An Overview of Field Specific Designs of Microbial EOR

Eric P. Robertson
Gregory A. Bala
Sandra L. Fox
Janice D. Jackson
Charles P. Thomas
Idaho National Engineering Laboratory

Abstract

The selection and design of a microbial enhanced oil recovery (MEOR) process for application in a specific field involves geological, reservoir, and biological characterization. Microbially mediated oil recovery mechanisms (biogenic gas, biopolymers, and biosurfactants) are defined by the types of microorganisms used. The engineering and biological character of a given reservoir must be understood to correctly select a microbial system to enhance oil recovery. The objective of this paper is to discuss the methods used to evaluate three fields with distinct characteristics and production problems for the applicability of MEOR technology. Reservoir characteristics and laboratory results indicated that MEOR would not be applicable in two of the three fields considered. The development of a microbial oil recovery process for the third field appeared promising. Development of a bacterial consortium capable of producing the desired metabolites was initiated and field isolates were characterized.

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Presented at the Fifth International Conference on Microbial Enhanced Oil Recovery and Related Biotechnology for Solving Environmental Problems, September 11-14, 1995, Plano, Texas.
Introduction

Microorganisms, most commonly bacteria, have been employed in the recovery of crude oil for decades. Bacteria assist in oil recovery by the in situ production of metabolites (i.e., by-products as a result of growth) and biomass. Some bacterial products that may be useful in oil recovery include gases, surfactants, polymers, biomass, acids, solvents, and alcohols.

Biogases, if produced in sufficient quantities, can reduce oil viscosity, displace immobile oil, and swell oil in place. Biosurfactants reduce interfacial tension; thus, improving pore-scale displacement efficiency. They can also alter wettability, which may affect oil recovery. Purified and concentrated biosurfactants have been reported to reduce interfacial tension between oil and water to $10^{-3}$ dyne/cm.

Bacterial polymers and biomass are used to improve the sweep efficiency of waterfloods by plugging high permeability strata or water invaded zones. Recent field work has shown promise in the area of microbial plugging for improving sweep efficiency.

Less is known about the effectiveness of acids, solvents, and alcohols produced by bacteria on oil recovery. Acids may improve permeability by altering the reservoir rock and can also create CO$_2$ in situ by the dissolution of carbonate. Solvents may help remediate damaged wellbores resulting from paraffin deposition, dissolve crude oil, and act as co-surfactants. Alcohols may also assist oil recovery by acting as co-surfactants and solvents.

Every producing oil field possesses its own set of production problems. In order for microbial EOR to be successful the treatment must be specifically designed to overcome problems associated with a given field. The objective of this paper is to discuss the methods used to evaluate three different fields for their suitability to microbial enhanced oil recovery.

Schuricht Field

The Schuricht is a small single-well field in the Powder River Basin, Crook County, Wyoming. The well (21-24) was completed in 1983 in the Minnelusa "A" sand between 6500 to 6508 ft subsurface. Fluid expansion is the probable drive mechanism. The well is currently producing 100% oil at about 80 bbl/month and is near the economic limit. There is no associated gas or water production. Reservoir and crude oil characteristics are summarized in Table 1. Figure 1 shows the production history of the well. There is no H$_2$S associated with the oil; however, there is 3.24 wt% elemental sulfur in Schuricht crude.

This field is similar to many Minnelusa fields in the Powder River Basin. If microbial EOR could be successfully demonstrated in this field then the technology could hold promise for other fields in the area. Moreover, this field has had no other EOR operations or off-pattern wells that could interfere with interpretation of results.

Demonstrating the effectiveness of a multi-well process in a single well huff 'n' puff test is difficult. However, a technical success in this field would hold promise for economical successes in multi-well
Determination of MEOR method to be applied

A single-well pump-in/pump-out test of the microbial system is the only available option in the Schuricht field because there are no plans to drill a second well in this field in the foreseeable future. For this field, two options for microbial EOR were evaluated: in situ biosurfactant production and in situ gas generation. A simplified microbial soak process was evaluated using Buckley-Leverett fluid displacement principles to determine the results that could be expected under ideal circumstances. The Buckley-Leverett fluid displacement method uses relative permeability curves and viscosities of the flowing fluids as the basis of saturation front advancement.

Relative permeability data needed for the Buckley-Leverett simulations were not available for the Schuricht field, but initial and irreducible oil saturations were known. Relative permeability curves for the Schuricht field were taken from similar neighboring Minnelusa fields with similar end-point saturations.

Simplifying assumptions were made for both microbial options before running the simulations. The formation was assumed to be homogeneous and no bacterial plugging occurs. The bacterial injection slugs were dilute and the relative permeability curves for water were used during injection of the slug. No attempt was made to model bacterial transport, growth, or metabolite production. The following assumptions were made for the biosurfactant case. 1) Oil and water viscosity remain constant. 2) Relative permeability end points are altered after bacterial incubation corresponding to a 40% reduction in residual oil saturation resulting from biosurfactant production. The following assumptions were made for the microbial gas production case. 1) No change in the relative permeability curve end points. 2) Enough CO$_2$ is produced to saturate all the contacted oil. Saturating the Schuricht crude oil with CO$_2$ would swell the contacted oil and lower its viscosity from 15 cP to 6 cP. These assumptions represent best-case scenarios and may not be representative estimates of actual field results.

Simulated incremental oil recovery for the microbial gas mechanism over the biosurfactant mechanism is shown in Figure 2. In this figure, normalized incremental oil recovery of the CO$_2$ process over the surfactant process is plotted against the normalized total fluid production. Normalized incremental oil production is calculated by the equation:

$$\text{Normalized incremental oil production} = \frac{\text{CO}_2 \text{ process} - \text{surfactant process}}{\text{contacted oil in place}}.$$  \hspace{1cm} (1)

Normalized total fluid production is calculated by the following equation:

$$\text{Normalized total fluid production} = \frac{\text{total produced fluid volume}}{\text{total injected fluid volume}}.$$  \hspace{1cm} (2)

Figure 2 is a good way of comparing one process to another and, as can be seen, the option of saturating the contacted oil with CO$_2$ appears to recover more oil than generating a biosurfactant in situ for this particular single-well field. The reason for the poorer performance of the biosurfactant
option is because the mobilized oil is in the high water saturation portion of the relative permeability curves. Oil mobility is low in this region and, consequently, the additional mobilized oil moves through the formation to the producing well very slowly. On the other hand, the microbially generated carbon dioxide lowers the viscosity of all the contacted oil, which changes its mobility or relative permeability allowing the oil to flow faster to the producing well. Swelling the oil by saturating it with carbon dioxide also aids in its recovery.

This simple analysis indicates that for the Schuricht field it would be more advantageous to employ bacteria capable of producing enough CO₂ to saturate the contacted oil instead of bacteria that reduce interfacial tension between oil and water. Based upon this result, it was decided to find and evaluate bacteria that could produce a copious quantity of CO₂ or other similar gas to be applied in a possible microbial EOR demonstration in the Schuricht field.

Preparatory Microbiological Work for Field Test

A successful field application of microbial EOR is highly dependent on the selection of the bacterial strain or consortium to be used in the field. Enrichment procedures to isolate microorganisms indigenous to the Powder River Basin of Wyoming began by collecting and screening Schuricht field fluids and solids. Specific characteristics sought for the enriched microbial cultures were: 1) growth at the reservoir temperature of 138°F (60°C), 2) growth with and without oxygen present (i.e., facultative anaerobe, microaerophilic, denitrifying), 3) salt tolerant to 3% KCl to match the reservoir rock and fluid compatibility, 4) compatible with Schuricht crude oil, and 5) production of large amounts of CO₂ under reservoir conditions.

Soil samples retrieved from the Powder River Basin were enriched for bacteria capable of gas production. A 1.0 g sample of oil-laden cow manure was added to liquid media [trypticase soy broth (TSB), potato dextrose yeast (PDY) medium (ATCC 337), and potato medium (ATCC 1126)]12 and incubated aerobically at 60°C. The medium was amended by adding 3% KCl and 1% NaN₃. After 24 hours of growth, the organisms were subcultured to identical media and incubated anaerobically at 60°C. Growth (turbidity) and gas production (bulging septa) were observed within 24 hours. Potato medium continued to show a positive response for gas production and was used for further study. Organisms were streaked on agar plates and colonies were picked and transferred to isolate the organisms. Four Schuricht enrichment cultures were obtained and identified as 1, 3a, 3b and 4. All four isolates are similar; however, the #1 isolate produced more gas and was singled out for further studies. This organism was renamed Powder River Basin #1 (PRB #1) and was stored in maintenance broth with 2% glycol for long term storage.13

Medium development. A potato base medium was used initially to study the bacteria because of the availability of a cheap carbon source (potato starch). The potato based growth medium was analyzed to determine bacterial utilization of the components. The carbon and energy sources provided in potato medium were varied along with other constituents to determine the necessary components required for bacterial growth. Potato was added to provide minerals and a starch substrate (carbon source) for PRB #1; whereas, sodium nitrate serves as the terminal electron acceptor of the electron transport chain, and yeast extract was added as a source of water soluble vitamins, amino acids, peptides, and an additional source of carbon. Results indicated that PRB #1 requires yeast extract.
and sodium nitrate for growth and does not metabolize potato starch.

Because yeast extract and sodium nitrate are required nutrients for these organisms, a modified medium E (ATCC 1502 amended with nitrate and yeast extract) was used to cultivate the organisms. The modified medium provides mineral salts (molybdenum, iron, and copper) for enzymatic functions; phosphates for metabolic reactions; yeast extract for water soluble vitamins; amino acids, peptides, and carbon; nitrate as a terminal electron acceptor; and fructose as the major source of carbon. The constituents of modified medium E per liter of water are as follows: 10 g fructose, 1 g (NH₄)₂SO₄, 0.51 g MgSO₄, 10.6 g K₂HPO₄, 5.3 g KH₂PO₄, 5 g yeast extract, 20 g NaNO₃, 30 g KCl, and 10 mL trace mineral salts.

Characterization of PRB #1. PRB #1 is a thermophilic, gram positive, non-sporing rod. The organism does not decrease the surface tension of water and will not grow in a salt concentration above 10% KCl, but will grow and reproduce in 5% KCl. PRB #1 does not adhere to hydrocarbons or produce any organic acids or alcohols when grown on modified medium E. The organism will grow in a temperature range from 113°F to 162°F (45°C to 72°C). The organism does not produce ammonia, but does produce large amounts of carbon dioxide (CO₂) and nitrous oxide (N₂O) gas when cultivated on modified medium E. PRB #1 is a thermophilic bacterium capable of reducing nitrate to nitrous oxide under limited oxygen conditions.

Gas Production. Gas chromatography was used to analyze the culture headspace for the presence of CO₂ and N₂O in media containing fructose (sugar) and without fructose. Tests were performed at 138°F (60°C) and results indicate that the PRB #1 produces more CO₂ than N₂O with fructose present in the growth medium. PRB #1 without fructose in the medium yields higher N₂O concentrations than CO₂. However, there was no significant difference in the total amount of gas produced with the two media. For example, in sealed serum vials, fructose media yielded 0.483 g/L of gas (CO₂ and N₂O combined) whereas, media without fructose yielded 0.556 g/L. Thus, while the overall amount of gas remains constant the specific type of gas can be controlled by choosing the appropriate nutrient source.

Results of In Situ Growth. A Berea sandstone core 1 inch in diameter by 6 inches in length was used to determine if the organism can be transported with brine through sandstone rock, can grow within the rock matrix, and produce the same quantity and mixture of gases inside a sandstone matrix as in a laboratory shake flask. The Berea sandstone core used in the experiment had a permeability of 650 mD and the porosity was 23.5%.

Bacteria were clearly visible in the core effluent under a microscope after injecting 1.5 core pore volumes of the bacterial suspension. Effluent from the core inoculated in fresh medium grew well indicating cells were distributed throughout the core. A total of 2.0 core pore volumes of the PRB #1 cell suspension was injected into the sandstone core. A 60-mL syringe was attached to the outlet end of the core, the inlet end was capped, and the core and syringe were then incubated at 138°F (60°C).

The gas displaced into the syringe was qualitatively analyzed on a gas chromatograph to determine the type of gases produced and found to be predominately CO₂ with some N₂O present. This gas
mixture is also the same mixture produced during incubation of PRB #1 cells in serum vials. The amount of gas produced from the core system was about 2.5 g/L or 5 times the amount produced from the sealed serum systems. However, calculations show that a yield of 22 g/L is required to saturate the contacted oil for conditions at the Schuricht lease.

**Permeability of Formation**

At the time that the field was made available for a demonstration project, there was some uncertainty about the permeability of the reservoir. This characteristic is especially important when considering an application of in situ MEOR. A formation permeability less than about 75 mD is reportedly too tight to inject and deliver vegetative microorganisms into the reservoir.\(^{15}\)

There were indications that the permeability of the field was 10 mD or less, but the operators believed that this information was incorrect. A build-up test was run to confirm the reservoir permeability and other key properties such as skin and static reservoir pressure. Reservoir permeability calculated from a Horner analysis of the data was 2.2 mD. This permeability value was substantially lower than the field owners and operators had estimated, but only slightly lower than the DST-calculated permeability of 10.2 mD. A Fetkovitch decline curve analysis\(^{16}\) indicated a permeability of 3.1 mD. Other methods and analyses yielded permeabilities consistent with the pressure build-up calculated permeability.

**Decision to Terminate the Schuricht Field Test**

On the basis of the analyses indicating that the average permeability of the Schuricht reservoir was between 2.2 mD and 10.2 mD, which was much lower than thought by the operators, it was determined that the Schuricht field would be a poor candidate for a microbial EOR field demonstration. Such low permeability would not be expected to allow the successful injection and delivery of microorganisms into the formation.

**Smackover Field**

The operators of the Smackover field in southern Arkansas wanted to determine if MEOR could be successfully applied in this old, declining-production field. The average reservoir porosity is 36% and the permeability in the clean, unconsolidated sand sections averages 5,000 mD, but ranges as high as 12,000 mD in the productive lenses. Connate water saturation averages 20%. The API gravity of the crude oil is 20° and oil viscosity is presently 75 cP at the reservoir temperature of 110°F. The concentration of salt in the produced water varies from 50,000 to 60,000 ppm TDS.

The discovery well for the field, the Murphy No. 1, blew out during drilling operations in 1922 and formed a crater 450 feet across and 50 feet deep. Blow-down of the gas cap and the absence of significant solution gas resulted in the almost complete dissipation of the reservoir energy in slightly more than five years. By 1930, vacuum installations were in operation and the reservoir energy had been essentially exhausted. Production thereafter resulted from gravity drainage and bottom-water influx. Large volumes of sand were removed in the early life of the reservoir during the periods of high producing rate and created channels and voids in parts of the reservoir.
Of the approximately 500 million stock tank barrels (MMSTB) of oil originally in place, about 35% has been recovered to date. Total reservoir produced water-cut was more than 80% as early as 1934 and has been controlled only through continuous remedial work and well abandonment. The reservoir is not well suited for secondary recovery because the vast majority of the field is not unitized, yet the volume of oil presently in place is greater than that found in many new fields and every effort should be made to increase the ultimate recovery.

**Microbial Oil Recovery Mechanism**

During meetings with field operators it was agreed to study the possibility of using indigenous bacteria to produce a biogas (CO₂) process to lower the in situ crude oil viscosity as a mechanism of oil recovery. This process would be most effective in the areas of the reservoir with the greatest reservoir pressure because more CO₂ can be dissolved into the oil at higher pressures resulting in lower oil viscosity. It was also decided to consider the use of indigenous gas-producing bacteria, if possible, to produce the CO₂ because they would be best suited to reservoir conditions.

**Microbial Isolation and Characterization**

Bacteria were isolated from samples of produced brine collected from wellheads and from produced water tanks. Water samples were collected anaerobically in 1 liter glass bottles previously purged with nitrogen. In the laboratory, nutrients (phosphate, nitrate, and molasses) were added to the samples and tests were conducted to enrich for gas producing bacteria.

The nutrients were added to 100 mL serum bottles. The bottles were then autoclaved and then placed in the anaerobic chamber for 2 to 3 days to allow for an exchange of anaerobic gases. A base of filter sterilized (0.2 μm) or non-sterilized Smackover brine was added to the bottles under anaerobic conditions. The serum bottles were then sealed and capped.

Data to monitor head space pressure were collected using three different base brines: filtered (0.2 μm) reservoir brine, unfiltered reservoir brine, and a filtered synthetic brine. The synthetic brine is based on chemical analysis of field brine.

Results from these headspace pressure experiments are shown in Figure 3. The difference observed between the filtered and unfiltered brine samples may be caused by a secondary microbial population in the unfiltered brine that uses metabolites from the primary culture, utilization of insoluble nutrients that were filtered out of the filtered brine, or a combination of both. The data obtained from the synthetic brine indicate that it is suitable for experimentation if field brine is unavailable.

The field operator studied reservoir data and ran build-up tests to determine reservoir pressures at different locations in the field. They found that while the pressure did vary some throughout the reservoir, the highest pressure observed was 33 psia. From a published correlation of heavy crude oil and CO₂ mixtures it was found that saturating the oil with CO₂ would have a negligible effect on oil viscosity at reservoir pressure. For an immiscible CO₂ process to have a significant effect on oil viscosity, pressures in excess of 200 psia are required (see Figure 4).
Except for gas production, bacteria enriched from the field brine were not studied extensively. However, the bacteria are known to produce n-propanol, ethanol, methanol, formate, acetate and propionate. Their effect on oil recovery is not clearly understood. A sandpack made from produced sand collected at the Smackover field was used to determine the oil recovery potential of the enriched bacteria.

A sandpack filled with cleaned produced Smackover sand was brought to initial oil saturation conditions at reservoir temperature and then waterflooded with 4 pore volumes (PV) of filtered (0.2 μm) field brine. It was then shut in for 2½ weeks to simulate a bacterial incubation. This was followed by 2 PV of filtered brine and 4.3 PV of bacterial inoculum; then shut in to allow bacterial growth. The sandpack was incubated until the rise in pore pressure ceased (4 weeks). Pressure in the sandpack was maintained at 33 psia (reservoir pressure) by periodically bleeding the microbial gas into an attached syringe. Figure 5 illustrates the effect of bacterial growth and gas production on oil recovery.

Following the bacterial incubation period, both oil recovery and saturation followed the respective curves established during waterflood and bacterial injection. An increase in the slope of the oil recovery curve would be indicative of bacterial induced oil recovery. Sandpack recovery data after bacterial growth followed the same trend as the waterflood which indicated no additional oil was recovered as a result of bacterial growth in the sandpack.

**Smackover Work Stopped**

The results of the sandpack experiment were disappointing, but expected. At such low reservoir pressure, saturating the oil with CO₂ is of little value. It was concluded jointly with the field operator that the Smackover field had little potential for successfully demonstrating microbial gas technology because of the low reservoir pressure and large gas cap.

**Naval Petroleum Reserve #3**

The Naval Petroleum Reserve #3 (NPR-3) is located 40 miles north of Casper, Wyoming and produces from the Teapot Dome structure in the Powder River Basin. This structure contains nine producing horizons ranging from 300 ft subsurface to 4820 ft subsurface. The Shannon sandstone is the shallowest and largest reservoir in the field with over 600 wells. Following discussions with NPR-3 engineers and studying the history of the field, it was decided that a small area in the Northern Second Wall Creek (NSWC) reservoir would be the best location for a MEOR field trial.

The NSWC reservoir is bounded to the northeast by the Salt Creek South unit and to the south by a sealing northeast-southwest trending strike-slip fault which separates it from the Southern Second Wall Creek reservoir. The eastern and western boundaries are the corresponding oil-water contacts.

Initial production was established from the NSWC reservoir on November 17, 1922. Development and production continued until December 31, 1927 when operations were discontinued by order of the United States District Court and the reserve was turned over to the Navy Department. Peak production of 2,542 barrels of oil per day (BOPD) occurred in 1923, and 2,338 MMSTB of the
original 39.21 MMSTB oil in place had been produced from the NSWC reservoir before shut-in.

In response to concerns of lease drainage to the adjacent Salt Creek South Unit, limited production began along the lease boundary. A waterflood was initiated in 1979; production peaked quickly at 1469 BOPD and began a rapid decline.

The Second Wall Creek reservoir at NPR-3 is naturally fractured and the waterflood is performing poorly because much of the oil is bypassed by the fracture system. Natural gas huff 'n' puff has recently been proven successful at NPR-3 in the Shannon formation. Based upon that insight, it was decided to investigate the use of native bacteria that produce large quantities of gas in conjunction with other bacteria that produce biosurfactants. The combination of the two bacterial products (gas and surfactant) along with any bacterial plugging of the fractures that may occur appeared to have potential for recovering additional oil from NPR-3.

Microbial Enrichment

Produced water, injection water, produced oil, and wellhead soil samples were collected anaerobically from NPR-3. Soil samples, collected near wellheads, were transferred to Hungate tubes containing modified medium E (as mentioned above, with fructose as a carbon source) to enrich for native gas-producing organisms. A mixed consortia of microorganisms were enriched from the soil samples. The most promising bacterial culture was designated as NPR-3A. The culture is a facultative anaerobe and grows robustly within 48 hours at the reservoir temperature of 50°C (122°F).

Water samples were also collected at the wellhead and used to determine if sulfate-reducing bacteria (SRB) were present and to enrich for other gas-producing bacteria. SRB were found in two of the four wells sampled for water. Bacteria that did not produce gas were cultivated from the produced water, but no native gas-producing bacteria were grown from any of the produced water samples tested.

Microbial Characterization of NPR-3A

Microbial Physiology. The organism (NPR-3A) enriched from the NPR-3 site is a facultative anaerobe and reduces nitrate to nitrous oxide while producing carbon dioxide. Using a facultative anaerobic bacteria (capable of growth with and without oxygen present) for a field project is desirable because the reservoir matrix is anaerobic while the surface facilities would be an aerobic environment. The organisms do not reduce surface tension, indicating that biosurfactants are not produced.

Gas Production. NPR-3A begins gas production sooner in sealed vials with oxygen present in the headspace than under completely anaerobic conditions (see Figures 6 and 7). The total gas (combined CO₂ and N₂O) produced did not significantly vary with oxygen or without oxygen present in the headspace (0.444 g/L and 0.545 g/L respectively).

Surfactant Producing Organisms. The inclusion of a biosurfactant producing bacteria, Bacillus subtilis, in the proposed bacterial consortia for improving oil recovery in the Second Wall Creek
reservoir of NPR-3 may be a more effective approach than applying gas-producers by themselves. *Bacillus subtilis* ATCC 21332 appears to grow well and produce surfactant at 50°C.

*B. subtilis* 21332 were grown at 50°C in medium E, trypticase soy broth, potato medium, and sugar beet medium to determine the most effective medium for surface tension reduction (biosurfactant production). Surface tensions were measured using the supernatants. The cell pellets were lyophilized to determine cell dry weights. *B. subtilis* generated similar amounts of biomass in each media type; however, the surface tensions were only decreased in potato medium, medium E with 1% yeast extract, and trypticase soy broth.

**Coreflood.** The average pressure of NSWC reservoir is 500 psia. A coreflood was run at reservoir temperature and pressure to determine if the bacteria can survive a sudden pressure increase as would occur during injection operations. NPR-3A organisms were injected into a Berea sandstone core (700 mD) to determine transport and growth efficacy of these bacteria at reservoir temperature and pressure. Cells were injected into a brine-saturated core under anaerobic conditions at 500 psia and 50°C. Breakthrough of the cells occurred at 1.75 pore volumes, indicating good microbial transport through the core. A gas sample was collected from the core after bacterial incubation and confirmed to be predominantly carbon dioxide and nitrous oxide, indicating that the bacteria grew well in the core at reservoir temperature and pressure.

**Development of a Field Medium**

A field medium was prepared using production water collected from the 45-AX-20 wellhead. Water analysis indicated that the produced water was deficient in phosphate, nitrate, and several minerals. Modifications to the reservoir water were necessary before a microbial population could be established. The water was amended with the following nutrients per liter: 20 g KNO₃, 5 g yeast extract, 1 g (NH₄)₂SO₄, 10 g fructose, 10 mL mineral salts (0.01 g Na₂MoO₄·2H₂O, 0.1 g CoCl₂·6H₂O, 0.01 g CuSO₄·5H₂O, 0.1 g ZnSO₄·7H₂O, and 1.0 g Na₂EDTA), 100 mL phosphates (53.3 g KH₂PO₄ and 106.0 g K₂HPO₄). The amended water would be used as the injection medium for the active culture during a field trial. Initial tests indicate positive growth and gas production from the NPR-3 consortia in the field medium.

**Project Status**

The microbial process for improving oil recovery at NPR-3 looks promising. However, funding for the project ended before the process design was completed for field testing. Additional work needed to be complete the process design includes determining (1) the ability of bacteria to plug natural fractures; (2) the compatibility of the two microbial systems (NPR-3A and *B. subtilis*); and (3) the synergistic effect on oil recovery of combining the two microbial recovery processes (biogas and biosurfactants).

**Discussion**

The application of microbial EOR to an oil field involves input from engineers, microbiologists, field personnel, and chemists. Engineers can help determine which microbial process will be of most
value to the reservoir and the quantities of bioproducts required. Microbiologists are needed to select the application organism and in fine-tuning growth conditions to achieve the quantities of bioproducts required. Field personnel and engineers who know the problems associated with a particular producing field can help steer the microbial EOR project away from poor candidate sites and help select a viable microbial oil recovery mechanism. The importance of a knowledge of the field fluids chemistry becomes obvious when considering the application of living organisms.

The gas-producing bacteria that we worked with produced CO₂ and N₂O. It is a well established that microbial denitrification proceeds from nitrate to N₂ (and in some cases to N₂O) with the help of various enzymes. The respiratory denitrification pathway is expressed as follows:

\[ \text{NO}_3^- \rightarrow \text{NO}_2^- \rightarrow \text{NO} \rightarrow \text{N}_2 \text{O} \rightarrow \text{N}_2. \] (3)

When a bacterium lacks nitrous oxide reductase, the enzyme required to convert N₂O to N₂, the final product in the denitrification pathway is N₂O. The molecular weight of nitrous oxide is the same as carbon dioxide; and N₂O is slightly more soluble in water than CO₂. Other physical properties of N₂O are similar to CO₂. Nitrous oxide is not commonly used in the recovery of petroleum; however, it may be of some value to oil recovery based upon the comparison of its physical properties with carbon dioxide.

The Schuricht field initially appeared like an ideal location for a microbial field test - small field, pristine conditions, no other wells to interfere with interpretation of results. However, the permeability of the formation was too low to allow effective injection and placement of the bacteria into the reservoir. If the permeability had been acceptable, then there was still the issue of producing enough gas to effectively recover oil.

Calculations indicate that on the order of 20 grams of CO₂ per liter of injected inoculum would be required to saturate the contacted oil in the Schuricht field. The theoretical maximum CO₂ production from 10 g of fructose is 14.7 g of CO₂ based on stoichiometric chemistry for anaerobic metabolism.19 Shake flask experiments (batch) obtained 0.5 g (CO₂ and N₂O combined) per liter of inoculum. An experiment in a core obtained 2.5 g/L with a single nutrient slug. This number could be improved by optimizing growth conditions, increasing fructose concentration, and improving metabolite production kinetics, but reaching the goal of 20 g/L from a single nutrient slug injection is still questionable.

The Smackover field also held high initial promise for microbial EOR. High reservoir permeability, low temperature and moderate salinity are ideal for bacterial growth. However, the production problems associated with that field appear to be too great to be overcome with microbial EOR. A multi-well flood was not feasible because of the very low reservoir pressure, large gas cap overlying the reservoir, and because the field is not unitized. This left the single-well treatment as the only currently viable option for the field. The current recovery mechanisms for this field are gravity drainage and water-drive. Reducing the viscosity of the heavy oil may increase the efficiency of the natural water-drive enough to recover additional oil. The reservoir pressure, however, is too low for CO₂-producing bacteria to be effective at reducing oil viscosity.
NPR-3 Second Wall Creek reservoir appears to have a need that microbial EOR might be able to fill. There is an active waterflood that has poor sweep efficiency because of the naturally fractured reservoir and gas huff 'n' puff has been successful in other reservoirs in the area. The application of bacteria to at least partially plug the fractures and at the same time produce CO₂ and biosurfactants in situ appears to be a promising recovery mechanism for this field. More testing of the systems and their interactions needs to be done before field application.

Obviously, one MEOR process cannot be successfully applied to every oil reservoir. Each field must be evaluated individually before choosing a microbial treatment. And not all fields are well suited for microbial EOR techniques.

The bacteria to be applied in the field must be compatible with field properties. Two of the most important field properties are temperature and salinity. Bacteria have a limited growth temperature range and their optimal growth temperature range is much smaller. At higher temperatures their metabolism may shift to produce other unwanted metabolites or shut down altogether. Salt concentration in the reservoir brine is also an important element in the metabolism of bacteria. High salt concentration is a natural preservative (or inhibitor of bacterial growth) just like very hot or cold temperatures.

Complete modelling of bacterial systems in a porous medium is a very daunting task. Besides the issue of transport, there is the complication of cell division and product formation. Decoupling these factors can be helpful in designing a microbial EOR system. For example, before deciding on a bacterial system to apply in the Schuricht field, two mechanisms were modelled abiotically using Buckley-Leverett methods. Bacterial transport and growth were neglected, and assumptions of product formation and efficacy were based on laboratory results and productivity. It was determined that in situ biogas generation would have a more distinguishable effect on oil recovery than an in situ biosurfactant soak (see Figure 2).

**Conclusions**

1) A field design of microbial enhanced oil recovery should involve the expertise of engineers, microbiologists, field personnel, and chemists.

2) Simple models and correlations that consider only the abiotic portion of microbial EOR can lead to important knowledge regarding what will and will not work.

3) Field specific laboratory data on microbial growth and metabolite production, including corefloods, are vital to the design of a microbial field project.

4) Field properties such as temperature, salinity, and permeability are significant factors in microbial EOR design.

**Acknowledgements**

We would like to express our gratitude to K S L Enterprises, TIORCO, Phillips Petroleum Company,
and the staff at the Naval Petroleum Reserve #3 for their support and guidance with regard to the various projects discussed. Thanks also go to the U.S. Department of Energy for funding the work (Contract Number is DE-AC07-76ID01570) and to Leonard Keay (DOE-ID) and Rhonda Lindsey (DOE BPO) for their project management. We are also grateful to Lockheed Martin Idaho Technologies for allowing the publication of these findings.

References


13. Ibid. 544.


Table 1. Reservoir and fluid property data, Schuricht 21-24, Minnelusa "A" sand.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth, ft subsurface</td>
<td>6500</td>
</tr>
<tr>
<td>Sand thickness, ft</td>
<td>8</td>
</tr>
<tr>
<td>Porosity, %</td>
<td>12</td>
</tr>
<tr>
<td>Connate water saturation, %</td>
<td>.37</td>
</tr>
<tr>
<td>Reservoir temperature, °F</td>
<td>138</td>
</tr>
<tr>
<td>Crude oil gravity, °API</td>
<td>25.4</td>
</tr>
<tr>
<td>Crude viscosity at reservoir temperature, cP</td>
<td>15</td>
</tr>
<tr>
<td>Original oil in place, MSTB</td>
<td>480</td>
</tr>
<tr>
<td>Recoverable oil, MSTB</td>
<td>115</td>
</tr>
<tr>
<td>Areal extent, acres</td>
<td>103</td>
</tr>
<tr>
<td>Number of wells</td>
<td>1</td>
</tr>
<tr>
<td>Cumulative oil produced, STB</td>
<td>8300</td>
</tr>
</tbody>
</table>
Figure 1. Production history of the Schuricht 21-24 well.
Figure 2. Comparison of simulated oil recoveries from in situ-produced CO$_2$ and biosurfactant.
Figure 3. Headspace pressure data from Smackover field cultures.
Figure 4. CO₂-saturated Smackover crude oil viscosity reduction with increasing pressure. Reservoir temperature is 110°F.
Figure 5. Effect of brine injection, bacterial cell injection, and bacterial growth on oil recovery and saturation in an oil saturated sandpack.
Figure 6. Growth of NPR-3A at 50°C in capped vial with air headspace.
Figure 7. Growth of NPR-3A at 50°C in capped vial with helium headspace.