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Heavy and Thermal Oil Recovery Production Mechanisms

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Abstract

This technical progress report describes work performed from January 1, 2002 through March 31, 2002, for the project, "Heavy and Thermal Oil Recovery Production Mechanisms." We investigate a broad spectrum of topics related to thermal and heavy-oil recovery. Significant results were obtained in the areas of multiphase flow and rock properties, hot-fluid injection, improved primary heavy oil recovery, and reservoir definition. The research tools and techniques used are varied and span from pore-level imaging of multiphase fluid flow to definition of reservoir-scale features through streamline-based history-matching techniques.

Briefly, an apparatus was constructed and used to image pore-level matrix-to-fracture production of oil from a fractured porous medium. A simulation study continued in the area of recovery processes during steam injection into fractured porous media. Also continuing was an experimental study of heavy-oil production mechanisms from relatively low permeability rocks under conditions of high pressure and high temperature. The progress of oil production is monitored using X-ray computed tomography (CT). Also in the area of imaging production processes in laboratory-scale cores, we use CT to study the process of gas-phase formation during solution gas drive in viscous oils. Finally, significant progress was made in using the producing water-oil ratio to define reservoir heterogeneity and integrate production history into a reservoir model using streamline properties.

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Project Objectives

The objective of this research project is to improve the recovery efficiency from difficult to produce reservoirs including heavy-oil and fractured low permeability systems. This objective is accomplished by developing laboratory techniques and apparatus for studying multiphase flow properties in fractured and unfractured porous media, identifying oil production mechanisms from the pore to the core to field scale, and translating this understanding into mathematical models incorporating newly understood physics.

The project is divided into 5 main areas. These projects and their goals include:

1. Multiphase flow and rock properties—to develop better understanding of the physics of displacement in porous media through experiment and theory. This category includes work on imbibition, flow in fractured media, and the effect of temperature on relative permeability and capillary pressure.
2. Hot fluid injection—to improve the application of nonconventional wells for enhanced oil recovery and elucidate the mechanisms of steamdrive in low permeability, fractured porous media.
3. Mechanisms of primary heavy oil recovery—to develop a mechanistic understanding of so-called "foamy oil" and its associated physical chemistry.
4. In-situ combustion—to evaluate the effect of different reservoir parameters on the insitu combustion process.
5. Reservoir definition—to develop and improve techniques for evaluating formation properties from production information.

Technical progress in each of these areas is now described briefly.

Area 1. Multiphase Flow and Rock Properties

Work in this project area focused on a micro-visual analysis of matrix-to-fracture transfer in transparent, two-dimensional replicas of fractured systems. *i.e*, micromodels. Most of the progress is associated with establishing the experimental apparatus.

Rationale and Summary–Matrix/Fracture Transfer. Understanding and modeling flow behavior in naturally fractured rocks, including oil and gas reservoirs requires a detailed analysis of these systems at various length scales. To understand how fluids communicate between the high conductivity fracture and the lower conductivity matrix requires both pore- and core-scale analysis of the problem. Several experiments have focused on matrix-fracture interaction at core-scale. Rangel-German and Kovscek (2001) reported a number of experiments exploring matrix-fracture interaction covering a wide range of fracture apertures and flow rates using different fluids. They reported two imbibition regimes. The first is the named filling-fracture regime. It shows a variable length plane source due to relatively slow water flow through fractures. Water advance in the fracture is controlled by the interaction between the matrix and the fracture as shown in Fig. 1. It was found that for this early-time of imbibition (filling-fracture) the water front advance in a fracture that interacts with a porous-rock block scales with the square-root of time. The second regime is named instantly-filled fracture, in which little water imbibes before the fracture fills with water. The second image in Fig. 1 is nearly one-dimensional water advance.

In this task, a number of micromodel experiments at constant injection rates were performed to study the flow behavior of fractured media at the pore-scale and to help understand similar macroscopic experiments conducted at the core-scale (Rangel-German and Kovscek, 2001). The ultimate goal is to provide realistic information on how to model or simulate matrix to fracture transfer under thermal and isothermal conditions. Exhaustive pore-scale imaging of fluid flow driven by capillary imbibition was achieved. Filling-fracture and filled-fracture regimes were analyzed. Results showed that the mode of imbibition is clearly counter-current within the instantly-filled regime, whereas imbibition is co-current while the fractures fill (non-wetting fluid is expelled from a matrix-block to a fracture ahead of the water front in the fracture). It was also found that counter-current imbibition took place in “channels” at discrete locations along the fracture as opposed to counter-current flow with a pore or set of pores.

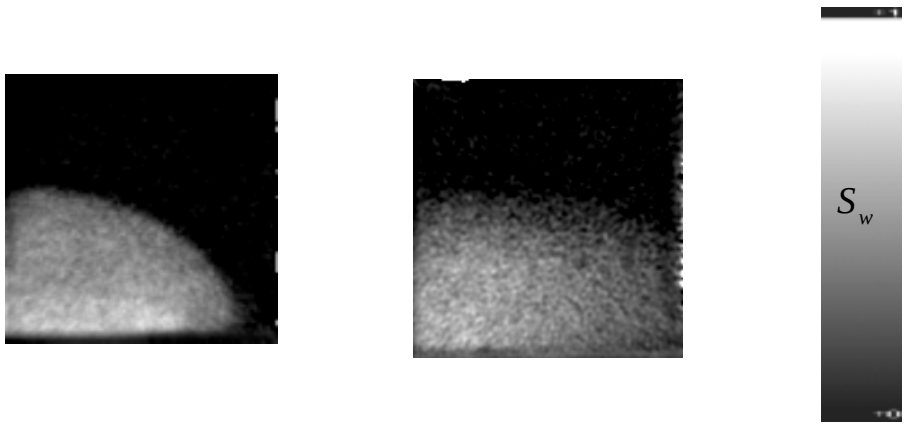

Figure 1. CT saturation images showing the imbibition regimes: (left) “filling-fracture" and (right) “instantly-filled fracture”. (Rangel-German and Kovscek, 2001).

Etched-silicon-wafer micromodels of the type used by George (1999), initially developed by Hornbrook *et al.* (1991), were used in this work. Typically micromodels are made up of a repeated pattern of an SEM (Scanning Electron Microscopy) image of a reservoir or quarried rock thin section. Usually, digital modification of the image is necessary to ensure continuity in the porous medium. The micromodels here are 5-cm squared etched pore patterns of Berea sandstone. These patterns have grains ranging from the size of 30 to 200 um. The porosity of these micromodels is roughly 0.2. The permeability of the micromodel is approximately 0.1 mD. For the current study, an inlet/outlet port is located in every corner of the pore network. Holes are drilled into the silicon wafer at these ports, providing locations that allow fluid to enter and exit the micromodel. The two parallel channels etched on the micromodels, thus, act as fractures adjacent to the porous medium.

A holder to mount the micromodels for unobstructed viewing under the microscope was specially designed. This aluminum (6061 T6) micromodel holder has conduits connected to the injection and production systems. It has four ports (one for each hole of the micromodel) that are sealed with viton O-rings. See Fig. 2.

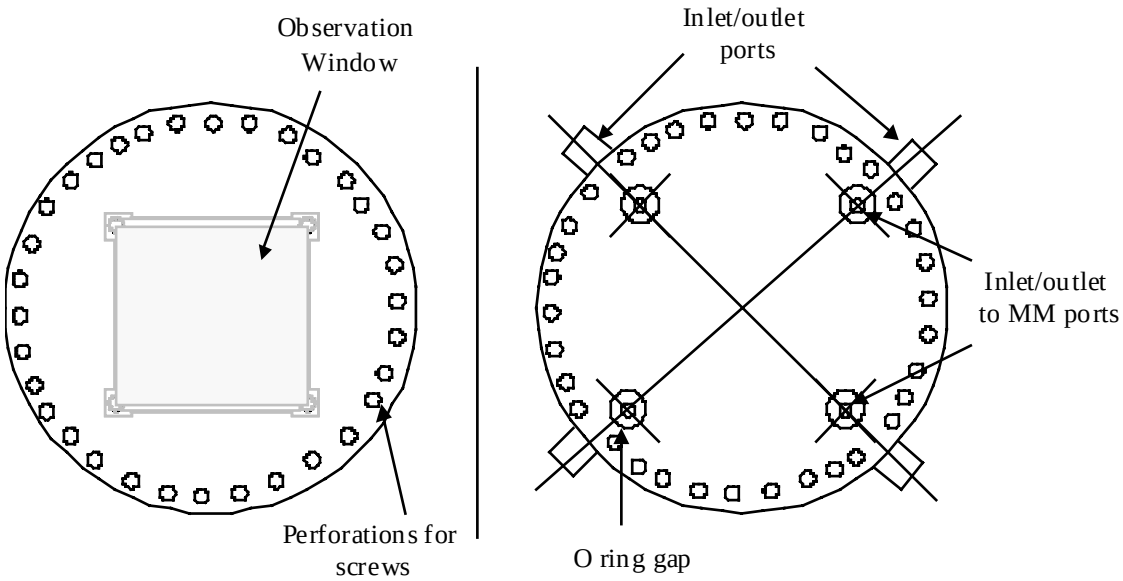

Figure 2. Schematic of the micromodel holder. Top and Bottom pieces.

Typical results within the filling fracture regime are shown in Figs. 3 and 4. This regime shows a variable length line source due to relatively slow water flow through fractures. Water advance is controlled by the interaction between the matrix and the fracture. Figure 3 shows a series of pictures obtained at early stages of the experiment focusing on the matrix-fracture interface close to the inlet. One can see that a fairly large amount of water imbibes into the matrix. Air is not trapped or by-passed by the water front to a sizeable extent, and no air moves counter-currently. Figure 4 shows images of the water advance in the matrix in the direction perpendicular to the fracture. The water front has advanced further on the left than it has done on the right. These observations lend support to the assumption of a linear superposition of one-dimensional solutions of the diffusion equation proposed in the analytical model of Rangel-German and Kovscek (2001). The filling-fracture regime is dominated by co-current imbibition as witnessed by little or no escape of air from the region upstream of the water front in the fracture (Fig. 3). Work in this area continues with oil as the nonwetting fluid.

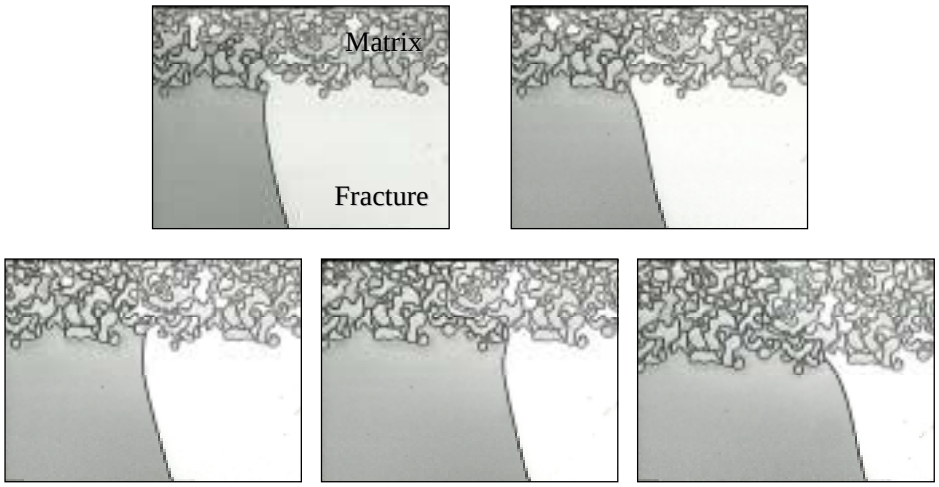

Figure 3. Micromodel images at fracture-matrix interface. Water is shaded darkly and nonwetting fluid is unshaded.

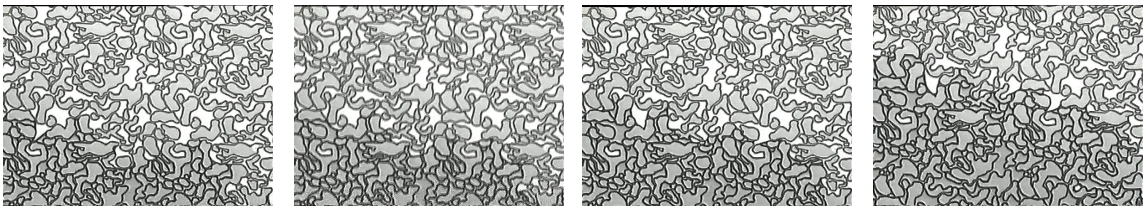

Figure 4. Water advance in the matrix in the direction perpendicular to the fracture. Water is shaded darkly and nonwetting fluid is unshaded.

Area 2. Hot Fluid Injection

Work in this project area progressed in two much different, but related, directions. First high-temperature, high-pressure experiments were conducted to understand thermal recovery mechanisms of heavy oil from relatively low permeability rocks. Second, a simulation study is underway to understand thermal production mechanisms of light and medium gravity crude oil during steam injection into diatomite.

Rationale and Summary--Experimental Study of Thermal Recovery. Oil production from many fractured reservoirs is frustrated by not only low matrix permeability but also large oil viscosity and a matrix wettability state that is not sufficiently water wet to favor water imbibition. Some diatomaceous reservoirs, especially those containing heavier crude oil, appear to exhibit these attributes. Thermal recovery using hydraulically fractured wells is one process to improve oil recovery and unlock these heavier resources. Steam injection is typically carried out under saturated conditions and initial heating of a reservoir is accompanied by significant condensation and flow of the resulting hot water away from the injector. Thus, hot-water imbibition is an important component of thermal recovery in fractured, low permeability porous media.

In this task, we are performing a series of spontaneous, counter-current water imbibition tests using outcrop diatomite cores (2 to 4 md) and reservoir diatomite cores (0.8 to 2 md). The experiments are isothermal and temperatures from 20 to 180 °C are explored. Decane, two white mineral oils with differing viscosities (35 and 407 vP), and heavy diatomite crude oil were all used as oil phases. At room temperature, oil-phase viscosities ranged from 0.9 to 6400 mPa-s. An X-ray computed tomography (CT) scanner, in combination with a high-temperature and high-pressure core holder, was used to visualize fluid movement and production of these oils. The apparatus is detailed in Fig. 5.

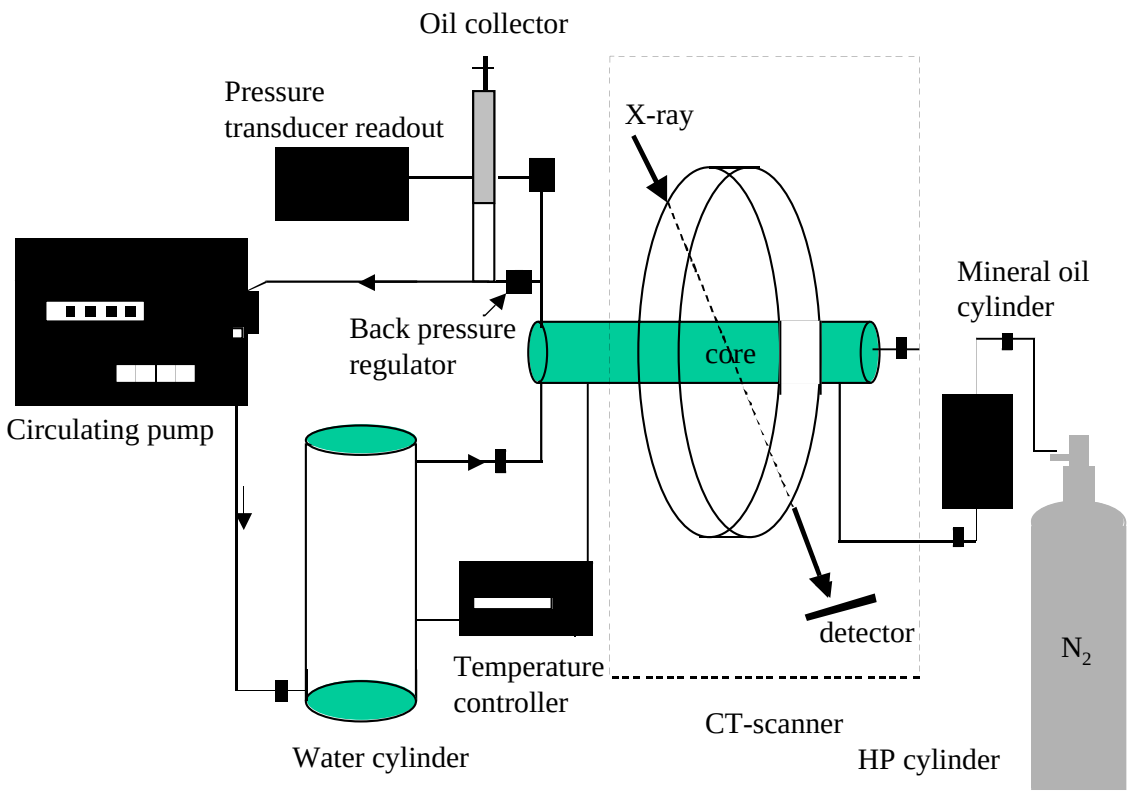

Figure 5. High-pressure, high-temperature experimental setup.

It is observed that temperature has a significant effect on water imbibition rate and residual oil saturation to spontaneous imbibition. In reservoir core filled with crude oil, the spontaneous oil recovery increased from 3% at 40 °C (reservoir temperature) to more than 40% of oil in place at 180 °C as shown in Fig. 6. The effect of temperature is to reduce oil-phase viscosity and increase water wetness of the rock. Finally, it is found that the experimental data for mineral oils can be nearly scaled according to dimensionless groups available in the literature. Inclusion of the mobility ratio as a function of temperature during scaling is necessary to collapse data.

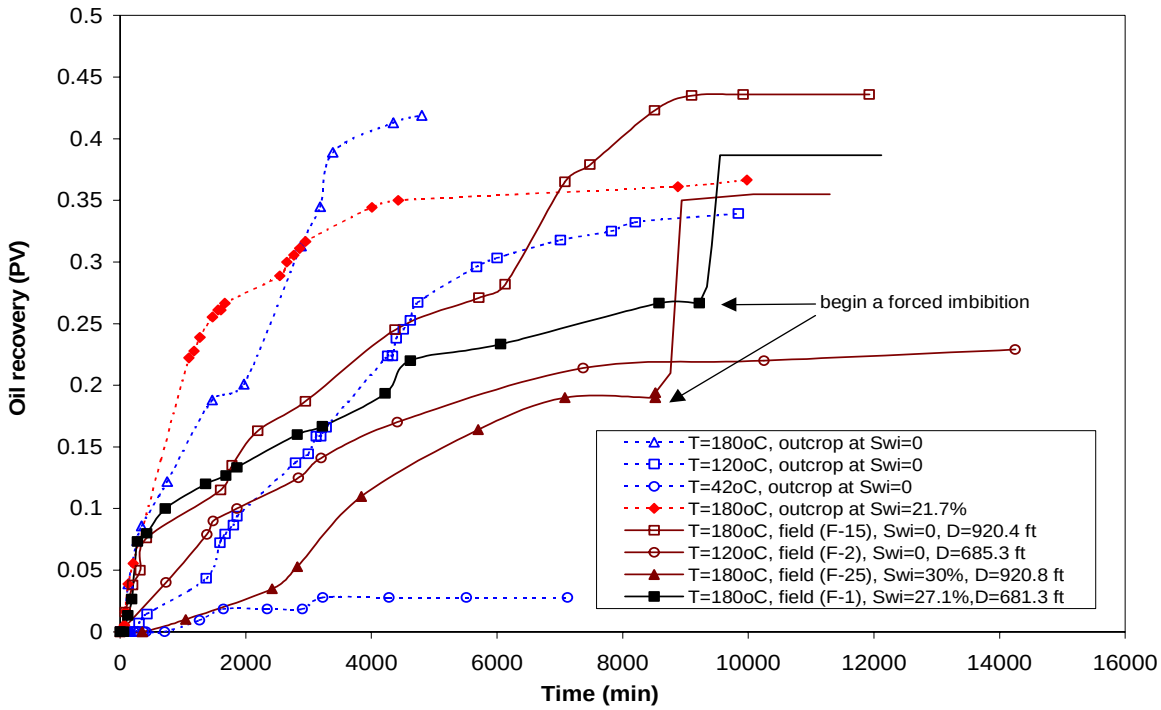

Figure 6. Spontaneous and forced oil recovery from field and outcrop diatomite cores as a function of temperature.

Rationale and Summary--Simulation Study of Thermal Recovery Mechanisms. Steam injection into heavy oils has been characterized very well over the last 40 years, and while steam has been injected into light oils almost as long, this process is much less understood. When this lack of understanding is coupled with the complexities of low permeability fractured reservoirs, even less is known. This study sheds some light onto the subject at hand through the use of thermal simulation. By studying the recovery mechanisms, this work shows that thermal expansion of the hydrocarbon fluids accounts for about two-thirds of the incremental recovery early in the steam drive; afterwards, the incremental recovery is equally split among thermal expansion, vaporization, and viscosity reduction. Three separate fluid banks form in this type of steam injection process: a cold water bank, a combined hot water and distillate bank, and the steam front. The combined bank is a complex mixture of hydrocarbon components and condensed steam. Since this work uses diatomite, which is known for its high porosity, as the fractured medium, the issue of steam front stability is also considered. Although both analytical and modeling information show that as porosity increases the stability of the steam front decreases, the actual results show a small variation between sandstone (25% porosity) and high porosity diatomite (70%) that is typified by a 10% increase in break through time. The significance of this work can easily be extended to include all low permeability fractured reservoirs that have low primary and waterflood recoveries. For appropriate reservoirs, significant additional recovery could be obtained by implementing a steam drive into a low permeability fractured reservoir that contains light or medium weight oils. A full description of this work will be included in our Annual Report for 2002.

Area 3. Mechanisms of Primary Heavy Oil Recovery

This project area is concerned with so-called foamy oil production. More correctly this process is characterized as heavy-oil solution gas drive. Gas released from solution during pressure depletion remains dispersed rather than uniting to form a single phase.

Rationale and Summary--Solution Gas Drive in Viscous Oils. Primary production in some heavy-oil reservoirs has been found to be higher than that estimated by conventional calculations. Conventionally, the main driving force behind primary recovery is pressure depletion through solution gas drive. Solution gas drive is the mechanism, whereby the lowering of reservoir pressure through production in an undersaturated reservoir will reach a point where gas starts to evolve from solution (bubble point pressure). Because gas is quite compressible, it acts as the primary driving force by keeping reservoir pressure high. The evolved gas does not begin to flow until the critical gas saturation has been reached. Once the critical gas saturation point is reached, there is an increase in rate of pressure drop due to the production of the gas-phase. It has been noted that the oil at the wellhead of these heavy-oil reservoirs resembles the form of foam, hence the term "foamy oil". A key to developing a mechanistic understanding of heavy-oil solution gas drive is to delineate bubble growth, interaction and gas flow. The objective of this work is to characterize experimentally fluid relative permeability with respect to flow rate and viscosity. This would further our understanding regarding fluid behavior during the solution gas drive mechanism of a heavy oil system.

The equipment is setup as in Fig. 7. The sandpack holder is 16 inches long, 2 inches in diameter, and has 11 pressure ports attached to it. A circular water jacket surrounds the sandpack holder thus allowing for experiments to be conducted at a specified temperature. The water jacket also helps to reduce X-ray diffraction. The pressure ports are connected using high pressure plastic tubing (EFTE) to a 12 port multiplexer (Scannivalve 12L8-175), that leads to a central pressure transducer (Scannivalve). This system is hooked up to a computer via the digital interface unit (Scannivalve) where automatic remote port measurements are recorded using a visual basic program. The position of the pressure ports is such that they do not interfere with axial CT scans of the sandpack. The CT scanner is a Picker 1200 SX X-ray scanner and will be used to scan the sandpack lengthwise. A video camera is positioned at the outlet to monitor instantaneous GOR as the effluent is produced out of the clear plastic tubing. A high pressure piston accumulator with holding capacity of 882 mL is used to combine the CO_2 with dead oil. An ISCO Model 500D syringe pump is used in conjunction with an accumulator. This accumulator is filled with water and is used at the outlet as an intermediary oil depletion device. This setup allows us to conduct constant volumetric depletion at a set rate. Experiments in this apparatus are ongoing. Further details will be given in subsequent reports.

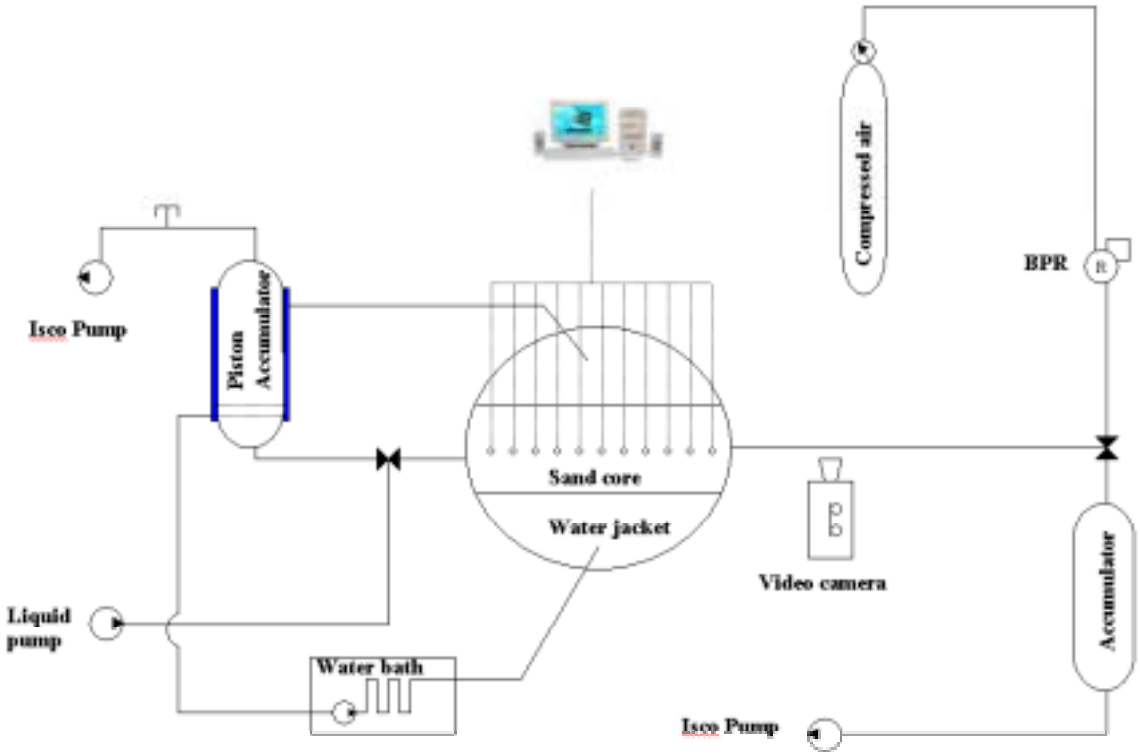

Figure 7. Apparatus for viscous-oil solution gas drive experiments.

Area 4. In-Situ Combustion

Two tasks are underway in this area. The first is the preparation of a Chapter for the Reservoir Engineering Section of the Petroleum Engineers Handbook detailing material and energy balance calculations that can be used to design an in-situ combustion field project. This chapter should appear in 2003. The second task regards the potential for in-situ upgrading during combustion.

Rationale and Summary--In-Situ Upgrading. Crude oil upgrading is of major economic importance. Heavy crude oils exist in large quantities in the western hemisphere but are difficult to produce and transport because of their high viscosity. Some crude oils contain compounds such as sulfur and/or heavy metals causing extra refining problems and costs. In-situ upgrading could be a beneficial process. For heavy oils, numerous field observations shown upgrading of 2 to 6 °API for heavy oils undergoing combustion (Ramey, 1992) . During in-situ combustion of heavy oils, temperatures of up to 700°C can be observed at the combustion front. This is sufficient to promote some upgrading. This task examine the changes caused by the various reactions occurring during combustion with emphasis on the upgrading potential for various oil types. Secondly, combustion-tube runs aimed at sulfur removal are conducted.

Sulfur can be a major problem for refiners. To investigate the possible use of in-situ combustion to improve sulfur content of produced oil three combustion tube runs were performed using a matrix made of 95% Ottawa sand and 5% fire clay. All three runs were made using a crude oil containing 6% by weight sulfur. In the runs, oil saturation was about 20% and water saturation about 20%. The oil, water and matrix were premixed and packed in the combustion tube. The

first run was a simple dry forward combustion run. As the combustion was not good, we decided to use metallic additives. The second run was made using a solution of 5% by weight of stannous chloride in the water to increase the amount of fuel deposited. The third run contained 5% iron nitrate in the water. Further details after the data is fully analyzed will be presented in future Quarterly and Annual Reports.

Area 5. Reservoir Definition.

Reservoir definition is the process of using data from a variety of length scales (pore-core-reservoir) and sources (laboratory-field) to improve our understanding of reservoirs and their petrophysical properties. Work during the past quarter focused on developing a technique that integrates production history into reservoir models using streamline-based properties.

Rationale and Summary--Streamline-Based Time-of-Flight Ranking. The reservoir models generated by geostatistical techniques provide equally probable reservoir descriptions that honor observed geology. However, flow simulation results on these models may vary widely indicating uncertainty. Constraining geostatistical models to known production history reduces uncertainty. To this end, a streamline-based algorithm for ranking geostatistical realizations with regard to production history is proposed. First, a rapid, streamline-based inversion method is applied to obtain a history-matched reservoir model. Then, unit mobility ratio streamline geometries are computed, without full flow simulation, for the history-matched model and the geostatistical models considered. Each model is then compared to the history-matched model with regard to streamline properties, such as time-of-flight. In this way, a reservoir model that matches production history and honors known geological information is obtained. This approach is computationally efficient because the use of full flow simulation is minimized.

A simple example illustrates the utility of the method. We concentrate on heterogeneity in the permeability field. Five hundred reservoir models are generated along with a reference field by the geostatistical routine SGSIM (Deutsch and Journel, 1998). Computational cost of this step is minimal. The reference field is excluded from the 500 samples. Permeability in all the models is isotropic. The simulator, 3DSL (Batycky *et al.*, 1997), is used for forward simulation and evaluation of unit mobility streamline geometries. Note that any reservoir simulator might be used here. The choice of 3DSL is based on its rapid execution times and availability. Mobility ratio is unity and applicability to unfavorable displacements is under way.

First, the reference production history is obtained by running full flow simulation on the reference reservoir model (Fig. 8a). This model is not available in practice and here is used only to obtain production data. The well pattern is a five spot with an injector in the center and a producer in each corner of the permeability field. Then starting from another initial model generated by SGSIM, a streamline-based history matching method is used to generate a history-matched model (Wang and Kovscek 2000). No geological constraints are applied while history matching. Figure 8 shows the reference reservoir model and the history-matched model as expressed by permeability distributions. Figure 9 shows the match of the fractional-flow at all four producers obtained in six iterations. Other terms, i.e. pressure and flow-rate are also well matched. Obviously, the match to the production history is excellent, but the history-matched model does not honor the geology as expressed by the permeability distribution.

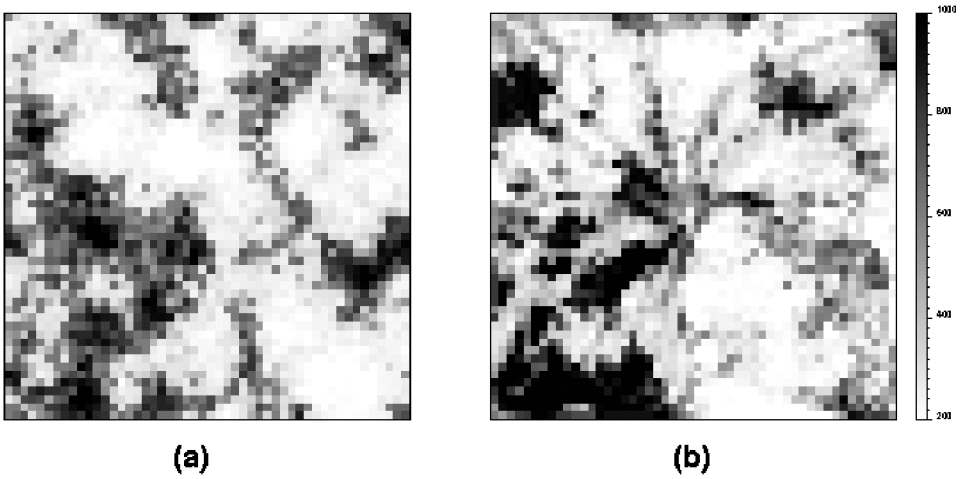

Figure 8. Unit mobility ratio example. (a) reference permeability field and (b) unconstrained history-matched permeability field.

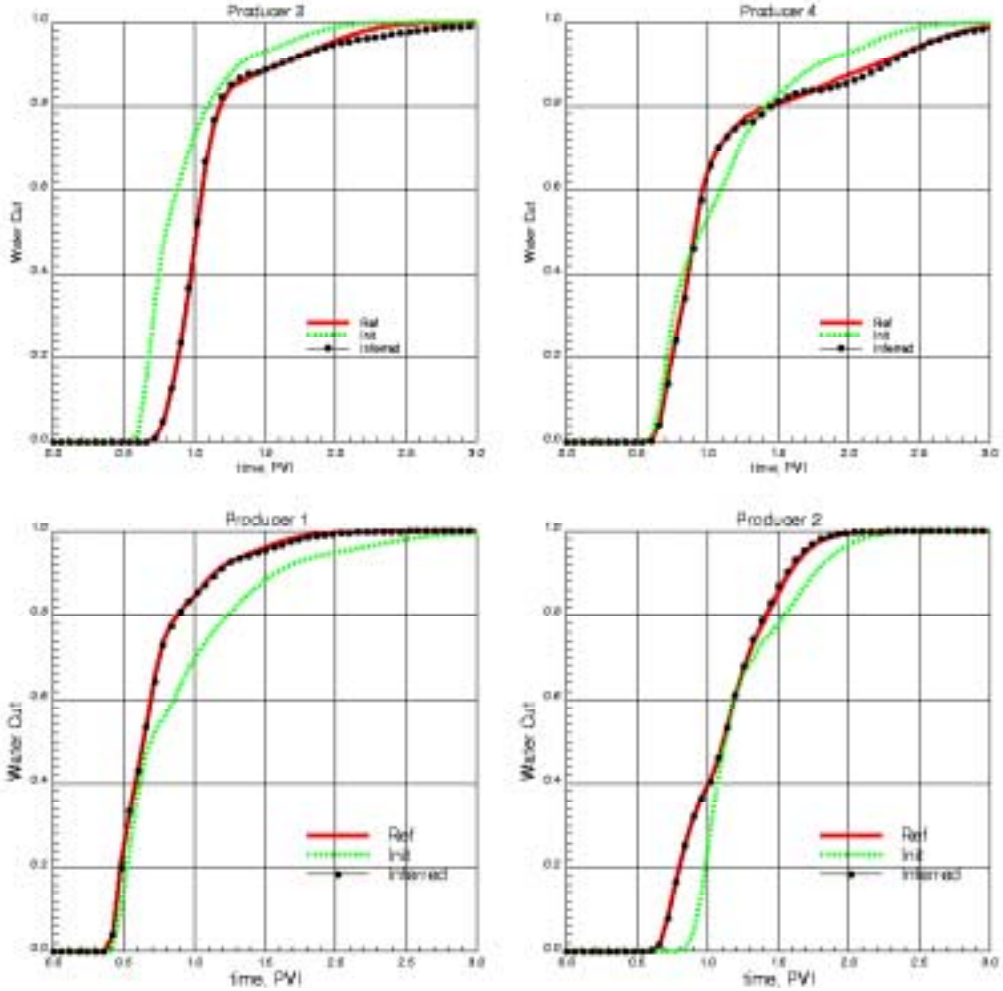

Figure 9. History-matched water-cut at the producers of a five-spot pattern, unit mobility ratio example.

The difference in production response of each geostatistical model with respect to the history-matched model is computed. Here, 500 such models are evaluated. For unit mobility ratio, the match in fractional-flow is most difficult and important. After ranking, full flow simulation was conducted on the five best-matched models. Figure 10 shows these fractional-flow curves and the reference fractional-flow curve. The match is satisfactory.

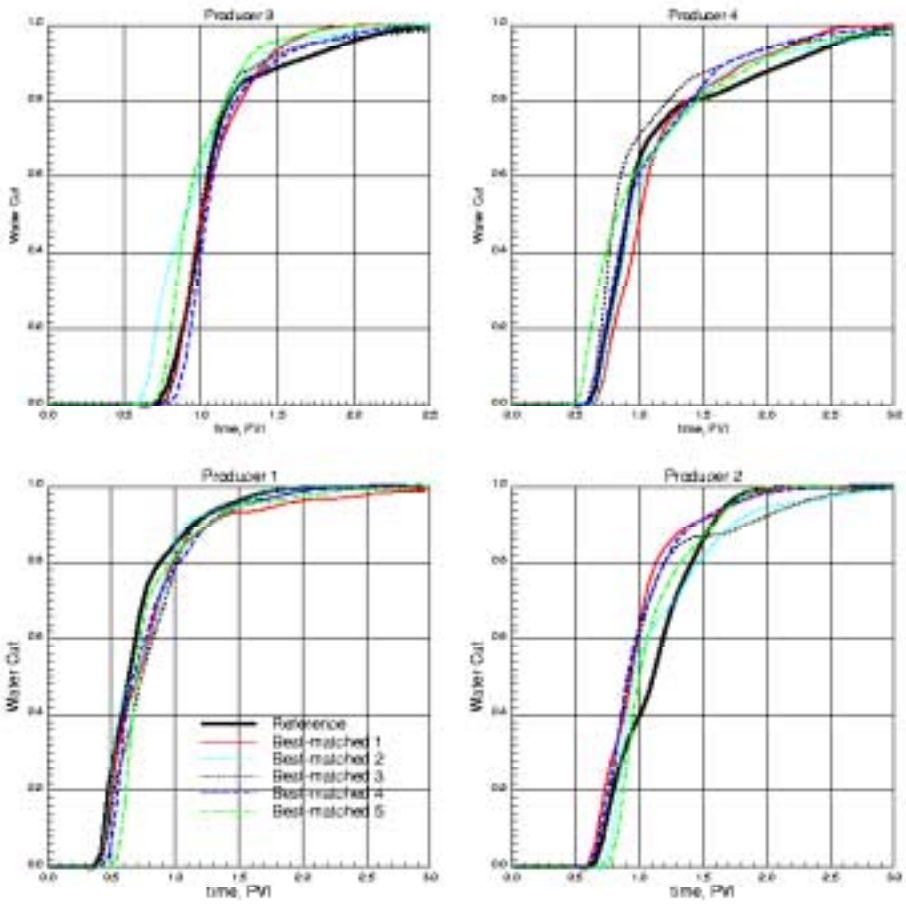

Figure 10. Water-cut history of reference model and selected best-match permeability fields.

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