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Solvent Stimulation Tests in Two California Oilfields

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SOLVENT STIMULATION TESTS IN TWO CALIFORNIA OILFIELDS

by

H. J. Lechtenberg,¹ G. L. Gates,² W. H. Caraway,¹ and O. C. Baptist³

ABSTRACT

This Bureau of Mines report investigates solvent injection as a means of increasing oil production from low-gravity oilfields; thus, wells in two California oilfields that produce from reservoirs having low-gravity oil were injected with highly aromatic solvents to increase their oil recovery. The wells were either allowed to soak or the solvent was circulated for a period of time. In some of the wells, the solvent was followed by a slug of water.

The post-stimulation production rate was considerably higher than the prestimulation rate of the wells. Wells in which the solvent was not followed by water showed an immediate increase in oil production, and essentially all of the solvent was recovered. The wells in which solvent was followed by water essentially showed a delay in the increase in oil production, thus indicating a temporary water block.

The results show that the production rate is usually increased by the injection of solvent, and the method may prevent early abandonment of marginal producers. Cumulative post-stimulation oil production indicates that cyclic solvent injection treatment can be an economic success.

INTRODUCTION

There are over 100 billion barrels of low-gravity viscous crude oil (25° API or less) present in approximately 2,000 reservoirs in the United States (2, 9).⁴ Maximum production of the oil in these reservoirs becomes of vital importance as the demand for energy increases and the production from higher gravity oilfields decreases. The Bureau of Mines, in cooperation with oil companies, is investigating solvent injection as a means of improving oil recovery from these viscous oil reservoirs.

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

Liquid mixtures are believed to be viscous because large molecules or clusters of molecules cannot move freely over one another. The viscosity of an emulsion varies depending on the nature of the oil, the proportion of water emulsified, the fineness of dispersion, the temperature, and possible other factors. Monson (7) has shown that viscosity increases as the amount of water in the emulsion increases. Emulsion viscosities have been reported to be as large as 46.5 times the clean oil viscosity (10). Solvents can break the emulsions and thus decrease the viscosity of the mixtures. Jeffries-Harris and Coppel (4) have shown a reduction in the emulsion in production after a solvent was introduced into the petroleum reservoir.

The importance of reducing viscosity of oil to aid in production has been known for a long time. Steam stimulation is an example of this concept.

Organic and inorganic deposits decrease the flow from wells by plugging screens, liners, gravel packs, and probably the formation around the well bore. Laboratory and field tests have shown that the injection and backflow of solvents improve production from wells. Krueger (5) described the migration of solids in a well flushed with solvent and crude oil and then produced at a controlled rate. Teberg (8) credits well bore cleanup as the most important contribution of the first cycle of steam stimulation in the Wilmington field. Highly aromatic solvents have been used successfully to remove well bore deposits. Aromatic solvents have been reported to have improved production and to have lowered the asphaltene content of produced oils.

Solvents, therefore, when added to petroleum reservoirs containing viscous crude oils have four primary functions in stimulating oil production. These functions are (1) to remove organic deposits, (2) to reduce the viscosity of the crude oil, (3) to break emulsions, and (4) to remove insoluble solids.

Gates and Caraway (3) made laboratory evaluations of the effect of solvents on crude oils. They showed that the rate and volume of production by gravity drainage were greatly increased when a small volume of solvent was placed on top of sand columns containing viscous crude oils. They also found that low-molecular-weight aromatic hydrocarbons were the most effective solvents. Small volumes of solvents generally caused a large reduction in the viscosity of the crude oils.

A report giving the preliminary results of solvent stimulation of wells A and B has been published by the Bureau of Mines in Technical Progress Report 62 (6).

Solvent injection tests were run on four wells in the Tar zone of the Wilmington oilfield and one well in the Fruitvale oilfield. This report explains how the tests were made and gives the results.

The field tests consisted of injecting solvent, followed or not followed by water, and allowing the well to soak for a few days or as in one well by circulating the injected solvent down the casing and up through the tubing for a week. The solvents used were a coker oil in the Wilmington field and

a "weed" oil in the Fruitvale field. Both solvents contained large quantities of aromatic hydrocarbons and were readily available to the operators in the fields at a reasonable price.

FIELD DATA

The Wilmington oilfield is located in the Los Angeles Basin of California. The field is a multilayered reservoir. In some areas the field is known to have a natural water drive. Oil production has exceeded 1.5 billion barrels. In recent years, the field has produced at the highest rate of any field in the United States. Production in 1972 was over 191 million barrels of oil. Several waterfloods and other secondary recovery processes are being utilized to increase recovery. Water injection, in addition to increasing oil recovery, is used to dispose of waste water and to prevent land subsidence.

The uppermost broad oil producing horizon of the Wilmington field is the Tar zone. This sand initially contained an estimated 2,150 barrels per acre-foot of stock tank oil in place. Primary recovery was estimated to be 12 percent of the oil in place. The sand is unconsolidated with porosities ranging from 34 to 40 percent. Air permeabilities range from 1 to 8 darcys. The oil gravity is low, ranging from 14° to 17° API. The bottom hole pressure in the area of the stimulation tests ranges from 400 to 800 psi.

Wilmington crude oil, like most California oils, contains many cyclic compounds and a relatively large amount of nonhydrocarbons. A composite sample of the Wilmington crude oils contained, in weight-percent, 1.53 sulfur, 0.65 nitrogen, and 0.44 oxygen. It is an asphaltic oil containing a small amount of gasoline and large amounts of high-molecular-weight cyclic compounds. The hydrocarbon portion of the oil has been shown to contain primarily naphthenic compounds (1). Bureau of Mines characterization methods indicate that the naphthenic and aromatic hydrocarbons predominate in the Tar zone crude oil. See figure 1 and table 1.

The Fruitvale field is located in the San Joaquin Valley of California near the west edge of the city of Bakersfield. Over 99 million barrels of oil have been produced from the field. The 1972 oil production exceeded 1 million barrels. Secondary recovery projects have been started, but to date they have been small. The sand is unconsolidated, and silt in the produced liquids is a problem. The bottom hole pressure of the well treated was approximately 1,000 psi.

TABLE 1. - Crude petroleum analysis

Bureau of Mines Bartlesville Laboratory
 Sample 66097

IDENTIFICATION

Wilmington (X-98) field

California
 Los Angeles County

GENERAL CHARACTERISTICS

Gravity, specific, 0.968 Gravity, ° API, 14.7 Pour point, ° F., 25
 Sulfur, percent, 1.76 Color, brownish black
 Viscosity, Saybolt Universal at 100°F., 2,224 sec.; 130°F., 987 sec. Nitrogen, percent, 0.629

DISTILLATION, BUREAU OF MINES ROUTINE METHOD

STAGE 1—Distillation at atmospheric pressure, 747 mm. Hg
 First drop, 187 ° F.

Fraction No.	Cut temp. ° F.	Percent	Sum. percent	Sp. gr., 60/60° F.	° API, 60° F.	C. I.	Refractive index, n_D at 20° C.	Specific dispersion	S. U. visc., 100° F.	Cloud test, ° F.
1.....	122									
2.....	167									
3.....	212									
4.....	257	0.7	0.7	0.718	65.6	-	1.41434	123.3		
5.....	302	.8	1.5	.772	51.8	29	1.42183	124.1		
6.....	347	1.2	2.7	.791	47.4	31	1.43352	124.7		
7.....	392	2.1	4.8	.819	41.3	39	1.44798	129.1		
8.....	437	3.1	7.9	.844	36.2	45	1.46027	130.6		
9.....	482	4.7	12.6	.865	32.1	49	1.47223	142.6		
10.....	527	6.5	19.1	.886	28.2	55	1.48550	156.1		

STAGE 2—Distillation continued at 40 mm. Hg

11.....	392	2.8	21.9	0.911	23.8	63	1.49766	162.0	47	Below 5
12.....	437	6.4	28.3	.925	21.5	65	1.50468	172.1	63	do.
13.....	482	12.5	40.8	.946	18.1	72	1.51824	186.4	160	do.
1/14.....	527	1.5	42.3	.957	16.4	74	1.52561	182.1	230	do.
15.....	572									
Residuum		57.3	99.6	1.021	7.1					

Carbon residue, Conradson: Residuum, 11.9 percent; crude, 7.2 percent.

APPROXIMATE SUMMARY

	Percent	Sp. gr.	° API	Viscosity
Light gasoline.....				
Total gasoline and naphtha.....	4.8	0.789	47.7	
Kerosine distillate.....	-	-	-	
Gas oil.....	16.6	.875	30.1	
Nonviscous lubricating distillate.....	7.3	.914-.933	23.4-20.2	50-100
Medium lubricating distillate.....	9.8	.933-.952	20.2-17.1	100-200
Viscous lubricating distillate.....	3.8	.952-.958	17.1-16.2	Above 200
Residuum.....	57.3	1.021	7.1	
Distillation loss.....	.4			

1/ Distillation discontinued at 489° F.

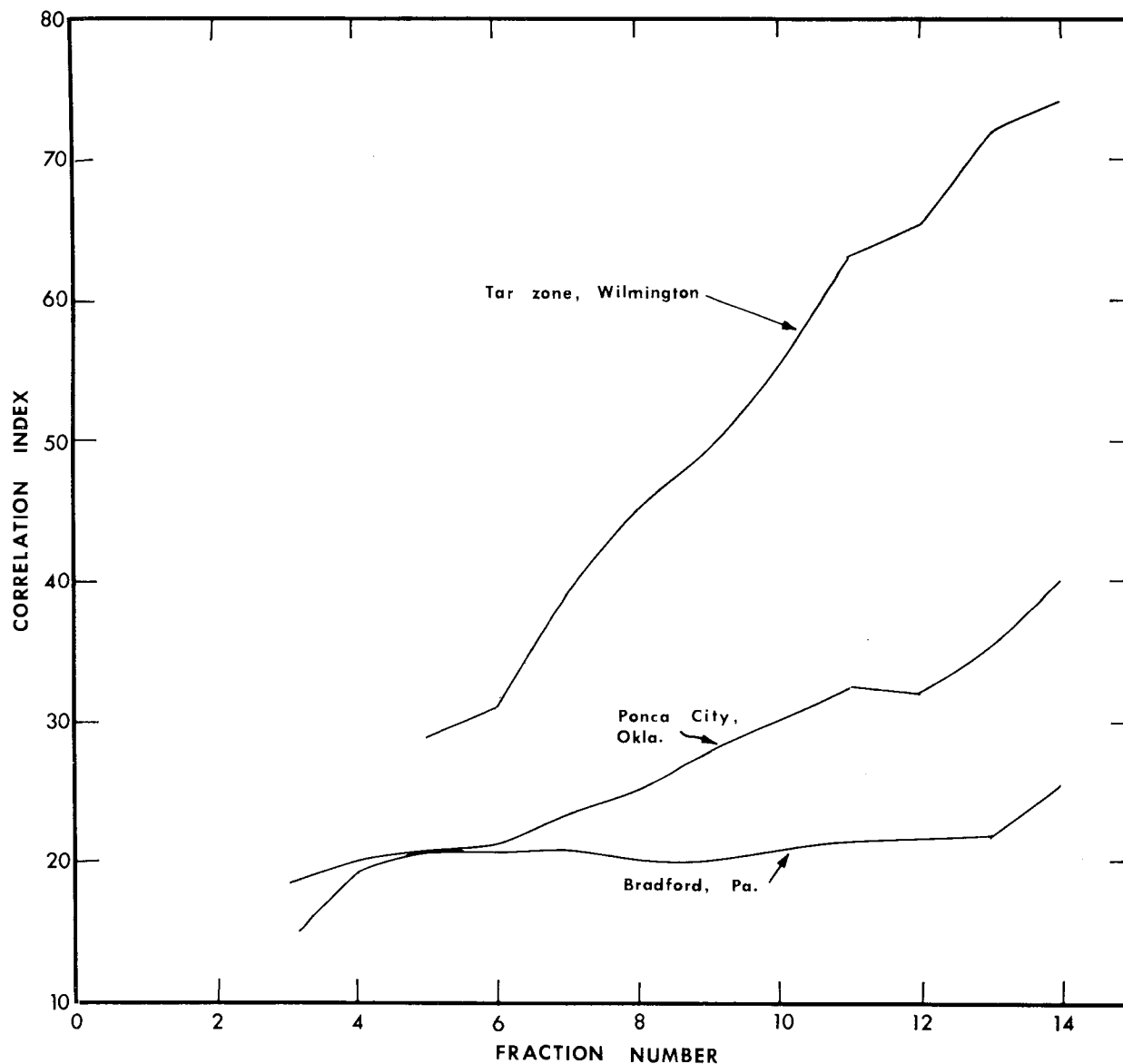


FIGURE 1. - Crude oil chemical characterization.

SOLVENT PROPERTIES

The solvent used in the Wilmington Tar zone stimulation field tests was a coker oil. This is an intermediate product of the company's refinery and was available at a cost of \$3.57 per barrel to the producer. The viscosity of the coker oil was 2 centipoises at 100° F. The gravity was 33° API at 60° F.

The solvent used in the Fruitvale field was a "weed" oil. It is a residue from catalytic cracking. It was available to the producer at a cost of 10.75 cents per gallon. The API gravity of the "weed" oil was 17.2° at 60° F and had a viscosity of 4 centipoises at 100° F. The "weed" oil had an emulsifier in it.

The distillation range and the types of hydrocarbons present in the coker oil were determined by the Bureau of Mines Energy Research Center at Laramie, Wyo., by simulated distillation using gas-liquid chromatographic methods. The distillation range of the "weed" oil was supplied by the refinery. Table 2 shows the distillation range for the solvents.

TABLE 2. - Distillation range of the solvents

Distillation or simulated distillation, vol-pct	Temperature, ° F	
	Wilmington coker oil ¹	Fruitvale weed oil
IBP ²	240	412
1	275	NS
2	320	NS
5	360	NS
10	380	481
20	434	NS
30	473	NS
40	505	NS
50	538	553
60	572	NS
70	609	NS
80	652	NS
90	713	654
95	766	NS
EP ³	830	700

NS--Not supplied by refinery.

¹Simulated distillation.

²Initial boiling point.

³End point.

The types of hydrocarbons present in the Wilmington coker oil were determined by absorption chromatography. Each fraction (naphtha, etc.) was passed through a silica gel column, and each type of hydrocarbon in the effluent was determined by measuring the refractive index. Table 3 shows the hydrocarbon composition of the coker oil. No data were available regarding the types of hydrocarbons present in the "weed" oil.

TABLE 3. - Composition of Wilmington coker oil

Fraction	Boiling range, ° F	Percent of oil, vol-pct	Composition, pct of fraction		
			Saturates	Olefins	Aromatics plus polars
Naphtha.....	¹ 240- 400	11.5	43.7	31.9	24.4
Light distillate....	400- 600	56.0	38.5	29.3	32.2
Light gas oil.....	600- 800	30.1	41.9	2.0	56.1
Heavy gas oil.....	800- ² 830	2.4	(³)	(³)	(³)
Total oil.....	240- 830	100.0	⁴ 40.2	⁴ 21.2	⁴ 38.6

¹Initial boiling point.

²End point.

³Too small to determine.

⁴Not including heavy gas oil.

LABORATORY ANALYSIS

Solvent Evaluation

Three solvents, a commercial-grade toluene, a 90 percent aromatic solvent, and a Wilmington light coker oil, were tested in the laboratory to determine the effectiveness of each to displace the Wilmington Tar zone crude oil. The tests performed using the three solvents were (1) the reduction of the viscosity of the crude oil using varying weight-percent of the solvents, (2) removal of crude oil from packed sand columns, and (3) the removal of crude oil from small-diameter capillary tubes. The third test was shown by Gates and Caraway (3) to be a rapid method of estimating the probable effectiveness of a solvent in removing crude oil from the formation. Solvents found effective by this method were evaluated further in sand column tests.

Varying mixtures, in weight-percent, of Wilmington crude oil and solvent were prepared, and the viscosity was measured. A Brookfield⁵ viscosimeter was used to measure the viscosities of the liquid mixtures that had a viscosity greater than 50 centipoises. Viscosity of the mixtures having a value less than 50 centipoises was measured with a Zeitfuch viscosimeter. Standard procedures were used to determine the viscosities of the mixtures. Crude oil samples contained less than 2 percent water. Table 4 shows the viscosities of the mixtures of solvent and crude oil.

TABLE 4. - Viscosities of mixture of Wilmington Tar zone crude oil and solvents

Solvent in mixture, wt-pct	Viscosity of mixture, cp at 100° F		
	Commercial-grade toluene	90 pct aromatic solvent	Wilmington light coker oil
0	645.0	645.0	645.0
1	505.0	568.0	583.0
5	195.0	324.0	358.0
10	93.0	187.0	193.0
20	25.5	66.0	91.0
30	11.0	35.0	55.0

Tests were made to determine the ability of a solvent to remove oil from glass columns packed with Monterey beach sand. The sand columns were saturated with water, and the water then was displaced with Tar zone crude oil that was heated as it was flowing into the columns. This resulted in a sand column (2 centimeters inner diameter and 30 centimeters long) containing about 90 percent oil and 10 percent water. The porosity was 39 percent. A volume of solvent equal to 10 percent of the pore volume was placed on top of the sand column (3.7 milliliters). Oil was then produced from the column by gravity drainage. The percent recovery versus time was recorded. Figure 2 shows the results for percent recovery versus time for a 10 percent volume of solvent added to the top of the column. A photograph of the sand columns producing heavy oil is shown in figure 3.

⁵Reference to specific equipment, manufacturers, or trade names does not imply endorsement by the Bureau of Mines.

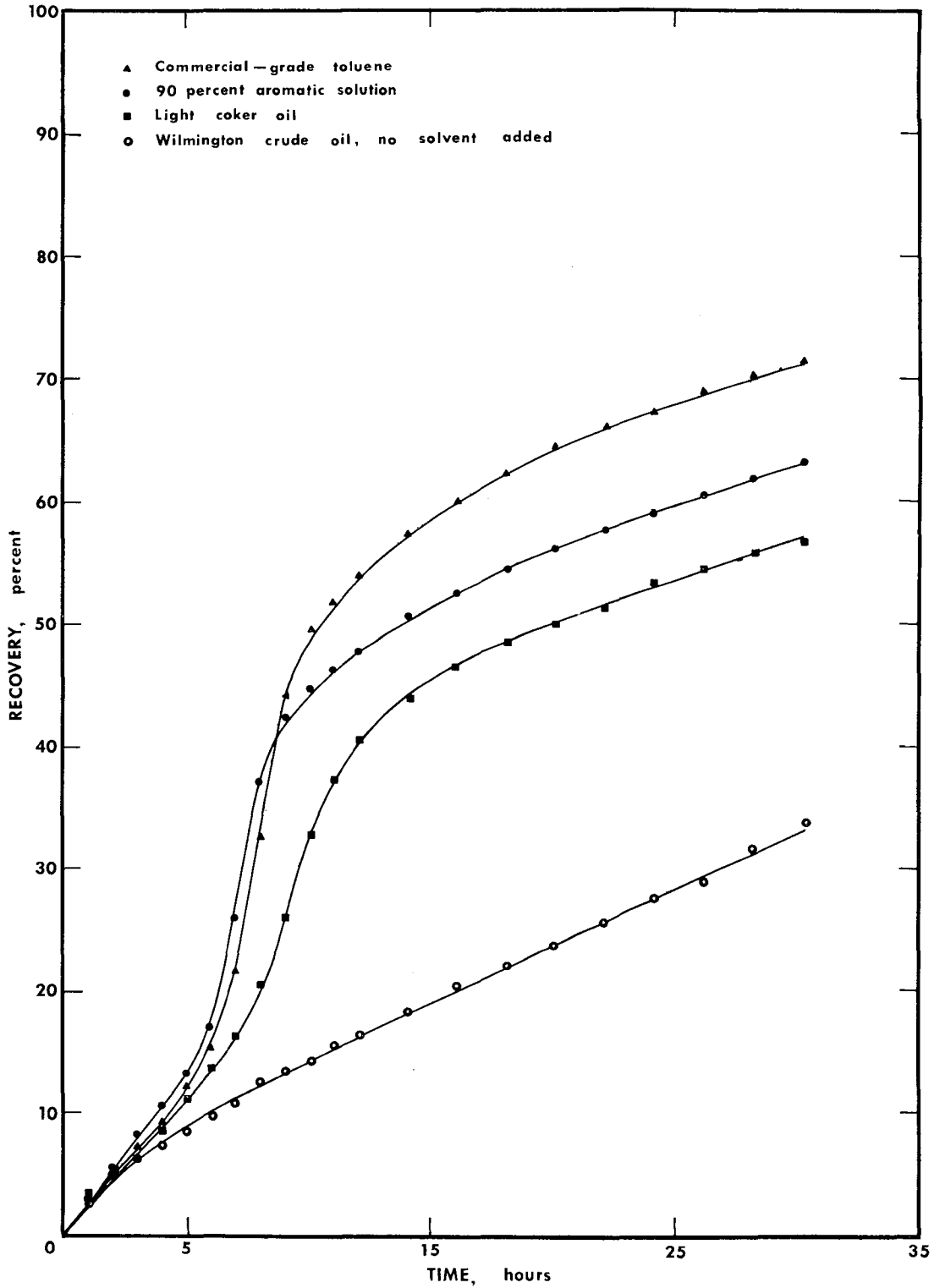


FIGURE 2. - Recovery of Wilmington crude oil from sand columns by gravity drainage with and without solvent added to top of columns. Solvent volumes equaled 10 percent of crude oil volume.



FIGURE 3. - Sand column test apparatus.

The effectiveness of a solvent in removing viscous crude oil from glass capillary tubes was also measured. Capillary tubes, having a 0.4-millimeter-diameter capillary and 1.5 inches long, were filled with heated Tar zone crude oil. After cooling to room temperature, the capillary tubes were immersed in the solvents in a horizontal position. The time for the solvents to remove the crude oil was recorded. The results of this test are shown in table 5.

Column Production

Laboratory analyses of the sand column effluents were performed with the aid of a vapor pressure osmometer and a gas-liquid chromatograph (GLC). The molecular weights of the solvents as determined by the vapor pressure osmometer were lower than the molecular weight of the crude oil. Intermediate mixtures were also determined. Thus, a

calibration curve was established. By interpolation, composition of unknown mixtures could be determined. The GLC was used to determine key peaks of standard mixtures, thus a calibration curve was established and intermediate mixtures were determined. Values obtained by these two methods agreed fairly well.

TABLE 5. - Horizontal capillary tube test

Solvent	Time for complete removal of oil from capillary, hours
Commercial-grade toluene..	6.5
90 pct aromatic.....	46.0
Wilmington light coker oil	27.0

Produced Fluids

Laboratory analyses to determine the solvent content of the produced fluids from the field test wells were performed with the aid of a vapor pressure osmometer and a GLC. The instruments were calibrated by using samples containing known percentages of crude oil and solvents. The GLC was modified to accept oils containing nonvolatile fractions at a column temperature of 100° C. Excellent results were obtained by using a glass insert in the injection tube of the GLC. Field samples were centrifuged to remove water prior to analyzing for the solvent content.

WELL TREATMENT AND RESULTS

Two types of solvent injection methods were performed on the wells described in this report. The solvent injection methods consisted of either injecting fluids and allowing the well to soak for a period of time or injecting the fluid and then circulating up the tubing and down the annulus for a period of time.

Two different solvents were used in the injection tests. Both solvents contained predominantly aromatic hydrocarbons. A coker oil was used in the four wells in the Wilmington field and a "weed" oil in the one well in the Fruitvale field. These solvents were readily available in the field at a reasonable cost to the producers.

The coker oil was injected either down the tubing or the casing and allowed to soak for a period of 3 to 5 days. Lease saltwater was injected after the solvent in three of the wells to displace the coker oil further into the formation. The volume of coker oil injected in the wells ranged from 300 to 1,000 barrels, and the volume of saltwater when used was from 550 to 1,000 barrels. In two of the wells, an additive, n-butylamine, was added to the coker oil and mixed thoroughly prior to injection.

The well in the Fruitvale field was treated in two stages. Initially, the well was treated with a mixture of 180 barrels of "weed" oil plus 19 gallons of n-butylamine and 19 gallons of a nonionic surfactant. The well was then circulated for 4 days and again treated with 150 barrels of "weed" oil, 15 gallons of n-butylamine, and 15 gallons of nonionic surfactant. The well was circulated an additional 3 days and returned to production. Table 6 gives the treatment data for the five wells.

TABLE 6. - Well treatment data

Solvent	Coker oil				"Weed" oil, well E
	Well A	Well B	Well C	Well D	
Volume.....bbl..	1,000	550	300	300	¹ 300
Additive.....pct..	-	-	0.5	0.5	0.3
			<u>n</u> -butylamine	<u>n</u> -butylamine	<u>n</u> -butylamine plus 0.3 surfactant.
Chaser, water.....bbl..	-	550	1,000	1,000	-
Gravitated through.....	Tubing	Casing	Casing	Casing	-
Soak time.....days..	3	5	3	3	-
Circulating time.....days..	-	-	-	-	7
Solvent injected per foot of perforations.....bbl..	4.4	2.9	1.4	1.3	1.7

¹2-stage treatment: 180 bbl injected and circulated for 4 days and 150 bbl injected and circulated for 3 additional days.

The fluid production was monitored and samples were collected at intervals until the API gravity of the produced oil returned to the prestimulation gravity. Samples were analyzed in the laboratory to determine the percent solvent in the produced oil. Daily well tests were taken for 4 or 5 days, and the wells were then returned to their normal well testing schedule. The results from well tests and the percent solvent in the samples were used to calculate the volume of the solvent recovered.

Well A in Wilmington was treated with the largest volume coker oil (1,000 barrels) and was the only well in which the coker oil was not followed by saltwater. The early post-stimulation rate of production was considerably greater than the prestimulation rate, and the produced mixture contained a high percentage of coker oil. Both the rate of production of the oil-solvent mixture and the percentage of coker oil declined sharply within a short time after the stimulation. Almost all of the 1,000 barrels of coker oil used in well A was recovered after 72 days and about 85 percent of this was recovered within the first 10 days of production (fig. 4).

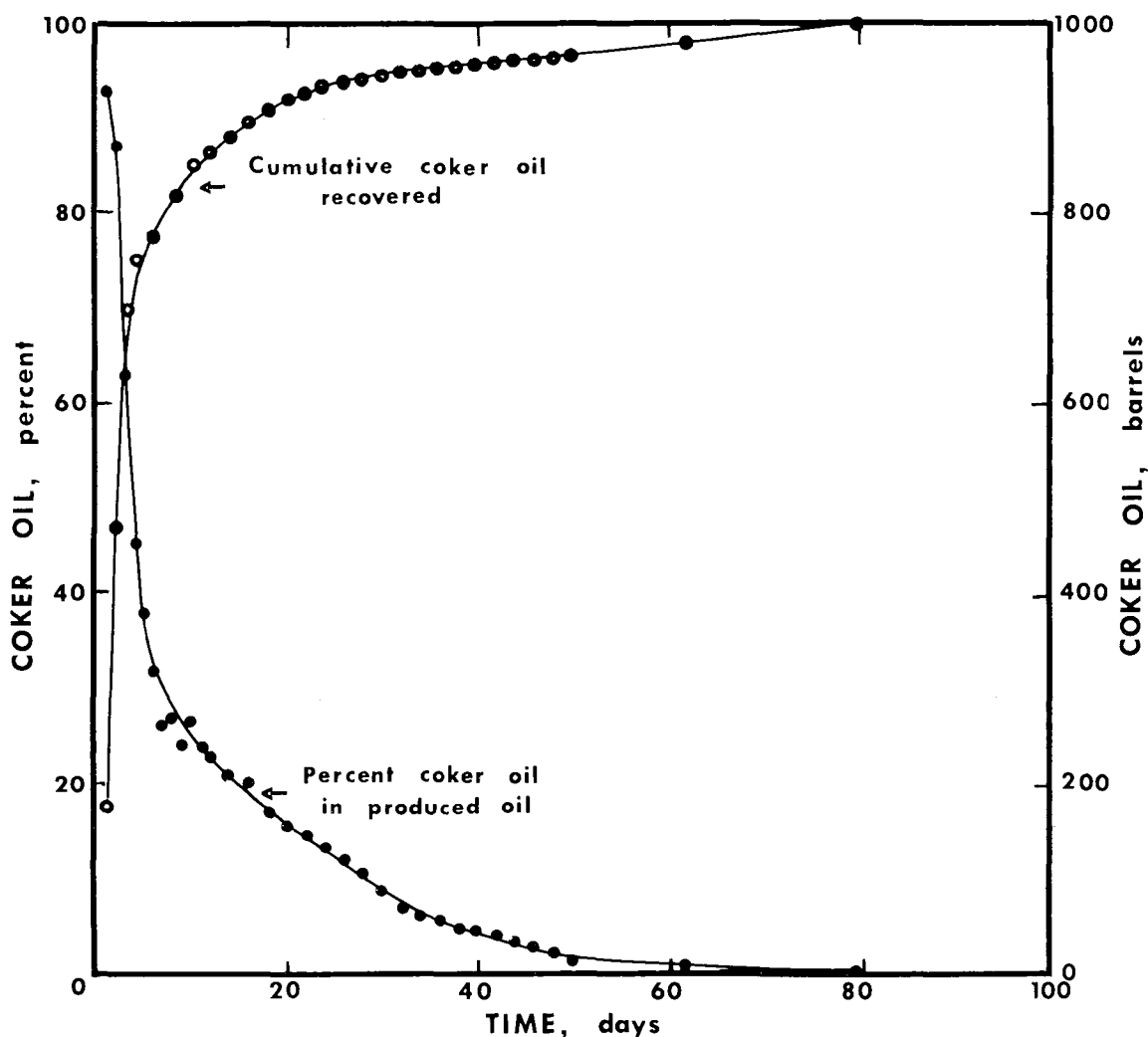


FIGURE 4. - Coker oil recovered and percent coker oil in produced oil, well A.

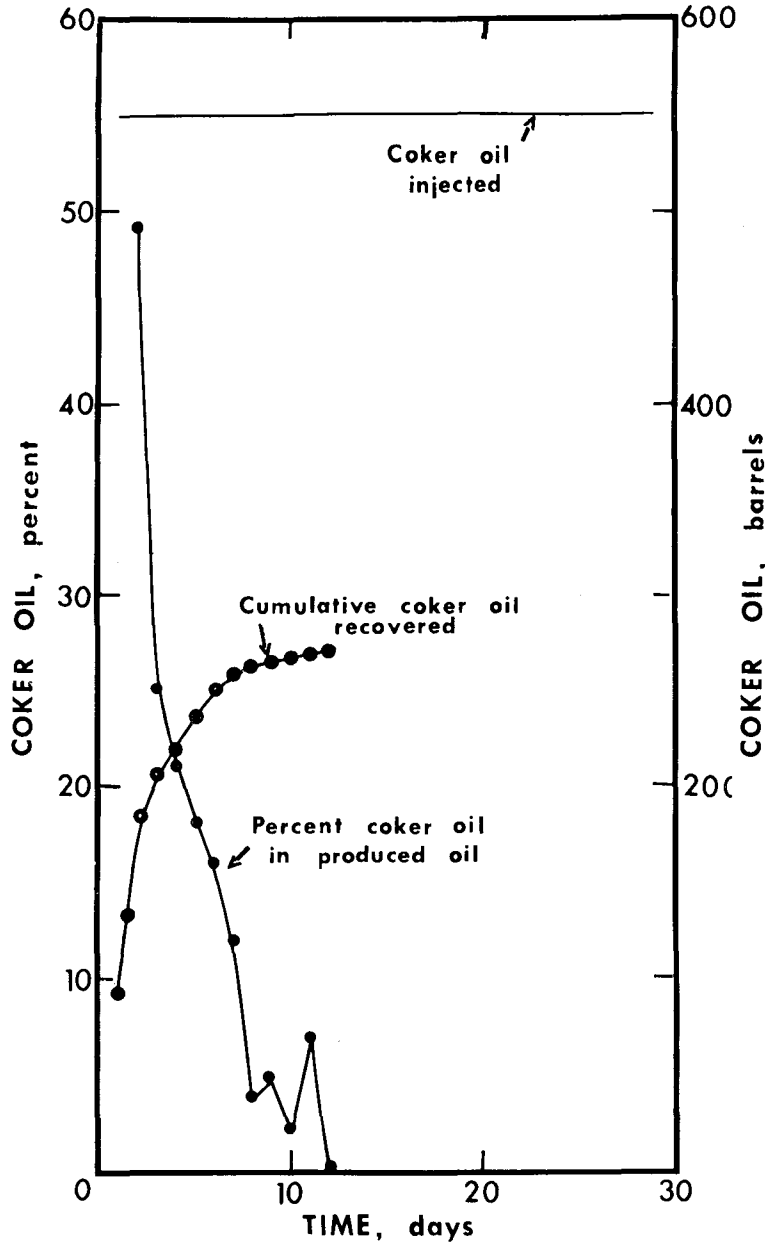


FIGURE 5. - Coker oil recovered and percent coker oil in produced oil, well B.

incremental oil production, the monthly oil production, the average daily oil production, and the prestimulation daily oil rate for well A are shown in figure 6.

Wells C and D in the Wilmington field, which were treated with coker oil and saltwater, had a short initial period of flush production. This included the solvent recovered. The daily oil production then returned to or near the prestimulation rate, and this rate was maintained for a period of 3 to 5 months.

The injected solvent was followed by a saltwater chaser in wells B, C, and D. The post-stimulation production in these wells was tested until the percentage of solvent in the oil declined to almost zero. This time ranged from 14 to 60 days. (The possibility that more coker oil was subsequently produced will be discussed later.) The percentage of coker oil recovered in these three wells ranged from 33 to 49 percent, which was considerably less than the almost 100 percent recovered from well A. The history of coker oil recovered from well B is shown in figure 5.

Cumulative incremental oil production is the total oil produced in excess of that which would have been produced if the prestimulation rate had been maintained. This was approximately 4,000 barrels since the stimulation in well A. The average of the daily oil production, total barrels of oil produced divided by the number of days the well had produced during the time period of the test, has approximated 26 barrels of oil per day compared with a prestimulation rate of 19 barrels of oil per day. The cumulative

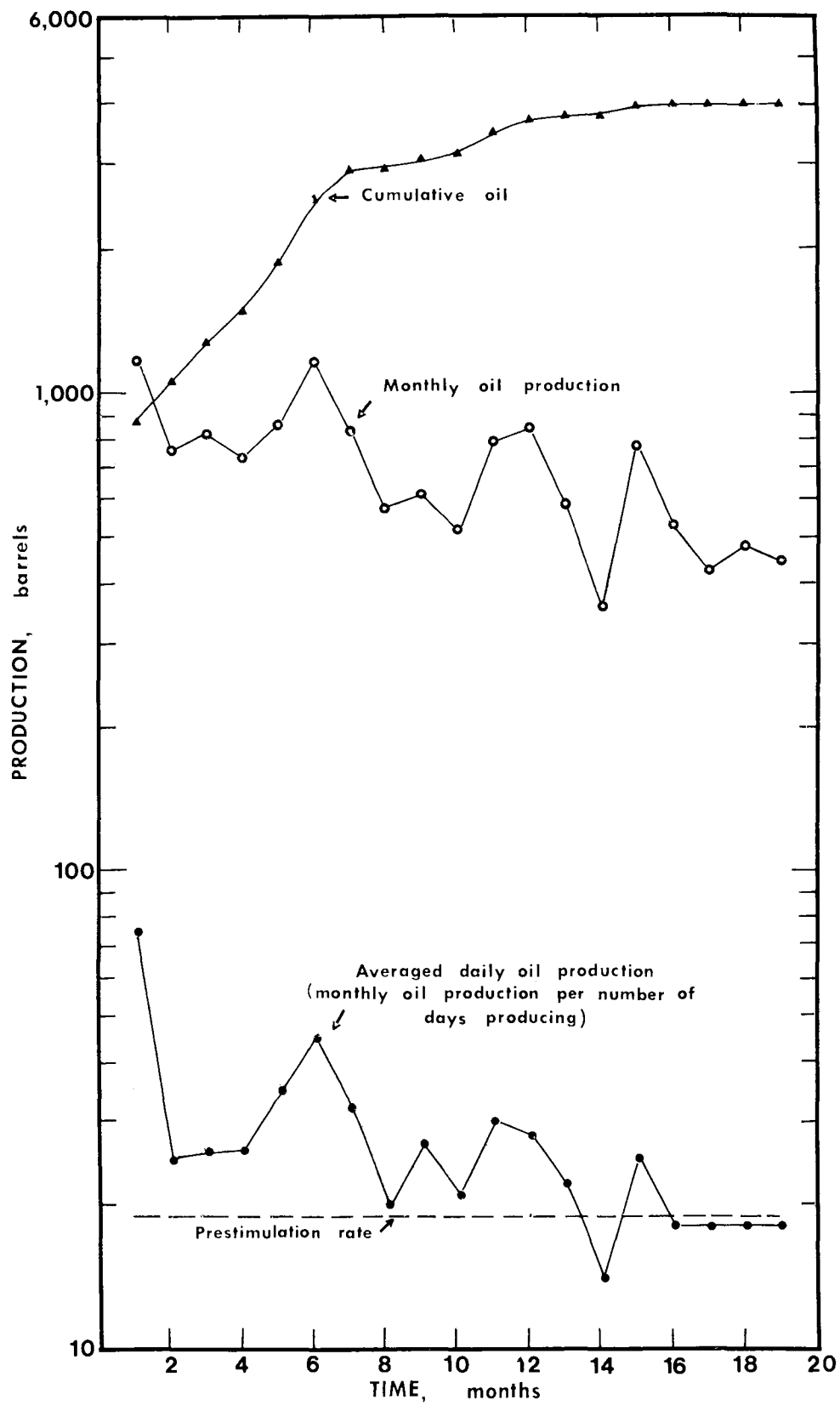


FIGURE 6. - Oil production, well A.

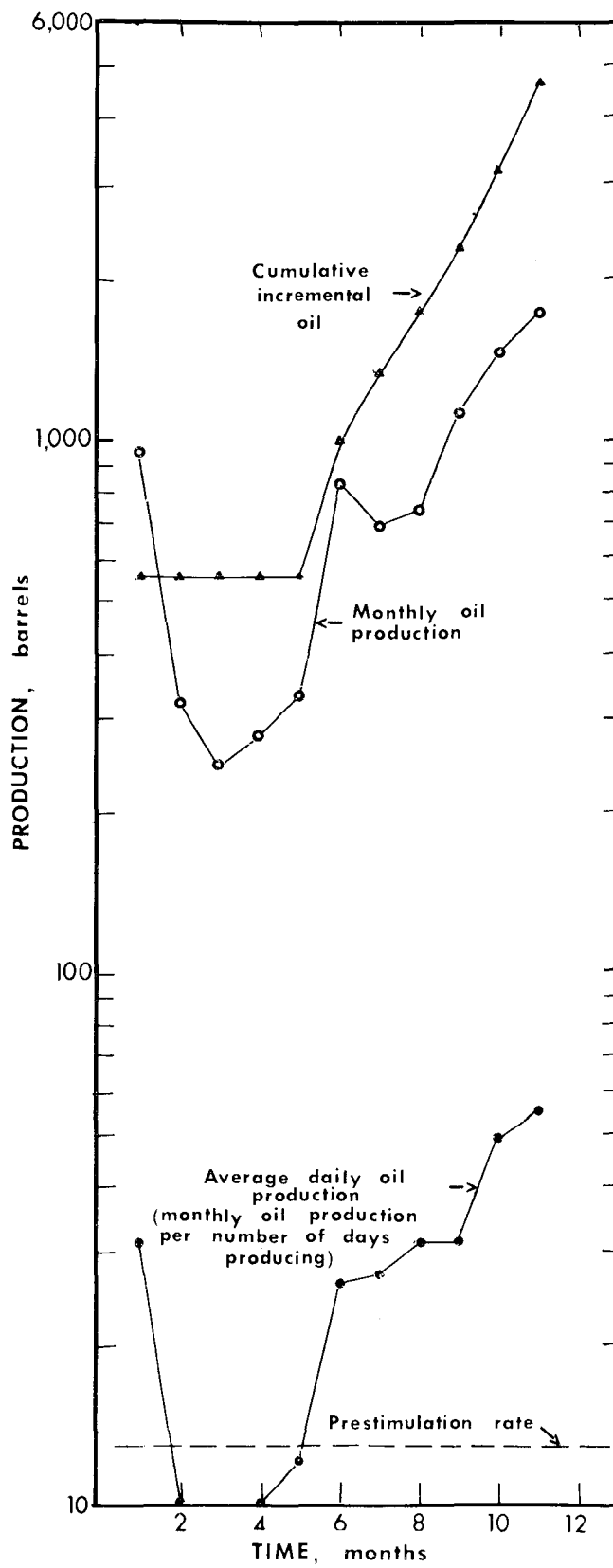


FIGURE 7. - Oil production, well D.

At this point, oil production began to increase greatly and showed a sizable gain over the prestimulation rate. The cumulative incremental oil production, the monthly oil production, the average daily oil production, and the prestimulation rate for well D are shown in figure 7.

Some of the increase in oil production for wells C and D could have been due to a possible "mini" flood caused by an offset well located 250 to 300 feet away from these wells. The offset well was produced from two zones, the upper zone being the same zone that was produced in wells C and D and a lower zone in which water injection was initiated in another well 500 feet from the multizone offset well. The water injection was started 3 months after wells C and D were treated with solvent. Production increased in multizone well and the fluid level in this well rose to a point above the upper zone. In the vicinity of the multizone well other wells which produced from the upper zone also showed an increase in fluid production; however, the increase in oil production was not as great as that observed in wells C and D.

Samples from well E, the well in which the solvent was circulated for 7 days, showed a high concentration of solvent in the produced oil for several

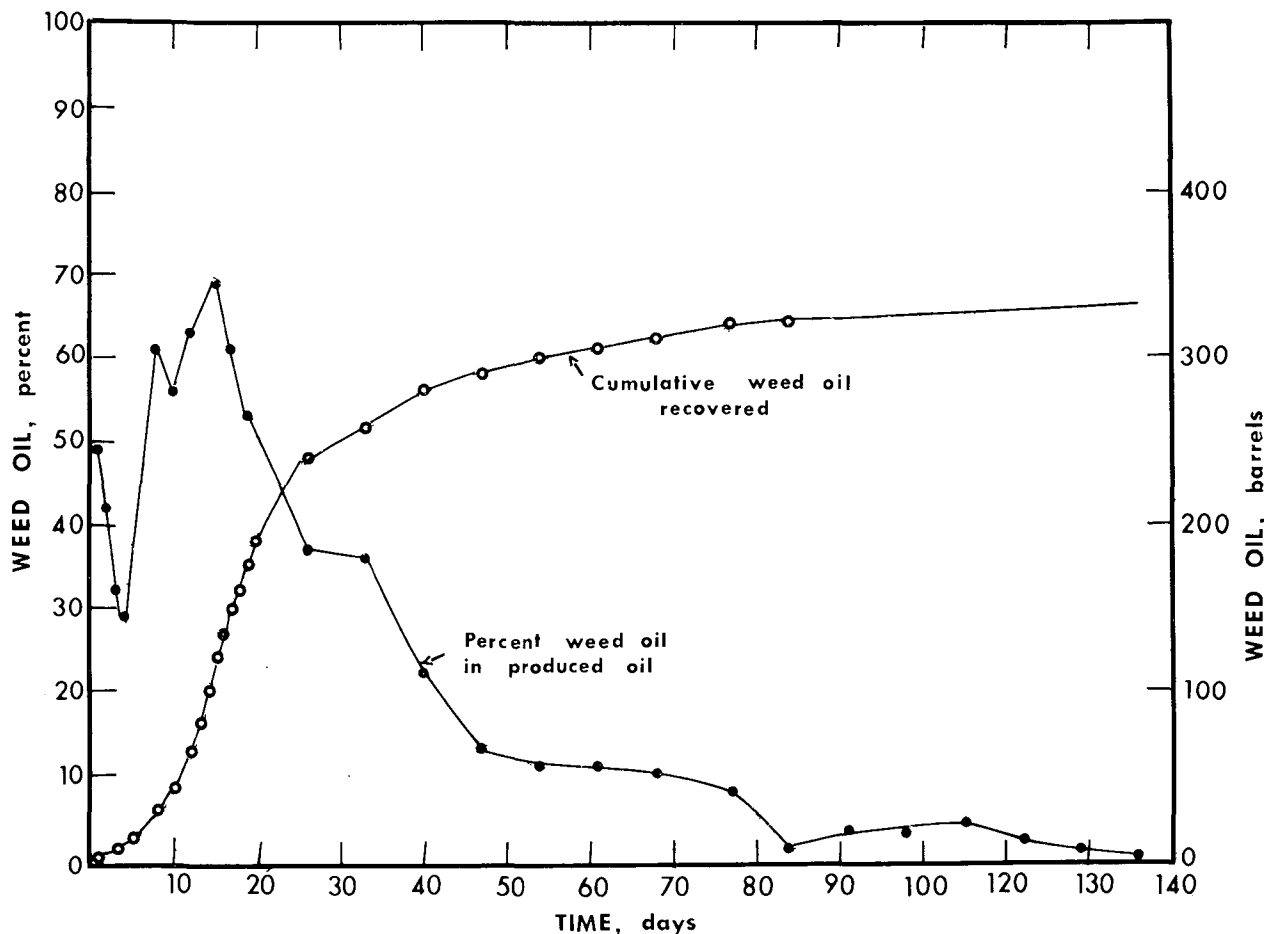


FIGURE 8. - Weed oil recovered and percent weed oil in produced oil, well E.

days prior to decreasing sharply. The solvent content was 13 percent or greater for 47 days before the rate of decline began to stabilize. In this well, all the solvent was recovered in 136 days, and approximately 80 percent of the solvent was recovered in 30 days. The cumulative "weed" oil recovered and the percent solvent in the produced oil for well E are shown in figure 8.

The average daily oil production for this well has stabilized at 8 to 9 barrels per day compared with the prestimulation rate of 3 barrels of oil per day. The cumulative incremental oil production, the monthly oil production, the average daily oil production, and the prestimulation rate for well E are shown in figure 9.

Table 7 shows the results of all wells that were stimulated by solvent injection. These results can be compared with the prestimulation history as shown in table 8.

TABLE 7. - Solvent stimulation results

	Well A	Well B	Well C	Well D	Well E
Additional oil.....bbl..	2,949	249	1,208	4,361	2,760
Solvent recovered.....bbl..	1,000	270	(¹)	(¹)	330
Average of daily oil production					
bbl..	26.3	15.7	23.4	26.6	9.6
Water cut.....pct..	96.6	93.4	93.1	94.6	85.2
Time since treatment.....months..	19	13	11	11	13
Ratio of additional oil to solvent injected.....	2.9	0.45	4.03	14.54	8.36

¹Uncertain.

TABLE 8. - Prestimulation data for wells

	Well A	Well B	Well C	Well D	Well E
Gross production.....bbl/day..	244	245	306	559	34
Net oil production.....bbl/day..	19	16	19	13	3
Water cut.....pct..	92.7	93.9	94.3	97.8	89.0
Gravity.....° API..	15.1	15.2	16.1	15.8	17.0
Perforated interval.....	2,359-	2,444-	2,332-	2,355-	3,700-
	2,584	2,634	2,558	2,606	4,200
Bottom hole pressure.....psi..	400	800	400	400	1,000

The average of the daily oil production rate over the test period for four of the five wells treated with solvent ranged from 5 to 14 barrels of oil greater than the prestimulation rate. The fifth well showed no improvement. The average of the daily oil production rates of the wells before and after solvent stimulation is shown in figure 10.

The cumulative oil production, both prestimulation and post-stimulation, for the wells is shown in figure 11. Prestimulation cumulative oil production was assumed to be the product of the prestimulation daily oil rate and the number of days the well had produced since the date of stimulation. Post-stimulation cumulative oil production includes the volume of solvent that was produced with the oil.

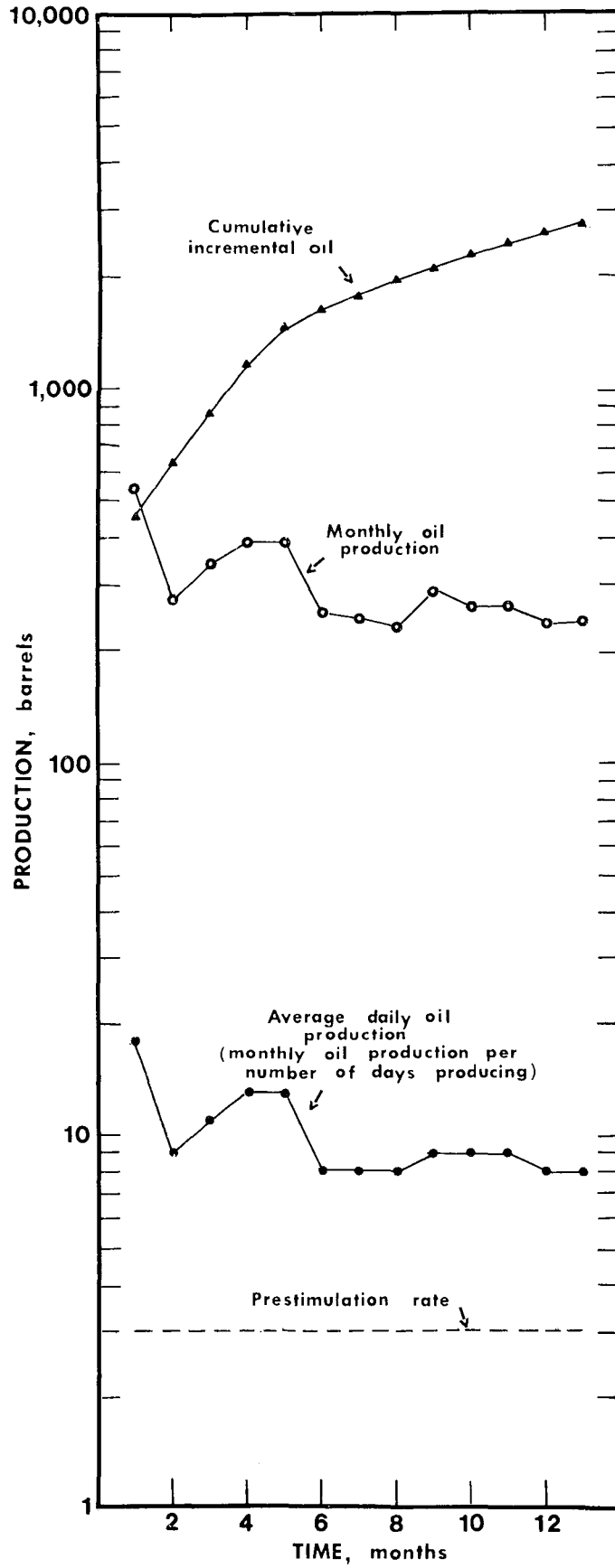


FIGURE 9. - Oil production, well E.

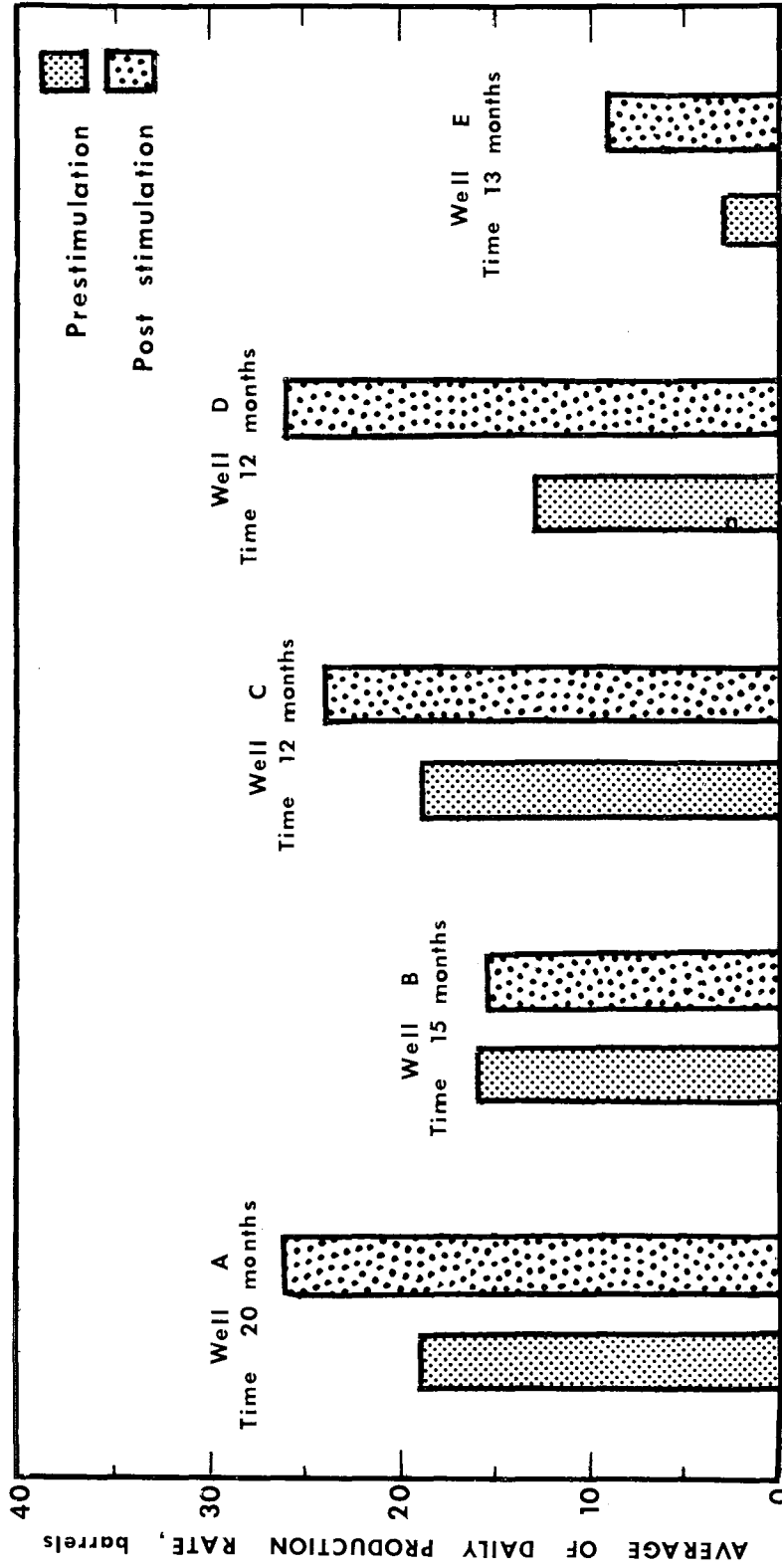


FIGURE 10. - The daily production rate of wells before stimulation and the average daily production rate after solvent stimulation. Also shown is the number of months used to calculate the post-stimulation averaged daily rate.

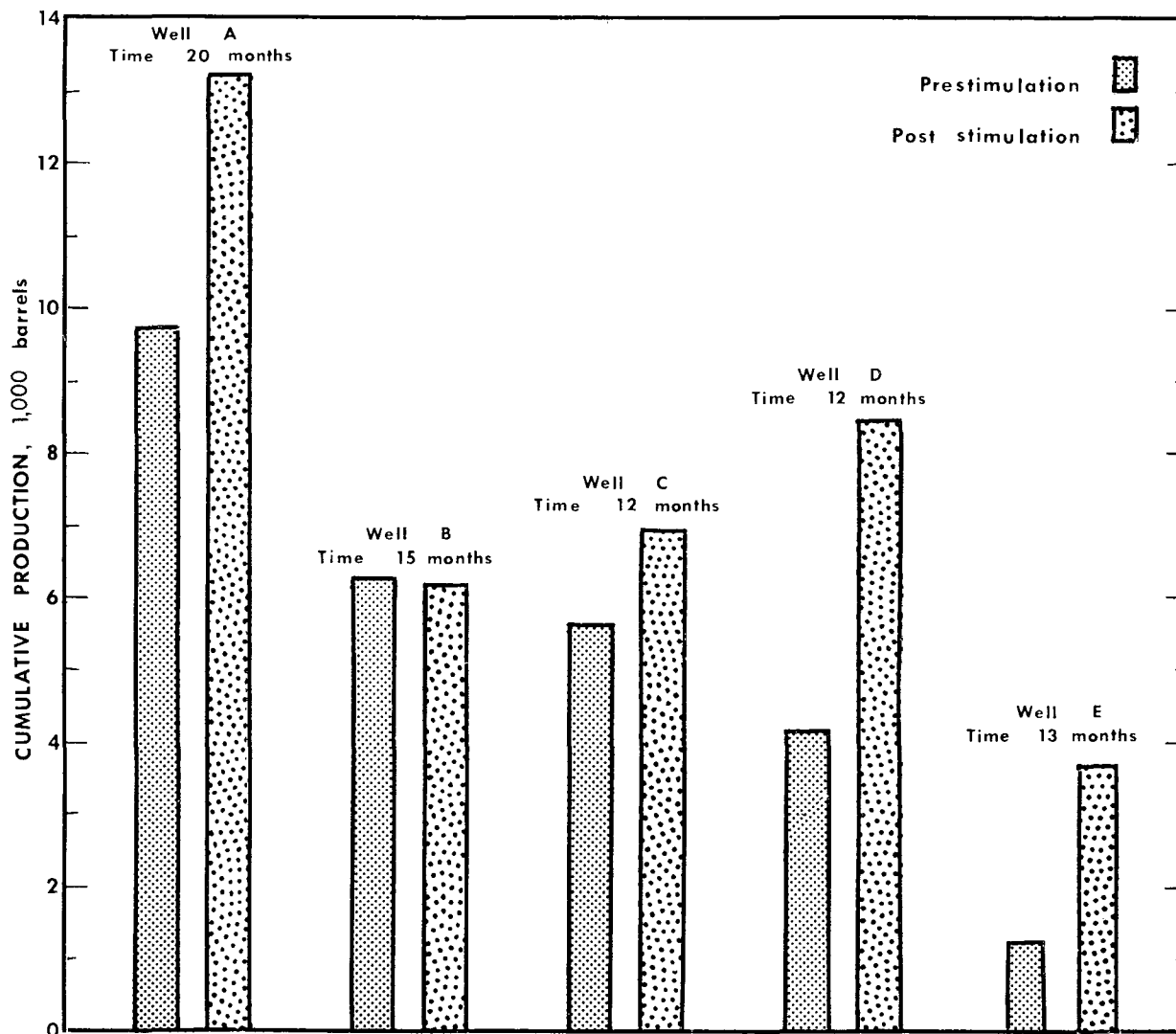


FIGURE 11. - Cumulative oil production of the wells and the number of months since the time of stimulation. Prestimulative cumulative production was considered to be the average daily prestimulation rate times the total number of days a well was produced during the time period.

DISCUSSION OF RESULTS

Two different methods of solvent stimulation were used in the five wells discussed in this report. Two wells were treated with solvent alone, whereas in three wells the injected solvent was followed by water. Also, two different solvents were used; both of these contained a high percentage of aromatic hydrocarbons. Therefore, any statistical evaluation of the effect of any of the variables on the results is precluded by the small number of wells treated and the variance in the solvent stimulation methods. More tests will be necessary to determine how each variable affects the results.

None of the five wells has been stimulated a second time, although this may be done in the near future. Coppel (4) reported that wells in a field in the Santa Maria basin, California, responded well to repeated treatments of solvent stimulation.

The data show that on the average 5 barrels of additional oil was obtained for each barrel of solvent used in these five wells. This favorable ratio of additional oil to solvent injected indicates that four of the five wells have already recovered sufficient additional oil to be an economic success. The operator in the Wilmington field was satisfied with the results and planned to stimulate more wells with solvent.

A large part of the increase in oil produced in the treated wells may be due to the cleaning of asphaltenes and other solid deposits from the well bore, casing perforations, gravel pack, and nearby formation.

The sustained increase in rate of oil production, even after the produced oil no longer contained solvent, indicated that the cleaning of the flow channels was the most beneficial effect of the solvent. Although viscosity reduction was important during the period of flush production immediately following stimulation, the volume of solvent injected probably did not penetrate the reservoir formation far enough to cause extensive mixing of solvent with the reservoir oil.

The well in the Fruitvale field (well E) was producing only about 3 barrels of oil per day before stimulation and was approaching the end of its economic life. The rate of oil production was increased to 8 barrels by the solvent treatment, and this rate has been maintained for a considerable time. Since the well will be operated as long as this rate is maintained, the life of the well was lengthened, and the ultimate recovery of oil was increased.

Water injection following the injection of the solvent to assist in displacing the solvent further into the formation apparently caused a water block. In two of the three wells so treated this was a temporary condition. In these two wells, oil production temporarily decreased to or below the pre-stimulation rate. Water production remained high until a volume of additional water approximately equal to the volume of water injected was produced, and then production decreased. Correspondingly, oil production gradually increased to a rate considerably above the prestimulation rate as the water production decreased. Figure 12 shows the relationship of oil and water production for well D. It is unknown if additional solvent was recovered from these wells. Fluid sampling was discontinued when the samples collected showed no solvent in the production, but more solvent may have been produced later when the oil production increased.

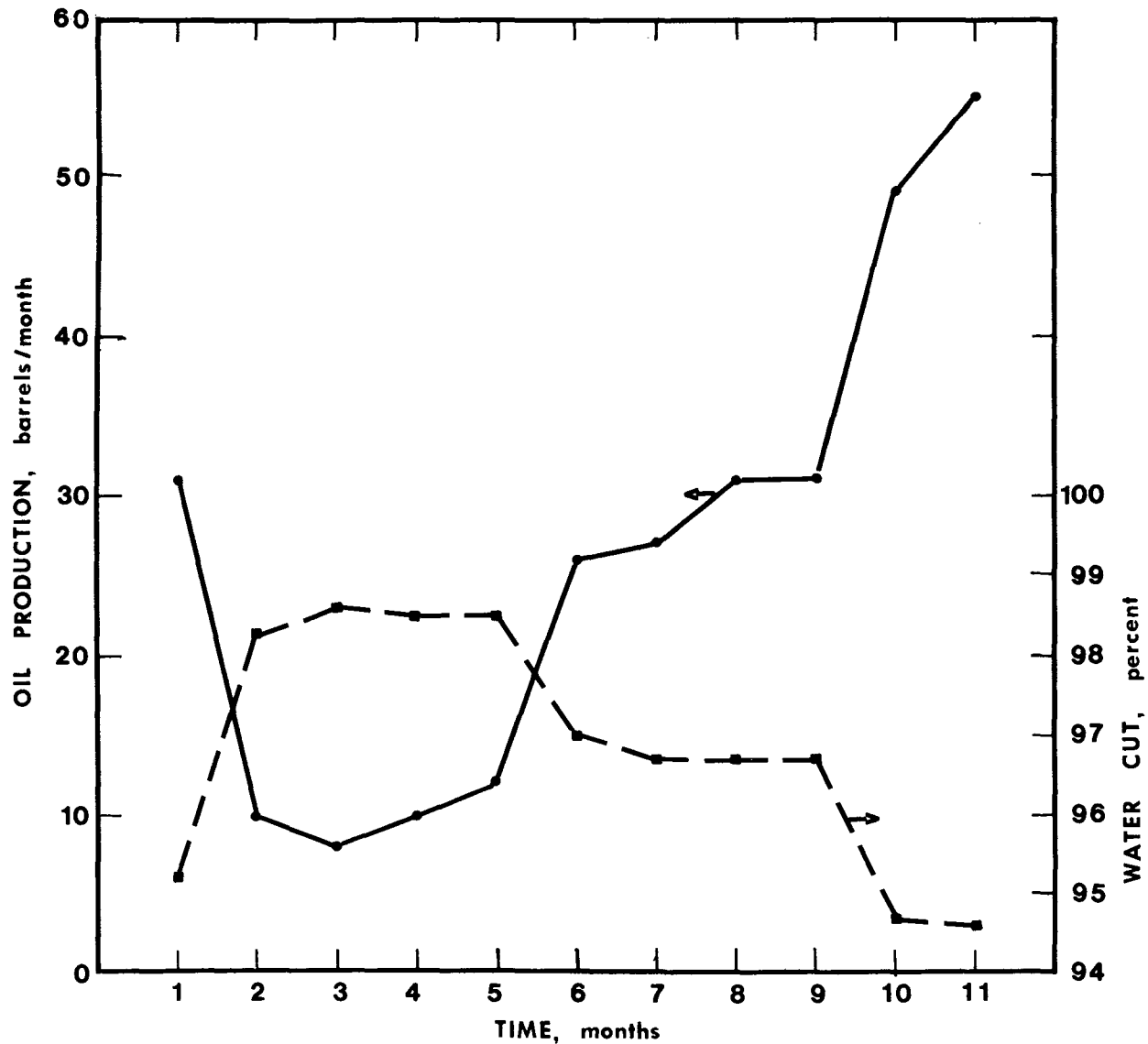


FIGURE 12. - Monthly oil production and percent water cut, well D.

CONCLUSIONS

A large part of the resources of heavy oil located in California and elsewhere cannot be recovered without improved methods of stimulation. The use of solvents for well stimulation resulting in the production of additional petroleum shows promise of being a useful tool in the future. Cyclic solvent stimulation increased production from some wells producing heavy oil.

The results indicate that the sustained increase in rate of production is probably due primarily to the cleaning of the well bore and flow channels. If the increased rate prevents abandonment of marginal producers, the ultimate recovery will be increased.

Monitoring production from treated wells indicated that essentially all of the solvent was recovered with the produced oil in wells in which the solvent was not followed by water. However, solvent was only partially recovered from wells in which solvent was followed by water.

The water injected in three wells apparently caused a temporary water block. A period of high water-oil ratio lasted until essentially all of the injected water had been produced, then the oil production increased until it was considerably above the prestimulation rate and this higher rate continued.

Several combinations of solvents and methods of stimulation were used in these tests. Because of the large number of variables in each test, it is impossible to evaluate the relative effect of each variable on the overall results.

Cumulative post-stimulation oil production indicates that cyclic solvent injection can be an economic success. More laboratory research and field experimentation are needed to determine the limits of applicability of the methods.

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