**MICROBIAL ENHANCED WATERFLOODING
MINK UNIT AND PHOENIX FIELD PILOTS**

**Final Report
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ABSTRACT

To determine the feasibility of improving oil recovery and the economics of microbial enhanced waterflooding in mature oil wells in the United States, two field pilots have been conducted. Candidate fields were screened to determine whether they have any potential for a microbial system developed at the National Institute for Petroleum and Energy Research (NIPER), and microbial compatibility tests were conducted in the laboratory to select the target field. A specific microbial formulation was selected that was compatible with the chosen reservoir environment and had been shown to recover oil after waterflooding in Berea sandstone and field core. The microbial formulation was designed to improve microscopic oil displacement efficiency by surfactant, gas and acid production from fermentation of molasses. A 20-acre pilot test was initiated in October 1986, and completed in December 1989. Results from this pilot demonstrated that microorganisms could be injected into an ongoing waterflood and that such injection could increase oil production by at least 13%. A larger test (520 acres) was completed in the same formation to evaluate the feasibility of commercial application of the technology. This field pilot was injected with microorganisms and molasses from a centralized injection station in June 1990. Although microorganisms were injected only once per site, nutrient injection continued throughout the project life. All 19 injection wells were treated, and oil production was monitored from the 47 production wells. Injection pressures and volumes were monitored throughout the project. No operational problems were encountered. At the end of May 1993, oil production was improved by 19.6 %. Results from both projects are presented and the potential for microbial-enhanced waterflooding technology is evaluated.

INTRODUCTION

A DOE Fossil Energy report, "Oil Research Program Implementation Plan" has stressed the need for near-term oil recovery activities by independent petroleum producers for declining oil fields and stripper wells.¹ According to that study, these activities are particularly important because independent operators produce about 40% of the total oil recovered in the United States, but many cannot afford to conduct needed EOR research. Microbial methods for improving oil recovery are potentially cost-effective and particularly well suited for today's economic climate.

The technology is flexible, relatively inexpensive, and can be applied by independent producers. Microbial formulations can be used in a variety of methods including well stimulation treatments, permeability modification treatments, and microbial-enhanced waterflooding. Well stimulation treatments are inexpensive and easy to implement and can provide rapid recovery of nominal investment costs. Microbial-enhanced waterflooding has significant potential for increasing production from aging oil fields that are currently undergoing waterflood. The incremental cost for injecting microbes and nutrient is relatively small in an existing waterflood, which may make this recovery method applicable at low oil prices when more expensive methods are not economically feasible.

The concept of the use of microorganisms to recover oil from depleted petroleum reservoirs is not new. Beckmann first suggested microbial techniques for enhancing oil production.² Field and laboratory research has been performed, and patents have been granted for this technology since the late 1940s. Early microbial enhanced oil recovery (MEOR) patents by Zobell,³ Hitzman,⁴ and Updegraff and Wren⁵ described the use of microorganisms in reservoirs to produce chemicals that could help to mobilize oil. Several literature reviews on MEOR have been published.⁶⁻⁹

Laboratory research has demonstrated that the products from microbial fermentation of nutrients can change the interfacial properties between oil and water, selectively plug high-permeability zones to improve sweep efficiency, and increase wellhead pressures in single-well injections. Some microbial species can also significantly improve oil production by helping to remove suspended debris and paraffins from the near wellbore region.

Microorganisms most commonly used for MEOR field processes that rely on improving the efficiency of microscopic oil displacement are species of *Bacillus* and *Clostridium*. These species have a greater potential for survival under petroleum reservoir conditions than other species because they produce spores, which are dormant, resistant forms of the cells that can survive under stressful environmental conditions. *Clostridium* species produce surfactants, gases, alcohols and solvents, whereas some *Bacillus* species produce surfactants, acids, and some gases.

In microbial-enhanced waterflood applications, it is important that the microbes be capable of moving through the reservoir matrix and producing chemical products that can mobilize oil. The relative rates of transport of the nutrient and microorganisms will affect the injection strategy and design of the microbial system.

A microbial treatment requires careful design and sound reservoir engineering practice, as does any enhanced oil recovery (EOR) method. A microbial-enhanced waterflood field project sponsored by the U. S. Department of Energy (DOE), Microbial Systems Corp. (MSC), and INJECTECH, Inc., and 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 the feasibility of injecting a microbial formulation in a mature, ongoing waterflood, and if such an injection could increase oil production. The microbial formulation was designed to improve microscopic oil displacement efficiency by surfactant, gas and acid production from fermentation of molasses. Molasses was the nutrient of choice because it was readily available in inexpensive (\$100/ton). Based on the the favorable results of the initial pilot, an expanded microbial-enhanced waterflood was initiated in June of 1990. Figure 1 shows the location of these pilots.

FIGURE 1 — Sites of NIPER's microbial enhanced waterflood field pilots.

These particular field experiments were designed to use microorganisms that produced chemicals (surfactants, gases, alcohols, and fatty acids) for improved oil mobilization, and had the ability to transport through porous media. Detailed information about the Mink Unit Project through January 1990 has been published previously.¹⁰

FIELD TEST DESIGN – MINK UNIT

The Mink Unit site, which includes both the Candy and Sallie Mink leases, selected for the project is located in Delaware-Childers field in Nowata County, Oklahoma (Figs 2 and 3). This particular part of Delaware-Childers field was owned by B & N Oil Company when the project was initiated in 1986. The legal description of the Mink Unit is Section 36, Township 27N, Range 16 E of Nowata County.

The 1,200-acre Sinclair Oil and Gas Company Tanner Waterflood, initiated in March 1954, included the Mink leases, the site of the microbial field experiment. Surface water from the nearby Verdigris River has continued to be the source water for this flood since its initiation. The flood has been in continuous operation, although under various owners, to the present time.

At the beginning of the microbial project, the Mink leases were determined to have an average porosity of 20%, an initial average oil saturation of 32.6%, and a combined net pay bulk volume of 2,900 acre-feet. Cumulative oil production from the two leases was 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.

In 1988, as a result of the sale of this oilfield, cores were drilled on the Mink Unit and Brown leases of this field, and data from core analyses were provided by the new owners to NIPER. The average permeability was 90 millidarcies, which was higher than that of some of the earlier core analyses, and the average porosity was 19.1%.

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

FIGURE 2 — Map of Mink Unit - Delaware-Childers field (S36-T27N-R16E).

FIGURE 3 — Pilot area of Mink Unit showing well spacing in feet.

TABLE 1
Reservoir Properties for Mink Unit

Formation	Bartlesville sandstone
Depth, ft.....	600
Average net pay thickness, ft.....	30
Average permeability, mD	90
Porosity, %	20
Average formation temperature, °F.....	75
Number of injection wells.....	21
Number of production wells.....	15
Average water injection rate, bbl/d.....	40/well
Average injection pressure, psi.....	530
Average oil production, bbl/d/well	0.4
Oil gravity, ° API.....	34
Oil viscosity, cP @ 77° F.....	7
Total dissolved solids of injection water, %.....	0.03
Average total dissolved solids of produced water, %.....	0.5
Average oil saturation, % (at start of project).....	33

FIELD OPERATIONS – MINK UNIT

A chemical tracer study was implemented during the baseline period (December 1986) to determine: (1) the flow patterns of the injected fluids in the Mink Unit; (2) if any gross channeling existed; and (3) if there was communication among all producing wells and the four treated injectors. Each producing well was sampled daily for the first 5 days after tracer injection, then biweekly sampling was continued until no fluorescein was detected in the production wells. Samples were protected from light and transported to NIPER where the fluorescein concentration was determined using a spectrophotometric method. The tracer studies seemed to indicate a northeasterly flow pattern (Fig. 2) because wells C-CP-1 and C-CP-3 and S-AP-4 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.

Using simulation studies, it was anticipated that tracer would begin to break through the formation about 1.5 years after injection. We began to conduct intermittent sampling for tracer about this time. Fluorescein was again observed about 1.8 years after injection. The persistence of this response indicated that the tracer had just transported through the matrix of the formation, and that the earlier response of tracer was due to low-volume, high-permeability streaks in the formation. Of the wells sampled, the fluorescein appearance again indicated a northeasterly flow

pattern, because C-CP-1 and C-CP-3 showed fluorescein in high amounts, as did S-AP-2, the middle well.

The tracer results obtained were consistent with reports from a micellar-polymer pilot conducted on a nearby lease.¹¹ Chemical tracers (ammonium thiocyanate and isopropyl alcohol) were used in that study; however, no breakthrough of the tracers was ever detected in the produced water. Later, after injection of the micellar-polymer solutions, polymer was detected in off-pattern wells to the northeast of the pilot site, which indicated a directional permeability flow from the southwest to the northeast.

The Bartlesville sandstone is a Cherokee Group, Desmoinesian Series, Middle Pennsylvanian System fluvial-dominated deltaic deposit.¹² Ultimate recovery of oil from reservoirs in the Cherokee Group is affected by facies, bedding boundary and other permeability barriers, and diagenetic changes. Because of these factors, permeability trends such as those observed in Delaware-Childers field would be fairly common.

Injection of NIPER Bac 1 and Molasses

Twenty-six gallons (0.65 bbl) of a microbial formulation, NIPER Bac 1, was injected into each of the four targeted injection wells, C-DW-2, S-BW-2, S-AW-3, and S-BW-3 (Fig. 3). 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 molasses diluted to a concentration of approximately 4% was injected into each well periodically during 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, when water injection was resumed. The other 17 injection wells in the Mink Unit were still in operation during the shut-in period. After water injection was resumed, the injection wells were backflushed to determine if microbial activity could be observed. Samples of water backflushed from the treated injection wells foamed when shaken, indicating surfactant production and that the microbial populations were viable. Subsequently, the four injection wells received the equivalent of 2 gal/d/well of undiluted molasses until September 21, 1989.

PROJECT EVALUATION – MINK UNIT

The sequence of events in this project is briefly outlined in Fig. 4. Field sampling for baseline values began in November 1986, and continued to March 17, 1987. The data from these studies showed that the total dissolved solids (TDS), pH, oil viscosities, and microbial counts were consistent during this period. Field data, including injection pressures and volumes, oil

production, and water/oil ratios all remained fairly constant during the baseline monitoring period. Detailed results from the studies were presented in the Mink Unit Final Report.¹⁰

FIGURE 4 — Sequence of events in the Mink Unit Project.

In May 1988, a portion of Delaware-Childers field was sold which included the Mink Unit leases. Immediately after this sale, the new owners began an extensive drilling program and constructed a new waterflood injection facility. When the drilling was started, a large amount of gas was encountered which caused total fluid production in the Mink Unit to decrease dramatically. During the remainder of the monitoring period through December 1989, the oil production never achieved the levels prior to the drilling activity. Since 1989, all of the original Mink Unit wells have been plugged, and a total of 350 new wells have been drilled.

Injection pressures at the microbially treated injection wells did not increase throughout the duration of the microbial treatment. Injection pressure monitoring was critical to this microbial-enhanced waterflood experiment. In NIPER laboratory coreflooding experiments, no facial plugging was ever observed by NIPER Bac 1. Later coreflood experiments with similar microorganisms indicated that microorganisms and their products transport at reasonable rates

through porous media.¹³ Based upon laboratory and field results, we conclude that no adverse plugging effects have occurred because of the microbial injection.

The average water-oil ratios (WOR) at all monitored production wells in the Mink Unit decreased when compared to the averages during the baseline period (Fig. 5). These WORs have high standard deviation values, primarily because of gas production in the wells, which causes large fluctuations, but the overall averages have definitely decreased, and in wells S-P47R and C-CP-3, the decrease is significant. Note that in the two off-pattern wells, S-AP-4 and C-BP-2, the WOR has not decreased; thus, the microbial treatment has probably affected those wells closest to the injectors.

Oil production increased since the microbial injection through May 1988 (Fig. 6). After the infill drilling and hydraulic fracturing occurred, the wellhead pressures at some of the nearest Mink Unit producers were much lower, as was the total produced fluid. The MEOR injection had a positive effect on oil production until the drilling and hydraulic fracturing activity occurred. Table 2 and Fig. 6 show the predicted and actual average production for 1981-1990. Since that time, actual oil production has dropped significantly below the predicted decline curve.

FIGURE 5. — Average water-oil ratios of monitored Mink Unit producers.

TABLE 2
Predicted and Actual Oil Production Rates for the Mink Unit

Year	Production, Pred. avg bbl/wk	Production, Actual avg bbl/wk
1981	50.0	50.5
1982	48.8	46.5
1983	47.7	46.8
1984	46.6	46.4
1985	45.6	44.8
1986	44.5	45.1
1987	43.5	48.8
1988A ¹	42.6	48.2
1988B ²	42.6	46.5
1989	41.7	36.3
1990	40.7	26.3

¹ 1988A - Jan. 1 - May 31.

² 1988B - Jun. 1 - Dec. 31.

FIGURE 6. — Predicted and actual average oil production for Mink Unit during 1981-1990.

Economic Analysis - Mink Unit

Limited economic analyses of the Mink Unit field pilot showed that the major cost of a microbial-enhanced waterflood would be the nutrient support for the microorganisms. When determining the cost per incremental barrel of oil for the Mink Unit, the following assumptions were made: (1) No cost was assigned for the research and development of the microbial formulation; (2) The cost for equipment for this particular microbial injection was less than \$500; and (3) Because the microbial population was not overfed, the total effect of the

microbial injection may not have been attained. Since the chemical tracer began to appear only after 1.8 years (22 months) of injection, based on preliminary data from early breakthrough of tracer, microorganisms should have begun to appear in the production wells about 0.6 - 0.8 year (7-10 months) after the tracer appearance. Unfortunately, this would have been about the time that infill drilling near the Mink Unit began, and the sampling period ended.

During the 14 months of microbial/nutrient injection before infill drilling and hydraulic fracturing activity, 577 bbl of incremental oil was obtained when compared to the predicted oil recovery by waterflooding alone. A total of 18.7 tons of molasses was injected during this period. Using a nutrient cost of \$100/ton, this is equivalent to \$3.24/bbl of incremental oil. This does not take into account any other injection costs, although for this particular project, the costs were fairly minimal. Field personnel were used for the daily injection of the molasses. However, this analysis also does not include any projected recoveries beyond the time of infill drilling. Detection of fluorescein in the Mink Unit producing wells after the infill drilling in the Tanner lease, indicates that the microbial treatment had not yet transported through the formation matrix; thus, the complete effect on incremental oil production that may have occurred would have been masked.

FIELD TEST DESIGN - PHOENIX SITE

In May 1988, Comdisco Resources, Inc. purchased property in the Delaware-Childers oilfield from B & N Oil company. The Mink Unit leases were a part of this purchase. After much negotiation, an agreement was executed on April 18, 1989, by Microbial Systems Corporation (MSC) and Comdisco Resources, Inc. (Comdisco) that financially compensated the project for relocating the planned expansion of the project in three nearby leases in the B & N property of Delaware-Childers field to an alternate site. With DOE's approval, MSC and NIPER began to search for the new site; which ideally would have the same or similar properties to that of Delaware-Childers field.

Compatibility tests were conducted with reservoir fluids from three nearby waterfloods and selected microorganisms from the NIPER microbial culture bank. Based upon these studies, a new field site was selected. The site selected for the MEOR project site is in Section 8, Township 24 North, Range 17E of Rogers County, Oklahoma. This site is part of Chelsea-Alluwe field in the Bartlesville formation and was initially developed soon after Delaware-Childers field. The site is currently being waterflooded and owned by Phoenix Oil and Gas, Ltd. An isopach and top of structure map indicated fairly uniform gross thickness of the Bartlesville Formation, over the area of about 32 – 38 ft. Table 3 lists the reservoir data for the five leases in

this site. This field is in an isolated area, with virtually no other oil-producing leases nearby. Porosity was obtained from the compensated density logs to estimate the average porosity and net pay thickness.

Four core analyses were available from wells drilled in 1981 which were also logged and the data compared. Figures 7 through 9 show some of the results of these core analyses. Porosities from the logs averaged about 1% lower than that of the core analysis and were adjusted accordingly. The net pay thickness was estimated to be 60% of the gross thickness. Using these data, the gross formation, net reservoir and pore volumes were estimated for the portion of each lease under production.

TABLE 3
Reservoir Data for Leases in the Phoenix Site

	E & L Ward	Walter Ward	Wm Ward	Bright Heirs	Payne
Surface area, acres	160	80	27.5	10	10
Net Reservoir Acre-ft	3,393	175.8	596	189.6	204
Pore Vol., @20% bbl	5,264,812	2,721,317	924,795	294,196	316,540
OOIP @ S _o 65%, bbl	3,422,128	1,768,856	601,117	191,278	205,751
OIP @ Ab. S _o 25%, bbl	1,316,203	860,329	231,199	73,549	79,135
Init. Recov. Oil, bbl	2,105,925	1,088,527	369,918	117,729	126,616
Prod. 7/53 to 12/88, bbl	461,066	266,662	95,896	20,196	—
Current Recov., bbl	1,644,859	821,865	274,022	97,533	—

FIGURE 7 — Distribution of porosity in core analyses from the Phoenix site.

FIGURE 8 — Distribution of permeability in core analyses from the Phoenix site.

FIGURE 9 — Distribution of oil and brine saturations in core analyses from the Phoenix site.

Estimates of original oil saturation from core analyses and from Delaware-Childers field were used to estimate the oil currently in place for each individual lease. An average porosity of 20% was assigned. The recoverable oil-in-place values at discovery are the same for each property when estimated in bbl/acre-ft. Figure 10 shows a map of the Phoenix site, and Table 4 lists the reservoir properties.

FIGURE 10 — Map of the Phoenix field site.

TABLE 4
Reservoir Properties for Phoenix Field Site

Formation	Bartlesville sandstone
Depth, ft,	400
No. of injection wells	19
No. of production wells	47
Net pay thickness, ft	19-23
Well spacing, acres	2-5
Avg formation temperature, °F	66
Avg. permeability, mD	16
Avg. porosity, %	20
Avg water injection rate/well, bbl/d	111
Avg oil prod. rate/well, bbl/d	1
Oil gravity, ° API	34
Est. avg original S _O , %	65
Est. avg irreducible S _O , %	25

FIELD OPERATIONS – PHOENIX SITE

Figure 11 shows the sequence of events for the Phoenix field project. Fluorescein was injected as a tracer on June 6, 1990. Eighty-five barrels of a solution containing 126 ppm fluorescein was injected. Samples were collected from all 19 injection wells at 2-hr intervals the first day. Twenty-one producers were sampled 24 hr after injection of tracer, sampled daily, then weekly, once a month, and finally, intermittently. Since the second day of sampling, the tracer response has only been higher than 0.30 ppm for one (WM-13-10) of the wells (Table 5). The pattern of the fluorescein response seems to follow the same trend as that observed during the monitoring of the Mink Unit. There was an initial quick response of tracer from some of the nearest production wells; the response then leveled out to very low values. Fluorescein values seemed to peak at 145 days and were monitored for 599 days post-injection.

FIGURE 11 — Sequence of events for the Phoenix project.

To determine the commercial feasibility of microbial-enhanced waterflooding, a method of microbial and molasses injection had to be designed for the entire field. Figure 12 shows a schematic of the centralized injection station used for the Phoenix field site. After the initial injection of the microbial formulation, molasses was injected continuously from the station.

TABLE 5**Fluorescein Concentrations Observed at Selected Producing Wells at the Phoenix Field Site, ppm**

Post Inj. days¹	EL-3	EL-4	EL-5	EL-6	EL-6A	EL-11	EL-12	EL-15	EL-16
1 a.m.	0.000	0.463	0.128	0.106	1.000	0.058	0.324	0.346	0.186
1 p.m.	0.383	0.893	0.005	0.106	1.000	0.032	0.346	0.080	0.351
2	0.351	0.542	0.021	0.117	0.484	0.058	0.250	0.096	0.261
3	0.170	0.362	0.016	0.048	0.229	0.016	0.191	0.053	0.112
4	0.186	0.292	0.021	0.058	0.221	0.011	0.112	0.043	0.101
5	0.133	0.239	0.011	0.133	0.197	0.016	0.122	0.043	0.074
6	0.170	0.255	0.005	0.043	0.149	—	0.069	0.021	0.053
7	0.064	0.197	0.027	0.032	0.133	0.032	0.090	0.021	0.053
15	0.129	0.178	0.017	0.112	0.123	0.039	0.062	0.079	—
24	0.028	0.056	0.000	0.028	0.090	0.034	0.011	0.034	—
51	—	0.079	0.146	0.022	0.062	0.006	0.011	0.006	0.039
85	0.067	0.084	0.028	0.120	0.140	—	0.050	0.028	0.275
112	0.017	0.028	0.000	0.045	0.095	0.000	0.000	0.000	0.073
145	0.062	0.039	0.213	0.079	0.039	0.062	0.062	0.073	0.039
256	0.010	0.031	0.005	0.000	0.031	0.000	0.005	0.000	0.000
299	0.037	0.049	0.000	0.104	0.061	0.000	0.000	0.000	0.000
421	0.101	0.079	0.028	0.118	0.079	0.090	0.056	0.034	0.067
500	0.023	0.016	0.000	0.035	0.041	0.000	0.000	0.000	0.004
595	0.000	0.041	0.000	0.053	0.000	0.000	0.000	0.000	0.000

¹Injection was 8:00 a.m., June 6, 1990.

TABLE 5**Fluorescein Concentrations Observed at Selected Producing Wells at the Phoenix Field Site, ppm - Continued**

Post Inj. days¹	WL-5	WL-6	WL-7	WL-8	WM-11	WM-12	WM-19	WM-20	PP-2A
1 a.m.	0.053	0.064	0.027	0.064	0.505	0.016	0.096	0.043	0.053
1 p.m.	0.048	0.101	0.074	0.053	0.292	0.005	0.027	0.005	0.011
2	0.037	0.080	0.074	0.058	0.128	0.011	0.000	0.027	0.043
3	0.005	0.053	0.016	0.085	0.064	0.011	0.032	0.021	0.011
4	0.043	0.058	0.027	0.021	0.043	0.021	0.064	0.005	0.011
5	0.027	0.085	0.016	0.048	0.069	0.011	0.080	0.011	0.011
6	0.037	0.058	0.043	0.032	0.043	0.011	0.096	0.058	0.005
7	0.085	0.005	0.133	0.000	0.016	0.016	0.000	0.011	0.032
15	0.056	0.062	0.051	0.157	0.123	—	—	0.023	0.039
24	0.011	0.028	0.084	0.006	0.067	0.000	0.028	0.067	0.084
51	0.000	0.090	0.011	0.123	0.000	0.000	0.006	0.000	0.006
85	0.079	0.129	—	—	0.067	0.011	0.056	0.039	0.107
112	0.107	0.129	0.073	—	0.034	0.017	0.073	0.107	0.135
145	0.039	0.157	0.118	0.230	0.157	0.118	0.017	0.382	0.084
256	0.072	0.000	0.000	0.072	0.021	0.000	0.046	0.036	0.000
299	0.055	0.129	0.049	0.086	0.031	0.012	0.037	0.037	0.049
421	0.101	0.118	0.118	0.079	0.056	0.051	0.051	0.028	0.051
500	0.023	0.078	0.004	0.000	0.000	0.000	0.016	0.000	0.000
595	0.000	0.029	0.000	0.004	0.000	—	0.000	—	0.000

¹Injection was 8:00 a.m., June 6, 1990.

TABLE 5**Fluorescein Concentrations Observed at Selected Producing Wells at the Phoenix Field Site, ppm - Continued**

Post Inj., days¹	PP-3A	BH-7	EL- RET.	WALT.- RET.	P/BH- RET
1 (a.m.)	0.043	0.053	—	—	—
1 (p.m.)	0.043	0.027	—	—	—
2	0.021	0.117	—	—	—
3	0.011	0.043	—	—	—
4	0.011	0.027	—	—	—
5	0.021	0.043	0.048	0.096	—
6	0.016	0.016	0.009	0.016	0.005
7	0.053	0.032	0.058	0.101	0.122
15	0.056	0.056	0.056	0.090	0.090
24	0.118	0.028	—	—	—
51	0.039	—	0.006	0.006	0.000
85	0.017	—	0.039	0.067	0.056
112	0.163	—	0.028	0.095	0.107
145	0.208	—	0.000	0.140	0.281
256	0.000	—	0.000	0.036	0.041
299	0.055	0.012	0.043	0.037	0.000
421	0.051	0.051	0.051	0.073	0.073
500	0.016	0.004	0.023	0.016	0.000
595	0.000	—	0.010	0.010	0.000

¹Injection was 8:00 a.m., June 6, 1990.

FIGURE 12 — Map of the Phoenix injection facilities.

The microbial formulation consisting of NIPER 1A and NIPER 6 was selected for this field injection. NIPER 1A is a variation of the same strain that was used in the Mink Unit project, and produces surfactant and acid from molasses.¹⁰ However, its growth in the reservoir brine from the Phoenix field site was never as optimal as that from the Mink Unit. There are two potential reasons for this: (1) the Mink Unit injection water was fresh; thus, the fluids for cultivation of NIPER 1A had always been relatively low (0.5%) in salinity. The Phoenix brine is recycled produced water and has a salinity of about 2.9%. (2) There is a higher concentration of iron in the Phoenix brine that may be inhibiting the growth of NIPER 1A. Table 6 shows the mineral analysis of the produced water from Phoenix field. We selected another *Clostridium*, NIPER 6, to be injected with NIPER 1A. NIPER 6 was smaller in size than NIPER 3 *Clostridium* that was used in the Mink Unit. Since the Phoenix had a lower average permeability, we felt this would be a better microbial species for injection. After conducting several corefloods, observations showed that the other two microorganisms used in the Mink Unit had relatively little effect in terms of improved oil production, so they were not injected into this site.

Table 6**Trace Mineral Analyses from Phoenix Water Sample, mg/L**

	Injection water	E & L #6 (producer)
Cation		
Sodium	8,080	9,813
Calcium	764	1,240
Magnesium	422	362
Strontium	50.7	0
Barium	153	0
Iron	40.2	96
Anion		
Chloride	14,700	17,702
Sulfate	<0.1	0
Bicarbonate	869	1,171
Carbonate	0	0

On June 20, 1990, approximately 100 bbl of NIPER 1A and NIPER 6 was injected in a solution of 4% molasses. This injection was followed by continuous injection of 40 gal/d of molasses, which was increased after 1 year, to 80 gal/d until December 31, 1991.

The objective of the expanded Phoenix project was to determine how the process could be expanded for a whole field, and to determine whether microbial-enhanced waterflooding is economically feasible. The monitoring for this field site was designed to be minimal; including only those field parameters that would affect oil production. In addition to oil production from the field, individual injection pressures and volumes were monitored. Since this was a recycled flood, produced volumes could not be monitored; thus no water-oil ratios were available.

Selected producers were monitored for tracer concentrations; data and representative graphs are shown in Table 5 and Fig. 13. The tracer concentrations observed in the selected producing wells indicated a very quick show in some wells, probably from very low-volume, high-permeability stringers in the formation. This very quickly decreased to baseline levels. These data were corroborated by our observations of tracer response in the Mink Unit.¹⁰ Both the Mink Unit and the Phoenix reservoirs are very mature fields that have been waterflooded for many years. The operators of the fields had indicated that channeling of fluids was never a major problem. The measurements of fluorescein tracer in both fields indicates that fluid flow patterns were similar.

FIGURE 13 — Tracer response in selected Phoenix producers.

PROJECT EVALUATION - PHOENIX SITE

Injection well volumes and pressures did not significantly change after microbial injection (Figs. 14 and 15). These are important parameters when monitoring a microbial injection project. Obviously significant plugging problems have not occurred.

Figure 16 shows the oil production from the Phoenix leases. The hyperbolic decline curve analysis indicates that oil production has increased after microbial treatment. An incremental 3,690 bbl of oil has been produced over the projected hyperbolic decline curve, which corresponds to approximately 17.4% improvement in oil production.

FIGURE 14 — Injection well volumes at the Phoenix field site.

FIGURE 15 — Injection pressures at the Phoenix field site.

Economic Analysis - Phoenix Site

An economic scenario from these results is shown in Fig. 17. The total amount of molasses injected was 104 tons. From the oil production data above, an incremental 4,440 bbl of oil was obtained through May 1993. Using \$20/bbl as the cost of oil, this amounts to \$88,800 gross income. At a cost of \$100/ton, \$10,332 was spent for injected nutrient, indicating a cost of \$2.33/incremental bbl of oil compared to that of the Mink Unit which was \$3.24/incremental bbl. The cost of the centralized injection station facilities was \$2,500. Thus, a total of \$12,832 was spent for the microbial-enhanced flooding.

FIGURE 16— Oil production from the Phoenix field site.

ECONOMIC SCENARIO FROM PHOENIX PROJECT

FIGURE 17 — Economic scenario from the Phoenix pilot results.

CONCLUSIONS

These microbial-enhanced waterflood field projects demonstrated the feasibility of microbial EOR technology in a manner that an independent operator could implement. It is noteworthy that no operating problems were encountered before or during either project. No corrosion problems were experienced; in fact, the sulfate-reducing bacterial populations remained relatively low compared to the baseline counts. There were no problems with injectivity. The Phoenix project demonstrated the commercial applicability of microbial-enhanced waterflooding, and showed an improvement in oil production to date of 19.6%. Although these two pilots have shown the potential for microbial waterflooding technology, there are many other MEOR processes and types of applications that merit further field testing. Use of microorganisms for permeability modification is a technique that can greatly enhance oil production in the near term. Development of microbial waterflooding and single well stimulation techniques for a wide variety of reservoirs is critical, both for the United States and other oil-producing nations.

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