Contracts for field projects
and supporting research on . . .

72

Enhanced Oil Recovery

Reporting Period July–September 1992

DOE/BC--92/4
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PROGRESS REVIEW

Quarter Ending September 30, 1992

United States Department of Energy

Office of Gas and Petroleum Technology
and Bartlesville Project Office

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Quarterly Reports

DOE/BC-91/4 Contracts for Field Projects and Supporting Research on Enhanced Oil Recovery. Progress Review No. 68. Quarter ending September 30, 1991. November 1992. 188 pp. Order No. DE92001052. Status reports are given for various enhanced oil recovery and gas recovery projects sponsored by the Department of Energy. The field tests and supporting research on enhanced oil recovery include chemical flooding, gas displacement, thermal/heavy oil, resource assessment, geoscience technology, microbial technology, novel technology, and environmental technology.

General

NIPER-596 General-Purpose Automation Programming: A Case Study on Using a Graphic Language. Topical Report. National Institute for Petroleum and Energy Research. October 1992. 48 pp. Order No. DE92001071. As part of an ongoing effort to transfer technology to the petroleum industry and other engineering, science and manufacturing areas, this report conveys background information and the benefits of data acquisition/control/analysis/presentation software to operate a high temperature, high pressure steamflood laboratory. The National Institute for Petroleum and Energy Research developed the background and extensive applications by using National Instruments™ LabVIEW™, an object-oriented programming software, as the programming platform. The software was developed to automate the thermal lab, but was designed in such a way that the program would be general and could be configured to any laboratory automation during the run time. This modular program has been constructed so that application, with minor modification, can be used in other laboratory, pilot plant or commercial operations for data acquisition/control/analysis/presentation.

Gas Displacement

NIPER-632 Application of Polymer Gels for Profile Modification and Sweep Improvement of Gas Flooding. Topical Report. National Institute for Petroleum and Energy Research. December 1992. 36 pp. Order No. DE93000106. This study included evaluation of several different candi-

dates for their potential as gelled polymer treatments for in situ profile modification. Crosslinking of one gel system (melamine resin/xanthan polymer) was activated in the pH range of 4 to 5. This method depended upon CO₂ contacting reservoir brines to form carbonic acid. For a CO₂ gas flood, brines contacted by CO₂ will have a lower pH than the reservoir brine. The primary disadvantages of the melamine resin-gel system were the high sensitivity of the gel to shear and the inability of the gel to reheal because the resin degraded after the resin activation in acidic brines. Another gel system was evaluated which was a blend of hydroxypropyl cellulose (HPC) and sodium dodecyl sulfate (SDS). A gel was formed by increasing the salinity of the polymer/surfactant blend. This gel had the advantage of not requiring a crosslinking agent such as a heavy metal compound and did not require any specific solution pH to form a gel. However, because the gel formed immediately upon increasing salinity, the gel could be placed only a short distance from the point of injection. This gel system did not appear to be a practical method for profile modification because of the inability for deep penetration and placement of the HPC/SDS solutions in the reservoir. Also, brine injection following gel placement produced an increase in the sand-pack permeability. This demonstrated that the gel was not stable to subsequent brine flooding.

Thermal Recovery

NIPER-580 Practical Aspects of Steam Injection Processes, A Handbook for Independent Operators. National Institute for Petroleum and Energy Research. October 1992. 448 pp. Order No. DE92001070. This handbook explores the concept behind steam injection processes and discusses the information required to evaluate, design, and implement these processes in the field. The emphasis is on operational aspects and those factors that affect the technology and economics of oil recovery by steam. The intended purpose of this handbook is twofold: (1) to provide operators with a ready reference, a starting point when searching for information to engineer a steam injection project; and (2) to provide a bibliographic source on the subjects discussed in the handbook. This handbook is not, however, a "troubleshooter" manual on field problems. The first four chapters describe the screening criteria, engineering, and economics of steam injection operation as well as discussion of the steam injection fundamentals. The next four chapters begin by considering the treatment of the water used to generate steam and discuss in considerable detail the design, operation and problems of steam generators, distribution and steam quality determination. The subsurface aspects of steamflood operations are addressed in chapters 9 through 12. These include thermal well completion and cementing practices, insulated tubulars, and lifting equipment. The next two chapters are devoted to subsurface operational problems encountered with the use of steam. Briefly described in chapters 15 and 16 are the steam injection process surface production facilities, problems and practices. Chapter 17 discusses the importance of monitoring in a steam injection project. The environmental laws and issues of importance to steam injection operation are outlined in chapter 18.

DOE/BC/14600-36 Chemical Composition Profiles During Alkaline Flooding at Different Temperatures and Extended Residence Times. Topical Report. University of Southern California. December 1992. 152 pp. Order No. DE93000107. The objective of this work was to investigate whether or not caustic effectively sweeps the major portion of the reservoir efficiently during an alkaline flood process. It was also the objective of this work to study the state of final equilibrium during a caustic flood through determination of the pH and chemical composition profiles along the porous medium. For this purpose, a long porous medium which provided extended residence times was required. It was necessary to set up the porous medium such that the

changes in the pH and chemical composition of the solution could be monitored. Four Berea sandstone cores (8" in length and 1" in diameter) placed in series provided the desired length and the opportunity for sampling in between cores. This enabled establishment of pH and chemical composition profiles. The experiments were run at temperatures up to 180°C, and the flow rates varied from 4.8 to 0.2 ft/d. The samples were analyzed for pH and for Si and Al concentrations. The results show that caustic consumption is insignificant for temperatures up to 100°C. Above 100°C, consumption increases and is accompanied by a significant decrease in pH. The sharp decline in pH also coincides with a sharp decline in concentration of silica in solution. The results also show that alumina is removed from the solution and solubility of alumina ultimately reaches zero. Sharp silica and pH declines take place even in the absence of any alumina in solution. As a result, removal of silica from solution is attributed to the irreversible caustic/rock interaction. This interaction is in the form of chemisorption reactions in which silica is adsorbed onto the rock surface consuming hydroxyl ion. Once these reactions are satisfied, caustic breakthrough occurs at a high pH. However, significant pore volumes of caustic must be injected for completion of the chemisorption.

DOE/BC/14600-37 Characterization of Surfactants in the Presence of Oil for Steam Foam Application. SUPRI TR 88. Stanford University Petroleum Research Institute. December 1992. 60 pp. Order No. DE93000108. A one-dimensional sandpack (6 ft x 2 1/2 in.) model is used to investigate the behavior of four anionic sulfonate surfactants of varying chemical structure with steam. The study is performed with a crude oil at residual oil saturation of about 12% of pore volume. The observed pressure drops across the various sections of the pack are used to study the behavior of the surfactant. The surfactants tested vary in chain length, aromatic structure and number of ionic charges. A linear toluene sulfonate produced the highest strength foam in presence of the oil at residual saturations, as compared to the alpha olefin sulfonates. This is in contrast to the behavior of the surfactants in the absence of oil, where the alpha olefin sulfonates perform better. The reason for this change in behavior is the relative propagation rate of the foams produced by the surfactants. This conclusion is based on the observation that increase in propagation rate decreases the detrimental effect of oil, while the propagation rate is of little significance without oil. The disulfonate performed better in the presence of oil. The improvement in the performance is embedded in the propagation rate of these surfactants, as the rate of propagation in this case is also high. But the true mechanism of improvement in the strength of the foam instead of deterioration needs further study.

Resource Assessment Technology

DOE/BC/14403-3 Characterization of Oil and Gas Reservoir Heterogeneity. Final Report. The University of Texas at Austin. October 1992. 232 pp. Order No. DE92001072. Research described in this report addresses the internal architecture of two specific reservoir types: restricted platform carbonates and fluvial-deltaic sandstones. Together, these two reservoir types contain more than two thirds of the unrecovered mobile oil remaining in Texas. The approach followed in this study was to develop a strong understanding of the styles of heterogeneity of these reservoir types based on a detailed outcrop description and a translation of these findings into optimized recovery strategies in select subsurface analogs. Research targeted Grayburg Formation restricted-platform carbonate outcrops along the Algerita Escarpment and in Stone Canyon in southeastern New Mexico and Ferron deltaic sandstones in central Utah as analogs for the North Foster (Grayburg) and Lake Creek (Wilcox) units, respectively. In both settings, sequence stratigraphic style profoundly influenced between-well architectural fabric and permeability structure. It is concluded that reservoirs of different depositional origins can therefore be categorized into a "heterogeneity matrix" based on varying intensity of vertical and lateral heterogeneity. The utility of the matrix is that it allows prediction of the nature and location of remaining mobile oil. Highly stratified reservoirs such as the Grayburg, for example, will contain a large proportion of vertically bypassed oil; thus, an appropriate recovery strategy will be waterflood optimization and profile modification. Laterally heterogeneous reservoirs such as deltaic distributary systems would benefit from targeted infill drilling (possibly with horizontal wells) and improved areal sweep efficiency. Potential for advanced recovery of remain-

ing mobile oil through heterogeneity-based advanced secondary recovery strategies in Texas is projected to be an incremental 16 Bbbl. In the Lower 48 States this target may be as much as 45 Bbbl. at low to moderate oil prices over the near to mid term.

NIPER-611

CT Imaging of Surfactant-Enhanced Oil Recovery Experiments. Topical Report.

National Institute for Petroleum and Energy Research. December 1992. 32 pp. Order No. DE93000103. Four CT monitored corefloods were conducted, and oil saturation distributions were calculated at various stages of the experiments. Results suggested that this technique could add significant information toward interpretation and evaluation of surfactant/polymer EOR recovery methods. CT-monitored tracer tests provided information about flow properties in the core samples. Non-uniform fluid advance could be observed, even in core that appeared uniform by visual inspection. Porosity distribution maps based on CT density calculations also showed the presence of different porosity layers that affected fluid movement through the cores. Several types of CT-monitored corefloods were conducted. Comparisons were made for CT-monitored corefloods using chemical systems that were highly successful in reducing residual oil saturations in laboratory experiments and less successful systems. Changes were made in surfactant formulation and in concentration of the mobility control polymer. Use of a poor mobility control agent failed to move oil that was not initially displaced by the injected surfactant solution, even when a "good" surfactant system was used. Use of a less favorable surfactant system with adequate mobility control could produce as much oil as the use of a good surfactant system with inadequate mobility control. The role of mobility control, therefore, becomes a critical parameter for successful application of chemical EOR. Continuation of efforts to use CT imaging in connection with chemical EOR evaluation is recommended.

Thermodynamics

NIPER-623

Thermodynamic Modeling for Organic Solid Precipitation. Topical Report.

National Institute for Petroleum and Energy Research. December 1992. 32 pp. Order No. DE93000104. A generalized predictive model which is based on thermodynamic principle for solid liquid phase equilibrium has been developed for organic solid precipitation. The model takes into account the effects of temperature, composition, and activity coefficient on the solubility of wax and asphaltene in organic solutions. The solid liquid equilibrium K value is expressed as a function of the heat of melting, melting point temperature, solubility parameter, and the molar volume of each component in the solution. All these parameters have been correlated with molecular weight. Thus, the model can be applied to crude oil systems. The model has been tested with experimental data for wax formation and asphaltene precipitation. The predicted wax appearance temperature is very close to the measured temperature. The model not only can match the measured asphaltene solubility data but also can be used to predict the solubility of asphaltene in organic solvents or crude oils. The model assumes that asphaltene is dissolved in oil in a true liquid state, not in colloidal suspension, and the precipitation/dissolution process is reversible by changing thermodynamic conditions. The model is thermodynamically consistent and has no ambiguous assumptions.

Fundamental Petroleum Chemistry

NIPER-598

The Thermodynamic Properties of 4, 5, 9, 10-Tetrahydropyrene and 1, 2, 3, 6, 7, 8-Hexahydropyrene. Topical Report. National Institute for Petroleum and Energy Research. December 1992. 64 pp. Order No. DE93000102.

Measurements leading to the calculation of the ideal-gas thermodynamic properties are reported for 4, 5, 9, 10-tetrahydropyrene and 1, 2, 3, 6, 7, 8-hexahydropyrene. Experimental methods included combustion calorimetry, adiabatic heat capacity calorimetry, vibrating tube densitometry, comparative ebulliometry, inclined-piston gauge manometry, and differential-scanning calorimetry (d.s.c.). Critical properties were estimated for both materials based on the measurement results. Entropies, enthalpies, and Gibbs energies of formation were derived for the ideal gases for selected temperatures between 380 K and 700 K. The property-measurement results reported here for 4, 5, 9, 10-tetrahydropyrene and 1, 2, 3, 6, 7,

8-hexahydropyrene are the first for these important intermediates in the pyrene/H₂ hydrogenation reaction network.

Microbial Technology

NIPER-629

Modeling and Laboratory Investigations of Microbial Oil Recovery Mechanisms in

Porous Media. Topical Report. National Institute for Petroleum and Energy Research. December 1992. 36 pp. Order No. DE93000105. Simulation and experimental results on the transport of microbes and nutrients in one-dimensional cores are presented, and the development of a three-dimensional, three-phase, multiple component numerical model to describe the microbial transport and oil recovery in porous media is described. The change of rock's wettability and associated relative permeability values after microbial treatments were accounted for in the model for additional oil recovery. Porosity and permeability reductions because of cell clogging have been considered and the production of gas by microbial metabolism has been incorporated. Governing equations for microbial and nutrient transport are coupled with continuity and flow equations under conditions appropriate for a black oil reservoir. From our concepts of the hydrodynamics, physics, chemistry and microbiology of microbial oil recovery (MEOR) processes, microbial parameters incorporated into the microbial transport model include: (1) microbial growth and decay; (2) microbial deposition; (3) chemotaxis; (4) diffusion; (5) convective dispersion; (6) tumbling; and (7) nutrient consumption. Laboratory experiments were conducted to obtain actual data for the simulator regarding microbial growth and decay, nutrient consumption, microbial deposition, convective dispersion, and diffusion. Unsteady state relative permeability measurements using microbial formulations were made to determine the effects of microbial metabolites on fractional fluid flow in porous media.

Mechanisms considered important for oil recovery include changes in microscopic properties such as interfacial tension, wettability, and adsorption that govern oil mobilization and affect fractional flow and relative permeability. Computer tomography studies demonstrated that gas production by microorganisms in porous media can reduce residual oil saturation in porous media.

DOE/BC/14665-8

A Study of the Interactions Between Microorganisms, Microbial By-Products,

and Oil-Bearing Formation Materials. Final Report. Mississippi State University. December 1992. The results of this investigation support the concept that microorganisms indigenous to subterranean oil reservoirs enhance oil recovery. Studies were conducted to test this concept under the most realistic conditions possible in the laboratory. Specifically, cores from oil reservoirs were used in coreflood experiments. This way, microorganisms, formation materials, oil, and water were in as close to their natural state as possible. Simulated production water containing supplemental nutrients then were allowed to flow through these cores. No supplemental nutrients were added to the water flowing through the control cores. One test core and one control core were prepared from cores obtained from five different reservoirs. The following results were obtained when supplemental nitrogen and phosphorous sources were added to the injection water: (1) oil was released from the test cores, (2) there was an increase in the number of microorganisms present in the core effluent, (3) the production of acid by the microflora resulted in the dissolution of large amounts of carbonate material and the development of new channels, (4) some plugging of the more porous zones occurred, (5) gas was produced in some cases, and (6) the addition of trace amounts of ethanol to the injection water greatly enhanced the release of oil and the dissolution of carbonate in the formation material.

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CHEMICAL FLOODING— SUPPORTING RESEARCH

SURFACTANT FLOODING METHODS

**Cooperative Agreement DE-FC22-83FE60149,
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Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this year's work are to (1) apply advanced enhanced oil recovery (EOR) technology based on mixed surfactant systems to improve oil recovery from

Class 1 reservoirs, (2) extend the use of surfactant EOR to different salinity and temperature ranges by developing surfactant systems that are more adaptable to changes in chemical composition in selected reservoirs, and (3) develop cost-effective chemical systems for selected field applications that may contain low concentrations of synthetic surfactants and alkaline additives. The emphasis of these studies will be on problem areas that may have adverse effects on the performance and economics of chemical flooding processes in an effort to achieve a balance between cost and oil recovery effectiveness.

Summary of Technical Progress

Mixed Surfactant Systems

In previous phase inversion temperature (PIT) studies, the difference in behavior of the nonionic surfactants, particularly the linear alkyl alcohol ethoxylate type (i.e., the Neodol® and Genapol® series) compared to the dialkyl phenol surfactants (i.e., the Igepal series) at similar hydrophilic-lyophilic balance (HLB) levels was reported.¹ The mixtures of dialkyl phenols exhibited a more significant dependence on the HLB value than the linear ethoxylates did. The contrast in the behavior of these two types of surfactants was more pronounced at lower HLB values and decreased at higher HLB values. Additional PIT studies were conducted on similar chemical systems with different oils. A series of hydrocarbons was used in these studies, and the results were compared to the

results with *n*-decane. Comparisons of the results with *n*-decane and *n*-octane are presented in Figs. 1 and 2. These figures show plots of the optimum salinity of the different mixtures vs. the HLB of the nonionic components with

(1) *n*-decane and (2) *n*-octane at 50 and 60 °C, respectively. As previously reported, the two types of surfactants indicated a difference in dependence of optimal salinity with the HLB of the nonionic components in the system. The comparable

Fig. 1 Comparison of optimal salinity [phase inversion temperature (PIT) method] vs. hydrophilic-lyophilic balance (HLB) of nonionic surfactant component using Genapol® and Igepal mixtures at 50 °C with *n*-decane and *n*-octane.

Fig. 2 Comparison of optimal salinity [phase inversion temperature (PIT) method] vs. hydrophilic-lyophilic balance (HLB) of nonionic surfactant component using Genapol® and Igepal mixtures at 60 °C with *n*-decane and *n*-octane.

results obtained using the *n*-octane support the indicated pattern difference between the two types of nonionics. The surfactant structure appears to have a significant effect on the HLB of the system.² The results also show that altering the carbon chain length of the oil resulted in a shift of the effective salinity range at a specific calculated HLB value. This was similar to observations made by other researchers.² At a higher temperature level (Fig. 2), the two types of surfactants also indicated a difference in dependence of optimal salinity with the HLB of the nonionic components in the system, up to an HLB level of 11. Greater than 11, the pattern in behavior of the two types of nonionic surfactants was almost identical. This may indicate some possible "shift" in the structure-dependence of the required HLB at this level.

The PIT method has been shown to be a relatively fast screening method for determining approximate optimal conditions for candidate surfactant systems. Although the method was primarily used by Shinoda and others in screening nonionic surfactants,^{3,4} it was also useful in identifying possible combinations of anionic-nonionic mixtures. The relative speed and ease by which the chemical systems were screened made it possible to evaluate a large number of combinations of several series of surfactants. Compared with the conventional way of screening using salinity scans, the PIT method allowed several surfactant systems to be screened in relatively short order. One drawback of the PIT method, though, is the inability to quantify the solubilization capacity of each of the chemical formulations. One still would need the more time-consuming method of conducting a salinity scan to determine solubilization parameters. The use of the two methods in sequence allowed a much better approach in optimizing chemical screening time and effort. To this effect, the optimal salinity regions mapped using the PIT method were used as reference points in narrowing the scale needed to conduct a sufficient salinity scan. To validate the reliability of the optimal salinity regions mapped with the PIT method, comparisons were made of similar salinity regions identified with the conventional salinity scan on selected chemical systems. The results of these comparisons showed fairly good agreement between the salinity regions determined using both methods, within $\pm 1.5\%$ NaCl. These results support the possibility of utilizing the PIT method for initially identifying the salinity regions of interest, followed by additional studies including salinity scans and interfacial tension (IFT) measurements to determine oil recovery potential.

For task 3, Topical Report NIPER-611, *CT Imaging of Surfactant Enhanced Oil Recovery Experiments*, was completed and delivered to the Department of Energy (DOE). The computerized tomography (CT) imaging techniques can play an important role in understanding the roles of surfactant formulation, mobility control, and rock pore structure in chemical EOR processes. For example, Fig. 3 shows CT images of the oil saturation distributions near the core entrance for oil recovery experiments with North Burbank Unit (NBU) oil and two different surfactant systems. The mixed surfactant system (alkyl aryl sulfonate and ethoxylated sulfate) used for

Fig. 3 Comparison of computerized tomography (CT) images of oil saturation distributions near the core entrance for two oil recovery experiments with North Burbank Unit oil and different surfactant chemical formulations.

case A left a higher oil saturation near the core entrance than the petroleum sulfonate system shown for case B. Average oil saturations were 10 and 3.9%, respectively. The mixed surfactant system also exhibited a higher IFT value than that of the petroleum sulfonate system (0.014 and 0.001 mN/m, respectively).

Other tests demonstrated that the use of a poor mobility control agent failed to move oil that was not initially displaced by the injected surfactant solution, even when an effective surfactant system was used. Use of a less favorable surfactant system with adequate mobility control could produce as much oil as the use of a good surfactant system with inadequate mobility control. The role of mobility control, therefore, becomes a critical parameter for successful application of chemical EOR.

For task 4, Status Reports NIPER-608, *Development of a Chemical Flooding EOR Literature Database System*, and NIPER-609, *Low-Concentration Surfactant Flooding: Partitioning of Synthetic Surfactants*, have been completed and delivered to DOE.

For task 6, Topical Report NIPER-631, *Evaluation of Mixed Surfactants for Improved Chemical Flooding*, has been submitted for review. This report summarizes the results of the work performed this year for tasks 1 and 2 of this project.

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DEVELOPMENT OF IMPROVED ALKALINE FLOODING METHODS

**Cooperative Agreement DE-FC22-83FE60149,
Project BE4B**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$195,000**

**Principal Investigator:
Troy R. French**

**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The overall objective of this project is to develop cost-effective and efficient chemical flooding formulations using surfactant-enhanced, weakly alkaline systems. Specific objectives for FY92 are to (1) determine the effect of variables on polymer propagation and retention during alkaline flooding and (2) perform studies designed to support a field test.

Summary of Technical Progress

The interactions that can occur during surfactant-enhanced alkaline flooding are complex. Some of the parameters are pH level, ionic strength, polymer properties, cosurfactant (alcohols) properties, and surfactant properties. The presence of crude oil may also affect interaction, as can other chemicals.¹ At least six types of surfactant-polymer complexes have been described, and the interactions that occur between polymers and surfactants could be the most significant of the possible interactions that can occur during surfactant-enhanced alkaline flooding.¹⁻⁵ Polymer-surfactant interaction is the focus of this work. Rheological properties of polymer solutions were monitored over a long period of time in the presence of surfactants, at different pH levels, and in the presence of crude oil.

REAGENTS and CHEMICALS

Hepler (Kansas) Tucker Sand crude oil

Surfactants:

Chevron Chaser XP-100, an anionic surfactant,
mol wt = 434

Chevron Chaser CF-100, an experimental anionic
surfactant

Stepan Petrostep B-110, an anionic surfactant,
mol wt = 500

Stepan Petrostep B-105, an anionic surfactant mixture,
mol wt = ~424

Shell Neodol 25-9, ethoxylated alcohol, mol wt = 610

Polymers:

Pfizer Flopaam 3230E, a low-molecular-weight, partially
hydrolyzed emulsion polyacrylamide,
mol wt = $7-8 \times 10^6$

Pfizer Flopaam 3230S, a low-molecular-weight, partially
hydrolyzed solid polyacrylamide, mol wt = $7-8 \times 10^6$

Pfizer Flocon 4800CX, a biopolymer

Allied Colloids Alcoflood 1135, a medium-molecular-
weight partially hydrolyzed solid polyacrylamide
polymer

Alkalis:

Sodium carbonate, analytical reagent

Sodium bicarbonate, certified ACS

Sodium hydroxide, certified ACS

Sodium tripolyphosphate (STPP), technical

Make-up water:

Deionized water (DIW)

Hepler supply well water, mg/L:

Sodium and potassium	830
Chlorides	908
Calcium and magnesium	21
Bicarbonate	720
TDS	2483
pH	7.9

Rheology and pH of mixtures were periodically monitored for 191 d. All compositions are given as weight per volume. A Contraves low-shear viscometer was used for initial measurements of viscosity. Because of mechanical problems with the Contraves, the later measurements were made with a Brookfield Model LVT-C/P 1.565" cone and plate viscometer. Rheological measurements were displayed graphically in three-dimensions using a computer program that was specifically designed for three-dimensional (3-D) plots. An Orion Model 601 digital pH meter was used for pH measurements. Samples were monitored visually for phase separation, cloudiness, and precipitation.

Interfacial properties of selected systems were measured with a University of Texas spinning drop interfacial tensiometer. Transient (dynamic) interfacial tension (IFT) behavior was monitored over a time interval of several hours.

The polymer used for the tests shown in Figs. 1 through 4 was Alcoflood 1135, a medium-molecular-weight anionic polymer that is furnished in solid form. Alcoflood 1135 is a partially hydrolyzed polyacrylamide. The detrimental effect of salt solutions on the rheological properties of polyacrylamide polymers is well-known. It is also known that certain interactions occur between anionic polymers and surfactants.

The surfactant used for the tests shown in Figs. 1 through 4 was Chevron XP-100, an anionic surfactant. Adjustment of pH was done with sodium hydroxide, a strong alkali.

Fig. 1 Viscosity of 2000 ppm Alcoflood 1135 polymer and 0.5% Chevron XP-100 surfactant in 0.4% NaCl, pH 7.04, 23 °C.

Fig. 3 Viscosity of 2000 ppm Alcoflood 1135 polymer, 0.5% Chevron XP-100 surfactant, and 0.1% Hepler (Kansas) crude oil in 0.4% NaCl, pH 7.07, 23 °C.

Fig. 2 Viscosity of 2000 ppm Alcoflood 1135 polymer and 0.5% Chevron XP-100 surfactant in 0.4% NaCl, pH 10.70, 23 °C.

Fig. 4 Viscosity of 2000 ppm Alcoflood 1135 polymer, 0.5% Chevron XP-100 surfactant, and 0.1% Hepler (Kansas) crude oil in 0.4% NaCl, pH 10.73, 23 °C.

Weak, buffered alkalis have properties that are advantageous for field use.⁶ For these studies, however, the strong alkali is more useful because pH adjustment can be accomplished with the addition of small amounts of the strong alkali; therefore, the ionic strength is changed only very little during pH adjustment. Ionic strength adjustments were accomplished with NaCl.

The rates of change in apparent viscosity for mixtures that contain polymer and surfactant are shown in Figs. 1

through 4. Figures 1 and 2 show the results of periodic measurements of polymer-surfactant mixtures at pH 7.04 and 10.70, respectively, in 0.4% NaCl. At pH 7.04, viscosity decreased sharply for 50 d and continued to decline over the entire time interval. Overall, viscosity decreased from 60 to 19 cP at low shear rate, a decrease of 68%. For pH 10.70, behavior was very similar. After a slight initial increase in viscosity at early time, viscosity decreased sharply during the first 40 d of measurements. Overall, viscosity

decreased from 58 to 27 cP at low shear rate, a decrease of 54%. A slight increase in viscosity at early time was measured for all of the mixtures that contained polymer and surfactant.

The rates of change in apparent polymer viscosity for polymer-surfactant-oil mixtures are shown in Figs. 3 and 4. Figures 3 and 4 show the results of periodic measurements of polymer-surfactant-oil mixtures at pH 7.07 and 10.73, respectively, in 0.4% NaCl. At both pH values, initial viscosity was lower and the rate of viscosity decrease was less steep than that for the previously discussed mixtures of polymer-surfactant mixtures. Polymer-surfactant-oil mixtures were more homogeneous in appearance, and there was less scatter in measurements. At pH 7.07, viscosity decreased from 50 to 19 cP over the time interval, an overall decrease of 62%. At pH 10.73, viscosity decreased from 52 to 40 cP, an overall decrease of only 23%.

In 1.2% NaCl, very similar results were obtained for polymer-surfactant-oil mixtures. At pH 6.87, overall viscosity decrease at low shear rate was from 20 to 8 cP, or 60%. At pH 10.79, viscosity decrease was from 25 to 15 cP, or 40%.

A report that summarizes the results from FY 1992 research, *The Effect of Polymer-Surfactant Interaction on the Rheological Properties of Surfactant-Enhanced Alkaline Flooding Formulations* has been submitted for peer review.

Observations and Conclusions

The following observations and conclusions are based on results of work that was performed this year:

1. Polymer-surfactant interaction can be expected to have an adverse effect on oil recovery, especially when permeability is low.
2. Polymer-surfactant interaction (phase separation, precipitation, and viscosity loss) occurred between most of the polymers and surfactants that were tested.
3. Polymer-surfactant interaction is difficult to eliminate, and no method was found for completely eliminating interaction.
4. Polymer-surfactant interaction occurred at optimal salinity and below optimal salinity.
5. The magnitude of the interaction was least for nonionic surfactant and biopolymer.
6. Polymer-surfactant interaction had an adverse effect on polymer rheology.
7. The adverse effect of interaction on polymer rheology was lessened when oil was present.
8. When oil was present, the adverse effect of interaction on polymer rheology was further reduced by increasing pH.

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MOBILITY CONTROL AND SWEEP IMPROVEMENT IN CHEMICAL FLOODING

Cooperative Agreement DE-FC22-83FE60149,
Project BE4C

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1992
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Principal Investigators:
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Project Manager:
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Bartlesville Project Office

Reporting Period: July 1-Sept. 30, 1992

Objectives

The objectives of this project are to develop improved methods for maintaining effective mobility control throughout the reservoir in chemical flooding and to use the permeability modification simulator to design cost-effective gel treatments using polymer gels.

Summary of Technical Progress

To investigate the effect of lamination angle on polymer retention, corefloods were conducted with two fired rectangular Berea cores. The first one had laminations parallel to

the longest axis of the core. The second one had laminations at 90° from the longest axis of the core. Two slugs of a 1000 ppm biopolymer solution in 53 meq/L NaCl were injected into each core. It was found that polymer retention in the first core was greater than that in the second core. Comparison of polymer retention in three cores showed that polymer retention was greater in cores that had laminations parallel to the direction of flow than in cores that had crossbed laminae. In cores that had crossbed laminae, polymer retention increased with the increase in the lamination angle.

Application to Enhanced Oil Recovery

Understanding the effect of lamination angle on polymer retention will help to maintain effective mobility control throughout a reservoir in chemical flooding. Mechanical degradation of high-molecular-weight polyacrylamides is a problem in field applications. A mobility control system based on crosslinking a low-molecular-weight polyacrylamide may be much less susceptible to mechanical degradation. A permeability modification simulator is very useful to facilitate the design of cost-effective gel treatments and assess potential fields for permeability modification treatments using gelled polymers.

Polymer Retention in Berea Sandstone Cores

Four corefloods were conducted with two fired rectangular Berea sandstone cores, A and C. Core A (4.00 × 4.06 × 24.37 cm, porosity = 19.6%, brine permeability = 258 mD) was cut along the longest axis of the core, and core C (4.02 × 3.84 × 24.33 cm, porosity = 19.7%, brine permeability = 180 mD) was cut at 90° from the longest axis of the core. Before polymer flow, each core was scanned with computerized tomography (CT) to determine the exact locations and directions of the laminations and to identify areas of porosity contrast. After brine permeability was measured, tracer (10% sodium iodide) tests were conducted to determine the flow path of brine before polymer injection. The flow behavior of the tagged (sodium iodide) brine was monitored throughout its advance through the core by using conventional CT procedures and the rapid topogram scanning approach. The resulting images of tracer slug in each core were compared with those after the polymer flow.

The polymer solution used in the corefloods was 1000 ppm biopolymer in 53 meq/L NaCl, which was prepared from Pfizer's FLOCON 4800C. Brine concentration was 53 meq/L NaCl. Both biopolymer solution and brine contained 500 ppm of 37.3% formaldehyde as a biocide. Effluents were collected with a fraction collector and analyzed for the amount of biopolymer produced. The effluent biopolymer concentration was determined by viscosity measurements at a shear rate of 20.4 s⁻¹ with a Contraves Low Shear 30 viscometer. All corefloods were conducted at room temperature (22.4 °C).

Two slugs of polymer solutions with each slug chased by about 8 pore volumes (PV) of brine were injected into

each core. The sizes of the two slugs injected into core A were 3.51 and 4.49 PV and those injected into core C were 3.5 and 4.54 PV. The flow rates used in cores A and C were 5.47 mL/h (1.35 ft/d) and 4.3 mL/h (1.11 ft/d), respectively. These flow rates corresponded to an apparent shear rate of about 10 s⁻¹ in each core.

Figures 1 and 2 show the normalized effluent biopolymer concentration as a function of PV injected into each core. As shown in each figure, the effluent biopolymer concentration never reached that of the injected biopolymer solution, indicating that equilibrium retention had not been reached under the experimental conditions. The maximum

Fig. 1 Normalized effluent concentration profiles for biopolymer from core A, fired Berea sandstone with lamination angle of 0°, porosity of 19.6%, brine permeability of 258 mD, flow rate of 5.47 mL/h, apparent shear rate of 10 s⁻¹, and 1 PV = 77.6 mL. —, 1st slug, 0–3.51 PV. ---, 2nd slug, 0–4.49 PV.

Fig. 2 Normalized effluent concentration profiles for biopolymer from core C, fired Berea sandstone with lamination angle of 90°, porosity of 19.7%, brine permeability of 183 mD, flow rate of 4.3 mL/h, apparent shear rate of 9.9 s⁻¹, and 1 PV = 74 mL. —, 1st slug, 0–3.50 PV. ---, 2nd slug, 0–4.54 PV.

effluent biopolymer concentration from core A was greater than that from core C, indicating that polymer retention was greater in core A than in core C.

Figures 3 and 4 show the cumulative polymer retention as a function of PV injected during and after the first slug of polymer injection and during and after the second slug of polymer injection, respectively, for three different cores. Data from corefloods with core B conducted in the last quarter¹ are also shown in these two figures for comparison. Core B had laminations at 30° from the longest axis of the core. As shown in each figure, during the polymer injection, core A, which had laminations parallel to the flow direction, gave the greatest polymer retention, and core B, which had a lamination angle of 30° with respect to the direction of the longest axis, gave the least polymer retention. The maximum amounts of polymer retention in cores A, B, and C were 1007, 816, and 916 kg/acre-m, respectively.

Fig. 3 Retention of biopolymer in cores A (—○—), B (---□---), and C (---×---) during and after the first slug of polymer injection with apparent shear rate of 10 s^{-1} .

Fig. 4 Retention of biopolymer in cores A (—○—), B (---□---), and C (---×---) during and after the second slug of polymer injection with apparent shear rate of 10 s^{-1} .

tively, during the first slug of polymer injection, and 894, 768, and 859 kg/acre-m, respectively, during the second slug of polymer injection.

During the post-brineflood, most of the retained polymer was flushed out of the core, leaving irreversible polymer retention inside the core. As shown in Figs. 3 and 4, core A, which gave the greatest polymer retention during polymer flow, also gave the greatest irreversible retention, and core B, which gave the least polymer retention during polymer flow, also gave the least irreversible retention. The amounts of irreversible retention from the first slug of polymer injection in cores A, B, and C were 309, 73, and 201 kg/acre-m, respectively. From the second slug of polymer injection, the amounts of irreversible retention were 188, 15, and 138 kg/acre-m, respectively. Total amounts of irreversible retention from these two slugs of polymer injection into cores A, B, and C were 497, 88, and 339 kg/acre-m, respectively. These results indicated that polymer retention was greater in cores that have laminations parallel to the direction of flow, such as core A, than in cores that have crossbed laminations, such as cores B and C. In cores with crossbed laminations, polymer retention increased with an increase in the lamination angle. Because of the low salt concentration and clean core materials used, adsorption was negligible under experimental conditions. X-ray diffraction analysis showed that this Berea sandstone contained only trace amounts of kaolinite. Therefore, most of the polymer retained can be attributed to mechanical entrapment.

CT Tracer Tests

Comparison of the CT images of the tracer slug advancing through the cores during tracer tests conducted before and after the polymer flow in core A showed that fingering became more severe after the polymer flow. This was caused by an increased permeability contrast between various rock layers after the polymer flow. The increased permeability contrast was caused by retained polymer that decreased the permeability in the low-permeability laminations to a larger degree than in the high-permeability layers. Therefore, in cores that have laminations parallel to the direction of flow, retained polymer has an adverse effect on the stability of the fluid front.

In core C, the tracer front became more piston-like after the polymer flow than before the polymer flow. Before polymer flow, gravity effect caused the fluid front to deviate from the direction of laminations. After the polymer flow, the front became more uniform, indicating that gravity effect was overcome by retained polymer in the low-permeability laminations. A similar effect of retained polymer on the shape of tracer front was also seen in core B. Therefore, in cores that have crossbed laminations, retained polymer is helpful in improving the stability of the fluid front.

A paper, entitled *The Effects of Layer Permeability Contrast and Crossflow on the Effectiveness of Polymer Gel*

Treatments in Polymer Floods and Waterfloods, was accepted for presentation at the 1993 Society of Petroleum Engineers Production Operations Symposium to be held in Oklahoma City, March 21–23, 1993.

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SURFACTANT-ENHANCED ALKALINE FLOODING FIELD PROJECT

**Cooperative Agreement DE-FC22-83FE60149,
Project SGP41**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

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**Principal Investigator:
Troy R. French**

**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this pilot project are to (1) obtain information and data that will help to demonstrate the applicability of surfactant-enhanced alkaline flooding as a cost-effective enhanced oil recovery (EOR) method, (2) transfer the surfactant-enhanced alkaline flooding technology that has been developed under the sponsorship of the Department of Energy (DOE) to the petroleum industry, and (3) obtain information regarding procedures for designing and applying this technology that will assist independent producers in sustaining production from mature producing oil fields rather than abandoning marginal wells.

Summary of Technical Progress

The site selected for conducting a field pilot test using surfactant-enhanced alkaline flooding methods is Hepler (Kansas) oil field. Hepler field is in Crawford and Bourbon

counties. This near-term application of a promising EOR technology in a fluvial-dominated deltaic type reservoir is consistent with DOE oil research strategy.¹ This report covers final site selection and the optimization of slug sizes and chemical (especially polymer) concentrations.

In June 1992 a categorical exclusion (CX) was approved by the DOE Pittsburgh Energy Technology Center (PETC) and returned to the National Institute for Petroleum and Energy Research (NIPER). The CX is for the drilling of evaluation wells in the producing pattern in Hepler field under the class of actions in B3.7, "Siting, construction, and operation of new infill exploratory and experimental (test) oil, gas and geothermal wells, which are to be drilled in a geological formation that has existing operating wells." The CX is part of new DOE regulations approved in late May 1992 and was necessary before DOE funds could be allocated for expenditure at the field site.²

In September field cores were obtained from three additional locations on the lease site. The evaluation of field cores and the evaluation of maps of permeability, porosity, oil saturation, and stratigraphy resulted in selection of an alternate location (in Hepler field) for the pilot project. The pilot will be conducted in the N $\frac{1}{2}$ SW $\frac{1}{4}$ NE $\frac{1}{4}$ S30 T27S R22E area of the field operator's lease. This location is northeast of the location that was originally selected.³ The project well pattern is shown in Fig. 1. Wells J-2, J-4, H-2, and H-4 will be used as injectors. Oil recovery tests with field cores from wells J-4, H-4, and G-5 are now in progress.

With large pore volumes and high polymer concentrations, a chemical system that contained 0.5% active Chevron Chaser XP-100, 0.45% active sodium tripolyphosphate (STPP), and 1.2% NaHCO₃ (1.6% NaHCO₃ also gave low IFT) in water supply well (WSW) water produced extremely good oil recovery in core tests conducted in Berea sandstone cores. After chemical flooding, final core oil saturations were as low as 5% PV.⁴ For economic reasons, smaller volumes of chemicals will be injected during the field test. Because of the limits on field injection pressure, which is determined by depth and overburden pressure, polymer viscosity will also be reduced for field application. The results of core tests conducted in Berea cores with smaller slug sizes of the injected chemicals and lower polymer concentrations are shown in Table 1.

The adverse effect of decreasing permeability on oil recovery was previously reported.⁴ The permeabilities of the Berea cores used for the corefloods shown in Table 1 vary from 86 to 122 mD, which is representative of field permeabilities. The maximum total oil recovery efficiency (waterflood + chemical flood) achieved in this series of corefloods was 71% original oil in place (OOIP).

In corefloods RP-19 through RP-23 the main chemical slug contained surfactant, alkali, and polymer. In each case the main chemical slug was preceded by an alkaline preflush and followed with polymer, the concentration of which was graded to increasingly lower viscosities. In coreflood RP-19 chemical flooding was commenced after waterflooding,

Fig. 1 Field site in the Elmer C Lease, Hepler (Kansas) oil field.

and the total oil recovery was 57.2% of OOIP. In coreflood RP-20 there was no waterflood; chemical flooding was commenced at initial oil saturation. In this coreflood total oil recovery was 53.9% of OOIP, which was slightly less than that for coreflood RP-19 where chemical flooding was preceded by a waterflood. Coreflood RP-21 was a repeat of

RP-20, except that polymer concentration and viscosity were further reduced. Oil recovery was 54.0% of OOIP, which was almost identical to that from coreflood RP-20.

Coreflood RP-21R was commenced in the same core as RP-21 by injecting an additional 0.20 PV of the same chemical formulation. Total oil recovery increased from

TABLE 1
Summary of Coreflood Injection Strategies and Results—Hepler (Kansas) Oil

Coreflood	Core type	K, mD	Preflush solution		First chemical formulation injected		Second chemical formulation injected		Recovery efficiency, %		
			Composition	Vol., PV	Composition	Vol., PV	Composition	Vol., PV	S _{owf} , %*	S _{oef} , %*	Total†
RP-19	Berea [§]	96	pH 8.3 STPP ⁷ /carbonate mixture	0.10	0.5 g STPP ⁷ + 1.2 g NaHCO ₃ + 0.5 g XP-100/100 mL and 2000 ppm Flopaam 3230S polymer, $\mu = 20.0$ cP	0.20	Graded concentration of Flopaam 3230S $\mu = 14.6$ cP to 5.8 cP	0.15	45.8	35.4	57.2
RP-20	Berea [§]	92	pH 8.3 STPP ⁷ /carbonate mixture	0.10	0.5 g STPP ⁷ + 1.2 g NaHCO ₃ + 0.5 g XP-100/100 mL and 2000 ppm Flopaam 3230S polymer, $\mu = 20.0$ cP	0.20	Graded concentration of Flopaam 3230S $\mu = 14.6$ cP to 5.8 cP	0.15	N.A.*	37.4	53.9
RP-21	Berea [§]	87	pH 8.3 STPP ⁷ /carbonate mixture	0.10	0.5 g STPP ⁷ + 1.2 g NaHCO ₃ + 0.5 g XP-100/100 mL and 1200 ppm Flopaam 3230S polymer, $\mu = 20.0$ cP	0.20	Graded concentration of Flopaam 3230S $\mu = 10.0$ cP to 7.2 cP	0.15	N.A.*	37.0	54.0
RP-21R	Berea [§]	87	pH 8.3 STPP ⁷ /carbonate mixture	0.10	0.5 g STPP ⁷ + 1.2 g NaHCO ₃ + 0.5 g XP-100/100 mL and 1200 ppm Flopaam 3230S polymer, $\mu = 20.0$ cP	0.20	Graded concentration of Flopaam 3230S $\mu = 10.0$ cP to 7.2 cP	0.15	N.A.*	31.0	61.5
RP-22	Berea [§]	122	pH 8.3 STPP ⁷ /carbonate mixture	0.10	0.5 g STPP ⁷ + 1.2 g NaHCO ₃ + 1.0 g XP-100/100 mL and 1200 ppm Flopaam 3230S polymer, $\mu = 20.0$ cP	0.10	Graded concentration of Flopaam 3230S μ of alk polymer = 7.0 cP	0.15	N.A.*	38.8	52.4
RP-23	Berea [§]	77	pH 8.3 STPP ⁷ /carbonate mixture, 600 ppm Flopaam 3230S polymer, $\mu = 3.3$ cP	0.10	0.5 g STPP ⁷ + 1.2 g NaHCO ₃ + 0.5 g XP-100/100 mL and 2000 ppm Flopaam 3230S polymer	0.10	Graded concentration of Flopaam 3230S $\mu = 14.6$ cP to 5.8 cP	0.15	40.5	33.0	58.3
RP-24	Berea [¶]	86	pH 8.3 STPP ⁷ /carbonate mixture	0.10	0.5 g STPP ⁷ + 1.2 g NaHCO ₃ + 0.5 g XP-100/100 mL	0.20	Graded concentration of Alcoflood 1135 $\mu = 19.4$ cP to 5.8 cP	0.30	37.1	23.5	71.0

*S_{owf}, oil saturation after waterflood; S_{oef}, oil saturation after chemical flood; STPP, sodium tripolyphosphate; N.A., not available.

†Recovery efficiency = (oil produced during chemical flood/oil remaining after waterflood) $\times$ 100.

‡Recovery efficiency = (oil produced during waterflood and chemical flood/original oil) $\times$ 100.

§Cores were saturated with synthetic brine containing 1.022 g NaCl, 0.033 g CaCl₂, and 0.0694 g MgCl₂·6H₂O/100 mL.

¶Cores were saturated with lease return water.

54.0 to 61.5% of OOIP, an increase of 7.5%. This indicates that oil recovery is increased by increasing the size of the chemical slugs injected, but the amount of increase in oil production is not proportionate to the increase in the chemical slug sizes, which were effectively double for coreflood RP-21R.

Coreflood RP-22 shows the result of injecting a smaller chemical slug with increased surfactant concentration. In this coreflood one-half of the volume of main chemical slug used in the other corefloods was injected, but the surfactant concentration was doubled from 0.5 to 1.0%. The total amounts of surfactant, polymer, and alkali injected were the same for both corefloods. The total amounts of alkali and polymer were maintained equal to that of other corefloods by replacing some of the drive water slug with water that contained polymer and alkali. Therefore, the total amounts of injected chemicals were equal to the amounts injected in the prior floods. This flood can be directly compared to RP-21. Oil recoveries from the two corefloods were very similar: 54.0% from coreflood RP-21 and 52.4% from coreflood RP-22.

Previous experiments have shown conclusively that an alkaline preflush increases the amount of Hepler oil recovered during surfactant-enhanced alkaline flooding.⁴ Coreflood RP-23 is the same as coreflood RP-19, except that the alkaline preflush was slightly viscified. Comparison of corefloods RP-19 and RP-23 shows that oil recoveries were almost identical, 57.2 and 58.3%, respectively. Therefore, even though an alkaline preflush can increase oil recovery, viscifying the preflush accomplishes little. (Note: the result in a heterogeneous reservoir may be quite different.)

For coreflood RP-24, injection strategy was changed. The main chemical formulation was the same as that for the other corefloods, except that it did not contain polymer. This injection strategy was tested because of the interaction that occurs between XP-100 and polymers. Polymer-surfactant interaction (phase separation, precipitation, and viscosity loss) occurs between XP-100 and biopolymers and polyacrylamides.⁵ No satisfactory method has been found to completely eliminate the interaction.

Oil recovery from coreflood RP-24 was greater than that for any of the other corefloods reported in Table 1. Total oil recovery was 71.0%; final oil saturation after chemical flooding was 23.5%. Higher oil recoveries were obtained in higher permeability cores and with higher polymer concentrations, but this was the best recovery achieved with small slugs of chemicals that have viscosities low enough for application in Hepler field. It was previously suggested that, for the field test, we should inject alkali, surfactant, and polymer in a single slug.⁶ However, the current plan is to inject polymer as a separate slug that follows injection of alkali and surfactant.

Chevron Chemical has now ceased production of Chaser XP-100 surfactant, although a large supply still remains in inventory. In the event that sufficient XP-100 is not avail-

able, a similar surfactant, Chaser CF-100, will be used for the project. CF-100 is similar to XP-100 except for higher salt tolerance. The dynamic interfacial tension (IFT) behavior of this system at several sodium bicarbonate concentrations is shown in Fig. 2. Optimum sodium bicarbonate concentration is in the 1.2 to 1.6% range, which is about the same as that for XP-100.

Fig. 2 Dynamic interfacial tension (IFT) between Hepler (Kansas) crude oil and a mixture of 0.1% active Chaser CF-100, 0.45% active sodium tripolyphosphate (STPP), and NaHCO_3 in water supply well (WSW) water, 23°C.

Summary

With large pore volumes and high polymer concentrations, injection of chemical formulations produced extremely good oil recovery in core tests conducted in Berea sandstone cores. After chemical flooding, final core oil saturations were as low as 5% PV. For economic reasons, smaller volumes of chemicals will be injected during the field test. Because of the limits on field injection pressure, which is determined by depth and overburden pressure, polymer viscosity will also be reduced for field application. The results

of core tests with smaller slug sizes in Berea cores with permeabilities representative of the reservoir showed that total oil recovery up to 71% OOIP can be achieved by injection of smaller chemical slugs. Final oil saturations after waterflooding and chemical flooding were as low as 23% PV.

Field cores were obtained from four locations on the lease site. The evaluation of field cores and the evaluation of maps of permeability, porosity, oil saturation, and stratigraphy resulted in changing the location for the pilot project to an area northeast of the location originally selected. Oil recovery tests with the field cores are in progress.

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GAS DISPLACEMENT— SUPPORTING RESEARCH

QUANTIFICATION OF MOBILITY CONTROL IN ENHANCED RECOVERY OF LIGHT OIL BY CARBON DIOXIDE

**Morgantown Energy Technology Center
Morgantown, W. Va.**

FY92 Total Project Cost: \$300,000

**Principal Investigator:
Duane H. Smith**

**Principal Manager:
Royal Watts
Morgantown Energy Technology Center**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives during the current year focus on factors affecting mobility control with surfactant-based dispersions. Furthermore, three different fluid phases (gas, oil, and water) are encountered in CO₂-enhanced oil recovery with surfactant-based mobility control, and these phases can form many different morphologies of fluid dispersions other than "foam." Hence primary emphasis has been on studying the morphologies of two-phase and three-phase ex situ and

in situ dispersions to develop the in-depth knowledge needed to solve these problems.

Summary of Technical Progress

In many different applications, such as gas-flood enhanced oil recovery with carbon dioxide,^{1,2} simple, accurate equations are needed to describe the physical properties of equilibrium vapor and liquid phases from the lowest temperature and pressure of coexistence up to their vapor-liquid critical point. Various cubic equations have been proposed and used for this purpose since van der Waals' original equation of state. Because of their cubic form, these equations and the equations derived from them all contain exponents that have "classical" values (that is, the exponents are always some multiple of 1/2). These equations often describe the properties of real fluids accurately except near their critical points.

The past four decades have brought an increasing awareness of the importance of critical point fluctuations, which are neglected in cubic equations of state. During this time the study of critical phenomena has become a mature scientific field in which the theory is well understood and shows excellent agreement with experiment on a wide variety of systems.³⁻⁶

This work shows that, near the critical point, the standard cubic equations of state give the wrong power-law behaviors. For example, on the critical isotherm ($T = T_c$),

where the dependence of the molar volume (v) on pressure (P) is described by

$$v = v_c + A'(P - P_c)|P - P_c|^{d-1} \quad (1)$$

the cubic equations give the classical exponent $d = 3$, whereas accurate measurements and theoretical calculations both yield the nonclassical value for this critical exponent $d = 4.8$ (Ref. 7). Likewise, for the shape of the vapor-liquid equilibrium coexistence curve (boundary of the two-phase region),

$$v^{\pm} = v_c \pm A''|T/T_c - 1|^{\beta} \quad (2)$$

all standard cubic equations of state predict the classical value for the exponent $\beta = 1/6$, whereas accurate measurements and theoretical calculations both show that $\beta = 0.325$ (Ref. 7). (The plus/minus sign denotes the liquid (gas) phase, values of A' and A'' depend on the chemical system, and subscript c denotes the critical point value.)

Because of the accuracy of modern scaling equations for single-component fluids near critical points, various authors⁸ have successfully applied a "modified Leung-Griffiths" approach⁹ (originally developed by Leung and Griffiths¹⁰ for He³/He⁴ vapor-liquid equilibrium) to numerous binary systems. Recently this approach also has been used¹¹ to predict ternary equilibria from fits to experimental data for the constituent binaries. However, the binary and ternary fits are accurate only over temperatures for which $|T/T_c - 1| < 0.1$. This limitation occurs partly because the equations for the single-component vapor-liquid equilibria (on which the binary equations are based) are limited to a restricted temperature range.

In fact, for more than a decade it has been recognized that scaling equations are accurate near critical points (but not far away) and that cubic equations are accurate far from criticality (but not near critical points). This recognition has led to combinations of the two types of equations into new equations that "cross-over" from classical to nonclassical behavior as criticality is approached.¹²⁻¹⁶ These approaches tend to produce new problems of finding and fitting the crossover region in addition to the problems of fitting the classical and nonclassical regions of phase behavior.

In common with other branches of thermodynamics, scaling theory has recognized the problem of choosing the appropriate concentration variable or "order parameter."¹⁷⁻¹⁹ An improved order parameter should extend the accuracy of the scaling equations to regions far from critical without changing their fundamental form or requiring that they be combined with equations that are fundamentally unsatisfactory.

Extending the accuracy of modern scaling equations by introducing a better order parameter is the objective sought here. More exactly, van der Waals' classic approach is combined with modern scaling theory, not by combining the equations but by using van der Waals' "free-space volume," $v - b$ (where b is the so-called excluded volume of the molecules), as the order parameter in the scaling equations.

Somewhat analogous to the approach of van der Waals, who improved the ideal-gas equation by substituting into it the volume available to the molecules in place of the molar volume, is the approach to substitute $v - b$ for v , not in the ideal-gas law, but in modern scaling equations.

The scaling equations were fit with the "new" order parameter to values²⁰ for the densities of vapor and liquid carbon dioxide from the vapor-liquid critical point to the solidus limit to illustrate this approach and the accuracy that it provides.

The scaling theory equations for the equilibrium liquid and vapor may be written⁴ as

$$r^{\pm} = r_c \pm t^b (B + C t^{\Delta} + \dots) + D t^{1-\alpha} + F t + \dots \quad (3)$$

where r is the order parameter; the plus sign applies for the liquid and the minus sign for the gas; subscript c denotes the critical point value; $t = |T/T_c - 1|$; the values of the universal exponents are $\alpha = 0.11$ (Ref. 7), $\beta = 0.325$ (Ref. 7), and $\Delta = 0.496$ (Ref. 21); and the values of B , C , D , and F depend on the chemical system.

For the order parameter, the following was chosen:

$$r = r^+ f \equiv \frac{1}{v^+ - b} \quad (4)$$

where b is taken to be a constant (independent of T and P), the value of which depends only on the compound.²² The constant b is identified with the effective volume occupied by a mole of molecules (i.e., the so-called excluded volume of the van der Waals equation). However, because it will be treated as a fitting parameter in the noncubic equation of state (Eq. 3), values of b in Eq. 4 are not expected to equal tabulated values obtained from fits of cubic equations.

The approximations $\beta + \Delta \approx 0.82 \sim 1$ and $1 - \alpha \approx 0.89 \sim 1$ are used to reduce the number of fitting parameters in Eq. 3. Furthermore, $C_l = C + D + F$, $C_g = -C + D + F$, $r_l^+ = r_{l,l}$ and $r_l^- = r_{l,g}$ are defined so that Eq. 3 becomes

$$r_{l,l} \approx r_{l,c} + B t^{\beta} + C_l t \quad (5a)$$

and

$$r_{l,g} \approx r_{l,c} - B t^{\beta} + C_g t \quad (5b)$$

and the regression is performed to minimize the percent difference between Eqs. 5a and 5b and the experimental data using $r_{l,c}$, T_c , b , B , C_l , and C_g as the parameters for the fits to the liquid and vapor data.

Figure 1 illustrates, for carbon dioxide from the vapor-liquid critical point down to the solidus limit, fits of Eqs. 5a and 5b to experimental data²⁰ for the molar volumes of the coexisting vapor and liquid as well as the experimental values. As shown in Fig. 1, the fit is too accurate for the

fitting errors to be visible when the data and the fit are plotted in this way.

Figure 2 shows the fitting error vs. the temperature for Fig. 1. The maximum error occurred near the critical point and was less than 1%. Over most of the temperature range, Eqs. 5a and 5b with the order parameter of Eq. 4 fit each

Fig. 1 Experimental vapor and liquid densities²⁰ (x) and fit of Eqs. 5a and 5b to the data.

Fig. 2 Fitting error (percent difference) vs. molar volume for fits of equations of state to carbon dioxide densities: $\circ$, Eqs. 5a and 5b; $\bullet$, Eqs. 5a and 5b with $b = 0$; $+$, modified Leung-Griffiths model.

phase within 0.5%, and the root-mean-square percent difference, or "fitting error," was $(R/n)^{1/2} = 0.46\%$ (where n is the number of experimental points).

Figure 2 also shows the fitting error vs. the temperature for Eqs. 5a and 5b with $b = 0$ and for the modified Leung-Griffiths model,⁹ which is a special case of Eqs. 5a and 5b, in which $b = 0$ and $C_1 = C_g$.

Setting $b = 0$ increased the fitting error from 0.46 to 1.7%; the modified Leung-Griffiths model further increased the fitting error to 1.9%, about four times the error of the improved fit.

The values of the fitting parameters are listed in Table 1. The critical temperature (304.12 K) is essentially the same as the values (304.09, 304.11, 304.12, and 304.19 K) arrived at by Levelt Sengers and coworkers.^{20,23} The excluded volume, $b = 10.4 \text{ cm}^3 \text{ mol}^{-1}$, is about one-fourth as large as the van der Waals value of b (Ref. 24). The value of C_g is about one-half the value of C_l , and C is a significant contributor to C_g and C_l .

TABLE 1

Values for the Excluded Volume, Critical Point, and Nonuniversal Parameters for the Free-Space Equation of State (Eqs. 5a and 5b)

$b, \text{cm}^3 \text{mol}^{-1}$	10.4
T_c, K	304.12
$r_{l,c}, \text{mol cm}^{-3}$	0.012189
$B, \text{mol cm}^{-3}$	0.003727
$C_l, \text{mol cm}^{-3}$	0.0001045
$C_g, \text{mol cm}^{-3}$	0.0000465

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GAS FLOOD PERFORMANCE PREDICTION IMPROVEMENT

**Cooperative Agreement DE-FC22-83FE60149,
Project BE5A**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$250,000**

**Principal Investigator:
Ting-Horng Chung**

**Project Manager:
Jerry Casteel
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this project are to (1) develop improved prediction techniques for asphaltene deposition during gas flooding and (2) conduct a feasibility study for the application of gas displacement in Naval Petroleum Reserves (NPR) oil reservoirs.

Summary of Technical Progress

Feasibility Study for the Application of Gas Displacement in NPR-3 Reservoirs

The objective of this task is to conduct a preliminary study to investigate the feasibility of gas miscible or immiscible displacement methods for recovering oil from NPR-3 reservoirs. This study is a preliminary screening based on the phase behavior of the CO₂/crude oil at reservoir conditions. Laboratory coreflooding experiments and full-scale reservoir simulations were not planned at this stage.

A summary of reservoir data for NPR-3 reservoirs is given in Table 1. In general, crude oils with gravity ranging from 30 to 40° API are good candidates for gas miscible

**TABLE 1
NPR-3 Reservoir Data**

	Formation				
	2nd Wall Creek	Shannon	Lakota	Morrison	Tensleep
Lithology	Sandstone	Sandstone	Sandstone	Sandstone	Sandstone
Porosity, %	16	16	15	16	11
Permeability, mD	10–50	50	5–5	Unknown	5
Average pay thickness, ft	25	30	13	26	25
Depth, ft	2210	Variable	Unknown	Unknown	Unknown
Initial pressure, psi	1000	Unknown	1850	1430	2333
Present pressure, psi	400–700	41–320	Unknown	Unknown	Unknown
Reservoir temp., °F	Unknown	60–70	Unknown	Unknown	Unknown
API gravity of oil	36	35.2	46.9	35.5	29.6
Gas/oil ratio, scf/bbl	Variable	19.6	6300	24	0
Drive mechanism	Solution gas	Solution gas and water drive	Solution gas	Water drive	Water drive

displacement. Unfortunately, in the two major producing formations—2nd Wall Creek and Shannon—reservoir pressures have been depleted to a low level. Present reservoir temperatures and pressures for other formations are not available. Also, available production data are not complete. Reservoir fluid analysis data for a crude oil sample obtained from a well penetrating the Shannon formation are given in Table 2. These data provided the information used for this study.

TABLE 2

Hydrocarbon Analysis of Separator Products and Calculated Wellstream

	Separator oil, mol %	Separator gas, mol %	Wellstream, mol %
Nitrogen	0.01	1.40	0.06
Carbon dioxide	0.01	1.16	0.05
Methane	0.38	70.85	2.92
Ethane	0.05	6.58	0.29
Propane	0.17	8.82	0.48
Isobutane	0.14	2.17	0.21
n-Butane	0.40	4.33	0.54
Isopentane	0.33	1.46	0.37
n-Pentane	0.42	1.28	0.45
Hexanes	6.37	1.14	6.18
Heptanes plus	91.72	0.81	88.44
Total	100.00	100.00	100.00

Heptanes plus properties (separator oil)

API gravity @ 60 °F = 31.7

Specific gravity @ 60/60 °F = 0.8669

Molecular weight = 231.9

Gas/oil production ratios used for study

Primary separator gas/stock tank oil ratio

19.6 scf/bbl @ 60 °F

Stock tank oil properties

API gravity @ 60 °F = 33.0

Specific gravity @ 60/60 °F = 0.8893

On the basis of compositional analysis, crude oil with more than 94 mol % of C_{7+} is close to dead oil. The primary separator gas/oil ratio is only 19.6 scf/bbl at 60 °F. Therefore, the saturation pressure is fairly low, as shown in Fig. 1. A pseudoternary phase diagram for the crude oil with CO_2 at reservoir conditions is plotted in Fig. 2, which shows that the two-phase region almost covers the entire phase region and the crude oil is in the two-phase region. Therefore, CO_2 is unable to achieve miscibility with the crude oil under reservoir conditions.

Preliminary Screening

According to the provided data for Shannon oil field, the reservoir temperature and pressure are low ($T = 60$ °F, $P = 50$ psig). Usually, lower temperature will lower minimum

Fig. 1 Bubblepoint pressure for Shannon crude oil.

Fig. 2 Ternary phase diagram for Shannon crude oil with CO_2 at 60 °F, 65 psia.

miscibility pressure (MMP) and thus favor gas miscible displacement; however, low temperature is always accompanied with low pressure, which does not favor gas miscible displacement. The estimated MMP for CO_2 with Shannon crude oil is plotted as a function of temperature in Fig. 3 by using Glaso's correlation.¹ It can be seen that the MMP is about 819 psia at 60 °F. Under such pressure, the CO_2 is already liquefied. It will be expensive to raise the reservoir pressure up to the MMP by injecting liquid CO_2 . The solubility of CO_2 in crude oil is very low under present reservoir pressure. Therefore, at such low temperature and pressure conditions, application of the CO_2 miscible or immiscible method is not feasible. The application of nitrogen gas or hydrocarbon gas injection is also impractical because of the following: (1) there is insufficient producing gas for reinjection and (2) the MMP for N_2 and lean gases to achieve miscibility with such low gas/oil ratio crude oil is extremely high. In addition, geological information shows that the NPR-3 reservoir is made up of fractured formations and most oil production zones are shallow. These factors are unfavorable for gas enhanced oil recovery (EOR).

Fig. 3 Minimum miscibility pressure (MMP) as a function of temperature for CO₂-Shannon crude oil.

Conclusions

On the basis of the preliminary study, gas EOR methods are not applicable in NPR-3 reservoirs because the reservoir pressures and temperatures of the two major oil formations—Shannon and 2nd Wall Creek—are too low and the formations are fractured.

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PROFILE MODIFICATIONS, MOBILITY CONTROL, AND SWEEP IMPROVEMENT IN GAS FLOODING

Cooperative Agreement DE-FC22-83FE60149,
Project BE5B

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

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Principal Investigator:
Clarence Raible

Project Manager:
Jerry Casteel
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this project are to (1) develop experimental models to investigate placement of polymer gels for profile modification of CO₂ gas floods, (2) conduct laboratory investigations to select the polymer gel systems applicable to CO₂ gas flooding conditions, (3) conduct laboratory experiments to selectively place gel polymer systems for profile modification, and (4) use the 3-phase flow simulator developed by the National Institute for Petroleum and Energy Research (NIPER) to investigate the effect of polymer gels on gas-flow profile.

Summary of Technical Progress

Experimental Models for Gel Placement

Successful gel treatments require placement of a gel in high-permeability zones with minimal damage to the adjacent, less permeable, oil-productive reservoir. Numerous laboratory studies have used single permeability floods or parallel floods with different permeabilities for testing the effectiveness of gels and fluid-diversion agents. Although these studies were useful for measuring resistance factors of gels, the experiments can provide erroneous results on improvement of sweep efficiency. Single or parallel cores do not evaluate the effects of crossflow during placement of the diversion agents. Crossflow into the nearby oil-productive zone during injection of profile modification agents can seriously impair flow and reduce sweep efficiency of the oil-productive formation. Therefore, evaluation of profile modification agents must consider the impact of crossflow into the adjacent oil-productive zone.

To measure the effect of crossflow, profile modification experiments using layered sandpacks with contrasting permeabilities were conducted. A sandpack holder was constructed of a Plexiglas cylinder with an internal diameter of 7.62 cm and a length of 51 cm. For heterogeneous sandpacks, layers of high- and low-permeability silica sands were packed parallel to the direction of flow. Different size sands were used to obtain sand layers with different permeabilities. The permeability contrast between layers of 80- to 120-mesh and 200- to 325-mesh sands was about 5, and the permeability contrast between 20- to 40-mesh and 200- to 325-mesh sands was about 50.

CT Cross Sections of Experimental Models

Computerized tomography (CT) imaging was used for visualization of fluid flow and gel placement. Each CT scan was a 4-mm slice of the sandpack cross section. For a sandpack, 51 cm in length, 25 CT scans at 2-cm intervals were obtained to characterize the sandpack. The resolution of the image along the sandpack axis was about 4% of the sandpack length. By computer reconstruction, a three-dimensional image was obtained of the sandpack.¹ For this report, a two-dimensional image was made showing a

lengthwise projection of the sandpack perpendicular to the high- and low-permeability layer plane. The figures used in this report show the most permeable layer at the top of the image.

A potassium iodide tagging agent was used to provide an X-ray contrast between the injected and displaced fluids. Injected brines and polymer solutions contained 6 to 7.5 wt % of potassium iodide. To further enhance the X-ray images, the sandpack was scanned prior to injecting the tracer fluid. For each scan location, the appropriate background scan was subtracted from all subsequent scans. This enhanced the location and intensity of the injected tracer.

Flow Experiments for Polymer Placement

Experiments with layered sandpacks were performed by injecting an X-ray-tagged brine or polymer solution. The permeability contrast between layers of sand was about 5. These experiments were designed to demonstrate the simple case of permeability contrast between sand layers and the relative penetration of the injected brine. A CT cross section of the sandpack shown in Fig. 1 was made after injecting 0.5 PV of brine. The distance of brine penetration for the high-permeability layer was about 5 times that of the low-permeability layer. Also, as shown in the CT cross sections, there was virtually no crossflow between the high- and low-permeability layers because the viscosities of the injected brine and the displaced brine were the same. For this idealized case of fluids with the same viscosity and mobility, the injection fluid placement was largely controlled by the permeability contrast of the porous media. The length of penetration into the high- and low-permeability layers (L_1/L_2) was proportional to the permeability contrast of k_1/k_2 . For this experiment, the relative displacement of the two brine fronts remained nearly constant as the brine was injected. Other factors, such as gravity and capillary forces, also could influence this relationship in a reservoir. These factors were small because of large pores in the sandpack and small differences in liquid densities.

Fig. 1 Computerized tomography cross section of layered sandpack with a permeability contrast between layers of 5. The cross section shows the relative position of fluids after injecting 0.5 PV of an X-ray-tagged brine.

Effect of Polymer Solution Viscosity and Permeability on Crossflow

There are many studies of gel properties in porous media. Typically, these studies measure the resistance to brine flow after gel formation. Although these studies are useful in gel assessment and the determination of residual resis-

tance factors, flow through virtually any porous media can be effectively reduced if sufficiently high concentrations of polymer are used, and often these polymer solutions have high viscosities. These studies ignore the problems associated with placement of high viscosity solutions that can seriously influence crossflow and cause damage to lower permeability strata.

Layered sandpacks were used to show the effect of viscous crossflow on gel penetration and placement. For one experiment, the permeability contrast (k_1/k_2) between the two sands was about 5. A polymer solution (1500 ppm xanthan) was injected at a flow rate of 75 cm³/h. The polymer solution contained 6% potassium iodide as an X-ray tracer. Some polymer retention was expected as the gelant flowed through the sandpack. Separation of the polymer and tagged brine, however, was minimal because of the large sandpack pores. Location of the polymer and tagging agent, therefore, was nearly coincident and within the resolution limitations of the CT images.

A CT cross section (Fig. 2) shows the relative position of frontal advancement after injection of 0.54 PV of polymer solution. The figure shows only a small offset of the lower permeability polymer front and the large quantity of polymer crossflow into the low-permeability layer. For this experiment, the ratio of the polymer viscosity to displaced brine (μ_p/μ_w) was much larger than the permeability contrast of the two layers ($k_1/k_2 = 5$), which resulted in nearly total invasion and damage of the lower permeability layer.

Fig. 2 Computerized tomography cross section of layered sandpack with a permeability contrast between layers of 5. The cross section shows the relative position of a polymer solution after injecting 0.54 PV of an X-ray-tagged brine.

A similar experiment was conducted with a brine-saturated sandpack with a larger permeability contrast. The brine-saturated sandpack consisted of sand layers with a permeability contrast (k_1/k_2) of about 50. A 1500-ppm xanthan polymer solution with 6% potassium iodide as an X-ray tagging agent was injected at 100 cm³/h. Figure 3 shows a CT cross section of the sandpack after injection of 0.73 PV of polymer. Even with the high-permeability contrast of the two layers, the cross sections show considerable polymer invasion into the low-permeability layer. When the polymer penetrated to the end of the high-permeability layer, more than 50% of the low-permeability layer was invaded by polymer. This dramatically shows the problems associated with placement of viscous polymers in a high-permeability thief zone without extensive damage of the adjacent oil-producing strata.

Fig. 3 Computerized tomography cross section of layered sandpack with a permeability contrast between layers of 50. The cross section shows the relative position of the polymer solution after injecting 0.73 PV of an X-ray-tagged brine.

The mobility ratio of the polymer to the displaced brine was interesting. CT cross sections were used to determine the distance of polymer penetration and the polymer frontal velocity of sand layer L_1 . As the polymer penetrated the high-permeability layer, the distance and injection time gave a frontal velocity of 6.75 ft/d (darcy velocity of 2.43 ft/d). Because the polymer solution was a non-Newtonian fluid, mobility of the injected fluid was corrected for shear thinning and flow behavior in sandpacks. Rheological fluid properties and flow behavior indices by Hejri² were used in sandpacks to determine the biopolymer mobility factor. The mobility factor (apparent viscosity) of the polymer in L_1 was estimated to be about 1870 mD/cP at a darcy velocity of 2.43 ft/d. Sorbie³ defined a resistance factor (F_r) as the ratio of the displaced fluid mobility divided by the gelant mobility. This gave a gelant F_r of about 53, which was close to the permeability ratio ($k_1/k_2 = 50$) of the two layers. The value of $F_r k_2/k_1 = 1$ was too high for this gelant placement without significant damage of L_2 .

Sorbie³ performed similar experiments using beadpacks with contrasting permeability layers. Newtonian liquids with different viscosities were used to simulate the injected gelant and displaced fluid. His study indicated an approximate guideline of $F_r k_2/k_1 \leq 0.3$ to reduce crossflow to an acceptable level.

Even this experiment, with relatively high permeability contrast, was not sufficient to place the polymer solution without significant crossflow and damage to the low-permeability layer. The polymer solution was too viscous for satisfactory placement, which emphasizes the need for gelant injection with a low viscosity and a low resistance factor.

Discussion

There are other factors that may affect the placement of the gelant. These include the effects of vertical to horizontal permeability and oil saturation. These factors were not considered in the experimental models.

The ratio of vertical to horizontal permeability typically is less than unity because of reservoir stratification. Zapata and Lake⁴ discussed the effect of these relationships on vertical equilibrium. With the assumption that there is not a barrier to flow between layers, vertical equilibrium will depend upon the reservoir aspect ratio (L/H) and the ratio of vertical to

horizontal permeabilities (k_v/k_h). They proposed the following relationship as a measure of vertical equilibrium:

$$R = L/H(k_v/k_h)^{0.5} \quad (1)$$

Using experimental and numerical simulation data, they determined a range of values for Eq. 1. Vertical equilibrium was essentially achieved when $R \geq 10$ and for the condition of virtually no crossflow when $R \leq 0.1$. For example, a reservoir with an aspect ratio of 50 ($L = 1000$ ft and $H = 20$ ft), vertical permeability must be less than 4×10^{-6} times k_h to achieve no crossflow and greater than 0.04 times k_h to achieve total crossflow and vertical equilibrium. In between these extremes, the degree of crossflow would vary depending on the value of R .

Finally, oil saturation and relative permeability may influence the relative penetration and crossflow of the polymer injection. Because of the experimental complexities for obtaining different oil saturations in layered models, numerical simulation studies were performed with heterogeneous models. Simulation results indicated that mobility of the displaced fluids can have a significant effect on crossflow and invasion of the low-permeability layer. Displaced oil with a high viscosity or low mobility will reduce the amount of crossflow of the injected viscous polymer.

Observations and Conclusions

Crossflow and damage to oil-productive formations during polymer placement is minimized when the polymer solution has a low viscosity or low resistance factor. A gelant with a low resistance factor during injection will improve the performance of gel treatments in unfractured reservoirs. This emphasizes the need for an effective gelant with a low resistance factor during placement.

CT imaging techniques enabled visualization of fluid flow in porous media, such as sandpacks and cores. This technique provides information on crossflow and gel placement that cannot be conveniently measured by other techniques.

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THERMAL RECOVERY— SUPPORTING RESEARCH

RESEARCH ON OIL RECOVERY MECHANISMS IN HEAVY OIL RESERVOIRS

Contract No. DE-FG22-90BC14600

**Stanford University
Petroleum Research Institute
Stanford, Calif.**

**Contract Date: Feb. 23, 1990
Anticipated Completion: Feb. 22, 1993
Government Award: \$590,000
(Current year)**

Principal Investigators:

**W. E. Brigham
K. Aziz
H. J. Ramey
L. M. Castanier**

Project Manager:

**Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The goal of the Stanford University Petroleum Research Institute (SUPRI) is to conduct research directed toward

increasing the recovery of heavy oils. Presently SUPRI is working in five main directions:

1. Flow properties research—to assess the influence of different reservoir conditions (temperature and pressure) on the absolute and relative permeability to oil and water and on capillary pressure.
2. In situ combustion studies—to evaluate the effects of different reservoir parameters on the in situ combustion process. This project includes the study of the kinetics of the reactions.
3. Additives to improve steam injection—to investigate the mechanisms of the process using commercially available surfactants for reduction of gravity override and channeling of steam.
4. Reservoir definition—to investigate and improve techniques of formation evaluation, such as tracer tests and pressure transient tests.
5. Field support services—to provide technical support for design and monitoring of DOE-sponsored or industry-initiated field projects.

Summary of Technical Progress

Flow Properties Studies

Formatting of the matrix of computerized tomography (CT) numbers for better processing of the saturation maps in the experiments on relative permeabilities is complete. It was necessary to obtain images in the 160×160 format to scan the length of the core in a reasonable amount of time

(20 min for 17 scans). In parallel, simulation runs have continued where the core is simulated using an r,z grid under various drainage and imbibition conditions. The preliminary results show possible fingering even when the viscosity ratio is around one. Experiments were delayed because of possible channeling of the injected fluids around the core. This problem was solved in September by using a combination of Epoxy glue and a heat-shrinkable Teflon sleeve.

A history matching computer program is being developed to analyze the results.

In Situ Combustion

A one-dimensional (1-D) temperature prediction model was developed for combustion-tube runs. This extension of the Pemberthy and Ramey method allows calculation of the combustion-zone thickness and temperature. First, the length of the combustion zone is calculated with an iterative method where the amounts of fuel and oxygen are compared taking into account the front velocity. The heat-transfer parameters are then calculated with the Pemberthy and Ramey model, which allows the determination of temperature profiles.

The calculated temperature profiles were compared with experimental results from a tube run using 10°API Hamaca (Venezuela) oil. The matches are very good except in the beginning of the run where the igniter affected the experiments.

Steam with Additives

The mathematical model developed for 1-D transient foam flow in porous media was presented at the International Energy Administration Meeting in Bann Springs, Alberta, Sept. 27–30, 1992, and a companion paper at the Society of Petroleum Engineers Fall meeting in Washington, D.C., Oct. 4–7, 1992. A report summarizing this project has already been published by the Department of Energy (DOE).

A report was published on steam-foam characterization in the 1-D model. It discusses how slug size, concentration, and steam quality, using four different surfactants, affect the pressure gradients at residual oil saturation.

Numerical simulation of the three-dimensional steam model has focused on adapting the STARS numerical simulator for a good mathematical description of the heat loss in the laboratory model. Comparisons were made between the heat losses measured experimentally by heat-flow sensors and the heat losses calculated by simulation. They showed the need for a different set of input parameters and a modification of the grid to include the insulation present in the experimental setup. Results of the simulation with corrected

heat losses will be compared with the experimental data in the Fall.

The design has been finalized for an experiment to study matrix-fracture transfer in steam injection recoveries. A box of polysulfone plastic will be built which will allow a study of a 20 × 20 × 8 cm block of sandstone surrounded by a fracture under moderate (120 °C and 40 psi) steam injection conditions. Special thermocouples have been ordered and will be calibrated upon arrival.

Preliminary scans of a mock-up model containing air and water were promising. The position of the water front in the fracture can be determined accurately, and water saturation in the matrix can be measured within 1%. The use of insulation around the mock-up model resulted in a significant reduction of beam hardening and greatly improved the quality of the CT data.

Formation Evaluation

No work was done on gravity drainage well testing this quarter because the researcher was on summer training with an oil company.

The prediction of tracer behavior in systems where the mobility ratio is not 1-D is being considered, but this problem must be solved by computer. Unfortunately, the best model for this purpose (UT-CHEM) exhibits some errors. Recent work indicates that these errors might be reduced to manageable levels. The progress of this effort is being tracked so that this problem can be attacked once the appropriate tool is available.

Field Support Services

Data from the calibration runs on the test loop for downhole two-phase flow metering compare well with the known rates in single-phase, gas or liquid, flow. Tests are being run to determine the upper and lower range limits of the ultrasonic device, and testing has started in air-water, two-phase flow conditions. A report on this project was sent to DOE for review.

A critique of the SUPRI field test on steam foam run in the early eighties is being written. The results of this project will be reviewed. Possible improvements in the design of such field tests will be suggested. A paper on this topic is scheduled for February 1993.

A report on multivariant optimization will be sent to DOE for review in December.

An extension of the semianalytical steam model is being attempted to include the case of multilayered reservoirs. As a first step, modeling is under way for two noncommunicating layers. The results will be compared with data obtained from the STARS numerical simulator.

**MODIFICATION OF RESERVOIR
CHEMICAL AND PHYSICAL FACTORS
IN STEAMFLOODS TO INCREASE
HEAVY OIL RECOVERY**

Contract No. DE-FG22-90BC14600

**University of Southern California
Los Angeles, Calif.**

Contract Date: Feb. 23, 1990

Anticipated Completion: Feb. 22, 1993

**Government Award: \$150,000
(Current year)**

**Principal Investigator:
Yanis C. Yortsos**

**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this contract are to continue previous work and to carry out new fundamental studies in the following areas of interest to thermal recovery: the displacement and flow properties of fluids involving phase change (condensation–evaporation) in porous media; flow properties of mobility control fluids (such as foam); and the effect of reservoir heterogeneity on thermal recovery. The specific projects are motivated by and address the need to improve heavy oil recovery from typical reservoirs as well as less conventional fractured reservoirs producing from vertical or horizontal wells.

Thermal methods, particularly steam injection, are currently recognized as the most promising for the efficient recovery of heavy oil. Despite significant progress, however, important technical issues remain. Specifically, knowledge of the complex interaction between porous media and the various fluids of thermal recovery (steam, water, heavy oil, gases, and chemicals) is inadequate. The interplay of heat transfer and fluid flow with pore- and macro-scale heterogeneity is largely unexplored.

Summary of Technical Progress

Vapor–Liquid Flow

Work in the area of vapor–liquid flow continued. Steam injection and steam displacement experiments were conducted in glass-bead-packed Hele–Shaw cells to explore the effects of pore structure on the displacement mecha-

nisms. Examination of the importance of spreading on film flow during steam–water–oil flow continued in order to test the theoretical models developed in parallel. Theoretical work also continued. Exploration of the regime where percolation theory is expected to apply in the description of vapor-phase growth continued. The effect of superheat on the growth pattern was numerically investigated. Pore network simulations were carried out for processes at larger superheats where percolation patterns do not develop and the growth of the vapor phase is compact. A linear stability analysis was implemented to explore the nature of these fronts in the absence of capillarity. A similarity solution to the vapor growth problem in a porous medium was found and was assumed as the base state. The solution of the linear stability problem is currently under study.

Heterogeneity

Work continued on the modeling of displacement processes in fractured media. Visualization experiments for drainage in etched-glass micromodel geometries were simulated with pore network models with good results. However, the previously proposed hypothesis that the process can be described by gradient percolation was not confirmed. Although invasion of the matrix requires that a threshold in the capillary number (and the flow rate) be exceeded, viscous forces compete with capillary forces to set the ensuing displacement pattern. A technical report on this subject is currently in preparation.

Conversely, the hypothesis on the analogy between gravity and heterogeneity for capillary-controlled displacements^{1,2} was tested experimentally and theoretically. It was found that both processes can be quite well described by gradient percolation.³ Work to examine the effects of heterogeneity during displacement at the pore network level, both for drainage and imbibition processes, continues.⁴ On the macroscopic scale, the concept of vertical equilibrium was extended to steam injection processes to assess the effects of heterogeneity, viscous forces, and gravity during steam injection. This problem is still under investigation.

Chemical Additives

In the area of chemical additives, a technical report was completed on the subject of alkaline-assisted thermal recovery.⁵ Work continued on the study of non-Newtonian flow in porous media. The study of drainage involving pairs of power-law fluids is complete. The single-phase flow of Bingham plastics, often taken to represent heavy oils, was also simulated numerically. The macroscopic behavior was found to obey a law similar to flow in a single capillary but with a different threshold. A technical report is currently in preparation. Work also continued in the modeling of foam generation and propagation in porous media. Currently, a pore network simulator has been developed that models formation of lamellae during drainage and subsequent

imbibition processes. The numerical model is capable of predicting the existence of a minimum pressure gradient for the onset of foam mobilization as proposed in previous works (see Ref. 6 for details). The numerical predictions are currently being compared with the experimental observations.⁶

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OIL FIELD CHARACTERIZATION AND PROCESS MONITORING USING ELECTROMAGNETIC METHODS

**Lawrence Livermore National Laboratory
Livermore, Calif.**

**Contract Date: Oct. 1, 1984
Anticipated Completion: Oct. 1, 1992**

**Principal Investigator:
Mike Wilt**

**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this project are to apply surface and borehole electromagnetic (EM) methods to characterize the oil-bearing strata and to monitor in situ changes in the electrical conductivity in an oil reservoir during enhanced oil recovery (EOR) operations. The goal of this project is to develop practical tools for geophysical characterization of oil strata and monitoring of an ongoing EOR operation. Crosshole and surface-to-borehole EM methods are being used to map discontinuous oil sands and to provide an image of electrical conductivity changes associated with EOR operations.

Summary of Technical Progress

During the final quarter of 1992 the scope of activities was broadened to include the characterization of oil fields in addition to process monitoring. In particular, EM techniques were applied to map discontinuous oil sands in a developing oil field using the California Central Valley oil fields as a model. Efforts at process monitoring continue, and these techniques were recently applied at the Richmond field station to map a saltwater flood. Preliminary results from this completed experiment follow.

Research Objectives in Heavy Oil Reservoir Characterization

Although the primary focus of this program was to provide tools for EOR monitoring, the crosshole EM technique is sufficiently powerful to provide good subsurface resistivity mapping information for reservoir characterization. With a small shift in the emphasis, the same technology could be used to map stratigraphy and structure in a producing oil field.

Most heavy oil (defined here as having API gravity of 10 to 20 inclusive) reservoirs exist at shallow to moderate depths in younger strata. Heavy oil petroleum reservoirs in the central valley of California, for example, occur in the Tertiary and Quaternary sands, mudstones, and diatomite shales at depths ranging from 100 to 3000 ft with the shallower reservoirs typically containing the heavier oil. They tend to comprise discontinuous, high-permeability lenticular sands separated by impermeable shales. At the South Belridge field, for example, the shallow sands resemble shoestrings.¹ There is also considerable structure

overprinted on the central valley reservoirs because of the proximity to the continuously active San Andreas fault system. Reservoirs tend to be complex plunging anticlines with systems of faulting superimposed on the folded structure.

The determination of such complex structure requires the analysis of borehole logs from many wells in a particular field. At South Belridge, for example, more than 6000 wells have been drilled since its discovery in 1911. Figure 1 is a simplified east-west section across the center of the South Belridge oil field.¹ The figure depicts the configuration of oil and water sands and the intervening shales in the upper 1500 ft of section across the central anticlinal structure. The individual sand bodies are only piecewise continuous, and the oil and water sands are interfingered on the eastern part of the structure. Typical sand structures at South Belridge are from 150 to 500 ft wide in cross section but are often continuous in the northeasterly direction (along strike) for many miles, forming undulating strands (shoestrings). The configuration of individual sand bodies is controlled by the depositional environment and by geological structure. Communication between sand bodies ranges from good to poor, which means that steam drives, although usually economically successful, bypass much of the oil.

The preceding cross sections were assembled largely from wireline logs from the many wells at South Belridge. Wireline logs are extremely effective in selecting sand and shale horizons and are the primary source of data in wellfield stratigraphic correlations. Note that these measurements are reflective only of the region immediately surrounding the borehole.

One of the goals in this proposed research is to develop technology that extends the borehole log from the region immediately surrounding the well into the formation between wells. With such information the geologist can confidently map the configuration of subsurface beds and better plan his or her exploration and exploitation strategies. A second goal is to provide the geologist with similar information if he or she has only a single well to work with. If he or she had a tool at his or her disposal to map the configuration of oil sands from a single borehole, the uncertainty would be substantially reduced and production and steamflood patterns could be optimized. This would also reduce the amount of missed or bypassed oil. The following research program is being implemented over the next 3 yr.

For the cross-borehole technique, a multifrequency transmitter is required to take advantage of the high resolution possible. The device would be an extension of the

Fig. 1 East-west cross section of the Tulare Sands in the South Belridge oil field, San Joaquin County, Calif.

existing Lawrence Livermore National Laboratory (LLNL) borehole EM source. The new transmitter would switch between a selection of capacitors and alternate windings on the tool to operate at a series of discrete frequencies covering several decades. Computer-controlled switches could be operated from the surface to automatically change frequencies when appropriate. A related improvement is the development of an automatically controlled surface-to-borehole system. With automatically controlled discrete frequencies, the surface-to-borehole system could increase the depth of penetration in a fiberglass-cased borehole from 400 m to more than 1.5 km. These hardware advances are being developed together with private industry in an effort to reduce the individual costs for more effective transfer of the technology.

The development of software concurrent with the development of hardware is a critical part of this process, which depends largely on close collaboration with Lawrence Berkeley Laboratory (LBL) and the University of California, Berkeley (UCB). In particular, the discrete frequency imaging codes presently available need improvement, and the recently developed wavefield imaging approach at LBL needs to be applied to field data. Other proposed software developments include the interpretation of EM data through steel well casing and the adaptation of imaging codes to the surface-to-borehole configuration.

Field studies are needed as the hardware and software are being developed. The test facility at Richmond field station will be used initially for prototype testing of both the multifrequency transmitter and the surface-to-borehole system. Use of the steel-cased wells at Richmond will allow an assessment of the limitations of measuring through casing and the provision of data to test interpretation techniques. Concurrent with this work at Richmond, several of these techniques will be applied to the Lost Hills No. 3 oil field owned and operated by Mobil. At this facility the opportunity for steamflood monitoring as well as reservoir characterization on a shallow heavy oil reservoir with discontinuous oil sands exists.

Saltwater Injection Monitoring at Richmond Field Station

A plan view of the Richmond test facility, which lies approximately 7 miles north of the UCB campus and adjacent to the San Francisco Bay, is given in Fig. 2. From April to August 1992 this facility was used for a saltwater injection monitoring experiment. With the use of well INJ1, 50,000 gal of 1- Ω -m saltwater was injected into a 3-m-thick aquifer at a depth of 30 m. A variety of surface and borehole geophysical measurements were made before injection, during injection, and after withdrawal of the fluid in an attempt to track the saltwater plume.

Crosshole EM measurements were made with a five-well set with the transmitter deployed in the central bore-

Fig. 2 Plan view of the Richmond field station well field.

hole (INJ1) and the other boreholes (EMNE, EMNW, EMSE, and EMSW) used for the receiver tool. This arrangement provides the first-order cylindrical symmetry required by the present imaging code.⁷ In addition to the expanded crosshole measurements, an expanded set of supporting data was also collected. This includes induction resistivity logs in all holes before and after saltwater injection, a set of crosshole resistivity measurements (using wells RES1 and RES2), measurements of water conductivity in all the wells before and after injection, and a set of water-level measurements during the extraction and recovery stages of the experiment.

Figure 3 is a display of a tomographic inversion of the crosshole EM data collected at Richmond. Part a of Fig. 3 shows the reconstructed conductivity section before saltwater injection and part b of Fig. 3 shows the conductivity image after injection. Both images accurately depict the resistivity distribution as known from the well logs. The upper 36 m in each well consists of high-conductivity (0.04 to 0.2 S/m) alluvial sediments below which is lower conductivity (0.002 to 0.03 S/m) sandstone or shale. The anomalous mass that resulted from the saltwater injection is evident at a depth of 25 to 30 m and extends 8 to 10 m away from the injection well (at the left margin of the images). This is in accord with wireline logging data from boreholes INJ1 and INJ³ and is likely a good representation of the extent of movement of the saltwater plume.

Presentations Given

A technical paper entitled "The Variation of Electrical Conductivity During Steam Injection in Unconsolidated Sand Saturated with a Salt Solution" was given as a poster at the Society of Exploration Geophysicists Development and Production Forum in Big Sky, Mont.

A technical paper entitled "Cross-Borehole Electromagnetic Induction at the Underground Dynamic Stripping Clean-Site" was given as a poster at the Society of

Fig. 3 Tomographic inversion of electromagnetic (EM) profile IN-11-FMSW (a) before and (b) after injection of salt water.

Exploration Geophysicists: Development and Production Forum in Big Sky, Mont.

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THERMAL PROCESSES FOR LIGHT OIL RECOVERY

**Cooperative Agreement DE-FC22-83FE60149,
Project BE11A**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$295,000**

**Principal Investigator:
David K. Olsen**

**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The FY92 objectives are to (1) develop procedure and apparatus for measuring dynamic saturation changes in steamfloods with an X-ray computerized tomographic (CT) scanner and incorporate temperature and pressure measurements to calibrate numerical simulator for predictive purposes; (2) conduct laboratory research in support of Naval Petroleum Reserve (NPR) No. 3, Teapot Dome (Wyoming) field light oil steamflood; (3) conduct laboratory research in support of NPR No. 1, Elk Hills (California) field light oil steamflooding pilot; (4) transfer technology developed from this project to others in the field of thermal oil production; and (5) participate in the Annex IV meetings between the Department of Energy (DOE) and the Venezuelan Ministry of Energy and Mines.

Summary of Technical Progress

Four reports were delivered to DOE this quarter.

NIPER-596, entitled *General-Purpose Automation Programming: A Case Study on Using a Graphic Language*,¹ by S. M. Mahmood, describes the object-oriented programming language from which NIPER developed in National Instruments LabVIEW 2™ the data acquisition/control/analysis/presentation software to operate a high-temperature, high-pressure steamflood laboratory. The manuscript was reviewed by National Instrument engineers as part of the formal review process.

This report is an overview of what has been developed and provides a background so that readers can appreciate not only the simplicity of the programming platform but also follow the discussion and judge the applicability of

this software to their specific application. The background demonstrates the simplicity of writing, testing, debugging, and maintaining large programs when using the graphical interface language (LabVIEW 2) compared with traditional line-code programming, such as FORTRAN, with which the reader may be more familiar. Discussion of the concepts of object-oriented programming includes a simple FORTRAN program for comparison with LabVIEW 2 to show by example a program written in both LabVIEW 2 environment and a traditional line-code language.

Object-oriented programming is the future direction of computer programming and automation. It provides a fast, easy, and very reliable methodology for developing large complicated software programs to test prototype configurations and develop computer control of multiple operations. NIPER developed this general modular program for data acquisition/control/analysis/presentation to have the following capabilities: (1) allow users to operate interactively through a computer panel by communicating with laboratory instruments, such as pumps, controllers, balances, temperature sensors, pressure sensors, fluid flow controllers, and alarms; (2) warn operators of conditions out of preprogrammed ranges and shut down operations systematically if the operator does not respond; (3) monitor the test progress with a material balance-based system and provide early warnings to the user for situations that may need attention in the near future, such as a feed tank running low on liquid or sudden changes in material balance indicating, for example, a possible leak in the system; (4) prohibit the user from making unsound operations, such as running a pump when an outflow valve is closed; (5) let the user manipulate current and/or previous data interactively (e.g., analyze, compare, plot, curve-fit, and print); and (6) communicate with other applications and users for sending data and warnings and receiving instructions.

This modular program, developed by NIPER using LabVIEW 2, has been constructed so that application, with minor modification, can be used in other laboratory or pilot plant operations for data acquisition/control/analysis/presentation. The software permits analysis and presentation within LabVIEW 2 and other software programs written for a Macintosh computer.

NIPER-605, entitled *Results of Task 52 Research on Light Oil Steamflooding*,² summarizes the research performed over the previous 18 months as part of the Annex IV agreement between the U.S. Department of Energy and the Venezuelan Ministry of Energy and Mines. The report covers the evaluation of a numerical, semianalytical, predictive steamflood model developed at Stanford University Petroleum Research Institute (SUPRI) that provided laboratory experimental support for two light oil steamfloods operated by DOE. The semianalytical numerical model is a two-dimensional (2-D) steam drive model. As delivered, it does not permit areal modeling or modeling of cyclic steaming used to increase injectivity. It is not recommended for pattern modeling of heavy or light oil steamfloods until

modified as it does not predict field performance. Recommendations are made for further advancement of the model. Laboratory 2-D steamfloods using reservoir oil and sand from the Shallow Oil Zone of NPR No. 1, Elk Hills (California) field show similar production characteristics and problems to those encountered in the field (i.e., there is significant oil production with steam; steam reduces the oil saturation below that of a waterflood, but the flood suffers from buildup of scale at the producers, migration of fines, and high CO_2 production).

One-dimensional laboratory evaluation of steam diverters (foaming surfactants) was conducted for the steamfloods at both NPR No. 1 and NPR No. 3, Teapot Dome (Wyoming) field. Of the tested surfactants, none was found suitable for steam diversion under conditions corresponding with those encountered in the steamflood at NPR No. 1. Chevron Chaser 1020 was found to develop a significant pressure differential in laboratory tests under the simulated NPR No. 3 reservoir conditions, indicating that this surfactant may have potential for application as a steam diverter to improve sweep efficiency to recover additional oil. Shell's LTS-18 showed similar potential in one test, but no conclusion was made because only a few tests were performed with LTS-18. Discussion of the results has appeared in previous quarterly reports.

NIPER-612, *Status of Reconstruction of NIPER's Steamflood Laboratory*,³ and NIPER-603, *Operating Guide and Specifications for NIPER Steamflood Laboratory*,⁴ detail the progress on project BELLA in FY92 and provide a background and documentation for assessing the environmental, safety, and health (ES&H) aspects of the steamflood laboratory and the research conducted therein. A draft of NIPER-603 was provided to the NIPER Configuration Review Committee as background for its assessment of ES&H aspects before construction or operation of the steamflood laboratory. The preparation of this report helped to define the limits of design and ensure that risks are identified and mitigated or avoided before the project begins. The operating guidelines provided in this report are for use by an experienced researcher familiar with the steamflood laboratory operation. It is not a cookbook or step-by-step set of standard operating procedures for inexperienced operators of the equipment. The steamflood laboratory may be one of the highest temperature, highest pressure laboratories at NIPER. These guidelines update previous operating guidelines that have been filed with NIPER and DOE in 1985 and 1988.

The overall goal of the steamflood laboratory and research conducted therein is to provide laboratory data to calibrate numerical simulators for predicting the behavior of field steamfloods. A series of six tasks has been outlined to accomplish this goal, and the first four involve laboratory research within the steamflood laboratory. These tasks are to (1) design a steamflood laboratory to meet environmental, safety, and health guidelines and to meet the goal

of having a high-temperature, high-pressure steamflood laboratory capable of operating (simulating) field conditions; (2) construct a steamflood laboratory to meet the above criteria; (3) test the steamflood equipment and electrical conductivity measurements; (5) conduct steamflood experiments using X-ray CT scanning to analyze data and correlate scanned images with data obtained by other techniques; and (6) use laboratory data to calibrate numerical simulators. The dynamic saturations determined from X-ray CT measurements of density and simultaneous temperature and pressure and electrical conductivity measurements should enable NIPER to track fluid front behavior rather than infer behavior on the basis of mass balance and temperature and pressure measurements that have been the primary tracking methodology. The new laboratory and titanium steamflood physical model will allow laboratory simulation of conditions corresponding to field steamflood conditions. The results of these laboratory experiments will help calibrate numerical simulators for predictive purposes in support of light oil steamflooding field projects.

Within NIPER-603 are schematics of overall laboratory configuration, configuration of individual systems and components, specifications of components, and operating guides (general procedures). The schematic of the titanium steamflood model is shown in Fig. 1. Software for operation of the steamflood model and supporting data collection and control has successfully been tested at 150 psi and ambient temperature through a series of simulated failures in equipment and electrical power.

Fig. 1 Schematic of titanium steamflood model with hydraulic ends for compression, thermocouples, pressure ports, electrical conductivity connections, and heat flux sensors.

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THERMAL PROCESSES FOR HEAVY OIL RECOVERY

**Cooperative Agreement DE-FC22-83FE60149,
Project BE11B**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

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Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$200,000**

**Principal Investigator:
Partha Sarathi**

**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The FY92 objectives of this project are to (1) evaluate computer modeling group's (CMG) "STARS" steamflood simulator, (2) conduct model and reservoir studies to determine the applicability of thermal enhanced oil recovery (EOR) techniques in the Nacatoch sands of Arkansas and Louisiana, and (3) collect information/data on the resource and economical recovery of heavy oil from the West Sak reservoirs in Alaska.

Summary of Technical Progress

Compilation of the Steamflood Operator's Guide

As part of the technology transfer work under thermal processes for heavy oil recovery, a handbook on the practical aspects of steam injection processes (NIPER-580) was prepared and delivered to the Bartlesville Project Office (BPO) in mid-July.

Evaluation of the Steamflood Potential in Nacatoch Sands of Arkansas

The principal objective of this task is to conduct an in-depth simulation study to assess the viability of steam injection processes in the thin, moderately heavy oil Nacatoch reservoirs of Arkansas. If the study establishes the technical and economic viability of steam injection, it may encourage independent operators who own these leases to implement this proven technology in their leases to increase recovery.

This quarter, in-depth studies were performed on Charivari Creek field to assess the technical and economic viability of steam injection in this reservoir.

Charivari Creek Steam Injection Simulation Study

Charivari Creek is a marginal heavy oil reservoir with thin low-permeability zones and high water saturation. This is typical of many Gulf Coast heavy oil reservoirs. The selection of this marginal reservoir permits the evaluation of the feasibility of the steam injection process in an unconventional heavy oil reservoir and the development of operating strategies. This is in line with the thermal EOR research needs as outlined by Tham et al.¹

Both cyclic and steamflood simulations were carried out with the STARS simulator to test the applicability of steam injection in the Nacatoch sands. Because many reservoir parameters were unknown and there were no field data to history match, best-estimate parameters were used to investigate the problems associated with conducting a steam injection process in a marginal reservoir and to gain some insight into the process mechanisms. General levels of performance calculated by the model were reasonable, and changes seen in temperature, pressure, and saturation distribution and the recovery history are believed to be realistic. Several runs were carried out by varying certain of the operating parameters, and the resulting changes in performance were analyzed. No detailed economic analysis of the process was performed; however, an economic analysis, based on California development and operation costs, was performed to gain some insight into the economics of conducting thermal EOR in a less-than-ideal heavy oil reservoir.

Cyclic Steam Simulation

For cyclic steam simulation, a grid block configuration representing two-dimensional radial flow into a single well was selected. The external drainage radius of the model was set to correspond to the 5-acre spacing. In the radial direction the drainage area was represented by 13 grids, and in the vertical direction, the reservoir was divided into five layers. The layers are separated by impermeable shale streaks that are not, however, sufficiently continuous to represent a serious impediment to vertical communication. Table 1 summarizes parameters for each layer. In the absence of actual data for oil-water and gas-liquid relative permeabilities,

TABLE 1
Reservoir Model Properties for Cyclic Simulation Study

Layer No.	Thickness, ft	Porosity	Horizontal permeability, mD	Vertical permeability, mD	Initial oil saturation	Initial water saturation	Depth to the top, ft	Temp., F	Pressure, psi
5 (top)	4.0	0.28	235	118	0.5	0.5	2350	110.0	200.0
4	9.0	0.29	181	90	0.48	0.52	2354	110.0	202.6
3	5.0	0.335	171	85	0.42	0.58	2359	110.0	205.0
2	5.0	0.335	171	85	0.35	0.65	2364	110.0	206.9
1 (bottom)	19.0	0.29	100	50	0.0	1.0	2369	110.0	211.8

the oil-water relative permeability data for a consolidated shaly sandstone have been chosen to represent this field.² The 4th SPF comparative solution project data³ were used for all other unknown parameters.

Several runs were made by varying the steam slug size from 60 to 13,600 bbl to determine the optimum slug size. The optimum was determined by plotting the operation costs per barrel of oil produced vs. the slug volume (Fig. 1) and determining the slug volume that resulted in lowest operating cost. From this plot, the optimum volume was found to be 750 bbl of steam (cold water equivalent), injected over a 3-d period. A base run was performed to analyze the cyclic steam performance in this reservoir. Sensitivity to selected reservoir parameters was also investigated. The following specific conclusions were reached from this simulation study:

1. Because of the thin pay zone (23 ft net) and high water saturation, cyclic steam is not economically attractive in this reservoir; however, stimulation is necessary to improve steam injectivity during subsequent steamdrive.
2. The optimum duration of production for the first cycle was found to be 40 d. Prolonging the operation beyond this time increased the per barrel production cost above well-head oil price (assumed as \$18.00/bbl).
3. Because of very low oil saturation near the wellbore, the subsequent cycles were not effective and produced only a very small amount of oil (less than 4 bbl/d).
4. Sensitivity studies were conducted with respect to reservoir pressure, reservoir permeability, degree of communication between bottom water sand and upper oil sand and initial oil saturation.
5. Increasing the reservoir pressure above the base case prolonged the production time and increased both the cumulative oil production and peak oil production rates. The volume of oil produced per MM BTU heat injected, however, decreased significantly and contributed to increased production cost.
6. For the same volume of steam injection, both cumulative oil production and peak oil production rates increased with an increase in reservoir permeability.
7. In the absence of vertical communication between the bottom water sand and upper oil sand, the average daily oil production increased about 60% over the base case.

Fig. 1 Plot of operation cost per barrel oil production vs. steam injection volume.

Steamflood Simulation Study

For steamflood simulation, a $9 \times 5 \times 5$ grid configuration was used. Several runs were made using different steam injection rates to arrive at an optimum injection rate. The optimum was found to be 250 bbl of steam per day (cold water equivalent) or 4.3 bbl/acre ft. Both single-pattern (a single inverted 5-spot) and multipattern configurations were studied. Sensitivity studies were carried out with respect to well spacing, pattern size, steam quality, and completion intervals. For the system studied, the following conclusions were found:

1. The studies indicated that the steam front progressed almost piston like with very little gravity override because of the thin pay zone and high water saturation. The in situ water by virtue of its higher heat capacity absorbed much of the injected heat and resulted in very low heat losses to the overburden. During the early stages of steam drive, the bulk of the injected heat was expended in converting the in situ water to steam. This resulted in large steam zone volume that progressed in nearly piston-like fashion and displaced the oil toward the producer.
2. The residual oil saturation in the steam-invaded zone was less than 8%. However, not all of this displaced oil was

produced. Because of the assumption of the existence of a good vertical communication between the bottom water sand and the upper oil layer, much of the displaced oil was drained into the water layer and was lost. Only 35% of the oil in the steam-invaded zone was produced. This made the process economically unattractive.

3. When the communication between the bottom water sand and the upper oil layer was negated, over 60% of the oil-in-place was produced and improved the economics dramatically. The available well logs indicate the presence of a thick shale barrier (>3 ft thick) between the bottom and upper layers. However, the continuity of the shale barrier could not be established with any degree of certainty because of the poor quality of the logs.

4. Under the assumption of no vertical communication between the oil layer and the bottom water layer, the study

indicated that the field developed on 2.5-acre spacing will maximize the recovery compared to that of 5.0- or 10.0-acre spacing.

Oil can be economically produced from the Charivari Creek reservoir through the use of steam provided that no, or very little, communication exists between the bottom water sand and the upper oil layer.

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FEASIBILITY STUDY OF HEAVY OIL RECOVERY IN THE MIDCONTINENT REGION: OKLAHOMA, KANSAS, AND MISSOURI

**Cooperative Agreement DE-FC22-83FE60149,
Project SGP37**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Apr. 1, 1990
Anticipated Completion: June 1, 1993
Funding for FY 1992: \$839,440**

**Principal Investigator:
David K. Olsen**

**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this research program are to (1) determine the known heavy oil resources of the United States, (2) evaluate the various economic factors that may impact development of this resource, and (3) determine if steam or other enhanced oil recovery (EOR) processes are applicable to economic production of this resource.

Summary of Technical Progress

Heavy Oil Database

The heavy oil database was reformatted this quarter to include source (origin) of data. A review of the Gulf Coast heavy oil database has been undertaken to make additions/corrections to this spreadsheet listing of reservoir properties.

Reports on Heavy Oil Refining Feasibility

A review of the results of the refining study conducted by Bonner and Moore under contract to the National Institute for Petroleum and Energy Research (NIPER) was presented to the Department of Energy (DOE) in Washington, D.C., on Sept. 14, 1992. The report for the study¹ has three parts: a background, base case projections of the U.S. refining industry from 1990 to 2010, and projections of the U.S. refining industry from 1990 to 2010 where an additional 300,000 or 930,000 barrels of oil per day (BOPD) of domestic heavy oil is produced.² The study estimates the cost of additional refining capacity (units) that would be required to process this heavy oil. The study was designed to estimate the impact to the U.S. refining industry if it were possible to increase domestic heavy oil production by the volumes above. Future studies will try to estimate the needed incentives to achieve this level of production and the cost of transport and incentives or oil price where refining this oil is feasible.

Anticipated U.S. oil production is shown in Fig. 1 by Petroleum Administration for Defense Districts (PADDD) for the years 1990 to 2010. Significant loss in production is shown for Alaska and the U.S. Gulf Coast.

To meet the crude oil demand with an anticipated 1% per year oil growth rate over 1990 to 2010, an increasing volume of imported oil will be required to replace declining domestic production. Figure 2 shows U.S. production and

imports as well as the point of origin of the imports. An increasing volume of imports from the Mideast is anticipated as well as increases from South America. Most other imports remain nearly constant.

Fig. 1 Projected U.S. crude oil production for 1990 to 2010 in thousands of barrels per day, by Petroleum Administration for Defense Districts (PADD).

Fig. 2 Projected U.S. crude oil production and imports for 1990 to 2010 in thousands of barrels per day.

NIPER supplied Bonner and Moore with projections of potential heavy oil production by location, volume, and date. The United States was divided into 10 refining areas (Figs. 3 and 4) and a linear programming model of the refining

industry was developed in each area. Interchange of crude oil and product are allowed. The model was validated against the 1990 refining industry performance. Projections were made for handling domestic and imported crude oils based

Fig. 3 Distribution of light, medium, and heavy oil refined in 1990.

Fig. 4 Distribution of light, medium, and heavy oil refined by region with the addition of 300,000 BOPD of domestic heavy oil.

on API gravity and sulfur content. Imports were used to meet demand as shown in Fig. 2.

Additional (projected) domestic heavy oil² displaced imported medium crude oil under the scenario studied, and the impact (cost for basic refinery units) to accommodate (process) the higher sulfur domestic heavy oil was calculated. Based on producing an additional 900,000 BOPD of domestic heavy oil, the investment in additional refinery capacity needed for processing is nearly 7 billion dollars. Nearly 50% is the result of compliance with the Clean Air Act Amendment of 1990. Figure 3 shows volumes, origin, and gravity range for oil refined in 1990. Figure 4 shows oil

gravity, origin, and volume for the scenario in 2010 where an additional 900,000 BOPD of heavy oil is refined. Results of other scenarios are given in the report.¹

References

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2. D. K. Olsen, *Estimates of Future Heavy Oil Production at Three Production Rates—Background Information for Assessing Effects on the U.S. Refining Industry*, DOE Report NIPER-606, in press.

SIMULATION ANALYSIS OF STEAM-FOAM PROJECTS

**Cooperative Agreement DE-FC22-83FE60149,
Project SGP58**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: June 1, 1992
Anticipated Completion: May 31, 1994
Funding for FY 1992: \$350,000**

**Principal Investigator:
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**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this research program are to (1) conduct a study on the viability of the steam-foam process by analyzing data from selected completed steam-foam projects and (2) assess under what conditions the process is likely to succeed, both technically and economically.

Summary of Technical Progress

The literature on completed steam-foam pilots and previous steam-foam simulation studies was reviewed, and

hypothetical data sets were assembled to evaluate the steam-foam modeling capabilities of the STARS simulator.

To describe foam propagation in porous media, the simulator uses an empirical foam model, consisting of two interrelated components. The first, surfactant propagation, is modeled rigorously—surfactant adsorption, partitioning into oil, and surfactant decomposition are all expressed as a function of temperature. The second component, foam mobility reduction, is handled empirically by modifying the gas phase relative permeability. This empirical model takes into consideration the experimentally observed effects of surfactant concentration, oil saturation, and velocity on foam mobility reduction. The model assumes that in porous media the generation and decay of foam occurs much more quickly in relation to surfactant propagation.

Analysis of the preliminary simulation results indicates that the model produces an overly optimistic amount of oil in comparison to that from field data. This is because the model assumes that the foam propagates at the same rate as the surfactant, while in actuality (in real reservoirs) the foam front lags behind the surfactant front. An increase (fictitious) in surfactant adsorption or an increase in residual gas saturation can be used to retard the foam propagation rate and compensate for this phenomenon. Nevertheless, the model is capable of predicting many of the observed trends in the field and can be used qualitatively in observing steam-foam pilot behavior. Because of the complex nature of the steam-foam drive process, it is suggested that simulations be performed using idealized conditions and the parameters be adjusted to match the observed trend. The published field results are being reviewed to formulate a simulation strategy. Base case steam injection simulations are planned for the next quarter.

FIELD APPLICATION OF FOAMS FOR OIL PRODUCTION SYMPOSIUM

**Cooperative Agreement DE-FC22-83FE60149,
Project SGP63**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: July 1, 1992
Anticipated Completion: June 30, 1993
Funding for FY 1992: \$50,000**

**Principal Investigator:
David K. Olsen**

**Project Manager:
Thomas Reid
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of the symposium on Field Application of Foams for Oil Production are to (1) document updates in

field application of foams technology, (2) provide a means of information exchange on field application of foams to improve production of crude oil, and (3) enhance the development of this technology through the reports and discussion on success and failure of applications of foam.

Summary of Technical Progress

The Department of Energy (DOE) and National Institute for Petroleum and Energy Research will cosponsor a 1½-day symposium on the Field Application of Foams for Oil Production, scheduled for Feb. 11–12, 1993. This symposium will follow the 1993 International Thermal Operations Symposium scheduled for Feb. 8–10, 1993. The Foam Symposium will be held at the Red Lion Inn, Bakersfield, Calif.

In August, a call for papers was distributed to a list of 400 selected names, and meeting announcements were sent to 20 petroleum industry publications. A Program Committee was selected to help review abstracts and papers. The committee members are being asked to encourage participation in selection of panel participants. Abstracts were to be received by Sept. 10, 1992, for review by the Program Committee. Authors were notified of acceptance of their papers and posters in early October. DOE has assigned this symposium Conference Number CONF-930217.

GEOSCIENCE TECHNOLOGY

GEODIAGNOSTICS FOR RESERVOIR HETEROGENEITIES AND PROCESS MAPPING

**Sandia National Laboratories
Albuquerque, N. Mex.**

**Contract Date: Oct. 1, 1987
Anticipated Completion: Sept. 30, 1993
Funding for FY 1992: \$200,000**

**Principal Investigator:
David A. Northrop**

**Project Manager:
Robert Lemmon
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this project is to increase the producibility of existing oil resources by better definition of reservoir heterogeneities and monitoring of oil recovery processes through the application of advanced geodiagnostics systems. This project provides a geologic and reservoir engineering perspective for the integrated Electromagnetic Geophysical

Method research and development (R&D) program being coordinated by the Department of Energy (DOE) at Sandia National Laboratories (SNL), Lawrence Livermore National Laboratory (LLNL), Lawrence Berkeley Laboratory (LBL), and the University of California at Berkeley (UCB). Tasks for FY92 include (1) develop and apply an oil recovery-resistivity simulator system, (2) apply reservoir characterization concepts to bulk resistivity and electrical/electromagnetic (E/EM) field data interpretation, (3) acquire and characterize an industry field site, and (4) field test the collection of reservoir characterization data.

Summary of Technical Progress

Presentation of Cooperative Program Work

July 12–17, a poster on Coupling Electromagnetic Monitoring and Reservoir Engineering was presented at the Society of Exploration Geophysicists Development and Production Forum in Big Sky Montana. A number of the presentations on interpreting seismic monitoring of process changes included reservoir simulation. Thus the approach to integrating EM monitoring of reservoir changes and reservoir engineering that is incorporated into the oil recovery-resistivity simulator system (ORRSIM) is being adopted for the interpretation of seismic data. This similarity of approaches for interpreting EM and seismic data allowed the presentation of the poster to be explained in terms of analogies. As a result, interest in EM

monitoring is growing, and attendees not familiar with reservoir engineering were able to gain a better appreciation of the approach incorporated into ORRSIM. Several of the attendees at the poster session expressed an interest in obtaining more information about ORRSIM and exploring its applicability to their work. Two issues in interpreting EM monitoring data raised in the poster session were anisotropy and bulk resistivity (scale effects). Discussions of seismic anisotropy and reservoir simulation pseudofunctions (used to incorporate fine-scale hydrodynamic variations) demonstrated that the issues of anisotropy and scale are fundamental geological issues, not just problems in EM monitoring.

Frequency Dependence of Bulk Rock Resistivity

The geology of an oil reservoir is not homogeneous at the scale of resolution of an EM measurement or at the grid scale of an oil reservoir simulator. It is therefore necessary to understand how the petrophysical laws governing resistivity of homogeneous rocks average to give bulk or grid scale resistivity. A concern in past work has been that resistivity variations on a scale finer than those resolved by EM techniques may cause the bulk rock resistivity to be frequency dependent. A code for evaluating the equations governing the propagation of plane waves through a layered medium was developed to investigate this issue. The code was used to compare the amplitude of a signal passing through a layered medium with that passing through a homogeneous medium to determine if the effective conductivity is frequency dependent.

The code has been exercised in a number of ways to test for frequency dependence as a result of resistivity or dielectric constant variations on a scale smaller than bulk property variations. In particular, the code has been used for an angle of incidence of 45° and the magnetic field in the plane of bedding. The electric field thus crosses bedding boundaries and therefore induces charge fluctuations at the boundaries that result in a dispersive medium (a medium with frequency-dependent bulk property) caused by Maxwell-Wagner relaxation if these charge fluctuations are large enough. Relative dielectric constants up to 1000 were used. The basic approach to determining the effect of fine-scale variations on bulk properties was to pass a wave through baseline material, through finely layered media that have the same average resistivity as the baseline material, and then through baseline material. Both the surface impedance of reflected media and effective resistivity calculated from the transmitted wave amplitude were examined. Neither showed a frequency dependence for 0.1 to 5 skin depths between the source and receiver.

This work suggests (but does not prove) that frequency-dependent bulk properties are not an issue in the EM program. Other physical phenomena not incorporated into this modeling effort may be important. This work was done to follow up calculations presented at the First Archie Conference.¹ The

calculations presented there were interpreted, at that time, to imply that frequency dependence is an issue. Laboratory work has suggested that rock inherently has frequency dependence often overlooked, although this frequency dependence generally occurs at frequencies above those used in the EM program.¹ A second conclusion suggested by the work presented here is that the change of scale from lab-size samples to bulk rock considered in EM inversions or to the reservoir simulation scale does not change the frequency at which d-c properties are no longer adequate. The only way of really answering the question of whether frequency dependence is important is by experiment, preferably at the field scale, but laboratory scale may be adequate; however, the conclusion of this work is that such experiments are not a high priority at this time.

The interpretation of the work presented at the First Archie Conference has been reviewed in light of the current work. The original work investigated a conceptual experiment in a one-dimensional medium with a resistivity change at $z=b$ ($\rho(z)=\rho$ when $z<b$ and $\rho(z)=\rho'$ when $z>b$) (see top of Fig. 1). An effective resistivity (ρ_{eff}) was defined by equating the solutions for $\rho=\rho'=\rho_{eff}$ and $\rho \neq \rho'$ (middle and top parts of Fig. 1). That work stated: "The meaning of this effective resistivity is that if the material on the left of $z=D$ [point of measurement] were replaced with a material with resistivity ρ_{eff} and the material on the right of $z=D$ [point of measurement] remains the same [resistivity ρ'], M [the meter] would report the same measurement." (Italics added to explain

Fig. 1 Regions for defining effective resistivity.

symbols.) Unfortunately the substitution $\rho = \rho' = \rho_{\text{eff}}$ was for all space (middle part of Fig. 1), not just the signal side of the meter (lower part of Fig. 1). Hence the original interpretation of that conceptual experiment is open to debate. An equally valid interpretation is that it demonstrates the need for full-waveform full three-dimensional space solutions to Maxwell's equations or it demonstrates the dependence of the interpretation on how space is gridded. Effects of how space is gridded on inversions of EM data have already been reported.³

References

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2. G. R. Olhoeft, Low-Frequency Electrical Properties, *Geophysics*, 50(12): 2492-2503 (December 1985).
3. C. W. Beasley, A. C. Tripp, D. J. LaBrecque, J. A. Stodt, S. H. Ward, and P. M. Wright, *Applications of the Cross-Borehole Direct Current Resistivity Technique for EOR Process Monitoring: A Feasibility Study*, Borehole Geophysics: Petroleum, Hydrology, Mining and Engineering Applications, Univ.

ELECTRICAL AND ELECTROMAGNETIC METHODS FOR RESERVOIR DESCRIPTION AND PROCESS MONITORING

**Lawrence Berkeley Laboratory
University of California
Berkeley, Calif.**

**Contract Date: Oct. 1, 1990
Anticipated Completion: Sept. 30, 1993
Funding for FY 1992: \$200,000**

Principal Investigators:

**H. Frank Morrison
Ki Ha Lee
Alex Becker**

Project Manager:

**Robert Lemmon
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objective of this project is an integrated effort by Lawrence Berkeley Laboratory/University of California at Berkeley (LBL/UCB), Lawrence Livermore National Laboratory (LLNL), and Sandia National Laboratories (SNL) in

the electrical and electromagnetic (EM) geophysical method Research and Development (R&D) program for petroleum reservoir characterization and process monitoring. The overall objectives of the program are to (1) integrate research funded by the Department of Energy (DOE) for hydrocarbon recovery into a focused effort to demonstrate the technology in the shortest time with the least cost; (2) assure industry acceptance of the technology developed by having industry involvement in the planning, implementation, and funding of the research; and (3) focus the research on real-world problems that have the potential for solution in the near term with significant energy payoff.

Summary of Technical Progress

Research this quarter focused on the saltwater-injection controlled field experiment conducted at UCB's Richmond Field Station (RFS). The data obtained from the experiment have been analyzed in terms of the injected saltwater plume migration. The experiment has been the result of a joint effort of an ongoing EM method R&D program and the LBL/industry consortium for subsurface EM method development for mapping formation conductivity.

Description of Experiment and Initial Analysis

A cross-well EM experiment was completed in the summer of 1992. The purpose of this experiment was to inject approximately 50,000 gal of conductive salt water into an aquifer at 30 m depth, and, by making cross-well and surface-to-borehole (STB) measurements, determine which direction the saltwater plume migrates. The cross-well experiment was run by placing the source magnetic dipole in the injection well and making vertical magnetic field measurements in four surrounding monitoring wells located 20 to 25 m away from the injection well. Multiple transmitter-receiver measurements were made both before and after injection with the tools at depths ranging from 5 to 60 m below the surface. In addition to the cross-well EM experiment, an STB measurement was also completed. In such a configuration a receiver placed near the top of a borehole was used to measure the vertical magnetic field, while a vertical magnetic dipole in another borehole was used to transmit EM energy into the ground. The dipole source was lowered from the top to the bottom of the transmitter borehole. In this experiment thirteen nearby wells were selected for receiver boreholes (see Fig. 2 for reference) and one well (INJ1) was selected as the transmitter borehole. Three different sets of measurement were taken in May, June, and August 1992. These periods correspond to before saltwater injection, after saltwater injection, and after saltwater pumping, respectively. However, only the INJ1-EMNE configuration has a complete set of data taken during all three experiment periods. Data from the other boreholes were taken in June and August only, which correspond to periods before and after the salt water was drawn out.

Comparison of the data measured in different periods should show the changes in the anomalous magnetic field

produced by the injected saltwater plume. Figure 1 shows three sets of difference in magnetic fields measured in two different periods in borehole EMNE. They are June-May, August-May, and June-August. Ideally, the difference in magnetic fields between May and August should be approximately zero if the salt water was drawn out completely. Yet, as shown in part a of Fig. 1, a considerable amount of anomaly seems to be increasing with transmitter depth. The cause of this is still unknown. Part b of Fig. 1 illustrates a numerical process by which the anomaly caused by the saltwater plume is calculated for the June-August pair. First, the June-August anomaly curve shown in part a of Fig. 1 is smoothed. Next, the June-August difference in background field is estimated by simply interpolating the smoothed curve. The plume-related anomaly is then calculated by subtracting the background difference from the smoothed June-August anomaly curve. The phase anomaly was obtained with the same procedure. Figure 2 shows the location of boreholes at RFS, overlapped with the amplitude and phase anomalies calculated in all thirteen boreholes with respect to transmitter depth.

To examine the actual distribution of the salt water after injection, a numerical experiment was conducted by calculating the response of a thin sheet model. The model consists of a rectangular conductive thin sheet placed in a less conductive background. Computer program SHEETS is used for the simulation. Among eighteen models tested, the one that best fits the field data is a thin sheet 12 m long and 10 m wide with conductivity thickness product of 1 S. It is located 30 m beneath the surface of a half-space of $15 \Omega\text{-m}$ resistivity. Its center is shifted by 2.5 m in the direction 20° northwest of the injection borehole INJ1. This model is shown in Fig. 3, and the numerical results in amplitude and phase at nine selected positions are shown in parts a and b of Fig. 4, respectively. The amplitude anomaly seems to fit the field data better than the phase anomaly. As a preliminary study, although not satisfactory, it is quite encouraging that the numerical simulation fits the field data reasonably well. However, a trial-and-error technique using a forward numerical simulation is not sufficient for more detailed underground conductivity mapping. An imaging method might be used for the future study.

Fig. 1 Plots showing differences in magnetic fields measured in different periods in borehole EMNE. (a) Anomalous magnetic field intensity calculated from the measurement [difference in H_z (vertical component of the magnetic field), % (INJ-NE, 0.5 m)]. (b) Recovered intensity anomaly in H_z (%) (INJ-NE, 0.5 m).

(a)

(b)

Fig. 2 Map of Richmond Field Station showing (a) amplitude anomaly in H_g (vertical component of the magnetic field, %) and (b) phase anomaly (degrees) of field data in 13 receiver boreholes. ●, shallow holes, depth ~2 m. ○, deep holes, depth > 5 m.

Fig. 3 Map of Richmond Field Station showing thin sheet model that best fits the field data. ●, shallow holes, depth ~2 m. ○, deep holes, depth > 5 m.

Fig. 4 Map of Richmond Field Station showing (a) amplitude anomaly in H_v (vertical component of the magnetic field, %) and (b) phase anomaly (degrees) of field data in 9 selected boreholes. The model used for this calculation is shown in Fig. 3. ●, shallow holes, depth ~2 m. ○, deep holes, depth > 5 m.

LAWRENCE BERKELEY LABORATORY/ INDUSTRY HETEROGENEOUS RESERVOIR PERFORMANCE DEFINITION PROJECT

Lawrence Berkeley Laboratory
University of California
Berkeley, Calif.

Contract Date: Apr. 1, 1992
Anticipated Completion: Apr. 1, 1993
Funding for FY 1992: \$275,000

Principal Investigators:

J. C. S. Long
E. L. Majer
L. R. Myer

Project Manager:

Robert Lemmon
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this work is to validate geophysical and hydrological techniques for characterizing heterogeneous reservoirs in the most optimal (economic) manner. The overall objective of the project is to develop a methodology that can be used by the petroleum industry in a variety of heterogeneous regimes for characterizing and predicting the performance of petroleum reservoirs.

Summary of Technical Progress

The project objectives will be accomplished through a cooperative research program between Lawrence Berkeley Laboratory (LBL) and British Petroleum, Inc. (BP) which is focused on the characterization of heterogeneous reservoirs in a meander belt porous medium formation. BP has done characterization and data integration at several test facilities. The present program will continue BP's multiyear efforts at the Gypsy site in northeastern Oklahoma. BP itself has terminated its research and development (R&D) efforts on the Gypsy site and outsourced the Gypsy data to Oklahoma University. The resulting research will integrate various

geophysical and hydrological methods and apply them at a well-calibrated and characterized site where their use can be assessed. This cooperation will allow techniques developed for waste storage and geothermal energy to be adapted for use in heterogeneous and fractured reservoirs. The work will be coordinated with the cross-well electromagnetic (EM) R&D Project and the LBL/Morgantown Energy Technology Center (METC) Reservoir Performance Definition Project.

Hydrologic-Related Work

Substantial progress was made on the first hydrologic task, reviewing the subsurface pilot-site well test data and evaluating its potential for inclusion in a hydrologic inversion to characterize heterogeneities at the pilot site. Activities included (1) reading and studying two summary reports on the well tests; (2) studying well logs for the six pilot-site wells, and extending a hydrologic model developed using three of the wells to the other three wells; (3) checking, correcting, and categorizing pressure-transient data received on computer diskette; (4) creating cross sections to display well-test results; and (5) creating a matrix of well test results.

An example of the cross-section display is shown in Fig. 1. Basically, it identifies the pumping and observation well intervals and indicates whether or not there is communication between them. A comparison of multiple cross sections provides a useful way of visualizing the dominant flow channels in the subsurface, but it is quite cumbersome to do because 37 cross sections are needed to describe the responses to 14 different well tests. A powerful computer package for three-dimensional (3-D) visualization of geological data, called 3D-ROCK, was recently obtained by LBL and will be used to develop more convenient means of data visualization. 3D-ROCK is a microcomputer-based, centralized system for site investigations that includes collection, processing, and integrated interpretation of geological, geophysical, hydrological, and rock mechanical data. An IBM-compatible 486 personal computer with a large color monitor will be dedicated to the use of 3D-ROCK.

A matrix display of well-test results provides a concise way to assess the consistency, precision, and coverage of a large number of well tests. Each entry in the matrix describes the response between a pair of pumping and observation well intervals. On the basis of the principle of reciprocity,¹ the response at Well A during a test in which Well B is pumped should be the same as that at Well B during a test in which Well A is pumped if the same pumping rates are used in both tests. This relationship even holds when different flow rates are used if each drawdown response is normalized by the flow rate used. Several entries in the matrix have been located which qualitatively contradict the reciprocity principle (i.e., no response at Well A when Well B is pumped but a large response at Well B when Well A is pumped). This is an indication of instrument or operational failure (e.g., packer failure and electrical power outage). Reciprocal en-

tries have been found in the matrix that are qualitatively the same but differ quantitatively; these will be used to assess the precision of the pressure measurements and flow-rate control. Finally, the matrix has been used to identify gaps in coverage (i.e., combinations of wells that have not been tested together which would be useful locations for future well tests).

On the basis of the reports describing the pilot-site well tests conducted in 1989 and 1990, 130 pressure transients from 16 different well tests will be used for hydrologic inversions. Evaluation of the data has indicated that 90 pressure transients from a total of 13 tests will be directly usable in the inversion method. The remaining 40 pressure transients fall into one of five categories:

- 13 pressure transients that qualitatively satisfy the reciprocity principle or involve duplicate tests; these will be useful for checking the precision of the data.
- 6 pressure transients that qualitatively contradict the reciprocity principle; these have been used to identify three occurrences of instrument failure.
- 10 pressure transients that were measured during one of the tests with instrument failure.
- 8 pressure transients for which the data were missing or garbled.
- 3 pressure transients from tests that were designed in such a way as to make the results uninterpretable with the inverse method.

Overall, 103 out of 130 pressure transients will be used either directly in the inversions or indirectly to check the precision of the data.

On the basis of evaluation of the data, the well test data as a whole supports the conceptual geological model of the pilot site presented in the BP report on the 1989 well tests. This model is composed of three sand channels (lower, middle, and upper) separated vertically by two clay layers. The lower clay layer (the dense red clay) is inferred to be continuous, whereas the upper clay layer is discontinuous.

A tentative strategy has been developed for hydrological inversions. Initially, just the lower sand channel will be modeled with a two-dimensional (2-D) areal model. There are 17 pressure transients between lower layer intervals. Of these, 2 are from vertical tests, 5 are from buildup tests, and 10 are from interference tests. The interference and buildup tests are most amenable to use in the inversion. Some of the data will not be used during the inversion process but will be predicted by the resulting model to validate it. After assessment of the results of the 2-D inversion, 3-D effects, such as leakage through the dense red clay layer, will be added if needed. Next, the upper-middle sand channels will be modeled as a single layer followed by a multilayer treatment. Finally, if the results indicate substantial leakage across the dense red clay layer, a 3-D model including all the sand channels and intervening clay layers will be developed.

Preliminary work on the second hydrologic task, creating a numerical model of the outcrop site for use in generating

1990 Test
Sequence 4, Test 2

Fig. 1 Example of the cross-section display.

synthetic hydrologic data, indicated that the progress made by BP in this area would substantially aid these efforts. Efforts

are under way to obtain the numerical model developed and the associated reports.

Seismic-Related Work

The goal of FY92 seismic field work was to do a set of mini cross-hole seismic surveys at the Gypsy outcrop site. During August three wells were drilled to a depth of 75 ft around Well No. 5 as shown in Fig. 2. The new wells, labeled A, B, and C, are all 25 ft from Well No. 5. While arranging for drilling, it was learned that Well No. 4 had been covered over by dirt. When an attempt was made to perform the surveys on August 8, it was discovered that Well A water level was 58 ft

below the surface. Well B water level was 68 ft below the surface, and Well C was dry and blocked at a depth of 45 ft. When an attempt was made to fill each well with water, none would hold water for enough time to perform a reliable survey (the cross hole source and receivers need to be in water to function properly). Note that Well No. 5 maintained a water level of about 5 ft below the surface throughout attempts to fill the other wells.

The limited data collected indicated that good data could be collected if the wells were sealed. Further field work will be

Fig. 2 Illustration showing location of Wells A, B, and C. (Reproduced from the best available copy.)

conducted in FY93 by first sealing the wells so that they will hold water and then conducting the cross-hole survey.

The other seismic task planned for this quarter, processing existing high-frequency cross-well seismic data, could not be accomplished because the relevant data have not been received from BP.

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AN EXPERIMENTAL AND THEORETICAL STUDY TO RELATE UNCOMMON ROCK-FLUID PROPERTIES TO OIL RECOVERY

Contract No. DE-AC22-89BC14477

**Pennsylvania State University
University Park, Pa.**

Contract Date: Sept. 21, 1989

Anticipated Completion: Sept. 20, 1992

Government Award: \$260,221

Principal Investigators:

Turgay Ertekin

Robert W. Watson

Project Manager:

Gene Pauling

Metairie Site Office

Reporting Period: July 1–Sept. 30, 1992

Objectives

The overall objectives of the project are to develop a better understanding of some important, but not well-investigated rock properties, such as tortuosity, pore-size distribution, surface area, wettability, and neck-throat average rock size; develop a better insight on capillary pressure variation with respect to wettability and pore geometry of Berea sandstone, limestone, and dolomite; develop a relationship between oil recovery at breakthrough and wettability and surface area of the rocks; develop correlations between ultimate oil recovery and wettability and surface area of these different porous media; investigate variations of average irreducible water saturation (S_{wi}) and average residual oil saturation (S_{or}) with respect to wettability; and improve the understanding of fluid flow in porous media under conditions of secondary and tertiary recovery through the laboratory study of the performance of enhanced recovery methods, such as waterflooding.

During the previous quarter, waterflooding experiments were initiated on Berea sandstone linear cores. Preliminary tests were completed on five core samples and the results analyzed.

Summary of Technical Progress

This study is part of an ongoing research project aimed at correlating rock-pore characteristics to oil recovery from various reservoir rock types and incorporating these properties into empirical models for predicting oil recovery. For that reason, this report deals with the analyses and interpretation of wettability experimental data collected from core plugs and related to previously measured petrophysical and waterflood properties. Simple empirical equations based on these relationships were developed. Except for the relationships that were statistically not significant at $\alpha = 0.1$ level, the simple empirical equations were used to draw trend lines on the plots.

Experimental Procedure

After the completion of the waterflood experiments, core plugs were extracted from the waterflooded cores. Sixteen Indiana limestone cores were taken from each of the 32 core plugs, for a total of 512 Indiana limestone core plugs. The core plugs were drilled perpendicular to the bedding planes on each sandstone and limestone core with a diamond core bit that uses water as the coolant and lubricant. Each core plug was identified by a sample number, using blue color wax-base pencil. On the average, the extracted core plugs were 1.3 cm in diameter and 1.7 cm long. The core plugs were cleaned prior to performing the wettability and mercury porosimetry tests using the method presented in the next section.

Samples Cleaning

The core plugs were cleaned by soaking for 48 h in solution containing 50% by volume acetone and 50% by volume isopropyl alcohol (IPA). This was followed by an additional soaking for 24 h in acetone solution only. Finally, the core plugs were dried in a vacuum oven for 24 h at a temperature of 60 °C. The core plugs were weighed before and after the treatment to ensure that the core plugs were clean. This technique was developed by Texaco Research Laboratory. Results derived from samples cleaned in this way are as reliable as other more rigorous methods of cleaning core plugs.

Wettability Experiments

Wettability is a major factor controlling the location, flow, and distribution of fluids in a reservoir. The term is generally used to describe the ability of a fluid to wet a solid surface in the presence of a second fluid. Wettability changes have been shown to affect waterflood behavior, S_{wi} , and S_{or} .

According to Morrow,¹ reservoir wettability is determined by complex interface boundary conditions acting within the pore space of sedimentary rocks. These conditions have a

dominant effect on interface movement and associated oil displacement.

The Amott-Harvey method² was used to measure the average wettability of the core plugs that were extracted from the waterflooded cores. The method is based on the fact that the wetting fluid will generally imbibe spontaneously into the core, thereby displacing the nonwetting phase. In determination of the wettability index, the ratio of spontaneous imbibition to forced imbibition is used to reduce the influence of other factors, such as relative permeability, viscosity, and the initial saturation of the rock because only the surface forces are changed.

Wettability is well established in the literature as a dominant variable in controlling the performance of displacement of oil by water in porous media, and it is often described with the terms "water-wet," "intermediate," or "oil-wet." For the Amott-Harvey method, the water-wet range is from +0.3 to +1.0, the intermediate range is from -0.3 to +0.3, and the oil-wet range is from -0.3 to -1.0. The intermediates are further broken down to a range of +0.1 to +0.3 for slightly water-wet, -0.1 to +0.1 for neutral and -0.1 to -0.3 for slightly oil-wet.

Results and Discussion

Wettability Properties

From each of the waterflooded Indiana limestone cores, 32 core plugs were extracted from along the flow path at an average interval of about 2.5 cm. The core plugs were perpendicular to the flood plane. As in the case of Berea sandstone core plug samples, during the process of the extraction, the distance of each core plug relative to the inlet face of the core was noted. For a given distance, two core plugs were obtained, one from the bottom and the other from the top of the core. An average value of the wettability index is obtained for a given distance. Distances are normalized by dividing the value of the measured distance relative to the core inlet by the total length of the core.

Figure 1 shows the frequency distribution of wettability index for the 512 Indiana limestone core plugs. The plots of

Fig. 1 Frequency distribution of wettability index for Indiana limestone core plugs.

the wettability indexes vs. the normalized distances for each of the 16 cores are shown in Figs. 2 to 9. From the core plugs, an average value of wettability index was obtained for each of the cores. The mean wettability index for all the cores combined was 0.67. On the basis of these determinations, the Indiana limestone cores investigated in this study are classified as water-wet rocks.

Fig. 2 Wettability index vs. normalized length for Indiana limestone core samples 9A and 9B.

Fig. 3 Wettability index vs. normalized length for Indiana limestone core samples 10A and 10B.

Fig. 4 Wettability index vs. normalized length for Indiana limestone core samples 11A and 11B.

Fig. 6 Wettability index vs. normalized length for Indiana limestone core samples 13A and 13B.

Fig. 5 Wettability index vs. normalized length for Indiana limestone core samples 12A and 12B.

Fig. 7 Wettability index vs. normalized length for Indiana limestone core samples 14A and 14B.

Relationship Between Wettability and Petrophysical Properties

For Indiana limestones average wettability index has no relationship to porosity, permeability, tortuosity, and formation resistivity factor. At $\alpha = 0.1$ level, the relationships of average wettability index vs. these petrophysical properties failed the statistical test.

Relationship Between Wettability and Waterflood Properties

Figure 10 shows that average wettability index is inversely proportional to S_{wr} . The relationship is statistically significant at $\alpha = 0.1$ level. Figures 11 to 14 show the plots of S_{or} and oil recovery vs. average wettability index at both the breakthrough and floodout. From the results, wettability of Indiana

Fig. 8 Wettability index vs. normalized length for Indiana limestone core samples 15A and 15B.

Fig. 9 Wettability index vs. normalized length for Indiana limestone core samples 16A and 16B.

limestone cores seems to govern the S_{or} and the ultimate oil recovery values at floodout. No relationships exist between S_{or} and oil recovery vs. average wettability index at breakthrough. This is shown in Figs. 11 and 13, respectively. Figure 12 shows that S_{or} at floodout is directly proportional to average wettability index. As shown in Fig. 14, ultimate oil recovery at floodout is inversely proportional to average

Fig. 10 Average wettability index vs. irreducible water saturation for Indiana limestone cores for 16 samples. Wettability index, 1.333–1.047.

Fig. 11 Residual oil saturation vs. average wettability index for Indiana limestone cores at breakthrough.

wettability index. From these observations, it can be deduced that for water-wet Indiana limestone rocks, as wettability index increases, S_{or} at floodout also increases and ultimate oil recovery at floodout by waterflood decreases. These findings are in agreement with the observation of Morrow¹ and Jadhunandan and Morrow^{3,4} that oil recovery by waterflooding is optimum close to neutral wettability for water-wet systems.

Fig. 12 Residual oil saturation vs. average wettability index for Indiana limestone cores at floodout.

Fig. 13 Oil recovery vs. average wettability index for Indiana limestone cores at breakthrough.

Conclusions

The following conclusions are deduced from this study:

- The Indiana limestone cores investigated are all water-wet.
- No relationship exists between average wettability index and petrophysical properties, such as porosity and permeability.
- Irreducible water saturation is inversely proportional to average wettability index.

Fig. 14 Ultimate oil recovery vs. average wettability index for Indiana limestone cores at floodout.

- No relationship is evidenced when average wettability index is compared with residual oil saturation at breakthrough and oil recovery at breakthrough.
- Average wettability index is directly proportional to ultimate oil recovery at floodout and inversely proportional to residual oil saturation at floodout.

Nomenclature

B.T.	breakthrough time
C.V.	coefficient of variation
F	statistical F-test
F.O.	floodout time
n	number of samples
OR	oil recovery, % IOIP
R	correlation coefficient
R^2 or R-sq	coefficient of determination
S_{or}	residual oil saturation, fraction
S_{wi}	irreducible water saturation, fraction
UOR	ultimate oil recovery, % IOIP
WI	wettability index
α	level of significance
σ	standard deviation
ϕ	porosity, fraction

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OIL RECOVERY ENHANCEMENT FROM FRACTURED, LOW- PERMEABILITY RESERVOIRS

Contract No. DE-FG07-89BC14444

**Texas A&M University
College Station, Tex.**

**Contract Date: June 13, 1989
Anticipated Completion: Sept. 1, 1992
Government Award: \$256,000
(Current year)**

**Principal Investigator:
S. W. Poston**

**Project Manager:
Rhonda Lindsey
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this project is to develop and advance new concepts and technology to increase oil and possibly gas recovery from fractured, low-matrix permeability reservoirs. The overall study is to encompass geological, geophysical, laboratory, and imaging flow studies and analytical and computer modeling as well as field trials.

Summary of Technical Progress

Interpreting and Predicting Natural Fractures

Field observations focused on the vertical continuity of fractures in the Austin Chalk. These studies indicate that many fractures are contained within brittle chalk members when the latter are bounded by relatively ductile shales or marls that exceed 10 cm in thickness.

A series of simple laboratory experiments has been completed where fractures were initiated in a brittle rock and propagated toward a bedding plane. The specimen rock is a 5-cm-diameter by 10-cm-long cylinder consisting of two sub-cylinders of brittle rock (Berea sandstone) either in contact with a ductile layer consisting of bentonitic clay or in contact with each other (i.e., no clay). The upper brittle member contains a notch (2 mm wide) sawed partially through the piece that terminates in a finer notch (1 mm wide). The purpose of these notches is to produce a stress concentration that causes a fracture to propagate toward the ductile layer when the upper piston forces a steel wedge into the notch.

Whether or not the produced fractures cross the bedding or are contained within the brittle member is dependent upon the thickness of the ductile layer, the effective confining pressure,

and the displacement rate for the fracture propagation. Fracture containment is enhanced by increasing thickness of the ductile layer, decreasing effective confining pressure, and slowing displacement. The fact that fracture bed-containment is favored by low effective confining pressure is of paramount importance.

Extrapolation of fracture data from outcrop to Austin Chalk reservoirs in the subsurface is dependent upon having been brittlely deformed at low effective confining pressure. The maximum vertical effective stress and assumed lithostatic conditions during fracture was only 500 psi since fractures in the outcrops of the chalk occurred at a maximum depth of burial of only 1000 ft.

Two cases are possible: (a) fracturing of the Austin Chalk could have taken place at a shallow depth of burial (i.e., low effective pressures) or (b) the chalk might have faulted and fractured at near its maximum depth of burial when high pore pressures arose from maturation of its indigenous hydrocarbon or from that in the underlying Eagleford carbonaceous shale.¹ In either case, high pore pressures would reduce the effective stresses and cause the chalk to be weak brittle. Therefore, fracture containment could be predicted at depth, provided the stratigraphic architecture of the Austin Chalk was characterized by shales or marl intercalated between chalk layers.

Relating Recovery to Well-Log Signatures

Compilation of the final report is nearly complete, and new core data have been incorporated in the previous analyses. The original correlation of water saturation (S_w) as a function of true resistivity (R_{td}) showed a straight line on a semi-log plot (Fig. 1).² The addition of new data introduces some scatter that was not found in the original data set. However, all data points for the reservoir zone (except one) are within the predicted range of 10 to 40 Ω -m. The out-of-range point has a high water saturation and is in a section not known to be oil

Fig. 1 Relation of water saturation (S_w) measured in cores and true resistivity (R_{td}). Solid line shows fit to the original data, dotted curve shows possible fit to added data.

productive. The high resistivity of this point appears to be a more massive limestone than the typical reservoir sections in the core.

The interpretation of productivity and well-log response was supported by analysis of production-decline curves. The method is illustrated by a rate-time graph for one well (Fig. 2).³ The rapidly decreasing rate of production during the first 20 months is attributed to oil being produced from fractures. Beyond the inflection point at about 20 months, the more gradually decreasing, low rates of production reflected a significant contribution of oil being produced from the rock matrix.

Fig. 2 Production-decline curve for an Austin Chalk well showing the agreement with a type curve presented by Poston.³ Early production is interpreted to be from fractures and later production, beyond the inflection point, from the rock matrix.

Additional cores have been examined for the occurrence of fractures, particularly microfractures as they may relate to oil production. Four cores have been studied, three from vertical wells and one from a horizontal well. The microfractures will be studied and described by petrographic methods and correlated with other rock properties, particularly those properties that can be deduced from well-log response. These interpretations will be incorporated in the final report of the research.

Daily production data from three horizontal Austin Chalk wells were analyzed and interpreted in terms of the pseudo-steady state dual fracture-matrix flow model.

The production response of the three horizontal wells completed in the Austin Chalk indicated early time linear flow. The early time data in some cases appeared to be obscured because of the quality of recorded data or multiple porosity transition period. The middle time data was characterized by a linear flow as a result of fractures, followed by a late time pseudo-steady flow, boundary dominated.

The production data were matched with Chen type curves. The decline curve analysis was developed under the assumption of a constant flowing bottomhole pressure. The well production data were normalized by dividing the flow rate by the pressure drop between the initial and current flow tubing

head pressure ($q/\Delta p$). The normalized flow rate magnified the changes in storage compressibility and fracture intensity terms.

Different decline periods have been identified for each well. Each decline period was initialized. These individual decline periods were caused by the well being closed-in. The initialized declines were matched to the Chen type curves. Storage compressibility remains constant, whereas in most cases the fracture intensity terms are seen to increase with time.

The pseudo-steady state material balance equation was arranged in the form of a straight line. The slope of the line from a Cartesian plot of $\Delta p/q$ vs. Q_{cum}/q yielded an approximate estimate of the matrix pore volume. Also, an estimate of the reservoir permeability can be determined if the pressure-volume-temperature (PVT) data are available.

A plot of $\log \Delta p/q$ vs. $\log Q_{cum}/q$ transferred the production decline plot to a pressure-well testing plot. Thus, well testing analysis techniques were applied to interpret production data. Also, the pressure derivative analysis technique was attempted during the reported period.

Laboratory Studies of the Imbibition Process

Study of the effects that microfractures have on oil recovery has been started. A core sample of 10-mD permeability was cut in half before saturation. Oil saturation was achieved by placing a temporary seal in the created fracture and forcing oil through the rock. The fractured rock was subjected to spontaneous imbibition of unadulterated water. The fracture was subjected to a complete closure. The conducted experiment used nuclear magnetic resonance (NMR) to monitor oil saturation changes at different locations. There were no obvious effects observed but the study of that fracture width will be included in the final report.

Oil recovery from unevenly oil saturated core samples was studied. A waterflood was simulated by injecting water through a single inlet at one end of 2-in.-diameter by 3-in.-length cylindrical samples. The asymmetric injection created a sample with vertical oil saturation gradients. Imbibition was started under these conditions. Although addition of CO_2 did not create additional oil recovery after unadulterated water imbibition (see Fig. 3), several samples have shown oil recovery as a result of imbibition only when water is carbonated (see Fig. 4).

Mathematical Modeling

The dual-porosity compositional simulator for CO_2 -enriched waterflood in a naturally fractured reservoir was tested against a test case presented by Peng and others.¹ The test case is a depletion of a volatile oil reservoir having initial oil pressure of 6000 psi and a bubble-point pressure of 5390 psi. The results obtained by single-porosity and dual-porosity simulation are presented in Fig. 5, and input data are given in Table 1. The same test case was simulated for single porosity using the VIP-COMP simulator of Western Atlas Software Inc.⁵

Fig. 3 Oil recovery from an unevenly oil saturated rock sample. Oil recovery that results from unadulterated and carbonated water imbibition is shown. Rock porosity, 17.4%; permeability, 21.4 mD; and initial oil saturation, 53.0%.

Fig. 4 Oil recovery that results from unadulterated and carbonated water imbibition is shown. Oil recovery that results from unadulterated water is nonexistent. Rock porosity, 17.6%; permeability, 19.4 mD; and initial oil saturation, 52.4%.

Fig. 5 Comparison of the simulated results for single-porosity and dual-porosity simulation.

The results presented are for the one quarter of the total area of 160 acres. The results obtained by VIP-COMP and this study for single-porosity simulation are slightly lower than Peng's test case. This may be caused by the lack of binary-interaction parameters in the test case presented by Peng. The data available are overall compositions of the components and the bubble-point pressure. Therefore, the binary interaction parameters of 14 components by DESKTOP-PVT software developed by Western Atlas Software Inc. were determined.

The results obtained by laboratory imbibition studies using water and carbonated water are being simulated to describe the oil recovery behavior from the naturally fractured reservoirs.

TABLE 1

Rock and Fluid Properties of Fracture and Matrix Systems

No. of hydrocarbon components	14
Reservoir area	160 acres
Reservoir thickness	100 ft
Grid system	5 × 5 × 1
Initial reservoir pressure	6000 psi
Bubble point pressure	5390 psi
Bottomhole flowing pressure	2000 psi
Location of producing well	5 × 5 × 1

Fracture system properties		Matrix system properties	
k_{AX}	60 mD	k_{MX}	1 mD
k_y	30 mD	k_{My}	0.5 mD
L_{AX}	264 ft	L_{MX}	3.5 ft
L_y	100 ft	L_{My}	3.5 ft
S_{wi}	0.0	S_{wi}	0.1
ϕ	0.01	ϕ	0.4
E_s	1.0	E_s	1.0

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5. VIP-COMP Compositional Simulator Developed by Western Atlas Software Inc.

GEOPHYSICAL AND TRANSPORT PROPERTIES OF RESERVOIR ROCKS

Contract No. DE-AC22-89BC14475

**University of California
Berkeley, Calif.**

**Contract Date: Sept. 22, 1989
Anticipated Completion: Sept. 30, 1992**

**Principal Investigator:
Neville G. W. Cook**

**Project Manager:
Robert Lemmon
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this research is to understand, with analysis and experiment, how fluids in pores affect the geophysical and transport properties of reservoir rocks. The definition of reservoir characteristics, such as porosity, permeability, and fluid content, on the scale of meters, is the key to planning and control of successful enhanced oil recovery (EOR) operations. Equations relating seismic and electrical properties to pore topology and mineral–fluid interactions are needed to invert geophysical images for reservoir management. Both the geophysical and transport properties of reservoir rocks are determined by pore topology and the physics and chemistry of mineral–fluid and fluid–fluid interactions.

Summary of Technical Progress

During the reporting period, research was carried out in three areas: (1) application of graph theory to imbibition and drainage, (2) laboratory measurement of pore compressibility in Berea Sandstone, and (3) laboratory measurement of seismic wave propagation in Berea Sandstone.

The processes of imbibition and drainage were added to the graph theory model. Simulations were compared to phenomena observed in laboratory experiments and found to show good visual agreement. Laboratory measurements of pore compressibility were extended to biaxial stress conditions. Laboratory measurements of seismic wave propagation were extended to include biaxial stress and hexadecane saturated conditions. Detailed descriptions in each area are as follows.

Application of Graph Theory to Imbibition and Drainage

During this quarter, progress was made in the numerical simulation of two-phase flow in Berea Sandstone using graph

theory. Invasion process results were reported in the previous quarterly report. Kung's¹ field experiments on wetting fluid flow were cited, showing a strong tendency to preferential patterns. To understand this phenomenon, the imbibition and drainage processes have been included in the numerical simulations.

The preferential pattern for wetting fluid invasion is not significantly different from that of a nonwetting fluid. For a wetting fluid, the imbibition process will continue and drainage will start if the wetting fluid is terminated. This is not the case for nonwetting fluid flow. A wetting fluid tends to fill the small throats when the externally imposed pressure gradient is removed. Because total fluid mass is conserved, fluid in the large throats will drain simultaneously with the filling of the small throats until equilibrium is reached. In contrast, nonwetting fluid flow will cease when the externally imposed pressure gradient is removed.

The simulation of the imbibition and drainage processes is accomplished by using a data structure called a priority queue. A queue is a series of elements arranged and manipulated in a specific order. A simulation using this method is shown in Fig. 1. The fluid is supplied at the top of the structure and flows toward the bottom. The fluid supply is removed from the top when invasion first reaches the bottom of the structure (part b of Fig. 1). For a wetting fluid the system is not in equilibrium. The small throats near the invasion front have larger capillary (sucking) pressures than those of the large throats exposed to air. The fluid will move until the current imbibition throat is of the same size as that of the current drainage throat. In part c of Fig. 1, the double lined and single elements represent the drained and imbibed throats, respectively. The simulation uses two priority queues to handle the problem. One queue is the imbibition queue. It orders the throats by increasing diameter. Whenever a neighbor throat of the imbibition front is added to the queue, it is placed into the appropriate diameter location. The other queue is the drainage queue, where the throats are placed in descending order. Throats added to the drainage queue must be adjacent to open nodes. Open nodes are defined as those open to air. All the top nodes become open when the fluid supply is removed. After a throat is drained, both of its nodes become open. As drainage progresses, more throats adjacent to open nodes are added to the drainage queue. If both nodes of a throat are opened before it drains, the water cannot drain and remains trapped in the throat.

This is exactly the phenomenon observed in the paraffin imbibition experiments performed on Berea Sandstone reported by Schluter et al.² In these experiments, some of the large voids were observed to be coated but not filled by the paraffin, a wetting fluid. This is evidence that they were once occupied by the wetting fluid, possibly as initial preferred paths that later drained.

Laboratory Measurement of Pore Compressibility

The pore compressibility studies reported in previous quarters showed that significant differences existed in the

(a)

(b)

(c)

(d)

Fig. 1 Simulation examples based on uniform distribution of throat diameter with spatial correlation. (a) Original network for spatially correlated throats. (b) Invasion process for spatially correlated net (frozen). (c) Imbibition and drainage process for spatially correlated net. (d) Critical path (thick) and preferred path (thin) for spatially correlated distribution.

pore compressibility of Berea Sandstone under hydrostatic and uniaxial states of stress. Experiments were continued this quarter on a new specimen, core KBS27. This core was saturated in a brine concentration, then placed in a brass jacket as described previously. The core was then subjected to hydrostatic, uniaxial, and biaxial stresses. The total fluids displaced and the associated compressibilities are shown in

Fig. 2. The hydrostatic and uniaxial values were similar to those reported previously for other cores. The agreement of compressibility values among water, brine concentrations below the critical salt concentration, and brine concentrations above the critical salt concentration suggests that the mobility of clay particles is not a major factor in compressibility.

Fig. 2 The (a) measured total volumes displaced and (b) calculated compressibilities for Berea Sandstone core KBS27 sealed in a brass jacket and tested under varying states of stress.

The biaxial data fall between the uniaxial and hydrostatic data. These results provide further indications that pore geometry will depend on the stress state. This could be an important factor for seismic wave propagation.

Laboratory Measurement of Seismic Wave Propagation

Measurements of seismic wave propagation in Berea Sandstone have continued. In this last quarter, core KBS27 was

measured for hydrostatic, biaxial, and uniaxial stress states while the core was dry, while saturated with brine, and while saturated with hexadecane. The biaxial stress was applied orthogonally to the direction of wave propagation. The measured velocities were similar to those reported last quarter for cores KBS15, KBS16, and KBS17. The measured peak-to-

peak amplitudes are given in Fig. 3. The brine and dry values are similar to those reported last quarter. The P- and S-wave amplitudes in the hexadecane-saturated cores are consistently larger than for the water-saturated cores. This suggests that the polarity of water may be introducing a secondary attenuation mechanism into the experiments.

Fig. 3 Measured peak-to-peak amplitudes for (a) P-waves and (b) S-waves on core KBS27 tested with different fluids and under varying states of stress.

For a given mean stress, the largest P wave amplitudes were measured under uniaxial stress conditions, followed by hydrostatic and biaxial. This indicates that the stress in the direction of propagation has a large effect on P wave propagation. For a given mean stress, the S-wave amplitudes for hydrostatic and uniaxial stresses are similar. The S wave amplitude for biaxial stress is slightly lower. This may be the

result of insufficient coupling between the transducers and specimens under biaxial loading. The similarity suggests that overall mean stress, as opposed to directional stress, is a dominant factor in S wave propagation.

Plots of peak to peak amplitudes vs. corresponding velocities are presented in Fig. 4. Data from all the tests conducted to date are included. The data separate into two distinct

Fig. 4 Plots of peak-to-peak amplitudes vs. velocities measured for (a) P-waves and (b) S-waves for all tests conducted to date.

curves on the basis of the saturation of the core—either dry or fluid saturated. The fact that data with different applied stresses and saturating fluids fall onto the same curve suggests that velocity and attenuation in wave propagation are controlled by the same mechanism. The smaller amplitudes for the fluid-saturated data compared to dry amplitudes at the same velocity indicates that fluid introduces a viscous loss mechanism in addition to scattering. This relationship will be investigated over the next quarter.

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CHARACTERIZATION AND MODIFICATION OF FLUID CONDUCTIVITY IN HETEROGENEOUS RESERVOIRS TO IMPROVE SWEEP EFFICIENCY

Contract No. DE-AC22-89BC14474

**University of Michigan
Ann Arbor, Mich.**

**Contract Date: Sept. 26, 1989
Anticipated Completion: Sept. 25, 1992
Government Award: \$112,000
(Current year)**

**Principal Investigator:
H. Scott Fogler**

**Project Manager:
Robert Lemmon
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this work is to develop effective flow-diverting techniques through experimentation with the use of neutron imaging for flow characterization before and after treatment. Theoretical modeling will be used to identify the important parameters that govern the process of diverting fluids.

Summary of Technical Progress

Our three-dimensional (3-D) network model for the simulation of flow, precipitation, and dissolution in a porous medium was described in a previous quarterly report. Some of the features of this model were demonstrated during the study of the acidization of limestone with HCl. The results of these simulations indicated that this 3-D network model was capable of describing the flow and reaction of various species in a porous medium. Furthermore, the change of the pore space structure resulting from the dissolution-precipitation processes could be represented graphically.

The goal of this project is to be able to quantitatively, as well as graphically, describe the changing reservoir characteristics (i.e., permeability and porosity) that occur during the process of diagenesis. Our network model has advantages over continuum models because of the ability to describe the diagenetic processes on a pore level where many important phenomena are occurring. Currently the formation of precipitation waves in a BaSO_4 - CaSO_4 system are being studied in an effort to verify the model by comparing these results with those obtained by other simulators.^{1,2} Once these simulations are completed, efforts will focus on the precipitation and dissolution of minerals more closely associated with the diagenesis process.

The model system used in these simulations will be simplistic in an effort to more clearly understand some of the important processes that affect the properties of a reservoir. A uniform network matrix composed of sandstone in contact with a characteristic formation water will be assumed in the initial simulations. No other minerals will be present in the matrix initially and the reservoir conditions (temperature and pressure) will be uniform. Later runs may start with a sandstone matrix that has varying amounts of calcite or dolomite. Appropriate solutions will then flow into the sandstone matrix to ensure calcite precipitation in the pores and pore throats. Calcite will be examined because of its prominence as an authigenic material in many types of sandstones (Frio, Plio, and Stevens sandstones).³ During successive time steps, the amount of calcite that precipitates in the media will be calculated and how this calcite deposition affects the permeability and porosity of the medium will be examined. This calcite precipitation will be an accurate representation of the calcite cementing that plays such an integral role in dictating a reservoir's characteristics in many diagenetic systems. The fact that pore bodies are accounted for in this network model will greatly enhance the porosity determination and offers a significant advantage over other models. Because this network model functions on the pore level, such phenomena as porosity occlusion will also be studied. The inclusion of calcite precipitation kinetics will provide another decided advantage over other models because kinetics can play such an important role in diagenetic reactions such as this.³ Once the effect of calcite deposition on the permeability and porosity of a simulated porous medium is examined, another solution of different composition will flow into the matrix to

ensure the dissolution of the calcite. Again, the features of this model (pore body inclusion and kinetic rate expressions) will aid in providing an accurate description of how the dissolution of calcite from pores and pore throats affects the permeability and secondary porosity (enhanced porosity) of a reservoir. All simulations will graphically show in 3-D the pore and pore throat evolution during the course of diagenesis.

After these initial simulations are completed, systems that contain more than one mineral will be examined. As stated above, other authigenic minerals such as dolomite or siderite can be included in the initial matrix or the formation water and invading fluid compositions can be set so that deposition of these minerals in the matrix is induced. With inclusion of these minerals, precipitation waves with representative diagenetic materials can be attained, as mentioned previously. The fact that dolomite dissolution is reaction-rate-limited below 323 K and calcite dissolution is often mass-transfer-limited can provide these characteristic precipitation waves by varying the invading fluid flow rates.⁴ Another important parameter that will be examined is the temperature of the matrix under study. The temperature effects will be incorporated by changing the appropriate kinetic parameters of precipitation and dissolution. In the case of calcite, different

temperatures will affect the resulting deposition regime.⁵ By comparing simulations at different temperatures, an examination can be conducted of how reservoir temperatures affect the resulting permeability and porosity changes. In addition, a dual zone matrix will be incorporated with each zone having a different temperature. The effect of upward flow in a formation caused by compaction (accompanied by a temperature gradient) and how it affects the permeability and porosity of a formation will be examined in these experiments.

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DISPERSION MEASUREMENT AS A METHOD OF QUANTIFYING GEOLOGIC CHARACTERIZATION AND DEFINING RESERVOIR HETEROGENEITY

Contract No. DE-AC22-90BC14652

**University of Oklahoma
Norman, Okla.**

**Contract Date: July 12, 1990
Anticipated Completion: July 11, 1993
Government Award: \$332,871**

**Principal Investigator:
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**Project Manager:
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Metairie Site Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of the project is to present the results of the ongoing laboratory investigation of gas–gas dispersion and oil–oil dispersion in the presence of connate water.

Summary of Technical Progress

Investigation of Gas–Gas Dispersion

The measurement of the dispersion of gases flowing through porous media is the continuation of this investigation of the dispersion phenomenon and the characterization of the flow system of reservoir rocks. Most of the research in the area of investigating dispersivity has been made with miscible liquid–liquid displacement processes. The measurement of dispersivity with the gas–gas displacement system will provide another approach to visualize the flow system of the reservoir rocks and the dispersivity parameter.

Experiments pertaining to gas dispersion are under way as part of the study of dispersivity as a reservoir rock characteristic. The equipment has been set up as shown in Figs. 1 and 2. This equipment consists of two parts. The first part is a flow system used to simulate the gas dispersion process in porous media. It consists of gases (high purity helium and nitrogen), core holder, vacuum pump, gas flowmeter, pressure gauges, and flow valves. The second part is the measurement system, which consists of a gas chromatograph (GC), carrier gas, and chart recorder.

Several test runs of the experimental procedure that follows have been made. From these test results it was found that the breakthrough time in gas–gas dispersion is much earlier than in liquid–liquid dispersion. The difference appears to be worth further study.

Fig. 1 Flow system of gas-gas dispersion experiment.

Fig. 2 Measurement system of gas-gas dispersion.

The molecular diffusion between gases takes a fair part of dispersion measured through the breakthrough curves. Therefore, an attempt is being made to separate the gas molecular diffusion from the gas dispersion attributed to flow. Different cores will be used under different flow rates to continue the gas-gas dispersion experiment.

Oil-Oil Dispersion in the Presence of Water

One of the main purposes of this research on the dispersion phenomenon is to design and optimize a new enhanced oil recovery (EOR) process. Therefore the effects of the water phase will be considered. In the near future, research on the oil-oil dispersion in the presence of water will compose an important part of this work.

The research on the effects of water on oil-oil dispersion is being continued. One change should be mentioned: in treating the experimental data, the total pore volume of the core system (core plus end plates) was used in calculating the pore volume injected rather than using only the pore volume of the core. Physical parameters of the brine and the two miscible fluids used (i.e., displaced oil and displacing oil) are given in Table 1.

Figures 3 and 4 show the effluent concentration curves obtained with two Berea cores in the presence and absence of connate water in the cores. These figures also show the slopes of breakthrough curves vs. pore volume injection. Some of the parameters measured and calculated from the two cores are shown in Table 2.

TABLE 1

The Parameters of Liquids Used for Miscible Displacing of Oil in the Presence of Connate Water

Liquids	Density at 74 °F, g/mL	Viscosity at 74 °F, cP	Refractive index at 74 °F
Brine [†]	1.035	1.0	
Naphtha	0.74	0.63	1.4192
ISOONYL	0.78	0.63	1.4450

[†]With 4% potassium chloride concentration.

[‡]Mixture of 54% isooctane with 46% xylene.

Fig. 3 Effluent concentration profile for core LB2.

Fig. 4 Effluent concentration profile for core LB4.

It can be seen from Table 2 and Figs. 3 and 4 that the presence of connate water increases the dispersion coefficients of the oil phase under comparable flooding conditions. The magnitude of increase varies from core to core. So far, the variation in connate water saturations and permeability was responsible for this difference. A general correlation is being attempted.

Among the many characteristics of reservoir rocks, those pertinent to the distribution of flow channels, such as the

TABLE 2
Parameters of the Berea Sandstone Cores

Cores	I.B2	I.B4
Length, cm	14.5	14.1
Diameter, cm	3.70	3.70
Porosity, %	19.8	19.9
Absolute permeability (measured with brine), mD	78	49
Miscible displacement in the absence of connate water		
Interstitial flooding rate, cm/s	0.0101	0.0101
Dispersion coefficient, cm ² /s	0.00083	0.00094
Miscible displacement in the presence of connate water		
Connate water saturation, %	28	33
Effective permeability to oil, mD	40	13
Interstitial flooding rate, cm/s	0.0092	0.0122
Dispersion coefficient, cm ² /s	0.00102	0.00540

relative permeability curve and the S-shaped curve of miscible flooding correlate to each other closely. An attempt is being made to identify the connections between relative permeability and dispersion.

Procedure for Gas-Gas Dispersion Experiment

The following steps have been established to measure the gas dispersion flowing through porous media:

1. Calibrate the GC. Before the experiment the GC must be calibrated since it is impossible to make the flow rates of the carrier gas in the GC the same every run. This variability would affect the measurement results.
2. Set up the core holder (the core was previously coated with JB weld). Place the two end plates of the core holder on the core. It is very important to make sure that there are no leaks anywhere in the core holder.
3. Clean the flow system. The material used to flush the core and flow system is naphtha. Flushing should be continued until the naphtha coming out of the flow system is clean.
4. Dry the core with air until there is no residual naphtha in the core.
5. Vacuum the flow system. To ensure accuracy, because the GC is very sensitive to air, the flow system should be carefully vacuumed before gas injection. Even a very small percentage of air existing in the flow system may result in a large error in the results given by the gas detector of the GC.

6. Begin the experiment. After the preparation work above has been done, the experiment may begin. First, inject helium into the core until the pressure at the outlet end of the core has stabilized. This indicates that the helium has filled the core. The valve at the outlet end should be closed.

7. Open the valves at the outlet end and at the same time change the flow direction of the three-way valve at the inlet end to nitrogen to allow the nitrogen to flow into the core. Record the time as soon as this step is completed. All of these steps should be done in as short a time as possible.

8. Use a syringe to take gas samples from the sampling outlet every 10 or 20 seconds. The length of time depends on the flow of the nitrogen. Use the shorter time for higher flow rates and the longer time for lower flow rates. Different time periods may be used in one run (i.e., near the time when the injection gas will probably break through shorter time periods should be used). This will make the experimental results more accurate. Sampling should be continued until 100% of the nitrogen flows out of the core. For the cores tested this usually requires at least two pore volumes.

9. Take 0.2 cm³ gas samples and inject into the GC to measure the concentration of nitrogen in the samples. With the chart recorder connected to the GC, it is possible to get different peaks of different concentrations of nitrogen. Using the GC calibration curve, the concentration of nitrogen in every sample may be calculated.

10. Plot the concentration of nitrogen vs. the ratio of gas injection volume to core pore volume. An S-shaped curve (breakthrough curve) should be obtained.

**MEASURING AND PREDICTING
RESERVOIR HETEROGENEITY
IN COMPLEX DEPOSITS**

Contract No. DE-AC22-90BC14657

**West Virginia University
Appalachian Oil and Natural Gas
Research Consortium
Morgantown, W. Va.**

**Contract Date: Sept. 20, 1990
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Government Award: \$1,915,000**

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Reporting Period: July 1–Sept. 30, 1992

Objectives

This research project is designed to use a multidisciplinary approach to measure and map heterogeneity at various scales and ultimately to develop tools and techniques to predict heterogeneity both in existing fields and in undrilled areas. Two stratigraphic units were chosen for this research: the Big Injun sandstone (Mississippian) in West Virginia and the Rose Run sandstone (Ordovician) in Ohio and Pennsylvania. The main objectives of this research are to

1. Map the geometry of sandstone bodies within a regional depositional system and classify these bodies in a scheme of relative heterogeneity; this will determine the heterogeneity across the depositional systems.
2. Map facies changes within the given reservoirs, interpret environments responsible for each facies, predict the inherent relative heterogeneity of each facies, and share these results with petrologists and petroleum engineers.
3. Correlate structural variations with hydrocarbon production and variations in geologic and engineering parameters that affect production in the Big Injun reservoirs in West Virginia.
4. Develop a reliable seismic model of the reservoir expressed in terms of impedance variation such that physical heterogeneity within the reservoir can be interpreted.
5. Describe the pore types and relate them to permeability, fluid flow, and diagenesis and, by integrating petrographic studies with facies and depositional environments derived

from stratigraphic work, develop a technique to use diagenesis as a predictive tool in future reservoir development.

6. Study effects of heterogeneities on fluid flow and efficient hydrocarbon recovery to improve reservoir management and future development.

7. Apply graphical methods to production data and develop new geostatistical methods to detect regional trends in heterogeneity.

8. Use the geologic and engineering data on the Big Injun reservoirs in West Virginia to construct facies maps and compute the local probability that new, in-fill wells will intersect rock with favorable reservoir characteristics.

The main goal of this research project is to understand reservoir heterogeneity sufficiently to predict optimum drilling locations vs. high-risk locations in a given field so that the most cost-effective infill-drilling programs can be recommended.

Summary of Technical Progress

Heterogeneity in the Big Injun Sandstone

Stratigraphy

A base map for a four-county area (Clay, Calhoun, Roane, and Kanawha counties), which includes the oil fields of Rock Creek, Granny Creek, Tariff, Blue Creek, and Reed/Carbide prospect, was completed. Two stratigraphic cross sections were constructed correlating sandstones in the interval between the Sunbury Shale and Little Lime. Cross sections for Granny Creek field were constructed to show the relationships of subfacies to log porosity and core-measured permeabilities, initial oil production, and cumulative oil production.

The Big Injun sandstone reservoirs in Granny Creek and Tariff fields are within the Pocono (Price), whereas the Macerady Big Injun is the reservoir in Rock Creek and Blue Creek fields. Sandstones within both Pocono (Price) and Macerady Big Injun(s) form the reservoir in the Reed/Carbide prospect. This interpretation is based on the presence of Macerady red beds in Rock Creek, Blue Creek, and Reed/Carbide areas.

Stratigraphic heterogeneity occurs within Granny Creek field, and it has influenced both the initial and cumulative oil production. The heterogeneity occurs (1) in permeability related to subfacies with the proximal bar subfacies containing the best log porosity and core-measured permeabilities of the C member pay zone; (2) in the B member, which serves as a possible seal, and when absent through erosion or diagenetic change in reduced oil production results from wells within the field; and (3) in barriers that extend between wells within the C member and consist of impermeable, thin zones between prograding tongues (concordant with bedding) and across the tongues (discordant to bedding). Reservoir compartments resulted from this heterogeneity within Granny Creek field.

Stratigraphic heterogeneity is related to growing structures involving both the Rome Trough and West Virginia dome

during sedimentation of the Big Injun sandstone and is also related to the depositional environments in which reservoir sandstones were deposited and diagenetic modifications that occurred during burial history.

Structural Geology

An attempt to map surface structure in the Rock Creek–Granny Creek area using air photos was determined to be impractical. The well database was updated with old reports and West Virginia Geological Survey files in order to modify maps of subsurface structure in the same area.

Seismic isotime and isochron maps were constructed for reflections of the Big Injun sandstone, Huron Shale, Onondaga Limestone, Salina Salt, Trenton Limestone, Rose Run sandstone, and the basement in the Granny Creek field area. The seismic isotime maps reveal that high initial open zones probably are associated with deeper structures or decoupled zones observed in the Onondaga and lower horizons. The recent seismic study suggests that certain major basement faults have right-lateral movement and may have influenced the Big Injun structure. Structure and isopachous maps of the Little Lime, Big Lime (Greenbrier), Big Injun, and Squaw have been made and interpreted to understand well communication during water flooding of the field.

Geostatistics and Modeling

Three objectives for this quarter were the (1) analysis of the continuity of Big Injun stratigraphic subdivisions recognized from Granny Creek geophysical logs, (2) preliminary modeling of reservoir properties at field scale for Granny Creek, and (3) continued acquisition and verification of Rock Creek data. During the month of July, gamma-ray log signatures for various Big Injun intervals (total Big Injun, upper coarse unit, and lower fine unit) in Granny Creek field were examined and compared on several geographic scales—well to well, waterflood injection area, and whole field. Specifically, the correlation between gamma-ray logs was investigated to see if the degree of correlation (indicated by the correlation coefficient R) differed with geographic distance and compass direction between wells. Automated cross-correlation was performed between each log and all possible neighbors to produce a data file containing well-to-well distance, correlation coefficient, direction between wells, and the “shift” in log footage required to bring the Big Injun interval in each well to the stratigraphic elevation of its correlated neighbor.

The mean correlation coefficient for all correlated gamma-ray logs in Granny Creek is approximately 0.9 (1.0 is a perfect correlation). On a finer scale (wells 250 to 2500 ft apart), several areas were identified that exhibited “poor” correlation (R less than 0.8). Investigation of the source of these poor correlations revealed two possible factors: geographic heterogeneity in log signature and choice of logging company. One logging company was found to be associated with 38% (100 m neighborhood), 64% (500 m neighborhood), and 76%

(1000 m neighborhood) of poor gamma-ray correlations in Granny Creek. Statistical analysis is currently under way to determine the relative importance of geographic location vs. choice of logging company for poor well correlations in the field.

In August and September, indicator variograms were created on the basis of density logs from Granny Creek. Analytical results (variable is the presence or absence of density barriers) are shown in Table 1. The results confirm the existence of a strong north-south anisotropy in the occurrence of density barriers in Granny Creek wells.

TABLE 1

Results of Indicator Variography for the Presence or Absence of Density Barriers in Granny Creek*

Lag, m	N-S	NE-SW	E-W	SE-NW
250	1.02	1.42	1.54	1.13
500	1.19	1.41	1.32	1.34
750	1.24	1.40	1.43	1.45
1000	1.21	1.40	1.68	1.55

*Consistently small values for a single direction (N-S) at all lag distances indicates a directional anisotropy in variance in that direction.

Heterogeneity in the Rose Run Sandstone

Classification schemes for defining heterogeneity types from the field scale down to the intra-well level are necessary to account for heterogeneities observed during field development. The classification of heterogeneity types (Fig. 1) developed by Weber¹ is applicable to heterogeneity observed in the Rose Run. Hydrocarbon production within individual Rose Run and Beekmantown oil and gas fields is the result of a complex interplay of many of these heterogeneity types.

Heterogeneity Types

Reservoir heterogeneity as a result of faulting (Fig. 1, type 1) is apparent along the Suffield Fault system in southwestern Portage County, Ohio. Subsurface mapping and seismic data verify the existence of a northwest-southeast trending fault that controls, in part, the entrapment of hydrocarbons in the Rose Run.

As many as five sandstone lenses separated by interbedded, nonporous dolostones may be present and can be correlated on geophysical logs across county-wide areas, although they are not regionally persistent across the entire study area. The interbedded, nonporous dolostones are baffles to fluid flow and create fluid-flow compartments (Fig. 1, type 2). In Holmes and Coshocton counties, Ohio, operators traditionally have numbered these sandstones 1 through 5 based on gamma-ray and density log characteristics (Fig. 2). Hydrocarbons have been produced from all five of these sandstones in stratigraphic pinchouts and erosional remnant traps along the subcrop trend from Fairfield County, Ohio, to Crawford County, Pa.

Reservoir heterogeneity type

1 Sealing fault Semi-sealing fault Non-sealing fault
2 Boundaries genetic units
3 Permeability zonation within genetic units
4 Baffles within genetic units
5 Lamination Cross-bedding
6 Microscopic heterogeneity Textural types Mineralogy
7 Fracturing - Tight Open

Fig. 1 Classification of reservoir heterogeneity types.¹

Fig. 2 Type log of Rose Run from Coshocton County, Ohio.

Permeability zonation (Fig. 1, type 3) is present in both the Rose Run and Beekmantown. It is most dramatic in the bioturbated dolostone lithofacies of the Beekmantown where vuggy porosity probably developed through selective dissolution by meteoric water² or mesogenetic brines.³ On the basis of geophysical logs and core analyses, porosity in this lithofacies is generally less than 4%. Locally in Coshocton

and Tuscarawas counties, there can be well-developed pin-point and massive vuggy porosity near the Knox Unconformity. Vuggy porosity also is present in this lithofacies approximately 30 miles downdip from the Rose Run subcrop in Scioto County, Ohio. Permeability measurements were performed on one core sample from a vuggy zone in the Beekmantown and showed a maximum permeability (Kmax) of 231 mD.

Two types of heterogeneity are evident within the cross-bedded and flaser-bedded sandstone lithofacies (Fig. 1, types 4 and 5). Vertical permeability variations are, in part, the result of thin argillaceous shale laminae that are prevalent in this lithofacies. Discontinuous to continuous shale laminae serve as baffles to fluid flow reducing the vertical permeabilities. Low vertical permeabilities associated with very high horizontal permeabilities in this lithofacies illustrate the effect that these laminae can have on baffling fluid flow. The major difficulty in predicting or quantifying these baffles is the fact that these thin argillaceous shale laminae cannot be correlated from well to well. Cross-bedding probably has a lesser influence on fluid flow for this lithofacies. High horizontal permeabilities indicate low permeability contrasts in adjacent cross-bed sets. Limited data precluded the ability to do any quantitative analyses.

Heterogeneities at the microscopic level (Fig. 1, type 6) are a result of textural, mineralogical, and diagenetic changes in the rocks. The nature of heterogeneity at this scale will be discussed in detail in the final report for this project.

Secondary vuggy porosity associated with fracturing (Fig. 1, type 7) is present within the Beekmantown and has produced hydrocarbons in Columbiana County, Ohio, along the Highlandtown Fault System. Fractured dolostone within the Beekmantown is present in three cores in Coshocton, Guernsey, and Morgan counties, Ohio. Fractures and associated vugs, however, are often healed with secondary mineralization. Vugs can be up to 1 in. across and often are filled with white dolomite. In southwest Morgan County, Ohio, intense fracturing has resulted in brecciated zones that are composed of green shale and angular clasts of dolomite up to 2 in. across. Fractures near this brecciated zone are healed by secondary mineralization of white dolomite which partially reduces or totally eliminates secondary porosity.

Naturally occurring and drilling-induced fractures were observed throughout the Rose Run and Beekmantown in the No. 3-A Reiss well based on the formation microscanner (FMS) images. Most of these fractures appear to be induced by drilling. Determination of the azimuth of drilling-induced fractures from the FMS tool is useful in determining minimum in-situ stress. Azimuths calculated from the FMS showed a predominant northeast-southwest trend and a secondary northwest-southeast trend. Fracturing in the overlying Lockport Dolomite (Silurian), on the basis of FMS images, also indicated a predominant north 60 east trend. Images observed from the FMS indicated naturally occurring fractures that were both open and partially healed.

Two different generations of fractures have been described in a silicified oolitic dolostone in the Rose Run from the core of the Aristech monitor test well. The first generation formed prior to silicification and is partially filled by silicified calcite and ankerite. The second generation of fracturing occurred after silicification. This later set of fractures is partially open and forms an orthogonal pattern across the brecciated clasts. Much of the fracture porosity, however, has been reduced by secondary mineralization of carbonates. Porosity and permeability for this lithofacies were measured in one sample from the Aristech well in Scioto County, Ohio. This fractured sample had a porosity of 9.1% and horizontal (K-90) and vertical permeabilities of 3.3 mD and 0.07 mD, respectively. The maximum permeability (Kmax) measured for this sample was 6.6 mD.

Structural Geology

On the basis of geophysical logs and seismic data in Ohio, a number of regional structural features have affected sedimentation, erosion, and structure of the Knox Dolomite. These features include the Waverly Arch, the Grenville/East Continent Rift boundary, Grenville thrust sheets and structural highs, the Akron-Suffield-Smith-Highland-Pittsburgh-Washington fault systems, the Rome Trough, and the Cambridge Cross-Strike Structural Discontinuity (CSSD) (Fig. 3). Woodward¹ mapped

the thickness distribution of Beekmantown Dolomite subcropping at the Knox unconformity. The mapped pattern at the unconformity was used to describe a "broad, low, concealed arch extending from north-central Ohio southward into Kentucky," called the Waverly Arch (Fig. 3).

Current work in this project on the basement tectonics of western Ohio indicates that the development of the Waverly Arch may have been controlled by deep basement faulting at the plate boundary between the Precambrian Grenville province on the east and the Precambrian East Continent Rift to the west. Tectonic inversion along zones of weakness defined by Grenville thrust sheets and basement highs occurred in the Paleozoic during regional episodes of compression and extension. Regional mapping and cross sections in this study suggest that the rift region was actively subsiding during the Cambrian and early Ordovician, causing increased accumulation of sediments and defining the early position of the Waverly Arch. Tectonic inversion resulting in the Knox unconformity emphasized the feature. This work suggests that the Waverly Arch may in fact be an early subtle precursor to the Cincinnati Arch, resulting from the migration of regional tectonic stresses deep in the crust. Structural movement affected structure and sedimentation during the Cambrian and Ordovician. Later subsidence of the Appalachian basin after Ordovician time masked the presence of the Waverly Arch in Ohio.

Fig. 3 Base map of the study area showing major tectonic features that affected Late Cambrian deposition and subsequent structure in Ohio and Pennsylvania.

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THREE-PHASE RELATIVE PERMEABILITY RESEARCH

Cooperative Agreement DE-FC22-83FE60149,
Project BE9

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Oct. 1, 1985
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$290,000

Principal Investigator:
Dan Maloney

Project Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this project are to (1) improve the reliability of laboratory measurements of three-phase relative permeability for steady- and unsteady-state conditions in core samples; (2) investigate the influence of rock, fluid, and rock-fluid properties on two- and three-phase relative permeabilities; and (3) expand the state of the art for measuring relative permeabilities at higher temperatures and pressures.

Summary of Technical Progress

Milestone 4—Unsteady-state relative permeability tests were conducted on 1.5-in.-diameter by 2.5-in.-long plugs of rock from the three depth intervals. Test fluids were a 1-cP viscosity brine containing 2 wt % potassium chloride and a mineral oil of 21-cP viscosity. The test temperature was 74 °F.

The plugs were subjected to 1000-psig confining pressure. Brine permeabilities were measured after the plugs were saturated with brine. The plugs were oil flooded to residual water saturation conditions in preparation for waterflood tests. Constant rate waterflood tests were conducted with injection rates of 65 mL/h.

Figure 1 shows unsteady-state oil/brine relative permeability results for plug 4959B. A second test with the plug and an additional test using plug 4961 provided similar results. Figure 2 shows two-phase steady-state oil/water relative permeability results for sample 4959 for comparison. The steady-state oil relative permeability results of Fig. 2 are in good agreement with those from the unsteady-state test, whereas the brine results do not match. The brine relative permeability vs. saturation plots from the steady-state oil/water test show a more pronounced change in relative permeability with changes in saturation compared with the unsteady-state result. The steady-state brine data project to the relative permeability of water ($k_{rw} = 1$ at water saturation (S_w) = 1 endpoint, whereas the unsteady-state data appear to have a $k_{rw} = 0.1$ at $S_w = 1$ end point. The unsteady-state water relative permeability data are probably incorrect. Better agreement might have been achieved had the sample been longer or if other test conditions had been imposed.

Fig. 1 Unsteady-state oil/brine relative permeability results for plug 4959B.

Fig. 2 Steady-state oil/water relative permeability results for plug 4959. Results are normalized with respect to $k_w = 5.78$ mD at $S_w = 1.000$.

The rock was flooded with brine to residual oil and gas saturation conditions. Brine and oil were injected into the rock with a brine fractional flow of 0.90. Gas injection was initiated, and three-phase relative permeability and saturation measurements were recorded as the gas rate was incrementally increased and both the oil and brine rates were decreased to maintain the ratio of brine-to-oil fractional flow. The rock was flooded with brine to return to residual oil and gas saturation conditions. Brine and oil were injected into the rock with a brine fractional flow of 0.6. Gas injection was initiated, and three-phase measurements were recorded as the gas rate was increased and the brine and oil rates were decreased. Additional measurements were recorded for a final cycle that started with a brine fractional flow of 0.20. Maximum injection rates were limited to prevent the pore pressure within the rock from exceeding 400 psig. The intent of this pressure limitation was to prevent excessive pressures from damaging the casing-plastic jacket that surrounded the rock and flow distribution end-pieces.

In calculation of saturations, microwave and X-ray results from end-point calibrations were not in perfect agreement. An analysis of the data revealed that some of the microwave signal bypassed the sample near the 100% dry and 100% saturated sample conditions. Corrections were made to the microwave calibrations to bring the X-ray and microwave saturation calibrations into agreement. The oil was vacuum filtered and was reused during the three-phase tests. Evaporation of light ends apparently caused the relative concentration of the X-ray dope within the oil to increase during the third set of three-phase measurements. The change in iododecane concentration was not compatible with the X-ray calibrations, so the final set of three-phase data was unusable. Some additional room-temperature three-phase measurements will be recorded during FY93.

Three-phase results are shown in Figs. 3, 4, and 5 along with two-phase steady-state results for comparison. Three-phase brine relative permeability results are very similar to those from two-phase measurements. Gas and oil three-phase results are clustered near their two-phase residual saturation

Fig. 3 Two- and three-phase brine steady-state relative permeability results for plug 4959. Results are normalized with respect to $k_{rw} = 5.78$ mD at $S_w = 1.000$.

Fig. 4 Two- and three-phase oil steady-state relative permeability results for plug 4959. Results are normalized with respect to $k_{rw} = 5.78$ mD at $S_w = 1.000$.

Fig. 5 Two- and three-phase gas steady-state relative permeability results for plug 4959. Results are normalized with respect to $k_{rw} = 5.78$ mD at $S_w = 1.000$.

conditions. The three-phase gas and oil results are similar to those from the two-phase tests at comparable saturation conditions. Gas and oil saturations below their two-phase residual conditions were achieved during the three-phase tests. Comparison of the results for this Almond formation sample from the 4959 ft depth with FY91 project results for 260-mD, fired Berea¹ yields the following observations:

1. With each sample, two- and three-phase k_{rw} vs. S_w trends were similar. For equivalent saturations below $S_w = 75\%$, the water relative permeabilities for the Almond formation rock were somewhat lower than those for the Berea.
2. Comparison of oil relative permeability results shows that those of the Almond formation rock were generally greater than those of the Berea at equivalent oil saturations for both two- and three-phase flow systems. The Almond formation rock oil relative permeability results showed more scatter than those of the Berea.
3. Two-phase gas results for the Almond formation rock were generally less than those for the Berea. Three-phase relative permeabilities for the Almond formation rock were

generally greater than those for the Berea at equivalent gas saturations. Three-phase gas relative permeability vs. gas saturation results for both samples were scattered.

The body of the composite core holder and O-rings was replaced in preparation for flow tests with elevated temperature conditions. Pumps and pressure transmitters were recalibrated. The elevated temperature environment was assembled. The temperature environment consists of two hot-air circulation boxes—one for the core holder that rests on the X-ray/microwave scanning track and another that is located directly under the scanning track. The two are connected by air ducts. The air ducts provide circulation between the upper and lower boxes and also serve as heated conduits for tubing and other flow lines. The temperature controller was tested to ensure that the boxes would heat properly. Elevated temperature relative permeability tests will be started during the next reporting period and will continue into the first quarter of FY93 as described in the FY93 Annual Plan.

Milestone 5—A topical report describing FY92 research results from this project was written. The report was titled *Special Core Analyses and Relative Permeability Measurements on Almond Formation Reservoir Rocks*. The following is the abstract from the report:

This report describes the results from special core analyses and relative permeability measurements conducted on samples of rock from the Almond formation Greater Green River Basin of southwestern Wyoming. The core was from Arch Unit well 121 of Patrick Draw field. Samples were taken from the 4,950 to 4,965 ft depth interval.

Thin section evaluation, X-ray diffraction, routine permeability and porosity, capillary pressure, and wettability tests were performed to characterize the samples. Fluid flow capacity characteristics were measured during two-phase unsteady- and steady-state and three-phase steady-state relative permeability tests. Test results are presented in tables and graphs. Relative permeability results are compared with those of a 260-mD, fired Berea sandstone sample which was previously subjected to similar tests. Brine relative permeabilities were similar for the two samples, whereas oil and gas relative permeabilities for the Almond formation rock were higher at equivalent saturation conditions compared to Berea results.

Most of the tests described in this report were conducted at 74 °F laboratory temperature. Additional tests are planned at 150 °F temperature. Equipment and procedural modifications to perform the elevated temperature tests are described.

Reference

1. D. R. Maloney and A. D. Brinkmeyer, *Three-Phase Relative Permeabilities and Other Characteristics of 260-mD Fired Berea*, DOE Report NIPER 581, February 1992.

IMAGING TECHNIQUES APPLIED TO THE STUDY OF FLUIDS IN POROUS MEDIA

Cooperative Agreement DE-FC22-83FE60149,
Project BE12

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contact Date: Oct. 1, 1987
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$545,000

Principal Investigator:
Liviu Tomutsa

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this project are to (1) develop and correlate reservoir engineering parameters from petrographic image analysis, computerized tomography (CT) scanning, and nuclear magnetic resonance imaging (NMRI); (2) characterize the recovery efficiency and measure the saturation distributions in cores for enhanced oil recovery (EOR) processes applicable to specific reservoirs, including Class I, using state-of-the-art imaging technology; (3) investigate the applicability of imaging technologies for the development of scale-up procedures from core plug to whole core to interwell scale; (4) develop an industry consortium or industrial advisory panel organized to help plan, review, and participate in the research through the Work-for-Others program and provide for effective technology transfer; and (5) strongly encourage collaborative research by industrial participants.

Summary of Technical Progress

Improvements in imaging techniques and equipment were designed to assist other projects investigating various advanced oil recovery processes. To improve the versatility of the CT equipment for multiproject use, the image transfer program from the CT to the Macintosh workstation was modified to run with a National Instruments AT-DIO-32F board on a desktop IBM compatible. The desktop IBM compatible 386SX, which previously has been used mainly to control the position of the high-accuracy CT table, is used now also to capture images from the CT scanner and to transfer them via the newly installed Ethernet network to various user computers for storage, analysis, and processing. A second Somatom II CT scanner has been purchased and moved to the National Institute for Petroleum and Energy Research (NIPER).

The second scanner will ensure backup for the first scanner and will improve the turnaround time of the CT scanning tasks for various projects. Installation is expected to be completed and the scanner fully operational by February 1993.

To perform the large number of permeability measurements needed to characterize heterogeneous samples, automation of the minipermeameter measurements is needed. An automated minipermeameter has been designed, and construction of the probe activation and positioning mechanism has been completed. The system will be completed with the installation of two motors. The completed system is expected to measure a permeability value unattended every 30 s. This will achieve a considerable increase in speed and efficiency compared to the present system in which an operator positions the sample and takes the data.

Assistance was provided in using CT scanning for sample characterization and fluid distribution measurements in Improved Microbial Flooding (Project BE3), Improved Surfactant Flooding (Project BE4A), Improved Mobility Control Methods (Project BE4C), Mobility Control, Profile Modification, and Sweep Improvement in Gas Flooding (Project BE5B), and Alkaline Surfactant Polymer Field Projects (Project SGP41). Some of the imaging work in these projects is listed.

Improved Mobility Control Methods (Project BE4C). Porosity and permeability distributions generated for a parallel laminated Berea sample were used as input in tracer test simulations with the BEST VHS simulator modified for single-phase core simulations. Various gridding configurations and vertical-to-horizontal permeability ratios were tested. The best agreement between the front advancement profiles generated by the simulations and those observed by X-ray CT scanning was observed for simulations involving gridding with a small ratio between the vertical and horizontal grid block dimensions and with a high ratio between the horizontal and vertical permeability. Tracer tests were performed on three other parallel laminated Berea blocks cut with the laminations parallel, perpendicular, and at a 30° angle with respect to the flow directions.

Mobility Control, Profile Modification, and Sweep Improvement in Gas Flooding (Project BE5B). CT scanning experiments were set up to monitor the effect of gel polymer as a permeability profile modification agent in sandpacks consisting of two sand layers with a permeability ratio of 5:1. The plugging of the high permeability layer by the gel polymer and the diversion of the flow into the low-permeability layer were clearly observed.

Alkaline Surfactant Polymer Field Projects (Project SGP41). CT imaging of three fresh field cores was used to characterize the core heterogeneities and to select locations for plug sampling. For longitudinal scans, the rapid topogram procedure previously described was used in combination with transversal scans.

Study of Scale-Up Procedures

Field trips to various fluvial deltaic outcrops (Bartlesville sandstone formation) in northeastern Oklahoma were under-

taken to identify outcrops where samples containing heterogeneities at various scales can be obtained. The field trips allowed direct viewing of heterogeneities characteristic of fluvial deltaic deposition environments at various scales and selection of samples for corefloods. Rock samples containing generic heterogeneities characteristic to fluvial deltaic deposition environments (small-scale crossbedding and ripple bedding) were collected and cut in rectangular shape for observation of small-scale heterogeneities and for minipermeameter measurements. The three-dimensional (3-D) porosity distribution was computed using 63 CT transversal sections each 4 mm thick for a rectangular block (2 in. × 2 in. × 10 in.) of ripple-bedded fluvial-deposit sandstone from the Tallant formation. The 3-D permeability distribution was generated using the 3-D porosity distribution generated by CT and the porosity permeability correlation (Fig. 1) generated by petrographic image analysis of thin sections cut from the same block. Permeability profiles obtained by CT/thin section analysis were compared with minipermeameter-generated profiles for the same rectangular block measured before encapsulating the block in clear epoxy for coreflood experiments. Although the trend of the permeability values was similar, much higher permeability contrasts exist between the image analysis generated values (30 to 60 mD for the clay-rich laminae and 200 to 1000 mD for the rest of the sandstone) than for the minipermeameter measured values (200 and 450 mD, respectively). This is the result of the smaller volume investigated by image analysis of thin sections. Mercury injection porosimetry indicates a weakly bimodal pore throat size distribution with a highest peak of the throat radii around 6 µm and a much smaller peak around 2 µm.

Fig. 1 Permeability-porosity correlation for Tallant sandstone.

Tracer tests were performed and monitored by CT to identify the high- and low-permeability zones in the rectangular block (2 in. × 2 in. × 10 in.) of ripple-bedded fluvial-deposit sandstone from the Tallant formation. Simulations were performed on rock models using porosity and permeability data generated by CT and petrographic image analysis of

thin sections as well as data generated by stochastic methods such as turning bands (Fig. 2).¹ Because of the nature of heterogeneities and practical computing considerations, only two dimensional simulations on a 63 × 126 grid were performed and compared with the CT observed tracer distributions. An adequate agreement between the CT imaged and the

simulated tracer distributions was observed for the grid selected (Fig. 3). To improve the agreement, simulations with finer gridding and smaller time steps are required. Benchmark tests indicate that a dedicated 50 MHz, 80486 EISA bus desktop computer would be adequate to perform such simulations with an overnight turnaround time.

Fig. 2 Porosity distributions generated by computerized tomography (CT) and turning bands.

Fig. 3 Tracer flow (a) from computerized tomography (CT), (b) simulated using CT data, and (c) simulated using turning bands data.

Two phase flow experiments were performed and were monitored by CT to identify the oil trapping that resulted from the alternation of high and low permeability zones in the climbing rippled sedimentary structures of the rectangular block (2 in. $\times$ 2 in. $\times$ 10 in.) of ripple bedded fluvial deposit sandstone from the Tallant formation.

Pore level images were generated by NMRI microscopy on small (5 mm diameter, 5 mm long) samples of the Tallant sandstone formation to show the relationship between the pore level scale and the core plug and whole core scales (Fig. 4). The lower porosity permeability laminations observed both in the direct visual observations and CT scans were observed to display significantly smaller pore sizes than those in the higher porosity permeability zones. The microcoring apparatus previously built has been used to take these small samples from the larger cores.

Efforts continued toward improving the NMRI resolution by the following:

1. *Constructing a new radio frequency (RF) coil for the NMRI sample probe.* The new coil has a smaller sample volume and more turns that provide shorter 90° RF pulses. The tuning parameters are also more advantageous for a variety of samples.

Fig. 4 Nuclear magnetic resonance image of pore network in Tallant sandstone sample.

2. *Studying pore systems with narrow line widths, such as sintered glass and ceramics.* A small diameter plug (4.1 mm OD $\times$ 4.0 mm long) was cut from a piece of sintered glass filter medium having a nominal pore throat of 40 to 60 μ m. The glass fragments were irregular in shape. The natural proton line width of the brine saturated plug was about 300 Hz, indicating a very clean substratum without paramagnetic material. An NMRI of the plug was obtained at a resolution of 20 μ m. A small diameter core plug (4.1 mm OD $\times$ 4.5 mm long) was cut from a piece of sintered ceramic. The ceramic matrix was in the form of ceramic beads about 125 μ m in diameter sintered to form a matrix having a pore throat about 40 μ m. The natural proton line width of the brine saturated plug was about 1100 Hz, which indicates that the ceramic contains some paramagnetic material. An NMRI of the ceramic plug was obtained at a resolution of 20 μ m (Fig. 5).

Because the processing of data to generate images takes up to 10 h using the i860 board and while the processing takes place the Gateway 2000SM 33 MHz 386 computer cannot be used for other tasks, it is highly desirable to install a multitasking operating system that allows several tasks to run simultaneously. The new multitasking operating system IBM OS/2 2.0SM was obtained and installed on the Gateway 2000SM 33 MHz 386 computer. Upgrades on the FORTRAN compilers for the 386 and the i860 board to make them OS/2 compatible have been purchased. When installed, these upgrades will permit image file processing on the i860 board while making the Gateway 2000SM computer available for image display and analysis, data analysis, and software development.

A poster titled "Integration of Computerized Tomography, Nuclear Magnetic Resonance Microscopy, Computer Assisted

Fig. 5 Nuclear magnetic resonance image of pore network in ceramic sample.

Petrographic Image Analysis and Flow Simulation for Heterogeneous Core Characterization" was presented at the SPE Forum, Special Core Analysis and Its Application to Reservoir Engineering, held in Snowmass Village, Colo., July 12-17, 1992.

Reference

1. D. A. Zimmerman and E. E. Wilson, *Description of and Users Manual for HUBA: A Computer Code for Generating Two Dimensional Fields via the Lining Bands Method*, prepared by New Mexico Institute for Mining & Technology, distributed by GARAM, Inc., Albuquerque, N. Mex., 1990.

OIL RECOVERY FROM NATURALLY FRACTURED RESERVOIRS BY STEAM INJECTION METHODS

Contract No. DE-AC22-90BC14661

University of Texas at Austin
Austin, Tex.

Contract Date: Sept. 25, 1990
Anticipated Completion: Sept. 24, 1993
Government Award: \$405,051

Principal Investigators:

John Reis
Mark Miller

Project Manager:

Jerry Ham
Metairie Site Office

Reporting Period: July 1-Sept. 30, 1992

Objective

The objective of this study is to develop accurate models for predicting oil recovery in naturally fractured reservoirs by steam injection. This objective is being met through an integrated experimental, numerical, and analytical study of the recovery mechanisms that control oil recovery for this process. These mechanisms include capillary imbibition, thermal expansion, gas generation from chemical reactions, and temperature dependent thermal properties.

Summary of Technical Progress

Recovery Mechanisms

In the annual report of 1992, a new dual porosity simulator is presented. Some new features are developed to enhance dual porosity modeling of naturally fractured reservoirs. Fracture equations are treated fully implicitly. In the simulator matrix blocks are further discretized into sub-grids to enhance pressure and saturation resolutions. The finite difference equations for matrix blocks are solved using the implicit pressure and explicit saturation (IMPES) method. These equations are mathematically decoupled from fracture equations to reduce computer time cost. The simulation studies show that this simulator accurately and efficiently models fluid flow in fractured reservoirs.

For this quarter, two new modeling options are included in the simulator: (1) an implicit diffusion equation and (2) results from single matrix block studies. In the first option, matrix blocks are further discretized and finite-difference equations are treated implicitly if diffusion is applied to the problem under consideration. The second new option requires

the fine-grid simulation of a single matrix block under totally immersed condition. The simulator will automatically make correction for the partial coverage of a matrix block surface at results from dynamic fracture flow conditions. The simulator results from these two options are favorable compared with those from IMPES options and fine-grid simulations of fractured reservoirs. About one-third of the computer time can be saved with the first new options. The inclusion of simulation results of matrix block studies makes the dual porosity modeling much like single porosity modeling except for a source/sink term for each fracture grid-block.

Thermal Properties

Revision of some programs to determine thermal conductivity and thermal diffusivity using temperature and heat flux

data recorded from the transient method experiment is being accomplished.

New thermal conductivity data were found to complete the database. These data have been divided into consolidated rocks, unconsolidated rocks, and limestone for a better analysis. Therefore other graphs are being plotted according to this classification.

Simulation on Thermal Transfer Functions

Literature review and formulation works were conducted this quarter. The new simulator will have oil, water, and steam phases and use fully implicit methods. The discretization in space is using first-order finite difference, and the discretization in time is carried by a forward difference first-order scheme. A Jacobi matrix has been set up and the work will be continued to next quarter.

GEODIAGNOSTICS FOR FOSSIL ENERGY RECOVERY

Sandia National Laboratories
Albuquerque, N. Mex.

Contract Date: Oct. 1, 1986
Anticipated Completion: Sept. 30, 1993
Funding for FY 1992: \$320,000

Principal Investigators:
L. C. Bartel
G. A. Newman

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

Objective

The overall objective of this project is to develop electromagnetic (EM) geophysical methods for imaging and monitoring oil recovery processes and for characterizing oil reservoirs. Information obtained from the application of these methods will aid in the production of existing oil resources. As part of the objective of this project, transfer of this technology to industry is a key element.

Summary of Technical Progress

During July, three investigators attended the Society of Exploration Geophysicists (SEG) Development and Production Forum held in Big Sky, Mont. At the forum the investi-

gators presented results from the EM surveys conducted at Marathon's Lawrence Field site in Illinois, of the comparison of EM sources for application for monitoring petroleum production, and of the reservoir simulation work. In addition, results of the joint work with Mobil on the use of the controlled source audio-frequency magnetotellurics (CSAMT) technique to monitor a steam flood recovery process in California were presented. The paper involving the joint work with Mobil was selected to be presented at a workshop to be held at the conclusion of the Annual SEG Meeting held in New Orleans during October. There seemed to be a consensus of the forum participants that it is important to determine reservoir characteristics and perform diagnostics of petroleum extraction techniques using both seismic and EM methods.

As reported in an earlier report, EM surveys were performed at the Marathon polymer flood field site during April and May 1992. Wave migration techniques (discussed later in this report) are being applied to the Marathon data. A preliminary interpretation indicates a more-or-less uniformly conducting saltwater body around the injection well with a more resistive zone (probably having a high concentration of polymer) between the injection wells and the producing wells. Because of the large responses near the producing well, there appears to be a significant resistivity contrast to the host medium. This resistivity contrast appears to be the result of a significant amount of polymer in the vicinity of the producing well.

During September, results of the Marathon project were presented at Marathon Oil Co. in Littleton, Colo. At that time an investigator met with Marathon personnel to discuss an interpretation of the EM data in conjunction with results from induction logs taken by Marathon. In addition, plans were formulated for a second EM survey at the Lawrence Field in Illinois. This second survey is to be performed during the first part of November 1992.

Marathon Field Experiment

Marathon Oil Co. has been conducting a pilot polymer flood to enhance oil production in their Lawrence Field in eastern Illinois. This pilot project began in approximately 1987. The procedure for a polymer flood was to first inject a surfactant to wash the oil from the rocks. The surfactant was followed by a polymer to push the surfactant through the reservoir and bank the oil. The polymer was then followed by a freshwater slug to protect the polymer for saline water. The freshwater slug was followed by a waterflood using produced water. Electrical induction logs taken by Marathon show that the surfactant and the produced water yield a resistivity of approximately $10 \Omega\cdot\text{m}$ and the polymer and fresh water yield a resistivity of approximately $80 \Omega\cdot\text{m}$, giving a significant resistivity contrast. In addition, those areas containing high oil saturation show a resistivity contrast in excess of the $80 \Omega\cdot\text{m}$. Because of these electrical resistivity contrasts, Marathon is interested in testing EM measurements to determine the status of the flood. Marathon decided that seismic methods did not appear feasible since the reservoir is saturated and there are only slight density changes between the various fluids.

Field activities commenced during the latter part of April. The EM surveys that were performed included (1) borehole-to-surface EM survey using the vertical electric source (VES), (2) cross-borehole EM survey using the VES, (3) surface-to-surface CSAMT survey over a limited area, and (4) surface-to-borehole EM survey using a surface-grounded electric bipole source.

Figure 1 shows the layout of the surface data stations, the locations of the cased observation wells (OB-1, OB-2, OB-3, and OB-4), which are fiberglass cased through the production zone, a limited number of the injection wells (MF-9, MF-11,

and MF-13), and a limited number of production wells (MF-10, MF-12, MG-10, and MG-12). Production wells MF-10 and MG-12 are cased with fiberglass through the production zone. The layout of the surface data stations was dictated by terrain, brush and trees, and Marathon's interest in the southern part of the flood area.

Wave Migration Imaging

The fundamental theory behind the wave migration imaging is that the upcoming (or incoming) wave originates at time (t) equals zero and has a phase of zero. The upcoming (incoming) wave response at the surface (or in a borehole) is projected downward (or outward) and at each step the phase of the upcoming (incoming) wave is checked by Fourier transforming the frequency-dependent wave to the time domain and setting the time equal to zero. If, at a particular depth (or distance), the imaginary part of the projected wave is zero, then the phase is zero and hence the upcoming (incoming) wave originated at that depth (distance). If one obtains data along a line (x-space, for example), then the wave must be migrated along the line, as well as projected downward (outward), to determine the origin of the wave and fix the position of the image in x- and z-space. For the application of the wave migration theory to EM waves, EM data must be obtained over a frequency range with EM wavelengths appropriate for the depth (distance) to the expected target (e.g., frequencies with wavelengths significantly longer than the depth to the target do not contribute to the image).

For application to the horizontal, surface magnetic fields and/or the borehole and surface vertical magnetic field produced by the VES, the incoming magnetic field wave is simply the secondary magnetic field produced by the VES and its origin is that part of the geoelectric section that is not axially symmetric about the VES. The primary EM fields need not be considered. Thus migrating the surface magnetic fields and/or the borehole, vertical magnetic fields to their origination should produce an image of the source of the secondary magnetic fields and hence the target of interest.

As examples of the wave migration, results from using the data from along the line of data stations at Station 7 with transmitters in OB-1 and OB-3 are shown in Figs. 2 and 3. The gray bars are the wave migration images of the origin of the measured x-component of the magnetic field (H_x) at the surface caused by the appropriate transmitter. The darker the shade of the image, the larger the magnitude of the source H_x field. At the source location, the strength of H_x is related to the contrast between the conductivity of the target and the conductivity of the host, as well as the strength of the transmitter signal at that location. Shown are the depths of the images as a function of distance along the line of data stations. In Fig. 2 there is a strong image at a depth of approximately 250 m at a y-distance of 20 m. This location is near the production well MF-10. This same strong image is evident in Fig. 3 as well. In Fig. 2 where OB-1 was used as the transmitting well, there is a discontinuity of the images at a distance of approximately

Fig. 1 Site map for the Marathon experiment. Shown are the locations of the surface data stations, observation wells, and the injection and producing wells.

Fig. 2 H_x wave migration image along the line of data stations at Station 7 using the transmitter in OB-1 ($T_x = 1$). The darker shades indicate larger values of H_x in the subsurface.

Fig. 3 H_x wave migration image along the line of data stations at Station 7 using the transmitter in OB-3 ($T_x = 3$). The darker shades indicate larger values of H_x in the subsurface.

110 m, which indicates a subsurface electrical structure change. This discontinuity is also evident in Fig. 3 where OB-3 was used as the transmitting well. The wave migration images shown in Figs. 2 and 3 aided in the preliminary interpretation discussed previously. As can be seen from Fig. 1, OB-1 is located at a distance of approximately 140 m and OB-3 is located at a distance of approximately 75 m along the Station 7 line of data stations. The shallow, strong image in Fig. 3 at a depth of approximately 50 to 60 m and at a y-distance of 80 m is probably the result of the transmitter in OB-3. It is noteworthy that the depth of the image is dependent upon the assumed host resistivity used in the migration. In the migrations shown here, a resistivity of 20 Ω -m was assumed. In addition, only the frequency range of 16 to 512 Hz was used in the migration process.

Work is continuing to determine an estimate of the actual resistivity of the zone of the image from the strength of the image. In addition, work is under way to sharpen the lateral extent of the images and obtain a better depth estimate of the images.

OIL RECOVERY IMPROVEMENT THROUGH PROFILE MODIFICATION BY THERMAL PRECIPITATION

Contract No. DE-AC22-90BC14660

**University of Texas at Austin
Austin, Tex.**

**Contract Date: Aug. 28, 1990
Anticipated Completion: Aug. 27, 1993
Government Award: \$103,567**

**Principal Investigator:
John Reis**

**Project Manager:
Gene Pauling
Metairie Site Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this study is to develop a method of temperature-dependent precipitation as a means to modify injection profiles in petroleum reservoirs. A saturated solution is injected into a reservoir at high temperature and allowed to cool. If the chemical has a decreasing solubility with decreasing temperature, the chemical will precipitate in the reservoir. This will plug that part of the reservoir and divert subsequently injected fluids into other regions of the reservoir.

Summary of Technical Progress

Testing of the apparatus is completed. Modifications to the chemical mixing system now allow full saturation of the chemicals at temperature with continuous pumping. Two Berea sandstone cores have been treated with potassium carbonate at a temperature of 260 °F. Both cores showed a reduction in permeability of around 50% and a 28% drop in porosity. This follows the predicted results reported in the 1991 Annual Report. The ratio of change in permeability to original permeability is calculated to be twice the change in porosity to original porosity,

$$\frac{\Delta K}{K} = 2 * \frac{\Delta \phi}{\phi}$$

Examination of the core with a scanning electron microscope (SEM) has identified high concentrations of potassium in treated cores. Photographs of the core demonstrate how the sand grains and pore space have become coated with the precipitated deposits. Further work on the SEM is planned to examine the nature of precipitation throughout the core and to extend the treatment to limestones and dolomites.

ADVANCED SEISMIC GEODIAGNOSTICS— BOREHOLE ACOUSTIC SOURCE

**Los Alamos National Laboratory
Los Alamos, N. Mex.**

**Contract Date: Mar. 1, 1988
Anticipated Completion: Sept. 30, 1992
Government Award: \$197,000**

**Principal Investigators:
Robert O. Hedges
Ray Engelke**

**Project Manager:
Robert Lemmon
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this project are to (1) improve oil reservoir characterization techniques by interwell tomographic imaging of producing horizons, (2) investigate the design of a totally new downhole acoustic source that will permit interwell seismic surveying between oil wells with much larger separation distances, and (3) evaluate the performance

of a Department of Energy borehole receiver developed for interwell seismic surveying in the environment of a producing oil field.

Summary of Technical Progress

Design of a Chemically Powered Seismic Source for Crosswell Seismic Surveying

The goal of this effort is to develop and field test a prototype seismic source that will meet oil field requirements for low-cost, high-resolution characterization of rock masses between wellbores. The source must deliver sufficient energy to transmit a high-frequency signal over 300 m (1,000 ft) between boreholes in typical oil reservoirs comprised of sandstone or limestone, at depths ranging from 100 m (300 ft) to 4600 m (15,000 ft). The goals for the prototype tool include providing many repetitive detonations that can be fired during one trip in the wellbore; downhole mixing, encapsulation, and detonation of individual charges; and operation on a standard 7-conductor wireline. The seismic source and its associated instrumentation will not exceed 114 mm (4.5 in.) in diameter and 5.5 m (18 ft) in length.

A highly energetic source is required to maximize the distance between the seismic source and the receivers from which useful data can be obtained. To satisfy the high energy requirement, the source will use an insensitive explosive that can only be initiated by sophisticated, but nonetheless low-cost, technical means. Because the source is explosive, a major consideration is the design of a tool that is inherently safe. To accomplish this, the explosive will be manufactured downhole, in single-shot quantities, with two chemicals, neither of which are classified as explosives by the U.S. Department of Transportation.

During the fourth quarter there was considerable effort to simplify the design of the explosive source. There have been numerous continuing discussions among Los Alamos personnel of alternate schemes for containment of the explosive mixture after it has been mixed and while it is being moved to the location in the tool where detonation will be initiated.

Small test chambers were acquired that will be used to perform static tests to confirm the ability of the slapper/barrel/barrier assembly to maintain the required air gap at hydrostatic

pressures to 6500 psi. Preparation and assembly of test hardware that represents the latest prototype design for the explosive confinement were completed in preparation of firing tests.

A series of tests was completed using actual prototype explosive containment hardware as designed for the operational source. The liquid explosive mixture was contained in thin-wall containers, and the success of firing through the composite barrier was identical with previous tests using heavier walled plastic confinement methods. The firing voltage threshold was confirmed as being consistent with earlier tests that used the same slapper configuration. These tests are summarized in Table 1. Note that the single failure was intentional to establish and confirm the lower firing voltage limit. The important information gained from these tests is that the confinement material does not significantly affect the ability to initiate the chosen explosive mixture through a barrier with a slapper.

Efforts to place a contract for additional testing continue. A surplus pressure vessel that can be used for firing tests at hydrostatic pressure has been identified and has been checked for actual pressure design levels. This pressure vessel has been acquired and is being modified for use as soon as a contract is placed.

TABLE 1
Summary of Test Firings, Sept. 17, 1992*

Test number	Firing voltage	Result
1	7500	Detonate
2	5500	Detonate
3	5000	Detonate
4	4500	Failed
5	5000	Detonate
6	4750	Detonate

*Configuration for all tests was 0.0007-in.-thick, 3.0 mm square copper slapper bridge; 0.003-in.-thick Kapton flyer; 0.064-in. barrel length; 0.062-in.-thick Lexan tamper; 0.011-in.-thick, 2-ply barrier; 0.005-in. wall, 0.25-in. inside diameter Teflon "sack" containment.

Fire set was 12- μ F capacitor, 10-kV max charge voltage.

Firing voltage was the only parameter that was varied for these tests.

RESOURCE ASSESSMENT TECHNOLOGY

***ASSIST IN THE RECOVERY OF
BYPASSED OIL FROM RESERVOIRS
IN THE GULF OF MEXICO***

Contract No. DE-AC22-92BC14831

**Louisiana State University
Baton Rouge, La.**

**Contract Date: Feb. 18, 1992
Anticipated Completion: Mar. 18, 1994
Government Award: \$2,025,755**

**Principal Investigator:
Philip A. Schenewerk**

**Project Manager:
Gene Pauling
Metairie Site Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this research is to assist the recovery of noncontacted oil from known reservoirs on the Outer Continental Shelf in the Gulf of Mexico. Mature offshore reser-

voirs, declining oil reserves, declining production, and other natural forces are accelerating the abandonment of offshore oil resources and production platforms. As these offshore wells are plugged and the platforms are abandoned, an enormous volume of remaining oil will be permanently abandoned. Significant quantities of this oil could be recovered using advanced technologies now available if the resource can be identified.

Summary of Technical Progress

Much of the remaining oil offshore is trapped in formations that are extremely complex as a result of intrusions of salt domes. Conventional seismic processing techniques cannot clearly image these traps or the full extent of oil-bearing segments near the salt domes; therefore, substantial volumes of oil may have remained uncontacted by previous drilling. Recently, however, significant innovations have been made in seismic processing and mathematical migration of seismic signal. In addition, significant advances have been made in deviated and horizontal drilling technologies and applications. These technology advances make it possible to reprocess existing seismic data to identify noncontacted portions of the reservoirs, which can then be contacted using advanced drilling technologies to kick out new wells from existing wells. Effective application of these technologies, along with improved recovery methods,

offers opportunities to significantly increase Gulf of Mexico production, delay platform abandonments, and preserve access to a substantial remaining oil target for enhanced recovery and other advanced recovery processes.

This project will proceed under three broad phases:

- **Analysis.** Tertiary Oil Recovery Information System (TORIS) level data will be collected on the major fields located in the piercement salt dome province of the Gulf of Mexico Outer Continental Shelf. Representative reservoirs will be studied in detail in order to evaluate undeveloped and attic oil reserve potential. These detailed investigations will be used to calibrate the TORIS level predictive models. The recovery potential of advanced secondary and enhanced oil recovery (EOR) processes and the exploitation of undeveloped and attic oil zones for salt dome reservoirs in the Gulf of Mexico will be assessed.

- **Supporting Research.** Supporting research will focus on the modification of public domain reservoir simulation models to accurately simulate the conditions encountered in the piercement salt dome province of the Gulf of Mexico. Laboratory research will focus on the development of fluid relationships that will be used in the simulation of miscible processes in the project area.

- **Technology Transfer.** A significant effort is planned to transfer the results of this project to potential users of the technology. Technology transfer activities will also provide feedback channels that will help keep the analysis and supporting research focused on the most important problems associated with this project.

During July 1992, a meeting was held between Louisiana State University (LSU), Department of Energy (DOE), and BDM International, Inc. (BDM) and ICF Resources Inc. (ICF), the subcontractors for the project, to finalize the data request from Minerals Management Service (MMS). DOE developed a data collection protocol for submission to MMS. Also during July, the public domain simulation software (BOAST II and MASTER) was obtained for use on the LSU Department of Petroleum Engineering computer network. In addition, parameters critical to the recovery of attic oil continued to be evaluated.

During August 1992, the subcontract with ICF was finalized and signed. DOE submitted a proposed data protocol to MMS for approval. Data collection could not begin without this approval because of the sensitive nature of the MMS data. Additionally, the process of modifying BOAST II for radial grid systems began and parameters critical to the recovery of attic oil continued to be evaluated.

During September 1992, data compilation and analysis for identifying and screening piercement salt dome fields in the Gulf of Mexico was begun by BDM and LSU. Modification of BOAST II for radial grid systems and evaluation of the critical parameters to the recovery of attic oil continued.

Data Compilation and Analysis

To date, sources include:

Salt Domes, Gulf Region, United States and Mexico, by Michel T. Halbouty (1979); *MMS OCS Operations Field Names Master List* (1992); *EIA Oil and Gas Field Code Master List* (1991); *MMS Platform Inspection Database* (1992); and *Petroleum Information Production Data*.

A database was compiled by BDM with data from these sources. It includes a detailed summary table of the information, a listing of the data from the platform database, operator listings, production plots on each field, and detailed production data summary tables.

Other sources of information are being pursued through literature searches conducted on the GEOREF database at the U.S. Geological Survey Library in Reston, Va.; Petroleum Abstracts at the LSU library in Baton Rouge, La.; the MMS library in New Orleans, La.; and various geological societies in the Gulf of Mexico area.

Screening of Candidate Fields

A meeting was held with representatives of BDM to discuss a methodology for screening the candidate salt dome fields. A final listing of candidate fields for further analysis will be decided upon by LSU and BDM with input from ICF. The first screening step will be to isolate piercement salt dome fields. The primary cutoff criterion for piercement salt dome fields is that the depth of at least one producing interval must be equal to or greater than the top of the salt.

Once identified, the fields will be categorized as follows:

1. Case studies for aging fields that have had new technologies successfully utilized in them.
2. Fields in which new technologies could be applied to extend and enhance the productive life.
3. Fields that do not fit into category 1 or 2 will be cut at this point.

Once the fields have been categorized, they will be grouped into 3 groups on the basis of the depth of the top of the salt as follows:

1. Deep, >10,000 ft
2. Intermediate, 5,000 to 10,000 ft
3. Shallow, <5,000 ft

They will then be ranked according to:

1. Size
2. Number of productive intervals
3. Range or height of productive column
4. Degree of structural complexity
5. Production anomalies vs. well count vs. platform count
6. Number of similar reservoirs
7. Degree of impending abandonment
8. Operator willingness

CONTINUED SUPPORT OF THE NATURAL RESOURCES INFORMATION SYSTEM FOR THE STATE OF OKLAHOMA

Contract No. DE-FG22-92BC14853

**Oklahoma Geological Survey
University of Oklahoma
Norman, Okla.**

**Contract Date: May 18, 1992
Anticipated Completion: May 17, 1994
Government Award: \$350,000
(Current year)**

**Principal Investigators:
Charles J. Mankin
Terry P. Rizzuti**

**Project Manager:
R. Michael Ray
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this research program is to continue developing, editing, maintaining, utilizing, and making publicly available the Oil and Gas Well History file portion of the Natural Resources Information System (NRIS) for the state of Oklahoma. This contract funds the ongoing development work as a continuation of earlier contract numbers DE-FG19-88BC14233 and DE-FG22-89BC14483. The Oklahoma Geological Survey (OGS), working with Geological Information Systems at the University of Oklahoma Sarkeys Energy Center, has undertaken to construct this information system in response to the need for a computerized, centrally located library containing accurate, detailed information on the state's natural resources. Particular emphasis during this phase of NRIS development is being placed on computerizing information related to the energy needs of the nation, specifically oil and gas.

Summary of Technical Progress

The Well History File contains historical and recent completion records for oil and gas wells reported to the Oklahoma Corporation Commission (OCC) on Form 1002-A. At the start of this quarter, the Well History File contained 250,432 records, providing geographical coverage for most of Oklahoma (all but the northeast part of the state). Data elements on this file include American Petroleum Institute (API) well number, lease name and well number, location information, elevations, dates of significant

activities for the well, and formation items (e.g., formation names, completion and test data, depths, and perforations). In addition to the standard Well History File processing, special projects are undertaken to add supplemental data to the file from well logs, scout tickets, and core and sample documentation.

A large portion of the Well History File work involves photocopying the completion reports for use in coding prior to data entry. The historical completion reports are checked out of the OGS Archive Library and copied at an average rate of about 1,500 forms per week. All new completion reports are copied as soon as they're received from the OCC. Completion reports for areas of the state that have already been (or are being) "worked" are entered into the processing stream immediately. All others are filed for processing at the appropriate times. Nearly 318,000 completion reports had been copied by the end of the quarter.

Processing of the OCC's oil and gas well completion reports (Form 1002-A) is proceeding smoothly. Presently, well records are being prescanned, keyed, and edited for the following counties in north central and northeastern Oklahoma: Creek, Payne, Tulsa, and Wagoner. (A four-township area in Pawnee County was also completed as part of a special project.) Nearly 26,000 well records were added to the file this quarter. As of September 1992, there were 276,262 records on file. The Well History File progress is shown in Table 1 by NRIS Regional Division. The current status of county coverage and the total record counts by county are shown in Figs. 1 and 2.

TABLE 1

Well History File Progress by Regional Division

Area of coverage	Start of contract	Start of quarter	Current
Southeast region	65,712	65,820	65,945
Southwest region	69,453	69,785	69,916
Northeast region	23,467	37,228	58,558
Northwest region	32,507	32,543	32,697
North central region	40,883	45,056	49,146
Total	232,022	250,432	276,262

Fig. 1 Status of well history database project by county coverage as of September 1992.

Fig. 2 Status of well history database project. Total well records, 276,262.

Both general and specialized edit procedures were continued on the well data. Search strategies are used to re-search well records with incorrect township-range-section (TRS) or county location data and well records that should be cross-referenced. Oklahoma Tax Commission (OTC) lease numbers are being assigned to well records through a combined machine and manual matching process between the lease and well files. This process was completed for seven more counties this quarter, bringing the total number completed to thirteen. A state-wide Lease File-Well File match was used to identify sections with significant discrepancies in the lease and well counts. The search was facilitated by cooperation from NRIS users and from Sooner Well Log Service, located in Oklahoma City, which has an extensive, well-organized hard-copy collection of completion reports available for research at reasonable cost. Since the start of the contract, efforts to locate missing 1002-A forms for areas identified through these methods has resulted in the addition of approximately 1046 additional records to the file.

Further efforts were continued this quarter on a system for standardizing the formation names on the Well History File. This PC-based program uses a conversion table to standardize spellings and allows the user to interactively build new entries for the conversion table as new spelling variations are encountered. As previously reported, there are more than 28,500 entries in this table. In the southeast and southwest regions, more than 98% of the 609,848 reported names have been standardized in this effort. Current efforts are focused on the northwest region. This formations-editing process is further enhanced by the addition of a table to determine the standard "Franklinized" abbreviation for each reported name, following the convention with which industry users are familiar.

One goal of the NRIS system involves efforts to "assign" leases and wells to fields based on the official field outlines designated by the Midcontinent Oil and Gas Association's Oklahoma Nomenclature Committee (ONC). Some areas exist in which significant field extension

drilling has taken place, but the ONC has had insufficient resources to update the field boundaries accordingly. To assist the ONC in updating their field outlines, information packages are produced from the NRIS system for selected areas; these packages include well data listings and well spot maps. Based on this input, the Committee is first updating all gas field boundaries and then emphasizing the oil field boundaries. Considerable progress has been made in this area, and the efforts are continuing. Overall, unassigned gas production is 13% of the annual average production, and unassigned oil production is 20%.

Special efforts were also undertaken this quarter to finalize the user and programming documentation for the NRIS system. The documentation should be completed early next quarter.

Public Data Release

Efforts have been made since early 1991 to disseminate NRIS information through meetings, workshops, OGS annual reports, and mass mailings to numerous individuals, companies, and organizations. As a result, a dramatic response to the release of NRIS data began last summer and has continued. Feedback from the public continues to reflect a great deal of excitement about this new resource for the oil and gas industry in Oklahoma. Data and analyses have been provided that would not have been feasible prior to construction of the NRIS system.

NRIS well data have been made available through the Oklahoma City Geological Society Library with very positive results. The high level of interest by library members has led to the acquisition of several thousand records by several members, as well as constructive feedback on data anomalies they have detected.

Three companies now subscribe to the Well History File, and large data orders received from two other companies will likely result in additional subscriptions. Typically, small companies and independents are acquiring NRIS subsets to evaluate within their specific computer systems before committing to large data acquisitions.

The OGS is in the process of establishing a user lab to facilitate user access to the NRIS data, initially by Survey staff and eventually by the public. A PC-level relational database management system called Advanced Revelations will be used to develop a menu-driven retrieval system customized to NRIS data. A large digitizer, large plotter, and desk-top scanning equipment will enhance capabilities available through GeoGraphix software. Radian, a company that markets a contour mapping package, donated a copy of their CPS/PC software for use in the user lab, and Van Tech, Inc., the regional Radian distributor, incorporated the NRIS Well History file formats within the menu system of their Master Well Manager software (much like GeoGraphix has done). Similarly Energy Software Co., located in Midland, Texas, incorporated the NRIS file formats within their Paragon database management software.

Several mapping demonstrations were given using NRIS Well History data, including one to visitors from Russia who are interested in establishing a natural resources database for the city of Moscow and another to visitors from India who are interested in setting up a water resources database. Additionally, NRIS data presentation was given before the Oklahoma Mineral Owners Association whose board of directors is interested in the possibility of gaining access to NRIS lease production data.

For the OGS, NRIS data continued to play a major role in the final development of the Oklahoma section of a Midcontinent Gas Atlas. Field and reservoir maps, well lists, and reservoir production summaries were generated for the project.

RESERVOIR ASSESSMENT AND CHARACTERIZATION

**Cooperative Agreement DE-FC22-83FE60149,
Project BE1**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Oct. 1, 1985
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$785,000**

**Principal Investigator:
Susan R. Jackson**

**Project Manager:
Edith Allison
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this project is to develop an improved methodology for effective characterization of barrier island reservoirs to predict oil saturations at interwell scales and flow patterns of injected and produced fluids.

Summary of Technical Progress

Recovery Efficiency and Residual Oil Saturation

Oil recovery efficiency and oil saturation remaining after waterflood were calculated for each well pattern in Patrick Draw field. The distribution of oil recovery efficiency is presented in Fig. 1. The best production at Patrick Draw

field lies primarily in the area of good oil reserve with a thick pay and a high oil saturation value. Water injection and the expansion of neighboring gas cap contributed to successful production of reserves from the southwestern area of Arch Unit and the northwestern area of Monell Unit. A decline of reservoir pressure and little water production before the initiation of waterflood suggest an inactive aquifer or poor lateral communication with the Almond formation aquifer downdip of the oil-water contact.

In the Arch Unit, waterflood recovery ranges from 7 to 288 Mbbl and is poor as a result of fast water breakthrough and short periods of oil bank production. The mean and median of waterflood recovery from 39 Arch wells are 62.7 and 53.3 Mbbl, respectively. This corresponds to about 6% OOIP and about one-third to one-half of primary recovery of Arch wells.

In the Monell Unit, the waterflood production ranged from 50 to 1366 Mbbl of oil per well with a mean of 321.7 Mbbl and a median of 244.4 Mbbl. This is comparable to the primary recovery (average 290.7 Mbbl per well) and equivalent to a recovery of approximately 23% OOIP. Oil production decreases from the western part toward the eastern part of the field. The smooth decrease in oil production is caused by a gradual variation of pay thickness and oil saturation.

Monell wells have ultimate recovery efficiencies ranging from 20 to more than 50%, indicating efficient oil recovery. Arch Unit has a relatively poor recovery efficiency except in the area immediately west of the low-permeability thin pay. The water injection volume in Monell Unit is proportional to its waterflood production of nearby producers. The water injected ranged from 15 to 60% pore volume (PV) for most Monell wells and 10 to 40% PV for most Arch wells.

A high degree of heterogeneity in the Arch Unit is evidenced by (1) sand discontinuity or compartments indicated by the drastic change in pay thickness and fluid saturations, (2) a poor sweep efficiency and low waterflood recovery compared to that in the Monell Unit, and (3) the large contrast of water breakthrough times that ranged from less than 1 month to more than 100 months. The early breakthrough may be a result of severe water channeling in the gas phase in high permeability zones.

Investigation of the lateral variation of cumulative and initial oil production from UA-5B sandstone along three east-west profiles indicates that the production in the southwestern part of the Arch Unit was relatively much higher compared with that in the central part of the unit, although the latter area had greater pay thickness and better flow properties. Further analysis was conducted to document this distribution and to determine possible causes for the production differences.

No significant wellbore damage was identified in the Hall plot analysis for most injection wells in the Arch Unit. This is evidenced by the constant slope of the Hall plots after the gas space in the reservoir was filled by water. The

Fig. 1 Map of ultimate recovery efficiency in Patrick Draw field.

values of Hall plot slopes in the Arch Unit are related to the presence of a thin pay or deterioration of the quality of pay sands. Some sharp increases in the Hall plot slope at the late injection stage were caused by shut in of surrounding production wells.

Numerical simulations demonstrate that the slope of the Hall plot increases with the number of nearby barriers and with the decrease in the distance between barriers and the injection well. Analytical calculations of injection pressures show a significant increase when one barrier is less than

200 ft away or two intersecting barriers are less than 400 ft away. The effect of the orientation of barriers on injection pressure, however, is not as significant as the distance of barriers from the injector.

Distribution of Coquina

Distribution of the coquina that acts as a barrier to fluid flow between the western and eastern portions of Arch Unit was determined by mapping its occurrence based on resistivity logs. It was found that there is good correspondence in general between log signatures and facies (once the facies are recognized) and an excellent correspondence between occurrence of coquina and the log signatures. Coquina is defined as an accumulation dominated by shell material. In the upper Almond formation, coquina is created by accumulations of oyster shells. The accumulations are of two broad general types. First is whole and broken oyster shells in sparse, poorly sorted sandstone. The sand particles are commonly among the coarsest examined in UA-5B. Frequently this first type of coquina is massively bedded and very tight as a result of abundant carbonate cement. Often the first type of coquina is technically a carbonate rock. Calcite- and dolomite-filled fractures have been examined from this type of coquina deposit. The other type of coquina typically consists of shell materials in a fine-grained matrix, usually silty sandstone, or mudstone, and is most common at the very top of the UA-5B interval. Both types of coquina have characteristically high resistivity, which allows the unit to be traced laterally.

Because of the relatively limited amount of core control, resistivity logs were used to map the coquina. The high resistivity kick indicating the coquina (and carbonate cemented sandstone) was primarily the result of high carbonate content. The excellent correspondence between log signatures and all cored coquina intervals minimizes the possibility that high resistivity is the result of oil saturation or water salinity alone. Core descriptions supplied by Union Pacific Resources Company (UPRC) as well as those by National Institute for Petroleum and Energy Research (NIPER) staff were used whenever possible to calibrate the core to log correlations. The resulting map could, therefore, be extended far beyond those parts of the field where cores were available. All available logs from Arch and Monell units were correlated, and the distribution of the high-resistivity zone near the top of UA-5B was determined (Fig. 2).

The distribution of the high resistivity marker (coquina) shown in Fig. 2 shows several unexpected features. First, the greatest thickness of coquina is indicated along the area of thin, permeable sand in sections 13 and 24 (T19N, R99W) in southern Arch Unit. However the overall trend of the coquina thickness does not simply mirror the area of elongate, thin sand. Instead, a second NW-SE trend is indicated by isolated thick areas of coquina in sections 12 (T19N, R99W) and 7 and 18 (T19N, R98W). The two subparallel coquina accumulations are probably genetically distinct

Fig. 2 Isopach map showing the distribution of the high-resistivity marker at the top of UA-5B.

based on this distribution. Second, the coquina becomes markedly thinner at the southern margin of the thin sand area in Arch Unit (SE 1/4 section 24) but thickens on the eastern (seaward) margin of the buildup in section 30 (T18N, R98W) in northeastern Monell Unit. Third, the more northerly buildup does not closely follow the thin, permeable sand in sections 1 and 12. Both the core data and the high resistivity log data indicate that the coquina and calcite cemented sands are dominant only eastward of the prominent north-south oriented sand thin in Arch Unit. Based on these data, it appears that the fluid barrier between eastern and western bars may be created by a combination of thin, calcite cemented sand in the north and impermeable coquina in the south of Arch Unit. The isopach map showing the distribution of the high resistivity marker at the top of UA-5B (Fig. 2) also shows a small area (section 13) lacking the resistivity kick in the area that lies between the thick coquina and corresponds to one of the better producing areas in eastern Arch Unit. The area is also a small but prominent sand thick in eastern Arch Unit.

Additional high-resistivity thick areas are indicated in the southern portion of Monell Unit, however, as core control is entirely lacking in this area, it cannot be confirmed whether these represent coquina deposits or not.

On the basis of the examination of cores and analysis of thin sections within and adjacent to coquina deposits, it is suggested that the broad thin area (0-5 ft thick interval) of higher resistivity in Fig. 2 represents areas with abundant calcite cement in contrast to the thicker (5-10) which mark the discontinuous, generally linear trending, coquina deposits.

When the distribution of the high resistivity deposits (coquina and calcite cemented sandstone) in UA 5B are compared with the formation salinity map, a general tendency can be seen for the high resistivity zones to be located in regions of high salinity gradient (especially in Arch Unit). The correspondence between the occurrence of carbonate cemented sands and the high gradient areas of the salinity map indicate that the carbonate precipitated along a geochemical rather than a lithological boundary with precipitation dominantly at the contact between the zone of high salinity and low salinity formation waters. The relative timing for carbonate cementation may have been very early because the zone of abundant carbonate cement (delimited by the boundary of the high resistivity zone in UA 5B) shows a generally negative relation to the area of deposition of UA 5A sands. Only along the UA 5B sand thin between the eastern and western bars can we find overlapping UA 5A deposition with UA 5B carbonate cemented sands. This arrangement suggests that generally the carbonate cemented area may have remained topographically high during UA 5A deposition diverting those sands from the area, except in the topographic low between the eastern and western UA 5B bars.

General distribution of facies indicates that the coquina deposits are on the back or lagoonal side of the barrier. They are most commonly encountered in association with tidal channel or tidal delta sandstones. The general linearity of the coquina deposit thicks shown in Fig. 2 tend to support the concept of a channel like morphology; however, a closer look at the internal geometry of the deposit provides an alternate interpretation.

Five stratigraphic resistivity cross sections were constructed to help define the geometry of the coquina deposits in eastern Arch Unit. One cross section parallel to the sand thin showed that the "coquina deposit" actually consists of several successively overlapping deposits. Together the cross sections show that the three dimensional geometry of the successive resistivity marker beds is that of imbricated wedges, each having limited lateral extent rather than elongate channel like shapes.

The net result of the overlapping or imbricated coquina beds and carbonate cemented zones is to create within the overall UA 5B sandstone package a low permeable upper sandstone with complex geometry that partitions the UA 5B sandstone in eastern Arch Unit, creating highly variable petrophysical properties within the sandstone, and, except where the carbonate is absent in section 13, to degrade the reservoir quality and hinder lateral communication.

Water Salinity

Approximate boundaries of several square miles size megacompartments and much smaller subcompartments have been identified in Patrick Draw field, Wyoming, on the basis of mapped salinity contrasts and heterogeneity of hydrochemical facies. Reservoir compartments were also indicated by the salinity and composition of in situ formation water that remained unchanged after long term water flooding of the surrounding area.

In the Arch Unit of Patrick Draw field most wells of superior productivity are concentrated in the high salinity megacompartment, whereas wells of inferior productivity are predominantly located within zones of high hydrochemical gradient (salinity decrease) that reflect the position of barriers to flow.

Approximate oil saturation calculations based on mapped distribution of water salinities and corresponding resistivities indicate up to 12% more original oil in place (OOIP) in the area of highly saline formation waters generally updip, and up to 5% less oil in the much lower salinity sections of Patrick Draw field near the oil-water contact. Recommendation for further improvement of the calculations is provided on the basis of resistivity values corrected for non-NaCl formation waters in identified areas of the field.

This study of Patrick Draw field illustrates the high potential for application of simple hydrogeochemical indicators for improved reservoir development. Mapped salinity contrasts provided the basis for recalculation of OOIP and provided a guide for improved enhanced oil recovery (EOR) tactics. Identification of fluid compartments may be used to improve flood patterns and may aid in selection of the most prospective sites for infill drilling. Compartments with distinct fluid salinity and composition have been shown to have a strong effect on calculation of oil saturation. In addition, compartments with contrasting fluid types may adversely affect some EOR processes because the processes are sensitive to salinity and the presence of divalent cations, such as bicarbonates and sulfates. Hydrogeochemical data strongly indicate that individual compartments within the Almond formation could have been in communication with allochthonous (originating elsewhere) multiple sources of formation waters.

The original calculations of oil saturation in Patrick Draw field were based on uniform water resistivity values of 0.2 Ω m and most probably on the assumption that the formation water composition was a simple sodium chloride type. Revised oil saturations based on the distribution of salinities and corresponding resistivities may still be fraught with error because the conversion of resistivity values measured at ambient temperature to the resistivity at reservoir temperature was also based on the assumption of simple chloride sodium composition of formation waters in the Almond system. The commonly used conversion procedure is based on the graphic relationship between resistivity and temperature in NaCl solutions. However, the documented

composition of formation waters in Patrick Draw field based on geochemically defined water types reveals common presence and even domination of bicarbonates over chloride, predominantly in waters of lower salinity. This means that the revised oil saturations are probably nearly correct in the high-salinity portions of Patrick Draw field where Na-Cl, Na-(Ca)-(Mg)-Cl and Na-Cl-(HCO₃) water types predominate but may be overestimated in the low-salinity sections where bicarbonate-rich Na-HCO₃-Cl and Na-Cl-HCO₃ waters tend to predominate.

In addition to their effect on interpretation of log responses and miscalculation of oil saturations, the differences in salinity and composition of the fluids may adversely affect some EOR processes that are sensitive to water salinity, divalent cations, and possibly bicarbonates.

Log-Derived Oil Saturation Calculations

Because of the availability of core and almost a complete suite of wireline logs, well Arch 120 from Patrick Draw field was selected to conduct investigations on the effect of variations in formation water salinity on the determination of oil saturations (S_o) or water saturations (S_w) at Patrick Draw field. This well was drilled in December 1987, and no oil production was reported from this well.

Besides salinity of formation water, porosity and the shale content or clay content in the sandstone pore spaces have a strong effect on the estimation of water saturation.¹⁻³ The clay content and porosity in Patrick Draw field could be calculated very accurately from the available gamma-ray and density or other porosity logs.^{4,5}

In the absence of the direct measurement of salinity of the formation water, spontaneous potential (SP) logs were used to estimate the salinity or, for wireline applications, the resistivity of the formation water. The average value of water resistivity (R_w) for UA-5B sandstone from several computations was found to be 0.1907 Ω -m. The best estimates of R_w from the SP log are obtained from thick, clay-free zones where there is full development of the SP (Refs. 1 and 2). The presence of hydrocarbons also depresses the SP response and may result in the calculation of too high a value of R_w . Although all precautions were taken in the estimation of R_w , the actual value of R_w may be somewhat different as a result of the possible sources of errors discussed previously. In the following discussions on the computation of reliable S_w values for well Arch 120, three different values of R_w (0.1907, 0.25, and 0.35 Ω -m) were used. From earlier studies the acceptable values of the constants a , m , and n for the UA-5B sandstone reservoir were 0.62, 2, and 2, respectively, and these values were used for all the calculations. Figures 3 through 5 show the S_w calculations for the UA-5B sandstone for three different values of R_w .

The accuracy of calculated S_w values will be strongly dependent upon the accuracy of the porosity data and the R_w data. As explained earlier, porosity could be calculated

Fig. 3 Calculation of water saturations in the producing UA-5B sandstones in well Arch 120 for a resistivity of formation water, $R_w = 0.1907 \Omega$ -m.

Fig. 4 Calculation of water saturations in the producing UA-5B sandstone in well Arch 120 for a resistivity of formation water, $R_w = 0.25 \Omega$ -m.

Fig. 5 Calculation of water saturations in the producing UA-5B sandstones in well Arch 120 for a resistivity of formation water, $R_w = 0.35 \Omega$ -m.

with a good deal of confidence from the density log; therefore, the accuracy of S_w calculations strongly depends on the use of a reliable value of R_w . According to Archie's equation, S_w increases with an increase in R_w and a decrease in porosity. This appears to be the reason for the

erroneously high S_w values ($>100\%$) calculated for $R_w = 0.35 \Omega\text{-m}$ (Fig. 5) where the sandstone has low porosity (calcite cemented). The calculated values for $R_w = 0.25$ and $R_w = 0.1907 \Omega\text{-m}$ are within acceptable limits.

Figures 3 through 5 show the distribution of clays in the sandstone. Note that the difference in S_w calculated by the two methods increases with an increase in formation R_w and clay content.

If most reservoir parameters except R_w have been judiciously selected in water saturation calculations, then a reasonably correct R_w value may be obtained from an analysis of the type of calculations shown in Figs. 3 through 5. For example, for $R_w = 0.35 \Omega\text{-m}$, the calculated S_w by the methods of Simandoux and Archie (Fig. 5) are more pessimistic than the core-derived values, which is an unrealistic condition. For $R_w = 0.1907 \Omega\text{-m}$, the S_w values by the Simandoux method are significantly more optimistic than the core-derived values and are slightly more optimistic than the values calculated by Archie's formula. For $R_w = 0.25 \Omega\text{-m}$, the difference between the core-derived values and the Simandoux values decreases, and that between the Simandoux and the Archie values increases. Considering that for $R_w = 0.25 \Omega\text{-m}$, the S_w values by the Simandoux method and by core measurements are almost identical for certain depths and since normally a very high degree of accuracy is not expected from the core-derived values, it may be argued that the actual value of R_w is closer to 0.1907 than to 0.25 $\Omega\text{-m}$.

Data Requirements and Acquisition for Reservoir Characterization

The two basic sources of data for reservoir characterization are data from the specific reservoir and data from analog reservoirs, outcrops, and modern environments. Reservoir data can be divided into three broad categories: (1) rock properties (the container), (2) fluid properties (the contents), and (3) rock-fluid interactions. Both static and dynamic measurements are required.

Reservoir characterization requires data on a range of scales from basin and field-scale information to pore-size information. Field-scale information establishes the spatial framework and the general architecture of the reservoir for describing and predicting smaller scale reservoir geometries and heterogeneities along with their associated petrophysical and fluid-flow properties. Mesoscopic-scale information addresses variations of properties within the facies or reservoir units, where microscopic- or pore-scale information includes pore size, pore throat, surface roughness, grain size, and sorting.

Outcrop exposures of reservoir rocks provide laterally continuous sampling of rock characteristics and provide lateral information on scales not available from reservoir data. Studies of outcrops and analog modern environments can

be a valuable, low-cost source of high-quality geological and petrophysical data. Outcrop studies can provide a wealth of quantitative information on the dimensions and geometries of sandbodies, fluid-flow barriers forming compartments, permeability baffles, and the spatial distribution of matrix permeability and porosity. The constraint in applying outcrop data to reservoirs is the ability to determine the degree of transferability of characteristics between different deposits, even from the same depositional system.

Although much of the effort in reservoir characterization is focused on pore- to bedding-scale features, it is the larger scale reservoir architecture that controls the communication between wells and exerts a very strong influence on sweep and recovery efficiency. Regional-scale studies are essential for understanding the origin of the reservoir architecture and predicting the occurrence and location of heterogeneities. Examples are given to illustrate how the understanding of regional-scale processes aid the prediction of the location, orientation, and density of reservoir heterogeneity.

The scales of heterogeneities dominating production are different for different field development stages. As field development stages progress from primary to secondary to tertiary recovery, the scale of important heterogeneities generally decreases and is dependent on the enhanced oil recovery (EOR) process applied. The data required for the development and application of various EOR methods are presented.

The value of data can be assessed as the equivalent loss resulting from poor or incomplete data; however, determination of the optimum data density for reservoir characterization is difficult because often the value of the data is not known until it is acquired and analyzed. Extensive simulation studies are needed to evaluate the magnitude and direction of errors that can be expected in oil recovery prediction with various amounts of data. A quantitative approach using the variogram is proposed, where the correlation length is used as a guide to the minimum sampling distance for data collection.

References

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TORIS RESEARCH SUPPORT

**Cooperative Agreement DE-FC22-83FE60149,
Project BE2**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.**

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1992: \$340,000**

**Principal Investigator:
James F. Pautz**

**Project Manager:
Chandra Nautiyal
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this project is to provide research support to the Department of Energy (DOE) Program Manager for the Tertiary Oil Recovery Information System (TORIS) in the areas of enhanced oil recovery (EOR) projects and reservoir database management, EOR project technology and trends analysis, and computer simulation.

Summary of Technical Progress

The DOE encouraged oil companies and operators to undertake EOR projects through an incentive program from 1979 to 1980. Those companies and operators that received

an incentive have been asked to submit annual reports. Initially, the companies were required to certify the projects as true EOR operations. A total of 423 certifications were received. After the requirements for the "Annual Reports for Enhanced Oil Recovery Incentive Projects" were published, any response was voluntary. Each year after 1982, operators have been requested to return a completed "Annual Report for Enhanced Oil Recovery Incentive Program," form FE-748. The information from these annual reports is used to maintain the EOR Project Database used by the Bartlesville Project Office (BPO). Maintaining this database is part of this project.

Since 1986, the National Institute for Petroleum and Energy Research (NIPIER) has surveyed the operators for annual information. Unfortunately, the number of completed reports is decreasing because many of the original projects have been terminated, completed, changed, were never started, or are not reporting. For the 1986 reporting year, information was obtained on 150 projects of which 110 projects were active. As of the last report,¹ only 53 projects were reported as active.

FE-748 forms were sent to operators of EOR projects in March 1991 requesting information for calendar year 1990 and previous years. Three telephone follow-ups were made to those operators that had not responded, once in June 1991, again in October 1991, and in December. Frequently, the telephone follow-ups identified new contacts within the company.

A total of 61 FE-748 forms were received for 1990. Of this information, 52 projects are active, 4 are terminated, 3 have been deferred, 1 is completed, and 1 has been sold. Table 1 displays selected data on each of the 1990 projects. These projects produced 26.8 million barrels of incremental oil, or over 10% of the total EOR recovered during 1990.

TABLE 1
Summary of the FE-748 Forms Submitted for 1990

Project No.	Year	Project status	Process type	Incremental oil production, Mbbl	Operator
SF006	1990	Active	Alkaline (caustic) flooding	103	City of Long Beach Dept. of Oil Prop.
SF011	1990	Active	Miscible gas displacement	79	Pennzoil E&P Co.
SF018	1990	Active	Steam	1,439	Union Oil Co. of Calif.
SF037	1990	Active	Polymer-augmented waterflooding	77	Phillips Petroleum Co.
SF041	1990	Active	Miscible gas displacement	92	Chevron U.S.A. Inc.
SF085-087	1990	Active	Miscible gas displacement	107	Citronelle Unit Manager
SF092	1990	Completed	Steam	0	Chevron U.S.A. Inc.
SF094	1990	Deferred	Steam	0	Chevron U.S.A. Inc.
SF096	1990	Active	Steam	356	Chevron U.S.A. Inc.
SF097	1990	Active	Steam	530	Chevron U.S.A. Inc.
SF098	1990	Active	Steam	783	Chevron U.S.A. Inc.
SF101	1990	Terminated	Steam	0	Chevron U.S.A. Inc.
SF107	1990	Active	Steam	0	Chevron U.S.A. Inc.

(Table continues on next page.)

TABLE 1 (Continued)

Project No.	Year	Project status	Process type	Incremental oil production, Mbbl	Operator
SF108	1990	Active	Steam	1,000	Chevron U.S.A. Inc.
SF110	1990	Active	Steam	376	Chevron U.S.A. Inc.
SF111	1990	Active	Steam	759	Chevron U.S.A. Inc.
SF120	1990	Active	Steam	256	Chevron U.S.A. Inc.
SF121	1990	Active	Steam	117	Chevron U.S.A. Inc.
SF122	1990	Active	Steam	484	Chevron U.S.A. Inc.
SF123	1990	Active	Steam	1,271	Chevron U.S.A. Inc.
SF124	1990	Active	Steam	1,056	Chevron U.S.A. Inc.
SF125	1990	Active	Steam	1,920	Chevron U.S.A. Inc.
SF127	1990	Active	Steam	0	Chevron U.S.A. Inc.
SF131	1990	Active	Miscible gas displacement	661	Phillips Petroleum Co.
SF135	1990	Active	Miscible gas displacement	590	Conoco Inc.
SF136	1990	Active	Miscible gas displacement	1,024	Arco Oil & Gas Co.
SF137	1990	Active	Miscible gas displacement	179	Arco Oil & Gas Co.
SF138	1990	Active	Miscible gas displacement	1,550	Arco Oil & Gas Co.
SF139	1990	Active	Miscible gas displacement	341	Arco Oil & Gas Co.
SF148	1990	Active	Miscible gas displacement	843	Oxy U.S.A. Inc.
SF149	1990	Active	Steam	0	THUMS Long Beach Co.
SF168	1990	Active	Miscible gas displacement	0	The George R. Brown Ptn.
SF169	1990	Active	Miscible gas displacement	185	Phillips Petroleum Co.
SF171	1990	Active	Miscible gas displacement	1,873	Hunt Oil Co.
SF178	1990	Active	Alkaline (caustic) flooding	0	Conoco Inc.
SF204	1990	Sold	Microemulsion flooding	35	Marathon Oil Co.
SF206	1990	Active	Polymer-augmented waterflooding	0	Mexican Oil Inc.
SF219	1990	Active	Miscible gas displacement	351	Amerada Hess Corp.
SF222	1990	Active	Miscible gas displacement	250	Enron Oil & Gas Co.
SF228	1990	Active	Steam	0	Union Oil Co. of Calif.
SF241	1990	Active	Steam	264	Chevron U.S.A. Inc.
SF242	1990	Terminated	Steam	145	Chevron U.S.A. Inc.
SF243	1990	Terminated	Steam	57	Chevron U.S.A. Inc.
SF245	1990	Active	Steam	124	Chevron U.S.A. Inc.
SF247	1990	Active	Steam	900	Chevron U.S.A. Inc.
SF249	1990	Deferred	Steam	0	Chevron U.S.A. Inc.
SF251	1990	Active	Steam	20	Chevron U.S.A. Inc.
SF252	1990	Active	Alkaline (caustic) flooding	74	Chevron U.S.A. Inc.
SF279	1990	Active	Miscible gas displacement	0	Mobil E&P U.S. Inc.
SF305	1990	Active	Miscible gas displacement	1,018	Arco Oil & Gas Co.
SF312	1990	Active	Immiscible non-hydrocarbon gas displacement	19	Phillips Petroleum Co.
SF341	1990	Active	Steam	0	Arco Oil & Gas Co.
SF343	1990	Active	Steam	0	Arco Oil & Gas Co.
SF345	1990	Active	Steam	0	Arco Oil & Gas Co.
SF369	1990	Terminated	Steam	0	Chevron U.S.A. Inc.
SF370	1990	Active	Steam	2,949	Chevron U.S.A. Inc.
SF380	1990	Active	Miscible gas displacement	0	Mobil E&P U.S. Inc.
SF381	1990	Active	Miscible gas displacement	0	Mobil E&P U.S. Inc.
SF382	1990	Active	Miscible gas displacement	91	Mobil E&P U.S. Inc.
SF383	1990	Deferred	Miscible gas displacement	37	Mobil E&P U.S. Inc.
SF422	1990	Active	Steam	2,424	Chevron U.S.A. Inc.
Total incremental production				26,807	

In addition, annual information on 22 projects was received for years 1987, 1988, and 1989. Nine of these projects are active, eight have been deferred, three are terminated, and two are completed. Table 2 contains selected information about these projects.

BE2 staff have been reviewing annual information for errors in format, typographical errors, reporting errors, and missing data.² A total of 6408 changes were made to the DOE EOR Project Database based upon this review.

TABLE 2

Summary of the FE-748 Forms Submitted for 1987 to 1989 Since the Last Status Report

Project No.	Year	Project status	Project name	Process type	Operator
SE-094	1987	Deferred	Poso Creek Section 21	Steam	Chevron U.S.A. Inc.
SE-108	1987	Active	Midway Sunset Section 15a	Steam	Chevron U.S.A. Inc.
SE-245	1987	Deferred	Midway Sunset Section 25c	Steam	Chevron U.S.A. Inc.
SE-249	1987	Deferred	Poso Creek Section 9	Steam	Chevron U.S.A. Inc.
SE-369	1987	Terminated	Buena Vista Hills Sec. 36b Losf	Steam	Chevron U.S.A. Inc.
SE-092	1988	Completed	Kern Front Section 27	Steam	Chevron U.S.A. Inc.
SE-094	1988	Deferred	Poso Creek Section 21	Steam	Chevron U.S.A. Inc.
SE-108	1988	Active	Midway Sunset Section 15a	Steam	Chevron U.S.A. Inc.
SE-136	1988	Active	South Pass Block 61	Miscible gas displacement	Arco Oil & Gas Co.
SE-137	1988	Active	South Pass Block 61	Miscible gas displacement	Arco Oil & Gas Co.
SE-138	1988	Active	South Pass Block 61	Miscible gas displacement	Arco Oil & Gas Co.
SE-139	1988	Active	South Pass Block	Miscible gas displacement	Arco Oil & Gas Co.
SE-245	1988	Deferred	Midway Sunset Section 25c	Steam	Chevron U.S.A. Inc.
SE-249	1988	Deferred	Poso Creek Section 9	Steam	Chevron U.S.A. Inc.
SE-369	1988	Terminated	Buena Vista Hills Section 36b Losf	Steam	Chevron U.S.A. Inc.
SE-092	1989	Completed	Kern Front Section 27	Steam	Chevron U.S.A. Inc.
SE-094	1989	Deferred	Poso Creek Section 21	Steam	Chevron U.S.A. Inc.
SE-108	1989	Active	Midway Sunset Section 15a	Steam	Chevron U.S.A. Inc.
SE-206	1989	Active	Deadman Creek	Polymer-augmented waterflooding	Meridian Oil Inc.
SE-245	1989	Active	Midway Sunset Section 25c	Steam	Chevron U.S.A. Inc.
SE-249	1989	Deferred	Poso Creek Section 9	Steam	Chevron U.S.A. Inc.
SE-369	1989	Terminated	Buena Vista Hills Section 36b Losf	Steam	Chevron U.S.A. Inc.

References

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2. J. E. Pautz, personal communication to C. M. Nautiyal, Sept. 15, 1992.

DEVELOPMENT OF METHODS FOR MAPPING DISTRIBUTION OF CLAYS IN PETROLEUM RESERVOIRS

Cooperative Agreement DE-FC22-83FE60149,
Project SGP42

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: July 1990
Anticipated Completion: June 30, 1992
Funding for FY 1992: \$210,000

Principal Investigator:
Bijon Sharma

Project Manager:
Chandra Nautiyal
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this project is to develop techniques for mapping the types and volumes of clays in clastic reservoirs from signature analysis of log responses in clayey formations. The scope of work in this project includes identification of a few clastic reservoirs where oil production has been affected by the presence of different types and volumes of clays and mathematical processing of wireline logs from the clayey formations to identify certain mathematical properties that may be correlated with the clay characteristics. The characteristics of clays under investigation are evaluated from detailed thin-section petrography, computerized tomography (CT) scans, and geological investigations.

Summary of Technical Progress

Research results were organized for writing the final report, which was completed and submitted for review. Some time was devoted to a presentation for the Society of Petroleum Engineers (SPE) Annual Technical Conference in Washington, D.C., Oct. 3–7, 1992.

**THIRD INTERNATIONAL RESERVOIR
CHARACTERIZATION TECHNICAL
CONFERENCE**

Cooperative Agreement DE-FC22-83FE60149,
Project SGP47

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Dec. 1, 1990
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$33,000

Principal Investigator:
Bill Linville

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

**UPGRADE OF THE BARTLESVILLE
PROJECT OFFICE CRUDE OIL
ANALYSIS DATABASE**

Cooperative Agreement DE-FC22-83FE60149,
Project SGP56

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: June 1, 1992
Anticipated Completion: May 31, 1993
Funding for FY 1992: \$106,000

Principal Investigators:
James F. Pautz
Paul Woodward

Project Manager:
Chandra Nautiyal
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of the Third International Reservoir Characterization Technical Conference are to (1) explore methods to integrate engineering and geological disciplines to improve the understanding of fluid flow in petroleum reservoirs; (2) review current practices, procedures, and technologies applied to reservoir characterization; (3) identify problems related to current practices and procedures for accurate reservoir descriptions and the information and technology required to solve the problems; (4) identify emerging technologies and promising directions for future research; and (5) provide a means for technology transfer.

Summary of Technical Progress

Completed papers were received from all authors for publication in the proceedings. The keynote address and the luncheon speeches were also received. All papers presented in Sessions 1 through 4 were delivered to PennWell Books for processing. Papers for Session 5, the poster session, will be delivered early in October. All material to be published in the proceedings will be delivered to PennWell by Oct. 15.

Objective

The purpose of this work is to (1) develop and maintain a crude oil analysis database that maintains data integrity and system security online and available to the public and (2) upgrade and update crude oil analyses for approximately 12 months on best efforts consistent with funding.

Summary of Technical Progress

This project was just started so there are no results to report.

ANALYSIS OF THE U.S. OIL RESOURCE BASE AND ESTIMATE OF FUTURE RECOVERABLE OIL

**Cooperative Agreement DE-FC22-83FE60149,
Project SGP60**

**National Institute for Petroleum
and Energy Research
Bartlesville, Okla.
and
Texas Bureau of Economic Geology
University of Texas at Austin
Austin, Texas**

**Contract Date: June 15, 1992
Anticipated Completion: Oct. 15, 1992
Funding for FY 1992: \$110,000**

**Principal Investigators:
James F. Pautz, NIPER
Noel Tyler, BEG**

**Project Manager:
Chandra Nautiyal
Bartlesville Project Office**

Reporting Period: July 1–Sept. 30, 1992

Objective

The objective of this project is to develop a consensus estimate of the technically and economically recoverable oil resource in the United States. This will be done by analysis of the existing estimates of U.S. oil resource and future recoverable reserves and then use of expert opinion through a modified Delphi process to develop a consensus.

Summary of Technical Progress

Background

The U.S. oil resource base is substantial. Current estimates place the known resource at more than 500 billion bbl, of which 153 billion bbl (31% of the resource base) has been produced and 25 billion bbl is classified as proved reserves (or 5% of the resource base). Thus a substantial resource exists in discovered reservoirs. In addition to the known resource, significant amounts of oil await discovery. Estimates are in the range of 200 billion bbl.

Although there is general agreement that the U.S. oil endowment is significant, there is considerable variation in the estimates of the volume of oil that is technically and economically recoverable from the resource. Five groups have made estimates of the potential for reserve additions at moderate costs and with varying levels of technology: Governor's Energy Council (Texas), National Research Council, American Association of Petroleum Geologists, National Petroleum

Council, and the Department of Energy. Estimates of the recoverable resource at moderate cost (exclusive of reserves) ranged from 55 to 108 billion bbl. The average of these estimates, made with assumptions of existing technology and prices ranging from \$20 to 32/bbl, was 71 billion bbl. However, at the same assumed price but with the further assumption of advanced technology, the average estimate was 121 billion bbl, 70% greater. Three of the groups estimated oil resources accessible at prices of \$40 to 50/bbl but assuming only existing technology. The average of these estimates was 125 billion bbl, roughly the same volume accessible at lower prices but with assumptions of advanced technology.

The differences in the estimates are partially the result of different assumptions about including or excluding enhanced oil recovery (EOR) and including or excluding access to the resource. This project attempts to include all recovery methods and all of the U.S. endowment. Important contributors from each of the previous studies were included in the expert panel.

Results

The HTT Research Institute/National Institute for Petroleum and Energy Research (NIPER) and the Bureau of Economic Geology, University of Texas at Austin (BEG), convened a panel of oil resource experts in August 1992 to analyze the U.S. oil resource, both discovered and undiscovered, to estimate the volume of oil technically and economically recoverable. The members of this Oil Resource Panel are listed in Table 1. A NIPER/BEG team prepared for the panel an analysis of previous estimates of potential oil reserve additions that were desegregated for high and low oil prices, implemented and advanced technology, onshore and offshore, Alaska and lower 48, and the inclusion or exclusion of EOR potential.

The panel concluded that the remaining, recoverable volume of crude oil in the United States ranges from 99 to 204 billion bbl inclusive of 25 billion bbl carried as proved reserves in 1991.

The range in estimates reflects different assumptions of price and technology (including the geological ability to apply that technology). The lower estimate assumes a stable oil price of \$20/bbl (1992 dollars) with existing technology. The higher estimate assumes a price of \$27/bbl (1992 dollars) but with advanced technology. The range in estimates of the remaining resource base recoverable under the given assumptions is equivalent to 35 to 75 years of continued U.S. crude oil production at the current annual rate of 2.7 billion bbl. These results are shown in Table 2.

In the panel's estimation of recoverable resources, price and technology are equally sensitive. The average estimate for recoverable volumes at a given price was approximately two-thirds greater with the assumption of advanced technology than with existing technology. The impact of technology and its application was judged to boost recoverable discovery volumes by about 45%, as panelists assumed

TABLE 1

Members of the Oil Resources Panel

Jerry Brashcar, Senior Vice President ICF Resources	Steven E. Plotkin, Senior Analyst Congressional Office of Technology
Tom Burchfield, Director of Energy Production Research National Institute for Petroleum and Energy Research	Arlie M. Skov, Executive Consultant BP Exploration, Inc.
Robert D. Gunn, President Gunn Oil Company	Noel Tyler, Associate Director Bureau of Economic Geology
Don Juckett, Director of Oil and Gas Exploration and Production Office of Fossil Energy U.S. Department of Energy	Ray Thomasson, President Thomasson Partner Associates (formerly Chief Geologist and Manager, Planning Economics and Forecasting, Shell Oil Company)
Gary Lore, Regional Supervisor Resource Evaluation Minerals Management Service U.S. Department of the Interior	John Wood, Director Dallas Field Office U.S. Department of Energy
Charles J. Mankin, State Geologist and Director Oklahoma Geological Survey	Dalton Woods, President Dal Woods Corporation
Richard Mast, Research Geologist U.S. Geological Survey U.S. Department of the Interior	Thomas J. Woods, Executive Energy Analyst Gas Research Institute
Riley Needham Phillips Fellow Emeritus Phillips Petroleum Company	William L. Fisher, Director Bureau of Economic Geology <i>Panel Chair</i>
Richard Nehring, President NRG Associates	

TABLE 2

Summary of Estimates by the Oil Resources Panel

	Existing technology*	Advanced technology*	Existing technology†	Advanced technology‡
Lower 48, onshore:				
Reserve growth	24 (4.4)	45 (6.5)	33 (5.5)	70 (14.1)
Undiscovered resources	24 (10.3)	34 (15.3)	33 (17.5)	48 (28.4)
Subtotal	48	79	66	118
Lower 48, offshore:				
Reserve growth	2 (1.3)	3 (1.7)	3 (1.6)	6 (2.3)
Undiscovered resources	11 (6.4)	14 (7.3)	13 (7.5)	17 (7.9)
Subtotal	13	17	16	23
Alaska, onshore:				
Reserve growth	5 (2.1)	7 (3.2)	7 (2.4)	13 (6.1)
Undiscovered resources	8 (2.6)	12 (3.5)	12 (2.6)	17 (4.1)
Subtotal	13	19	19	30
Alaska, offshore:				
Undiscovered resources		2 (2.8)	4 (3.9)	8 (6.0)
Total undiscovered resources	43	62	62	90
Total reserve growth	31	55	43	89
Total undiscovered resources and reserve growth	74	117	105	179
Proved reserves at year end 1991	25	25	25	25
Total recoverable resources	99	142	130	204

* \$20/bbl '92 dollar.

† \$27/bbl '92 dollar.

‡ Numbers in parentheses are standard deviations of estimates by panelists.

that the 30-year history of discovery efficiencies and improving recovery would continue. The collective judgment of the panel was that advancing technologies will be applied at the reservoir level and could result in reserve growth of 40 to 100% over that of existing or implemented technology. Recoverable volumes from reserve growth were judged to be slightly higher at \$20/bbl with advanced technology than at \$27/bbl with existing technology, showing the substantial substitute of technology for price within the price range.

Future potential was estimated by the panel to be nearly equally divided between reserve growth from existing, already discovered fields and new fields yet to be discovered along with the reserve growth these new fields will experience. About two-thirds of the total remaining potential is onshore in the lower 48 States, largely because of the judged prospects for reserve growth from existing fields. The frontier areas—Alaska and the lower 48 offshore—hold about one-third of the judged future potential. These areas hold nearly half of the future discovery potential and nearly all of the potential for giant field discovery.

As expected with a diverse panel, individual estimates varied. There was a narrow distribution of estimates of reserve growth and a wide distribution of the estimates of undiscovered resource. The average estimates of the panel were higher than the average of several previous estimates

made in the past 5 years for overall future potential at the lower price level, and they were approximately the same at the higher price level (Table 3). For reserve growth potential, the panel's average estimates were, with one exception (advanced technology at higher oil prices), lower than previous estimates. The panel's estimates of future discovery potential at current oil price assumption were 20 to 60% higher than previous estimates. Slightly over half of the undiscovered economic oil is estimated to be in the lower 48 States for all cases. Alaska has an estimated 19 to 27% of the undiscovered oil with the remainder in the offshore lower 48.

Although the estimate by the panel of future oil resources recoverable at moderate prices is substantial, only sensitivity to price and technology were considered. Physical access to the remaining resource base was not evaluated, although current policy seriously limits the potential of the U.S. offshore and Alaska—areas of significant potential for large-field discovery. Future costs were assumed to be held down or reduced through advanced technology, but the substantial costs of environmental regulations and the impact of future, long-term environmental liabilities were not considered explicitly. Finally, wellhead prices considered were assumed to be stable though no guarantee against future price volatility exists.

TABLE 3
Comparison of Average Estimates of the Oil Resources
Panel with Average of Other Recent Estimates
(billion barrels, constant dollars)

	Existing technology, lower price	Advanced technology, lower price	Existing technology, higher price	Advanced technology, higher price
Undiscovered resources	43 (31)*	62 (38)	62 (52)	90 (61)
Reserve growth	31 (24)	55 (62)	43 (53)	89 (121)
Total resources	74 (55)	117 (100)	105 (105)	179 (182)

*Numbers in parentheses are the average of estimates made during the past 5 years.

MICROBIAL TECHNOLOGY

QUANTITATION OF MICROBIAL PRODUCTS AND THEIR EFFECTIVENESS IN ENHANCED OIL RECOVERY

Contract No. DE-AC22-90BC14662

University of Oklahoma
Norman, Okla.

Contract Date: Aug. 21, 1990
Anticipated Completion: Aug. 20, 1993
Government Award: \$97,467

Principal Investigators:
Michael J. McInerney
Roy M. Knapp

Project Manager:
E. B. Nuckols
Metairie Site Office

Reporting Period: July 1–Sept. 30, 1992

Objectives

The objectives of this project are to determine the growth kinetics and the relationships that exist among microbial growth, microbial product formation, and oil recovery and

to develop mathematical models that predict microbial activity in porous materials.

Summary of Technical Progress

Oil Recovery Related to Microbial Product Formation

Studies were initiated on the influence of microbial growth and product formation on the recovery of residual oil from Berea sandstone cores. A high-pressure core apparatus was designed and built as outlined in Fig. 1. The core experiments are to be carried out at 500 psig and 35 °C with a confining pressure of 1200 psig. Pressure transducers with a range of 0 to 50 psig were calibrated (Fig. 2) and incorporated into the

Fig.1 High-pressure experimental diagram.

Fig. 2 Calibration of pressure transducers.

influent and effluent lines of the apparatus to determine the differential pressure increase from microbial growth. This can then be correlated with specific growth rate.

The initial experiment will use the anaerobic, acid, solvent, and gas producer, *Clostridium acetobutylicum*. At neutral pH this microorganism produces mainly acetate, butyrate, CO_2 , and H_2 from glucose. If the pH of the fermentation broth drops below pH 5.0, acids are no longer produced and *n*-butanol and acetone appear as new products of metabolism. During this solvent production phase *C. acetobutylicum* takes up butyrate and H_2 to form *n*-butanol resulting in a pH increase in the fermentation broth. Throughout the solvent production the acetate concentration remains relatively constant. Primary studies show that *C. acetobutylicum* grows in a defined medium and reaches maximum density within 24 h of incubation. Identical growth rates were observed in both buffered (acid-producing conditions) and unbuffered media (solvent-producing conditions).

A Berea sandstone core was cut (5.08 cm $\times$ 28.42 cm), cleaned, and dried, and its bulk volume, pore volume, and porosity were determined (Table I). Once in place in the

core holder the core was treated with 12 pore volumes (PV) of a methanolic calcium chloride brine solution (0.1M CaCl_2 + 0.125M NaCl in 5% methanol) to prevent swelling of the clay deposits in the core and sterilize the experimental apparatus. During this process the absolute permeability of the core was determined (Table I). The core was then saturated with 12 PV of sterile NaCl (0.125M) to remove excess calcium prior to oilflooding to connate water saturation and further waterflooding to residual oil saturation. Growth medium (2.8 PV) for *C. acetobutylicum* was then injected into the core after which sterile medium with 10% of an actively growing culture was injected. The core was incubated at 35 $^\circ\text{C}$. Growth is being monitored by core pressure and differential pressure.

DEVELOPMENT OF IMPROVED MICROBIAL FLOODING METHODS

Cooperative Agreement DE-FC22-83FE60149,
Project BE3

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$295,000

Principal Investigator:
Rebecca S. Bryant

Project Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period: July 1–Sept. 30, 1992

TABLE I

Experimental Core Characteristics

Core dimensions	
Diameter	5.08 cm
Length	28.42 cm
Bulk volume	5.76 ml
Pore volume	106 ml
Porosity	18.4%
Absolute permeability	1.78 mD
Oilflood	
Effective permeability to oil	112 mD
Connate water saturation	31%
Waterflood	
Effective permeability to water	42 mD
Residual oil saturation	29%

Objective

The objective of this research is to develop an engineering methodology for designing and applying microbial methods to improve oil recovery.

Summary of Technical Progress

The National Institute for Petroleum and Energy Research (NIPER) has shown that gas and surfactant production are important microbial mechanisms for oil mobilization. It is important to determine the contribution of microbial gas production to oil mobilization. In this regard, experiments with computerized tomography/nuclear magnetic resonance (CT/NMR) imaging and an X-ray/microwave

relative permeability apparatus may provide information to assist in the determination of the effect of trapped gas saturation in porous media. To date there are no reports in the literature where these types of experiments have been conducted with microbial formulations. The only reported relative permeability data for microbial formulations were obtained by NIPER's BE3 research program. This year experiments with oil wet rock will provide more information on the effects of wettability on microbial oil mobilization.

Work on this project has included the continuing development of a three dimensional, three phase, multiple component numerical model to describe microbial transport phenomena in porous media. Initial efforts have focused on incorporating the most important phenomena for which mathematical models or correlations are available or can be available in a reasonably brief period of time.

Work for FY92 will continue to develop laboratory experiments to refine the model, not only with the above parameters, but also to obtain data to incorporate microbial oil recovery mechanisms. Mechanisms considered to be important for oil recovery include changes in microscopic properties, such as interfacial tension, wettability, and adsorption, that govern oil mobilization and affect fractional flow and relative permeabilities. Other oil recovery mechanisms traditionally associated with fluid flow changes include polymer and biomass production by microorganisms.

Microbial retention and adsorption experiments have shown that adsorption does significantly contribute to microbial retention. Several experiments were designed this quarter to further investigate these phenomena.

A status report was completed this quarter on microbial alteration of wettability.¹ Wettability experiments using siloxane treated Berea sandstone showed that NIPER 1A microbial formulation could change the wettability index from very oil wet to an intermediate wettability state. This change also resulted in a decrease of residual oil saturation, as shown in Fig. 1.

Fig. 1 Wettability indices vs. residual oil saturations for siloxane-treated Berea sandstone cores.

A paper, "Parameters Involved in Microbial Oil Mobilization in Porous Media," was presented at the 4th International MEOR Conference, Brookhaven National Laboratory, Sept. 8-11, 1992.² The results of this research were presented at the DOE/Venezuelan Ministry of Mines Annex XIII meeting held in conjunction with the conference at Brookhaven.

A CT experiment was conducted this quarter with Chelsea Alluwe crude oil tagged with 20% iododecane. The core was waterflooded to residual oil saturation and then injected with 0.1 PV of NIPER 1 and 7 and 0.4 PV of 4% molasses. The core was then incubated for 48 h, and the pressure was monitored. The core was then waterflooded at 1 ft/d while maintaining a pore pressure of 40 psi. The saturations of this core were as follows: (1) initial oil saturation (S_{oi}), 68%; (2) oil saturation after waterflood (S_{orw}), 34%; (3) oil saturation after incubation during the second waterflood (S_{orm}), 32%; and (4) oil saturation after release of pore pressure, 27%. During microbial incubation, the pressure rose to 40 psi.

This particular microbial injection gave a recovery efficiency (E_r) of 5.8%. The release of pore pressure obviously caused some additional oil production.

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2. A. K. Stepp, R. S. Bryant, K. M. Bertus, and M. M. Chang, *Parameters Affecting Microbial Oil Mobilization in Porous Media, Proceedings of the 4th International Conference on Microbial Enhanced Oil Recovery*, Upton, NY, Sept. 8-11, 1992.

MICROBIAL ENHANCED WATERFLOODING FIELD PROJECT

Cooperative Agreement DE-FC22-83FE60149,
Project SGP13

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1992
Funding for FY 1992: \$419,000

Principal Investigator:
Rebecca S. Bryant

Project Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period: July 1-Sept. 30, 1992

Objectives

The objectives of this research are to determine the feasibility of improving oil recovery in an ongoing waterflood with microorganisms and to expand the initial pilot and determine the economics of microbial enhanced waterflooding. The scope of work includes continued monitoring of the Phoenix field site.

Summary of Technical Progress

The expanded microbial enhanced oil recovery (MEOR) project site is in Section 8, Township 24 North, Range 17E of Rogers County, Oklahoma. This site is part of Chelsea-Adluwe field in the Bartlesville formation and was initially developed soon after Delaware Childers field. The site, owned by Phoenix Oil and Gas, Ltd., is being waterflooded. This field is in an isolated area with virtually no other oil-producing leases nearby.

Fluorescein was injected as a tracer on June 6, 1990. Samples were collected from all 19 injection wells at 2-h intervals the first day. Twenty-one producers were sampled 24 h after injection of tracer, sampled daily, weekly, once a month, and quarterly. Since the second day of sampling, the tracer response has never been higher than 0.30 ppm for any of the wells. 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 d and were monitored until the end of the molasses injection (599 d).

Wellhead injection pressures and volumes continue to be monitored, and no signs of plugging or any other problems have been observed. Molasses injection ceased at the end of December 1991. Figure 1 shows oil production values of

Fig. 1 Oil production from the Phoenix site through August 1992.

the baseline and postmicrobial injection. Oil production appears to be increasing, and the decline curve is improving. Oil production data will continue to be obtained through Dec. 31, 1992.

A paper, "Microbial Enhanced Waterflooding Field Pilots," was presented at the 4th International MEOR Conference, Brookhaven National Laboratory, Upton, N.Y., Sept. 8-11, 1992.

Reference

1. R. S. Bryant, A. K. Stepp, K. M. Bertus, J. E. Burchfield, and D. M. Dennis, Microbial Enhanced Waterflooding Field Pilots, *Proceedings of the 4th International Conference on Microbial Enhanced Oil Recovery*, Upton, N.Y., Sept. 8-11, 1992.

MICROBIAL ENHANCED OIL RECOVERY AND WETTABILITY RESEARCH PROGRAM

Contract No. DE-AC07-76ID01570
Project 5AC3

Idaho National Engineering Laboratory
EG&G Idaho, Inc.
Idaho Falls, Idaho

Contract Date: Oct. 1, 1988
Anticipated Completion: Sept. 30, 1995
Funding for FY 1992: \$600,000

Principal Investigator:
C. P. Thomas

Project Managers:
Linda McCoy
Idaho Operations Office

Rhonda Lindsey
Bartlesville Project Office

Reporting Period: July 1-Sept. 30, 1992

Objectives

The objectives of this research program are to develop microbial enhanced oil recovery (MEOR) systems for application to reservoirs containing medium to heavy oils and to evaluate reservoir wettability and its effects on oil recovery.

The MEOR research goals include

- Development of bacterial cultures that are effective for oil displacement under a broad range of reservoir conditions.
- Improved understanding of the mechanisms by which microbial systems displace oil under reservoir conditions.

- Determination of the feasibility of combining microbial systems with or following conventional enhanced oil recovery (EOR) processes, such as miscible and immiscible gas flooding, polymer and chemical flooding, and thermal methods.

- Development of an MEOR field process design.
- Implementation of an industry cost-shared field demonstration project.

The goals of the reservoir wettability project are to develop

- Better methods for assessment of reservoir core wettability.
- More certainty in relating laboratory core analysis procedures to field conditions.
- Better understanding of the effects of reservoir matrix properties and heterogeneity on wettability.
- Improved ability to predict and influence EOR response through control of wettability in reservoirs.

Summary of Technical Progress

Microbially Mediated Oil Recovery

The focus of this communication is a comparative analysis of potentially useful surfactants produced by *Bacillus licheniformis* JF-2 (ATCC 39307) and *Bacillus subtilis* (ATCC 21331 and ATCC 21332) growing on various sources of carbohydrates. Initial data from this study were reported in a previous quarterly report. Historically, molasses has been the feedstock of choice for the in situ production of biosurfactants.¹ Alternative carbon substrates (i.e., processing wastes from the agricultural industry were proposed as replacements for molasses. These wastes are currently disposed of at a cost and may be employed as viable feedstocks for the production of biosurfactants.

Bacillus licheniformis (ATCC 39307) and *Bacillus subtilis* (ATCC 21331 and 21332) were obtained from American Type Culture Collection (ATCC). Organisms were stored according to ATCC protocols.² *B. licheniformis* is a gram-positive, facultatively anaerobic, spore-forming rod approximately 0.7 by 2.0 μm (width by length).³ The organism is capable of utilizing starch as a carbon source, has a maximal growth temperature of 50 °C, tolerates salt (as NaCl) to 10% (highest value tested), grows well from pH 4.5 to 8.5, does not adhere to hydrocarbons (determined by the Bacterial Adhesion to Hydrocarbons assay),⁴ and does not degrade Schuricht crude oil. *B. subtilis* is a gram-positive spore-forming rod that is also capable of utilizing starch as a carbon source. Most strains of *B. subtilis* are considered aerobic bacterium; however, both ATCC 21331 and 21332 were observed to be facultative anaerobes. *B. subtilis* 21331 will grow to 50 °C. *B. subtilis* 21332 will grow to 55 °C. Both strains of *B. subtilis* tolerate NaCl to 10% and are roughly the same size as *B. licheniformis*. Neither strain of *B. subtilis* adheres to hydrocarbons and both slightly degrade Schuricht crude oil.

Schuricht crude oil from the Minnelusa formation in the Powder River Basin, Wyoming, was selected for experimentation. Schuricht crude is 25.4 °API, has a viscosity of 0.054 Pa · s at 23 °C, and a density of 0.9081 g/cm³ at 15.6 °C. The Schuricht well is on primary production and is not producing H₂S. Potential application of MEOR technologies in the Powder River Basin has been previously discussed.⁵

Three media were used for microbial cultivation: (a) medium E (ATCC 1502) supplemented with 2.5% NaCl and 1% carbon source,⁶ (b) Trypticase Soy Broth (TSB), and (c) Potato Dextrose Yeast (PDY) medium (ATCC 336).⁷ Carbon sources used to supplement medium E to determine the feasibility of using alternative carbon substrates were sucrose, fructose, galactose, dextrose, molasses, starch, glycerol, pyruvate, acetate, citrate, casitone, and yeast extract. All carbon substrates were 1% (v/v) except starch was 0.5% (v/v). One percent (v/v) of fresh culture was used for inoculating the selected media. The organisms were incubated in shake flasks at 30 °C until the stationary phase of growth ($\approx$ 72 h). The optical density was monitored at 550 nm using a UV-VIS Spectrophotometer 2000 (Bausch & Lomb, Rochester, NY). After 72 h of growth, cells were removed by centrifugation in a Sorvall RC-5B Refrigerated Superspeed Centrifuge at 6000 $\times$ g for 20 min.

A growth curve was initially performed on all microorganisms. Cells were inoculated into TSB and incubated at 37 °C. Samples for optical density and surface tension were obtained every 12 h. The optimal growth temperature for the bacteria was determined by incubating the cultures containing TSB at five temperatures (22, 30, 35, 45, and 55 °C). The optical density was monitored over time for each flask and the growth rate was calculated. Surface tensions were measured on the final (72 h) cell-free extracts. Interfacial tensions (IFT) (liquid-liquid) and surface tensions (air-liquid) were measured by the inverse pendant-drop method. Instrument configuration and measurement methodology has been previously reported.⁸ NANO-pure water was used to calibrate the system, and measurements were taken in replicates of seven. The reported values are expressed as the arithmetic mean and standard deviation (method of least squares). All IFT measurements were measured at room temperature.

Of the five temperatures tested, 35 °C was the optimal growth temperature for all strains. It was hypothesized that maximum surfactant production would occur at the optimal growth temperature. However, if surface tension is plotted against temperature, it appears that this hypothesis is not true for all strains. *B. subtilis* strains 21331 and 21332 produce maximum surfactant at 35 °C. However, surfactant production by *B. licheniformis* (manifested by a reduction in surface tension) appears to be optimal at the lowest temperature tested.

B. subtilis 21332 exhibits a typical growth curve having lag, log, and stationary growth phases when grown on TSB. Surfactant production was approximately proportional to cell growth; as the cell density increased the surface tension

decreased. The greatest decrease in surface tension was observed during the log phase of growth (within 24 h). This curve strongly suggests that a 72-h incubation is sufficient time for surfactant production. Surface tension dropped from 57.10 mN/m to 30.17 mN/m within the first 24 h and stabilized over the next 48 h to a value of 28.49 mN/m.

Similar trends for *B. subtilis* 21331 were observed. The surface tension dropped from 57.10 mN/m to 29.91 mN/m in 72 h. The largest decrease in surface tension occurred during the exponential phase of growth. Likewise, *B. licheniformis* showed a decrease in surface tension within 24 h. However, the surface tension for *B. licheniformis* did not drop as low as the *B. subtilis* strains. The 72-h surface tension value was 45.65 mN/m for *B. licheniformis*.

Reductions in surface tension as a result of growth on various carbon substrates for *B. licheniformis* and *B. subtilis* 21331 have been previously reported. Positive growth was observed for all carbon sources. Yeast extract was the only suitable carbon source for a reduction in surface tension for *B. licheniformis*. However, for *B. subtilis* 21331 sucrose, fructose, starch, pyruvate, casitone, and yeast extract all resulted in surface tensions lower than 27 mN/m. Likewise, *B. subtilis* 21332 facilitated a significant decrease in surface tension when sucrose, fructose, starch, glycerol, pyruvate, casitone, and yeast extract were the carbon sources. The reduction in surface tension indicates at least six alternative carbon substrates suitable for MEOR applications.

IFTs between medium E, TSB, and PDY medium cell free supernatants of all strains and Schuricht crude oil are shown in Table 1. Sucrose was chosen because it represents the major carbohydrate constituent of beet molasses (molasses has historically been the feedstock of choice for MEOR applications in the field). Sucrose represents 63.5% of total solids in beet molasses and 95.4% of all carbohydrate present.⁹ TSB was selected as a complete growth medium for comparison, and PDY medium was chosen based on experimental results.

Although the lowest IFT was observed using the complete TSB medium (*B. subtilis* 21331, 2.73 mN/m), the decrease noted for minimal medium E with the same organism was 4.24 mN/m. This reduction in surface tension represents an 87% reduction in medium E vs. 85% in TSB. Interfacial tensions for *B. subtilis* 21332 grown on PDY

medium dropped from 17.18 mN/m to 8.07 mN/m. The data confirms using starchy wastes from agricultural processing industries as viable carbon substrates for surfactant production by fermenting organisms.

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POLYSACCHARIDES AND BACTERIAL PLUGGING

Contract No. DE-AC22-90BC14664

University of Michigan
Ann Arbor, Mich.

Contract Date: July 1, 1990
Anticipated Completion: June 30, 1993
Funding for FY 1992: \$50,000

Principal Investigator:
H. Scott Fogler

Project Manager:
Chandra Nautiyal
Bartlesville Project Office

Reporting Period: July 1-Sept 30, 1992

TABLE 1

Interfacial Tensions Between Medium E, Trypticase Soy Broth (TSB), and Potato Dextrose Yeast (PDY) Medium Cell Extracts and Schuricht Crude Oil *

Media	Abiotic control	<i>Bacillus licheniformis</i>	<i>Bacillus subtilis</i> 21331	<i>Bacillus subtilis</i> 21332
Medium E	32.37 ± 0.07	23.10 ± 0.07	4.24 ± 0.31	18.03 ± 0.18
TSB	18.72 ± 0.24	7.65 ± 0.32	2.73 ± 0.12	7.71 ± 0.14
PDY	17.18 ± 0.15	9.12 ± 0.03	14.24 ± 0.05	8.07 ± 0.13

*Number of samples = 7

Objectives

The objectives of this research are to elucidate and model bacterial transport in porous media, determine the importance of polysaccharides bridging as a retentive mechanism, and identify key parameters that influence porous media plugging.

Summary of Technical Progress

A continuum core plugging model is being developed. This model will include the resulting cell, polysaccharide, and nutrient profiles as growth occurs with time. Initial cell profiles were found to be needed for the model. Experiments and a cell retention model have been completed to predict cell profiles for a high permeability core (7 D).

Continuum Core Plugging Model

The development of a continuum model starts with application of a mass balance to an elemental volume of porous media with the following assumptions:

1. Cells once deposited remain sessile.
2. Polymer and enzyme remain in location of cells.
3. Neglect dispersion and diffusion in model.
4. Neglect yeast extract balance.
5. Neglect changes in the interstitial velocity.

The resulting general mass balance then follows the form

$$\epsilon \frac{\partial f}{\partial t} + U_s \frac{\partial f}{\partial z} = -\epsilon r_f \quad (1)$$

where ϵ = porosity

f = concentration of species f

U_s = Darcy or superficial velocity

z = length dimension

t = time dimension

r_f = rate of reaction for species f (fluid volume basis)

This model can apply to the bacterial cells (x), polymer (p), enzyme (e) (as reported in the 1992 annual report), and sucrose (s). However the convective terms for bacteria, enzyme, and polymer are removed from Eq. 1 as a result of Assumptions 1 and 2. Assumption 5 inherently assumes that the porosity of the core is constant. This assumption will have to be addressed in the future as the model is further developed.

The initial conditions (IC) and boundary conditions (BC) are needed to solve the system of equations. Most of the IC and the BC are preset by the experiment that is to be modeled. Note that the model being developed is going to be used for the simulation of the Damkohler experimental results. The simulation of these experimental results, however, requires knowledge of the initial cell profile in the porous media. This initial cell profile has been determined to follow a linear profile for high-permeability cores

(7 darcys). The determination of this profile will be presented in the next section.

To solve the above set of partial differential equations (PDEs) the following steps were performed:

1. Express equations, ICs, and BCs in dimensionless form, which results in the expression of three dimensionless numbers (Damkohler numbers): Da_x , cell growth, and Da_p and Da_e , nutrient consumption.
2. Solve PDEs by Method of Lines. The spacial derivative is discretized by a second order central differencing scheme. The resulting set of Ordinary Differential Equations (ODEs) are then solved by time integration using LSODE (Livermore Solver for Ordinary Differential Equations).

The results from one simulation, which describes the sessile cell, polysaccharides, and sucrose profiles as a function of dimensionless time, are presented in Figs. 1-3.

Fig. 1 Sessile cell profile for a high-permeability core as a function of dimensionless time (Q , 1.0 mL/min. Sucrose, 15 g/L. Yeast extract, 10 g/L).

Fig. 2 Polysaccharide profile for a high-permeability core as a function of dimensionless time (Q , 1.0 mL/min. Sucrose, 15 g/L. Yeast extract, 10 g/L).

Fig. 3 Sucrose profile for a high-permeability core as a function of dimensionless time (Q , 1.0 mL/min. Sucrose, 15 g/L. Yeast extract, 10 g/L.).

Cell Profile Model

Cell inoculation profiles are needed to predict the development of a bacterial plug. As with the core plugging experiments it was believed that the cell profile could be determined by the bacterial staining techniques detailed in the 1991 Annual Report. However, cell concentrations (cores that were only inoculated and not subjected to nutrient injection) were too low to measure. To overcome this problem, the cell profile was determined indirectly by Deep-Bed Filtration (DBF) theory.

Steps to determine cell profile:

1. Conduct cell transport experiments with cores of varying lengths.
2. Fit resulting data to DBF model using typical capture and entrainment models.

The following DBF equations were used to predict the cell profiles after inoculation for high-permeability cores. The resulting profile can be seen in Fig. 4.

planktonic cell (X_p) balance

$$\epsilon \frac{\partial X_p}{\partial t} + U_s \frac{\partial X_p}{\partial z} = -R \quad (2)$$

sessile cell (X_s) balance

$$\epsilon \frac{\partial X_s}{\partial t} = R \quad (3)$$

where: $R = k_1 X_p - k_2 X_s$
 k_1 = deposition rate constant
 k_2 = entrainment rate constant

Fig. 4 Predicted inoculum profile of a high-permeability core ($X_s = 8.0 \times 10^{-11}$ cell/L.).

EFFECTS OF SELECTED THERMOPHILIC MICROORGANISMS ON CRUDE OILS AT ELEVATED TEMPERATURES AND PRESSURES

Contract No. DE-AC02-76CH00016

Brookhaven National Laboratory
Upton, Long Island, N.Y.

Contract Date: Mar. 1, 1989
Anticipated Completion: Sept. 30, 1992
Government Award: \$155,000
(Current year)

Principal Investigators:
E. T. Premuzic
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Project Manager:
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Objective

The objective of this program is to determine the chemical and physical effects of thermophilic and thermoadapted organisms on crude oils and cores at elevated temperatures and pressures. Ultimately a database will be generated that will be used in technical and economic feasibility studies leading to field application.

Summary of Technical Progress

Duration of Biotreatment and Media Effects

Brookhaven National Laboratory continued its effort to identify trends in the biochemical interactions between microorganisms and crude oils. This effort has led to comparative studies of microbial effects on different types of heavy oils. These included oils that are heavy because they are immature and oils that are heavy because they are biodegraded. The effects of several thermoadapted microorganisms on Monterey crude oil, an immature offshore Monterey, California, crude, were reported.¹ Comparative studies were carried out with another immature offshore Monterey crude oil (A837) and an onshore heavy crude that is biodegraded (A851).

The details of these studies were recently discussed at the Fourth International Microbial Enhanced Oil Recovery Conference.² The results are summarized in Tables 1 through 6 and Figs. 1 and 2. Media 2 and 3 were used throughout.^{2,3} Medium 2 contains 0.0075% of added nutrient carbon, whereas Medium 3 contains only inorganic salts in which sulfates were replaced by chlorides. The experiments were carried out under identical experimental conditions in the presence

TABLE 1

Monterey Oil A837 Biotreatment in Medium 3
and in the Absence of an Emulsifying Agent

Microorganisms	Oil, %	Incubation, d	Extent of emulsification, Klett units	pH
BNL-4-22	0.489	7	16.875	5.0
BNL-4-23	0.534	7	3.710	4.9
BNL-NZ-3	0.482	7	7.265	5.7
Control, oil	0.486	7	1.205	5.0
BNL-4-22 control	0.000	7	3.550	4.9
BNL-4-23 control	0.000	7	1.825	5.0
BNL-NZ-3 control	0.000	7	2.105	5.7
Control/control	0.000	7	0.080	4.9
BNL-4-22 (65 °C)	0.496	7	3.565	5.5
BNL-4-23 (65 °C)	0.494	7	2.900	5.5
BNL-NZ-3 (65 °C)	0.589	7	4.515	5.5
Control, oil (65 °C)	0.501	7	6.495	5.5
BNL-4-22 control (65 °C)	0.000	7	3.760	5.5
BNL-4-23 control (65 °C)	0.000	7	1.970	5.5
BNL-NZ-3 control (65 °C)*	0.000	7	3.275	5.5
Control/control (65 °C)†	0.000	7	2.915	5.5
BNL-4-22	0.539	20	33.325	4.0
BNL-4-23	0.509	20	33.950	4.0
Control, oil	0.559	20	39.085	4.0
BNL-4-22 control	0.000	20	14.595	4.3
BNL-4-23 control	0.000	20	5.365	4.0
Control/control	0.000	20	9.710	4.0
BNL-4-22	0.476	20	40.885	5.5
BNL-4-23	0.476	20	7.225	5.5
BNL-NZ-3	0.476	20	5.675	5.3
Control, oil	0.480	20	5.465	5.5
BNL-4-22 control	0.000	20	9.080	5.0
BNL-4-23 control	0.000	20	3.670	5.0
BNL-NZ-3 control	0.000	20	5.105	5.5
Control/control	0.000	20	3.160	5.5

*Medium plus organism only.

†Oil plus water only.

of a detergent (e.g., tergitol) over a period of 20 d and a period of 7 d. The results are consistent with previously reported observations.^{4,5} Biochemical interaction between the selected microorganisms and oils follow distinct patterns. Thus treatment of Monterey A837 with BNL-4-22, BNL-4-23, and BNL-NZ-3 leads to the conversion of heavier hydrocarbon fractions of crude oil to lighter. Furthermore, there are differences in the effects caused by the presence or absence of tergitol, a C₂₆ hydrocarbon-based surface-active agent. For all cases in this series of experiments, a 7-d treatment appeared to be sufficient to bring about the biochemical conversion.

The working hypothesis is based on the premise that the biochemical conversion starts by an attack on the complex structure, possibly on the N-, S-, O-rich polar components of the maltene fraction derived from the asphaltene component of the crude.³ In the three crude oils considered, A836, A837, and A851, the highest concentration of this fraction is in

TABLE 2

**Monterey Oil A837 Biotreatment in Medium 2
and in the Absence of an Emulsifying Agent**

Microorganisms	Oil, %	Incubation, d	Extent of emulsification, Klett units	pH
BNL-4-23 control	0.503	21	380.000	5.50
BNL-NZ-3	0.543	21	1700.000	4.50
A837 control, oil	0.502	23	2000.000	4.50
BNL-4-23 control	0.000	20	79.000	5.30
BNL-NZ-3 control	0.000	20	60.500	3.70
BNL-4-23 control	0.000	20	74.500	4.50
BNL-NZ-3 control	0.000	20	65.500	3.80
BNL-4-22	0.492	20	259.155	5.5
BNL-4-23	0.483	20	110.245	5.5
BNL-NZ-3	0.497	20	188.6	5
A837 control	0.486	20	5.19	5
BNL-4-22 control	0.000	20	342.155	5
BNL-4-23 control	0.000	20	139.235	5.1
BNL-NZ-3 control	0.000	20	6.09	5
Control/control	0.000	20	4.58	5.4

TABLE 3

**Monterey Oil A837 Biotreatment in Media 2 and 3
in the Presence of an Emulsifying Agent***

Microorganisms	Medium	Oil, %	Incubation, d	Extent of emulsification, Klett units	pH
BNL-4-23	2	0.479	21	2000.000	5.50
BNL-NZ-3	2	0.496	20	1880.000	3.75
A837 control, oil	2	0.487	23	255.000	3.50
BNL-4-23 control	2	0.000	20	95.000	4.50
BNL-NZ-3 control	2	0.000	20	67.000	4.30
A837 control, oil	2	0.487	22	195.000	4.00
BNL-4-23 control	2	0.000	20	82.500	4.50
BNL-NZ-3 control	2	0.000	20	69.500	4.00
BNL-4-22	3	0.567	20	13.000	3.50
BNL-4-23	3	0.510	20	9.000	3.50
Control, oil	3	0.500	20	7.000	3.50
BNL-4-22 control	3	0.000	20	26.000	3.50
BNL-4-23 control	3	0.000	20	15.000	3.50
Control/control (65 °C)	3	0.000	20	19.500	3.50
BNL-4-22	3	0.490	7	18.785	4.25
BNL-4-23	3	0.521	7	10.010	4.00
Control, oil	3	0.530	7	6.035	4.00
BNL-4-22 control	3	0.000	7	51.800	4.25
BNL-4-23 control	3	0.000	7	61.950	4.00
Control/control	3	0.000	7	10.285	4.25
Control, oil	3	0.488	7	7.300	5.5
BNL-4-22 control	3	0.000	7	5.150	5.25
BNL-4-23 control	3	0.000	7	5.125	5.5
Control/control	3	0.000	7	3.465	5.5

*Emulsifying agent is 0.0075% tergitol

A851. The overall redistribution of the relative amounts of heavy and light hydrocarbons is shown in Figs. 1 and 2. The results also show that BNL-4-22 and BNL-4-23 are not very effective in the biotreatment of A851. BNL-NZ-3, on the other hand, is remarkably effective.

TABLE 4

**Biotreatment of Monterey Oil A851 in Medium 3
in the Absence of an Emulsifying Agent**

Microorganisms	Medium	Oil, %	Incubation, d	Extent of emulsification, Klett units	pH
BNL-4-22	3	0.505	7	2.500	3.5
BNL-4-23	3	0.511	7	2.500	3.5
Control, oil	3	0.447	7	0.500	3.5
BNL-4-22 control	3	0.000	7	5.000	3.5
BNL-4-23 control	3	0.000	7	0.500	3.5
Control/control	3	0.000	7	0.000	3.5
BNL-4-22	3	0.484	7	6.270	5.5
BNL-4-23	3	0.476	7	3.950	5.5
BNL-NZ-3	3	0.476	7	6.035	5.5
Control, oil	3	0.480	7	3.660	5.5
BNL-4-22 control	3	0.000	7	3.500	5.5
BNL-4-23 control	3	0.000	7	2.815	5.5
BNL-NZ-3 control	3	0.000	7	0.505	5.5
Control/control	3	0.000	7	0.031	5.3
BNL-4-22	3	0.483	7	6.470	5.0
BNL-4-23	3	0.476	7	3.850	5.0
BNL-NZ-3	3	0.476	7	4.500	5.0
Control, oil	3	0.480	7	2.250	6.0
BNL-4-22 control	3	0.000	7	3.065	5.8
BNL-4-23 control	3	0.000	7	2.175	5.9
BNL-NZ-3 control	3	0.000	7	3.170	5.9
Control/control	3	0.000	7	0.185	6.0
Average of 7 d					
BNL-4-22	3	0.491	7	5.508	5.0
BNL-4-23	3	0.488	7	3.265	5.0
BNL-NZ-3	3	0.476	7	5.275	5.8
Control, oil	3	0.469	7	2.135	5.0
BNL-4-22 control	3	0.000	7	3.550	4.9
BNL-4-23 control	3	0.000	7	1.825	5.0
BNL-NZ-3 control	3	0.000	7	2.105	5.7
Control/control	3	0.000	7	0.080	4.9
BNL-4-21 (65 °C)	3	0.628	7	3.355	5.5
BNL-4-22 (65 °C)	3	0.628	7	4.220	5.5
BNL-4-23 (65 °C)	3	0.625	7	3.335	5.5
BNL-NZ-3 (65 °C)	3	0.629	7	4.020	5.5
Control, oil (65 °C)	3	0.626	7	3.615	5.5
BNL-4-21 control (65 °C)	3	0.628	7	1.160	5.5
BNL-4-22 control (65 °C)	3	0.000	7	3.760	5.5
BNL-4-23 control (65 °C)	3	0.000	7	1.970	5.5
BNL-NZ-3 control (65 °C)	3	0.000	7	3.275	5.5
Control/control (65 °C)	3	0.000	7	2.915	5.5
BNL-6-32 (65 °C)	949	0.476	7	20.310	5.3
Control, oil (65 °C)	949	0.480	7	8.530	4.5
BNL-6-32 control (65 °C)	949	0.000	7	28.265	4.9
Control/control (65 °C)	949	0.000	7	26.170	4.4
BNL-4-22	3	0.477	20	2.335	4.8
BNL-4-23	3	0.481	20	1.015	4.3
Control, oil	3	0.493	20	1.830	4.5
BNL-4-22 control	3	0.000	20	14.595	4.3
BNL-4-23 control	3	0.000	20	5.365	4.0
Control/control	3	0.000	20	9.770	4.0
BNL-4-22	3	0.484	20	12.605	5.5
BNL-4-23	3	0.484	20	14.205	5.5
BNL-NZ-3	3	0.476	20	6.720	5.0
Control, oil	3	0.480	20	1.070	5.5
BNL-4-22 control	3	0.000	20	9.080	5.0
BNL-4-23 control	3	0.000	20	3.670	5.0
BNL-NZ-3 control	3	0.000	20	5.105	5.5
Control/control	3	0.000	20	3.160	5.5
BNL-4-22 control	3	0.000	20	5.105	5.0

Further biochemical evidence that supports a mechanism or mechanisms by which microorganisms may interact with crude oils by converting the complex N, S, O structure is offered by a comparative chromatographic analysis of organosulfur compounds present in Monterey A836, A837,

TABLE 5

**Biotreatment of Monterey Oil A851 in Medium 2
in the Absence of an Emulsifying Agent**

Microorganisms	Oil, %	Incubation, d	Extent of emulsification, Klett units	pH
BNL-4-23	0.537	22	2000.000	5.50
BNL-NZ-3	0.490	21	2000.000	4.50
A851 control, oil	0.516	21	1280.000	5.25
BNL-4-23 control	0.000	20	79.000	5.30
BNL-NZ-3 control	0.000	20	60.500	3.70
BNL-4-23 control	0.000	20	74.500	4.50
BNL-NZ-3 control	0.000	20	65.500	3.80
BNL-4-22	0.482	7	282.310	5.00
BNL-4-23	0.480	7	155.935	5.50
BNL-NZ-3	0.479	7	130.510	5.50
A836 control	0.494	7	5.900	5.00
BNL-4-22 control	0.000	7	309.785	5.50
BNL-4-23 control	0.000	7	183.655	5.50
BNL-NZ-3 control	0.000	7	111.665	5.00
Control/control	0.000	7	1.685	5.00
BNL-4-22	0.478	20	407.525	4.50
BNL-4-23	0.476	20	116.25	5.50
BNL-NZ-3	0.490	20	261.07	4.00
A836 control	0.484	20	60.98	5.50
BNL-4-22 control	0.000	20	342.155	5.00
BNL-4-23 control	0.000	20	139.235	5.10
BNL-NZ-3 control	0.000	20	6.09	5.00
Control/control	0.000	20	4.58	5.40

TABLE 6

**Biotreatment of Monterey Oil A851 in Media 2 and 3
in the Presence of an Emulsifying Agent**

Microorganisms	Medium	Oil, %	Incubation, d	Extent of emulsification, Klett units	pH
BNL-4-23	2	0.490	20	940.000	5.3
BNL-NZ-3	2	0.511	20	1360.000	3.5
A851 control	2	0.494	23	1380.000	5.0
BNL-4-23 control	2	0.000	20	95.000	4.5
BNL-NZ-3 control	2	0.000	20	67.000	4.3
BNL-4-22 control	3	0.510	7	10.900	4.0
BNL-4-23 control	3	0.517	7	13.900	4.25
Control, oil	3	0.488	7	5.450	4.0
BNL-4-22 control	3	0.000	7	51.800	4.25
BNL-4-23 control	3	0.000	7	61.950	4.0
Control/control	3	0.000	7	10.285	4.25
Control, oil	3	0.480	7	58.425	5.25
BNL-4-22 control	3	0.000	7	5.150	5.25
BNL-4-23 control	3	0.000	7	5.125	5.5
Control/control	3	0.000	7	3.465	5.5
BNL-4-22	3	0.504	20	19.000	3.50
BNL-4-23	3	0.505	20	12.500	3.50
Control, oil	3	0.485	20	11.000	3.50
BNL-4-22 control	3	0.000	20	26.000	3.50
BNL-4-23 control	3	0.000	20	15.000	3.50
Control/control	3	0.000	20	19.500	3.50

Fig. 1 Gas chromatography-mass spectroscopy (GC-MS) fragmentograms, m/z 57, Monterey crude A837 treated with BNL-4-22, BNL-4-23, and BNL-NZ-3.

and A851 before and after biotreatment. The extent of bioconversion of the crude oils varies with different microorganisms used. Biotreatment of Monterey A836 with BNL-4-22 and BNL-4-23 results in changes of organosulfur composition as reported in the previous quarterly report. These changes differ from those caused by the biotreatment of A836 with BNL-NZ-3 as shown in Fig. 3. Relative to control there is a compositional change without an overall decrease in organic sulfur content. However, biotreatment of Monterey A837 with BNL-4-22, BNL-4-23, and BNL-NZ-3 under identical experimental

Fig. 2 Gas chromatography-mass spectroscopy (GC-MS) fragmentograms, m/z 57, Monterey crude A851 control treated with BNL-4-22, BNL-4-23, BNL-NZ-3, pyrolyzed, and pyrolyzed with BNL-NZ-3.

conditions results in a significant overall decrease in organic sulfur content as shown in Figs. 4 and 5.

In this series of experiments, the Monterey A851, an onshore highly biodegraded California crude oil, was considered a test case in terms of differentiation of biotreated and

Fig. 3 Gas chromatographic trace with flame photoemission detector (FPD) of (a) Monterey A336 control; (b) Monterey A337 treated with BNL-NZ-3, Medium 3, 7 d, no tergitol.

biodegraded crude oil. Biotreatment of this crude oil further indicated the importance of diagnostic evaluation of the biotreatment [i.e., an initial small-scale evaluation of the microorganism's potential for microbial enhanced oil recovery (MEOR)].

Fig. 4 Gas chromatographic trace with flame photoemission detector (FPD) of (a) Monterey A336 control; (b) Monterey A337 treated with BNL-4-22; (c) Monterey A337 treated with BNL-NZ-3, Medium 3, 7 d, no tergitol.

Fig. 5 Gas chromatographic trace with flame photoemission detector (FPD) of (a) Monterey A337 control; (b) Monterey A337 treated with BNL-NZ-3, Medium 3, 7 d, no tergitol.

All the experiments referred to in this discussion were run under identical experimental conditions for sample treatment, concentration, and chromatographic conditions. Thus treatment of A851 with BNL-4-22 and BNL-4-23 had no effect, as shown in Figs. 2 and 6. However, treatment of A851 with BNL-NZ-3 resulted in major changes in the composition of A851, as shown in Figs. 2 and 7. This thermophilic isolate breaks down A851 into a much more volatile hydrocarbon mixture (see Fig. 2) with a significant increase in the lower molecular weight ($<C_{30}$) hydrocarbons.

The flame photoemission detector (FPD) gas chromatographic trace shown in Fig. 7 is consistent and supports further the proposed mechanism(s) that the initial biochemical reactions may occur in the heavy N, S, O portion of asphaltenes.⁵ A qualitative test for crude is offered by a comparison of the two FPD scans in Fig. 7. To plot the FPD

Fig. 6 Gas chromatographic trace with flame photoemission detector (FPD) of (a) Control; (b) Monterey A851 + BNL-4-22; (c) Monterey A851 + BNL-4-23. Medium 3, 7 d, no tergitol.

traces in a manner consistent with previous analysis, the sensitivity of the chromatograph (i.e., attenuation) was set at 32. At that setting, the response was off-scale (Fig. 7a) and the sensitivity had to be reduced by 50% to 64 (Fig. 7b) to get a full response on that scale. This chromatographic analysis result indicates that the biotreatment causes a substantial breakdown and conversion of the complex structures associated with heavy crude oils.

Pyrolysis of A851 at 640 °C produced a volatile fraction with some enrichment in the lighter ends of the crude; however, this method is not very effective when compared to biotreatment. Pyrolysis at 640 °C of the BNL-NZ-3 treated oil produced a hydrocarbon product whose gas chromatograph-mass spectrometer (GC-MS) fragmentogram compares to the nonpyrolyzed one (Fig. 2); however, it also produced a loss of very light fraction in the 1200–1800 (C_{10} – C_{18}) scan region. The FPD scans (Fig. 8) are consistent with the GC-MS results.

Fig. 7 Gas chromatographic trace with flame photoemission detector (FPD) of Monterey A851 crude treated with BNL-NZ-3. Medium 3, 7 d, no tergitol. (a) scan at attenuation of 32 and (b) at attenuation 64 (see text for discussion).

Comparative experiments are continuing. Analysis by X-ray absorption near-edge structure (XANES) spectrometry has also been expanded to a number of other oils.

Construction of Coreflooding Systems

The first generation of a coreflooding apparatus has been designed and constructed. The core bioreactor was constructed from a 304 stainless $1\frac{1}{2}$ × 12 in. tube with a thickness

Fig. 8 Chromatographic trace with flame photoemission detector (FPD) of (a) Monterey A851 crude treated with BNL-NZ-3 and then (b) analyzed by pyrolysis-gas chromatography (PY-GC), Medium 3, 7 d, no tergitol.

of 0.065 in. and can be operated up to a pressure of 2600 psi. The tube can be treated under controlled conditions and various pressures. Cores made of Berea sandstone cut to appropriate size are introduced into the tube and a tight fit achieved by means of an epoxy treatment of the core. Several coreflooding experiments are under way. Details of the construction, the flow diagram, and preliminary results will be reported upon completion of this series of experiments.

Microscopic Comparison of Reaction Mixtures

The effects on crude oils that result from the biotreatment of the crude oils as described in preceding paragraphs are different from the effects of biodegradation that may occur in the reservoir over geological periods of time. Results obtained from comparative studies of interaction between different crude oils and microorganisms deliberately introduced for the purposes of biotreatment suggest that the process(es) may be driven by the introduced and not indigenous microorganisms. Concurrent with chemical analysis, a microscopic analysis of reaction mixtures was initiated. In all three sets of experiments, Medium 2 was used [i.e., a medium that contains 0.0075% of added organic nutrient (other than the crude oil)].⁵ This was done deliberately to encourage the growth of indigenous microorganisms. In all cases the microscopic characteristics change drastically upon the introduction of the test organisms. Continuing comparative and microscopic studies should ultimately lead to a better understanding of the reaction mixtures' (see refs.) components and their influence on the formation of products.

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NOVEL TECHNOLOGY

A NOVEL APPROACH TO MODELING UNSTABLE ENHANCED OIL RECOVERY DISPLACEMENTS

Contract No. DE-AC22-90BC14650

**University of Texas at Austin
Austin, Tex.**

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**Principal Investigator:
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**Project Manager:
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Objective

The objective of this research is to develop a methodology for predicting the performance of unstable displacements in heterogeneous reservoirs. A performance prediction approach that integrates numerical modeling with laboratory imaging experiments will be developed. Flow visualization experi-

ments will be performed on laboratory corefloods using X-ray Computerized Tomography (CT) and other imaging technologies to map the in situ fluid saturations in time and space. A systematic procedure will be developed to replicate the experimental image data with high-resolution numerical models of the displacements. The well-tuned models will then be used to scale the results of the laboratory coreflood experiments to heterogeneous reservoirs in order to predict the performance of unstable displacements in such reservoirs.

Summary of Technical Progress

A new procedure was derived to simplify the analysis, numerical modeling, and scaling of laboratory coreflood experiments. The procedure consists of the following steps:

1. Image the coreflood by CT to obtain the temporal and spatial saturation profiles.
2. Transform the saturation profiles by means of a dimensionless self-similarity variable to obtain a unique, dimensionless response function that is characteristic of the coreflood.
3. History-match the characteristic response function for the coreflood with a numerical simulator.
4. Compare the experimental and computed saturation profiles and recovery curves for the coreflood after a satisfactory match.
5. Scale the results of the laboratory coreflood experiment to other systems with the well-tuned numerical model.

Steps 1 through 4 of this procedure were demonstrated in previous quarterly reports. In the first report, a dimensionless self-similarity variable (x_p/t_p) was derived for two phase immiscible displacement and then used to transform the saturation profiles of two laboratory corefloods to obtain their characteristic dimensionless response functions (steps 1 and 2). In the second report, steps 3 and 4 of the procedure were demonstrated by numerically simulating the two corefloods. In this report the foundation is laid for implementing step 5 of the procedure. The heterogeneous permeable media to be used in implementing step 5 are presented and discussed.

Measures of Reservoir Heterogeneity

The heterogeneous permeable media to be used in the scaling studies were generated geostatistically and characterized by two measures of heterogeneity: the Dykstra-Parsons coefficient (DP) and the dimensionless spatial correlation length (l_x). The Dykstra-Parsons coefficient is a measure of the permeability variation in the permeable medium.¹ It is defined as:

$$DP = \frac{(k)_{0.5} - (k)_{0.5+1}}{(k)_{0.5}} \quad (1)$$

where $(k)_{0.5}$ is the median of the permeability and $(k)_{0.5+1}$ is one standard deviation below the median. It is calculated from a set of permeability data arranged in increasing or decreasing order. The data are plotted on a log-probability paper, and $(k)_{0.5}$ and $(k)_{0.5+1}$ are read from a best fit line through the data. When DP is zero, there is no permeability variation with respect to location and the resulting permeable medium is homogeneous. As DP increases, the permeability variation increases and the permeable medium becomes more and more heterogeneous. When DP is one, the medium is "infinitely" heterogeneous. Thus a DP between zero and one represents the degree of heterogeneity of the permeable medium.

The spatial correlation length is a measure of the distance over which neighboring permeability values are related to one another. The correlation length can be determined from the variogram which is the variance of the differences between the permeabilities at two locations separated by a distance h (Ref. 2). The variogram is calculated as

$$\gamma(h) = \text{Var}[k(x) - k(x+h)]/2 \\ = \sum[k(x) - k(x+h)]^2/2N(h) \quad (2)$$

Here, $k(x)$ is the permeability at location (x) , $k(x+h)$ is the permeability at location $(x+h)$, $N(h)$ is the number of data pairs separated by the distance h , and $\gamma(h)$ is the variogram. The distance h is called the lag distance. When the variogram is plotted against the lag distance (h) , its value increases with increasing h until a certain distance is reached at which the variogram levels off. The value of h at which the variogram

levels off is the correlation length, or the range of influence, and the value of the variogram at this point is called the sill. If the correlation length is zero, then the permeability at a given location is independent of its neighbors and the resulting permeability distribution is fully random. With increasing correlation length, the range of influence of one permeability on its neighbors increases up to a distance equal to the correlation length. In the limiting case, when the correlation length approaches infinity, all the permeability values will be the same and a homogeneous medium will result. It should be noted that the correlation length is a directional quantity which can be different in different directions.

In this study, the dimensionless correlation length in the direction of bulk flow (l_x) or the x -direction was varied, while the dimensionless correlation length in the direction perpendicular to that of the bulk flow (l_y) or the y -direction was held constant. The correlation lengths were made dimensionless by dividing the correlation length in a given direction by the length of the permeable medium in that direction.

Results and Discussion

The permeability distributions were generated geostatistically in two dimensions with a computer program developed at the University of Texas at Austin.² The computer program is based on the Turning Bands Method.¹

Twelve stochastic permeability fields were generated to cover a wide range of DP and correlation length. Figure 1 shows a schematic layout of the twelve fields together with the average permeability and the standard deviation for each field. Permeability fields were generated at DP's of 0.01, 0.55, and 0.87 and dimensionless correlation lengths of 0, 0.2, 0.7, and 2.0. A DP of 0.01 represents a nearly homogeneous medium, whereas a DP of 0.89 represents an

	DP = 0.01	DP = 0.55	DP = 0.87
$l_x = 0.0$	$\mu = 9.261 \text{ D}$ $\sigma = 0.101 \text{ D}$	$\mu = 9.350 \text{ D}$ $\sigma = 8.652 \text{ D}$	$\mu = 9.242 \text{ D}$ $\sigma = 40.94 \text{ D}$
$l_x = 0.2$	$\mu = 9.266 \text{ D}$ $\sigma = 0.095 \text{ D}$	$\mu = 9.354 \text{ D}$ $\sigma = 8.308 \text{ D}$	$\mu = 7.400 \text{ D}$ $\sigma = 26.167 \text{ D}$
$l_x = 0.7$	$\mu = 9.239 \text{ D}$ $\sigma = 0.104 \text{ D}$	$\mu = 7.845 \text{ D}$ $\sigma = 6.301 \text{ D}$	$\mu = 4.708 \text{ D}$ $\sigma = 9.758 \text{ D}$
$l_x = 2.0$	$\mu = 9.233 \text{ D}$ $\sigma = 0.105 \text{ D}$	$\mu = 7.509 \text{ D}$ $\sigma = 6.444 \text{ D}$	$\mu = 4.622 \text{ D}$ $\sigma = 10.753 \text{ D}$

Fig. 1 Schematic layout of the simulated permeability fields. μ = mean, σ = standard deviation.

extremely heterogeneous medium. Petroleum reservoirs typically have DPs that range from 0.6 to 0.8. A correlation length of zero represents an uncorrelated or random permeability distribution; a correlation length of 0.2 represents mild correlation; a correlation length of 2.0 represents extremely strong correlation. Depending on the depositional environment, petroleum reservoirs can have widely different correlation lengths. The value of L_y was constant at 0.2 for the permeability fields generated in this study.

Permeability maps were generated for the twelve permeability fields. Two observations can be made from these maps

First, as the correlation length (L_x) increases, the permeability distributions become more and more stratified. The number of layers is inversely proportional to L_x . In fact, as L_x approaches infinity, for $L_y = 0.2$, the permeability distribution will consist of exactly five ($1/0.2$) distinct homogeneous layers. Second, with increasing DP, at a given L_x , the contrast in the permeability values increases while their spatial arrangements remain similar. Figure 2 shows the permeability histograms which indicate that the permeability fields are log-normally distributed in accordance with observations in sedimentary rocks. Figure 3 shows the variograms for the

Fig. 2 Permeability histograms.

twelve permeability fields which give a visual impression of the degree of correlation in each permeability field.

Conclusions

The heterogeneous permeable media to be used in scaling laboratory corefloods have been presented and discussed. In the next report, an unstable laboratory waterflood in a homogeneous sandpack will be scaled to predict the expected performance in the heterogeneous reservoirs presented in this report.

Nomenclature

DP	Dykstra-Parsons coefficient
h	Lag distance
k	Absolute permeability
L_x	Dimensionless correlation length in the x direction
L_y	Dimensionless correlation length in the y direction
N	Number of data pairs
γ	Variogram
μ	Mean of permeability field
σ	Standard deviation of log of permeability

Fig. 3 Permeability variograms in the x-direction.

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