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UNDERGROUND COMBUSTION OIL-RECOVERY EXPERIMENT IN THE VENANGO FIRST SAND, WARREN COUNTY, PA.

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UNITED STATES DEPARTMENT OF THE INTERIOR

BUREAU OF MINES

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UNITED STATES DEPARTMENT OF THE INTERIOR
Stewart L. Udall, Secretary

BUREAU OF MINES
Marling J. Ankeny, Director

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UNDERGROUND COMBUSTION OIL-RECOVERY EXPERIMENT IN THE VENANGO FIRST SAND, WARREN COUNTY, PA.

by

N. A. Caspero,[1] W. T. Wertman,[2] and W. E. Eckard[3]

ABSTRACT

A thermal oil-recovery experiment was conducted in the Venango First sand, Goodwill Hill oilfield, Warren County, Pa., about 10 miles northeast of Titusville. The Quaker State Oil Refining Corp., Bradford, Pa., performed the experiment with assistance from Sinclair Research, Inc., Tulsa, Okla., and the Federal Bureau of Mines.

The Goodwill Hill field was discovered in 1885. Primary-production operations continued until 1930 when an air-gas injection project, which is still in operation, was started. At the location of the combustion experiment, the reservoir is 400 feet deep and 30 feet thick, with wide permeability and porosity variations. The crude oil is typical Pennsylvania Grade paraffin-base oil with a gravity of 43.9° API and a viscosity of 4.55 cp at 60° F.

The well pattern for the experiment consisted of 5 producing wells, enclosing an area of 1.28 acres, and a central ignition-injection well. An air-natural gas mixture was ignited in the ignition well on July 29, 1961. Ignition was followed by injection of air and natural gas at various rates. The experiment was suspended January 5, 1962, when it became evident that economic oil production could not be achieved.

There was no conclusive evidence that self-sustained combustion was achieved or that combustion increased oil and water production. A slight increase in liquid production was attributed to stripping action caused by the air-injection rates, which were higher than those normally used during air-gas injection.

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Work on manuscript completed July 1963.

Additional experiments using the underground combustion process in high-gravity, low-viscosity crude-oil reservoirs is considered warranted.

INTRODUCTION

During 1958, the Bureau of Mines started laboratory experiments to determine if the in situ combustion method of oil recovery could be applied to the high-gravity, low-viscosity crude oils found in Appalachian area reservoirs.

In situ combustion is a thermal oil-recovery technique by which movement (or production) of residual hydrocarbon material, usually considered unrecoverable by current production methods, is achieved by a series of complex displacement processes. The driving mechanisms derive their energy in part from water of combustion and the vaporization of water and oil that occurs immediately ahead of a high-temperature zone. Some crude oil is consumed in the presence of free oxygen. Oxygen to support combustion of the residual fuel is supplied by injecting air into the reservoir through the ignition well. The thermochemical reaction will continue as long as requirements for combustion are met.

Appalachian area secondary-recovery production methods (6)[4] afford several favorable conditions for the application of in situ combustion. Several areas that have been developed intensively for air-gas injection operations have high-capacity air compressors available for operation at relatively low pressures (200 to 300 psig). Close well spacing on properties previously subjected to air-gas injection reduces necessary development costs. The relatively shallow depths of the oil-bearing formations (300 to 800 feet) also reduce development costs. However, this shallowness would limit air-injection pressure and thus could prevent the injection of sufficient quantities of air. The price of Pennsylvania Middle District and other Appalachian area crude oils provides additional incentive for increasing production.

Considerable laboratory (1, 10, 13) and field (9, 14, 15) investigative work has aided in the evaluation of the in situ combustion process and the determination of various optimum requirements. Previous effort has been made to develop techniques for recovering crude oils of much greater viscosity and less mobility than the Pennsylvania Grade high-gravity paraffin-base crude oils.

This field experiment was made in the shallow Venango First sand reservoir on the Hunter lease, Goodwill Hill field, Warren County, Pa. The Quaker State Oil Refining Corp., Bradford, Pa., owned and operated the property which is located about 10 miles northeast of Titusville. Quaker State conducted the experiment with assistance from Sinclair Research, Inc., Tulsa, Okla., and the Bureau of Mines.

The primary objective of the experiment was to determine if a heat wave could be initiated. The secondary objective was to determine the advancement rate of the heat wave and the optimum requirements to sustain combustion.

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[4] Underlined numbers in parentheses refer to items in the list of references at the end of this report.

The experiment described in this report and other preliminary reports (3, 4, 16) represents one of the more recent attempts to study the effects of combustion in a Pennsylvania Grade crude oil reservoir. A previous test was reported in October 1959 (11). Additional testing and evaluation is required before the feasibility of the in situ combustion method can be determined.

ACKNOWLEDGMENTS

The cooperation of the officials and employees of the Quaker State Oil Refining Corp., Sinclair Research, Inc., and the Bartlesville (Okla.) Petroleum Research Center of the Bureau of Mines is gratefully acknowledged.

Special thanks are extended to Q. E. Wood and C. V. Gray, Quaker State Oil Refining Corp.; L. W. Emery and H. Wolcott, Sinclair Research, Inc., and F. E. Armstrong and W. D. Howell, Bartlesville Petroleum Research Center, Bureau of Mines, for their significant contributions during various phases of this experiment.

SYSTEM	SERIES	GROUP		ROCK COLUMN	AVERAGE THICKNESS, feet	CUSTOMARY SAND NAME
Mississippian	Pocono	Berea			30	Corry sand
		Conewango			90	Cussewago sand
Devonian	Conewango	Riceville			95	Riceville shale
		Venango oil sand	1st Venango sand		85	Venango 1st sand
					50	Saegerstown shale
			2d Venango sand		25	Red Valley sand
					25	Shale
					25	Venango 2d sand
					60	Amity shale
			3d Venango sand		40	Venango 3d Stray sand
					35	Venango 3d sand

FIGURE 1. - Columnar Section of Geologic Formations of the Titusville Quadrangle.

GENERAL GEOLOGY, FIELD DEVELOPMENT, AND PRODUCTION HISTORY

The First sand of the Venango group (hereafter referred to as the First sand) is of Devonian age (fig. 1). The Venango group of oil pools is generally classed as stratigraphic and characterized as sand lenses embedded in less permeable sandstone and shale (17). In the Goodwill Hill field, Southwest Township, Warren County, Pa., 90 to 100 feet of Riceville shale with occasional thin silty sandstone beds overlays the sand section. Below the First sand there is about 50 feet of dark Saegerstown shale (5). About 200 feet below the First sand is the Venango Third Stray, or upper interval of the Venango Third sand.

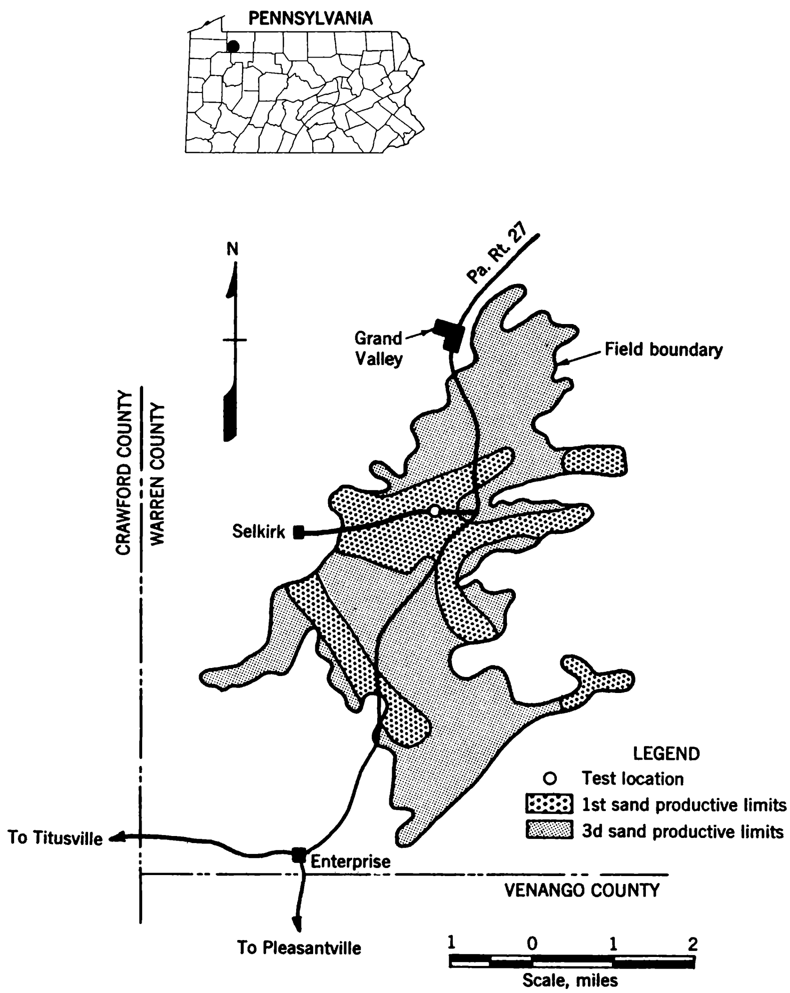

FIGURE 2. - Goodwill Hill Oilfield, Southwest Township, Warren County, Pa.

About 37 feet of the 80 to 85 feet of First sand present is considered pay sand, and the average depth to the First sand is 400 feet. The First sand lies in a northeast-southwest trend about 50 miles long and 10 miles wide. The interbedded shales, sandy shales, and tightly cemented pebbly zones are essentially nonproductive. When present, the pebbles are usually in the top and bottom of the formation; however, fine-to-coarse-grained, pebbly sandstone sections are known to exist at different intervals of the pay sand throughout the field. The First sand is mostly light-gray sandstone with occasional thin and discontinuous streaks of shale. The highest oil-saturated sections of the First sand usually appear in the lower part of the formation. These factors and the omission of the First sand from many drillers' logs make correlations difficult.

Figure 2 shows the irregularly shaped area comprising the Goodwill Hill field. Drilling records to 1885 show that the First sand was ignored while the lower Third Stray was being developed. That development continued into the early 1900's, at which time the average well density was one well to 5 acres. Vacuum was applied to the field for about 10 years and effected a slight increase in oil production. In the early 1930's, the field was developed for air-gas injection on a slightly modified seven-spot pattern. A substantial increase in production resulted and was attributed to accidental injection into the First sand.

Figure 3 shows the oil-production history and well-development rate for the Hunter and Campbell leases and the adjoining Stanton lease. Oil production before 1902 was estimated from initial production records after the wells has been shot with nitroglycerin and by the well-development rate. Oil and water produced from the First and Third Stray sands was allowed to mix; consequently, individual production records are not available. Total oil

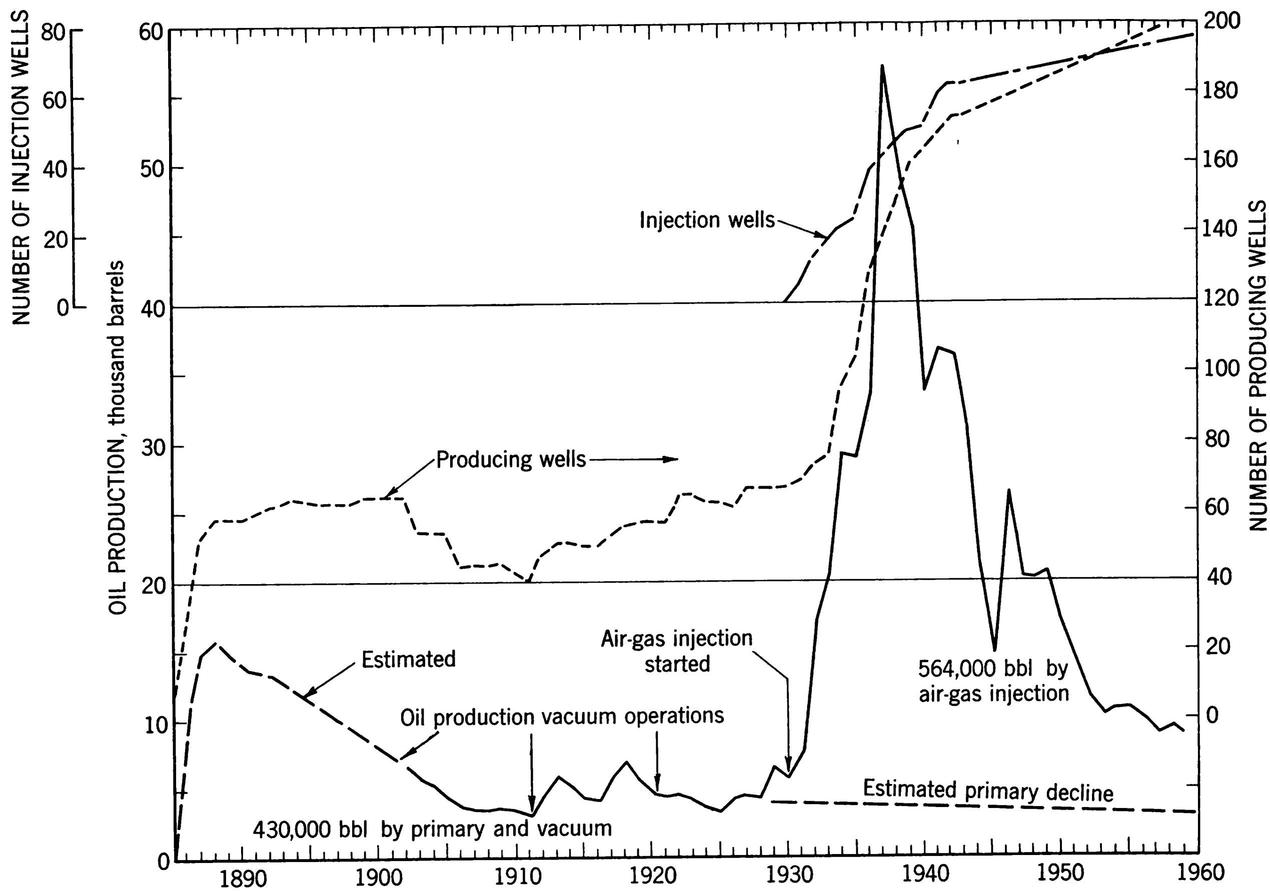

FIGURE 3. - Oil-Production History and Well-Development Rates of the Hunter, Campbell, and Stanton Leases.

production from the Campbell, Hunter, and Stanton leases to 1960 was approximately 994,000 barrels. Estimated total oil production from 1885 to 1960 by primary and vacuum-secondary recovery operations was 430,000 barrels, or about 43 percent of the total recovery. Approximately 564,000 additional barrels of oil were produced by air-gas injection.

Total oil in place, on January 1, 1942, for the Colorado-Goodwill Hill-Grand Valley field has been estimated by Lytle (12). He reports that 2,750 acres of First sand contained 17 million barrels of oil, or about 6,200 barrels per acre. Using an average sand thickness of 30 feet, about 206 barrels of oil was contained in each acre-foot of sand at the beginning of 1942. The results of core analysis, from Experimental well 1, which was cored with air during November 1960, show 243 barrels of oil per acre-foot.

PREPARATION FOR THE EXPERIMENT

Air-gas injection and production-well characteristics indicated a highly permeable reservoir section extending about 4 well-locations wide (900 feet)

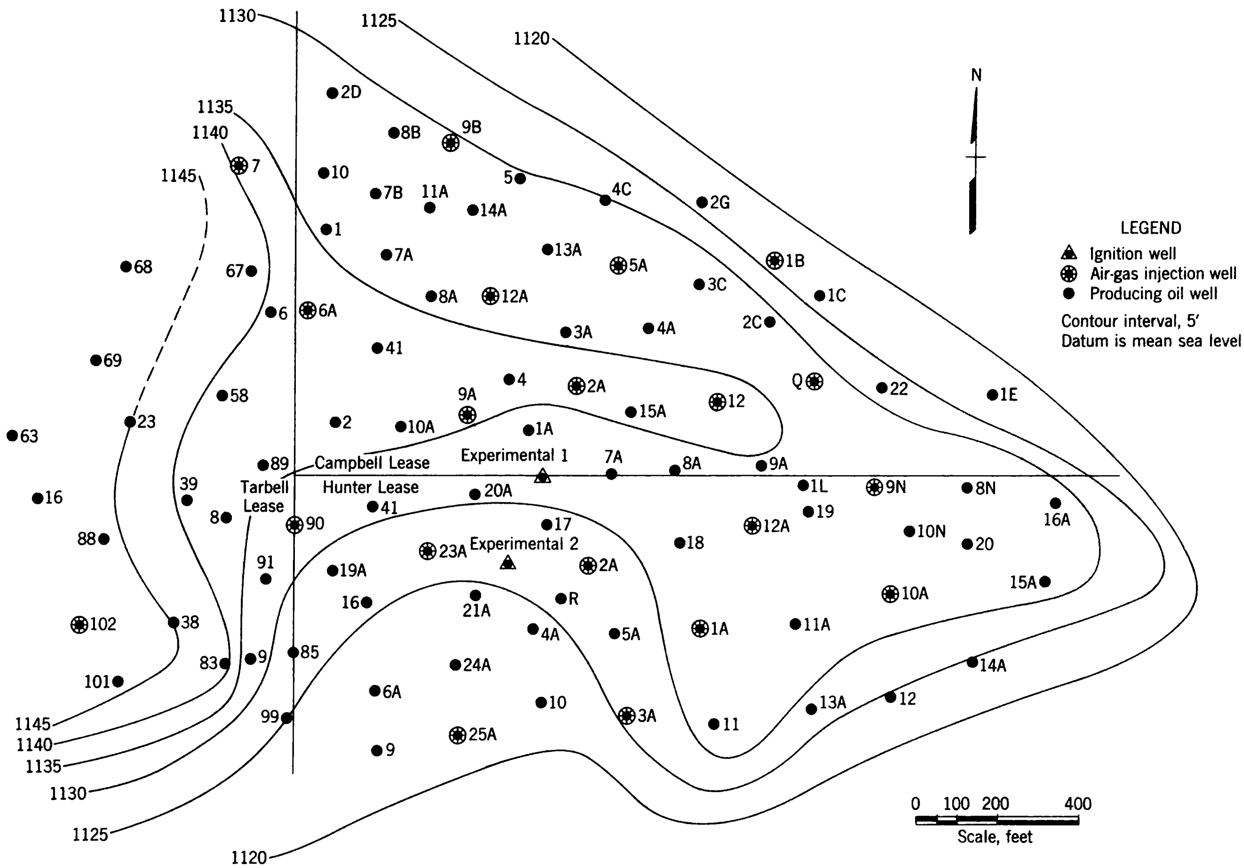

FIGURE 4. - Structural Contour Map of the Top of the Effective Venango First Sand in the Vicinity of the Combustion Experiment.

through the property in a northwest-southeast trend; the test site was located in the approximate center of that trend. Figure 4 is a structural contour map showing the top of the First sand in the vicinity of the experiment.

In November 1960, the proposed ignition well, Experimental well 1, was drilled with cable tools to a depth of 394 feet. The First sand and adjacent formations were rotary diamond-cored with air to 444 feet and 7-inch casing was set at 411 feet. The top of the First sand was located at 406.1 feet; the bottom was at 436.6 feet. After the casing was cemented, an air-injection survey showed that air was leaving the borehole at the casing seat. Rather than attempt to rework this well, a second ignition well (Experimental well 2) was drilled about 225 feet southwest of Experimental well 1 (figs. 4 and 5).

Experimental well 2 was drilled with cable tools to 375 feet, then a cable-tool core was cut with water-base aquagel mud to 436.5 feet. A 5-1/2-inch string of carbon steel casing was set at about 390 feet and cemented to the surface with a temperature-resistant cement (50-50 mixture of Pozmix A and regular cements with an admixture and accelerator).

Two spinner-type air-injection flow surveys were run in Experimental well 2 with an inflatable packer that could be set at 1-foot intervals. Some

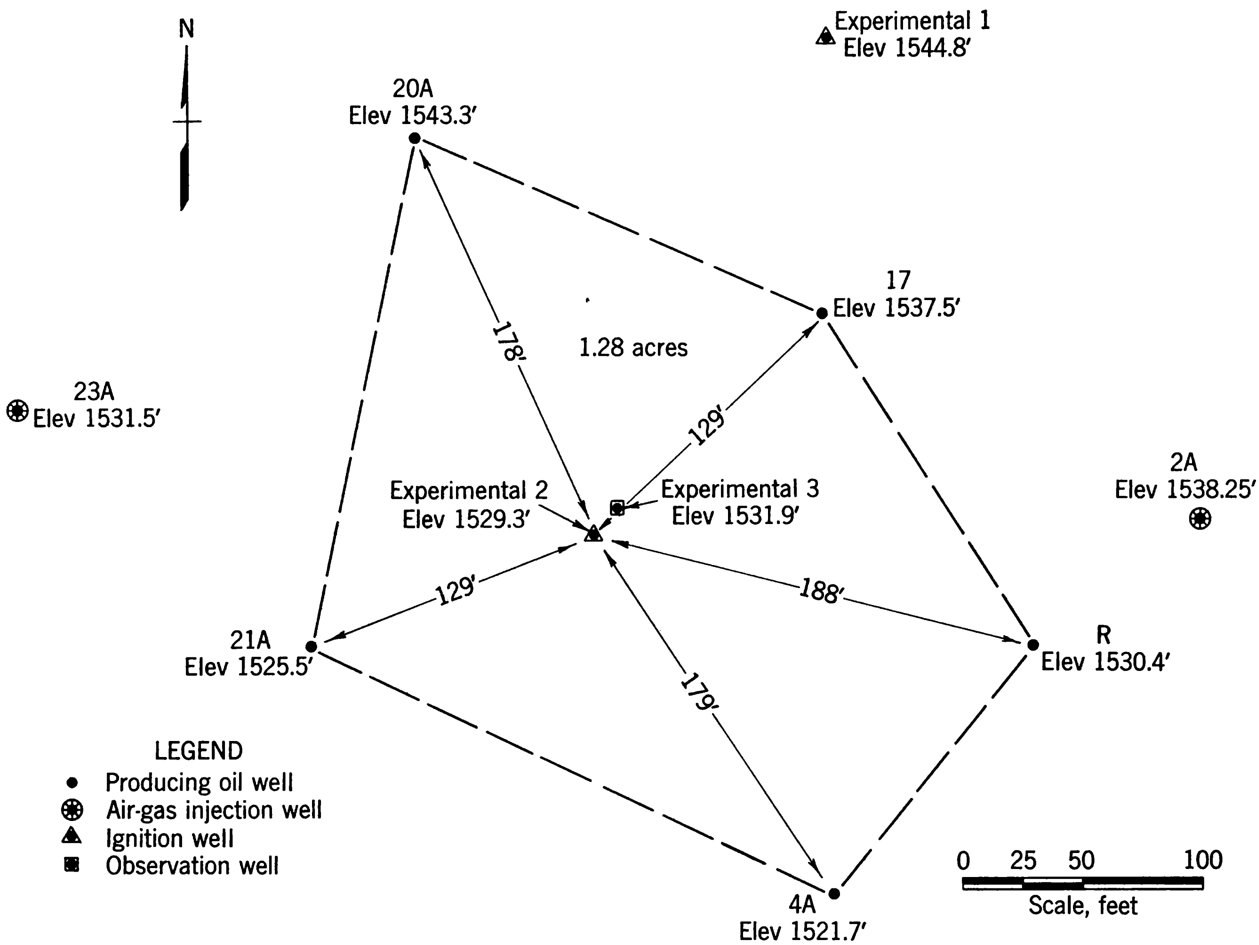

FIGURE 5. - Combustion-Experiment Well Pattern.

bypassing occurred around the inflatable packer during run 1; however, the bypassing was evaluated and the results of the two runs were used to calculate the injectivities,[5] flux, and percent of total intake for various reservoir intervals. Metered air-injection rates and pressures and an average reservoir pressure of 30 psig were used for the calculations. The results of 24-hour pressure-buildup tests on the pattern producing wells and the ignition well were used to determine the average reservoir pressure before ignition. Table 1 shows the calculated results for each flow survey.

Several packer settings were made below 403.5 feet, and the air injectivity was determined to be zero. About 19 percent of the injected air entered the formation between the casing seat at 390 and 395 feet, and 81 percent entered the formation between 395 and 403.5 feet.

[5]Standard cubic feet of air injected per day divided by the difference in the squares of the injection and average producing-well bottom-hole pressures.

TABLE 1. - Results of air-injection flow surveys, Experimental well 2

Reservoir interval, feet	Run 1 83,000 scf/day at 110 psig			Run 2 160,000 scf/day at 124 psig		
	Injectivity, scf/day/ Δ (psi)^2	Flux, scf/hr/ feet^2	Percent of total intake	Injectivity, scf/day/ Δ (psi)^2	Flux, scf/hr/ feet^2	Percent of total intake
390-391.....	-	-	-	0.80	182.5	4.3
391-393.....	1.41	117.1	10.6	.91	104.2	5.0
393-395.....	1.05	88.0	8.1	-	-	-
393-399.....	-	-	-	6.93	265.0	38.1
395-397.....	1.95	162.5	15.1	-	-	-
397-403.5...	8.60	221.0	66.2	-	-	-
399-403.5...	-	-	-	9.53	486.0	52.6

Results of core analysis from Experimental wells 1, 2, and 3 (observation well cored after completion of the experiment; location shown in fig. 5) are shown in figure 6. Electric and nuclear logs for wells 1 and 2 are shown in figure 7.

Average water saturation calculated from the electric logs run in Experimental well 1 was 30 percent less than that obtained from core analysis and decreased toward the bottom of the sand.

Average oil saturation from core analysis was 23.4 percent of the pore volume, or 243 barrels per acre-foot. Log interpretations of water saturation and free-gas space indicated that average oil saturation approaches 35 percent pore volume below a depth of 410.5 feet.

The top of the First sand in Experimental well 2 was established at 391.3 feet and the bottom at 421.2 feet. Air permeability ranged from 0.1 md to 246.7 md, and averaged 70.8 md; porosity ranged from 1.7 to 29.5 percent, and averaged 19.1 percent. Porosity of 10 percent, determined from the dual-spaced neutron log, probably resulted from insufficient liquid saturation. Below the depth of 403 feet, porosity values obtained by each technique were in reasonable agreement. From 403.5 feet to the bottom of the sand a 50-percent water saturation was calculated from electric logs. This value was 20 percent lower than the results from core analysis. Water saturation calculated from electric logs was higher for Experimental well 2 than well 1. Oil saturation for Experimental well 2 did not vary considerably from the value determined for Experimental well 1.

An atmospheric distillation, by the Bureau of Mines method, was made on a sample of produced crude oil from well 17. At the final boiling point of 527° F, 54.3 percent of the fractions had been distilled, leaving 45.3 percent residuum; the balance was loss. The results of the analysis are shown in table 2. Several other produced crude oil samples were tested at 527° F by the ASTM distillation procedure, and the residuum varied between 40.5 and 53.0 percent. The paraffin point for crude oil samples from the pattern producing wells varied from 43° to 54.5° F.

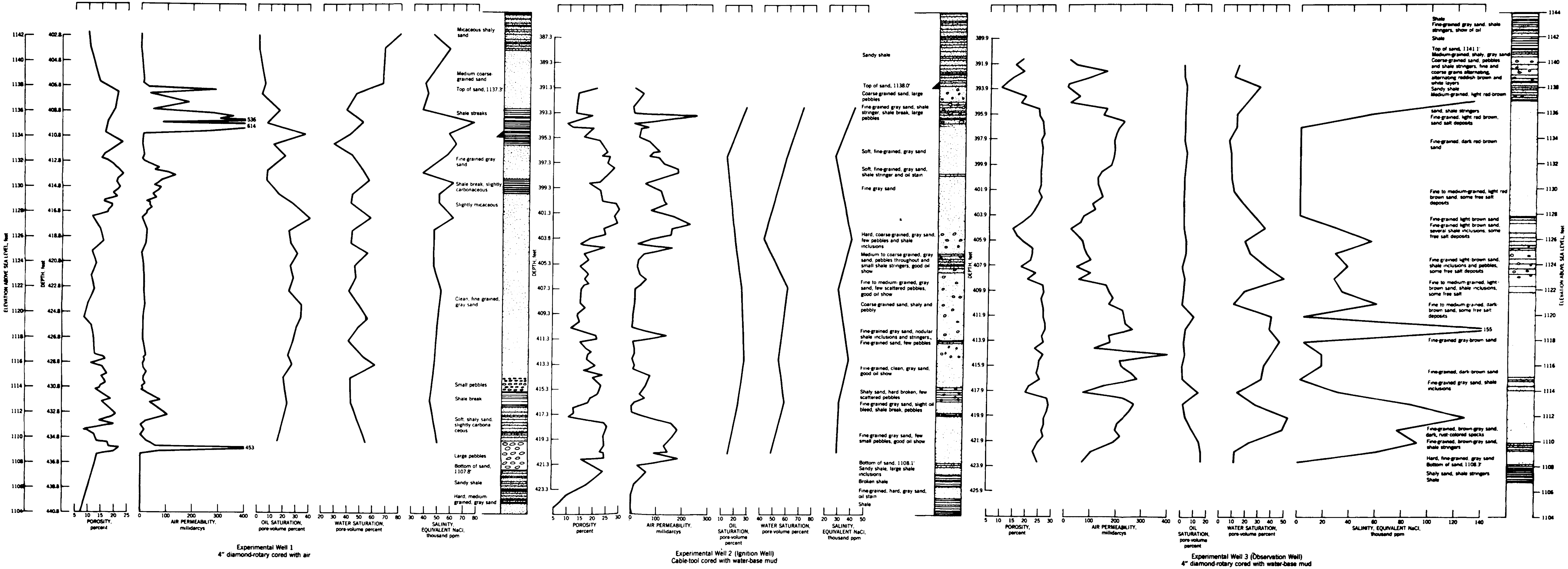

FIGURE 6. - Core Analyses, Experimental Wells 1, 2, and 3.

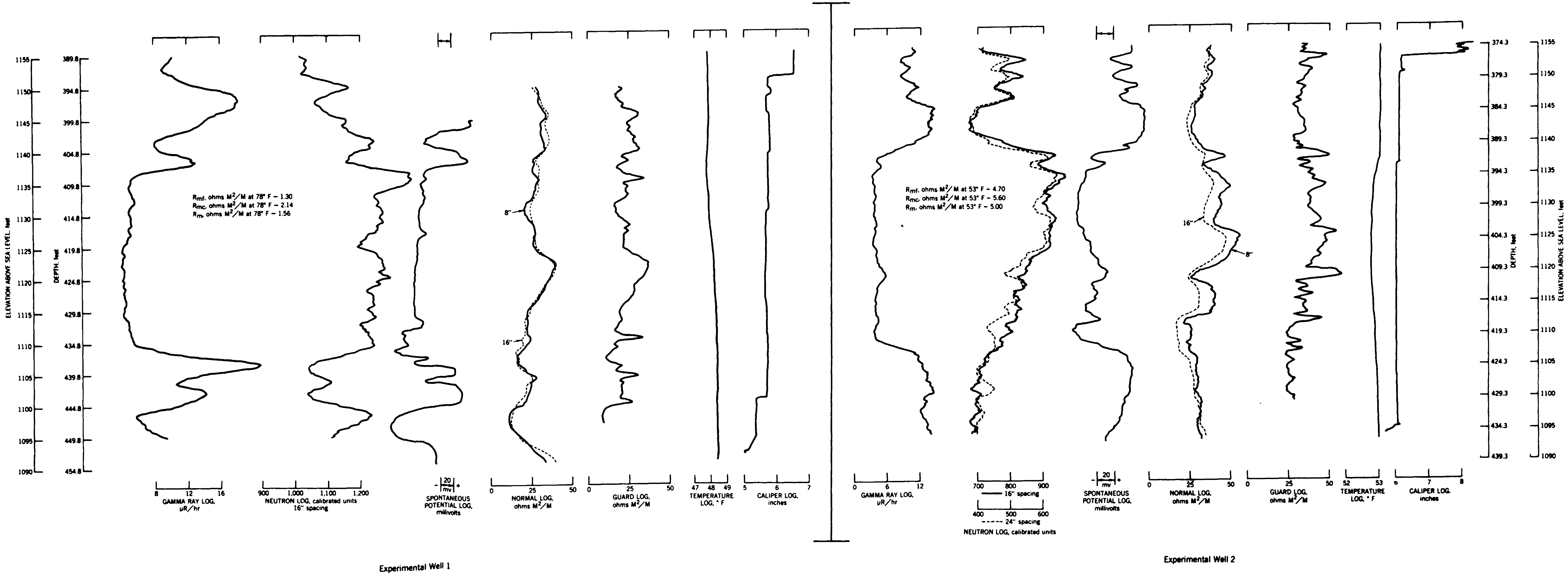

FIGURE 7. - Well Logs for Experimental Wells 1 and 2.

TABLE 2. - Analysis of crude oil from Hunter well 17

GENERAL CHARACTERISTICS

Gravity, specific, 0.812	Viscosity at 60° F, 6.16 cs 5.00 cp
Gravity, ° API, 42.8	70° F, 5.35 cs 4.32 cp
BS&W,[1] volume-percent, 4.0	80° F, 4.68 cs 3.76 cp
Color, green	90° F, 4.14 cs 3.31 cp
Pour point, ° F, below -5	100° F, 3.69 cs 2.74 cp

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

Distillation at atmospheric pressure, 745 mm Hg — First drop, 183° F

Fraction	Cut temp., ° F	Percent	Sum, percent	Sp gr, 60/60° F	° API 60° F	Correlation index
1..........	122	-	-	-	-	-
2..........	167	-	-	-	-	-
3..........	212	0.3	0.3	0.716	66.2	-
4..........	257	2.4	2.7	.717	65.9	11.0
5..........	302	15.6	18.3	.730	62.4	9.4
6..........	347	10.2	28.5	.751	57.0	13
7..........	392	5.3	33.8	.766	53.1	14
8..........	437	6.1	39.9	.778	50.3	14
9..........	482	6.5	46.4	.790	47.6	14
[2]10..........	527	7.9	54.3	.808	43.6	18

APPROXIMATE SUMMARY

Yield	Percent	Sp gr	° API
Light gasoline..................................	0.3	0.716	66.2
Total gasoline and naphtha......................	33.8	.741	59.5
Kerosine distillate.............................	20.5	.793	46.6
Gas oil...	-	-	-
Residuum..	45.3	.864	32.4
Distillation loss...............................	.4	-	-

[1] Basic sediment and water.
[2] Final boiling point.

The gravity and viscosity of crude oil samples from pattern test wells were determined at various temperatures. The results of the tests are shown in table 3. Crude oil produced from well R apparently had not been affected by air-gas injection.

The air- and natural gas-injection system to the ignition wellhead (Experimental well 2) is shown in figure 8. The ignition well was equipped with a bottom-hole burner (8) and concentric strings of tubing for natural gas and air injection.

TABLE 3. - Gravity and viscosity of crude oil from thermal experiment pattern wells

Well	Temperature, ° F	Viscosity, cp	Specific gravity
20A	42	23.77	0.819
	50	7.15	.815
	60	-	.812
	81	4.33	.804
	93	3.87	.799
21A	43	11.80	.813
	50	6.14	.810
	60	-	.806
	81	3.86	.798
	93	3.54	.794
R	34	11.40	.799
	42	5.10	.796
	50	4.18	.792
	60	-	.788
	81	2.64	.780
	94	2.29	.775
17	42	18.09	.817
	50	7.80	.814
	60	-	.810
	81	4.24	.802
	94	4.05	.788
Exp. 2	26	-	.817
	29	-	.815
	36	-	.810
	40	20.80	.807
	42	17.78	.805
	44	14.80	.804
	46	11.82	.803
	48	9.20	.803
	51	4.69	.802
	54	4.59	.800
	56	4.49	.799
	60	4.31	.798
	64	3.80	-

Each offset producing well was reconditioned by setting a bridge at the top of the Third Stray and plugging back with gravel approximately 30 to 50 feet below the bottom of the First sand. Each producing well was shot with 1 quart of liquid nitroglycerin per foot of pay sand to remove paraffin deposits. The wells were cleaned out and equipped with 4-inch carbon steel casing set on a hookwall packer at the top of the First sand. Well 4A was converted from an

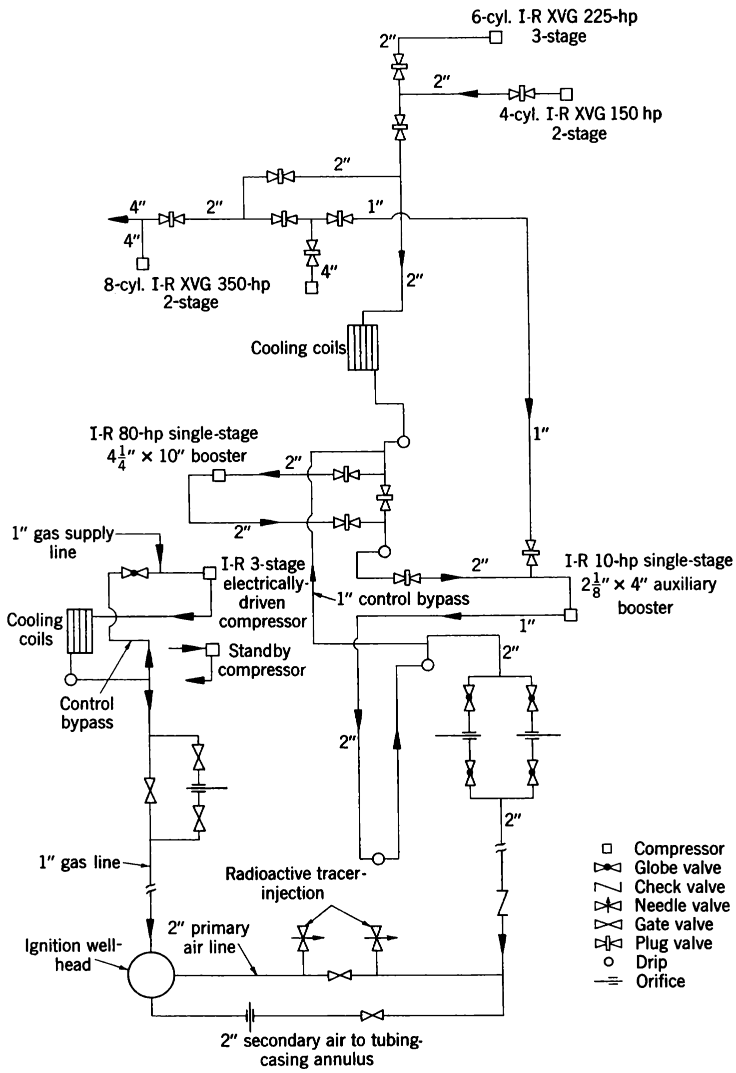

FIGURE 8. - Air- and Natural Gas-Injection System.

air-injection well to a producing well and had not been shot previously, while the other 4 producing wells had been shot two or three times. Individual electrified pumping units were set at each producing well.

Downstream from each producing-well orifice-meter run, produced gas was diverted through a 55-gallon drum. Fill and vent lines and a geiger-tube counting device were attached to the drum. When the gas-tracer study was made, using the method described by Armstrong and his coworkers (2), the calibrated system served as a nonpressurized container to continuously monitor produced gas for radioactivity.

The daily average production per well before ignition was 0.25 barrel of oil and 0.30 barrel of water. The gas that was produced from pattern wells and secondline offset wells prior to ignition was analyzed for oxygen, carbon dioxide, and carbon monoxide. The average values, in volume-percent, were as follows:

Oxygen......................	20.3	(range 19.1 to 20.9)
Carbon dioxide.............	.6	(range 0.3 to 1.4)
Carbon monoxide............	.20	(range 0.05 to 0.3)

The gas samples were collected and liquid production was gaged at the same time that air was being injected into adjacent pressure wells outside the experimental pattern.

PERFORMANCE OF THE EXPERIMENT

Ignition and Gas Injection

For a period of 36 hours before the injected air-natural gas mixture was ignited, the total air- and natural gas-injection rate was 231,000 scfd at 185 psig wellhead pressure. The heating value per cubic foot of mixture injected was 15 Btu. The natural gas volume was 2 to 3 percent of the total gas injected. Natural gas was analyzed periodically with a combustion Orsat apparatus, and air contamination of the natural gas was detected occasionally. Laboratory analysis of an uncontaminated natural gas sample was:

Component:	Volume, percent
CO_2	0.1
O_2	.3
C_2H_6	26.4
CH_4	72.0
CO	.0
N_2	1.2

Each cubic foot of the natural gas would require 2.35 cu ft of oxygen for complete combustion and would generate 1.25 cu ft of CO_2. Heating value of the natural gas varied from 825 to 1,180 Btu per cu ft at 60° F and 30 in. of mercury, and generally averaged 825 to 1,000 Btu per cubic foot.

The air-natural gas mixture was ignited chemically (7) on July 29, 1961, by personnel of Sinclair Research, Inc. The temperature at the burner shell increased from 60° to 460° F in 25 minutes. About 12 hours after ignition, the injection pressure began to increase slowly and reached 500 psig in 57 hours, then gradually decreased to 370 psig in 12 more hours. During the gradual pressure increase, the air- and natural gas-injection rates varied from 144,000 to 240,000 scfd and 3,360 to 6,000 scfd, respectively, while the heating value per cubic foot of injected air-natural gas mixture was maintained at about 25 Btu. Figure 9 shows the air- and natural gas-injection rates and pressures throughout the experiment.

The air injectivity decreased from 8.7 to 1.2 after burning natural gas for one day, and further decreased to 0.86 in 3.5 days. When the injection pressure declined to 370 psig, the injectivity increased to 2.0 and remained at that value for the period that air and natural gas were burned in the borehole.

Air and natural gas injection rates were maintained relatively constant during the next 9 days at 360,000 and 6,000 scfd, respectively, and at an average injection pressure of 420 psig. Two weeks after ignition, the produced oxygen had decreased to 16.4 percent by volume and the carbon dioxide had increased to 2.3 percent by volume. The air-injection rate was increased to about 330,000 scfd during the second week. The injection pressure continually decreased from 500 to 400 psig. Natural-gas injection rate was maintained at about 2 percent of the air-injection rate.

During the 2-week period that natural gas was burned in the wellbore, the volumes of air and natural gas injected were 4 million and 83,000 scf, respectively. Complete combustion of the natural gas would generate 99 million Btu, or 3.25 million Btu per vertical foot of First sand. The average heat-release rate was 290,000 Btu per hour.

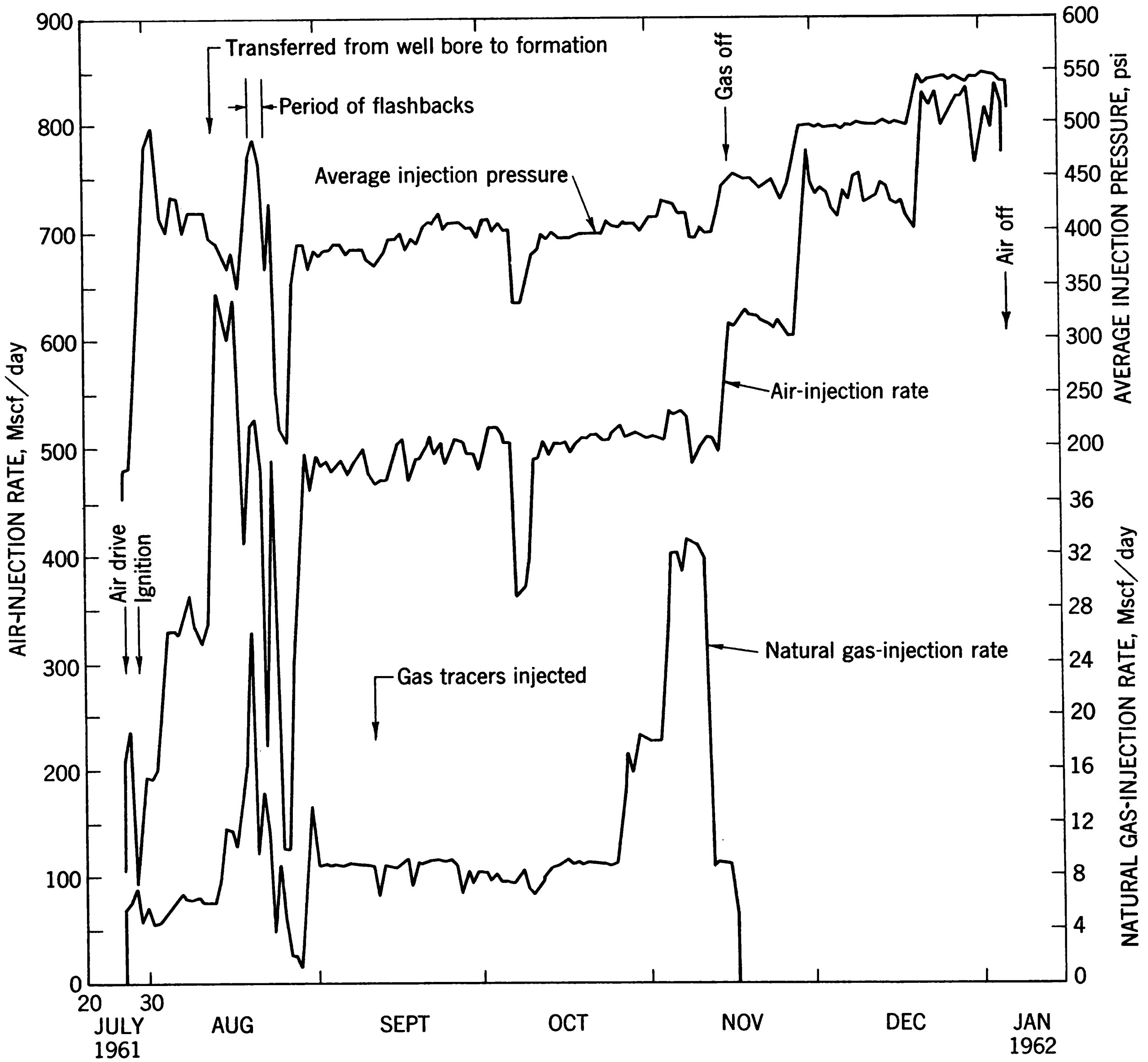

FIGURE 9. - Air- and Natural Gas-Injection History of the Combustion Experiment, Experimental Well 2.

The average reservoir pressure before ignition was 30 psig. Recompletion of well R and conversion of well 4A from an air-injection well to a producing well was completed 3 and 5 days, respectively, after ignition. Wells 17, 21A and 20A were each producing at a rate of 10,000 scfd, or about 5 percent of the total injection rate, with a casing-head pressure of 18 to 37 psig. When the casing-head pressure of the wells was reduced and reconditioning of wells R and 4A was completed, total gas production was 107 percent of the 330,000 scfd injected volume.

Air injection into the First sand through 3 firstline offset injection wells was discontinued approximately 4 days after ignition. About 110,000 scfd of air had been injected into the 3 wells at pressures between 65 and 150 psig. When air injection into offset injection wells was discontinued and the wellhead pressures reduced to atmospheric pressure, the volume of produced gas was 110 percent of the total gas injected in the ignition well and increased to 133 percent after 15 days.

The oxygen and carbon dioxide content in the produced gas 2 days after ignition was 19.0 and 0.65 percent, respectively. Reducing the back pressure on the producing wells, increasing injection rates, or stopping air injection into the offset pressure wells, all of which occurred within the same day, did not change the produced volume of oxygen or carbon dioxide.

Produced gas was analyzed at least twice a day with Orsat apparatus or a chromatographic analyzer. Figures 10, 11, 12, 13, and 14 show the daily average oxygen and carbon dioxide content of the produced gas and the gas-production rate of wells 4A, 17, 20A, 21A, and R, respectively.

Well 21A did not respond to the increased injection rate as rapidly as the other wells. The gas-production rates of individual wells correlated with changes in air and natural gas injection rates and pressures throughout the life of the test. Wells 17 and R showed the greatest response.

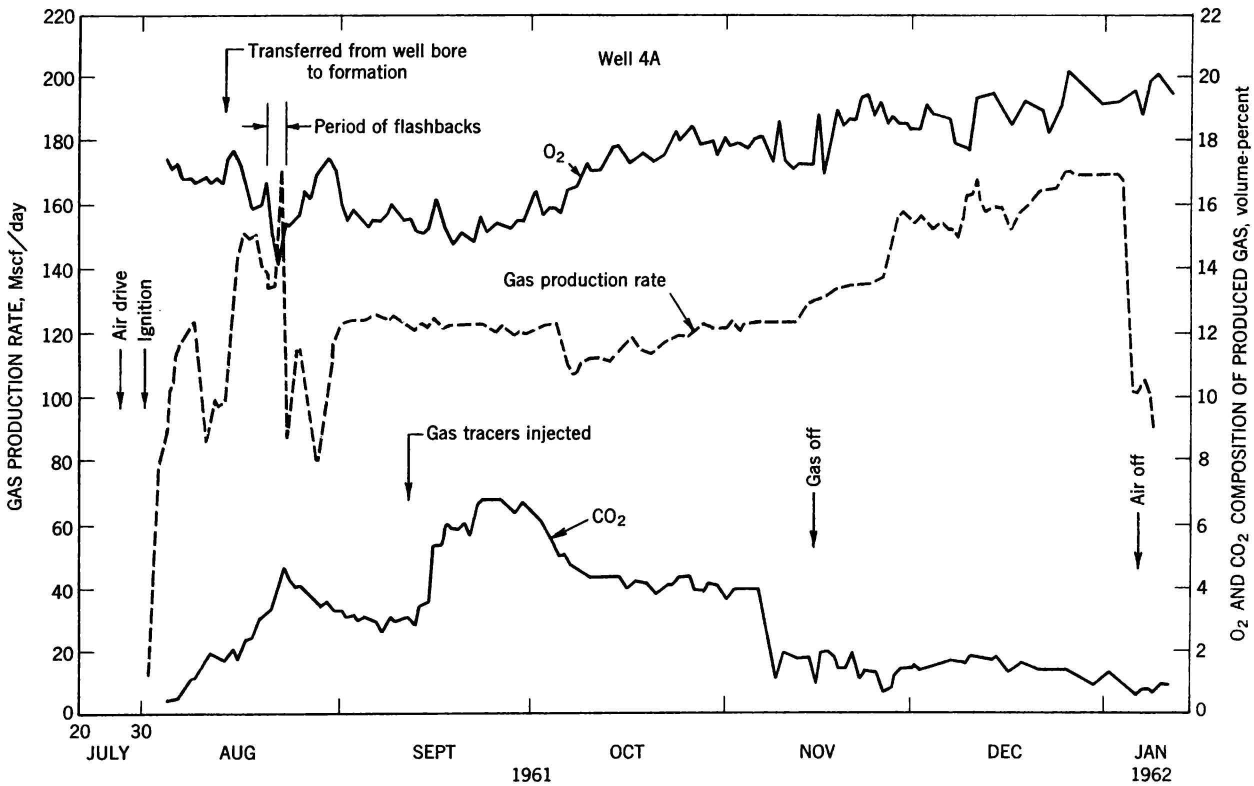

FIGURE 10. - Gas Production and Oxygen and Carbon Dioxide Content of Produced Gas From Well 4A.

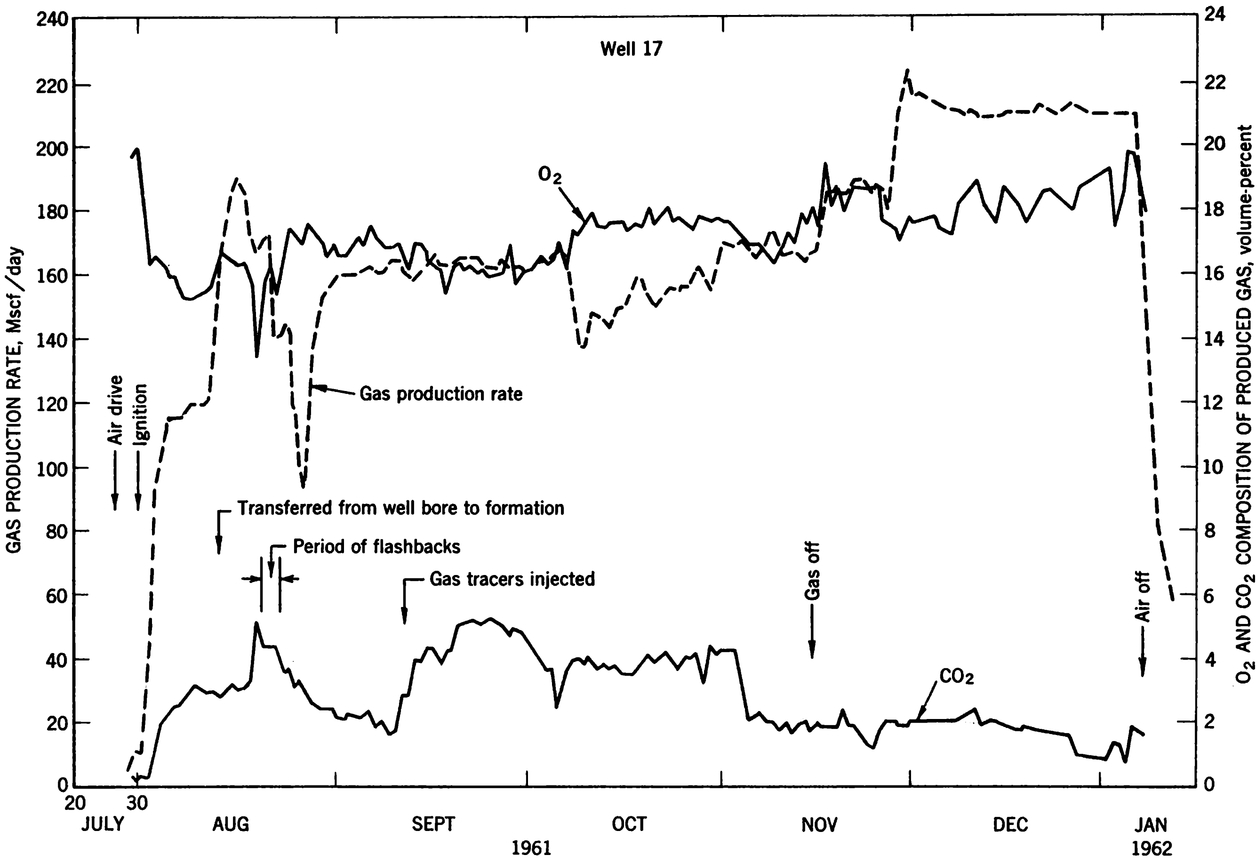

FIGURE 11. - Gas Production and Oxygen and Carbon Dioxide Content of Produced Gas From Well 17.

The oxygen or carbon dioxide content of the produced gas did not indicate efficient combustion of residual carbonaceous material; therefore, combustion was transferred to the formation.

Natural gas injection was stopped for about 4 hours (not shown in fig. 8) and the air-injection rate was increased about 30 percent. Natural-gas injection was resumed and the air-injection rate maintained to give a heating value of 15 Btu per cu ft for the injected mixture. The temperature in the wellbore declined to about 70° F. The air-injection rate increased from about 330,000 to 625,000 scfd after transfer, while the injection pressure decreased from 400 to 360 psig. The calculated injectivity was 4.5 after transfer. The higher air-injection rate was maintained for about 4 days. Injected natural gas was maintained at about 2 percent of the injected air and averaged 10,000 scfd. The increased injection rate did not reduce the volume of produced carbon dioxide.

The air-injection rate was varied between 120,000 and 530,000 scfd for 11 more days. Natural gas-injection rates varied between 2,400 and 24,000 scfd. The air-injection pressure ranged from 200 psig to 500 psig, and the injectivity decreased from 4.2 at the lowest air-injection rate to 2.5 at the maximum injection rate. The average produced oxygen was 14.5 percent by volume and

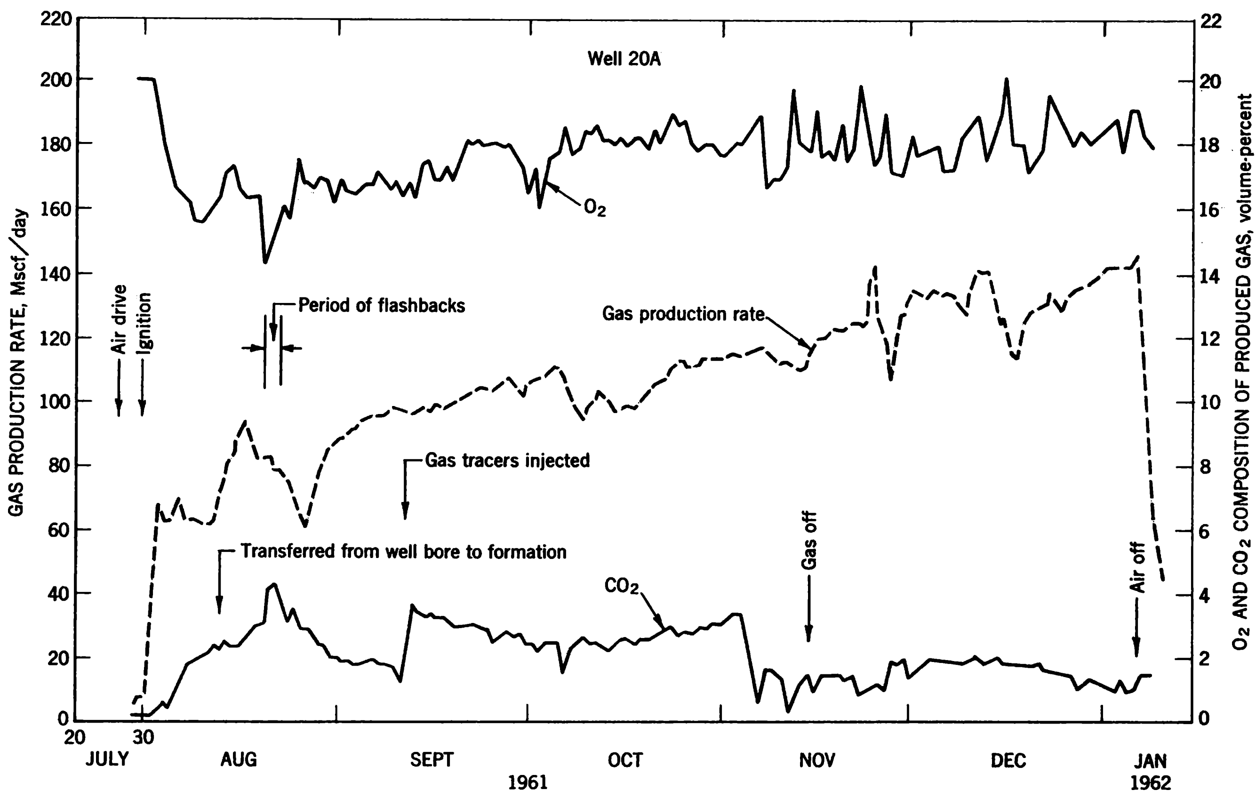

FIGURE 12. - Gas Production and Oxygen and Carbon Dioxide Content of Produced Gas From Well 20A.

the average carbon dioxide was 3.7 percent by volume. During the period when 24,000 scfd of natural gas was injected, the produced methane increased from a background of about 0.25 percent to 0.55 percent of the total gas produced. The higher percentage corresponded to 18 percent of the total volume of methane injected. When the natural gas-injection rate was decreased, produced methane decreased. This indicated that injected gases were bypassing the high-temperature zone. However, the volume of injected gas passing unreactively through the reservoir could not be quantitatively determined because of air dilution from outside the pattern.

On three occasions, the burning air-natural gas mixture was flashed back into the wellbore from the formation by increasing the natural gas-injection rate. The thermocouple in the wellbore indicated a rapid increase in temperature. The flashback proved that there was sufficient temperature at some reservoir interval, if not throughout the entire section, to ignite the injected air-natural gas mixture. The temperature required to ignite the mixture was about 1,000° F. When the wellbore temperature began to increase rapidly, natural gas injection was stopped. The wellbore was allowed to cool before natural gas injection was resumed. The first flashback occurred about 30 hours after increased natural gas injection. The second flashback occurred in about 28 hours after natural gas-injection was resumed. After the second

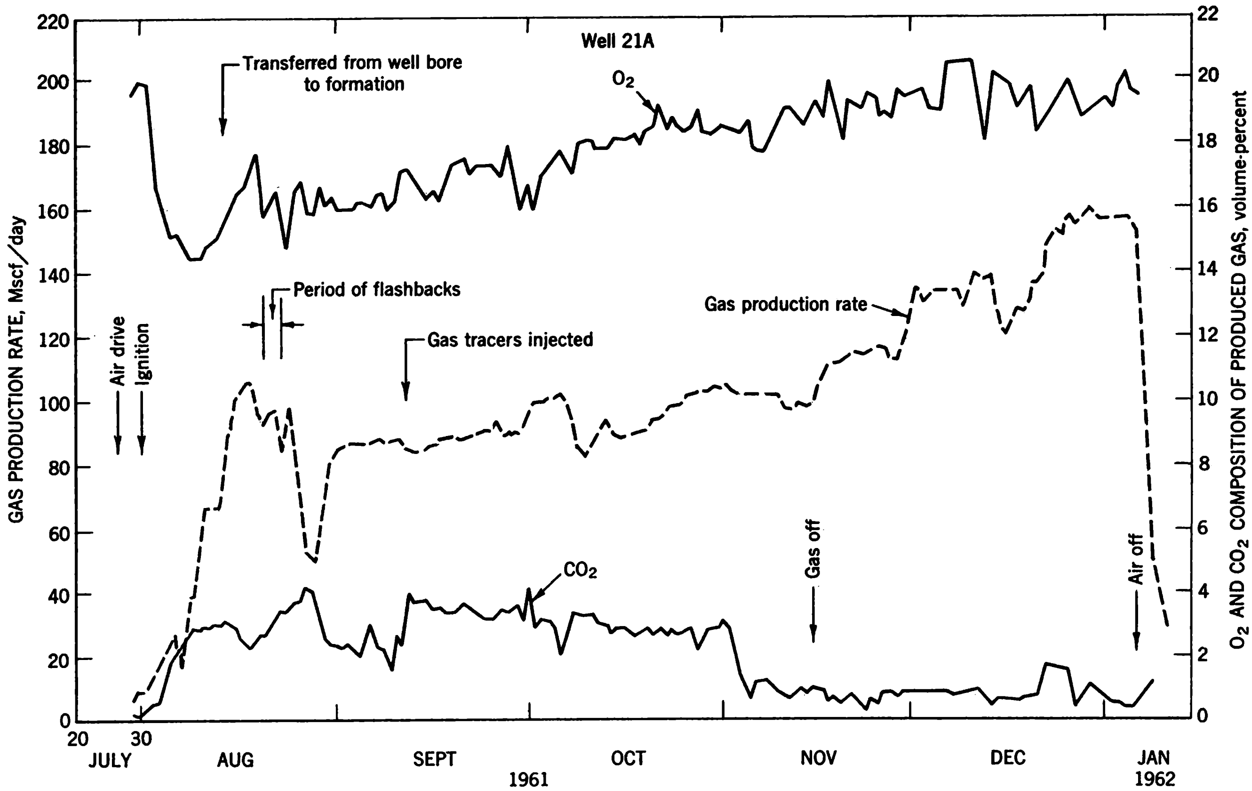

FIGURE 13. - Gas Production and Oxygen and Carbon Dioxide Content of Produced Gas From Well 21A.

flashback, an air-gas mixture of 15 Btu per cu ft was injected for 1 day. This volume of natural gas was injected to determine if there was an increase in produced methane. Natural gas injection was then increased and a third flashback occurred about 4 hours later.

It was estimated from the length of time for the first flashback to occur that combustion of the injected air-gas mixture was taking place within a 2- to 3-foot radius from the wellbore. When the flashback occurred, the indicated temperature in the wellbore increased immediately to 1,350° F. Less time was required for each subsequent flashback, indicating the relative closeness of the burning air-gas mixture to the wellbore. During the flashbacks, the average produced oxygen was 14.6 percent and the carbon dioxide was 3.8 percent. When the large volume of natural gas was injected, the oxygen content from well 17 decreased to 13 percent and the carbon dioxide increased to 5 percent. However, when the natural gas-injection rate was increased, bypassing was indicated by increased methane production.

Natural gas injection continued for 95 days after combustion was transferred from the wellbore to the formation. For 56 days, air- and natural gas-injection rates were maintained at 480,000 and 9,600 scfd, respectively, at about 400 psig. During the last 21 days of natural gas injection, rates were

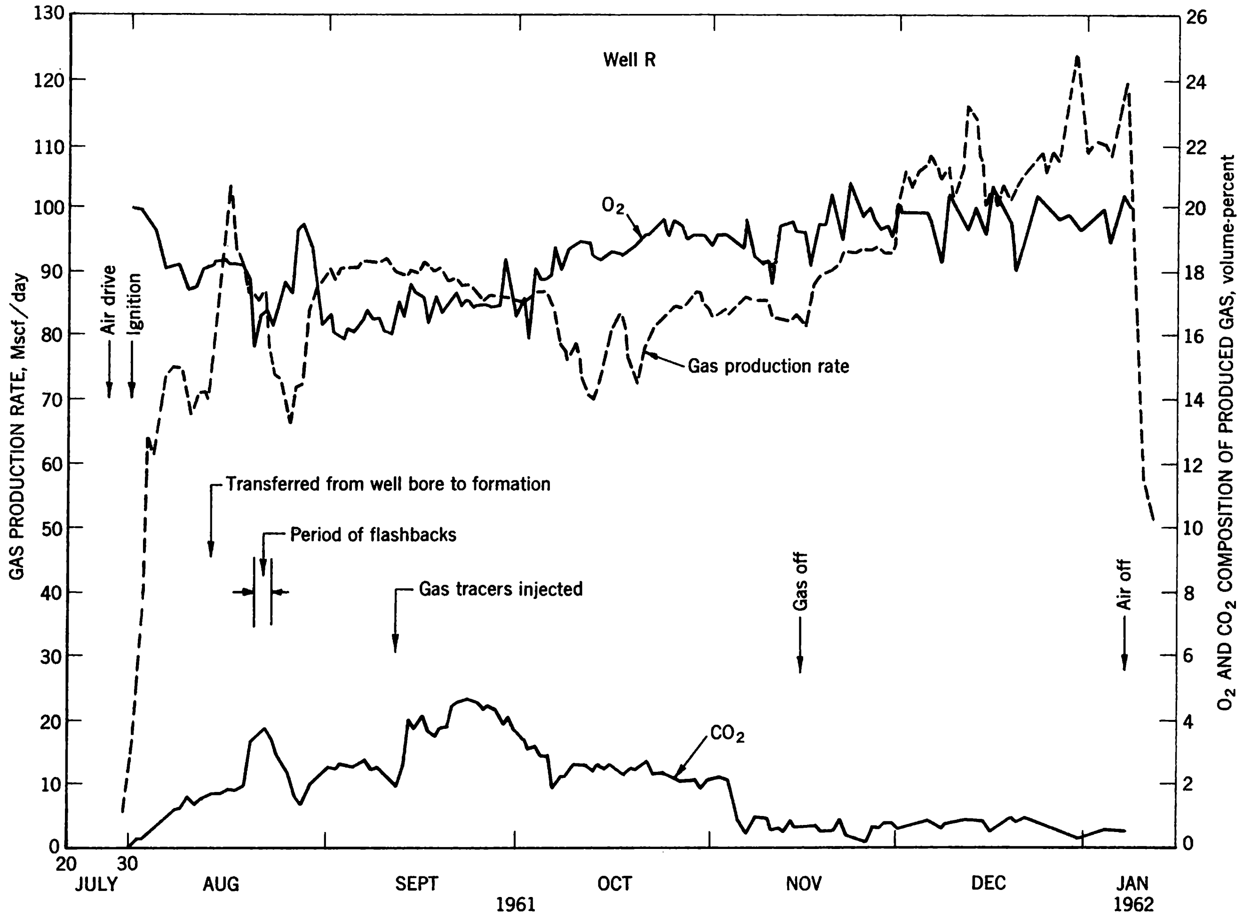

FIGURE 14. - Gas Production and Oxygen and Carbon Dioxide Content of Produced Gas From Well R.

changed from 9,600 to 18,000 to 32,500 scfd, with an average air-injection rate of 480,000 scfd and an injection pressure of about 400 psig. As the natural gas-injection rate increased, the quantity of produced methane rapidly increased; and at peak natural gas injection, about 88 percent was being produced.

The total volume of natural gas injected was 1.2 MMscf, which was capable of generating 1,400 million Btu upon complete combustion. After combustion of the injected air-natural gas mixture was transferred to the formation, 1.1 MMscf of natural gas was injected. Total air injected during the natural gas injection period was 49.8 MMscf, of which 45.8 MMscf was injected after combustion was transferred to the formation.

Prior to termination of natural gas injection, the air-injection rate was decreased to 120,000 scfd (the heating value of the mixture was maintained at 20 Btu per cu ft) in an attempt to improve combustion efficiency by increasing the contact time between the injected air and the fuel. After 1 day, the amount of oxygen and carbon dioxide in the produced gas began to increase and decrease, respectively. These changes in composition of the produced gas were due to increased dilution by air entering the pattern producing wells from the reservoir beyond the experimental pattern and were not caused by a decrease in combustion in the reservoir at the lower injection rate. It was apparent at this time that the amount of outside dilution was very dependent upon injection rates and pressures. The air-injection rate was then increased to 485,000 scfd. The average injection pressure at the low injection rate was 225 psig and increased to 375 psig at the high injection rate. These rapid changes are not shown on figure 8.

Natural-gas injection was discontinued because of the apparent low combustion efficiency, poor oxygen utilization, and bypassing of injected methane.

The oxygen and carbon dioxide content of the produced gas did not significantly change with increased air injection in the latter stages of the experiment. Because continued air injection did not improve conditions, the operation was terminated.

A total of 38 MMscf of air was injected after natural-gas injection was terminated. During the experiment, air injection was 87.8 MMscf, total gas (air and natural gas) injected was 88.9 MMscf, and a total of 95 MMscf of gas was produced.

When air injection was discontinued, the ignition wellhead pressure decreased from 540 to 250 psig in 1.5 hours and to 100 psig in 24 hours, after which the decline to 5 psig was quite rapid. Three hours after shutdown, shutin pressures for wells 17, R, 4A, 21A, and 20A were 78, 64, 53, 98, and 54 psig, respectively. The rapid decline of the ignition wellhead pressure indicates that high-permeability zones existed in the reservoir. The producing wells were opened after wellhead pressure measurements were completed. The ignition well remained shutin to minimize backflow and caving of the formation.

During the experiment, oil and water production each averaged 0.75 barrel per well per day for the pattern test wells. The slight increase in production probably cannot be attributed to the effects of combustion. The air-injection rate for the duration of the experiment was considerably higher than the 50,000 to 75,000 scfd usually injected during the air-gas injection operation and more likely resulted in the increased fluid production.

Subsurface Gas-Tracer Tests

The gas tracers and their functions were (1) krypton 85, to determine travel time between injection and production wells; (2) tritium, to determine vertical extent of the thermal front and relative degree of combustion in the vicinity of the injection wellbore; and (3) helium, to determine areal sweep efficiency and the volume of air being produced from outside the experimental well pattern.

Air was injected at a rate of 485,000 scfd at 375 psig for 2 weeks before the tracers were injected until gas production from the pattern test wells stabilized at 560,000 scfd. Of the total produced gas, well 17 produced 29 percent; well R, 16 percent; well 4A, 22 percent; well 21A, 16 percent; and well 20A, 17 percent. The average oxygen content of the produced gas was 16.5 percent and the average carbon dioxide content was 2.6 percent.

The gas tracers were injected 44 days after ignition. Natural gas injection was stopped 6 hours before the tracers were injected to allow the tritium to enter the formation without being decomposed. Natural gas injection was resumed immediately after krypton injection was completed. Before the tracer was injected, several background measurements were made to determine natural gamma radiation and helium content of the produced gas. Average results are listed in table 4.

TABLE 4. - Background gamma radiation and helium content of produced gas

Well	Background gamma radiation		Background helium concentration, ppm
	cpm	$\mu c/ft^3$	
21A...........	55.0	0.011	50
20A...........	49.2	.010	40
17............	37.8	.008	60
R.............	37.1	.007	60
4A............	36.0	.007	50

About 1 curie (±20 percent) of radioactive krypton 85 and 27 curies of tritium in a gaseous phase were injected in about 15 seconds. Helium was concurrently injected at an average rate of 108 scfh, or 0.5 volume-percent of the air-injection rate. Helium was continuously injected at that rate for 7 days with only a few minor interruptions.

Counting apparatus was installed at each pattern producing well for continuous krypton monitoring. Samples from each well were also collected automatically in evacuated cylinders when a predetermined krypton 85 count-level occurred. An ion-chamber detector was used in the laboratory to determine tritium content. A helium leak detector (mass-spectrometer type) was adapted to quantitatively determine helium concentration in the produced gas 2 or 3 times each day for 3 weeks, until helium concentration was almost to background. Gas production from secondline offset wells was tested without tracer detection. The results of the radioactive and inert gas-tracer tests are shown in figures 15 and 16.

The helium-detection equipment and sampling technique indicated wide variations in recorded helium concentration in the produced gas. The use of this equipment at a field location necessitated difficult standardization procedures. The radioactivity monitoring system gave similar but less severe problems. The accuracy of the ratemeters was on the order of ±5 percent. This accuracy, along with a better sampling technique, provided more reliable results.

Radioactive krypton first appeared 6 hours after injection at well 17, which was 129 feet from the injection well. Breakthrough times for the

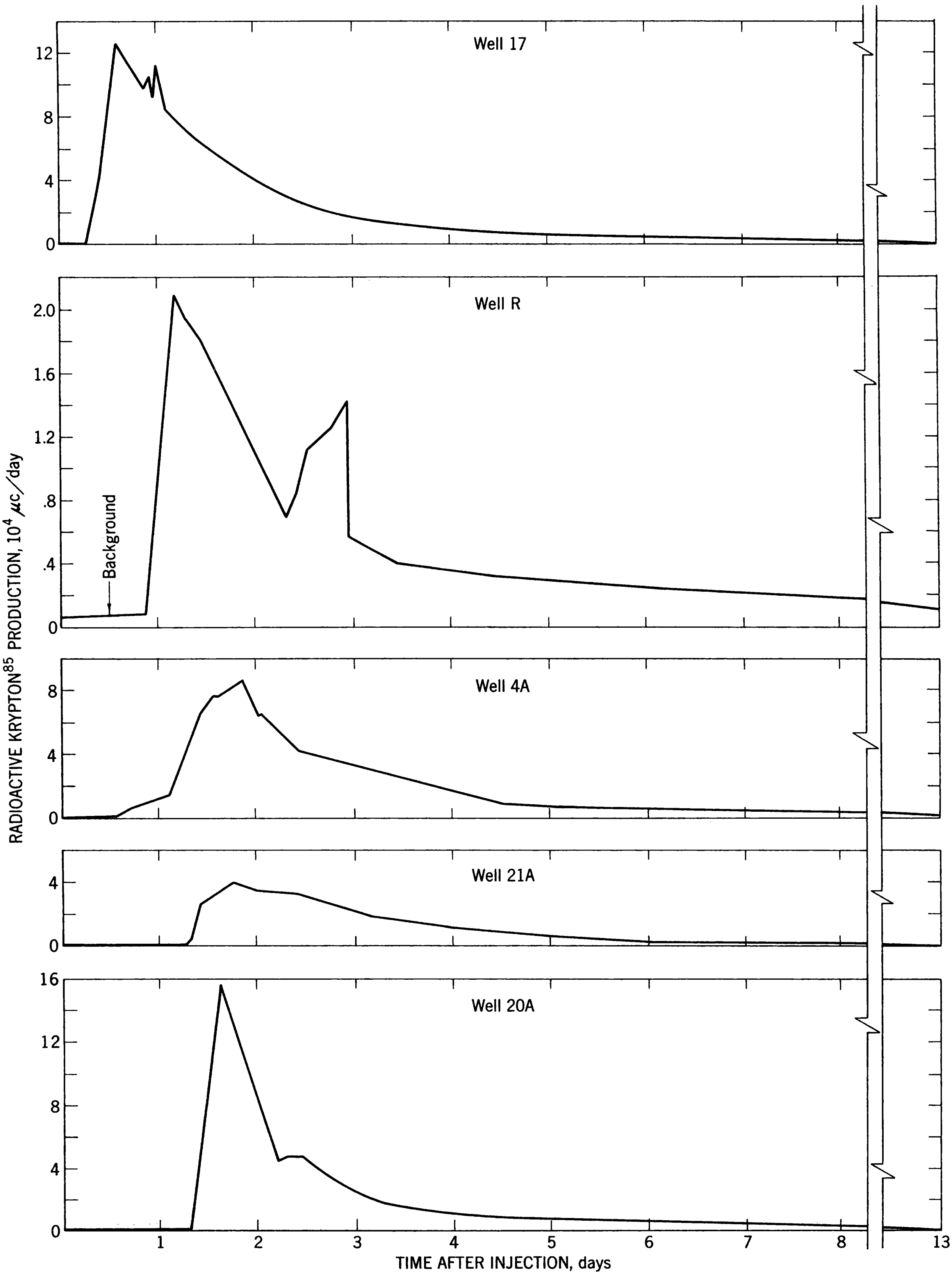

FIGURE 15. - Results of Radioactive Krypton 85 Gas-Tracer Test.

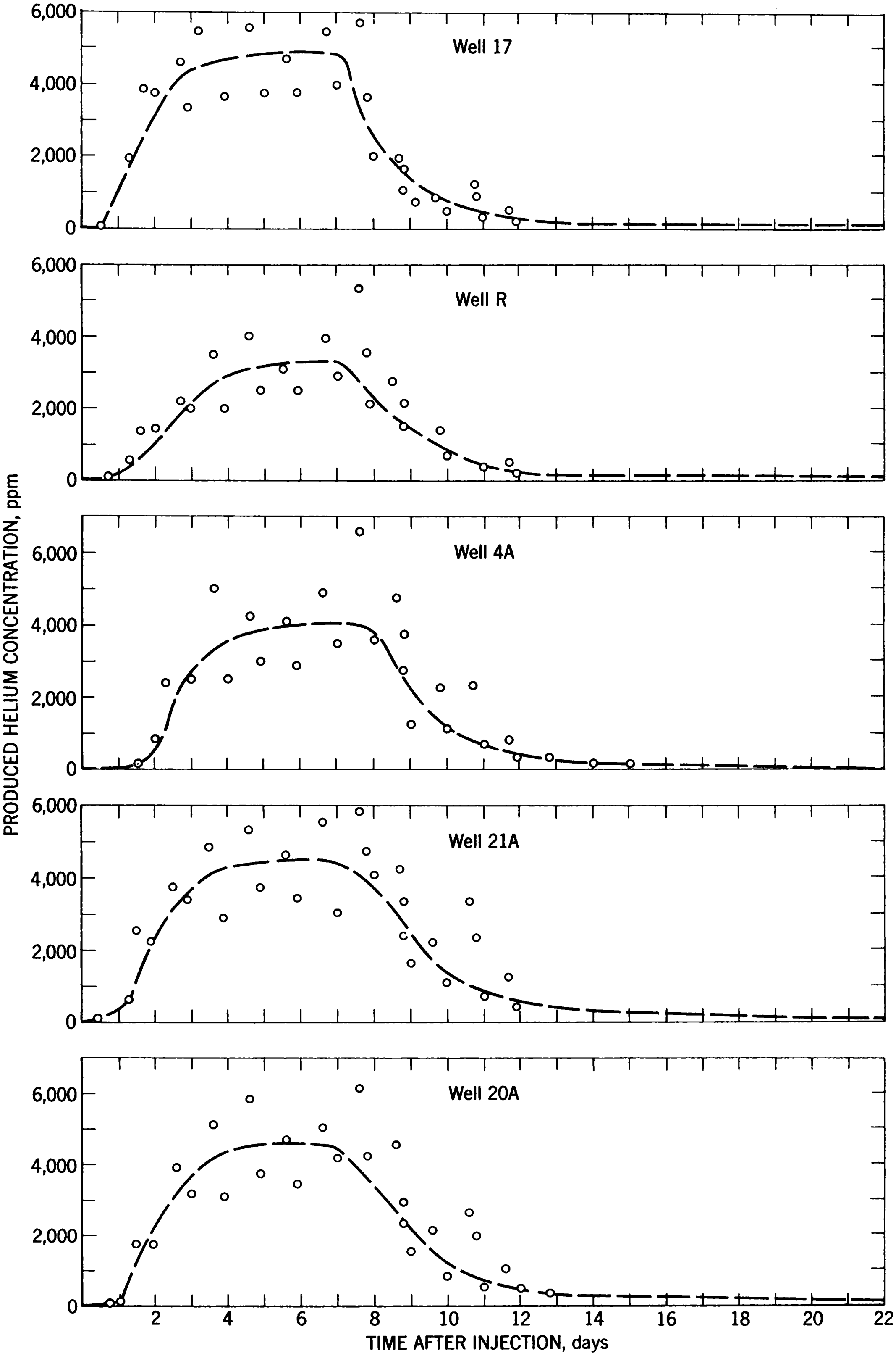

FIGURE 16. - Results of Helium Gas-Tracer Test.

pattern wells and the average rates of travel for both helium and krypton tracers are shown in table 5.

TABLE 5. - Krypton 85 and helium tracer results

Well	Distance from injection well, ft	First breakthrough				Second breakthrough	
		Helium		Krypton		Krypton	
		Time, hr	Rate, ft/hr	Time, hr	Rate, ft/hr	Time, hr	Rate, ft/hr
17...........	129	11	11.7	6	21.5	20	6.5
R............	188	19	9.9	14	13.4	51	3.7
4A...........	179	18	9.9	8	22.4	42	4.2
21A..........	129	13	9.9	27	9.2	53	2.4
20A..........	178	19	9.4	25	7.1	47	3.8

Although the helium tracer was not intended to determine travel time, it is interesting to note the breakthrough time for each gas tracer. The average helium-tracer rate of travel to each producing well was considerably more uniform than for krypton. The initial breakthrough of krypton was considered to be through the highly permeable reservoir interval between 391.5 and 403.5 feet. The average travel rate for the second krypton breakthrough indicated that travel was through a more uniform and lower permeability zone between 403.5 feet and the bottom of the reservoir.

The use of more sensitive equipment and continuous monitoring for krypton detection provided a more exact breakthrough-time indication than the helium sampling procedures. However, the large difference between mobility and diffusivity of the two gases was the most important factor in determining breakthrough time. The much smaller helium atom, with its correspondingly greater diffusivity and mobility, encountered a much larger effective pore volume than the larger and much heavier krypton atom. The net effect was that the breakthrough peak for krypton was much sharper. The combination of these two factors was an apparent lag in breakthrough for helium, although the breakthrough times were essentially the same.

About 95 percent of the 16,750 scf of helium injected was recovered. An assay was not made of the amount of krypton injected; therefore, the krypton recovery cannot be established. Table 6 gives the total gas, helium, and radioactive-gas production for each well and the percentage that each well produced.

The recovery of gas, helium and krypton from the individual wells, as percentages of the total recovery of each, are in reasonably good agreement. When air-injection rates were increased as the experiment progressed. the individual wells produced gas in the same percentages as shown in table 6.

Six gas samples from each pattern producing well were analyzed for tritium content. Tritium was detected in the produced gas from all except well 4A. Gas samples from wells 17 and 20A, collected 48 hours after tracer injection, had the same tritium content. Gas samples from wells R and 21A, collected 24 hours after tracer injection, had 2.5 and 7 times, respectively, the amount of tritium that was present in wells 17 and 20A. The analytical results were not conclusive enough to indicate combustion in the reservoir or vertical conformance of a high-temperature zone.

TABLE 6. - Gas production and gas-tracer recovery

Well	Gas production[1]		Helium production		Krypton 85 production	
	Scf	Percent of total	Scf	Percent of total	Curies	Percent of total
17............	163,000	29.0	5,050	31.7	0.164	28.4
R.............	87,000	15.5	2,050	12.9	.039	6.7
4A............	123,000	21.8	3,150	19.8	.158	27.4
21A...........	89,000	15.8	2,520	15.8	.085	14.7
20A...........	101,000	17.9	3,150	19.8	.131	22.8
Total....	563,000		15,920		.577	

[1]Daily average for tracer-test period.

A significant increase in the carbon dioxide content of the produced gas occurred during the gas-tracer tests, from about 2 to 5 percent in 10 days; however, the produced oxygen remained about 16 percent. Air- and natural gas-injection rates and individual-well gas-production rates were constant. Each well showed about the same percentage increase in the carbon dioxide produced. Produced carbon dioxide from wells 17, R, and 4A decreased slightly after reaching a peak. Carbon dioxide production from wells 21A and 20A increased and remained constant. The interruption of natural gas injection at the time the tracers were injected might have caused the change in carbon dioxide production.

Areal sweep efficiency for the reservoir interval between 391 and 403.5 feet was 42 percent, as calculated from the helium-tracer results. The calculation was based on an assumed pressure distribution, a uniform porosity, the elapsed time for the tracer to travel a certain distance along a line between the injection and each producing well assuming a relatively uniform rate of advance, and the total gas injected during that elapsed time.

The volume of air produced from the reservoir outside the experimental pattern was also calculated for each well from the results of the helium-tracer test. The volume of helium produced by each well as a percent of the volume injected represented the volume of injected gas and combustion products that each well would produce. The calculations assume radial uniformity of combustion in the reservoir and that 1 cubic foot of combustion gas is produced from 1 cubic foot of oxygen-natural gas combustion mixture. Table 7 shows the calculated results of the individual well dilution volumes.

Flow Tests in Experimental Well 1

Gas-production tests were made in Experimental well 1 on November 2 to determine the composition and volume of gas produced from different reservoir intervals. A hookwall packer was set on 2-inch tubing to isolate gas production from two separate reservoir intervals. Four packer-setting depths were selected from the permeability profile and a depth correlation with

Experimental well 2. Gas production from above and below the packer was stabilized at each depth before open flow was measured and samples were collected. Results of the tests are shown in table 8.

TABLE 7. - Calculated volumes of air dilution from wells outside the experimental pattern

Well	Helium produced, percent of injected helium	Total gas production, scfd	Injected gas produced, scfd	Dilution, scfd	Percent dilution
17.........	30.1	163,000	144,500	18,500	11.3
R..........	12.2	87,000	58,500	28,500	32.7
4A.........	18.8	123,000	90,000	33,000	26.8
21A........	15.0	89,000	72,000	17,000	19.1
20A........	18.8	101,000	90,000	11,000	10.9
Total.	94.9	563,000	455,000	108,000	

TABLE 8. - Results of gas-production tests in Experimental well 1

Packer setting depth, ft	Equivalent depth, ft, Exp. well 2	Open flow, scfd		Oxygen, volume-percent		Carbon dioxide, volume-percent	
		Above packer	Below packer	Above packer	Below packer	Above packer	Below packer
416.0	400.5	1,100	1,510	17.2	10.2	2.6	7.4
421.9	406.4	2,110	910	17.1	8.4	3.1	8.2
425.8	410.3	2,170	860	16.4	7.2	3.5	10.3
429.9	414.4	2,130	805	17.0	6.6	3.6	10.8

Below the packer, oxygen content decreased and carbon dioxide increased, generally, in proportion to the gas production. At 416 feet, the gas production was less than at other depths, possibly because part of the formation face was sealed over by the packer rubber. Before the packer tests were made, produced gas from Experimental well 1 had an average oxygen content of 14.2 and carbon dioxide content of 4.3 percent. The significance of the results of the tests was the difference in composition of the produced gas from above and below the packer toward the bottom of the sand. Even though the gas production from Experimental well 1 was only a small percentage of the total gas production from the pattern wells, the results indicated bypassing through the high permeability section at the top of the reservoir. At each lower packer-setting depth the decreasing oxygen and increasing carbon dioxide content of the gas produced from below the packer indicate that gas production was influenced to a lesser degree by the air bypassing through the upper high-permeability section.

After the packer tests were completed, the packer was permanently set at 416 feet and gas samples were taken daily from above and below the packer. During the latter stage of natural gas injection, when the rate was 32,000 scfd and air injection was 500,000 scfd, the average oxygen content from above and below the packer was 17.5 and 9.3 percent and the carbon dioxide was 1.4 and 4.8 percent, respectively. When natural gas injection was stopped, the oxygen content below the packer decreased to 7.4 percent and the carbon dioxide content in the gas produced from above the packer decreased to 1.0 percent. Before the experiment was discontinued, the air-injection rate increased to 715,000 scfd, the oxygen below the packer decreased to 4.1 percent, and the carbon dioxide increased to 9.0 percent. The oxygen and carbon dioxide content of the gas produced from above the packer was 15.8 and 1.5 percent, respectively. In January 1962, 2 weeks after the project was shut down, the oxygen and carbon dioxide content of gas produced from below the packer was 3.1 and 10.0 percent, respectively; above the packer the oxygen was 10.8 and the carbon dioxide was 1.1 percent. These data indicate that combustion of residual hydrocarbons may have been occurring in the lower interval of the reservoir.

RESERVOIR CHARACTERISTICS FROM THE OBSERVATION WELL

Coring and Core Analysis

After air injection was discontinued in January 1962, the reservoir pressure was allowed to dissipate. An observation well, Experimental well 3 (fig. 5), was then drilled and a rotary core taken of the sand section using water-base mud. The location of Experimental well 3, on a line 14 feet from Experimental well 2 between wells 17 and Experimental well 1, was based on the calculated burned-out radius and the composition of gas produced from those wells, which indicated more efficient combustion in that direction.

Results of the core analysis are shown in figure 6. The top of the First sand was determined to be at 391.0 feet and the bottom at 423.7 feet. The shale and interbedded, fine-grained, thin sandstone sections above the First sand showed a color transition from bluish gray to light brown. Only a fraction of an inch of the shale adjacent to the First sand apparently was affected by the high temperature, which indicates the value of overlying shale as a heat barrier. The top 2.5 feet of First sand consisted of alternating layers of coarse-grained and well-cemented and fine-grained porous sandstone with crossbedding. A carbonaceous white crystalline solid was noted on the surface of the coarse-grained sandstone after coring water evaporated. Qualitative laboratory tests indicated the presence of carbonates in that reservoir interval of Experimental well 2. Below that section was about 0.5 foot of natural-colored sandy shale. At 394.1 feet the sandstone became uniform with some interbedded shale. From 395 to 403.8 feet, the sandstone core was brick-red and contained considerable free salt on the surface. The equivalent sodium chloride content of rock samples, taken from the center of the core after removal of the exterior surface, was less than 1,000 ppm.

At 404 feet, the brick-red sandstone graded into a light, brownish-gray sandstone distinguishable from the natural-gray sandstone. Some free salt was present on the surface of the core material down to 419 feet, but was considerably less than in the 395- to 404-foot interval. At 419 feet, natural-gray sandstone became prevalent with thin brown streaks irregularly spaced but parallel to the bedding plane. From 422 feet to the bottom of the reservoir at 423.7 feet, a very strong odor of oxidized hydrocarbons was detected. Core analysis specimens selected from that interval were difficult to clean by solvent extraction. The bottom one-half foot of the reservoir sand showed a slight oil bleed when removed from the core-barrel. The core was almost completely devoid of crude oil except in the bottom 2 to 3 feet of sand. Also, the bottom 1 foot of the reservoir sand and adjacent underlying shale was natural in color and appearance.

A formation-temperature measurement made with coring fluid in the hole showed that the temperature was greater than 230° F. After the coring fluid was bailed from the well, a weighted thermocouple could not be lowered below 407 feet, either because of caving of the formation or dehydration of the coring fluid. After the well was cleaned out to 444 feet (28 days after coring), a maximum temperature of 160° F was recorded at 420 feet. The temperature decreased from 152° F at the bottom of the sand to 75° F at 444 feet. The temperature at the top of the sand was 140° F. The measured temperatures are not the reservoir temperature before coring because the formation was cooled by the coring fluid and the backflow of gas from the formation.

Petrographic studies of samples were made to determine the approximate temperature to which various reservoir intervals had been elevated. Table 9 presents the results of these tests.

TABLE 9. - Reservoir temperatures determined by petrographic thin-section analyses, Experimental well 3

Depth, feet	Estimated temperature, ° F	Depth, feet	Estimated temperature, ° F
391.6	1,100	411.6	1,300
395.6	1,200	415.0	>400
399.6	1,300	417.6	>400
403.6	1,300	421.6	>400 but <700
407.6	1,300		

Comparison of Core-Analysis Results, Experimental Wells 2 and 3

Core-analysis results for Experimental well 3 are compared with those determined for Experimental well 2 in figures 17 and 18. The differences could be due to either natural changes in the reservoir or to elevated temperature.

Figure 19 shows average relative permeability ratios (relative permeability to gas to the relative permeability to oil - K_{rg}/K_{ro}) at different liquid saturations as a percent of the pore volume for Experimental wells 1, 2, and 3. For Experimental well 2, the ratio rapidly approaches infinity as the liquid saturation approaches 40 percent; whereas, the sand in well 1 with lower average air permeability approaches high values of K_{rg}/K_{ro} at lower liquid saturations. The average curve for well 3 unexpectedly fell on the average curve for well 2, but it represents the portion of the reservoir that was affected by high temperature. Since the ratio is an indication of the gas-oil ratio, it would be expected that for a given liquid saturation, the reservoir at Experimental well 2 would permit a greater flow of gas per unit volume of oil and water than the reservoir at Experimental well 1. The

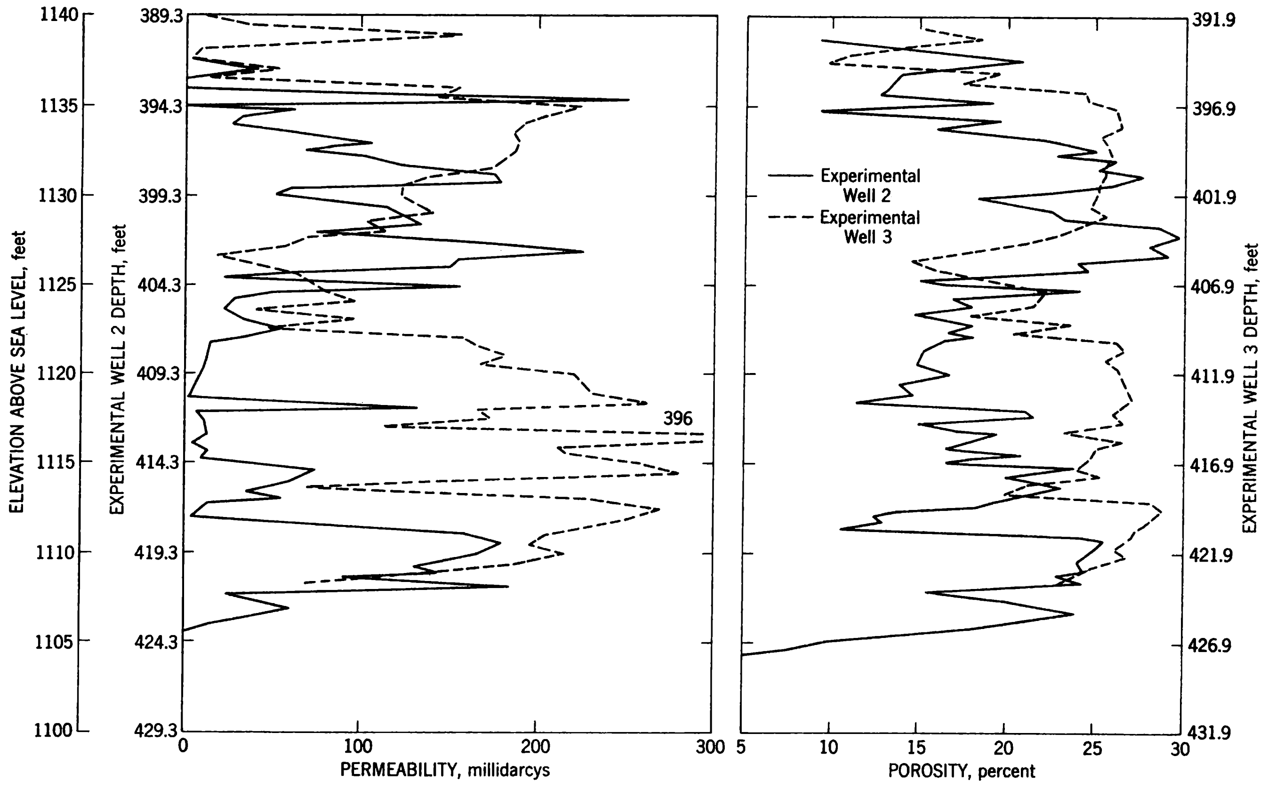

FIGURE 17. - Comparison of Permeability and Porosity, Experimental Wells 2 and 3.

reservoir behind the combustion zone would permit an infinite volume of gas to flow without liquid movement at a liquid saturation of 25 percent of the pore volume. Ahead of the combustion zone, where products of combustion would be condensing and mobile reservoir liquids collecting, the average K_{rg}/K_{ro} curve for Experimental well 2 indicates a decreasing volume of gas flowing per volume of reservoir liquids as the liquid saturation increases. If liquid accumulation ahead of the advancing high-temperature zone had occurred in the field operation, a decrease in the gas-liquid ratio should have been, but was not, observed. The quantities of liquid which could have been moved ahead of the front may have been too small to affect the ratio with the well spacing at this location.

Figure 20 shows the relationship of formation-resistivity factor and porosity for Experimental wells 2 and 3.

The bulk density and effective porosity for each core sample from Experimental wells 2 and 3 were used to calculate the sand-grain or apparent density (mineral specific gravity). The profile of the data for Experimental well 2 was erratic. Values of sand-grain densities for individual samples varied from a minimum of 2.48 to a maximum of 2.90 grams per cu cm and averaged 2.74 grams per cu cm for the total sand thickness. For the total reservoir thickness in Experimental well 3, the values of effective sand-grain densities were more uniform, ranging from 2.64 to 2.86 grams per cu cm and averaging 2.71 grams per cu cm. From the top of the sand to 407 feet in Experimental well 3,

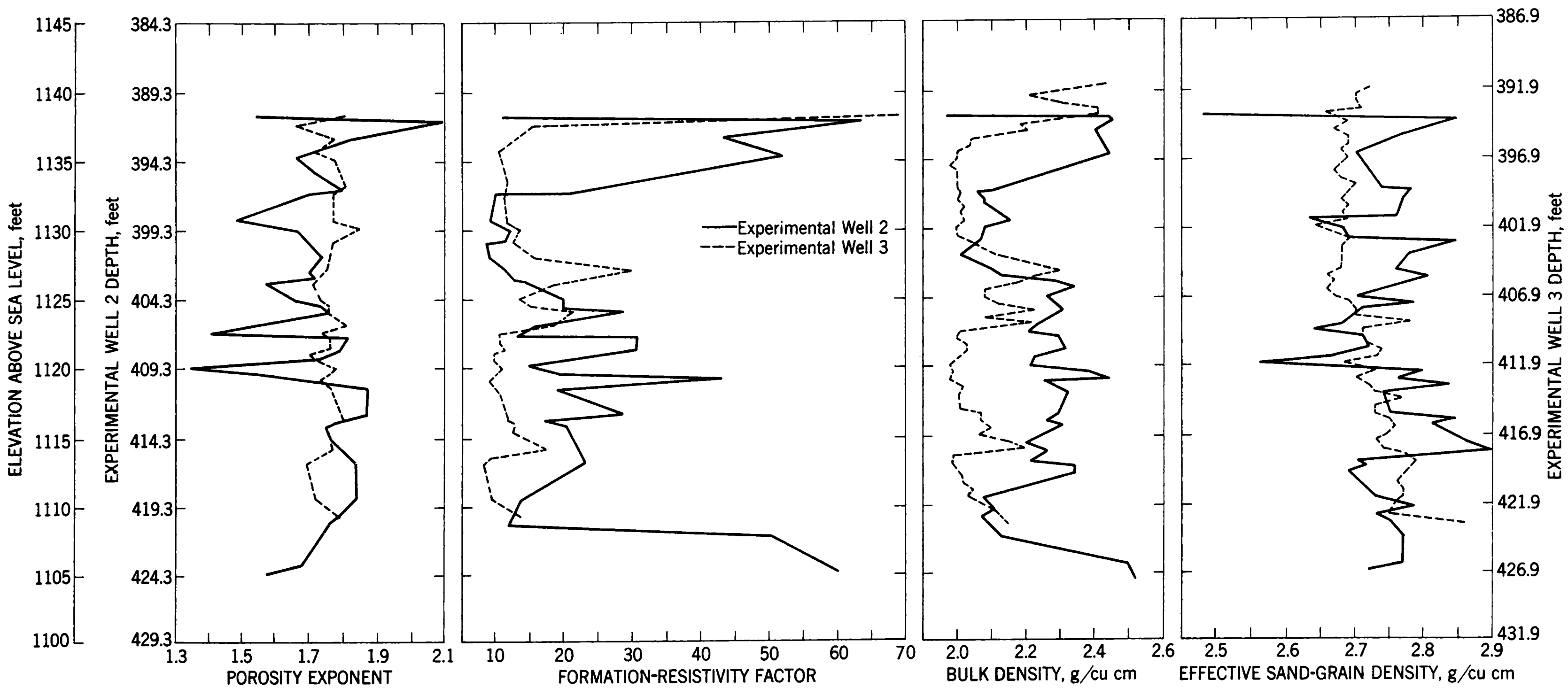

FIGURE 18. - Comparison of Porosity Exponent, Formation-Resistivity Factor, Bulk Density, and Effective Sand-Grain Density, Experimental Wells 2 and 3.

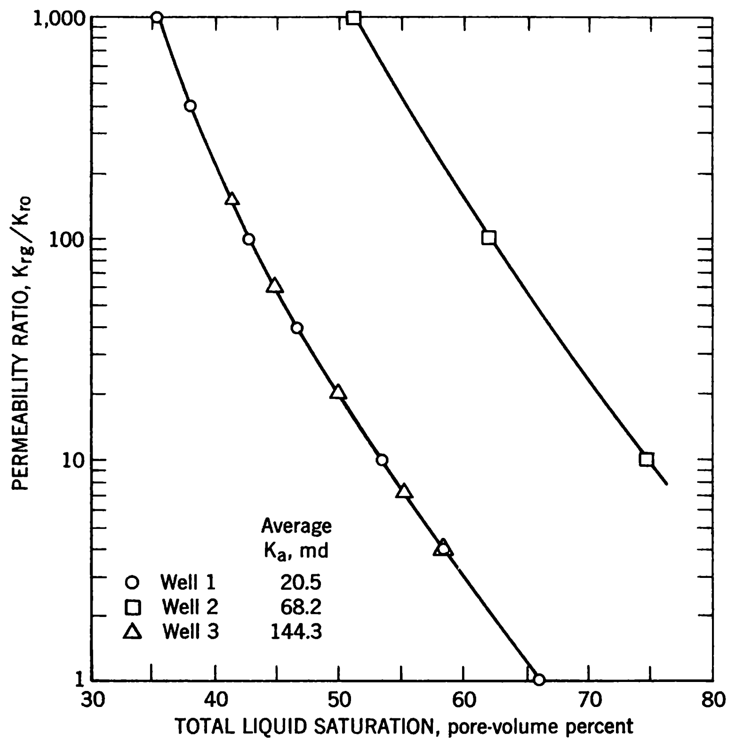

FIGURE 19. - Gas-Oil Relative Permeability Ratio—Total Liquid Saturation Relationships, Experimental Wells 1, 2, and 3.

the effective sand-grain density averaged 2.68 grams per cu cm compared with 2.74 grams per cu cm for the same interval in Experimental well 2. Sand-grain density below 407 feet to the sand bottom in Experimental well 3, and in the same interval in Experimental well 2, averaged 2.74 grams per cu cm. The combustion process should decrease the bulk density while increasing the effective porosity. As the porosity increases, the volume of reservoir framework decreases and the sand-grain density should decrease.

Carbon-Hydrogen Tests

Samples of core material at 2-foot intervals throughout the sand section from Experimental well 3 were analyzed for total carbon and hydrogen by the standard ASTM method (D 271-58). Table 10 shows the results of the analyses. Inorganic carbonates and water of hydration of silicates, if present, in addition to hydrocarbon material are included in the determinations. The weight-percent of each element is based on the absolute sand-grain density because the analytical determinations were made for crushed samples of core material.

Structurally, Pennsylvania Grade crude oil has an atomic hydrogen-carbon ratio of 2:1. On a weight basis, there is about a 6:1 ratio of carbon to hydrogen. A correlation of these basic relationships and the analytical results indicated that the ratio of carbon to hydrogen had been altered by elevated temperature and/or that quantities of inorganic compounds were present. The gross heat of combustion of the samples was determined by assuming that inorganic compounds were present. The analytical technique was in accordance with ASTM method D 271-58 for determining calorific values using benzoic acid as the standard combustion sample in a Parr adiabatic oxygen calorimeter. By this method, only the organic carbon and hydrogen in the sample contribute to the heating value. Samples from three depths were analyzed and the results are shown in table 11. Based on the heating value of First sand crude oil (19,800 Btu per lb), the percentages of crude oil necessary to produce the measured heating values were calculated. Next the percentages of carbon and hydrogen that contribute to the gross heating value were determined. It was necessary to assume that carbon and hydrogen existed in the same ratio as in the crude oil. A comparison of these results with the combustion analyses are shown in table 11.

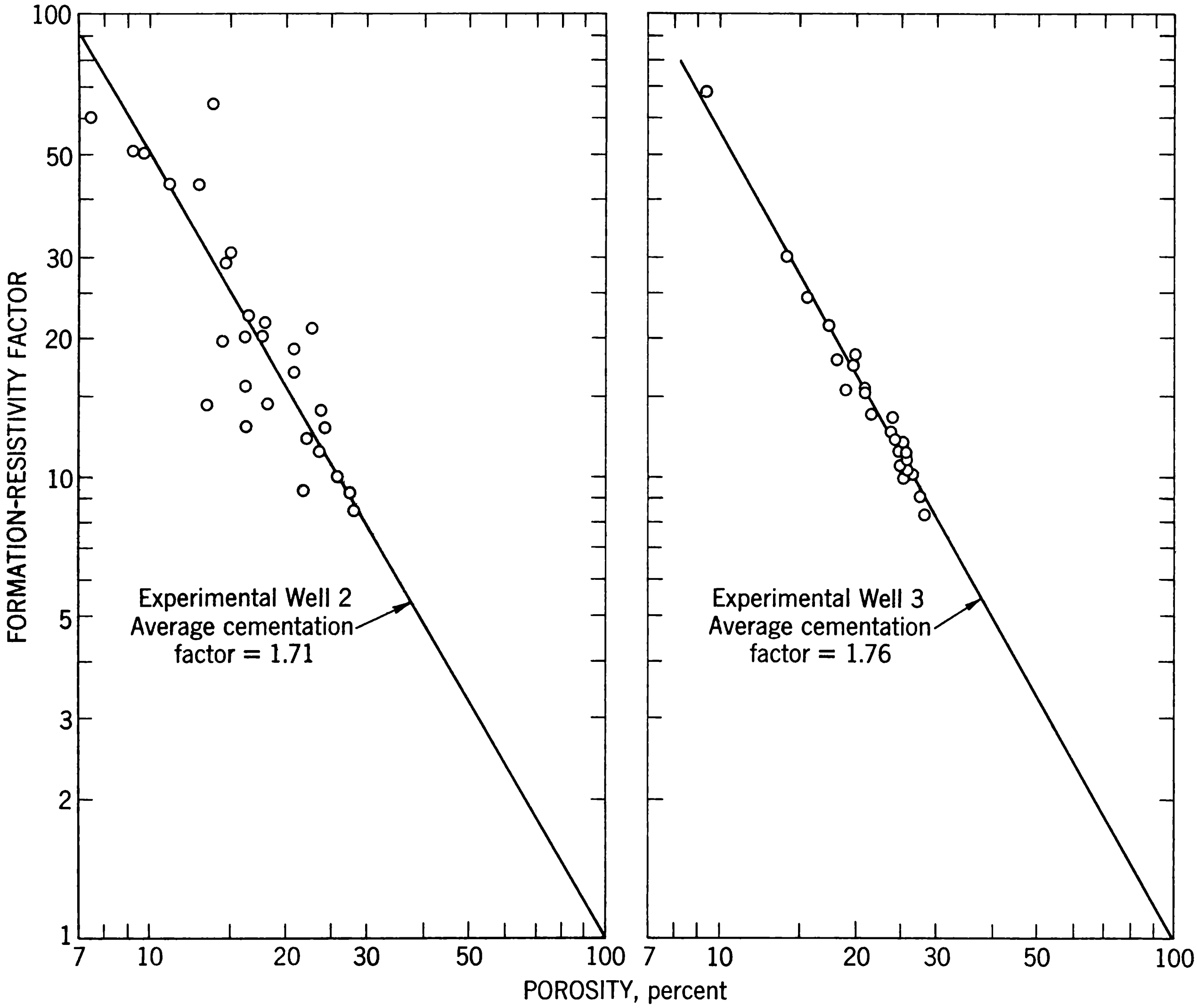

FIGURE 20. - Formation-Resistivity Factor–Porosity Relationships, Experimental Wells 2 and 3.

It appears that the assumption upon which the percentages of hydrogen and carbon were calculated from the heating values was invalid because the percentage of carbon determined from the heating value is greater than the value determined by combustion for each depth.

An additional calculation was made by assuming the percentage of carbon determined by combustion analyses represented only organic carbon and did not include carbonates. The percentage of hydrogen was then calculated using the gross heating value of the samples determined analytically and the calorific values per pound of carbon and hydrogen. For the sample from 407.7 feet, the percentage of hydrogen was determined to be 0.085 compared with the combustion analysis of 0.110; and for the sample representing 417.7 feet, the hydrogen value was calculated to be 0.018 percent compared with 0.188 percent determined by combustion analysis. The carbon-hydrogen ratio was calculated to be 2.7 and 2.4 for the respective depths. The same procedure could not be used for the sample representing 395.5 feet where the weight-percent of hydrogen based on the gross heating value of the sample was greater than the weight of carbon determined by combustion analysis.

TABLE 10. - Carbon-hydrogen analyses, Experimental well 3

Depth, ft	Ash weight-percent	Moisture, weight-percent	Hydrogen		Carbon	
			Weight-percent[1]	Lb/cu ft of sand[2]	Weight-percent	Lb/cu ft of sand[2]
391.7.........	97.39	0.22	0.087	0.144	0.520	0.858
393.6.........	92.54	.26	.055	.091	2.160	3.564
395.5.........	99.14	.18	.089	.147	.069	.114
397.6.........	99.24	.14	.074	.122	.096	.158
399.5.........	99.36	.18	.046	.087	.052	.086
401.6.........	99.24	.08	.084	.139	.047	.078
403.6.........	98.97	.03	.093	.153	.110	.182
405.5.........	97.77	-	.079	.130	.370	.611
407.7.........	97.74	.08	.110	.182	.370	.611
409.7.........	99.84	.08	.087	.144	.105	.173
411.7.........	98.74	.04	.141	.233	.140	.231
413.6.........	98.32	.07	.128	.211	.095	.157
415.6.........	98.60	.10	.160	.264	.093	.153
417.7.........	97.98	.26	.188	.310	.603	.995
419.6.........	97.80	.28	.200	.330	.565	.932
421.7.........	97.38	.36	.140	.231	.805	1.328
423.5.........	97.73	.29	.254	.419	1.010	1.667

[1]Based on removal of free moisture.

[2]Calculated on the basis of an average sand-grain density of 2.65 grams per cu cm.

TABLE 11. - Gross calorific values of core samples, Experimental well 3

Depth, ft	Btu per lb	Oil saturation, percent pore volume		Heating value calculation		Combustion analyses	
		Calculated	Core analysis	Percent hydrogen	Percent carbon	Percent hydrogen	Percent carbon
395.5........	66	4.2	1.5	0.020	0.369	0.089	0.069
407.7........	106	8.9	.5	.033	.592	.110	.370
417.7........	160	13.4	11.0	.049	.896	.188	.603

INJECTED AND PRODUCED GAS MATERIAL BALANCE

A complete material balance could not be made between the injected- and produced-gas volumes because of the unknown quantities for (1) air dilution from outside the pattern, (2) sweep efficiency of the injected-gas volumes, (3) vertical conformance of the injectivity profile, (4) degree of combustion of injected and residual hydrocarbon, and (5) volumes of oxygen used and carbon dioxide generated by combustion of the residual reservoir hydrocarbons. The partially oxidized state of the reservoir oil, caused by previous air-gas injection operations, and the presence of organic and inorganic carbon compounds complicated the evaluation of thermochemical reactions in the reservoir.

Air injection into the First sand, one well location beyond the test pattern, was discontinued 4 days after ignition; therefore, gas-production rates from the pattern producing wells before ignition were not known. The gas-production rates from each well were plotted against total gas-injection rates for different periods after ignition. An extrapolation of the curve for each well indicated a probable production rate at zero injection. The combined initial production rate was 150,000 scfd (estimated dilution volume).

A nitrogen balance between the injected and produced gas volumes during the latter stage of burning gas in the wellbore indicated that about 120,000 scfd of air could be entering the pattern producing wells from the reservoir beyond the experimental pattern-assuming that none of the injected air or gas generated by combustion left the pattern. Oxygen consumption would then amount to about 60 percent of the volume injected; complete combustion of the injected natural gas would have resulted in using only about 38 percent of the oxygen consumed.

A material-balance calculation was made using the helium-tracer results and average injection and production rates. About 485,000 scfd of air and 9,000 scfd of natural gas was injected during the tracer-test period; therefore, some 97,000 scfd of oxygen was being injected. Complete combustion of the injected natural gas would require about 21,000 scfd of oxygen and would generate 11,000 scfd of carbon dioxide. Helium-tracer recovery indicated that 5.1 percent (or about 5,100 scfd) of the available oxygen was unrecoverable. Assuming that loss occurred and that in situ combustion was not achieved, some 76,000 scfd of the oxygen injected should have been recovered.

Complete combustion of the injected natural gas would have liberated 11,000 scfd of carbon dioxide and the average production was 24,000 scfd, thus additional oxygen was utilized to generate the additional carbon dioxide produced. The source of the additional carbon dioxide produced may have been from one or a combination of the following: (1) Combustion of residual hydrocarbon, (2) oxygenation of partially oxidized crude oil left in the reservoir after the long-term air-repressuring project, or (3) natural carbonates and bicarbonates in the reservoir.

A nitrogen material-balance calculation was made to determine air dilution, assuming that recovered volume of injected gases and combustion products was proportional to the volume of injected helium recovered. Approximately 383,000 scfd of the inert gas was injected; but considering the helium-tracer test results, about 19,500 scfd of that amount was not recovered. The difference between the 445,000 scfd of actual nitrogen production and the 363,500 scfd of the injected volume calculated to have been recovered shows some 81,500 scfd as the volume of nitrogen dilution. If air was the diluting gas, some 21,500 scf of oxygen would accompany the 81,500 scf of nitrogen, or 103,000 scfd of air would be produced from outside the pattern.

Combining the volume of diluting oxygen and the 76,000 scfd of the injected volume not used in the reaction with the natural gas, 97,500 scfd of oxygen should have been produced. However, daily average oxygen production was 93,000 scf, leaving only some 3,500 scf available to generate the balance of the carbon dioxide produced from a source other than combustion of the injected natural gas.

This rather inconclusive interpretation applies only to the time during the experiment when the tracer test was conducted. In addition, the solubility of combustion products was discounted in the evaluation because of rapid travel times.

DISCUSSION OF RESULTS

The experiment was suspended January 5, 1962, when it became evident that economic oil production could not be achieved. However, an important original objective was achieved by establishing that a heat wave could be initiated in the vicinity of the wellbore and then propagated radially through the reservoir rock toward the oil-producing wells.

There was no conclusive evidence from injection and production results that self-sustained combustion was achieved or that combustion was responsible for increasing oil and water production. A slight liquid-production increase was attributed to stripping action caused by the air-injection rates, which were higher than those normally used during air-gas repressuring. There was no indication that liquid banks had formed in the reservoir.

Several reasons can be given for the lack of success or low oxygen utilization and inability to support a sulf-sustaining heat wave. The reservoir was excessively heterogeneous, which permitted bypassing of the injected air through a highly permeable, low-fluid-saturated reservoir interval. This condition would not permit sufficient oxygen to enter the more uniform lower-permeability interval where the oil saturation was higher. However, good vertical conformance was shown by the core taken from a post-experiment observation well drilled 14 feet from the ignition well. Core samples indicated that much of the sand was completely devoid of hydrocarbons and had been heated to temperatures in the range of 1,100 to 1,200 degrees F.

Poor combustion could also be attributed to the characteristics or properties of this crude oil and/or low oil saturation. Test data did not indicate whether insufficient fuel deposition or short contact time between the injected air and fuel caused the unsatisfactory results. The effects of air-gas injection on the oil (that is, low-temperature oxidation) and/or formation are unknown with respect to the experiment. Adverse airflow patterns could have been established prior to the experiment. Core analysis results obtained before the test, however, indicated sufficient oil saturation and a satisfactory range of permeability. Probable fuel deposition also was believed to be adequate for combustion-wave propagation.

The test was discontinued when it became evident that any high-temperature heat wave going through the reservoir was being transferred by convection and might require up to 10 years for definitive evaluation.

CONCLUSIONS

1. There was no conclusive evidence from injection and production data that self-sustained combustion was achieved.

2. Bypassing of the injected air through a highly permeable, low-fluid-saturated reservoir interval may not have permitted sufficient oxygen to enter the more uniform, lower permeability reservoir interval where the oil saturation was higher.

3. Combustion was not responsible for increasing oil and water production. There was no apparent indication that liquid banks had formed in the reservoir.

4. The rate of advance of the combustion front and optimum air requirements were not established because of the inability to attain self-sustained combustion.

5. Sweep efficiency and the effect of heterogeneity could not be evaluated from the single observation well drilled after the experiment.

6. The ignition-well completion method was satisfactory to withstand the conditions of pressure and temperature during ignition.

7. Interpretation of the test data was greatly complicated because the experiment was conducted in a reservoir that previously had been subjected to air-gas injection.

8. Additional experimentation with the process in high-gravity, low-viscosity crude-oil reservoirs is warranted.

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