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MICROBIAL-ENHANCED WATERFLOOD FIELD EXPERIMENT

Topical Report

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January 1989

Performed Under Cooperative Agreement No. FC22-83FE60149

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National Institute for Petroleum and Energy Research
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**Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma**

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ABSTRACT

A microbial-enhanced waterflood field project sponsored by the U.S. Department of Energy (DOE), Microbial Systems Corp. (MSC), and INJECTECH, Inc., and being conducted in cooperation with the National Institute for Petroleum and Energy Research (NIPER) was initiated in October of 1986. The purpose of the project was to determine if injection of a microbial formulation could increase oil production in a mature waterflood.

The site selected for the project is in the Mink Unit of the Delaware-Childers field in Nowata County, Oklahoma. The pilot area consists of four adjacent inverted five-spot patterns drilled on five-acre spacing. Baseline monitoring was conducted to establish pretest conditions from Oct. 28, 1986, to Mar. 17, 1987. Fluid samples were collected on a weekly basis from producing wells and analyzed for microbial populations, total dissolved solids (TDS), trace mineral analyses, pH, and oil viscosities. Other parameters measured included total oil production (Mink unit); total water production (Mink unit); injection well pressures and fluid rates from each well; and water-oil ratio from each well.

Laboratory studies were conducted to screen microbes for the test. Several different microbial formulations were tested in Berea sandstone cores with Mink Unit water and crude oil to determine oil recovery efficiency. A core from the Delaware-Childers field was flooded with the microbial formulation selected for the project. The microbial system recovered 28% of the residual crude oil remaining in the core after waterflooding.

Injectivity and microbial field survivability tests were conducted during the baseline period on two off-pattern wells. The microbial formulation was injected and the wells were shut in for 12 days and then backflushed. Pressures at injection wells were unaffected by injection of the microbial formulation. Fluids backflushed from the wells indicated that the microorganisms survived and multiplied during the shut-in period.

This field project has identified several key factors that impact the design of an MEOR field project. Knowledge of fluid flow patterns and

microbial compatibility with the reservoir environment are two major criteria for successful field test design. Laboratory optimization and field efforts must be correlated to fully evaluate the results. In this particular field application, the MEOR process was compatible with the reservoir environment, improved the water-oil ratio and at the present time, has increased the oil production rate on the entire Mink Unit by 13 percent over the rate in 1986.

INTRODUCTION

This report describes the progress of an ongoing microbial-enhanced waterflood field experiment that was initiated October 1, 1986. Since the site selection and baseline information were previously reported,¹ they will be only briefly reviewed in this report.

Field Site Selection

Several petroleum operators in the Bartlesville, Oklahoma, area were interviewed during the site selection, and many individual oil properties were analyzed for their suitability for the project. Several criteria were selected that would assist in the successful completion of the microbial-enhanced waterflood pilot. Some of the desirable parameters included operator cooperation, site accessibility, low brine salinity, established oil production decline curve and oil saturation, reasonably uniform water injection rates, favorable well spacing and pattern, availability of reservoir and oil production data, ability to isolate the project site and measure increases in incremental oil, and compatibility with our microbial species bank. The Mink Unit (Sec. 36, Twp. 27N, Rge. 16 E) selected for this project is located in Delaware-Childers field in Nowata County, Oklahoma (fig. 1).

A data base was established for the Mink Unit. Some of the material compiled for the data base included surface maps, drilling reports, core analyses, logs, geological and reservoir reports, and injection and production records. The U.S. Bureau of Mines reports for Delaware-Childers field were also used.²⁻⁴

Field personnel installed valves, meters, and miscellaneous injection equipment to prepare for sampling and testing of the field site.

Field Data

The Delaware-Childers field was discovered in 1906, and by 1911 initial development was essentially complete. The field was produced by primary methods until 1925 when air injection was initiated and by 1932 air injection was essentially in progress field-wide. By the 1940's, the field was approaching the economic limit, and waterflooding was initiated. In 1945, four small waterfloods were in operation in less prolific areas of the field. During the next 10 years, many waterfloods were installed throughout the field.

One such waterflood, which began in March 1954, was the Sinclair Oil and Gas Company's Tanner Flood. This flood encompassed about 1,200 acres and included the Mink leases, where the subject MEOR project is located. Surface water from the nearby Verdigris River was (and still is) the source water for this flood. The waterflood, under various owners, has been in continuous operation, in basically the same operating mode, until the present time.

Fortunately, more field information exists than would normally be expected for a shallow field which has been producing for over 80 years. This results, in part, from the field size, pioneering secondary recovery efforts, and the close proximity of a petroleum research facility which was founded in 1917 as the Bureau of Mines Petroleum Experiment Station, in Bartlesville.

Several Bureau of Mines reports provided information which was relevant to the Mink leases.²⁻⁴ One such report² shows that most of the Mink leases were developed after primary production was depleted. Another 1955 report³ lists the production history of the Sinclair-Tanner Flood (annual totals for the 1,200 acres, but not by lease). The old Bureau of Mines files provided drilling/completion reports for about 75 wells on the Mink leases, many of which have since been plugged. Also, the current operator provided core analyses from several wells on the Mink leases, taken in 1935 and 1936.

With this information and the assumption that the leases were developed in 1935-36, we were able to construct a net pay isopach map (fig. 2), estimate initial oil saturation, and develop the production history from initial development to 1952. Actual lease production records from 1953 to date are available.

As a result, it was determined that the Mink leases have an average porosity of 20%, an initial average oil saturation of 36.2% and a combined net pay bulk volume of 2,900 acre-feet. The estimated cumulative production from the two leases selected for the project has been 341,217 bbl through 1986. The project area has a surface area of 17.78 acres and a net pay bulk volume of 516 acre-feet.

With an estimated irreducible oil saturation of 25%, the recoverable oil within the leases is 76.3 bbl/acre-foot or about 40,000 bbl in the pilot area, at the start of the project. The Mink Unit covers a 160-acre area of which 110 acres are productive and contain 21 injection wells and 15 producing wells drilled on 5-acre spacing (fig. 1). Only one of the producing wells is being pumped. Well completions are open-hole (fig. 3). The average reservoir properties are listed in table 1.

The Mink Unit contains the Sallie and Candy Mink leases. Net pay thickness in Mink Unit decreases from approximately 40 ft to less than 10 ft in a northeasterly direction from the southwest corner of the unit. The original oil in place is estimated from historical oil production records to be 1,666,000 bbl of which 341,000 bbl had been produced as of the end of 1986. The remaining 1,325,000 bbl of oil in place in the 2,900 acre-foot of net pay yield an average oil saturation of approximately 460 bbl/acre-foot (30%). The annual oil production rate from the Mink Unit has remained relatively constant since 1982.

The pilot site for the project was four adjacent inverted 5-spot patterns within the Mink Unit (fig. 2). The pilot site covers an area of 17.8 acres and a net pay volume of 516 acre-foot. The pilot area has four injection and eight production wells. In addition, two off-pattern wells (C-BP-2 and S-AP-4) were monitored as part of the test. All possible efforts were made to ensure that no changes in operating conditions or procedures were made during the pilot test. No workovers were performed during the test, and the normal procedure of backflushing all injection wells each week has been continued.

Baseline Monitoring

Field sampling began in November 1986, and continued to March 17, 1987. The data from these baseline studies showed that the total dissolved solids (TDS), pH, and oil viscosities were consistent during this period. The

microbial counts and field data were also consistent. During the baseline period, single-well injection tests and a fluorescein tracer study were implemented. The single-well injection tests showed that no plugging occurred after microorganisms and molasses were injected and that all microorganisms survived in the formation under reservoir conditions.

Chemical tracer studies were initiated in December, 1986, to determine the flow patterns of the injected fluids in the Mink Unit, and to ensure that there was communication between all producing wells and the four treated injectors. The approximate total fluid production per day for each monitored well is given in table 2. Fluorescein was found to be compatible with the formation fluids, as well as with the microbial cultures, and was chosen as the tracer for the test. On Jan. 13, 1987, 27 bbl of a fluorescein solution at a concentration of 174 ppm was injected into wells S-BW-2 and S-BW-3, respectively; and on March 5, 1987, well C-DW-2 was injected with 5.2 bbl of 302 ppm fluorescein, and S-AW-3 was injected with 5.2 bbl of 210 ppm fluorescein solution. Sampling of each producing well was conducted daily for the first 5 days after tracer injection, then biweekly samples were taken for 2 months. Samples were protected from light and transported to NIPER where the fluorescein concentration was determined using a spectrophotometric method. The fluorescein concentration curve was plotted against time for each producing well, and these curves indicated that there was communication between all of the wells since every well showed some fluorescein. There did not appear to be gross channeling because the response persisted for a reasonable period of time. The area under each curve was integrated, and a value was obtained. This value was divided by the average number of barrels of produced fluid for that well, and the wells were ranked accordingly (table 3). The tracer studies seemed to indicate a northeasterly flow pattern (see fig. 1), because the C-CP-1 and C-CP-3 wells and the S-AP-4 well received fluorescein in greater amounts and more quickly than the other wells. The middle well, S-AP-2, received the highest amount of fluorescein, which was expected since this well is affected by all four injection wells.

EXPERIMENTAL

Laboratory Design of the Microbial System

Several different microbial formulations from INJECTECH and NIPER were grown with the Mink Lease reservoir fluids to determine the compatibility of the microorganisms. These formulations were tested in Berea sandstone cores to determine oil recovery efficiency. Table 4 presents results from some of the corefloods. Based upon the coreflooding information, four microorganisms (designated as NIPER Bac 1) were selected from NIPER's laboratory for the field test. These four microorganisms had been used in coreflooding experiments for several years, and produced primarily surfactants, acids, and alcohols. A core from Delaware-Childers field was obtained and tested with NIPER Bac 1, and a graph of the residual oil saturation in the core versus pore volumes of brine injected is presented in fig. 4. Although this core had not been preserved, it is representative of the lithology of the formation. The microbial system recovered 28% of the residual oil remaining in the core after waterflooding. Although a total of 8 pore volumes of brine was injected, most of the oil was recovered before the first pore volume of fluid. This is consistent with our observations in Berea sandstone cores.

Micromodel studies were conducted to determine if the microbial formulation could mobilize oil in the simulated porous media. A micromodel was saturated with brine from the Mink tank battery and flooded with crude oil from the Mink lease. The micromodel was then flooded with plant injection water until no more oil movement was observed (residual oil saturation). NIPER Bac 1 was injected and the micromodel shut in at room temperature for 3 days. The micromodel was then waterflooded and video-taped using a video-enhanced microscopy apparatus. It was observed that there were some gas bubbles produced during incubation of the micromodel, and when the micromodel was waterflooded, there was efficient oil mobilization (approximate incremental recovery of 60%).

Single-well injection tests were performed in February to establish certain parameters before injection of the microbial system was initiated in the Mink Site. An off-pattern injection well was injected with 26 gallons of NIPER's microbial formulation (approximately 1×10^8 cells/ml; NIPER Bac 1) and shut in for 12 days. The well was backflushed and samples were collected every 10 to 15 minutes until microorganisms and molasses were detected. The

injection rates and pressures after the shut-in period were normal, indicating no plugging had occurred. All of the injected microorganisms were detected in the backflush samples, and in high numbers, indicating the microbes were still growing after 12 days of incubation under reservoir conditions.

Injection of the Microbial System and Nutrient

Twenty-six gallons of the microbial formulation, NIPER Bac 1, was injected into each injection well. Wells C-DW-2 and S-BW-2 were treated on March 19, 1987, and wells S-AW-3 and S-BW-3, on March 23, 1987. Twenty gallons of pure molasses was injected into each well at a diluted concentration of approximately 4% periodically during and after the microbial injection. The molasses and microorganisms were injected by means of a header bypass system. The four treated injection wells were shut in until April 3, 1987, although the other 17 injection wells in the Mink Unit were still in operation. After water injection was resumed, the injection wells were backflushed to determine if microbial activity could be observed. All wells produced foam, indicating surfactant production and that the microbial populations were viable. The four injection wells are currently being injected with 2 gallons of pure molasses per well per day.

RESULTS

Sampling of the producing wells was conducted on a weekly basis. Samples were collected from a flowing stream in sterile 4-oz flint glass bottles. Each bottle was filled completely and tightly capped. The samples were taken to the laboratories and processed immediately. The parameters monitored after microbial injection are given in table 5. All results were reported as of March 15, 1988.

Microbial Counts and Molasses Concentration

Microbial counts have been surprisingly low for this field. In only a few instances has there been a significant increase (for example, see figures 5 and 6). No molasses has been detected at any producing well since about 8 weeks after injection of the microbial formulation. This probably indicates that the microorganisms are metabolizing all the molasses that is available.

TDS

Total dissolved solids (TDS) have been measured for every producing well, the tank battery water, and the plant injection water weekly since the initiation of the baseline monitoring period. Table 6 shows the average values obtained for each well during the baseline and post microbial injection. The TDS values have remained very stable since the baseline period.

pH

The pH of each sample has been recorded for the baseline and post microbial periods. Table 7 shows the average values obtained during these periods. The pH has not changed significantly from the baseline averages, which was expected since the volume of the reservoir is large. The injected microbes produce short-chained fatty acids, but the dilution effect with a large volume of water must be considered. It is unlikely that the microbes can have a drastic effect on the pH of the produced water.

Surface and Interfacial Tensions

Although interfacial tension between the produced oil and water from each well was not measured during the baseline period, this testing was initiated 1 month after the microbial solution was released. The surface tension of the produced water from each well was measured during the baseline monitoring and weekly since May, 1987. This parameter is being monitored as an indicator of surfactant production. The data are presented in table 8. In all cases the average surface tension is lower than the baseline data, but not low enough to be the sole cause of oil mobilization.

Crude Oil Viscosity

Weekly viscosities of crude oil from each producer were determined weekly during the baseline period, and samples have been measured every 2 weeks since the microbial treatment (table 9). Note that in all wells the crude oil viscosity has not changed significantly.

Injection Pressures

Injection pressures at the injection wells have not increased since the beginning of the microbial treatment. In fact, they have actually decreased somewhat primarily because the injection plant pressures have decreased (figure 7). Decreases in injection pressures have paralleled changes in the pressure at the injection plant. No adverse plugging effects are occurring because of the microbial treatment.

Water-Oil Ratio

Average water-oil ratios at all monitored producing wells have decreased when compared to the averages in the baseline period. Although the WOR values have a high standard deviation, there is a significant decrease in some wells (table 10).

Oil Production

Figure 8 shows the seasonal weekly oil production average for April-December of the years 1976 through 1987. It is evident that the oil production has not been this high since 1982. When comparing the increase for this period in 1987 and 1986, there appears to be about a 25% improvement in oil production rate in the treated portion of the Mink Unit, and a 13.5% improvement in oil production rate in the whole Mink Unit.

Backflush Analyses

Backflush samples were analyzed for the four treated injection wells, and microbial counts, surface tensions, and pH measurements were taken. Table 11 shows the data for these analyses. Note that the microbial counts increased from 10^4 to 10^7 cells from the 22nd to the 26th week post-injection. This increase is probably due to the amount of molasses reaching an acceptable concentration level in the near wellbore region after 22 weeks of injection. The count has since remained this high. All microorganisms that were injected have been observed in these backflush samples.

Gas Analyses

Gas chromatography has shown that in two of the producing wells, S-AP-2 and S-P47R, there are compounds present with corresponding retention times to those obtained in Berea sandstone corefloods with the same NIPER Bac 1 (figures 9 and 10). Note that in well C-CP-3, a well that is farther from the injection wells, no compounds have been detected. The compounds have been tentatively identified as propionic acid and ethanol in well S-P47R, as well as isopropanol in well S-AP-2. This indicates that microbes are metabolizing nutrient in situ and that the products of the fermentation are propagating through the reservoir.

MODELING THE MINK MEOR UNIT

Preliminary estimates of the oil recovery from the Mink Unit were obtained using DOE's polymerflood predictive model. This model treats the reservoir as several tanks (layers) and estimates recovery based on similar fields. This model works well for overall values like annual or total oil recovery; but not for details like breakthrough time or concentrations. One advantage of this model is the inclusion of economics.

Some work was also done using BOAST II, a three-dimensional, three-phase black oil model. This model worked well for waterflood prediction and history matching but was abandoned because it couldn't really predict polymer or microbial oil recovery. This model also has difficulty predicting breakthrough of an injected fluid or tracer.

The University of Texas Chemical Flood Simulator was used for the studies reported here. The version used (3.2) is a three-phase, eleven component, three-dimensional cartesian, finite difference simulator that uses implicit pressure, explicit concentration solution method. For preliminary studies the reservoir was represented by a three 8-foot layers with permeabilities of 135, 40, and 15 millidarcies, respectively. Other model characteristics are shown below. Tracer studies using one-quarter of a five-spot and rates equivalent to the highest rate by an injection well (S-BW-2) of 35 barrels per day were run with this model. A reasonable history match of recent waterflood data was obtained. However, tracer breakthrough times were between one and two years and increased EOR production was barely detectable until three years and didn't peak until ten years after injection.

Later studies used a four layer model with a 1-foot thick layer with 200 md and three 8-foot layers with permeabilities of 100, 40, and 15 md respectively. Various ways of ordering the layers were tried with high permeability at the top decreasing to the lowest permeability at bottom was selected as the overall best representation. Vertical permeability was 2 md in the top 2 layers and 1 md in the bottom two. The waterflood history match shown in figure 10 and table 13 used a five-spot pattern with injection rates matching the 4 injection wells in the pilot area (35,13,5, and 31 bbl per day) to represent the Mink Unit. Tracer breakthrough times were decreased but still greatly exceed field results. The addition of a thinner high (greater than 1,000 md) permeability layer is currently being considered with thickness and permeability varied to match field tracer and MEOR fluid breakthrough times.

Model Characteristics

Porosity,	0.2
Reservoir pressure, psi	260
Depth to top of formation, ft	600
Water saturation	0.6
Oil saturation	0.4
Residual oil	0.3
Oil viscosity, cP	7.0
Water viscosity, cP	0.7
MEOR viscosity, cP	3.4

Although the results of these preliminary simulations are not accurate in detail, the overall predictions should be reasonable. Based on 16 months of production data, these predictions are that oil production will increase for several years peaking after 6 ±2 years. Oil recovery is dependent on MEOR injection time (see table 14).

DISCUSSION

It appears that the injection of microorganisms and molasses has improved the oil production rate in the Mink Unit. There are several supporting findings for microbial activity in the field. First and foremost, nothing has

been changing operationally since the beginning of this test. No new wells have been drilled, and all injection pressures, as well as injection volumes have remained stable. We have observed a reduction in the surface tension of the produced water from all monitored producing wells, indicating that a surface active agent is being produced. Products very similar to those obtained from NIPER Bac 1 metabolizing molasses in Berea sandstone cores have been detected in two of the producing wells. The microbial populations in the backflush samples are still very high, and some injected microorganisms have been detected in the produced waters from the production wells. Some of the monitored parameters, surface and interfacial tensions, water/oil ratios, fluorescein and microbial responses, and crude oil viscosities were ranked for each producing well. The rankings were averaged and compared with the field ranking determined by producer distances and fluid production and injection well volumes. In figure 11, the average ranking for each well was compared with the field ranking, and in 8 of 10 wells, the rankings corresponded very well, which indicates that the responses we are observing were expected. Only two wells, C-CP-1 and S-BP-2, are not very well correlated. C-CP-1 has a better average ranking than its field rank indicates, and S-BP-2 has a better field ranking than the average response ranking. Overall, it appears that the two key wells, S-P47R and S-AP-2, are responding as predicted by their proximity to the injection wells.

CONCLUSIONS

This microbial waterflood project has successfully demonstrated that such a field injection of microorganisms can be implemented in an ongoing waterflood. The injection of microorganisms and molasses has improved the rate of oil production at the Mink Unit Project Site by approximately 13%. The average water/oil ratio at all monitored producing wells in the Mink Unit has decreased from the baseline average value, some by as much as 30%. No adverse effects on injectivity have been caused by the microbial treatment, since monitored injection pressures have remained constant. Some of the injected microorganisms have been able to propagate through the formation from an injection well to a production well, although the numbers of microorganisms are not nearly as high as the numbers found in the injection well backflush samples. By comparing the average rankings of several monitored parameters, the wells predicted to respond more quickly to the microbial treatment are indeed showing the most change.

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TABLE 1. - Average reservoir properties for Mink Unit

Formation	Bartlesville sandstone
Depth, ft	600
Net pay thickness, ft	30
Permeability, md	60
Porosity, %	20
Formation temperature, °F	65
Number of injection wells	21
Average water injection rate per well, bbl/d	40
Injection pressure, psi	530
Average oil production rate for Mink Unit, bbl/d	6.4
Oil gravity, °API	34
Oil viscosity, cP @ 77° F	7

TABLE 2. - Average total produced fluid for monitored wells

Well	Average total produced fluid, bbl/d
C-BP-2	169
C-CP-1	43
C-CP-3	56
S-AP-1	76
S-AP-2	27
S-P47R	193
S-AP-4	43
S-BP-1	168
S-BP-2	115
S-BP-3	36

TABLE 3. - Fluorescein results and rankings

Well	Area of integrated curve, cm ² A	Average total produced fluid, bbl/d	Ratio A:B	Rank
C-BP-2	6.07	169	0.036	10
C-CP-1	5.38	43	.125	5
C-CP-3	12.0	56	.21	3
S-AP-1	15.87	76	.209	4
S-AP-2	7.45	27	.276	1
S-P47R	11.73	193	.06	7
S-AP-4	9.37	43	.218	2
S-BP-1	7.73	168	.046	8
S-BP-2	4.42	115	.038	9
S-BP-3	2.35	36	.065	6

1 = most response.

10 = least response.

TABLE 4. - Microbial coreflooding results for design of field formulation

Core	k	Injected	S _{owf}	S _{ocf}	E _r	Shut in period, days
MSC 10	214	INJECTECH1	30.2	28.8	4.6	7
MSC 14	180	INJECTECH2	38.5	36.6	4.9	5
MSC 15	181	INJECTECH3	33.9	31.7	6.6	7
MSC 21	99	INJECTECH4	36.4	35.1	3.6	10
MSC 22	133	NIPER BAC 1	36.9	30.0	18.7	10
MSC 23	52*	NIPER BAC 1	31.5	22.6	28.3	6
MSC 24	162	NIPER BAC 1	38.6	34.2	11.9	4

* = Unpreserved field core from Delaware-Childers field.

k = Absolute permeability to brine in millidarcies.

Injected = source of microbial solution injected.

S_{owf} = Residual oil saturation in core after waterflooding (%PV).

S_{ocf} = Residual oil saturation in core after microbial treatment (%PV).

E_r = Recovery efficiency,

$$\frac{S_{owf} - S_{ocf}}{S_{owf}} \times 100\%$$

All cores were unfired Berea sandstone. Cores were injected with 0.2 PV of microbial solution and 0.3 PV OKC molasses, shut in for the designated time period, and waterflooded at 1 ft/d.

TABLE 5. - Monitored parameters of field test

Parameter			Sampling time	Wells sampled
Total dissolved solids			Weekly	Each producer, plant water
pH			Weekly	Each producer, plant water
Surface tension			Weekly	Each producer, plant water
Oil viscosity			Biweekly	Each producer
Interfacial tensions			Biweekly	Each producer
Aerobic and facultative microbial populations			Weekly	Each producer, plant water
Anaerobic microbial population			Weekly	Each producer, plant water
Sulfate-reducing bacterial population			Weekly	Each producer, plant water
Molasses concentration			Weekly	Each producer, plant water
Aerobic and facultative microbial population			Monthly	Each (4) injection well
Surface tension			Monthly	Each (4) injection well
pH			Monthly	Each (4) injection well
Gas analysis			Every few months	Random producers

TABLE 6. - Total dissolved solids values for each producing well

Well	Base avg., %	Post avg., %
C-BP-2	0.66 ±0.02	0.67 ±0.06
C-CP-1	1.08 ±0.04	0.96 ±0.08
C-CP-3	1.12 ±0.01	1.08 ±0.07
S-AP-1	0.66 ±0.03	0.65 ±0.05
S-AP-2	1.06 ±0.10	1.05 ±0.06
S-P47R	0.28 ±0.03	0.29 ±0.02
S-AP-4	0.73 ±0.03	0.67 ±0.03
S-BP-1	0.48 ±0.03	0.48 ±0.04
S-BP-2	0.56 ±0.10	0.51 ±0.04
S-BP-3	0.48 ±0.02	0.49 ±0.03
Tank battery	0.50 ±0.02	0.51 ±0.04
Plant Inj.	0.03 ±0.006	0.03 ±0.01

TABLE 7. - pH values for each producing well

Well	Base avg	Post avg
C-BP-2	6.62 ±0.26	6.65 ±0.20
C-CP-1	6.60 ±0.29	6.68 ±0.20
C-CP-3	6.53 ±0.18	6.69 ±0.21
S-AP-1	6.63 ±0.15	6.66 ±0.28
S-AP-2	6.53 ±0.26	6.62 ±0.17
S-P47R	6.53 ±0.11	6.66 ±0.28
S-AP-4	6.55 ±0.13	6.69 ±0.15
S-BP-1	6.65 ±0.18	6.75 ±0.20
S-BP-2	6.56 ±0.21	6.74 ±0.19
S-BP-3	6.64 ±0.30	6.71 ±0.19
Tank Battery	6.80 ±0.28	6.69 ±0.16
Plant Inj.	7.40 ±0.09	7.50 ±0.13

TABLE 8. - Surface tension values for each producing well

Well	Base avg., dynes/cm	Post avg., dynes/cm	Decrease, %	Rank
C-BP-2	57	53.7	5.8	5
C-CP-1	56.5	52.3	7.4	2
C-CP-3	58.5	55.9	4.4	7
S-AP-1	57	55	3.5	8
S-AP-2	58	54	6.9	4
S-P47R	58.6	54.2	7.5	1
S-AP-4	58	57.1	1.6	9
S-BP-1	57	54.4	4.6	6
S-BP-2	57.5	53.4	7.1	3
S-BP-3	58	57.3	1.2	10

TABLE 9. - Viscosities of crude oil from each producing well

Well	Base avg., cP @ 77° F	Post avg., cP @ 77° F	Rank
C-BP-2	6.79 ±1.0	7.90 ±0.7	4
C-CP-1	5.88 ±1.4	6.90 ±0.8	3
C-CP-3	6.71 ±1.1	7.17 ±1.0	9
S-AP-1	5.77 ±0.8	6.67 ±0.3	5
S-AP-2	7.44 ±1.4	7.18 ±1.1	10
S-P47R	7.5 ±2.5	9.11 ±0.7	2
S-AP-4	8.11 ±1.6	9.11 ±1.9	7
S-BP-1	6.43 ±1.6	7.90 ±1.2	1
S-BP-2	6.23 ±0.8	7.17 ±0.7	6
S-BP-3	6.92 ±0.9	7.7 ±1.2	8

TABLE 10. - Water/oil ratio values for each producing well

Well	Water/oil ratio		Decrease, %	Rank
	Base avg	Post avg		
C-BP-2	72 ±19	71 ±14	1.8	10
C-CP-1	22 ±11	20 ± 9	8.0	8
C-CP-3	46 ±12	33 ±12	29.0	2
S-AP-1	18 ± 7	16 ± 8	11.8	6
S-AP-2	51 ±21	46 ±17	16.5	5
SP-47R	162 ±70	105 ±39	35.6	1
S-AP-4	77 ±31	71 ±14	8.3	7
S-BP-1	44 ±19	33 ±15	25.6	3
S-BP-2	32 ±18	31 ±17	2.2	9
S-BP-3	46 ±12	37 ±18	19.1	4

TABLE 11. - Backflush sampling results

Well	Aerobic, cfu/ml	Anaerobic, cfu/ml	Surface tension, dynes/cm	pH
<u>Sample 1 - 7 wk post-injection</u>				
S-AW-3	2.3×10^3	2.61×10^4	62	6.1
S-BW-2	7.05×10^2	9.64×10^3	59	6.55
S-BW-3	2.96×10^3	2.66×10^4	65	6.05
C-DW-2	8.66×10^2	1.7×10^4	57.5	6.25
<u>Sample 2 - 10 wk post-injection</u>				
S-AW-3	1.1×10^4	7.4×10^3	64	6.6
S-BW-2	4.5×10^3	6.2×10^3	68.6	7.4
S-BW-3	1.7×10^3	5.1×10^3	63.1	6.8
C-DW-2	3.9×10^3	4.5×10^3	54.8	6.7
<u>Sample 3 - 22 wk post-injection</u>				
S-AW-3	1.24×10^3	5.57×10^4	45	4.3
S-BW-2	1.7×10^2	9.6×10^3	57	6.58
S-BW-3	4.0×10^2	1.44×10^4	53.9	6.42
C-DW-2	1.4×10^3	2.8×10^4	44.3	4.7
<u>Sample 4 - 26 wk post-injection</u>				
S-AW-3	1.09×10^7	1.87×10^7	67.5	5.55
S-BW-2	3.73×10^6	7.75×10^6	65	6.25
S-BW-3	3.13×10^6	9.45×10^6	68.5	6.35
C-DW-2	1.02×10^7	4.37×10^7	51.5	5.4
<u>Sample 5 - 34 wk post-injection</u>				
S-AW-3	5.46×10^7	2.04×10^7	62.5	5.6
S-BW-2	7.09×10^7	2.41×10^7	64	5.9
S-BW-3	4.11×10^8	1.26×10^7	65	5.55
C-DW-2	1.82×10^7	5.39×10^7	52	5.5

TABLE 11. - Backflush sampling results (cont'd.)

Well	Aerobic, cfu/ml	Anaerobic, cfu/ml	Surface tension, dynes/cm	pH
<u>Sample 6. 41 weeks post injection</u>				
S-AW-3	9.88 X 10 ⁶	1.98 X 10 ⁷	53.9	5.55
S-BW-2	2.16 X 10 ⁶	8.80 X 10 ⁶	51.2	5.19
S-BW-3	1.66 X 10 ⁶	1.77 X 10 ⁷	46.1	5.05
C-DW-2	2.07 X 10 ⁶	2.60 X 10 ⁷	45.0	4.65
<u>Sample 7. 46 weeks post injection</u>				
S-AW-3	*	3.9 X 10 ⁸	52	4.1
S-BW-2	*	4.3 X 10 ⁸	57.5	5.05
S-BW-3	*	1.45 X 10 ⁷	60.5	5.9
C-DW-2	*	8.0 X 10 ⁸	48	4.7
<u>Sample 8. 50 weeks post injection</u>				
S-AW-3	1.01 X 10 ⁷	8.1 X 10 ⁷	50.5	4.9
S-BW-2	1.17 X 10 ⁷	3.8 X 10 ⁷	54.3	6.03
S-BW-3	4.09 X 10 ⁶	1.0 X 10 ⁷	55.5	6.1
C-DW-2	1.83 X 10 ⁷	4.4 X 10 ⁷	48	4.8
S-DW-1**	1.40 X 10 ³	2.6 X 10 ⁴	62.5	7.1

*Aerobic counts were not obtained.

**S-DW-1 is an off-pattern control well that was sampled.

TABLE 12. - Total ranking values for producing wells, March 18, 1988

Well	Visc	S.T.	IFT	WOR	Fluor	Micro.	Avg.	Rank	Field
C-BP-2	4	5	2	10	10	10	6.8	9	10
C-CP-1	3	2	1	8	5	2	3.5	2	7
C-CP-3	9	7	9	2	3	4	5.7	6	5
S-AP-1	5	8	6	6	4	3	5.3	5	4
S-AP-2	10	4	7	5	1	1	4.7	3	3
S-P47R	2	1	5	1	7*	5	3.5	1	1
S-AP-4	7	9	8	7	2	6	6.5	8	9
S-BP-1	1	6	4	3	8	9	5.2	4	6
S-BP-2	6	3	3	9	9	8	6.3	7	3
S-BP-3	8	10	10	4	6	7	7.5	10	8

*May have missed some fluorescein due to sampling times.

Viscosity = % increase in crude oil viscosity, where 1 is highest .

S.T. = % decrease in surface tension from baseline avg, where 1 is highest.

IFT = lowest interfacial tension values, where 1 is lowest (no baseline taken).

WOR = % decrease in water/oil ratio average of baseline and post, where 1 is highest.

Fluor = Integrated area under curve of conc. vs. time/TBD (total bbl fluid/d); where 1 is highest ratio.

Microbial = Rank of 1st appearance of a microbial conc. of 1000 X greater.

Avg. = Average of Visc., S.T., IFT, WOR, Fluor., and Micro. rankings.

Rank - Ranking of the Avg.

Field = Rank according to influence of 4 injection wells.

Table 13.- Mink Unit oil production

Year	Actual Production, Barrels per week	Waterflood Model Prediction
1976	53.9	56.7
1977	54.0	54.6
1978	58.2	53.7
1979	59.8	52.4
1980	55.8	51.1
1981	50.5	50.0
1982	46.5	48.8
1983	46.8	47.7
1984	46.4	46.6
1985	44.8	45.6
1986	45.1	44.5
1987	48.8	43.5
1988	48.4	42.6
1989		41.7
1990		40.7

Table 14. - Effect of MEOR injection time on oil recovery

MEOR injection time, years	Fraction of pore volume injected	Barrels oil recovered per year of injection
1	0.04	1768
2	0.08	844
3	0.12	548
4	0.16	516
5	0.20	488
6	0.24	464

Notes: Only polymer aspects of MEOR are considered and recovery is after 1.0 pore volume injected.

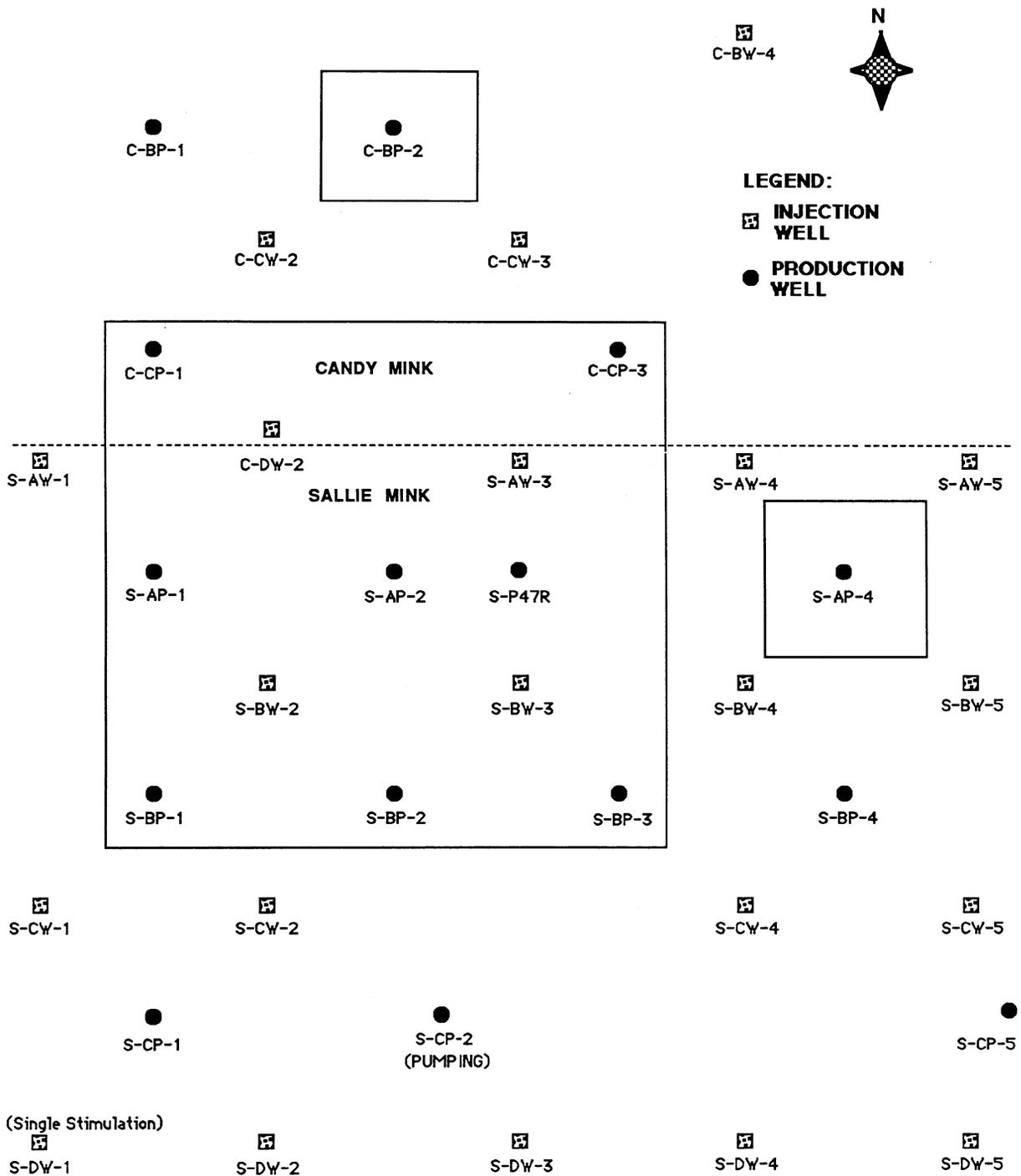


FIGURE 1. - Map of Mink Unit - Delaware Childers field (sec. 36, Typ. 27 N, RGE. 16E).

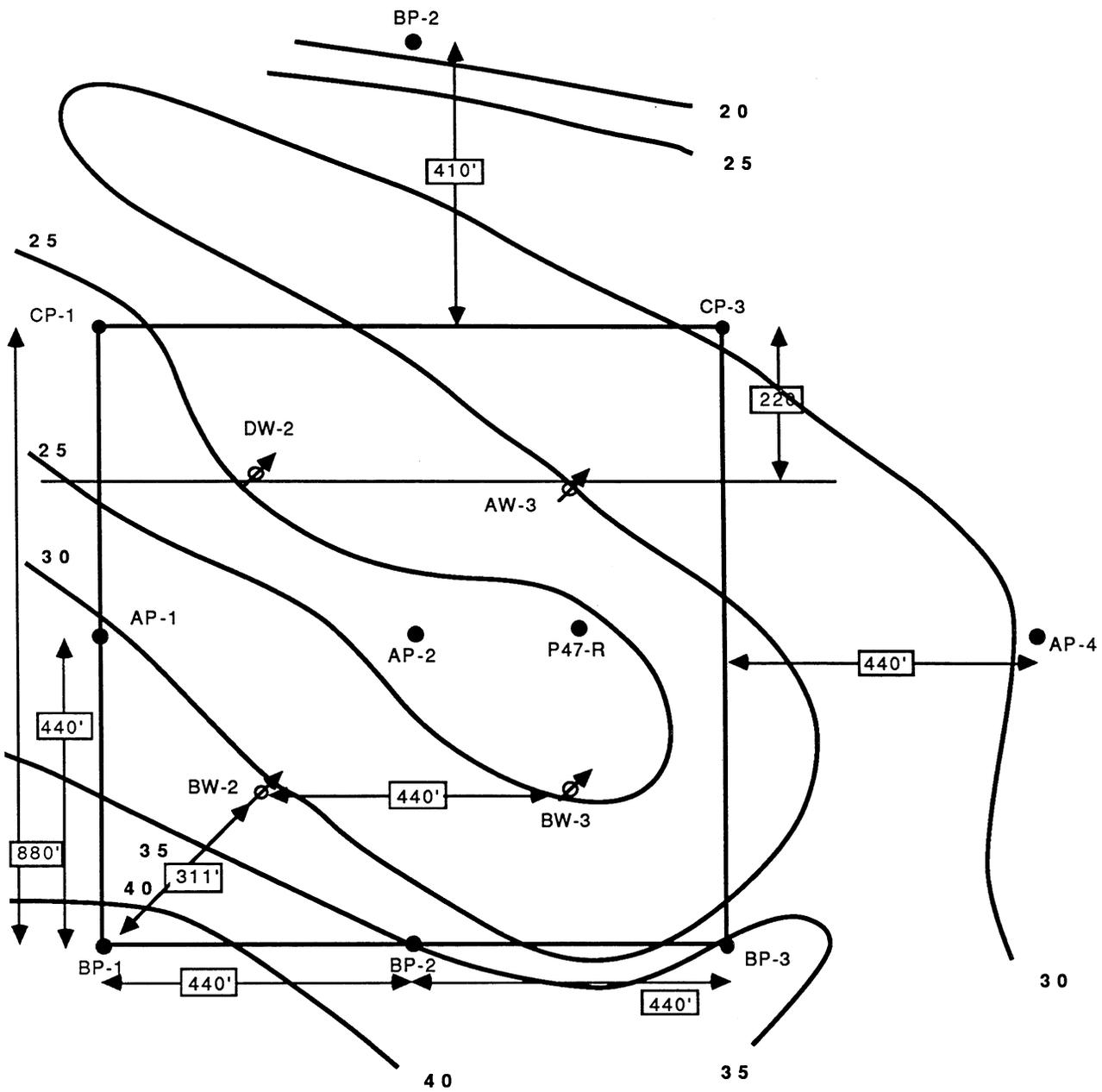


FIGURE 2. - Net pay isopach of Mink pilot area - Delaware Childers field.

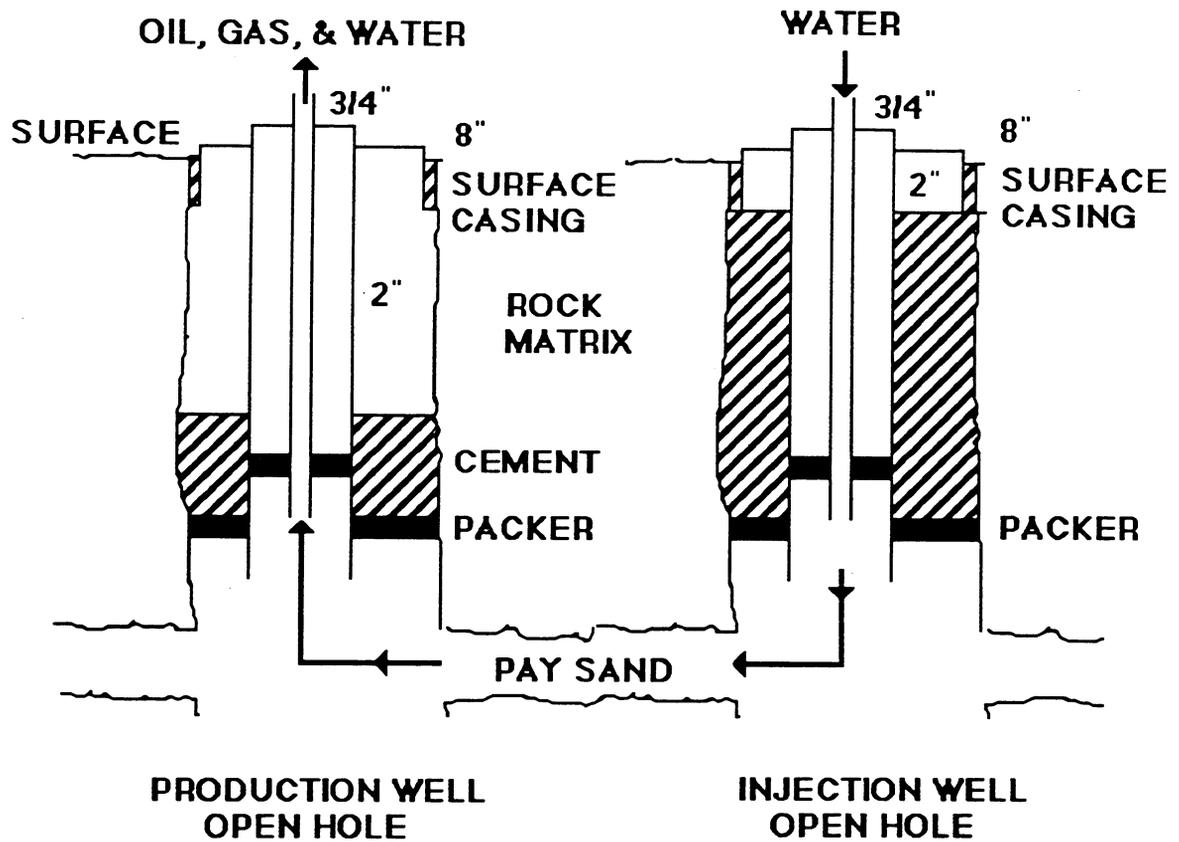


FIGURE 3. - Mink Unit well completion diagrams.

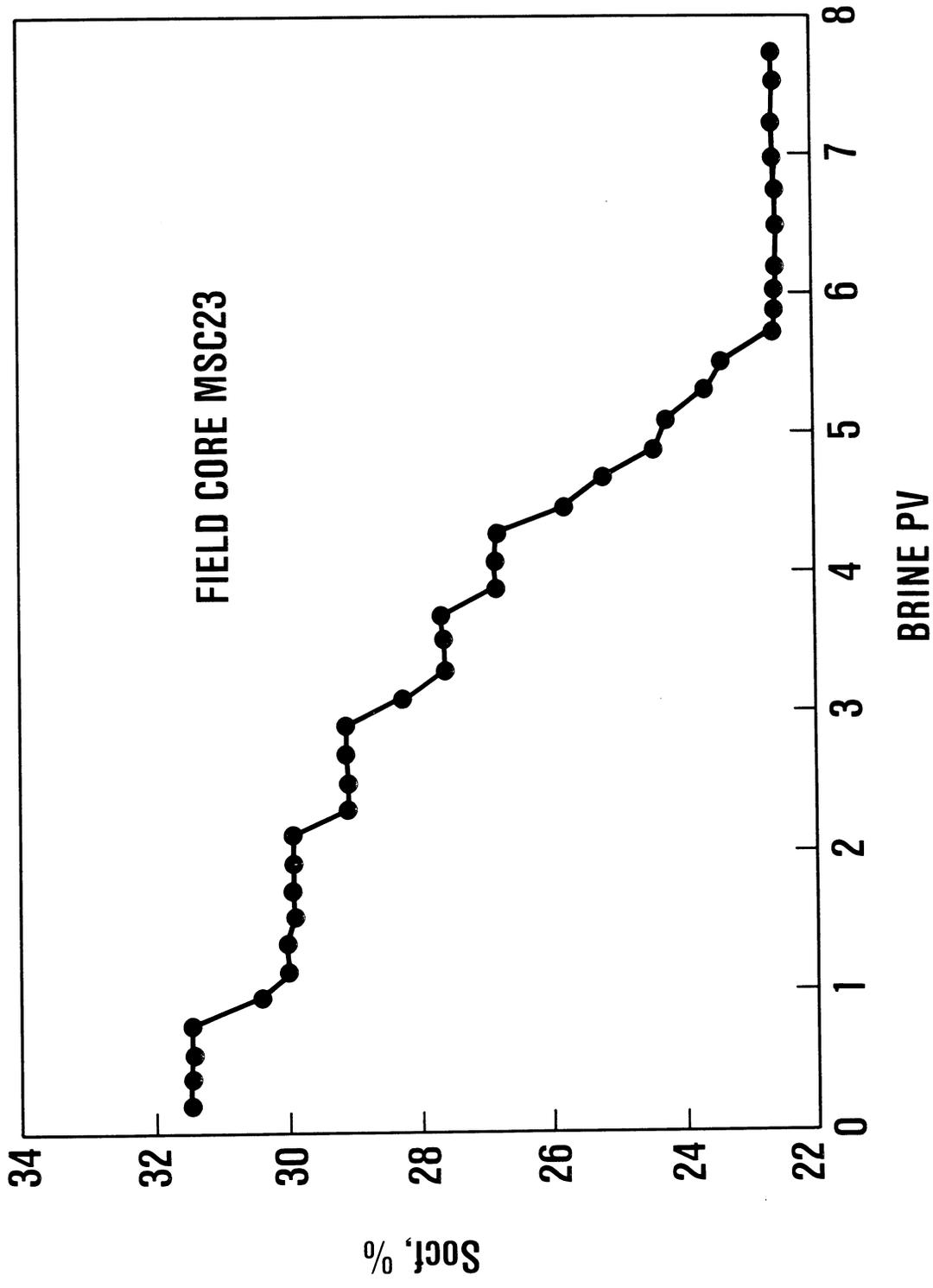


FIGURE 4. - Residual oil saturation versus brine injected of a field core.

AEROBIC

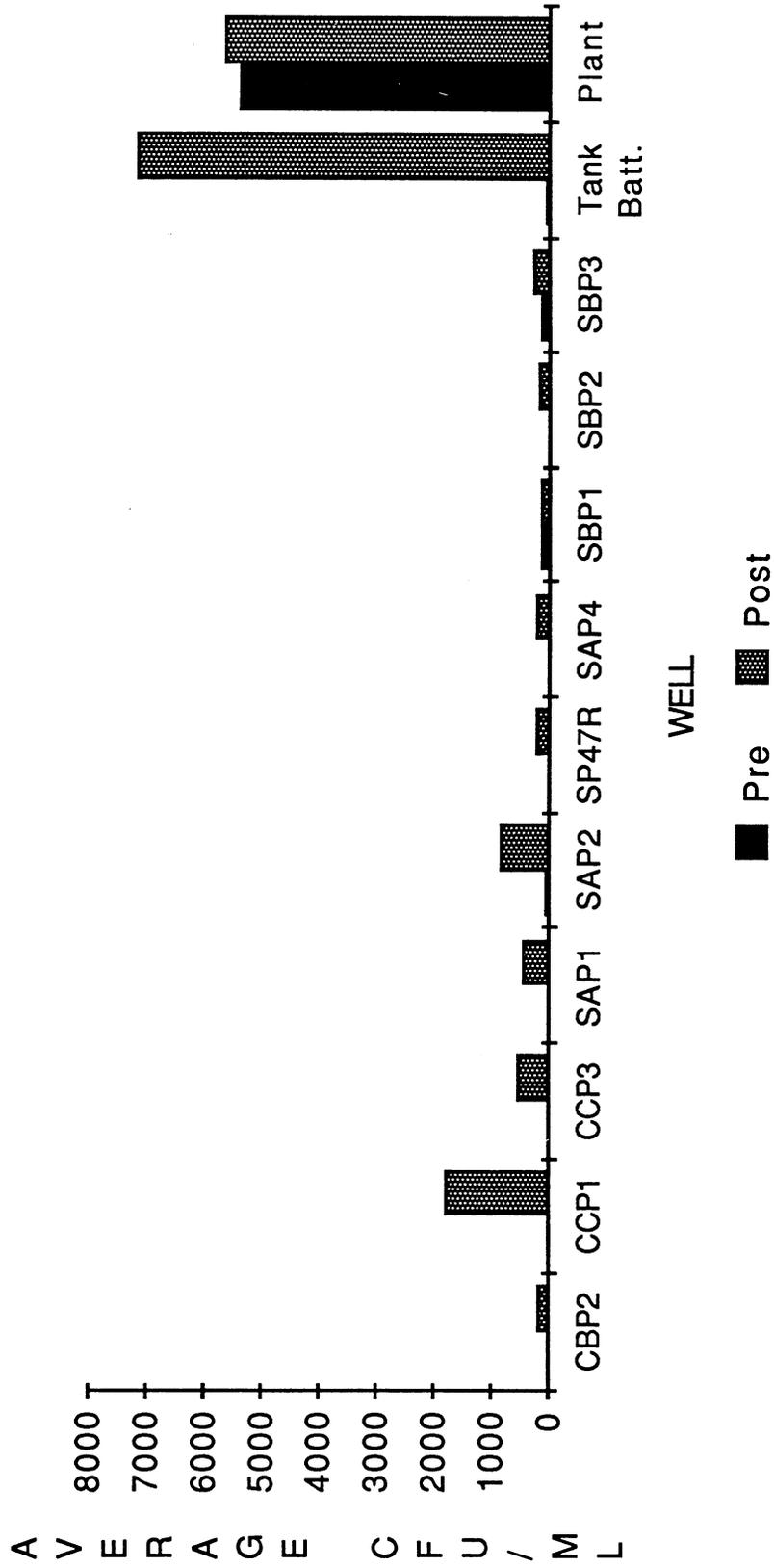


FIGURE 5. - Average aerobic microbial counts of Mink wells.

ANAEROBIC

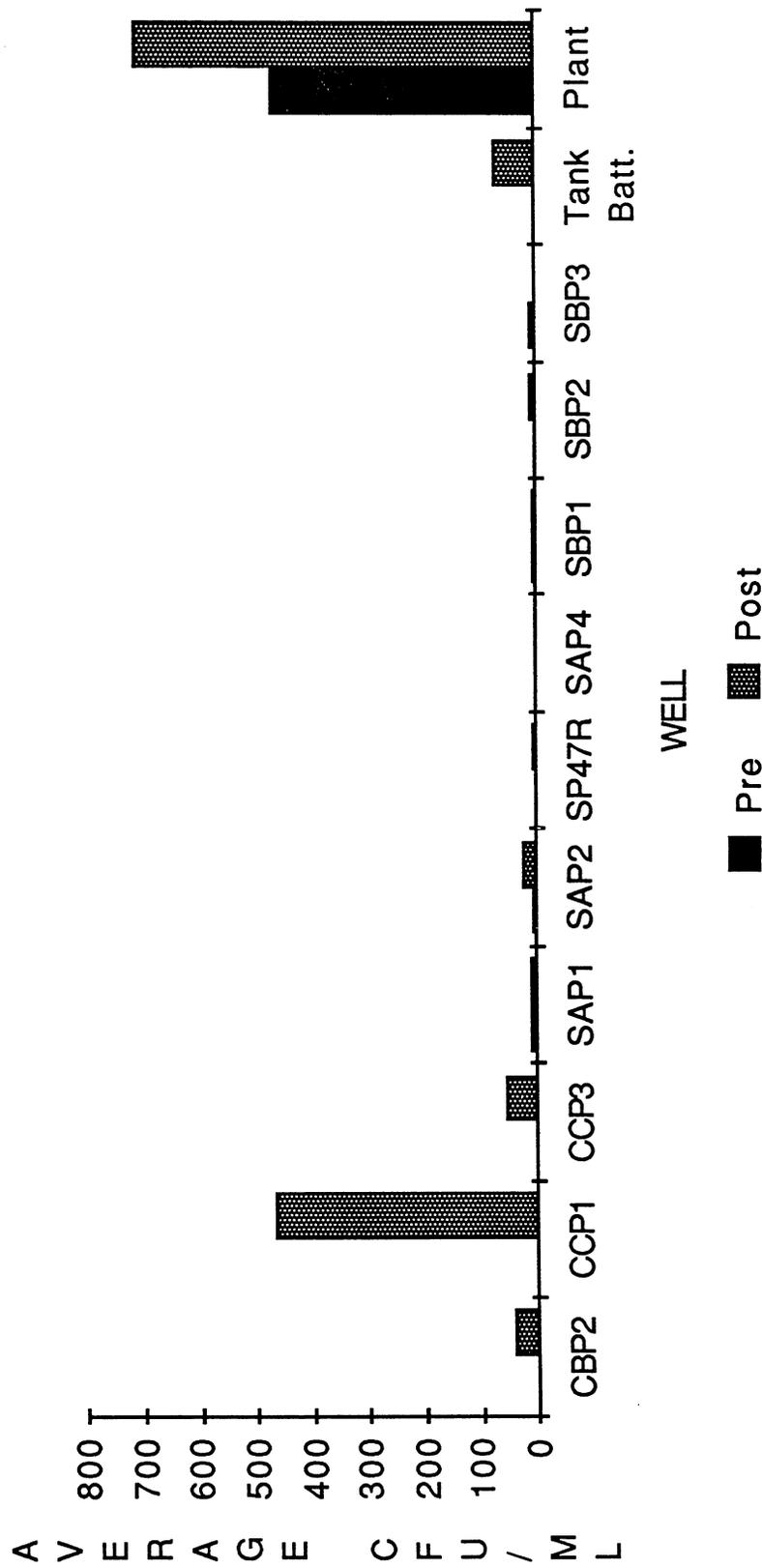


FIGURE 6. - Average anaerobic microbial counts of Mink wells.

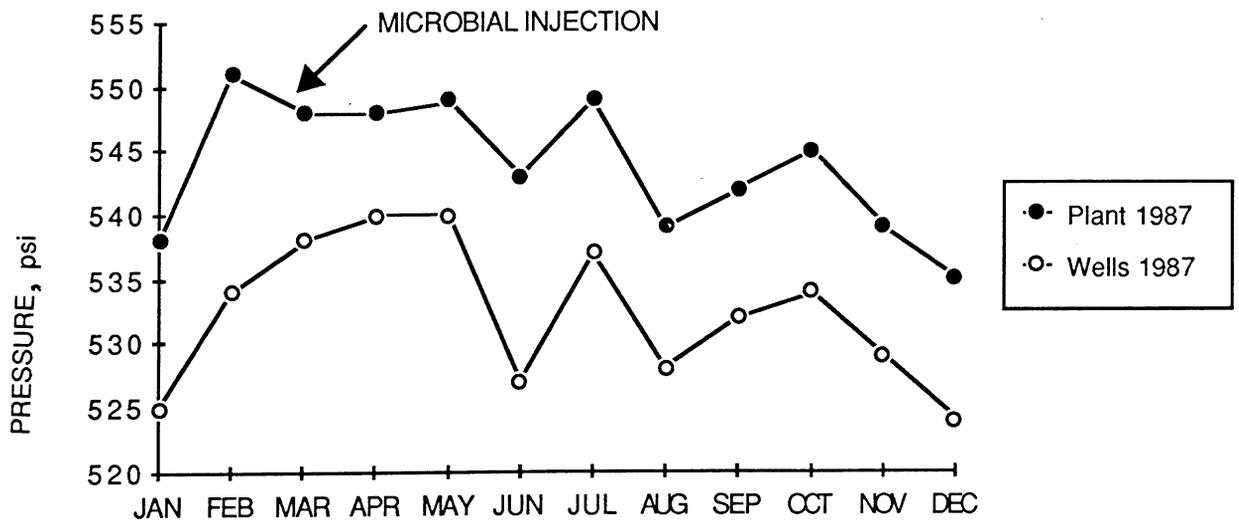


FIGURE 7. - Injection pressures of plant and Mink Unit wells.

MINK UNIT OIL PRODUCTION
SEASONAL AVG/WEEK APR - DEC

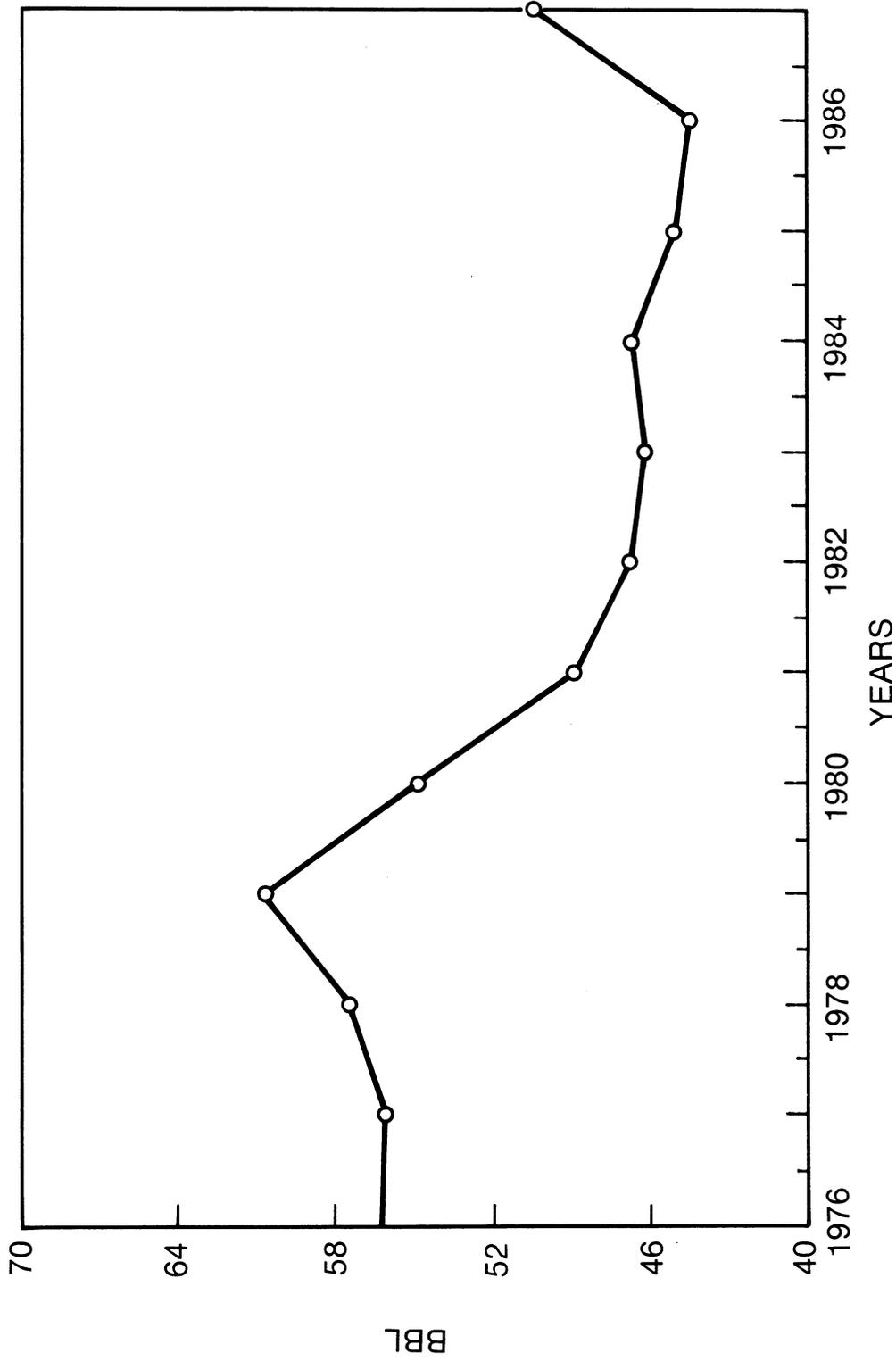


FIGURE 8. - Weekly oil production from the Mink unit.

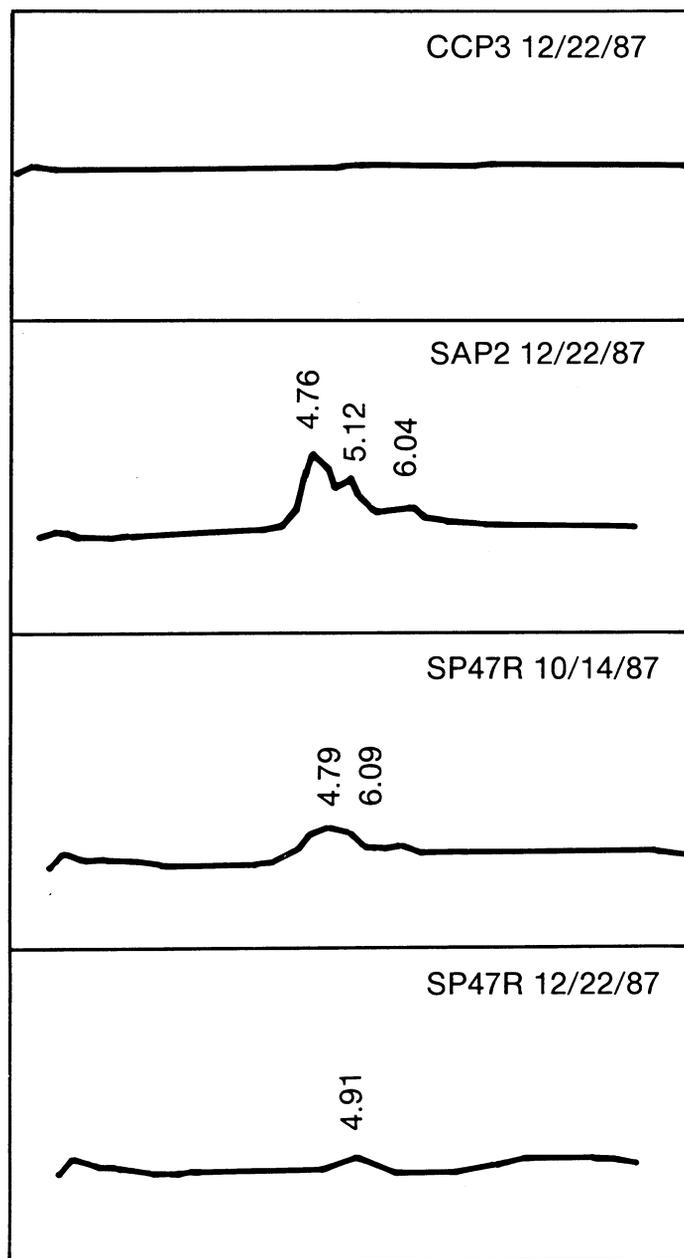


FIGURE 9. - Gas chromatographic analyses of produced water from Mink wells. Retention times of 4.76, 4.79 and 4.91 correspond to ethanol. Retention time 5.12 corresponds to isopropanol, and 6.04 and 6.09 correspond to propionic acid.

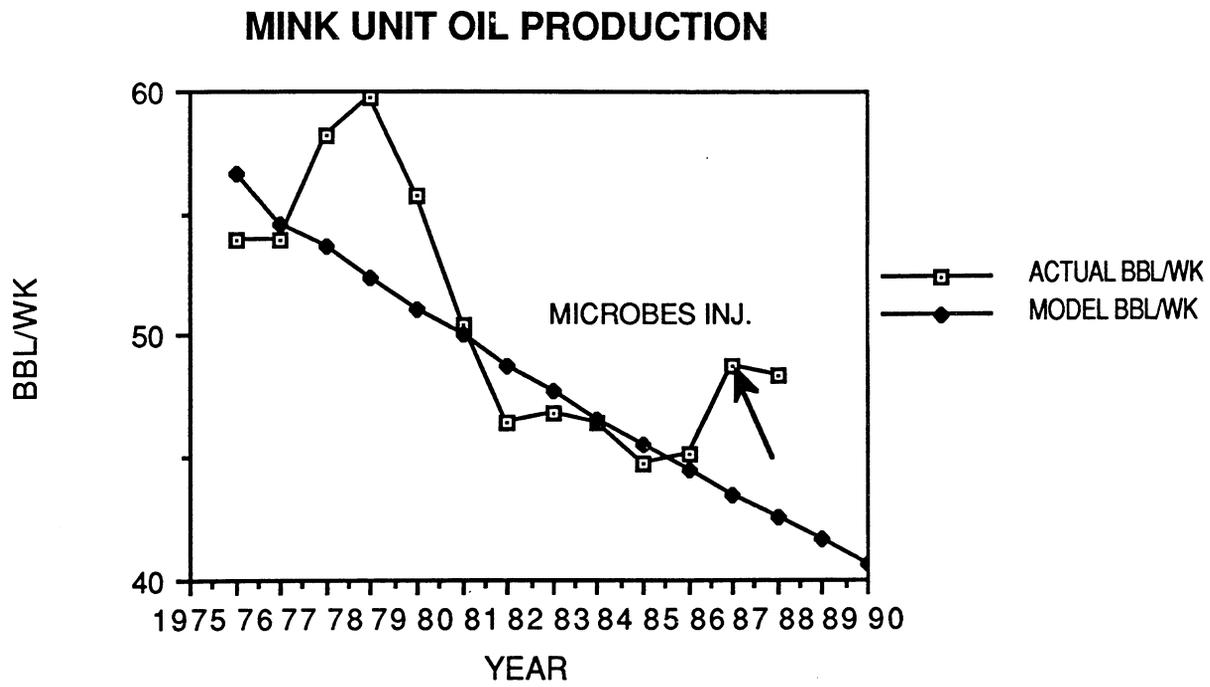


FIGURE 10. - History match of Mink Unit oil production.

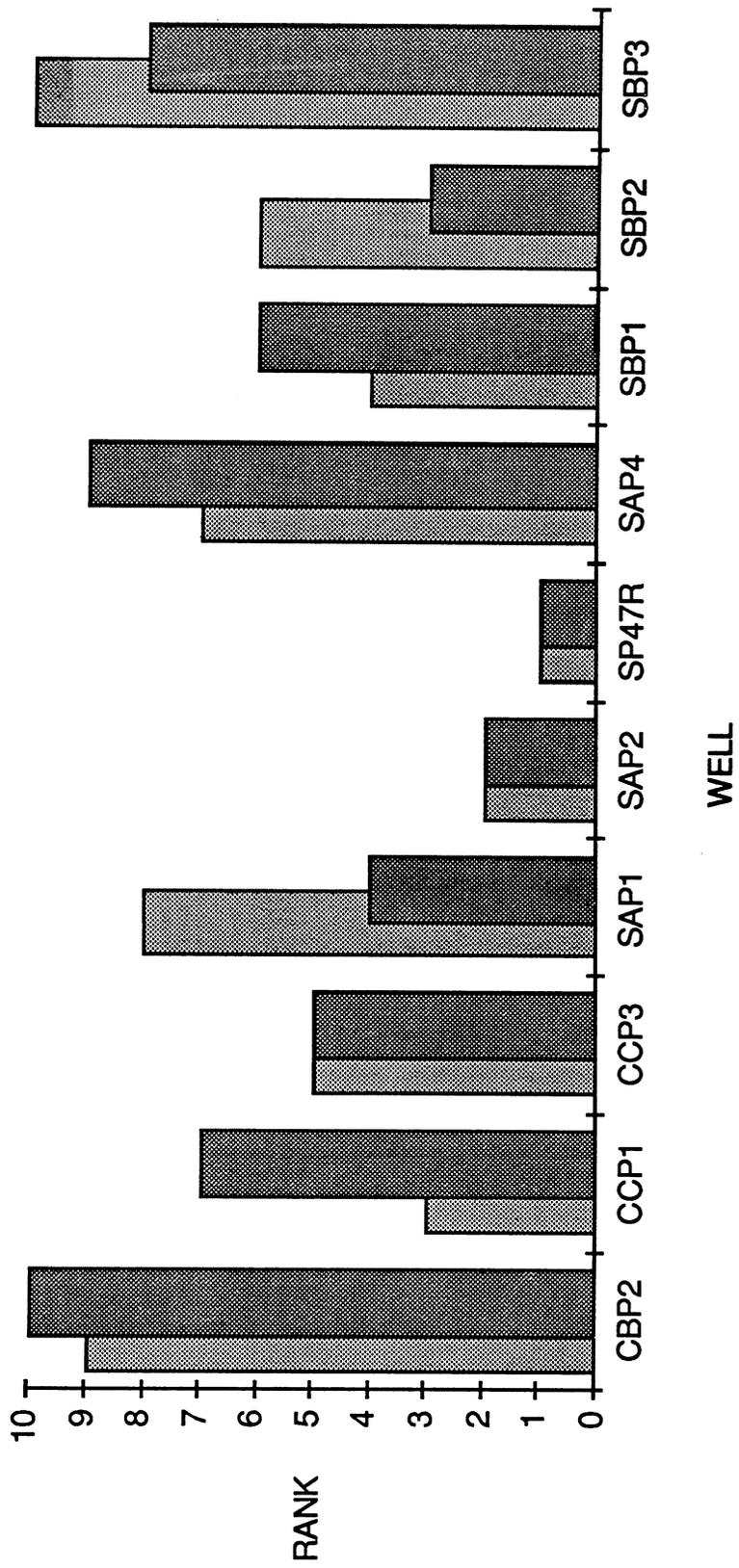


FIGURE 11. - Comparison of well ranking average and field rank average.

