Heavy and Thermal Oil Recovery Production Mechanisms

Quarterly Technical Progress Report
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Abstract

This technical progress report describes work performed from January 1 through March 31, 2003 for the project "Heavy and Thermal Oil Recovery Production Mechanisms," DE-FC26-00BC15311. In this project, a broad spectrum of research is undertaken related to thermal and heavy-oil recovery. The research tools and techniques span from pore-level imaging of multiphase fluid flow to definition of reservoir-scale features through streamline-based history-matching techniques.

During this period, previous analysis of experimental data regarding multidimensional imbibition to obtain shape factors appropriate for dual-porosity simulation was verified by comparison among analytic, dual-porosity simulation, and fine-grid simulation. We continued to study the mechanisms by which oil is produced from fractured porous media at high pressure and high temperature. Temperature has a beneficial effect on recovery and reduces residual oil saturation. A new experiment was conducted on diatomite core. Significantly, we show that elevated temperature induces fines release in sandstone cores and this behavior may be linked to wettability. Our work in the area of primary production of heavy oil continues with field cores and crude oil. On the topic of reservoir definition, work continued on developing techniques that integrate production history into reservoir models using streamline-based 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.
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 in-situ 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 described briefly.

Experimental

Experimental studies are conducted in Areas 1 to 4. The apparatus and techniques employed within each area are described in the summaries below.

Results and Discussion

A full spectrum of research in heavy and thermal oil recovery mechanisms is underway. Results obtained and related discussion are given in the subsection "Rationale and Summary" in each topic area.

Area 1. Multiphase Flow and Rock Properties

Work in this area focused on numerical validation of an interpretation of previous experimental work that imaged the water imbibition in an idealized, fractured matrix block (Rangel-German and Kovscek, 2001, 2002). A new apparatus incorporating multiple matrix blocks was also assembled in preparation for experiments to probe matrix-fracture transfer in multiple-block systems.

Rationale and Summary–Shape Factors for Dual-Porosity Simulation. Fractured systems are usually modeled by means of a dual-porosity or dual permeability formulation. The rate of mass transfer between the rock matrix and fractures is significant, and calculation of this rate, within dual-continuum models, depends on matrix-fracture transfer functions incorporating the shape factor. Generally, constant, time-independent shape factors are used to describe matrix-fracture transfer. Rangel-German and Kovscek (2002) investigated the rate of fracture to matrix transfer and the pattern of wetting fluid imbibition as a function of the rate of water propagation in a fracture. Detailed and accurate measurements were made of the extent and rate of imbibition in an idealized fracture and matrix block. Two different modes of matrix and fracture fill-up were found. Relatively slow flow through fractures is found when fracture to matrix fluid transfer is rapid, fracture aperture is wide, and/or water injection is slow. In this regime, fractures fill slowly with fluid and the regime is referred to as a "filling fracture." The recovery scales linearly with time. On the other hand, relatively low rates of fracture to matrix transfer, narrow apertures, and/or high water injection rates lead to rapid flow through fractures. This regime is labeled "instantly filled", and recovery scales with the square-root of time. These results show clearly that shape factors may vary with time and that recovery predictions based on constant shape factors may be pessimistic.

In our Quarterly report for the period, October 1 to December 31, 2003, we asserted that dimensional analysis taught that the shape factor, s, is expressed as

$$\sigma(t) = \frac{A(t)}{Vl^*(t)} \tag{1}$$

where $A(t)$ is the area of the matrix block contacted by water, V is the bulk volume of the rock matrix block and l^* is the distance between the saturation at the fracture and the matrix average saturation, $\overline{S_w}$. For a steady-state problem, it is clear that l^* is the half distance between the fractures (i.e. half-length of the matrix block). However, for unsteady state behavior such as early-time filled-fracture or during the filling-fracture regime, the behavior of l^* is variable. It is obtained as the integral of the average saturation in the matrix times a characteristic distance to the centroid of the domain. The characteristic distance, l^*, for one set of orthogonal fractures is

$$l^*(t) = \frac{\int_0^L S_w(x,t)dx}{\overline{S}_{wm}(t)} \tag{2}$$

where $\overline{S}_{wm}$ is the average water saturation in the matrix block. The shape factors found from the experimental data are expressed as

$$\sigma = \sigma^* \left(\frac{t_D}{t_D^*}\right)^{-m} \text{for} \quad t_D < t_D^* \tag{3}$$

and

$$\sigma = \sigma^* \qquad \text{for} \quad t_D \geq t_D^* \tag{4}$$

where

$$t_D = \frac{\alpha_h t}{L_x^2} \tag{5}$$

The exponent m is a function of flow rate and aperture and t^*_D is 0.1. This formulation converges to the classical constant σ (Kazemi *et al.*, 1976), and also has a time varying portion for t_D less than t_D^*.

A validation exercise of the proposed shape factor was performed. Experimental data was compared versus a dual-porosity simulation modified for the shape factors above, analytical model, and fine-grid numerical simulation. Good agreement was found as illustrated in Fig. 1.

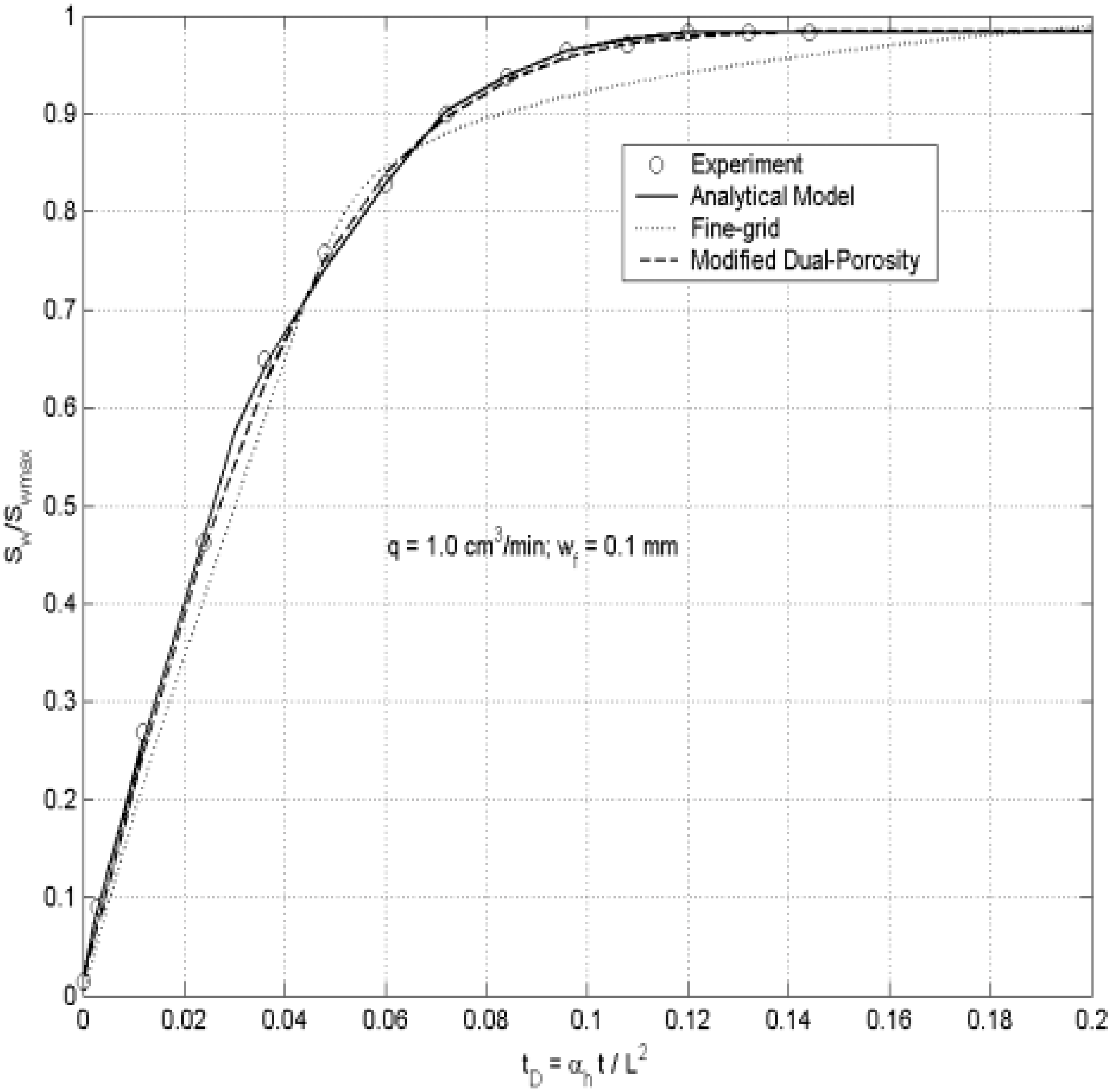

Figure. 1. Comparison of average water saturation versus time among experimental results and various models.

Rationale and Summary–Imbibition in Multiple Matrix Blocks. Prior research related to capillary imbibition in fractured porous media is mostly limited to experiments with fractures that are external to the core, imbibition in one dimension, non-intersecting fractures, or numerical studies that utilize those experimental results or use purely analytical methods. While dual-continuum formulations have been shown to be useful and valid for use in modeling of fractured reservoirs (Kazemi *et al* 1992, Beckner *et al* 1987, Rangel-German 2002, Lim and Aziz 1995), the accuracy of such models may be improved by more realistically representing matrix flow, fracture flow, and matrix-to-fracture fluid transfer. Transfer function formulations incorporating shape factors, for unsteady and steady state conditions, have been developed from simple cubic or cylindrical matrix/fracture models (Kazemi *et al* 1992, Beckner *et al* 1987, Rangel-German 2002), but further validation using more geometrically complex models is needed. Better understanding of the physical processes of imbibition, multiphase matrix and fracture flow, and matrix-fracture interactions will lead to more accurate models when using dual-continuum models.

To improve understanding of the physical processes of imbibition, viscous effects, and buoyancy effects in fractured porous media, a core-scale lab experiment was designed to allow direct observation and characterization of transient saturation and flow in fractured sandstone, Fig 2. Computerized tomography imaging will be employed to measure saturation distributions as well as rock properties in a 4.5 inch diameter core with two perpendicular artificial fractures. The applicability and robustness of published mass transfer imbibition formulations will be tested against new experimental results. The apparatus is fully constructed and experiments will commence in the coming quarter.

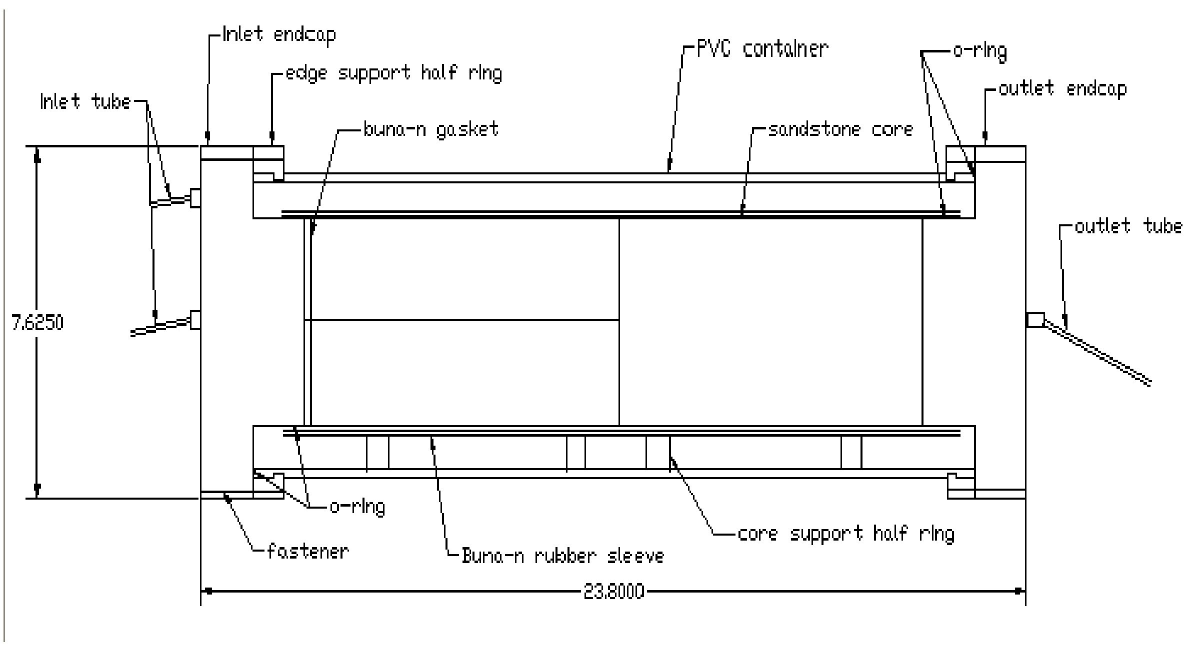

Figure 2. Cross-section of the coreholder for studying imbibition in multiple matrix blocks.

Area 2. Hot Fluid Injection

Work in this project area continued toward the formulation of a mechanism for a shift toward water wetness measured during previously reported high-pressure, high-temperature imbibition experiments in low permeability rocks. We are formulating a colloidal theory to explain the release of fine particles from porous media at elevated temperature. New high-temperature imbibition experiments were also conducted in reservoir core with crude oil.

Rationale and Summary--Experimental Study of Thermal Recovery. We began a set of spontaneous imbibition tests on field core from a diatomite reservoir. These new experiments broaden our range of study to medium gravity crude oils in low permeability matrix material. To date, experiments in a single core at 45, 120, and 180 °C have been conducted. As expected, spontaneous recovery increases with temperature. More complete reporting will be made once several tests have been completed.

Rationale and Summary– Fines Release at Elevated Temperature. Oil production from many fractured reservoirs is frustrated by low matrix permeability, large oil viscosity, and a matrix wettability state that is not sufficiently water wet to favor water imbibition. Thermal recovery using hydraulically fractured wells is one process to improve oil recovery and unlock these heavier resources. Steam injection is accompanied by significant condensation and flow of the resulting hot water away from the injector. Thus, hot-water imbibition is a fundamental component of thermal recovery in fractured, low permeability porous media.

High-temperature counter-current imbibition experiments documented in reports for the period January 1 through March 31 2002 and April 1 through June 30, 2002 Experiments were isothermal and temperatures ranged from 20 to 180 °C. Spontaneous recovery increased significantly with temperature due to increased water wetness of the rock. A mechanism for increase in water wetness with temperature is fines detachment from rock surfaces. Oil-wet rock surfaces and mixed wettability result when polar, asphaltenic components of crude oil adhere to reservoir solids in a fashion perhaps similar to that suggested by Kovscek et al (1993). An increase in temperature may destabilize fines attached to rock surfaces. Fresh, water-wet rock surfaces are exposed upon fines release. This results in an increase in water wetness for the entire core.

We have been studying the role of temperature on colloidal attractive forces. We applied DLVO (Derjaguin, Landau, Vervay, and Overbeek) theory to compute the attractive forces between a clay colloid particle and silica surfaces. The analysis assumes that a single phase wetting fluid is in contact with the pore surface and fines. A fine attached to a pore wall is modeled as a sphere attached to a flat surface (sphere-plate system) Both kaolinite and illite clays demonstrate temperature sensitivity in the range of salinity and pH characteristic of steam condensates.

An experimental program was designed to corroborate the theoretical calculations. They are designed to accomplish the following objectives: (a) validate the hypothesis that temperature can be crucial in fines release. (b) Map the conditions under which drastic change is initiated and sensitivity of the conditions to the temperature. The rock samples are Berea sandstone and the apparatus is illustrated in Fig. 3. The cores are subjected to single-phase corefloods at different conditions. Changes in permeability are observed by measuring the pressure drop across the core.

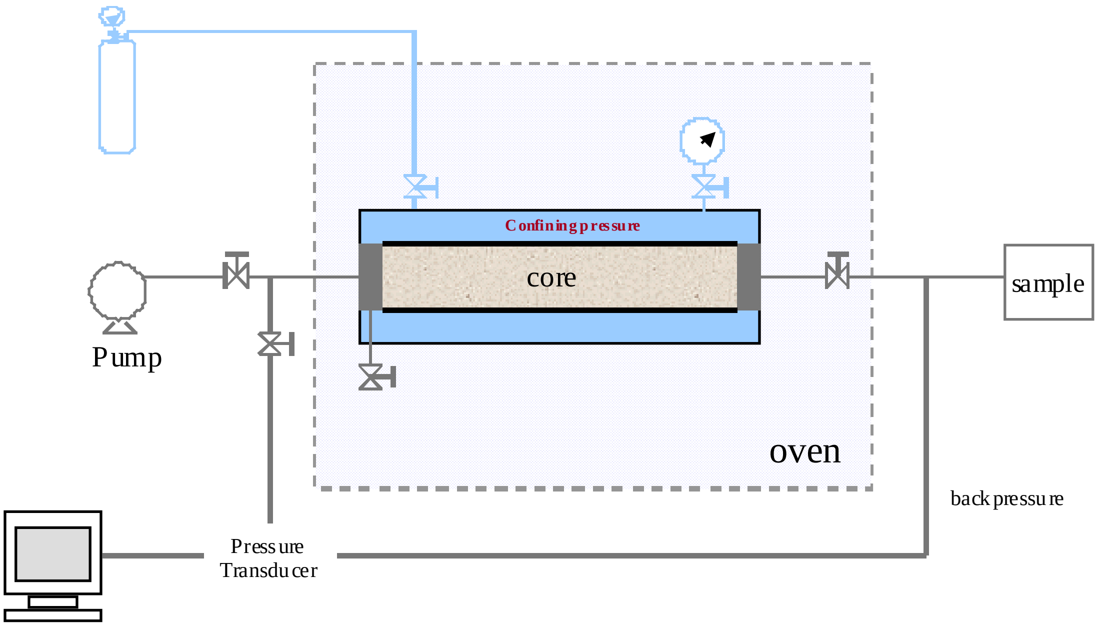

Figure 3. Schematic of the experimental setup used in the corefloods.

Experiments are performed at a variety of temperatures under isothermal conditions. Fines migration is quantified by collecting effluent samples from experiments. Results obtained to date are summarized in Fig. 4 that shows the change in permeability as the temperature is increased. Closed symbols indicate that fines are found in the produced liquid. All experiments illustrate sensitivity of permeability to the flood temperature. This is consistent with the existence of swelling smectite clays. Importantly, fines production is witnessed at temperatures predicted by DLVO theory.

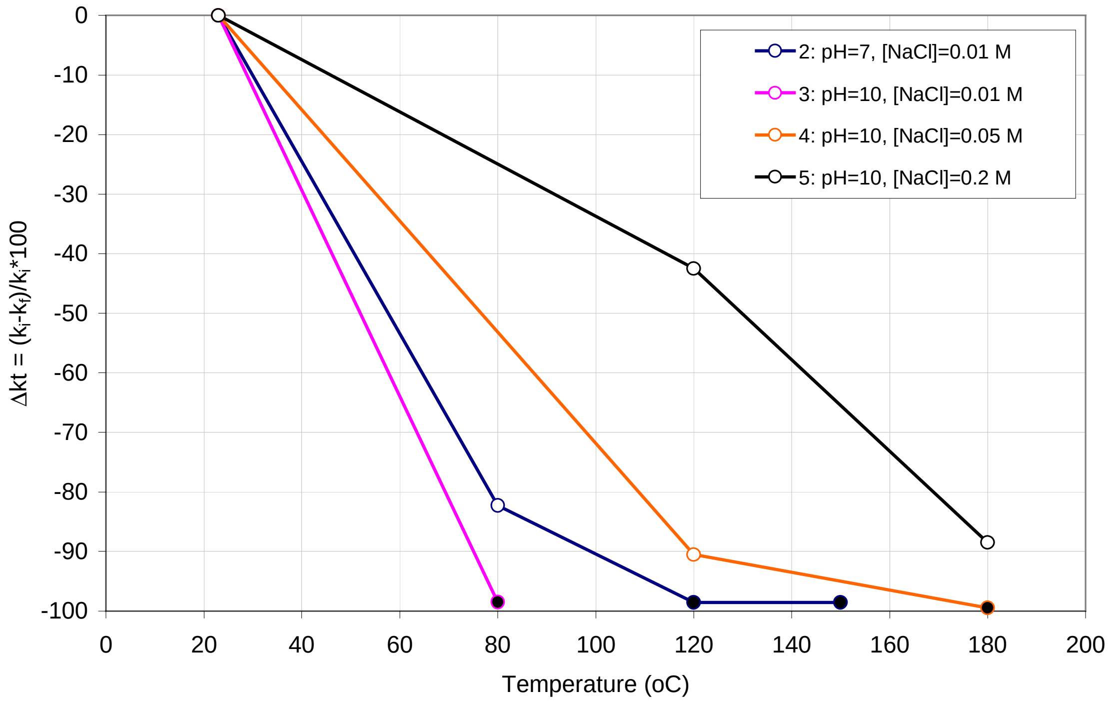

Figure 4. Summary of results for fines-mobilization experiments. : Permeability variation as a function of temperature. Open symbol: no-fines produced, closed symbol; fines produced.

Elemental chromatography using a scanning electron microscope (SEM) confirmed the existence of aluminum and silica in the filtrate from core effluent. SEM images obtained in back-scatter mode are sensitive to the density of material. SEM images showed numerous particles of 1 to 2 μm diameter in the effluent filtrate. In combination, these observations indicate that the fine particles produced as temperature increased are clays.

Future experiments will assure repeatability of these measurements. Additionally, fired cores will be employed at a variety of temperature, salinity, and pH. Firing oxidizes the clays making them inert. These experiments should illustrate no sensitive of permeability or fines production to temperature.

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. Primary production in some heavy-oil reservoirs is larger than that estimated by conventional calculations. The dispersed nature of the gas appears to enhance primary recovery relative to systems where the gas-phase unites easily forming a continuous phase.

Rationale and Summary--Solution Gas Drive in Viscous Oils. Previously, we reported pressure-depletion experiments conducted with white oils. We have expanded our range of investigation to sandpacks saturated with representative live crude oil. Crude oil is recombined with methane based on PVT data at reservoir conditions. Oil gravity is 12 °API and viscosity is 258 cP at 80 °C. Solution gas oil ratio (GOR) is around 20 vol/vol at standard conditions. Sandpacks are prepared using clean Ottawa sands with grain size that ranges from 75 to 150 μm.

The sand was packed in a specially designed aluminum coreholder that incorporates 11 pressure taps along the core axially (Akin and Kovscek, 2002). A circular water jacket surrounds the coreholder lengthwise as indicated in Fig. 5. The water jacket reduces X-ray artifacts arising from the unconventional scanning geometry and allows experiments to be conducted at a specific temperature. The coreholder with water jacket sits inside the gantry of the CT-scanner. The scanning plane is indicated in Fig. 5. Sandpacks are scanned lengthwise. A heating-circulating water bath controlled the temperature of the water in the water jacket.

Figure 6 shows the evolution of the gas phase as a function of pressure. White shading denotes gas whereas black shading indicates oil. Gas appears around the bubble point of 1200 psi. As time progresses, more gas appears. Interestingly, the images demonstrate little formation of a continuous gas phase within the volume of the pack scanned. It appears that the gas phase remains dispersed as gas bubbles for most of the duration of the experiment. This is in contrast to our earlier work with white mineral oils where the formation of continuous gas within megascopic portions of the porous media was witnessed.

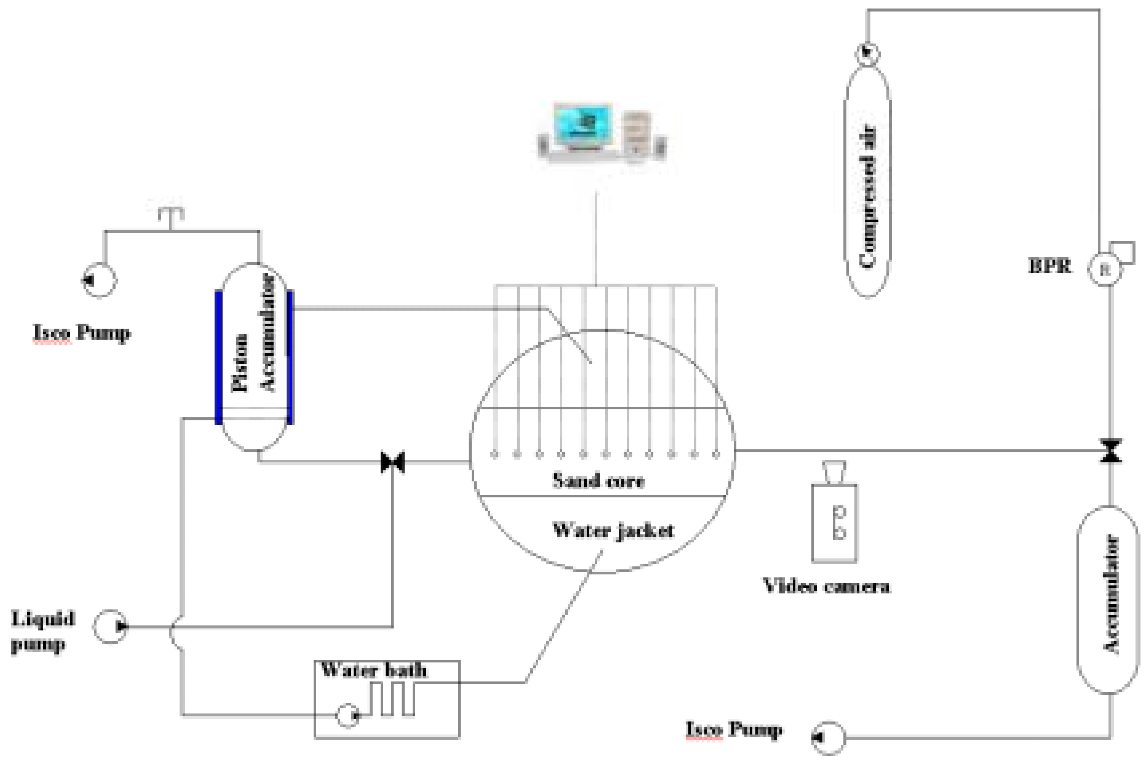

Figure 5. Apparatus for viscous-oil solution gas drive experiments.

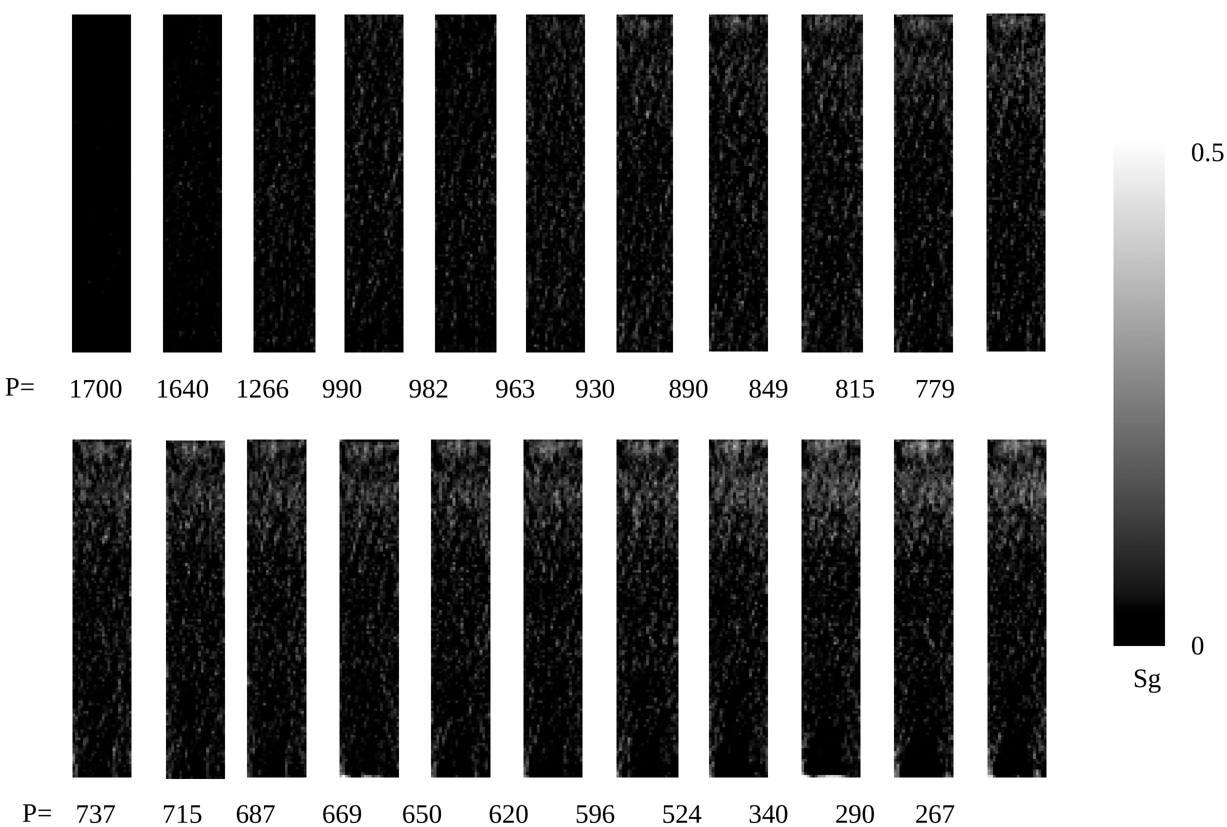

Figure 6. Gas evolution versus pressure for Test 5: HO-1.

Area 4. In-Situ Combustion

Steam injection is not suitable for all types of reservoirs. Steam injection candidates must be relatively shallow and thick to prevent, for instance, excessive heat losses. In contrast, in situ combustion makes use of air to manipulate burning in place. It takes advantage of the sensitivity of heavy oil viscosity to temperature to improve the mobility of oil. In situ combustion (ISC) is accomplished by burning a part of oil during which heat and steam are generated that bring about a series of reactions on crude oil. These include thermal viscosity reduction, thermal cracking, catalytic cracking, gas and water displacement, and distillation.

The factors that determine combustion performance have been always among researchers' highest interest. Among the possible means to improve combustion performance are chemical additives such as metallic salts. These appear to enhance in-situ upgrading and the reduction of sulfur content of the oil.

Rationale and Summary—Metallic Additives to Alter ISC Performance. A study was designed and begun to investigate the effect of different metallic additives on combustion of several oils. Especially, we seek to understand if additives can be transported a significant distance while remaining effective. Also the joint effects of metallic additives and clay are under investigation. In the experiments, temperature profiles were measured, effluent gas analyzed, produced liquid tested, and the burned sand checked.

The experiment apparatus was composed of a combustion tube or cell, gas analyzer, and data logging system. Oxygen and nitrogen were provided by gas cylinder and metered using a mass flow controller. The gas analyzer was on line recording effluent gas concentration every minute on a computer. Temperatures were read every centimeter along the inside of the tube during the combustion tube run, while in the kinetic cell run, temperatures were measured all the time during experiment. One tube run and several kinetic cell runs were completed.

In the combustion tube, the first one third was packed with a mixture of sand, clay, oil, and water, but no metallic additive. The lower two-thirds were packed similar with the exception that 1 wt% $SnCl_2$ was added to the aqueous phase. The front position and temperature versus time are plotted in Figure 7. The relation between front position and time is linear until 300 minutes. The front moves at a constant velocity of about 0.14cm/sec up to this time. The front temperature and velocity drops at about 200 minutes, corresponding to the position of 40 cm from the inlet on the position versus time curve. This is roughly where metallic additives begin. The reduction in front velocity is consistent with the deposition of extra fuel resulting from the additives.

The API gravity of initial and produced oil was measured. Oil was isolated from the vials after being centrifuged. API gravity of the produced oil is 20.6°, a significant increase compared to 15.8° of the initial oil. This upgrading is due to distillation and thermal cracking. Also, the heavy fraction was deposited on the sand as fuel, leaving a large fraction of light ends in the produced oil. Altogether 190 ml of oil and 280 ml of water were produced representing, respectively, 27% and 80% of their original content. Some water production is, of course, a result of combustion.

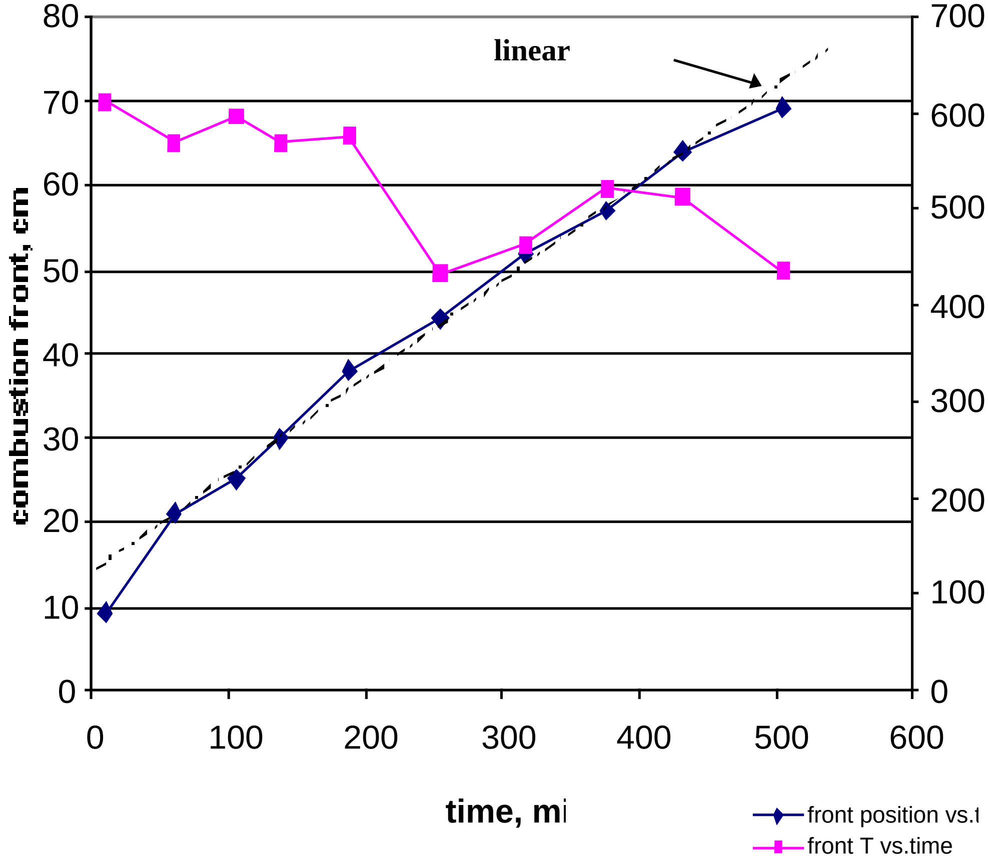

Figure 7. Front position and temperature versus time for combustion tube runs.

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. Perturbing the characteristics of a permeability field while history matching can result in a loss of geological consistency. Measured data may not be respected or histogram trends violated. It would be ideal to have a method of that preserves geological consistency while perturbing a permeability field. We are proposing a method to perturb a permeability field in such a way that it achieves a better match with history while staying fully consistent with known geology. This technique is called multi-zone gradual deformation.

Multi-zone gradual deformation is a technique that uses streamline simulations combined with a geostatistical simulation algorithm. Corrections are computed using streamlines, and new fields accounting for corrections are generated using sequential Gaussian simulation. Work during the past quarter has focused on applying the method to realistic appearing, 3D synthetic reservoirs to to robustness and accuracy.

Conclusions

1. Constant, time-independent shape factors for dual-porosity simulation do not describe well the physics of imbibition in fractured porous media. A new formulation is proposed; however, further experiments and interpretation of the results are required to develop a general, extensible understanding of imbibition.

2. Temperature has a profound effect on the wettability of porous media. A mechanism for wettability shift is the mobilization of fines as temperature increases. Fines mobilization creates clean, water wet surfaces where fines detach from pore walls.

3. Solution gas drive is an effective primary recovery technique for some heavy oils. Experiments monitored with x-ray CT show that the coalescence of gas bubbles into a continuous gas phase occurs relatively slowly when recovery is appreciable.

4. The properties of streamlines are well suited to the process of reservoir definition. The geostatistical technique of multi-zone gradual definition combines well with streamline simulation for reservoir definition.

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