities between 20.8 and 25.5 percent. Porosities estimated with the aid of electric logs range from 20 to 24 percent. From these data a weighted average porosity of 21.3 percent was taken as representative of the oil-productive section of the fourth sand and was used in reserve calculations for this sand throughout the field.

It is more difficult to estimate the porosity of the upper sands underlying the leases throughout the field. Cores and electric logs were taken on only 27 leases in the more prolific parts of the field, and these do not provide enough data to construct a porosity map of the upper sands throughout the field. Likewise a field-wide average porosity based upon analyzed cores and estimations from electric logs would give a value too high for much of the field and too low for a few prolific leases. Drillers' logs and production records indicate that the porosity of the sands does vary greatly, so that reserve estimates for individual leases based upon a field-wide average porosity would be inaccurate. To obtain reasonable reserve estimates, some indirect method was needed for estimating the porosity of the sands underlying each individual lease.

To some extent, the initial daily oil production per foot of penetrated sand reflects the character of that sand; and, with certain limitations, the initial production can be used to estimate the relative porosity of the sand surrounding that well. In estimating porosity, a method similar to that described by Fox, Thigpen, Ginter, and Alden (15) was followed. The initial potentials of the first few wells on each lease were studied, considering drainage area and probable interference of other wells. An average porosity value was calculated for each of the 27 leases mentioned above on which some reliable porosity data were available. These average porosities were plotted on semilogrithmic paper against the square root of the average initial oil production per foot of penetrated sand (fig. 14). Although the points are widely scattered because cored wells may not be representative of the entire lease, a general relationship is apparent. Average initial production is higher for those leases with more porous sands. This graph was used with initial-oil-production data to estimate probable porosity of the upper oil sands on 180 other leases in the field. Based on the study of many upper Healdton-sand cores, which rarely showed porosity values greater than 32 percent, an estimated porosity of 32 percent was fixed as the highest average value likely to be representative of the best leases. Estimated lease porosities read from this graph ranged from 31.8 percent for an average initial oil production of 11 barrels per day per foot of open sand to 12 percent for 1/2 barrel per day per foot of open sand.

No porosity measurements were made on stray sands; and, in the absence of suitable core data, the following rough method was used to approximate the average porosity of the stray sands underlying each lease. Drillers' logs describe "good oil sand," "oil sand," "fair oil sand," "oil sand tight," and "poor oil sand" in these stray sand zones. By comparing drillers' log descriptions of other sands with the core analyses on the same sand, a quantitative porosity value was assigned to each descriptive term. Using this comparison as a basis, the porosity of the stray sands in each well was estimated and averaged for the lease.

Reservoir Fluids

Water

Nearly all sands in structurally low areas along the flanks of the field were water-saturated originally. In the fourth sand, the oil-water contact has been drawn from well data and is shown as the limiting line in figure 10. This oil-water contact in the fourth sand ranges from about 180 feet below sea level in the north end of the field to 470 feet below sea level along the southwest flank in the southeast extension. This original oil-water contact in the fourth sand has been fairly well established, and the advance of water as the oil was produced has been traced and will be discussed later in the section under Production.

In the main part of the field, no definite oil-water contact has been established in the upper Healdton sands above the fourth sand. Along the edges of the field, upper

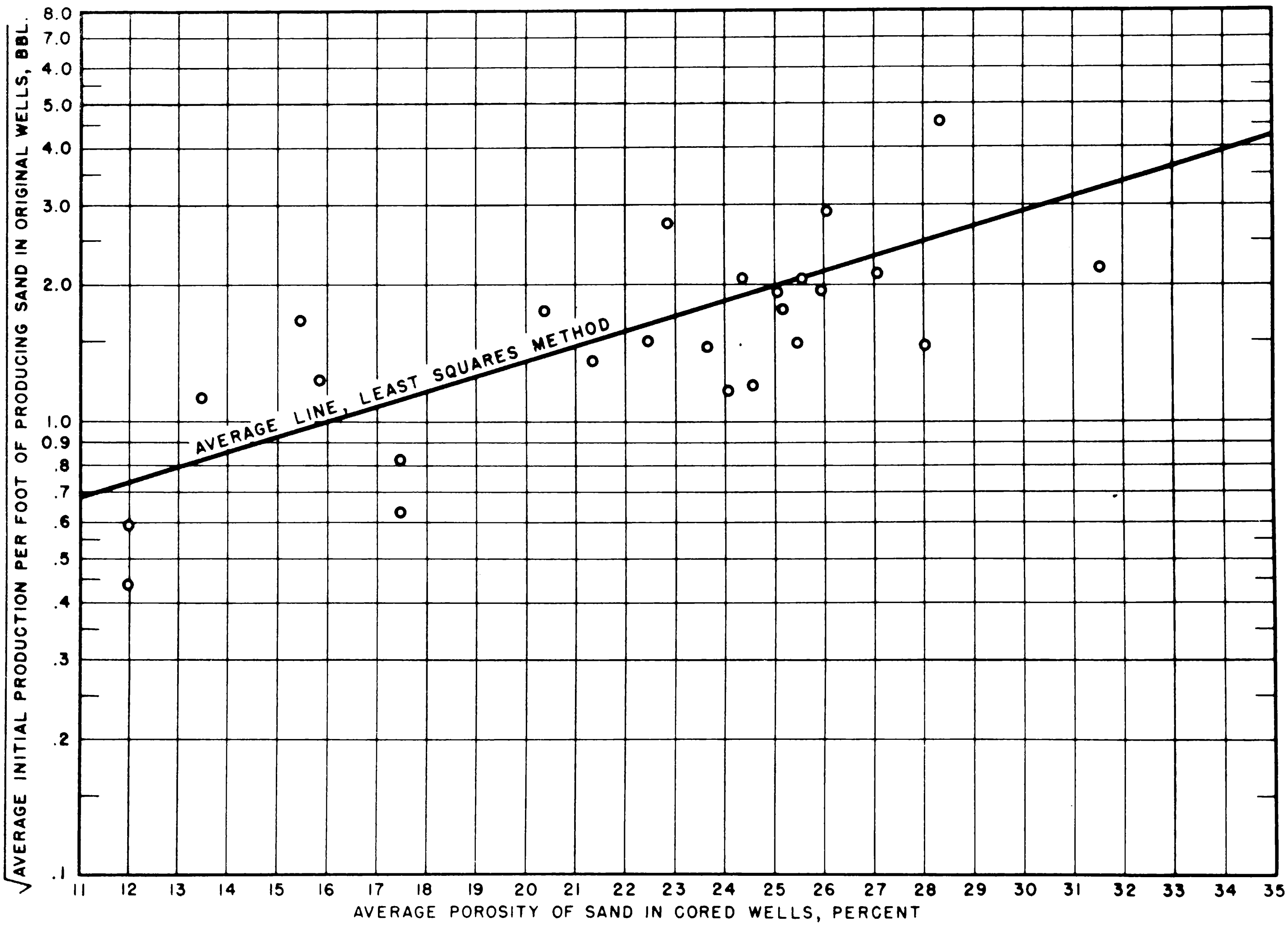


Figure 14. - Relationship between average porosity of sand in cored wells and the average initial production per foot of producing sand in original wells on the lease.

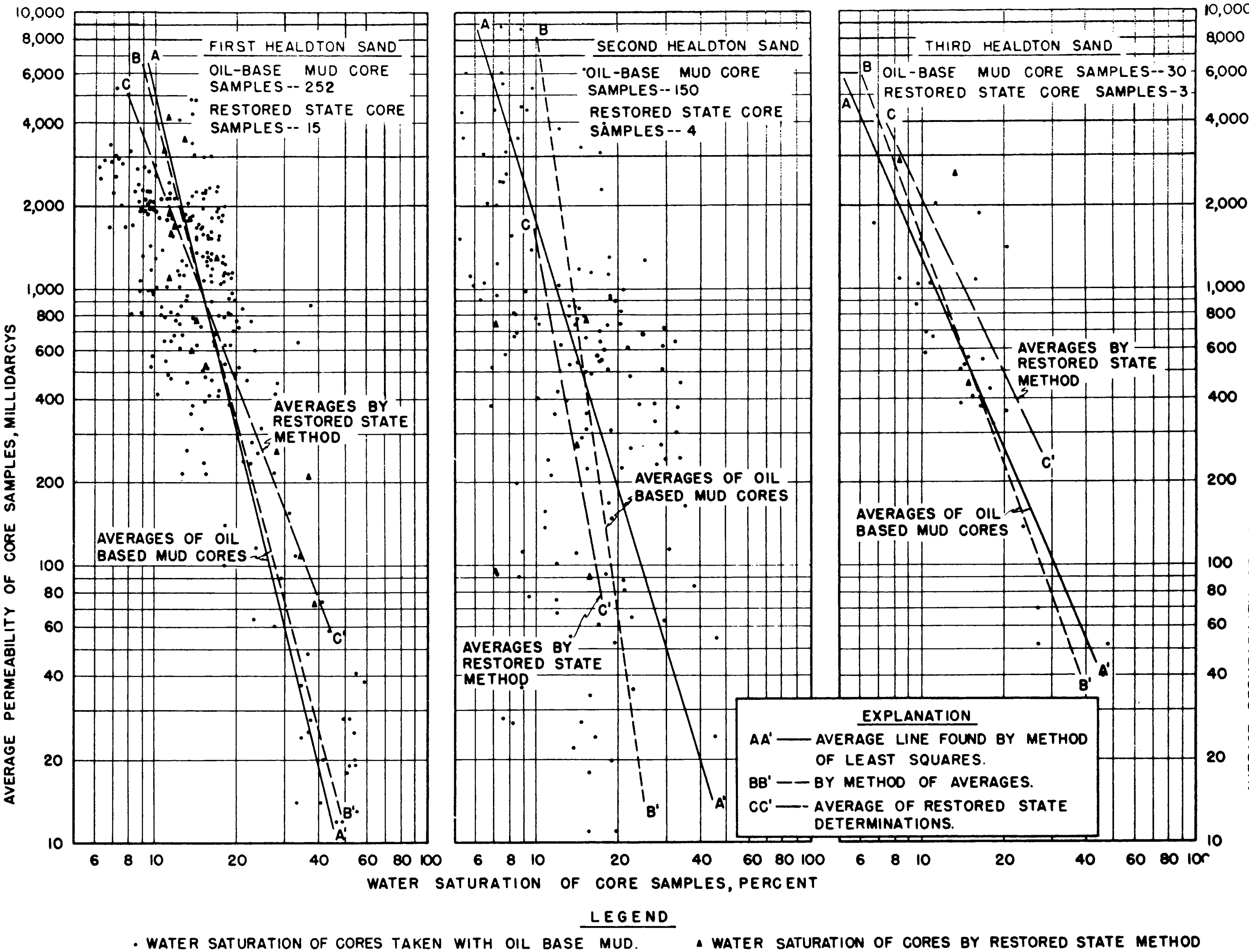


Figure 15. - Relationship between connate-water saturation and permeability in the first, second, and third Healdton sands, Healdton oil field, Carter County, Okla.

Healdton sands that were penetrated in early wells were water-saturated at depths ranging from 110 to 430 feet below sea level. A study of these data shows that the water level follows in general the structural pattern but exhibits less relief. However, the water level was not consistent in depth locally, and many wells produced water-free oil from sands at depths below those of the water-producing sands in adjacent wells. After continued production, the water has become depleted. Water production from the upper sands will be more fully discussed under Production.

Above the oil-water contact and above a transition zone of indefinite thickness, the water in the sand is connate water as defined on page 12. To estimate the amount of oil originally in place in the several sands, it was necessary to calculate the percent of the pore space originally filled with connate water. In the Healdton oil field nine wells were cored with oil-base mud, and the connate-water saturation was determined by the operators on a total of 502 core samples from the several sands. The connate-water saturation of 57 core samples was measured in the Bureau of Mines laboratory by the restored-state method. These data have been used to construct figure 15, which shows the relationship between permeability and connate-water saturation.

Of 317 core samples obtained by coring the first Healdton sand, several showed abnormally high or low water saturation and were eliminated from consideration. In all, 252 determinations of the connate-water saturation of first sand cores cut with oil-base mud have been plotted against the corresponding permeability in the left section of figure 15. The scattering of points is at once apparent. Two lines, A and B, have been drawn by two mathematical methods to represent the locus of the average connate-water saturation of these oil-base mud cores. These lines show fairly close agreement and indicate the decrease in connate-water content with increasing permeability. Line C represents the locus of average connate-water saturation, as determined on 15 cores by the restored-state method.

Permeability is only one of several factors that control the connate-water saturation in the pendant zone above the oil-water contact. As discussed earlier, the size, shape, and interconnection of the individual pore spaces are important factors. Measurements of grain size and clay and limestone content were compared with the measured connate-water saturation to determine the possible effect of these variables upon the connate-water saturation, as determined by the restored-state method, but no conclusions could be drawn from the available data.

Permeability and connate-water data for the second and third Healdton sands were assembled and plotted in the center and right section of figure 15. Although fewer data were available for the second sand, it is apparent from lines A, B, and C that somewhat less connate-water saturation can be expected in the second than in the first Healdton sand. The sparse data available for the third Healdton sand indicate a somewhat greater variation in connate-water saturation with different permeability than for the first or second Healdton sands. No data were available as to the permeability-connate-water relationships for the fourth sand. Comparison of the three graphs shows that, with a permeability of 1,000 millidarcys, the first sand would have an average connate-water saturation of 15 percent, the second sand 11 percent, and the third sand 12 percent.

Cores used to construct figure 15 were obtained from a few wells on several leases in the western part of the field, but definite data regarding the connate-water content of the upper sands underlying most of the leases are not available. In the absence of connate water-saturation values for each lease, data from figure 15 were considered applicable to upper sands throughout the field. These data show that connate water is related to permeability and porosity, although it differs slightly for the several sand zones. Based upon the relative percentages of first, second, and third sands underlying the several leases and upon an average permeability estimated from the assigned porosity, a weighted average connate-water saturation was assigned to each lease and used in calculations of the oil originally in place in the upper sands for each lease.

No connate-water data were available for the fourth sand, so a round figure of 20 percent of the pore space was assumed for the average connate-water saturation of that sand.

Apparently the stray sands resemble the first Healdton sand in character; and, since no data as to connate water in the strays were available, a connate-water content of 19 percent, corresponding to a permeability of 500 millidarcys, from first-sand data, was assigned to all oil-productive stray sands in calculating the volume of oil originally in place.

Reservoir Oil

Above the oil-water contact in the several sands, that portion of the pore spaces not filled with connate water is assumed originally to have been saturated with reservoir oil. As far as can be ascertained, a bottom-hole sample of oil from the Healdton sands has never been obtained, and definite data are not available as to the original reservoir pressure and temperature and the quantity of gas dissolved in the reservoir oil. Free dry gas originally was present above the oil in gas-cap areas throughout the field, indicating that probably the reservoir oil originally was saturated with gas at the initial reservoir pressure and temperature. Early records of gasoline plants showed that the gasoline content of the produced wet gas ranged from 0.28 to 3.3 gallons per thousand cubic feet.

Assuming a pressure gradient of 0.4 p.s.i. per foot of depth, the initial reservoir pressures in the Healdton oil field would have ranged from 260 p.s.i. at 650 feet to 480 p.s.i. at 1,200 feet. Reservoir temperatures at these depths, as determined in several wells, would range from 73° to 85° F.

In October 1950 measurements showed that the specific gravity of gas in relation to air ranged from 0.83 to 1.3. Katz (16) has shown that, for the average gas gravity of 0.88 and oil gravity of 31.9° A.P.I., 70 cubic feet of gas per barrel of stock-tank oil would be dissolved in the reservoir oil. Data published by Standing (17) indicates that at 260 p.s.i. pressure and at a reservoir temperature of 73° F., reservoir oil with gravity of 31.9° A.P I. would contain about 70 cubic feet of gas in solution per barrel of oil, as measured at stock-tank conditions. In the deeper zones of the Healdton reservoir with oils of higher specific gravity, it is estimated that approximately 110 cubic feet of gas per barrel of oil was in solution at about 480 p.s.i. pressure and at a temperature of 85° F. Assuming an average for the field of 90 cubic feet of gas per barrel of oil, it has been calculated that reservoir oil would shrink approximately 4.2 percent, as measured at stock-tank conditions, indicating a formation volume factor of 1.044. This average formation volume factor was used to calculate the volume of oil in place, as measured under stock-tank conditions, in the sands throughout the field.

After deduction for connate water and shrinkage, the original saturation of the pores in the upper Healdton sands with stock-tank oil would range from 87.5 percent of the pore space at 32.0 percent porosity and 3,000 millidarcys permeability to 36.8 percent at 12.0 percent porosity and 18 millidarcys permeability.

Reservoir Calculations

Nonrecoverable Oil Saturations

Little is known definitely regarding the percent of oil that is left in the pore spaces and termed nonrecoverable. In general, it is recognized that oil displacement by water, either in a natural water drive or by artificial water flooding, is more efficient in reducing the oil saturation to a minimum than is solution-gas drive, gas-cap drive, or gravity drainage. Cores with oil saturations ranging from 28 to 84 percent of the pore space were subjected to flooding tests in the laboratory under controlled conditions, and the data available on 19 cores so tested showed that the residual-oil saturation, after continued flooding with several thousand pore volumes of water, ranged from 9 to 29 percent and averaged 19 percent. No relationship was apparent between residual-oil saturation and other measured properties of the core. In actual practice such high water-oil ratios and complete flooding of the sand would not be economically feasible. In the Healdton field most oil wells are abandoned when oil constitute less than 1 percent of the total produced liquid. Assuming 1 percent as an economic limit, when the throughput fluid in laboratory tests reached the ratio of 1 volume of oil to 99 volumes of water, the residual-oil saturation of cores ranged from 18 to 45 percent and averaged 29 percent. The mobility ratio of water to oil increases disproportionately with increased water saturation and decreased oil saturation, so that at an average oil saturation of 29 percent, the water-oil mobility ratio and production is about 99:1. At this saturation, the remaining oil may be considered as economically immobile or fixed, whereas that oil saturation greater than 29 percent of the pore space can be considered as mobile and recoverable under the most favorable conditions. Inasmuch as the porosity and permeability of these 19 core samples covered the complete range of values measured on Healdton oil-producing sands, this figure of 29 percent was adopted as a reasonable average residual-oil saturation. Original mobile-oil saturation ranged from 58.5 percent of the pore volume for an average sand of 32.0 percent porosity to 7.8 percent for the average sand of 12.0 percent porosity cited earlier.

Original Mobile Oil

The volume of mobile oil originally present in the Healdton reservoirs was calculated for individual leases by the following formula:

$$\text{O.M.O.} = 7{,}758 \times A \times T \times P \left[\frac{(1 - C_w)}{\text{FVF}}\right] - \text{N.R.O.} \quad ;$$

where:

O.M.O. = original mobile oil, measured at stock-tank conditions, bbl.;

7,758 = conversion factor, acre-feet to barrels;

A = area of sand, acres;

T = effective thickness of sand, feet;

P = average porosity of sand, decimal fraction of total volume;

C_w = average connate-water saturation, decimal fraction of pore space;

F.V.F. = formation-volume factor;

N.R.O. = nonrecoverable-oil saturation, decimal fraction of pore space.

Average data for the Healdton reservoirs based upon a summation of lease totals are listed below:

	Fourth Healdton	Upper sands (first, second, and third Healdton)	Stray sands (above first Healdton)
A.	1,960	7,016	1,420
T.	23.00	64.71	13.31
P.	0.213	0.216	0.234
C.	0.200	0.190	0.187
F.V.F.	1.044	1.044	1.044
N.R.O.	0.29	0.29	0.29
O.M.O.	35,455,000	369,765,000	16,780,000

The original stock-tank oil for the Healdton reservoir was calculated to be as follows:

	Bbl.
Fourth Healdton	57,026,000
Upper sands	590,448,000
Stray sands	26,721,000
Total	674,195,000

PRODUCTION

The Healdton oil field has been one of the most prolific oil-producing areas in Oklahoma. Cumulative oil production to January 1, 1951, from 7,142 productive acres of Healdton sand exceeds 211 million barrels, averaging 29,570 barrels of oil per acre and 410 barrels per acre-foot. Oil recovery from several leases exceeds 120,000 barrels per acre. With few exceptions, to be discussed later, this oil has been recovered by primary production methods utilizing the natural energy of the reservoir fluids.

Production Mechanism

Although all four natural-energy sources - dissolved gas, water drive, gas-cap expansion, and gravity drainage - undoubtedly have contributed to the oil production, dissolved gas primarily and water drive secondarily have been the principal natural-energy sources active in the Healdton field.

Expansion of dissolved gas has been most important in producing oil from the upper Healdton sands, whereas natural water drive has been effective in recovering oil from edge leases producing principally from the fourth Healdton sand. Gravity drainage has been an important recovery factor in some structurally low areas. During the life of the field, no particular effort was made to conserve gas energy or to utilize it most effectively to recover oil. The result was a rapid decline in pressure and oil production between 1917 and 1925 (see fig. 3). Vacuum, applied

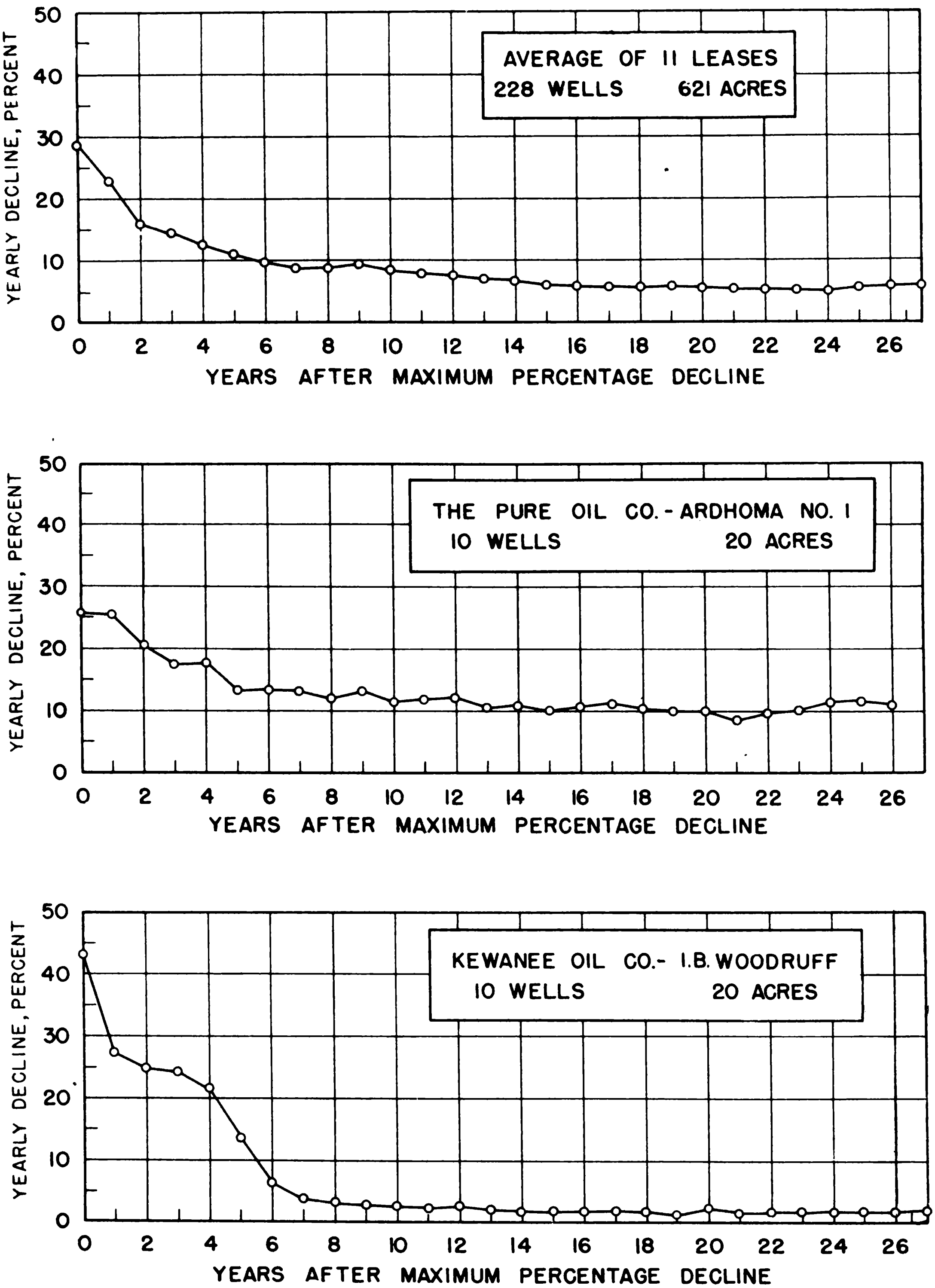


Figure 16. - Percent yearly decline in the rates of oil production from representative leases with no secondary development, Healdton oil field, Carter County, Okla.

intermittently since 1918 and consistently since 1938, reduced the pressure further, so by 1950 the reservoir pressure was very near atmospheric throughout most of the field. In the southeast extension, where vacuum has not been as generally applied and where edge water may be slowly encroaching into some of the upper Healdton sands, fluid levels in idle wells indicate reservoir pressures in some sands greater than 100 p.s.i.

Representative Decline Curves

To illustrate the effects of natural energy on the rate of oil production, the percentage decline of several leases with long uninterrupted production histories is shown in figure 16.

To construct these curves the actual annual oil production, in barrels, was plotted against time for each lease. Normal yearly oil production was read from a smooth curve through the points. The percentage decline then was calculated by taking the difference in normal yearly oil production between 2 successive years and dividing this difference by the normal production in the earlier year. Annual percentage decline was plotted for yearly intervals, beginning with the year of the maximum percentage decline. The upper graph shows the yearly average percentage decline of 11 leases that have not had infill drilling or other interruption of the normal production decline. Declines for the first two periods were 29 and 23 percent respectively, but thereafter the percentage decline decreased slowly until it became more or less stable at 6 percent per year. Twenty-five years after the maximum percentage decline a slight increase to 6-1/2 percent per year is noted. This increase in percentage decline reflects an actual marked decrease in the oil-production rates, probably attributable to wearing-out of production equipment on the leases.

The graph of The Pure Oil Co. Ardhoma 1 lease shows the highest percentage decline of the 11 leases considered. During the early life of the lease the decline in oil production was 33.5 percent per year, and from this peak the rate of decline dropped rather sharply until the oil production was decreasing at the rate of about 13 percent per year. From this point, in the sixth year after the maximum percentage decline, the rate of decline decreases slowly and appears to become more or less constant at about 10 percent per year.

On this lease in the NW1/4 sec. 9, T. 4 S., R. 3 W., where the fourth Healdton sand is thin or entirely absent, oil is produced from upper Healdton sands, and water encroachment has little, if any, effect on oil production.

The graph for the Kewanee Oil Co. I. B. Woodruff lease illustrates the oil-production history of a lease, which after the tenth year showed the lowest percentage decline of any of the 11 leases considered. After the peak decline of 43.5 percent, the rate of decline dropped sharply to about 27 percent and then dropped less sharply for about 4 years. Ten years after the year of highest percentage decline the yearly percentage decline continued more or less constant for 17 years at 2 to 2-1/2 percent per year. This extremely low percentage decline reflects a nearly constant production rate.

Wells on this lease, in sec. 31, T. 3 S., R. 3 W. at the northwestern edge of the field, have been producing increasingly larger volumes of water since 1920. Several down-structure wells in this area already have been abandoned or plugged back because of high water production. Apparently, advancing edgewater has sustained the oil production at a nearly constant rate.

The percentage-decline curves for 17 leases with long, uninterrupted production histories were used as typical curves to calculate the normal expected decline in yearly production of other leases in the field. Where it was important to calculate the increased oil production resulting from infill drilling or secondary recovery or where an extrapolation of the rate of future oil production was necessary, the typical curve that best fitted the available data was used.

Water Production from Upper Healdton Sands

Water production from wells that did not penetrate to the fourth Healdton sand has been reported by operators since early in the life of the field. Several drillers' logs recorded water in the upper Healdton sands at the time of drilling, and tests on some of the wells indicate that water was produced during the early productive life of the field.

Information from well test records, plug-backs, and abandonments indicates that the water is produced primarily from the third sand. However, along the edges of the field, water is present in all of the upper Healdton sands, including some of the oil-productive stray sands above the main Healdton sands.

Figure 17 shows areas in which the water produced from the upper Healdton sands exceeded 50 percent of the total fluid production from these areas in 1950. Areas where the water production ranges from 2 to 10 barrels daily and other areas where it exceeds 10 barrels daily are shown by different types of cross hatching. A few individual wells with high water-production rates are not shown on the map. Areas in which the daily water production exceeds 10 barrels per well are not related to structural position or to any particular location in the field. Areas bounded by the dashed heavy line include wells from which the water is believed to be produced from the first sand.

There is no evidence of an extensive water drive in any of the upper Healdton sands, although in a localized area a limited water drive may exist. Figure 18 shows graphs of the average daily oil and water production per well and the percentage of water in the total fluid for wells producing from upper Healdton sands for 1920, 1930, 1935, 1940, 1945, and 1950. The number of well tests considered in calculating these average daily volumes is shown along the average daily-oil production curve. The average daily oil production decreased from 20.5 to 6.1 barrels per well between 1920 and 1930. During this interval, water production decreased from approximately 7.5 to 6.3 barrels per well; but, because of the greater decrease in oil production, the percentage of water in total fluid produced increased from 27 to 51 percent. In 1935 the average daily oil production increased to approximately 7.5 barrels per well, probably because of infill drilling, whereas the average daily water production remained approximately the same. Since 1935 the average daily rate of oil and water production has decreased steadily, and by 1950 it was approximately 3.8 and 4.5 barrels per well, respectively. Between 1935 and 1945 the percentage of water in total fluid produced increased from 46 to 54 percent, but since 1945 it has remained constant.

From these data and from a study of the oil- and water-production history of 100 other wells, it is concluded that both oil and water in the upper Healdton sands are being depleted and that in these sands there is no appreciable water drive.

Natural Water Drive

Natural water drive has been more important in producing oil from the fourth sand than from the upper Healdton sands. The fourth sand originally was oil-productive

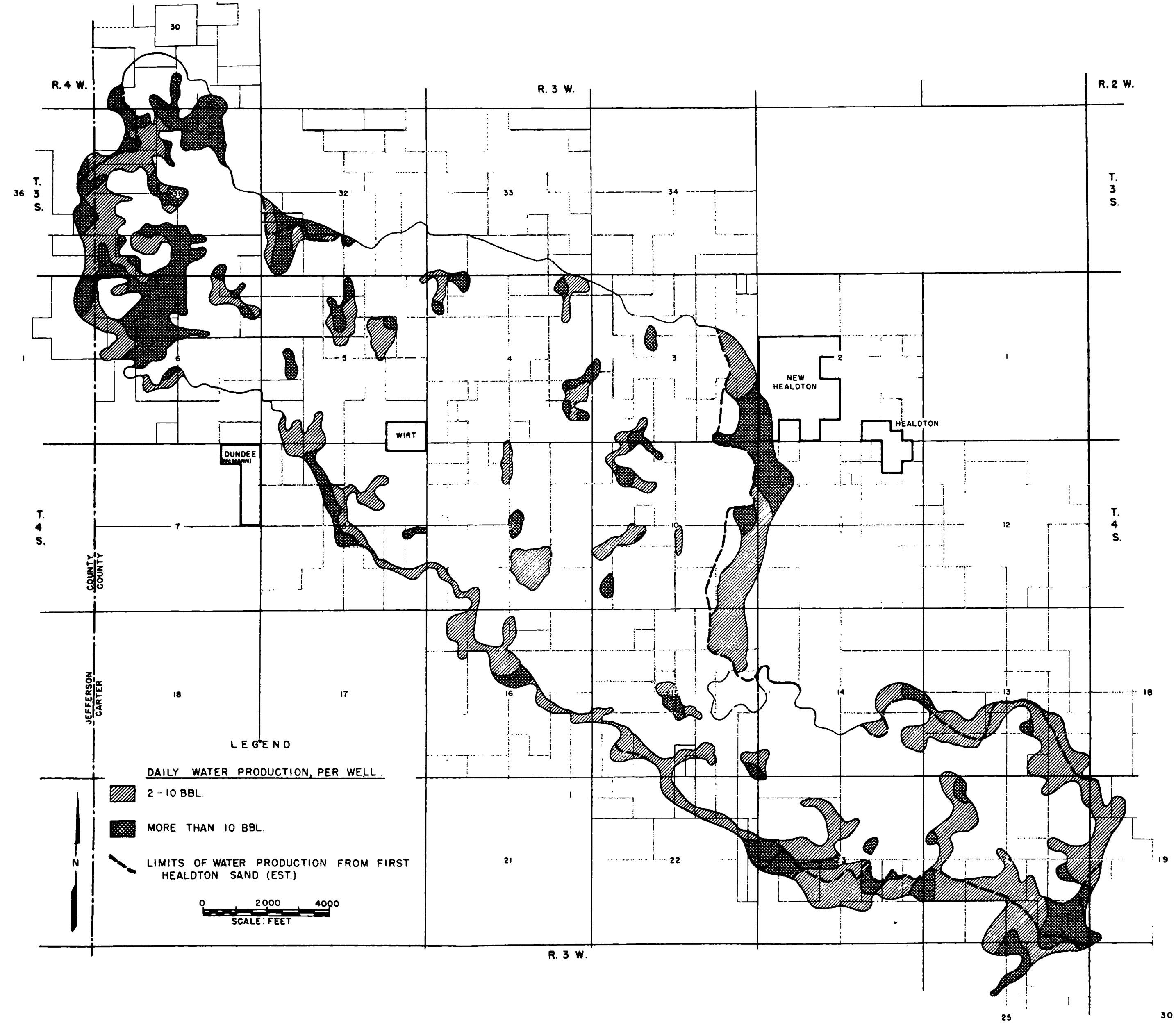


Figure 17. - Areas in which production from upper Healdton sands is more than 50 percent water, Healdton oil field, Carter County, Okla.

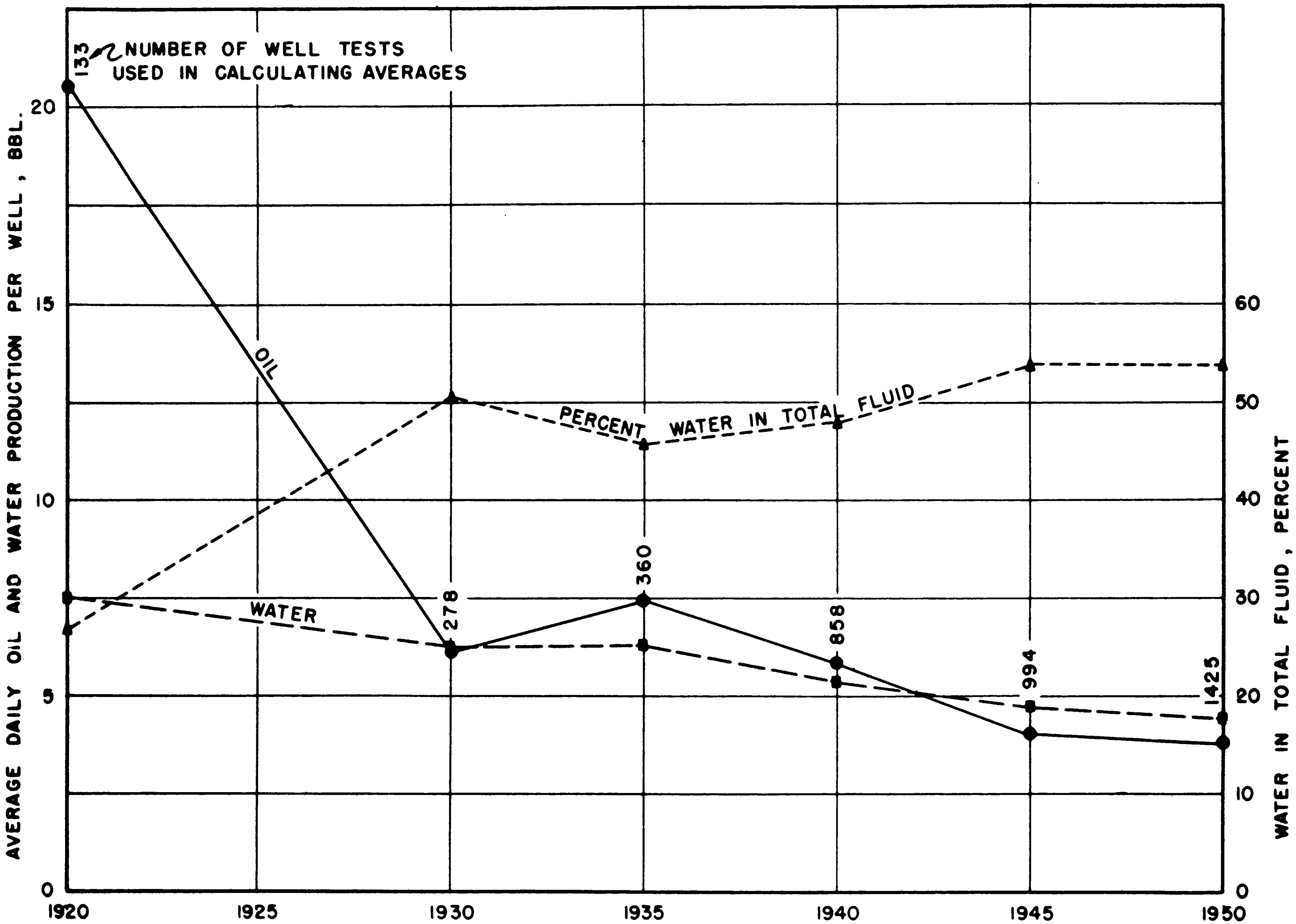


Figure 18. - Average daily oil and water production history of wells in upper Healdton sands, Healdton oil field, Carter County, Okla.

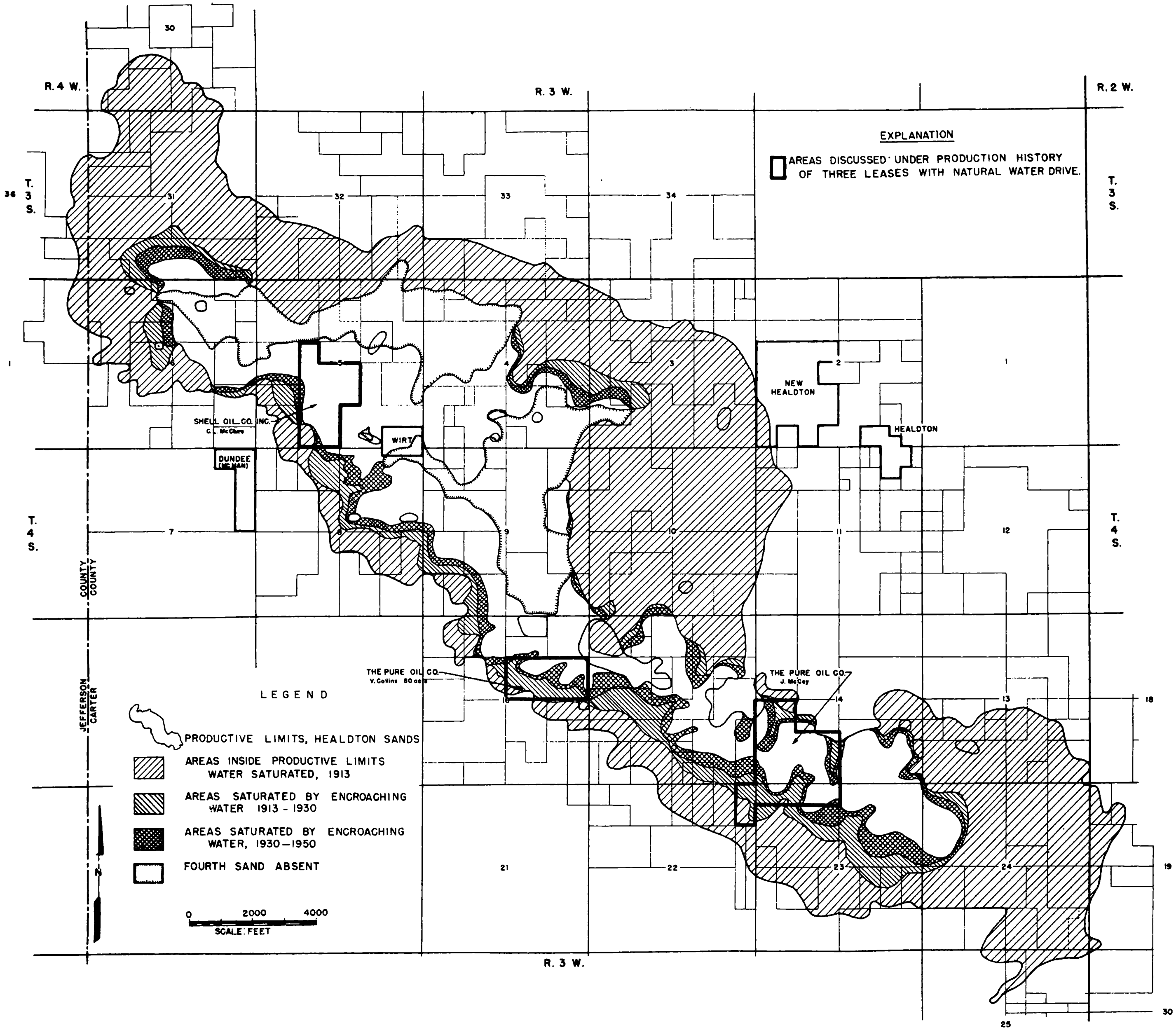


Figure 19. - Progressive advance of water in fourth Healdton sand, Healdton oil field, Carter County, Okla.

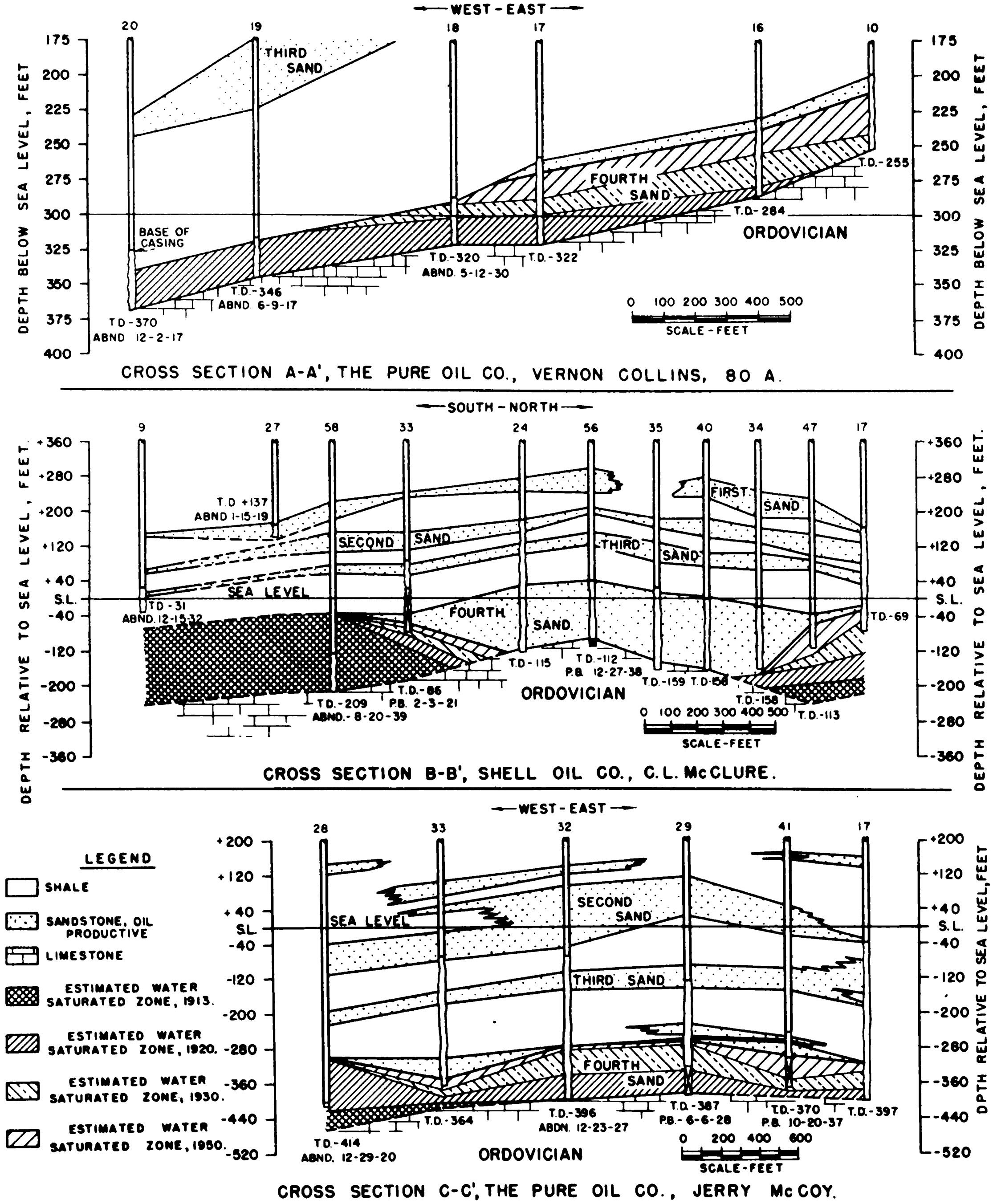


Figure 20. - Structure sections through three leases showing water encroachment in the fourth Healdton sand, Healdton oil field, Carter County, Okla.

under a comparatively limited area in the field. As discussed earlier, the fourth sand was not deposited over the topographically high areas in the north-central part of the field, and much of the structurally lower areas were water-saturated when the field was developed. Figure 19 shows the progressive advance of edgewater in this sand. It shows that between 1913 and 1930, wells in an area of 470 acres, principally along the southwestern edge of the field, were abandoned because of excessive water production. Between 1930 and 1950, inclusive, an additional area of 420 acres of the fourth sand was similarly flooded.

Production History of Three Leases with Natural Water Drive

To show in more detail the progress of advancing water, three leases, The Pure Oil Co. Vernon Collins 80-acre, The Pure Oil Co. Jerry McCoy, and the Shell Oil Co., Inc., C. L. McClure, where the water advance in the fourth sand is quite apparent and a long oil- and water-production history is available, were selected for study.

The Pure Oil Co. Vernon Collins 80 Acre.- The production data on this lease, in sec. 16, T. 4 S., R. 3 W., along the southwest flank of the structure near the south edge of the main part of the field, indicate that the fourth sand alone has an effective water drive. The strata in this area dip to the southwest about 800 feet per mile, the northeast corner of the lease being near the crest of the field structure, whereas the southwest corner is at the productive limit of the field. West-east cross section A-A' (fig. 20) from well 20 to well 10 shows the thickness and attitude of the fourth sand zone. Wells on this lease were not cored or electrically logged, and the cross section was made from the interpretation of drillers' logs. The cross section shows the top of the fourth sand at 341 feet below sea level in well 20 near the west edge of the lease and at 197 feet below sea level in well 10 near the east edge of the lease. The thickness of the fourth sand varies according to locations, 113 feet being penetrated in well 8 along the north edge of the lease, as compared to an estimated thickness of 70 feet along the south edge of the lease.

The initial production of the wells ranged from 2 to 850 barrels of oil per day with an average of about 165 barrels per day. Generally the wells along the north and east edges of the lease where the sand is thicker had higher initial oil-production rates, although the highest initial production of 850 barrels per day was recorded from a well along the south edge of the lease.

Well 1 near the southeast corner of the lease was completed in the upper Healdton sands in November 1915, and the initial production was only 5 barrels of oil per day. The lease was developed slowly, and by December 1917, 27 wells had been drilled. During this interval of development six of the wells were abandoned, presumably because of low oil production or because of encroaching water. By January 1921, 7 additional wells had been abandoned making a total of 13 abandonments during the first 5 years of operation of the lease. Since then 1 well has been abandoned, and in 1950 only 13 wells were producing oil; 9 of these were producing from the fourth sand. There has been no secondary development or drilling of new wells on this lease, although there have been several deepenings and plug-backs since the primary development.

When wells 22 and 24, in the southwest corner of the Vernon Collins 80-acre lease, were completed in 1917, water, but no oil, was reported in the fourth sand. Operation of wells 14 and 15 along the south edge of the lease was discontinued by 1919 because of high water production. Twenty barrels of salt water and no oil were pumped from well 14 soon after completion in 1917. The depths of these wells indicate that the original oil-water contact was approximately 380 feet below sea level in the extreme southwestern corner of the lease. Figure 21 shows water-advance maps of the three leases, with the estimated water-saturated areas as of 1913, 1920, 1930, and 1950. The water-advance map of The Pure Oil Co. Vernon Collins 80-acre lease shows that about 8 acres of the fourth sand in the extreme southwestern corner of the lease originally was water-saturated.

Between 1917 and 1920, inclusive, wells 5, 9, 13, 14, 15, 19, 20, 23, and 27, all along the south and west edges of the lease (see fig. 21), were abandoned in the fourth sand. By 1920 the water had advanced up-structure to include one third of the southwestern portion of the lease. During this period approximately 767,000 barrels of oil was produced from the fourth sand. From all data available, it appears that edgewater had advanced by 1930 in the central portion and at the eastern end of the lease. Well tests show that well 18, in the center of the lease was producing essentially 100 percent water before it was abandoned in the fourth sand in May 1930. By 1950 approximately 60 percent of the original productive area of the fourth sand had been flooded, and all the wells were producing high percentages of water. At no time during the advance of the water from its original position to its position in 1950 was the oil-water contact horizontal, and its advance was not controlled entirely by structure. This irregular advance may have been due to differences in permeability or to different methods of operation of the individual wells. At the current rate of water advance, it is estimated that within 10 or 12 years the fourth sand underlying this lease will be completely flooded.

Figure 22 is the yearly oil- and water-production history of the three leases. The graph of the fourth-sand oil production from The Pure Oil Co. Vernon Collins 80-acre lease shows that the maximum yearly oil production occurred in 1917 and that after this peak the rate declined rapidly in a manner similar to the decline rate of oil production from a solution-gas drive reservoir. In 1917, during the year of maximum oil production, two wells were abandoned because of high water production. Also two wells were abandoned in 1918 and three in 1919 for the same reason. In 1920 and 1921 the rate of oil production decreased, but the rate of total fluid production increased. In 1922 wells 6 and 18 were plugged back, causing a sharp decrease in total fluid-production rates. From 1922 through 1928 yearly oil production decreased steadily, whereas yearly water production increased sharply. From 1928 through 1935 the rate of oil production was essentially constant, but the volume of produced water dropped sharply because one well was abandoned and three others were plugged back. From 1936 through 1950 oil production remained nearly constant. During this period yearly water production increased steadily, until in 1950 approximately 307,000 barrels of water was produced from the fourth sand. The graph of the percentage of water in total fluid illustrates more convincingly the advance of water in the fourth sand. In 1950 water production was approximately 97 percent of the total fluid produced. (See Brine Disposal, p. 59.)

Lifting costs on the Vernon Collins lease increased from 17 percent of the value of the produced oil in 1930 to approximately 41 percent in 1950. Heavier pumping equipment and a water-disposal system will have to be installed to lift and dispose of the increasing quantities of water produced with the oil. It may be assumed that within the next 10 to 12 years the increasing water production (see figs. 21 and 22) and lifting costs will require that the remaining wells be abandoned in the fourth sand and plugged back to upper Healdton sands.

On The Pure Oil Co. Vernon Collins lease, the cumulative oil production from the fourth sand through 1950 was approximately 1,152,000 barrels. It is estimated that, by the time the fourth sand is abandoned, the total oil recovery will be about 1,227,000 barrels, or approximately 467 barrels per acre-foot from 74 productive acres.

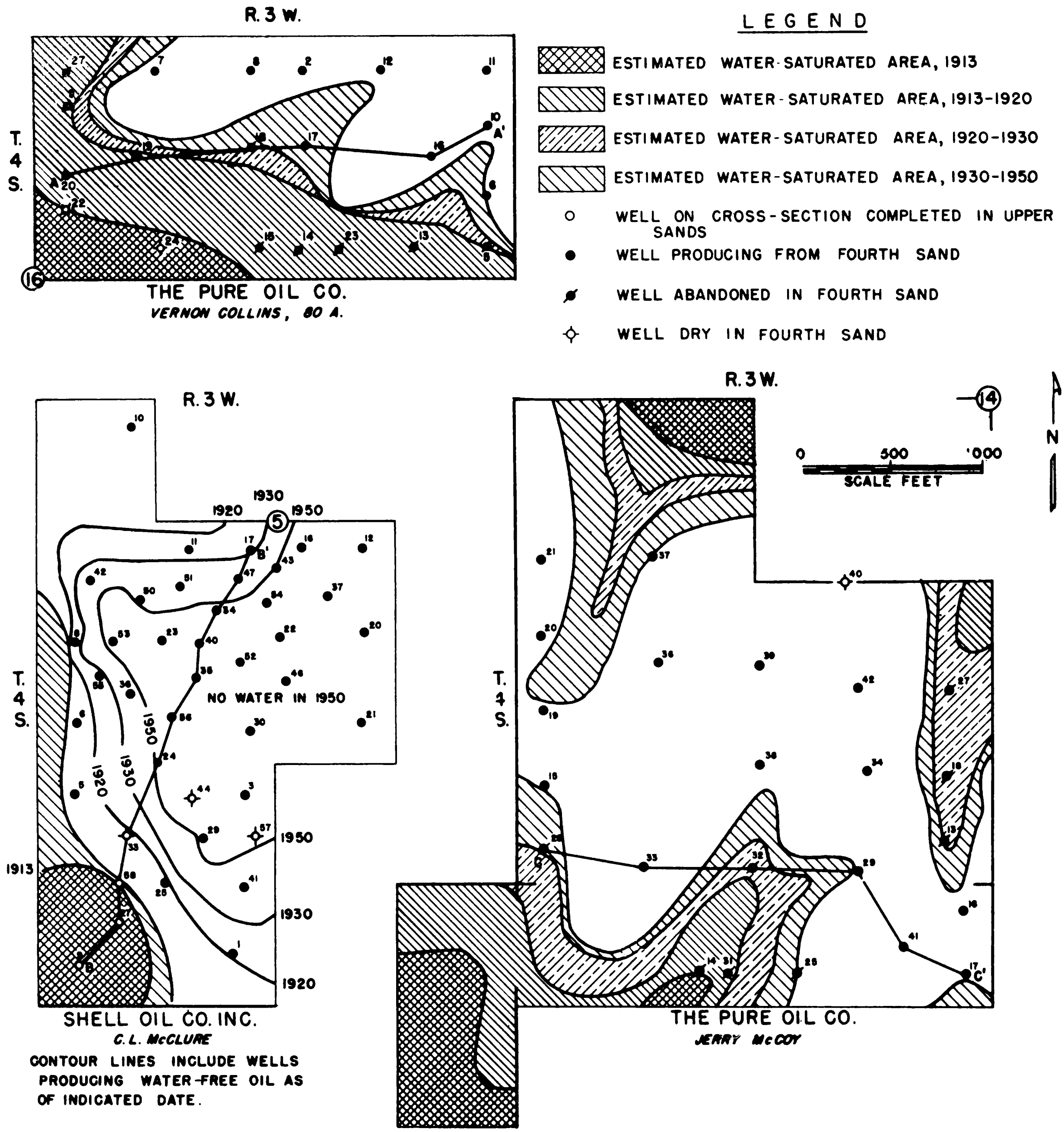


Figure 21. - Progressive advance of water in fourth Healdton sand underlying three leases, Healdton oil field, Carter County, Okla.

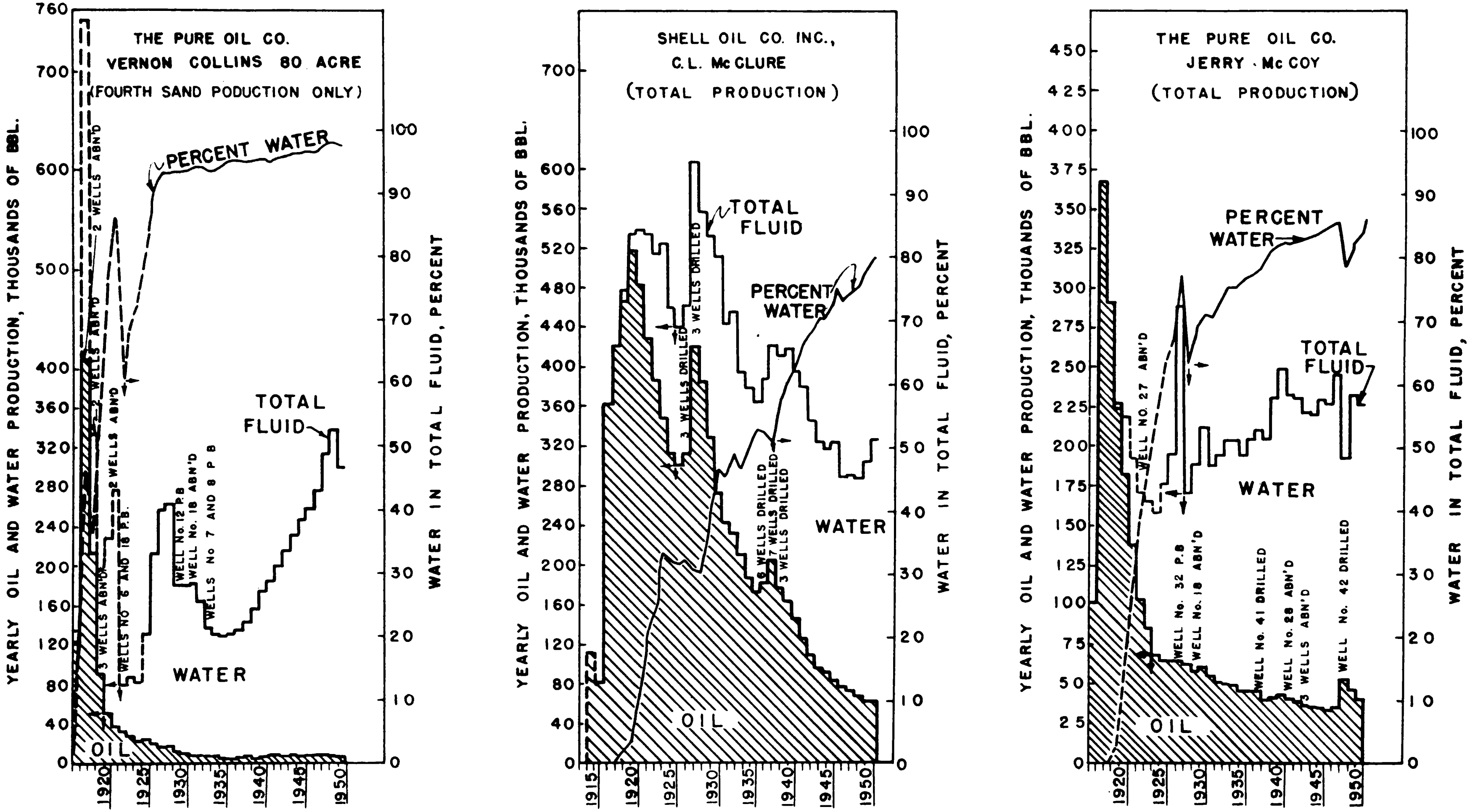


Figure 22. - Production histories of three leases with active water drive in fourth Healdton sand, Healdton oil field, Carter County, Okla.

As computed from drillers' logs, 2,629 acre-feet of the fourth sand on the Vernon Collins 80-acre lease originally contained mobile oil. The comparative wealth of fourth-sand data available permitted calculations of porosity and connate water for this lease that differed from the average porosity and connate water values used for the fourth sand throughout the rest of the field. Porosity ranges from 12 percent to 27.5, according to location and sand conditions, and the weighted average porosity of the sand is 17.8 percent. Using the formation volume factor of 1.044 and estimating the connate water at 27.5 percent, the oil originally in place was calculated to be approximately 2,519,500 barrels. As discussed earlier the residual-oil saturation could be reduced to an average of about 29 percent by efficient flooding. After deducting this 29 percent residual-oil saturation, the volume of mobile oil would be approximately 1,466,700 barrels. The efficiency of the water drive would be the total oil recovered at abandonment date (1,227,000 barrels) divided by the total mobile oil (1,466,700 barrels), an efficiency of 83.7 percent.

Shell Oil Co., Inc., C. L. McClure. - The second lease studied is a 110-acre lease, located in sec. 5, T. 4 S., R. 3 W. near the crest of the field structure, but the southwest corner is near the outer productive limit of the field. Drillers' logs of wells near the center of the lease record the first Healdton sand at approximately 300 feet above sea level (fig. 11). From this high the strata dip southwest at about 440 feet per mile and northwest at approximately 480 feet per mile.

South to north cross section B-B' (fig. 20) from well 9, completed in the upper Healdton sands, to well 17, completed in the fourth sand, shows the thickness and attitude of the several sand zones. Production data indicate that the fourth sand zone had an effective water drive and that on the southern edge of the lease the third sand zone may have had a limited water drive. Wells on this lease were neither cored nor electrically logged, although radioactivity well logs were available for five wells to help correlate the sands. Within the last 15 years, 19 new wells have been drilled and several old wells have been deepened, so that more reliable and complete data as to sand conditions are available for this lease than for The Pure Oil Co. Vernon Collins 80-acre lease described above. Cross section B-B' shows the top of the first sand to be at 144 feet above sea level in well 9, and the top of the Ordovician strata is estimated to be 240 feet below sea level, giving a thickness of 384 feet for the total Healdton-sand section. In well 56 the top of the first sand is 299 feet above sea level and the top of the Ordovician strata 89 feet below sea level, indicating a thickness of the total Healdton-sand section of 388 feet. In well 17 at the north end of the cross section, the top of the first sand is 158 feet above sea level and the estimated top of the Ordovician strata is 220 feet below sea level, showing a thickness of 378 feet. The total Healdton-sand section does not vary much with structure, but the individual sands are not consistent in thickness.

The initial oil production of the original wells ranged from 25 barrels per day to a high of 436 barrels per day and averaged about 140 barrels daily. Infill wells drilled later in the life of the lease had lower initial production rates.

Well 1 in the southeast corner of the lease was completed in the fourth sand in September 1913, and all producing sands above were open for production. The lease was developed slowly, and it was not until February 1921 that the last well in the original drilling campaign was completed. During this development period two dry holes were drilled, and wells 27 and 28 were abandoned soon after completion because of high water production. Water was produced from other wells on the lease as early as 1917. From 1921 to 1926 one well was abandoned, presumably because of low oil production. In July 1926 an infill-drilling campaign was begun, and by August 1927 six additional wells were completed as oil producers. In 1932 structurally low wells 7 and 9 along the south line of the lease were abandoned because of high water production. Drilling of well 40 in February 1936 initiated the second infill-drilling campaign, during which 16 producing wells were drilled and several of the older wells were deepened to lower sands. The last productive infill well was completed in December 1938, but since then, some wells have been either deepened to lower sands or plugged back to upper sands.

Although water was not reported in any early wells that penetrated the fourth sand, the probable oil-water contact in the fourth sand was established by interpreting drillers' logs on adjacent leases. From all the data available, it appears that, had wells been drilled deep enough during primary development, water would have been encountered in the fourth sand in the southwest corner of the C. L. McClure lease between 50 and 60 feet below sea level and in the northeast corner of the lease between 180 and 200 feet below sea level. Figure 21 shows a map of the Shell Oil Co., Inc., C. L. McClure lease, with the original water-saturated area in the fourth sand in the southwest corner of the lease. It is estimated that approximately 9 acres of the fourth sand originally was water-saturated.

By 1920 the water had advanced up-structure to the position shown on the map (fig. 21), and some water was being produced from four fourth-sand wells. During this period of primary development and flush production, 2,457,000 barrels of oil was produced from all sands on the lease. From the data available, it appears that the water advanced up-structure from the southwest and northwest corners and along the west edge of the lease. Individual monthly oil- and water-production records were available for all producing wells, and the advance of edgewater during a period of time could be discerned readily. By 1930 varying amounts of water was being produced with the oil in all wells included within the contour line for that year. By 1950 water was being produced from 15 wells in the fourth sand in the western part of the lease, and that sand underlying an area represented by the cross-hatching was estimated to be entirely water-saturated.

Figure 22 shows the production history for all sands on the Shell Oil Co., Inc., C. L. McClure lease. Because many early wells were open to all sands, it was impossible to separate the fourth-sand production from that produced from the other sands. Most of the water produced on the lease was definitely from the fourth sand, and, if available, a graph of the fourth-sand oil and water production alone would show the natural water drive more clearly. The graph shows that the maximum yearly oil production from all sands was not reached until 1919, almost 6 years after primary development was begun. One year before this peak oil production, a small amount of water was produced and this volume is shown on the graph as the difference between the oil and the total fluid production. The two peaks in 1927 and 1937 on the oil-production and the total-fluid curves are primarily the results of infill drilling. Except for these two peaks the oil and water production has declined steadily since 1919. In 1950 the oil production was 65,000 barrels and the water production was 328,000 barrels. The curve showing the percentage of water in total produced fluid illustrates the natural water drive on this lease more decisively. Since 1917 the percentage of water in the total produced fluid has increased almost steadily, being about 80 percent by 1950.

The Pure Oil Co. Jerry McCoy. - The third lease considered is in secs. 14, 22, 23, T. 4 S., R. 3 W., near the west edge of the southeast extension. The axis of the main anticlinal structure passes northwest to southeast across this lease, and there is a small dome near the east edge of the lease. The rock strata dip north, west, and south from this dome.

West to east cross section C-C' (fig. 20) from well 28 to well 17 shows the thickness and attitude of all the sands. Only one core analysis of the fourth sand was available on this lease. Electric logs were not made in any of the wells, and subsurface structure was interpreted almost entirely from drillers' logs. In this area the first sand is discontinuous, and most of the wells are completed in lower sands. The tops of the sands are higher structurally in wells 29 and 32 than in well 28 on the west edge or in well 17 on the east edge of the cross section. The sands vary in thickness according to location and are thicker near the center or structurally high part of the lease.

The initial oil production from the individual wells ranged from 5 to 400 barrels per day, with an average of about 130 barrels per day. Logs of wells drilled nearer the crest of the structure recorded higher initial-production rates than did logs of wells drilled near the productive limits of the reservoir.

Well 1, drilled in July 1914, near the center line along the west edge of sec. 14, T. 4 S., R. 3 W., was a dry hole. Well 2, completed in April 1916, in the northeast corner of sec. 22, T. 4 S., R. 3 W., initially produced 100 barrels of oil per day. By October 1918, 37 additional wells had been completed. In May 1922 well 27 was abandoned, presumably because of low oil production. Since 1922 two additional wells have been drilled - well 41 in October 1937 and well 42 in September 1948. Several wells were abandoned because of high water production, and some of the earlier wells were deepened to lower sands.

The logs of some wells, drilled on the south side of the anticlinal structure, recorded water in the fourth sand. Using these logs and those of wells on adjacent leases, the original oil-water contact in the fourth sand zone was established at approximately 400 to 430 feet below sea level. On the north side of the anticlinal structure, the original oil-water contact was established at approximately 350 feet below sea level. Figure 21 shows that approximately 12 acres of the fourth sand zone in the southwest part of the lease and 20 acres in the north part of the lease were water-saturated originally.

From all data available it appears that the water drive was confined to the fourth sand. Between 1913 and 1920 the water had advanced in the fourth sand, underlying an area shown in figure 20. By 1930 the water had advanced up-structure, four wells had been abandoned, and considerable amounts of water were being produced from all wells in the fourth sand. By 1950 three more wells had been abandoned, and the fourth sand underlying approximately 40 percent of the lease had been flooded. Although the advance of water was influenced by structure, it appears that "coning and fingering" occurred in the southern and western parts of the lease where the water advance was more rapid. This irregular advance could have been caused by variance in permeability or by different methods of operation of the individual wells.

Figure 22 shows the oil- and water-production history of The Pure Oil Co. Jerry McCoy lease and the percentage of water in the total produced fluid. As it was impossible to separate the fourth-sand production from the total, the indicated oil production is from all the sands, whereas the major portion of the produced water is from the fourth sand. Yearly oil production was at a maximum in 1917 and from this peak of 367,750 barrels per year declined sharply, with the result than by 1925 yearly oil production was 65,550 barrels. Small quantities of water were produced from the wells in 1919, but the total fluid production decreased until 1924, when well 32 began to yield large volumes of water. This well was plugged back in 1927, and the volume of total produced fluid decreased sharply at this time, but the proportion of water to total produced fluid remained approximately 68 percent. In 1929 well 18 was abandoned, resulting in a sharp drop in total produced fluids, as shown by the curve. From 1930 to 1940 the rate of oil production decreased steadily, whereas water production increased. The abandonment of well 28 in 1941 and wells 8, 14, and 26 in 1943 caused yearly water production to decrease. Deepening of several wells and the drilling of well 42 in 1948 caused a slight increase in both oil and water production.

Between 1929 (when well 18 was abandoned) and 1948 the percentage of water in the total produced fluid increased from 64 to 85 percent. Following the deepening and drilling in 1948 the water percentage dropped sharply to 79 percent, but by 1950 produced water constituted about 86 percent of the total fluid production.

On the three leases studied, a natural water drive in the fourth sand is apparent in that increasingly larger areas are being flooded, the oil-production rates are being sustained, and the percentage of water in total produced fluid has steadily increased. Other areas where natural water drive may be active should be carefully studied before secondary-recovery methods are applied.

Gas Production

In addition to a large production of oil, substantial quantities of gas also have been produced from the Healdton field.

The first big gas well, with an estimated initial production of 33 million cubic feet daily, was completed in December 1913 by the Crystal Oil Co. on what is now the Sinclair Oil & Gas Co. Million and Thomas lease in sec. 5, T. 4 S., R. 3 W. As many as three gas sands, including stray sands and the first Healdton sand, were penetrated at depths of 500 to 900 feet in wells on this lease. Pressures up to 600 p.s.i. were reported. A few wells completed in 1915 and 1916 in sec. 4, T. 4 S., R 3 W., produced gas from Healdton sands ranging in depth from 800 to 1,100 feet. The initial daily volumes from these wells were not recorded. Several gas wells with capacities of 20 to 40 million cubic feet daily were completed in sec. 15, T. 4 S., R. 3 W. during the same years. These wells penetrated dry-gas sands in the Healdton sand section at depths ranging from 900 to 1,200 feet.

During these early years dry gas was piped to Ardmore, Ringling, and Wilson by local gas companies (10).

Table 2, page 6, shows that only 26 gas wells were completed in the Healdton field during the first 3 years of development; many oil wells penetrated gas-producing zones in the first sand or in the stray sands above the Healdton series.

Approximately 50 wells originally were completed as dry-gas producers, but none of these were producing gas by 1950. Some were abandoned as early as 1919, and most of the remaining ones were shut in during the 1930's. These wells produced dry gas in the beginning, but many "went to oil" and were "put on the pump" a few years after completion. Some wells, however, remained dry after the gas was exhausted and were abandoned.

Figure 23 shows the approximate extent and thickness of the original gas-productive sands in the first sand and the stray sands above.

Gas was produced from the first sand in several scattered, structurally high areas throughout the field; the largest area, in secs. 4, 5, 8, and 9, T. 4 S., R. 3 W., along the crest of the anticline includes 335 acres. Smaller areas are

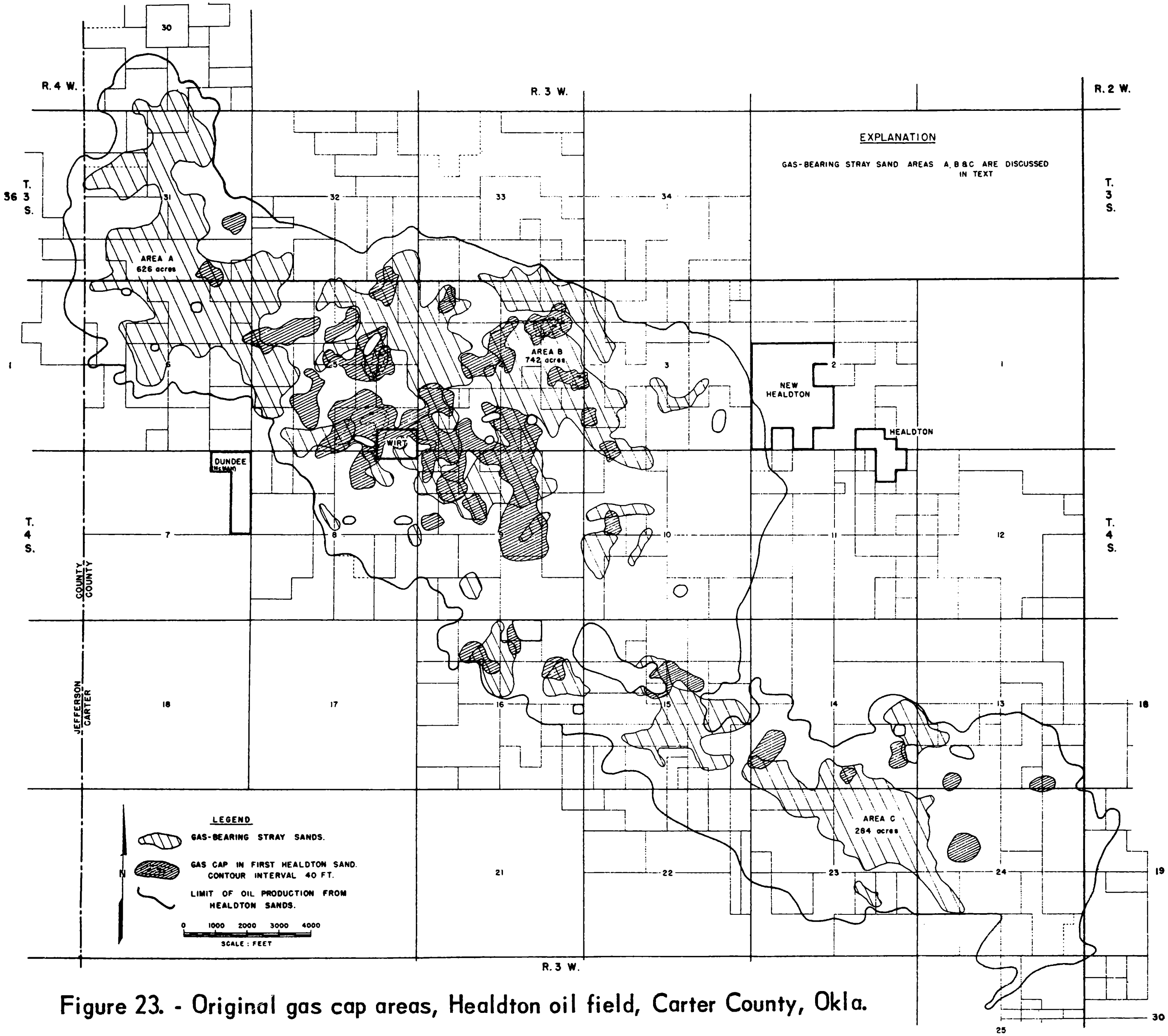


Figure 23. - Original gas cap areas, Healdton oil field, Carter County, Okla.

scattered throughout the field on local structural highs. Thickness of the gas-productive first sand ranges from less than 1 to 120 feet. with an average of 25 feet. Apparently the gas-oil contact was not horizontal but varied in elevation from 150 to 350 feet above sea level on the highest part of the structure and from 50 feet above sea level to as low as 50 feet below sea level in scattered areas on the flank.

Although stray sands are highly lenticular and discontinuous, figure 22 shows three principal areas, designated as areas A, B, and C, where the stray sands produced gas.

Area A in the northwestern part of the field covers 626 acres, in which gas sands range in thickness from less than 1 foot to 50 feet. In this area the elevation of the gas-oil contact ranges from 202 to 239 feet above sea level.

Area B includes 742 acres in the north-central part of the field where gas sands range in thickness from a mere parting to a maximum of 50 feet. Average thickness is about 22 feet. Gas was found above the oil at elevations between 129 and 202 feet above sea level.

Stray gas-cap area C in the southeastern part of the field includes 284 acres and averages 20 feet in thickness. The original gas-oil contact ranges from 130 to 200 feet above sea level.

Figure 22 also shows many small stray gas areas scattered throughout the field, ranging in size from 5 to 146 acres and totaling 509 acres.

In general, the thickness of stray sands containing gas averages 19 feet over a total area of 2,161 acres. Although the elevation of this gas-oil contact varies considerably, depending on local conditions, dry gas was not found in sands at elevations less than 129 feet above sea level, and oil was not found at elevations greater than 239 feet above sea level.

Non-Healdton wells in the field have yielded large quantities of gas, some from shallow sands and some from deeper sands. Two wells penetrated gas sands at depths greater than 2,000 feet. The first of these, in sec. 4, T 4 S., R. 3 W., was completed in 1924, with an initial rate of 50,000 cubic feet of gas daily. The second well was completed in 1948 in sec. 3, T. 4 S., R. 3 W., at a depth of 2,258 feet. The drill pipe and bit were cemented in this well to control the gas, which "blew out" and caught fire. No initial production test was made, but the capacity was estimated to be 500,000 cubic feet of gas daily. In 1951 mud in the drill pipe was bailed out; and, after a small shot, shut-in pressure measured 1,500 p.s.i., but open-flow capacity was only 6,500 cubic feet daily.

The volume of casinghead gas produced during the early life of the field was undoubtedly quite large, although before 1928 no substantiating records of gas production are available.

Table 6 lists the known gas-compressor plants in the Healdton field. A number of natural-gasoline compression plants began operation in 1916 and 1917, and in 1918 the Humble Oil Co. began operating a natural-gasoline refrigeration plant on the Lucy Tubbee lease in sec. 24, T. 4 S., R. 3 W. The amount of gasoline recovered by these early plants is not known.

TABLE 6.--Gas compressor plants, Healdton oil field, Carter County, Okla.

Name	Location: Lease	Q.	S.	T.	R.	Leases connected	Type operation	Date operation begun	Date operation discontinued	Units	Type prime mover	Capacity, M c.f. daily	Pressure: Intake	Exhaust, p.s.i.
Shell Oil Co. Barco plant	Wirt Franklin do.	NE NE	8 8	4S 4S	3W 3W	51 63	Gasoline comp. Gasoline absorp.	1916 1940	1940 1946	1-Aux. Miller 3-Laidlaw compressors 1-Cooper-Bessemer 18x24" Compressor	3-110 hp. Millers do. 170 hp. combination	2,000	13" vac.	48
Shell Oil Co. (Harry Ells, Inc., Lessee)	do.	NE	8	4S	3W	67 leases	do.	1946	Operating	(Same as above)	(Same as above)	2,000	13" vac.	48
The Pure Oil Co.	Westheimer & Daube 60 acre	NE	9	4S	3S	11 Pure leases- 9 others	Vacuum and compression	Gaso. plant- 1916 Vacuum-1935	Discontinued 1935 Operating	3-14x20" Ingersoll-Rand 180 r.p.m.	3-80 hp. Cooper	212 -	10" vac. -	3-7 -
Sinclair Oil & Gas Co.	J.S.Mullen	NE	4	4S	3W	J.S.Mullen and Ardworth (after 1945)	Vacuum and repressuring	October 1943	do.	-	-	-	10" vac.	250
Shell Oil Co.	L.Tubbee	NW	24	4S	3W	L.Tubbee, M.Tubbee, and Rhodes	do.	1928	do.	2-17x12" single stage 1-2 stage 4x10", 9½x10" Ingersoll-Rand	Superior 35 hp.	-	-	-
Gates Oil Co. (now Cox & Hamon)	Jackson	SE	15	4S	3W	Cox & Hamon-L.Watkins, Carnes, Ward, Ingram,E. Watkins,Wesley,Simpson	Gasoline compression	1916	1932	3-vacuum pumps	4-110 hp. Millers 3- 70 hp. Millers	2,000	-	75 low 250 high
Do.	Wesley	SW	3	4S	3W	Wesley	Vacuum and compression	1916	1940(?)	1-Blaisdell combination 16x20"(180 r.p.m.)	180 hp. Blaisdell	-	-	-
Magnolia Petroleum Co.	Hamon	NW	15	4S	3W	J.L.Hamon,R.Johnson,	Gasoline compression	1916-17	1935	3-Cooper-Bessemer compressors	3-90 hp. Cooper-Bessemer	-	-	-
Do.	C.Richards	NE	31	3S	3W	C. Richards, E. T. Richards, Woodruff	Gassoline compression and vacuum	1916	1924-25	9-Cooper-Bessemer compressors	90 hp. Cooper-Bessemer	-	6" vac.	Atmos.
Do.	J.B.Rose	NW	23	4S	3W	Rose, Daniels, Watkins, Tubbee	Gasoline compression	1916-17	1926-27	5-Cooper-Bessemer compressors	5-90 hp. Cooper-Bessemer	-	-	-
McGraw Oil Co.	Stewart & Hawk	SW	33	3S	3W	Stewart &Hawk	Vacuum repressuring	1939	1941	1-Twin 20x12" Ingersoll-Rand	-	-	-	-
Do.	do.	SW	33	3S	3W	do.	do.	1946	Oct. 1946	1-9x8" Ingersoll-Rand 130 r.p.m.	25 hp. Superior	-	-	-
Humble Oil Co.(now Shell)	L.Tubbee	NW	24	4S	3W	L. Tubbee	Gasoline refrigeration	1918	1922	5-14x20" Gaso. (belted to engine)	Bruce McBeth	-	2" vac.	-
Carter Oil Co.(now Shell)	C.R.Smith	NW	5	4S	3S	Schermerhorn-Smith, Shell-Willis	Vacuum and gasoline compression	1918	1920	Ingersoll-Rand 6-units-V-type-2-stages	-	3,000	20" vac.	350
Shell Oil Co.	H.Z.Ward	NW	6	4S	3W	Ward	Vacuum and compression	-	1942	Ingersoll-Rand Twin-cyl. 160 r.p.m. 12x10"	35-hp.Superior-4 cycle gas	200	6" vac.	Atmos.
Do.	C.R.Smith	NW	5	4S	3W	Smith, Johnson "B", Koskie	Vacuum	Before 1939	1942	18x10" Twin cyl.-160 r.p.m. Ingersoll-Rand 2-stages	Superior 35 hp.	200	-	-
Merrick Gasoline Co. (now Schermerhorn Oil Co.)	Fee 40 acre	CW½	5	4S	3W	Fee 20 and 40, Merrick	Gasoline compression	July 1918	May 1922	2x10" 2 stage Ingersoll-Rand, High-350 p.s.i., Low-70 p.s.i.	2-200 hp. engines	1,000	Atmos.	350
Schermerhorn Oil Co.	do.	CW½	5	4S	3W	Fee 40	Vacuum repressuring	Mar. 1935	Nov. 1935	2-National compressors	100 hp. combination	450	Atmos.	50-150
Kewanee Oil Co.	Jones	CW½	4	4S	3W	Jones	do.	Nov. 1937	1940	9x18" Ingersoll-Rand 160 r.p.m.	4 cyl. Waukesha	250	-	-

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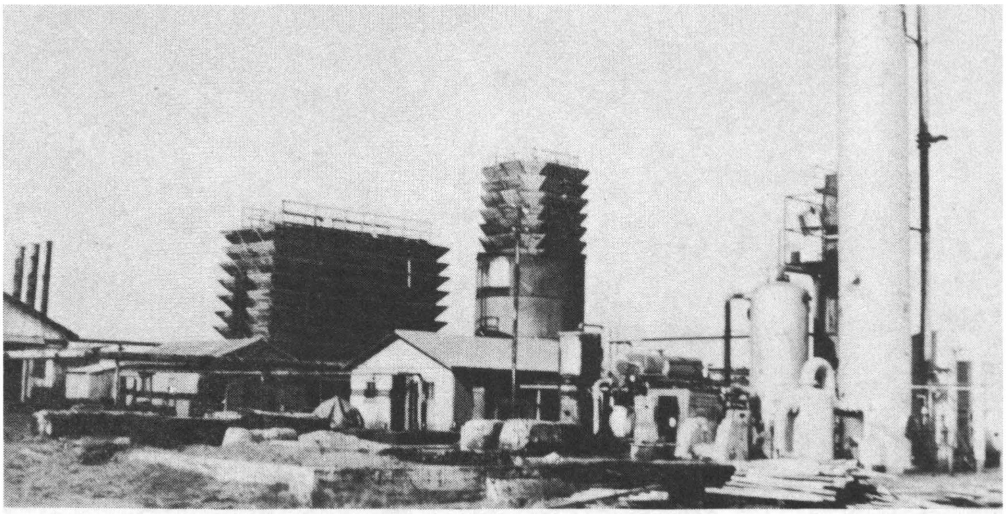

Figure 24. - Shell Oil Co. Barco gasoline plant (Harry Ells operator), Healdton oil field, Carter County, Okla.

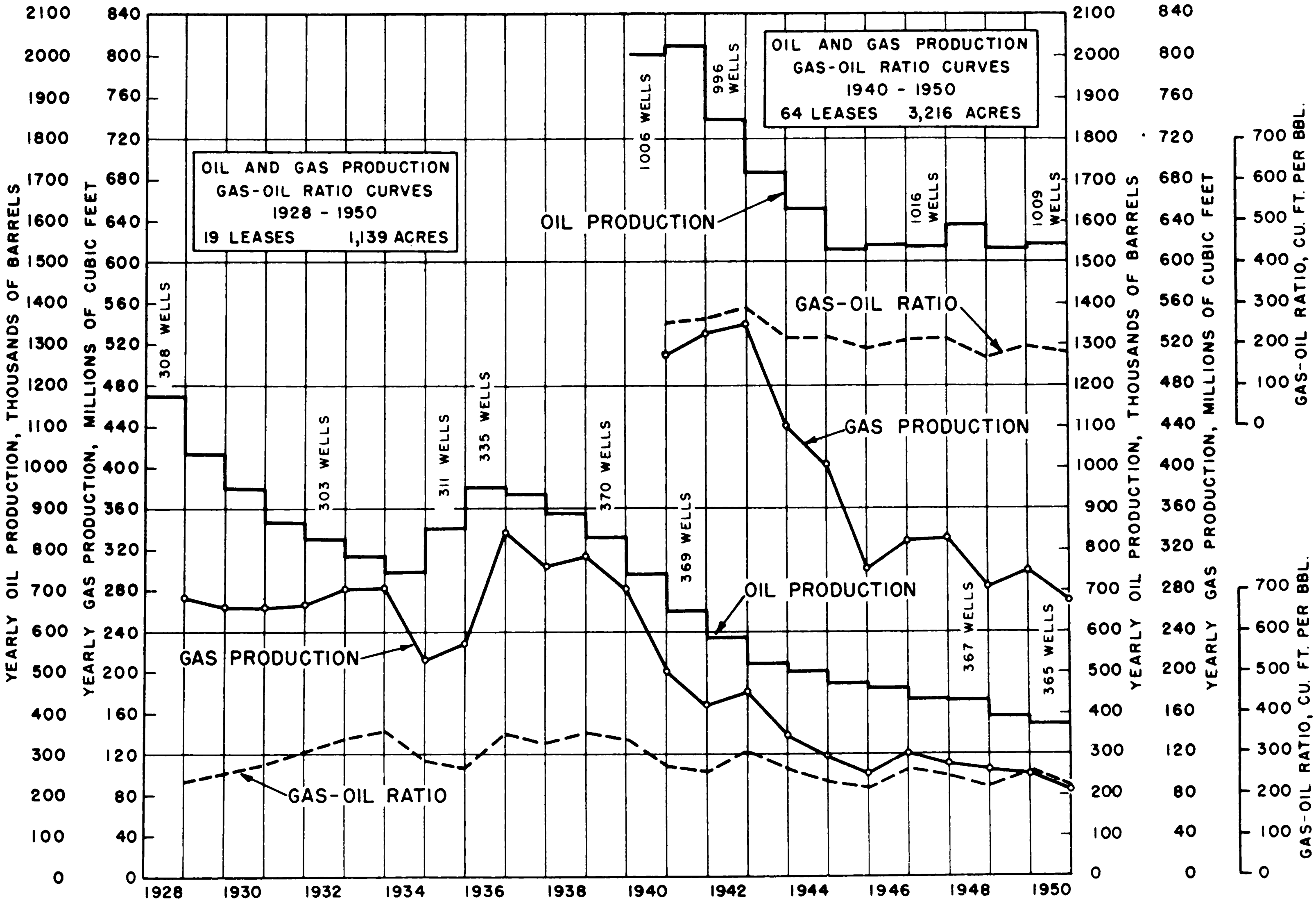

Figure 25. - Oil- and gas-production history of representative leases, Healdton field, Carter County, Okla.

Vacuum, which has been applied intermittently since 1917, has aided production of casinghead gas (2). In 1917 the Oklahoma Corporation Commission ruled against the use of vacuum in any field in oklahoma unless permission was obtained from the Commission. However, a limited use of vacuum at the casinghead for gathering gas to be used for lease operations and delivery to gasoline plants was condoned. A few plants, which were operating at a vacuum of almost 20 inches of mercury, were shut down by the Commission.

Some operators continued to apply vacuum in varying amounts until 1935, when a controversy arose over its use in the field. The Oklahoma Corporation Commission issued another order prohibiting the application of vacuum in the Healdton field. After an appeal to the State Supreme Court by the Gilmer Oil Co., a temporary order was issued by the Court on October 8, 1937, limiting the use of vacuum to 6 inches of mercury. Consequently, a final Order by the Commission (No. 12429) was issued on July 22, 1938, permitting the use of vacuum up to 6 inches of mercury at the casinghead in producing oil in the Healdton oil field. Also, each lease was required to be equipped with a back-pressure vacuum regulator and chart-recording meter of an adequate type to control and record the amount of vacuum applied.

During recent years the Shell Barco plant at Wirt, Okla., in sec. 8, T. 4 S., R. 3 W., operated by Harry Ells, Inc. (fig. 24), has been the only gasoline plant in operation in the field. This plant, built by Jake Hamon early in the life of the field, was operated as the Shell Oil Co., Inc., Barco gasoline plant between 1916 and 1947, when Harry Ells, Inc., took over the operation on a farm out. First built and operated as a compression plant, it was converted to an absorption plant in 1940, when gathering lines were extended to include several additional leases. During 1950 the plant processed an average of 1.7 million cubic feet of gas daily, gathered at 6 inches of mercury vacuum from 67 leases in the Healdton field and from 9 leases in the nearby Hewitt field.

Three other plants are operated to apply vacuum to the casingheads of the wells. Largest of these is The Pure Oil Co. booster plant on the Westheimer and Daube 60-acre lease in sec. 9, T. 4 S., R. 3 W. Operated as a compression gasoline plant between 1916 and 1935, the plant now gathers gas from 11 leases of The Pure Oil Co., and 9 other leases, at vacuum equivalent to 6 inches of mercury, and delivers it to the Harry Ells, Inc., gasoline plant at a pressure of 3 to 7 p.s.i. A smaller plant on the Sinclair Oil & Gas Co. J. S. Mullen lease in sec. 4, T. 4 S., R. 3 W., gathers gas from the Mullen and Ardworth leases for injection into wells on the Mullen lease. A plant on the Shell Oil Co., Inc., L. Tubbee lease in sec. 24, T. 4 S., R. 3 W., originally was used for gas injection but now is used to apply vacuum to wells on three Shell Oil Co., Inc., leases in the area. On several edge leases not served by compressor plants vacuum is applied to the wells by rodline pumps operated from the central power.

Natural Gasoline Association of America contracts between the operators and the Harry Ells, Inc., plant provide for the purchase of casinghead gas from each lease at a price depending upon the periodically tested gasoline content of the incoming gas and the market price of natural gasoline. Denuded residue gas not required for plant operation is returned to the several leases. Additional dry gas may be purchased from Harry Ells, Inc., when the volume of gas returned is not adequate for lease requirements.

Figure 25 shows the oil- and gas-production history of several representative leases in the Healdton oil field. Oil- and gas-production data since 1928 were available for 19 leases covering 1,139 acres and including more than 300 producing oil wells.

Both the oil- and gas-production rates increased in 1936 with the drilling of additional wells but have declined steadily since that date. The indicated gas production is that volume sold to the gasoline plant less included air (see table 10, p. 43) and is not necessarily the total volume of gas produced on the leases. The gas-oil ratio for all 19 leases based upon total oil and gas sales, less included air, has varied somewhat from year to year with a marked increase between 1936 and 1939 following the infill drilling. For most of this period gas was being injected through wells on one or two of these leases, but the total volume of gas thus injected constituted only 6 to 18 percent of the total gas production.

Since 1940 gas-sales data are available for 64 leases, including the 19 mentioned above. These 64 leases, with approximately 1,000 producing oil wells, cover 3,216 acres of the most productive areas of the field. The gas-oil ratio, after deduction for air content, declined from a high of 290 cubic feet per barrel in 1942 to 185 cubic feet per barrel in 1950. Gas production declined from 530 million cubic feet per year in 1942 to 270 million cubic feet per year in 1950. During part of this period gas was being injected into wells of five leases, but the total volume of gas injected constituted 8 percent or less of total gas production.

If these gas-oil ratios are representative of Healdton-sand production in the field, they indicate that about 16 billion cubic feet of gas has been produced since 1929 compared to a total injected volume of about 1 billion cubic feet during the same period.

When it is considered that the original solution gas-oil ratios were about 90 cubic feet per barrel, it is surprising that so much gas is available after 20 years of vacuum application. The conclusion is obvious that a large volume of unproduced oil in the reservoir is contributing to the gas production from the leases; but, because definite data are not available regarding the solubility of the gas in the reservoir oil and the reservoir pressure history, it would be impossible to make any quantitative estimates of this volume.

Character of Produced Fluids

Produced Oil

Thirteen samples of Healdton crude oils were analyzed by the Bureau of Mines routine method, and a study of these analyses has brought forth the conclusion that two and possibly three distinctly different types of oil are being produced from the Healdton sands. For convenience the oils will be referred to as types A, B, and C.

The 3 crude-oil analyses in table 7 are representative of 13 samples studied; sample A-8 is a typical type-A oil, sample B-3 is a typical type -B oil, and sample C-1 is a typical type -C oil.

Table 8 shows the distinguishing characteristics (gravity, sulfur content, and viscosity) of 23 samples of crude oil separated into types A, B, and C. From a detailed study of the 13 complete analyses available it was possible to determine the type of oil for the remaining samples by checking their A.P.I. gravities and percentages of sulfur. The type A oils have higher gravity, definitely lower sulfur content, and lower viscosity than the other two types. The type C oils differ from the type B in having slightly lower gravity and higher viscosity, sulfur content, and carbon residue.

TABLE 7. - Chemical and physical properties of three crude oils, Healdton oil field, Carter County, Okla.

Typical A-type crude oil
Magnolia Petroleum Co.
E. T. Richards well 93

Sample A-8, table 8
1,102-1,142 feet
Sec. 31, T. 4 S., R. 3 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.868 A.P.I. gravity, 31.5° Pour point, °F. below 5
Sulfur, percent, 0.72 Color, dark green
Saybolt Universal viscosity at 77° F., 87 sec.; at 100° F., 66 sec.

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1. - Distillation at atmospheric pressure, 736 mm. Hg
First drop, 33° C. (91° F.)

Fraction No.	Cut at- °C.	Cut at- °F.	Percent	Sum, percent	Sp. gr., 60/60 °F.	°A.P.I., 60 °F.	C.I.	Aniline point, °C.	S.U. visc., 100 °F.	Cloud test, °F.
1	50	122	0.1	0.1)						
2	75	167	.7	.8)						
3	100	212	2.8	3.6)	0.723	64.2	-	50.2		
4	125	257	4.1	7.7	.757	55.4	30	48.6		
5	150	302	3.9	11.6	.778	50.4	32	48.4		
6	175	347	4.4	16.0	.800	45.4	36	48.6		
7	200	392	4.2	20.2	.816	41.9	37	52.9		
8	225	437	3.6	23.8	.825	40.0	36	60.0		
9	250	482	5.3	29.1	.831	38.8	33	64.4		
10	275	527	7.2	36.3	.836	37.8	31	69.8		

STAGE 2. - Distillation continued at 40 mm. Hg

Fraction No.	Cut at- °C.	Cut at- °F.	Percent	Sum, percent	Sp. gr., 60/60 °F.	°A.P.I., 60 °F.	C.I.	Aniline point, °C.	S.U. visc., 100 °F.	Cloud test, °F.
11	200	392	2.9	39.2	0.843	36.4	30	74.4	42	10
12	225	437	6.7	45.9	.852	34.6	31	77.6	46	25
13	250	482	6.3	52.2	.865	32.1	34		57	40
14	275	527	5.1	57.3	.878	29.7	37		82	55
15	300	572	8.0	65.3	.887	28.0	38		155	70
Residuum			32.5	97.8	.951	17.3				

Carbon residue of residuum, 7.0 percent; carbon residue of crude, 2.5 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	°A.P.I.	Viscosity
Light gasoline	3.6	0.723	64.2	
Total gasoline and naphtha	20.2	.777	50.6	
Kerosine distillate	3.6	.825	40.0	
Gas oil	21.1	.840	37.0	
Nonviscous lubricating distillate	11.5	.857-.880	33.6-29.3	50-100
Medium lubricating distillate	8.9	.880-.893	29.3-27.0	100-200
Viscous lubricating distillate	-	-	-	Above 200
Residuum	32.5	.951	17.3	
Distillation loss	2.2			

TABLE 7. - Chemical and physical properties of three crude oils, Healdton oil field, Carter County, Okla. (Cont.)

Typical B - type crude oil
Cox & Hamon
L. Carnes well 9B

Sample No. B-3, table 8
845 - 1,189 feet
Sec. 15, T. 4 S., R. 3 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.876 A.P.I. gravity, 30.0 Pour point, °F. 20
Sulfur, percent, 0.93 Color, dark green
Saybolt Universal viscosity at 77 °F., 140 sec.; at 100 °F., 87 sec.

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1. - Distillation at atmospheric pressure, 755 mm. Hg
First drop, 27 °C. (81 °F.)

Fraction No.	Cut at- °C.	Cut at- °F.	Percent	Sum, percent	Sp. gr., 60/60 °F.	°A.P.I., 60 °F.	C.I.	Aniline point, °C.	S.U. visc., 100°F.	Cloud test, °F.
1	50	122	0.4	0.4)						
2	75	167	.7	1.1)						
3	100	212	1.5	2.6)	0.683	75.7	-	-		
4	125	257	2.8	5.4	.731	62.1	18	56.0		
5	150	302	3.9	9.3	.760	54.7	24	55.0		
6	175	347	3.7	13.0	.783	49.2	28	53.0		
7	200	392	3.4	16.4	.801	45.2	30	53.9		
8	225	437	4.0	20.4	.815	42.1	31	57.0		
9	250	482	5.2	25.6	.827	39.6	31	62.4		
10	275	527	7.0	32.6	.834	38.2	30	68.6		
STAGE 2. - Distillation continued at 40 mm. Hg										
11	200	392	3.3	35.9	0.844	36.2	31	73.2	40	10
12	225	437	6.6	42.5	.853	34.4	31	76.4	45	30
13	250	482	6.8	49.3	.866	31.9	34		56	45
14	275	527	5.7	55.0	.881	29.1	38		82	65
15	300	572	7.2	62.2	.891	27.3	40		150	80
Residuum			36.3	98.5	.970	14.4				

Carbon residue of residuum, 7.6 percent; carbon residue of crude, 3.1 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	°A.P.I.	Viscosity
Light gasoline	2.6	0.683	75.7	
Total gasoline and naphtha	16.4	.757	55.4	
Kerosine distillate	4.0	.815	42.1	
Gas oil	22.0	.839	37.2	50-100
Nonviscous lubricating distillate	11.5	.859-.883	33.2-28.8	50-100
Medium lubricating distillate	8.3	.883-.897	28.8-26.3	100-200
Viscous lubricating distillate	-	-	-	Above 200
Residuum	36.3	.970	14.4	
Distillation loss	1.5			

TABLE 7. - Chemical and physical properties of three crude oils, Healdton oil field, Carter County, Okla. (Cont.)

Typical C - type crude oil
The Pure Oil Co.
V. Collins 80-A well 21

Sample No. C-1, table 8
1,068-1,091 feet
Sec. 16, T. 4 S., R. 3 W.

GENERAL CHARACTERISTICS

Specific gravity, 0.888 A.P.I. gravity, 27.9° Pour point, °F. below 5
Sulfur, percent, 1.40 Color, dark green
Saybolt Universal viscosity at 100° F., 130 sec.; at 130° F., 95 sec.

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1. - Distillation at atmospheric pressure, 736 mm. Hg
First drop, 27° C. (81° F.)

Fraction No.	Cut at- °C.	Cut at- °F.	Percent	Sum, percent	Sp. gr., 60/60 °F.	°A.P.I., 60 °F.	C.I.	Aniline point, °C.	S.U. visc., 100 °F.	Cloud test, °F.
1	50	122	1.2	1.2)						
2	75	167	.7	1.9)						
3	100	212	1.5	3.4)	0.681	76.3	-	58.0		
4	125	257	2.4	5.8	.734	61.3	19	55.9		
5	150	302	3.1	8.9	.761	54.4	24	55.5		
6	175	347	3.1	12.0	.782	49.5	27	55.0		
7	200	392	2.9	14.9	.800	45.4	30	55.4		
8	225	437	3.5	18.4	.817	41.7	32	58.0		
9	250	482	4.2	22.6	.829	39.2	32	62.8		
10 1/	275	527	7.7	30.3	.838	37.4	-	66.9		

STAGE 2. - Distillation continued at 40 mm. Hg

Fraction No.	Cut at- °C.	Cut at- °F.	Percent	Sum, percent	Sp. gr., 60/60 °F.	°A.P.I., 60 °F.	C.I.	Aniline point, °C.	S.U. visc., 100 °F.	Cloud test, °F.
11	200	392	1.8	32.1	0.849	35.2	33	-	42	15
12	225	437	6.1	38.2	.859	33.2	34	72.4	46	30
13	250	482	6.3	44.5	.873	30.6	37		60	50
14	275	527	5.6	50.1	.888	27.9	41		85	65
15	300	572	7.5	57.6	.896	26.4	42		170	80
Residuum			40.3	97.9	.974	13.8				

Carbon residue of residuum, 11.0 percent; carbon residue of crude, 4.8 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	°A.P.I.	Viscosity
Light gasoline	3.4	0.681	76.3	
Total gasoline and naphtha	14.9	.750	57.2	
Kerosine distillate	3.5	.817	41.7	
Gas oil	18.5	.842	36.6	
Nonviscous lubricating distillate	11.6	.863-.889	32.5-27.7	50-100
Medium lubricating distillate	7.7	.889-.899	27.7-25.9	100-200
Viscous lubricating distillate	1.4	.899-.901	25.9-25.6	Above 200
Residuum	40.3	.974	13.8	
Distillation loss	2.1			

1/ Distillation discontinued at 273 °C. (523 °F.)

TABLE 8.--Comparison of properties of crude oil samples from the Healdton oil field, Carter County, Okla.

Sample No.	Company	Lease	Well No.	Location	Producing sands	Gravity °A.P.I.	Sulfur, percent	Viscosity, 80°F., cp.	Year analyzed
A-1*	Shell Oil Co., Inc.	Wirt Franklin	46	NE NE sec. 8, T. 4 S., R. 3 W.	1,2,3,3a	34.6	0.72	8.7	1939
A-2*	Do.	A. D. Horton	11	NW SE sec. 6, T. 4 S., R. 3 W.	1	32.5	.75	14.0	1950
A-3*	The Pure Oil Co.	V. Collins, 80 acre	11	SE NE sec. 16, T. 4 S., R. 3 W.	4	32.3	.75	10.9	1950
A-4	Texas-Gulf Producing Co.	Apple & Franklin	2	SW NE sec. 9, T. 4 S., R. 3 W.	No log	32.3	.80		1951
A-5*	Shell Oil Co., Inc.	A. D. Horton	7	NW SE sec. 6, T. 4 S., R. 3 W.	1,2,3	31.9	.72	13.0	1939
A-6*	Do.	C. L. McClure	41	SE SW sec. 5, T. 4 S., R. 3 W.	4	31.9	.74	11.8	1949
A-7*	Magnolia Petroleum Co.	C. Richards	8	SE NW sec. 31, T. 3 S., R. 3 W.	2,3(?)	31.9	.70	15.0	1949
A-8*	Do.	E. T. Richards	93	SW SE sec. 31, T. 3 S., R. 3 W.	2,3(?)	31.5	.72	14.0	1950
A-9	Do.	K. W. Dawson	3	NW NE sec. 4, T. 4 S., R. 3 W.	1	31.5	.80	-	1951
A-10*	Magnolia Pipeline		-	-	-	31.1	.72	13.5	1920
A-11	Shell Oil Co., Inc.	K. N. Hapgood	14	NE SW sec. 3, T. 4 S., R. 3 W.	1,2	31.0	.87	-	1951
B-1	Do.	L. Tubbee	6	NE NW sec. 24, T. 4 S., R. 3 W.	1,2	30.8	1.22	-	1951
B-2*	Rockland Oil Co.	Sarasota	49	SE NE sec. 23, T. 4 S., R. 3 W.	1,2,3,(?)	30.6	1.00	18.3	1949
B-3*	Cox & Hamon	L. Carnes	98	SE SE sec. 15, T. 4 S., R. 3 W.	4	30.0	.93	23.9	1950
B-4	Shell Oil Co., Inc.	L. Tubbee	9	SE NW sec. 24, T. 4 S., R. 3 W.	1	29.7	.98	-	1951
B-5	Magnolia Petroleum Co.	J. A. Smalley	33	SW NE sec. 10, T. 4 S., R. 3 W.	1,2,3	29.1	.99	-	1951
B-6*	Gray Oil Co.	Pugh	1	SW SW sec. 18, T. 4 S., R. 2 W.	Pugh	28.9	.92	31.3	1949
B-7	The Pure Oil Co.	J. McCoy	16	NE NW sec. 23, T. 4 S., R. 3 W.	1,2,3,4	28.7	.95	-	1951
B-8	Magnolia Petroleum Co.	J. Hamon	12	NE NW sec. 15, T. 4 S., R. 3 W.	No log	28.2	1.02	-	1951
C-1*	The Pure Oil Co.	V. Collins, 80 acre	21	SW NE sec. 16, T. 4 S., R. 3 W.	2	27.9	1.40	31.7	1950
C-2	Engelbrecht	Mobley	5	SE SE sec. 13, T. 4 S., R. 3 W.	No log	27.1	1.10	-	1951
C-3	Ring & Trachenburg	J. McCoy	1,2	NE SW sec. 14, T. 4 S., R. 3 W.	3	26.8	1.10	-	1951
C-4*	Magnolia Petroleum	F. E. Watkins	5	SW SE sec. 24, T. 4 S., R. 3 W.	No log	26.1	1.21	58.9	1949

* Distillation, Bureau of Mines routine method.

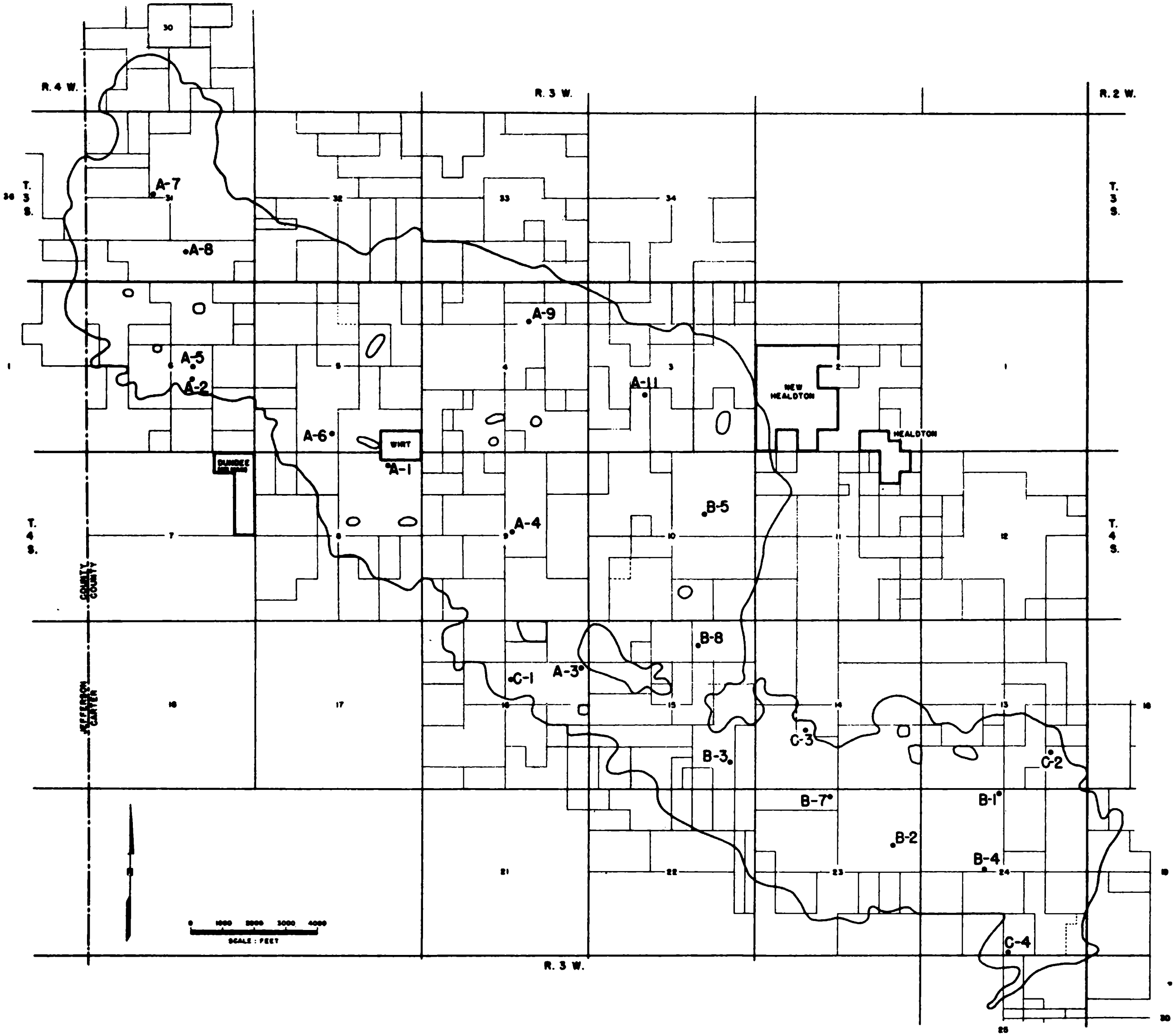

Figure 26. - Location of oil sample analyses shown in table 8.

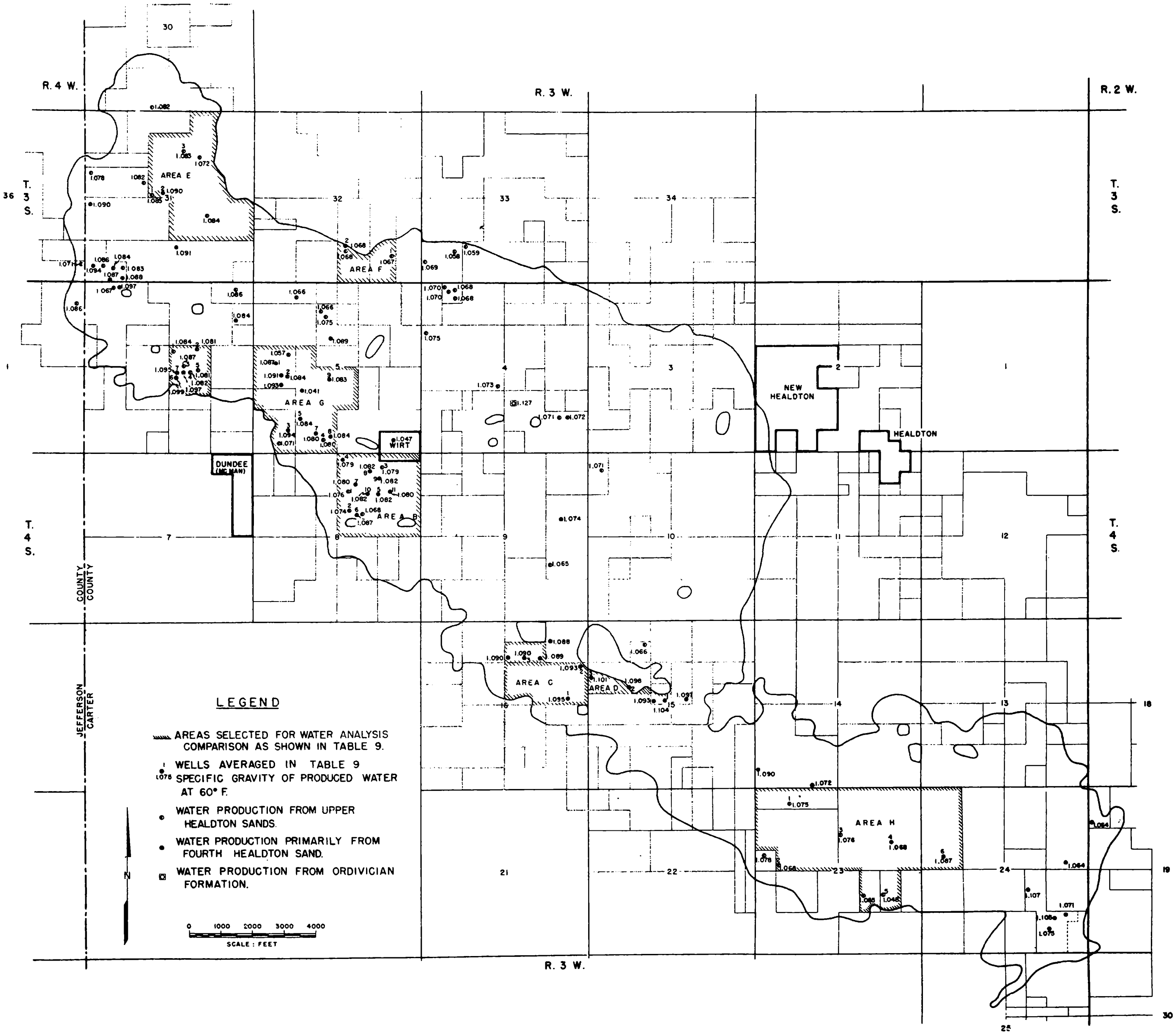

Figure 27. - Areas and wells considered in a study of produced water samples, Healdton oil field, Carter County, Okla.

No satisfactory explanation can be advanced as to the reasons for the different oils produced from the Healdton sands. Differences do not depend upon the sand or age of the well but do seem to show a relationship to their areal distribution in the field. Figure 26 shows the location of wells from which samples were obtained. The A-type oils are found in secs. 30, 31, 32, and 33, T. 3 S., R. 3 W., and secs. 3, 4, 5, 6, 8, 9, and part of 16, T. 4 S., R. 3 W., whereas the B- and C-type oils are found in secs. 10, 15, and part of 16, T. 4 S., R. 3 W., and in the entire southeast extension of the field.

Produced Waters

In an attempt to differentiate between waters produced from several stratigraphic horizons, as well as to identify and trace the sources of produced water in individual wells, a detailed study was made of produced water throughout the field.

Figure 27 is a map of areas and wells from which samples of produced water were collected and analyzed. The well symbol denotes whether water is being produced from upper Healdton sands or the fourth sand. The specific gravity of the produced water at 60° F. is below the well symbol. The numbered wells are those from which sample analyses were averaged and presented in table 9. In general, the specific gravity of waters from upper Healdton sands is lower than that of water from the fourth sand. In some wells water is produced from both the upper Healdton sands and fourth sand, and the mixture of these waters results in an intermediate specific gravity.

Included in table 9 are averages of 47 mineral analyses of waters, which have been grouped according to areas (see fig. 27) in which the water is being produced. This grouping by areas was advisable because of the difficulty of comparing waters from widely separated parts of the field.

Because of difficulty in determining the exact sources of the water, no attempt has been made to differentiate between waters produced from the first, second, or third Healdton sands. Analyses of waters from these upper Healdton sands have been grouped and called upper-sand waters. Waters collected from wells that penetrated the fourth sand and where water production is believed to be primarily from the fourth sand are included in another group as fourth-sand waters.

The principal ions in all of the produced waters are calcium, magnesium, sodium, and chloride, with very little bicarbonate and sulfate. The total solids content and the specific gravity of the waters analyzed vary, depending primarily upon the water-producing formation. The difference in the relative proportion of ions in upper-sand waters and fourth-sand waters can be seen when the average reacting values, in percentage, are compared.

In the Healdton field the reacting values of calcium appear to increase with depth, and the reacting values of sodium and magnesium appear to decrease with depth. For instance, water produced from the Ordovician formation has reacting values of 12.2, 4.6, and 33.2 percent for calcium, magnesium, and sodium, respectively, as compared to reacting values of approximately 11.5, 4.7, and 34.0 percent for those ions in fourth-sand waters.

TABLE 9.--Analyses of water produced with oil, Healdton oil field, Carter County, Okla.

Area	No. of analyses averaged	Calcium(Ca),		Magnesium(Mg),		Sodium(Na),		Bicarbonate(HCO_3),		Sulfate(SO_4),		Chloride(Cl),		Total solids,		Specific gravity, 60°F.
		p.p.m.[1/]	r.v.[2/]	p.p.m.	r.v.	p.p.m.	r.v.	p.p.m.	r.v.	p.p.m.	r.v.	p.p.m.	r.v.	p.p.m.	r.v.	
A																
Average Upper sand waters	5	7,790	9.49	2,595	5.21	33,233	35.30	150	0.06	1	0.0	72,513	49.93	116,302	100.00	1.083
Average Fourth sand waters	2	11,165	11.58	2,739	4.69	37,251	33.74	119	.04	2	0	85,102	49.96	136,361	100.00	1.097
B																
Average Upper sand waters	3	6,538	8.66	2,621	5.74	30,741	35.59	245	.11	5	0.	66,486	49.89	106,634	100.00	1.076
Average Fourth sand waters	8	8,445	10.42	2,435	4.96	32,311	34.81	141	.06	61	.03	71,169	49.84	114,562	100.00	1.082
C																
Average Fourth sand waters	3	10,705	11.42	2,836	4.99	36,141	33.59	370	.13	6	0.	82,736	49.87	132,791	100.00	1.093
D																
Average Fourth sand waters	3	11,513	11.47	3,002	4.93	38,657	33.60	160	.06	58	.01	88,646	49.94	141,997	100.00	1.101
E																
Average Upper sand waters	5	7,148	8.75	2,536	5.14	33,721	36.11	276	.11	0	0.	71,890	49.89	115,571	100.00	1.083
F																
Average Upper sand waters	2	4,829	7.11	2,149	5.22	29,355	37.66	107	.05	22	.01	60,011	49.94	96,468	100.00	1.069
G																
Average Upper sand waters	4	8,500	10.73	2,459	5.15	30,742	34.12	127	.05	45	.01	69,542	49.94	111,381	100.00	1.081
Average Fourth sand waters	6	8,470	10.12	2,621	5.19	33,174	34.70	109	.04	11	.01	73,724	49.95	118,107	100.00	1.085
H																
Average Upper sand waters	5	7,414	10.80	2,028	4.87	27,004	34.34	22	.01	0	0.	60,661	49.99	97,129	100.00	1.070
Average Fourth sand waters	1	9,083	10.47	2,822	5.36	34,023	34.17	106	.04	541	.26	76,295	49.70	122,869	100.00	1.083

1/ p.p.m. - parts per million.

2/ r.v. - reacting value in percentage (Palmer)

Table 9 shows that, for water samples from five upper-sand wells in area A, the average reacting value of calcium was 9.49 percent compared with an average of 11.58 percent for the average reacting value of calcium in waters from two fourth-sand wells. The average reacting value of magnesium in water from upper sands was 5.21 percent, whereas the average reacting value of magnesium in water from the fourth sand was 4.69 percent. The average reacting value of sodium was 35.30 percent in upper-sand waters and 33.74 percent in fourth-sand waters. This comparison of water analyses indicates that, for upper-sand waters in area A, the specific gravity and reacting value of calcium were lower and reacting values of magnesium and sodium higher than those in fourth-sand waters.

In area B analyses were made of water from three wells producing from upper sands and of water from eight wells producing from the fourth sand. In comparing the average reacting values of ions in upper-sand waters with those of fourth-sand waters, it can be seen that, for the upper sands, the average reacting value of calcium is low and the average reacting values of magnesium and sodium high. The reacting value of calcium in upper-sand waters is 8.66 percent, whereas in fourth-sand water it is 10.42 percent. The average reacting value of magnesium in upper-sand waters is 5.74 percent, whereas in fourth-sand waters it is 4.96 percent. The average reacting value of sodium are 35.59 percent in upper-sand waters and 34.81 percent in fourth-sand waters. This would indicate that in area B, as in area A, upper-sand waters have lower specific gravities and lower reacting value of calcium and higher reacting values of magnesium and sodium than do fourth-sand waters.

In areas C and D samples of fourth-sand waters only were collected; therefore a quantitative comparison, such as that for areas A and B, cannot be made. However, the average reacting values of the several ions in these waters in areas C and D can be compared with the average reacting values of ions in the fourth-sand waters in areas A and B. It will be noted that the average reacting values of the three metallic ions (calcium, magnesium, and sodium) in waters from areas C and D are very similar and that for both areas they agree closely with the respective reacting values in fourth-sand waters from areas A and B. In the absence of upper-sand-water analyses, it may be assumed that the relationship that existed between upper-sand waters and fourth-sand waters in areas A and B also would exist between upper-sand waters and fourth-sand waters in areas C and D.

Averages of analyses of upper-sand waters from five wells in area E and from two wells in area F are shown in table 9. The average reacting values of the metallic ions were comparable to those in upper-sand waters from areas A and B. No sample of fourth-sand water from E and F was analyzed, but it may be assumed that in fourth-sand waters from areas E and F, as in fourth-sand waters from other areas, the reacting value of calcium would be higher and the reacting values of sodium and magnesium lower than in upper-sand waters.

For area G analyses of waters from four upper-sand wells and six fourth-sand wells are shown. From comparison of these analyses it can be seen that the average reacting value of calcium in upper-sand waters is slightly higher than that of calcium in fourth-sand waters. The average reacting values of magnesium and sodium in upper-sand waters are slightly less than those of magnesium and sodium in fourth-sand waters. The average reacting values of these waters are completely reversed from what has been shown to be the normal relation of the reacting values. Such a discrepancy may be explained as follows. A well drilled in 1918 in area G in the vicinity of wells 5, 7, and 8 (fig. 27) was plugged and abandoned to prevent flooding of lower sands after it had encountered large quantities of water in an upper Healdton sand. Two other upper Healdton sand wells in the vicinity were abandoned about 1930 because of high water production. A well drilled in 1939 reported water in the upper Healdton sands also. Most of the wells that penetrated the fourth sand were open to production in the upper Healdton sands also, and these wells may have permitted a mingling of waters. From all available data as to the volume of water and the high percentage of water from these wells, it would appear that water is being produced from both the upper Healdton sands and the fourth sand and that the waters have been mixed. If this is the case, the analyses should be similar, and by comparing the average reacting values of calcium, magnesium, and sodium in the two groups such a similarity is evident. Therefore, it is believed that, in this limited area, these two waters have mingled.

Table 9 shows five analyses of water produced from wells in upper Healdton sands in area H. In this area few wells produce from the fourth sand alone, and the one analysis shown in table 9 as fourth-sand water is of water produced from a well open in the upper Healdton sands as well as the fourth sand.

The specific gravity of the fourth-sand water is higher than that of the upper-sand waters, but the relative reacting values of calcium and magnesium for the two groups of waters differ from those that would be expected by comparison with waters from areas A and B. The one analysis of water that probably is from the fourth sand is not conclusive evidence as to the character of fourth-sand water in this area.

Produced Gas

The mass-spectrometer analyses of a raw gas and a gas from which gasoline has been removed are shown in table 10, part A. Field analyses listing the air, carbon dioxide, and gasoline content of natural gas from a number of leases in the Healdton field, as of October 1950, are shown in table 10, part B. The air content ranges from 7 to 52 percent, carbon dioxide from 0 to 4.8 percent, and gasoline content from 0.56 to 3 gallons per thousand cubic feet. The large air content undoubtedly resulted from leaks in the vacuum gathering-lines because comparatively little air has been injected into the sands. No earlier gas analyses are available.

"Infill" Drilling

Most of the wells in the Healdton oil field drilled before 1920 were completed with a series of perforated liners set through 200 to 400 feet of the Healdton-sand section. Sometimes caving sands and shales plugged the liners, and often the operators found that the necessary "work-over" job was almost as expensive as drilling a new well. Undoubtedly this factor is the main reason approximately 440 additional producing wells have been drilled to the Healdton sands since 1919. Figure 28 shows the productive limits of the field in 1919 and 1950 and the location of wells drilled during the intervening period.

Several companies initiated planned infill drilling of wells between the original wells in 1926, 1935, and 1946. Thirty-eight wells were drilled between 1926 and 1935, 288 wells drilled between 1935 and 1946 (the principal infill-drilling period), and 114 wells between 1946 and 1950. The initial production of a new well usually was much greater than the daily oil production of an offset old well. Many old wells in the field were deepened after 1920 to lower oil sands.

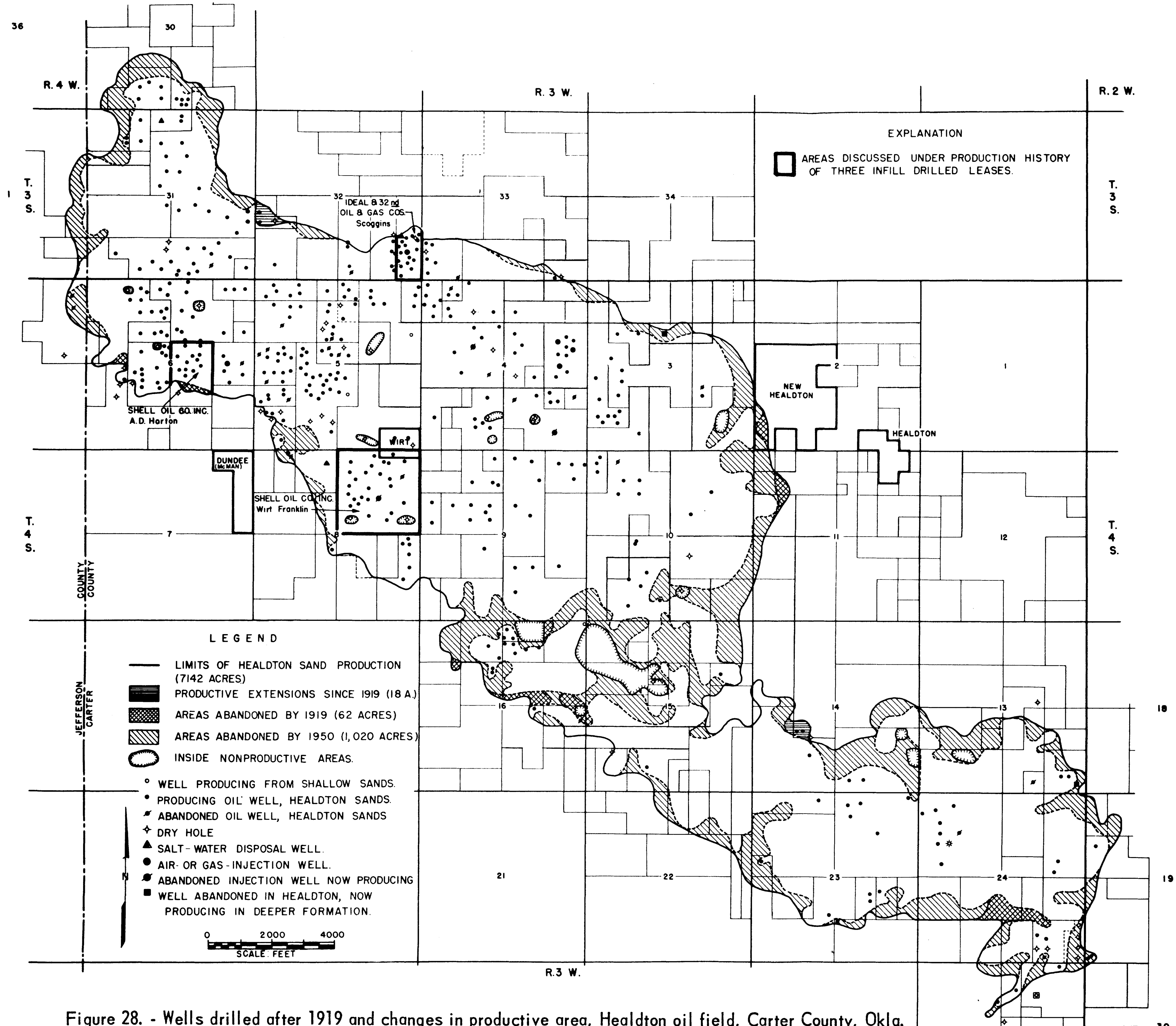

Figure 28. - Wells drilled after 1919 and changes in productive area, Healdton oil field, Carter County, Okla.

TABLE 10.--Analyses of gas samples, Healdton oil field, Carter County, Okla.

Part A - Mass Spectrometer Analyses
November 22, 1950

Sample source	Harry Ells, Inc., gasoline plant (denuded gas from compressor)	Sinclair Oil and Gas Co., J. S. Mullens lease (raw gas)
	Percent	Percent
Methane	35.21	29.38
Ethane	8.37	8.30
Propane	6.25	7.68
Normal Butane	.25	1.56
Isobutane	.18	.86
Normal Pentane	.13	.41
Isopentane	0	.07
Cyclopentane	.04	.05
Hexanes plus	.10	.27
Nitrogen	39.90	42.41
Oxygen	7.80	6.15
Argon	0	.51
Helium	.02	.01
Carbon Dioxide	1.75	2.34
Total	100.00	100.00
Calculated gross B.t.u./cu. ft.*	695	763

* Dry at 60°F. and 30 inches mercury.

Part B - Field Analyses

Company	Lease	Specific gravity	Volume percent CO_2	Volume percent air	Gasoline content, gal./M c.f.
The Pure Oil Co.	Titsworth	0.936	0.0	14.0	1.76
Do.	W & D 80 acre	.992	0	31.0	1.20
Do.	Ruby Ingram	.880	7.4	10.0	.94
Do.	W. R. Ingram	.929	5.0	33.0	1.08
Do.	J. McCoy	.935	0	19.0	1.44
Do.	Watson	.904	0	52.0	60
Do.	Ardhoma #1	.981	1.4	35.0	1.04
Do.	F. Lowery	1.058	' 2	30.0	1.42
Do.	W & D 60 acre	1.085	2.0	27.0	1.82
Do.	Ardhoma #2	1.141	1.4	36.0	1.76
Do.	J. Moyer	.951	4.8	30.0	1.30
Do.	J. Davis 1/	.991	0	36.0	.78
Ring and Trachenburg	J. McCoy	.748	0	10.0	.28
Kewanee Oil Co.	J. Ott	.990	2.8	7.0	1.30
Carlock and Dexter	Tillis	1.018	.6	47.0	1.32
Do.	Brokenshoulder	1.264	4.4	8.0	3.06
Texas-Gulf Producing Co.	Apple and Franklin	1.202	1.2	15.0	2.50
Sun Oil Co.	Mullen "A"	1.000	1.0	23.0	1.40
Do.	Mullen "B"	1.136	1.0	16.0	2.28
Do.	Mullen "C"	1.136	1.0	16.0	2.28
Tomlinson	O. Johnson	1.041	0	7.0	2.76

1/ Analysis of October 12, 1949.

By January 1, 1935, when the principal infill-drilling program was begun, 166,008,000 barrels of oil had been produced from Healdton oil sands. Figure 29 shows the recovery, in barrels per acre, for each lease to that date. On eight leases, including 170 productive acres, recovery exceeded 80,000 barrels of oil per acre, while on eight other leases, including 408 productive acres, recovery exceeded 60,000 barrels of oil per acre. However, in most of the field (4,324 acres) oil recovery was less than 20,000 barrels per acre.

Figure 3, production history of the Healdton oil field, shows that between 1926 and 1950 20,198,000 barrels of oil over and above that expected by normal production methods was produced as a result of additional drilling, deepening, clean-out, vacuum application, and gas injection. The estimated normal decline rate between 1926 and 1950 was 7.7 to 5.0 percent per year. It is estimated that during this period approximately 285,400 barrels of additional oil was gained by injecting air and gas into the Healdton sands. The remaining 19,912,600 barrels of additional oil recovery is attributable to the drilling of new wells, deepenings, clean-outs of oil wells, and vacuum application.

Between 1925, when annual oil production was 5-1/4 million barrels, and 1950, when it was 2-1/4 million barrels, 88-1/2 million barrels of oil was recovered from Healdton sands. During this interval the over-all decline rate was less than 3-1/2 percent per year, much lower than that of most fields of comparable age. Additional drilling, deepening of wells to new sands, and clean-outs of old wells have sustained this oil-production rate. Very little is attributable to secondary-recovery operations.

Although 440 new wells have been drilled in the Healdton oil field during the last 25 years, it is interesting to note that at no time since 1920 has the number of producing wells equaled the number of wells (1,971) producing at that time. The number of wells abandoned exceeded the number of new wells completed, and in 1950 the number of producing wells was 95 less than in 1920.

The recovery per acre to January 1, 1951, from individual leases in the field is shown by degrees of shading in figure 30. The oil recovery from 5 leases, including 135 productive acres, exceeded 120,000 barrels per acre, whereas the recovery from 10 leases, including 338 productive acres, exceeded 80,000 barrels of oil per acre. An idea of the oil recovered from the leases between 1935 and 1950 may be obtained by comparing figures 29 and 30. Oil recovered since January 1, 1935, from a few leases has been nearly 40,000 barrels per acre and from most of the leases in the main part of the field has been nearly 20,000 barrels of oil per acre. Oil recoveries in the southeast extension are much lower.

Oil recovery, between 1935 and 1950, from Healdton sands underlying infill- and noninfill-drilled leases has been compared. The cumulative oil recovery from 31 infill-drilled leases, including 2,100 productive acres, was increased from 80 million to 105 million barrels between 1935 and 1950, 31.2 percent increase over their cumulative recovery to 1935. By contrast, the oil recovery from 44 noninfill-drilled leases, including 1,726 productive acres, was increased only 22.2 percent over their cumulative recovery to 1935. Assuming that without infill drilling the increased recovery after 1935 normally would be about 22 percent of the cumulative recovery through that date, the infill-drilled leases recovered an additional 3,430 barrels of oil per acre or 29,500 barrels per infill well between 1935 and 1950 by drilling the 244 additional oil wells. In general, the infill wells were drilled in the more prolific parts of the field, which had lower decline rates. No attempt was made to estimate future oil production from the leases in these two groups.

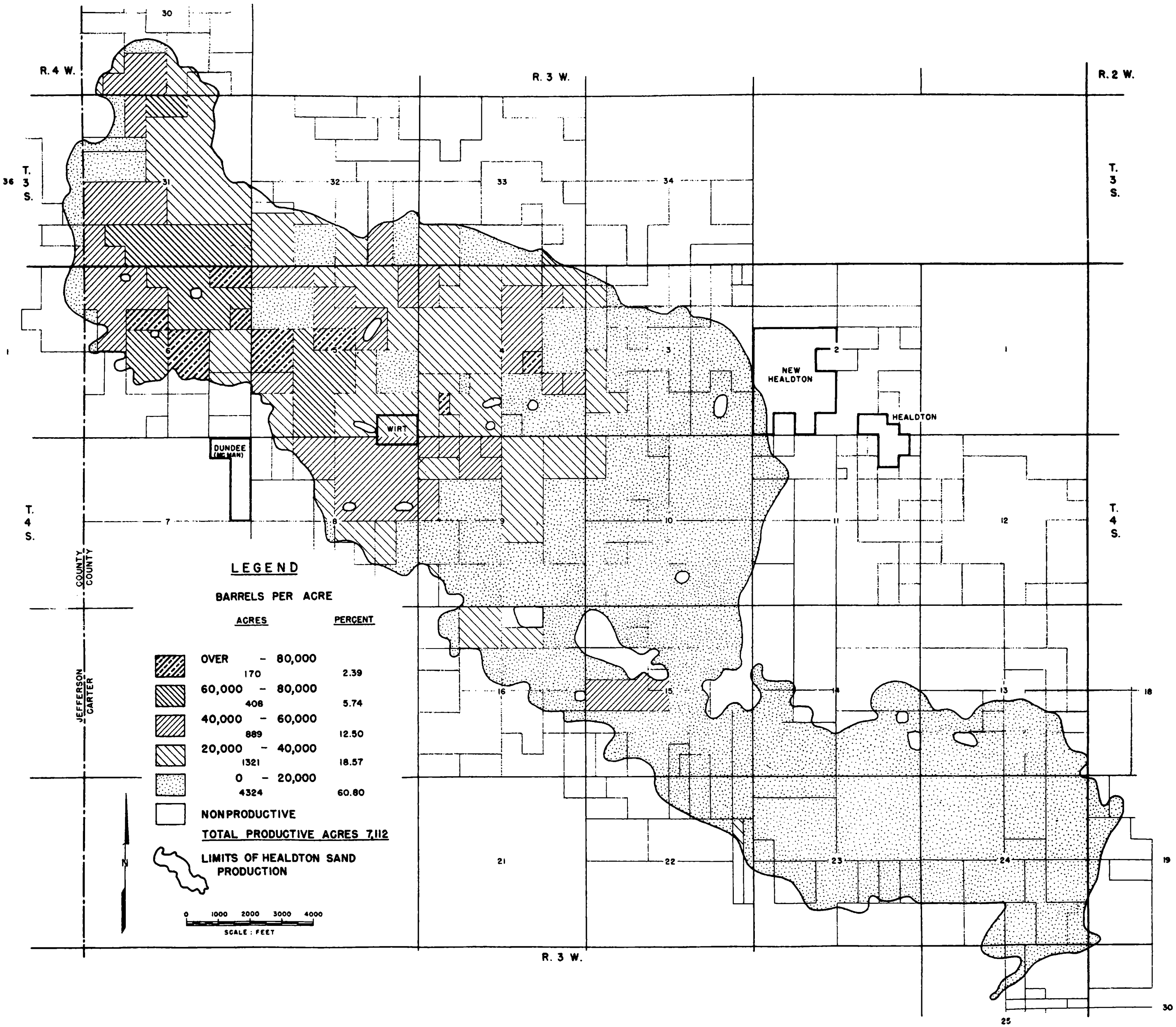

Figure 29. - Oil recovery from Healdton sands to January 1, 1935, Healdton oil field, Carter County, Okla.

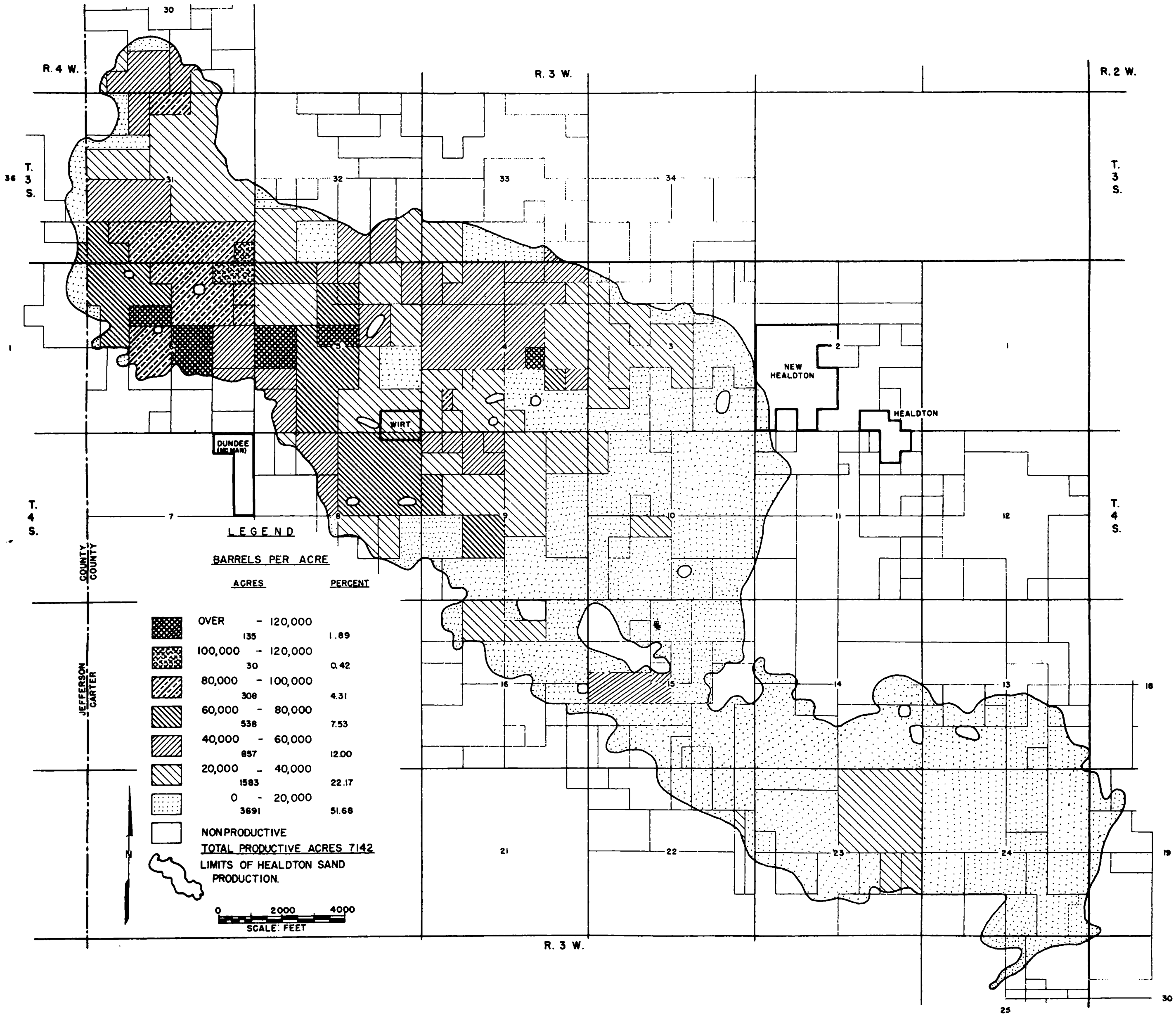

Figure 30. - Oil recovery from Healdton sands to January 1, 1951, Healdton oil field, Carter County, Okla.

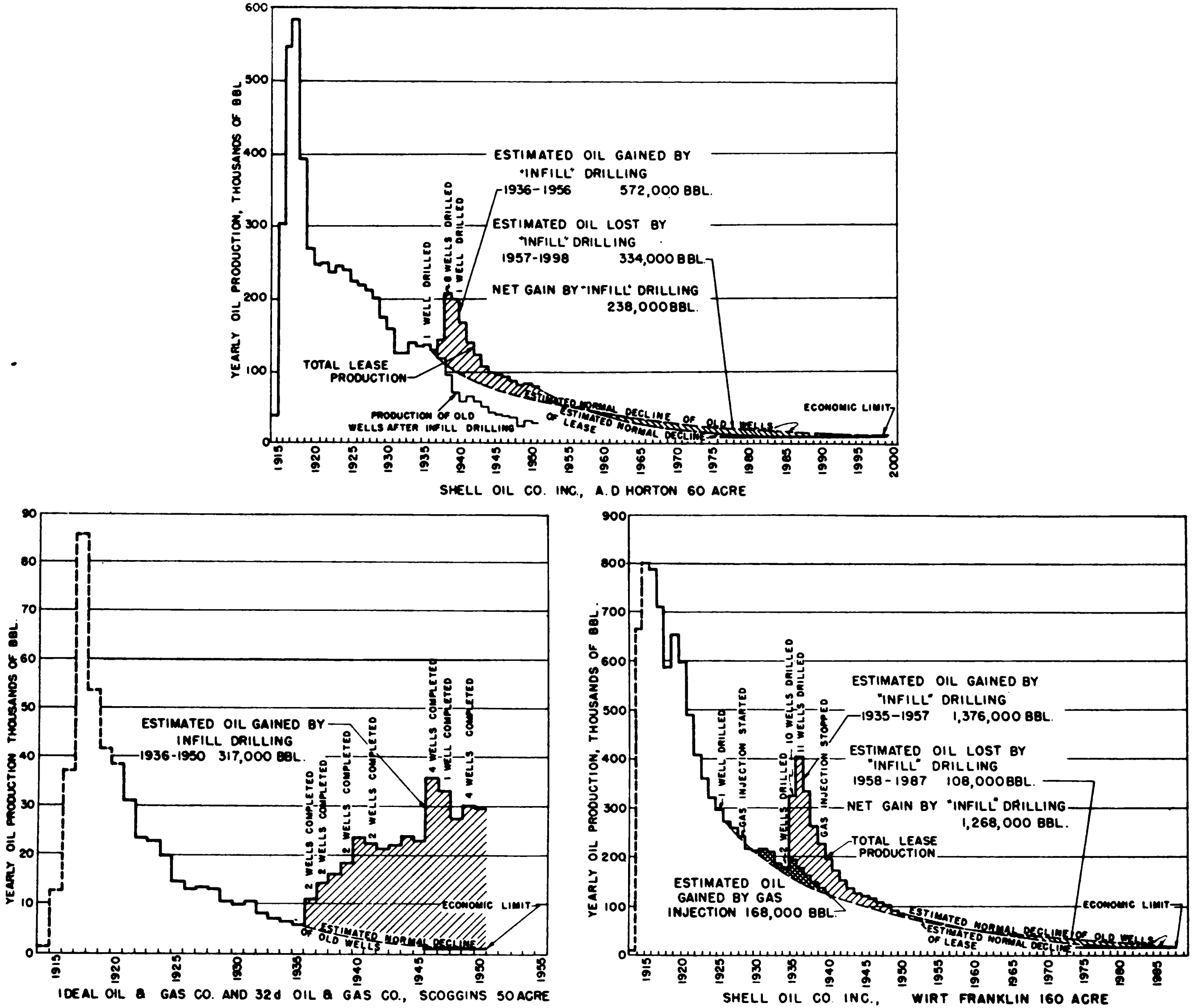

Figure 31. - Oil-production histories of three infill-drilled leases, Healdton oil field, Carter County, Okla.

Production History of Three Leases

A detailed study was made of the results of drilling infill wells on three leases in an effort to determine the effect of closer spacing of wells in the Healdton sands. These three leases were selected because data were available regarding oil and water production and sand conditions. From these studies it is concluded that closer spacing will recover more oil from these leases before the production from the wells declines to the economic limit. These conclusions are based upon expected oil production, as indicated by extrapolations of decline curves of old wells, and of decline curves after infill drilling. The increases, after infill drilling, in the rates of oil production from these leases resulted not only from closer spacing but from penetration of deeper, undrained oil sands and reconditioning of old wells.

Shell Oil Co., Inc., A. D. Horton. - The Shell Oil Co., Inc., A. D. Horton 60-acre lease in sec. 6, T. 4 S., R. 3 W., includes about 45 oil-productive acres; the productive limits are defined by two dry holes. The yearly oil production had declined from a peak of 587,780 barrels in 1917 to 131,507 barrels in 1935 before the infill-drilling program began. Eleven oil-producing wells were drilled between 1936 and 1939.

The results of this infill-drilling development are illustrated graphically in figure 31.

Yearly oil production from the lease reached a second peak of 203,411 barrels in 1938 after 10 wells had been drilled on locations between the original wells. The graph shows that the decline rate of old wells was abnormally high after infill wells were drilled. The curve showing the estimated normal decline of production from the old wells was extrapolated from 1936 to an economic limit in 1998, as shown by the dashed heavy line, to calculate how much oil the lease would have produced had the infill wells not been drilled. The estimated normal decline in the rate of oil production of the lease from 1950 to an economic limit in 1982, as shown by the dashed light line, illustrates the more rapid decline of the closer-spaced lease. By January 1, 1951, an additional 538,000 barrels of oil over and above the expected decline had been recovered on this lease, and by 1957 the increased oil production should total about 572,000 barrels. After that year, the more-rapid decline in the rate of oil production from the closer-spaced wells should result in lease production below the estimated normal decline, effecting a calculated production loss of 334,000 barrels of oil between 1957 and abandonment date.

The total cumulative oil production between 1914 and 1998, assuming that infill wells had not been drilled, is estimated to be about 7,514,000 barrels, whereas the cumulative oil production to 1982 is estimated to be approximately 7,752,000 barrels. This is an increased recovery of 238,000 barrels, or 5,300 barrels per acre, attributable to drilling new wells. By January 1, 1951, the lease already had produced over 150,000 barrels of oil per acre.

Ideal and 32d Oil & Gas Cos. Scoggins. - The Ideal Oil & Gas Co. and 32d Oil & Gas Co. Scoggins lease is the east 50 acres of the SE1/4 sec. 32, T. 3 S., R. 3 W. The estimated productive area of this lease, as defined by two dry holes drilled on the north edge of the field, is 29 acres.

Nine productive wells were drilled on this lease during the primary development period between 1914 and 1921. Yearly oil-production data before 1920 are not available, but the peak yearly oil production is estimated to have occurred in 1917 and was about 86,000 barrels, as shown in figure 31. The yearly oil production of the lease declined to 6,000 barrels in 1935, when an infill-drilling campaign was begun. Eight wells were drilled between 1936 and 1941, and yearly oil production increased steadily to 24,000 barrels in 1940. During 1943 and 1944 six of the old wells were cleaned out and deepened, and the decline in lease production was retarded perceptibly. From 1946 through 1950 nine oil wells were completed, resulting in a marked increase in yearly oil production. Gas injection beginning in 1947 had little effect on the rate of oil production. The estimated normal decline of the old wells to an economic limit of 1,475 barrels in 1948 is shown by the dashed light line. Because of additional drilling in 1949 the probable production from 1950 to the date that an economic limit will be reached was not estimated.

If infill wells had not been drilled, the oil recovered from 1935 to an economic limit in 1948 would have been approximately 36,400 barrels, whereas the actual oil recovered from 1935 through 1950 was 356,650 barrels. This increase in recovery of 320,250 barrels of oil through 1950 is attributable largely to the drilling of new wells, representing over 20,000 barrels of oil per new well. It is expected that much additional oil will be recovered before the lease is abandoned.

Shell Oil Co., Inc., Wirt Franklin. - The Shell Oil Co., Inc., Wirt Franklin lease, NE1/4 sec. 8, T. 4 S., R. 3 W., includes a productive area of 155 acres.

Well 1 on this lease, drilled in August 1913, was the discovery well for the field. By 1922, when primary development ended, 37 productive wells had been drilled, and yearly oil production had declined from a peak of 800,000 barrels in 1915 to 406,000 barrels in 1922. In 1926 one infill well was drilled. In 1929 gas injection was begun and, except for 2 months in 1934, continued until 1939. Between 1934 and 1936, 23 oil-productive infill wells were drilled on the lease.

The past and estimated future production history of the lease is shown in the lower graph of figure 31. The upper line indicates total lease production, which reached a second peak of 403,250 barrels per year in 1936. The dashed heavy line is the estimated normal decline of the original wells at rates of 6 to 4-1/2 percent per year to an expected economic limit of 1 barrel per well per day in 1987. The shaded area, amounting to 168,000 barrels, is the volume of oil estimated to have been produced by gas injection, which will be discussed later. The total lease production is shown by the dashed light line extrapolated after 1950 at a decline rate of 6 percent per year until 1979. It is estimated that between 1934 and 1957 infill drilling will recover an additional 1,376,000 barrels of oil, but after 1957 the more rapid decline of this lease with closer-spaced wells will result in the loss of 108,000 barrels of oil. The net gain attributable to drilling 23 infill wells will be approximately 1,268,000 barrels or 8,200 barrels of oil per acre.

Gas Injection

General Discussion

Gas has been injected into 26 wells on 16 leases to increase oil production or store excess gas for later use. Table 11 shows a summary of gas-injection operations on 12 of the more important projects in the field.

TABLE 11.--Gas injection projects, Healdton oil field, Carter County, Okla.

	Company	Lease	Total prod. area, acres	Estimated affected area, acres	Location			Average sand thickness, feet	Date injection started	Date injection discon.	Total No. of injection wells	Original wells		New wells drilled	Gas injected		Ave. da. oil prod. bbl.			Oil gained, bbl.
					Sec.	Twp.	Rge					Total No.	No. affected		Ave. inc. pressure, p.s.i.	Ave. da. vol. inj., M c. f.	Before inj.	Maximum during inj.	1-1-51 or when discon.	
	Operating Projects																			
1	Ideal & 32nd Oil & Gas Cos.	S. Scoggins	29	12	32	3 S.	3 W.	64	8-47	Oper.	1	21	6	2	7-10	-	83	68	60.3	3,500(?)
2	McGraw Oil Co.	Stewart & Hawk	50	44	(33 (4	3 S. 4 S.	3 W. 3 W.	50	11-44	do.	1	14	11	5	18-20	8-17	1/ 82.7	99.7	96	39,000
3	Do.	W. Woodworth	24	24	32	3 S.	3 W.	57	11-43	do.	2/ 2	6	6	3	15-20	10-15	46	56	3/ 70	19,800
4	The Pure Oil Co.	Westheimer & Daube 60 Acre	60	33	(9 (10	4 S. 4 S.	3 W. 3 W	115	3-37	do.	1	23	14	1	3- 8	4/ 30-65	160	169	40	-
5	Sinclair Oil & GassCo.	J. S. Mullen	60	52	4	4 S.	3 W.	82	11-43	do.	3	19	17	3	50-200	33-144	49.7	63.3	42.6	35,600
6	Kewanee Oil Co.	H. Willis	40	14	6	4 S.	3 W.	25	6-48	do.	1	17	5	1	17-25	6-12	42	3/ 55.2	3/ 50	3,500
	Discontinued Projects																			
7	Shell Oil Co., Inc.	W. Franklin	155	155	8	4 S.	3 W.	110	6-29	12-39	5/ 6	35	35	23	60-65	65-175	587	644	370	168,000
8	Do.	L. Tubbee	160	149	24	4 S.	3 W.	39	5-28	193(?)	1	35	32	0	-	31	105	152	107	12,500
9	Kewanee Oil Co.	S. Jones	120	75	4	4 S.	3 W.	89	6-36	8-46	3	34	15	1	15-18	30-40	232	265	3/ 133	1,740
10	The Pure Oil Co.	F. Lowery	88	37	4	4 S.	3 W.	40	5-46	11-47	2	28	10	0	16-32	16-20	59.8	61.5	53.8	-
11	Do.	Westheimer & Daube 80 Acre	80	10	9	4 S.	3 W.	87	7-46	10-46	1	21	2	0	14-18	3	30.6	31.5	25.9	-
12	Schermerhorn Oil Co.	Fee 40 Acre	40	34	5	4 S.	3 W.	90	3-35	11-35	2	15	15	3	30	450	392	404	382	1,740

1/ Average daily production on affected wells only.
2/ Well No. 11 took only a small amount of gas.
3/ Production from all wells including new wells.
4/ Injection of gas discontinued during winter months.
5/ Some wells were used only a short time for gas injection.

The first gas-injection operation was begun in 1928 on what is now the Shell Oil Co., Inc., Lucy Tubbee lease, and other projects have been initiated at various times since; the last one was begun in August 1948. On some leases gas injection was discontinued after several months, but on one lease gas has been injected intermittently over a period of 14 years. Currently gas is being injected into wells on six leases.

Figure 32 shows the location and area affected by the gas-injection projects in the field. Denuded gas from the Harry Ells, Inc., gasoline plant comprises most of that injected, although some additional gas has been purchased from the Oklahoma Natural Gas Co. On a few leases air was injected at the beginning of the operation and then later augmented with gas.

An attempt was made to direct the injected gas into a definite sand zone using packers in one instance. Usually no change was made in the casing depth when producing wells were converted to gas-injection wells. Gas was injected through the casing, often with the tubing left in the well. Although some of the projects were highly successful, others yielded little increase in oil production that could be attributed to gas injection. In many instances drilling additional wells during the gas-injection program has masked the effects of gas injection.

It is estimated that, between May 1928 when injection was begun and December 1950, approximately 285,400 barrels of oil was recovered from nine leases as a result of gas injection. Results on three other leases, where gas was injected primarily for storage, were inconclusive. On the 12 leases only 168 wells on 678 acres showed increases in the rate of oil production attributable to gas injection compared with 1,971 wells and 7,142 acres in the field.

It is believed that the poor results obtained on many of these projects do not necessarily condemn those areas for gas injection, because with better control of the injected gas much additional oil could be recovered from the sands.

Table 11 shows that by 1950 only six projects, with eight injection wells, were operating. Daily volumes of 6,000 to 144,000 cubic feet of gas were being injected at pressures ranging from 7 to 200 p.s.i. on individual projects. Following are descriptions of several of the more important projects.

Description of Individual Leases

Ideal and 32d Oil & Gas Cos. Scoggins. - In August 1947, the Ideal Oil & Gas Co. and the 32d Oil & Gas Co. began to inject excess gas into well 16 on the Scoggins lease in the SE1/4 sec. 32, T. 3 S., R. 3 W. In this area the first Healdton sand is split into two members by a thick shale and limestone section. The top member of the first sand was cored in three wells, and analyses show that the porosity ranges from 16 to 28 percent. A total of 64 feet of oil-productive sand, including parts of the first and third Healdton sands, was penetrated in this well. The second Healdton sand was shaly and nonproductive.

Oil production from this lease was increased in 1946 by drilling additional wells, as described under infill drilling, so that results from gas injection are not clearly defined.

Well 16, converted in August 1947 to an injection well, was completed in April 1941 with an initial production of 3 barrels of oil daily from first and third sands, at depths from 955 to 1,018 feet and 1,107 to 1,188 feet, respectively. An 8-1/4-inch casing was set above the first sand at 948 feet, and a 6-inch liner, perforated

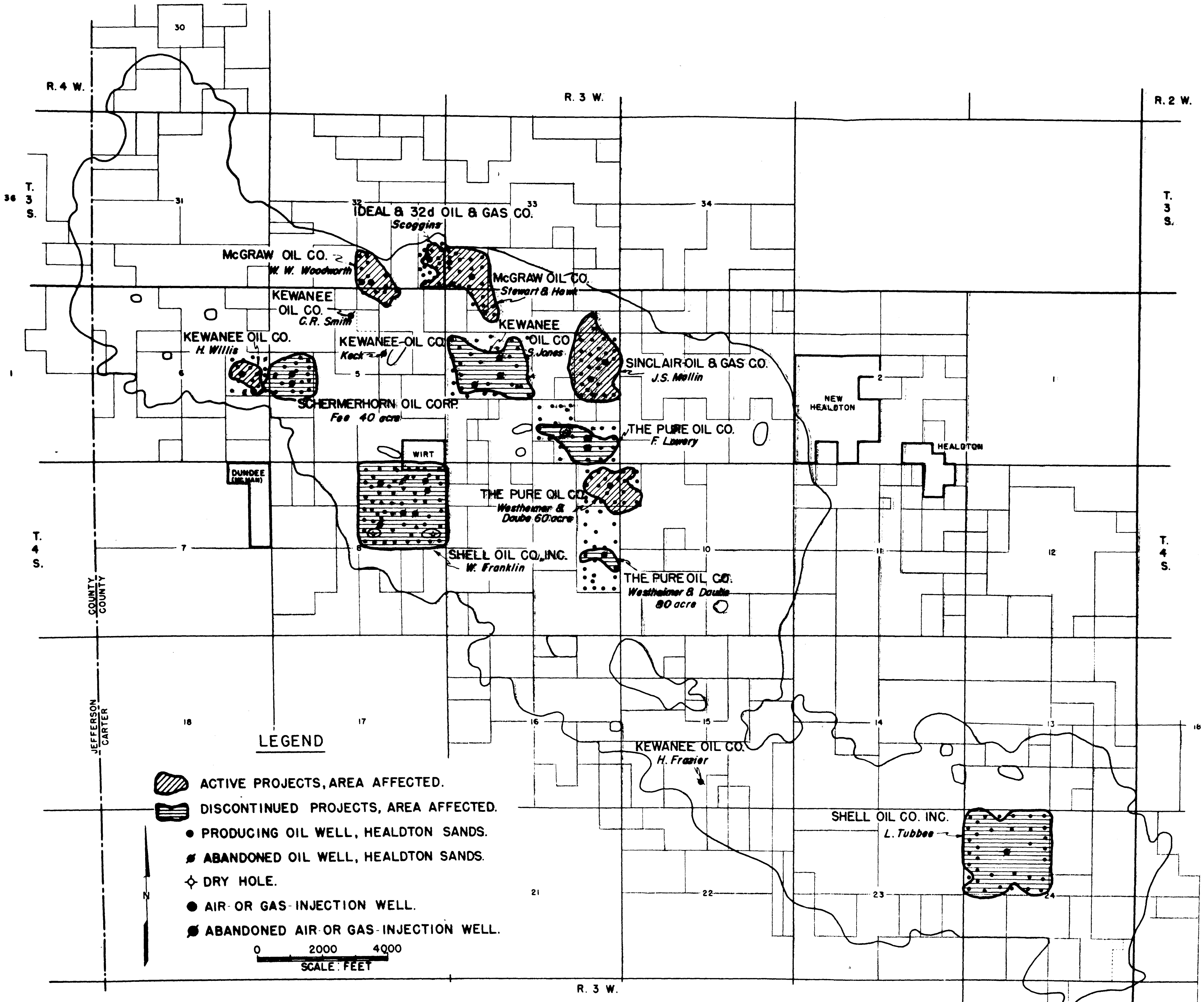

Figure 32. - Location of gas-injection projects and area affected, Healdton oil field, Carter County, Okla.

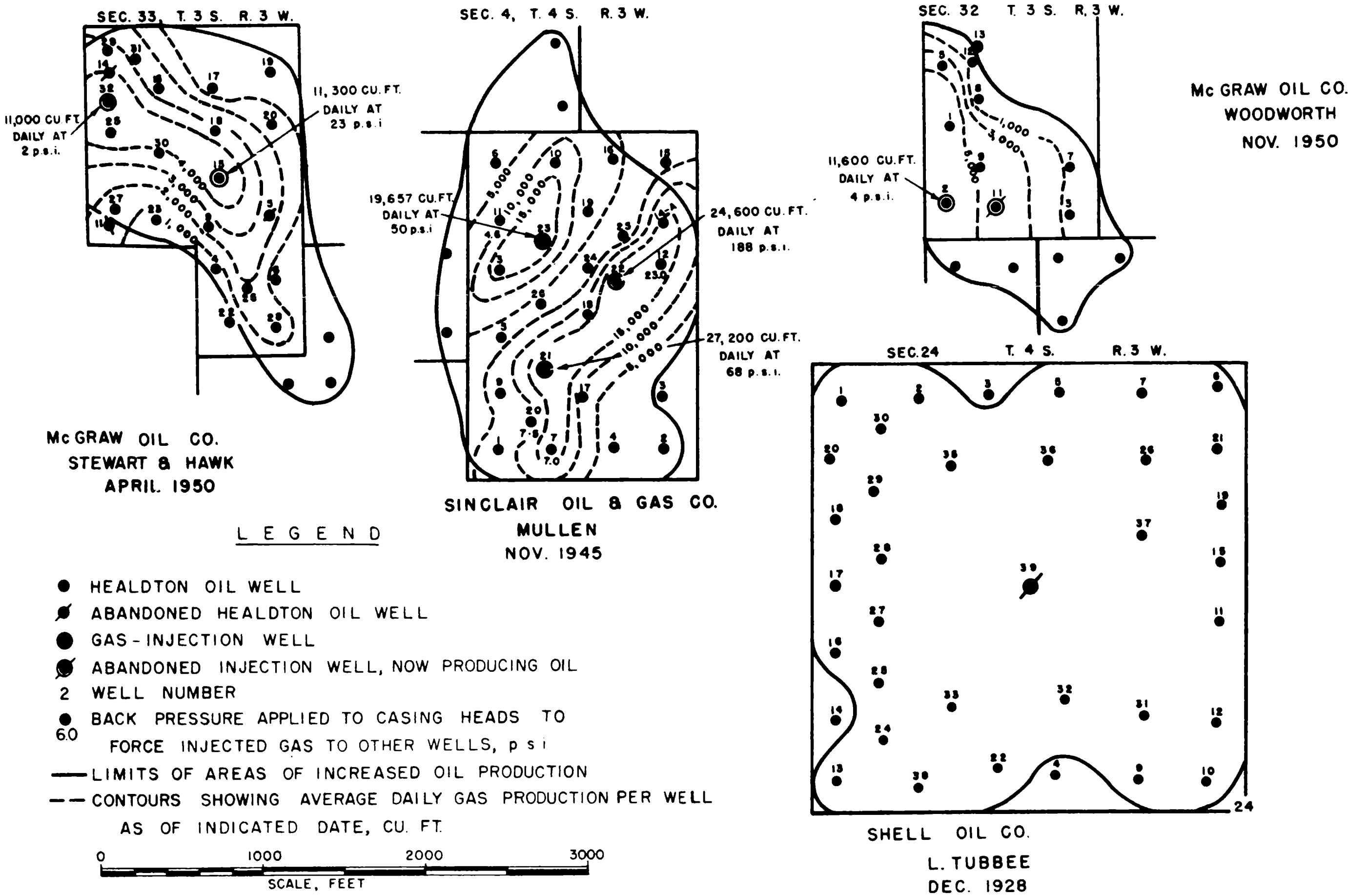

Figure 33. - Map of four leases showing areas and wells affected by gas injection, Healdton oil field, Carter County, Okla.

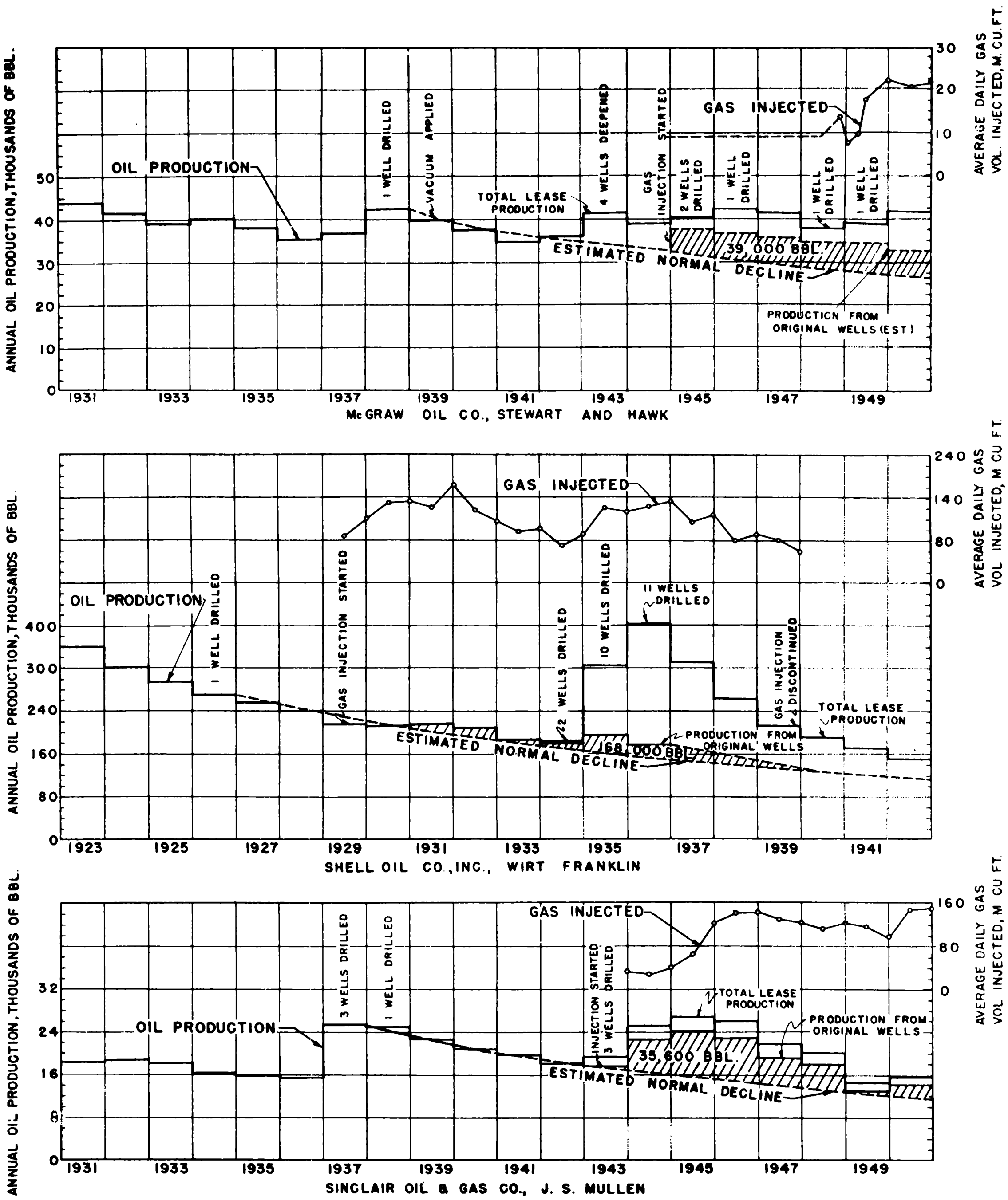

Figure 34. - Histories of gas injection on three successful projects, Healdton oil field, Carter County, Okla.

opposite the first and third sands, was set on bottom. This completion was not changed when this well was converted for gas injection.

During the period of gas injection no attempt was made to measure or control the volume of gas injected into the sands. During 1950 an average of 12,500 cubic feet daily of denuded gas was returned from the gasoline plant to the Scoggins lease. All of the gas not used by the 25-hp. central-power engine and in a five-room dwelling was injected into well 16 at pressures from 7 to 10 p.s.i. Casingheads of the producing wells on this lease are connected to the Harry Ells, Inc., gas-gathering line under a vacuum equivalent to 6 inches of mercury.

The average gas-oil ratio for the entire lease increased from about 160 cubic feet per barrel in 1947 to 182 cubic feet per barrel in 1950. Gas produced from individual wells was not measured.

Oil-production tests taken in 1948 and 1949 show that eight wells surrounding the injection well had slight increases in the rate of oil production, ranging from 0.2 to 2 barrels of oil daily. Total lease production, continued to decline during these years, but this decline may have been influenced by the more rapid decline of five new wells completed shortly before gas injection was begun. Undoubtedly, the total lease production would have declined more rapidly without gas injection, but it is undeterminable just how much of the total oil production can be attributed to gas injection. Table 11 shows 3,500 barrels of oil gained as a result of gas injection, but this figure is based upon the individual well tests and is questionable.

McGraw Oil Co. Stewart & Hawk. - Late in 1944 the McGraw Oil Co. began to inject gas into well 15 on the 50-acre Stewart & Hawk lease in sec. 33, T. 3 S., R. 3 W., and sec. 4, T. 4 S., R. 3 W. Figure 33, upper left, shows the location of injection and producing wells on the lease, the total area affected by gas injection, and an isogram map of gas-oil ratios as of April 1950.

In this area the first Healdton sand is approximately 50 feet thick, and the combined thickness of the second and third sands ranges from 10 to 50 feet. Few wells have penetrated below the first sand. The fourth Healdton sand is not productive in the area of this lease (see figs. 10 and 19). Two wells on this lease have been cored, and analyses of first-sand cores show that the porosity ranges from 25 to 28 percent and the permeability from 230 to 900 millidarcys.

When gas injection was begun in 1944, 14 oil wells were producing about 105 barrels of oil and 72 barrels of water daily. The upper graph of figure 34 shows the oil-production history of the lease between 1931 and 1950.

The first 22 wells on this lease were completed between 1914 and 1917, three additional wells were drilled between 1926 and 1928, and one well was drilled in 1938. Beginning in 1940 and continuing to the present, vacuum equivalent to 6 inches of mercury has been applied to casingheads of the wells. In 1943 four wells were deepened to untapped sands, resulting in substantial increases in the rate of oil production. Five wells were drilled on the lease between 1945 and 1949.

Injèction of gas into well 15 was begun in November 1944. This well was completed in June 1917 at a total depth of 1,128 feet, producing oil from sands between 972 and 1,087 feet in depth. The well was cased with 8-1/4-inch casing set above the first sand at 967 feet and 200 feet of 6-5/8-inch perforated liner set on bottom.

A total of 77 feet of oil-productive sand was penetrated in the first and second sands, but the third sand, composed of broken sand and shale, was nonproductive. Late in 1949 well 32, drilled in June of that year, was converted to an injection well. Only 1 barrel of oil daily was produced from a sand between 1,183 and 1,195 feet. As the lower part of the sand was watered-out the well was plugged back to 1,190 feet. Seven-inch casing was set through the shaly first sand and cemented at 1,183 feet, and only the second sand is open for gas injection. The upper curve in figure 34 shows the average volume of gas injected per day during each year from 1944 to 1950. Between 8,000 and 15,000 cubic feet of gas daily was injected into the sand through well 15 during the first 4 years at pressures between 18 and 20 p.s.i. During 1949, additional gas was purchased from the Oklahoma Natural Gas Co. to increase the average volume injected through wells 15 and 32 to 17,000 cubic feet daily. During 1950 about 11,000 cubic feet of gas per day was injected into well 32 at a pressure of 2 p.s.i., but the volume injected into well 15 was decreased, so that the total volume into the two wells was 22,000 cubic feet per day.

Since 1946 periodic measurements of gas production have been made on the oil wells to observe the spread of injected gas. Below are produced gas volumes from several oil wells in 1946 and 1950.

Well No.	Daily gas production, cubic feet: November 1946	Daily gas production, cubic feet: April 1950
6	1,061	337
9	1,061	2,133
16	671	2,868
17	820	598
20	1,061	1,547
23	475	331
25	3,350	4,567
27	672	1,512

The comparatively high gas production in April 1950 of the wells surrounding the injection wells is shown by the gas-oil-ratio contour lines in figure 34.

Available records of gas sales beginning in 1940 show that during that year an average of 24,400 cubic feet of gas per day was sold. In 1942 gas sales were 45,600 cubic feet per day. They declined to 21,000 cubic feet per day in 1944 before injection was begun and then increased to 33,100 cubic feet in 1950.

The first increases in the rate of oil production were noted in 1945, and by January 1946 six wells had shown increases in the rate of oil production, totaling 20 barrels daily.

The production curve in figure 34 shows an increase in yearly lease production in 1943 as a result of deepening four wells. Since gas injection was begun five new wells have been drilled to the Healdton sands, and the oil produced from these deepened and new wells has masked the effects of gas injection. The dashed extrapolated curve in figure 34 illustrates the expected normal decline in yearly oil production before wells were deepened and gas injection was begun. Actual tests on individual wells indicate that 11 old wells and 4 new wells showed increases of 1/2 to 6 barrels daily in their rates of oil production. The probable increased production attributable to gas injection, as calculated from these well tests, is shown as the shaded area in figure 34. This total increased production between 1945 and 1950 amounts to approximately 39,000 barrels or 780 barrels per acre.

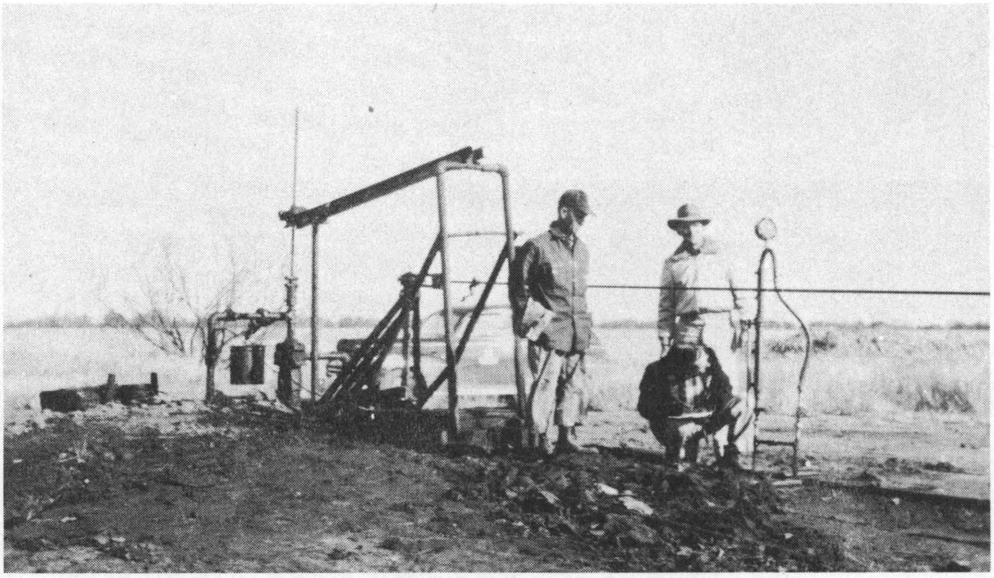

Figure 35. - Measuring produced gas from a well on a gas-injection lease, Healdton oil field, Carter County, Okla.

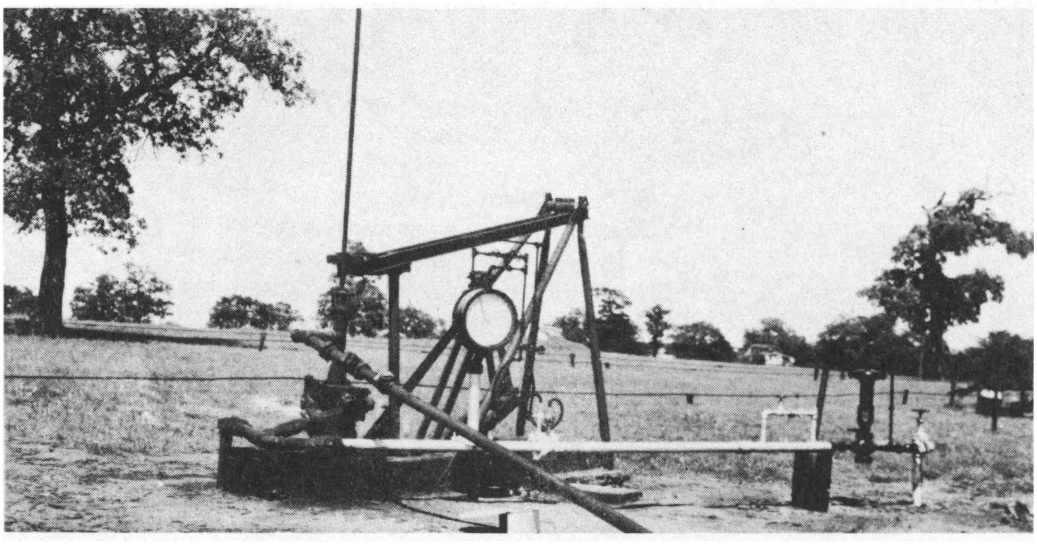

Figure 36. - Gas-injection well, Healdton oil field, Carter County, Okla.

This project has been in operation for 7 years, and although increases in the rate of oil production attributable to gas injection have been overshadowed by the increased production from deepened and new wells, substantial amounts have been recovered by gas injection with little cost of operation.

McGraw Oil Co. Woodworth - The McGraw Oil Co. has been injecting gas into well 2 on the Woodworth lease, sec. 32, T. 3 S., R. 3 W., since November 1943 to increase oil production and store gas for future use.

The Woodworth lease includes 24 productive acres along the north edge of the field where the first Healdton sand is oil-productive and the sands below are water-saturated and nonproductive. The total thickness of oil-productive sand ranges from 4 to 62 feet (fig. 12), with the individual sand members being separated by shale beds.

First wells were drilled in 1914, but records of initial daily production are not available. Nine wells (seven oil-productive) had been drilled before the present owner took over the operation in 1941. By January 1943 approximately 894,000 barrels of oil or 37,000 barrels per acre had been recovered on the lease. At that time the seven wells were producing about 48 barrels of oil and 11 barrels of water daily. Since 1939 vacuum equal to 6 inches of mercury had been applied to the casinghead of the wells. Before injection was begun in November 1943, approximately 19 000 cubic feet of gas daily was produced from the lease. In 1949 gas production averaged 15,300 cubic feet daily.

In November 1943 well 2, which had been producing one barrel of oil daily from the first sand at depths from 1,050 to 1,117 feet, was converted to a gas-injection well, and 10,000 to 15,000 cubic feet of gas daily was injected at pressures of 15 to 20 p.s.i. Dry gas returned from Harry Ells, Inc., gasoline plant was augmented with gas purchased from the Oklahoma Natural Gas Co. for injection. In 1946 an attempt was made to inject gas through well 11, but very little gas could be forced into the sand at 150 p.s.i., the pressure limit of the injection pump. In November 1950 an average of 11,600 cubic feet of gas daily was being injected into well 2 at a pressure of 4 p.s.i.

Few data are available regarding the movement of injected gas during the first few years of gas injection, but since 1946 periodic tests of gas production have been made at the wellheads of the oil-producing wells (see fig. 35). In 1946 tests showed higher gas production from wells surrounding the injection well than from the more remote wells. Daily gas production from all wells on the lease in November 1950 is shown by the gas-oil-ratio contour lines on the lease map in the upper right corner of figure 33.

Daily oil-production tests on individual wells indicate that seven wells on the Woodworth lease and five wells on adjacent leases to the south increased oil production 1 to 16 barrels daily as a result of gas injection. Yearly oil production from the Woodworth lease increased from 17,300 barrels in 1942 to 20,000 in 1943 and 1944. In 1946 wells 11 and 12 were completed as oil producers, and yearly production increased to 26,200 barrels, principally as a result of the completion of the two wells. Well 13 was completed in 1949. The increased lease production resulting from these completions made it difficult to estimate the volume of oil recovered by gas injection.

It has been estimated that, without gas injection, yearly oil production would have declined about 3-1/2 percent per year. Using this decline rate and deducting the oil produced from new wells as indicated by well tests it is estimated that to

January 1951 gas injection resulted in recovery of an additional 19,800 barrels of oil from the lease, equivalent to 825 barrels per acre.

The Pure Oil Co. Westheimer and Daube 60-Acre. - Gas injection into well 17 on The Pure Oil Co. Westheimer and Daube 60-acre lease, secs. 9 and 10, T. 4 S., R. 3 W., was begun in March 1937.

The total oil-productive thickness of upper Healdton sands in this area ranges from 60 to 100 feet (see fig. 12), but the individual sand numbers are lenticular and contain shale and limestone streaks. The fourth sand is not productive in this area (see fig. 10).

The lease was developed in 1914 and 1915 by drilling 17 oil wells. Initial daily oil production ranged from 60 to 900 barrels of oil. Nine wells were deepened 10 to 40 feet in 1926, resulting in an increase in annual lease production from 27,000 in 1925 to 49,000 barrels of oil in 1926. Seven wells were drilled during 1936 and 1937, and the annual lease production increased from 44,000 to 57,000 barrels. Since 1937 oil has been produced from 23 wells on the lease.

Well 17, in the center of the lease, was drilled in 1916 and had an initial production of 150 barrels of oil daily. This well, later converted to a gas-injection well, penetrated three sands with a total thickness of 115 feet. In March 1937 a gas line from The Pure Oil Co. Lowery-lease gasoline plant was connected to the casinghead of the well (see fig. 36). From 20,000 to 100,000 cubic feet of gas daily, depending upon the volume available, was injected into this well at pressures of 2 to 8 p.s.i. In April 1943 gas injection was discontinued until May 1944 and has since been interrupted for a few months each winter, when excess gas is not available for injection. In May 1950 when gas injection was recommenced after the regular winter shut down about 28,000 cubic feet of gas daily at a pressure of 9 p.s.i. was injected into the well. Injection continued until November 1950 at about 30,000 cubic feet of gas per day.

In April 1937, 1 month after injection was begun, eight wells surrounding the injection well had shown increases of 1/2 to 2 barrels in daily oil production. Since March 1937, 15 wells on 33 acres have shown increases in the rate of oil production that could be attributed to gas injection. One well on The Pure Oil Co. Westheimer and Daube 80-acre lease to the south also was affected.

Production increases resulting from new well completions and deepening of other wells make it difficult to calculate increases in the rate of oil production resulting from gas injection, and no attempt has been made to estimate this gained oil. However, each time injection was discontinued temporarily, the rate of lease production decreased sharply. The volume of gas injected has steadily decreased in recent years, and the annual oil production from this lease had declined to approximately 15,000 barrels by 1950.

Sinclair Oil & Gas Co. Mullen. - Gas injection on the Sinclair Oil & Gas Co. J. S. Mullen 60-acre lease, sec. 3, T. 4 S., R. 3 W., was begun in November 1943 and is still in progress.

Figures 6 and 7 show the stratigraphy of the sands in this area. A more or less continuous stray sand, open to oil production in most of the early wells, overlies the first Healdton-sand member. Analyses of cores of the stray sands cut in November 1943 using water-base mud show the porosity, permeability, and oil saturation to be 19 percent, 20 millidarcys, and 26 percent, respectively. Averages of analyses of cores from the upper member of the first sand were as follows: Porosity, 30.1 percent; permeability, 1,632 millidarcys; and oil saturation, 35 percent.

All injection wells were cased through the stray sands and through the upper member of the first sand.

The first 16 wells on the Mullen lease were drilled between 1914 and 1916, and by 1936, when infill drilling was begun the rate of oil production was declining at about 3.2 percent per year. Four wells were drilled in 1937 and 1938, and one old well was abandoned. By 1943 the rate of decline in oil production from the 19 producing wells on the lease was about 5.8 percent per year.

In November 1943 about 36,000 cubic feet of gas daily was injected into newly drilled wells 21 and 23 (see fig. 34) at pressures of 27 to 48 p.s.i. In July 1944 well 22, drilled in August 1943, was converted to an injection well. Casing in this well was perforated opposite the upper member of the first sand, and a tubing packer was set below the perforations. For a few years 24,000 to 31,000 cubic feet daily of air and gas was injected through the perforations at about 7 p.s.i. pressure, while a similar volume was injected through the tubing into lower sands at pressures ranging from 167 to 205 p.s.i. Before gas injection was begun, the casingheads on the producing wells on this lease were open to the atmosphere until vacuum applied to offset wells on adjacent leases caused a flow of air into six of the Mullen wells. When gas injection was begun in November 1943 vacuum equivalent to about 1 inch of mercury was applied to the casingheads of all Sinclair Oil & Gas Co. Mullen wells.

The volume of gas injected was increased to 140,000 cubic feet daily in 1945, was decreased slightly in 1947 and 1948, and was increased again to about 150,000 cubic feet per day in 1950 (see fig. 33). As the injected gas spread to nearby wells 7, 11, and 20, back pressure was applied to the casingheads of these wells, and vacuum on the more remote wells was increased to an amount equivalent to 3 inches of mercury. Areas of high gas production and the amount of back pressure applied to wells 7, 11, 12, and 20 in November 1945 are shown in figure 33. As the gas spread over the lease, vacuum and back pressure of the casingheads of the producing wells were manipulated so as to force the gas to, and increase the oil production from, the more-remote wells. Since injection was begun, virtually all of the injected gas has been produced from the wells on the lease, so that gas has not been stored underground and reservoir pressure has not increased.

First increases in the rate of oil production were noticed early in 1944 on wells 7, 9, 10, 11, 17, and 20; by November 1945 20 wells on the Mullen lease and 4 wells on adjacent leases had shown increases in the rate of oil production (see fig. 33).

At the same time the three injection wells were drilled three new oil wells also were drilled. Figure 34 shows the total lease production and the assumed production of the original wells (those drilled before 1943) as obtained by subtracting the production of the new wells from the total lease production. Although it is possible that the new wells received some benefit from the gas injection, the gained oil has been calculated from the increase in yearly oil production of the original wells only. Figure 34 shows that the maximum yearly oil production from the original wells was 24,000 barrels in 1945, and the rate of oil production in 1950 (15,500 barrels) is shown to be only slightly above that estimated by extrapolating the normal production curve at 5.7-percent decline per year. From these data the oil gained from the original wells by gas injection is estimated to be 35,600 barrels, or 685 barrels per acre, from 52 affected acres on the lease.

Kewanee Oil Co. Willis. - The Kewanee Oil Co. Willis 40-acre lease, sec. 6, T. 4 S., R. 3 W., lies along the southwest flank of the field structure.

Drillers' logs show that two to five sands were penetrated in the producing wells on the lease. The upper sands produce little oil and usually are cased off, but one to three of the lower sands are left open for production. The injection well, well 17, penetrated about 25 feet of oil sand.

Operations on this project were begun on June 1, 1948, when the Kewanee Oil Co. began injecting about 8,000 cubic feet of gas daily into well 17 at a pressure of 25 p.s.i. Injection was suspended in the winter when excess gas was not available. During 1950, 11,000 cubic feet of gas daily was injected into well 17 at pressures between 14 and 17 p.s.i.

At the beginning of gas injection, there were 17 wells on the lease producing 43 barrels of oil daily. Three wells were abandoned in November 1948, and one new well (well 9-A) was completed in January 1950.

Produced gas from the lease is gathered at a vacuum by the Harry Ells, Inc., gasoline plant. In 1948 gas sales were 5,071,000 cubic feet, an increase of 781,000 cubic feet over those of the previous year. Based on these figures the average lease gas-oil ratio increased from 278 cubic feet per barrel in 1947 to 328 cubic feet per barrel late in 1948. In 1949 gas sales were 3,922,000 cubic feet but, in 1950 had declined to 3,527,000 cubic feet.

The effects of gas injection on oil production from this lease have not been too well defined. When gas injection was begun oil production was declining at the rate of approximately 4 percent per year. Monthly oil production for June 1948, when injection was begun, was 1,276 barrels and in August was 1,337 barrels. Oil production from well 9-A, drilled in January 1950, increased the rate from the Willis lease much more than did gas injection, so that it is impossible to calculate the increase resulting from the injection accurately. In 1949 individual well tests showed increases totaling 2-1/2 barrels of oil daily from six wells on 12 acres surrounding the injection well. In 1950, five wells were showing increases in the rate of oil production totaling 5-1/4 barrels daily. Based upon these well tests it is estimated that approximately 3,500 barrels of oil was gained by January 1951, as a result of the injection of excess gas into well 17.

Shell Oil Co., Inc., Wirt Franklin. - In June 1929, the injection of gas was begun into the Shell Oil Co., Inc., Wirt Franklin lease, sec. 8, T. 4 S., R. 3 W., wells 1, 20, and 22. Well 1 was the discovery well for the Healdton field. Structure sections (not presented) through this lease show four Healdton sands with stray sands above. The strays were open in the early wells but cased off in those drilled later. Most wells penetrate only the upper Healdton sands, but some were drilled through the fourth sand and into the Ordovician limestone. The three injection wells penetrated about 110 feet of the upper Healdton sands. Well 28, converted to gas injection in August 1929, originally was drilled into the Ordovician limestone, but oil was not found below the third sand, and the well was plugged back before being used for gas injection. Figure 34 shows the gas-injection and oil-production history of the lease between 1928 and 1942. When gas injection was begun, about 88,000 cubic feet of gas daily was injected into the three wells.

By November 1929, after well 28 was converted to a gas-injection well, the total volume of gas injected was increased to about 150,000 cubic feet daily (see fig. 34).

In April 1930 wells 20, 22, and 28 were abandoned as gas-injection wells and converted to oil producers. Average daily volumes varying from 160,000 cubic feet in 1931 to 72,000 cubic feet in 1934 were injected into well 1 at pressures of 60 to 65 p.s.i. In December 1934 gas was injected through well 45. The initial daily production of this well, drilled in November 1934, was 36 barrels of oil per day. Gas was injected for 2 months without results, so the well was returned to oil production in February 1935. Well 47, drilled as a dry hole in April 1935, was used for gas injection. The average volume of gas injected into wells 1 and 47 in 1939 was about 70,000 cubic feet daily. The project was discontinued in December 1939; well 1 was returned to oil production and well 47 shut down.

Produced gas from the lease was gathered by the Shell Oil Co., Inc., Barco gasoline plant. Average daily gas sales were 141,000 cubic feet in 1928 before gas injection was begun but increased to 170,000 cubic feet in 1931 and 1932. Gas production increased considerably in 1935, and sales of about 475,000 cubic feet daily were made in 1936. These increases are attributed to the 23 oil wells completed during the infill-drilling program in 1935 and 1936, some of which produced large volumes of gas. Gas production dropped sharply after 1936; gas sales averaged 130,000 cubic feet daily in 1940. Two of the 35 oil wells, which were producing at the beginning of gas injection, were abandoned during the injection period.

The rate of oil production first increased in August 1929 and amounted to 25 barrels daily for wells 24 and 25. Ten wells on 50 acres surrounding the injection wells had shown increases in oil production by January 1930, and by 1934 the entire lease had been affected by the injection. Daily lease production in May 1929 averaged 596 barrels of oil and increased steadily to a maximum of 644 barrels in July 1931. Total lease production increased rapidly after the infill-drilling program, which was begun late in 1934 and reached a peak in 1936. Injected-gas volumes were increased in 1935, causing an increase in the rate of oil production from the original wells. The increased oil production from the original wells, which can be attributed to deepenings and clean-outs in 1935, has been deducted from the total increase from the original wells, and only the increase due to gas injection is shown in figure 34.

After 1936 interference from the infill wells caused an abnormal decline of oil production from the original wells. The normal decline of the original wells without gas injection was calculated to be 6 to 4.5 percent per year. Based upon the history of other projects, it may be assumed that, with gas injection, the actual output of the original wells would have declined at a rate greater than the normal decline rate without gas injection, as is shown in figure 34. A rate of 8 percent per year has been used to illustrate this more rapid decline in the production of the original wells with gas injection.

The cross-hatched area above the estimated normal-decline curve (fig. 34) is an estimate of the oil gained as a result of gas injection, amounting to about 168,000 barrels. Oil production from infill wells may have been increased by the gas injection, but the production from these infill wells was not considered, so that the above figure is a reasonable estimate of the amount of oil attributable to gas injection.

<u>Humble Oil Co. (now Shell Oil Co., Inc.) L. Tubbee</u>. - Gas injection on the L. Tubbee lease, sec. 24, T. 4 S , R. 3 W., was begun by the Humble Oil Co. in May 1928. The injection well, in the center of the 160-acre lease (see fig. 33), was completed in January of that year and had an initial daily production of 5 barrels of oil.

The well penetrated a number of sandy shales that showed oil, but most of these were cased off. A perforated liner was set on the bottom opposite about 43 feet of shale and oil sand.

During the injection period oil was being produced from 35 wells. It is not known if vacuum was applied to these wells during the life of the project.

Repressuring operations were undertaken with the idea of checking the decline in rate of oil production. Crude-oil prices were decreasing, so it was not deemed advisable to make any great effort to increase the rate of production. In the beginning air was injected into the formation at the rate of 50,000 cubic feet daily at unknown pressures.

The first noticeable effect of injection was an increase in the rate of oil production from wells 27 and 28 along the west side of the lease. Well 17, also on the west side, was affected early in the life of the project, and within 11 weeks the combined oil production from wells 17 and 28 had increased from 17-1/2 to 44-1/2 barrels daily. Other wells on the west side showed slight increases, but those east of the injection well were not appreciably affected. Since much of the gas appeared to be moving toward the west side of the lease, the fluid level was raised on those wells along the west side of the lease to try to force the gas toward other wells. On July 14 the tubing in well 17 was raised 42 feet, and oil production from the well decreased abruptly. Oil production increased by November 1928 until it was at the former rate of production. On July 18 the tubing in well 27 was raised 54 feet, which resulted in a drop in daily oil production from that well that continued until the middle of December 1928. Raising the tubing in the two wells on the west side of the lease caused the gas to spread to other parts of the lease. By the end of July 15 wells - 3 on the east side - had shown increases in the rate of oil production.

Total lease production increased to a peak of 4,432 barrels during July 1928. Gas was substituted for air in July 1928, and the daily injected volume was decreased from 50,000 cubic feet to about 17,000. The rate of oil production declined in August but increased to a new peak of 4,563 barrels in October following an increase in the rate of gas injection to 36,000 cubic feet per day. By the end of 1928 an area of about 149 acres, which included 32 producing wells, had been affected by the injection (see fig. 33). Wells 3, 4, and 14 on the lease had shown no change in rate of oil production.

During 8 months of operation between May and December 1928 an average of 30,700 cubic feet daily of air and gas, or a cumulative volume of about 7,500,000 cubic feet, was injected. Injection may have continued until early in 1929, but the exact date of discontinuance is not known.

Semiannual production for the L. Tubbee lease averaged about 22,000 barrels during the period immediately before gas injection. Based upon the average decline of other leases in this area, it is estimated that the normal 6-month rate of decline for the Tubbee lease would have ranged from 4 percent in 1925 to 1.1 in 1931. Semiannual oil production remained above this estimated decline rate between 1928 and 1931 but dropped below it between 1931 and 1936. During the earlier period (1928-31) the increased oil production attributable to gas injection amounted to about 18,200 barrels, whereas the lost production in the later period (1931-36) amounted to 5,700 barrels. Undoubtedly a large part of the lost production was the result of operation curtailment during the depression years because of low crude-oil prices. If all of the lost production is subtracted from the oil gained during the earlier period, the net gain as a result of gas injection would amount to 12,500 barrels, or 84 barrels per acre.

Infill drilling, beginning in 1936 and continuing through 1940, resulted in increases in annual oil production from 33,500 to 80,000 barrels - overshadowing the former increases by gas injection.

Kewanee Oil Co. S. Jones. - The Kewanee Oil Co. S. Jones 120-acre lease, sec. 4, T. 4 S., R. 3 W., is in the north central part of the field. On June 1, 1936, the Kewanee Oil Co. began to inject excess gas into well 32 primarily as a gas-conservation project and not as a planned repressuring operation. Later other injection wells were added.

About 89 feet of the second and third Healdton sands was open in the injection wells. Structure and correlation sections Y-Y' and Z-Z' (figs. 6 and 7) show the thickness and attitude of the upper sands underlying the northeast part of the lease. The fourth Healdton sand is absent in certain areas of the lease (see figs. 10 and 19).

Oil was being produced from the Healdton sands through 34 wells when gas injection was begun in June 1936; one well was abandoned in July 1937, and one new well was drilled in October 1937.

Vacuum in varying amounts was applied to the casingheads of most of the producing wells, less vacuum being applied to those wells surrounding the injection wells than to those more distant. During the period of gas injection through well 32, a back pressure of approximately 18 p.s.i. was maintained on the casinghead of the adjacent well (well 30) to prevent channeling to that well and to force the gas to more remote areas.

At the beginning of gas injection in June 1936 approximately 30,000 cubic feet per day of gas was injected into well 32 through the casing, while oil was being produced through the tubing. In 1940, when wells 29 and 39 were converted to gas-injection wells, the total volume of gas injected was increased to 90,000 cubic feet per day. After injection through well 39 was discontinued in June 1940 volumes injected were decreased irregularly until 1944, when only 4,000 to 5,000 cubic feet per day was being injected. Gas injection was discontinued in August 1946.

By January 1937, 11 wells on 45 acres surrounding injection well 32 had shown increases in the rate of oil production. By January 1941, 5 other wells also had shown increases, thus raising the total area affected to approximately 75 acres. From the data available it appears that during the later life of the injection project additional acreage was not affected. Monthly oil production from the lease increased from 7,288 barrels in January 1936 to a peak of 8,222 barrels in December of that year, a daily increase of about 30 barrels of oil. Records of volumes of gas produced before 1940 are not available, but in 1940 the average daily gas sales were about 170,000 cubic feet. After 1940 the amount of gas produced and sold declined irregularly to about 65,000 cubic feet daily in 1945 but thereafter increased to an average of 98,000 cubic feet daily in August 1946. Gas produced from the lease was sold to the Harry Ells, Inc., gasoline plant, and the dry gas returned from the plant was used for injection.

Based upon earlier production records and the decline in yearly production of unaffected wells, an extrapolated curve representative of a normal decline rate of from 4 to 2 percent per year was constructed for the lease. As a result of gas injected, the actual rate of oil production between July 1936 and January 1941 exceeded that estimated from the extrapolated curve, but after January 1941 it dropped below that estimated rate. By implication, oil recovery was hastened by gas injection, and the net gain to January 1951 was only in the neighborhood of 1,700 barrels.

The Pure Oil Co. F. Lowery. - Well 28 on this lease in sec. 4, T. 4 S., R. 3 W., was connected to the return gas line from the Harry Ells, Inc., gasoline plant in May 1946; during that month about 25,000 cubic feet of gas daily was injected through the well at a pressure of approximately 20 p.s.i.

Structure sections (not presented) across the lease show two main oil-producing sands, with the thickness ranging from 26 to 120 feet. Thirty feet of the oil-productive sand was open in injection well 28.

Between May and October 1946, when gas injection was suspended, an average of 20,000 cubic feet of gas was injected daily into well 28 at pressures ranging from 16 to 20 p.s.i. Between May and November 1947 well 32 instead of well 28 was connected to the return gas line and about 40,000 cubic feet of gas daily was injected, at pressures between 5 and 32 p.s.i. For short periods during the summers of 1948, 1949, and 1950, limited amounts of excess gas were injected into the casinghead of well 32. The well was producing oil through the tubing at the same time.

Twenty-eight wells on this 90-acre lease were producing about 31 barrels of oil daily from Healdton sands when injection was begun. Ten of the wells surrounding the injection well have shown slight increases or sustained rates of oil production as a result of the gas injection; however, the volume of gas never was enough to stem the steady decline in yearly oil production from the whole lease. In 1950 the Healdton-sand wells were producing approximately 24 barrels of oil daily.

Schermerhorn Oil Corp. Fee 40-Acre. - The Schermerhorn Oil Corp. Fee 40-acre lease, sec. 5, T. 4 S., R. 3 W., contains 40 oil-productive acres on which 24 wells have been drilled.

The thickness of the oil-productive upper Healdton sands, into which gas was injected, ranges from 13 to 181 feet, being thickest in the middle of the lease and thinnest along the north line and in the southeast corner (fig. 12). Injection well 16, drilled in November 1916, penetrated an upper oil sand, about 90 feet thick, and a thinner, limy sand below, about 20 feet thick. Well 26 (drilled in September 1926) penetrated a thick, nonproductive upper sand and a lower, oil-productive sand 26 feet thick.

The injection project was begun late in March 1935, when there were 15 old and 2 recently drilled oil wells on the lease. Oil produced from the 40- and 20-acre Fee leases is produced together into the same tanks, so that the production from the 40-acre lease could not be computed separately. In March 1935 daily production of oil from both leases averaged 400 barrels.

Because of new wells completed just before and during gas injection, a graph of total lease production does not indicate clearly the results of the injection. The graph does show that the oil production was considerably higher than the estimated yearly production obtained by extrapolating a decline curve before infill drilling and gas injection. The production decline curve was extrapolated at yearly percentage declines ranging from 11.7 to 7 percent.

Well 16 was converted to an injection well late in March 1935, and an average daily volume of about 450,000 cubic feet of air was injected at 30 p.s.i. On April 13, 1935, gas was added to the air for injection. Injection through well 16 was discontinued in July 1935 and begun through well 26. The compressors were shut down on August 15, 1935, and injection was not recommenced until late in October of the same year. In November 1935 the plant was shut down for repairs, and there is no record of any gas injection after that date.

During the period of air and gas injection it appeared that channeling occurred to the line wells on leases west and south of the Schermerhorn Oil Corp. Fee 40-acre lease. The wells on these leases were reported as producing air during the early period of the air injection. When shut in, the pressures in the line wells on Schermerhorn Oil Corp. Fee 40-acre lease decreased rapidly. Casing leaks in the line wells, which allowed air to migrate to upper sands with accompanying decreases in pressure, was considered another possible cause of the loss of pressure.

The daily gas production from the Schermerhorn Oil Corp. Fee 40-acre lease increased from about 4,600 cubic feet per day in March 1935 to a peak of 493,300 cubic feet per day on August 19, 1935. After the plant was shut down in August 1935, gas production declined, so that, by December 15, 1935, the daily gas production was about 163,000 cubic feet, and in January 1935 daily gas production was 22,500 cubic feet.

The scarcity of tests of the rate of oil production of individual wells does not permit an estimation of the affected area on the basis of oil increases. However, monthly gas-production tests show that gas production from virtually all wells increased as a result of the injection.

From an extrapolation of the decline curve of the rate of oil production from the 40- and the 20-acre leases it is estimated that approximately 1,740 barrels of oil was gained during the 8 months of operation. This estimate is conservative because new wells drilled during the period of gas injection were not considered as being affected by gas injection.

The Pure Oil Co. Westheimer and Daube 80-Acre. - Since July 1946 small amounts of excess gas have been injected through the casing of The Pure Oil Co. Westheimer and Daube 80-acre lease, well 18, sec. 9, T. 4 S., R. 3 W. In October 1946 about 3,000 cubic feet daily was being injected at 14 to 18 p.s.i. During the gas-injection period some oil was produced through the tubing of the same well. The injection well near the center of the lease penetrated three oil sands totaling 87 feet in thickness.

Individual tests show that adjacent wells 8 and 16 had temporary increases of about 1/2 barrel in daily oil production. Well 4 in the northeast corner of the lease showed some increases in daily oil production as a result of the gas injection on the adjacent Westheimer and Daube 60-acre lease.

Miscellaneous Injection Projects. - On several small leases one or more wells called volume wells have been connected temporarily to the gas-return line from the Harry Ells, Inc., gasoline plant. The primary purpose was to cycle any excess dry gas returned from the gasoline plant during the summer months so that it would pick up gasoline vapors from the formation oil and the enriched gas could be sold to the gasoline plant. Included in this group of volume wells are Kewanee Oil Co. Frazier lease, well 13 in sec. 15; Keck 30-acre lease, well 1 in sec. 5; and C. R Smith lease, well 5 in sec. 5, all in T. 4 S., R. 3 W.

In 1934 an attempt was made to inject gas into Magnolia Petroleum Co. Smalley well 35 in sec. 10, T. 4 S., R. 3 W. Very little gas could be injected at 1,500 p.s.i.

Brine Disposal

In recent years large quantities of produced brine have been disposed in subsurface formations in the Healdton field. As of November 1, 1951, 14 disposal wells, most of them on leases in the western and northwestern part of the field, were receiving approximately 7,100 barrels daily of produced brine. This was nearly half of the 14,600 barrels of brine produced daily in the field. In most of the disposal wells, brine was being injected into Ordovician formations through 7-inch casing set and cemented through the Healdton sands. However, in three structurally low wells, produced brine was being returned to the fourth Healdton sand.

Usually treatment is not required to condition the brine for subsurface injection, although at one disposal well the produced brine is aerated in an open tank before being injected (see fig. 37, lower photograph). To inject the brine a 3-cycle, 2-1/2- by 4-inch Gaso pump was being used to pump nearly 2,000 barrels per day of produced brine into the well at a pressure of about 400 p.s.i. At four other disposal wells surface-injection pressures ranging from 150 to 550 p.s.i. are required to inject volumes ranging from 320 to 2,500 barrels of brine per day. In nine other disposal wells, all available brine was injected by gravity. Figure 37, upper photograph, shows one of these wells in sec. 16, T. 4 S., R. 3 W. In March 1942 this well was converted from an oil well to a disposal well in the fourth Healdton sand. To September 1, 1951, 677,000 barrels of produced brine from the Healdton sands had been injected into this well. Several structurally higher wells on this lease, which produce oil from the fourth sand, are receiving some benefit from the flooding by the injected water.

MOBILE-OIL RESERVES

In the section Reservoir Conditions, it was stated that the volume of mobile oil originally present in the Healdton sands (measured at stock-tank conditions), was approximately 422 million barrels. To January 1, 1951 about half of this mobile oil had been recovered.

Figure 38 shows the areal distribution, in barrels per acre, of the remaining oil. The illustrated data were obtained by subtracting the total produced oil for each lease from the mobile oil originally present and dividing this remainder by the number of productive acres of the lease. To compensate for possible drainage, production data and estimated reserve data for several adjoining leases occasionally were combined, as shown by the outlined areas in figure 38.

Because in most of the wells, oil was produced simultaneously from several sands it is impossible to calculate what fraction of the 211 million barrels of produced oil was recovered from the separate sands and, by deduction, how the remaining mobile oil is distributed among the several sand zones. Much of the oil undoubtedly was produced from the first developed and more extensive upper sands, but probably 180 to 200 million barrels of mobile oil remain in these sands. Reserves in the naturally water-flooded fourth-sand zone are comparatively less important.

The economic recovery of oil reserves remaining in the Healdton sands depends upon the type of mechanism that displaces oil from the pore spaces and upon the pressure differentials available to move it through the reservoir sand into the well bores. It is well-recognized that the mobility or freedom with which oil will move through the sand depends upon the oil saturation of the sand and upon the viscosity of the oil and that as oil saturation decreases and viscosity increases more pressure is required to move oil through the sand to the producing wells.

In the upper-sand reservoirs relatively inefficient solution-gas expansion was the displacement mechanism; and, since little, if any, of the original reservoir pressure now remains, only that relatively small pressure differential created by vacuum

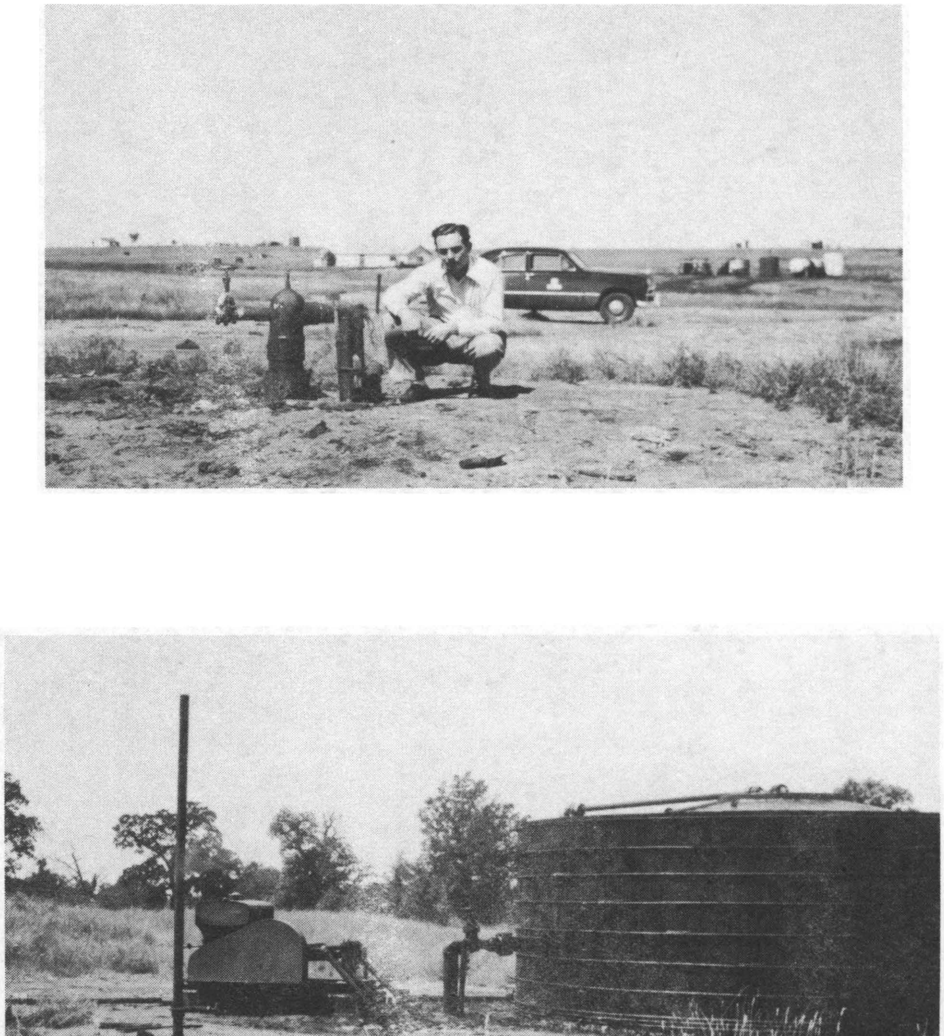

Figure 37. - Brine-disposal wells, Healdton oil field, Carter County, Okla.

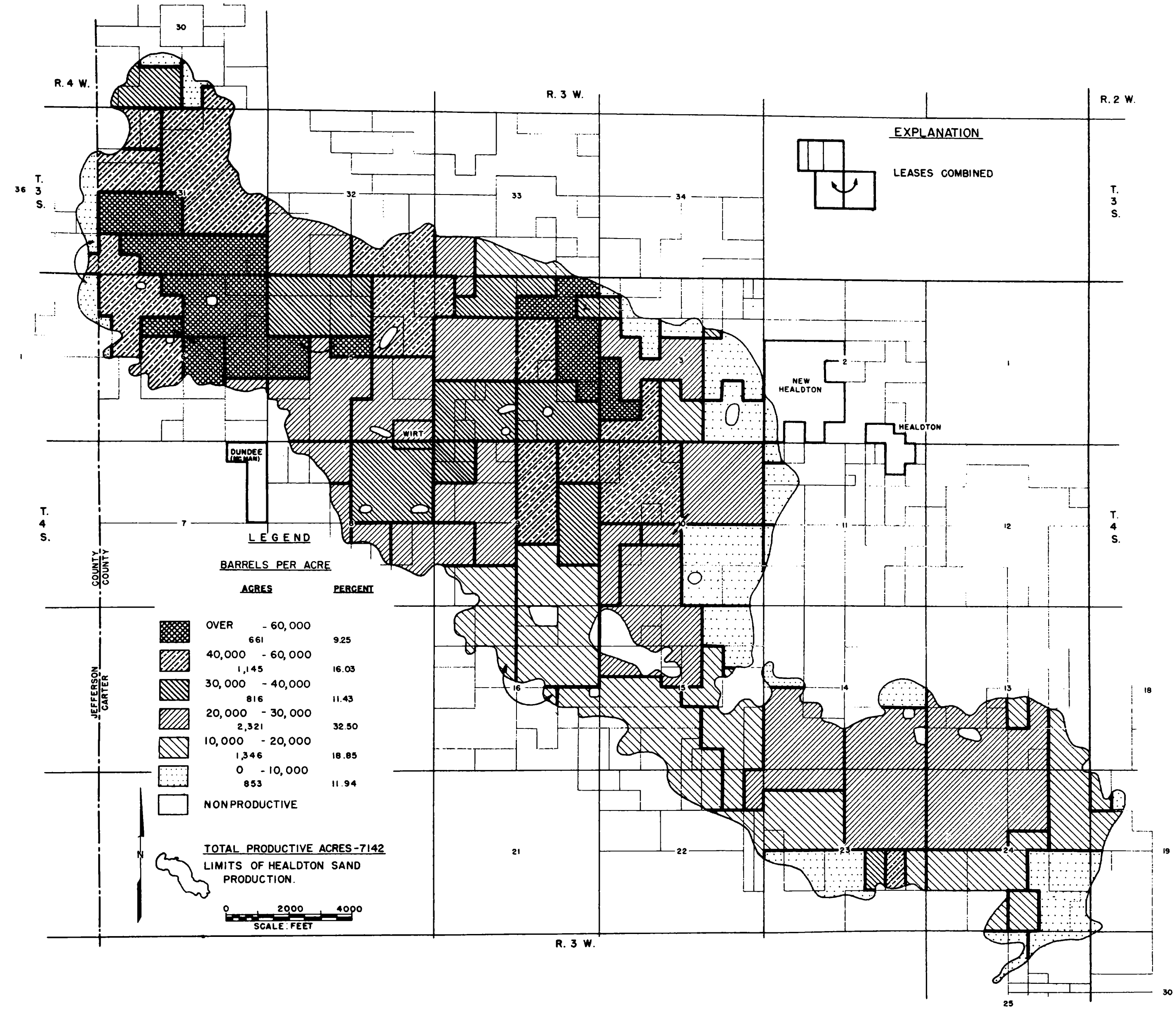

Figure 38. - Mobile oil reserves, Healdton sand, Healdton oil field, Carter County, Okla., 1951.

application and gravity is now acting to move oil to the wells. The rate of production is decreasing yearly, and the history of wells and leases producing from the upper sands clearly indicates that much mobile oil will not be recovered unless some extraneous pressure is applied to the reservoir to move oil to the producing wells.

In most areas of the fourth sand a natural water drive is supplying the mechanism and pressure necessary to effect an efficient recovery of mobile-oil reserves. Calculations made for one lease showed that the efficiency of this natural water drive in recovering mobile oil from the fourth sand was about 83 percent, as compared to a calculated efficiency of less than 50 percent for depleted upper sands without benefit of water displacement.

WATER FLOODING

The oil-production history and reserves remaining in the Healdton sands have been discussed in the preceding pages. The principal purpose of this report is to encourage recovery of these oil reserves by outlining methods and problems involved in their production.

The injection of water into partly depleted oil-bearing sands simulates a natural water drive and is the most efficient secondary-recovery method in common use. Water flooding has been used successfully in many oil fields in Kansas (18), Oklahoma (19, 20), Texas (21), Illinois (22), Pennsylvania (23), and California (24). Recoveries exceeding 100 percent of the primary recovery have been obtained in some of these areas. By carefully considering the many factors involved and controlling the injected fluid, water flooding can be used to recover much additional oil from the Healdton sands.

Theoretical Considerations

Efficiency

Earlier in this report efficiency was defined as the ratio of recovered oil to mobile oil originally in place, mobile oil in the Healdton sands being that oil in the interconnected pore space that exceeds 29 percent saturation. Theoretical calculations show that at the time the injected water first reaches the producing well in the conventional five-spot pattern (four input wells surrounding one oil well), about 72 percent of the area between the wells has been swept by the injected water. For other patterns, the area swept ranges from 32 to 89 percent. This theoretical area swept applies only to a homogeneous sand or uniform thickness. Discontinuous sands, open channels, fractures, tight streaks, highly water-saturated zones, and differences in fluid viscosity are other important factors affecting the area swept and the efficiency of any water flood.

Mechanism

Buckley and Leverett (25), in describing the mechanism of water flooding, have stated that during an initial phase the water saturation in the sand increases rapidly and oil is ejected ahead of an advancing water front. During a subordinate phase both oil and water flow through the sand with a gradual increase in water saturation, so that water flows more readily and effects the removal of comparatively small and continuously decreasing volumes of oil.

According to Dickey and Bossler (26):

> The percentage saturations of oil, water and gas in a depleted field determine whether it will be economically possible to recover oil by secondary methods, and whether water-flooding or gas-driving, or either, will be successful.
>
> It is suggested that economic recovery of oil by secondary water-flooding can occur only when a rich bank of oil is formed by the encroaching water. If the sand has a greater effective permeability to water than it has to oil before flooding, a bank will not be formed, and water flooding will not be successful, . . .

Horner (27) has cited leases where water flooding has failed because of high initial water saturation.

Relative Permeability

Leverett and Lewis (28) have shown that, in unconsolidated sands, the relative permeability to either oil or water depends primarily upon the saturation of that phase. Their experiments were made on unconsolidated sands and their quantitative results are exact only for loose sands. Inspection and analyses of core samples indicate that many of the Healdton sands are loose or poorly cemented. Without definite relative permeability data on the Healdton sands, it is assumed that, with care and within certain limitations, the data of Leverett and Lewis can be applied to many of the sands in the Healdton field to indicate relative permeability.

Mobility

The mobility of a liquid depends upon the relative permeability of the sand to that liquid and upon its viscosity. Dykstra and Parsons (29) have defined mobility as the ratio of a liquid's relative permeability to its viscosity. The mobility ratio, the comparative ease with which two liquids will move through a sand, depends directly upon the relative permeability of the sand to those liquids and inversely upon the viscosities of the liquids. If the ratio of the mobility of the water to the mobility of the oil is less than 1, a bank of oil is formed ahead of the water when it is injected into an oil sand.

In an attempt to apply mobility ratios to water flooding of the Healdton oil sands, figure 39 was constructed to show the limiting initial oil and water saturations that, at representative viscosities, would result in a mobility ratio of 0.9. A mobility ratio of 0.9 instead of 1.0 was arbitrarily selected to provide a safety margin of oil saturation, which would assure the formation of an oil bank ahead of injected water.

Viscosity

Table 8 lists viscosities of Healdton oils at 80° F., ranging between 8.7 and 58.9 centipoises. Because sample C-4 may have been weathered and therefore is not representative of Healdton oil in the reservoir, sample C-1 with a viscosity of 31.7 centipoises, was considered in the calculations as the upper viscosity limit of Healdton crudes. Temperatures of Healdton sands range between 86° F. at 1,250 feet and 73° F. at 650 feet. At these limiting temperatures, the extremes of viscosity of Healdton oils are 8.1 and 34.0 centipoises. The viscosity of injected water is considered to range from 1.1 centipoises at 60° F. to 0.8 centipoises at 86° F.

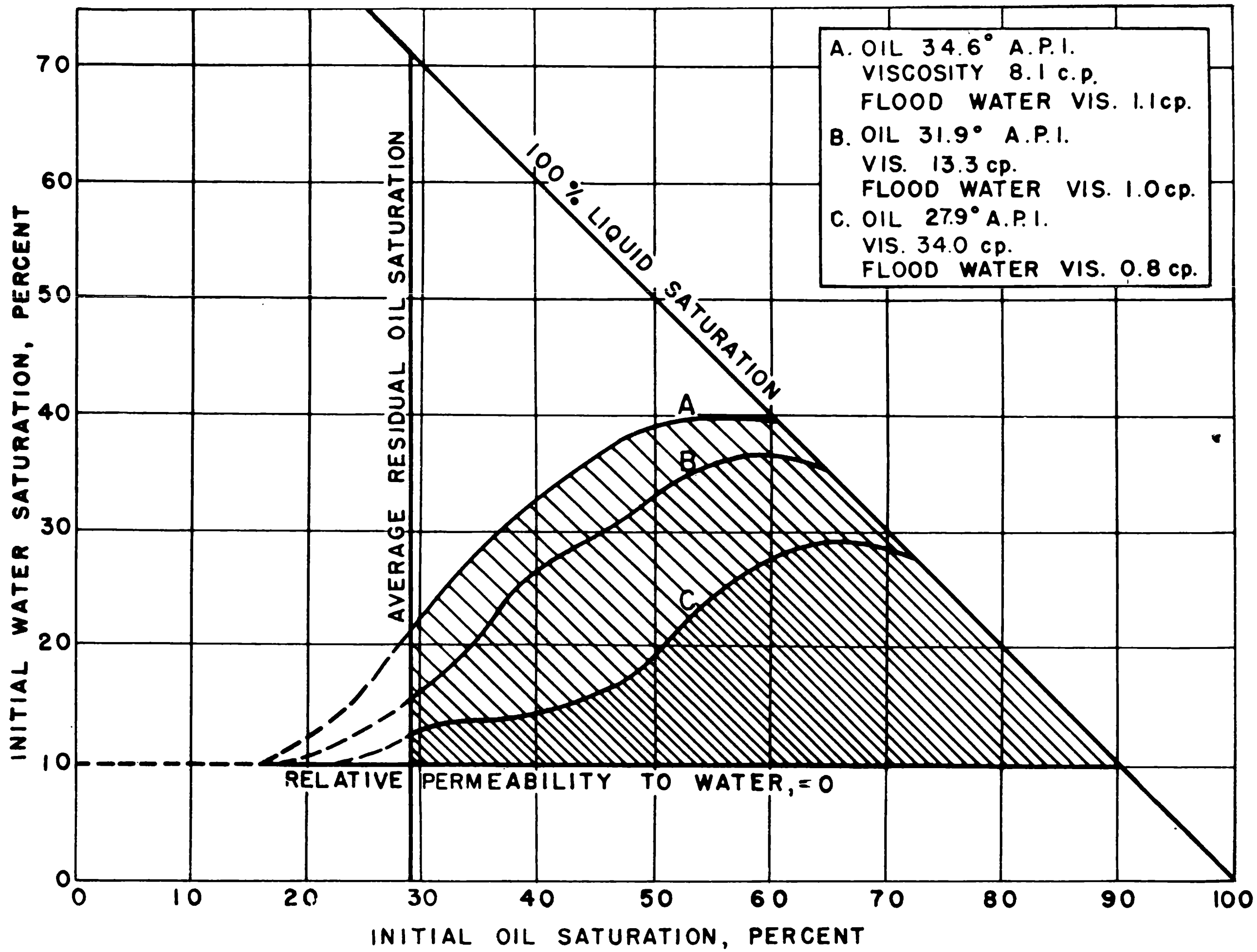

Figure 39. - Limiting initial liquid saturation for successful water flooding of loosely consolidated sands in the Healdton oil field.

(After Data by Leverett & Lewis)

Theoretical Application to Healdton Field

Curves A, B, and C (fig. 39) show the minimum oil and maximum water saturations permissible to water-flood Healdton sands successfully under assumed flooding conditions.

Curve A is the limit of liquid saturations, in percent, to permit a mobility ratio of 0.9 for an oil viscosity of 8.1 centipoises and a flooding-water viscosity of 1.1 centipoises. This combination of oil and water viscosities is considered to include the widest range of floodable liquid saturations possible in the Healdton field. Curve C marks the limit of liquid saturations for an oil of 34.0 centipoises viscosity and a flooding-water viscosity of 0.8 centipoise, which would include the narrowest range of permissable liquid saturations in the Healdton field. Curve B represents the limiting liquid-saturation conditions for the average oil in the Healdton field - oil 13.3 and water 1.0 centipoises.

In figure 39, the shaded areas bounded by the three curves, A, B, or C are those areas that contain the combinations of water and oil saturations that in the Healdton sands could be flooded successfully. The area above any of these curves includes saturations unfavorable for water flooding - oil saturations too low or water saturations too high to permit the formation of an oil bank.

From a study of figure 39, it is apparent that, under similar conditions, more water saturation and less oil saturation are permissible for less viscous oils to permit formation of an oil bank. In deep sands a wider range of oil and water saturations is floodable, since viscosity of the oil is lower at the higher temperatures prevailing there. For example, the C-type oil illustrated in figure 39 should not be floodable at 50-percent oil and 20-percent water saturation at a viscosity of 34 centipoises, which would obtain at a depth of 600 feet, whereas a sand with these oil and water saturations should be floodable at a depth of 1,300 feet, where the temperature would be about 90° F. and where the viscosity of the same oil would be 27.5 centipoise.

Injection Rates and Pressures

Water-injection rates and pressures are the subject of much controversy. Some operators believe that low injection rates (2 to 5 barrels per acre-foot per day) increase efficiency, whereas others claim that higher rates recover more oil. Usually there is a critical pressure (about 1 p.s.i. per foot of depth) above which the formation may be ruptured, resulting in extreme bypassing and channeling to producing wells with subsequent loss in efficiency.

Sources and Treatment of Water

In considering water flooding of oil sands in the Healdton field an adequate volume of water for injection probably would be the most important problem confronting the operators. In other fields developed for water flooding, both surface and subsurface water commonly are used for flooding. Where a river or large stream is available, such as the Verdigris River in Nowata and Rogers Counties, Okla., or the Arkansas River in the Burbank pool, surface water is being used successfully. Sometimes rain water collected in ponds is used, but this seldom is satisfactory for a regular flood. The streams draining the Healdton field area are not large enough to provide the volume of water necessary for successful flooding. Possibly a combination of several sources of water could be used to obtain the volume of water required.

Many of the wells drilled in the field penetrated a number of upper Permian sands that were reported by the driller as water-bearing. Water for the city of Healdton in sec. 2, T. 4 S., R. 3 W., and for many lease operations is obtained from these shallow Permian sands at depths between 175 and 400 feet. The city-water-supply wells showed initial daily production rates ranging from 500 to 1,000 barrels. It is problematical whether such volumes of water could be produced continuously by these wells.

Table 12 gives analyses of six samples of water produced from wells in the Healdton field. Three of the mineral analyses were made on samples of water produced from Permian sands, two on samples produced from the Healdton oil sands, and one on a sample of water produced from an Ordovician formation.

Study of the analyses shows that the Permain-sand water could be injected into the Healdton sands with comparatively little chemical or physical conditioning in a water-injection system completely closed from the atmosphere. Because of the fairly high oxygen content and the low supersaturation of carbonates, it might be necessary to use an inhibitor to minimize corrosion (30). Even in a closed water-injection system it is likely that the Permian-sand waters, as produced, would contain organic matter, and an algaecide or bactericide should be used, particularly in warm weather, to prevent plugging in the injection wells.

Examination of the clay minerals associated with the Healdton oil sands indicates that these clays are of the nonswelling type, and probably Permian-sand waters could be injected without hydrating the clays and plugging the sand.

Although considerable water is produced with the oil in the Healdton field (see figs. 17, 18, 21, and 22), the volume of the water produced on any lease would not be adequate for a regular water-flooding project. Produced water from several leases might be gathered at a central point to constitute a major portion of the water requirements for a small flood. For instance, in the northwestern part of the field about 4,400 barrels of water is produced daily from 21 leases. This might be enough water to flood a sand 30 feet thick on one 80-acre lease.

Analyses of two samples of brine produced from Healdton sands in separate areas of the field are shown as samples 4 and 5, table 12. The brines contain comparatively large quantities of dissolved iron, free carbon dioxide, and carbonate supersaturation. Because of changing conditions of temperature and pressure accompanying production and injection, it would be almost impossible to maintain these components in solution. In a closed water-injection system they might be precipitated and plug the formation. An open water-injection system permitting complete aeration and settling would be more satisfactory.

Brine sample 6, in table 12, was produced from an Ordovician formation approximately 3,900 feet in depth. When this well was drilled in 1924 a large volume of water was reported in the formations below the present depth of the well, and the well was plugged back. Water from this lower formation would be suitable to use in water flooding the Healdton oil sands, provided it is properly treated before injection. The possibility of using waters from Ordovician formations as a supply source should be investigated further.

TABLE 12. - Analyses of water available for water flooding, Healdton oil field, Carter County, Okla.

Field Analyses

Sample No.	Sampling-point location Q.	S.	T.	R.	Source formation	Volume produced, bbl./day	Oxygen, p.p.m.	Carbon dioxide, p.p.m.	Hydrogen sulfide, p.p.m.	pH value	Iron, p. p. m. Total	Dissolved	Alkalinity as $CaCO_3$, p.p.m. P.1/	M.1/	Supersat. of carb. as $CaCO_3$, p.p.m.
1.....	NW	4	4S	3W	Permian	500-1,000	1.8	14	0	7.3	0.8	0.2	0	509	-28
2.....	SW	1	4S	3W	do.	500-1,000	4.9	0	0	8.8	0	0	30	486	+14
3.....	SW	2	4S	3W	do.	500-1,000	1.1	0	0	8.4	.2	0	21	568	-10
4.....	SE	31	3S	3W	Healdton	1,400	0	153	0	6.5	35.5	29.4	0	216	+72
5.....	NE	15	4S	3W	do.	2,500	0	127	0	6.4	46.0	44.8	0	190	+71
6.....	SE	4	4S	3W	Ordovician ls.										

Mineral Analyses

Sample No.	Spec. grav., 60° F.	Calcium (Ca) P.p.m.	R.v.2/	Magnesium (Mg) P.p.m.	R.v.	Sodium (Na) P.p.m.	R.v.	Carbonate (CO_3) P.p.m.	R.v.	Bicarbonate (HCO_3) P.p.m.	R.v.	Sulfate (SO_4) P.p.m.	R.v.	Chloride (Cl) P.p.m.	R.v.	Total solids3/ P.p.m.	R.v.
1.....	1.000	38	7.79	18	6.07	203	36.14	30	4.10	529	35.61	30	2.54	67	7.75	710	4/100
2.....	1.000	8	2.01	4	1.66	212	46.33	33	5.54	464	38.32	17	1.76	31	4.38	591	4/100
3.....	1.000	4	.80	2	.64	278	48.56	36	4.82	597	39.35	7	.60	46	5.23	719	4/100
4.....	1.084	7,260	8.82	2,700	5.41	33,800	35.77	0	0	144	.06	0	0	72,700	49.94	116,604	100
5.....	1.101	12,200	11.96	3,130	5.05	38,600	32.99	0	0	137	.04	0	0	90,200	49.96	114,267	100
6.....	1.127	15,627	12.09	3,700	4.72	49,222	33.19			872	.22	526	.17	113,469	49.61	183,416	100

1/ End-points as determined by P. - phenolphthalein, M. - methyl orange.
2/ R.v. - reacting values in percentage (Palmer).
3/ Stoichiometrical.
4/ Total solids by evaporation.

Barium content: Samples 1, 2, and 3 - 0 p.p.m.; 4 - 67 p.p.m.; 5 - 60 p.p.m.; 6 - no test.

Where an extraneous water is used for flooding provisions usually are made to recycle the brine produced with the crude oil. In many water-flooding projects two or more water-supply sources are used. If water from the Permian sands was mixed with produced brine a closed water-injection system would not be practical because the Healdton sand waters contain barium in quantities ranging from 20 to 70 p.p.m. If these waters were mixed with the Permain-sand waters containing 5 to 30 p.p.m. of soluble sulfates, insoluble barium sulfate would be precipitated and would plug the formation. The dissolved oxygen in the Permian-sand waters would oxidize the dissolved iron in the Healdton-sand waters, causing it to form a precipitate, which might plug the formation also. Without chemical treatment the dissolved oxygen would cause excessive corrosion of metallic equipment.

The most practical method of conditioning the waters for injection would be to use an open system and condition the produced brines before mixing them with Permian-sand waters. Figure 40 is a diagram of a proposed open-type treating system. The produced brine should be aerated to oxidate the ferrous iron compounds to insoluble ferric compounds, to release part of the dissolved free carbon dioxide, and to reduce the supersaturation of carbonates. Chemical treatment with lime probably would be needed to stabilize the free carbon dioxide, to maintain the carbonate balance, and to reduce the supersaturation of carbonates to a concentration where only a thin, protective coating of carbonates would be deposited on the interior walls of pipes and other metallic surfaces. A coagulant, such as aluminum sulfate, should be added to aid in congealing of the precipitates.

Chemicals might be added to the waters by dry-chemical feeders as the mixed water gravitated from the aeration pond through a chamber set in the pond dike and into the sedimentation pond. Water and chemicals could be agitated with a mechanical mixer in the chamber. For reserve supply and detention time, the sedimentation pond, as shown in figure 40, should be large enough to hold a volume of water equivalent to that injected in 3 days and should contain baffles designed to afford maximum mixing and detention of the water to permit sedimentation.

In an open water-injection system some sterilizing agent probably would have to be used to control the growth of organic matter, particularly during the summer months. The most advantageous point to introduce the sterilizing agent would be between the sedimentation pond and the filters, or in the last compartment of the sedimentation pond.

Probable characteristics of a water resulting from the mixing of waters from different sources cannot be predicted. Details as to definite treatment procedures and quantities of chemicals needed for adequate conditioning would have to be worked out from theoretical consideration of characteristics of waters available and the ratio in which they were to be mixed. Tests and analyses should be made after the plant is operating.

The filter medium could be sand, crushed anthracite, or diatomaceous earth, which could be supported on successive layers of graded, crushed rock or a screen. The filters should be connected so that the beds could be back-washed with water from the clear-water tank pumped into the bottom of the filters, upward through the bed, and then to the reaction end of the sedimentation pond.

The effluent from the filters would flow into a clear-water tank or a partly submerged concrete clear-water well from where it would be pumped to the input wells.

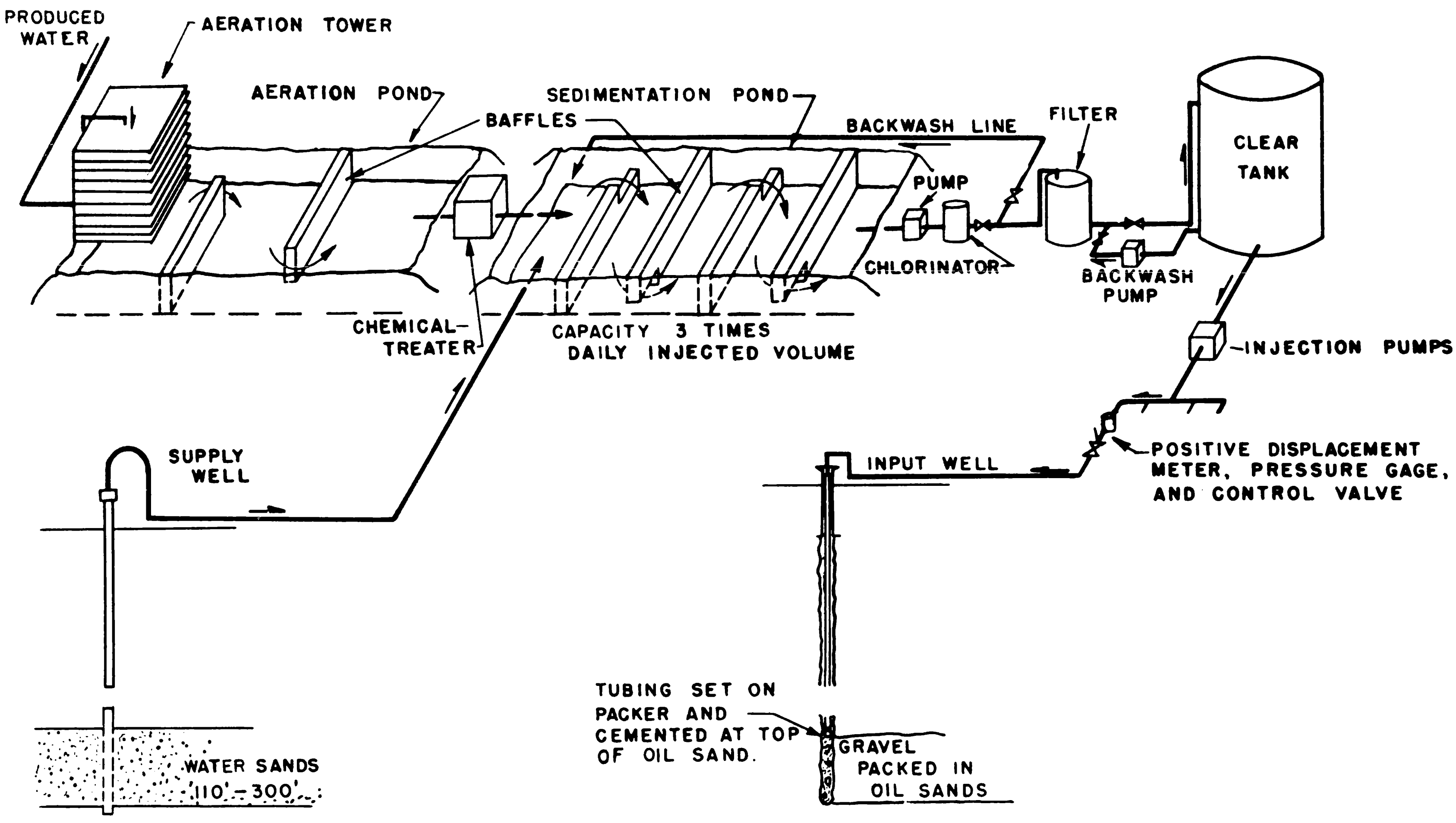

Figure 40. - Flow diagram of suggested water-conditioning and injection system, Healdton oil field, Carter County, Okla.

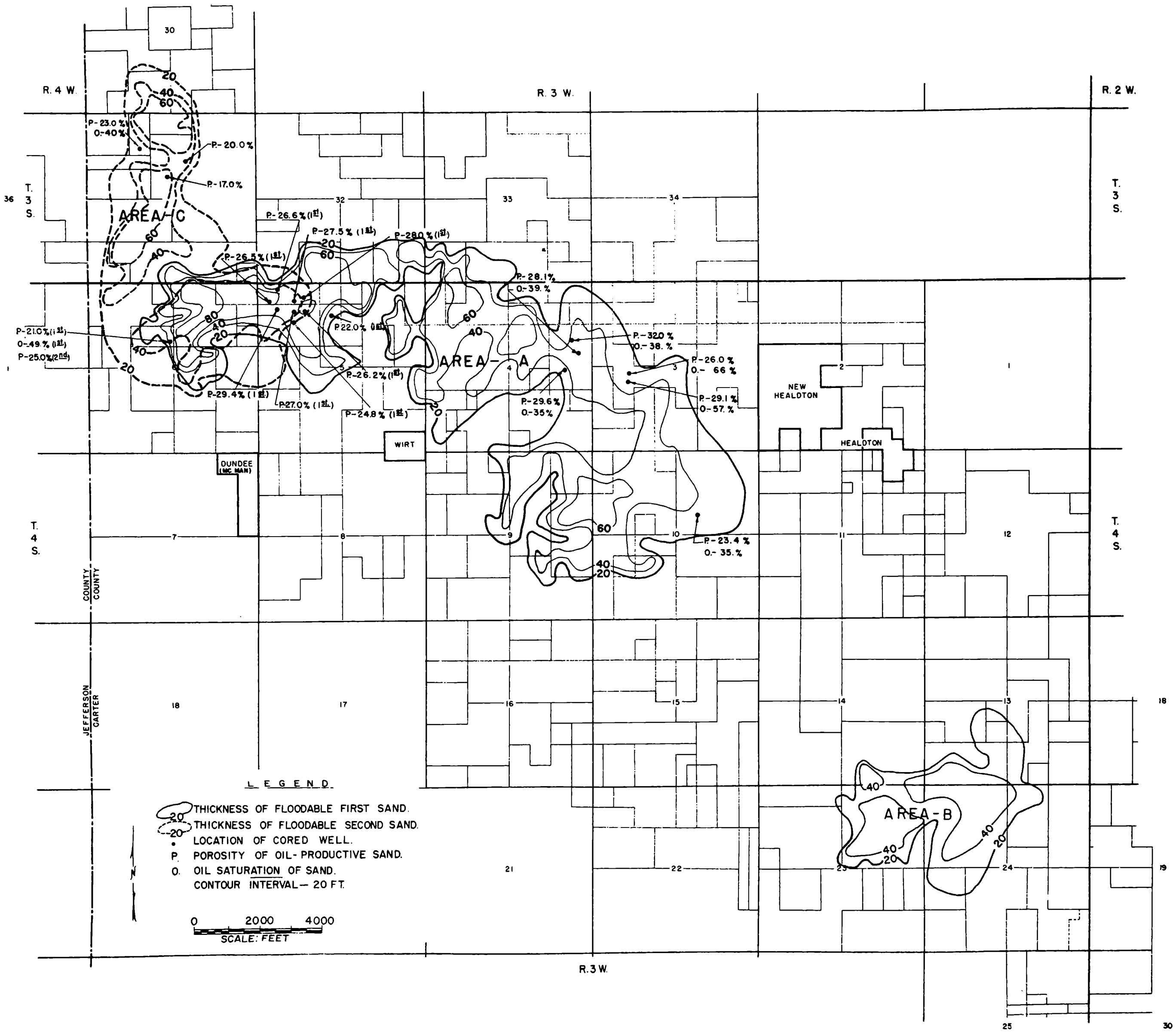

Figure 41. - Areas and sands most suitable for initial water-flooding development, Healdton oil field, Carter County, Okla., 1951.

If the input wells are drilled with rotary tools, they could be completed inexpensively without casing. To prevent caving, washed gravel should be packed in the hole opposite the producing sands. Two-inch tubing could be set on a packer above the sand and securely cemented to prevent upward movement of the injected water. Normally, input wells require little servicing except to back-flow or treat with mud acid, and such an input well should last the life of the flooding project. To aid in salvaging the tubing after the project was flooded out, right- and left-hand-thread nipples could be installed just above the top of the cement.

Three Areas Suitable for Water-Flooding Tests

Although many of the sands in the Healdton field might be flooded successfully, certain sands in local areas are considered especially suitable for initial water-flooding tests. Figure 41 shows three areas, A, B, and C, where the first or second Healdton sand probably could be flooded successfully.

In area A, containing 2,400 acres along the northeast flank of the structure, the upper member of the first Healdton sand varies in thickness between 20 and 100 feet. Detailed correlation studies indicate that this sand is fairly continuous throughout the area. The structure of the top of this sand member is shown in figure 11. The depth varies from about 150 feet above sea level in the southwest corner of sec. 4, T. 4 S., R. 3 W., to about 150 feet below sea level along the east edge of sec. 10, T. 4 S , R. 3 W.

The upper member of the first Healdton sand was cored, using water-base mud in 16 wells in area A, and analysis of the cores show the average porosity of the sand in individual wells to range from 20.9 to 31.7 percent. The oil saturation of these cores ranged from 34.6 to 60.0 percent. As some of these cores presumably were partly flushed by the drilling fluid, the actual oil saturation of the reservoir rock might be higher than the reported values. The permeability of cores from these wells ranged from 210 to 2,316 millidarcys. Based upon the permeability - connate-water relationship as shown in figure 15, the connate-water content of the oil sands represented by the cores should range between 12.3 and 22.0 percent and average 15.4 percent.

Throughout most of this area the first sand has been under vacuum for a number of years and is partly depleted, so that recently drilled wells do not record "free" oil from these sands. In sec. 6, T. 4 S., R. 3 W., many logs of early wells show 100 or more feet of solid sand section, but logs of later wells drilled in this area, show sand and shale or broken sand. Electric logs show 40 to 50 feet of oil-productive sand in a total of 60 to 70 feet of section.

In the NW1/4 sec. 5, T. 4 S., R. 3 W., the sand was cored in many wells, and analyses of these cores show the sand to be fairly uniform and continuous with only minor shale partings. However, several faults (see fig. 11) are present in the north half of section 5 and could act as barriers to the movement of fluids. Because of these faults, much of the NE1/4 sec. 5 is not considered as the most satisfactory area for water flooding.

In sec. 4, T. 4 S., R. 3 W., the upper member of the first Healdton sand is shown as having thicknesses of approximately 40 to 60 feet (see fig. 41). In many areas this sand member is split by a shale or limestone bed 5 to 15 feet thick. In some areas the upper portion of the sand originally was gas-saturated in the gas-cap area and consequently has been excluded from consideration as floodable oil sand. Three wells on the Sinclair Oil & Gas Co. J. S. Mullen property, NE1/4 sec. 4, T. 4 S., R. 3 W., were cored. Analyses of cores show the porosities to range from 28 to 31 percent.

In secs. 9 and 10, T. 4 S., R. 3 W., this upper member of the first Healdton sand reaches a maximum thickness of 60 feet, although the sand bed may contain some shale layers. Only one well was cored through this sand, and analyses show the average porosity to be 23.4 percent and the average oil saturation 35 percent. Drill cuttings of several more recently drilled wells were available for microscopic study, which shows that here the sand contains more shale and limestone than do the soft, clean sands in secs. 5 and 6, T. 4 S., R. 3 W. Radioactivity logs were made in five wells in sec. 10, T. 4 S., R. 3 W., and comparison of these logs with the original drillers' logs, made in 1915 and 1916, show considerable difference in the depth and thickness of sands. Where the drillers' logs show a total of 25 to 40 feet of oil sand, radioactivity logs show shale partings 2 to 8 feet thick 6 to 11 feet below the top of the sand.

In the southeast extension, an area of approximately 500 acres (area B) is outlined as being suitable for water flooding in the first Healdton sand. In this area the thickness of the sand ranges between 20 and 80 feet, although most of the sand is less than 40 feet thick. In this area the depth to the top of the sand ranges from 100 feet above sea level to 200 feet below.

Wells in this area were not cored, and only one electric log of a recent well is available. However, drill cuttings from several wells have been examined, and these show the sand to be fine-grained and somewhat shaly, with the shale content increasing with depth. The porosity of the first sand has been estimated to range between 18 and 23 percent.

Figure 41 shows an area of approximately 900 acres (area C) in which the second Healdton sand is continuous and suitable for water flooding. In this area the sand ranges between 20 and 100 feet in thickness, although the average thickness may be close to 40 feet.

In sec. 31, T. 3 S., R. 3 W., the sand is described as fine-grained, shaly, and somewhat calcareous, with pitted grains. In sec. 6, T. 4 S., R. 3 W., the formation contains more limestone. In a few wells beds of oolites, composed of limestone surrounding sand grains, were encountered near the top of the second Healdton sand.

Five wells in this area were cored, and the analyses show the porosity ranges from 17 to 25 percent and the oil saturation from 20 to 40 percent.

Some water is produced from wells along the west edge of this area in sec. 31, T. 3 S., R. 3 W., and sec. 6, T. 4 S., R. 3 W., and it is possible that there is a limited, natural water drive in the second sand. However, it is believed that this water drive is not adequate to insure maximum oil recovery.

The above areas and sands are by no means the only ones that might be water-flooded successfully. Rather, they are those about which enough data now are available for water-flooding consideration.

In selecting any area for water flooding, detailed studies of the sand conditions and the production history should be made. The continuity of the sands, as well as their oil and water content, are most important. Where the accuracy of drillers' logs may be doubtful, radioactivity logs can be made in the old holes. New wells should be cored and electrically logged.

Water-Flooding Calculations

Suder and Cahoun have presented a method for predicting the water-flood behavior of a property from core analyses data and water-injection pressures (30). Their method assumes that water flooding progresses in a horizontal plane with no vertical movement and that the total water flowing in a formation, including beds of different permeability, can be represented by the sum of the volumes of water flowing in the individual beds. An adaptation of this method, assuming a constant injection rate, was used in calculating the probable water-flood behavior of two leases in the Healdton field.

These calculations were based upon a uniformly spaced five-spot pattern with four input wells surrounding each producing well. Upon repetitive development, the five-spot pattern becomes one in which four producing wells surround each input well, and in the entire flood there are an equal number of producing and input wells. The fraction of the total five-spot area theoretically swept by the injected water, when it first reaches the producing well, is 0.72 as described by Muskat (32), and this value was used in the calculations as the theoretical sweep efficiency. After injected water from each bed first reached the producing wells, it was assumed that water and no oil would be produced from that bed. In actual practice some oil is continuously produced with increasing volumes of water before the residual-oil-saturation value of 29 percent is reached. When the oil saturation in the more permeable beds is reduced to 29 percent or less, these beds might permit disproportionately large volumes of water to move to the producing wells, so that when the total volume of water pumped becomes too great to be handled economically, only in the more permeable beds would the oil saturation be reduced to the theoretical minimum. Selective plugging or packing off of these watered-out beds then would be necessary to effect oil recovery from the other less permeable sands.

Based upon the amount of flooding water that might be available, an injection rate of 500 barrels of water daily into each input well was assumed.

Lease 1

The first lease considered was in area A (fig. 39), where the thickness of the upper member of the first Healdton sand averaged 34.7 feet at a depth of approximately 900 feet. Analyses showed that the permeability of the individual core samples ranged from 400 to 3,100 millidarcys and the porosity from 18 to 38 percent. For the calculations a spacing between like wells of 660 feet was assumed.

The entire sand body was considered as 17 individual homogeneous beds 0.9 to 3.6 feet thick, and each bed was assumed to have uniform horizontal permeability with values for the different beds ranging from 450 to 3,000 millidarcys.

It was calculated that during the life of the flood, 500 barrels of water daily could be injected into the sand body at pressures exerted by a hydrostatic head of water in the input wells.

An average oil and water saturation of 35.0 and 14.2 percent, respectively, before flooding was used for each individual bed. The relative rate at which the injected water entered each individual bed was assumed to be proportional to the ratio that the millidarcy-foot capacity of that bed bore to the total capacity of the sand.

The volume of water necessary to effect flood-oil production is that volume required to saturate the gas space and commonly is referred to as the fill-up volume. This fill-up volume can be calculated by the following equation:

$$V = 0.72\,D^2\,T\,P(1 - C_w - O)\,0.178;$$

where:

V = fill-up volume, barrels;

0.72 = theoretical sweep efficiency at water breakthrough for five-spot pattern;

D = spacing between like wells, feet;

T = thickness of bed, feet;

P = porosity, decimal fraction;

C_w = water saturation, decimal fraction;

O = oil saturation, decimal fraction;

0.178 = factor converting cubic feet to barrels.

The time required to fill up or begin flood-oil production from each bed was calculated by dividing the fill-up volumes of the bed by the injection rate into that bed.

As discussed earlier under the topic of original mobile oil, the oil saturation after water flooding is assumed to be reduced to 29 percent. If after fill-up 1 barrel of injected water displaced an equal volume of oil to the producing wells, the total volume of water required to reduce the saturation of the bed to 29 percent in the area theoretically swept would be the fill-up volume plus 4.32 percent (0.72 (35-29)) of the total pore volume of that bed.

Based upon these data and assumptions it was calculated that the first flood oil would reach the producing well about 11 months after the water injection was begun. The peak rate of oil production probably would occur about 6 months later. It was calculated that the life of the flood to an economic limit of 1 percent oil in total fluid would be about 7 years and that during this time approximately 3,470 barrels of oil per acre would be recovered from this sand.

Because early in the life of the flood several of the more permeable beds would be depleted of oil and would be producing mostly water, provisions should be made to handle comparatively large volumes of water.

Lease 2

Water-flooding calculations were made for a second lease included in area A, where the average thickness of the upper member of the First Healdton sand was 21.4 feet at approximately 1,000 feet.

Analyses of the one cored well were considered to be representative of the sand underlying the flood area, where the assumed spacing was 900 feet between like wells. These analyses showed that the porosity of individual core samples ranges between 19.0

and 28.3 percent and that the oil saturation ranges between 24.5 and 49.3 percent. It is entirely possible that these cores were somewhat flushed and that the oil saturation of the sand would be greater than that of the core samples. The permeability of the core samples ranged between 15 and 548 millidarcys.

Calculations based upon the data presented in the core analyses indicate that at an injection rate of 500 barrels per day per well the first flood-oil production would be obtained 1 year after injection was begun, and that the peak rate of oil production would be reached very soon thereafter. During the estimated 6 years of flood life, a total of 1,756 barrels of oil per acre would be recovered at a limiting ratio of 1 percent oil in total fluid.

If the oil saturation of certain beds were as low as indicated in the core analysis, large volumes of water would be produced early in the life of the flood.

The above calculations are exemplary only, and the conclusions should not be construed as predicting the actual water-flood behavior of any particular lease. These data and discussions are presented to encourage oil operators to examine the water-flooding possibilities of leases in the Healdton oil field.

APPENDIX

Calculations of Porosity and Water Saturation from Electric Logs

Archie (14) and other investigators have studied the relationships between electrical resistivity, porosity, and water content of a formation. Since, in most cases, brine is the only conductor of an electric current in a sand, the measured electrical resistivity of the sand is inversely proportional to the porosity and water saturation of the sand. The relationship for brine-saturated sands is expressed by the equation:

$$\text{(A)} \qquad \frac{Ro}{Rw} = P^{-m} = F;$$

where:

Ro = resistivity of brine-saturated sand, ohm-meters;

Rw = resistivity of brine, ohm-meters;

P = porosity, fraction;

m = cementation factor;

and F = formation resistivity factor.

For oil sands partly saturated with brine the equation becomes:

$$\text{(B)} \qquad F = \frac{W^n Rt}{Rw};$$

where:

W = brine saturation, fraction;

n = a positive exponent, approximately 2;

Rt = true resistivity from electric logs,
and F and Rw are the same as defined above.

Fifty-eight clean core samples of the first, second, third, and fourth Healdton sands were saturated under vacuum with formation brine. The saturation of these cores ranged from 57 to 100 percent of the pore volume as measured using helium. Any relationship between this percentage of brine saturation and other measurable properties of the core was not apparent.

The formation resistivity factor (Ro/Rw) and other measured properties of each core are shown in table 5 (p. 16). A plot of these formation resistivity factors versus percent porosity is shown in figure 42. Considering the entire range of porosity between 2 and 33 percent, the scattering of data may be assumed to lie within a band, the slope of which is minus 1.67. However, for porosity values between 18 and 32 percent, which includes most of the oil-productive sands in the Healdton field, there is no such alinement of the data and consequently no assurance that porosity calculations based upon an exponent of minus 1.67 would be valid. The spread of the data is not explainable.

The conception that clays or other solids were made conductive by water absorption was suggested by Patnode and Wyllie (33). DeWitte (34) pointed out that the conductivity of these solids in association with conductive liquids is not constant, and, although related to the brine resistivity and the percent of brine saturation, it is not entirely dependent upon these factors.

In an attempt to make quantitative use of electric logs to calculate porosity and brine saturation of a sand, it is important to determine the presence or absence of conductive solids. The presence and significance of conductive solids, when associated with brines of different salinity and resistivity, should be indicated by lower Ro/Rw values for saturation with less saline brines. When it is associated with the more resistive brines, the conductivity of any conductive solids would have a greater relative value. Given below are resistivity measurements of four brine solutions at 76° F. and of five cores saturated with each of these brines at the same temperature.

Chloride content, p.p.m.	1,000		2,000		10,000		100,000	
Brine resistivity, Rw	0.0349		0.0189		0.00514		0.00065	
Core No.	Ro	Ro/Rw	Ro	Ro/Rw	Ro	Ro/Rw	Ro	Ro/Rw
2808................	0.7386	21.157	0.4031	21.268	0.0958	18.642	0.0123	18.987
2809................	.1924	5.510	.1160	6.120	.0376	7.316	.0047	7.282
2812................	.8925	25.564	.5396	28.470	.1134	22.080	.0148	22.858
2814................	.4512	12.925	.2686	14.172	.0709	13.803	.0088	13.670
2827................	.2907	8.327	.1740	9.181	.0373	7.253	.0044	6.855

A trend of lower formation resistivity factors (Ro/Rw) accompanying the higher brine-resistivity values may be indicated by cores 2809 and 2814. A decrease in the Ro/Rw values for the more-concentrated brine saturations, as shown for cores 2808, 2812, and 2827, is more difficult to explain. Possibly all of these differences are within the limits of accuracy of the measurements and are not conclusive evidence as to the presence or absence of conductive solids in the formation.

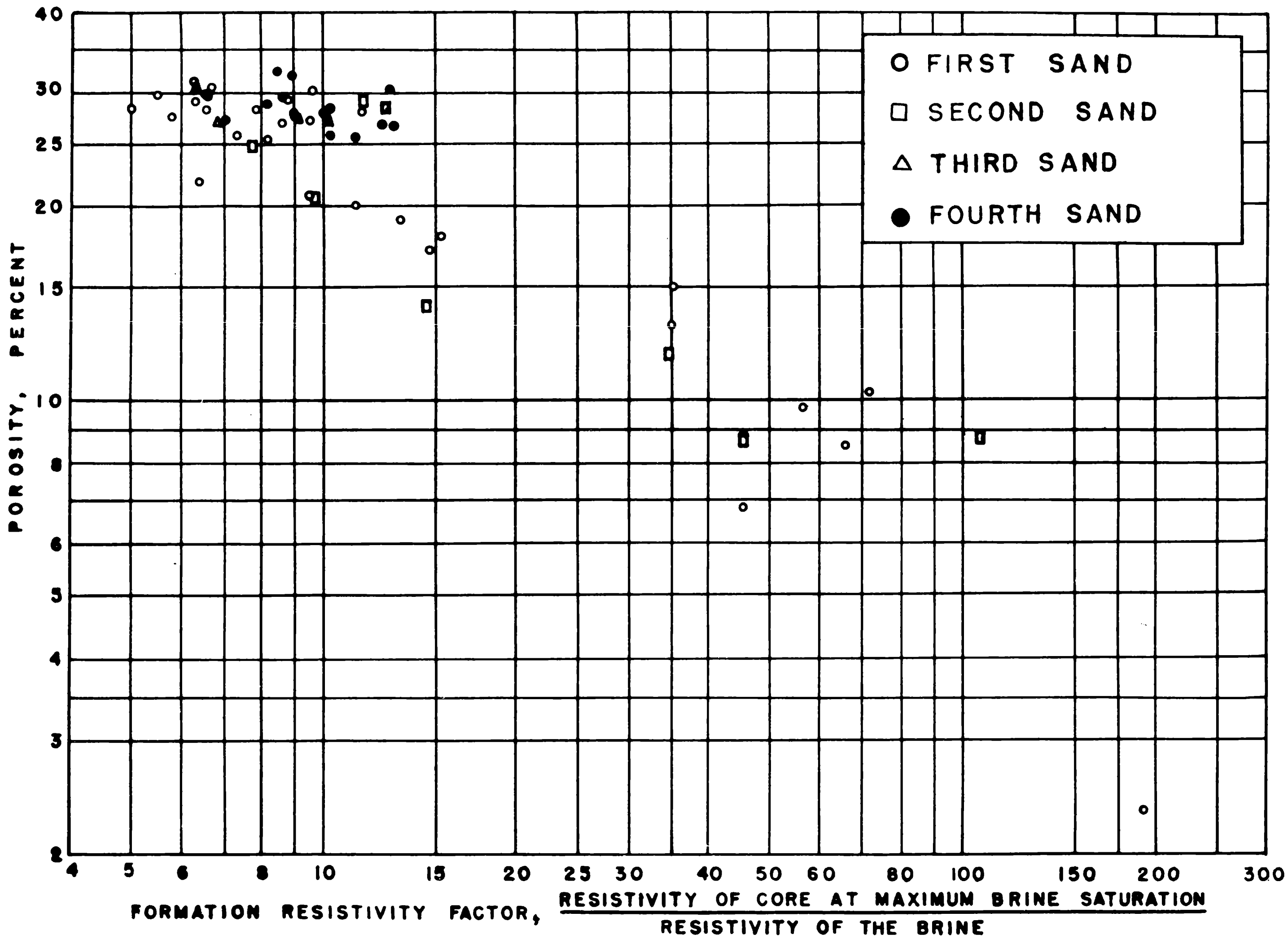

Figure 42. - Relationship between porosity and formation resistivity factor, Healdton oil field, Carter County, Okla.

Resistivity measurements at a series of different brine saturation were made on three core samples. The ratio of the resistivity of the core partly saturated to that of the core completely saturated (known as the resistivity index) was plotted on logrithmic paper versus the percentage of brine saturation. The water-saturation exponent, n in equation (B), is the slope of the average line of such a plot and should approximate 2.0. The summarized results of the resistivity measurements on the three cores are as follows:

Core No.	Porosity, percent	Permeability, millidarcys	Formation factor F	Water-saturation exponent n
2808....................	28.7	1,200	8.1	1.874
2812....................	15.1	12	24.2	1.115
2814....................	25.6	500	11.2	2.97

Only for core 2808 did the slope of the average of the water saturation versus resistivity-index curve approximate the experimental value of 2.0 as set forth by other investigators. Because neither a porosity exponent m or a water-saturation exponent n could be calculated from the data with reasonable accuracy, it was assumed that computations by Archie's basic equation would not be valid. Graphical solutions were then considered.

Separate plots were prepared on logrithmic and semi-logrithmic paper for 58 Healdton core samples, the formation resistivity factor was plotted versus air porosity, water porosity, permeability, and a product of porosity times permeability. The wide scattering of points on logrithmic paper again indicated that one exponent would not fit all the data and satisfy Archie's basic equation. On semilogrithmic paper the points fell more nearly along two straight lines, the slopes of which differed in the high and low porosity ranges. However, in the range of porosities between 20 and 32 percent, the slope of the average was very flat, indicating a wide divergence in porosity for a slight change in the formation resistivity factor. In general, it appears that the formation resistivity factor of these cores is more closely related to permeability than to porosity.

Forty oil-productive sand zones in 13 wells were electrically logged and cored. Sixteen of these beds on which core analyses were available were selected to compare porosity values graphically calculated from electric logs with those determined in the laboratory.

A water-saturation value, estimated from the relationship between water saturation and permeability (fig. 15), was used for each bed. Formation resistivity factors were calculated by equation (B), using water-saturation exponents 2 and 1.87 and the true resistivity values from electric logs. Using these formation resistivity factors, porosity values were read from figure 42. The calculated porosity values differed widely from porosity values measured in the laboratory. Calculated porosity values approached those measured in the laboratory in only 5 of the 16 beds studied.

Considerable data are available from oil-base-mud cores and restored-state measurements (see fig. 15) to show that the average connate-water saturation of most of the Healdton sands ranges from 10 to 20 percent. Since calculated porosity values are roughly inversely proportional to the square of this low connate-water-saturation value, a slight error in assumed connate-water saturation in this range, results in a large error in computed porosity values. Usually electric logs are used with an estimated porosity to calculate the water saturation of a sand bed, but in the Healdton-field study it was considered that the exact connate-water saturation was less valuable in reservoir calculations than a reasonable porosity value.

After considering the matter from all viewpoints, it was decided that electric-log resistivity measurements could not be used with any degree of accuracy to calculate porosity.

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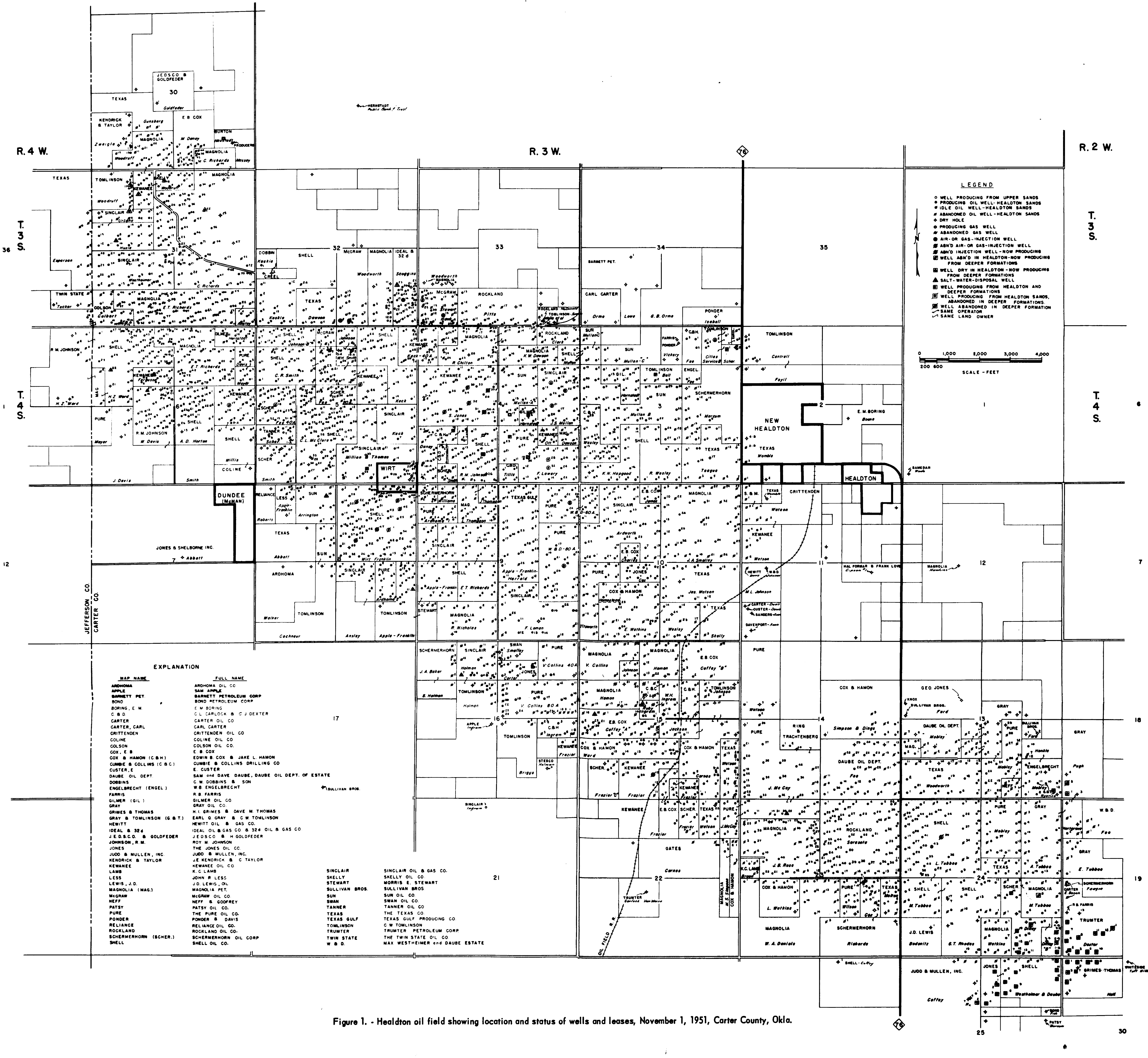

Figure 1. - Healdton oil field showing location and status of wells and leases, November 1, 1951, Carter County, Okla.