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Contracts for field projects
and supporting research on . . .

Enhanced Oil Recovery

Reporting Period January–March 1993

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DOE/BC-93/2
(DE93000147)

PROGRESS REVIEW
Quarter Ending March 31, 1993

United States Department of Energy

Office of Gas and Petroleum Technology
and Bartlesville Project Office

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Quarterly Reports

DOE/BC-92/2 **Contracts for Field Projects and Supporting Research on Enhanced Oil Recovery. Progress Review No. 70. Quarter ending March 31, 1992. March 1993. 185 pp. Order No. DE93000110.** 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.

DOE/BC-92/3 **Contracts for Field Projects and Supporting Research on Enhanced Oil Recovery. Progress Review No. 71. Quarter ending June 30, 1992. June 1993. 140 pp. Order No. DE93000116.** 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-664 **1991 Annual Report. October 1, 1990-September 30, 1991. National Institute for Petroleum and Energy Research. May 1993. 84 pp. Order No. DE93000137.** The eighth year of research was completed under the cooperative agreement established in 1983 between the Department of Energy (DOE) and IIT Research Institute for operation of the National Institute for Petroleum and Energy Research (NIPER). During the year, research at NIPER was conducted in three areas: (1) enhanced oil recovery, (2) alternative fuels testing and evaluation, and (3) environmental technology. FY91 was the first year of research under the DOE National Energy Strategy - Advanced Oil Recovery Program, an integrated, highly targeted research, development, and demonstration program focusing on near-, mid-, and long-term objectives to bring new and advanced recovery technologies to the field within the earliest possible time frame.

Thermal Recovery

NIPER-578 **Feasibility Study of Heavy Oil Recovery in the Permian Basin (Texas and New Mexico). Topical Report. National Institute for Petroleum and Energy Research. May 1993. 40 pp. Order No. DE93000141.** This report is one of a series of publications assessing the feasibility of increasing domestic heavy oil production. Each report covers select areas of the United States. The Permian Basin of West Texas and Southeastern New Mexico is made up of the Midland, Delaware, Val Verde, and Kerr Basins; the North-western, Eastern, and Southern shelves; the Central Basin Platform, and the Sheffield Channel. The present day Permian Basin was one sedimentary basin until uplift and subsidence occurred during Pennsylvanian and early Permian Age to create the configuration of the basins, shelves, and platform of today. The basin has been a major light oil producing area served by an extensive pipeline network connected to refineries designed to process light sweet and limited sour crude oil. Limited resources of heavy oil (10° to 20° API gravity) occurs in both carbonate and sandstone reservoirs of Permian and Cretaceous Age. The largest cumulative heavy oil production comes from fluvial sandstones of the Cretaceous Trinity Group. Permian heavy oil is principally paraffinic and thus commands a higher price than asphaltic California heavy oil. Heavy oil in deeper reservoirs has solution gas and low viscosity and thus can be produced by primary and by waterflooding. Because of the nature of the resource, the Permian Basin should not be considered a major heavy oil producing area.

NIPER-675 **Evaluation of NIPER Thermal EOR Research, State-of-the-Art and Research Needs. Topical Report. National Institute for Petroleum and Energy Research. June 1993. 152 pp. Order No. DE93000145.** Research was conducted in elucidation of the mechanisms of steam oil recovery; effect of steam temperature on wettability modification; quantification of the temperature dependency of capillary pressures; development of techniques to measure capillary pressure of unconsolidated cores at steamflood conditions; elucidation of the mechanism of steam diversion with foam; development and evaluation of analytical and numerical thermal oil recovery models; field-scale simulation studies to assess the steamflood potential of non-California heavy oil reservoirs; domestic heavy oil database development; domestic heavy oil resource and refinery capacity assessment; thermal enhanced oil recovery environmental impact assessment; and laboratory automation software development and testing. This report summarizes the research that has been conducted under the program, analyzes the contributions of the research, describes how the technology was transferred to potential users, analyzes current trends in thermal research and thermal oil production, and makes suggestions for future research.

DOE/BC/14600-43 **Capillary Effects in Drainage in Heterogeneous Porous Media: Continuum Modeling, Experiments and Pore Network Simulations. Topical Report. University of Southern California. April 1993. 40 pp. Order No. DE93000134.** An investigation was conducted on the effects of capillary heterogeneity induced by variations in permeability in the direction of displacement in heterogeneous porous media under drainage conditions. The investigation is three-pronged and uses macroscopic simulation, based on the standard continuum equations, experiments with the use of an acoustic technique and pore network numerical models. It is found that heterogeneity affects significantly the saturation profiles, the effect being stronger at lower rates. A good agreement is found between the continuum model predictions and the experimental results based on which it can be concluded that capillary heterogeneity effects in the direction of displacement act much like a body force (e.g. gravity). A qualitative agreement

is also found between the continuum approach and the pore network numerical models, which is expected to improve when finite size effects in the pore network simulations diminish. The results are interpreted with the use of invasion percolation concepts.

DOE/BC/14600-45 Alkaline Assisted Thermal Oil Recovery: Kinetic and Displacement Studies.

Topical Report. University of Southern California. June 1993. 156 pp. Order No. DE93000144. This report deals with two major issues of chemical assisted flooding — the interaction of caustic, one of the proposed additives to steamflood, with the reservoir rock, and the displacement of oil by a chemical flood at elevated temperatures. A mathematical model is developed to simulate the kinetics of silica of silica dissolution and hydroxyl ion consumption in a typical alkaline flooding environment. The model is based on the premise that dissolution occurs via hydrolysis of active sites through the formation of an intermediate complex, which is in equilibrium with the silicic acid in solution. Both static (batch) and dynamic (coreflood) processes are simulated to examine the sensitivity of caustic consumption and silica dissolution to process parameters, and to determine rates of propagation of pH values.

DOE/BC/14600-48 Visualization and Simulation of Immiscible Displacement in Fractured Systems Using Micromodels: I. Drainage. Topical Report. University of Southern California. June 1993. 36 pp. Order No. DE93000146.

Consideration is given to drainage processes in model geometries that represent a matrix block-fracture system. Flow visualization in etched glass micromodels was carried out for various pairs of fluids, injection rates (capillary numbers) and viscosity ratio values. The experiments were then modeled with the use of a pore network simulator based on meniscus displacement. It was found that displacement occurs only in the fracture as long as the flow rate is below a critical value. Invasion of the matrix block occurs after this critical value (capillary number threshold) is exceeded. Numerical and experimental results were compared and found in good agreement. A theory for the invasion process and the critical capillary number was then developed. Displacement efficiencies were evaluated as a function of the capillary number and the mobility ratio. The process is reminiscent of a capillary pressure-saturation curve, with the notable exception that the role of capillary pressure is here played by the capillary number, and that the process is dynamic rather than quasi-static. Finally, effective relative permeabilities for the matrix-fracture system were calculated. Contrary to homogeneous systems, these curves depend on the mobility ratio.

DOE/BC/14600-42 Multivariate Optimization of Production Systems — The Time Dimension. SUPRI

TR 90. Stanford University. April 1993. 116 pp. Order No. DE93000131. Traditional analysis of oil and gas production systems treats individual nodes one at a time. This only calculates a feasible solution which is not necessarily optimal. Multivariate optimization is able to determine the most profitable configuration, including all variables simultaneously. The optimization can also find the optimal recovery over a period of time, rather than just at a single instant as in traditional methods. This report describes the development of multivariate optimization for situations in which the decision variables may change as a function of time. For example, instead of estimating a tubing size which is optimal over the life of the project, this approach determines a series of optimal tubing sizes which may change from year to year. Examples show that under an optimal strategy, tubing size can be changed only infrequently while still increasing profitability of a project. The methods used in this work considered the special requirements of objectives which are not smooth functions of their decision variables. The physical problems considered included artificial lift production systems.

Resource Assessment Technology

DOE/ID/12842-2 BOAST II for the IBM 3090 and RISC 6000. Final Report. May 1993. Louisiana

State University. 152 pp. Order No. DE93000138. BOAST II, a three-dimensional three-phase black oil applied simulation tool, was modified for efficient use on IBM mainframe computers. A vectorized code was prepared that will run on the IBM Risc 6000 workstation as well as other large scale platforms. Pre-processing and post-processing programs were written

to assist in data preparation and output analysis. This manual is a modification of the previously released manual by Fanchi, Kennedy, and Dauben. It was written to provide documentation for the revised software available as a result of the work done by Louisiana State University for the Department of Energy.

Fundamental Petroleum Chemistry

NIPER-659 The Thermodynamic Properties of Thian-

threne and Phenoxathin. Topical Report. National Institute for Petroleum and Energy Research. April 1993. 60 pp. Order No. DE93000124. Measurements leading to the calculation of the ideal-gas thermodynamic properties are reported for thianthrene (Chemical Abstracts registry number [92-85-3]) and phenoxathin (registry number [262-20-4]). 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 gas for both compounds for selected temperatures between 298.15 K and 700 K. The property-measurement results reported here for thianthrene and phenoxathin provide the first experimental gas-phase Gibbs energies of formation for tricyclic diheteroatom-containing molecules.

Microbial Technology

DOE/BC/14126-11 Microbial Field Pilot Study. Final Report. University of Oklahoma. May 1993. 216

pp. Order No. DE93000140. A multi well microbially enhanced oil recovery field pilot has been performed in the Southeast Vassar Vertz Sand Unit in Payne County, Oklahoma. The primary emphasis of the experiment was preferential plugging of high permeability zones for the purpose of improving waterflood sweep efficiency. Studies were performed to determine reservoir chemistry, ecology, and indigenous bacteria populations. Growth experiments were used to select a nutrient system compatible with the reservoir that encouraged growth of a group of indigenous nitrate-using bacteria and inhibit growth of sulfate-reducing bacteria. A specific field pilot area behind an active line drive waterflood was selected. Surface facilities were designed and installed. Injection protocols of bulk nutrient materials were prepared to facilitate uniform distribution of nutrients within the pilot area.

DOE/BC/14205-17 Mechanism and Environmental Effects on MEOR Induced by the Alpha Process.

Final Report. Alpha Environmental, Inc. April 1993. 108 pp. Order No. DE93000133. The purpose of this project was to investigate in parallel laboratory and field studies: (1) the response of a portion of the Shannon Sandstone reservoir to two single well treatments with a commercial microbial enhanced oil recovery (MEOR) system, (2) basic bacteria/rock interactions, and (3) mechanisms of oil release. The MEOR system consisted of a mixed culture of hydrocarbon utilizing bacteria, inorganic nutrients, and other growth factors. Parallel field and laboratory investigations into the effect and mechanisms of the treatment were carried out by independent principal investigators.

Geoscience Technology

DOE/ID/01570-T164 Alaska North Slope National Energy Strategy Initiative. Analysis of Five Un-

developed Fields. Idaho National Engineering Laboratory, EG&G, Inc. May 1993. 356 pp. Order No. DE93000142. The U.S. Department of Energy was directed in the National Energy Strategy to establish a federal interagency task force to identify specific technical and regulatory barriers to the development of five undeveloped North Slope Alaska fields and make recommendations for their resolution. The five fields are West Sak, Point Thomson, Gwydyr Bay, Seal Island/Northstar, and Sandpiper Island. Analysis of environmental, regulatory, technical, and economic information, and data relating to the development potential of the five fields lead to a number of conclusions discussed in this report.

NIPER-646 Techniques for Mapping the Types, Volumes, and Distribution of Clays in Petroleum Reservoirs and for Determining Their Effects on Oil Production. Final Report. National Institute for Petroleum and Energy Research. May 1993. 36 pp. Order No. DE93000143. This report presents the results of correlation of log signatures with information on distribution of the types and volumes of clays in sandstone pore spaces determined from detailed CT-scan, XRD, SEM, and thin section analyses of core samples from three sandstone reservoirs. The log signatures are then analyzed to determine if suitable mathematical/statistical parameter(s) could be calculated from the logs to determine their effects on permeability and oil production.

DOE/BC/14475-12 Geophysical and Transport Properties of Reservoir Rocks. Final Report for Task 4: Measurements and Analysis of Seismic Properties. University of California. May 1993. 176 pp. Order No. DE93000139. The principal objective of research on the seismic properties of reservoir rocks was to develop a basic understanding of the effects of rock microstructure and its contained pore fluids on seismic velocities and attenuation. Ultimately, this knowledge would be used to extract reservoir properties information such as the porosity, permeability, clay content, fluid saturation, and fluid type from borehole, cross-borehole, and surface seismic measurements to improve the planning and control of oil and gas recovery.

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Enhanced Oil Recovery**

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CHEMICAL FLOODING— SUPPORTING RESEARCH

RESPONSIVE COPOLYMERS FOR ENHANCED PETROLEUM RECOVERY

Contract No. DE-AC22-92BC14882

**University of Southern Mississippi
Hattiesburg, Miss.**

**Contract Date: Sept. 22, 1992
Anticipated Completion: Sept. 21, 1993
Government Award: \$273,400
(Current year)**

**Principal Investigators:
Charles McCormick
Roger Hester**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

The overall goal of this research is the development of advanced water-soluble copolymers for use in enhanced oil recovery which rely on reversible microheterogeneous associations for mobility control and reservoir conformance.

Summary of Technical Progress

Advanced Copolymer Synthesis

During the quarter synthetic efforts have centered on preparation of copolymers of acrylamide with a hydrophobic cationic comonomer, N,N-dimethyl-N-dodecyl-N-(2-acrylamidoethyl) ammonium bromide (DAMAB). These copolymers bind anionic surfactants strongly to form viscous solutions.

Monomer Synthesis

Figure 1 illustrates the synthesis of hydrophobically modified acrylamido monomer DAMAB. Into a 250-mL three-neck round-bottom flask were placed methylene chloride (82 mL), N,N-dimethylethylenediamine (8.82 g, 0.100 mol), and 6N sodium hydroxide (25 mL). The mixture was placed in an ice bath and agitated by a magnetic stirrer under nitrogen atmosphere. When the temperature dropped below 5 °C, acryloyl chloride (9.36 g, 0.104 mol) in 20 mL of methylene chloride was added slowly from an addition funnel to maintain the temperature below 10 °C. The mixture was stirred for an additional 30 min after complete addition of acryloyl chloride. The organic layer was then separated, washed twice with water and once with concentrated NaCl solution, and dried over anhydrous sodium sulfate. The solvent was removed on a rotary evaporator to yield a slightly yellow oil (11.67 g, 80% yield). The crude product was purified by vacuum distillation in the presence of a small amount of

Fig. 1 Synthesis of N,N-dimethyl-N-dodecyl-N-(2-acrylamidoethyl) ammonium bromide (DAMAB) monomer.

phenothiazine as an inhibitor. A colorless oil was collected at 88 to 90 °C under vacuum of 0.5 mm Hg. IR (KBr) 3284 (N–H), 165 (C=O) cm^{-1} ; ^1H NMR (CDCl_3) δ 2.23 (s, 6 H), 2.46 (t, 2 H), 3.42 (m, 2 H), 5.55 to 5.60 (m, 2 H), 6.25 to 6.27 (m, 4 H), 7.53 (br, 1 H); ^{13}C NMR (CDCl_3) δ 36.45, 44.43, 57.29, 124.61, 130.59, 165.05.

Freshly distilled N-(N,N-dimethylaminoethyl)acrylamide (5.0 g, 0.035 mol) was then treated with dodecylbromide (13 g, 0.052 mol) under nitrogen at room temperature for 48 h. Excess dodecylbromide was decanted and the transparent gel remaining was placed in a freezer overnight. The resulting white solid was washed with two portions of ether and dried under vacuum. Further purification of the final product was accomplished by recrystallization from a 1 : 1 mixture of acetone and ether. Yield: 13.26 g (96%). m.p. 70.5 to 72 °C ^1H NMR (CDCl_3) δ 0.88 (t, 3 H), 1.25 to 1.34 (br m, 20 H), 1.76 (m, 2 H), 3.42 (s, 6 H), 3.82 (m, 4 H), 5.63 to 5.74 (m, 1 H), 6.28 to 6.48 (m, 2 H), 8.79 (br, 1 H); ^{13}C NMR (CDCl_3) δ 13.18, 21.71, 21.97, 25.36, 28.36, 28.55, 28.65, 30.94, 33.18, 50.89, 51.18, 64.39, 165.56.

Copolymerization in the Absence of External Surfactant

To a 1000-mL three-neck round-bottom flask equipped with a mechanical stirrer, a condenser, and a nitrogen inlet were added acrylamide (AM) and DAMAB in the desired ratio and 500 mL of deionized water. The total concentration of the monomers was kept 0.21 M. The solution was heated to 50 °C in a water bath with a small nitrogen stream passing through the system. Polymerization was then initiated by the addition of $\text{K}_2\text{S}_2\text{O}_8$ (0.0262 g, 9.71×10^{-5} mol in 3 mL of deionized water) via a syringe. Polymerization was conducted continuously at 50 °C for 6 h, and then the reaction was stopped by precipitating the polymer in 800 mL of acetone. The precipitated polymer was washed twice with acetone and vacuum dried. Conversion was 60 to 72%. Further purification was accomplished by redissolving the polymer in water and dialyzing against water with a 12,000 to 14,000-molecular-weight cutoff dialysis tubing for a week. The polymer was recovered by freeze drying.

Copolymerization in the Presence of Surfactant

Equimolar amounts of cetyltrimethylammonium bromide and DAMAB monomer were added with acrylamide to the polymerization system. The same procedure as in the previous case was followed for polymerization and polymer purification.

Solution Polymerization

A copolymer containing 5 mol % DAMAB in the feed was prepared via homogeneous solution polymerization. The AM (23.3 g, 0.328 mol) and DAMAB (6.79 g, 0.0173 mol) were dissolved in 300 mL *t*-butanol. The solution was deoxygenated with nitrogen for 30 min at 50 °C. AIBN (0.056 g, 3.4×10^{-4} mol) was then added to initiate the polymerization. Polymerization was conducted for 10 h. In this case, polymer precipitated from solution as polymerization continued. Purification procedure was as described for the heterogeneous polymerization. A quantitative yield was obtained.

Characterization of Molecular Structure

A Bruker AC-300 was used to record ^1H and ^{13}C NMR spectra. A Mattson 2020 Galaxy Series FTIR was used to obtain infrared spectra. Surface-tension measurements were performed with a Kruss Processor tensiometer K12 instrument at 25 °C. Viscosity measurements were conducted with a Contraves LS-30 low shear rheometer at a constant shear rate of 6 reciprocal seconds at 25 °C. Classical light-scattering studies were performed on a Chromatix KMX-6 low-angle laser light scattering spectrophotometer with a 2-mW He–Ne laser operating at 633 nm. Refractive index increments (dn/dc) were obtained using a Chromatix KMX-16 differential refractometer. Steady-state fluorescence measurements were made with a Spex Fluorolog-2 fluorescence spectrometer. Elemental analyses to determine bromine content were conducted by MHW Laboratories of Phoenix, Arizona. Characterization results are summarized in Table 1.

Solution Rheology

In the last progress report, relationships were developed to estimate the resistance of a polymer solution to movement in

TABLE 1
Structural Parameters
of the Copolymers

Copolymer	DAMAB content, mol %	$M_w \times 10^{-6}$
PAM	0	1.12*
R-C12-1	0.32	0.74*
BS-C12-4.3	4.3	0.95†
B-C12-4.7	4.7	1.04†
R-C12-5.1	5.1	0.46†
B-C12-10.5	10.5	1.12†

*Measurement was taken in deionized water.

†Measurement was taken in MeOH/H₂O mixture (50/50 by volume).

porous media as a result of extension of the polymer.¹ Solution resistance increased with polymer molecular weight, higher fluid velocities, and porous media geometries, which favored formation of extensional flow fields. For porous media composed of uniformly packed spheres, the sphere diameter defined the geometry and the propensity to produce extensional flow conditions.

The effects of the preceding parameter on fluid-flow resistance were expressed by

$$\Psi = \Psi_{\max}^{\epsilon} \quad (1)$$

where Ψ is the normalized solution mobility, $\Psi_{\max}$ is the maximum mobility change per volume fraction of polymer coils, and ϵ is an exponent that controls the extent to which the maximum mobility change conditions develop. $\Psi_{\max}$ was shown to be a function of polymer molecular properties and concentration. The exponent ϵ is a function of a Deborah number, N_{De} , which is a product of elongation rate, Γ , and polymer molecular response time, τ . When N_{De} increases, ϵ approached unity and Ψ approached $\Psi_{\max}$.

$$\epsilon = \frac{1 + \operatorname{erf}\left(\frac{N_{De} - \mu}{\sigma}\right)}{2} \quad (2)$$

Equation 2 defines ϵ . The dimensionless parameters μ and σ adjust for local variation of the porous media structure and/or the distribution of polymer molecular weights found in the solution.

The preceding analysis will now be expanded to sandstone reservoirs. The porosities, ϕ , in these reservoirs range from 0.1 to 0.4 and the permeabilities, k , vary from 1.0×10^{-10} to 3.0×10^{-8} cm² (10 to 3000 mD). For many sandstone reservoirs, ϕ can be related to k in the following manner.

$$\phi = a + b \log k \quad (3)$$

The parameters a and b vary with the particular reservoir. Woodbrine sandstone values for a and b are 0.465 and 0.025, respectively, where k is expressed in centimeter square dimensions.²

Although a sandstone reservoir is composed of compressed or consolidated sand particles, this porous medium can be crudely characterized by an average sand sphere diameter, d . This diameter can be estimated from ϕ and k values of the reservoir using the Kozeny-Carman relationship.³

$$d = \frac{1 - \phi}{\phi} \left(\frac{180 k}{\phi} \right)^{1/2} \quad (4)$$

The reservoir characteristic particle diameter, d , can be used to estimate the extension rate, Γ , for a fluid forced through the media at velocity, v . As previously discussed,¹

$$\Gamma = \frac{(2)^{1/2}}{\phi} \frac{v}{d} \quad (5)$$

The fluid velocity in the porous media, v , varies with distance from the wellhead. For cylindrical wells with volumetric injection rates Q through a pay length of L , the local fluid velocity at radial distance r can be calculated.

$$v = \frac{Q}{2\pi r L} \quad (6)$$

The combination of Eqs. 4, 5, and 6 shows that the fluid extension rates in sandstone near the wellhead can be determined by

$$\Gamma = \frac{Q}{\pi r L (1 - \phi)} \left(\frac{\phi}{360 k} \right)^{1/2} \quad (7)$$

If a relationship such as Eq. 3 is used to define porosity in terms of permeability, then the fluid extension rate is a function of only well injection rates, Q/L , reservoir permeability, k , and radial distance from the well, r .

The preceding relationship was used with Eq. 1 to model the relative near well reservoir resistance to injection of high-molecular-weight polyacrylamide solutions. With this model, Fig. 2 was constructed to show the solution to solvent resistance ratios, f_p/f_s , as a function of polymer molecular weight, M , solution dimensionless concentration, $[\eta]C$, reservoir permeability, k , and radial distance from the wellhead, r . A constant injection rate of 20 bbl per day per foot of pay was used to construct this figure.

Fig. 2 Predicted polyacrylamide dilute solution flow resistance in typical Woodbrine sandstones near a 6-in.-diameter wellhead at injection rates of 20 bbl per day per foot of pay. (a) $M = 5.0 \times 10^6$, $[\eta]C = 0.1$. (b) $M = 5.0 \times 10^6$, $[\eta]C = 0.25$. (c) $M = 10.0 \times 10^6$, $[\eta]C = 0.1$. (d) $M = 10.0 \times 10^6$, $[\eta]C = 0.25$. —, 10 mD. --, 20 mD. - · -, 40 mD.

Examination of Fig. 2 reveals the following:

1. Extension of polymer molecules, and thus increased fluid-flow resistance, occurs only very near the wellhead.
2. The total fluid-flow resistance, which is proportional to the area under a curve, increases with polymer molecular weight (compare condition a to c and b to d), polymer concentration (compare condition a to b and c to d), and lower reservoir permeabilities.
3. Complete polymer extension, and thus maximum fluid resistance, can easily develop with typical injection condition. This is shown by the flattening of the curves to zero slope under conditions c and d.
4. Although not shown by Fig. 2, an increase in wellhead fluid injection magnifies fluid-flow resistance significantly.

The preceding analysis was done for injection of dilute polymer solutions ($[\eta]C \leq 0.25$). Many of the arguments used to develop this extension model are less accurate or invalid as

polymer concentration increases. Usually polymer flooding solutions are much more concentrated ($[\eta]C > 0.50$). Under more concentrated conditions, fluid resistance as a result of polymer coil extension is expected to be much greater. Injection conditions with concentrated solutions can degrade the polymer because extensional forces exceed macromolecular covalent bonding forces. Future efforts will expand and experimentally validate the dilute solution extension model for more concentrated solutions and also explore polymer degradation in extensional flow fields.

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IMPROVING RESERVOIR CONFORMANCE USING GELLED POLYMER SYSTEMS

Contract No. DE-AC22-92BC14881

**University of Kansas
Center for Research
Lawrence, Kans.**

**Contract Date: Sept. 25, 1992
Anticipated Completion: Sept. 24, 1995
Government Award: \$707,123**

**Principal Investigators:
Don W. Green
G. Paul Willhite**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The general objectives of this project are to (1) identify and develop gelled polymer systems that have potential to improve reservoir conformance of fluid displacement processes, (2) determine the performance of these systems in bulk and in porous media, and (3) develop methods to predict the capability of these systems to recover oil from petroleum reservoirs.

This work focuses on three types of gel systems—an aqueous polysaccharide (KUSPI) system that gels as a function of pH, the chromium-based system where polyacrylamide and xanthan are cross-linked by Cr(III), and an organic cross-linked system. The KUSPI system will be developed, and a suitable organic cross-linked system will be evaluated and identified.

The laboratory research is directed at the fundamental understanding of the physics and chemistry of the gelation process in bulk form and in porous media. This knowledge will be used to develop conceptual and mathematical models of the gelation process. Mathematical models will then be extended to predict the performance of gelled polymer treatments in oil reservoirs.

Summary of Technical Progress

Task I—Development and Selection of Gelled Polymer Systems

Development of KUSPI and Derivatives

One goal was to determine if the polysaccharide that comprises the capsule of *Cellulomonas flavigena* is chemically modified by the alkali used for extraction of the polymer.

To that end, the encapsulated cells were extracted with dimethylsulfoxide (DMSO). Polysaccharide was precipitated from the DMSO extracts by the addition of isopropanol. The chemical composition of the polysaccharide prepared in this manner appeared to be identical to that of the alkali-extracted form (KUSPI). However, gels prepared from the polymer extracted with DMSO hold less water. This implied that the in vivo arrangement of the polysaccharide chains was disrupted by dissolution in alkali and that the polymer renatured in a different form when neutralized.

Carboxymethyl derivatives have been prepared from KUSPI. This was accomplished by treatment of the polysaccharide dissolved in alkali with chloroacetic acid. The acidic ether that was obtained by such treatment was soluble in water. The degree of polymerization has not yet been determined.

Selection of Organic Cross-Linking System To Be Investigated

A search of U.S. Patents and Society of Petroleum Engineers literature was conducted to identify gel systems applicable to permeability reduction treatments. A draft database containing twenty-six systems that contains entries for Description, Environmental Acceptability, Temperature Range, Gel Time, Gel Stability, pH Requirement, Composition, Applications, and Reference was constructed.

Criteria for the selection of an organic gel system were defined. The principal selection criterion dealt with environmental concerns and toxicity of the gel system. This criterion, termed Environmental Acceptance, was difficult to assess in that most gel systems contained chemicals that were considered toxic by some standard. A systematic approach of rating systems for Environmental Acceptance is being considered for further study. Three additional criteria for the selection of a gel system were (1) gel times on the order of several days to months, (2) wide temperature range with a minimum temperature of 25 °C, and (3) wide pH range that encompassed pH values between 6.0 and 8.0.

Three systems were selected for initial screening experiments. An aqueous system containing sulfonated resorcinol and formaldehyde formed gels as a result of a polycondensation reaction. The salt tolerance of the system increased with the use of sulfonated resorcinol rather than resorcinol. Sulfonation of the resorcinol was performed before the preparation of the gel system. Gel samples were prepared, maintained at 41 °F, and monitored for pH, viscosity, and visual formation of gel. Gel times, as determined from visual observation, were determined for selected concentrations of gel components, selected initial pH values of the gel solution, and selected salt concentration and type.

Observed gel times are given in Table 1 as a function of salt concentration obtained for a sulfonated resorcinol–formaldehyde system and for a similar (unsulfonated) resorcinol–formaldehyde system at 25 °C. The data show that gel time decreases with increased salt concentration and

TABLE 1
Effects of Salt Concentration and Sulfonation on Gel Time for a Resorcinol-Formaldehyde System

NaCl concentration, wt %	Gel time, h	
	Resorcinol-formaldehyde*	Sulfonated resorcinol-formaldehyde*
0.5	75	1600
1	34	
3	11	
5	8	190
7		64
8	7	50
9		38
10	7	28
13	6	21
15	6	16
20	4	12

*Compositions (wt %): Resorcinol-formaldehyde system—1.23% formaldehyde, 3.0% resorcinol, initial pH of 9.5. Sulfonated resorcinol-formaldehyde system—1.06% formaldehyde, 3.0% resorcinol, initial pH of 9.5; the resorcinol was sulfonated in a preliminary step using an additional 0.614% formaldehyde and 1.72% sodium sulfite (all concentrations based on final gel composition).

longer gel times were observed for the system prepared with *sulfonated* resorcinol. Gel times for both systems were less sensitive to salt concentration at higher salt content.

Screening experiments for two additional systems were planned. A cross-linked polymer system using organic compounds that contain at least two positively charged nitrogen atoms as the cross-linker will be studied. Examples of the cross-linker are salts of diamines, including alkylene diamines such as propylene diamine. These organic nitrogen compounds will be used to cross-link partially hydrolyzed polyacrylamide.

Initial experiments on an aluminum cross-linked polymer system are also planned. This system was attractive because of its low toxicity level and its similarity to the KUSPI gel system in that the gelation is triggered by a decrease in pH.

Task II—Physical and Chemical Characterization of Gel Systems

Rheological Characterization

The development of methods to monitor the gelation process as a function of time using rheometers was initiated. Central to these methods is the use of oscillatory shear where a gel sample is subjected to sinusoidal shear deformation at relatively low shear strain. Results from these types of experiments are commonly reported in graphical form showing the shear storage modulus (G') as a function of time. The storage modulus (sometimes referred to as the dynamic rigidity) is

directly proportional to the average energy storage in a cycle of deformation and is indicative of the buildup of structure or gelation. G' is determined from applying the linear theory of viscoelasticity to the oscillatory measurements, and thus the measurements must conform to the assumptions inherent in the theory. Measurements on a sample that conforms to these assumptions are said to be in the "Linear ViscoElastic Region" (LVER). Measurements are taken on samples to determine the LVER. Other conditions, in addition to determining the LVER, must be met in the rheometers in order to obtain reliable, reproducible, accurate, and precise data. These conditions include (1) gap loading, (2) no slip between sample and platens, and (3) reproducible preparation of gel samples. These factors are being evaluated for the gel systems being studied in this program.

Reproducible preparation of gel samples is inherent in acquiring reliable data. The history of the solutions used to make gel samples is critical for several types of systems. In particular, rheological properties of polyacrylamide solutions change with time because of the disentanglement of polymer molecules. In these systems, several days or weeks may be required after preparation of a stock solution before equilibrium is reached.

The physical characteristics of a gelling solution change significantly from the time of preparation through the development of the gel. The criteria described previously must be met throughout the gelation process. A systematic procedure is being developed to determine optimum conditions for rheological measurements and to assess the integrity of the data.

An example of the age of stock solutions affecting rheological measurements is shown in Fig. 1 where the development of storage modulus with time is plotted for samples prepared from stock solutions of selected ages. The storage modulus developed faster for samples prepared from fresher

Fig. 1 Effect of stock solution age on development of storage modulus for a polyacrylamide-Cr(III) system. 7500 ppm polyacrylamide; 100 ppm chromium; 2.0% NaCl; initial pH, 5.0; and temperature, 25 °C. Cone and plate diameter, 7.5 cm; angle, 0.96°; frequency, 10 Hz; and strain, 0.5.

stock solutions. The data show that these stock solutions must be aged for approximately 2 weeks before reproducible measurements can be obtained. In addition, care must be taken to ensure that biological activity is not degrading the polymer solutions.

Chemical Reaction Kinetics

A study was initiated to determine the effect of anion type and concentration on the gelation rate of the Cr(III)-polyacrylamide system. The same anion will be used for both the Cr(III) and the added salt. Anions to be studied are chloride, nitrate, perchlorate, sulfate, and acetate. Preliminary results have been obtained by monitoring gelation with a microviscometer. Portions of the sample are periodically removed, and the viscosity is determined at selected shear rates. The viscosity increased slowly for a period of time followed by a sharp increase, which indicated gelation. Future work will include gelation monitoring by oscillatory shear measurements.

Task III—Mechanisms of In Situ Gelation

Assembly, testing, and calibration of equipment for conducting flow experiments in porous media have begun. Initial flow experiments will be conducted with the KUSPI system.

Task IV—Mathematical Modeling of Gel Systems

Development of Mathematical Model(s) of Laboratory In Situ Gelation

Analysis of data collected in the laboratory has demonstrated that many fluid-rock interactions were rate controlled rather than equilibrium processes. For example, the pH of effluent from sandpacks and cores varies with injection rate. The version of the UTCHEM chemical flooding simulator does not model rate-controlled processes. Work is in progress to develop a simulator that incorporates kinetics of fluid-rock interactions.

A one-dimensional, single-phase, multicomponent simulator was developed and tested. Kinetic data for silica dissolution have also been mathematically modeled. Incorporation of the kinetic model into the simulator is being addressed.

Spring 1993 Meeting

An international meeting of people conducting research related to gelled polymer technology was scheduled for the spring of 1993. The purpose of this focused meeting was to enhance the exchange of information between different organizations. This meeting was canceled as a result of the scheduling of a Society of Petroleum Engineers (SPE) Forum on "Advances in Conformance Control" during August 1993. The SPE forum will accomplish the same purpose as that proposed for the University of Kansas meeting.

INVESTIGATION OF OIL RECOVERY IMPROVEMENT BY COUPLING AN INTERFACIAL TENSION AGENT AND A MOBILITY CONTROL AGENT IN LIGHT OIL RESERVOIRS

Contract No. DE-AC22-92BC14886

**Surtek, Inc.
Golden, Colo.**

**Contract Date: Sept. 28, 1992
Anticipated Completion: Sept. 30, 1995
Government Award: \$219,925
(Current year)**

**Principal Investigator:
Malcolm J. Pitts**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

The objective of this study is to investigate two major areas concerning coinjecting an interfacial-tension (IFT) reduction agent(s) and a mobility control agent. The first will consist of defining the mechanisms of interaction of an alkaline agent, a surfactant, and a polymer on a fluid-fluid and a fluid-rock basis. The second is the improvement of the economics of the combined technology.

This report examines the effect of different alkaline agents, surfactants, and combinations of surfactant and alkaline agents on the reduction of IFT between a fluvial deltaic crude oil and the aqueous solution. In addition, the effect of alkali and surfactant addition to polymer solution viscosity was evaluated. Finally, the effect of increasing temperature on the IFT characteristics and solution viscosity characteristics will be discussed.

Summary of Technical Progress

Crude Oil

Crude oil from the Adena field in Morgan County, Colo., was selected for use in the study. The Adena crude oil is a 42 °API gravity crude oil with a dead oil viscosity of 3.8 cP at 72 °F and 1.3 cP at the 180 °F reservoir temperature. This oil reservoir is defined as a fluvial deltaic sandstone.

Water

All solutions are dissolved in 1000 mg/L NaCl.

Interfacial Tension with Surfactant

The IFT was determined at 72 °F using either a spinning drop tensiometer¹ or a DuNouy ring tensiometer (ASTM D971). Surfactants were selected on the basis of commercial availability and structure variation. Surfactant concentrations of 0.1 and 0.2 active wt % were selected for study; field economic restraints on injected solutions were considered.

The results listed in Table 1 suggest that, for the linear alkyl aryl sulfonates, the IFT is lowest when the surfactant molecular weight (M.W.) is between 370 and 425 and increased when the M.W. either increased or decreased. Placing methyl groups on

the aromatic ring did not alter the IFT trend. With the branched side chain alkyl aryl sulfonate, the lowest IFT was achieved at 430 M.W.—slightly above the range observed with the linear side chain alkyl aryl sulfonates. In general, the branched alkyl aryl sulfonates gave lower IFT values. Again, the addition of a methyl group to the aromatic ring did not affect the interfacial trend. The internal bonding of the sulfonate group of the linear alkyl side chain did not have a significant effect on the IFT.

An aromatic ring in the structure resulted in lower IFT values regardless of the structure of the alkane surfactant. Varying the structure of the alkane surfactant as well as sulfonate vs. sulfate did not affect the IFT significantly.

TABLE 1
Interfacial Tension for Various Surfactants

Surfactant	Structure	Interfacial tension, mN/m	
		0.1 wt %	0.2 wt %
Linear alkyl group surfactants			
Naccanol 90F	Linear alkyl benzene sulfonate—M.W., 341; 11 carbon side chain	1.204	0.864
Polystep A-7	Linear alkyl benzene sulfonate—M.W., 348; 12 carbon side chain	0.936	1.662
LXS-370	Linear xylene sulfonate—M.W., 370; 11 to 12 carbon side chain	0.437	0.253
Petrostep B-120	Linear alkyl aryl sulfonate—M.W., 370; 13 to 14 carbon side chain	0.583	1.345
LXS-395	Linear xylene sulfonate—M.W., 395; 13 to 14 carbon side chain	0.590	0.836
LXS-420	Linear xylene sulfonate—M.W., 420; 15 to 16 carbon side chain	0.551	0.042
TRS 10-410	Linear alkyl aryl sulfonate—M.W., 423; 16 to 17 carbon side chain	3.745	1.672
LTS-18	Linear toluene sulfonate—M.W., 446; 18 carbon side chain	2.783	0.009
Petrostep B-105	Linear alkyl aryl sulfonate—M.W., 465; 20 to 21 carbon side chain	4.5	5.1
Linear alkyl group—internal bond to aryl functionality—group surfactants			
Petrostep H-67	Linear alkyl aryl sulfonate, alkyl group bonded to aryl group internally to give dialkyl side chain—M.W., 415; total side chain, 17 carbons	0.275	2.542
Branched alkyl group surfactants			
Petrostep B-100	Branched alkyl aryl sulfonate—M.W., 410; 16 to 17 carbon side chain	0.086	0.851
Chaser XP-100	Branched toluene sulfonate—M.W., 430; 16 to 17 carbon side chain	0.032	0.016
Petrostep B-110	Branched alkyl aryl sulfonate—M.W., 495; 20 to 21 carbon side chain	2.007	2.411
Internal olefin sulfonates			
Neodol IOS 1517	Internal olefin sulfonate—M.W., 348; 15 to 17 carbon chain	0.9	1.5
Neodol IOS 1720	Internal olefin sulfonate—M.W., 380; 17 to 20 carbon chain	2.0	1.8
Alpha olefin sulfonates			
AOS 12	Alpha olefin sulfonate—M.W., 270; 12 carbon chain	4.766	4.243
Bioterger AS-40	Alpha olefin sulfonate—M.W., 314; 14 to 16 carbon chain	0.931	2.151
Sulfonated linear alkane			
Bioterger PAS 8S	Alkane sulfonate—M.W., 216; 8 carbon chain	1.946	4.182
Sulfonated ethoxylated linear alkane			
Avanel S-30	Sulfonated ethoxylated alkane, 3 mol ethylene oxide—M.W., 383; 12 to 15 carbon chain	1.022	1.349
Sulfated linear alkane			
Stepanol WAC	Sodium laurel sulfate—M.W., 288; 12 carbon chain	1.727	1.806
Sulfated ethoxylated linear alkane			
Neodol 25-3S	Sulfated ethoxylated alcohol—M.W., 399; 12 to 15 carbon chain	1.595	1.473

Interfacial Tension with Surfactant Plus Alkaline Agents

The IFT between the Adena crude oil and various surfactants combined with the five alkaline agents was determined. Alkaline agents dissolved with the surfactants were sodium carbonate (Na_2CO_3)–sodium bicarbonate (NaHCO_3), sodium hydroxide (NaOH), and sodium dibasic phosphate (Na_2HPO_4)–sodium tribasic phosphate (Na_3PO_4). With some surfactants,

the multi basic alkaline agents were tested with each component individually as well as with a 2:1 and a 1:2 mixture. Alkaline agent concentrations between 0.50 and 2.0 wt % were tested. A 2.0 wt % limit was imposed as a result of economic restraints on an injected chemical solution in a field application. Surfactant concentrations were 0.1 and 0.2 active wt %. The minimum IFT values for the various surfactant–alkaline agent combinations are listed in Table 2.

TABLE 2
Interfacial Tension for Various Surfactant–Alkaline Agent Combinations

Surfactant	Alkali	Minimum interfacial tension, mN/m		Alkali concentration, wt %		pH	
		0.1 wt %*	0.2 wt %*	0.1 wt %*	0.2 wt %*	0.1 wt %*	0.2 wt %*
Linear alkyl aryl surfactants							
Nacconol 90F	NaOH	0.171	0.285	1.50	2.00	12.33	12.64
	Na ₂ CO ₃	0.621	0.680	2.00	2.00	11.54	11.02
	NaHCO ₃	0.729	0.677	1.00	2.00	9.20	9.18
	Na ₃ PO ₄	0.338	0.580	1.00	1.00	11.86	11.56
	Na ₂ HPO ₄	0.866	0.907	1.00	2.00	8.75	8.76
Polyster A-7	NaOH	0.143	0.274	2.00	1.50	12.95	12.30
	Na ₂ CO ₃	0.426	0.340	2.00	1.50	11.15	11.02
	NaHCO ₃	0.337	0.362	2.00	2.00	9.09	9.10
	Na ₃ PO ₄	0.218	0.244	1.50	2.00	12.12	12.67
	Na ₂ HPO ₄	0.395	0.322	2.00	2.00	8.84	8.96
LXS 370	NaOH	0.009	0.017	1.00	0.75	12.44	12.89
	Na ₂ CO ₃	0.011	0.001	0.75	1.50	11.08	11.13
	NaHCO ₃	0.015	0.002	2.00	2.00	9.83	9.63
	Na ₃ PO ₄	<0.001	0.018	0.50	2.00	12.13	12.29
	Na ₂ HPO ₄	0.369	0.001	1.00	1.00	8.92	8.60
Petrostep B-120	NaOH	0.012	0.008	2.00	2.00	13.55	13.81
	Na ₂ CO ₃	0.001	0.001	1.25	1.25	12.16	11.45
	NaHCO ₃	0.270	1.390	2.00	2.00	8.98	8.98
	Na ₃ PO ₄	<0.001	<0.001	0.50	0.50	12.17	12.33
	Na ₂ HPO ₄	0.085	0.117	2.00	2.00	8.91	8.89
LXS 395	NaOH	0.023	<0.001	0.50	1.00	12.68	12.84
	Na ₂ CO ₃	0.011	0.011	1.00	0.75	11.58	11.22
	NaHCO ₃	0.015	0.018	1.00	1.00	9.86	9.79
	Na ₃ PO ₄	0.017	0.018	0.75	2.00	12.12	12.27
	Na ₂ HPO ₄	0.051	0.022	0.50	1.00	8.59	8.73
LXS 420	NaOH	0.004	0.056	0.50	0.50	12.11	12.39
	Na ₂ CO ₃	0.007	0.017	0.50	0.50	10.71	10.22
	NaHCO ₃	0.032	0.037	0.50	0.50	8.85	9.09
	Na ₃ PO ₄	0.037	0.017	0.50	0.50	11.62	11.60
	Na ₂ HPO ₄	0.032	0.032	0.50	0.50	8.61	8.30
TRS 10-410	NaOH	0.001	0.006	0.50	0.75	12.33	12.59
	Na ₂ CO ₃	0.002	0.034	1.50	1.50	11.23	11.09
	NaHCO ₃	0.062	0.034	2.00	1.50	9.37	8.93
	Na ₃ PO ₄	0.001	<0.001	1.25	0.50	11.60	11.50
	Na ₂ HPO ₄	0.007	0.015	1.25	1.50	8.97	9.04
LTS-18	NaOH	0.004	0.019	2.00	0.50	13.03	12.69
	Na ₂ CO ₃	0.093	0.109	1.25	0.50	11.21	11.13
	NaHCO ₃	0.114	0.260	2.00	0.75	8.43	8.50
	Na ₃ PO ₄	0.047	0.036	2.00	2.00	12.12	12.12
	Na ₂ HPO ₄	0.120	0.056	2.00	0.50	8.86	8.65

(Table continues on next page.)

Table 2 (Continued)

Surfactant	Alkali	Minimum interfacial tension, mN/m		Alkali concentration, wt %		pH	
		0.1 wt %*	0.2 wt %*	0.1 wt %*	0.2 wt %*	0.1 wt %*	0.2 wt %*
Petrostep B-105	NaOH	0.143	0.006	2.00	2.00	13.01	13.23
	Na ₂ CO ₃	0.188	0.352	2.00	2.00	11.28	11.53
	NaHCO ₃	2.5	1.5	1.00	2.00	9.16	8.97
	Na ₃ PO ₄	0.003	0.002	2.00	2.00	12.48	12.38
	Na ₂ HPO ₄	1.7	1.144	2.00	2.00	9.05	8.81
Branched alkyl aryl surfactants							
Petrostep B-100	NaOH	0.001	0.001	0.50	0.50	12.82	12.76
	Na ₂ CO ₃	<0.001	<0.001	0.50	0.50	11.74	11.66
	NaHCO ₃	0.034	0.007	1.25	1.25	9.64	9.65
	Na ₃ PO ₄	0.007	0.005	0.50	0.50	12.22	12.30
	Na ₂ HPO ₄	0.003	1.144	1.50	2.00	8.90	8.65
Chaser XP-100	NaOH	0.007	0.004	1.25	1.25	12.90	12.87
	Na ₂ CO ₃	0.002	0.004	0.75	2.00	11.35	11.69
	NaHCO ₃	0.001	<0.001	1.25	1.00	8.97	8.97
	Na ₃ PO ₄	0.003	0.002	0.75	1.25	12.10	12.43
	Na ₂ HPO ₄	<0.001	<0.001	0.75	1.00	8.79	8.74
Petrostep B-110	NaOH	0.033	0.034	1.00	1.25	12.49	12.26
	Na ₂ CO ₃	0.077	0.035	2.00	2.00	10.99	10.86
	NaHCO ₃	0.083	0.083	2.00	2.00	9.14	9.16
	Na ₃ PO ₄	0.078	0.040	2.00	1.25	12.14	11.95
	Na ₂ HPO ₄	0.085	0.065	2.00	1.00	8.96	8.64
Linear alkyl group—internal bond to aryl functionality—group surfactants							
Petrostep H-67	NaOH	0.039	0.033	1.00	0.50	12.81	12.64
	Na ₂ CO ₃	0.145	0.047	2.00	2.00	10.92	10.89
	NaHCO ₃	0.062	0.059	1.25	2.00	9.19	9.37
	Na ₃ PO ₄	0.029	0.026	0.75	1.50	11.94	12.19
	Na ₂ HPO ₄	0.035	0.018	2.00	2.00	8.30	8.07
Internal olefin sulfonates							
Neodol IOS 1517	NaOH	0.348	0.282	1.50	2.00	12.89	13.23
	Na ₂ CO ₃	0.344	0.222	2.00	2.00	11.43	11.22
	NaHCO ₃	0.680	0.645	2.00	2.00	9.88	9.83
	Na ₃ PO ₄	0.292	0.186	0.75	0.75	12.13	11.98
	Na ₂ HPO ₄	0.700	0.701	2.00	2.00	9.18	9.14
Neodol IOS 1720	NaOH	0.061	0.018	2.00	2.00	13.84	13.94
	Na ₂ CO ₃	0.040	0.026	1.50	2.00	11.78	11.72
	NaHCO ₃	0.066	0.124	2.00	1.50	9.83	9.85
	Na ₃ PO ₄	0.006	0.012	1.25	2.00	12.71	12.87
	Na ₂ HPO ₄	0.280	0.281	2.00	2.00	8.90	9.02
Alpha olefin sulfonates							
AOS 12	NaOH	0.428	0.961	0.50	1.00	12.63	12.60
	Na ₂ CO ₃	0.534	1.056	1.25	2.00	11.07	10.93
	NaHCO ₃	3.231	2.731	1.00	2.00	9.22	9.22
	Na ₃ PO ₄	0.328	0.696	0.50	0.75	11.71	11.80
	Na ₂ HPO ₄	2.874	3.147	1.00	1.50	8.74	8.81
Bioterge AS 40	NaOH	0.001	<0.001	0.50	1.25	12.63	12.54
	Na ₂ CO ₃	0.008	0.011	2.00	1.25	10.90	10.75
	NaHCO ₃	0.114	0.009	2.00	2.00	8.67	8.71
	Na ₃ PO ₄	0.002	0.001	0.50	2.00	11.99	12.02
	Na ₂ HPO ₄	0.117	0.015	2.00	2.00	8.87	8.69

Table 2 (Continued)

Surfactant	Alkali	Minimum interfacial tension, mN/m		Alkali concentration, wt %		pH	
		0.1 wt %*	0.2 wt %*	0.1 wt %*	0.2 wt %*	0.1 wt %*	0.2 wt %*
Sulfonated linear alkane							
Bioterge PAS 8S	NaOH	<0.001	<0.001	0.75	1.00	12.62	12.40
	Na ₂ CO ₃	0.001	<0.001	2.00	1.50	10.59	10.92
	NaHCO ₃	0.074	<0.001	2.00	2.00	9.29	9.31
	Na ₃ PO ₄	<0.001	<0.001	1.50	1.25	12.07	12.00
	Na ₂ HPO ₄	0.068	0.045	2.00	1.25	8.75	8.81
Sulfonated ethoxylated linear alkane							
Avel S-30	NaOH	0.145	0.239	0.50	0.75	12.77	12.91
	Na ₂ CO ₃	0.130	0.144	2.00	2.00	11.39	11.37
	NaHCO ₃	0.430	0.290	1.50	1.50	9.24	9.36
	Na ₃ PO ₄	0.109	0.117	0.50	1.50	12.05	12.38
	Na ₂ HPO ₄	0.362	0.317	1.50	1.50	9.20	9.28
Sulfated linear alkane							
Stepanol WAC	NaOH	0.340	0.371	1.50	0.50	13.32	13.32
	Na ₂ CO ₃	0.364	0.606	1.50	0.50	11.42	11.26
	NaHCO ₃	0.983	0.893	1.25	1.25	9.30	9.30
	Na ₃ PO ₄	0.343	0.740	1.50	1.00	12.56	12.47
	Na ₂ HPO ₄	0.723	0.874	2.00	1.50	9.17	9.29
Sulfated ethoxylated linear alkane							
Neodol 25-3S	NaOH	0.131	0.087	2.00	2.00	13.00	13.15
	Na ₂ CO ₃	0.131	0.188	2.00	2.00	11.62	11.60
	NaHCO ₃	0.340	0.373	2.00	1.00	9.00	8.92
	Na ₃ PO ₄	0.141	0.194	1.25	2.00	12.11	12.59
	Na ₂ HPO ₄	0.260	0.385	2.00	2.00	8.99	8.92

*Surfactant concentration.

Combining the various surfactants with the different alkaline agents reduced the IFT values significantly for a number of surfactants, which suggests that a synergism exists between the two IFT agents. Other investigators have observed the same phenomenon.²⁻⁵ The variation of the IFT with surfactant structure with each of the five alkalis suggests that the surfactant is the dominant agent. However, each alkaline agent obviously interacts differently with each surfactant.

Figures 1 and 2 plot the minimum IFT vs. the M.W. of the linear alkyl aryl sulfonate surfactants and the branched alkyl aryl sulfonate surfactants, respectively. Each group of surfactants is shown with the five alkaline agents. Both groups of surfactants show low IFT values with surfactant M.W. between 370 and 430. A similar optimum surfactant M.W. effect on IFT values was observed within each linear alkane surfactant group.

Adding a methyl group to the aromatic ring did not appear to affect the IFT; compare LXS 370 and LXS 395 with Petrostep B-120, LXS 395 and LXS 420 with TRS 10-410, and Petrostep B-100 with Chaser XP-100.

Neither the type of alkaline agent nor the pH of the solutions was a significant factor in lowering the IFT when

Fig. 1 Minimum interfacial tension (IFT) vs. surfactant molecular weight of linear alkyl aryl sulfonate surfactants (0.1 wt %). ○, Na₂CO₃, Δ, Na₂HCO₃, ×, Na₃PO₄, □, Na₂HPO₄, *, NaOH.

blended with alkyl aryl surfactants with M.W. in the optimum range and when each alkaline agent concentration is allowed to vary to produce the minimum IFT value. If the alkaline agent concentration is kept constant, the IFT will vary with pH, as depicted in Fig. 3 for TRS 10-410. When blended with

Fig. 2 Minimum interfacial tension (IFT) vs. surfactant molecular weight of branched alkyl aryl sulfonate surfactants (0.1 wt %). $\circ$, Na_2CO_3 ; Δ , NaHCO_3 ; $\times$, Na_3PO_4 ; $\square$, Na_2HPO_4 ; $*$, NaOH .

Fig. 3 Interfacial tension vs. pH of 0.1 wt % TRS 10-410. $\circ$, 1.50 wt % Na_2CO_3 - NaHCO_3 ; $\times$, 1.25 wt % Na_2HPO_4 - Na_3PO_4 ; $*$, NaOH .

the alkane surfactants, the lower pH alkaline agents did not reduce the IFT values to as low a value. As a result, the presence of an aromatic ring appears to be beneficial but is not an absolute requirement. The location of the sulfonate group on the linear alkane sulfonates made a difference in defining which M.W. resulted in ultralow IFT values. Internal sulfonated and alpha sulfonated alkanes produced lower IFT values as the surfactant M.W. increased.

Effect of Temperature on the Interfacial Tension Between Crude Oil and Alkaline-Surfactant Solutions

The IFT between the Adena crude oil and selected surfactants combined with the five alkaline agents was determined at 180 °F. The minimum IFT values at 72 and 180 °F for the various surfactant-alkaline agent combinations are listed in Table 3.

Effect of Alkali and Surfactant on Polymer Solution Viscosity

The effect on solution viscosity of blending alkali and surfactant with polyacrylamide, xanthan gum, and hydroxyethyl cellulose polymers was examined. Brookfield viscosities at 6 rpm were measured at ambient temperature (70 °F) and at 180 °F. Three surfactants from different classes were selected: Petrostep B-100, LXS 420, and AS 40. The five alkaline agents used in the previous studies were blended with the polymer and surfactants. Cyanatrol 750 was the polyacrylamide polymer, K7D-226 was the xanthan gum, and hydroxyethyl cellulose polymer was 210-HHR.

Polyacrylamide solution viscosities decreased with the addition of alkali regardless of type. Viscosity reduction was

TABLE 3

Interfacial Tension for Various Surfactant-Alkaline Agent Combinations

Surfactant	Alkali	Minimum interfacial tension at 72 °F, mN/m		Minimum interfacial tension at 180 °F, mN/m	
		0.1 wt %*	0.2 wt %*	0.1 wt %*	0.2 wt %*
Linear alkyl aryl surfactants					
LXS 370	NaOH	0.009	0.017	0.061	0.015
	Na ₂ CO ₃	0.011	0.001	0.010	0.012
	NaHCO ₃	0.015	0.002	0.006	0.018
	Na ₃ PO ₄	<0.001	0.018	0.049	0.013
	Na ₂ HPO ₄	0.369	0.001	0.008	0.006
LXS 395	NaOH	0.023	<0.001	0.006	0.001
	Na ₂ CO ₃	0.011	0.011	0.001	0.008
	NaHCO ₃	0.015	0.018	0.007	0.022
	Na ₃ PO ₄	0.017	0.018	0.001	0.001
	Na ₂ HPO ₄	0.051	0.022	0.022	0.007
LTS-18	NaOH	0.004	0.019	0.007	0.013
	Na ₂ CO ₃	0.093	0.109	0.059	0.030
	NaHCO ₃	0.114	0.260	0.008	0.004

Table 3 (Continued)

Surfactant	Alkali	Minimum interfacial tension at 72 °F, mN/m		Minimum interfacial tension at 180 °F, mN/m	
		0.1 wt %*	0.2 wt %*	0.1 wt %*	0.2 wt %*
Petrostep B-105	Na ₃ PO ₄	0.047	0.036	0.047	0.126
	Na ₂ HPO ₄	0.120	0.056	0.004	0.004
	NaOH	0.143	0.006	0.042	0.013
	Na ₂ CO ₃	0.188	0.352	0.342	0.425
	NaHCO ₃	2.5	1.5	—	—
	Na ₃ PO ₄	0.003	0.002	0.109	0.126
	Na ₂ HPO ₄	1.7	1.144	—	—
Branched alkyl aryl surfactants					
Petrostep B-100	NaOH	0.001	0.001	0.012	<0.001
	Na ₂ CO ₃	<0.001	<0.001	0.002	0.002
	NaHCO ₃	0.034	0.007	0.005	0.001
	Na ₃ PO ₄	0.007	0.005	0.005	0.002
	Na ₂ HPO ₄	0.003	1.144	0.001	0.001
Chaser XP-100	NaOH	0.007	0.004	0.005	0.008
	Na ₂ CO ₃	0.002	0.004	0.008	0.025
	NaHCO ₃	0.001	<0.001	—	—
	Na ₃ PO ₄	0.003	0.002	0.008	0.008
	Na ₂ HPO ₄	<0.001	<0.001	—	—
Internal olefin sulfonates					
Neodol IOS 1517	NaOH	0.348	0.282	0.151	0.343
	Na ₂ CO ₃	0.324	0.222	0.519	0.267
	NaHCO ₃	0.680	0.645	0.726	1.525
	Na ₃ PO ₄	0.292	0.186	0.197	0.220
	Na ₂ HPO ₄	0.700	0.701	1.105	0.869
Neodol IOS 1720	NaOH	0.061	0.018	0.023	0.125
	Na ₂ CO ₃	0.040	0.026	0.062	0.110
	NaHCO ₃	0.066	0.124	0.175	0.119
	Na ₃ PO ₄	0.006	0.012	0.018	0.065
	Na ₂ HPO ₄	0.280	0.281	0.294	0.252
Sulfated ethoxylated linear alkane					
Neodol 25-3S	NaOH	0.131	0.087	0.120	0.177
	Na ₂ CO ₃	0.131	0.188	0.366	0.392
	NaHCO ₃	0.340	0.373	—	—
	Na ₃ PO ₄	0.141	0.194	0.326	0.260
	Na ₂ HPO ₄	0.260	0.385	—	—

*Equivalent IFT values were achieved at both temperatures with the varied structured surfactants. However, the alkali concentrations at which the minimum IFT occurred did change as the temperature increased.

greater at 180 °F. The addition of surfactant to either the polyacrylamide polymer or the alkaline–polyacrylamide polymer solution increased the solution viscosity for LXS 420 but not for Petrostep B-100 or AS-40. The LXS 420 increase of solution viscosity was more pronounced at 180 °F. Comparative plots of viscosity vs. polymer concentration are depicted for Na₂CO₃ plus LXS 420 and Na₂CO₃ plus Petrostep B-100 in Figs. 4 and 5, respectively. Different alkaline agents blended with the three surfactants gave identical viscosity characteristics for each surfactant.

Hydroxyethyl cellulose solution viscosities decreased significantly with alkali addition at 70 °F but not at 180 °F.

Surfactant addition, regardless of structure, increased the solution viscosity at 70 °F but decreased the viscosity at 180 °F. Again, no difference in alkaline agent was observed with any of the surfactants.

The addition of the three high pH alkalis to the xanthan gum solution decreased the solution viscosity with the two lower pH alkalis having no effect on the solution viscosity at 70 °F. At 180 °F, however, the addition of alkali to the xanthan gum solution increased solution viscosity with the two lower pH alkalis producing the highest viscosities. The addition of surfactant to the alkaline–polymer or polymer solution resulted in increased viscosities with each of the three

Fig. 4 Effect of alkali and surfactant addition on polyacrylamide solution viscosity vs. polymer concentration.

Fig. 5 Effect of alkali and surfactant addition on polyacrylamide solution viscosity vs. polymer concentration.

surfactants at both temperatures, the effect being most pronounced with LXS 420.

Continued Investigations

Continued investigations are to study the effect of polymer and alkali addition on the critical micelle concentration and the effect of polymer addition on the IFT between Adena crude oil and the aqueous alkaline-surfactant solutions.

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IMPROVED TECHNIQUES FOR FLUID DIVERSION IN OIL RECOVERY

Contract No. DE-AC22-92BC14880

**New Mexico Institute of Mining and Technology
Petroleum Recovery Research Center
Socorro, N. Mex.**

**Contract Date: Sept. 17, 1992
Anticipated Completion: Sept. 30, 1995
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**Principal Investigators:
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**Program Manager:
Jerry Casteel
Bartlesville Project Office**

Reporting Period: Jan. 1-Mar. 31, 1993

Objectives

This three-year project has two general objectives. The first objective is to compare the effectiveness of gels in fluid

diversion with those of other types of processes. Several different types of fluid-diversion processes will be compared, including those using gels, foams, emulsions, and particulates. The ultimate goals of these comparisons are to (1) establish which of these processes are most effective in a given application and (2) determine whether aspects of one process can be combined with those of other processes to improve performance. Analyses will be performed to assess where the various diverting agents will be most effective (e.g., in fractured vs. unfractured wells, in deep vs. near-wellbore applications, in reservoirs with vs. without crossflow, or in injection wells vs. production wells). Experiments will be performed to verify which materials are the most effective in entering and blocking high-permeability zones. Another objective of the project is to identify the mechanisms by which materials (particularly gels) selectively reduce permeability to water more than to oil. In addition to establishing why this occurs, this research will attempt to identify materials and conditions that maximize this phenomenon.

Summary of Technical Progress

Several experiments are under way to investigate why some gels reduced permeability to water more than to oil. A number of different mechanisms for the disproportionate permeability reduction have been suggested. Two concepts that have some elements in common are the "hydrophilic film theory," proposed by Sparlin and Hagen¹ and the "lubrication effect," proposed by Zaitoun and Kohler.² Both concepts apply to strongly water-wet cores where a layer of polymer or gel is adsorbed onto pore walls. For different reasons, the two theories suggest that the presence of the hydrocarbon-adsorbed-polymer interface effectively "lubricates" the flow of oil or gas through the center of pores. These ideas appear to be an extension of the theory that Odeh proposed for the effect of oil/water viscosity ratio on relative permeabilities.³

On the basis of the ideas of Zaitoun and Kohler² and Odeh,³ residual resistance factors were expected to vary with oil viscosity during core experiments with gels present. Therefore, with two oils with different viscosities, the lubrication effect in a strongly water-wet Berea sandstone core at 41 °C was investigated. One oil (Soltrol 130®) had a viscosity of 1.05 cP, whereas the other (Banco® IC46980 paraffin oil) had a viscosity of 31.6 cP. After the core was saturated with brine, Soltrol 130® was injected to determine oil permeability at the residual water saturation. The Soltrol was then displaced by the paraffin oil, and oil permeability was again measured. The paraffin oil was then displaced by Soltrol, and oil permeability was determined once more. Next, brine was injected to determine water permeability at the residual oil saturation. This procedure was repeated three times. Two sets of measurements were performed using the original flow direction, and two sets were obtained using flow through the core in the reverse direction. This experiment provided four Soltrol permeabilities before paraffin injection (averaging

512 ± 16 mD), four paraffin oil permeabilities (averaging 574 ± 18 mD), four Soltrol permeabilities after paraffin injection (averaging 549 ± 20 mD), and four water permeabilities (averaging 118 ± 7 mD). If the lubrication effect was important, the apparent oil permeability should have been much greater for the paraffin oil than for the Soltrol oil.³ Given the similarity of the Soltrol and paraffin oil permeabilities, no significant lubrication effect was evident before placing gel in the core.

Next, 6 pore volumes of Cr³⁺-HPAM gelant (Marcit®) was injected into the core. The gelant contained 1.39% HPAM, 212-ppm Cr³⁺ (acetate), and 1% NaCl. After the core was saturated with the gelant and shut in for 5 days, water was injected. Residual resistance factors for water were found to be over 35,000. The core was then oil flooded to establish a residual water saturation, and residual resistance factors for both oils were determined. These factors ranged from 10 to 19 (see Table 1). Finally, the core was water-flooded, and residual resistance factors for water (F_{rw}) were redetermined. The latter values could be described by the equation $F_{rw} = 1430 u^{-0.44}$, where u is superficial velocity in units of feet per day.

Table 1 shows that the residual resistance factors for both oils were measured at two residual water-plus-gel saturations. At a given saturation, the residual resistance factors for the two oils were essentially the same. Thus no lubrication effect was apparent. Through the water-oil-water injection cycle, the gel reduced water permeability substantially more than oil permeability. These observations suggest that the disproportionate permeability reduction was not caused by a lubrication effect.

TABLE 1
Residual Resistance Factors for Oils (F_{ro})
with Different Viscosities*

Oil injected	Oil viscosity, cP	Residual water-plus-gel saturation	F_{ro}
Banco® paraffin oil	31.6	0.46	19
Soltrol 130® oil	1.05	0.46	19
Banco® paraffin oil	31.6	0.43	11
Soltrol 130® oil	1.05	0.43	10

*Strongly water-wet Berea sandstone core, 41 °C, first oil flood after gelation.

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SURFACTANT FLOODING METHODS

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Reporting Period: Jan. 1–Mar. 31, 1993

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 and other Department of Energy (DOE)-targeted reservoirs, (2) adapt surfactant EOR technology to different salinity and temperature ranges by developing surfactant systems that are tolerant to changes in chemical composition in selected reservoirs, and (3) develop cost-effective systems for selected applications using low-concentration surfactants with alkaline additives or other sacrificial agents. Studies will concentrate on problem areas that have adverse effects on performance and economics of chemical EOR in an effort to achieve a balance between cost and oil recovery effectiveness.

Summary of Technical Progress

Mixed Surfactant Systems

The phase inversion temperature (PIT) screening experiments being conducted with selected combinations of TRS 10-410–isobutyl alcohol (IBA) and the nonionic surfactants (e.g., Genapol and Igepal series) with different alkanes have been completed. The alkanes used in these tests now include *n*-heptane, *n*-octane, *n*-nonane, *n*-decane, *n*-dodecane, and *n*-tetradecane. These tests were performed with different alkanes to evaluate the shift in optimal salinity behavior of these surfactant solutions as a function of the oil's chain length. The results showed that decreasing the carbon chain length of the oil resulted in a reduction of the effective salinity range at a specific calculated hydrophilic-lyophilic balance

(HLB) value and temperature. This meant that, because the change in hydrocarbon resulted in a shift in the surfactant system's relative affinity for the oil phase, a reduction in salinity was necessary to "rebalance/reoptimize" the overall system. It was observed that at a fixed salinity the PIT of the system increased with HLB value. The shift in optimum temperature was necessary to offset the relative higher hydrophilic tendency (higher HLB) of the solution. Increasing the temperature shifts or balances the oil-water affinity of the higher HLB system. Conversely, altering the salinity at a fixed HLB rendered the system more lipophilic such that a reduction in temperature was needed to improve the hydrophilic tendency of the system. Changing the alkane chain length results in a shift in the observed optimal salinity of these surfactant mixtures at a fixed temperature. The use of an oil with a shorter carbon chain length results in a relative increase in affinity of the surfactant for the oil, which requires lower optimal salinity levels to provide a corresponding relative shift in the affinity of the surfactant mixture for the water phase. The task of developing a correlation for the behavior of these types of nonionic-nonionic and anionic-nonionic mixtures is ongoing.

Similar PIT experiments were also conducted on selected samples of alpha-olefin sulfonate (AOS) surfactants, C₁₄₋₁₆ AOS and C₁₆₋₁₈ AOS, in combinations with Genapol and Igepal series of surfactants. The PIT studies with the primary anionic surfactant system alone did not indicate any trend in solution behavior of these systems over a selected range of salinities. However, tests with combinations of these AOS surfactants with selected nonionic surfactants at a fixed component proportion (50%:50% by weight) indicated some trends in solution conductivity changes that can be attributed to relative proximity of optimal conditions for these anionic-nonionic mixtures. Additional tests with these combinations indicated that the trends with these mixtures were not as distinct compared with earlier results with the mixtures of TRS/IBA and the different nonionic components. These results indicate that the AOS surfactant solution behavior appears to dominate the solution behavior of the overall mixture. Additional salinity scans and PIT tests are currently being conducted with mixtures containing higher nonionic component proportions (e.g., greater than 50% nonionic component). Preliminary results using systems with the higher nonionic component indicate very distinct phase inversion trends. These results showed that under the conditions tested (e.g., greater than 50% nonionic surfactant) the nonionic surfactant behavior appeared to dominate the overall solution behavior.

Surfactant Loss—Mixed Surfactants

A mixed surfactant system that contains the surfactants Stepan B-100, an anionic surfactant, and Igepal DM 530, a nonionic ethoxylated dialkyl phenol, at a total concentration of 2.0% by weight was selected for evaluation. It will be determined if surfactant adsorption from the mixed surfactant

system is different from adsorption of the individual surfactants. Analysis for the nonionic surfactant (cobalt thiocyanate method) was complicated by the formation of emulsions. For quantification of the amount of nonionic surfactant present in surfactant mixtures using the cobalt-thiocyanate surfactant analysis method, the nonionic surfactant species must be separated from the anionic surfactant in the mixtures. An analytical separation of Stepan B-100 from DM-530 using an ion exchange column was successfully accomplished. The anionic exchange column was also found to be successful in separating the anionic and nonionic surfactants in a mixture of known composition in the presence of 3% NaCl brine.

The adsorbent will be Davison Grade 62 silica gel with a specific surface of 330 m²/g. Since reservoir rock generally has about 1 m²/g specific area, a nonconsolidated core of 1-ft length can represent the surface area of a hundred or more feet of reservoir. Bottle adsorption tests of the unmixed surfactants are under way as well as calibration curves for the analytic technique with the use of these mixed surfactants.

CT Imaging of Oil Recovery in Class 1 Reservoir Rock

Computerized tomography (CT) imaging was also used to study the effect of reducing the amount of total injected surfactant on oil-bank formation and overall oil recovery efficiency. Adsorption losses could significantly affect the recovery efficiency as total surfactant amounts are reduced. A low-concentration mixed surfactant system that had been studied previously¹ with Hepler (Kansas) oil was used in this study. Injection of 0.75 pore volume (PV) of surfactant with a total concentration of 0.4 wt % recovered approximately 90% of residual oil saturation. Reducing the amount of injected surfactant to 0.4 PV resulted in production of approximately 30% of the residual oil saturation. The oil bank produced by the smaller surfactant slug was not as sharp a front nor was the oil saturation in the bank as high as that observed for the larger slug. An additional test using 0.2 PV of injected surfactant is in progress. Small slugs of low-concentration surfactant may be insufficient to efficiently mobilize the maximum amount of oil.

A paper, entitled *CT-Imaging of Surfactant/Polymer EOR Corefloods*, was presented Mar. 31, 1993, at the 205th National American Chemical Society Meeting Symposium on Enhanced Oil Recovery.²

Surfactant Database

A surfactant literature database has been assembled to aid in predicting conditions and application for chemical oil recovery methods. It is the purpose of this task to compile and develop a system for identifying surfactant structure-performance correlations. The database system in its present form is a two-part system. The master list contains a compilation of references on surfactant use in micellar-polymer enhanced oil recovery. Over 50 references were added to the master list this quarter; there are now over 1800 references in

it. The second part contains references that have been chosen for in-depth review. Currently, this section contains further information from 175 papers. Surfactant identification, properties, and experimental data from the literature and from studies performed at the National Institute for Petroleum and Energy Research (NIPER) are being entered in this portion of the database.

Final Report

A final report for the period FY84-93 is in preparation for research conducted for DOE. One chapter of the report will summarize research for surfactant flooding, alkaline-surfactant-polymer EOR, and polymer research conducted at NIPER. During this quarter a first draft of the state of the art and accomplishments for FY84-92 was prepared. Expected completion date is June 1993.

References

1. F. M. Llave, B. L. Gall, T. R. French, L. A. Noll, and S. A. Munden, *Phase Behavior and Oil Recovery Investigations Using Mixed and Alkaline-Enhanced Surfactant Systems*, DOE Report NIPER-567, March 1992.
2. B. L. Gall, CT Imaging of Surfactant-Enhanced Oil Recovery Experiments, *Am. Chem. Soc., Div. Pet. Chem., Prepr.*, 38(1): 1120-1125 (February 1993).

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, 1993
Funding for FY 1993: \$200,000**

**Principal Investigator:
Troy R. French**

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

Reporting Period: Jan. 1-Mar. 31, 1993

Objectives

The major objective of this project is to develop cost-effective and efficient chemical flooding formulations using

surfactant-enhanced, weakly alkaline systems. Specific objectives for FY93 are to (1) determine the effect of variables on surfactant and polymer propagation and retention during alkaline flooding and (2) perform studies designed to support a field test.

Summary of Technical Progress

The interactions that occur between enhanced oil recovery (EOR) chemicals during surfactant-enhanced alkaline flooding were investigated during FY92. The effects of interactions between polymers and surfactants on rheology were shown to be significant, and so far no satisfactory way has been found to mitigate these effects.¹ During FY93, experiments are being conducted that should contribute to a better understanding of chemical interactions that have detrimental effects on the rheological properties of surfactant-enhanced alkaline flooding chemical formulations.

The subjects of this report are the status of experiments with dispersions—interactions associated with surfactant-enhanced alkaline flooding and the differences found in the properties of different oil samples taken from the Tucker sand of Hepler (Kansas) oil field. The differences in properties of oil samples from Hepler field are of particular interest because the field is being used for a field project being conducted under the Supplemental Government Program.

The characterization of dispersions that are typical of surfactant-enhanced alkaline systems has proven to be more complicated and time-intensive than anticipated. The results from light-scattering techniques employed for this task have been found to be extremely sensitive to polymer molecule shape, which changes, depending on such parameters as extremely small changes in the ionic character of the solutions. No further time will be expended on light-scattering experiments this year. Computerized tomography will be used to determine oil saturations in field cores that have been partially swept with surfactant-enhanced alkaline chemical formulations. It has recently been determined that this research is necessary because, as the result of heterogeneities in Midcontinent field cores, it is difficult to predict accurately the final oil saturations that result after application of chemical flooding methods in Midcontinent fluvial-dominated (DOE Class 1) reservoirs. The extent and significance of heterogeneity in these reservoirs have been shown recently to be greater than previously believed.¹

Figures 1 and 2 show the dynamic interfacial tension (IFT) between two samples of crude oil from the Tucker sand of Hepler field and a chemical formulation that contains 0.1% active Chaser CF-100 surfactant, 0.45% active sodium tri-polyphosphate (STPP), and NaHCO₃. Dynamic IFT behavior is considerably different for the two oil samples. The IFT between the oil sample of Fig. 1 (oil sample taken from field in 1990) and the chemical formulation is significantly less than the IFT for the second oil sample (1992) of Fig. 2. Table 1 summarizes the results for these two samples along with data for an additional oil sample. The additional sample

Fig. 1 Dynamic interfacial tension between 1990 sample of Hepler (Kansas) crude oil and a mixture of 0.1% Chaser CF-100, 0.45% sodium tripolyphosphate, and NaHCO_3 in water from the Water Supply Well, 23 °C. NaHCO_3 , %: —○—, 1.4. —□—, 1.6. —◇—, 2.0. —△—, 2.2.

Fig. 2 Dynamic interfacial tension between 1992 sample of Hepler (Kansas) crude oil and a mixture of 0.1% Chaser CF-100, 0.45% sodium tripolyphosphate, and NaHCO_3 in water from the Water Supply Well, 23 °C. NaHCO_3 , %: —○—, 1.2. —□—, 2.0. —△—, 2.8.

is a mixture of oil obtained after recirculation of 1992 oil through a field core; therefore it is a mixture of core oil and the 1992 oil sample.

In Table 1 the magnitude of the IFT value correlates with oil gravity. The higher the gravity, the lower the IFT. It is therefore possible that some of the effect is due to weathering of samples. More likely, the properties of the oil vary somewhat throughout the reservoir. This is not unlikely because extensive compartmentalization in the reservoir could reflect the possibility of there being pockets of oil that differ in geochemical history. The differing properties of the crude oil

samples obviously create some problems for design of an optimum oil recovery chemical formulation. It is favorable that optimum salinity is nearly the same for all the oil samples and that a significant lowering of IFT was achieved with all three oil samples.²

A final report for the period FY84–93 is in preparation. One chapter of the report contains a summary of research conducted on alkaline–surfactant–polymer EOR. Anticipated completion date is June 1993. During this quarter a first draft of the state of the art and accomplishments for FY84–92 was prepared.

TABLE 1

Interfacial Tension (IFT) Between Hepler (Kansas) Crude Oil Samples and a Mixture of 0.1% Chaser CF-100, 0.45% Sodium Tripolyphosphate, and NaHCO_3 in Water from the Water Supply Well, 23 °C

Sample	CF-100 concentration, %	Optimal salinity, %	IFT, $\mu\text{N/m}$		Gravity, °API
			Initial	Equilibrium	
1990	0.1	1.6	20	1	75
1990	0.5	1.2	100	5	75
Core oil	0.5	1.6	300	10	65
1992	0.1	2.0	800	100	58
1992	0.5	2.0	500	100	58

References

1. T. R. French, R. A. Schatzinger, G. B. Barnett, L. Tomutsa, and W. I. Johnson, *Characterization of a Midcontinent Fluvial-Dominated Deltaic Sandstone Reservoir by Routing and Advanced Analytical Methods*, paper presented at the Fluvial-Dominated Deltaic Reservoirs in the Southern
2. Julie Smith, *How to Rate Crude Oils for Alkaline Flooding Potential—A Study Based on 239 Crude Oils*, paper 25171 in *Proceedings of the International Symposium on Oilfield Chemistry*, New Orleans, La., Mar. 2–5, 1993, pp. 211–221.

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, 1993
Funding for FY 1993: \$240,000

Principal Investigator:
Hong W. Gao

Project Manager:
Jerry Casteel
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1993

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 a cost-effective gel treatment using polymer gel systems.

Summary of Technical Progress

Polymer Retention in an Unfired Rectangular Berea Sandstone Core

Corefloods designed to investigate the effect of lamination angle on polymer retention in unfired rectangular Berea sandstone cores were continued. The injection of 9.3 PV (670 mL) of post brine (2% KCl) into a rectangular Berea sandstone core was completed. Measured irreversible polymer retention from the first slug of polymer injection was 402 kg/(acre-m). A second slug (4.5 PV or 324 mL) of the same polymer solution (1000-ppm biopolymer solution in 2% KCl) was injected into the same rectangular Berea sandstone core followed by 9 PV (650 mL) of 2% KCl. The biopolymer solution used in the coreflood was prepared from Pfizer's FLOCON 4800C. Both biopolymer solution and brine contained 500 ppm of 37.3% formaldehyde as a biocide. The core used was cut along the direction of laminations. Its dimensions were 4.00 × 3.94 × 24.02 cm. Brine permeability was 180 mD. The porosity determined from a computerized tomography (CT) scanner was 18.9% compared with 19% from a brine saturation method. The injection rate used was 4.3 mL/h (apparent shear rate inside the core = 10 s⁻¹). Effluent biopolymer concentration was determined by viscosity

measurements at a shear rate of 20.4 s⁻¹ using a Contraves Low Shear 30 viscometer and comparing with a calibration curve.¹

Results are shown in Figs. 1 and 2. As shown in Fig. 1, after 4.5 PV of polymer injection, equilibrium retention was not obtained because the effluent biopolymer concentration had not reached that of the injected biopolymer solution. The maximum amount of polymer retained inside the core during polymer flow (Fig. 2) was 916 kg/(acre-m) compared with 1200 kg/(acre-m) during the first slug of polymer injection.¹ Irreversible polymer retention after the post brine flood, as shown in Fig. 2, was 93 kg/(acre-m) compared with 402 kg/(acre-m) after the first slug of polymer injection. The total amount of irreversible polymer retention from the first and

Fig. 1 Normalized effluent concentration profile for a biopolymer from an unfired Berea sandstone core. Unfired Berea sandstone core: Lamination angle, 0°; porosity, 19%; 1 PV = 71.9 mL; brine permeability, 180 mD. Polymer injection, 0 to 4.5 PV; flow rate, 4.3 mL/h; apparent shear rate, 10 s⁻¹.

Fig. 2 Retention of a biopolymer in an unfired Berea sandstone core during and after polymer flow. Unfired Berea sandstone core: Lamination angle, 0°; porosity, 19%; 1 PV, 71.9 mL. Brine permeability, 180 mD. Polymer injection: 0 to 4.5 PV; flow rate, 4.3 mL/h. Apparent shear rate, 10 s⁻¹.

second slugs of polymer injection was 495 kg/(acre-m). This amount is about the same as that retained in a similar but fired Berea core.² These results will be compared with those of corefloods with unfired rectangular Berea cores that were cut at 30° and 90° with respect to the direction of laminations.

CT Tracer Tests

Tracer tests were conducted before and after the polymer flow to determine how the retained polymer affected the stability of the fluid front in core. Tracer tests were conducted at 1.4 ft/d (5.34 mL/h) by injecting a slug (0.278 PV) of tagged brine (7% KI) into the core followed by 2% KCl brine. The flow behavior of the tagged brine was monitored throughout its advance through the core by conventional CT and topogram scanning. The resulting images before and after the polymer flow were compared with each other.

Figure 3 shows CT scans of the flow of tracer (light shade) through the core before and after the polymer flow. As shown in the figure, before polymer flow, layer permeability contrast caused the fluid front to advance unevenly. The fluid front near the top of the core advanced fastest. After the polymer flow the fluid front near the top of the core moved even faster than before polymer flow, which indicated that retained polymer decreased the permeability in the lower permeability laminations to a larger degree than in the higher permeability laminations. As a result, the stability of the fluid front worsened.

A paper entitled "The Effects of Layer Permeability Contrast and Crossflow on the Effectiveness of Polymer Gel Treatments in Polymer Floods and Waterfloods" was presented at the 1993 Society of Petroleum Engineers Production Operations Symposium in Oklahoma City, Mar. 21–23, 1993.

Fig. 3 Computerized tomography (light color) propagation through an unfired rectangular Berea sandstone core before and after the polymer flow.

References

1. National Institute for Petroleum and Energy Research, *Quarterly Technical Report for October 1–December 31, 1992*, Vol. II, Energy Production Research, DOE Report NIPER-671, February 1993.
2. H. W. Gao, *The Effect of Lamination Angle on Polymer Retention*, DOE Report NIPER-630, September 1992.

SURFACTANT-ENHANCED ALKALINE FLOODING FIELD PROJECT

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

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

**Contract Date: July 18, 1990
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$318,000**

**Principal Investigator:
Troy R. French**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The objectives of this pilot project are to (1) obtain information and data that will help 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 from abandoning marginal wells.

Summary of Technical Progress

The site selected for conducting a field pilot test using surfactant-enhanced alkaline flooding methods is Hepler (Kan-

sas) oil field. Hepler field is located 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

Results of an environmental investigation were reported.² As a result of no significant impact, Russell Petroleum Company requested a Finding of No Significant Impact (FONSI) from DOE. Methods for evaluating core from a Midcontinent fluvial-dominated deltaic sandstone reservoir were compared.³

The Tucker sand is a local equivalent Bartlesville sand and is typical of many reservoirs in the area that are operated by independent oil companies. The work presented showed that there was extremely good agreement between routine and advanced analytical methods that can be used for reservoir evaluation. Routine analytical methods for reservoir evaluation are open-hole logs and routine core analysis. Advanced analytical methods are computerized tomography (CT) and minipermeability and thin-section analysis. Core obtained from the pilot site in Hepler field was used in all the experiments described. Because of the interest generated by this work, results were presented at another conference.³

Routine core analyses and wireline logs indicate that the Tucker sand is heterogeneous. Special core analyses showed that the heterogeneities extend to microscale. Microscale heterogeneities adequately explain laboratory coreflooding results. Extrapolation of results from laboratory scale to field scale is difficult because of lack of information about the lateral extent of compartmentalization. Therefore the effect of reservoir heterogeneity on chemical flooding will not be known until the field project is implemented.

It was decided that a better estimate of the final oil saturation in the area swept by chemical flooding is needed. This has been difficult to estimate from coreflooding experiments because of channeling of fluids through high-permeability streaks in the field cores. In an attempt to better estimate oil saturation in the zone swept by chemicals, corefloods are being performed while monitoring flow patterns with CT scanning. These experiments are being performed under Project BE4B, which is supporting the Supplemental Government Program project with some laboratory experiments.

References

1. U.S. Department of Energy, *Oil Research Program Implementation Plan*, DOE Report DOE/FE-0188P, April 1990.
2. W. I. Johnson and T. R. French, *Environmental Investigation of Hepler Field, Crawford County, KS, for an Alkali-Surfactant-Polymer Enhanced Oil Recovery Field Demonstration*, DOE Report NIPER-668, 1993.
3. T. R. French, R. A. Schatzinger, G. B. Barnett, L. Tomutsa, and W. I. Johnson, *Characterization of a Midcontinent Fluvial-Dominated Deltaic Sandstone Reservoir by Routine and Advanced Analytical Methods*, paper presented at the Fluvial-Dominated Deltaic Reservoirs in the Southern Midcontinent Workshop in Norman, Okla., Mar. 23–24, 1993, and at the Tenth Oil Recovery Conference in Wichita, Kans., Mar. 10–11, 1993.

**SURFACTANT LOSS CONTROL
IN CHEMICAL FLOODING:
SPECTROSCOPIC AND CALORIMETRIC
STUDY OF ADSORPTION AND
PRECIPITATION ON RESERVOIR
MINERALS**

Contract No. DE-AC22-92BC14884

Columbia University
New York, N.Y.

Contract Date: Sept. 30, 1992
Anticipated Completion: Sept. 29, 1995
Government Award: \$602,232

Principal Investigator:
P. Somasundaran

Project Manager:
Jerry Casteel
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

The objective of this project is to elucidate the mechanisms of adsorption and surface precipitation of flooding surfactants on reservoir minerals. The effect of surfactant structure, surfactant combinations, and other inorganic and polymeric species will be determined with the use of solids of relevant mineralogy. A multipronged approach consisting of micro and nano spectroscopy, microcalorimetry, electrokinetics, surface tension, and wettability will be used to achieve the goals. The results of this study should help in controlling surfactant loss in chemical flooding and also in developing optimum structures and conditions for efficient chemical flooding processes.

Summary of Technical Progress

The adsorption of selected individual surfactants on oxide minerals was studied. The goal was to determine the effect of structure on surfactant adsorption at the solid–liquid as well as at the liquid–air interface. Nonionic polyethoxylated alkyl phenols and anionic *meta*-xylene sulfonates (MXS) were the surfactants studied. The position of the sulfonate and methyl groups on the benzene ring of the MXS was varied, and its effect on adsorption on alumina was determined. Electrokinetic behavior and adsorption were studied to determine the effect of electrostatic forces on adsorption. In addition, the effect of varying the number of ethylene oxide (EO) groups on the adsorption of polyethoxylated alkyl phenols on silica was determined because the ethoxyl groups offer unique opportunities to control adsorption as well as wettability. The effect of pH was studied both because it is a parameter with first-order

effect and also because pH effects can help in the development of mechanisms.

Interfacial Behavior of Nonionic Surfactants

The study of the effect of the number of EO groups on the adsorption behavior of polyethoxylated alkyl phenols on silica continued this quarter. The number of EO groups on the surfactants, 10, 15, 20, and 40, offered a wide range (Fig. 1). During the first quarter, fluorescence spectroscopy, adsorption, and surface-tension measurements were used to study the adsorption of polyethoxylated nonyl phenol with 40 EO groups (EO40). It was determined that the commercial-grade EO40 surfactant used was not pure and the bulky surfactant did not form aggregates at the silica–water interface. Subsequent studies were conducted with pure reagents with 10, 15, and 20 EO groups obtained from Nikko Chemicals, Japan.

The purity of the surfactants used is evident from the surface-tension behavior of the surfactants shown in Fig. 2; these measurements were performed on the Fisher du Nuoy ring tensiometer. The surface tension of the commercial-grade polyethoxylated nonyl phenol with 40 EO groups (EO40) is also shown for comparison. The minimum in surface tension, which is indicative of impurities, is detected only for

Fig. 1 Polyethoxylated nonyl phenol surfactant (n: 10, 15, 20, 40).

Fig. 2 Surface tension of polyethoxylated nonyl phenols (NP) with 10, 15, 20, and 40 ethylene oxide (EO) groups. ○, NP-10. ▽, NP-15. □, NP-20. ■, EO, 40.

the commercial EO40. There is no minimum on the curves for the NP type of surfactants, which are more pure than the EO40.

As shown in Fig. 2, as the number of EO groups are increased, the surface activity is decreased and the critical micelle concentration is increased. These agree with earlier results on the behavior of the nonionic surfactants.

The adsorption isotherms for some polyethoxylated nonyl phenols on silica are shown in Fig. 3. With an increase in the number of EO groups on the surfactant, the adsorption density at the silica-water interface is decreased.

The slope of the curve in the preadsorption maximum region, which is an indication of cooperative association behavior of the hydrocarbon chains at the solid-liquid interface, decreases as the number of EO groups increases. An increase in the number of EO groups on the surfactant causes the molecule to become bulky. This will provide steric hindrance to the packing of the molecules into aggregates and, as a result, the adsorption density will be lower. Future work will focus on characterizing the microstructure of the adsorbed layer in terms of size and mobility of aggregates formed at the interface with fluorescence and electron spin resonance spectroscopic techniques.

The effect of pH on the adsorption of polyethoxylated nonyl phenol with 10 EO groups (NP-10) was determined, and the results are shown in Fig. 4. Three different concentrations were studied, and the pH was varied from 2.5 to 11.

Interestingly, there was no effect of pH on the adsorption of NP-10 on silica in the ranges studied. The mechanism of adsorption of ethoxylated surfactants on silica is considered to be hydrogen bonding between the ether oxygen of the EO

Fig. 3 Effect of change in number of ethylene oxide (EO) groups on the adsorption of polyethoxylated nonyl phenols (NP) on silica. $\circ$, NP-10. ∇ , NP-15. $\square$, NP-20. $\blacksquare$, EO-40. I.S., 0.03 M NaCl. Solid/liquid ratio: 0.01. pH, 6.2 to 6.9. Temperature, $23 \pm 2^\circ\text{C}$.

group and the surface silanol groups. As the pH was raised, the number of silanol groups on the silica surface decreased and the adsorption of NP-10 could have decreased if the mechanism of adsorption had been via hydrogen bonding. To explain this behavior, the electrokinetic behavior of silica was determined, and the results are given in Fig. 5.

Silica is negatively charged in the entire pH range studied. By extrapolation, the isoelectric point (IEP) is less than 2. Above pH 4.5 the zeta potential of silica is constantly suggesting that there is no change in the charged surface

Fig. 4 Effect of pH on the adsorption of polyethoxylated nonyl phenol on silica.

Fig. 5 Zeta potential of silica.

groups above this pH value for this sample. On the basis of this, pH will be expected to have no effect on adsorption of NP-10 on silica above pH 4.5. As shown in Fig. 4, however, the adsorption of NP-10 is constant down to even a pH value of 3. At pH values higher than the IEP, the number of silanol groups ($-\text{SiOH}$) on the surface are very few, and there is no significant change in their number to affect adsorption drastically. However, this interesting effect merits further investigation with the use of spectroscopic techniques to probe the interfacial region.

Effect of Surfactant Structure on Adsorption of Xylene Sulfonates

Studies initiated during the first quarter indicated that the position of the functional groups has a significant effect on the adsorption of alkyl xylene sulfonates: with the sulfonate in the *meta* position with respect to the methyl groups (124 MXS), surfactant adsorption on alumina was lower than with the sulfonate in the *para* position (135 PXS-*para*1). When the position of the methyl group was changed but the sulfonate remained in the *para* position [125 *para*-xylene sulfonate (*para*2)], the adsorption isotherm was identical to that of the *para*1. This suggested that the position of the methyl groups does not play as important a role as that of the sulfonate. To examine this aspect further, another structural variation of the xylene sulfonate, *ortho*-xylene sulfonate (OXS), was selected. The structure of the surfactants is shown in Fig. 6.

The adsorption behavior of OXS on alumina at room temperature is shown in Fig. 7. The adsorption isotherm of OXS is different from that of *meta*- and *para*-xylene sulfonates, but the adsorption of these surfactants was studied at 43 °C and hence the results cannot be strictly compared to isolate the structure effect.

The results in Fig. 7 indicate that at room temperature OXS adsorbs on alumina only above a certain concentration

Fig. 6 Structure of surfactants. (a) 4C11 2,4 *Meta*-xylene sulfonate (*meta*). (b) 4C11 3,5 *para*-xylene sulfonate (*para*1). (c) 4C11, 2,5 *para*-xylene sulfonate (*para*2). (d) 4C11, 4,5 *ortho*-xylene sulfonate (OXS).

($\approx 2 \times 10^{-5}$ kmol/m³). In the next quarter residual concentrations will be measured with the use of alternative analytical techniques (e.g., ultraviolet spectroscopy) and the adsorption of OXS will be studied at 43 °C to isolate the effect of structure on the adsorption of alkyl xylene sulfonates on alumina.

The surface tension of aqueous solutions of OXS was measured using a Fisher du Nuoy ring tensiometer. The results obtained in the absence and presence of salt are shown in Fig. 8. The surface tension continuously decreases as the concentration is increased in both cases with increased surface activity in the presence of salt.

This behavior is typical of surfactants at temperatures below their Krafft point. Further experiments will be conducted at higher temperatures to verify this detail.

Fig. 7 Adsorption of *meta*-xylene sulfonates on alumina. ∇ , *para*1. $\square$, *para*2. $\diamond$, *ortho*. $\circ$, *meta*.

Fig. 8 Surface activity of *ortho*-xylene sulfonate in the absence and presence of salt. Temperature, 23 ± 2 °C. $\circ$, water. $\bullet$, 0.03M NaCl.

GAS DISPLACEMENT— SUPPORTING RESEARCH

FIELD VERIFICATION OF CO₂-FOAM

Contract No. DE-FG21-89MC26031

**New Mexico Institute of Mining and Technology
Petroleum Recovery Research Center
Socorro, N. Mex.**

Contract Date: Sept. 17, 1992

Anticipated Completion: Sept. 16, 1995

Total Project Cost:

DOE	\$2,000,000
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Contractor	2,035,000
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Total	\$4,035,000
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Principal Investigators:

F. David Martin

John P. Heller

William W. Weiss

Project Manager:

Royal Watts

Morgantown Energy Technology Center

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

This project is a cooperative effort of industry, university, and government to transfer laboratory research technology to a field demonstration test. The primary objective of the project is to evaluate the use of foam for mobility control and fluid diversion in a field-scale CO₂ flood. Seven tasks were identified for the completion of this 4-yr project: (1) evaluate and select a field site, (2) develop an initial site-specific plan, (3) conduct laboratory CO₂-foam mobility tests, (4) perform reservoir simulations, (5) design the foam slug, (6) implement a field test, and (7) evaluate results.

Summary of Technical Progress

The East Vacuum Grayburg/San Andres Unit (EVGSAU), operated by Phillips Petroleum Company (PPCo), was selected for a comprehensive evaluation of the use of foam for improving the effectiveness of a CO₂ flood. The Petroleum Recovery Research Center (PRRC), a division of the New Mexico Institute of Mining and Technology, is providing laboratory and research support for the project. The 4-yr project is jointly funded by the EVGSAU Working Interest Owners (WIO), the U.S. Department of Energy (DOE), and the State of New Mexico. A Joint Project Advisory Team (JPAT) composed of WIO technical representatives from

several major oil companies provides input, review, and guidance for the project. The project began in late 1989 and is now in the fourth and final year.

Figure 1 shows the pattern (3332) selected for the foam injection test, the pattern injector (3332-001), and the observation well (3332-003) that was drilled to aid in evaluating the test. Cores were obtained from Well 3332-003, and the well was completed so that it would serve as a logging observation well. Results of laboratory work leading to the selection of a specific foaming surfactant (Chevron CD-1045) and background on the project were reported previously.^{1,2} The field operating plans, design criteria, foam injection schedule, data collection program, and performance criteria were reported also.^{3,4} The foam test design called for the initial injection of surfactant solution to satisfy the adsorption requirement of the reservoir followed by a rapid surfactant-alternating-gas (SAG) mode. The rapid SAG mode consists of 3-d cycles of surfactant solution [3000 reservoir barrels (RB)] alternated with 12-d cycles of CO₂ (12,000 RB). Thus the rapid SAG should closely approach the benefits achieved by simultaneous injection of surfactant solution and CO₂ and would provide an approximate foam quality of 80%.

The actual foam injection test has basically followed the original project schedule shown in Fig. 2. During a prefoam baseline period, a rapid water-alternating-gas (WAG) cycle was conducted from September to December 1991 followed by a 3-month CO₂ injection cycle. Three months of a prefoam surfactant pad to satisfy the adsorption requirement of the reservoir was started on Apr. 14, 1992, and was completed on July 14, 1992. The rapid SAG foam generation period started on July 17, 1992, and was completed on Oct. 9, 1992. During both the injection of the adsorption pad and the foam generation period, 2500-ppm Chevron CD-1045 was the surfactant used. An approximate 3-month CO₂ injection cycle began on Oct. 9, 1992, and ended on Jan. 12, 1993. During the next 10 d, a pressure falloff test was conducted, and water injection was

Fig. 1 Location of the East Vacuum Grayburg/San Andres Unit (EVGSAU) foam pilot area.

Fig. 2 East Vacuum Grayburg/San Andres Unit (EVGSAU) CO₂-foam project schedule.

started on Jan. 22, 1993, and continued through this reporting period (the end of March 1993). This quarterly report provides an update on the recent results obtained from the foam injection test and a status of supporting research related to the project.

Injection Well Response

Seven flow units or zones are laterally continuous across the foam pilot area and, as shown in Fig. 3, injection profile tests in Well 3332-001 indicate that Zone C is the major flow unit. Before the foam test, approximately 60% of the injected water was entering Zone C. An average of ten profiles obtained during the SAG foam test suggests that fluids are continuing to enter the high-permeability zones, although a 10 to 15% decrease was observed in Zone C. The results suggest that the bulk of the foam is probably being generated in the high-permeability Zone C, but a slight improvement in the injection profile was observed.

Fig. 3 Injection profile for Well 3332-001.

Figure 4 shows the performance of Injection Well 3332-001 during and after the foam test. The higher injection pressures during and after the rapid SAG infer that the reduced injectivities can be attributed to in situ foam generation. A preliminary analysis of pressure falloff tests, injectivity indexes, and modified Hall Plots provides the apparent viscosities shown in Table 1. Compared with water with a bottomhole viscosity of 0.72 cP, the foam generated during the rapid SAG had an "apparent" viscosity of 1.5 cP. Compared with the rapid WAG, a resistance factor of 2.5 was observed during foam generation near the end of the rapid SAG test.

has been completed, most of the saturation changes are occurring primarily in the highest permeability C-2 Subzone and in the E Zone, with significant change also occurring in the C-3 Subzone. During the foam test, CO₂ saturation in the E Zone increased and oil saturation decreased. These results are consistent with the results of the profile tests in the injector and provide additional details about fluid movement and diversion that are not available from the injection well tests.

Producing Well Response

Samples from producing wells in the pattern area were analyzed for both gas-phase and water-phase tracers that were

Fig. 4 Well 3332-001 injection pressure and rate during foam generation.

TABLE 1
Results from Falloff Tests and Hall Plot Slopes

	Apparent viscosity,* cP
Rapid WAG	0.6
CO ₂	0.3
Surfactant solution	0.9
Rapid SAG	1.5

*Based on $\mu_w = 0.72$ cP at bottomhole conditions and assuming $p_c = 1800$ psi.

Observation Well Logging Program

A large number of logs have been run in the observation well (3332-003) to monitor fluid movement and saturation changes in the various zones near the injection well. This analysis is being completed by PPCo and Schlumberger personnel for a pending paper. Results will be summarized in the next quarterly report. From the preliminary analysis that

injected into Well 3332-001. In December 1991 tritium was injected in the water phase at the end of the rapid WAG cycle and krypton 85 was injected at the beginning of the 3-month CO₂ injection cycle. Additionally, cobalt 60 was injected in the water phase just before the start of the adsorption slug of surfactant in mid-April 1992. None of the injected gas-phase tracer has been detected in any of the pattern producing wells, and water-phase tracers have been observed only in Producing Well 3332-032. This producer is referred to as the offending well because it has experienced excessive CO₂ breakthrough. The results of the water-phase tracer analyses presented in Fig. 5 suggest that the cobalt appeared more quickly on the basis of time than did the tritium. However, the tritium was injected just before 3 months of CO₂ injection, whereas the cobalt was injected after about 1 month of water injection and just before about 3 months of surfactant solution injection. On the basis of cumulative water injected, the arrival times of the two tracers are expected to be more similar. In any event, the tracer results indicate that there is

no direct fracture communication between the injector and the producers in this pattern.

Weekly water samples were taken at the offending well (3332-032) to detect the presence of the surfactant injected in Well 3332-001. As shown in Table 2, no surfactant has been found in the water produced from Well 3332-032 through the end of December 1992.

As reported in the last quarterly report, the offending producer (3332-032) has experienced a positive oil response as a result of the foam test. Production data for this well is updated in Fig. 6. Currently, this well is still flowing at a rate of approximately 20 bbl of oil per day and about 400 mcf/d of

gas. The improvements in oil cut and gas/oil ratio (GOR) are shown in Fig. 7, where the oil cut is expressed as a percentage

TABLE 2

Analyses of Produced Fluids from
Well 3332-032 for Surfactant Content

Sample date	Hyamine, mL	CD-1045, ppm
1-9-92	0.00	0
1-11-92	0.00	0
1-13-92	0.00	0
1-18-92	0.00	0
1-20-92	0.00	0
1-21-92	0.00	0
1-24-92	0.00	0
1-31-92	0.00	0
2-25-92	0.00	0
3-17-92	0.00	0
3-20-92	0.00	0
4-14-92	0.00	0
4-17-92	0.00	0
5-29-92	0.00	0
10-26-92	0.00	0
11-6-92	0.00	0
11-20-92	0.00	0
12-12-92	0.00	0
12-17-92	0.00	0
12.5 ppm standard solution	0.02	12

Fig. 5 Tracer content in brine produced from Well 3332-032 .

Fig. 6 Weekly well tests for East Vacuum Grayburg/San Andres Unit Well No. 3332-032 (February 91-March 93).

Fig. 7 East Vacuum Grayburg/San Andres Unit Well 32-032. □, oil cut (production records). ▲, oil cut (well tests). ■, gas/oil ratio.

of the total reservoir barrels of produced fluids. To date, no significant production response has been observed in the other pattern producers.

Laboratory Core Work

Foam mobility tests in reservoir cores, especially at very low flow velocities, are continuing to be conducted for input into the simulation studies. During the next quarter all the laboratory tests that have been obtained in the project will be summarized.

Simulation Studies

Reservoir simulation studies of the EVGSAU CO₂-foam field test are being conducted at the University of Houston. As reported in the last annual report,² the history match and scaleup portions of the pilot foam simulation study are complete. Modifications to the commercial simulator VIP-MISC were made to account for gas mobility reduction and surfactant adsorption during foam generation. During this quarter plots of simulated oil rate, GOR, and water cut vs. time for the eight main producers in the pilot area were compared with the field-observed data. For Zones C and E in the pilot area, maps of water saturation, solvent saturation (CO₂), and oil saturation were constructed at the following times: (a) before baseline rapid WAG cycle (Sept. 25, 1991), (b) end of rapid WAG cycle (Dec. 10, 1991), (c) end of CO₂ injection baseline (Mar. 1, 1992), (d) end of surfactant solution injection (July 17, 1992), (e) end of SAG cycle (Oct. 9, 1992), and (f) end of CO₂ injection after SAG (Jan. 11, 1993). In addition, surfactant adsorption maps for each layer at times (d), (e), and (f) and pressure maps at times (a) and (f) were prepared. Results of these simulation studies indicate that gravity effects are not a major consideration and that most of the response is occurring in Zone C. Zone E and the other zones have contributed little to the production response. Further work will consist of improving a few of the matches and beginning the predictive cases using the history-matched model with the modified commercial simulator.

Parallel simulation work has been under way at the PRRC. A limited compositional foam-flood reservoir simu-

lator is currently being developed at the PRRC by including foam mechanisms in a multicomponent, pseudomiscible reservoir simulator. The multicomponent, pseudomiscible reservoir simulator, MASTER (Miscible Applied Simulation Techniques for Energy Recovery), was obtained from DOE. The major modifications made to MASTER include (1) the addition of two conservation equations to track surfactant solution concentration and foam bubble density and (2) the addition of an algorithm to calculate the mobility of the gas/foam phase. In this new foam-flood simulator, the foam features can be bypassed, giving essentially the MASTER model, which can be used to simulate a wide range of immiscible-to-miscible gas-injection recovery processes. In addition, the simulator can be used to simulate most of the common primary and secondary recovery mechanisms by bypassing both the foam and miscible features in the model. Ideal test cases were run to validate the foam features in the model. Both the foam-bubble and surfactant-solution fronts matched the gas and water fronts very well, respectively. Current emphasis has been on the addition of a foam-apparent-viscosity table-lookup option to bypass the solving of the foam-bubble population balance equation. This new model will be modified on the basis of response obtained during the EVGSAU field test. The prediction of field performance made by this model will be compared with the results from commercial reservoir simulators during and after the field test.

A new mathematical algorithm for estimating reservoir properties via automatic and multi-well history matching is being developed at the PRRC and tested on the EVGSAU field pilot test. The reservoir parameters estimated, by solving an inverse problem, are the permeability distributions, average relative permeability, capillary pressure curves, the productivity index of each producer, the injectivity index for each injector in the pilot area, and the net injection rates into the pilot area. All parameters were estimated at reservoir scale. A least-squares error objective function was minimized by using the Simulated Annealing Method (SAM). The field data matched were the oil, water, and gas production at each well. The convergence of this new algorithm is guaranteed by the use of SAM, and the generated permeability distributions are conditioned to dynamic field data. At each iteration a limited number of reservoir parameters were perturbed according to a certain rule. Then a black oil reservoir simulator, BOAST, was used to evaluate the impact of these new parameters on the field production data. Finally, after the simulated production curves are compared with field data, the adjustments of parameters tested are rejected or retained until optimization is achieved. The algorithm was tested on the EVGSAU field during the water injection period (1979-1985). Production of oil, water, and gas was matched at the 15 wells located in the waterflood pattern. After optimization, a good match was obtained for all the field data at all the wells. The resulting large-scale reservoir description obtained by inverse modeling will be used to simulate CO₂ injection with the modified version of

MASTER. Results are being evaluated for a pending technical paper⁵ and will be summarized in the next quarterly report.

Project Plans

On Mar. 11, 1993, a JPAT meeting was held in Odessa, Tex., to review the current operations and production data, the results of the logging program in the observation well, and the progress in the simulation studies. On the basis of the favorable results observed in the foam injection test, the JPAT agreed to proceed with a second foam test. Plans for the second test are to continue to inject water for 3 to 4 weeks until the injectivity stabilizes, inject one 12-d cycle of CO₂, and inject 2 to 4 cycles of rapid SAG with the same conditions as in the first test (2500-ppm CD-1045, 80% foam quality). A comparison of the two tests will help to assess whether foam can be generated in a second test without the need for another surfactant pad for surfactant adsorption. Following the 2500-ppm test, approximately two SAG cycles will be completed at 1750 ppm followed by approximately two SAG cycles at 1000 ppm. Because all these cycles will be at the same 80% quality, the tests will evaluate how well the foam is generated at lower surfactant concentrations as well as how the field results compare with the laboratory data. A smaller working

group of the JPAT will convene to evaluate all the results that have been obtained in the project, correlate the various types of data, and provide input to be used in the final simulation runs that will be performed.

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

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

**Contract Date: Oct. 1, 1985
Anticipated Completion Date: Sept. 30, 1993
Government Award: \$347,000**

**Principal Investigator:
Duane H. Smith**

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

Reporting Period: Jan. 1-Mar. 31, 1993

Objectives

The objectives of this work are to develop the in-depth knowledge needed to improve miscible and near-miscible CO₂ flooding and related processes and to assist industry and others in the commercialization of new technologies based on this new knowledge. Primary emphasis is on (1) scaling

thermodynamics, (2) models of fluid flow and miscible fingering that also conform to current scaling theory, and (3) experiments and modeling for the development of surfactant-based mobility control on the basis of either leave-behind lamellae or fluid dispersions (two- and three-phase emulsions and foams).

Summary of Technical Progress

Continuous Phases in Emulsions of Three Liquids

Many combinations of an amphiphile, an oil, and water can simultaneously form three liquid phases over a range of temperatures and compositions. These phases, called (according to their relative densities) the top phase (T), middle-phase microemulsion (M), and bottom phase (B), respectively, form "new" morphologies that cannot occur when only two phases are present.

The literature contains only a few papers that refer to emulsions of three isotropic liquids, and most of these references are very brief. Hence there is no body of systematic studies about the morphologies of these emulsions. In particular, there is no well-substantiated model for which phase(s) can be the continuous phase and what parameter(s) determines which phase shall be the continuous one.

According to hypothesis I (part a of Fig. 1),¹ the continuous phase is always the middle phase regardless of all other

Fig. 1 Hypotheses for predicting which phase is continuous in a three-phase emulsion: (a) **M**, always continuous; (b) **B**, continuous for $T_{lc} < T < PIT$; and **T** continuous for $PIT < T < T_{uc}$; (c) **B**, **M**, or **T**, continuous at all temperatures, depending on phase volume fractions. Dashed line in part c: experimental path for Fig. 2.

parameters. On the contrary, according to hypothesis II (part b of Fig. 1),² the temperatures ($T_{lc} < T < T_{uc}$) over which three phases coexist can be divided into two ranges: for nonionic amphiphiles, the continuous phase is always the bottom phase (**B**) over the lower range of temperatures, $T_{lc} < T < PIT$; whereas the continuous phase is always the top phase (**T**) over the upper temperature range, $PIT < T < T_{uc}$. [Here PIT is the phase inversion temperature,^{1,2} also called the hydrophilic-lipophilic balance (i.e., HLB) temperature.] Hypothesis II was proposed to interpret measurements of the electrical conductivity of two systems of constant system (not phase) composition over the temperature range of three-phase coexistence.² Hypothesis I was stated in the literature some years ago, and the experimental evidence for it seems to be very limited.¹

A large number³⁻⁶ of steady-state, isothermal measurements on the effects of phase volume fractions on the electrical conductivities of two-phase emulsions indicate that neither hypothesis I nor hypothesis II could be generally correct. Therefore model III (part c of Fig. 1) was postulated. In this model the tiertriangle that bounds the composition limits for formation of triconjugate phases (at constant temperature and pressure) can be divided into three regions. In each of these

regions a different phase—**T**, **M**, or **B**—is the continuous phase. Moreover, these three regions exist at all temperatures ($T_{lc} < T < T_{uc}$) over which the three phases form.

The studies of three-phase emulsions reported here have used the amphiphile 2-(2-hexyloxyethoxy)-ethanol [$C_6H_{13}(OC_2H_4)_2OH$, i.e., $C6E2$]; *n*-tetradecane; and “water” (aqueous 10 mM NaCl) to form top, middle, and bottom phases. The phase inversion temperature of this system is 29 °C. Steady-state three-phase emulsions were formed and their electrical conductivities measured with techniques and apparatuses similar to those previously used³⁻⁶ for two-phase emulsions.

Figure 2 illustrates the effects on the steady-state emulsion conductivities at 25 °C of successive additions of phase **T** to an initial **M/B** emulsion ($\Phi_M = 0.60$, $\Phi_B = 0.40$). Clearly, the composition dependence of the conductivities of the three-phase emulsions falls into three ranges ($0.0 < \Phi_T \leq 0.11$, $0.11 \leq \Phi_T \leq 0.37$, and $0.37 \leq \Phi_T$).

Within each range the emulsion conductivity changed smoothly, slowly, and monotonically, whereas the boundaries of the three ranges are defined by large, discontinuous changes in the conductivity. These three ranges correspond to phase **B**-continuous, phase **M**-continuous, and phase **T**-continuous emulsions, respectively.

Hence Fig. 2 shows that at a single temperature any one of the three phases of a three-phase “microemulsion” emulsion can be the continuous phase and that changes of the continuous phase can be induced isothermally by appropriate changes of the phase volume fractions. Furthermore, the data of Fig. 2 explicitly show that the morphology changes **B**-continuous $\rightarrow$ **M**-continuous and **M**-continuous $\rightarrow$ **T**-continuous both occur. (The other morphology changes, **B**-continuous $\leftrightarrow$ **M**-continuous, **M**-continuous $\leftrightarrow$ **T**-continuous, and **B**-continuous $\leftrightarrow$ **T**-continuous, also can be observed along appropriately chosen experimental paths.)

Fig. 2 Electrical conductivities of steady-state emulsions along path **a** in part c of Fig. 1 showing ranges of continuous-phase **B**, **M**, and **T**, respectively, and isothermal morphology changes **B**-continuous $\rightarrow$ **M**-continuous and **M**-continuous $\rightarrow$ **T**-continuous.

Because the results in Fig. 2 demonstrate that (depending on the phase volume fractions) any of the three phases can be the continuous phase, these data show in a single experiment that neither hypothesis I nor hypothesis II is correct: Hypothesis I predicts that neither top-phase continuous nor bottom-phase continuous emulsions form; hypothesis II predicts that neither middle-phase continuous nor (at this temperature) top-phase continuous emulsions will occur. None of these four predictions is correct; only model III is in agreement with the experimental results.

This work is believed to be the first report of isothermally induced changes of morphology in three-phase emulsions. These findings can be used in the interpretation of visual studies on the flow of three-phase emulsions through porous media.⁷

Conclusions

Data are presented from three-phase, three-component emulsions in support of four claims:

1. Depending on the phase volume fractions, at every temperature any of the phases [bottom (B), top (T), or

middle (M)] of a three-phase emulsion may be the continuous phase.

2. Therefore the "choice" of continuous phase does not depend solely on the temperature.

3. Hence the "choice" of continuous phase is not uniquely determined by the wettabilities among the three phases.

4. A phase inversion temperature (PIT) cannot be uniquely defined as the temperature at which the continuous phase changes in emulsions of T, M, and B phases.

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SCALEUP OF MISCIBLE FLOOD PROCESSES

Contract No. DE-FG22-92BC14852

Stanford University
Stanford, Calif.

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Principal Investigator:
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Project Manager:
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Reporting Period: Jan. 1-Mar. 31, 1993

Objective

The objective of this research is a systematic effort to quantify the relationships between process mechanisms that can lead to improved recovery from miscible floods performed in heterogeneous fluvial deltaic (Class 1) and carbonate (Class 2) reservoirs. It will provide a rational basis for the design of displacement processes that take advantage of crossflow that

results from capillary, gravity, and viscous forces to offset partially the adverse effects of heterogeneity. In effect, the high-permeability zones are used to deliver fluid by crossflow to zones that would otherwise be flooded only very slowly. The potential is very large, as previous experiences indicate.

Summary of Technical Progress

The current project is a systematic research effort aimed at quantifying the interactions of physical mechanisms that control the scaling behavior of miscible floods. Displacement performance in a miscible flood is the result of a complex set of competing and interacting mechanisms. Phase behavior is of fundamental importance because the transfer of components from the oil to the injected fluid (as in most CO₂ floods) or from the injected fluid to the oil (as in rich gas floods) can generate mixture compositions with displacement properties very different from those of pure CO₂ and original oil. In one-dimensional (1-D) flow, the favorable effects of phase behavior can lead to displacement efficiencies that approach 100%. Displacements in reservoir rocks are anything but one dimensional, however. The rocks themselves are heterogeneous, and even if they were homogeneous, most miscible floods are subject to a hydrodynamic instability that results from displacement of oil by gas with lower viscosity. The result is nonuniform flow whether the cause is viscous fingering, reservoir heterogeneity, or, more likely, some combination of the two. When flow is nonuniform, then there is the potential, at least, for crossflow between zones of fast and slow flow.

Such crossflow can result from diffusion and dispersion, gravity segregation, or capillary or viscous forces and can cause mixing of fluids of different composition. That mixing, in turn, causes mixture compositions that occur during a multidimensional displacement to differ from the corresponding compositions in a 1-D displacement. Because composition route can strongly influence local displacement efficiency, crossflow and the resulting induced mixing will influence recovery performance in field-scale floods. The magnitude of the influence depends on the lengths over which crossflow occurs, the rate at which fluids are moved, and, of course, the phase behavior of the resulting mixtures.

The goal of this project, therefore, is to make more accurate quantitative predictions of the impact of nonuniform flow, crossflow, and phase behavior in flows in heterogeneous reservoir rocks. Past reports discussed instabilities arising from unfavorable mobility ratios that occur during injection of a solvent such as CO_2 .

In this report two-dimensional (2-D) and three-dimensional (3-D) computations by a particle-tracking technique are com-

pared for unstable displacements in homogeneous porous media with and without gravity. In homogeneous porous media without gravity, 2-D fingering patterns and the length of the transition zone are nearly the same as those obtained in 3-D displacements. When gravity is added, however, calculated gravity tongues and fingering patterns can be very different when viscous and gravity forces are of comparable magnitude.

Results obtained concerning 2-D and 3-D fingering in homogeneous media are summarized, and displacements with and without gravity segregation are compared. The computations show conclusively that there are some situations in which 2-D simulations reproduce 3-D behavior well and others in which they do not.

Homogeneous Domains

Displacements Without Gravity

Figure 1 compares a corresponding 2-D displacement with horizontal and vertical slices through the 3-D porous medium.

Fig. 1 Comparison at 0.2 pore volume injected of 2-D and 3-D displacements with $M = 30$ in a homogeneous porous medium in the absence of gravity.

Figure 1 shows that fingers have penetrated slightly farther in the 3-D displacement, but overall, fingers clearly have dimensions that are nearly the same whether the flow is 2D or 3D. Furthermore, in the absence of gravity, the numbers of fingers and their widths are essentially equal in the horizontal and vertical directions. That result is not surprising because the dimensions of fingers depend on the level of transverse dispersion, mobility ratio, and flow length, factors that act similarly in 2D and 3D.

Another comparison of 2-D and 3-D fingering is given in Fig. 2, which compares transversely averaged concentration profiles for 2-D and 3-D simulations for $M = 30$ ($M = \text{mobility ratio}, \mu_o/\mu_w$). In 2-D flow, fingering is recorded as noticeable kinks and dips in the 1-D profiles of Fig. 2. The profiles obtained from 3-D simulations are smoother. Figure 2 shows that overall the 1-D concentration profiles are remarkably similar in 2D and 3D.

There are some differences, however. The leading edge of the transition zone travels slightly faster in 3-D flow, although the total amount of solvent associated with the separation between the leading edges in 2-D and 3-D flow is small. Figure 1 indicates that the leading region of low average concentration results from a small number of fingers that have penetrated slightly farther than the rest of the pack. More fingers lead to a higher degree of nonlinear interactions. Coalescence, which is frequently observed when dispersion is anisotropic and almost absent when dispersion is isotropic,¹ coupled with shielding² enhances the growth rate of the dominant fingers. The faster penetration of the leading edge observed in 3D is the result of an enhancement of coalescence and shielding brought about by the increased competition

among more numerous fingers. The faster penetration in 3D leads to earlier breakthrough in all 3-D simulations for all the mobility ratios investigated.

The 2-D simulations summarized in Fig. 2 show several local concentration maxima. Those maxima are associated with the tips of individual fingers (see Fig. 1). Fingers spread at their tips^{3,4} and hence just behind the tips of a finger the area occupied by a finger is a smaller fraction of the flow area, and the recorded average concentration therefore can be slightly lower. Figure 1 indicates that the amount of spreading is essentially the same in both 2-D and 3-D fingers, so it is the averaging over a larger number of fingers, which have penetrated differing distances, that eliminates the maxima. A maximum could also be the signature of a sideways attack as the tip of a shorter finger coalesces with the body of a longer one. The larger sample being averaged in 3D eliminates those maxima from the 1-D profiles as well.

Displacements With Gravity

When effects of gravity transverse to the mean flow are included in the simulation, whether 2-D or 3-D displacements are similar depends on the relative importance of viscous and gravity forces. In both 2-D and 3-D displacements, of course, there is a competition between viscous forces that drive the hydrodynamic instability and buoyancy forces that attempt to create a gravity tongue.

That transition is illustrated in Fig. 3 for 2-D flow. Previous investigators have used various forms of a dimensionless group to describe the relative importance of viscous and gravity forces. Here the definition of Fayers and Muggeridge is used.⁵

$$R_{v/g} = 2 \frac{\bar{v} \Delta \mu}{\Delta \rho g k_z} \frac{H}{L} \quad (1)$$

The onset of viscous fingering occurs at about $R_{v/g} \approx 1$. When gravity effects were included, a density difference, $\Delta \rho = 0.2 \text{ g/cm}^3$, and a permeability, k , of 100 darcys, which is also the geometric mean of the heterogeneous domains, were used. The oil viscosity, μ_o , was 1 cP. The viscosity of solvent, μ_s , was varied for a particular mobility ratio, $M = \mu_o/\mu_s$, and the average darcy velocity, $\bar{v}$, was varied to obtain different $R_{v/g}$ values. The height, H , and width, W , of the 3-D domains were always equal. Unless explicitly stated otherwise, the simulations were for systems with L/H of 4. Reported were the values of all the parameters involved in $R_{v/g}$ that were used in the simulations because extensive simulations indicate that, when both viscous and gravity forces are significant, no one version of $R_{v/g}$ captures all the phenomena at work. The major point of concern is the presence of L/H as a multiplier in $R_{v/g}$. L/H appears as a coefficient elsewhere in the governing equations and cannot be varied independently.

As Fig. 3 shows for 2-D flow, at low values of $R_{v/g}$, a significant gravity tongue develops which leads to early

Fig. 2 Comparison of transversely averaged concentrations of injected fluid in 2-D and 3-D displacements with $M = 30$ in a homogeneous porous medium in the absence of gravity. ---, 3D. —, 2D.

Fig. 3 Effect of viscous/gravity ratio, $R_{v/g}$, in 2-D displacements for $M = 30$ at 0.2 pore volume injected.

breakthrough of the injected fluid. As viscous forces become more important ($R_{v/g}$ increases), the gravity tongue recedes and thus gives way to viscous fingering, which results in improved coverage and delayed breakthrough. In 2-D displacements, Fig. 3 also indicates that, for values of $R_{v/g}$ greater than about 10 for $M = 30$ and $L/H = 4$, gravity segregation has a small effect on the distribution of fluids and breakthrough time. For $R_{v/g} < 1$, gravity segregation dominates the flow.⁵ Experimental observations confirm the existence of the transition described.⁶⁻⁸

The effects of the gravity transition are summarized in Fig. 4, which reports simulation results of breakthrough times for 2-D displacements at three mobility ratios, $M = 10, 30$, and 50. Clearly, breakthrough recovery declines as M increases and/or as $R_{v/g}$ decreases. Figure 4 also shows the effect of the gravity transition for 3-D displacements with $M = 30$. Gravity

segregation causes significantly earlier breakthrough in 3D than in 2D at the same value of $R_{v/g}$ and M . Figure 4 also indicates that when flow is 3D, gravity segregation has significant impact on breakthrough time at values of $R_{v/g}$, an order of magnitude larger than those at which 2-D flow is dominated by viscous fingering.

The following explanation is given for the difference between 2-D and 3-D displacement behavior under the influence of gravity. In unstable 2-D flow (see Fig. 3), at a sufficiently high value of $R_{v/g}$, the effect of gravity is to cause upward flow of injected fluid within the fingers and downward flow of the resident, more viscous fluid, between the fingers. In 2D, that flow can only occur in the plane, and hence it must cause mixing of the two fluids. The displacements at $R_{v/g} = 1$ and 2 in Fig. 3 show clear evidence of that mixing, for example. That mixing reduces the local contrasts in viscosity

Fig. 4 Effect of viscous/gravity ratio ($R_{v/g}$) on breakthrough recovery for 2-D and 3-D displacements when $L/H = 4$. +, 3D, $M = 30$. -Δ-, 2D, $M = 30$. -■-, 2D, $M = 10$. -●-, 2D, $M = 50$.

and density and thus changes the balance between the horizontal and vertical driving forces.

In a 3-D displacement, however, vertical flow need not take place in a single plane. Instead, downward flow of the heavy, more-viscous fluid can occur between the fingers. Less mixing takes place, the viscosity and density contrasts remain higher than in 2D, and hence segregation remains important at larger values of $R_{v/g}$. Figure 5 further illustrates the enhanced vertical flow in 3D for $R_{v/g} = 20$. The corresponding 2-D flow shows no evidence of a gravity tongue. In 3-D flow, a fingered gravity tongue forms, and several fingers in various vertical slices show some upward movement with minimal mixing and dilution.

Figure 4 indicates that, whether the flow is 2D or 3D, at sufficiently low values of $R_{v/g}$ the flow is dominated by gravity override and that at sufficiently high values viscous fingering dominates. Thus, at either limit when gravity or viscous fingering dominates, 2-D and 3-D flows display similar behavior. In the transition region, which spans a wider range of $R_{v/g}$ in 3D, displacements in 2-D and 3-D flow yield significantly different distributions of fluid in the porous medium.

Fig. 5 Comparison at 0.3 pore volume injected of 2-D and 3-D displacements with $M = 30$ and $R_{v/g} = 20$ in a homogeneous porous medium.

The effect of the interplay of viscous and gravity forces on recovery in 2-D and 3-D flows is illustrated in Fig. 6, which shows recovery curves for 2-D and 3-D simulations at $R_{v/g} = 5$ for systems with $L/H = 4$ and 16. Differences between 2-D and 3-D recovery curves are small for the $L/H = 4$ case. However, the recovery curves when $L/H = 16$ differ substantially for this value of $R_{v/g}$, which is in the range where the 2-D flow is fingering-dominated for the $L/H = 16$ system, but the 3-D flow is still strongly affected by gravity segregation. Thus 2-D calculations can yield inaccurate predictions when $R_{v/g}$ is in the transition region and L/H is large, as it is likely to be in field-scale flows.

Fig. 6 Comparison of calculated oil recovery for 2-D and 3-D simulations including gravity segregation. ●, 2D, $R_{v/g} = 5$, $L/H = 4$. —, 3D, $R_{v/g} = 5$, $L/H = 4$. ○, 2D, $R_{v/g} = 5$, $L/H = 16$. ---, 3D, $R_{v/g} = 5$, $L/H = 16$.

Discussion

The examples given here show that unstable displacements in 3-D homogeneous media can be very different from displacements in 2-D porous media, especially when the effects of gravity are also considered. Thus use of 3-D simulations to assess the relative importance of viscous and gravity forces is desirable, although it is clear that such simulations will continue to be limited by the computation

time required and by the availability and resolution of 3-D reservoir description data. The results presented here suggest that at the very least some 3-D simulations should be performed to assess the uncertainty that arises if 2-D cross sections are used to select injection rates, for example. The particle-tracking technique used here is one relatively efficient approach that can be used to perform such an assessment.

Conclusions

Comparison of 2-D and 3-D simulations of unstable displacements in homogeneous porous media leads to the following conclusions:

1. In the absence of gravity, 2-D and 3-D simulations predict similar finger dimensions and averaged concentration profiles. Breakthrough times are always earlier in 3D, but 2-D and 3-D systems display similar recovery behavior.
2. The transition from flow dominated by gravity to flow dominated by viscous fingering occurs over a wider range of $R_{v/g}$ in 3-D flows. The concentration profiles and recovery in the transition region obtained from 2-D flows show significant differences from those obtained from 3-D flows.
3. For gravity-dominated ($R_{v/g} < 1$) or fingering-dominated flows, 2-D predictions of average displacement performance agree well with 3-D calculations.

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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, 1993
Funding for FY 1993: \$250,000**

**Principal Investigator:
Ting-Horng Chung**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

The objective of this research project is to improve prediction techniques for gas miscible displacement through fundamental research on displacement mechanisms. The effects of carbon dioxide on interfacial tension (IFT) and relative permeability for reservoir fluids are the research subject of this project.

Summary of Technical Progress

Calibration and Testing of the IFT Measurement Method

A high-pressure IFT measurement apparatus has been constructed for IFT measurements of CO₂, water–brine, and hydrocarbon–oil systems. The hardware and the method for the IFT measurement of pendant drops using video image profile matching were described in the previous quarterly report. Calibration and testing conducted in this quarter are described as follows:

1. *Horizontal vs. vertical coordinates.* The video camera and the monitor give an image composed of 400 lines, each having a resolution of 512 pixels. The digitized coordinate readings from the video monitor are based on the pixel number (x-coordinate) and the horizontal line number (z-coordinate). A low reflection chrome contact reticle (Edmund Scientific Co.), which has scales in 0.1-mm increments on both horizontal and vertical cross-hair lines, was used to convert the digitized coordinate readings (pixel numbers at x- and z-coordinates) to the unit of length (cm).

2. *Magnification of drop image.* The small liquid drop at the tip is magnified by a high-resolution stereo microscope

(Nikon SMZ-2T). To obtain the magnification factor, several calibration objects, which included a spherical ball and a cylindrical bar of known diameters comparable to that expected for the test drop, were installed at the position of the drop in the test cell. Illumination light was adjusted to give a sharp image of the calibration object on the monitor. The magnification was determined from the actual object diameter and the horizontal pixel number of the image diameter. The obtained magnification factor was within 0.5% accuracy. This value was used to determine the real liquid drop size and shape from the digitized image.

3. *Justification of the digitized drop image.* The drop image shape was plotted on the basis of the calibrated coordinate-readings for the digitized edge points (as shown in Fig. 1). Because of the symmetrical nature of the drop, the plotted drop shape should be symmetrical, too. On the basis of this criterion, the accuracy of digitization and the located apex point can be checked by superimposing the left-hand half on the right-hand half (Fig. 2). In this method for IFT determination through drop shape matching, only the half-part points were used. Therefore the two half parts must match each other.

The three calibration steps are very critical to the accuracy of the IFT measurement. Preliminary IFT measurements were conducted for water and *n*-heptane. The measured pure-water surface tension at 25 °C is 72.0 dynes/cm (literature reported value is 72.14 dynes/cm). The surface-tension measurement method was also compared with the Du Nouy ring method using a deionized water sample and an *n*-heptane sample. The results are as follows: This method: water, 70.62 dynes/cm; *n*-heptane, 20.40. Du Nouy method: water, 70.58 dynes/cm;

Fig. 1 A digitized pendant drop shape.

Fig. 2 Testing the symmetry of the digitized drop shape.

n-heptane, 20.49. These tests demonstrated that the National Institute for Petroleum and Energy Research method is accurate and comparable with other methods.

Prediction of CO₂ Solubilities in Hydrocarbon and Water-Brine Phases

For the measurement of the IFT for CO₂-saturated water-brine and hydrocarbon-oil systems, an accurate prediction technique for CO₂ solubility in aqueous and nonaqueous phases is required. Conventional equations of state (EOS), such as the Peng-Robinson (PR) EOS and the Soave-Redlich-Kwong (SRK) EOS, cannot adequately predict the phase behavior of CO₂-aqueous systems. The predicted aqueous-phase gas solubility may be in orders of magnitude of error.¹ Several modifications to cubic EOS have been proposed to achieve a better prediction for the phase behavior of mixtures including water.¹⁻⁶ Recently, a modified PR EOS was published by Soreide and Whitson¹ for CO₂ with pure water and NaCl brine. They modified the constant “*a*” of the PR EOS for water-brine and the binary interaction parameters as functions of temperature and salinity by fitting experimental data. For a mixture including the aqueous phase, two different EOS constants *a_{ij}* are used, one for aqueous phase and the other for nonaqueous phase. This modified PR EOS was tested with experimental data for CO₂ solubility in pure water and NaCl brine. Results are shown in Figs. 3 and 4. This modified PR EOS is not accurate enough to predict CO₂ solubility in water and brine. In addition, the modified PR EOS is applicable only for NaCl brine.

Fig. 3 Measured and predicted CO₂ solubility in water phase (experimental data from Ref. 5).

Fig. 4 Measured and predicted CO₂ solubility in water and brine (experimental data from Ref. 6).

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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.

Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$375,000

Principal Investigator:
Clarence Raible

Project Manager:
Jerry Casteel
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The objectives of this project are to (1) conduct phase behavior experiments and evaluate feasibility for alcohol-induced salt precipitation as a method for profile modification, (2) conduct experiments to change permeability of porous media using salt precipitation, and (3) conduct profile modification studies using polymer gels or alcohol-induced salt precipitation as methods to modify flow profiles.

Summary of Technical Progress

For mobility control of gas flooding, additional phase studies were conducted for alcohol-induced salt precipitation. As stated in the previous quarterly report, isopropanol and butanol were not candidates for this process because of limited miscibility in brines, whereas methanol and ethanol were completely miscible with NaCl-saturated brines. Additional precipitation experiments were conducted by mixing these alcohols and brine saturated with NaCl. Solutions were agitated for over 1 week to allow for complete phase equilibration. The solutions were then filtered through a 5- μ m filter, and the filtrate was allowed to evaporate to measure the quantity of dissolved salt. The quantity of salt precipitation was calculated as the difference between the salt in the initial brine and the salt remaining in solution. Therefore the amount of salt remaining in solution was an indirect measure of salt precipitation.

Figure 1 shows a comparison of NaCl solubility for methanol and ethanol mixtures at 23.9 °C. The NaCl was more soluble in pure methanol (0.0147 g/g) than in pure ethanol (0.0007 g/g). On a weight basis, the plot indicated that methanol would be less effective for the precipitation of salt for all alcohol concentrations.

Fig. 1 Solubility of NaCl in water and alcohol solutions of methanol and ethanol at 23.9 °C.

As a mechanism for profile modification, the salt precipitation method depended on forming salt particles to plug flow channels in the porous media. Therefore the particle size of precipitated salt was measured after NaCl-saturated brine was mixed with ethanol. With the use of a microscope to observe the particle sizes, different proportions of brine and ethanol were observed for mixtures ranging from 2.5 to 90% brine. The particles were distinctly cubic in shape, which is characteristic of halite or NaCl crystals. For solutions with a very low concentration of brine, many of the particles were too small for measurement with a microscope. For solutions with 2.5 to 5% brine, sizes of many of the observable particles were 1 to 3 μ m, and after 6 days there was little observable change in particle size.

For solutions containing 10 to 90% brine, initially after mixing brine with ethanol, there was only a small difference in particle size distributions for solutions containing different proportions of brine to alcohol. Initially, for solutions containing 10 to 25% brine, the smaller particles were about 2 to 3 μ m in size; larger crystals were 4 to 5 μ m. For solutions containing a higher concentration of brine (75 to 90% brine), the smaller sized particles were 3 to 5 μ m, with larger particles ranging in size from 6 to 12 μ m.

After 3 to 5 d, the mixtures were observed for changes in particle size. For the solutions containing a high concentration of ethanol (10% brine), there was only a small increase in particle size, and the particles remained cubic in shape. For solutions containing a higher proportion of brine, there was a noticeable increase in particle size with some of the larger particles increasing to 40 to 60 μ m. Many of the particles exhibited different crystalline shapes other than cubic, which indicated further crystalline growth with time.

From these experiments, several observations can be made on the effect of brine-to-alcohol concentration. For solutions with very low brine concentration, crystal size was limited because there was insufficient salt present to form larger crystals and to sustain further crystal growth. At

higher brine concentrations, larger crystals were formed initially and the size of the salt crystals increased with time.

Properties of Cores Used for Coreflood Tests

Coreflood tests of the profile modification method using alcohol-induced salt precipitation were conducted with Berea sandstone cores. The brine permeability of these cores ranged from 90 to 800 mD with a porosity ranging from 21.6 to 23.4%. Lengths of the cores were 27 to 30 cm with a diameter of 3.81 cm.

Two mercury invasion tests were performed to determine the pore throat radius of cores used in the coreflooding tests. The mercury injection samples were cut from high- and low-permeability Berea sandstone blocks. Brine permeabilities ranged from 700 to 800 mD and from 90 to 100 mD for the high- and low-permeability blocks. Of interest was the size of the larger pore throat radii that would control fluid flow. As shown in Fig. 2, the higher permeability sample contained a large number of pore throats ranging in size from 10 to 20 μm . The pore throat size peaked at about 12 μm . A broader spectrum of pore sizes was measured for the low-permeability

sample. The pore entry radius of larger pores ranged in size from 2 to 12 μm with a median size of about 7 μm .

Coreflood Procedures

All coreflood experiments were conducted at room temperature. The cores were initially saturated with NaCl-saturated brine and the core permeability was measured with NaCl-saturated brine. For coreflood tests, alternating-alcohol-brine slugs were injected to initiate salt precipitation in the cores. Brine and alcohol were injected into separate injection ports in the core-piece inlet to prevent fluid mixing before contacting the core. Further, during the ethanol slug injection, brine was injected continuously at 25% of the ethanol injection rate to minimize plugging in the inlet section of the core. Fluids were injected at 7.5 ft/d (9.5 cm/h), and each slug was about 5% pore volume (PV). After ethanol injection, the core was shut in to allow for salt precipitation. Various shut-in times were used to measure the effect of equilibrium time on permeability reduction. Then brine was injected at 3 ft/d (3.8 cm/h) to determine permeability reduction in the core.

Results of Coreflood Tests

Different parameters were evaluated to determine their effect on permeability reduction after injecting alcohol and saturated brine. These included the effect of core permeability, the size of the alcohol slug, and equilibrium time. Figure 3 shows the effect of alcohol slug size for cores ranging in permeability from 450 to nearly 800 mD. The higher permeability cores were less effectively plugged by alcohol injection. As measured by mercury invasion for the higher permeability cores, the median diameter of the larger pore throats was about 24 μm . Bottle test observations indicated that most of the salt crystals were not sufficiently large to plug pore throats of this size; therefore pore throats of lower permeability cores were more effectively plugged by the salt crystals. In addition, the size of the alcohol slug influenced the relative amount of permeability reduction, and the effect of the alcohol slug size is shown in this figure. When the ethanol slug size was compared (0.2 and 0.3 PV), the larger slug size was somewhat more effective in reducing the permeability.

Another factor that influenced permeability reduction was the shut-in time to allow for salt precipitation and salt crystal growths (Fig. 4). Although sufficient information is not available on the optimum shut-in time necessary to achieve maximum permeability reduction, data in Fig. 4 suggested a time interval of at least 1 week. This trend of time dependence for increasing particle size was also observed in bottle tests.

Further corefloods were conducted to determine the persistence of salt precipitation on permeability reduction by a conventional waterflood, as shown in Fig. 5. The cores were initially treated with saturated brine and ethanol. For coreflood 1, the initial brine permeability was 584 mD. The core was treated with saturated brine and ethanol slugs (a total of 0.19 PV ethanol was injected) followed by shut in of 144 h.

Fig. 2 Mercury invasion tests showing pore throat entry radii of sandstones used in coreflood experiments. (a) Brine permeability 700 to 800 mD. (b) Brine permeability 90 to 100 mD.

Fig. 3 Permeability reduction of cores after injecting NaCl-saturated brine and ethanol slugs.

Fig. 4 Permeability reduction for various shut-in times after initial injection of NaCl-saturated brine and ethanol slugs.

Coreflood 2 initially had a brine permeability of 683 mD. Core 2 was treated with saturated brine and a total of 0.31 PV of

Fig. 5 Plot showing the persistence of permeability reduction for two corefloods. The percentage of the original permeability is shown for the injection of 3 PV of NaCl-saturated brine followed by 5% NaCl brine.

ethanol. The core was then shut in for 65 h. For each coreflood, an injection rate of 3 ft/d (3.8 cm/h) was used. About 3 PV of saturated brine was injected followed by injection of 5% NaCl brine. A lower salinity brine (5% NaCl) was used rather than fresh water to reduce salinity shock and to prevent the possibility of clay swelling. Low-salinity brines provided a better measure of permeability changes than the injection of fresh water.

Initially, for the brine injection up to 1 PV, the corefloods appeared to increase about 5 to 7% in permeability. One reason for this apparent increase was the displacement of alcohol, which changed the fluid viscosity and permeability measurements. The permeability measured between 1 and 3 PV was probably a more accurate measure of the actual permeability. After 5% brine injection, the permeability increased about 5% for coreflood 1 and about 10% for coreflood 2. The corefloods indicated a good persistence of salt precipitation to maintain blocked pores after the injection of low-salinity brines.

THERMAL RECOVERY— SUPPORTING RESEARCH

***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. 22, 1990
Anticipated Completion: Feb. 21, 1993
Government Award: \$150,000**

**Principal Investigator:
Yanis C. Yortsos**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The objectives of this contract are to continue previous work and to carry out new fundamental studies in these areas of interest to thermal recovery: 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 open. 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, whereas the interplay of heat transfer and fluid flow with pore- and macro-scale heterogeneity is largely unexplored.

Summary of Technical Progress

This quarter was devoted to completing annual and final reports.

**STUDY OF HYDROCARBON MISCIBLE
SOLVENT SLUG INJECTION PROCESS
FOR IMPROVED RECOVERY OF HEAVY
OIL FROM SCHRADER BLUFF POOL,
MILNE POINT UNIT, ALASKA**

Contract No. DE-FG22-93BC14864

**University of Alaska
Fairbanks, Alaska**

Contract Date: Dec. 1, 1992

Anticipated Completion: Nov. 30, 1995

Total Project Cost:

DOE Funding for FY93 \$200,000

Contractor 119,720

Total \$319,720

**Principal Investigator:
G. D. Sharma**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The ultimate objective of this 3-yr research project is to evaluate the performance of the hydrocarbon miscible solvent slug process and to assess the feasibility of this process for improving recovery of heavy oil from Schrader Bluff reservoir. This will be accomplished through measurement of pressure-volume-temperature (PVT) and fluid properties of Schrader Bluff oil, determination of phase behavior of Schrader Bluff oil solvent mixtures, asphaltene precipitation tests, slim tube displacement tests, coreflood experiments, and reservoir simulation studies. The expected results from this project include: determination of optimum hydrocarbon solvent composition suitable for hydrocarbon miscible solvent slug displacement process, optimum slug sizes of solvent needed, solvent recovery factor, solvent requirements, extent and timing of solvent recycle, displacement and sweep efficiency to be achieved, and oil recovery.

Summary of Technical Progress

Work performed during this quarter includes preliminary reservoir fluid characterization and multiple contact test runs using equation-of-state (EOS) simulator. Reservoir fluid samples are being acquired from Conoco Inc., and the process is expected to continue through the next quarter. Also, the experimental apparatus for the displacement study was set up.

Reservoir Fluid Characterization

Reservoir fluid characterization is one of the most important considerations in simulation of slim tube experiments and simulation of miscible flood performance in a reservoir. The PVT simulator developed by Scientific Software-Intercomp is used in developing reservoir fluid characterization for Schrader Bluff crude. The PVT simulator is useful in simulating and/or matching laboratory PVT tests. Its regression capability allows the determination of EOS parameter values that result in best agreement between calculated and laboratory data. The EOS parameters determined from this simulator can be used as input data for multidimensional compositional reservoir simulation models in the future.

The PVT simulator is capable of simulating saturation pressure calculation, density, viscosity calculation, flash expansion, and multiple contact calculations. The simulator will split out any plus fraction in the hydrocarbon system into an automatically determined or specified number of extended fractions. The simulator can also be used to pseudoize the fluid sample into fewer components. Peng–Robinson EOS is used in the fluid characterization of Schrader Bluff reservoir crude.

The Schrader Bluff reservoir crude consists of thirteen components, from C_1 to C_{11+} , N_2 , and CO_2 . These thirteen components are regrouped into ten components using two pseudocomponents. C_6 to C_8 is grouped into one pseudocomponent (PC_1) and C_9 to C_{10} is grouped into other pseudocomponents (PC_2). These pseudocomponents are grouped on a weight basis. Regression is repeated on the pseudoized system for optimal match with laboratory data.

Multiple Contact Test Runs

The EOS parameters obtained from the regression on the pseudoized fluid system are used in conducting multiple contact tests using the PVT simulator. Multiple contact tests were performed up to fifteen contacts. In Schrader Bluff reservoir, the produced gas from the reservoir is reinjected back into the Schrader Bluff formation. Ninety percent of the gas is produced from the Kuparuk formation and ten percent is from the Schrader Bluff formation. From the PVT analysis report of these two gases, their compositions are mixed in the ratio of 9:1 to obtain the injected gas (KUPSCH gas) composition. The injection gas is enriched with different amounts of natural gas liquids (NGL) in each multiple contact test run. The enrichment by NGL is varied from 0 to 45%. The multiple contact test runs were conducted for 0, 5, 15, 25, 35, and 45% of NGL enrichment with the lean gas.

Figures 1 to 3 are plotted from the results obtained from the multiple contact test runs. These figures are plotted for density vs. number of contacts. For a miscible test run, the liquid and gas densities vs. the number of contacts should converge and thus show that the two fluids form one phase. From these figures, it is clear that these runs did not result in miscibility

Fig. 1 Plot of liquid and gas densities vs. contact number. (a) 100% KUPSCH gas. (b) 95% KUPSCH gas and 5% natural gas liquids.

Fig. 2 Plot of liquid and gas densities vs. contact number. (a) 85% KUPSCH gas and 15% natural gas liquids. (b) 75% KUPSCH gas and 25% natural gas liquids.

because the gas and liquid density lines do not converge. The liquid density decreases gradually because of the in situ mass transfer of intermediates from liquid phase to gas phase.

Figures 4 to 6 are plotted for equilibrium constants, K-values for different fractions (C_1 , C_2 , C_3 , C_4 , C_5 , PC_1 , PC_2 ,

and $C_{11}+$) vs. number of contacts. For a miscible test run, all lines representing each fraction in the K-value plots should converge to an equilibrium constant value of 1. These K-plots also do not show achievement of miscibility because the lines do not converge to a value of 1.

Fig. 3 Plot of liquid and gas densities vs. contact number. (a) 65% KUPSCH gas and 35% natural gas liquids. (b) 55% KUPSCH gas and 45% natural gas liquids.

Fig. 4 Plot of K-value vs. contact number. (a) 100% KUPSCH gas. (b) 95% KUPSCH gas and 5% natural gas liquids.

Future Work Plan

Core sample acquisition from Conoco Inc. will continue during the next quarter. The acquisition of field samples and materials is expected to be complete by the end of next quarter. Slim tube displacement experimental apparatus and the coreflood apparatus are being calibrated and are expected to

be available during this quarter. The General Equation of State Model (GEM) simulator developed by the Computer Modeling Group will be used to simulate the slim tube displacement runs. The PVT data-gathering process will continue through the next quarter. A three-phase compositional simulator will be used to verify the results obtained with the EOS simulator.

(a)

(b)

Fig. 5 Plot of K-value vs. contact number. (a) 85% KUPSCH gas and 15% natural gas liquids. (b) 75% KUPSCH gas and 25% natural gas liquids.

(a)

(b)

Fig. 6 Plot of K-value vs. contact number. (a) 65% KUPSCH gas and 35% natural gas liquids. (b) 55% KUPSCH gas and 45% natural gas liquids.

**DETAILED EVALUATION OF THE WEST
KIEHL ALKALINE-SURFACTANT-POLYMER
FIELD PROJECT AND ITS APPLICATION
TO MATURE MINNELUSA WATERFLOODS**

Contract No. DE-AC22-93BC14860

**Surtek, Inc.
Golden, Colo.**

**Contract Date: Jan. 7, 1993
Anticipated Completion: Sept. 30, 1994
Government Award for FY93: \$165,148**

**Principal Investigator:
Malcolm J. Pitts**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The objectives of this project are to (1) quantify the incremental oil produced from the West Kiehl alkaline-surfactant-polymer project by classical engineering and numerical simulation techniques, (2) quantify the effect of chemical slug volume injection on incremental oil in the two swept areas of the field, (3) determine the economic ramifications of the application of the alkaline-surfactant-polymer technology, (4) forecast the results of injecting an alkaline-surfactant-polymer solution to mature waterfloods and polymer floods, and (5) provide the basis for independent operators to book additional oil reserves by using the alkaline-surfactant-polymer technology.

This report will document the initial geological and reservoir engineering data gathering. In addition, some of the initial laboratory results will be discussed. Some evaluation of the West Kiehl has been published.^{1,2}

Summary of Technical Progress

Geological and Reservoir Engineering

A study area around the West Kiehl Field, located in T. 53N., R. 68W., secs. 25 and 36 of Crook County, Wyo., was selected to encompass sufficient productive Minnelusa oil fields to accomplish the objectives of the study. The area selected includes

T. 51N., R. 67W., secs. 4 to 9
T. 51N., R. 68W., secs. 1 to 12
T. 51N., R. 69W., secs. 1 to 3, 10 to 12
T. 52N., R. 67W., secs. 4 to 9, 16 to 21, 28 to 33
T. 52N., R. 68W., all secs.

T. 52N., R. 68W., secs. 1 to 3, 10 to 15, 22 to 27, 34 to 36
T. 53N., R. 68W., all secs.
T. 53N., R. 69W., secs. 1 to 3, 10 to 15, 22 to 27, 34 to 36
T. 54N., R. 67W., secs. 4 to 9, 16 to 21, 28 to 33
T. 54N., R. 68W., all secs.
T. 54N., R. 69W., secs. 1 to 3, 10 to 15, 22 to 27, 34 to 36
T. 55N., R. 67W., secs. 28 to 33
T. 55N., R. 67.5W., secs. 25 and 36
T. 55N., R. 68W., secs. 25 to 36
T. 55N., R. 69W., secs. 25 to 27, 34 to 36

This area includes over 1,500 Minnelusa penetrations and 62 separate Minnelusa oil-producing reservoirs with cumulative production ranging from 3,200 to 9,481,300 bbl. Table 1 is a list of the Minnelusa fields being studied.

Logs and scout tickets were retrieved from the Denver Earth Resources Library on all these wells. An east-to-west and north-to-south stratigraphic cross-section grid of the Minnekahta and Minnelusa sections was prepared on an approximate 2-mile grid (10 east-to-west and 4 north-to-south). With the correlation grid, tops and porous intervals in the Upper Minnelusa were determined for all the wells within the study area. A data table listing a stratigraphic breakdown of the productive portion of the Minnelusa formation for all the retrieved wells was constructed. This table includes the tops and bases of the sand units, their porous intervals, drill stem tests, and current oil production. The correlation and tabulation of these data are almost complete. The data table will be used to construct a series of geologic maps that will clearly define the geometry of the 62 producing Minnelusa reservoirs.

A series of geologic maps and cross sections were prepared for the West Kiehl Field. The cross sections were used to define three separate producing zones to be incorporated into the reservoir modeling. The structure and isopachous maps, constructed on a 1 in. = 400 ft scale, provide the basis for determining pore volumes for each of the zones. Porosity and water saturations from the logs were used to calculate hydrocarbon pore volumes. Results of the analysis of the West Kiehl Field are shown in Table 2.

A thorough search of available cores was conducted through the United States Geological Survey Core Repository in Denver and various industry sources. Because whole cores are preferable for laboratory analysis and general industry practice is to slab cores for analysis of sedimentary structure, the number of satisfactory cores available for the study is small. Three cores of productive Minnelusa reservoirs were obtained within the study area that are representative of the West Kiehl reservoir, and other whole cores will be located.

As soon as the regional map suite is completed on a 1 in. = 2000 ft scale, ten or more fields will be selected for more detailed analysis as proposed in the "Statement of Work." Two will be selected from this list for reservoir simulation. On the basis of work completed to date, at least five suitable Minnelusa reservoirs have been identified. They are Cambridge, Kiehl, Mellott Ranch, Prairie Creek South, and Semlek North.

TABLE 1
Minnelusa Field Production—ASP Study*

Field	Location			Field	Location		
	S	T	R		S	T	R
Alpha	1,2,11	51N	69W	M D	6;1; 31,36	52N,53N	68W,69W
American	5,6	52N	68W	M D North	25	53N	68W
Ammo	16,17	52N	68W	Mellott Ranch	2,10,11	52N	68W
Ash	27,28	52N	69W	Missouri	23	53N	68W
Berger Hill	6	53N	69W	Moorcroft	31,32	52N	67W
Bracken	12,13	52N	69W	Moorcroft North	24	52N	68W
Bracken South	13	52N	69W	Morel	17	53N	68W
Breaks	26	52N	69W	Mule Herder	32	53N	68W
Breaks South	35	52N	69W	Oshoto	21,22	53N	68W
Brislawn		54N	68W	Oshoto North	22	53N	68W
Brousa Draw	8	53N	67W	Oshoto South	27	53N	68W
Cambridge	28	53N	68W	Oshoto South-C	27	53N	68W
Cardinal	3	51N	69W	Ponderosa Ridge	21	53N	67W
County Line	31	52N	68W	Prairie Creek	6	53N	68W
Deadman Creek	18,19	53N	67W	Prairie Creek So	16	53N	68W
Edsel	25,26,35,36	53N	68W	Reynolds Ranch	6;1	52N	67W,68W
Guthery	3	51N	68W	Rule	15	52N	69W
Guthery North	34,35	52N	68W	Scribner	10	53N	69W
Heath	4,5,8,9	53N	68W	Semlek	27	52N	68W
Hilda	36	52N	69W	Semlek North	21	52N	68W
Hoover Gulch	24	52N	69W	Semlek NW	21	52N	68W
J B	20	53N	68W	Semlek West	28,29,33	52N	68W
Jewel	7	53N	67W	Sidner Draw	17	53N	67W
Kiehl	30,31	53N	67W	Simpson North	10	51N	69W
Kiehl West	25,36	53N	68W	Terrace	11,12	51N	69W
Lad	17-19	54N	67W	Terry Crow		54N	68W
Lad Se	20	54N	67W	Texas Trail	14,23	53N	68W
Lily	27,34,35	54N	68W	Trava	21	52N	67W
Little Missouri	5;31,32	54N,55N	67W	Wagonspoke	3;34	52N,53N	69W
Little Mitchell Creek	11,14	52N	69W	Wildfire	21	53N	68W
Little Mo	23,26	53N	68W	Wolf Draw	18	52N	68W

*T. 51N. to 55N., R. 67W. to 69W. Data: 4/9/93.

TABLE 2
Results of Analysis of West Kiehl Field

Well No.	Layer 1		Layer 2		Layer 3	
	H	oH	H	oH	H	oH
25-10	12	1.571	5	0.406	6	0.624
25-15	16	3.543	6	0.517	8	1.899
31-36	9	1.333	9	0.968	8	1.473
42-36	17	3.827	3	0.283	7	1.351
32-36	4	0.557	0		0	

Laboratory and Numerical Simulation Study

The laboratory evaluations were initiated with collection of fluid and rock samples. Crude oil, injection water, and produced water were collected from the West Kiehl. Core samples were collected from two analogous oil reservoirs: Wolf Draw (T. 52N., R. 68W., sec. 18) and Guthery (T. 51N., R. 68W., sec. 3).

Crude oil viscosity at 134 °F was 16.9 cP and the gravity was 24 °API. Produced water currently contains none of the injected chemicals. The total dissolved solids is 8100 mg/L and the hardness is 486 mg/L as CaCO₃. Injection water is from the Fox Hills formation. The total dissolved solids is 838 mg/L and the hardness is 5 mg/L as CaCO₃.

The interfacial tension (IFT) at 134 °F between West Kiehl crude oil and 0.8 wt % Na₂CO₃ plus 0.1 wt % Petrostep B-100 plus 1050 mg/L Pusher 700 is 0.017 mN/m. Dilution with produced water decreased the IFT. Dilution of the alkaline-surfactant-polymer solution with 20, 40, 60, and 80% produced water increased the IFT 2.7-, 3.9-, 13-, and 23.5-fold. These are consistent with previously published IFT values.¹

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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, 1993
Funding for FY 1993: \$300,000**

**Principal Investigator:
David K. Olsen**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The FY93 objectives of this project are to (1) analyze planned tasks in this project to ensure they meet environmental, safety, and health requirements; (2) assess the thermal research performed at the National Institute for Petroleum and Energy Research (NIPER) over the past 10 years; (3) develop procedure and apparatus for measuring dynamic saturation changes in steamfloods at field conditions using X-ray and computerized tomography (CT) scanning that incorporate temperature and pressure measurements to calibrate a numerical simulator for predictive purposes; (4) conduct laboratory research in support of Naval Petroleum Reserve No. 3 (NPR-3), Teapot Dome (Wyoming) field light oil steamflood; and (5) participate in the Annex IV meetings conducted by the Department of Energy (DOE) and the Venezuelan Ministry of Energy and Mines.

Summary of Technical Progress

This quarter three technical presentations were made: SPE paper 25786 was presented at the 1993 International Thermal Operations Symposium, Feb. 8–10, 1993, in Bakersfield, Calif.; a poster presentation entitled *Laboratory Evaluation of Surfactant as Steam Diverters* was presented at the DOE/NIPER-sponsored Symposium on the Field Application of Foams, Feb. 11–12, 1993, in Bakersfield, Calif. (part of SGP63); and a presentation of Task 58 research on light oil steamflooding was presented as part of the Annex IV meeting in Los Teques, Venezuela, conducted by DOE and the Venezuelan Ministry of Energy and Mines. A summary report (NIPER-675) on the NIPER thermal research conducted over the past 10 years was prepared. This report is a summary and critical analysis of the research that has been conducted. A

condensed version of the report will be combined with chapters from other research groups as the NIPER final report. Laboratory research conducted this quarter refined the software being developed for automation of the steamflood laboratory and is the subject of this quarter's report.

The software was developed as general laboratory operating software that is easily customized for an individual laboratory or pilot-plant application.

A new automation system was developed at NIPER to accommodate the new advances in automation technology. The research objective in developing this laboratory automation software was to enhance safety, efficiency, and the quality of research in the thermal laboratory operating under high pressure (1000 psi) and high temperature (600 °F). The software developed in 1992–1993 is user friendly and general-purpose and may be used in many different laboratory or pilot-plant applications for automation and real-time data management. The software package is for general distribution as well as for in-house use.

This software is an add-on to the National Instruments™ LabVIEW® 2, a high-level object-oriented dataflow language.¹ LabVIEW 2's visual environment allows users to develop their own automation program. However, some familiarity with their language is a prerequisite for effectively using LabVIEW 2. DOE/NIPER General Purpose Automation software eliminates the need for programming. Users can directly configure it for most automation needs in real time by following a few simple steps. It is also useful for laboratories and prototype pilot plants where instrumentation requirements change frequently.

This software is expandable to allow for future enhancements. It offers real-time data, graphics, and video display capabilities along with editing and adjustment features. The software offers instrument control by most standard methods. Warning and error recovery expert systems are other useful features. The software sends sound and text warnings to any authorized user on the network, and if no corrective action is taken in due time, it acts on a built-in logic to safely handle dangerous situations. It also prohibits users from making illogical decisions (e.g., running a pump while an in-line valve is closed or when there is no fluid in the pump's feedtank).

A topical report, *NIPER Lab Warden—The Description and LabVIEW 2® Executable Code of a General Purpose Automation Program Suitable for Laboratories Operating Under Extreme Conditions*, is being written which will contain the "General Description of NIPER Lab Warden" and "Operational Details of NIPER Lab Warden" as the two main sections. It will also include complete program code in LabVIEW 2, and the outline of a video tutorial will accompany the report. The report will contain all the material needed for anyone interested in adapting it for their own automation needs.

NIPER's automation software consists of the following three main interactive sections: Data Acquisition, Instrument Control, and Interactive Graphics.

All three of these facilities are fully integrated such that while the user interacts with one the others continue to process in the background. Facilities can be alternated manually or automatically on the basis of event priority. For example, the data acquisition panel may be activated during the actual scanning of data from pumps, pressure transducers, flowmeters, etc., to display the acquired data and report any errors. Then the interactive graphics can be called up to display the data graphically. Finally, the control panel may be activated to give a visual picture of the process. Events may be assigned priorities so that higher priority messages can automatically be switched to the interactive panel. The following is a brief description of each of the three facilities.

Data Acquisition

The data acquisition facility has three features: (1) let user manipulate current and/or previous data interactively (e.g., analyze, compare, plot, curve-fit, and print), (2) warn user of system errors and out-of-range measured values, and (3) allow user to reconfigure system setup (e.g., connect or disconnect instruments, define allowable ranges outside of which warning is issued and system is shut down, select interval between scans, and emergency shutdown sequence). The title bar contains nine buttons that allow users to select between features. By pointing and clicking on the buttons in

the title bar (see Fig. 1), users may switch between features. Some of these buttons open a new window, which allows users to make selections. Because these sub-windows have lower priority, they do not interfere with other activities, i.e., data acquisition and control functions continue in the background.

Instrument Control

The control panel for this facility is shown in Fig. 2 and is described in a report being written. The process control facility allows the user to operate the remote-sensing instruments, such as pumps, controllers, balances, temperature sensors, pressure sensors, fluid-flow controllers, and alarms, through the computer panel. The facility has a built-in logic that checks the validity of user commands and disallows them when unsound (e.g., it would not allow a user to run a pump if the outflow valve is closed), and thus the chances of avoidable accidents and failures would be reduced. Another safety feature built into the facility is the continuous monitoring of the test progress by material balance (i.e., the injected fluids and discharged fluids are continuously weighed and compared). If a discrepancy beyond the user's acceptable limits is found, the user is warned of possible leaks or other mishaps in the system. When a situation falls outside the user-defined ranges and no response from the user is received, the safety feature will automatically turn the system off.

Fig. 1 The main panel (screen) in DOE/NIPER General Purpose Automation software program.

Fig. 2 The instrument control panel (screen) in DOE/NIPER General Purpose Automation software program.

Interactive Graphics

The three-dimensional graphic display, as shown in Fig. 3, is an example of LabVIEW's data export and communication capability with other applications. In this example, every time a new data set was scanned, the graphic facility in NIPER's automation software automatically opened a Microsoft Excel™ file containing this chart. The chart was updated with new data. The chart was then automatically rotated with different attributes, such as at different angles and aspect ratios. Then the chart was closed and the control was transferred to the LabVIEW 2. All the while LabVIEW 2 continued to operate in the background acquiring (or waiting for) new data and checking for error and safety messages.

Microsoft Excel is one of many applications that can be integrated with LabVIEW 2. In fact, any application that supports the Microsoft System 7 feature of Dynamic Data Exchange (DDE) can be integrated (i.e., it can link, subscribe, and publish to or from other files). Also, any application that allows macro-expansion (sometimes called scripting) is also a good candidate for integration. The commercial applications that definitely appear to have these capabilities are Microsoft Excel, DeltaGraph Professional™, and Spyglass Transform™. Spyglass Transform can display diffused-color surreal graphics by filling in interpolated data points along with the actual data in a multidimensional spatial field.

Fig. 3 A sample snapshot of automatic three-dimensional visualization of data in Microsoft Excel. DeltaGraph Professional and Spyglass Transform can also be similarly used.

Reference

1. S. M. Mahmood and D. K. Olsen, *General-Purpose Automation Programming: A Case Study on Using a Graphic Language*, DOE Report NIPER-596, 1992.

THERMAL PROCESSES FOR HEAVY OIL RECOVERY

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

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

**Contract Date: Oct. 1, 1983
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$200,000**

**Principal Investigator:
Partha Sarathi**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The FY93 objectives are to (1) analyze the National Institute for Petroleum and Energy Research (NIPER) heavy oil database to screen Texas Gulf Coast reservoirs for priority ranking, (2) collect reservoir data for the most promising reservoirs, and (3) conduct simulation studies to determine the applicability of thermal enhanced oil recovery (EOR) techniques in the most promising heavy oil reservoirs in the Texas Gulf Coast area.

Summary of Technical Progress

Assessment of the Past NIPER Thermal EOR Research Program

The objective of this task is to review objectively the thermal EOR research performed at NIPER over the past 9 years and recommend future direction for the program. This task was jointly undertaken with researchers of BE11A (Thermal Processes for Light Oil Recovery), and a report detailing the assessment (NIPER-675) is being reviewed by NIPER and the Bartlesville Project Office.

Evaluation of the Steamflood Potential in Texas Gulf Coast Heavy Oil Reservoirs

From screening studies, Coleman and Taylor-Ina (Texas) fields were found to be comparatively better candidates for steamflooding. Only a limited amount of data were available for Coleman field. The core analysis report for this field indicated that the formation consists of shaly and silty sand with an average permeability of 400 mD. Formation thickness is less than 24 ft, and sometimes non-pay zones are present at the middle or at the bottom part of the pay zone. Conversely,

much data were available for Taylor-Ina field. A report on previous attempts of secondary and tertiary recovery methods in this field shows that a pilot cyclic steam stimulation was conducted in a well on the Hutzler "A" lease in 1966. The well produced 40 bbl of oil per day in the beginning and then continued to produce at a rate much higher than the unstimulated rate for several months. Similar attempts in other wells failed, probably because of sanding problems. Considering the previously mentioned factors and a high oil saturation, Taylor-Ina field has been selected for further studies.

Reservoir Description

Reservoir data were obtained from a recently conducted study on engineering and geological evaluation of the Hutzler "C" lease by Harper Petroleum Engineering, Inc. A core analysis report on well Hutzler "C" 44 was available. The producing zone was divided vertically into three sections, and the results are summarized in Table 1.

The vertical permeabilities were assumed to be one-half the horizontal permeabilities. The primary oil recovery was 2.3% (until February 1993), and no secondary–tertiary recovery process has yet been initiated on a field-wide basis.

TABLE 1
**Thickness, Porosity, Permeability, and Water
Saturation Values at Well Hutzler "C" 44**

Zone	Thickness, ft	Porosity, fracture	Permeability, mD	Water saturation, fracture
1	6	0.32	50	0.45
2	6	0.32	50	0.45
3	6	0.32	60	0.45

Fracture Characteristics

Most of the wells in the Hutzler "C" lease were hydraulically fractured and sand propped. A preliminary evaluation of the fracture job in a well (Hutzler "C" 3), using the procedures of Sarkar and Sarathi,¹ indicated that orientation of the fracture was vertical. The width and length of the fracture were 0.2 in. and 312 ft, respectively. The productivity index was 6.3. The permeability of the fracture was 2000 darcys, and the porosity was assumed to be the same as that of the matrix (0.32).

Viscosity of Oil

On the basis of viscosity vs. temperature data of oil from surrounding leases, the following data were assumed for the Hutzler "C" lease (Table 2).

Relative Permeability and Capillary Pressure

The matrix oil–water relative permeability curves were assumed to be the same as those given by Morgan and Gordon²

for fine-grain sandstone containing clay. The matrix gas-oil relative permeability values were assumed to be similar to those given by Aziz et al.³ The fracture oil-water relative permeability and capillary pressure values were assumed to be the same as those given by Kazemi et al.⁴ The fracture gas-liquid relative permeabilities were assumed to be linear. The temperature dependency of matrix relative permeability values was arbitrarily assumed and is given in Table 3 (Ref. 5).

TABLE 2

Crude Oil Viscosity Data as a Function of Temperature

Temperature, °F	Viscosity, cP
75	500.0
77	466.0
109	146.0
140	60.4
210	13.0
500	1.3

TABLE 3

Effect of Temperature on Relative Permeability*

Temperature, °F	S_{wr} , fracture	S_{orw} , fracture	S_{gr} , fracture
85	0.40	0.25	0.10
545	0.5	0.15	0.06

*See reference 5.

† S_{wr} , residual water saturation; S_{orw} , residual oil saturation to water in water-oil system; S_{gr} , residual gas saturation.

Numerical Simulation

Because a previous study¹ indicated that a reservoir with thin pay and low permeability is not conducive to cyclic steaming, no cyclic steam simulation was performed; instead, numerical simulation of a steamflood was initiated. A quarter of a 5-spot pattern of a 2-acre area was considered for the simulation of a steamflood. The dual-porosity model was used to represent the hydraulic fracture.⁶ For the injection well, the maximum injection pressure was limited to 1000 psi and the bottomhole steam quality was assumed to be 70%. The maximum steam injection rate was limited to 400 bbl/d.

In a run, using $8 \times 8 \times 3$ grid and 11 ft as the width of the block containing fractures, the oil recovery and the cumulative oil/steam ratio (COSR) were found to be 51% and 0.15, respectively, at the end of 1058 days of steamflooding. Figure 1 shows the histories of oil production rate, steam injection rate, and water/oil ratio. Figure 2 shows histories of cumulative oil production and COSR.

Fig. 1 Histories of oil production rate (—□—), steam injection rate (---○---), and water/oil ratio (---◆---) (WOR).

Fig. 2 Histories of cumulative oil production (—○—) and cumulative oil/steam ratio (---□---) (COSR).

Assessment of Mobil's Steamflood Predictive Model

A compiled version of the steamflood performance prediction software was received from Mobil E&P Inc., in late March 1993 and was installed in a 486-PC. The usefulness of this model as a field steamflood performance prediction tool will be assessed during the next quarter.

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5. D. F. Frizzell, *Analysis of 15 Years of Thermal Laboratory Data: Relative Permeability and Saturation Endpoint Correlations for Heavy Oils*, SPE paper 20528 presented at the 65th ATCE of the Society of Petroleum Engineers, New Orleans, La., Sept. 23-26, 1990.

6. V. Oballa, D. A. Coombe, and W. L. Buchanan, *Factors Affecting the Thermal Response of Naturally Fractured Reservoirs*, paper CIM/AOSTRA 91-53 presented at the CIM/AOSTRA Technical Conference in Banff, Apr. 21-24, 1991.

**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
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**Principal Investigator:
David K. Olsen**

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

Reporting Period: Jan. 1-Mar. 31, 1993

Objectives

The objectives of this nationwide heavy oil feasibility study are to (1) investigate from publicly available data the known heavy oil resources; (2) screen these resources for potential thermal or other enhanced oil recovery (EOR) techniques; and (3) evaluate various economic facets that may have an impact on the expansion of heavy oil production—refining, transportation, environmental, etc.

Summary of Technical Progress

Computer Model Analysis of Heavy Oil EOR Potential

Information is being compiled on the heavy oil (10 to 20 °API) resource. Although the compilation is not complete, preliminary data were computer modeled to obtain a rough approximation of the EOR potential on the basis of this new database. Reservoir information on 505 reservoirs represent-

ing 68.6 billion bbl of original oil in place for computer modeling has been compiled. The computer model that was used is an adaptation of the Department of Energy Tertiary Oil Recovery Information System (DOE TORIS) model derived from the National Petroleum Council (NPC) 1984 EOR study.¹

The sensitivity of potential EOR production to oil price, rate of return (ROR) on investment, and technology as well as the geological setting and geographic location was studied. The nominal oil price used for this study is the price for 40 °API. Oil prices are adjusted for API gravity and location of the production by an interpolation developed by M. W. Britton during the NPC study.¹ For example, 10 °API oil produced in California is 60.2% of the nominal price, 20 °API produced in California is 76.2% of nominal, and a Kern River 13 °API crude is interpolated to 64% of nominal. Discounts for non-California crudes are lower—20 °API non-California crudes are 83.8% and 10 °API non-California crudes are 60.5% of the nominal price.

The results are summarized in Table 1 for steam and Table 2 for in situ combustion and alkaline-surfactant-polymer (ASP) flooding. The results showed an 11.5 billion bbl potential for implemented steam technology, a 15.8 billion potential for advanced steam technology, a 1.3 billion bbl potential for implemented and advanced in situ combustion, and a 1.0 billion bbl potential for advanced alkaline flooding technology at \$20/bbl at 10% rate of return without considering mutually excluding results. This compares to the 4.4 billion bbl estimated by the NPC for implemented thermal recovery technologies at the same economics and the 10.5 billion bbl estimate for advanced thermal technology at \$30/bbl. Because the parameters that define implemented steam technology were expanded to include reservoir conditions of successful projects started during the 1980s and this new reservoir database is more inclusive, the results are not inconsistent with the NPC results for thermal recovery but are more optimistic. The NPC study did not specifically estimate ASP potential for heavy oil but estimated 9.9 billion bbl for surfactant and 0.07 billion barrels for alkaline at \$30/bbl, which would likely include this advancing technology.

The greatest potential recovery of heavy oil is from steam processes using advanced technology (deeper, thinner, and tighter reservoirs than those targeted by implemented technology). Within this large potential, the majority are unconsolidated California turbidite deposits. Another smaller but significant potential is 230 to 370 million bbl near the U.S. Gulf Coast. This area is likely underestimated because information is now being collected on heavy oil Gulf Coast reservoirs. The target reservoirs for in situ combustion and advanced alkaline recovery processes generally are targets for advanced steam recovery processes. The economic results generally favor steam recovery because the recovery efficiencies and operating costs are well understood for steam. There is a bias toward steam in the advanced technology because the model does not factor in future improvement in operational efficiencies that are likely for developing processes such as ASP.

TABLE 1
Potential Oil Recovery Estimated by TORIS Model on 1992 Data
Steam Injection Recovery Technologies (billions of barrels)*

	Steam injection											
	Implemented technology, \$/bbl						Advanced technology, \$/bbl					
	17	20	23	26	30	32	17	20	23	26	30	32
ROR† sensitivity												
Potential at 10% ROR	9.53	11.54	12.34	12.56	12.87	12.95	13.37	15.77	16.73	17.11	17.65	17.82
Potential at 15% ROR	9.08	9.73	11.94	12.19	12.55	12.59	12.71	13.61	16.27	16.68	17.28	17.39
Location												
California	9.29	11.30	12.00	12.24	12.55	12.60	13.10	15.40	16.30	16.70	17.37	17.40
Gulf Coast	0.23	0.27	0.30	0.30	0.30	0.30	0.26	0.32	0.37	0.37	0.37	0.37
Midcontinent	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04
Depositional system												
Fluvial-dominated delta	1.80	1.93	2.00	2.09	2.34	2.34	2.81	3.02	3.13	3.33	3.81	3.81
Turbidite	7.73	9.62	10.35	10.47	10.54	10.55	10.23	12.42	13.28	13.45	13.52	13.69
Other							0.32	0.32	0.32	0.32	0.32	0.32
Lithology												
Unconsolidated/friable sandstone	8.43	10.36	11.10	11.31	11.60	11.60	10.69	12.95	13.85	14.20	14.72	14.85
Consolidated sandstone	1.11	1.18	1.24	1.25	1.28	1.28	1.35	1.46	1.53	1.55	1.57	1.61
Fractured							1.32	1.35	1.35	1.36	1.36	1.36
No. of reservoirs at 10% ROR	109	121	131	134	134	135	128	141	151	155	155	155

*See reference 2.

†ROR, rate of return.

TABLE 2
Potential Oil Recovery Estimated by TORIS Model on 1992 Data In Situ Combustion
and Alkaline Flooding Recovery Technologies (billions of barrels)*

	In situ combustion advanced and implemented technology, \$/bbl						Alkaline-surfactant advanced technology, \$/bbl					
	17	20	23	26	30	32	17	20	23	26	30	32
	17	20	23	26	30	32	17	20	23	26	30	32
ROR† sensitivity												
Potential at 10% ROR	0.60	1.27	2.37	2.96	3.87	3.99	0.31	0.97	1.25	1.44	1.44	1.44
Potential at 15% ROR	0.60	0.79	2.16	1.65	3.21	3.54	0.28	0.89	1.15	1.27	1.27	1.27
Depositional system												
Fluvial-dominated delta	0.09	0.14	0.25	0.32	0.62	0.70	0.00	0.01	0.01	0.01	0.01	0.01
Turbidite	0.51	1.13	2.12	2.64	3.25	3.30	0.31	0.96	1.25	1.43	1.43	1.43
Location												
California	0.60	1.25	2.32	2.86	3.72	3.82	0.31	0.96	1.24	1.43	1.43	1.43
Gulf Coast	0.00	0.03	0.05	0.10	0.15	0.21	0.01	0.01	0.01	0.01	0.01	0.01
Lithology												
Unconsolidated/friable sandstone	0.60	1.06	2.02	2.52	3.36	3.49	0.31	0.95	1.21	1.38	1.38	1.38
Consolidated sandstone	0.00	0.15	0.26	0.34	0.38	0.39	0.00	0.02	0.04	0.06	0.06	0.06
Fractured	0.00	0.06	0.09	0.10	0.12	0.12						
No. of reservoirs at 10% ROR	4	15	31	51	70	75	3	9	15	19	19	19

*See reference 2.

†ROR, rate of return.

References

1. National Petroleum Council, *Enhanced Oil Recovery*, 1984.
2. J. F. Pautz, personal communication with T. Reid, DOE Bartlesville Project Office, Mar. 12, 1993.

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 1993: \$188,000**

**Principal Investigator:
Partha Sarathi**

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

Reporting Period: Jan. 1–Mar. 31, 1993

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

Two steam-foam runs were conducted after base-case history match. The objective was to qualitatively study the effect of the foam on the reservoir process before conducting the steam-foam history match. The reservoir grid description and the base-case history match results were previously reported.¹ The surfactant properties used in the simulation are shown in Table 1. The surfactant was injected at the bottom of the pay zone, where the field injection well was completed. A phase mobility reduction range of 1 to 12 was used to interpolate between the foam and no-foam cases. The surfactant concentration was kept constant at 0.3 wt % of the injection stream. The steam quality was assumed to be 50% to provide adequate liquid volume fraction for improved foam generation.² Analysis of the results indicated a gradual improvement in areal sweep (diversion of steam to lower portion of the reservoir) and significant improvement in oil production after a delay caused by the redistribution of steam flow paths. No surfactant breakthrough was predicted after 2 yr of foam injection, which indicates that foam and surfactant propagate at the same rate.

Foam History Match

An attempt to match Chevron's Section 26-C steam-foam pilot² data was made. Because of the need to estimate

TABLE 1
Surfactant and Foam Properties

Surfactant concentration	0.3 wt % per mg of fluid
Oil-water partitioning factor (k-value)	0.1
Sensitivity to residual oil	Above 50%, no foam
Adsorption	Adsorption
T (°F)	
120	0.378 mg surfactant/g of rock
300	0.170 mg surfactant/g of rock
480	0.055 mg surfactant/g of rock
Thermal degradation	
T (°F)	Half life, d
120	3580
420	60
520	25
Foam properties	
Maximum mobility reduction factor (MRF)	= 60
Reference capillary number N_c^f	= 10^{-6}
Relative permeabilities	
Water/oil: S_{wc} , S_{orw} , K_{rw} , K_{row}	= 0.3, 0.25, 0.4, 1.0
Gas/oil: S_{gc} , S_{org} , K_{rg} , K_{rog}	= 0.05, 0.1, 1.0, 1.0

Note:

S_{wc} , connate (irreducible) water saturation; S_{orw} , residual oil saturation to water in water-oil system; S_{gc} , residual critical gas saturation; S_{org} , residual oil saturation in steam swept zone; K_{rw} , relative permeability to water; K_{row} , relative permeability to oil in water-oil system; K_{rg} , gas phase relative permeability; K_{rog} , relative permeability to oil in gas-oil two-phase system with irreducible water present.

missing data and interaction among the various parameters, a satisfactory history match was not obtained. Although matching the pressure profile was successful, the temperature match was less than satisfactory. Although the simulation predicts significant temperature response after 45 d of foam injection, field observation indicated significant response after 80 d of foam injection. Attempts to match temperature profile caused the pressure profile to deviate significantly from the observed value and a reduction in oil production rate. The inability to match the temperature is attributed to the basic assumption of the simple foam model employed—namely, that foam (pressure pulse) and surfactant propagate at the same rate. Observation in the field indicated that this is not the case and that foam significantly lags surfactant propagation. Additional simulation runs with increased surfactant adsorption are planned to obtain better history matching.

References

1. National Institute for Petroleum and Energy Research, *1st Quarterly Technical Report for Oct. 1–Dec. 31, 1992*, DOE Report NIPER-671, Vol. 2, p. 21, 1993.
2. F. Friedmann, *Steam-Foam Mechanistic Field Trial in the Midway-Sunset Field*, paper SPE 21780 presented at the Society of Petroleum Engineers Western Regional Meeting, Long Beach, Calif., Mar. 20–22, 1991.

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: \$39,000

Principal Investigator:
David K. Olsen

Project Manager:
Thomas Reid
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The objectives of the symposium on Field Application of Foams for Oil Production were 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

On Feb. 11–12, 1993, the U.S. Department of Energy (DOE) and the National Institute for Petroleum and Energy Research (NIPER) cosponsored a 1½-d symposium on the Field Application of Foams for Oil Production. The symposium was held at the Red Lion Inn in Bakersfield, Calif. Seventy-two people attended the symposium, and participants listened to 13 papers and 8 discussions of posters and participated in a panel discussion. The preprints of the symposium, NIPER-667, contained the papers and abstracts of posters. The proceedings for the symposium, NIPER-669, contains the papers, extended abstracts of poster presentations, and a summary of the panel discussion. A summary of the meeting and additional comments on the future of foam technology were submitted to the Bartlesville Project Office as NIPER-681. It is anticipated that DOE will publish the proceedings as a Fossil Energy report, and copies will be sent to participants. The Foams Symposium was considered a success by participants, and many expressed a desire to see a similar specific-topic symposium that would focus on the potential and problems of an oil recovery technology.

OIL FIELD CHARACTERIZATION AND PROCESS MONITORING USING ELECTROMAGNETIC METHODS

Lawrence Livermore National Laboratory
Livermore, Calif.

Contract Date: Oct. 1, 1984
Anticipated Completion: Oct. 1, 1993
Government Award: \$350,000

Principal Investigator:
Mike Wilt

Project Manager:
Thomas Reid
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1993

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 second quarter of 1993 work continued on instrumentation and software and plans continued for an upcoming field survey. Much of the field hardware and companion software for this program are being developed jointly with Schlumberger–Doll Research (SDR) under a Cooperative Research and Development Agreement (CRADA).

In particular, the new borehole transmitter was field tested and the results were compared with the performance of the initial prototype and with the design specifications for the new coil. A new imaging code, developed by SDR, was tested on a set of crosshole EM data collected in Devine, Texas, in 1990. The resulting image is an improvement over earlier codes and is encouraging for the application of the crosshole method in regions of highly contrasting resistivity structure and complex geology.

Development of a 2½-Dimensional Imaging Code

Together with SDR a multifrequency multicomponent crosshole EM system is being developed for application to oil-field characterization and process monitoring. The new

system will offer improved data quality over the existing crosshole system and, with companion software, it will dramatically improve subsurface imaging capabilities.

Recently a new imaging code to interpret crosshole EM induction data was developed by SDR. This code assumes a two-dimensional rectangular earth geometry and arbitrary resistivity distribution within the image plane. The code is a

significant advance over previous codes because of its flexibility, speed, and ability to handle high contrast anomalies and irregular geology.

Figure 1 shows an image that uses the code of the crosshole EM data set collected in Devine, Texas, in 1990. As described by Wilt et al.,¹ the strata at Devine are flat-lying and continuous and the crosshole data set is of excellent quality. This same

Fig. 1 Image of the conductivity distribution at the British Petroleum Devine, Texas, test site. Image was obtained by tomographic inversion of crosshole electromagnetic data collected by Lawrence Livermore National Laboratory using a code developed by Schlumberger-Doll Research.

data were interpreted with the existing code.² Figure 1 also shows the borehole induction log to the left of the image for comparison purposes.

The image faithfully reconstructs the resistivity structure with significant error only at the top and bottom of the image plane, where the spatial coverage is incomplete for imaging. There are minor errors in the absolute value of the resistivities and some small artifacts, but, in general, the code does a good job of reconstructing the conductivity distribution between the boreholes.

Field Test of New Borehole Transmitter

The initial step in Lawrence Livermore National Laboratory's (LLNL's) cooperative research plan mentioned previously is the development of a single-frequency d-c-activated transmitter. With this transmitter only direct current is supplied from the surface, and the coil self-resonates at a frequency controlled by the inductance of the coil and the series capacitance. This d-c-activated transmitter lessens any chance of signal leakage, which was a significant problem with the previous source. The new design also allows the development of an automatic switching system, using computer-controlled relays, to control the transmission frequency. It is designed to operate at frequencies from 5 to 160 kHz.

During this past quarter the final stage of tool construction was completed, and the coil was tested at Richmond field station. The field tests were designed to measure the performance of the tool and the repeatability of field measurements. The results are summarized in Table 1, which shows the transmitter moment **M** (strength of the source) of the new and older coils along with repeatability estimates (in percent) for data collected at Richmond field station. Note that the new coil is much more powerful than the previous version but less powerful than the predictions based on the initial design specifications. The disparity is the result of unexpected losses in the ferrite core material and a current limitation in the

downhole resonant driver. Use of the new source also results in more repeatable data, which is primarily the result of the reduction of unwanted signal leakage from the source to the receiver.

The construction of the d-c-powered single-frequency tool is the first step in the development multifrequency transmitter, as directed by the LLNL/SDR CRADA. The multifrequency tool will have an array of capacitors and several separate windings on its core as opposed to the present tool, which has only one. To change frequencies, all that will be required is to switch between coil windings and capacitance values and the tool will self-resonate at a frequency governed by this new combination. The switching will be done with computer-controlled high-voltage relays located within the tool housing.

Upcoming Field Project at Lost Hills No. 3

Recent work by Mobil in the Lost Hills No. 3 oil field is improving the injectivity of the wells to the point that significant quantities of steam are being injected into oil-bearing sands. Because of this improvement and the fact that the baseline data to monitor the steam injection are almost 2 years old, the baseline survey will be repeated and expanded to include measurements in some new configurations. The new survey is scheduled for May 1993 and will include multifrequency crosshole measurements using existing fiberglass-lined wells that straddle one of the injectors. In addition to this, a series of surface-to-borehole measurements using fiberglass and steel-cased borehole are planned.

The surface-to-borehole profiles will use multiple surface-based loop and electrical dipole transmitters and borehole receivers. The borehole sensors will be spaced from the surface to the bottom of the 500-ft boreholes; this is shown schematically in Fig. 2. The new field data will help in the assessment of the ambient noise and resolution of the surface-to-borehole technique for a relatively shallow oil-sand target at Lost Hills.

TABLE 1
Test Results for New Borehole Transmitter

Frequency, kHz	Predicted M *	Actual M	Repeatability, %	Old coil M	Repeatability, %
1,000	400	275	0.5	105	1.0
2,000	400	275	0.5	105	1.5
5,000	400	275	0.5	105	1.5
10,000	400	275	0.8	105	2.0
20,000	400	250	1.0	95	2.5
50,000	250	150	1.5	50	3.0
1000,000	150	80	2.0	20	5.0

*Transmitter moment.

Fig. 2 Schematic representation of the surface-to-borehole data collection for the imaging of shallow oil sands, such as at Lost Hills.

References

1. M. J. Wilt, H. F. Morrison, A. Becker, and K. H. Lee, *Cross-Borehole and Surface-to-Borehole Electromagnetic Induction for Reservoir Characterization*, DOE Report DOE/BC/91002253, 1991.
2. D. L. Alumbaugh and H. F. Morrison, Tomographic Imaging of Crosshole EM Data, expanded abstracts from Society of Exploration Geophysicists Annual Meeting, New Orleans, Louisiana, 1992, pp. 495-497.

RESEARCH ON OIL RECOVERY MECHANISMS IN HEAVY OIL RESERVOIRS

Contract No. DE-FG22-93BC14899

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

**Contract Date: Feb. 8, 1993
Anticipated Completion: Feb. 7, 1997
Government Award: \$800,000
(Current year)**

**Principal Investigators:
W. E. Brigham
H. J. Ramey, Jr.**

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

Reporting Period: Jan. 1-Mar. 31, 1993

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 studies—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—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. Steam with additives—to investigate the mechanisms of the process using commercially available surfactants for reduction of gravity override and channeling of steam.
4. Formation evaluation—to develop 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 Department of Energy (DOE)-sponsored or industry-initiated field projects.

Summary of Technical Progress

Flow Properties Studies

Simulation of the relative permeability experiments with end effects was performed using the ECLIPSE simulator. One-dimensional runs proved to be inadequate to history match the experiments. Two-dimensional runs taking into account the end-plug geometry were successful. Both experiments and simulations show that the flow paths of oil and water are segregated. A high-average wetting-phase saturation is present at the outlet with small regions for nonwetting fluid flow. A nonlinear flow pattern was observed near both the inlet and outlet. High-saturation gradients remained at the end of the drainage experiments. Future work will include extension to other oil-brine pairs and comparison of the results obtained by two-dimensional simulation with results from the classic Johnson-Bosler-Newman method.

A report on the simulation of two-phase flow in fractured reservoirs is in the draft stage. Design of an experiment to study matrix-fracture flow patterns using the computerized axial tomography (CAT) scanner is in progress.

Development of interactive software for the interpretation of the CAT scanner results and display of the data continued. The IDL software package purchased last quarter was installed and tested. It worked as planned, especially for three-dimensional (3-D) display of flow experiments.

A search was initiated to investigate the possibility of improving the scanner. The result was a proposal to DOE to purchase a used fourth-generation scanner and modify it to allow both vertical and horizontal scans. This would improve both speed and quality of data acquisition and would allow the design and construction of gravity stabilized experiments.

A literature search on steam-water relative permeabilities was started. This is an important parameter not only in thermal recovery processes but also in geothermal systems.

In Situ Combustion

The notes gathered from the In Situ Combustion Forum held last April in Tulsa, Okla., were discussed during the industrial advisory committee meeting. The only new U.S. projects are from independents, and the level of research effort varies from company to company but is generally low. Industry advisors believe that the research on combustion should continue.

Tube runs were completed on crude oils from Cold Lake (Canada), Hamaca (Venezuela), and Huntington Beach (California) with various amounts of clay in the solid matrix. A report describing the results of the kinetics studies and tube runs is in the draft stage and is scheduled for publication by DOE in June 1993. This report will also include results of experiments performed on the same oils in Ankara (Turkey).

Steam with Additives

Computer modeling of the 3-D steam and steam-foam experiment continued. The experiment simulated one-quarter of a five-spot pattern. Because the steam zone growth obtained by simulation was slower than that during the experiments, the heat-transfer parameters of the simulator were modified by combining a convective heat-loss term with the existing semiinfinite overburden model. There was then a reasonably good match between the experiment and the simulator. Repeat experimental runs are needed to improve production data gathering and to include material-balance verification of the simulated results.

Construction of the apparatus for steam injection in fractured media is in progress. Special thermally resistant glues and fittings are needed to build the model. Various epoxies are being tested. In parallel, fine-grid numerical simulations are being made to finalize the design parameters, such as injection rates and insulation thickness.

A report was sent to DOE on characterization of foaming agents with oil present in the porous medium at typical California steam injection conditions. The rate of foam propagation appears to be an important factor in the ability of a surfactant to generate a large pressure gradient when there is crude oil. Further study is needed.

Formation Evaluation

A report on the numerical simulation of well tests in gravity drainage reservoirs is in the draft stage. The efforts to analytically model the same problem are also continuing. Publication of the report is scheduled for June 1993.

Field Support Services

A preliminary report on ultrasonic rate measurement of multiphase flow was sent to DOE for review. A commercial

transit time flowmeter was purchased and tested for this research. Results are promising for single-phase and gas-water flows. The goal of this project is to build and calibrate a true multiphase flowmeter. This tool could become important for production logging, especially for locating production and thief zones and monitoring production and injection rates.

Traditional analysis of production systems treats individual nodes one at a time. A report sent to DOE for review

describes multivariate optimization of production, which allows the determination of the most profitable configuration, including all variables simultaneously. This method can also find optimal recovery over a period of time rather than just at a single instant as in traditional methods. Examples show that, under an optimal strategy, tubing size can be changed only infrequently and still increase profitability of a project.

GEOSCIENCE TECHNOLOGY

**RESEARCH ON IMPROVED AND
ENHANCED OIL RECOVERY IN
ILLINOIS THROUGH RESERVOIR
CHARACTERIZATION**

Contract No. DE-FG22-89BC14250

**Illinois Department of Energy
and Natural Resources
Springfield, Ill.**

**Contract Date: June 29, 1989
Anticipated Completion: June 27, 1993
Government Award: \$373,000**

**Principal Investigator:
Donald F. Oltz**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

This project will provide information that can maximize hydrocarbon production, minimize formation damage, and stimulate increased production in Illinois. Such information

includes definition of hydrocarbon resources, characterization of hydrocarbon reservoirs, and the proposed implementation of methods that will improve hydrocarbon extractive technology. Increased understanding of reservoir heterogeneities that affect oil recovery can aid in identifying producible resources. The transfer of technology to industry and the general public is a significant component of the program. The project is designed to examine selected subsurface oil reservoirs in Illinois. The research team uses advanced scientific techniques to gain a better understanding of reservoir components and behavior and addresses ways of potentially increasing the amount of recoverable oil. In the Illinois Basin as much as 60% of the oil in place can be unrecoverable with standard operating procedures. Heterogeneities (geological differences in reservoir makeup) affect the capability of a reservoir to release fluids. Bypassed mobile and immobile oil remains in the reservoir. To learn how to get more of the oil out of reservoirs, the Illinois State Geological Survey (ISGS) is studying the nature of Illinois reservoir rock heterogeneities and their control on the distribution and production of bypassed mobile oil.

Summary of Technical Progress

Field Studies

The Tamaroa Field Study has been published.¹

Additional field studies in the project series that have been submitted for editing and drafting include Stewardson

field, Energy field, and Boyd field. The pressure-volume-temperature (PVT) study is soon to be published. An engineering simulation model of Zeigler field is also in the publication process.

Oil and Gas Development Maps

Development of a computer-generated series of maps to replace the older ISGS series of hand-drawn oil and gas development maps continues.

Maps completed to date	
Alto Pass	McLeansboro
Benton	Mt. Vernon
Carbondale	Murphysboro
Carlyle	Nashville
Cave-In-Rock	New Burnside
Centralia	Noble
Clay City	Patoka
Du Quoin	Pinckneyville
Effingham	Roaches
Fairfield	Rosiclare
Goreville	Shelbyville
Kinmundy	Thompsonville
Louisville	Xenia
Mattoon	
Maps in progress	
Carmi	

Reservoir Engineering

Reservoir simulation models have been constructed for the following fields: Dale Consolidated, Zeigler, Energy, and Lawrence. Flow units have been defined, and history match is in progress.

Technology Transfer

Four team members manned a booth at the 1993 annual Illinois Oil and Gas Association (IOGA) meeting in Evansville, Ind., Mar. 11 and 12, 1993. Over 300 oil and gas industry representatives attended the meeting. The team demonstrated Questor (a software package for accessing well data), showed examples of computer-generated oil and gas development maps, and reviewed several projects, including characterization and reservoir management at Tamaroa and Energy fields and results of PVT and carbon dioxide miscibility studies. Industry interest was excellent.

Reference

1. J. P. Grube, Reservoir Characterization and Improved Oil Recovery from Multiple Bar Sandstones, Cypress Formation, Tamaroa and Tamaroa South Fields, Perry County, Illinois, Ill., *State Geol. Surv., Ill. Pet.*, 138 (1993).

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
Government Award: \$195,000**

**Principal Investigators:
H. Frank Morrison
Ki Ha Lee
Alex Becker**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

This project is part of an integrated effort by Lawrence Berkeley Laboratory (LBL)–University of California at Berkeley (UCB), Lawrence Livermore National Laboratory (LLNL), and Sandia National Laboratories (SNL) in the electrical and electromagnetic (EM) geophysical method development 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.

Research conducted through this integrated effort focuses on five general activities:

1. EM forward modeling development.
2. Data interpretation methods development.
3. Hardware and instrumentation development.
4. Enhanced Oil Recovery (EOR) and reservoir characterization.
5. Controlled field experiments.

Lawrence Berkeley Laboratory–University of California at Berkeley research is focused on activities 1, 2, and 5. The primary focus is in the development of reliable inversion and imaging schemes that can yield conductivity distribution from measured electrical and EM field data. The development of

accurate forward modeling algorithms and the acquisition of high-quality scale-model data are necessarily the early part of the inversion scheme development for ultimately monitoring the front tracking in existing reservoirs.

Summary of Technical Progress

This report is focused on the time-domain electromagnetic (TEM) scale model experiment in support of the q-domain conductivity imaging methodology development. Data acquired from the experiment have been successfully transformed to wavefields. The travel time estimated from the constructed wavefield appears to be within 5% of theoretically expected value. The data were for a single transmitter-receiver pair, and the experiment will be extended to obtain data from multiple pairs.

The scale model consists of a 1.2-m-diameter, 0.5-m-thick, cylindrical graphite block with an electrical conductivity of about 10^5 S/m. The experiments are done on such a scale that 1 cm in the scale model is equivalent to 10 m in real world. The model represents a field environment with an average background resistivity of $10\text{-}\Omega\text{-m}$ so that the transmitted and received waveforms are observed on an identical time scale to that which would be used in a full-scale field experiment.

Figure 1 shows the acquired data in millivolts per unit moment at a sampling rate of $1\text{ }\mu\text{s}$. The transmitter and

Fig. 1 Plot of original data [in millivolts (mV) per unit moment] acquired at a sampling rate of $1\text{ }\mu\text{s}$.

receiver were located 2 cm below the surface (20 m below the surface of the earth in real world) and had a horizontal separation of 5 cm. Geonic's EM-47 was used as the transmitter for this experiment. Data quality is excellent up to 1-ms range and then gradually begins to deteriorate. Before put into use for wavefield transform, these data were smoothed with a variable time window. At early time the window width used was narrow and was increased logarithmically to late time. The result is shown in Fig. 2 where the late time response is

Fig. 2 Plot showing original data smoothed with a variable time window.

considerably smoothed out compared to the original data. For comparison, the experimental data transients were computed using the corresponding theoretical model, and the result is shown in Fig. 3. The model used for this calculation was a homogeneous half space of $10\text{-}\Omega\text{-m}$ resistivity. The transmitter and receiver were 20 m below the surface and were separated by 50 m horizontally. At early time there was only a small difference between the smoothed data and the theoretical values. The difference appears to increase at later time, especially toward the 1-ms range, where the rate of decay was larger for the smoothed data. This may have been the result of the smoothing.

The smoothed data were transformed to wavefields, and the results are shown in Fig. 4. There are ten wavefield traces in the figure. The same time-domain data were used to

Fig. 3 Plot showing results of experimental data transients computed with theoretical model.

Fig. 4 Plot showing transformation of smoothed data to wavefields. q is fictitious time.

generate these traces, but each trace represents a different time-domain data segment with a different starting time for the transformation. For example, the wavefield trace on the top represents transformed wavefield using the smoothed time-domain data with its first sample starting from 5 μ s. The travel time, the fictitious time in q at which the wavefield peaks, changes very little from one trace to the other, which

indicates that the transformation is stable and that the sampling can be as late as 14 μ s for this particular model. The differences in travel time and the corresponding equivalent distance between the experimentally obtained values and the theoretically predicted ones are summarized in Table 1. Experimental data were averaged for this purpose. These calculations are based on the theoretical model of 10^5 S/m ($10\text{-}\Omega\text{-m}$ real world).

TABLE 1

Differences in Travel Time and Corresponding Equivalent Distance Between Experimental and Theoretical Values

	Experimental	Theoretical	Distance
Travel time, * q	0.01856	0.01772	0.00084
Equivalent distance, m	52.352	50.0	2.352

* q is fictitious time.

GEOPHYSICAL AND TRANSPORT PROPERTIES OF RESERVOIR ROCKS

Contract No. DE-AC22-89BC14475

University of California
Berkeley, Calif.

Contract Date: Sept. 22, 1989
Anticipated Completion: Aug. 21, 1993

Principal Investigator:
Neville G. W. Cook

Project Manager:
Robert Lemmon
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

The objective of this research is to understand, through 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 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 this quarter work continued on the refinement of techniques based on graph theory to search the topological nature of flow in stochastic pore networks. A paper entitled “Analysis of Preferential Flow Paths Using Graph Theory” was submitted to the 34th U.S. National Symposium on Rock Mechanics and has been accepted for publication in the *International Journal of Rock Mechanics and Mining Sciences*.

The final report on “Micromechanics of Seismic Wave Propagation in Granular Rocks” was prepared and submitted to the Department of Energy. Work continued on the final report entitled “Predicting the Transport Properties of Sedimentary Rocks from Microgeometry.” Papers for submission to archival journals are being written based on the two reports described previously.

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. 26, 1993**

**Principal Investigator:
H. Scott Fogler**

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

Reporting Period: Jan. 1–Mar. 31, 1993

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

Introduction

A foamed gel fills the pore space of a porous medium (creating a foamed-gel plug) as follows: The wetting phase (gel) coats the pore walls and forms a lens in the pore throats. The nonwetting phase (gas) occupies the center portion of the pore bodies. This configuration of gel reduces the permeability of the pore space to essentially zero so long as the gelled lenses are intact. However, when a force is applied to one side of the foamed-gel plug (e.g., during a waterflooding operation where a foamed-gel plug diverts injected water into unswept, low-permeability zones), the gelled lenses may rupture. The successive rupture of gelled lenses leads to conductive channels that percolate the foamed-gel plug. The evolution of the conductive network of channels causes the permeability of the plug to increase.¹ Because the breakdown of the foamed gel is detrimental to the plugging ability of the foamed-gel plug, the following information would be useful for designing a foamed-gel plug for fluid diversion: (1) at what pressure will percolating channels form, (2) where does the percolating channel form with respect to the high-permeability zones, and (3) what effect does the network of the percolating channels have on the permeability of the foamed-gel plug.

The objective of the work performed during this quarter was to develop a model that could simulate the breakdown of a foamed-gel plug exposed to a pressure gradient in a porous medium. Such a model would help evaluate the effect of the foam and the characteristics of the porous medium on a foamed-gel fluid-diverting plug. The immediate modeling goals were to predict the pressure at which the first conductive channel forms as well as the pathway or location of that channel. Second, the model should be able to estimate the recovery of permeability as the conductive network of channels develops. Because some lenses remain intact and because gel remnants will remain in the pore throats where lenses ruptured, not all the permeability of the pore space can be recovered.

Rupture Phenomena

Individual gelled lenses can support a finite pressure drop without rupturing. The pressure at which a gelled lens ruptures is a function of the gel type, cross-link density, and some physical dimensions of the lens. For a given polymer gel, a relationship can be made between the rupture pressure and the ratio of the length of the gelled lens to the diameter of the pore throat it occupies (ℓ/d) (Ref. 1).

When a pressure drop is applied to a foamed-gel plug, many gelled lenses deform. Some of the pressure is converted to potential energy, which is stored in the gelled lens, and some of the pressure is transmitted to “downstream” lenses. If the applied pressure is too great, the pressure drop across individual lenses can exceed the rupture pressure and that lens may rupture. It is this rupture of successive gelled lenses that creates percolating channels through the foamed-gel plug. In

general, the ruptured channel will form along a path characterized by weak lenses (small ℓ/d).

Modeling Approach

Network models were used to model the breakdown of foamed-gel plugs to account for the pore-level phenomena of lens rupture and the microscopic heterogeneities inherent to porous materials. The network model represents the interconnected network of pore throats (bonds) and pore bodies (nodes) as capillary tubes and chambers of as yet unspecified geometry, respectively (see Fig. 1). Distributions of pore-throat and pore-body dimensions (and therefore gelled lens dimensions) are easily incorporated by assigning the dimensions based on experimental measurements or random number generators.

The network is initialized by assigning gelled lenses to the bonds (pore throats), and gas to the nodes (pore bodies). Initially, all the lenses are in an undeformed equilibrium state and the gas pressure in each node is the same. An injection pressure is then assigned to the left-hand side of the network, which causes the lenses to deform. After the equilibrium lens positions and gas pressure at each bond have been calculated, the pressure drop across each lens is compared with the experimental rupture pressure relationship. If lenses rupture (forming clusters of nodes and bonds), the node pressures and lens positions will be updated. If the cluster percolates the network, it is treated as a conductive channel and the pressure drop for fluid flow is calculated along with the lens positions and node pressures. If no lenses rupture at a given pressure drop, the injection pressure is increased by a small amount and the algorithm repeats itself.

Fig. 1 Schematic of the network representation of the pore space.

Results

Model predictions of the location of a percolating channel through a gelled plug were compared with experiments. The experimental percolation pathways were obtained by filling tiny micromodel pore spaces with foamed gel and then rupturing the

foamed gel with injected water. Figure 2 compares experimental vs. predicted pathways for two different experimental runs. The microscopic heterogeneity is not shown in the figure.

Explanations for the deviation between the actual and predicted pathways include difficulty in obtaining the actual gelled lens dimensions from the micromodels. Furthermore, the rupture pressure relationship used in the model was obtained for lenses with a cylindrical cross section. The lenses in the micromodels have either rectangular or elliptical cross sections. Ongoing work aims at improving the prediction of percolating channels as well as calculating the permeability of the network as the percolating channels form.

Fig. 2 Comparison of actual (■ ■ ■) and predicted (—) pathways of the first conductive channel through a foamed-gel plug.

Reference

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**LAWRENCE BERKELEY LABORATORY/
INDUSTRY HETEROGENEOUS
RESERVOIR PERFORMANCE
DEFINITION PROJECT**

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

**Contract Date: Apr. 1, 1992
Anticipated Completion: September 1995
Government Award: \$275,000**

Principal Investigators:

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

Project Manager:

**Robert Lemmon
Bartlesville Project Office**

Reporting Period: Jan. 1–Mar. 31, 1993

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.

This will be accomplished through a cooperative research program between Lawrence Berkeley Laboratory (LBL), British Petroleum, Inc. (BP), and the University of Oklahoma (OU) 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 multi-year efforts at the Gypsy site in northeastern Oklahoma. 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) research and development project and the LBL Morgantown Energy Technology Center Reservoir Performance Definition Project.

Summary of Technical Progress

Hydrologic-Related Work

Four tasks related to the hydrological inversion of the pilot-site well tests were carried out this quarter: (1) the coding

changes required for the iterated function system (IFS) inversion program to analyze the well tests conducted in the lower sand channel were completed, (2) a two-dimensional (2-D) numerical model of the lower sand channel was developed, (3) forward calculations of the five lower channel well tests assuming a homogeneous medium were made, and (4) a preliminary inversion of one of the tests using the IFS inversion program was made. Each of these tasks is briefly summarized, and plans for future activities are outlined.

Coding Changes to IFSINV

Four new capabilities were added to the iterated function system inversion program (IFSINV).¹ The first two modifications apply to the forward-flow calculation, which is embedded in the inversion process, whereas the last two apply to the way the inversion itself is conducted—they affect how the observed and modeled drawdown vs. time curves are compared after each forward-flow calculation.

1. Pumping well flow rate can vary with time (previously it had to be constant). A time-varying flow rate at a pumping well is approximated as a series of constant flow-rate periods. Each period can be made as short as necessary to achieve a desired accuracy for a highly variable flow rate. However, for the pilot-site well tests, in which the pumping schedule is a series of on-off pulses, the constant-flow periods need be no shorter than the pulse lengths, which range from 10 min to 4 h. Each time a flow-rate change occurs, the next few time steps of the numerical simulation must be small to properly account for flow transients. This means that simulations involving variable flow rates will be more computationally intensive than those with constant flow rates.

2. Multiple well tests can be modeled in one forward calculation (previously only one well test could be modeled at a time). This capability is a natural outgrowth of the ability to model time-varying flow rate because two tests using different pumping wells can be considered one long test in which initially only the first well pumps; after a while the first well is shut in and only the second well pumps. A feature to allow reinitialization of heads when flow rate changes has been included, which eliminates the need to simulate the period of time between tests when the system is reequilibrating; this allows multiple tests that occurred at widely separated times to be co-inverted more efficiently.

3. During curve matching, the drawdown vs. time curves, plotted on a log-log scale, can be shifted along the log(time) axis, along the log(drawdown) axis, along both axes, or along neither axis (previously curve shifting was either done for both axes or disabled entirely). For constant flow-rate well tests, it is usually advantageous to enable curve shifting for both time and drawdown. A shift along the log(drawdown) axis determines the background value of transmissivity in the model, and a shift along the log(time) axis determines the background value of diffusivity (transmissivity divided by storativity). Thus the inversion can search for heterogeneities in transmissivity and storativity without needing to know the

actual background values. For variable flow-rate tests, however, it is not possible to shift along the log(time) axis. Thus any shift along the log(drawdown) axis corresponds to a shift in transmissivity along with a corresponding shift in storativity so that diffusivity remains unchanged. The effect of this type of shift on the inversion process is an area of current research and will be explored in conjunction with the Gypsy inversions.

4. Curve matching can consider curves of drawdown vs. time, log(drawdown) vs. log(time), drawdown vs. log(time), or log(drawdown) vs. time [previously curve matching involved log(drawdown) vs log(time) only]. For constant flow-rate well tests, it is advantageous to match curves of log(drawdown) vs. log(time) because curve shifting can be used to determine background hydrologic properties, as described in the previous paragraph. If curve shifting is not done, it may be preferable to match linear-linear or log-linear plots rather than log-log plots. For example, log-log plots tend to emphasize early time behavior, which may be complicated by wellbore effects. The choice of curves to match and the effect this choice has on the success of the inversion is an open problem, and several alternatives will be examined.

Lower Sand Channel Model

The 2-D lattice shown in Fig. 1 has been created to represent an areal model of the lower sand channel at the subsurface pilot site. The lattice is composed of one-dimensional (1-D) linear finite elements that represent "pipes" of porous medium. The wells are modeled as nodes, or intersections between elements, and no detailed wellbore model is included. This type of lattice, although originally developed to model flow through fracture

Fig. 1 Lattice used for the numerical model of the lower sand channel at the Gypsy subsurface pilot site. Wells are shown as open circles.

networks, has been shown to effectively model flow through porous media by comparing numerical results with the Theis solution. The central region of the lattice, which covers the area of the well field, is finely discretized, with a lattice spacing of 10 m, to enable adequate resolution of heterogeneities. The lattice extends far beyond the well field so that spurious boundary conditions are not imposed on the flow calculation. The extent of the lattice (about 1000 m from the center of the well field in all directions) was chosen so that the outer boundary would not be felt during the course of the longest well tests (about 12 h). Beyond the well field, the lattice spacing steadily increases because fine resolution is not necessary there. Because the model is 2D, no vertical variations in flow or hydrologic properties can be modeled, which makes transmissivity and storativity, which represent depth-integrated properties, the appropriate variables to use. In fact, the thickness of the lower sand channel inferred from cores and well logs varies from about 10 ft to about 35 ft, which implies that variations in transmissivity might reflect a combination of thickness and permeability changes.

Homogeneous-Medium Simulations

Five lower channel well tests were done that yielded consistent drawdown data (a sixth test produced anomalous results that suggested packer failure; none of that data is currently being included in our analysis). The data available for the five tests are summarized in Table 1 and shown schematically on a well-field diagram in Fig. 2.

Before any inversions searching for heterogeneities are done, it makes sense to first simulate the well tests assuming a homogeneous medium. If a homogeneous-medium model adequately matches the drawdowns, then no information on heterogeneities is available from the hydrologic data and any hydrologic inversion that searches for heterogeneities is doomed to failure. The results of a forward calculation of each well test (drawdown as a function of time at the observation wells) using transmissivity $T = 9.7 \times 10^{-5} \text{ m}^2/\text{s}$ (equivalent to $kH = 32,000 \text{ mD-ft}$) and storativity $S = 9.3 \times 10^{-6}$ ($2.1 \times 10^{-5} \text{ ft/psi}$) are shown in Figs. 3 to 7 along with the observed drawdowns. The values of T and S used in the model fall within the range reported by Papadopoulos and

TABLE 1
Results of Five Lower Channel Well Tests

Test	Well					
	1	5	7	8	9	11
90/S4/T1	Pump	Observe	Observe		Observe	Observe
90/S3/T1		Observe	Observe	Pump	Observe	
90/S1/T1	Observe*	Observe				Pump
89/T2	Observe*	Pump	Observe			
89/T1	Observe*		Pump			

*Limited data available.

Fig. 2 Pilot-site well field showing a schematic view of the lower sand channel well tests.

Associates, Inc.,² ($27,000 < kh < 44,000$ mD-ft, $0.3 \times 10^{-5} < S < 3.2 \times 10^{-5}$ ft/psi) and were chosen to minimize the mismatch between calculated and observed drawdowns for test 90/S4/T1, the test for which the most observed data are available. The mismatch is quantified by a variable known as the energy E , which is defined as

$$E = \frac{N_0}{N} \sum_{i=1}^N [\ln(h_o) - \ln(h_c)]^2$$

where $N_0 = 100$

N = number of drawdown observations

h_o = observed drawdown

h_c = calculated drawdown

The sum ranges over all observation wells and all observation times. The normalization N_0/N is included so that energies from tests with different amounts of observed data can be compared. After some experimentation with the design of the lattice shown in Fig. 1, it was decided not to include the drawdown response at the pumping well in the energy sum for any inversions because the numerical model used does not accurately predict near-wellbore effects such as wellbore storage or skin effects. The lattice design may be modified at a later time to include this information in the inversion process.

Figure 3 shows that a homogeneous model does a good job matching the drawdowns from wells 5, 7, and 9 (except for very early times) when well 1 is pumped (test 90/S4/T1) but that drawdowns at well 11 are consistently underpredicted. This suggests that the lower sand channel may be relatively

homogeneous between wells 1, 5, 7, and 9 but includes some heterogeneity between wells 1 and 11. Figure 4 shows that the match becomes steadily worse from well 7 to well 5 to well 9 when well 8 is pumped (test 90/S3/T1), which suggests that hydrologic properties may gradually change from east to west in the region between wells 5, 7, 8, and 9. Figure 5 (test 90/S1/T1) shows small mismatches comparable to those of Fig. 3. Figures 6 and 7 show that the data from the 1989 tests (89/T2 and 89/T1) are either of limited extent (well 1 drawdowns for both tests) or anomalous behavior (the "flattened responses" of well 7 drawdowns for test 89/T2); therefore these data cannot be used as the basis of independent inversions but perhaps could be used in co-inversions with other data. Overall, the homogeneous-medium forward calculations indicate that there are heterogeneities in the lower sand channel that have an effect on hydrological behavior.

Preliminary Inversion of Test 90/S4/T1

A preliminary inversion of test 90/S4/T1 yields the drawdowns shown in Fig. 8 and the hydrologic property distribution shown in Fig. 9. Although the uniform-medium match was quite good for this test, the inversion yields a modest decrease in energy ($E = 3.5 \rightarrow E = 2.1$). The introduction of several regions with low T and S enhances the communication between wells 1 and 11 and slightly decreases communication between well 1 and wells 5, 7, and 9, which leads to better matches for the early-time drawdowns in wells 5, 7, and 9 and the entire response in well 11. Further inversions of test 90/S4/T1 are currently being conducted to examine the uniqueness of the inferred hydrologic property distribution. Additionally, inversions of test 90/S3/T1 are being done. Next, co-inversions of multiple tests will be carried out.

Seismic-Related Work

Seismic activities this quarter involved planning for field work this summer and looking ahead to next year's field work as well. The outcrop-site cross-hole seismic survey will be carried out this summer. This survey will be conducted on a relatively small scale (well spacings on the order of 25 ft) and very near the outcrop, so features of the seismic tomograms can be correlated with observed geology. The interpretation of this survey will provide the reference points necessary to interpret the larger scale pilot-site survey, planned for FY94. At the subsurface pilot site, the cross-well survey will be done on the same scale as the hydrologic well tests (well spacings on the order of 100 m), so features of the seismic tomograms can be compared with results of the hydrologic inversions.

BP has already conducted cross-hole seismic surveys at the pilot site. That data will be reviewed in order to better prepare for this field work so that it complements rather than duplicates previous efforts. The cross-hole seismic data collected by BP (about 20 magnetic tapes plus some hard-copy material) has been requested from OU. It will be reviewed during the remainder of FY93 in order to concentrate on the pilot-site field work in FY94.

Fig. 3 Observed (•) and modeled (—) observation-well drawdowns for test 90/S4/T1 ($E = 3.5$). The model consists of a homogeneous medium with transmissivity and storativity values that minimize the mismatch between the observed and calculated drawdown curves.

Fig. 4 Observed (●) and modeled (—) observation-well drawdowns for test 90/S3/T1 ($E = 28.1$). Same model as in Fig. 3.

Fig. 5 Observed (●) and modeled (—) observation-well drawdowns for test 90/S1/T1 ($E = 5.8$). Same model as in Fig. 3.

Fig. 6 Observed (●) and modeled (—) observation-well drawdowns for test 89/T2 ($E = 26.9$). Same model as in Fig. 3.

Fig. 7 Observed (●) and modeled (—) observation-well drawdowns for test 89/T1 ($E = 5.4$). Same model as in Fig. 3.

Fig. 8 Observed (●) and modeled (—) observation-well drawdowns for test 90/S4/T1 ($E = 2.1$), corresponding to the hydrologic property distribution shown in Fig. 9.

Fig. 9 Central portion of the lattice representing the lower sand channel. The thickness of each lattice element is proportional to its transmissivity T and storativity S . Note that as the lattice gets coarser, T and S increase so that in the outer regions of the lattice, although there are fewer elements, the overall values of T and S do not decrease. Within the well field the inversion has found that a hydrologic property distribution, including several regions of low T and S , produces a better match to the observed drawdowns (shown in Fig. 8) than does a uniform medium.

References

1. J. C. S. Long, C. Doughty, K. Hestir, and S. Martel, Modeling Heterogeneous and Fractured Reservoirs with Inverse Methods Based on Iterated Function Systems, in *Proceedings of the Third International Reservoir Characterization Technical Conference*, Tulsa, Okla., Nov. 3–5, 1991, 1992; also DOE Report LBL-31333.
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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, 1993
Funding for FY 1993: \$340,000

Principal Investigator:
Dan Maloney

Project Manager:
Rhonda Lindsey
Bartlesville Project Office

Reporting Period: Jan. 1–Mar. 31, 1993

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 2—After 1 yr of exposure to 7 MPa confining pressure and 4 months at 49 °C, the epoxy–resin jacket around sample 4959 developed a leak. Sample 4953 was prepared for reservoir condition tests. An oil–brine steady-state relative permeability test was conducted on sample 4953. The 4953 sample characteristics are similar to those of sample 4959. Both rocks are from the Almond formation.

Relative permeability characteristics of sample 4953 were anticipated to be similar to those of 4959. The sample was subjected to the same test conditions as the 4959 sample except that the test temperature was 49 °C instead of 23 °C.

Figure 1 shows relative permeability results from tests at the two test temperatures. The results suggest an increase in wetting-phase relative permeability and a decrease in nonwetting-phase relative permeability with an increase in temperature. The test may be repeated during the next quarter to test this hypothesis if time permits. Milestone 2 was completed.

Milestone 3—Fontainebleau sandstone was selected as the test rock for FY93 activities. Samples were cut and plugged from a block of the rock. Air permeability and

porosity, X-ray-diffraction (XRD) mineralogical analysis, thin-section and scanning electron microscope (SEM) analyses, and mercury injection tests were performed to measure properties of the sandstone.

Air permeabilities measured on unconfined samples of the sandstone ranged from 60 to 130 mD, depending on the plugging direction. Porosities ranged from 8 to 11.3%. The XRD results indicate that the sample is predominantly quartz (99%) with traces of feldspar, calcite, kaolinite, and illite. The SEM photomicrographs of the rock illustrate the moderately porous character of the medium-grain, very-well-sorted, quartz-cemented, quartzarenitic sandstone. Detrital grains were interlocked throughout the sample. Detailed inspection of the intergranular contacts showed the presence of traces of authigenic illite matting the grain surfaces. The thin-section description of the sample provided by Mineralogy Inc. is as follows:

This sample is comprised of medium-grained, very-well sorted, well-rounded, quartz-cemented, quartzarenitic sandstone. The mean grain diameter is approximately 0.26 mm, with a maximum grain diameter of 0.60 mm. The detrital framework is mildly to moderately compacted, and displays a predominance of point-to-point and elongated intergranular contacts. The interlocking nature of the authigenic quartz overgrowths is suggestive of a densely-compacted framework, however, careful inspection of the intergranular relationships indicates that quartz overgrowth cement precipitated early on in the burial history of this sandstone prior to significant compaction. Petrographic modal analysis indicates that the detrital composition is dominated by monocrySTALLINE quartz (59.0%), together with minor amounts of polycrystalline quartz (7.0%), and feldspar (1.0%). In addition to these three components, traces of chert, as well as metaquartzite fragments, are also present. Quartz overgrowth cement is the dominant authigenic constituent within this sandstone, accounting for approximately 19.0% of the bulk volume. The quartz cement occurs as ubiquitous syntaxial rims flanking the detrital quartz grains. As previously mentioned, the overgrowths are commonly interlocked between the adjoining quartz grains. Traces of pore-lining and grain-coating clay matrix are present within the sandstone, occurring as dust rims which separate the detrital and authigenic quartz constituents, as well as late-stage pore-lining clays commonly situated within the intergranular pore throats. Authigenic clay matrix is estimated to account for approximately 0.5% of the bulk volume within this sandstone. Illite is the dominant pore-lining and grain-coating clay constituent. In addition to illite, traces of authigenic kaolinite are present as a scattered replacement for altered feldspar grains and chert grains. X-ray diffraction analysis indicated the presence of traces of calcite within the sample, however, none was detected in the thin section sample. The macro pore volume is comprised of moderately well-preserved intergranular porosity, together with trace amounts of intragranular dissolution void space and rare grain-moldic pores. The secondary voids have developed chiefly at the expense of altered and leached feldspar grains and chert fragments. Intergranular macro porosity accounts for approximately 13.5% of the bulk volume within this sandstone. The intergranular voids are moderately well interconnected, and are likely to contribute to moderate to good fluid permeability for this sandstone. Percentage values for mineral constituents and pore types listed above are based on a 200 point modal analysis of the thin section.

Fig. 1 Oil-brine relative permeability (k_r) results from 74 °F (sample 4959) and 120 °F (sample 4953) tests. S_w , water saturation. ●, water, 23 °C. ○, oil, 23 °C. ◆, water, 49 °C. ◇, oil, 49 °C.

A brief inspection of the mercury injection porosimetry results indicates that most of the pore throats are in the 10- to 20- μ m range.

Milestone 4—A laboratory was refurbished for combined interfacial tension (IFT)/pressure-volume-temperature (PVT) analyses with elevated temperature and pressure conditions. Equipment was moved into the laboratory and the apparatus was assembled. Condensate fluid components were ordered and received. A fluid system was designed for tests simulating condensate systems. The IFT between the hydrocarbon liquid and gas phases will be less than the IFT for a typical brine-oil or oil-gas system. Preliminary phase behavior predictions were made with a simulator. One of the fluid components is bromopropane. Because little information describing characteristics of bromopropane is available, bubble point and other characteristics must be experimentally determined. The bubble-point characteristics of bromopropane were measured and were found to be different from predicted values. A fluid system consisting of methane, propane, and bromopropane is in design. The PVT characteristics of the fluid system will be tested during the next reporting period.

Milestone 6—Computer requirements for simulating laboratory coreflood results were evaluated and component selections were made. The computer was purchased and installed. Coreflood simulator designs were discussed with personnel from a major oil company. A request was extended to another research laboratory to try their coreflood simulator on some of the laboratory data from this project. Samples of rocks were prepared for tests in which coreflood results will be matched with simulator results.

Milestone 7—A chapter on relative permeability and special core analysis projects was written for the National Institute for Petroleum and Energy Research final report.

Technology Transfer

Coreflood simulator design and operation were discussed with representatives of a major oil company. During a week

long visit to a Venezuelan petroleum laboratory to provide X-ray scanner training, seminars on X-ray scanning technology and special core analysis were presented.

Two employees served as technical judges at the 1993 Oklahoma Science Bowl.

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.**

**Contract Date: Oct. 1, 1987
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$350,000**

**Principal Investigator:
Liviu Tomutsa**

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

Reporting Period: Jan. 1–Mar. 31, 1993

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; (2) investigate the applicability of imaging technologies in the development of scaleup procedures from core plug to whole core to interwell scale; (3) 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 (4) strongly encourage collaborative research by industrial participants.

Summary of Technical Progress

Milestone 2—Topical report NIPER 663, *Imaging Techniques Applied to the Study of Fluids in Porous Media*, was delivered to the Department of Energy.

Milestone 3—Investigation of using single- and multi-energy scans for rapid characterization of cores. To further improve the capability of scanning large amounts of core and

to optimize the selection of the time when data should be transferred to the workstation for processing, a hard drive with a removable disk pack was added to the CT scanner. A removable pack can store 200 images and can be exchanged within minutes with a blank pack. The hard drive installed is one of the two drives recently purchased as part of the second CT scanner. Detailed scanning of a 3-ft section of a whole core was performed, and the core is ready for drilling to take plugs. Topogram and CT reconstructed images were compared for 5-in.-diameter core of strongly consolidated sandstone containing millimeter-scale layers. Although the topograms showed the general sedimentary features, the quality generated by the images reconstructed from 2-mm sections taken at 141 kV was clearly superior. For large core diameters or high CT attenuation rock, to use the topogram mode, higher X-ray energies, as found in industrial X-ray equipment, are needed. When only a medical CT scanner is available (with maximum energy in the 140- to 150-kV range), the CT reconstructed images can provide the needed detailed core information but at considerably larger time and equipment use investment. The topogram images acquired for a Midcontinent Class I reservoir have been used to characterize the producing interval and to select locations of plugs. When combined with plug and minipermeameter permeability measurements, these data were used to provide a detailed description of the core, at scales of millimeters to meters, corresponding to the heterogeneity scale.

Milestone 4—Application of imaging technology to derive scaleup procedures for permeability and relative permeability in large heterogeneous samples. To handle the large amount of data generated when long cores are scanned, an expansion of data storage capability was achieved by installing a magneto-optical drive, which can store 128 MB on one cartridge on each of the two main computers used in image data processing. The data access time is comparable to the computer fixed hard drive. Compression programs are used to further reduce the data file sizes (often to less than 30% of the original size). For long-term backup, the data are stored on magnetic tape. The testing and calibration of the high-pressure mercury injection apparatus (0 to 60,000 psia) used in pore throat characterization of small volumes were completed. Improved data for pore throat distributions were obtained for the Tallant sandstone.

As part of the experimental investigation in scaling up relative permeability in a heterogeneous rock, brine and oil relative permeability were measured in a first imbibition steady-state cycle for a Tallant sandstone sample. The experimental setup for relative permeability measurements uses the CT scanning for saturation measurements and a computer data acquisition system for pressure measurements. Constant pressure drop across the sample over time is the first indication of reaching steady state. Consecutive CT scans are used to further verify the steady-state conditions as shown by a constant longitudinal oil and brine saturation profile. The relative permeability values generated are shown in Fig. 1. They are normalized to the absolute brine permeability. The

Fig. 1 Steady-state relative permeability (k_r) brine and oil curves of Tallant sandstone sample. First imbibition cycle. Values normalized to single-phase brine permeability.

points are taken at fractional brine flow rates of 0.0, 0.05, 0.1, 0.2, 0.4, 0.7, 0.9, and 1.0. Each point is taken after 6 pore volumes of total fluid flow at the respective fractional flow. A flow rate of 18 mL/h corresponding to a front advancement of 2 ft/d was used. The brine was tagged with 7% NaI to ensure the appropriate X-ray attenuation contrast between it and the oil. The oil used was Soltrol with a viscosity of 26 cP. Because of the strongly water-wet nature of the rock, the oil saturation drops significantly even for a fractional brine flow of 0.05. In Fig. 2 longitudinal saturation profiles corresponding to the points on the relative permeability curves are shown. The saturation values were generated by averaging the saturation for each of the 63 cross sections (slices) perpendicular to the flow direction generated by CT scanning. It is noticeable that a uniform longitudinal initial oil saturation could not be achieved, the inlet end having a higher oil saturation than the outlet. This profile shape is preserved but in a gradually more attenuated form as the imbibition cycle proceeds. The saturation variation is the strongest close to the sample ends and is only a few percent between the pressure ports. The actual spatial oil saturation distribution within the sample is shown for a vertical cross section in Fig. 3. Each view corresponds to each of the points on the relative permeability curves. The brine fractional percent flow is indicated at the left of each image. The contrast in oil saturation between the ripples and the clean sand is the most pronounced for the initial oil saturation stage and the least pronounced for the residual oil stage. As the brine fractional flow increases, the gravitational effect becomes apparent with the oil saturation being higher near the top of the sample. At the highest brine flow fraction, the gravitational effect disappears. To study in more detail the oil saturation dependence on rock properties, in Fig. 4 saturations and porosity are plotted along a vertical line situated in the center of the sample at the intersection of a longitudinal plane (slice 108) and cross-section plane (slice 32). At the initial oil saturation, and for most of the fractional flows, a significant dependence of the saturation on the porosity is

Fig. 2 Oil saturation distributions in a longitudinal, vertical cross section during steady-state measurements (slice 108). The brine fractional percent flow is indicated at the left of each image.

Fig. 3 Average oil saturation along the sample during first imbibition cycle. $\bullet$, S_{wir} . $\circ$, $fw = 0.05$. $\blacklozenge$, $fw = 0.10$. $\diamond$, $fw = 0.20$. $\blacktriangle$, $fw = 0.40$. $\triangle$, $fw = 0.70$. $\blacksquare$, $fw = 0.90$. $\square$, $fw = 1.00$.

observed, with contrasts in oil saturation between the high and low porosity zones as high as 25%. At residual oil the saturation dependence on rock properties becomes much less significant. Figure 5 plots oil saturation vs. porosity for initial oil and residual oil data from Fig. 4. A correlation factor of 0.69 is observed for initial oil saturation data, whereas no correlation is apparent for the residual oil data. For the initial oil saturation, the oil saturations vary from 55% for the lower porosity values to 85% for the higher porosity values. At residual oil, most of the oil saturation values are distributed in a band between 26 and 40% oil saturation. These findings agree with measurements performed previously during unsteady-state waterfloods on the same sample. Further analysis of the data is necessary to clarify the dependence of saturations on rock properties. A drainage cycle will follow. This imbibition cycle will be followed by a drainage cycle

Fig. 4 Porosity and oil saturation values along a vertical line (intersection of longitudinal slice 108 and transversal slice 32) at various stages during imbibition cycle. The brine fractional flow (percent) is indicated in the legend. —, S_{wf} , ---, $fw = 0.20$, ···, $fw = 0.70$, - · -, $fw = 1.00$, - - -, porosity.

Fig. 5 Oil saturation vs. porosity for values along a vertical line (intersection of longitudinal slice 108 and transversal slice 32) at residual brine and residual oil stages during imbibition cycle. —●—, oil saturation at S_{wf} , ●, oil saturation at S_{or} , —, $y = -0.096832 + 3.2827x$ $R = 0.6892$.

to complete the set of relative permeability data. Next, simulations will be performed for scaling up investigations.

Milestone 5—NMR imaging experiments were begun on a micro-coreplug of Fontainebleau sandstone saturated with brine containing 0.5% NaCl with 0.02% $MnCl_2$ as a relaxation agent. Measurement of the natural line width of the water nuclear magnetic resonance (NMR) signal from the brine in the rock gave a result of 750 Hz. This compares to the value of 800 to 900 Hz obtained for brine in Bentheim sandstone. A narrower line width was anticipated for the Fontainebleau sandstone because its white color would indicate a much lower content of iron, which is known to cause broadening in other sandstones. An image of the water was obtained with 256 X,Y-gradient steps with 128 Z-gradient steps. The image obtained had a resolution of 30 μm . Slice images from the three-dimensional (3-D) image data set for the Fontainebleau sandstone revealed the presence of randomly scattered large pores with little porosity in between. A thin section of the sandstone was prepared, and computer-assisted Petrographic Image Analysis (PIA) measurements showed an average porosity of 12%. An upgrade of the DICER image analysis software permits surface rendering of 3-D volumes. Figure 6 shows a surface rendering of an isolated large pore from the preceding data set. The lower intensities corresponding to rock grains and the higher intensities corresponding to bulk water have been made transparent, so only the thin layer of water near the rock grain surface is visible. The irregular shape of the pore volume determined by the surrounding rock grains is apparent, as are several narrow pore throats connecting to other pores outside the volume shown. The thickness of this layer seems to change in certain spots around the pore volume, which may be related to the grain wettability. Further experiments using thin glass capillary tubing with part treated to be oil-wet and part treated to be water-wet are planned to investigate this possibility.

Spin-lattice (T_1) relaxation measurements were made on several types of rock saturated with brine as part of the wettability determination experiments. An inversion-recovery pulse sequence was used with 50 time values ordered in a decreasing geometrical progression from 15 s to 2.44 ms. Samples of Berea, Cleveland, and Fontainebleau sandstones saturated with 0.5% NaCl brine have been studied. Relaxation time measurements were also made on the bulk brine solution. Figure 7 shows the relaxation curves for water in the three sandstones together with the bulk brine. The water in the Berea sandstone showed the fastest relaxation rate as exhibited by the steeper slope for the curve, followed closely by water in Cleveland sandstone and then Fontainebleau sandstone. The water in the rocks does not exhibit the single relaxation time that the bulk water has, as revealed by the straight line, but shows a multicomponent relaxation process involving faster rates from fluid near the surface of the rock grains to slower rates for fluid in the centers of the larger pores. Computer programs have been developed to fit the relaxation data for the fluids in rock using the stretched exponential relationship. Other research indicates that lower frequency

Fig. 6 Surface rendering of Fontainebleau sandstone showing the thin layer of water near the rock grain surface. The rock grains and bulk water have been made transparent.

NMR may better reveal differences in wettability effects on NMR relaxation measurements. Thus a lower magnetic field (<1 T) is recommended to improve the sensitivity of NMR signals to wettability changes.

Milestone 6—All the reports and publications needed for preparing the Rock Fluid Imaging Research chapter for the final report have been compiled and reviewed for selection of the material to be included in the first draft. The first draft for the Rock Fluid Imaging Research chapter in the National Institute for Petroleum and Energy Research (NIPER) Final Report was prepared.

Milestone 7—Technology Transfer. One employee participated by invitation in a symposium with industry members in the area of application of minipermeameter measurements of outcrops to characterization and scaleup in analogous reservoirs. A talk entitled "Imaging Technology Applied to Rock and Fluid Measurements in Cores" was given at the February luncheon meeting of the Bartlesville Section of the Society of Petroleum Engineers. The talk highlighted the advances made at NIPER in the imaging technology and their applicability to solving practical problems for the oil industry. A paper entitled "Pore Scale Fluid Imaging in Reservoir Rock by NMR Microscopy" was presented at the American Chemical Society National Spring Meeting Symposium on Applications of Magnetic Resonance Imaging in Enhanced Oil Recovery, Denver, Colo., Mar. 28–Apr. 2, 1993. A paper entitled "Characterization of a Midcontinent Fluvial-Dominated Del-

taic Sandstone Reservoir by Routine and Advanced Analytical Methods" was presented at the 10th Tertiary Oil Recovery Conference, Mar. 10–11, Wichita, Kans., and by invitation at the Fluvial Dominated Deltaic Reservoirs in Southern Midcontinent Workshop, Mar. 23–24, Norman, Okla.

Fig. 7 Longitudinal relaxation time (T_1) data for bulk water and water in Fontainebleau, Cleveland, and Berea sandstones. The Y-axis represents the fractional inverted magnetic moment of the fluid remaining after τ_1 in milliseconds. The curves are fitted to the data using a stretched exponential relationship. —●—, bulk water. - ● -, Fontainebleau. —▲—, Cleveland. ···· ▲····, Berea.

GEODIAGNOSTICS FOR FOSSIL ENERGY RECOVERY

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

**Contract Date: Oct. 1, 1986
Anticipated Completion: Sept. 30, 1993
Funding for FY 1993: \$340,000**

Principal Investigators:

**L. C. Bartel
G. A. Newman**

Project Manager:

**Robert Lemmon
Bartlesville Project Office**

Reporting Period: Jan. 1–Mar. 31, 1993

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

As part of the analysis of vertical electric source (VES) EM data, the multifrequency, multisource holographic method, discussed briefly in the following text, is being applied to the data obtained from the Marathon site in April, May, and November 1992. As a preliminary step to test the holographic method, the holographic method was applied to calculated model results. For the calculated model results in the audio-frequency range, targets were detected and imaged. The resolution, however, is limited by the frequencies used but is improved over that expected because of the focusing action of the holographic method. The holographic algorithm keeps a faithful representation of the phase, which is important for the location of the image. The algorithm, however, does not maintain proper amplitude data necessary to determine the conductivity structure from the hologram. This same problem exists for the holographic method applied to seismic data. Work has been started to maintain the necessary amplitude information and hence determine the conductivity structure.

Representatives of Marathon Oil Company visited Sandia during March to review the progress of the analysis of the VES EM data taken at the Marathon site during April, May, and November 1992. Preliminary borehole-to-surface and cross-borehole holograms were compared with well-log

data supplied by Marathon. The borehole-to-surface holograms do not appear to have sufficient resolution for a detailed comparison with the logs. The cross-borehole preliminary holograms compare favorably with the well data. The theoretical aspects of the holographic method were discussed. During the Marathon visit, future joint efforts, including the initiation of a Cooperative Research and Development Agreement (CRADA) were discussed. Future joint efforts also included additional field activities to further develop the EM methods and application of seismic wave migration methods to EM data.

EM Holographic Method

The multisource holography applied to seismic imaging has been adapted for EM waves in earth materials. Multisource holography is a generalization of the traditional single-source holography. It is a numerical reconstruction procedure based on the double focusing principle for both the source array and the receiver array. The measured scattered (secondary) magnetic wave fields are back propagated (migrated) to the image point, which, in turn, are then back propagated (migrated) to the source point. Summations over all receivers and source points focus on both the receiver array and the source array. Multiple frequencies are used to enhance the holographic method. Multifrequency, multisource holography is equivalent to prestack wave migration used in the analysis of seismic data. The holograms, discussed in the following text, were formed with the use of plane-wave propagators. For the multifrequency holograms, the phase coherency is determined by a Fourier transformation from the frequency domain to the time domain and setting time $t = 0$. At time $t = 0$, the image is formed when the in-phase part (real part) is not zero and the out-of-phase part (imaginary part) is a minimum (i.e., the EM wave is phase coherent at its origination).

Marathon Field Experiment

Marathon Oil Company 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 from 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 Ω -m and 5 Ω -m, respectively, and the polymer and fresh water yield a resistivity of approximately 80 Ω -m, which gives a significant resistivity contrast. In addition, those areas containing high oil saturation show a resistivity contrast in excess of the 80 Ω -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 because the reservoir is saturated and there are only slight density changes between the various fluids.

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 (ME-10, ME-12, MG-10, and MG-12). Production wells ME-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.

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. The location of the cross section for the holograms is also shown by the "dot-dash" line.

Image Using the Holographic Method

Phase holograms are shown in Figs. 2 and 3 for a cross section at $x = 60$ m along the y -axis (see Fig. 1) for data taken in April, May, and November 1992, respectively. The cross-sectional view is indicated in Fig. 1. The imaged area was divided into 5×5 m pixels from a depth of 250 m to a depth of 300 m and from $y = 0$ to 160 m. Note that the vertical and horizontal scales in the figures are not equal. The projections of OB-1, OB-2, and ME-10 onto the cross-sectional line are indicated in the figures. The holograms were formed from the measurements of the vertical magnetic field (H_z) data measured in OB-1, OB-2, OB-3, and ME-10 for transmitters located in OB-1, OB-2, and OB-3. (Note: measurements of H_z were not taken in a borehole when it was used as a transmitting borehole.) The gray scale indicates the phase (ϕ), darker shades indicate negative phases ($-180^\circ < \phi \leq 0^\circ$), and the lighter shades indicate positive phases ($0^\circ < \phi \leq 180^\circ$). The sharp contrast between the dark

and light shades occurs when $\phi = 180^\circ$ such that the real part of H_z $\{\text{Re}[H_z(t = 0)]\}$ is negative whereas the imaginary part of H_z $\{\text{Im}[H_z(t = 0)]\}$ is zero. The demarcation at $\phi = 0$ is indicated by the solid line to aid in the identification. At $\phi = 0^\circ$ the $\text{Re}[H_z(t = 0)]$ is positive whereas $\text{Im}[H_z(t = 0)] = 0$. The $\phi = 0^\circ$ and $\phi = 180^\circ$ parts of the holograms are areas of complete phase coherency and are indicative of areas of the origin of the measured secondary magnetic H_z fields. The background resistivity for the plane-wave back propagation was assumed to be $20 \Omega\text{-m}$. The frequencies used to generate the holograms were 512, 1024, 2048, and 4096 Hz.

Figures 2 and 3 show notable differences. First, near ME-10 the $\phi = 0^\circ$ area has moved to shallower depths between the two surveys. From the induction logs supplied by Marathon, there was a decrease in the resistivity from April to November over the depth interval 279 to 289 m, whereas at deeper depths the resistivity remained essentially unchanged. The holograms shown in Figs. 2 and 3 appear to be imaging this change in resistivity. Second, the $\phi = 180^\circ$ demarcation at a depth of 300 m has moved from $y \approx 48$ m to $y \approx 58$ m. The induction logs taken in OB-3 indicated an increase in resistivity over the depth interval of 277 to 284 m. Third, the $\phi = 180^\circ$ demarcation near OB-1 at the deeper depths has moved to $y \approx 135$ m, whereas at the shallower depths (~ 260 m) the $\phi = 0^\circ$ area has moved from $y \approx 112$ m to $y \approx 132$ m. In addition, there appears to be a $\phi = 180^\circ$ zone at a depth of 250 m at $y \approx 138$ m. The induction logs taken in OB-1 indicated a decrease in resistivity in the regions shallower than 271 m and over the intervals 274 to 276 m, 280 to 289 m, and 294 to 299 m. Producing zones are being water-flooded above and below the zone subjected to the polymer flood.

For a background resistivity of $20 \Omega\text{-m}$ and at a frequency of 4096 Hz, the wavelength of the EM waves is approximately 221 m. At the frequencies used it will be difficult to resolve fine features. Because of the focusing action of the holographic method, however, the resolution will tend to be better than that predicted by the wavelength. The holograms obtained from the VES EM data detect changes in the resistivity structure, and a "smeared" image of the process can be obtained even for the frequencies used. The interpretation of the apparent changes in resistivity is not complete at this time.

The resistivity of the scattering anomaly and its relationship to the transmitting antenna will determine the phase structure and the sign of $\text{Re}[H_z(t = 0)]$ when $\text{Im}[H_z(t = 0)] = 0$. However, when using plane-wave propagators it is difficult to recover the proper magnitudes to determine if the resistivity of the scatterer is greater than or less than the assumed background resistivity. For the determination of the resistivity structure from the holographic image, a more sophisticated method of back projection is being considered. This new method utilizes the Helmholtz-Kirchhoff integral theorem to project data taken on a surface to an area to be imaged. The "data surface" can be borehole data or surface data.

Fig. 2 Cross-section phase hologram using cross-borehole vertical electric source data taken in April and May 1992 at the Marathon location, 20 Ω -m background. Transmitting antennae were located in wells OB-1, OB-2, and OB-3 for measurements of the vertical magnetic field in wells OB-1, OB-2, OB-3, and ME-10. The location of the cross section is indicated in Fig. 1.

Fig. 3 Cross-section phase hologram using cross-borehole vertical electric source data taken in November 1992 at the Marathon location, 20 Ω -m background. Transmitting antennae were located in wells OB-1, OB-2, and OB-3 for measurements of the vertical magnetic field in wells OB-1, OB-2, OB-3, and ME-10. The location of the cross section is indicated in Fig. 1.

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, 1993
Government Award: \$256,000
(Current year)**

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

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

Reporting Period: Jan. 1–Mar. 31, 1993

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

Previous work showed that the strike of vertical fractures in the subsurface can be detected with four-component data from vertical seismic profiles (VSP). The strike was determined by mathematically "rotating" the traces into their principal axes. This operation minimizes the amplitudes on the traces representing horizontal displacements that are perpendicular to the horizontal source orientations. Errors in the determined orientation were caused by differences in the strengths of the orthogonally oriented surface sources and in the couplings of the horizontal geophones located in the well.

Substantial improvement in the determination of the orientation of the fractures was obtained when these source imbalances were corrected. Further improvement was achieved when the down-hole geophones were assumed to be in the direction of the sources and their coupling variations corrected. In this case the geophone-coupling corrections were obtained by a linear least-squares procedure, which minimizes the seismic energy in the off-diagonal trace.

Investigations are continuing into the case in which the geophones are *not* initially oriented parallel to the source

directions. A nonlinear least-squares method is required to determine these corrections. The method leads to multiple possible fracture orientation determinations and to an unstable behavior.

Three additional, nine-component, VSP data sets were received from Chevron Oil Company. These data sets were put into memory on the computer and preliminary processing and editing were completed. Maximum effort will be expended on these data sets during the summer, June through August 1993.

A student has been working on a combined p-wave/s-wave data set from Burleson County, Texas, for the Austin Chalk formation. The purpose of this study is to determine the advantages in imaging or detecting fractures when the two types of data are available. The student is working on this project as part of his M.S. thesis, and his effort has been at no cost to the project. His study will be completed during the early part of the summer. Preliminary results indicate that the signal-to-noise ratio of the data sets may be too low to extract much meaningful information.

During the quarter, progress was made on acquisition and analysis of Formation Micro Scanner (FMS) data from wells in the Giddings and Pearsall Fields, S. Texas, and correlation of results to previously obtained outcrop data.

Initial studies from a borehole in the Giddings Field showed that only one fracture set striking northeast and essentially vertical was developed in the subsurface. Extension fractures of this orientation followed exactly the regional trend expected from extrapolation of fault traces from the nearest outcrops. In addition, however, this fracture set was oriented essentially perpendicular to the axis of the nearly horizontal wellbore. The fact that only one fracture set was developed was an unexpected result because at least two orthogonal sets were developed at the outcrop. Therefore the question arose as to whether or not the identification of only one set was the result of FMS sampling bias or because drilling the borehole itself had introduced fractures normal to the borehole axis or indeed whether the measurements were a valid assessment of the orientation of natural fractures in the subsurface.

The distribution of fracture spacing in the well located in the Pearsall Field was essentially identical to that in the well located in the Giddings Field. Fracture spacing in the borehole from the Pearsall Field varied from 1 to 10 per ft with some of the highest spacing correlated with low gamma-ray values. The fracture spacing in the well from the Giddings Field varied from less than 1 to 12 per ft and correlated similarly with the gamma-ray values (i.e., the greatest fracture spacing seemed to correlate with the lower gamma-ray values). The inverse correlation between high fracture density and low gamma ray is not surprising in that gamma-ray values often correlate with clay content. Rock strength increases with decreasing clay content and therefore so would fracture abundance increase with decreasing clays (i.e., increasing gamma-ray values).

Fracture aperture data from the well in the Giddings Field show apertures ranging from 0.02 to 4.0 mm. Fracture

apertures from the well in the Pearsall Field range from 0.002 to 2.0 mm with an estimated average between 0.1 and 1.0 mm. These apertures were not calibrated and thus reduced to absolute values. When not calibrated the aperture data are valid only for relative comparisons within a given borehole survey. Accordingly, there are depths within each borehole where fracture apertures are consistently wider than at other depths. This work is not yet sufficiently advanced to correlate these observations with the details of the structural stratigraphy.

Relating Recovery to Well-Log Signatures

Petrographic analysis of microseams was conducted on 16 thin sections to determine the gross composition and relationship of seams to microfractures. The observations indicated a geometric relation of microfractures that suggests propagation through the rock matrix. An analysis of microseams was conducted on selected samples of the Austin Chalk by means of electron microprobe. Aluminum and silicon in the insoluble residue found in two seams indicated the presence of clay minerals. Pyrite was also common in both the seams and in the rock matrix. Work was interrupted because of equipment failure. Analysis will be continued when equipment problems are corrected. Organic analysis will be conducted by means of cathode luminescence to detect the amount of kerogen and bitumen in the seams and in the microfractures.

Mathematical Modeling

The core face flushing imbibition experiments at elevated temperatures and pressures were performed on a cream chalk core. The semianalytical model was used to describe the laboratory imbibition oil recovery behavior by plain water and carbonated waterflood at 70, 110, and 150 °F. The experimental conditions and results of matching of oil recovery at 70 °F were reported in the previous quarterly reports. This quarter the semianalytical model was used to simulate the oil recovery behavior of the laboratory tests at 110 and 150 °F. The semianalytical model matched the laboratory oil recovery reasonably well when the exponential imbibition rate constant (λ) and the unitary maximum recoverable oil ($R\alpha$) were adjusted. The semianalytical model appears to be useful for providing a quick initial estimate of oil recovery performance for imbibition carbonated waterflooding when laboratory test data are available.

The core face flushing method was used to study the imbibition oil recovery from a chalk core. The compositional, dual-porosity numerical model (COMABS) was used to describe the laboratory imbibition oil recovery.

The cylindrical core was idealized by using a rectangular grid system (Fig. 1). The rock and fluid properties of the fracture and matrix systems are tabulated in Table 1. A linear, three-layer numerical model was used. Each layer was subdivided into five grid blocks; the water or carbonated water was injected into the fifth block of the fracture system at the

Fig. 1 Grid system for dual-porosity simulation.

TABLE 1

Rock and Fluid Properties of Fracture and Matrix Systems

No. of hydrocarbon components	1 (C_{10})
Grid system	$5 \times 1 \times 3$
Initial reservoir pressure	1000 psi
Location of producing well	$5 \times 1 \times 1$
Location of water injecting well	$5 \times 1 \times 3$
Water injection rate	$0.3 \text{ cm}^3/\text{min}$
Shape factor, F_s	0.09
Constant production pressure	500 psi

	Fracture system properties	Matrix system properties
$k_{x,y}$	9000 mD	9.1 mD
L_x	0.4 in.	
L_y	0.8862 in.	
S_{wi}	0.0	0.2
ϕ	0.03	0.23
P_c	0	$f(S_w)$
k_{rw}	S_w	$f(S_w)$

third layer. Oil and water were produced from the fifth block of the first layer.

Two-phase flow was implemented in the numerical simulation under the assumption that the entire simulating system was above the bubble point. The CO_2 was partitioned into the oil and water phase according to their individual solubilities. The oil viscosity reduction, the oil density change, the swelling of oil volume, and the residual oil saturation were quantified in the numerical simulation to reflect the partitioning or diffusion of the CO_2 . The transmissibility of the water and oil phases were updated correspondent to the concentration of CO_2 in each phase.

Figure 2 shows the imbibition oil recoveries obtained by plain water and 2.3, 4.0, and 5.5 wt % carbonated water. The simulated results matched the laboratory recovery very well. The simulator provides the oil and water saturation distributions in the fracture and matrix systems.

Fig. 2 Matching of imbibition oil recovery provided by plain water and carbonated water. O, laboratory data. —, COMABS.

MEASURING AND PREDICTING RESERVOIR HETEROGENEITY IN COMPLEX DEPOSIT SYSTEMS

Contract No. DE-AC22-90BC14657

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

Contract Date: Sept. 20, 1990
Anticipated Completion: Sept. 20, 1993
Government Award: \$1,915,000

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Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

This research 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 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 the 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 be able 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 series of regional maps was constructed that shows the geometry and trend of reservoir sandstones from six fields in Clay, Roane, and Kanawha counties and their occurrence in the regional study area. The reservoir sandstones mapped are the middle and upper Weir, Pocono/Price Big Injun, and Maccrady Big Injun. The Granny Creek and Tariff fields produce mainly oil from the Pocono Big Injun sandstone,

whereas the Bintree (Lizemores) field produces gas. The Rock Creek and Blue Creek fields produce oil from the Maccrady Big Injun sandstone. Clendenin, Pond Fork, and Blue Creek fields produce gas and oil from the middle Weir, upper Weir, and Maccrady sandstones. Structural elements associated with the basement (Rome trough and West Virginia dome) and detached fold axes were superimposed on these sandstone thickness maps. Paleogeologic maps of the pre-Greenbrier unconformity (Greenbrier Limestone subcrop map) also were constructed with and without the structural elements superimposed. Stratigraphic expression of a basement fault was observed in Kanawha County for the middle Weir and overlying upper Weir sandstones. Separate thickness maps of the middle and upper Weir sandstones indicate that both sandstones occur in narrow, north-trending belts with lengths of at least 30 miles above the eastern margin of the Rome trough. These coincidences are interpreted as evidence for growth faults during deposition.

Depositional environments (subfacies) shown in Fig. 1 were interpreted from textures, sedimentary structures, and fossils from cores in well 1126 in Granny Creek field and were related to the stratigraphic units of the Big Injun sandstone and their porosity and permeability values. Figure 2 shows a comparison of oil production from initial and cumulative flow with stratigraphic cross section P2-P2', which indicates the relationship between permeable proximal mouth-bar facies and probable partial barriers to fluid flow. Tongue boundaries and a high density zone result in reduced porosity forming

partial barriers. Primary initial and cumulative oil production data show two major trends in the field: (1) N/S orientation, which is also a thickness trend of tongues of the C member, and (2) NW-SE orientation, which is parallel to the erosive edge of the Big Injun by the pre-Greenbrier unconformity. Those trends consist of intermittent high-production areas of approximately 1000 × 1500 × 15 ft dimensions, which are separated by some NE-SW features. Major stratigraphic controls on oil production are the position, geometry, trend, and distribution pattern of permeable proximal bar subfacies in relation to (1) B member seal, (2) pre-Greenbrier unconformity, and (3) partial barriers. These barriers include thin shaly beds between prograding sandstone tongues and inclined thin intervals, cutting across C member tongues, of diagenetic origin. These partial barriers separate the proximal mouth-bar subfacies into compartments.

Structural Geology

Seismic Survey and Processing

The collection of additional high-resolution seismic data over Granny Creek field was completed. Data were collected over 13 miles of the most productive areas of the field with a group interval of 45 ft. High-definition data were collected locally for 2 additional miles around the vertical seismic profile (VSP) well. For these additional lines, a group interval of 22.5 ft was used.

Fig. 1 Interpretation of depositional environments (subfacies) from textures, sedimentary structures, and fossils of core from well 1126 in Granny Creek field, W. Va., and their relation to the stratigraphic units of the Big Injun sandstone and their porosity and permeability values.

Fig. 2 Comparison of oil production from initial and cumulative flow with stratigraphic cross section P2-P2' showing relationship between permeable proximal mouth-bar facies and probable partial barriers to fluid flow. Tongue boundaries and high-density zone are potential partial barriers as a result of reduced log porosity. MC, minor channels. DB, distal bar. FB, fluvial-influenced proximal bar. MB, marine-influenced proximal bar.

Seismic Reprocessing

Additional reprocessing of the Vibroseis data has led to further improvements in the quality of the stack data. A frequency domain inversion technique that uses the mixed-phase wavefield observed in the VSP as a desired wavelet for deconvolution design was used. Synthetic seismic calculations tie well to the processed data. This agreement increases the reliability of results obtained in the model studies.

Seismic Model Studies

Continuation of the seismic model studies indicates that it is possible to offer both stratigraphic and structural variability to explain the origins of waveform variability observed along Line 2 (and hence within the field as a whole). The results of the model studies are very much dependent on which version of the processed data is being modeled. If the wavelet deconvolved data presented by Zheng and Wilson¹ are used, then the signal-to-noise ratio is low, and areas suggested to represent fractures are characterized by an absence of signal. This makes such a display useful for visually locating possible fractured and faulted areas but is not useful for modeling. Post-stack frequency domain inversion, on the other hand, yields a section with high

signal-to-noise ratio. Given the higher signal-to-noise ratio of these data, better agreement was found between modeled fracture and fault zones with specific character changes observed across seismic time structures and areas where interwell conduits have been reported during waterflooding operations in the field. In areas where evidence of structural complication is absent, a stratigraphic origin seems likely.

Petrology

The Granny Creek data set was concluded, delivered to the West Virginia Geological and Economic Survey (WVGES), and entered into DOECOMMON. A nearly final version of the Rock Creek data set was delivered to WVGES to be entered into DOECOMMON. Petrographic results are being integrated with data from other workers in the project in an attempt to better quantify petrographic data.

The Big Injun sandstone in Granny Creek field can be divided into an upper, coarse-grained, fluvial-influenced unit and a lower, fine-grained, marine-influenced unit as described by Vargo and McDowell.² Conversely, the unit also can be divided into a four-unit system composed of a fluvial channel, a fluvially influenced proximal mouth bar, a marine influenced proximal mouth bar, and a distal mouth bar.

Three major types of porosity are prevalent in the Big Injun sandstone. The most common type, primary porosity, is observed throughout the Big Injun. Microporosity is next in importance, occurring within clay coatings, and is primarily observed in proximal and distal mouth bars. The third type of porosity, secondary porosity, resulting from dissolved feldspar, occurs throughout the Big Injun but is most prevalent in the higher density B zone.

Permeability is extremely variable but is most favorable in low-cement zones except where grain size is very fine and chlorite is not overly abundant.

The fluvial channel was interpreted by Smosna and Bruner³ as a meandering stream with high and widely fluctuating discharge. This facies was subdivided into A and B zones on a petrographic basis. The A zone is a medium- to coarse-grained, moderately-well-sorted zone exhibiting good porosity and permeability. Carbonate cement generally occurs in small concretions, which have only minor effects upon porosity, but locally the carbonate fills all pore space. Clay coatings are thin to nonexistent.

The B zone is characteristically secondary quartz rich exhibiting extremely low porosities and permeabilities. The major porosity found in this zone occurs from the dissolution of feldspar grains. Illitic coatings and laminae promoted pressure solution, as evidenced by the formation of coexistent illitic grain coatings and phyllosilicate grains. This formed a pseudomatrix with abundant pressure solution, which considerably lowered porosity and permeability.

The fluvial-influenced proximal mouth bar and the marine-influenced proximal mouth bar are petrographically identical. Porosities and permeabilities, which are high in these zones, are attributed mainly to well-developed chloritic clay coatings that affect, but do not clog, pore throats. These grain coats serve to protect the detrital quartz from secondary quartz growth. Other cements that would lower or eliminate porosity are absent in these facies except for small sideritic concretions that are present in the lower marine-influenced bar.

The distal mouth bar exhibits high porosities but extremely low permeabilities. The microporosity in the chloritic coatings (contributing to the high porosity values) ranges from 75 to 85%; however, the abundant chlorite tends to block pore throats in this fine-grained unit and thus drastically lowers or eliminates permeability. Siderite cement is common in this facies and is observed as patches and concretions of various sizes.

Reservoir Engineering

Oil Recovery and Reservoir Management

The transmissibility study for primary and secondary production was completed. Cases were developed for orthogonal and parallel heterogeneities with respect to streamlines. In the primary recovery cases, the streamlines and associated heterogeneities (Figs. 3 and 4) showed little effect on recovery. These effects are based on heterogeneities that span approximately 33% of the reservoir width.

Fig. 3 Major heterogeneity orientations—primary orthogonal streamlines.

Fig. 4 Major heterogeneity orientations—primary parallel streamlines.

The streamlines and heterogeneity orientations for the secondary recovery cases are shown in Figs. 5 and 6. The results for secondary recovery are much more profound than those for primary recovery.

For orthogonal heterogeneities (Fig. 7), the barrier case restricts flow especially at early times, but the overall recovery approaches the base recovery case as the injected water circumvents the barrier. The fracture case showed no effect on production as was expected on the basis of intuition from the streamlines.

For parallel heterogeneities (Fig. 8), the barrier case exhibited negligible effects because its limited lateral extent did not appreciably disrupt the majority of the streamlines. The

Fig. 5 Major heterogeneity orientations—secondary orthogonal streamlines.

Fig. 6 Major heterogeneity orientations—secondary parallel streamlines.

parallel fracture case, however, had a tremendous effect on oil recovery and water production (Fig. 9). Oil recovery is greatly decreased, and the difference between the base case and the fracture case increases over time. Also, cumulative water production is greatly increased as a result of early breakthrough of injected water.

Geostatistics and Modeling

In Granny Creek, original oil in place per well was calculated from the thickness of the Big Injun, average log porosity per well, and average water saturation per well for a range of effective drainage radii ranging from 50 to 200 m. A radius of

Fig. 7 Cumulative oil production with orthogonal heterogeneities. $\circ$, base. $\bullet$, barrier. ∇ , fracture.

Fig. 8 Cumulative oil production with parallel heterogeneities. $\circ$, base. $\bullet$, barrier. ∇ , fracture.

72 m gave an average recovery efficiency of 18% which matches values for the field computed from data in Whieldon and Eckard.⁴ When mapped, oil in place per well shows a broad, N-S swath of above-average values in the northern half of the field. This corresponds to a similar trend observed in 10-yr cumulative production. The southern part of the field exhibits lower values of both oil in place and cumulative production, but no feature matching the narrow N-S trend of relatively high cumulative production is observed in the oil-in-place map.

Throughout the field distribution maps for diagenetic density barriers, interbedded shale and siltstone within the Big Injun, and porosity show distinct N-S trends very similar to

Fig. 9 Cumulative water production with parallel heterogeneities. ○, base. ●, barrier. ▽, fracture.

those seen in probability maps of cumulative production. The fine-grained portion of the Big Injun is compartmentalized into a series of parallel, N-S-trending high- and low-porosity “zones” whose origins may relate to original depositional geometry, later diagenetic events, or a combination of both. In any event the strong linear trends of these zones appear to have produced subtle heterogeneities in reservoir porosity and permeability that in turn control oil volume. Additionally, the role of structure is suggested by an E-W discontinuity observed in structure and probability maps which separates production trends in the north half of the field from those in the south.

Several facies cross sections were created for Granny Creek on the basis of the various classification schemes proposed for the field (lithologic, depositional environment, and geophysical). Examination of the cross sections for all classification schemes revealed two common features: (1) each scheme, regardless of the actual number of facies divisions involved, divides the Big Injun in Granny Creek into two major units—a coarse-grained upper unit and a fine-grained lower unit, and (2) the fine-grained lower unit contains several, indistinct, adjacent “packets” of vertically repeated facies. None of the facies classification schemes has been able to resolve the precise geometry or orientation of these facies packets.

Digitization of Rock Creek well logs received from Eastern American Energy was completed and the corresponding production data for these wells were entered into the WVGES Oil and Gas database. In addition, pre-1930 production data for Pennzoil wells in the field were reconstructed with polynomial curve-fitting routines. Preliminary maps of Rock Creek reservoir thickness, porosity, water saturation, cumulative production, and estimated original oil in place were completed.

On the basis of drilling history analysis presented previously, it is known that the Rock Creek field was developed in two major phases (1900–1930 and 1961–1970). Most of the log data for the field were found to be restricted to the latter period of development, which apparently began when drilling into the “water leg” of the field became economic in the early 1960s. Because of this bias in the available log data, maps of Big Injun reservoir properties for Rock Creek must be viewed with a critical eye (Fig. 10). Note that the water saturation map, developed from log data collected in the 1960s and 1970s from the “water leg” of the field, shows high saturations within the older portion of the field where low saturations were expected.

Fig. 10 Average water saturation for the Big Injun sandstone in the Rock Creek Field. Note that highest water saturations are restricted to a band paralleling the northern margin of the field—this is the “water leg.” Contour interval is 10%.

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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: Oct. 16, 1993**

**Principal Investigators:
Robert W. Watson
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**Project Manager:
Gene Pauling
Metairie Site Office**

Reporting Period: Jan. 1-Mar. 31, 1993

Objectives

The overall objectives of the project are to develop a better understanding of some important, but not well-investigated, rock-pore properties, such as tortuosity, pore-size distribution, surface area, and wettability, and a better insight on capillary pressure variation with respect to wettability and pore geometry of sandstone and limestone; 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; develop empirical relationships between residual oil saturation and oil recovery at breakthrough and the uncommon rock-pore properties and relationships between residual oil saturation and ultimate oil recovery at floodout and the uncommon rock-pore properties for the different porous media; and investigate variations of irreducible water saturation, porosity, and absolute permeability with respect to the uncommon rock-pore properties, residual oil saturation, and oil recovery.

Summary of Technical Progress

An adequate estimation of the field behavior during primary and enhanced recovery period requires representative laboratory measurements. Moreover, the estimation of the behavior from mercury porosimetry properties data is important when routine measurements cannot be performed, as in the case of very small core plugs or drill cuttings. The estimation is also important when there is need to minimize core analysis cost or when the measurements of the behavior are of questionable accuracy, as in the case of reservoir rocks with microfractures.

Results and Discussion

Mercury Recovery Efficiency Correlation for Sandstones

An adequate prediction of the field behavior during primary or enhanced recovery period requires representative laboratory measurements. With the use of nonlinear multiple regression analysis, the correlation for estimating mercury recovery efficiency values for sandstones is developed from 450 experimentally obtained mercury porosimetry data. It was initially assumed that

$$RE = f(V_{int.}, SA, S_s, \bar{D}, \rho_s, \phi_{Hg}) \quad (1)$$

After a series of analyses with the use of the best subset algorithms, which is available in MINITAB statistical computer package,¹ it was observed that specific surface area could be removed from the list of independent variables in Eq. 1. The equation can then be rewritten as

$$RE = f(V_{int.}, SA, \bar{D}, \rho_s, \phi_{Hg}) \quad (2)$$

Again, with further modification, Eq. 2 is assumed to be of the general form

$$RE = \frac{SA^E \phi_{Hg}^F}{A V_{int.}^B \bar{D}^C \rho_s^D} \quad (3)$$

In Eq. 3, A, B, C, D, E, and F are coefficients of the correlation. By regressing the available mercury porosimetry data obtained from 450 Berea sandstone core-plug samples, the values of the coefficients were obtained. Substitution of the values of the coefficients into Eq. 3 results in the new correlation for estimating mercury recovery efficiency for sandstones, as shown in Eq. 4.

$$RE = \frac{SA^{0.689} \phi_{Hg}}{26.9 V_{int.}^{1.65} \bar{D}^{0.242} \rho_s^{0.369}} \quad (4)$$

The units of mercury recovery efficiency, RE, mercury porosity, ϕ_{Hg} , and the other variables in Eq. 4 are defined in the nomenclature.

So that the quality of the correlation could be tested, a cross plot was made to compare the predicted mercury recovery efficiency values using Eq. 4 with the measured values (Fig. 1). The solid 45° line in the figure represents a perfect correlation between the measured and estimated mercury recovery efficiencies. Most of the plotted data points of this new correlation fall close to the 45° line, which indicates its good degree of correlation. It has a standard deviation value of 0.0569, an F-test statistic value of 232.0, and is statistically significant with a p-value of 0.000.

Furthermore, another method of evaluating the adequacy of the regressed correlation is to examine a plot of the residuals, which are simply the differences between the individual measured values of the dependent variable and the predicted values. This plot of residuals vs. measured mercury recovery efficiency for sandstones is shown in Fig. 2. The behavior of the plot suggests that the independent variables in the correlation were enough to define the dependent variable.

Fig. 1 Comparison of measured mercury recovery efficiency values for sandstones with those predicted by the new correlation.

Fig. 2 Plotted residuals using the new correlation vs. measured mercury recovery efficiency for sandstones.

Permeability Correlation for Sandstones

The permeability dictates the speed at which fluid flows through various layers of reservoir rock.² There is an increasing need for good, simple-to-use correlation to estimate permeability. The estimation of reservoir rock permeability from mercury porosimetry data is important when routine permeability measurements cannot be performed, as in the case of very small core plugs or drill cuttings. This estimate is also important when there is a need to minimize core analysis cost or when measurements of permeability are of questionable accuracy, as in the case of reservoir rocks with microfractures.

With nonlinear multiple regression analysis, as in the case of mercury recovery efficiency, a new correlation for estimating permeability values for sandstones with the use of coreflood or mercury porosimetry measured data has been developed. The development was initiated using the 21 sandstone cores waterflood and mercury porosimetry experimentally obtained data. Here it was initially assumed that

$$k = f(\phi, V_{int.}, SA, S_s, \bar{D}, \rho_s) \quad (5)$$

The primary reason for using only the initial independent variables contained in Eq. 5 was to develop a correlation to estimate permeability on the basis of the rock properties determined with mercury porosimetry.

In Eq. 5 the independent variable, ϕ , can either be brine porosity or mercury porosity, depending on whether the permeability is to be estimated from waterflood experimental core data (brine permeability) or from mercury porosimetry experimental core plug data (mercury permeability). After a series of analyses, it was observed that permeability could be correlated with only porosity, surface area, and specific surface area as the independent variables in Eq. 5. The equation can then be rewritten as

$$k = f(\phi, SA, S_s) \quad (6)$$

To further improve the correlation, Eq. 6 was modified by dividing the dependent variable by $(1 - \phi)^2$, which implies that

$$\frac{k}{(1 - \phi)^2} = f(\phi, SA, S_s) \quad (7)$$

After applying multiple regression analysis methods in Eq. 7, the resulting developed correlation for estimating permeability is given as

$$k = \frac{7.834 \cdot 10^5 \phi^{3.46} (1 - \phi)^2 SA^{0.230}}{S_s^{0.192}} \quad (8)$$

In Eq. 8, permeability, k , is expressed in millidarcy and porosity, ϕ , is expressed in fraction. The other variables in the equation are as defined in the nomenclature.

To show how good the correlation is, a cross plot was made to compare the predicted brine permeability values using the new correlation, as shown in Eq. 8, with the measured values (Fig. 3). Most of the plotted data points of this new correlation fall close to the 45° line, which indicates a good correlation. It has a standard deviation of 0.0546, an F-test statistic value of 191.3, and is statistically significant at $\alpha = 0.001$ level. The plotted residuals vs. measured brine permeability values for sandstones are shown in Fig. 4. The behavior of the plot suggests that porosity, surface area, and specific surface area were enough to develop a good correlation for permeability.

Equation 8 was also used to estimate mercury permeability of the core-plug samples. The resulting estimates of mercury permeability values for the 450 sandstone core-plug samples were plotted against the respective values of their measured mercury porosity values as shown in Fig. 5. The plotted data points fall very close to an exponential trend, as expected for the relationship of porosity with permeability.

Swanson³ used parameters from capillary pressure curves to develop permeability correlations for sandstones and carbonates. His database consists of 116 carbonates and 203 sandstones from 74 formations. Thompson et al.⁴ used percolation theory to develop theoretical models to predict permeability from mercury porosimetry data. They proposed that the theory was valid for essentially all porous rocks. Other recent permeability correlations include those of Pittman⁵ and Kamath.⁶ The predictive strength of the new correlation for sandstones is not compared with that of these correlations because the conductivity formation factor values for the rock samples needed to use Thompson et al.'s model were not measured in this study. Also, it is time consuming to estimate the values of the maximum of the parameter, S_{Hg}/P_c , needed to be able to use the various models developed by Swanson, Pittman, and Kamath.

Fig. 3 Comparison of measured permeability values for sandstones with those predicted by the new correlation.

Fig. 4 Plotted residuals using the new correlation vs. measured permeability for sandstones.

Fig. 5 Mercury permeability for sandstones predicted by using the new correlation vs. measured mercury porosity.

Conclusions

The following conclusions are deduced from this study:

- New empirical correlations that can be easily programmed for computer application were developed to estimate mercury recovery efficiency and permeability for sandstones. The permeability correlations can also be used as a tool to estimate mercury porosimetry derived permeability values.
- It was shown that, in addition to porosity, total mercury intrusion volume, pore surface area, average pore diameter,

and apparent (skeletal) density are important factors for mercury recovery efficiency estimations. Further, in addition to porosity, pore surface area and specific surface area are important factors for permeability estimations.

Nomenclature

$\bar{D}$	average pore diameter, μm
f	function of
F	statistical F-test
k	permeability, mD
p-value	significance level
RE	mercury recovery efficiency, fraction
SA	total pore area (or surface area), m^2/g
S_s	specific surface area, cm^2/cm^3
$V_{\text{int.}}$	total intrusion volume (or pore volume), mL/g
ρ_s	apparent (skeletal) density, g/mL
ϕ	porosity, fraction
ϕ_{Hg}	mercury porosimetry measured porosity, fraction

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RESOURCE ASSESSMENT TECHNOLOGY

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

Contract No. DE-FG22-92BC14853

**Oklahoma Geological Survey
Norman, Okla.**

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

**Principal Investigators:
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**Project Manager:
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Reporting Period: Jan. 1–Mar. 31, 1993

Objective

The objective of this research program is to continue developing, editing, maintaining, using, 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 the construction of 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 NRIS 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

283,751 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 before data entry. The historical completion reports are checked out of the OGS Archive Library and copied at an average rate of about 1500 forms per week. All new completion reports are copied as soon as they are 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. More than 353,000 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. Well records are being prescanned, keyed, and edited for the following counties in northeastern Oklahoma: Delaware, Mayes, Osage, Rogers, and Washington. Approximately 27,000 well records were keyed this quarter; thus, as of March 1993, 310,890 records were 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, respectively.

TABLE 1

Well History File Progress by Regional Division

Area of coverage	Start of grant	Start of quarter	Current
Southeast region	65,712	66,028	66,699
Southwest region	69,453	70,048	70,996
Northeast region	23,467	63,582	85,359
Northwest region	32,507	32,771	33,164
North central region	40,883	51,322	54,672
Total	232,022	283,751	310,890

Both general and specialized edit procedures were continued on the well data. Search strategies are used to research 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. The statewide Lease File/Well File match used to identify sections with significant discrepancies in the lease and well counts has been facilitated by cooperation from NRIS users and from Sooner Well Log Service, located in Oklahoma City, which has an extensive, well-organized hard-

Fig. 1 Status of well history database project by county coverage as of March 1993.

Fig. 2 Status of well history database project. Total well records, 310,890.

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 have been highly successful. Additionally, efforts to assign API numbers to wells drilled between 1964 and 1969 resulted in 1266 updated records. Future plans are to complete a more thorough match of all well records.

Efforts are ongoing for standardizing the formation names on the Well History File. A 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. In the southeast and southwest regions, over 99% of the reported names have been standardized in this effort. Efforts on the northwest region have been completed, and efforts on the north central region have begun. 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 on the basis of the official field outlines as 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. On the basis of this input, the Committee began by first updating several gas-field boundaries; emphasis will soon shift to oil-field boundaries as work proceeds on a separate Department of Energy (DOE) project involving the identification and evaluation of Oklahoma's fluvial-dominated deltaic reservoirs. Overall, unassigned gas production is 13% of the annual average production and unassigned oil production is 20%.

Special efforts were also made this quarter to complete preparations for the January 1993 data release and to finalize the data manual (a reference dictionary for the various data elements), the operations guide (which documents the weekly processing jobs), and the system specifications (which document the computer programs) for the NRIS system. The operations guide for the Well History subsystem was completed in early January 1993, and the system specifications volume for the Well History subsystem is approximately 50% complete.

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 during the summer of 1991 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 before construction of the NRIS system.

One company subscribes to the Well History File. Additionally, several inquiries were received this quarter from small companies and independents who typically acquire NRIS subsets to evaluate within their specific computer systems before committing to large data acquisitions. Also, as previously reported, 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.

The OGS is 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 is being used to develop a menu-driven retrieval system customized to NRIS data. A large digitizer, large plotter, and desktop scanning equipment enhance the capabilities available through GeoGraphix and Radian CPS/PC contour mapping software as well as through ARC/INFO, a Geographical Information Systems (GIS) spatial analysis tool.

The 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. The NRIS data also factor significantly in two other projects. One, being developed in conjunction with the Geography Department, involves the creation of an oil and gas pipeline GIS database for the Oklahoma Ad Valorem Task Force using four Oklahoma counties as a pilot study. The NRIS well and lease data are being included as related data layers in this GIS project. The other, a DOE project, involves the study of Oklahoma's fluvial-dominated deltaic reservoirs.

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
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**Principal Investigator:
Susan R. Jackson**

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

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Objectives

The objectives of this project are to (1) develop geological and engineering methods to predict mobile oil saturation distribution and quantify reservoir architecture and flow unit geometry for application to targeted infill drilling and enhanced oil recovery (EOR) and (2) synthesize reservoir and production characteristics of shoreline barrier reservoirs and determine similarities and differences and the degree to which information from one reservoir can be applied to another.

Summary of Technical Progress

Controls on Production in the Arch Unit

Petrophysical and production data from the Arch Unit, Patrick Draw (Wyoming), field were reviewed to determine

the major controls on production. The major controls identified were (1) pay thickness and porosity, (2) oil saturation, (3) drive mechanism, and (4) recovery continuity. The pay thickness and oil saturation values were found, as expected, to be closely associated with the oil production amount.

The water production from Arch wells in sections 12, 7, and 1 during primary production was due to the high initial water saturations. Significantly higher than normal initial water saturation values occurred in Arch wells 11, 33, and 94. Water cut of produced fluids was 52% in the first month of production. Reservoir compartmentalization is suspected for the high water saturation values.

Pressure maintenance from gas-cap expansion and water injection increased the recovery efficiency from Arch wells 21, 44, 46, 98, and 99, which are located near the bottom of the oil column. Production data from wells located near the water-oil contact indicated that the aquifer did not provide a significant water drive. Poor waterflood production from wells in sections 12 and 7 was caused by multiple and discontinuous layering that was identified in well logging and reservoir core permeability measurements. High-resistivity, carbonate-cemented intervals (5 to 15 ft thick) identified in wireline logs and cores contributed to the poor lateral fluid communication.¹

EOR Potential Evaluation in Patrick Draw Field

The low variability of petrophysical properties, successful primary and secondary production, and significant residual oil saturation (30 to 50%) in the Monell Unit, Patrick Draw field, suggest that EOR recovery techniques have the potential to increase oil recovery. The comparison of key reservoir parameters to technical screening criteria for EOR processes indicates that gas injection and polymer flooding are candidate processes to improve oil recovery in the Monell Unit. However, the benefits of the polymer flooding process may be limited because conformance and fingering problems were not evident as the result of the low oil viscosity and low water relative permeability indicated by laboratory measurements.

Among the gas injection methods, CO₂ flooding has better potential than nitrogen or hydrocarbon to improve the displacement efficiency of oil. The initial 1790 psig reservoir pressure of the Monell Unit is higher than the minimum miscibility pressure measured by Core Laboratories for Patrick Draw crude oil at reservoir temperature 121 °F. The current reservoir pressure after waterflooding is close to or above the initial reservoir pressure in the Monell Unit, which allows miscibility of injected CO₂ and reservoir crude and thereby improves the displacement of oil by oil swelling and viscosity reduction. Nitrogen generally requires a much higher reservoir pressure to reach miscibility with oil than CO₂. The cost of CO₂ is usually less than that of hydrocarbon gas when a nearby access to CO₂ source is available, as is the case with Patrick Draw field. The CO₂ injection has additional benefits in reduction of interfacial tension. On the basis of the media recovery value of 20% original oil in place (OOIP) from CO₂

flood field projects,² a total production of 16 MMSTB (120 STB per acre-ft) can be expected from CO₂ injection in the Monell Unit.

Two localities within the Monell Unit have been selected as potential pilot sites: area A, around Monell wells 14 and 24, and area B, around Monell wells 39, 46, 50, 117, and 121 (Fig. 1). Both areas have pay thicknesses of approximately 30 ft, remaining oil saturation of about 40%, and good interwell communication indicated by pressurization during waterflood. Area A has larger well spacing (80 acres), which contains more oil per well and the possibility of greater amounts of remaining oil in place because of lower waterflood sweep efficiency, whereas area B has a well spacing of 40 acres that is representative of the well spacing in the Monell Unit.

To investigate the amount of oil recovery and the potential economical impact of CO₂ flooding in the pilot area and Patrick Draw field, Computer Modeling Group's compositional simulator GEM was obtained from the Department of Energy and installed on the National Institute for Petroleum and Energy Research's (NIPER's) VAX computer. The simulator GEM was successfully compiled after minor modifications and validated by running sample problems. Time permitting, a detailed flow unit model of proposed pilot area will be constructed and numerical simulation studies of CO₂ flooding will be performed.

Compartmentalization and Identification of Flow Barriers in Patrick Draw Field

Pressure Data Analysis

Reservoir pressure history was obtained from Union Pacific Resources Co., the operator of Patrick Draw field.³ Pressure-monitoring data collected during primary production (between 1959 and 1965), waterflood (1975), and in the post-waterflood period (1980) were analyzed to substantiate the position of barriers to flow and to refine boundaries of fluid compartments in Patrick Draw field. A set of bottomhole pressure (BHP) data acquired in August 1975 from five production wells in Monell Unit and a set of static reservoir pressure data acquired in April 1980 from five production wells in Arch Unit were mapped and compared with hydrodynamic barriers postulated earlier on the basis of pre-waterflood hydrochemical anomalies and pressure surveys performed in 1961, 1962, and 1965 (Fig. 2). Before definitive interpretations of the pressure data can be made, however, the decline rates on a per-well basis need to be analyzed to distinguish variations in reservoir pressures caused by production-injection field operations.

The BHP measurements taken in August 1975 and extrapolated to 2000 ft above sea level reveal significant differences in reservoir pressures within Monell Unit along strike of the Almond formation (NNE-SSW), ranging from about 500 psig in the northern part of the unit (wells 4 and 14 in sec. 26, T. 19 N., R. 99 W.) to nearly 2500 psig in the central

Fig. 1 Well location map of Patrick Draw field showing proposed location of a CO₂ pilot and wells with petrographically analyzed thin sections.

part of the unit close to the oil–gas contact (well 119 in sec. 3, T. 18 N., R. 99 W.) and 3735 psig in the southern part (well 93 in sec. 10, T. 18 N., R. 99 W.). (See Fig. 1 for well locations within the field.) At the same time the BHP monitored in the

gas-cap observation Monell well 58, located in sec. 4, T. 18 N., R. 99 W., was only 1224 psig. Wells 58, 93, and 119 are located less than 1 mile apart. Pressure differences of 1200 and 2500 psi between these wells provide the most direct evidence

Fig. 2 Compartmentalization of Patrick Draw field indicated by the formation pressure distribution and hydrogeochemical anomalies. ---, 1000-psi isobar. —, 750-psi isobar. —, water salinity anomaly. —, interpreted hydrodynamic barrier.

of highly impaired lateral communication of fluids within UA-5 sandstone body in the Monell Unit during the waterflood stage. Pressure distribution in the mid-1970s between wells 93 and 119 corroborates the position of flow barrier in the Monell Unit postulated earlier on the basis of hydrochemical and pressure data of the early 1960s. The postulated barrier seems to maintain SW-NE direction across the Monell Unit, although it may be locally discontinuous. The pressure survey of 1975 may indicate additional barriers to flow in the Monell Unit between wells 58 and 119 (1200 psi difference) and a probable baffle or barrier to flow between well 119 and a pair of wells (4 and 14) (2000 psi difference).

Static pressure data from five wells in the Arch Unit obtained in April 1980 reveal a highly pressurized zone by water injection in the area of wells 88 (sec. 13, T. 19 N., R. 99 W.) and 97 (sec. 12, T. 19 N., R. 99 W.), where about 3500-psi static pressures were monitored. In wells 14 (sec. 24, T. 19 N., R. 99 W.), 76 (sec. 6, T. 19 N., R. 98 W.), and 107 (sec. 11, T. 19 N., R. 99 W.), however, pressure dropped to 770, 1839, and 1280 psi, respectively, which indicated positions of barriers to flow that divide the Arch Unit into hydraulic compartments. This interpretation, based on data from 1980, fully corroborates the positions of postulated barriers in

the Arch Unit mapped earlier on the basis of pressure distributions in 1960s, when the reservoir was drained by primary production. The high waterflood pressure compartment indicated by 1980 data corresponds with a pressure "sink" to 700 psi in 1965 recorded during primary production. The pressure sink of 1965 was centered in Section 13 where well 88 is located. Both pressure surveys indicate limited potential for drainage and injection of fluids in the area. In the Arch Unit, the major fluid compartments are well defined by the distribution of UA-5 sandstone bodies.

Anomalous low formation pressures [about 500 psi in wells Monell 4 and 14 (1975 survey) and to 770 psi in well Arch 14 (1980 survey)] indicate that the Almond formation could have been fractured in the area by injection pressures as high as 2500 psi applied during waterflooding.²

Information that contradicts extensive hydraulic fracturing and a potential for escape of injected water somewhere outside the system includes (1) low Q_i/Q_p ratio (0.76) in the southwestern region of the Arch Unit (well Arch 14 is located downdip near the eastern border of the region), which allows the injection water to take space left by the produced hydrocarbons;³ (2) long (more than 100 months) breakthrough time in the area of wells Monell 4 and 14 (Ref. 3), which would not have been the case if the injected formation had been extensively fractured; and (3) relatively good cumulative oil production and waterflood performance in a general area of discussed pressure anomalies.⁴

In contrast to the central part of Patrick Draw field, the very high formation pressures recorded during the waterflooding in southern Monell Unit and in northern Arch Unit indicate fluid confinement within compartments of limited capacity. Intra-compartment hydraulic fracturing of the Almond formation sandstones is possible in these areas because in some wells the imposed pressure could exceed the rupture pressure. An integrity of barriers to flow between the compartments, however, seems to be preserved.

The pressure history and geochemical data from Patrick Draw field indicate that (1) the reservoir is compartmentalized, (2) crucial and most reliable information for the interpretation primarily comes from the initial stage of reservoir development, (3) monitoring of reservoir pressure responses during subsequent reservoir development stages corroborates the major reservoir hydraulic partition interpreted on the basis of data acquired in the early 1960s, (4) data collected under induced hydrodynamic conditions provide valuable supplement for refinement of compartment boundaries, (5) the reservoir may be fractured by extensive pressures applied during the waterflood stage, and (6) characteristics of the induced fractures and their influence on oil recovery may be difficult without additional tests, such as tracer tests and geochemical analyses.

Production-Injection Data and Fluid Distribution Analyses

An NE-SW-trending low-transmissibility zone in the Monell Unit indicated by formation water salinity and

composition contrasts¹ may be reflected in the gas/oil ratio (GOR) distribution but cannot be confirmed by other production–injection data analysis. The lack of evidence of a flow barrier or low transmissibility zone in the production–injection data may be because the barrier is not aerially extensive and does not form a compartment on a scale that affects the drainage area of a single well. Because changes in pay sand thickness and the thickness of carbonate-cemented intervals do not correspond with the salinity contrasts, a structural feature, such as a fault or healed fractured zone, is suspected.

Sharp contrasts in the distribution of producing GOR during primary production correspond with the NE-SW-trending low-transmissibility zone interpreted from formation water salinity data.¹ The producing GOR of Monell well 22 in December 1964 was 9153 scf/STB. This is much higher than a GOR range of 3500 to 5141 scf/STB from wells that are less than half a mile away from Monell well 22. The producing GORs of Monell wells 44 and 45 were 6185 and 6964 scf/STB, respectively, in comparison to a GOR range of 2680 to 3895 scf/STB from offset wells. The sharp contrasts of producing GOR around Monell wells 22, 44, and 45 suggest the presence of local low-transmissibility zones.

Contrasts in distribution of initial water saturation (S_{wi}) values, however, were not found in the Monell Unit.¹ The smooth decrease in S_{wi} from the water–oil contact (WOC) to the gas–oil contact (GOC) showed little evidence of flow discontinuity. The only exceptions are the relatively higher S_{wi} values shown from Monell wells 28, 34, and 39 than those from surrounding wells. The waterflood production data, however, did not support the existence of flow barriers or compartments around Monell wells 28, 34, and 39.

Barriers to fluid flow were not indicated by the distribution of oil recovery in the Monell Unit.¹ Wells with good recovery efficiency (>20%) during depletion production were scattered in the Monell Unit. No indication of high oil recovery was attributed to additional pressure maintenance through flow barriers and gas-cap expansion. Most Monell wells produced 15 to 25% of OOIP from waterflood. Low recovery from wells located at the NE and SW edges of the Monell Unit can be attributed to poor petrophysical properties. Water injection and production data during waterflood suggest good interwell communication within the Monell Unit. Local flow restrictions might be responsible for the relatively low recovery efficiency (10 to 15%) of waterflood in areas containing Monell wells 22 and 44. The overall flow communication in the Monell Unit is good, as evidenced by the water injection–production volume, water breakthrough time, and recovery efficiency.

Distribution of reservoir pressures and oil decline rates were analyzed for possible continuous-flow barriers in the Monell Unit. Reservoir pressures during primary production were simulated in an east-west-trending rectangular area of the Monell Unit with the reservoir simulator BOAST. This area includes Monell wells 53, 54, 55, 56, and 57 and a gas injector Monell well 169 near the gas cap. The laboratory measured pressure–volume–temperature and relative perme-

ability values and well production rates were entered in the simulation model. The log-calculated saturation value of each well was based on the contoured salinity values. An average permeability value was assigned in the model. The simulation results showed a high-pressure plateau near the gas cap and a sharp decline of reservoir pressure between Monell wells 55 and 56 after 4 yr of primary production. This was caused by the gas-cap expansion, gas injection from Monell well 169, and high production rates from Monell wells 54 and 55 near the WOC. This simulation result compared favorably with the reservoir pressure distribution in that area in 1964. A barrier of zero transmissibility was assigned between Monell wells 55 and 56 in the model for the sensitivity run to study the effect of the flow barrier on reservoir pressure distribution. A similar reservoir pressure profile was obtained with the inclusion of flow barrier in the model except that a sharp pressure drop of 200 psi was observed across the flow barrier in contrast to a 10-psi drop in the model without a flow barrier. Because the existing pressure distribution data around Monell wells 55 and 56 are not detailed enough, the existence of a flow barrier cannot be verified.

The oil decline rates during depletion in the Monell Unit wells near the gas cap showed a somewhat exponential decline with an effective decline rate of approximately 0.02 per month. The Monell wells near the WOC also showed an exponential decline with an effective decline rate of approximately 0.04 per month. The lower decline rates for wells near the gas cap suggest higher reserves than those near the WOC. This is due to a large well spacing near GOC and pressure maintenance from gas injection and gas-cap expansion. The water drive at the WOC is known to be weak. The Monell wells approximately 1 mile east of the gas cap showed decreases in decline rates with depletion times. Wells showing decrease in decline rates are located in the area of a high-pressure plateau maintained by gas-cap and gas injection. As gas injection proceeded, the increase of gas saturation increased the fluid compressibility so that the decline rate was reduced at the late depletion time. To determine whether the decrease of decline rate resulted from additional pressure support from a continuous NE-SW barrier would require additional study.

Hydrodynamics of Bell Creek and Patrick Draw Fields

Published effects of natural dynamic fluid flow on hydrocarbon distribution were compared with the observed anomalies in the composition of oil-associated formation waters for the microtidal subsystem in Bell Creek (Montana) field and the mesotidal subsystem in Patrick Draw field. Hydrogeochemical heterogeneity of the original oil associated formation waters in Patrick Draw field contrasts with a perplexing homogeneity of pre-waterflood formation waters in Bell Creek field.⁵

In Bell Creek field, a geologic separation of productive units within the Muddy formation is evident based on earlier

geological studies conducted by NIPER. Deep valley incisions into the oil productive shoreline barrier deposits apparently divide the reservoir into units with separate oil–water contacts. Despite the erosional–depositional lithological barriers, the salinity and composition of formation waters within individual compartments (production units A, B, C, D) are surprisingly uniform. Salinities of formation water in Bell Creek field are anomalously low (4,000 to 7,000 mg/L) at a reservoir depth of 4,600 ft. The oil productive shoreline barrier sandstones in Bell Creek field as well as underlying (Skull Creek) and overlying (Mowry) shales deposited in deep shelf environment were primarily saturated with the Lower Cretaceous marine water of characteristic composition and average salinity of 35,000 to 40,000 mg/L. Subsequently the original waters had to be uniformly replaced from the more permeable shoreline barrier–lagoonal system (Muddy formation) by waters of much lower salinity and different composition probably by atmospheric waters infiltrating into Muddy formation outcrops after their exposure to the surface. Potentiometric maps^{6–7} clearly indicate that Bell Creek reservoir is under hydrodynamic drive, which causes downdip tilt of oil–water contacts. The favorable (downdip–flow) hydrodynamic drive adds 429 ft (86%) of oil column to the 68 ft of calculated hydrostatic oil column.⁶ This hydrodynamic flow could be the mechanism for the observed homogenization of oil-associated formation waters. The suggested regional flow of waters downdip toward the center of the Powder River Basin passes by the internal permeability barriers, which retained, however, the majority of the upward (upstream) movement of oil. In the case of Bell Creek field, the regional hydrodynamic flow and leaking “barriers” seem to govern the oil reserves, oil distribution, and redistribution of most of the reservoir gas. The potential influence of reservoir hydrodynamics on different stages of hydrocarbon production in Bell Creek field is not well known.

Hydrochemical anomaly (low salinity and depth independent compositional uniformity), based on water analyses collected at the very early stage of reservoir development in Bell Creek field, provided a clear hydrodynamic message that could have been easily confirmed by isotopic analyses of the reservoir water. Although the stable isotope techniques were already available in the early 1960s, they were rarely used outside advanced hydrogeology. Underuse of hydrogeochemical techniques in the Bell Creek field delayed understanding of field hydrodynamics and related distribution of hydrocarbons for one to two decades.

Data presented by Momper and Williams⁸ on carbon stable isotope ratios and chemical characteristics of water-washed and biodegraded oils in the northeastern part of the Powder River Basin agree with the concept of a strong hydrodynamic drive within the Muddy formation postulated by Berg et al.⁶ An approximate gradient of flow in the Bell Creek field area is 50 ft/mile (21.6 psi/mile). An approximate calculated velocity of flow through lagoonal deposits may reach 21 ft per year if the presence of 250-mD permeability streaks within the otherwise low-permeability (and high displacement pressure)

barrier facies is assumed. The hydrodynamic data clearly indicate that atmospheric waters infiltrate through Muddy formation outcrops at the elevation of about 4000 ft, migrate downdip through Bell Creek reservoir at a depth of 4600 ft, and thus cause tilting of oil–water contact and homogenization of reservoir waters by mixing processes. Their atmospheric origin could be confirmed by stable isotope ratio analysis in water molecules along the flow path.

Little is known so far about the natural hydrodynamic regime within the oil- and gas-producing Almond formation in the area of Patrick Draw field. However, the regional potentiometric map of the Mesaverde formation in the Washakie Basin⁹ reveals the presence of numerous pressure anomalies and steep potentiometric head gradients across very short horizontal distances (up to 10,000 ft of hydraulic head difference), which indicate the presence of impermeable barriers (seals) and a lack of hydrodynamic flow between pressure compartments. In Patrick Draw field, located on the flank of the Washakie Basin, diversity and inversion of water salinities with depth, lateral diversity of chemical composition, fluid compartmentalization indicated by pressure distribution, and the presence of extensive gas cap indicate that direct hydrodynamic communication with the Almond formation outcrops on the east flank of the Rock Springs Uplift may have been disrupted.⁵ It has been suggested, however, that at least some formation waters documented in the Almond formation compartments are allochthonous. Upward movement of fluids from greater depths has been suggested. More information on the hydrodynamic regime in Patrick Draw field and its influence on reservoir productivity needs to be collected and interpreted before these questions can be answered.

Comparison of the contrasting geochemical and hydrodynamic information from Patrick Draw and Bell Creek fields provides an instructive example that (1) hydrodynamic and hydrochemical conditions are interrelated in the studied reservoirs; (2) reservoir dynamic conditions provide conclusive information when considered in a broader regional context rather than in a scale of a reservoir or a production unit; (3) hydrodynamic conditions in Bell Creek field strongly affect hydrocarbon reserves, distribution, and quality; and (4) a single source of information for reservoir hydrodynamic characteristics is informative but may not be conclusive.

Hydrogeochemistry, isotropy, and hydrodynamics seem to be strongly interrelated and provide the most reliable information when considered together.

Petrographical Analysis of Almond Formation Sandstones in Arch Unit of Patrick Draw Field

Petrographical analysis has been completed for 20 thin sections from four wells in the Arch Unit of Patrick Draw field (Fig. 1). Sandstones are dominantly feldspathic litharenites with lesser amounts of litharenite and sublitharenite. Most of

the sandstone samples are texturally submature (under 5% clay matrix but not well sorted) to mature (little or no matrix, grains well sorted but not rounded). A single sandstone sample contained more than 5% clay matrix and is classified as texturally immature, and one sample is technically a carbonate rock. Mean total rock volume of diagenetic features that have an effect on porosity and geometry of pores are indicated in Table 1. The data shown may be used to judge the relative impact of specific diagenetic stages on the pore system. At this time the effects of leaching and compaction cannot be quantified. The mean dolomite–ankerite/calcite ratio is 14.2 for 10 samples that contained carbonate minerals. The high ratio is somewhat unexpected and indicates that dolomite is much more abundant in the examined subsurface samples than is calcite. On the basis of preliminary observations, this relationship may be quite different in outcropping Almond formation sandstone samples. Average values for total carbonate cement indicate that it is approximately twice as abundant as clay cement and about 1.6 times as abundant as total clay content of examined samples. On the basis of these results, it can be predicted that carbonate cements had the primary control of reduced interparticle porosity in the sandstones followed by clay cement. Quartz overgrowths were of much less importance than either carbonate or clay cements but may have provided substantial framework stability by welding grains together and thereby providing increased resistance to compaction.

Correlation coefficients were derived for linear relationships between a number of petrophysical properties and diagenetic features (Table 2). Statistically significant relationships, with R values greater than 0.90, were found for total carbonate cement vs. dolomite–ankerite cement (0.99), total cement (of all kinds) vs. dolomite–ankerite cement (0.96), and total cement (of all kinds) vs. total carbonate cement (0.96). These relationships indicate that, for the samples analyzed,

total cement is a function of total carbonate cement and total carbonate cement is a function of dolomite–ankerite content.

These results imply that porosity should be a function of the amount of dolomite–ankerite cement or at least a function of the total carbonate cement. None of the examined petrographical parameters, however (clay or carbonate), correlate with porosity or permeability. A possible explanation for the lack of correlation between the carbonate cements and porosity (or permeability) may be the diagenetic processes of late-stage leaching and physical–chemical compaction, parameters that could not be included in Table 2.

Important diagenetic events recognized by Keighin, Law, and Pollastro¹⁰ include the leaching of calcite followed by late-stage leaching of ankerite. A mean value of 61.2% of total feldspars is altered or shows effects of corrosion. In addition, lithic fragments are often altered, corroded to partially moldic, and microporous. The high percentage of altered feldspars is the result of their instability in the presence of subsurface fluids. It is possible that the same fluids responsible for the leaching of carbonate minerals, for which there is good petrographical evidence, also had a corrosive effect on the feldspars and lithic fragments. In Almond formation samples from the Arch Unit, the potential result of leached carbonates and corroded–altered feldspars and lithic fragments would have been a moderate increase in interparticle porosity and a moderate to great increase in microporosity. The effects of leaching would, however, have been different in different parts of the reservoir, depending on the prior abundance of carbonate, feldspars, and other metastable components of the rock, which were likely quite variable. Therefore there is no statistically valid relationship between the abundant varieties of cement (calcite, dolomite–ankerite, and clay) and porosity.

Physical–chemical compaction of depositional matrix (dominantly clay minerals), stable framework grains, and unstable framework grains, such as altered feldspars and leached lithic fragments, is a common feature in Almond formation sandstones from Patrick Draw field. The overall result is difficult to quantify. Examination of thin sections, however, indicates that the process was important and widespread. A major factor related to reservoir quality is that physical compaction of matrix and unstable framework grains results in a decrease or destruction of pore throats. It is important to note that this process may occur regardless of increased competency of beds brought about by the amount of earlier cementation. The results of compaction are not distributed in a homogeneous fashion because of the spatial distribution of prior cements within the pore system, competency of the framework grains, and variations in the degree of alteration of unstable minerals and lithic components of the reservoir sandstone. On the basis of examination of thin sections, compaction is certainly one of the major reasons for low average permeability in Almond formation sandstones.

Linear ($R = 0.81$) and exponential ($R = 0.85$) curve fitting indicates that there is a high confidence of a relationship between porosity and permeability for the samples examined. The cross plots indicate that there is greater scatter of data in

TABLE 1

Diagenetic Stages and Minerals in Almond Formation Sandstones*

Diagenetic features	Mean	Range	N
Quartz overgrowths	0.9	0 to 4.0	11
Percent corroded feldspars	61.2	25 to 86.1	18
Calcite cement	1.1	0 to 6.4	10
Dolomite–ankerite cement	11.1	0 to 36.0	18
Siderite	0.03	0 to 0.5	1
Clay cement	6.9	0 to 13.6	16
Total clay	7.6	0.5 to 18.0	19
Total cements (all kinds)	18.4	3.9 to 41.6	19
Opalines and iron oxides	1.5	0 to 8.7	12
Dolomite–ankerite/calcite ratio	14.2	0.4 to 46.6	10

*Based on petrographic analysis of 20 thin sections from four wells in Arch Unit of Patrick Draw field. Numbers represent percent of total rock plus pore volume. The column titled "N" is the number of samples with non-zero values.

TABLE 2

Linear Correlation Coefficients for Petrographical and Petrophysical Properties Derived from Sandstone Samples in Four Wells in Arch Unit of Patrick Draw Field*

	Q.O.G.	Clay C.	Total clay	Calcite C.	Dol./A.C.	T.C.C.	T.C.A.	M.G.S.	S.D.G.S.	Q.	F.	A.F.	R.F.	Porosity
Clay cement	0.01													
Total clay	0.01	0.77												
Calcite cement	0.17	0.51	0.39											
Dolomite-ankerite cement	0.37	0.58	0.64	0.47										
Total carbonate cement	0.37	0.61	0.65	0.58	0.99									
Total cement (all kinds)	0.34	0.38	0.51	0.51	0.96	0.96								
Mean grain size	0.48	0.29	0.02	0.04	0.36	0.34	0.27							
S.D. grain size	0.46	0.23	0.04	0.21	0.41	0.40	0.36	0.94						
Percent quartz	0.16	0.07	0.17	0.08	0.14	0.12	0.10	0.46	0.31					
Percent feldspar	0.52	0.59	0.26	0.51	0.54	0.57	0.42	0.62	0.60	0.21				
Percent of feldspar corroded	0.47	0.35	0.45	0.52	0.65	0.66	0.62	0.23	0.35	0.17	0.56			
Percent rock fragments	0.47	0.39	0.20	0.03	0.41	0.38	0.27	0.41	0.28	0.27	0.40	0.22		
Porosity	0.15	0.67	0.47	0.48	0.66	0.56	0.57	0.12	0.06	0.54	0.53	0.58	0.46	
Permeability	0.24	0.43	0.03	0.40	0.39	0.35	0.37	0.16	0.09	0.26	0.33	0.20	0.23	0.81

*Abbreviations: Q.O.G., overgrowth; C., cement; Dol./A.C., dolomite-ankerite cement; T.C.C., total carbonate cement; T.C.A., total cement of all kinds; M.G.S., mean grain size; S.D.G.S., standard deviation of grain size; Q., percent quartz; F., percent feldspar; A.F., percent of total feldspars that are altered; R.F., percent rock fragments.

the low-porosity-permeability samples than in those with higher values. Because grain size does not correlate with any of the diagenetic parameters shown in Table 2, it is thought that the greater variance of porosity-permeability values in tighter samples is created by the increased relative importance of small absolute changes in the amount of cements and compaction in the tighter samples.

The only other relationship with a statistically significant correlation coefficient is that which exists between mean grain size and the standard deviation of grain size ($R = 0.94$). Standard deviation of grain size may be taken as a function of grain sorting where the smaller values indicate better sorting. The strong positive relationship between mean grain size and standard deviation of grain size reflects increased grain-size variance (poorer sorting) with increased grain size. This is not an unexpected trend and has been noted in many other sandstones.¹¹ Grain size in the samples examined varied between 85.1 and 186.7 μm (diameter) with a mean value of 133.6 μm , which indicates very fine- and fine-grained sandstones.

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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 1993: \$340,000**

**Principal Investigator:
James F. Pautz**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

The objective of this project is to provide research support to the Department of Energy 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

A comparison study of the TORIS recovery and economic model estimates to actual field results from Tertiary-Incentives-Program (TIP) projects is in progress. The model consists of two preprocessors that prepare the input data sets that are then run through EOR process predictive models. Understanding how the preprocessor programs, DEFLT and ROBLT, handle project data for use by the Steamflood Predictive Model (SFPM) was part of this comparison study. This quarterly report addresses some subtle differences discovered in the preprocessor programs DEFLT and ROBLT. The project-level comparison study is ongoing and progressing and will be discussed in a future report.

DEFLT, ROBLT, and SFPM

A TORIS Model compatible run involves the use of three programs, DEFLT, ROBLT, and SFPM. All are FORTRAN coded programs executed on the MicroVAX™ system at the National Institute for Petroleum and Energy Research. Project-level data are retrieved from the DOE EOR Project Database. This database contains specific information such as reservoir rock and fluid properties, production and injection data, and essential project data that describes the EOR projects. DEFLT reviews the project data and checks the data for reasonable-

ness. If data critical to the SFPM are missing or unknown, DEFLT will suggest, or provide in some cases, a replacement value. The output from DEFLT is passed to ROBLT, the program that converts the National Petroleum Council (NPC) flat-file format to the input format required by the SFPM. ROBLT also provides cost structure information and pattern development timing used for the economic evaluation portion of the input data.

During the course of reviewing the data-checking process, differences were noted in the way some fluid properties, solution/gas/oil ratios (SGOR is initial, and R_s is current), and oil formation volume factors (FVF) were being determined. These parameters ultimately have an impact on the original oil in place (OOIP) generated by DEFLT and the initial oil in place (IOIP, or target oil) generated by SFPM. After a careful review of both programs, some of the assumptions used in the volumetric algorithms were indeed different. The fact that there are differences does not imply that one is correct and the other is incorrect, only that they are inconsistent in their usage.

Gas Gravity

The Vasquez and Beggs correlations¹ for dissolved gas (SGOR and R_s) and FVF in DEFLT are a function of temperature, pressure, API oil gravity, and gas gravity. The gas gravity term is corrected to surface separator conditions of 100 psig. Two assumptions used in the calculation of the corrected separator gas gravity (SGG) are inconsistent with those found in the SFPM.

First, separator temperature conditions are neither consistent within DEFLT (there are several places where SGG may be calculated) nor with the SFPM. In DEFLT, separator temperatures of 60 and 70 degrees are used in different places and in SFPM the formation temperature is used.

Second, initialized SGG values (SGG_i) are corrected for temperature and pressure and yield SGG. SGG_i values are relative to air gravity ($= 1.0$), and DEFLT and SFPM use values of 1.0 and 0.8, respectively. A lower value (< 1.0) would normally be expected at initial conditions. DEFLT uses SGG in the calculation of SGOR and the initial FVF (IFVF).

Solution Gas/Oil Ratio

The R_s is calculated in DEFLT and passed to the SFPM for calculation of the current FVF (CFVF). DEFLT uses two correlations, one a function of depth and another of pressure, for the 1st and 2nd default values, respectively, when R_s is not provided in the input data. Use of the Vasquez and Beggs correlation as the first default value is recommended because it is a more rigorous calculation based on temperature, pressure, API oil gravity, and SGG.

Pressure Calculations

Many steam projects are unique in that they have very low initial and current pressures—oftentimes 100 psi or less. DEFLT recalculates all pressures that are less than or

equal to (.LE.) 100 psi. The calculated pressures are based on depth and pressure gradient. For most steam projects, the calculated pressures will be high relative to their actual initial and current pressures. An attempt was made to change the pressure constraint in DEFLT to .LE. 40 psi, which would allow all but very low actual field pressures to be honored, but strange results (e.g., $R_s > \text{SGOR}$ in some cases) indicate additional analysis is required.

Oil Formation Volume Factors

An error was discovered in the calculation of the IFVF and was traced to the Vasquez and Beggs correlation in DEFLT. Two regression analysis correlations for FVF are presented to represent the range of API oil gravities. API gravities greater than (.GT.) and .LE. 30 have unique solutions differing by their curve-fitting constants. Those constants in DEFLT have been switched. DEFLT uses the IFVF for the OOIP volume-checking routine only; it does not pass the IFVF to the SFPM. Because of the coding problems with pressure mentioned earlier, thermal projects will be estimated with a low value for IFVF, such as 1.05 reservoir barrels/stock tank barrels.

The CFVF calculation by the SFPM uses the regression constants correctly. However, the CFVF calculation includes an R_s value calculated in DEFLT based on a pressure that may be abnormally high.

Units Conversion

Hydrocarbon pore volume (PV) calculations require a conversion constant to change units from cubic feet (ft^3) to barrels (bbl). DEFLT uses "7758" as the conversion factor to calculate OOIP and the SFPM uses "7759.17" ($43,560 \text{ ft}^3 / 5.614 \text{ ft}^3/\text{bbl}$) to calculate IOIP. Neither value is incorrect, but this subtle difference can create confusion when setting up spreadsheets or hand calculating OOIP and IOIP.

Current Oil Saturation

When the current oil saturation (S_{oc}) is unknown and entered as "-1" in the input dataset and there is no primary production, ROBLT defaults S_{oc} to 0.6 PV. In some instances the S_{oc} will be greater than the initial oil saturation (S_{oi}), and all other volumetric parameters being equal, the IOIP will be greater than the OOIP. ROBLT apparently does not check the oil saturations to prevent this problem. A quick and easy fix to this problem is to give the project 10 bbl of primary production, which will not significantly impact the IOIP. When primary production exists and $S_{oc} = -1$, DEFLT back calculates S_{oc} from the ROIP (OOIP less primary production).

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UPGRADE 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: Sept. 30, 1993
Funding for FY 1993: \$192,000**

Principal Investigators:

**James F. Pautz
Johanna Shay**

Project Manager:

**Chandra Nautiyal
Bartlesville Project Office**

Reporting Period: Jan. 1-Mar. 31, 1993

Objective

The purpose of this work is to (1) develop and maintain a crude oil analysis (COA) database that maintains data integrity and system security online and available to the public, (2) upgrade and update crude oil analyses for inclusion in this database, and (3) participate in the UNITAR analysis study group.

Summary of Technical Progress

Repetitive requests are made by users of the COA database for information additional to what they can currently obtain from the database. The requests are for such things as well location and number; type of producing zone; source of sample (wellhead, separator, tank, etc.); metal content; hydrocarbon types; and benzene, toluene, and xylene (BTX) content.

Metal Content

Metal analyses for 15 heavy crude oils ($<20^\circ \text{API}$ gravity) with an inductively coupled plasma atomic emission spectrometer (ICP-AES) were completed. A portion of a homogenized crude oil was weighed and then diluted with tetralin on a weight-by-weight basis. Standards were prepared in the same manner. An internal standard (S_c) was added to the solutions to compensate for variations in sample-solution introduction efficiency. The solutions were introduced by using a peristaltic pump to an ICP-AES. By comparing emission intensities of elements in the crude sample with emission intensities measured with the standards, the

concentrations of elements in each crude sample were calculated.¹ Metal contents for these 15 crude oils are shown in Table 1.

Vanadium and nickel were studied more thoroughly than any other metallic elements found in petroleum because both of these elements occur in part as nitrogen complexes (porphyrins) closely related to chlorophyll and hemoglobin and thus appear to be associated with the genesis of crude oil. Many correlations based on vanadium and nickel content have been made in attempts to obtain information on the geological and geographical origins of petroleum.²

The iron and copper contents as well as those of the less prominent elements are apt to vary in more erratic ways in contrast with the regularity observed in the case of nickel and vanadium. This may be due to contamination from sources other than petroleum itself, for instance, rocks, brine, or well equipment. The presence of sodium, magnesium, potassium, and calcium in these 15 heavy crude oils is considered as evidence of undesirable contamination by salt water.

Hydrocarbon Types up to C13 (455 F) and BTX

A knowledge of the hydrocarbon components comprising a petroleum naphtha is useful in the evaluation of crude oils, in product quality assessment, and for regulatory purposes. Detailed hydrocarbon composition is also used as input in the mathematical modeling of refinery processes.

Determination of paraffins, isoparaffins, aromatics, and naphthenes (PIAN) up to C13 as well as BTX content for 16 heavy crude oils using gas chromatography was completed. A representative portion of the crude with an internal standard (isooctane) was introduced into a gas chromatograph equipped

with a methyl silicone bonded phase, fused silica capillary column. The vaporized sample was transported by helium carrier gas through the column in which the components are separated. Components were detected by a flame ionization detector as they elute from the column. The detector signal was processed by an integrating computer. Each eluting peak is identified by comparing its retention index to a table of retention indexes and by visual matching with a standard chromatogram. The concentration of each component was calculated by the following equations:

$$W_c = \frac{A_c \times R_{Fc} \times W_{is}}{A_{is} \times R_{Fis}}$$

where A_c = area of peak representing component c

A_{is} = area of internal standard (i-C8) peak

R_{Fc} = response factor of component c

R_{Fis} = response factor of internal standard (i-C8)

W_{is} = weight of internal standard (i-C8)

W_c = weight of component c

$$\text{Volume \% of component c} = \frac{W_c \times SG_s}{SG_c \times W_s} \times 100\%$$

where W_s is the weight of the sample (crude oil), SG_c is the specific gravity of component c, and SG_s is the specific gravity of the sample. Hydrocarbon types (PIAN) up to C13 and BTX data for these 16 heavy crude oils are very low, as listed in Table 2. Analysis of lighter crude oils for PIAN and BTX would provide more useful data.

TABLE 1
Metal Content for Analyzed Crudes

Field	Location	°API	P, ppm	Mg, ppm	V, ppm	Na, ppm	Ca, ppm	Zn, ppm	Cu, ppm	Ni, ppm	K, ppm	Fe, ppm
Forest Hill	TX	17.8	3.32	3.14	26.7	203	12.7	1.86	0.17	27.0	3.10	4.52
Midway Lake	TX	19.7	1.09	0.33	15.1	19.3	1.52	1.06	<0.01	16.4	1.54	1.96
Alba	TX	15.3	4.49	5.95	23.8	251	15.1	1.82	0.24	28.1	4.99	3.60
Beverly Hills	CA	20.0	3.61	2.74	120	51.8	2.46	2.01	0.15	97.4	2.93	32.3
Guadalupe	CA	13.3	1.95	5.06	217	35.6	6.19	1.71	0.11	96.7	3.20	5.36
Guadalupe	CA	10.9	14.5	98.6	253	1335	39.5	2.78	0.97	142	43.2	8.84
Guara (heavy)	VZ	18.2	0.84	<0.01	240	14.5	1.19	1.32	<0.01	58.8	0.97	2.59
Santa Maria Valley	CA	15.7	4.16	10.1	237	101	8.18	2.04	0.33	117	7.33	21.9
Lompoc	CA	15.4	3.14	4.51	202	25.3	2.05	1.65	0.24	92.5	3.84	9.29
Midway-Sunset	CA	14.4	1.70	<0.01	27.8	14.9	2.61	2.07	0.01	74.1	<0.01	36.6
Bellevue	LA	20.3	1.53	<0.01	0.50	47.5	29.5	1.52	0.23	2.51	0.87	21.2
Wilmington	CA	17.6	1.76	0.96	48.8	8.75	2.85	1.60	0.12	75.1	2.04	31.4
Wilmington	CA	17.1	4.88	8.84	52.8	108	8.63	1.69	0.36	86.2	6.06	46.7
Paris Valley (10-2)	CA	11.0	6.06	6.04	149	34.8	21.5	4.19	5.77	84.5	9.89	23.8
Wilmington	CA	14.8	4.10	6.96	84.5	110	10.2	1.67	0.26	81.2	4.55	52.7

TABLE 2
Hydrocarbon Types (PIAN) up to C13 and BTX Data for Analyzed Crudes

Field	Location	°API	Paraffins, vol %	i-Paraffins, vol %	Aromatics, vol %	Naphthenes, vol %	Benzene , vol %	Toluene, vol %	Xylenes, vol %
Forest Hill	TX	17.8	3.862	4.932	1.601	1.458	0.050	0.084	0.246
Midway Lake	TX	19.7	3.063	4.789	1.342	1.792	<0.002	0.014	0.171
Alba	TX	15.3	1.270	2.935	0.088	0.924	<0.002	<0.002	0.023
Guadalupe	CA	13.3	2.265	2.860	0.934	2.249	<0.002	0.055	0.144
Guadalupe	CA	10.9	2.306	3.279	1.358	2.891	<0.002	0.071	0.185
Cat Canyon, W	CA	16.5	0.692	3.687	1.933	5.798	<0.002	<0.002	0.272
Santa Maria Valley	CA	15.7	2.785	6.119	1.979	5.594	0.014	0.030	0.324
Lompoc	CA	15.4	4.797	5.949	3.275	4.666	0.035	0.184	0.513
Wilmington	CA	17.6	0.707	2.540	1.065	3.491	<0.002	<0.002	0.058
Wilmington	CA	17.1	1.140	2.887	1.085	3.441	<0.002	<0.002	0.117
Paris Valley (10-2)	CA	11.0	0.234	0.690	0.101	0.008	<0.002	<0.002	<0.002
Wilmington	CA	14.8	0.286	0.926	0.489	1.214	<0.002	<0.002	0.016
Cat Canyon	CA	10.0	1.709	2.541	1.333	2.030	0.012	0.017	0.115
Cat Canyon	CA	12.2	0.608	1.399	0.701	1.440	<0.002	<0.002	0.067
Jobo	VZ	9.4	0.222	0.129	0.107	0.062	<0.002	<0.002	0.004
Boscan	VZ	11.3	1.070	1.205	0.780	0.927	<0.002	0.006	0.066

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COMPILATION AND ANALYSIS OF OUTCROP DATA FROM THE MUDDY AND ALMOND FORMATIONS

Cooperative Agreement DE-FC22-83FE60149,
Project SGP69

National Institute for Petroleum
and Energy Research
Bartlesville, Okla.

Contract Date: Sept. 21, 1992
Anticipated Completion: May 31, 1993
Funding for FY 1993: \$24,000

Principal Investigator:
Susan Jackson

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1-Mar. 31, 1993

Objectives

The objectives of this project are to compile outcrop data from the Muddy and Almond formations, supply missing data, perform interpretations and analyses where needed, and process data for a transferable format so that it can be used by those interested.

Summary of Technical Progress

Milestone 1—Completed. Cross sections of three profiles described in outcrop RH located 150 and 200 m apart have been constructed and facies have been correlated. Tidal delta and channel facies dimensions exposed in the outcrop RH range from less than 150 to 250 m in lateral extent. The scale of lateral variability of facies is less, in some cases, than the spacing between described profiles, so only approximate dimensions can be determined. Meaningful facies dimensions data are difficult to obtain because of the two-dimensional exposure of the outcrop. The outcrop is oriented northwest, whereas the paleoflow directions in the tidal delta and channel deposits are primarily to the east and southeast. Therefore the azimuth of the outcrop exposure of these facies is oblique to depositional strike and a true cross-sectional or longitudinal

dimension cannot be obtained. Nevertheless, the data are useful for indicating the approximate magnitude of lateral variability in facies dimensions in comparison to typical well spacings.

Facies contacts that are erosional, disconformable, and sharp were indicated on the profiles to assist in correlation and also to indicate where permeability barriers may occur. It has been documented that erosional surfaces tend to have lower permeabilities because of grain-size changes and diagenetic cementation.

Milestone 2—Minipermeameter measurements of core well No. 2 were remeasured at selected intervals to check previously measured values because the minipermeameter had been modified since the last measurements were made. The two data sets are being compared to determine whether the core must be remeasured. Particular attention will be paid to permeability changes at the boundaries of facies to assist in defining flow units in the Almond shoreline barrier sandstones.

**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: Jan. 1–Mar. 31, 1993

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 reservoirs, 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 enor-

mous 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

Data Collection

So that data from Minerals Management Service (MMS) could be collected in the most efficient and accurate manner, efforts were shifted from keying on the 118 reservoirs that had more than 2.5 MMbbl reserves and more than 60% produced to date (i.e., large, incorrectly mapped reservoirs) to 208 sands in 46 fields that contained 1289 reservoirs. This represents 60% of the original oil in place (OOIP) for the entire offshore Gulf of Mexico. If time and resources permit, additional reservoirs will be included to increase the coverage to 70% (plus) OOIP. Figure 1 illustrates the distribution of the OOIP in piercement salt dome fields by sand horizon. The most efficient target for an accurate description of the bypassed oil in the Gulf of Mexico is 208 sands and 60% OOIP.

Personnel from ICF Resources Inc. (ICF) concentrated on data pertinent to Bay Marchand 2 field because this is the largest and most prolific field in the offshore Gulf Coast. Upon completion of the data collection on Bay Marchand 2 field, personnel began collecting data on South Marsh 73 field and other pertinent fields. Taylor Energy Company, the main operator of South Marsh 73 field, has agreed to provide a substantial amount of data for the project. Therefore efforts at MMS will be coordinated with the Taylor data collection efforts. Figure 2 shows the unit of analysis and scope of data collected for the sands. MMS will provide, through the Department of Energy (DOE), the content of the FRRE Database for the 1289 reservoirs. ICF's on-site personnel will compile measurements of fault blocks from maps, data elements from MER and other hard-copy files, and key reservoir properties from hard-copy files for cross-checking the FRRE Database.

Louisiana State University (LSU) is collecting the Taylor data and data from other operators. ARCO Oil and Gas Company has provided some excellent data on the South Pass

Fig. 1 Distribution of original oil in place in piercement salt dome fields by sand horizon.

Fig. 2 Unit of analysis and scope of data collection for sands in the piercement salt dome fields of the Gulf of Mexico.

60 and 61 field areas. Several other companies have indicated a desire to assist. Also, Amoco has agreed to provide an information package for sands in Eugene Island 208 pending approval from their partner, Texaco. Mobil Exploration has also agreed in principle to provide information and assistance. An initial meeting is scheduled with Mobil in April.

Data Analysis

LSU and BDM Federal, Inc. (name changed from BDM International, Inc.) (BDM), began analysis of data obtained from Taylor Energy on the South Marsh Island (SMI) Block 73 field in the Gulf of Mexico. Specifically, the development of a detailed data set for simulating the B-35 K sand and B-65 sand reservoirs began. This included the review and analysis of the geology of the reservoirs to define reasonable grid configurations for use in the simulator. Review of well histories, including production, gas injection, and pressure data also began. BDM concentrated on the B-35 K sand, and LSU concentrated on the B-65 sand.

Both the SMI 73 B-35 K and the B-65 sand reservoirs are excellent examples of steeply dipping salt-dome-related oil reservoirs. Initial efforts have been placed primarily on the B-35 K sand reservoir for several reasons. Production from the B-35 K sand reservoir has exceeded the mapped reserves as a result of poor definition of either the up-dip limit or the original oil-water contact or both. Recovery to date from the B-35 K sand represents 86% of the initially defined OOIP. Volumetric analysis of this additional potential will be performed as the study progresses to define a reservoir volume that results in a reasonable percentage recovery. This reservoir also provides an opportunity to simulate attic gas injection

because numerous gas injection cycles were conducted. The operator intends to conduct additional cycles so that the simulation can be used to help define the following: optimum injection rate and volume, an anticipated shut-in time necessary for optimum gas migration, and a more accurate estimate of the up-dip oil volumes.

Predictive Modeling Phase

The methodology for the predictive modeling phase of the project is about 50% complete. The design of the blueprint began in February 1993, and the computer coding began in March 1993.

Critical Process Parameter Laboratory Experiments

The building of an apparatus for the study of attic oil recovery techniques is continuing.

BOAST II Modification

Personnel from the LSU computer science department worked on the simulation of two-phase flow of slightly compressible fluids in a three-dimensional (3-D) porous medium. Progress to date has included the construction of a FORTRAN program that uses 3-D finite elements to approximate the governing equations. Although the solutions show numerical stability, minor oscillations inherent in the transient finite-element methods were discovered. The fact that the equations are highly nonlinear along with the fact that the model typically contains a sharp front (or discontinuity) magnifies these problems so that the resulting solutions are sometimes unsatisfactory. Problems of oscillations are traditionally resolved by refining the mesh, as in finite-difference methods. For acceptable answers, however, the refinement would have to be to such a degree that it would result in unacceptable memory and time requirements. Through further investigation, it is believed that the use of a better time integration scheme, such as either Crank-Nicholson, Pade Approximate, or Predictor-Corrector, should significantly reduce the oscillations. This is the current focus of efforts.

So that the source of the oscillation problem could be determined, considerable improvements were added to the program, and the code was scrutinized to gain confidence of its correctness. In addition, extensive information was gathered concerning Darcy-flow simulations when they are discretized with finite-element techniques. It is believed that an acceptable solution with the model can be obtained and can be reached with one of these time integration schemes. There is a high degree of confidence that these techniques will be easily extended to a large collection of simulation problems.

The existing finite-element code was adapted so that virtually any type of element can be easily incorporated into the solution scheme. This gives increased flexibility and makes it possible to use the mesh refinement techniques.

Additionally, a code was created that will refine and unrefine arbitrary elements in a mesh of bilinear quadrilateral elements. This code was tested and appears to be robust. The next step was to incorporate this mesh refinement code into the finite-element program to provide a tool that dynamically constructs small elements in regions of activity and coarse elements elsewhere.

The software is producing "believable" results in a reasonable though long period of time. Attempts to reproduce the results of small-scale experiments conducted in the Department of Petroleum Engineering are currently under way. The results appear to compare favorably with the experimental data, but more rigorous comparisons need to be performed. Also, difficulties with the inclusion of gravity in the model are being experienced; the problems are minor, however, and several ideas to resolve the difficulties have been considered.

Future work will include the resolution of the problem with the gravity term, followed by a quantitative comparison of the results with the experimental data. This will be followed by the construction of an adaptive finite-element program for full 3-D modeling. Although the solution methods will be similar to those used in two-dimensional problems, emphasis will be placed on efforts to produce an efficient code for reducing the computational resources needed for a simulation.

MASTER Modification

BDM modified the MASTER reservoir simulation model for use in simulating miscible gas injection processes in steeply dipping reservoirs. The simulation code has been modified to include the dip feature, and the program has been successfully installed and operated on in-house PCs. BDM began the process of verifying the model by comparing model output with published model results for an attic gas injection process in a steeply dipping reservoir. In addition, BDM is in the process of installing a post-processing package on the MASTER model that will greatly enhance the capability for plotting and mapping simulation output data.

Conclusions

During this reporting period ICF continued to collect data from MMS and LSU continued to collect data from several operators. LSU also continued to modify BOAST II for the integration of radial grid systems and the building of the experimental apparatus for studying the recovery of attic oil. BDM began modifying the MASTER reservoir simulation model for use in simulating miscible gas injection processes in steeply dipping reservoirs. LSU and BDM began analyzing data obtained from Taylor Energy in South Marsh 73 field.

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
(Current year)**

**Principal Investigators:
Michael J. McInerney
Roy M. Knapp**

**Project Manager:
E. B. Nuckols
Metairie Site Office**

Reporting Period: Jan. 1–Mar. 31, 1993

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 on the influence of microbial growth and product formation on the recovery of residual oil from Berea sandstone cores continued this quarter. The experiments were carried in the high-pressure core apparatus described in the quarterly report ending in September 1992. Five microbial nutrient treatments were carried out on a single Berea sandstone core at a pressure of 1000 psig with the anaerobic microorganism *Clostridium acetobutylicum*. The core pressure was followed during incubation after each nutrient treatment, and fermentation products were measured at the end of each incubation period.

A buildup of an active microbial population was observed in the core over the course of the five treatments as determined by substrate utilization and product formation (Table 1). The core effluent analysis after the first treatment indicated that no microbial activity took place during the 120-h incubation and that the core pressure increase observed was probably the result of thermal expansion. Tertiary oil recovery (4 mL) was first observed after the third nutrient treatment, which also resulted in the largest decrease of the permeability reduction factor during the course of the treatments (Fig. 1). A further 6 mL of oil was recovered after the fourth treatment and 3 mL

TABLE 1
Liquid Analysis for Core No. 2

Treatment No.	Sample No.	Vol., mL	pH	Glucose, mM	Acetate, mM	Butyrate, mM	Ethanol, mM	Butanol, mM	Cellular protein, mg/mL
1	0*	10.0	6.5	100.0	1.8	2.1	0.0	0.8	0.55
1	1	50.0	6.5	100.0	0.9	2.4	1.6	0.7	0.45
1	2	50.0	6.1	100.0	1.7	3.9	1.6	0.9	0.22
2	0	10.0	6.6	100.0	0.7	2.3	0.0	0.6	0.39
2	1	37.0	4.9	83.0	7.1	12.4	3.6	4.6	0.32
2	2	55.0	5.7	100.0	1.9	4.4	0.7	0.8	0.34
3	0	10.0	6.5	100.0	0.7	1.0	0.0	0.3	0.45
3	1	41.0	5.3	100.0	8.0	15.9	2.5	4.0	0.46
3	2	52.0	5.3	89.0	7.4	12.3	1.2	0.5	0.34
4	0	20.0	6.5	100.0	0.8	3.9	0.0	0.6	0.36
4	1	32.0	5.1	100.0	16.0	18.8	3.9	13.4	0.25
4	2	43.0	5.3	67.0	9.5	15.9	2.1	4.4	0.29
5	0	15.0	6.7	100.0	1.9	7.1	0.0	13.0	0.56
5	1	26.0	5.0	11.0	22.9	17.9	6.2	19.7	0.22
5	2	31.0	5.0	5.5	28.7	21.9	4.7	15.7	0.18

*Sample at initial time before injection.

Fig. 1 Plot showing permeability reduction factor (PRF) and accumulated gas and oil production (Core No. 2).

after the fifth treatment, although no significant permeability alteration was noted after these treatments (Fig. 1). Treatments four and five did, however, result in the highest gas yields (79 and 184 mL, respectively) and in the greatest metabolism of substrate (30 and 95 mM glucose, respectively). During these five treatments, *C. acetobutylicum* resulted in a total recovery of 28% of the residual oil in place.

Characterization of a Polymer Producing Facultative Anaerobe Useful for Microbial Enhanced Oil Recovery

Characterization and fermentation balance studies on the polysaccharide producing facultative anaerobe, strain SP018, continued this quarter. Previous chemostat studies with SP018 indicated that polymer production is observed only under anaerobic conditions and optimally between 4 and 10% NaCl. The kinetics of polymer production was complex, with polymer production observed in the early exponential phase and in the stationary phase of growth.

Studies this quarter indicated that the addition of nitrate to the medium resulted in reduced lag phase, increased growth rate, and higher cell yield under anaerobic conditions. End-product analysis revealed that ethanol, acetate, succinate, and a small amount of pyruvate were produced during anaerobic fermentation. The presence or absence of nitrate appears to have no effect on the relative concentrations of acetate or succinate, although no pyruvate production was observed in the presence of nitrate. Ethanol analysis was not done on the sample grown in the presence of nitrate. No 2,3-butanediol, acetoin, or diacetyl was observed in the fermentation broth, although there were other, as yet unidentified, fermentation end products present.

500 microns

Fig. 2 Nuclear magnetic resonance image of microbial formulation in Bentheim sandstone after 13-h incubation.

500 microns

Fig. 3 Nuclear magnetic resonance image of microbial formulation in Bentheim sandstone after 54-h incubation.

766 mD was completed. A ceramic core was chosen to determine if adsorption of NIPER 6 would result when used with a matrix material free of minerals. Fluorescein tracer tests were conducted before and after the injection of microorganisms, and the results were consistent with tests done with Berea sandstone, which showed 100% of the tracer being recovered. The core was injected with 1.2 PV of NIPER 6, but only 0.4% of the microorganisms were recovered. This low recovery may be caused by metals in the ceramic material, which caused the bacteria to adsorb, or possibly from a filtration effect. An adsorption test was also performed with crushed ceramic. The microbial counts decreased from an original count of 1.6×10^7 to 0 after stirring for 24 h. These results suggested that adsorption was occurring.

A second retention experiment was performed to obtain additional information on the effects of channeling during a coreflood such as that observed in a previous coreflood. For the test, a 3-darcy core was injected with 0.5 PV NIPER 6. The recovery of microorganisms was 28% in this test as compared with 42.3% in the previous test. Apparently, some channeling did occur in the previous experiment. The results with very high permeability cores do not show the same linear correlation between the amount of microbes injected and those recovered, which was observed in earlier experiments with 900-mD cores.

Another retention test was conducted in which the injectants were introduced at a flow rate of 100 ft/d to determine if a faster rate has any effect on microbial retention. All previous corefloods were performed at a flow rate of 10 ft/d. For the present test, a 2.4-darcy core was injected with 1.3 PV of NIPER 6. A tracer test preceded the microbial retention test and showed virtually 100% recovery in the effluent. The microbial recovery was only 11.7%. The pressure drop data are now being compared with results obtained at the lower flow rate.

All test data from past retention experiments are being evaluated. Two retention tests were designed and will be conducted next quarter to further elucidate mechanisms of microbial cell retention in porous media. The two mechanisms observed are filtration and adsorption. It would be desirable to determine the contributions of each of these phenomena to cell retention. Glass beadpacks are being considered in the evaluation of these two retention mechanisms.

The results of previous experiments showed considerable retention of NIPER 6 cells in porous media, both from adsorption on the rock and from filtration. Microbial cells that produce polymer may have slightly different cell surfaces that may adsorb or retain differently in porous media. Conducting retention tests and coreflooding studies with polymer producers will demonstrate whether there are differences in microbial cell retention and how these differences might relate to improved oil production. A retention experiment using a polymer producer is complete, and a coreflood to evaluate oil recovery with the same polymer producer has been initiated. Results will be reported in the next quarterly.

Relative permeability experiments using ceramic cores were unsuccessful. Unfortunately, the ceramic used had a

toxic metal or mineral component that either killed the microbial cells or caused considerable adsorption. Another experiment will be conducted with Berea sandstone with 5% NaCl brine to minimize contamination by other types of microbes. Also, the shut-in period will be eliminated to reduce overgrowth by contaminants.

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, 1993
Total Appropriation: \$419,000**

**Principal Investigator:
Rebecca S. Bryant**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The objectives of this project 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 for FY93 includes continued monitoring of oil production data from the Phoenix field site.

Summary of Technical Progress

The expanded microbial enhanced oil recovery (MEOR) project site is in sec. 8, T. 24 N., R. 17 E. of Rogers County, Oklahoma. This site is part of Chelsea–Alluwe field in the Bartlesville formation and was initially developed soon after

Delaware–Childers field. The site, 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 all but one 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 data through December 1992. The incremental oil produced shows an improvement of about 16% over the predicted hyperbolic decline.

Results of this test were presented.¹

Fig. 1 Oil production from the Phoenix site through December 1992.

Reference

1. R. S. Bryant, A. K. Stepp, K. M. Bertus, T. E. Burchfield, and M. Dennis, *Microbial Enhanced Waterflooding Field Pilots*, paper presented at the 10th Oil Recovery Conference, Wichita, Kans., Mar. 10–11, 1993.

**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
Government Award: \$600,000**

**Principal Investigator:
Linda McCoy
Idaho Operations Office**

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

Reporting Period: Jan. 1–Mar. 31, 1993

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.
- Development and implementation of industry cost-shared field demonstration projects of MEOR technology.

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 waterflood and EOR responses through the control of wettability in reservoirs.

Summary of Technical Progress

MEOR Research and Field Application

Field Activities

Reservoir characterization of the Schuricht lease (Crook County, Wyoming) before implementation of Phase I of the MEOR field trial is under way. Work was started in February 1993 with a pressure buildup test. The objectives of the test program are determination of reservoir permeability, static reservoir pressure, and near-wellbore formation damage. Results will be reported on completion of the test program and analysis of the data.

A National Environmental Policy Act categorical exclusion for the reservoir characterization activities associated with the pending field trial was granted on the basis that the proposed activity is a federal action defined in 10 CFR 1021 (57 FR 15152-3), Appendix B to Subpart D, Subsection B5.2 for "Modifications to oil/gas/geothermal pumps and piping."

The reservoir is a small, single-well field in the Minnelusa "A" formation of the Powder River Basin in northeastern Wyoming. Even though the field is still on primary production, it is nearing its economic limit and produces 2 to 3 bbl of 25 °API oil per day and no water. The perforations are from 6489 to 6497 ft subsurface, and the reservoir temperature is 138 °F (60 °C).

A 15-ft hollow chamber that is open to the wellbore on the bottom and connected to 1/8-in. capillary tubing at the top was secured to the bottom of the production tubing just below the pump inlet. The 1/8-in. capillary tubing was connected to the top of the chamber and strapped to the outside of the production tubing as it was run in the hole. The capillary tubing is connected to a nitrogen tank at the surface that is used to purge the tubing and to provide a nitrogen head. Accurate bottom-hole pressure can be calculated during the buildup test with this system.

Instrument Service International, Ventura, California, provided the technology and equipment for the capillary tubing and downhole chamber. The surface pressure recorder (Self-Powered Intelligent Data Retriever, or SPIDR) was obtained from Data Retrieval Corporation, Houston, Texas.

Laboratory Support

Initial calculations indicate that the most efficacious microbial mechanism to augment oil recovery in this specific well is viscosity reduction. Therefore organisms capable of gas or solvent production or both are desirable. Soil samples retrieved from the Schuricht lease area were successfully enriched for bacteria capable of gas production under reservoir conditions. Results strongly suggest that the organisms are respiring and not fermenting. Selective media were used to differentiate fermentative and respiratory metabolisms. Anaerobic medium was prepared by substituting fermentable

carbohydrate sources and terminal electron acceptors. Results are indicative of denitrifying metabolism (dissimilatory nitrate reduction–denitrification). It is well established and documented that complete microbial denitrification proceeds from nitrate to nitric (via the enzyme nitrate reductase) and nitric to nitrous oxide (via the same enzyme) and nitrous oxide to di-nitrogen (via nitrous oxide reductase).

Gas chromatography was used to confirm the presence of nitric oxide, nitrous oxide, di-nitrogen, and carbon dioxide. Chromatographic conditions were PoraPLOT-Q column, column temperature was -20°C for 2 min with a temperature ramp to 40°C at a rate of 10°C for 1 min, injector temperature was 100°C , thermal conductivity detector temperature was 250°C , split ratio was 22.3 mL/min, column head pressure was 5 psi, and the carrier gas was helium. Samples for analysis were taken from vial head space. Nitric oxide, nitrous oxide, di-nitrogen, and carbon dioxide were detected in all the experimental strains; however, the rates differed. The predominant gasses produced were di-nitrogen and carbon dioxide. These gasses were detected as early as 8 h after inoculation; maximum production was observed between 24 and 48 h and remained essentially unchanged after the fourth day.

Evaluation of Reservoir Wettability and Its Effects on Oil Recovery

Glass micromodels provide valuable insight into the mechanisms of crude oil displacement and have been used extensively to illustrate the complex interplay between capillary, viscous, and gravity forces. For more detailed analysis of displacement mechanisms observed in micromodels, the porous network formed by the fusion of two etched-glass plates has been mathematically described and used to model and interpret pore-level events in displacement of crude oil by water for mixed wet systems. The micromodels used in this research consist of a network of larger open volumes or pores interconnected by four narrower etched tubes or throats. Intersections not etched out to form pores are classified as nodes.

The average dimensions of the micromodel used for visualizations of crude oil floods were determined. The micromodel consists of a network as shown and described in Fig. 1. The cross-sectional shape of the etched-glass micromodel pores can be simulated by a figure defined by the intersection of two identical circular arcs. This shape was used to show that observed phenomena during waterfloods, as illustrated in Figs. 2 and 3, can potentially be described. It has been shown that snap-off in throats of this cross section is inhibited both by the higher saturations and by the slightly higher pressures required for the interface to swell to conditions of instability. Drainage pressures were calculated by the MS-P method^{1,2} for the likely range of pore sizes. Capillary pressure vs. saturation relationships were calculated for several scenarios observed in the micromodel floods. The contact angle for a crude-oil waterflood was

	depth μm	width μm
throat	60	240
node	75	575
pore	105	1150

(b)

(c)

Fig. 1 M-4 micromodel description. (a) Overview. (b) Plan view. (c) Cross section.

inferred from the shape of an interface as water displaces oil from a pore.

Video tapes of the waterfloods, including those with Schuricht crude, were prepared.

Fig. 2 Evidence for mixed wetting with crude oils in glass micromodels. (a) Waterflood of mineral oil—strongly water wet. (b) Waterflood of crude oil—mixed wet. Figure 2(b) shows examples of efficient displacement of oil from a large pore (marked A), water flowing through a wedge into downstream nodes or pores (from B to C), and contact-angle hysteresis of moving water/oil interfaces (at D) in contrast with undisturbed connate water (at E).

(a)

(b)

Fig. 3 Micromodel waterflood of Moutray crude oil. (a) Water fills pore at arrow through wedges. (b) Oil film thins between invading and connate water.

References

1. G. Mason and N. R. Morrow, Meniscus Curvatures in Capillaries of Uniform Cross-Section, *J. Chem. Soc., Faraday Trans. 1*, 80: 2375-2393 (1984).
2. G. Mason and N. R. Morrow, Capillary Behavior of a Perfectly Wetting Liquid in Irregular Triangular Tubes, *J. Colloid Interface Sci.*, 141(1): 262-274 (January 1991).

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, 1993
Government Award: \$125,000
(Current year)

Principal Investigators:

E. T. Premuzic
M. S. Lin

Project Manager:

Rhonda Lindsey
Bartlesville Project Office

Reporting Period: Jan. 1-Mar. 31, 1993

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 applications.

Summary of Technical Progress

Coreflooding Experiments

Coreflooding systems previously described¹ have been used for the study of the effects of two thermophilic organisms, TAQ-1 and TAQ-2, on the Prudhoe Bay, Alaska, crude oil. Results of these studies are given in Table 1. Consistent with previous experiments, a 200-mD Berea sandstone was also used in these experiments.

The core was saturated with a known amount of the crude oil and then flooded with brine, which displaced about 30% of

the original oil. Brine treatment was then followed by the introduction of microbial culture and brine under pressure. The cell count was determined in the original culture brine medium, which was then allowed to develop in the core over a period of 6 d, after which the additional oil recovered was collected and the cell count repeated in the brine exudate.

The original TAQ-1 culture contained 1.7×10^5 cells/mL. The cell count in brine exudate dropped by an order of magnitude to 5.71×10^4 after biotreatment of the crude oil with TAQ-1 compared to a much smaller change (negligible) in the reaction of TAQ-2 with crude oil—Berea sandstone core under identical conditions. In both cases the pH became more alkaline (i.e., pH 7.760 and 6.583 before biotreatment and pH 8.44 and 7.98 after the biotreatment with TAQ-1 and TAQ-2, respectively).

It is not clear what caused the differences in the effects as a result of TAQ-1 and TAQ-2. These differences might be the result of several reasons, such as poor growth of TAQ-1 in comparison to TAQ-2 under the experimental conditions used, preferential adsorption to the sandstone, or different chemistries. The mechanisms of oil displacement by different microbial cultures need to be examined in terms of biochemical, chemical, and physical interactions between microorganisms, oils, their metabolic products, and the inorganic matrices of core materials.

TABLE 1
Recovery of Prudhoe Bay Crude 1 from Berea Sandstone Cores at 60 °C

Core absorbed oil sample weight (g)*	16.7	16.7
Pressure, psi	40	40
Microorganisms	TAQ-1	TAQ-2
Surface tension of culture, dynes/cm	72.036	70.702
Oil recovered by brine (g)	5.5	5.0
Oil recovered by growing microorganisms (g)	1.7	4.5
Oil recovery by brine, %†	33	29.9
Additional oil recovery by growing microorganisms, %‡	15.2	38.5

*Sample of Prudhoe Bay crude obtained through courtesy of U.S. Department of Energy, Bartlesville Project Office.

$$\dagger \text{Percent oil recovery by brine} = \frac{\text{Oil recovered by brine (g)}}{\text{Oil sample weight (g)}} \times 100$$

$$\dagger \text{Percent additional oil recovered by growing microorganisms} =$$

$$\frac{\text{Oil recovered by microorganisms (g)}}{\text{Oil sample weight (g)} - \text{Oil recovered by brine (g)}} \times 100$$

Duration of Biotreatment and Media Effects

Experiments that explore trends in the biochemical interactions between different microorganisms continued. Results of emulsification studies using Alabama B69112 crude oil are given in Table 2 and Fig. 1. Although the effects of

TABLE 2
Alabama Oil B69112 Crude Oil Biotreatment*

Microorganism	Detergent	Medium	Volume, mL	Oil, %	Incubation, d	Viscosity, cP	Optical density, sys nm	Emulsion, Klett units	pH
BNL-4-22	No	3	125	0.500	7	2.55	0.0229	11,473	4.5
BNL-4-23	No	3	125	0.517	7	2.44	0.0097	4,828	4.5
BNL-NZ-3	No	3	125	0.476	7	2.42	0.0137	6,835	5.25
Control, oil†	No	3	125	0.494	7	2.44	0.0043	2.16	4.38
BNL-4-22 control	No	3	125	0.000	7	2.44	0.009	4.25	4.5
BNL-4-23 control	No	3	125	0.000	7	2.46	0.003	1.658	4.5
BNL-NZ-3 control	No	3	125	0.000	7	2.77	0.001	0.505	5.5
Control/control‡	No	3	125	0.000	7	2.58	3.2×10^{-5}	0.016	4.38
BNL-4-22	No	3	125	0.543	20	NA	0.2084	104	3.75
BNL-4-23	No	3	125	0.487	20	NA	0.0202	10	4.00
Control, oil	No	3	125	0.490	20	NA	0.0109	5	4.00
BNL-4-22 control	No	3	125	0.000	20	NA	0.0292	15	4.25
BNL-4-23 control	No	3	125	0.000	20	NA	0.0107	5	4.00
Control/control	No	3	125	0.000	20	NA	0.194	10	4.00

*Averages of triplicate experiments.

†Control, oil = oil and medium only.

‡Control/control = oil only.

Fig. 1 Alabama oil B69112 biotreatment (7 days, medium 3).

BNL-4-22, BNL-4-23, and BNL-NZ-3 are lower than other crudes tested so far, the overall trends are consistent: emulsification is achieved with the crude oil being the sole carbon source. Similarly, changes in organic sulfur content and sulfur speciation are also evident, as shown in Figs. 2 and 3 and Table 3. The small chemical changes that occur in biochemical conversion of the Alabama crude when treated with BNL-4-22, BNL-4-23, and BNL-NZ-3 are also reflected in their gas chromatography-mass spectroscopy (GC-MS) characteristics as well as in their X-Ray Absorption Near Edge Structure (XANES) analysis, as shown in Table 3.

The redistribution of organic sulfur species and a decrease of heavier fractions is also consistent with the GC-FPD traces in the region of the chromatographs, indicated by the arrows in Figs. 2 and 3. The Alabama oils are derived from reservoirs in the upper part of the Smackover Formation (Jurassic) and are known to have been subject to transformations,² which

Fig. 2 Flame photoemission detector (FPD) traces of Alabama B69112 crude oil. (a) Control. (b) Treated with BNL-4-22. (c) Treated with BNL-4-23.

Fig. 3 Flame photoemission detector (FPD) traces of Alabama B69112 crude oil. (a) Control. (b) Biotreated with BNL-NZ-3.

TABLE 3

**X-Ray Absorption Near Edge Structure (XANES)
Analyses of Organic Sulfur Species in Biochemically
Converted Alabama B69112 Crude**

	Chemical types of organic sulfur structures			
	Sulfide	Thiophene	Sulfoxide	Sulfone
Crude, control	0.308	0.535	0.130	0.028
Crude + BNL-4-22	0.351	0.476	0.132	0.039
Crude + BNL-4-23	0.322	0.523	0.129	0.026
Crude + BNL-NZ-3	0.301	0.536	0.129	0.033

may have led to chemically distinct types of oils differing from others tested at BNL. Therefore, using the three species of microorganisms under the experimental conditions used may not be the optimum condition for that particular type of oil. This possibility should be further explored.

References

1. E. T. Premuzic and M. S. Lin, *Effects of Selected Thermophilic Microorganisms on Crude Oils at Elevated Temperatures and Pressures*, Quarterly Report, October 1, 1992–December 31, 1992, DOE Report BNL-48560, Brookhaven National Laboratory, 1992.
2. G. E. Claypool and E. A. Mancilin, *Am. Assoc. Pet. Geol., Bull.*, 73: 904-924 (1989).

FIELD DEMONSTRATIONS IN HIGH-PRIORITY RESERVOIR CLASSES

INTEGRATED APPROACH TOWARD THE APPLICATION OF HORIZONTAL WELLS TO IMPROVE WATERFLOODING PERFORMANCE

Contract No. DE-FC22-93BC14951

**University of Tulsa
Tulsa, Okla.**

**Contract Date: Jan. 1, 1993
Anticipated Completion: Dec. 31, 1996
Government Award: \$250,973**

**Principal Investigator:
Balmohan G. Kelkar**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The overall objective of the proposed project is to improve secondary recovery performance of a marginal oil field through

the use of a horizontal injection well. The location and direction of the well will be selected on the basis of the detailed reservoir description using the integrated approach. With the use of this method, a recovery of about 2 to 5% of original oil in place is expected. This should extend the life of the reservoir by at least 10 yr.

The objectives of the project are divided into two stages. In the first stage, additional reservoir data will be collected from part of the Glennpool field (William B. Self, Unit) by conducting cross-borehole tomography surveys and Formation Micro Scanner (FMS) logs through a newly drilled well. In addition, analogous outcrop data will be used. By combining the state-of-the-art data with conventional core and log data, a detailed reservoir description will be developed on the basis of integrated approach. After conducting extensive reservoir simulation studies, a location and direction of a horizontal injection well will be selected. The well will be drilled on the basis of optimized design, and the field performance will be monitored for at least 6 months. If the performance is encouraging, a second stage will be scheduled for the project.

If continued, the second stage of the project will involve selection of part of the same reservoir (Berryhill Unit, Tract 7), development of reservoir description using only conventional data, simulation of flow performance using developed reservoir description, selection of a location and direction of a horizontal injection well, and implementation of the well followed by monitoring of reservoir performance.

A comparison of the results of the two stages will allow an evaluation of the collection of additional data using state-of-the-art technology. In addition, the application of horizontal wells to improve secondary recovery performance of marginal oil fields will be evaluated.

A successful completion of this project will provide new means of extending the life of marginal oil fields with the use of easily available technology. It will also present a methodology to integrate various qualities and quantities of measured data to develop a detailed reservoir description.

Summary of Technical Progress

During this quarter the technical progress was limited because of contractual problems associated with signing of the contracts with the subcontractors. Contracts have been signed with two of the subcontractors, Amoco Production Company and Joshi Technologies International. The third subcontract with Uplands Resources will be signed before the end of this month. Once all the contracts are signed, the project will pick up speed and progress according to the plans.

In the meantime, a detailed analysis continues on geological and engineering data from the William B. Self Unit. All the available core and log data have been collected from the existing as well as from plugged wells. Figure 1 shows the well locations in the unit. On the basis of the log and core analysis, the geological, facies-biased, maps have been prepared. These maps indicate that the Self unit can be described in terms of three subunits, A, B, and C. The maps of these three subunits are shown in Fig. 2.

In addition to preparing the geological map, the history of the Self unit has been constructed on the basis of the available data from the American Association of Petroleum Geologists log library. The Glennpool field was discovered in 1905. The first well in the Self unit is estimated to have

Fig. 1 Well location map.

(a)

(b)

(c)

Fig. 2 Contour maps for (a) sand A, (b) sand B, and (c) sand C.

been discovered in 1907. On the basis of the information presently available, the unit was produced with primary recovery until 1946 when the gas repressurization began. The production continued with gas repressurization until 1956 when the first pilot waterflooding project was initiated. The waterflooding was expanded to the entire unit in 1967. In 1978, ARCO Oil and Gas Company redrilled the entire unit with new wells with an intention to flood the Unit A of the sand. The field is currently producing essentially under the same conditions as started by ARCO except that the water injection in the unit is restricted to recycled, produced water. Table 1 contains the brief history of the field. Figure 3 presents the production data from the unit from the point of inception. This figure clearly indicates a clear relationship between additional injection of water and additional production. On the basis of the preliminary calculations, approximately only 22% of the original oil in place has been recovered.

Tracer Studies

The first phase of the project involves the drilling of a test well to conduct cross-borehole tomography surveys as well as to make FMS measurements at the new well. The newly drilled well needs to be located as close as possible to an area where the horizontal well will be drilled. To ensure the proper location of a test well, the geological model shown in Fig. 2 will be verified. Two tracer tests will be conducted. Test 1 will involve injecting tracer through well No. 59 and observing the tracer response in well Nos. 64, 54, and 63. This will allow confirmation of the connectivity for sand A within a macro unit as well as outside the macro unit. Test 2 involves injecting tracer through well No. 74 and observing the tracer response in Nos. 71, 77, and 78. This will allow confirmation of the connectivity for sand C within as well as outside macro units. Tretolite Company has already been contacted to provide appropriate tracer. The tracer studies will begin by the end of April.

TABLE 1
Historical Well Information

Year	No. of producers	Gas injectors	Water injectors	Plugged	Drilled
1907	14	—	—	—	—
1915	14	—	—	5 (3,5,11,12,4)	5 (15,16,17,18,19)
1920	14	—	—	2 (17-18)	2 (20-21)
1925	14	—	—	1 (19)	1 (22)
1936	18	—	—	1 (24)	5 (23-27)
1946	16	4 (21,28,31,32)	—	—	5 (29-33)
1947	19	5 (21,28,31,32,37)	—	—	6 (34-39)
1948	25	6 (21,28,31,32,37,43)	—	—	6 (40-45)
1950	27	7 (21,28,31,32,37,43,47)	—	—	—
1954	27	7 (21,28,31,32,37,43)	3 (22,48,49)	—	2 (48,49)
1957	28	—	10 (21,22,28,31,32,37,43,47,49,50)	—	1 (50)
1966	28	—	10 (21,22,28,31,32,37,43,47,49,50)	3 (1,7,8)	2 (51,52)
1971	27 (1st 1/2) 24 (2nd 1/2)	—	10 (21,22,28,31,32,37,43,47,49,50)	4 (2,9,10,13)	—
1972	20	—	10 (21,22,28,31,32,37,43,47,49,50)	4 (14-16,20)	—
1973	20 (1st 1/2) 18 (2nd 1/2)	—	10 (21,22,28,31,32,37,43,47,49,50)	2 (23,25)	—
1974	17	—	10 (21,22,28,31,32,37,43,47,49,50)	1 (26)	—
1977	16	—	10 (21,22,28,31,32,37,43,47,49,50)	1 (29)	—
1979	6 (1st 1/2) 9 (2nd 1/2)	—	10 (21,22,28,31,32,37,43,47,49,50)	10 (33-36,38-42,44)	3 (53-55)
1980 (June)	5	—	1 (50)	Inj. 9 Producer 3 (45,46,51)	—
1981 (Dec.)	21	—	10 (52,53,58,59,65,66,67,73-75)	—	—
1982	21	—	10 (52,53,58,59,65,66,67,73-75)	1 (6)	1 (80)
1984	20	—	11 (52,53,58,59,65,66,67,73-75,81)	1 (30)	1 (81)
1992	—	—	Same status	—	—

Fig. 3 Production history of Self Unit.

**REVITALIZING A MATURE OIL PLAY:
STRATEGIES FOR FINDING AND PRODUCING
UNRECOVERED OIL IN FRIO FLUVIAL-
DELTAIC RESERVOIRS OF SOUTH TEXAS**

Contract No. DE-FC22-93BC14959

University of Texas
Bureau of Economic Geology
Austin, Tex.

Contract Date: Oct. 21, 1992
Anticipated Completion: Dec. 31, 1994
Government Award: \$817,911

Principal Investigator:
Noel Tyler

Project Manager:
Edith Allison
Bartlesville Project Office

Reporting Period: Jan. 1-Mar. 31, 1993

Objectives

Advanced reservoir characterization techniques will be applied to selected reservoirs in the Frio fluvial-deltaic sandstone (Vicksburg Fault Zone) trend of South Texas to maximize the economic producibility of resources in this mature oil play. More than half the reservoirs in this depositionally complex play have already been abandoned, and large volumes of oil may remain unproduced unless advanced characterization techniques are applied to define untapped, incompletely drained, and new pool reservoirs as suitable targets for near-term recovery methods. This project will develop interwell-scale geological facies models of Frio fluvial-deltaic reservoirs from selected fields and combine them with engineering assessments to characterize reservoir architecture, flow unit boundaries, and the controls that these characteristics exert on the location and volume of unrecovered mobile and residual oil. The results of these studies are designed to lead directly to the identification of specific opportunities to exploit these heterogeneous reservoirs for incremental recovery by recompletion and strategic infill drilling.

Project objectives are divided into three major phases: The first phase involves reservoir selection and initial framework

characterization and includes the initial task of screening fields within the play to select representative reservoirs that have a large remaining oil resource and are in danger of premature abandonment and performing initial characterization studies on selected reservoirs to identify the potential in untapped, incompletely drained, and new pool reservoirs. The second phase will involve advanced characterization of specific reservoirs selected from the first phase work to delineate incremental resource opportunities; also included are the volumetric assessments of untapped and incompletely drained oil along with an analysis of specific targets for recompletion and strategic infill drilling. The third phase of the project will consist of a series of tasks associated with final project documentation, technology transfer, and the extrapolation of specific results from reservoirs in this study to other heterogeneous fluvial-deltaic reservoirs within and beyond the Frio play in South Texas.

Summary of Technical Progress

During the second quarter screening of South Texas fields within the Frio fluvial-deltaic sandstone/Vicksburg Fault Zone oil play was completed. Fields were screened to identify reservoirs that have a large remaining oil resource, are in danger of premature abandonment, and have geological and production data in sufficient quantity and of suitable quality to facilitate advanced reservoir characterization studies. Two fields were selected for inclusion in this study: Tijerina-Canales-Blucher (TCB) Field, located in the northern portion of the trend in Jim Wells County, and Rincon Field, located to the south in Starr County. Current plans are to incorporate data from both fields in the reservoir characterization and targeted resource addition studies. Project members met with operators of both fields to review available geologic and production field data and discuss research plans. Detailed geologic and production data required for the initial reservoir characterization studies are being collected. Details outlining specifics of project accomplishments for this quarter are provided.

Screen Play for Suitable Fields

Criteria for the selection of specific South Texas Frio reservoirs for detailed study were established at the onset of this project. Reservoirs from fields with large infield reserve potential and sufficient data to provide the means for identifying additional reserves were deemed to be the most suitable candidates for detailed study. Specific considerations in the field selection process included the (1) size of reservoir producing area, (2) density of well completions in individual reservoirs, (3) quality and quantity of existing geologic and production data, (4) availability of two-dimensional (2-D) or three-dimensional (3-D) seismic coverage, and (5) current level of drilling activity. Fields that contain reservoirs with large producing areas and numerous wellbores with a relatively wide completion spacing are excellent candidates for this project because they present good possibilities for the identification of bypassed and untapped reservoir compart-

ments. Fields with abundant, quality geologic, geophysical, and production field data, including conventional core and core analysis data, modern well logs, 3-D seismic coverage, and complete reservoir production histories, will provide the best chance of success for identifying additional reserve potential through advanced reservoir characterization techniques. Recent drilling activity in a field is an indication of an operator's current strategy for reservoir reexploration and additional field development and therefore highlights fields with the best potential for near-term implementation of recommendations resulting from this project.

Data were screened from productive Frio reservoirs distributed among fields along the entire Vicksburg Fault Zone play in South Texas (Fig. 1). There are 59 producing reservoirs distributed among at least 26 fields within the play. Screening was accomplished with various public data sources, including Texas Railroad Commission hearing files, commercially available production data from Dwight's Energydata and Petroleum Information, the Bureau of Economic Geology's Texas Oil Reservoirs database, miscellaneous trade and technical literature, and some additional nonpublic data contributed by companies.

Initial data screening was limited to the subset of fields that have both produced more than 1 MMSTB from the Frio and have wells that are producing oil from Frio zones. Geologic, engineering, and production data from fourteen major fields in the play from Garcia field in southern Starr County northeastward to Agua Dulce field in Jim Wells and Nueces Counties were examined. Data that were summarized and compared among fields included the number and sizes of individual Frio reservoirs, cumulative past production, the present status of Frio production, and, where available, completion densities for individual Frio reservoir units. Completion densities were determined from recent and past Texas Railroad Commission proration schedules and are used as an indicator of the level of remaining potential of finding additional reserves. Preliminary estimates of potential infield reserve growth were analyzed by determining current reservoir recovery efficiencies.

The screening criteria reduced the number of non-gas fields in the Frio fluvial-deltaic sandstone/Vicksburg Fault Zone play suitable for this study to only a few. On the basis of the preliminary assessments of additional reserve growth potential and the availability of abundant geologic and production data, two field areas have been selected for inclusion in this project: the western portion of the TCB Field, located in Jim Wells County and operated by Mobil, and the Rincon Field, located in Starr County and operated by Conoco.

Tijerina-Canales-Blucher Field, Kleberg County, Texas

The TCB Field is located in Kleberg and Jim Wells Counties, approximately 55 miles southwest of Corpus Christi, in southern Texas. The field was discovered and first developed by Sun in 1944. Multiple reservoirs in various portions of the field area have subsequently been discovered and

Frio Fluvial-Deltaic Oil Reservoirs

Vicksburg Fault Zone, South Texas

FRIO RESERVOIRS
Field Production and Completion Density
(Fields currently producing from Frio zones)

Field	Zone ¹ Name	Acre ² Spacing	No. ³ Wells
Agua Dulce	31219	40	16
Alta Mesa	garcia	20	12
Borregos	combined	40	37
Clara Driscoll	2 zones	10,20	2,3
Garcia	4 zones	40	7
Jay Simmons	1 zone	20	13
Kelsey	M-2	40	1
La Gloria	5 zones	40	14
Rincon	17334	20	15
Rincon North	2 zones	40	8
Seeligson	4 zones	40	37
Stratton	4 zones	40	17
Sun	2 zones	20,40	18
Sun East	F-4 sand	20	1
Sun North	3 zones	40	5
T-C-B	4 zones	40	87

¹Producing reservoir zone as reported to the Texas Railroad Commission

²Completion densities for individual reservoir zones based on acre-spacings from January 1993 proration schedules

³Number of producing wells as of December 1992

- Major oil field (>1 MMBO from Frio)
- Field (>1 MMBO from Frio)
- Selected for Detailed Reservoir Characterization
- Approximate trace Vicksburg Fault Zone
- County Line
- International Border

Fig. 1 Productive Frio fluvial-deltaic reservoirs in fields along the entire Vicksburg Fault Zone play in South Texas.

produced by Sun (now Oryx), Humble (now Exxon), Texaco, and Mobil. The majority of drilling activity took place in the late 1940s, and intermittent development activity continued through the 1980s. The field has produced significant volumes of oil and gas from Oligocene Frio and Vicksburg fluvial-deltaic sandstones; cumulative oil production from Frio zones alone is more than 50 MMSTB. The field is still under primary production, although only four wells are currently producing from Frio zones.

The portion of the TCB Field chosen for study consists of the western Blucher portion of the field operated by Mobil Exploration and Producing U.S. The primary data set available from Mobil includes well log, sidewall core, and detailed production data from more than 65 wells. Many modern (mid to late 1980s) log suites are available, including high-resolution dipmeter (SHDT) data. There is an extensive 2-D seismic grid over the acreage. Well spacing and reservoir completion densities within the TCB Field indicate that there may be

significant infill potential, more than many of the other Frio-producing fields in South Texas. There are numerous productive reservoir zones. More than 30 oil reservoirs have production reported from the Frio interval, which ranges from 5000 to 7600 ft in depth. Production data available from public sources indicate that no reservoir has been drilled at closer than a 40-acre spacing.

Rincon Field, Starr County, Texas

Rincon Field is located in eastern Starr County, Texas, 120 miles southwest of Corpus Christi and approximately 20 miles north of the United States–Mexico border. The field was discovered in 1939. Conoco took over field development in 1940 and is currently the principle operator for most of the Rincon area, which includes producing acreage from the Boyle, Cameron, Rincon–Vicksburg, North Rincon, and Urshel fields as well as the formerly productive Davenport and East Rincon fields. More than 65 MMSTB of oil have been produced from fluvial–deltaic sandstone reservoirs over the combined Frio–Vicksburg stratigraphic interval. Production from 38 separate Frio reservoirs has yielded over 45 MMSTB of oil. Development from Frio reservoirs peaked in the mid 1940s. Production continues today, although at much reduced, consistently declining rates, and all future field development plans are presently focused on deeper Vicksburg objectives. The field also has a well-documented waterflood history.

Rincon Field is densely drilled and has been extensively cored. Approximately 200 wells have been drilled in the central Rincon area, and conventional core analysis data exist for over 650 individual reservoir sand intervals. More than 50 individual reservoir sands within the Frio interval from 3000 to 5000 ft have been identified and mapped across the field. The large volume of conventional core analysis data and archived core available for study makes this field an excellent candidate for detailed reservoir characterization studies. Flow unit parameters and permeability architecture of individual reservoir units can be directly quantified by both new measurements and reinterpretation and synthesis of existing subsurface data. The quantity of available core data also provides an excellent opportunity to test and apply outcrop-derived constraints on flow units and permeability structure from analogous fluvial–deltaic reservoirs.

Planned Activities

Initial reservoir characterization efforts that comprise the remainder of Phase I for the project will be tailored to take advantage of the different kinds and quality of data available from both TCB and Rincon fields. The demonstration of additional potential in the TCB Field will first be accomplished through the construction of cross sections illustrating sandstone geometry within some of the more productive Frio reservoir zones, comparison of data from available sidewall cores by individual reservoir zone, and volumetric calculations of remaining reserves. Available engineering data, in-

cluding production rates and formation pressure tests, will be examined to identify the presence of compartmentalized reservoirs and quantify additional reserve growth potential.

In the Rincon Field, a geographic subset of the entire field area will be selected for detailed study. The decision on where to focus within the field will be based on where the most core data are available as well as where there is better potential for additional reserve growth. This work is currently under way. The geometries of individual reservoir zones will be examined by cross-section construction and detailed stratigraphic correlation within Rincon Field. In addition, reservoir data from core analyses will be synthesized, and available core will be studied and sampled for detailed sedimentologic, petrographic, and petrophysical analyses.

GREEN RIVER FORMATION WATERFLOOD DEMONSTRATION PROJECT, UINTA BASIN, UTAH

Contract No. DE-FC22-93BC14958

**Lomax Exploration Company
Salt Lake City, Utah**

**Contract Date: Oct. 21, 1992
Anticipated Completion: Oct. 1, 1995
Government Award: \$1,304,000**

Principal Investigators:

**John D. Lomax
Dennis L. Nielson
Milind D. Deo**

Project Manager:

**Edith Allison
Bartlesville Project Office**

Reporting Period: Jan. 1–Mar. 31, 1993

Objective

The project concerns itself with increasing recoverable petroleum resources in the United States. The Green River Formation of the Uinta Basin, Utah, contains abundant hydrocarbons that are not easily recovered by primary means. The successful Lomax Monument Butte Unit waterflood will be evaluated under this contract, and, on the basis of this information, waterfloods will be initiated in nearby Travis and Boundary units. In 1987, Lomax Exploration Company started a successful waterflood on their Monument Butte Unit. This is a low-energy, geologically heterogeneous reservoir producing a waxy crude oil. Primary production yielded about 5% of

the original oil in place (OOIP), whereas the waterflood will yield an estimated recovery of 20% OOIP.

Summary of Technical Progress

The drilling and completion of two of the wells, one in the Monument Butte Unit (10-34) and the other in the Travis (14A-28) Unit, were reported in the previous quarterly report. The use of novel logging techniques (Formation Microimaging and Magnetic Resonance Imaging) along with the compositions of the oils and gases from the Monument Butte Unit were also discussed.

The Monument Butte 10-34 (first production, Nov. 27, 1992) has produced 4953 bbl of oil and 4039 Mcf of gas, and the Travis 14A-28 (first production, Jan. 1, 1993) has produced 6187 bbl of oil and 7829 Mcf of gas from inception through Mar. 31, 1993. As a result of the success of the Travis 14A-28 completion, the behind pipe "D" zone in the Travis 14-28 was recompleted on Mar. 8, 1993. The 14-28 has produced 2411 bbl of oil through Mar. 31, 1993, or 105 bbl/d.

Water injection was resumed in the Travis 15-28 in mid-March. The average daily rate was 263 bbl/d. Lomax and the Department of Chemical and Fuels Engineering agreed to a slower injection rate in the 15-28 as a result of the fractures found in the logging and coring of the 14A-28 well. At this date tubing pressure of the 15-28 is at 90 psi and casing pressure is at 480 psi.

As a result of weather restraints, the Boundary 10-20 location was not approved by the Bureau of Land Management (BLM) until April of 1993. The Boundary 10-20 well was spudded in April. The tentative completion date is estimated to be the first half of May. The 10-20 is the first of two wells committed to be drilled in the Boundary unit in 1993 as part of the waterflood development. The main oil objectives in the 10-20 well are the lower Douglas Creek and the "D" sand members of the Green River formation.

A full-diameter core was collected from 5550 to 5646 ft in the Lower Douglas Creek interval of well 14A-28. The core was photographed and described in detail. The sandstone of the Lower Douglas Creek in well 14A-28 is composed of thick packages of planar-laminated, fine-grained sandstone exhibiting various degrees of dewatering and soft-sediment deformation that are separated by thinner disrupted or massive very fine-grained sandstone and siltstone beds. The planar-laminated sandstones occur in 15-ft-thick packages with an intraclast-rich base and a dewatered top. The sandstones are interpreted as moderate- to low-density turbidite channel deposits. Two deformed planar-laminated sandstone units occur, from 5632.7 to 5623.5 ft and from 5605.5 to 5588 ft. Both of these units are strongly oil-stained.

The most strongly oil-stained sandstones are those facies which are planar-laminated, whether or not they are disrupted or undeformed. Presumably, these laminated facies are also the best reservoir units. Moderately stained sandstones of the lower turbidite channel sequence have oil saturations that range from 49.6 to 40.5%, horizontal permeabilities in the

0.46- to 0.77-mD range, and vertical permeabilities in the 0.50- to 0.99-mD range. The plug from 5638 ft had the highest vertical permeability of any of the measured samples because the laminations are steeply inclined at this depth. Porosities in this facies range from 9 to 11.7%. Strongly oil-stained planar-laminated sandstones in the upper turbidite unit are 67 to 70.7% oil-saturated. Horizontal permeabilities in this sandstone unit are much higher than those in the lower turbidite unit and range from 2.5 to 13 mD. Porosities range from 14.8 to 16.6%.

The core from the Lower Douglas Creek interval is moderately fractured. There is some lithologic control on the formation of fractures. In general, fractures are developed in cemented sandstone beds rather than in more ductile finer grained lithologies. In the upper portion of the core, fractures are present in carbonate-cemented sandstone beds at 5570 to 5572 ft, 5582 ft, and 5589 to 5590 ft. In these beds the fractures are open, subvertical, and planar. Fractures in the upper and lower turbidite sandstone units are more irregular. At 5608 to 5611 and 5625 to 5627 ft, open fractures are subvertical but tend to mimic the orientation and geometry of dewatering pipes in the laminated sandstones and are nonplanar. In general, the open, natural fractures have dips greater than 60°. The dewatering pipes exhibit similar dips and are commonly subvertical.

A tracer test is being planned to take place within the Monument Butte Unit. The test is expected to consist of inserting one tracer into one injection well. However, the possibility of tagging more than one well is being examined with respect to the budget. Injection and production waters from several of the wells in this unit have been subjected to a comprehensive inorganic analysis. The analysis revealed unexpectedly high levels of nitrate, which was the tracer that had been planned for use. Iodide and/or bromide are being considered as alternate tracers. For a plan of the tracer test, estimates of dilution and travel time will be needed. These will be obtained from the reservoir simulation currently being run at the Department of Chemical and Fuels Engineering.

Procedures for the gas-chromatography-based, high-temperature simulated distillation of crude oils have been developed, validated, and used to develop a more accurate description of the composition of the oils in the reservoirs. The method measures the fraction of the crude oils for carbon numbers up to 90. This correlates to a boiling point of about 1300 °F. The use of an internal standard allows accurate calculation of the fraction of material above C₉₀.

The live-oil pressure-volume-temperature (PVT) core flooding system is complete. The system is nominally rated to a pressure of 5000 psi and a temperature of 250 °F. The equipment is currently being used to perform experiments and to measure the various properties of the reservoir fluids. A schematic of the system is shown in Fig. 1, and the details of the core holder are shown in Fig. 2. This equipment is designed to measure the thermodynamic properties of the reservoir fluids of interest. It will also be used to quantitatively evaluate the rock-fluid interactions in the reservoir, with the

use of reservoir fluids and cores, at the conditions prevailing in the reservoir.

The measured oil and gas compositions for the fluids from the Monument Butte Unit were used to calculate PVT properties. For a gas/oil ratio (GOR) of 230, at the reservoir composition and temperature, the bubble point was calculated to be 2017 psi. The thermodynamic model uses the Peng–Robinson equation of state for the calculations. The initial field GOR was greater than 230, but there is some uncertainty in the actual initial values. There is also some uncertainty in the model predictions because of the manner in which the oil components obtained with simulated distillation are lumped into pseudocomponents and the critical properties that are assigned to the pseudocomponents. More work is being done on the predictive models, and the models will eventually be validated by comparison with the properties measured in the system described previously.

Reservoir simulation work began during this quarter. A preliminary model for Monument Butte was constructed using a state-of-the-art black-oil simulator developed by the computer modeling group. The model uses the gas and oil

compositions in the reservoir, and it features the major features of the reservoir, including the separate B and D sands.

Major geologic features of the D and B sands are represented in the model with the use of a variable-depth, variable-thickness option. The model includes 20 wells in the Monument Butte Unit and keeps track of times of completion, water injection schedule, and other pertinent reservoir data. For accurate history matching and future waterflood behavior predictions, the model needs thermodynamic information about the oil and gas originally in place (PVT properties), reservoir geologic parameters and geometry, and rock–fluid interactions (relative permeabilities). The preliminary model incorporated realistic reservoir geologic features, PVT properties believed appropriate for the oil and gas of Monument Butte, and typical relative permeabilities for a water-wet sandstone. These input parameters to the simulator will be updated as more geologic information becomes available and as property measurements are completed in the PVT/core flooding system. Nevertheless, the preliminary model does provide a basic understanding about primary production and the nature of waterflooding in the unit.

In primary production the reservoir behaves in a manner similar to reservoirs containing fluids with analogous thermodynamic behavior. The average pressure in the reservoir drops below the bubble point pressure in a matter of months, and thus large increases in the production GOR and in free gas saturation in the reservoir result. With continued production the reservoir pressure declines to a point where oil production is no longer economical. The model shows a primary recovery of about 5 to 6% OOIP, which is considered typical for these types of reservoirs. The free gas in the reservoir is recompressed by the waterflood, and the oil production rate is dramatically increased.

For a quantitative match of production from each of the wells in the unit, a careful fine tuning of the model geologic features will be required. Even so, the model predictions from this preliminary model are reasonably close to the field results. For example, the model predicts a production rate of 88 bbl/d in May 1992 for Well 10-35, the most productive well in the unit, whereas the actual field rate was 100 bbl/d. The oil saturation contour plot for D sands at the end of May 1992 is shown in Fig. 3. The plot shows a mature waterflood and identifies zones of high oil saturation in the field.

Fig. 1 Schematic of live-oil pressure–volume–temperature/core flooding system. Exact details not shown. MPV, moving piston vessel. R, Ruska pump.

Fig. 2 Live-oil pressure–volume–temperature/core flooding system core holder.

Fig. 3 Oil saturation contour plot for W sands at end of May 1992.

Technology Transfer

The success of the Monument Butte Unit has influenced the start and the development of the Jonah waterflood unit by Equitable Resources Energy Company (Equitable). Equitable received approval from the State of Utah and the BLM to commence water injection in sec. 6, T. 9 S, R. 17 E of Duchesne County, Utah. Equitable plans to expand the waterflood unit to cover 4240 acres. The proposed unit is within 1 mile of the Monument Butte Unit.

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**SECONDARY OIL RECOVERY FROM
SELECTED CARTER SANDSTONE OIL
FIELDS—BLACK WARRIOR BASIN,
ALABAMA**

Contract No. DE-FC22-93BC14952

**Anderman/Smith Operating Company
Denver, Colo.**

**Contract Date: Oct. 21, 1992
Anticipated Completion: Jan. 5, 1996
Government Award: \$369,600**

**Principal Investigator:
James C. Anderson**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The project objectives are to (1) increase the ultimate economic recovery of oil from the Carter reservoirs and thereby increase domestic reserves and lessen U.S. dependence on foreign oil; (2) extensively model, test, and monitor the reservoirs so that their management is optimized; and (3) assimilate and transfer the information and results gathered to other U.S. oil companies to encourage them to attempt similar projects.

Summary of Technical Progress

Central Bluff

In December 1992 power lines and an electrical panel were installed. Public notice was resubmitted in the Fayette, Ala., newspaper.

In January 1993 the water well (source well for injection water that was drilled in November 1992) was cleaned out. A mechanical integrity test was run on this well and witnessed by a member of the Alabama State Oil and Gas Board. During this period a transformer on the Rural Electrification Administration (REA) power line was repaired.

Start-up water injection began on Jan. 12, 1993. Pumps, flow lines, and other facilities were checked after injection began. Daily operations began on Jan. 13, 1993, and are continuing. These operations include monitoring wellhead pressures at the injector and two producers and injection water treatment. Water

injection was running 200 to 300 bbl/d at the end of February. Once the unit is pressured up, well testing will begin. Unitization was approved on Mar. 1, 1993.

North Fairview

The North Fairview Field was discovered in July 1982 with the drilling of the Michigan Oil Company Perkins 33-11 No. 1 located in NESW sec. 33, T. 13 S., R. 14 W. Production is from the Carter sand with an initial reservoir pressure of 1000 psi. As of December 1992 this field had a cumulative production of 103,560 stock tank barrels of oil from three producing wells. Current production is 5 bbl of oil per day from two wells.

No cores were taken from the wells in North Fairview Field. Correlations and log analyses were used to determine the fluid and rock properties.

The results of the log analysis were used to construct the hydrocarbon pore volume map shown in Fig. 1. The map was planimetered to determine original-oil-in-place (OOIP) values and the hydrocarbon pore volume by tract. The OOIP summed over all tracts by this method was 824.7 Mbbl (Fig. 2). Original oil in place was also calculated directly: two such independent calculations gave 829.4 Mbbl and 835.6 Mbbl. Thus the three estimates of OOIP are within 1%. The approximately 88% of OOIP remaining provides an attractive target for secondary recovery.

The physical properties of the crude oil and gas are observed data. The crude has a gravity of 31 °API and the gas has a gravity of 0.76. The formation volume factor was calculated to be 1.10 on the basis of an initial gas/oil ratio of 400:1 and a bottomhole temperature of 100 °F.

Injection start-up is planned for mid-June. The J. E. Boman 33-5 No. 1 has been identified as a reentry candidate for the initial injection well. Injection into the Boman 33-5 No. 1 is expected to stabilize between 250 and 500 bbl of water injected per day (BWIPD). Initially, injection will be at the lower rate of 150 BWIPD. As the injection pressure stabilizes, Anderman/Smith will perform the necessary step rate and injection profile tests and increase the rate accordingly. The estimated injection schedule will allow fill-up to be reached in about 10 months. For the best efficiency, it is recommended that at least one additional well will be needed for injection. This well will be chosen on the basis of the observed results.

During the reporting period, unitization (land and title) work was started and is continuing. Unitization is expected to be approved in April.

South Bluff

No activity was conducted for South Bluff during the period. Geologic analysis work is planned to start in April.

Fig. 1 North Fairview Carter oil unit, Lamar County, Alabama, net oil pore volume map ($S_o = 80\%$).

Lease: TR8; TR1; TR2; TR3; TR4; TR5; TR6; TR7; TR9

Contour data		
Height, ft	Area, ft ²	Area, acres
1.5	354,152.3	8.1302
1	1.5427×10^6	35.4
0.5	3.9978×10^6	91.8
0	7.2961×10^6	167.5

Delta thickness of top layer: 0.25

Volume	106.3 acre-ft
Porosity	1.0000 fraction
S_o	1.0000 fraction
B_o	1.0000 rb/STB
RF	1.0000 fraction

Original oil in place	824,714.9 bbl
RES	824,714.9 bbl

Volumetrics		
Method	Volume, ft ³	Volume, acre-ft
Trapezoid	4.7270×10^6	108.5
Pyramid	4.5886×10^6	105.3
Trapezoid/pyramid	4.6296×10^6	106.3
Quadratic	4.9850×10^6	114.4
Simpson	4.6568×10^6	106.9
Ratio	4.4610×10^6	102.4
Step	2.9473×10^6	67.7
% Rule	4.5082×10^6	103.5

Fig. 2 North Fairview Carter oil flood hydrocarbon pore volume map.

**IDENTIFICATION AND EVALUATION
OF FLUVIAL-DOMINATED DELTAIC
(CLASS I OIL) RESERVOIRS IN
OKLAHOMA**

Contract No. DE-FC22-93BC14956

**Oklahoma Geological Survey
Norman, Okla.**

**Contract Date: Jan. 15, 1993
Anticipated Completion: Dec. 31, 1997
Government Award: \$1,390,752
(Current year)**

**Principal Investigators:
Charles J. Mankin
Mary K. Grasmick**

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

Reporting Period: Jan. 1–Mar. 31, 1993

Objectives

The Oklahoma Geological Survey (OGS), the Geological Information Systems department, and the School of Petroleum and Geological Engineering at the University of Oklahoma have engaged in a program to identify and address Oklahoma's oil recovery opportunities in fluvial-dominated deltaic (FDD) reservoirs. This program includes the systematic and comprehensive collection and evaluation of information on all of Oklahoma's FDD reservoirs and the recovery technologies that have been (or could be) applied to those reservoirs with commercial success. This data collection and evaluation effort will be the foundation for an aggressive, multifaceted technology transfer program that is designed to support all of Oklahoma's oil industry, with particular emphasis on smaller companies and independent operators in their attempts to maximize the economic producibility of FDD reservoirs.

Specifically, this project will identify all FDD oil reservoirs in the State; group those reservoirs into plays that have similar depositional and subsequent geologic histories; collect, organize, and analyze all available data; conduct characterization and simulation studies on selected reservoirs in each play; and implement a technology transfer program targeted to the operators of FDD reservoirs to sustain the life expectancy of existing wells with the ultimate objective of increasing oil recovery.

The elements of the technology transfer program include developing and publishing play portfolios, holding workshops to release play analyses and identify opportunities in each of the plays, and establishing a user laboratory called the OGS Geosystems Extension Laboratory. The laboratory will

contain all the play data files, as well as other oil and gas data files, together with the necessary hardware and software to analyze the information. Technical support staff will be available to assist interested operators in the evaluation of their producing properties, and professional geological and engineering outreach staff will be available to assist operators in determining appropriate recovery technologies for those properties.

Summary of Technical Progress

The execution of this project is being approached in three phases. The first phase, Planning and Analysis, will last 18 months and includes system design, play definition, and database development activities. Data from the Natural Resources Information System (NRIS), an Oklahoma data system that has been developed with the support of the Department of Energy's Bartlesville Project Office, will provide the foundation for this data collection effort. The other two phases will include implementation and technology transfer activities in which the collected information is organized and made available to the industry through the various methods. Activities for the first phase have been divided into five primary tasks.

Design/Develop Database Systems

System design and development activities were initiated during this quarter for the primary databases of the project. For the reservoir database, system design goals include a comprehensive data dictionary and a flexible design that will allow the capture of variable data from numerous sources into a systematic format. The initial specification includes about 150 data elements with the capability of recording the data source for each element. A bibliographic database is being developed to systematically record source information for each reservoir and for recovery technologies; literature references as well as unpublished data sources will be identified in this database.

An operator database will be maintained that will identify names and addresses of all active operators in Oklahoma as well as the specific FDD plays in which they have operations. The initial operator system was developed during this quarter; update processes for this system will be defined as the project develops.

Data Research

Data research activities were initiated this quarter. One fundamental precursor to the analysis of FDD reservoirs is the appropriate delineation of the boundaries of the fields in which the FDD reservoirs occur. Project staff are working closely with the Oklahoma Nomenclature Committee of the Midcontinent Oil and Gas Association to identify necessary updates to the official field boundaries; initial efforts this quarter have included working to complete field definitions in Beaver County, an area that will be included in the Morrow play.

Reservoir identification activities were also initiated during this quarter. On the basis of lease and well maps generated from the NRIS data, initial delineations were made of the geographic locations of reservoirs that may be in FDD depositional environments. The initial operator database was developed during this quarter through a combined scanning and data entry effort; as play boundaries are further defined, the operators' properties in FDD reservoirs will be identified on the basis of input from the NRIS data system. Efforts were also initiated during this quarter to perform comprehensive searches for relevant literature and theses and to define approaches to collection of private-domain data through the reservoir characterization and simulation pilot studies.

Play ID/Folio Plans

During this quarter the initial planning sessions were completed to identify Oklahoma's FDD plays and begin their boundary definitions. As a result, preliminary definitions were developed for ten FDD plays within the State, all of which are within the Pennsylvanian System. At this point the major plays have been identified as the Skiatook-Kansas City Play, which includes Layton, Marchand, and Cleveland sandstones; the Upper Cherokee Play, which includes the Prue and Skinner sandstones; the Middle Cherokee Play for the Red Fork sandstone; and the Lower Cherokee Play, which includes the Bartlesville and Booch sandstones.

Other identified plays include the Shawnee Play (Hoover, Carmichael, and Endicott sandstones), the Douglas Play (Wade and Tonkawa sandstones), the Ochelata-Lansing Play (Cottage Grove sandstone), the Marmaton Play (Peru sandstone), the Atoka Play (Gilcrease and Dutcher sandstones), and the Morrow Play (Upper and Lower Morrow sandstones). In the coming months, additional data collection efforts will help

refine the play boundaries by identifying where these sandstones have been deposited through FDD processes.

Computer Applications

User laboratory development activities include both the acquisition of hardware and software and the development of user interfaces for the data and applications that will be available through the user laboratory. Research is being conducted on the most valuable and cost-effective hardware and software selections for the user laboratory, and some acquisitions have already been completed. Advanced Revelations has been selected as the PC-level database software package that will offer the needed flexibility for user interfaces to the large and varying databases of this project. Although the effort required to develop these interfaces will be fairly significant, it is expected that in the long run the users (many of whom will be novices with computers) will be best served by a system that is tailored to the needs of these reservoir applications. Design efforts for these user interfaces have begun as part of the database design efforts.

Management/Reporting

Because this is the first quarter of the project, significant management activities have been required to designate staff assignments and initiate project tasks. Some staffing requirements have yet to be filled, including the hiring of one of the three designated play leaders; search activities are under way for an experienced petroleum geologist to fill this position.

Two contract deliverable reports were completed this quarter, including the Project Management Plan and the first topical report regarding the initial planning phase of the play identification process.

NOVEL TECHNOLOGY

A NOVEL APPROACH TO MODELING UNSTABLE ENHANCED OIL RECOVERY DISPLACEMENTS

Contract No. DE-AC22-90BC14650

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

**Contract Date: Aug. 28, 1990
Anticipated Completion: Aug. 27, 1993
Government Award: \$407,118
(Current year)**

**Principal Investigator:
Ekwere J. Peters**

**Project Manager:
Jerry Ham
Metairie Site Office**

Reporting Period: Jan. 1–Mar. 31, 1993

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 is being developed. Flow visualization experiments are being 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 to predict the performance of unstable displacements in such reservoirs.

Summary of Technical Progress

Previous reports have concentrated on the problem of modeling unstable immiscible displacements in heterogeneous porous media.¹⁻³ In this report the problem of modeling miscible displacements is examined. A miscible displacement is the most desirable type of displacement in enhanced oil recovery because there is no interfacial tension between the fluids and therefore no capillary trapping of the fluids. Thus, in a miscible displacement, it is possible to recover 100% of the oil in the areas contacted by the injected solvent.

The four major issues in miscible displacements are

1. *Quantitative description.* The first issue is the quantitative description of the mixing or dispersion that occurs in miscible displacements and the attendant problem of measuring the dispersion coefficient for the porous medium.

2. *Hydrodynamic instability.* Because the solvent is nearly always less viscous and less dense than the oil, instabilities in the forms of viscous fingering and gravity override frequently occur in miscible displacements. These instabilities reduce process efficiency and complicate process modeling and prediction.

3. *Impact of heterogeneity on the performance of miscible displacements.* Because natural reservoirs are nearly always heterogeneous at different length scales, the impact of heterogeneity on the performance of unstable miscible displacements is of practical significance.

4. *Process optimization and economics.* Because the injected solvents are more expensive than the oil to be displaced, they must be injected in small quantities as slugs and chased by less expensive fluids to make the project economically feasible.

What is the optimum slug size that will prevent complete degradation of the slug by mixing caused by dispersion, instabilities, and heterogeneity? The first three issues are addressed in this research. The fourth issue is outside the scope of this research.

In this report the first issue—the description of dispersion in porous media—is addressed. An improved method to measure the longitudinal dispersion coefficient of a porous medium from CT imaging of a tracer test in the medium is presented. The method is demonstrated by measuring the dispersion coefficients for a sandpack and a Berea sandstone. Imaging the tracer test allows the distinction of the effects of dispersion and heterogeneity.

Theory

To focus attention on the dispersion phenomenon, a tracer test consisting of a stable, first-contact miscible displacement of two incompressible fluids having equal viscosities and densities in a homogeneous porous medium is considered. For such a displacement, viscous and gravity instabilities are suppressed, and only dispersion will manifest itself. The mathematical model for this displacement in one dimension consists of the continuity equation, Darcy's law, and the convection–dispersion equation, respectively (Eqs. 1 to 3).

$$\frac{\partial u}{\partial x} = 0 \quad (1)$$

$$u = -\frac{k}{\mu} \frac{\partial P}{\partial x} \quad (2)$$

$$\frac{\partial C}{\partial t} + \frac{v}{R_f} \frac{\partial C}{\partial x} - \frac{D_L}{R_f} \frac{\partial^2 C}{\partial x^2} = 0 \quad (3)$$

In Eqs. 1 to 3, u is the superficial velocity (Darcy velocity), v is the interstitial velocity (u/ϕ), and R_f is a retardation factor

that accounts for the adsorption of the tracer by the porous medium. If there is no adsorption of the tracer by the porous medium, the retardation factor is unity, whereas if there is adsorption, the retardation factor is greater than unity. As shown in Eq. 3, the effect of the retardation factor is to reduce v and the longitudinal dispersion coefficient (D_L) for the displacement. Thus the speed of the solvent concentration is retarded by adsorption.

For a constant rate injection, Eqs. 1 and 2 lead to the following solution for the superficial velocity:

$$u = \frac{k}{\mu} \frac{\Delta P}{L} = \text{a constant} \quad (4)$$

where ΔP is the pressure drop across the porous medium and L is the length of the porous medium. Therefore the interstitial velocity is given by

$$v = \frac{u}{\phi} = \frac{k}{\mu \phi} \frac{\Delta P}{L} = \text{a constant} \quad (5)$$

Equation 5 can then be substituted into Eq. 3 to describe the longitudinal dispersion of the solvent in the porous medium. To solve Eq. 3 for the case of continuous injection of the solvent, the following initial and boundary conditions are applied:

$$C(x, 0) = 0 \quad (x > 0) \quad (6)$$

$$C(0, t) = C_0 \quad (t \geq 0) \quad (7)$$

$$C(\infty, t) = 0 \quad (t \geq 0) \quad (8)$$

The analytical solution to Eq. 3 for the initial and boundary conditions given by Eqs. 6 to 8 is⁴

$$C(x, t) = \frac{C_0}{2} \left\{ \operatorname{erfc} \left[\frac{x - (v/R_f)t}{2[(D_L/R_f)t]^{1/2}} \right] + \exp \left(\frac{vx}{D_L} \right) \operatorname{erfc} \left[\frac{x + (v/R_f)t}{2[(D_L/R_f)t]^{1/2}} \right] \right\} \quad (9)$$

where erfc is the complementary error function, an integral that is tabulated in mathematical handbooks. An approximate analytical solution normally used to determine the dispersion coefficient from breakthrough data is

$$C(x, t) = \frac{C_0}{2} \left(\operatorname{erfc} \left[\frac{x - (v/R_f)t}{2[(D_L/R_f)t]^{1/2}} \right] \right) \quad (10)$$

In dimensionless form, Eq. 10 becomes

$$C(x_D, t_D) = \frac{C_o}{2} \left(\operatorname{erfc} \left\{ (N_{Pe})^{1/2} \left[\frac{x_D - (t_D/R_f)}{(t_D/R_f)^{1/2}} \right] \right\} \right) \quad (11)$$

where the dimensionless variables are defined as

$$x_D = \frac{x}{L} \quad (12)$$

$$t_D = \frac{vt}{L} \quad (13)$$

$$N_{Pe} = \frac{vL}{D_L} \quad (14)$$

Equation 15 defines a Peclet number (N_{Pe}) that is the ratio of convective to dispersive transports. Equation 11 suggests a self-similarity transformation variable for first-contact miscible displacement of the form

$$\xi = \frac{x_D - (t_D/R_f)}{(t_D/R_f)^{1/2}} \quad (15)$$

If a mixing zone length is defined as the distance between $C = 0.1$ and $C = 0.9$, it can be shown from Eq. 11 that the growth of the mixing zone is given in dimensionless form by⁵

$$\Delta x_D = 3.625 (t_D/N_{Pe}R_f)^{1/2} \quad (16)$$

or in dimensional form by

$$\Delta x = 3.625 (D_L t/R_f)^{1/2} \quad (17)$$

Thus, by measuring the length of the mixing zone as a function of time, Eq. 17 can be used to calculate the longitudinal dispersion coefficient for the porous medium. The length of the mixing zone can easily be measured by imaging the experiment.

The longitudinal dispersion coefficient consists of a diffusion and a mechanical dispersion term, as shown in the following equation:⁶

$$D_L = \frac{D_o}{F\phi} + \alpha_L v \quad (18)$$

where D_o = molecular diffusion coefficient

F = formation electrical resistivity factor

ϕ = porosity

α_L = longitudinal dispersivity

At interstitial velocities greater than about 3.5×10^{-5} cm/s, the mechanical dispersion term ($\alpha_L v$) dominates the molecular diffusion term ($D_o/F\phi$).⁷ Therefore, at a sufficiently high displacement rate or Peclet number, Eq. 18 can be used to estimate the longitudinal dispersivity from the dispersion coefficient by neglecting the molecular diffusion term.

If a linear sorption isotherm is assumed, the retardation factor is related to the distribution coefficient (K_d) as⁸

$$R_f = \left(1 + \frac{1-\phi}{\phi} \rho_s K_d \right) \quad (19)$$

from which the distribution coefficient can be determined.

Experiments

Traditionally, the longitudinal dispersion coefficient is normally determined by measuring the solvent concentration at the outlet end of the porous medium for a tracer test and then applying Eq. 11 at the outlet end to calculate D_L or more correctly D_L/R_f if retardation is not explicitly accounted for. This method gives an average D_L that includes the effects of hydrodynamic dispersion and heterogeneity. A method of determining D_L that allows the effects of dispersion and heterogeneity to be distinguished is presented. This is accomplished by imaging the tracer test experiment in time and space. Equation 11 is used to determine the average D_L (because of dispersion and heterogeneity) and R_f by history matching the average concentration profiles and Eq. 17 to determine the component of D_L that is the result of dispersion only by measuring the length of the mixing zone with time from the image data.

Two tracer tests were performed and imaged by CT to demonstrate this method. The first test was in an unconsolidated sandpack, whereas the second test was in a consolidated Berea sandstone. In the tracer tests, brine containing an X-ray contrast agent was used to displace or was displaced by another brine of the same viscosity and density. The experiments were designed to approximate a one-dimensional displacement in accordance with the theoretical derivations given previously. Table 1 shows the pertinent experimental parameters.

Results and Discussion

Figure 1 shows the solvent concentration images for the tracer test in the sandpack at 0.2, 0.5, and 0.9 pore volume injected (PVI). The images show a vertical slice through the center of the sandpack. The growth of the mixing zone with distance or injection time is apparent. The distortion in the mixing zone is caused by inhomogeneities in the sandpack. Such distortions or heterogeneities serve to increase the average dispersion coefficient measured by the traditional breakthrough curve method.

Figure 2 compares the experimental and calculated solvent concentration profiles based on Eq. 11 using an average

TABLE 1
Experimental Conditions for Tracer Test

	Experiment 1	Experiment 2
Porous medium		
Type	Unconsolidated sandpack	Berea sandstone
Length, cm	54.2	60.2
Diameter, cm	4.8	5.1
Absolute permeability, darcys	6.4	0.160
Average porosity from CT, %	29.7	17.3
Fluids		
Displacing fluid	Distilled water + 13% NaCl	Distilled water + 10% NaI
Density of displacing fluid, g/cm ³	1.089	1.078
Viscosity of displacing fluid, mPa · s	1.262	1.029
Displaced fluid	Distilled water + 10% BaCl ₂	Distilled water + 1.4% NaCl + 10% KCl
Density of displaced fluid, g/cm ³	1.089	1.078
Viscosity of displaced fluid, mPa · s	1.127	1.028
Viscosity ratio	0.9	1.0
Darcy velocity, cm/s	3.037×10^{-3}	2.742×10^{-3}
Interstitial velocity, cm/s	1.023×10^{-2}	1.714×10^{-2}
Breakthrough recovery, %	95.0	84.4

Fig. 1 Solvent concentration images for a tracer test in a sandpack. (a) 0.2 pore volume injected. (b) 0.5 pore volume injected. (c) 0.9 pore volume injected.

Fig. 2 Experimental vs. computed solvent concentration profiles for tracer test in a sandpack. $D_L = 100 \times 10^{-5} \text{ cm}^2/\text{s}$, $R_f = 1.00$. —, experiment. . . ., calculated.

Fig. 3 Experimental vs. computed solvent concentration profiles for tracer test in a sandpack. $D_L = 100 \times 10^{-5} \text{ cm}^2/\text{s}$, $R_f = 1.04$. —, experiment. . . ., calculated.

longitudinal dispersion coefficient of $100 \times 10^{-5} \text{ cm}^2/\text{s}$ and a retardation factor of unity. The agreement between the experimental and calculated profiles is good at early times but poor at late times. At late times the calculated profiles traveled farther than the experimental profiles. The experimental and calculated profiles are essentially parallel at late times, however, which indicates that the average longitudinal dispersion coefficient is correct but the retardation factor of unity is incorrect. Figure 3 compares the experimental and calculated profiles with the same average dispersion coefficient but with a retardation factor of 1.04. The agreement between the experiment and Eq. 11 is good at all times steps. The dispersion coefficient estimated from the average solvent concentration profiles contains the effect of heterogeneity in the sandpack and is equivalent to the dispersion coefficient that would be obtained with a breakthrough curve. The average dispersivity for the sandpack was estimated to be 0.098 cm.

Figure 4 shows the growth of the mixing zone length with time for the sandpack experiment. The average mixing zone length at each time step was measured from the three-dimensional CT images of the tracer test. Thus the effect of the distortion of the mixing zone caused by heterogeneity in the sandpack was excluded from the mixing zone length. The mixing zone grows linearly with the square root of time, as predicted by Eq. 16 or 17. From the slope of the straight line of Fig. 4, D_L/R_f was calculated to be $78.5 \times 10^{-5} \text{ cm}^2/\text{s}$. Thus the dispersion coefficient without the effect of heterogeneity in the packing is $82 \times 10^{-5} \text{ cm}^2/\text{s}$. Therefore heterogeneity accounts for about 18% of the total dispersivity of the sandpack.

Figure 5 shows the solvent concentration images for the tracer test in the Berea sandstone at 0.2, 0.5, and 0.8 PVI. As in the sandpack, the growth of the mixing zone with distance or injection time is apparent. The distortion in the mixing zone

Fig. 4 Growth of mixing zone length with time for a tracer test in a sandpack. $y = 0.72204 + 0.10156x$, $R^2 = 0.993$.

is caused by heterogeneity in the sandstone. The lower half of the sandstone was more permeable than the upper half.

Figure 6 compares the experimental and calculated solvent concentration profiles based on Eq. 11 with the use of an average dispersion coefficient of $600 \times 10^{-5} \text{ cm}^2/\text{s}$ and a retardation factor of unity. The calculated profiles travel farther than the experimental profiles at all time steps, and the separation of the two profiles increases with time. The results indicate a satisfactory average dispersion coefficient but an incorrect retardation factor. Figure 7 compares the experimental and calculated profiles with the same dispersion coefficient but with a retardation factor of 1.11. The agreement

Fig. 5 Solvent concentration images for a tracer test in a Berea sandstone. (a) 0.2 pore volume injected. (b) 0.5 pore volume injected. (c) 0.8 pore volume injected.

Fig. 6 Experimental vs. computed solvent concentration profiles for tracer test in a Berea sandstone. $D_L = 600 \times 10^{-5} \text{ cm}^2/\text{s}$, $R_f = 1.00$. —, experiment. . . ., calculated.

Fig. 7 Experimental vs. computed solvent concentration profiles for tracer test in a Berea sandstone. $D_L = 600 \times 10^{-5} \text{ cm}^2/\text{s}$, $R_f = 1.11$. —, experiment. . . ., calculated.

between the experiment and Eq. 11 is excellent at all time steps. The average dispersivity for the Berea sandstone was estimated to be 0.379 cm.

Figure 8 shows the growth of the mixing zone length with time for the Berea sandstone experiment. The mixing zone grows linearly with the square root of time, as predicted by Eq. 16 or 17. From the slope of the straight line of Fig. 8, D_L/R_f was calculated to be $388 \times 10^{-5} \text{ cm}^2/\text{s}$. Thus the dispersion coefficient without the effect of heterogeneity in the porous medium is $431 \times 10^{-5} \text{ cm}^2/\text{s}$. Therefore heterogeneity accounts for about 28% of the total dispersivity of the sandstone.

Table 2 summarizes the results for the sandpack and the Berea sandstone. As may be expected, the Berea sandstone, which is a natural porous medium, has a higher dispersion coefficient (dispersivity) and a higher retardation factor than the clean sandpack. The effect of heterogeneities is to increase the average dispersion over that which would be obtained in a homogeneous medium.

Figure 9 shows the self-similarity variable plotted against the solvent concentration data at all time steps for the two experiments. As expected from Eq. 11, the data transform into unique dimensionless response functions characteristic of the two miscible displacements. The curve for the sandpack is steeper than that for the sandstone, a reflection of the higher Peclet number in the sandpack experiment ($N_{Pe} = 554$) than in the sandstone experiment ($N_{Pe} = 159$).

Conclusions

In this report the problem of describing the mixing or dispersion that occurs in first-contact miscible displacements was addressed. A technique based on CT imaging was presented to simultaneously determine the longitudinal dispersion coefficient and the retardation factor for a porous medium. With this technique the effect of heterogeneity on the dispersion coefficient can be estimated. The method was demonstrated by determining the dispersion coefficients (dispersivities) and retardation factors for an unconsolidated sandpack and a consolidated Berea sandstone. The estimated parameters are useful for modeling first-contact miscible

Fig. 8 Growth of mixing zone length with time for a tracer test in a Berea sandstone. $y = 0.62184 + 0.22594x$, $R^2 = 0.977$.

displacements at the laboratory scale. In the next report the problem of hydrodynamic instabilities in miscible displacements will be examined.

Nomenclature

C	Solvent concentration
C_o	Inlet solvent concentration
t	Time
t_D	Dimensionless time
x	Longitudinal coordinate
x_D	Dimensionless longitudinal coordinate

Greek Symbols

ρ_s	Grain density
μ	Viscosity
ξ	Self-similarity variable

TABLE 2
Summary of Results

	Experiment 1	Experiment 2
Porous medium	Unconsolidated sandpack	Berea sandstone
Longitudinal dispersion coefficient with heterogeneity, cm^2/s	100×10^{-5}	600×10^{-5}
Longitudinal dispersivity with heterogeneity, cm	0.098	0.379
Longitudinal dispersion coefficient without heterogeneity, cm^2/s	82×10^{-5}	431×10^{-5}
Longitudinal dispersivity without heterogeneity, cm	0.080	0.272
Distribution coefficient, cm^3/g	0.0057	0.0087
Retardation factor	1.04	1.11
Peclet number	554	159

Fig. 9 Similarity transformation of solvent concentration profiles for tracer tests in a sandpack (●) and a Berea sandstone (□).

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