Heavy and Thermal Oil Recovery Production Mechanisms

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Abstract

This technical progress report describes work performed from October 1 through December 31, 2002 , for the project "Heavy and Thermal Oil Recovery Production Mechanisms." In this project, a broad spectrum of research is undertaken related to thermal and heavy-oil recovery. 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.

During this period, experimental data regarding multidimensional imbibition was analyzed to obtain shape factors appropriate for dual-porosity simulation. It is shown that the usual assumption of constant, time-independent shape factors is incorrect. In other work, we continued to study the mechanisms by which oil is produced from fractured media at high pressure and high temperature. High temperature significantly increased the apparent wettability and affected water relative permeability of cores used in previous experiments. A phenomenological and mechanistic cause for this behavior is sought. 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 now described briefly.

Area 1. Multiphase Flow and Rock Properties

Work in this area focused primarily on interpretation of previous experimental work that imaged water imbibition in an idealized, fractured matrix block (Rangel-German and Kovscek, 2001, 2002).

Rationale and Summary—Shape Factors for Dual-Porosity Simulation. Modeling multiphase flow in fractured porous media relies on the accurate description of matrix to fracture transfer of water. 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. Typically, matrix-to-fracture transfer functions are obtained by assuming all fractures to be instantaneously immersed in water (instantly-filled), with a uniform fracture pressure distribution under pseudo-steady state conditions. The result is constant, time-independent, shape factors. Clearly, this is not necessarily true. Partially immersed fractures and other unsteady-state conditions do not lead to constant shape factors. In order to

simulate accurately multiphase flow in fractured porous media, it is necessary to obtain expressions that account for realistic boundary conditions (partially covered or totally immersed boundaries), as a function of parameters that can be obtained either in the laboratory or the field with high certainty. The following sections describe the transfer functions derived for a fractured system. Both filling- and instantly-filled fractures under unsteady state conditions are considered.

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. Experimental equipment was constructed to allow detailed and accurate measurement 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 rate injection is low. 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.

Due to the variable-extent of the imbibing area in the filling-fracture regime, it cannot be approached in as straight-forward a fashion as the instantly-filled fracture regime. To obtain a characteristic, dimensionless solution, a dimensional analysis was performed. It has two objectives: (i) to obtain a better understanding of the definition of shape factor within the dual porosity/dual permeability formulation, and (ii) provide a general shape factor for any kind of geometry, shape and regime that can be applied to current commercial numerical simulators without major corrections. Let τ_{wmf} be the matrix fracture mass transfer for a capillary-dominated transfer:

$$\tau_{wmf} = \sigma V \left[\alpha_h \Delta S_{wm} - \gamma_{wm} \left(\frac{Kk_{rw}}{\mu_w B} \right)_{mf} \Delta D_m \right] \quad (1)$$

where σ is the shape factor, V is the bulk volume of the rock matrix block, α_h is the hydraulic diffusivity, γ_{wm} is the acceleration due to gravity, Kk_{rw} is the effective permeability to water, μ_w is water viscosity, and B is the formation volume factor.

The definition of the transfer function in Eq. 1 is a Darcy's law type equation applied to a characteristic distance between the matrix block and the fracture. Dimensional analysis teaches that the proportionality constant, σ (shape factor), can be expressed as

$$\sigma(t) = \frac{A(t)}{V l^*(t)} \quad (2)$$

where $A(t)$ is the area of the matrix block contacted by water, and l^* is the distance between the saturation at the fracture and the matrix average saturation, $\overline{S_w}$. Thus, the transfer function proposed is

$$\tau = V \alpha_h \sigma (S_{w \max} - \overline{S_w}) \quad (3)$$

with the shape factor, σ , calculated using Eq. 2. This makes implementation in dual-porosity simulators relatively straightforward. An analytical model was also developed to describe the water advance in a single fracture in the presence of capillary imbibition into adjacent matrix blocks (Rangel-German and Kovscek, 2002). This equation was obtained by coupling the matrix and fracture implicitly, and it is used here to derive or estimate the transfer functions. It is important to mention that Eq. 2 is a general expression as it is derived from the dimensional definition of shape factor; thus, $A(t)$ can be obtained from any given model of imbibition.

The only term missing to compute the shape factor in Eq. 2 is the distance between the water saturation at the fracture and the matrix average water saturation, l^* . 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 not obvious. In this work, a simple analytical method to obtain l^* is proposed. The integral of the saturation distribution over the entire domain (n-D, if needed) is equal to 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

$$l^*(t) = \frac{\int_0^L x S_w(x, t) dx}{S_{wm}(t)} \quad (4)$$

thus, l^* depends on the shape of the matrix block. From experimental results obtained with CT scanning, the characteristic length, l^* , is computable for every CT image. That is, every CT image (corresponding to a single time) of every experiment is translated into a bitmap file containing the water saturation value at each pixel. The integral of Eq. 4 is calculated numerically. Then, one computes the average water saturation in the matrix. Thus, Eq. 4 is evaluated for every single CT image. The experimental data indicate that the dimensionless time at which the new shape factor converges to a constant value is approximately, $t_D^* = 0.1$ as shown in Fig. 1. In general, the new shape factor is written as:

$$\sigma = \sigma^* \left(\frac{t_D}{t_D^*} \right)^{-m} \quad \text{for } t_D < t_D^* \quad (5)$$

and

$$\sigma = \sigma^* \quad \text{for } t_D \geq t_D^* \quad (6)$$

where

$$t_D = \frac{\alpha_h t}{L_x^2} \quad (7)$$

and m is a function of the flow rate and the fracture aperture. Here, t_D^* is taken as 0.1. Note that 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 numerical validation of the proposed shape factor was also performed. Good agreement was found between the experimental data and analytical model, and the modified dual porosity formulation with the new time-dependent shape factor and transfer function.

Figure. 1. Shape factor versus dimensionless time for both filling-fracture and instantly-filled fracture experiments (log-log coordinates).

Area 2. Hot Fluid Injection

Work in this project area focused on formulating a mechanism for a shift toward water wetness measured during previously reported high-pressure, high-temperature imbibition experiments in low permeability rocks. We are focusing now on the colloidal aspects of porous media as a possible explanation for observed trends.

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. As stated previously, 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.

Previously, we performed 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 were isothermal and temperatures ranged from 20 to 180 °C. 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. The effect of temperature is to reduce oil-phase viscosity. But, reduction in viscosity cannot account for all of the improved recovery. We postulate an increase in water wetness of the rock also occurs.

There are at least two mechanisms for increase in water wetness with temperature in these experiments. The white oils, especially decane, exhibit solvent action on cores. A fraction of the increase in water wetness with the outcrop core/water/decane system may be due to dissolution of dirt or organic contamination on the rock surface. Simple cleaning action increases water wetness. Of course, experiments with crude oil do not exhibit this effect.

A second, and more field relevant, mechanism for increase in water wetness with temperature is fines detachment from rock surfaces. It is here that our efforts are concentrated. 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. The following experimental phenomena support this proposed mechanism.

It is observed that an increase in water imbibition efficiency at high temperature was accompanied by fines production in our previously reported experiments. Concurrent with an increase in oil production rate, appearance of fines in the core effluent is observed. The higher the temperature, the greater the fines production. Also, it is found that fines production correlates with non-wetting phase viscosity: the greater the oil viscosity the greater the fines production.

To study further the hypothesis that wettability shifts toward water wet as fines are produced, additional water imbibition experiments in decane saturated diatomite were conducted using a single core. The core was saturated with decane and subjected to water imbibition at room temperature until no obvious oil production occurred. The oil recovery was about 0.28 PV and no visible fines were produced. Thereafter, the temperature was raised to 90°C and forced displacement was performed ($\Delta p=5$ psi/cm). More oil was produced accompanied with some fines production (about 27 mg with size less than 3 μ). The final oil recovery was about 0.67 PV after forced water imbibition. Next, the fluids in the core were removed by applying house vacuum at $T=60^\circ\text{C}$. After the core was dry and cold, it was re-saturated with decane and again subjected to spontaneous water imbibition at room temperature. The results are presented in Fig. 2. One finds that both water imbibition rate and the extent of oil recovery are improved after some fines production from this core. The permeability prior to fines production is 3.32 md, whereas it is 2.71 following fines production. As the permeability decreased by about 18%, the increased water imbibition rate cannot be ascribed to an increase in permeability. The final oil recovery to spontaneous imbibition increases from 0.25 PV to about 0.4 PV after fines production; the modified Amott index is 0.37 before fines production and is 0.60 after fines production indicating a more water-wet state. Because the temperature is the same for these two imbibition tests, we infer that the increase in imbibition efficiency is due to an increase in water-wetness induced by hot-water injection and some fines production.

Figure 2. Effect of fines production on spontaneous imbibition of water into a decane saturated core.

Rationale and Summary—Fines Release at Elevated Temperature. Experimental evidence above appears to suggest fines release as a mechanism for altering the wettability of some consolidated porous media. A study was initiated to explore the role of temperature on colloidal attractive forces in porous media. In petroleum engineering, they are fundamental in understanding formation damage associated with permeability impairment due to fines migration (e.g., Mungan, 1965; Kia, 1987, Vaidya and Fogler, 1990). Yet, the focus of these investigations resides mostly in the relationship between the surfaces forces and properties such as composition, salinity and pH. Temperature is seldom mentioned.

Theoretical Calculations. Considerable research on surface forces exists outside the petroleum industry that can be applied to petroleum reservoirs. In order to understand the mechanisms of particle detachment we review and use DLVO (Derjaguin, Landau, Vervay and Overbeek) theory. DLVO theory explains the stability of colloidal systems as a result of the balance of attractive (F_A) and repulsive (F_R) forces. Likewise, we focus on the stability of clay particles while recognizing that a variety of materials (such as calcite) may contribute to fines production.

The balance between the forces acting on a clay particle in a reservoir determines the stability or detachment of that clay particle. In this study, we review of the theory of fines release and present preliminary results that illustrate dependence on pH, salinity and, temperature. 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), as shown in Figure 3.

Figure 3. Idealized sphere-plate system for fines stability calculations.

DLVO theory assumes that colloidal particles are very large as compared to electrolyte ions. This makes it possible to express the interaction forces between particles as a function of the interparticle distance, h . Thus, the interaction between a clay particle and a pore surface is described as

$$V_t(h) = V_{LVA}(h) + V_{DLR}(h) + V_{BR}(h) + V_{HR}(h) + V_{IHL}(h) \quad (8)$$

where V is the potential and subscripts represent the following: LVA, the London Van Der Waals attraction; DLR, the double layer repulsion; BR, the Born repulsion, HR, the hydrodynamic repulsion; and IHL, interfacial hydrate layer. The resulting potential of a clay particle is repulsive (unstable) if V_t is positive and, attractive (stable) if it is negative.

The calculation of the double-layer repulsion requires the zeta potential functions for clays (sphere) and quartz (plate). We consider values published in the literature for different temperatures (Williams and Williams, 1978; Ramachandran and Somsundaran, 1986) and, fit the experimental data to functions for interpolation and extrapolation purposes. In this study, we refer to the detachment temperature as the temperature where the resulting potential switches from attractive to repulsive for a given salinity and pH. Figure 4 shows a preliminary map of the detachment temperature for a given range of salinity and pH for a kaolinite-quartz system. At low salinity and high pH, the resulting potential at room temperature is mostly repulsive. As pH increases and salinity decreases the detachment temperature decreases. Interestingly, we recall that the condensate resulting from steam injection is low salinity and alkaline.

Figure 4. Detachment temperature (°C) for the kaolinite-quartz system at different pH and salinity (M)

Experimental Support. The experiments are designed to accomplish the following objectives: (a) validate the hypothesis that temperature can be crucial in fines release and (b) map the conditions under which drastic change is initiated and sensitivity of the conditions to the temperature.

The samples are Berea sandstone from Cleveland Quarries. We have two sets of cores. In one set, the cores are fired at temperatures of 800 °C and, in the second set the cores are used as received. Firing stabilizes clays and other fine materials and hence should be insensitive to variations in temperature, pH, and salinity. The cores will be subject to one phase corefloods at different conditions. Corefloods will be performed at constant Darcy velocities of approximately 1.0 m/day. Changes in permeability are observed by measuring the pressure drop across the core.

Experiments are performed at a variety of temperatures under isothermal conditions. Fines migration is quantified by collecting effluent samples from experiments. Three sets of experiments are planned for this part of the study as described next.

In the first set of experiments, fired and un-fired core is subjected to changes of salinity at room temperatures of 25 °C. The results obtained from this first experiment are used to validate both the experimental setup and procedures. In this test, a set formed by one fired and one unfired

core are exposed to fresh water (low sodium concentration) and another set is exposed to brine flow (30,000 ppm NaCl solution). Fines release obtained during this experiment is compared and gives us an idea of the sensitivity of the fired and unfired core to the change of salinity. In the second sets of experiments, two unfired cores at different pH (7 and 10) is exposed to brine flow at room temperature. After stabilizing flow, temperature is increased to 80 °C (353 K) and 120°C (353 K) while monitoring for changes in permeability and fines release. The pH of the solutions in all experiments is controlled by the use of buffers. The third set of experiments will follow the same procedures of the second set. The only difference is that fired core will be used.

The apparatus for these experiments has already been assembled and tested. Also, the first experiments with fresh water have been conducted. Complete results will be presented in subsequent reports.

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 composite reservoir cores saturated with live crude oil under overburden pressure. A live, crude-oil sample with solution gas oil ratio (GOR) of around 20 vol/vol at standard conditions was used as the oil phase. The measured viscosity of the live oil at reservoir temperature of 176°F and above bubble point pressure of 1336 psia is about 258 cp; liquid viscosity gradually increases to about 1,249 cp with decrease in pressure to about 300 psia while the temperature is held constant. The API gravity of the stock tank oil is about 10.

The total length of the core is 25.25 cm, whereas the porosity is about 29% and the permeability is roughly 2.4 darcy. A confining pressure of about 2000 psi is applied to the core. Figure 5 shows a schematic of the experimental setup. The coreholder containing the composite core was placed vertically in an oven (Blue-M) at the test temperature of 176±1°F. The bottom of the coreholder was connected to the outlet of the live oil cylinder; the top of the coreholder was connected to a visualization cell. The dimensions of the visualization cell are 5 (width) × 40 (length) × 0.05 (thickness) mm. With the visualization cell, we can monitor gas bubble flow behavior. There was bypass tubing along the visualization cell to allow live oil to bypass the cell during oil injection. An ISCO pump (ISCO-1) was connected to either inlet of the live oil cylinder or to the port of confining pressure of the coreholder. ISCO-1 was used for both live oil injection and a constant confining pressure during the depletion process. A second pump (ISCO-2) was used to control the depletion process and to control the outlet pressure of the coreholder when the live oil was injected. The visualization cell is made of polycarbonate polymer material and can hold a pressure up to 1,400 psia. This pressure is about 100 psia higher than bubble point pressure. When the test pressure was higher than 1,400 psia, the by pass was applied and the

valves at each end of the visual cell were closed. When the test pressure was below 1,400 psia, the bypass was closed and the oil flowed through the visualization cell. A digital video camera was used to record gas flow from the visualization cell. Three pressure transducers, p_1 , p_2 , and Δp were used to measure the pressure at inlet, outlet, and across the core. A PC combined with a data-acquisition logger (HP) was used to record the pressure data at an interval that ranged from 1 to 5 minutes. The gas-oil separator was used to separate gas and oil at the outlet of visualization cell. The produced oil was measured using an electronic balance and the produced gas was measured by displacing water from an inverted cylinder.

Figure 5. Experimental setup for heavy-oil pressure depletion tests.

Procedures. The system was subject to a leak test at a pressure of 2,000 psia and $T=176^{\circ}\text{F}$ for about 12 hours after being assembled. The coreholder was then subjected to carbon dioxide flooding for about 30 minutes at an injection pressure of 40 psia. This was to displace air or other gas from the system. Thereafter, the coreholder was vacuumed for about 4 hours before normal decane ($n\text{C}_{10}$) was injected. At a confining pressure of about 300 psia, the permeability to normal decane was measured at three different rates ($2\text{--}10\text{ cm}^3/\text{min}$). Then the confining pressure was raised to 2,100 psia accompanied with an increase of pore pressure to 1,800 psia. The pore pressure remained 300 psia less than the confining pressure. A mineral oil (blandol) was used as a confining fluid. The coreholder was allowed to reach a stable condition for about 12 hours before it was subjected to live-oil injection. During the live oil injection, the outlet pressure (p_1) was

about 1,700 psia and inlet pressure (p_2) was about 1900 psia. About 2 pore volumes of fresh live oil were injected into the core for each test. The permeability to live oil was measured at a pore pressure of 1,800 psia again.

Depletion tests were conducted at constant volumetric expansion rate (0.035, 0.0035, and 0.0008 PV/hr, respectively). The tests were initiated at $p \approx 1700$ psia. Before gas breakthrough from the core, the oil production was measured using the ISCO-2 pump. After gas breakthrough, the oil production rate at the outlet was measured by displacing all fluids from the ISCO-2 pump and measuring the oil weight using an electronic balance. The produced gas volume was measured using a volumetric gas trap. The average gas production rate under test conditions (pressure and temperature) equals the difference between total expansion volume from ISCO-1 pump and the oil volume from oil weight measured by the electronic balance. Note that density of the stock tank oil is 1.0 at standard conditions, thus the oil volume equals the weight at standard conditions. The confining pressure remained constant at 2,000 psia. The volume of liquid injected into the annular space by the pump to maintain constant pressure was measured. This volume is the total decrease in pore volume of the system. The depletion test was terminated at a pressure of about 200 psia.

Results p - ΔV . Figure 6a shows the pressure evolution versus depletion time for tests 1-3. At pressures above the bubble point, the pressure declines linearly. The decline rate is 910 psia/hr for test 1, 121 psia/hr for test 2, and 34 psia/hr for test 3. At each rate, there is an apparent supersaturation and rebound in the pressure versus time curve, as expected. The largest apparent supersaturation occurs for the largest depletion rate. The ratio of pressure decline rate for test 1 to test 2 is about 7.52 (the ratio of volumetric depletion rate for test 1 to test 2 is 10) and for test 1 to test 3 is about 26.7 (the ratio of volumetric depletion rate of test 1 to test 3 is 41). Apparently, compaction of pore volume caused by overburden pressure affects the pressure evolution during the depletion process.

Figure 6b shows the pressure evolution versus expansion volume. For test 1, the pressure begins to rebound at an apparent critical supersaturation pressure of 1084 psia; it increases from 1,084 to 1,093 psia before it resumes a declining trend at a lower rate, indicating the beginning of two-phase flow. The calculated supersaturation pressure for test 1 is about 252 psia. Note that the apparent supersaturation pressure is defined as the difference between bubblepoint pressure measured at a thermodynamic equilibrium state and the maximum pressure measured during the rebound phase. Below the critical supersaturation pressure, the pressure decline rate gradually decreases with volume expansion due to gas and the ensuing greater compressibility in the core. At the beginning of the two-phase flow regime, the pressure decline rate is about 13.3 psia/cm³; however, it is only about 0.84 psia/cm³ at the end of the test. Large pressure decline rate at the early stages of two-phase flow is ascribed as a feature of a non-equilibrium state. The apparent supersaturation pressure reduces with expansion volume which in turn relaxes the pressure decline rate.

Figure 6a. Effect of depletion rate on pressure evolution: pressure versus time.

Figure 6b. Effect of depletion rate on pressure evolution: pressure versus expansion volume.

For test 2, the apparent critical saturation pressure is about 1,190 psia and the apparent supersaturation pressure is about 146 psia. The pressure does not rebound at the critical supersaturation pressure, observed in test 1. Instead it continues decreasing, but at a lower rate, signaling the beginning of a two-phase flow regime. Similar to test 1, the pressure decline rate gradually decreases with expansion volume. At the early stage of two-phase flow, the pressure decline rate is about 17.3 psia/cm³; at the end of the test, the pressure decline rate is about 0.96 psia/cm³.

For test 3, the apparent critical saturation pressure is about 1,160 psia and the critical supersaturation pressure is about 180 psia. Below this critical point, the pressure continues declining at a relatively high rate of 171.6 psia/cm³. Similar to the other two tests, the pressure decline rate decreases with expansion volume; it is about 6.3 psia/cm³ at the end of the test.

Gas Bubbles. We also monitored the gas bubble flow using the visualization cell. The time for gas flow out of the core depends on the depletion rate. The first gas bubble was observed (from the cell) at a pressure of 470 psia for test 1, 640 psia for test 2, and 750 psia for test 3. Recall, that the flow lines contain dead volume and time is required for bubbles to flow from the core to the visualization cell. The gas flow rate also increases with depletion rate. The observed gas bubble size ranges from 0.001 cm³ to 0.01 cm³. However, most gas bubbles are of a size of 0.01 cm³. The frequency of gas flow through the visualization cell increases with expansion volume. Also, it increases with decrease in depletion rate from tests 1 to 3. Coalescence between gas bubbles is rarely observed in the cell. One important feature is that the gas flow is intermittent after gas breakthrough from the core. For test 1, a gas flow channel is observed. Due to the compaction drive effect, the gas bubble flow remains intermittent for tests 2 and 3 through the tests, but the gas bubble size and the number of each cluster increases with expansion volume. The observed gas bubble size is greater than the pore and throat size. That is, no bubbles smaller than pore size were witnessed.

Conclusions. Summarizing the conclusions from this set of experiments:

1. The primary recovery of this crude oil by depletion is dominated by both solution gas drive and compaction drive. As the depletion rate increases, the oil production mechanism is dominated by solution gas drive.
2. Flowing gas bubbles size is about 0.01 cm³, and this is greater than pore and throat size. Dispersed gas bubbles smaller than pore size do not appear to be a feature of this crude oil.
3. An increase in depletion rate results in an increased critical gas saturation and oil recovery.

Area 4. In-Situ Combustion

After many years of dutiful service, the gas analyzers needed to measure oxygen, carbon dioxide, methane, and carbon monoxide production during in-situ combustion experiments have given out completely. A new gas analyzer was ordered, calibrated, and installed. New experiments are planned for the coming quarter.

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 and 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. We are applying the method to 3D synthetic and real reservoirs to prove efficiency.

Streamline Simulation. The use of streamline simulation is two-fold: first streamlines are used to compute fluid displacement in complex 3D reservoir models, and, second, streamlines are used to compute the required amount of correction to match history. The first aspect is related to the spatial information carried along by each streamline; the second aspect is related to the temporal information carried along by each streamline.

The location of fluid displacement paths is particularly useful to locate isolated flow zones. A flow zone is a group of grid blocks crossed by streamlines that end in the same producer. Flow zones can change radically over time. Typically, the addition or the shutting-in of a well seriously changes the shapes of flow zones. It is necessary to keep track of those changes in time, and the history of each grid block with respect to the zones it belonged to during the field production history must be tracked. The correction on permeability is then localized in space by the mismatch of each individual well, through each production period.

The amount of correction for each zone at each production period is found by using the difference between the time at which a streamline breaks through, and the time at which this streamline should break through to match real production data. This information is based on producer water-cut increases: an increase on water-cut corresponds to a streamline breakthrough.

Sequential Simulation. Geostatistical methods are employed once the amount and the areas of the reservoir that need to be corrected have been computed using streamline simulation. Applying fundamental geostatistics to any field generated guaranties that we stay in the space of geologically consistent permeability fields. Of course, this implies that all prior geological data have been integrated in a geostatistical model. Using a stochastic simulation technique to march towards a better permeability field, accounting for local corrections, requires a non-trivial deformation technique.

This technique enables a gradual deformation between fields that both show interesting features in different zones, so that good features of the two fields are combined in one field without any discontinuities. To achieve that, it is necessary to not work directly on the attributes of the permeability field, but on the underlying random numbers that have been used to simulate those attributes. Doing so allows one to combine features of the two pictures, without creating any discontinuities in the new simulated image, and honoring all the prior information. This technique can be applied to any type of field (not necessarily Gaussian) but the underlying random numbers must be Gaussian to be combined linearly. In other words, the permeability values can have any type of distribution (log-normal, multimodal, etc.), but the random numbers used inside the simulation process must be Gaussian. In traditional geostatistical libraries (Deutsch and Journel, 1997), those random numbers are Gaussian in deed.

The deformation between the two sets of underlying random numbers is obtained by a trigonometric morphing:

$$y_{new} = y_1 \cdot \cos(\mathbf{r}_{zone}) + y_2 \cdot \sin(\mathbf{r}_{zone}) \quad (9)$$

The key idea in this multi-zone technique is to take a parameter $\mathbf{r}$ different for each flow zone. This is how the method handles multi-zone deformation, and is capable of keeping interesting features of a permeability field, while changing another feature, in another zone. Of course, it is not possible to say that the zones are independent, and finding the best parameter set $\mathbf{r}$ requires taking all the zones into account (for the computation of an objective function, typically). The importance of the distribution type of the parameter y : both y_1 and y_2 should be emphasized once more: they must have a Gaussian (standard normal) distribution, so that we can linearly combine them to have a new standard normal distribution y_{new} . Using this formula, and searching for the optimal value of $\mathbf{r}$ for each zone, we can obtain a third permeability field, with both interesting features of its two “parents”.

This multi-zone gradual deformation is robust, supports significant constraints in the way of prior data, and handles complex objective functions. It can nevertheless be slow and highly CPU demanding, because of its gradual character. The objective function between two gradually deformed images is smooth, and a simple descent algorithm (Dekker Brent, for instance) can be implemented to identify the best blend between two sets of random numbers. Geological consistency is preserved at all steps of the perturbation, and perturbations are computed in a deterministic fashion.

It is interesting to couple this method with a faster, more stochastic technique to screen out the best permeability fields in a pool of geologically consistent fields. Only those best permeability fields can then be used in multi-zone deformation. In terms of optimization, this coupled technique is equivalent to perform a rapid search, to find possible approximations to the

minimum, and then, to gradually deform those approximations to approach the real minimum. The application on synthetic and real 3D cases have shown that this multi-zone deformation was an efficient tool to perturb permeability fields within geological consistency. History matching and reservoir modeling are the current fields of application of this technique.

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