Heavy and Thermal Oil Recovery Production Mechanisms

By

**Anthony R. Kavscek, Principal Investigator
Louis M. Castanier, Technical Manager**

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**Jerry Casteel, Project Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101**

**Prepared by
Stanford University
Department of Petroleum Engineering
Green Earth Sciences Bldg., Room 080B
367 Panama Street
Stanford, CA 94305-2220**

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Summary

The Stanford University Petroleum Research Institute (SUPRI-A) conducts a broad spectrum of research intended to help improve the recovery efficiency from difficult to produce reservoirs including heavy oil and fractured low permeability systems. Our scope of work is relevant across near-, mid-, and long-term time frames. The primary functions of the group are to conduct direction-setting research, transfer research results to industry, and educate and train students for careers in industry.

Presently, research in SUPRI-A is divided into 5 main project areas. These projects and their goals include:

- 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.
- 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.
- Mechanisms of primary heavy oil recovery—to develop a mechanistic understanding of so-called “foamy oil” and its associated physical chemistry.
- In-situ combustion—to evaluate the effect of different reservoir parameters on the insitu combustion process.
- Reservoir definition—to develop and improve techniques for evaluating formation properties from production information.

What follows is a report on activities for the past year. Significant progress was made in all areas.

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MULTIPHASE FLOW AND ROCK PROPERTIES

A Technique for Measuring Two-Phase Relative Permeability in Porous Media Via X-ray CT Measurements

J. M. Schembre and A. R. Kavscek

ABSTRACT

A novel method for computing two-phase relative permeability curves from the results of spontaneous imbibition experiments is presented. Using a specially constructed imbibition cell and an X-ray Computed Tomography (CT) scanner, we obtain accurate measurement of saturation profiles along the length of cores as a function of time. The saturation profile history allows direct computation of the relative permeability for both phases from a single experiment when used in combination with a previously measured capillary pressure curve. Results are unique within experimental error. The proposed procedure works equally well for spontaneous and forced cocurrent imbibition. It was tested thoroughly using synthetic and experimental data, for water-air and water-oil systems. Test results are described within the paper. Advantages include the incorporation of capillary forces and no requirement for steady-state conditions. This method is useful to measure imbibition relative permeability curves, especially in low permeability rocks at relatively low wetting phase saturations. In such systems, it is laborious to reach multiple steady states and capillary forces are significant so that classical unsteady-state techniques do not apply.

1. INTRODUCTION

Simulation of multiphase flow in porous media requires knowledge of relative permeability functions. These functions are necessary to make estimates of productivity, injectivity, and ultimate recovery from oil reservoirs for evaluation and planning of production operations (Honarpour and Mahmood, 1988). Therefore, measurements of relative permeability in the laboratory and/or empirical and theoretical models are an important subject in reservoir modeling.

The laboratory methods used to calculate relative permeability functions are grouped into centrifuge, steady- and unsteady-state techniques. The centrifuge method has been improved (Hirasaki *et al.*, 1992; 1995), yet, it has many potential pitfalls in the experimental and interpretation parts. It also poses limitations including loss of information on the low saturation region that can not be gained from the production data at low mobility ratio (Hirasaki *et al.*, 1995). Additionally, concerns regarding the replacement of viscous forces with a range of centrifugal forces still remain for unsteady state displacement processes that are rate dependent (Ali, 1999). Steady-state methods offer disadvantages, especially in the case of low permeability rocks, in which it is laborious to reach multiple steady states and, capillary forces and capillary end effects are significant (Firoozabadi and Aziz, 1988; Kamath *et al.*, 1993). Steady-state techniques

have been improved in order to make corrections for capillary effects but they still require successive measurements for different total flow rates (Virnosvky *et al.*, 1995). Capillary pressure has a significant effect on saturation distribution and recovery, and capillary forces dominate multiphase flow in low-permeability rocks and fractured reservoirs. In developing unsteady-state methods for low-permeability systems, it is necessary to account for capillary pressure when obtaining the relative permeability curve. Akin *et al.* (1999) proved that the use of the JBN technique, an unsteady technique, leads to inaccurate measurements of relative permeability. Thus, most unconventional unsteady techniques do not apply.

There are also methods that infer relative permeability by history matching observable parameters such as fluid production, pressure drop, and saturation profile history. These methods assume that the relative permeability and capillary pressure curves behave according to a pre-determined function. The limitation imposed on the description of the actual shape of the relative permeability curve causes a bias error and a variance error (Watson *et al.*, 1986; Hirasaki *et al.*, 1995). When the number of parameters in the functional representation increases, the bias error tends to decrease. However, because more parameters are estimated on the basis of the same amount of information, the variance error tends to increase.

In the method we propose, two-phase relative permeability curves are computed from experimental in-situ, saturation profiles obtained from spontaneous imbibition experiments. Each relative permeability value at a particular saturation is treated independently when the experiment begins with low or zero initial water saturation. For experiments where the core is partially saturated with water initially, the water saturation increases almost uniformly in time throughout the core. In this event, the imbibition method becomes quite similar to that proposed by Sahni *et al.* (1998) for gravity drainage in three-phase systems. Fitting to a pre-determined functional shape is not necessary in either case. This paper proceeds by first describing the set up used for experiments. Next, the various equations needed for interpreting the data are developed. Synthetic CT data are then used to first verify the technique before application to experimental data. In all cases, the relative permeability curve obtained is input for numerical simulation and the agreement between input and computed saturation profiles checked.

2. EXPERIMENTAL APPARATUS

Brigham and coworkers were among the earliest researchers to apply X-ray CT to monitor the progress of multiphase displacement inside porous media (Liu *et al.* 1990, Demiral *et al.* 1991, Liu *et al.* 1992). They showed the critical importance of measuring the evolution of fluid phase saturation in situ for interpretation of experiments. The experimental program used in this method applies these foundational studies. Figure 1 shows a schematic of the experimental apparatus. Imbibition in this study is cocurrent. The experimental cell is constructed from acrylic tubes, and it consists of two separate chambers. The main chamber is the core holder and it is surrounded by water, contained in the second chamber. The objective of the second chamber is to reduce possible beam

hardening artifacts and provide temperature control. Core holder and water jacket fluids never mix.

The scanning plane is along the entire length of the core in the direction of the flow, as illustrated in Fig. 1. Hence, the porosity and saturation fields are measured on a single vertical volume section in the center of the core as a function of time. The total time of measurement is short enough to capture accurately the position of each saturation value. As a consequence of the scan geometry, many saturation data points are obtained and, importantly, a single scan provides the position of every saturation at a specific time. Images obtained are flat and do not exhibit detectable positioning errors. Scanning is performed every 50 seconds for the early stage of imbibition, afterwards the interval between images is longer because the change in saturation becomes slower with time. The duration of the early stage varies according to the rock and viscosity, and other properties, of the fluids present in the core.

The raw CT-number data is converted to a map of porosity. The water saturation profiles are obtained from subtracting images of raw CT data. One-dimensional saturation profiles are obtained from two-dimensional images by averaging the saturation values at a particular location. The procedure and expressions used for the calculation of saturation profiles depend on the saturation history of the core and fluid saturations at the beginning of the experiment. Further information about the experimental equipment, procedure, pure fluid CT numbers, and data processing is provided by Akin and Kovscek (1999) and Akin *et al.* (2000).

In the experiments to follow, diatomite cores come from a block of stone obtained from the Grefco Quarry (Lompoc, CA). Berea sandstone samples were obtained from Cleveland Quarries (Amherst, OH). The sandstone samples are fired at 450 °C for 12 hours in an oven to stabilize any clay present and prevent any fines migration. The quarry diatomite samples display no signs of clay swelling, and consequently were not fired.

3. RELATIVE PERMEABILITY FROM CT DATA

The equations necessary for data processing of experiments are developed next. First cases with little or no initial water saturation are considered. Then, equations appropriate to cases with medium to high initial water are developed. The method differs slightly among these two cases.

The mathematical model begins from the standard one-dimensional equation for flow of two immiscible phases in porous media. We neglect the effect of gravity, but this is not a necessary assumption. For the wetting-phase,

$$u_w = -\frac{kk_{rw}}{\mu_w} \frac{\partial p_w}{\partial x} \quad (1)$$

where u_w is the Darcy velocity, k is the absolute permeability, k_{rw} is the relative permeability, μ_w viscosity, and $\frac{\partial p_w}{\partial x}$ is the pressure gradient of the wetting phase.

The Darcy velocity is, in fact, a superficial velocity, that is identically equal to $\phi S_w \frac{dx}{dt} \Big|_{S_w}$. Substituting this expression for u_w in Eq. 1 results in

$$\phi S_w \frac{dx}{dt} \Big|_{S_w} = - \frac{k k_{rw}}{\mu_w} \frac{\partial p_w}{\partial x} \quad (2)$$

where $\frac{dx}{dt} \Big|_{S_w}$ is the velocity of a particular saturation S_w as a function of time and ϕ is the porosity. Integrating with respect to time, the relative permeability of a particular S_w is

$$k_{rw} = \left[\frac{x|_{S_w} S_w}{- \int_0^t \left(\frac{\partial p_w}{\partial x} \right) \Big|_{S_w} dt} \right] \frac{\mu_w \phi}{k} \quad (3)$$

In this function, the porosity, viscosity and, permeability are independently measurable and constant. The pressure gradient history and the position of a particular saturation as a function of time, $x|_{S_w}$, are measured during the experiment. Thus, Eq. 3 allows direct computation of k_{rw} solely from measured data. A similar development for the non-wetting phase yields

$$k_{rnw} = \frac{\mu_{nw} \phi S_{nw}}{k} \left(\frac{x|_{S_{nw}}}{\int_0^t \frac{\partial p_{nw}}{\partial x} \Big|_{S_{nw}} dt} \right) \quad (4)$$

where $\frac{\partial p_{nw}}{\partial x}$ is the non-wetting phase pressure gradient. Equations 3 and 4 are related by the summation of phase saturations to 1.

It is also noted that the capillary pressure function can be obtained uniquely, given the water relative permeability function, as

$$\frac{\partial p_c}{\partial S_w} = - \left(\frac{\frac{x|_{S_w} S_w \mu_w \phi}{k k_{rw}|_{S_w}} - \int_0^t \frac{\partial p_{nw}}{\partial x} \Big|_{S_w} dt}{\int_0^t \frac{\partial S_w}{\partial x} \Big|_{S_w} dt} \right) \quad (5)$$

The extension of the method to forced imbibition is given in the appendix. In cases with initial water saturation and where the water saturation shows diffuse-like behavior, it might be difficult to implement the method above. Multiple locations for a given saturation value at a specific time lead to uncertainty in the assessment of the velocity of the saturation value. For cases with initial water, a variant of the method of Sahni *et al.* (1998) for gravity drainage is developed.

The Darcy velocity and conservation equation for each phase are again used. Rather than integrating Darcy's Law, the material balance for each phase is integrated. The in-situ saturation measurement and an independently measured capillary pressure relationship are still needed. The result for the wetting phase is

$$k_{rw} = -\frac{\mu_w \phi}{k} \frac{\int \frac{\partial S_w}{\partial t} \Big|_{x,t} dx}{\frac{\partial p_w}{\partial x} \Big|_{x,t}} \quad (6)$$

and similarly, for the non-wetting phase,

$$k_{rnw} = -\frac{\mu_{nw} \phi}{k} \frac{\int \frac{\partial S_{nw}}{\partial t} \Big|_{x,t} dx}{\frac{\partial p_{nw}}{\partial x} \Big|_{x,t}} \quad (7)$$

4. VALIDATION

Next, we test and validate the method embodied in Eqs. 3, 4, 6, and 7, using synthetic experimental data. Known relative permeability functions and petrophysical properties are input to the simulator (ECLIPSE 100). Saturation histories are created that can be analyzed. Relative permeability curves obtained from the simulated data are compared to the corresponding input curves. The rock properties used in the synthetic cases are descriptive of diatomite (Akin *et al.*, 2000). Characteristics of the porous medium and fluid properties are shown in Table 1. Water-air and water-oil spontaneous cocurrent imbibition cases are considered. Further description of the models and results obtained for each case follows.

4.1. Water-Air

The first case is water-air spontaneous imbibition with zero initial water saturation. A one-dimensional grid with 1002 cells is used to generate the synthetic saturation data and later to check to the relative permeability functions obtained. The fine grid and small time steps limit, but do not eliminate, numerical artifacts.

We assume that the contribution of the non-wetting phase pressure gradient is not significant to the determination of k_{rw} . Air is inviscid and infinitely mobile compared to the wetting phase. Consequently, the wetting phase pressure gradient is approximately equal to $-\frac{\partial p_c}{\partial x}$. The relative permeability functions for water and gas phases follow the functions of Fatt and Klikoff (1959) with power-law coefficients of 3 for each phase. The capillary pressure curve is given by a polynomial fit to the Leverett function (1941):

$$P_c = \left(\frac{\phi}{k}\right)^{1/2} \sigma \cos \theta \left[4.013 - 13.68 S_w^* + 21.313 (S_w^*)^2 - 11.548 (S_w^*)^3 \right] \quad (8)$$

where σ is the fluid interfacial tension, θ is the contact angle, and the reduced saturation is given as

$$S_w^* = \frac{S_w - S_{wc}}{1 - S_w} \quad (9)$$

The subscript, wc, refers to connate water. A plot given by this function and the data in Table 1 is shown in Fig. 2. There is no initial water saturation, no connate water saturation, and no residual gas saturation. As these are synthetic cases, we are not too concerned with the shape of the capillary pressure curve. That is, the capillary pressure curve in Fig. 2 applies strictly to drainage, but it is convenient for use in this verification exercise.

Although the non-wetting-phase pressure gradient is neglected when finding the wetting-phase relative permeability, the method yields the non-wetting phase relative permeability via Eq. 4. A comparison of the input relative permeability curves with those obtained from applying Eqs. 3 and 4 to the synthetic input data is shown in Fig. 3. Solid lines are input and symbols represent output data. The curves shown for the water relative permeability include the case where the gas pressure gradient is neglected and the case where it is included in the calculations. The semi-logarithmic scale is used to accentuate any differences, especially in the low water saturation range. The computed curves follow the input curves with an error of approximately 12 per cent. The largest error is attributed to the computation of the integrals numerically. A second cause of error is due to uncertainty in locating the position of a particular saturation from the saturation profiles as a function of time. Neglecting the pressure gradient of the air leads to insignificant errors.

To test the ability of the calculated curves to reproduce the input saturation profiles, simulations were conducted. Figure 4 compares the input saturation history and that obtained using the computed relative permeability curves. The larger values of k_{rw} computed at low water saturation affect slightly the leading edge of the saturation fronts at late times. Otherwise, the saturation history is matched exactly.

4.2. Water-Oil

In this case, the properties of n-decane describe the non-wetting fluid and the initial water phase saturation is zero. The 1002 cell one-dimensional grid is again used to generate synthetic CT data. The non-wetting phase pressure gradient is included in Eq. (3). Despite the variation in interfacial tension among water-air (~ 70 mN/m) and water-oil (~ 50 mN/m) systems, the capillary pressure curve from the previous case is used again (Fig. 2). Figure 5 shows the input relative permeability curves and the output data as symbols. Note the ability of the method to reproduce the non-functional shape of the curve. Relative permeability is also computed and shown for the case where we chose to neglect the oil-phase pressure gradient. The relative permeability obtained when we neglect the oil-phase pressure gradient agrees with the input curve with the exception of water saturation values greater than 0.7. At high water saturations, the gradients in P_c and p_o are roughly equal in magnitude. The water relative permeability obtained when we include the oil-phase pressure gradient in the calculations matches the input data at large S_w somewhat better. The nonwetting phase is not especially viscous allowing the close match with or without incorporating the oil-phase pressure gradient.

The oil relative permeability computed from Eq. (4) is compared to the input curve in Fig. 5 as well. The inaccuracy is larger in this case than in the water-air case, especially at low oil (i.e., large water) saturations. The relative permeability values for the highest S_w values no longer follow the same trend as the input curve. A close examination of the computational output revealed spurious data reported by the simulator for the oil-phase pressure gradient at early times. Initial time-step size is set to the minimum value allowed by the simulator, yet the oil-phase pressures are not converged at early times. This numerical error affects the integral term in Eqs. 4 and 7. In short, the input-output mismatch for oil relative permeability is not inherent in the method proposed here, but lies in numerical artifacts generated by the simulator.

The input water saturation history and that obtained from simulation using the computed relative permeability curves are compared in Fig. 6. Similar to the water-air case, the larger values of k_{rw} at low water saturation affect slightly the leading edge of the saturation fronts at late times. The mismatch in the oil relative permeability curves for the largest water saturations (Fig. 5) affects the overall speed and shape of the imbibition front (Fig. 6). Nevertheless, overall agreement among the input and computed saturation profile is quite acceptable.

4.3. Water-Oil, Initial Water

Next, the method as applied to cases with initial water was validated using synthetic CT data. The capillary pressure curve is shown in Fig. 7 and the input relative permeability curves are shown in Fig. 8. The initial water saturation is uniform and equal to 0.6. This gives a core that fills slowly by spontaneous imbibition with little of the frontal-like displacement of the previous cases. The properties of the rocks are those of diatomite, Table 1, and the non-wetting fluid has the characteristics of decane. The water relative permeability obtained, using Eq. 6 and the oil relative permeability computed

from Eq. (7) are compared to the input curve in Fig. 8. In both cases, the curves obtained follow the corresponding input curves closely, with some scatter. The scatter is mainly related to the fact that the relative permeability curves are obtained from the scatterplot of $K_p(x)$ vs $S_p(x)$. Figure 9 compares the synthetic saturation history with that obtained using the measured relative permeability curves; the results match well.

5. EXPERIMENTAL CASES

The verification exercises indicate that the method yields accurate measurement of relative permeability for water-oil and water-air experiments provided that the non-wetting phase pressure gradient versus time is measured. A previously determined capillary pressure is also needed. Next, the method is applied to experimental data. We use water saturation profiles measured by X-ray CT during spontaneous imbibition water imbibition into air-filled Berea sandstone and diatomite. The properties of each system are summarized in Table 2. The column "pixel resolution" refers to the number of CT-measured saturation data.

5.1. Berea Sandstone

The imbibition capillary pressure curve given by Sinokrot et al. (1969), was modified for different fluid system and petrophysical properties (*i.e.*, k , ϕ) by using the Leverett J-function (Leverett, 1941; Ma *et al.*, 1991) That is, the required curve was first non-dimensionalized and then rescaled according to k , ϕ , and σ ($\theta = 0$). The capillary pressure relationship used in this case is shown in Fig. 10. The relative permeability curve obtained is shown in Fig. 11. The values of k_{rw} obtained are reasonable. Moreover, the endpoint k_{rw} obtained agrees with endpoints found in the literature for Berea sandstone (Lerdahl *et al.*, 2000; Oak *et al.*, 1990).

A comparison of the CT-determined experimental water saturation profiles versus time and the profiles obtained by simulating the core with the measured relative permeability is shown in Fig. 12. The results match especially well given the scatter in the experimental data. Notice that the shape and position of the imbibition front are well reproduced. Since the pressure gradient within the core was not measured in the experiments, it was not possible to find the non-wetting phase relative permeability. A linear k_{rg} relationship is used for simulation. Because the gas is inviscid, the shape of k_{rg} versus S_w has little effect on the computed saturation profiles in Fig. 12.

5.2. Diatomite

There is very little known about petrophysical properties in diatomite. The use of the classical unsteady state method in the determination of relative permeability for diatomite surely leads to inaccurate results because of low permeability and corresponding capillary effects. The same experimental method as in the case of the Berea sandstone was used to obtain the water saturation profiles. The core is initially air-filled.

The input imbibition capillary pressure curve was measured with the porous-plate method as reported by Akin and Kovscek (1999). It is similar to another curve shown by Kumar and Beatty (1995). The capillary pressure used is that shown in Fig. 7. The relative permeability curve obtained from the measured S_w profile is shown in Fig. 13. At high water saturation, the relative permeability is found to decrease as S_w increases. The reason for this artifact is shown in Fig. 14. Here, the experimental water saturation profile and the profile obtained by simulating the imbibition process are compared. High water saturations within the experiments advance slowly at earlier time. Note the first profile for a time of 0.0069 hr. This is indicative of flow that is not one dimensional at small times. Therefore, retardation exists for saturation values greater than 0.7. The solid line gives the relative permeability curve used for simulation:

$$k_{rw}(S_w) = 5E^{-5} \exp(8.3355 S_w) \quad (10)$$

Despite the difficulties in measuring k_{rw} at large S_w , the results obtained from simulation (solid line) with Eq. 10 match the saturation-history data well, as shown in Fig. 14. Additionally, the data points in Fig. 13 and the extrapolation at high water saturations indicate a low endpoint value of roughly 0.2 for k_{rw} . This is indicative of and consistent with the strong water-wetness of these core samples (Akin *et al.*, 2000; Zhou *et al.*, 2002).

6. CONCLUSIONS

A method has been developed to determine dynamic relative permeability from the water saturation profile history obtained during X-ray CT monitored spontaneous imbibition experiments. The method was tested using synthetic data for the water-air and water-oil cases. In addition, the method was adapted for cases with large initial water saturation. Computed relative permeability values matched well the input curves, suggesting reliability for these systems. In the water-oil case, discrepancies among the measured and input oil relative permeability values were attributed to numerical inaccuracies in the simulator. The air-phase pressure gradient can be neglected in the calculations of water relative permeability. A sensitivity study showed that neglecting the oil-phase pressure gradient might lead to error in the high water saturation values for viscous oils.

The procedure was used to determine the water relative permeability for two experimental cases with Berea sandstone and quarried diatomite. In both cases, the relative permeability curves obtained were used to simulate the water saturation profile versus time. The computed saturation history reproduced the experimental behavior well. Importantly, this method allows measurement of relative permeability from a single experiment. Potentially this represents a great savings of time.

7. NOMENCLATURE

h	height of the water column, L
k	absolute permeability, L ²
k_p	relative permeability of phase p, dimensionless
p	phase pressure, ML ⁻¹ T ⁻²
p_c	capillary pressure, ML ⁻¹ T ⁻²
S_p	saturation for phase p , dimensionless
S_w^*	rescaled water saturation, dimensionless
t	time, T
u_w	flow velocity of phase p , LT ⁻¹
x	length, L

Greek Symbols

σ	interfacial tension, MT ⁻²
ρ	density, ML ⁻³
ϕ	porosity, dimensionless.
μ	fluid viscosity, mL ⁻¹ T ⁻¹
θ	contact angle

Subscripts

o	oil
nw	non wetting
w	water, wetting

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APPENDIX: EXTENSION OF THE METHOD FOR FORCED IMBIBITION

Thus far, we have assumed spontaneous imbibition with no applied head in the analysis of the water saturation profile. One of the main concerns when analyzing the water saturation profiles is the maintenance of water supply such that the experimental results represent purely spontaneous imbibition behavior. In this section, we present the numerical solution for the case of slight forced imbibition.

For the case of forced imbibition, we recall that the psi-potential for any fluid is defined as (Dake 1978)

$$\Psi = p + \rho gh \quad (\text{A-1})$$

Assuming that the water level is constant and geometry is as shown in Fig. A-1, the water potential gradient can be approximated by

$$\frac{d\Psi_w}{dx} = -\frac{dp_c}{dx} + \frac{\rho_w gh}{x|_{S_w,t}} \quad (\text{A-2})$$

where, $x|_{S_w,t}$ is the position of a particular water saturation at a given time, and h is the level of the water column measured from the water-core contact.

Substituting Eq. (A-2) in Eq. 3 and making the same assumptions, we express relative permeability at any given water saturation and time as

$$k_{rw} = \frac{x|_{S_w} S_w}{\int_0^t \left(\frac{\partial p_c}{\partial S_w} \frac{\partial S_w}{\partial x} - \frac{\rho gh}{x} \right) \Big|_{S_w} dt} \frac{\mu_w \phi}{k} \quad (\text{A-3})$$

Equation A-3 shows that neglecting the height of the water column in the method leads to larger values in the relative permeability curve. The size of this error depends on the magnitude of the water column compared to the derivative of capillary pressure. In general, the derivative of the capillary pressure is more sensitive to these effects for high water saturation values. This result extends the application of this method to data collected during forced imbibition experiments.

Table 1: Properties of Rock and Fluids Used in Validation of the Method

Rock Properties		Permeability [md]	6.6
		Porosity	0.65
		Length [cm]	8.8
		Compressibility	5E5
Fluids Properties	Water	Viscosity [cp]	1.0
		Density [g/cm3]	1.0
	Air	Viscosity [cp]	0.02
		Density [g/cm3]	0.002
	Oil	Viscosity [cp]	0.86
		Density[g/cm3]	0.8

Table 2: Characteristic of the Berea Sandstone and Diatomite Cores

	Berea Sandstone	Diatomite
Porosity[fraction]	0.22	0.68
Permeability[md]	780.0	6.6
Diameter[cm]	2.43	2.43
Length	8.8	9.02
Pixel resolution	210	225

Fig. 1. Schematic of the imbibition cell.

Fig. 2. Capillary pressure relationship used for the synthetic water-air case.

Fig. 3: Relative permeability curves for the synthetic water-air case: solid lines are input and symbols are the output data obtained.

Fig. 4. Water saturation profiles obtained for reference and input relative permeability curves: solid lines are input and the symbols are obtained from computed relative permeability curve.

Fig. 5. Input and output relative permeability curves obtained for the synthetic water-oil case: solid lines are input and symbols are the output data obtained.

Fig. 6. Water saturation profiles obtained for the water-oilcase using input (solid) and output (symbols) relative permeabilities.

Fig. 7. Capillary pressure curve used for both the synthetic case with initial water saturation and the diatomite imbibition experiments. Data points are from Kumar and Beatty (1995) and Akin and Kovscek (1999).

Fig. 8. Relative permeability curves for the synthetic water-air case with initial water saturation: solid lines are input and symbols are the output data obtained.

Fig. 9. Water saturation profiles obtained for reference and input relative permeability curves for the synthetic water-air case with initial water saturation: solid lines are input and the symbols are obtained from computed relative permeability curve.

Fig. 10. Capillary pressure for Berea sandstone.

Fig. 11. Experimentally determined water relative permeability curve for Berea sandstone.

Fig. 12. Saturation profile obtained by simulation with measured k_{rw} compared to the experimental profile for Berea Sandstone.

Fig. 13. Experimentally determined water relative permeability curve for outcrop diatomite.

Fig. 14. Saturation profile obtained by simulation with measured k_{rw} compared to the experimental profile for outcrop diatomite.

Figure A-1: Outline of the experimental setup for the method with forced imbibition.

Micro-Visual Analysis of Matrix-Fracture Interaction

E. R. Rangel-German and A. R. Kavscek

ABSTRACT

To understand fully how fluids communicate between high conductivity fractures and lower conductivity matrices and how matrix-fracture mass transfer occurs, one needs to analyze the problem at different scales. In this paper, 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 reported previously in the literature (Rangel-German and Kavscek, 2001). The ultimate goal is to provide realistic information on how to model or simulate matrix to fracture transfer. Exhaustive pore-scale imaging of fluid flow driven by capillary imbibition was achieved. Pictures of the entire micromodel were also obtained to visualize the macroscopic behavior of the experiments. 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.

1. INTRODUCTION

Understanding and modeling flow behavior in naturally fractured rocks, including oil and gas reservoirs, geothermal, and environmental sites 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 pore-scale. Rangel-German and Kavscek (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 one is the named filling-fracture regime which 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. 3. 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. 3 is nearly one-dimensional water advance. They found that the mass of water imbibed scaled linearly with the square root of time for the instantly-filled fracture regime. These experiments and the proposed analytical model indicated that during the filling-fracture regime the overall rate of wetting fluid imbibed into the rock is proportional to time and that a considerable amount of water is imbibed. For a low injection rate, virtually all of the non-wetting fluid can be expelled from a square matrix block with all sides no-flow except the fracture face by the time the water front reaches the end of the fracture. This is because co-current imbibition apparently represents a more efficient displacement force than counter-current imbibition (Rangel-German and Kovscek, 2001; Pooladi-Darvish and Firoozabadi, 2000). Whereas the mode of imbibition is clearly counter-current within the instantly-filled regime, imbibition may be co-current while the fractures fill.

Water propagation and multiphase flow in fractured reservoirs depends upon, the combined, nonlinear effects of hydraulic connectivity and wettability of fractures, rock matrix permeability and porosity, matrix-block size, capillary pressure, and the interfacial tension between the resident and the imbibing phase. The rate of mass transfer between the rock matrix and fractures is significant, and calculation of this rate with dual-porosity reservoir simulations depends on matrix-fracture transfer functions incorporating shape factors. It is apparent that the transfer shape factors for totally immersed blocks (classic approach) will be different to those for blocks partially covered by water.

The ability of a fracture to conduct fluids at partial saturation is still one of the biggest unknowns in numerical reservoir simulation. In real reservoirs, wetting and non-wetting fluids will flow simultaneously in both fractures and the matrix, and the combination of these two flow processes results in a ‘combined’ relative permeability behavior that has not been determined. The difficulty of modeling this behavior comes from the fact that matrix and fracture interact in a specific manner depending on a number of parameters such as: fluid properties, rock properties, fracture properties, and the ‘combined’ properties. These combined properties include capillary pressure, relative permeability, and fracture continuity, and should be analyzed with the matrix and the fracture coupled.

To study the physics of this matrix-fracture transfer and to better understand some of the core-scale experiments regarding matrix-fracture interaction in the literature, we designed and built a micromodel and micromodel holder that mimic, macroscopically speaking, the set-up used in the core scale experiments of Rangel-German and Kovscek, 2001. This set-up allows observation of the water advance in the fracture and the pattern, extent, and mode of imbibition in the matrix at the pore scale. Micromodels are transparent networks of pores and constrictions that simulate some of the complexities of natural porous media.

We believe that the filling-fracture regime is mostly controlled by co-current imbibition, whereas the filled-fracture regime is controlled by counter-current imbibition. The objective of this paper is to prove the hypotheses and allow us to

observe whether the expulsion of non-wetting fluid from a matrix-block to a fracture takes place at pore-by-pore scale all along the fracture or if it occurs as “channels” that organize themselves at specific locations along the fracture to carry wetting fluid in one set of channels and non-wetting fluid in the other. This paper should also help in the efforts to derive general matrix-fracture transfer functions and to provide better recommendations on the use of non-zero fracture capillary pressure or the correct type of fracture relative permeability assumptions.

2. EXPERIMENTAL SET-UP AND PROCEDURE

Experiments at constant water injection rates into the fracture were performed using the micromodels and the general set-up described below.

2.1 Micromodels

Micromodels are transparent networks of pores and constrictions that simulate some of the complexities of natural porous media, as shown in Fig. 1a. Note the grains that appear as islands and the etched pores and throats. The etch depth is $25\ \mu\text{m}$. Generally speaking, micromodels have been developed to fill the need of researchers to see flow processes at the pore level (Buckley, 1999). They are produced with the objective of directly observing fluid flow through porous media. They contain an etched flow pattern that can be viewed with a microscope. The flow pattern can be a lattice of straight or constricted channels, or the pore network can be modeled after the pores found in naturally occurring rock. One limitation that is inherent to all micromodels is that they are only two-dimensional (George, 1999). Extrapolation of results to the three-dimensional flow problem occurring in real porous media must be done carefully. However, micromodels provide the best means to visualize fluid movement at the pore scale while honoring both geometric and topologic properties of real rocks. A detailed literature review on micromodels is provided by Buckley (1999).

2.1.1. Fabrication and Bonding of Stanford Micromodels

Etched-silicon-wafer micromodels of the type used by Castanier and Sagar (1998), 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 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. These patterns have grains ranging from the size of 30 to 200 μm (Fig. 1a). The porosity of these micromodels is roughly 0.2. The permeability of the micromodel is approximately 0.1 mD. These types of micromodels have been used to study flow behavior in multi-phase flow, oil-foam interaction, solution gas drive, contaminant hydrogeology, etc.

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. These micromodels contain some modifications as compared to those used by Castanier and Sagar (1998) and George (1999): narrow etched channels adjacent to the edges of the pore network carry fluid to the inlet/outlet ports. These channels allow fluid to enter and exit the porous medium at any point along the side of the pore network. The two parallel channels etched on the micromodels, thus, act as fractures adjacent to the porous medium as shown in Figure 1b.

The micromodels used for this work were fabricated at the Stanford Nanofabrication Facility (SNF), where we adapted fabrication techniques used for computer industry, such as microchips. The micromodels created this way offer 1:1 scaling of typical sandstone pores and, for this work, were made to represent Berea sandstone. There are two main steps in the construction of a micromodel:

2.1.2. Fabrication

The fabrication of a micromodel starts with the design and construction of a mask, which is a glass-chrome plate where the pattern (a digitalization of a rock section into a computer from a high quality photograph) is engraved. The mask is placed on a silicon wafer previously coated with a photosensitive chemical. The pattern of the mask is impressed on the wafer by means of passing ultraviolet light through the mask. The silicon wafer is developed and later etched with hydrofluoric acid (HF) to a depth of around 25-30 μm . In this way pore cavities are created. Flow channel depth is up to a maximum possible etching depth of 30-35 μm .

2.1.3. Cleaning And Anodic Bonding

The silicon wafer with the etched pattern is cleaned in a sulfuric acid (H_2SO_4) cleaning solution (Nochromix crystals and sulfuric acid) air dried, and then bonded to a glass plate to create a flowing medium. The procedure of bonding is simple, yet extremely important to guarantee a flow medium useful for the experiments. Firstly, the cleaned micromodel is placed with the pattern facing up on a previously heated hotplate at 600° F. This hotplate is connected to one of the electrodes (anode) of a power supply. The micromodel is left on the plate for around 45 minutes. The idea of this step is that the silicon becomes oxidized (because of the air at high temperature) resulting in the formation of a film of silicon dioxide, which is water wetting. The temperature is then dropped to 500° F. After the hotplate has stabilized to this temperature, a clean glass plate (cleaned with soap solution, then sulfuric acid solution, and then air dried) is placed on the micromodel. The other electrode (cathode) is placed on the top of the plate and the voltage on the power supply is brought to 1000Volts. After 50 minutes bonding should be achieved. Electricity is turned off and the new micromodel is allowed to cool to room temperature.

2.2. Micromodel Holder

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.

2.3. Microscope

A Nikon Optiphot-M reflected light microscope with a photo tube allowing for video imaging was used in the apparatus. The properties of the optical lenses used are outlined in Table 1. Working distance is the distance between the tip of the lens and the focal plane of the objective. Numerical aperture relates to the light gathering ability and is a dimensionless number between 0 and 1. The higher the value, the better the light gathering. The lens 50X magnifications were used to track the motion of the fluids in the micromodel, while the other lenses were used to focus on a specific portion of a micromodel to study fluid motion there.

TABLE 1. PROPERTIES OF THE OBJECTIVE LENSES

Model	Total Magnification	Working Distance (mm)	Numerical Aperture	Viewable Diameter (μm)
5X	50 X	20.0	0.1	3000
0.4LWD	200 X	6.0	0.4	800
0.5ELWD	400 X	10.1	0.5	375

2.4. Microscope Imaging

A television camera was used to record the images through the microscope into a video cassette recorder (VCR) that recorded at a speed of 30 frames per second. Then the images from the VCR were transferred to a Macintosh/PC computer system with the aid of imaging video/recording software.

2.5. Macroscopic Imaging

A commercial home-video digital camera was used as a second imaging device to obtain images of the entire micromodel (macro-scale) at different stages of the experiments. In these pictures the pattern and extent of imbibition in the entire micromodel was observed.

2.6. Pump, Filter and Fluids

An ISCO 100DM syringe pump (Instrumentation Specialties Co.) was used. This pump is very accurate for very low flow rates; i.e. 0.001 cc/min to 0.0001 cc/min. A Swagelock filter with a cartridge of 2-micron pores was used to filter out any small particles that might clog the micromodels. The properties of the fluids used in the experiments are shown in Table 2.

TABLE 2. FLUID PROPERTIES

Property	Water	Decane	Air
Specific Gravity	1.0	0.73421	0.0012
Viscosity	1.0 cp	0.95	~0.02 cp

2.7. Experimental Procedure

Experiments at different constant water injection rates into the fracture were performed. Injection rates were set at two values: one low and one high relative to the micromodel (0.001 cc/min and 0.01 cc/min). The fracture aperture was constant in depth and width as per the fabrication etching. This system mimics length, width, and approximate fracture aperture of the core scale set-up used with the CT Scanner to image in situ saturation reported in a previous work (Rangel-German and Kovscek, 2001). We performed experiments similar to those at the core-scale trying to achieve filling-fracture and instantly-filled fracture regimes using the low and high flow rates, respectively. Figure 3 displays typical core CT experiment results and illustrates the two different fracture-flow regimes. Both images were taken after 0.32 PV of water had imbibed into the core. White shading indicates water and black shading indicates air.

Setting the injection flow rate into the fracture, we observed the progress of multidimensional imbibition at two levels. At the first level, the pore scale was observed, and at the second level, images of the entire micromodel (macro-scale) were obtained. For the experiments reported here, water was injected on the left at constant rate and oil and water produced from the right-hand side. The objective was to have uniform advance of water along the fracture as was done with the core CT experiments. We performed experiments with water and air, water and CO₂, oil and CO₂; and water and oil. In the case of experiments with oil, CO₂ was first injected into the system to displace any gas and this was followed with oil. The CO₂ is relatively soluble in oil and the combination allowed the micromodels to be fully saturated with oil.

3. EXPERIMENTAL RESULTS

Following the aforementioned procedure, experiments were conducted to achieve filling-fracture and instantly-filled fracture regimes using low and high injection rates, respectively. The goal of the micromodel experiments was to observe how the non-wetting phase displacement and matrix-fracture interaction occurred at the pore level for two cases: when fractures were filling and when they were rapidly filled.

3.1. “Filling-Fracture” Regime

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 4 shows the images obtained of the entire micromodel for different times for the air-water system. Water is darkly shaded prior to water reaching the end of the fracture at 49 min., the imbibition pattern is two-dimensional.

The behavior of the filling-fracture regime is very similar to that observed during core CT experiments reported previously. Micromodel experiments allowed us to visualize how the non-wetting fluid is expelled within the pore structure.

Figure 5 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. That is, no air bubbles are seen in the watch filled portion of the fracture. Figure 6 shows a sequence of images of the filling of a section of the fracture close to the outlet. No air is expelled in the region covered by water but a small amount of air seems to be trapped close to the outlet. Figure 7 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. Figs. 4 and 7 illustrate that there is an elliptical imbibition pattern in the matrix. This lends 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.

A similar experiment was performed at this low flow rate (0.001 cc/min), CO₂ as the gas phase, but having all four ports open. The behavior of this experiment, during the filling-fracture regime, was found to be almost identical to the previous one. After the water front reached the end of the fracture, the water imbibed in a one-dimensional direction (perpendicular to the fracture) displacing the CO₂ and displaying a well defined front parallel to the fracture. In this case, the gas is not trapped (since all the ports are open) so the imbibition continues in a co-current mode. The advance of the front was found to be faster than that of the previous experiment (gas 'encapsulated')

and very little gas was trapped. These results support the assertion that co-current imbibition is a more efficient mechanism.

Because the advance of water in both directions (parallel and perpendicular to the fracture) each scale linearly with the square root of time, we anticipate that the mass of water imbibed scales linearly with time. That is, the mass imbibed in this two-dimensional geometry is proportional to the product of these two length scales.

3.2. “Instantly Filled” Regime

In this regime, little water imbibes before the fracture fills with water. Figure 8 includes the images obtained with the digital camera of the entire micromodel for different times for a water-air experiment. It shows that the water advance in the direction perpendicular to the fracture is nearly one-dimensional. Another important feature of this type of displacements is the production of non-wetting fluid through “channels”. Refer to image labeled 25 min. on Fig. 8, for instance.

Figure 9 shows microscope images during the “Instantly-filled fracture” regime focusing on the matrix-fracture interface. Almost no water is imbibed while the fracture fills. The water fills the fracture very fast and the air becomes “encapsulated” inside the micromodel; therefore, the non-wetting fluid can only be expelled by counter-current imbibition. Figure 10 shows images of the water advance in the matrix in the direction perpendicular to the fracture during “Instantly-filled fracture” regime. As it was observed macroscopically in Fig. 8, there is a well-defined spreading front parallel to the surface exposed to the imbibing fluid. Figure 11 shows the same water advance at 100X magnification close to the “channels”. One can see that there is a large amount of gas trapped/bypassed by water in these areas.

Similar experiments to the instantly-filled fracture regime were performed with water displacing CO₂ with very similar results. In this case some of the gas was also dissolved into the water so we could achieve 100% water saturation. Fig. 12 shows the trapped gas being dissolved and displaced at the end of this water-CO₂ experiment. This was done with the idea of eventually having a matrix saturated with oil to the irreducible water saturation. Once the matrix was completely saturated with water, oil was injected to displace the water.

The last experiment under instantly-filled fracture regime, and probably the most interesting, was conducted by injecting water into an oil saturated matrix with irreducible water saturation. Water was injected at 0.01 cc/min and no water imbibed while the fracture was filling. Once the water front reached the end of the fracture, it penetrated into the matrix displacing oil by counter-current imbibition. Fig. 13 shows how the oil is displaced through “channels” at discrete locations along the fracture. One can see how blobs of oil grew as more oil is pushed into them. Once the blobs have reached some critical volume they are displaced by the viscous forces in the fracture. This process was found to be intermittent; i.e., a blob grows, it is displaced, and after

some time a new blob starts to grow in the same location. However no constant periodicity was found.

The behavior of this second regime is very similar to that observed during both counter current and co-current imbibition experiments reported previously in the literature (Akin *et al.*, 2000; Handy, 1960; Cil and Reis, 1996; Reis and Cil, 1999; Reis and Haq, 1999; Rangel-German and Kovscek, 2000(a,b); Li and Horne, 2000; Zhou *et al.*, 2001; Rangel-German and Kovscek, 2001). The instantly-filled fracture regime is dominated by counter-current imbibition.

4. FUTURE WORK

As it was mentioned above, the objective of this paper was to prove a hypotheses on the mode of imbibition for filling- and instantly-filled fractures regimes. The ultimate goal of this ongoing research is to help in the efforts to derive general matrix-fracture transfer functions and to provide better recommendations on the use of assumptions while numerically simulating fractured systems.

One of our biggest concerns is the fact that current numerical simulators/formulations use transfer functions that include constant shape factors. It is clear from the results presented in this paper and the work by Rangel-German and Kovscek (2001) that the use of a constant shape factors for matrix block under filling-fractures regime will lead to erroneous results; most likely to pessimistic results. We have observed that the co-current imbibition nature of the filling-fracture regime is a much more efficient displacement process than the instantly-filled fracture (classic approach: totally immersed blocks). Mathematical analysis of the filling-fracture regime and the correct expression for the matrix-to-fracture transfer functions is our current focus of study.

A second concern is the case when a matrix block is adjacent to two fractures, but these fractures are not necessarily connected to each other. This is a very common case of clusters of parallel and disconnected fractures. This situation implies that neither the pressure nor the saturation within the fractures will be the same as it is supposed in the classic approach of totally immersed fractures. We believe that constant shape factors can be used for this kind of problems when dealing with instantly-filled fractures. However, we also believe that those shape factors will be quite different from those presented in the literature. This is because having different boundary conditions would eliminate the symmetry property under which previous shape factors have been developed. It is readily clear that the shape factors will not be constant when dealing with filling-fracture regimes.

For the case of parallel (and disconnected) fractures under instantly-filled fracture regime, we are undertaking the process of improving a method to calculate the water saturation profile as a function of distance from the fracture based on the micromodel images. Sets of images where obtained every two patterns (a pattern is the

unit used repeatedly to create the micromodels) from the injecting fracture to the opposite one. Three sets were obtained: one at a quarter of the distance from the inlet to the outlet; another set in the middle; and one more set at three quarters of the distance from the inlet to the outlet.

The calculation of the water saturation based on the micromodel images requires a complex processing of the images. Fig. 14 shows an example of the original image obtained through the microscope and the post-processing image obtained with the program written for this task.

The major difficulty to calculate the water saturation is the fact that the images obtained from the microscope are nearly monochromatic, which means that different tones of the same color are obtained. This makes it virtually impossible for any code to distinguish the rock grains from the liquids. However we can divide the images into two categories: gas and water and rock. Knowing that the micromodels have constant porosity we can work out the equations to calculate both the gas and water saturations. The value shown as S_w in the right image of Fig. 14 indicates the ratio of volume of rock plus water over the bulk volume.

5. CONCLUSIONS

A micromodel and micromodel holder were built that allow detailed visualization of fluid movement, matrix-fracture interaction, water advance in the fracture and the pattern, extent, and mode of imbibition in the matrix at the pore scale. The existence of two different modes of matrix and fracture fill-up found previously were verified and analyzed at the pore-scale. The "filling-fracture" regime represents a slow flow through fractures where fluid transfer is relatively rapid, fracture aperture is wide, and/or water injection is slow. Recovery scales linearly with time under this particular co-current imbibition mode. The "instantly-filled fracture" regime represents a rapid flow through fractures where relatively low rates of fracture to matrix transfer, narrow apertures, and/or high water injection rates. Recovery scales with the square-root of time on this counter-current imbibition mode. Experimentally, co-current imbibition was found to be more efficient than counter-current.

For a low injection rate, virtually all of the non-wetting fluid can be expelled from the matrix by the time the water reaches the end of the fracture. Although this filling-fracture regime may take longer than a fast injection/production rate, it represents a more efficient displacement in terms of recovery. ReInjection in a fractured reservoir that had an early breakthrough caused by high injection rate can become very expensive. When the fractures surrounding blocks are filled by water, non-wetting fluid from these blocks can only be produced by counter-current imbibition.

It was found that the reason for the more efficient displacement of the filling fracture regime comes from the fact that it takes place in a co-current imbibition mode.

Thus, little non-wetting fluid is trapped as the water front advances. Most of the non-wetting fluid is produced in the non-wetting phase.

Since matrix-fracture interaction is controlled by the injection rate, it is apparent that the relative permeability relationships are rate dependent. Wetting and non-wetting fluids will flow simultaneously in both fractures and the matrix, and the combination of these two flow processes results in a combined relative permeability behavior that has not been determined. These experiments help in the understanding of matrix-fracture interaction and maybe useful while modeling real fracture relative permeability and matrix-fracture transfer functions.

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Figure 1. Schematic of the micromodel: The network acts as the porous medium and the adjacent channels act as the high conductivity fractures.

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

Figure 3. CT saturation images showing the imbibition regimes: “Filling-fracture” and “Instantly-filled fracture”. (After Rangel-German and Kovscek, 2001).

Figure 4. Images of the micromodel showing “filling-fracture” regime.

Figure 5. Microscope images of the micromodel during “Filling-fracture” regime.

Close to inlet.

Figure 6. Filling of a section of the fracture close to the outlet.

Figure 7. Water advance in the matrix in the direction perpendicular to the fracture.

Figure 8. Images of the micromodel showing “Instantly-filled fracture” regime.

Figure 9. Microscope images of the micromodel during “Instantly-filled fracture” regime.

Figure 10. Water advance in the matrix in the direction perpendicular to the fracture during “Instantly-filled fracture” regime.

Figure 11. Water advance in the matrix in the direction perpendicular to the fracture during “Instantly-filled fracture” regime. 10X Magnification.

Figure 12. Gas dissolution in water in the matrix.

Figure 13. Production of oil by counter-current imbibition of water.

“Instantly-filled fracture” regime.

Figure 14. Calculaton of water saturation from micromodel images.

An Experimental Study of Imbibition in Diatomite and Chalk

S.S. LeGuen, A.R. Kovsky and L.M. Castanier

ABSTRACT

Studying fluid displacement in low permeability rocks allows petroleum engineers to better handle oil production. So researchers try to understand the imbibition process which plays a leading role in oil recovery. Thanks to an X-ray computerized tomography scanner saturation profiles can be drawn for oil-air and water-oil experiments. A special imbibition cell has been designed in order to hold diatomite, sandstone and chalk cores. Furthermore, scanning electron microphotographs and porosity scans were used to interpret our experimental results. Lastly, we confirmed the established theory that states that recovery increases proportionally with the square root of time.

1. LITERATURE REVIEW

In order to improve oil recovery, petroleum engineers try to better understand the process of displacement of oil towards the producing wells. Primary recovery corresponds to the volume of hydrocarbons produced with the energy available in the reservoir. Secondary recovery consists of the injection of fluids, which leads to an increase in the natural energy of the reservoir fluid system. The success of an injection project depends on well placement, fluid characteristics and formation quality.

This study deals with the comparison of imbibition between diatomite and chalk. Imbibition defines the process by which a wetting fluid displaces a non-wetting fluid. The capillary suction forces the wetting fluid to remain around the pore structure of the rock while the non-wetting fluid is extruded.

In the case of fractured systems, the stronger the imbibition forces are, the more efficient the recovery becomes. If imbibition cannot play a major part in the waterflood, water will be led through the fracture network between injector and producer and the waterflood will be a failure.

After studying the properties of diatomite and chalk, a brief presentation of the experimental set-up and its features will be made. Then it will be possible to compare those results with the theory regarding imbibition.

1.1. Diatomite and Chalk

The process of fluid injection such as waterflooding is linked to the fundamental properties of the porous medium. Imbibition depends on capillary pressure and

properties of fluid and rock. Porosity represents the proportion of the void space available in the rock. Permeability measures the medium's capacity to transmit fluids. Saturation is the fraction of gross void space occupied by a fluid. Although diatomite and chalk look alike because of their color and texture, their compositions and properties could account for their different behaviour with regard to imbibition.

Diatomite is a sedimentary rock composed of the fossilized skeletal remains of diatoms, one-celled algae-like plants ranging in size from 10 to 200 microns. The honeycomb silica structure gives diatomaceous earth a high absorptive capacity, chemical stability and low bulk density. So its permeability fluctuates between 0.1 mD and 10 mD and its porosity varies from 35 % to 65 %. The United States is the world's largest producer and consumer of diatomite. The major end applications are in filtration, absorbent and fillers.

Chalk is a porous marine limestone composed of fine-grained remains of micro-organisms with calcite shells, coccolithophores. Whereas diatomite is a hydrous form of silica SiO_2 , chalk consists mainly in calcium carbonate CaCO_3 . The Austin Chalk of the United States Gulf coast is a prolific, fractured oil reservoir that spurred widespread horizontal drilling activity.

1.2. Imbibition

As crucial as the rock characterization may be, the properties of fluids must be known in order to interpret the efficiency of the spontaneous imbibition. Thus the mass of water imbibed by the core depends on all the fundamental properties of the rock and the fluid (Handy, 1960).

$$m = \rho_w A \left(\frac{2P_c k \Phi S_w}{\mu_w} \right)^{1/2} t^{1/2} \quad (1)$$

In Eq. 1, m is the mass of imbibed water, ρ_w is the density of water, A is the cross-sectional area of the core, P_c the capillary pressure, Φ is the porosity, k is the permeability, S_w is the aqueous phase saturation, μ_w is the wetting-phase viscosity and t is the time. So, the mass of imbibed water varies according to the square root of time. Our experiments will be compared to this theory.

2. EXPERIMENTAL APPARATUS AND METHODOLOGY

In this section we briefly describe the equipment and procedures used for our experiments.

2.1. Experimental Set-up

To obtain saturation profiles and porosity images of cores we use a Picker™ 1200 SX CT-scanner. This give an inside view of the core without stopping the experiment

or destroying the sample. The computerized X-ray tomography (CT) scanner is composed of 1200 detectors located in a circular fashion within the gantry. The X-ray source rotates around the object in a circular path with an angle of 398° . After determining the best settings for our experiments, the tube current is 95 mA and the voltage is 130 kV. The scanner analyses a slice of the core of 5mm thickness. The gray scale images displayed on the monitor represent CT numbers in Hounsfield units. Those pictures are processed quantitatively with the software Fpviewer™, which allows determination of saturation profiles and porosity during the imbibition experiments.

As illustrated in Fig. 1, the whole length of the core is scanned and a series of scanning pictures show the progress of the fluid inside the rock. To minimize artifacts, a special imbibition cell was designed as shown in Fig. 2. The cell is composed of two chambers : the water jacket contains the first chamber which is the core holder. First of all, the rock is drilled so that a cylindrical core with a circular cross section was built. The core measures 8 cm in length and 2.6 cm in diameter. In the length, the rock surface is covered with a layer of epoxy (Epoxy 907, Miller-Stephenson Chemical) and potted in an acrylic tube. Then the two endcaps of the core holder are fixed on the two clear areas of the sample, the top and the bottom of the core, which constitutes a hermetic chamber. The core holder is introduced into the cylindrical water jacket in a vertical position. Lastly, the second chamber is filled with distilled water and tightly closed. It ensures a constant temperature in the rock during experiments. The whole system is mounted on a positioning system on the couch of the scanner. Two positioning lasers are used to ensure proper centering and horizontality of the experiment.

2.2. Imbibition Experiments

2.2.1. Oil-Air Experiments

First, the core is saturated with oil by injecting n-decane using a liquid chromatography pump which creates a flow rate of 5 cc/min. The endcap on the bottom of the core is closed and oil is introduced by the top. Oil goes through the fracture dug in the endcap, decane is imbibed by the core and the non imbibed oil and air come out by the other pipe on the top. While the imbibed oil goes down because of gravity, air has to rise through the pores of the rock to go out the core. This process is called counter-current imbibition. On the contrary, for the second diatomite sample, oil enters the core through the bottom and the top pipe is opened so that oil goes up and pushes air outside. This is called co-current imbibition.

The oil whose properties are mentioned in the Table 1, is recycled to ensure a constant pressure in the capillary pipes. At the beginning of the experiment, scanning images are taken every minute for the three first minutes, then it is possible to increase the interval up to one picture every hour. Actually, the process becomes slower because in imbibition, displacement of fluid depends on the square root of time.

By subtracting CT images, porosity scan and saturation profiles can be created. It appears that the image of the dry core is essential for these calculations. That is the reason why before starting any experiment, all cores were placed in a vacuum oven for 24 hours or more in order to obtain completely dry samples.

Equation 2 gives the calculation of the porosity from the CT images :

$$\Phi = \frac{CT_{wet} - CT_{dry}}{CT_{oil} - CT_{air}} \quad (2)$$

where CT means the CT value for a voxel. The subscripts wet and dry refer to the oil saturated core and the dry core. The subscripts a and o refer to the CT values of air and oil phase.

The calculations for oil saturation profiles need to use the formula (Eq. 3):

$$S_o = \frac{CT_{object} - CT_{dry}}{CT_{wet} - CT_{dry}} \quad (3)$$

where the subscript object refers to the image being processed. Before beginning water-oil experiments, it is useful to wait 8 hours to be sure that the core is fully saturated with oil.

2.2.2. Water-Oil Experiments

Water is then introduced in the same way as oil and the recycling system is stopped. 2 wt % of potassium bromide or sodium bromide are added to water so as to better distinguish the oil phase from water on profiles. Given the difficulty of fully saturating the core by draining off the imbibed oil, it is better to use the Eq. 4 to draw water saturation profiles:

$$S_w = \frac{CT_{object} - CT_{wet}}{\Phi(CT_{water} - CT_{oil})} \quad (4)$$

where Φ refers to the porosity scan. The subscripts o and w refer to CT values of the oil phase and water. The subscripts object and wet refer to the image being processed and the image of the fully oil saturated core.

Table 1. Fundamental Properties of Fluids.

	Water	N-Decane	Air
CT-number	-290	-570	-1275
(H)			
μ (mPa.s)	1.0	0.84	0.018
ρ (kg.m ⁻³)	1000	730	1.82

3. RESULTS

We first discuss rock characterization via various methods, then the imbibition results.

3.1. Rock Characterization

3.1.1. *Scanning Electron Microphotograph*

The scanning electronic microphotograph (SEM) reveals the pore structures of rocks and the size of diatomite and chalk pores. Put on a piece of carbon, the samples are covered with a palladium-gold (Pd-Au) coating, which acts as a conductor. The slightest area on the surface of the samples could be observed and enlarged up to a 100 000 $\times$ magnification. On Figs. 3 and 4, the SEM images of diatomite and chalk at several magnifications 500 $\times$, 2000 $\times$ and 5000 $\times$ show pore structures that appear thorny. We can clearly see significant structural differences between the rocks in terms of pore shape and size.

3.1.2. *Porometer*

We used a Ruska Universal Porometer (model 1051-801) which is an accurate apparatus for determining porosity of cores by using the mercury injection method. A clean dry sample of the cylindrical core with a diameter of 2.5 cm and a length of 3.2 cm is placed in the chamber of the stainless steel pycnometer. After having filled the pump cylinder with approximately 4 pounds of mercury, the plunger is advanced so that the capillary pressure reaches 910 psi, which provides the saturation of the sample with mercury. Mercury is injected at different pressures and the volume of mercury injected in the core recorded. The scale of volume has been translated in a scale of saturation: the largest measured volume has been considered as representing a mercury saturation of the core equal to 0 and a wetting phase saturation equal to 1. Figure 5 shows the chart giving the capillary pressure versus the wetting phase saturation. The curve shows a plateau as the Leverett correlation for air and water drainage behavior of clean sands.

3.2. Imbibition Results

Three experiments have been run, two of them with diatomite cores and the last one with a chalk core.

3.2.1 *Saturation Profiles for Diatomite in Counter-Current Imbibition*

Small fractures between the rock and the layer of epoxy were visible to the naked eye. Thus it is not really astonishing to observe that oil enters the rock by the side where there should be a fracture.

Figure 6 shows the saturation profiles for an oil-air experiment. On these pictures white means the rock is saturated by oil and black means the core is dry. At the beginning of this experiment, oil enters the core on the whole clear area at the top and the marked oil front goes down in a piston manner. It can be observed very quickly that oil has already begun to enter by the side of the core at the same time. Decane is progressively imbibed in an uneven way until it reaches the middle of the core. Then the oil front becomes less and less sharp. Some colors appear on the images, which proves the diffusion to increase.

In Fig. 8, times beneath the images are given in minutes. Water imbibition appears as a slower process than oil imbibition. For 22 hours, water has spread through the core.

3.2.2. Saturation Profiles for Chalk in Counter-Current Imbibition

The same experiment has been realized with chalk. On Fig. 8, white means oil saturated core and black means dry core. The front is very sharp at the beginning and diffusion can be observed after 426 minutes of experiment. As Fig. 9 illustrates, the water-oil experiment is slower than the oil-air experiment and the full saturation is not obtained. However, contrary to the imbibition with diatomite, the diffusion is not very obvious. The two last pictures look the same.

3.2.3. Saturation Profiles for Diatomite in Co-current Process for Oil Imbibition

First, the diatomite core is saturated by oil with a co-current imbibition process. Decane imbibes the core from the bottom. By putting the oil reservoir at a higher level than the cell, oil faster flows into diatomite. It reaches the top of the core after 9 hours as shown on Fig. 10. The oil front is initially sharp and gradually diffuses. After waiting 15 hours to ensure complete saturation of the core, water is introduced by the top. In Fig. 11 we can see that the water diffusion appears more considerable than the oil diffusion. The last image has been taken 50 hours after water was introduced so the core is supposed to be saturated by water. Water imbibition appears slower than oil imbibition in air saturated cores.

3.2.4. Porosity Scan

Porosity represents the percentage of the void space in the core, Fig. 12. The average porosities for diatomite cores are 38 % and 56 %, which shows that diatomite porosity really depends on the chosen sample. For chalk, the average porosity is 16 %. So, diatomite contains more void than chalk. Furthermore, black points on chalk porosity scan prove the presence of clay in the rock. So it becomes harder to foresee the displacement of oil or water in the rock. On the second diatomite core, there is a darker layer at the end of the core which looks like a fracture. During the experiment, oil and water go faster into the core through that irregularity, which could be easily seen on the CT images.

3.2.5. Recovery

As Eq. 1 shows, the mass of imbibed fluid is linked to the saturation of this fluid. Thus, the recovery can be compared to the saturation. By using the saturation average of each picture, it is possible to draw the recovery versus the square root of time in order to check theory with experiments. As Fig. 13 illustrates for diatomite, the relation between recovery and the square root of time is linear in the case of oil-air and water-oil experiments. Regarding experiments with chalk on Fig. 14, the linear relation is not so obvious. In the oil-air experiment, the linear property of the curve has been checked only for two hours. Moreover, the first 30 minutes do not give any results of recovery. It could be due to the imbibed oil. Actually, decane creates a kind of film on the top of the core and the flow rate of the pump is not powerful enough to destroy it in order to let water imbibe the rock. So waiting some hours is necessary to observe water imbibition.

4. CONCLUSION

The experimental apparatus composed of the CT-scanner and the special imbibition cell provides the possibility to observe quantitative saturation profiles. These CT images represent an efficient means to observe fluid displacements inside the rock.

The imbibition process in diatomite appears to be faster than in chalk. The imbibed fluid enters the rock in piston like manner so the saturation front is sharp. Next diffusion can be observed while imbibed fluid is going on spreading in the core. Thanks to calculations based on CT images, theory is confirmed since mass of fluid imbibed depends on the square root of time.

5. NOMENCLATURE

A	cross-sectional area
CT	CT number
k	absolute permeability
m	mass of water imbibed
μ	viscosity
P_c	capillary pressure
Φ	porosity
ρ_w	water density
S_o	oil saturation
S_w	water saturation
t	time

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Figure 1. Schematic of the experimental set-up.

Figure 2. Schematic of the imbibition cell.

Figure 3. Scanning electron microphotographs of diatomite pore structure at 500 $\times$ magnification (left), 2000 $\times$ magnification (center) and 5000 $\times$ magnification (right).

Figure 4. Scanning electron microphotographs of chalk pore structure at 500 $\times$ magnification (left), 2000 $\times$ magnification (center) and 5000 $\times$ magnification (right).

Figure 5. Capillary pressure versus wetting phase saturation for diatomite and chalk samples.

Figure 6. CT-derived oil saturation images of oil imbibition in dry core of diatomite. Times beneath the images are given in minutes.

Figure 7. CT-derived water saturation images of water imbibition in oil saturated core of diatomite. Times beneath the images are given in minutes.

Figure 8. CT-derived oil saturation images of oil imbibition in dry core of Chalk times beneath the images are given in minutes.

Figure 9. CT-derived water saturation images of water imbibition in oil saturated core of chalk. Times beneath the images are given in minutes.

Figure 10. CT-derived oil saturation images of oil imbibition in dry core of diatomite. Times beneath the images are given in minutes.

Figure 11. CT-derived water saturation images of water imbibition in a oil saturated core of diatomite. Times beneath the images are given in minutes.

Figure 12. Porosity scans for diatomite (left and right) and chalk (middle) with porosity scale.

Figure 13. Recovery versus square root of time for oil-air experiment (left) and water-oil experiment (right) with diatomite core.

Figure 14. Recovery versus square root of time for oil-air experiment (left) and water-oil experiment (right) with chalk core.

HOT FLUID INJECTION

Injecting Steam into Light Oil Diatomite Reservoirs

B. Todd Hoffman

ABSTRACT

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.

1. INTRODUCTION

A simulation study of steamflooding diatomite reservoirs that contain light to medium weight oils has been carried out. The work was accomplished using the commercial thermal simulator STARS. This paper begins by giving some background on the problem and why it needs to be studied. Next, the models that are used are described in moderate detail. Then, the results are displayed and discussed, and finally, the applicability of this work to other areas is illustrated.

1.1. Background

By way of review, steam injection, as an enhanced oil recovery technique, is discussed first, and then the challenges of unconventional reservoir are considered.

Both steam injection and unconventional reservoirs have a long and interesting history in the oil industry.

1.2. Steam Injection

In 1952, steamflooding was initiated as an enhanced recovery technique. The famous pilot at Yorba Linda Field in California began the steam drive process into oil reservoirs. Through the 1950's and 1960's steamflood technology was in the initial experimental phase with a number of pilot tests. This early work determined that steam injection is generally most efficient in highly permeable rock ($k > 1$ Darcy) and thick sands, usually greater than 30 feet. Once industry had gained enough confidence from these pilot tests, it was ready to make significant investments in steam flooding. By the 1970's a number of fields had benefited from steamdrive technology, and production peaked (Fig. 1) in the mid 1980's and has since been fairly constant. The important aspect of Fig. 1 is this production has been almost exclusively from the heavy oil realm (Blevins, 1990).

Light or medium oil steam flood (LMOSF) also had its roots in California. In the 1960's, one of the first LMOSF field trials was initiated at the Brea Field near Los Angeles. Brea consisted of steeply dipping sands that had an average permeability around 70 md and a typical porosity value about 22% (Volek and Pryor, 1972). The development of LMOSF was not as rapid as with heavy oil. Heavy oils benefit tremendously from steam injection, compared to waterflood, because of the oil viscosity reduction caused by the increase in reservoir temperature. In many instances, heavy oil can only be produced with enhanced thermal recovery such as steamflooding. Unlike heavy oils, light oils typically produce very well from water drives, and because water drives are seen as less risky with less initial investment than steam injection, LMOSF were developed more sparsely (Hanzlik, 1981). Nevertheless, there are a number of applications where LMOSF seem to be a good alternative to waterflooding, for example highly dipping reservoirs where steam assisted gravity drainage improves the recovery process, and confined unconsolidated sandstones where residual oil saturations can be very low, around 5%. Additionally, application in low-permeability highly-fractured reservoirs, such as diatomite, is also promising (Johnston and Shahin, 1995).

1.3. Non-Conventional Reservoirs

Low-permeability fractured reservoirs contain a large volume of oil around the world, yet production from these reservoirs has been modest. Primary production is notoriously low, usually 5% - 10% of the original oil-in-place. Furthermore, waterfloods in these reservoirs usually suffer from low injectivity, poor sweep, and injector-to-producer linkage which all tend to degrade the waterflood's effectiveness. All of these factors have facilitated an attempt to use enhanced recovery techniques, such as steam injection, to increase the recoverable reserves. The Teapot Dome Field in central Wyoming was an early attempt to steamflood a light oil (32° API) in a low-

permeability fractured reservoir (Olsen *et al.*, 1993). While this reservoir did not perform up to initial expectations, it showed that steam injection into these types of reservoirs is feasible. Also, the importance of steam quality and ϕ So was more clearly understood.

One specific type of the low-permeability fractured reservoir is diatomite. Pure diatomite is a hydrous form of silica composed almost entirely of the skeletal remains of unicellular aquatic plants called diatoms. These skeletal remains collect at the sea bottom along with silts, sands, and mud. A general observation is that the fewer the impurities with the diatoms, the higher the porosity and permeability. Porosity can range from 25% for the silty diatomite to 65% for the clean diatomite. An interesting property of diatomite is that it can have very high porosity, but unfortunately, its permeability is extremely low, ranging from 0.01 – 10 md. This is due to the extremely small size of the diatoms and diatom fragments. Another important feature of diatomite is a high pore-volume rock compressibility, yet some formations may contain a network of permeable natural fractures. This apparent inconsistency is because of the brittle nature of diatomite when it encounters non-compressive loads. Huge reserves lie in diatomites in the San Joaquin Valley of California. These diatomite reservoirs consist of a series of stacked layers separated by virtually impermeable shale layers. This makes fluid and heat communication among layers in the vertical direction exceptionally poor (Kovscek *et al.*, 1996 I, II). Diatomite is a complex rock-type that makes understanding the oil recovery mechanism very challenging.

Steamflood pilots in diatomites have shown positive results for at least three different operations. First, in the Cymric Field in San Joaquin Valley, CA, cyclic steam injection has been successfully used to produce a heavy oil (14°API) (Kumar and Beatty, 1995). In such a reservoir, heavy-oil and very low permeability, there is little to no primary or waterflood production therefore steamflooding makes an unproductive field productive. In the South Belridge Field also in the San Joaquin Valley, two separate continuous steam injection pilots were initiated. One is in the heavy oil part of the reservoir, and one in a more intermediate weight oil. The heavy oil pilot showed positive response to steamflooding but was economically unsuccessful due to high steam to oil ratios (Murer *et al.*, 2000). The pilot in the intermediate part of the reservoir was very promising. Early results on a single pattern showed that steamflooding could dramatically improve the amount of oil recovered from waterfloods (Johnston and Shahin, 1995). A multi-pattern project is currently underway to verify the previous results and determine the economic viability of a full-scale implementation.

Throughout the U.S. and the world there is a significant amount of light and medium oil in low-permeability fractured reservoirs. The success of fields like South Belridge show that a considerable amount of oil can be recovered from this type of reservoir. However, much of the recovery process is not well known in these reservoir applications. This study attempts to better describe this recovery process. Even though a diatomite reservoir is used as a model, this work can be extended to other low-permeability fractured reservoirs. The only difference with diatomite may be its high porosity, which will be treated in the next section.

1.4. Issues

Three separate subjects are to be covered in this work. First the stability of the steam front will be analyzed. The second issue will deal with the importance of individual recovery mechanisms, and the third will show the temperature and fluid profiles for steam drive in this type of reservoir.

1.5. Steam Front Stability

Steamflooding is considered to be a stable displacement process on a microscopic and core scale which leads to increased stability on the reservoir scale. The tendency of steam to “finger” beyond the front is suppressed by condensation of steam within the finger as it comes in contact with the lower temperature reservoir (Farouq, 1982). However, when the porosity is high, there is less rock to dissipate the heat; therefore less suppression of the instabilities. Depending on the porosity and other reservoir properties, the typical assumption of stability in steamfloods may not be valid.

Burger *et al.* (1985) published a method that relates steam front stability and rock properties. It starts with the mobility divided by Darcy velocity for the displaced fluid, and that is divided by the mobility divided by the Darcy velocity for the displacing fluid, so that you have the following equation:

$$\frac{\frac{k_{rw}}{\mu_w \bullet V_w}}{\frac{k_{rs}}{\mu_s \bullet V_s}} > 1 \quad (1)$$

where the subscripts w and s stand for water and steam, respectively. If the result is greater than one, then the process is considered stable. Upon assumption that the relative permeability for the displacing fluid is approximately equal to that of the displaced fluid, useful information can be drawn from

$$\frac{\mu_s \bullet V_s}{\mu_w \bullet V_w} > 1 \quad (2)$$

Burger *et al.* presented an expression to calculate the ratio of Darcy velocities, V_s/V_w , and it is displayed below.

$$\frac{V_s}{V_w} = \frac{1 + \frac{1 - \phi}{\phi} \frac{(hc)_s (T_h - T_r)}{\rho_{v,T_r} H_{v,T_h}^{Tr}}}{1 + \frac{1 - \phi}{\phi} \frac{(hc)_s (T_h - T_r)}{\rho_{w,T_r} H_{v,T_h}^{Tr}}} \quad (3)$$

where:

- ϕ is porosity,
- (hc_s) is average heat capacity per unit volume of solid matrix,
- T_h is steam temperature,
- T_r is reservoir temperature,
- $H_{v,T_h}^{T_r}$ is steam vapor enthalpy from reservoir temperature to steam temperature,
- ρ_{v,T_h} is vapor density at steam temperature,
- ρ_{w,T_r} is water density at reservoir temperature,
- μ_v is vapor viscosity, and
- μ_w is water viscosity.

This method was used to determine if steamflood in diatomite is a stable displacement process. The enthalpy and temperature of the saturated steam, along with the density and viscosity of both water and vapor, are calculated from correlations from Ejogu and Fiori (1987). The correlation for most of these properties is only a function of pressure. The viscosity correlations are a function of both temperature and pressure. Consequently, the results of the equation are only a function of porosity, heat capacity of the solid matrix, reservoir temperature, and pressure. Reservoir temperature has little effect on displacement stability. Heat capacity, within its known range, also changes the calculations only a small amount. Therefore, the stability parameter versus pressure is plotted for the range of porosities 25% to 65%. The outcomes are presented graphically in Figure 2, and lead to some interesting results. For a pressure of 500 psi, the steam front is stable for all porosity values in our range. At 2500 psi, the front will be unstable for all porosity values. Steam injection pressures ranging from 500 to 1200 psi have been reported for diatomite projects (Kovscek *et al.*, 1996 I, II). Figure 2 indicates that the more porous diatomite layers could be close to the stability limit and unstable at the largest injection pressures.

Due to this apparent instability in the highest porosities, the issue of steamflood stability will be examined in detail with the model. Multiple cases with increasing porosities will be completed and viewed to see if and where instabilities occur. Where the instabilities occur we will see how they affect our reservoir performance and in what magnitude.

1.6. Mechanisms

Whether steamflooding is applied to heavy or light oils and high or low permeability reservoirs, the general mechanisms remain the same. The difference occurs in the amount a particular mechanism effects a particular hydrocarbon reservoir (Blevins *et al.*, 1984). Figure 3 qualitatively displays one view of the roles certain mechanisms play for light to heavy oils. In the literature there is a significant detail paid to steamflooding mechanisms. Wu (1977) presented a critical review of

steamflood mechanisms. He and others have identified the following, which should be considered a thorough but not exhaustive list:

- viscosity reduction;
- distillation (vaporization);
- distillate (in situ solvent) drive;
- steam (gas) drive;
- thermal expansion;
- relative permeability and capillary pressure variation; and
- gravity segregation.

However, it can be seen from Fig. 3 that the three most important mechanisms are viscosity reduction, thermal expansion and vaporization. In high viscosity reservoirs, the objective of steamflooding is to increase oil production by reducing oil viscosity; thus allowing oil drainage at significantly higher rates. Conversely, for low viscosity oils the primary objective is to reduce residual oil saturation below that obtainable by ordinary waterflooding, which is primarily accomplished through vaporization. In fractured systems or highly heterogeneous reservoirs, thermal conduction allows heat to sweep areas of the reservoir not contacted by steam. In this case, thermal expansion is an important recovery mechanism.

While Fig. 3 presents a nice qualitative description of the recovery mechanisms for a general reservoir description, the relative importance of each mechanism is only speculated. This work attempts to quantify the relative importance of each mechanism for LMOSF in diatomite. It is important to understand the role of each mechanism because that information gives insight on how to best develop the steamflood.

1.7. Saturation Profiles

When steam is constantly injected into a continuous oil-bearing reservoir layer, several separate zones develop in the reservoir. Figure 4 displays one interpretation of how this profile may form. It includes four zones (steam, distillate, hot water, and oil) in a manner that only slightly takes into account gravitational forces. The way these zones are formed is of particular interest to LMOSF. When the initial steam contacts the cold reservoir, the steam is condensed to hot water. As the reservoir is heated up, some steam will remain in the vapor phase and a steam zone begins to develop. In this steam zone, the high temperature causes some of the hydrocarbons to be vaporized. As more steam is injected, the vaporized oil is carried forward along with the steam. A portion of the steam and distillate condense at the steam front causing a distillate bank to form.

Remembering that Fig. 4 is only one interpretation for a general reservoir, this research will attempt to find how the zones develop for our particular model. In a diatomite reservoir, each discrete layer is relatively thin so that gravitational forces do not greatly affect the profile; therefore, gravity can be ignored in this case. Because the

well spacings are close in most diatomite reservoirs (85 - 340 ft.), it has been hypothesized that the distillate zone does not have enough time to form. The critical time and length the specific zones begin to occur and when each particular zone reaches the producer will be determined. Also, we will find the size of different zones and if all the speculated zones actually develop.

1.8. Model Framework

The simulator STARS from the Computer Modeling Group will be used to perform the runs. The following sections layout the framework for the model that will be used. At first describing the general rock and fluid properties along with the initial conditions. Then the 4 different reservoir descriptions will be covered, and last to be covered will be what is changed for the different issues being studied.

1.9. General Set-up

This model attempts to represent a injection-production well pair development typically seen in diatomite reservoirs. Wells are 116.5 feet apart from each other. Much of the rock and fluid data used in this model comes from a previous reservoir model AERA Energy LLC had used. The fluid is characterized by three hydrocarbon components, a light, medium and heavy component and a water component. The fluid properties are developed from upscaling crude oil compositional analysis and fluid property evaluation. Table 1 shows the properties for each component.

Table 1. Component Fluid Properties

	Water Comp.	Heavy Comp. (1)	Medium Comp. (2)	Light Comp. (3)
Molecular Weight	18	530.7	152.7	27.89
Critical Temperature	705	10000	458.2	550
Critical Pressure	3217	10000	710	728
Density	62.4	58.51	52.28	34

Thermal expansion, liquid compressibility, and viscosity are all treated with equations using inputs for each component. Mole-fraction weighted oil viscosity as a function of pressure for the original composition is shown in Fig. 5.

Relative permeability for the oil-water and liquid-gas relationships is shown in Fig. 6 as the black lines. This relative permeability curve comes from one of twenty-eight different diatomite packages represented in the AERA model. In the that model, relative permeability was adjusted to match historical production data. The basecase curve roughly represents a median of the 28 separate curves. A second set of relative permeability curves was used for a sensitivity analysis, and they are displayed in Fig. 6 as the lighter curves. These curves represent the oil-wet end of the 28 available curves.

Initial pressure of the system is equal to 400 psi and initial oil saturation is equal to 0.50. The product of oil saturation and porosity is equal to 0.25, indicating that this is a good candidate for an enhanced oil recovery process. This is typical of a system that has produced on before steam injection commences. Also, there is no initial free gas saturation present; however, for a sensitivity case one run was completed with some initial free gas. The difference between the injection pressure and producing bottom-hole pressure (BHP) was held constant at 725 psi. In the 2 dimensional cases the injection pressure is 800 psi while the BHP is 75 psi. For the 1D case the injection pressure is 1125 and the BHP is equal to 400 psi. The 1D case's BHP had to be set to the initial pressure to prevent pressure depletion by the producer, which would have confused interpretation of mechanisms. The quality of the injected steam is 0.70. Initial reservoir temperature is 100°F and increases to above 500°F near the injector. The duration of the simulation runs are different for different models, but all are at least 1.0 hydrocarbon pore volume injected (HCPVI) and typically around 1.5 HCPVI.

1.10. Model Dimensions

Four separate model descriptions were used. The first was a 1D model with homogeneous permeability (2 md) and porosity (50 %). There is one injector and one producer that are 116.5 feet apart. The model is discretized with 50 blocks. The 1D model is used as part of the mechanisms study and to determine the saturation and component profiles.

The second model was also homogeneous with the same permeability and porosity as the 1D case, but it is 2D in the x-y direction. Again, the two wells are 116.5 feet apart, but in this case, one half of a hydraulic fracture (136.5 feet) in the orthogonal direction of the wells is also included in the model (Patzek, 1992). The total length of the model in that direction is 166.5 feet (Fig. 7).

There are 2500 total gridblocks; 50 in the x-direction and 50 in the y-direction. The height of the model is constant at 2.33 feet, so that we are modeling only one thin layer in a series of possibly 30 layers in the actual reservoir. This 2D model was used for the mechanism study, and the stability runs were completed on this model as well, however due to the homogeneous nature of the model, little information is gained from the stability element.

The third model is very similar to the second model (2D and same size), but the permeability and porosity are variable. The porosity is created using unconditional sequential Gaussian simulation (SGS) with a mean of 0.50, and a standard deviation of 0.20, and a minimum cut-off value of 0.25 (Fig. 8). In the SGS, no preferential direction was selected for the porosity. The permeability is calculated from the porosity using the following equation:

$$k = 100(\phi - 0.25)^{3.5} \quad (4)$$

and its mean was 1.8 md. Current thought says that this type of model is most representative of what is actually in a layer of a diatomite reservoir. This 2D geostatistical model gives good insight to both the stability issue and the importance of the various mechanisms.

The last model is a 2D geostatistical model with preference in the y-direction, a “thief zone” model. The mean and standard deviation of both the porosity and permeability were the same as the isotropic case, it is just distributed in a different manner. The porosity model is displayed in Fig. 9. This model represents a common feature of diatomite reservoirs, injector to producer link up. In reservoirs this is modeled here as high permeability streaks. This model is a description of reservoir conformance caused by injection induced fractures, but it is; here it signifies poor areal conformity, but it could also represent unconformities in the vertical direction, which are known to exist. This model offers some information about the mechanisms and it is very important when looking at the stability of the front.

1.11. Stability

Stability runs were made for all three 2D cases, however the two geostatistical cases provide the most information. For each model description, three separate runs were completed. They were exactly the same except for their porosity. One was a sandstone case with porosity of 25%; one was the diatomite basecase with 50% porosity, and one was a high porosity diatomite at 70 %. For the homogeneous case these values were constant and for the geostatistic cases these were the mean porosity values. Even though the porosity changed for each run, permeability remained constant so that the flow paths would not be affected. To insure a conservative solution, all the heat injected into the layer, stayed in the layer (heat loss to the over/underburden was turned off). The three cases are visually compared to see if the higher porosity cases are less stable.

1.12. Mechanisms

Three primary recovery mechanisms (vaporization, thermal expansion and viscosity reduction) are compared in all four model descriptions to see the relative importance of each mechanism in LMOSF in diatomite reservoirs. Five separate runs are needed for each description to quantify the impacts of each mechanism. One run where all the mechanism are turned on is the basecase. Then each mechanism is turned off individually and the production from the subsequent runs is less than the basecase. The difference between the run and the basecase shows the importance of that mechanism for that case. Finally, a waterflood case, representing the low end case, will serve as a base line for this study. The difference between the basecase and waterflood case should be very close to the sum of the three primary mechanisms. The small differences may be explained by secondary mechanisms, such as relative permeability/capillary pressure affects. These mechanisms along with others like

thermal expansion of initial gas saturation are examined but in less detail than the three primary mechanisms. The different mechanisms are all compared on a HCPVI basis.

2. RESULTS

Data for the three primary study areas is set out in the following sections. The stability of the steam front will be discussed first, followed by the relative importance of the three mechanisms, and end with a discussion on the profile for the three phases and the three component.

2.1. Stability

Stability cases were run on all three 2D models which resulted in some interesting findings. As hypothesized, instabilities did increase as the porosity increased; however, for these well conditions and reservoir properties, the instabilities are not very significant. Due to the dominating hydraulic fractures and close well spacing, finger growth is similar for both the average porosity sandstone case and the high porosity diatomite case. However, as the geologic descriptions became more complex and the relative permeability became more oil-wet, instabilities were more prevalent and there existed slightly larger differences between the sandstone case and high porosity diatomite case.

2.2. 2D Homogeneous

A quick look at the 2D homogeneous case (Fig. 10) shows at best a very small change between the three porosity runs. As porosity increases the front appears to be less smooth; however, no significant streaks of the displacing fluid are noticeable. In simulation of pure homogeneous rocks, instabilities tend not to occur because there are no permeability differences where a finger can begin to grow, therefore, we did not expect to see significant differences among the three porosities. The representations in Fig. 10 are all at a HCPVI of 0.15.

2.3. 2D Isotropic

In a pure homogeneous reservoir, porosity will not affect the stability of displacement in the reservoir; however, very few reservoirs can be treated as homogeneous. When even small heterogeneities exist in the reservoir, instabilities may begin to occur. The next case to be examined is the isotropic permeability description (Fig. 11). In this case, the graphics are shown at a HCPVI of 0.24. When looking at these three runs, we start to see some of the effects of the porosity on stability. In the high permeability regions, displacement tends to finger more for the high porosity cases; additionally, in the low permeability regions (the two unswept regions in the bottom-right) more oil has been

recovered in the low porosity case than in the higher cases. This shows that the effects of heat on oil recovery are more efficient for low porosity systems.

2.4. 2D Thief

Now let us move to the thief case where, as one might expect, there is the greatest amount of instability. In addition, this case has the largest difference between the sandstone porosity run and the high porosity diatomite run (Fig. 12). The following plots are again all shown at 0.15 HCPVI. For the lowest porosity, water is just breaking through at the producer at 0.15 HCPVI, while for both of the higher porosity runs, water has broken through earlier. For the 50% mean run, breakthrough occurs at 0.13 HCPVI and for the 70% mean run, it is 0.11 HCPVI. When comparing these runs it is easy to visualize the difference between all three different porosity cases. By examining the high permeability streak on the left, you can see that the front is progressively farther as the porosity increases.

2.5. Relative Permeability Sensitivity

When the more oil-wet relative permeability curves were used, instabilities increased for all model descriptions, and of course this is most apparent in the case with the highest heterogeneity, the thief case. Figure 13 shows displacement for the three porosity values at a HCPVI of 0.12. When this is compared with the thief case for the original relative permeability data (Fig. 12), all runs are a little less efficient. However, for the new relative permeability cases, porosity still does not play an important role.

2.6. Summary

Table 2 compares breakthrough time for all three model descriptions and for the three different porosity cases. To be able to compare the three model descriptions with each other the last column compares the higher porosity diatomite runs to the sandstone porosity runs as a percentage. As you can see, the biggest difference is for the most heterogeneous case.

Table 2. Breakthrough Time Comparisons in HCPVI for the Three Increasing Porosity Cases

		25 %	50 %	70 %	% before Sandstone	
					50 %	70 %
Original Relative Permeability	2D Homogeneous	0.28	0.26	0.26	95%	94%
	2D Isotropic	0.27	0.26	0.26	95%	93%
	2D Thief	0.15	0.13	0.11	87%	73%
New Relative Permeability	2D Homogeneous	0.23	0.22	0.21	93%	88%
	2D Isotropic	0.16	0.14	0.13	93%	86%
	2D Thief	0.10	0.08	0.07	85%	72%

Overall, there were noticeable differences between the stability of the displacing front as the porosity increased. However, the difference varied considerably depending on geologic description and relative permeability conditions. The largest difference observed was in the thief cases where the high porosity runs broke through in about three-quarters of the time the sandstone runs took.

2.7. Mechanisms

All four reservoir descriptions evaluate the mechanisms that were most important for oil recovery when injecting steam into diatomite reservoirs. Each description gives slightly different results as to which of the three primary recovery mechanisms is most important. These differences along with the similarities will be discussed in detail in the following sections. To begin, a couple generalities can be asserted. Early in the injection (less than 0.30 HCPVI) thermal expansion is the dominant mechanism, but as total injection increases the recovery is split more equally among vaporization, thermal expansion and viscosity reduction.

Two important aspects need to be covered before examining the results. First, the waterflood recoveries are higher than would be expected from typical diatomite reservoirs. In the models, the waterflood recovery is as high as 50 percent; whereas, typical diatomites usually produce less than 20 percent. One major difference between this model and the real reservoirs is that we have only one layer while the reservoir is many stacked layers. Those stacked layers have large permeability variations. One layer may show good waterflood recovery while the remaining layers demonstrate poorer recovery. It is hypothesized for steam injection that heat from the high permeability layers conducts into the low permeability regions and helps recover the fluid that is not swept within the lower permeability layer. This should increase the steamflood recovery relative to waterflood. To confirm this hypothesis, future work will include many stacked layers in a model.

The other key point is with the treatment of the results. As previously stated in the Model Set-up section, the summation of the effects of all three mechanisms does not exactly equal the difference between the thermal basecase and the waterflood. This difference can be attributed to other secondary mechanisms and/or the non-independence of the three primary mechanisms. This difference is represented by "Other" in the mechanism results plots and is basically insignificant for all but the 1D case.

2.8. 1 Dimension Homogeneous

The 1D description will be discussed first. Figure 14 shows the cumulative oil recovery for all the cases. The top line is the basecase thermal run and the lowest is the cold waterflood recovery. The three curves between the waterflood and basecase represent the recovery of the thermal case without that mechanism included.

Although this plot shows the ultimate recovery for each run without a particular mechanism, it is hard to see the relative importance of each one; therefore, plots like Figure 15 were created to better visualize the recovery. In this plot the incremental recovery of steamflood above waterflood is displayed, and the relative importance of each mechanism is also illustrated.

For this case, there was a rather large difference between the summation of the support from the three mechanisms and the total incremental recovery over waterflood. This discrepancy is noted by the large “Other” category. This phenomenon was only observed in the 1D case and can most likely be attributed to the sharp change in the relative permeability from the water-oil curves to the liquid-gas curves. To confirm this idea, an additional run was completed where the relative permeability curves were changed to straight line curves (keeping the end points the same). In this case the “Other” mechanism has increased which shows that sharper changes in the curves lead to increased relative permeability effects.

Ignoring the other affects, thermal expansion is the dominant recovery mechanism for the first 0.50 HCPVI. The large peak around 0.40 HCPVI corresponds to water breakthrough at the producer. After that, vaporization plays an increasingly more important role. This is because the distillate bank breaks through after the water bank. The heavier components begin to mobilize and viscosity reduction plays a significant role after water breakthrough, as well. The oil modeled has a significant proportion of heavy ends (14%), so that the relative importance of viscosity reduction is expected.

2.9. 2D Homogeneous

The next reservoir description to be examined is the 2 dimensional homogeneous model. The incremental plot is shown in Fig. 16. As noted before, the “Other “ mechanism is much smaller for the 2D case. Once again, thermal expansion is the primary recovery mechanism for the first 0.50 HCPVI, and vaporization and viscosity reduction increase after water breakthrough.

2.10. 2D Isotropic

It was expected that as the models became more heterogeneous and complex, there would be an increase in separation between the thermal case and the waterflood case; however, this expectation did not hold true. As Fig. 17 demonstrates, the waterflood recovery is still above 50 percent, and the thermal basecase recovery has come down about 15 percent from the 1D case. There are still very efficient sweeps for the waterflood case. The wells are all fracture stimulated and this is modeled as shown in Fig. 7 in the Model Set-up section. These fractures extend the majority of the model width, giving a very good initial displacement front for the waterflood. This type of displacement front is too optimistic and provides another reason for the waterflood to be

higher than expected. In future work, the fracture length will be shortened as a comparison to the current work to understand the sensitivity of fracture length.

The incremental plot is quite similar to the previous two models as far as relative importance of the mechanisms (Fig. 18). Thermal expansion is most important early in the steam flood life. After 0.70 HCPVI, the importance of viscosity reduction and thermal expansion are constant and the importance of vaporization increases at a constant rate as the distillate bank moves through to the producer.

2.11. 2D Thief

The major difference between the thief case and the previous cases is the water breakthrough time is much quicker (around 0.15 HCPVI) and the incremental peak associated with the water breakthrough is much smaller (Fig. 19). Nevertheless, the principal recovery mechanism early on is still thermal expansion of the oil phase. In this case the importance of all three mechanisms are fairly equally distributed for the middle time data than in the previous models. For the data after 1.0 HCPVI, viscosity reduction plays an increasing role as the heat migrates to the unswept regions. On the contrary, vaporization is not as significant as it was in the previous models. This is because the majority of the injected fluid channels through the high permeability streaks and there is less area in contact with the high temperature steam that causes the vaporization.

2.12. Summary

Figure 20 is a summary of the previous incremental plots at two different hydrocarbon pore volumes injected on a cold water basis. The top bar graph (0.30 HCPVI) shows the general observation that thermal expansion is the most important recovery mechanism in these reservoirs early in the injection. For all the 2D cases, thermal expansion accounts for more than half of the incremental oil recovery. Later in the injection time (1.0 HCPVI), each mechanism contributes approximately equal amounts to the recovery. As more heat is injected, more of the heavy ends are mobilized; consequently, viscosity reduction goes through the largest increase between the two injection times.

This is a dynamic process that changes dramatically as time and reservoir description change, and therefore it is difficult to pinpoint the exact relationship between mechanisms and recovery. However, it should be noted that for most diatomite systems the target total steam injection for the field is around 0.30 HCPVI. This is because the permeability and therefore the injectivity is very low in diatomites. Assuming that this criterion is proper, thermal expansion will be the primary recovery mechanism for diatomite reservoir containing light/medium weight oils.

2.13. Profiles

The 1D case was used to characterize the saturation, composition and temperature fronts as they moved through the homogeneous reservoir. Figure 21 shows the saturation profile for the water saturation (solid line) and minus the steam saturation (dotted line) at four injection times. The difference between the two curves represents the total hydrocarbon saturation. For 0.33 HCPVI, about one-quarter of the model is still at original reservoir conditions, which are 50 % water and 50 % oil.

These saturation profiles clearly display three separate saturation fronts. Starting farthest from the injector there is a cold water bank that breaks through to the producer some time between 0.33 HCPVI and 0.67 HCPVI. Closer to the injector is a mixed distillate and hot water bank. It can be seen most clearly for at 1.00 HCPVI where it forms from 15 to 42 distance units. This bank breaks through between 1.00 and 1.19 HCPVI. Finally, closest to the injector, a steam bank forms and is shown here as the dotted line. In this simulation run, the steam bank has not yet made it to the producer. The small dip in the water saturation curve seen in front of the hot water bank corresponds to a distillate bank that is formed by component one, and the large dip seen behind the hot water bank corresponds to another distillate bank formed by the medium weight component. In the simplified 3 component system, there is some distillate produced before the hot water bank and some after. In the complex reservoir where there is more than 3 components, there is probably no distinguishable boundary between the hot water and distillates. Most likely there is just one mixed zone that has lighter ends closest to the producer and the heaviest ends closest to the steam front.

Figure 2 provides the information to be able to determine how the hydrocarbons are distributed in the reservoir and consequently where the banks are forming. It is a plot of the fractions of each composition, again at the four different HCPVI. The peaks of both components 2 and 3 relate to the forming of their respective distillate banks. This can be seen in Fig. 21 where there are increases in the hydrocarbon fraction. Each individual bank is not constant in character either. The end of the bank closest to the steam zone is primarily made up of vapor phase while the end closest to the producer is primarily in the liquid phase.

Another concern was the timing of the bank formation; this plot shows unmistakably that the banks occur very early in the injection time and fairly close to the injector. The final figure shows the temperature profile in the reservoir at the four different HCPVI. There is a smooth and rather rapid change from original reservoir temperature to the temperature at the injector. It can be seen that where the temperature change occurs is also where the distillate and hot water bank is forming in the previous plots.

2.14. Conclusions

A pattern reservoir simulation study of steam injection into a fractured diatomite formation has been completed. The information gained includes a better understanding of steam front stability in high porosity mediums, primary recovery mechanisms in steam drives of light and medium oils, and front profiles in steam drives. The model consisted of two hydraulically fractured wells (one injector and one producer) that are set 116.5 feet apart from each other. There are multiple reservoir descriptions that vary from homogeneous to quite heterogeneous. They all contain the same three-hydrocarbon-component fluid. Viscosity, relative permeability and other rock and fluid properties come from a reservoir model developed by AREA Energy, LLC.

Analytic work showed that for high porosity, steam fronts would become unstable, and while simulation work confirmed this, the overall effects were minimal. In the most dramatic case, the 2D thief case, the breakthrough time decreased from 0.15 HCPVI for the sandstone case to 0.11 HCPVI for the 70 % porosity diatomite case.

For these reservoir descriptions and fluid properties, thermal expansion of the hydrocarbon fluids accounts for about two-thirds of the incremental recovery until breakthrough of the cold water bank to the producer. At which point vaporization, viscosity reduction, and thermal expansion all contribute approximately equal amounts to the recovery.

A cold water bank breaks through to the producer first. Then a mixture of distilled and condensed hydrocarbons and heated water forms another bank, which is closely followed by the steam front. This second bank is a complex combination that is characterized by the lightest hydrocarbon component at the front and the heaviest vaporized components closest to the steam front.

Diatomites are one type of low permeability fractured reservoir where steam injection can improve light to medium weight oil recovery; however, other low permeability fractured reservoirs that suffer from the same problems as diatomites such as below average primary recovery and poor waterflood performance, can have improved performance with steam injection. Injecting steam into low permeability fractured reservoirs that contain light and medium weight oil has been tried on a limited basis, and is being considered in additional areas

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Figure 1. Steamflood Production from initiation at Yorba Linda through 2000 (Moritis, 2000)

Figure 2. Steam drive stability in diatomite.

Figure 3. Contributions of different mechanisms to the improvement of oil displacement by a heated fluid instead of cold water (Burger *et al.*, 1985)

Figure 4. Schematic of light-oil steamflooding (Blevins *et al.*, 1984)

Figure 5. Viscosity as a function of temperature.

Figure 6. Relative Permeability.

Figure 7. General model schematic.

Figure 8. Porosity for geostatistical model. The injector is at the lower left corner, while the producer is in the upper left corner.

Figure 9. Porosity for geostatistical thief model.

Figure 10. Front comparisons for three different porosities in 2D homogeneous case. All figures correspond to 0.15 HCPVI on a cold water basis.

Figure 11. Front comparisons for three different porosities in 2D isotropic permeability case. All figures correspond to 0.24 HCPVI on a cold water basis.

Figure 12. Front comparisons for three different porosities in 2D thief permeability case. All figures correspond to 0.15 HCPVI on a cold water basis.

Figure 13. Front comparisons for three different porosities in 2D thief permeability case with more oil-wet relative permeability curves. All figures correspond to 0.12 HCPVI on a cold water basis.

Figure 14. 1 dimension oil recovery for waterflood, steamflood and steamflood without each mechanism.

Figure 15. Incremental oil recovery for steamflood over waterflood in 1D.

Figure 16. Incremental oil recovery for steamflood over waterflood in 2D. Homogeneous case.

Figure 17. 2 dimension oil recovery for waterflood, steamflood and steamflood without each mechanism with isotropic permeability model.

Figure 18. Incremental oil recovery for steamflood over waterflood in 2D. Isotropic case.

Figure 19. Incremental oil recovery for steamflood over waterflood in 2D. Isotropic case.

Figure 20. Incremental oil recovery for steamflood over waterflood in 2D. Isotropic case.

Figure 21. Saturation Profiles for water (solid) and 1-steam (dashed).

Figure 22. Fraction of hydrocarbon components.

Figure 23. Temperature profile for steam injection at four different HCPVI on a cold water basis.

Experimental Study of Heavy Oil Production From Diatomite by Water Imbibition at Elevated Temperatures

Tom Tang and A.R. Kavscek

ABSTRACT

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.

This work presents the results from 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 (nC_{10}), two white mineral oils with differing viscosities, 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. 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. 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.

1. INTRODUCTION

The ultimate goal of this work is to improve our understanding of multiphase fluid and heat flow characteristics of diatomite. Diatomite is a low permeability (0.1–10 md) and high porosity (35–70%) siliceous rock. We conduct X-ray computerized tomography (CT) monitored free and forced displacement experiments at various elevated temperatures to characterize oil recovery response to hot fluid injection and any possible enhancements due to wettability alteration with temperature. Diatomite field cores (Kern Co., CA) and relatively clean outcrop diatomite cores (Grefco Quarry, Kern

Co., CA) are the porous media employed. The major tool for analysis and interpretation of experimental data across the temperature range from 40 to 180 °C is an appropriate scaling group that accounts for water-oil mobility ratio as a function of temperature.

By the way of background, the diatomite resources in the San Joaquin Valley, CA are estimated at 12 to 16 billion barrels of initial oil in place (Ilderton *et al.*, 1996). In recent years, water flood has been implemented in diatomite reservoirs containing relatively light oil ($^{\circ}\text{API} > 22$) for improved recovery and to mitigate subsidence (Patzek, 1992). Steam injection in either drive (Kovscek *et al.*, 1996a, 1996b), or cyclic modes (Murer *et al.*, 2000, Kumar and Beatty, 1995) is also being tested for light and heavy oil diatomite reservoirs.

For both steam injection and water flood, production and injection wells are hydraulically fractured to overcome low reservoir permeability and improve productivity and injectivity. Thus, virtually all recovery processes for diatomite, and other tight fractured rocks, rely to an extent on free and/or forced imbibition. In imbibition, nonwetting fluid (i.e., oil) is spontaneously expelled as wetting fluid is drawn into rock by capillary forces. In strongly and moderately water wet samples of diatomite, capillary forces are significant and partially offset low formation permeability. Thus, the imbibition potential for water is large and, in some instances, imbibition rates rival those of much more permeable sandstone samples (Akin *et al.*, 2000). Capillary phenomena are equally important during steam injection into diatomite. Injected steam, especially at short times, is accompanied by condensation and flow of the resulting hot water away from the injector. In steam drive, a condensed hot-water bank precedes the steam zone within the reservoir; whereas, in cyclic steam operations the steam zone generally collapses during soak and production leaving a region filled with heated oil and condensed steam. Similarly, steam injection is carried out under saturated conditions with some fraction of the injected steam in the liquid phase. Thus, a necessary precursor to elucidating thermal oil recovery processes in diatomite is to understand the imbibition characteristics of hot water.

Diatomite is relatively unstudied in the laboratory because of a host of difficulties associated with low permeability. Most previous studies were performed on sandstone (Bourbiaux and Kalaydjianor, 1988, Jadhunandan and Morrow, 1991, Reis and Cil, 1993, and Tang and Morrow, 1997) or (Cuiec *et al.*, 1994, and Milter and Φ xnevard, 1996). Diatomite is composed of the siliceous, depositional, consolidated skeletal remains of colonies of unicellular aquatic plankton (Schwartz, 1988). As such, diatomite is fine grained, exhibits a variety of pore length scales, and flow pathways are complex (Akin *et al.*, 2000). Thus, injectivity is low (unless samples are severely fractured), the rock matrix is relatively fragile, and generalization of results across rock type from chalk or sandstone to diatomite is not currently possible. To our knowledge, the first X-ray CT images of diatomite undergoing water injection are given by Wendel *et al.* (1988). Subsequently, spontaneous co-current (Akin *et al.*, 2000) and counter-current (Zhou *et al.*, 2001) imbibition characteristics were imaged in outcrop with X-ray CT for a variety of mobility ratios, at room temperature. The pattern of water advancement and oil recovery during counter-current versus co-current imbibition appears to be more sensitive to core-scale

heterogeneity. Regardless of imbibition mode, oil was recovered at the laboratory scale at appreciable rates with sensibly zero pressure drop. On the other hand, Kamath *et al.* (1995) conducted long-term forced displacements revealing that water-oil relative permeability end points could be increased by as much as 31% with increased flow rate and/or pressure drop.

This paper proceeds by discussing the experimental set up constructed to conduct imbibition experiments at elevated temperature with an applied confining pressure. After the experimental results are given, they are explained and contrasted via a dimensionless scaling group. This simplifies the discussion that follows.

2. EXPERIMENTAL APPARATUS AND METHOD

Experimentally, we wish to obtain the change of average water saturation, measure the rate of imbibition, and determine fluid displacement patterns within the rock. X-ray CT meets these goals, is noninvasive, and measurements can be made without stopping an experiment. Some care, however, must be exercised in the choice of materials and in apparatus design. The major components of the apparatus are described next.

2.1. Coreholder

In order to perform spontaneous imbibition tests at elevated temperatures and high pressure, we fabricated a coreholder that resembles a Hassler-sleeve from aluminum (6061-T6) which is relatively transparent to X-rays and thereby CT-scanable. Cores with lengths from 2.5 to 7.5 cm (1 to 3 in) and 2.5 cm (1 in) diameter can be held. The apparatus is assembled by coating the core with a thin film of silicone gel (Ultra Copper High Temp RTV Silicone Gasket Maker) and placing the core inside FTP heat-shrink tubing (Plastic Professional). The silicone-gel is nonwetting and does not penetrate the core. It serves to prevent any fluid bypass during injection once a confining pressure is applied; thus, the silicone gel-tubing combination serves as a high-temperature sleeve. Mineral oil was used as a confining fluid in the annular space between the sleeve and the aluminum coreholder. Heating tape is wrapped around the outside of the coreholder and then covered with high temperature insulation. A temperature controller maintains constant coreholder temperature. This system was designed and tested for service up to 260°C (500 °F) and a maximum confining pressure of 7 MPa (1,000 psia). In addition to being compatible with a CT scanner, the main advantage of this design is that the effect of heating on rock compaction is minimized. The system is brought to the temperature of interest at a constant difference between confining and pore pressure.

The coreholder is attached to an L-shaped mounting bracket. This assembly is bolted to a stepper-motor driven precision positioning system (Compumotor RP240, Parker-Hannifin) that is used to position the core inside the CT gantry. Any position along the length of the core can be revisited with an accuracy of ± 0.01 mm.

2.2 CT Scanner

The scanner is a fourth generation Picker 1200SX with 1200 fixed detectors and a scan angle of 398° . The voxel dimension is 0.35 mm by 0.35 mm by 3 mm. The tube current is 95 mA and the energy level of the radiation is 130 keV. The acquisition time of one image is roughly 6 s, while the processing time is about 40 s. Images can be acquired in series and processing delayed until all the desired images are acquired. Thus, the total acquisition time to scan the length of the core is short enough to characterize the saturation profile along the core at a particular time.

2.3 Rock

Both field and outcrop cores are studied. Outcrop diatomite cores (Grefco Quarry, Lompoc, CA) have a porosity, ϕ , of 62-67% and an air permeability, k , of 2-4 md, as shown in Table 1. They are almost pure white and the porosity is relatively uniform, as shown by the representative CT image in Fig.1a. This quarried diatomite represents an end member of so-called "clean" reservoir rock resulting from Late Miocene diatomaceous sediments (Ross and Kovscek, 2002). It provides a convenient and appropriate contrast to the reservoir samples used here. A previous study (Akin *et al.*, 2000 and Zhou *et al.*, 2001) showed that this outcrop diatomite is strongly water wet. However, the outcrop diatomite core samples used in this work (from the same region, but not the same block of quarried stone) were not strongly water-wet. The relevant data are shown later. We used a similar process to cut and shape the outcrop diatomite core samples as described in (Akin *et al.*, 2000 and Zhou *et al.*, 2001). The cores were dried and preserved in an oven under house vacuum at a temperature of 50-60 $^\circ\text{C}$.

Field diatomite (Kern Co., CA) cores are also used. Their porosity ranges from 55 to 59 % and permeability from 0.8 to 1.3 md, as indicated by Table 1. The field cores were sampled from depths between 650 to 980 ft. F-1 depth=681.3 ft, F-15 depth=920.8 ft, and F-25 depth=928.1 ft. Cores were cleaned by injection of a mixture of methanol and toluene. After cleaning, they were preserved in synthetic reservoir brine and sealed in an airtight aluminum bag until used. The composition of the synthetic brine is listed in Table 2. Prior to an experiment, the brine was removed by drying carefully at 35 $^\circ\text{C}$ under house vacuum to avoid inducing fractures. Measurement of permeability after drying verified that cores had not fractured, see Table 1. Figure 1b shows a representative porosity image obtained for a field core. The bedding structure is obvious. The length of the field cores was about 4.0 to 6.5 cm (1.6 to 2.6 in) and the diameter was 2.5 cm (1 in).

2.4 Fluids

Three white oils, n-decane, blandol (Witco Chemical), and PAO40 (Chevron Lubricants), and filtered/dewatered crude oil from Midway-Sunset were used as the oil phases. The viscosity at room temperature (22 $^\circ\text{C}$) for these oils is 0.93 mPa-s, 35 mPa-s,

407 mPa-s, and 6,400 mPa-s, respectively. The decane was chosen because it has a viscosity similar to water for a range of temperature. With nC₁₀, we attempted to study water imbibition under favorable viscosity ratio ($\mu_w/\mu_{nw} \approx 1$) conditions. In the next stages, a modestly viscous mineral oil, blandol, and more viscous PAO40 were used. Hence, the viscosity ratio is progressively less favorable ($\mu_w/\mu_{nw} < 1$) at elevated temperatures. The chief reason for using the mineral oils was to identify the effect of temperature on recovery due to oil viscosity reduction without contribution to recovery from wettability alteration via crude oil-brine-rock interaction. Lastly, we used crude oil to study further water imbibition behavior that could be attributed to both reduction of oil viscosity and wettability alteration accompanying an increase in temperature.

Figure 2 shows the measured viscosity versus temperature for the oils used. It shows that the crude oil is the most sensitive to temperature. The viscosity of nC₁₀ and water versus temperature was obtained from “81st edition Handbook of Chemistry and Physics” (Lide 2000). Oil viscosity was measured with a Brookfield (LVT) viscometer. The same synthetic reservoir brine was used as the water phase for all tests. It was prepared by dissolving salts in house distilled water as listed in Table 2. It was assumed that the brine had the same viscosity versus temperature relation as pure water.

2.5 Procedures

Figure 3 shows how the individual pieces were assembled for imbibition tests. Brine flows past one face of the core at 0.5 cm³/min via pump (reciprocating or syringe pump at high temperature). We study counter-current behavior so the outlet of the coreholder was closed for all tests during the imbibition phase. A backpressure regulator (model R3A-C, N-norgren Inc) elevated the system pressure to 2.7 to 4.1 MPa (400 to 600 psia) such that water remained in the liquid phase throughout the duration of an experiment. The confining pressure was set from 4.1 MPa to 5.5 MPa (600 to 800 psia) so as to maintain roughly 1.4 MPa (200 psia) of net effective stress. All experiments were conducted under isothermal conditions. Produced oil was collected in a graduated cylinder to provide a check on the mass balance and average water saturation as measured by X-ray CT scanning. After the produced water was separated from the oil it was returned to a 300 cm³ water cylinder maintained at the experimental temperature.

The core was placed horizontally within the CT scanner gantry, as indicated by Fig. 3. Cylindrical volume sections were monitored at 5 mm intervals along the central axis of the core. About 8 to 10 images were collected sequentially to span along the core from inlet to outlet at any particular time. For the tests with $S_{wi}=0$, images of the dry air-saturated cores were taken first. Then oil was injected into the core until 100% saturated with oil and a second set of images acquired. The voxel-by-voxel values of porosity were calculated (Akin *et al.*, 2000, and Zhou *et al.*, 2001) as

$$\phi = \frac{CT_{or} - CT_{ar}}{CT_o - CT_a} \quad (1)$$

where CT represents CT number (Hounsfields). The subscripts *or* and *ar* signify oil-saturated rock and air saturated rock, respectively; whereas *o* and *a* represent the oil and

air bulk fluid phases. Average core porosity is obtained by averaging porosity across each cross section and then averaging cross-sectional porosities.

Once the initial condition was established, the core was subjected to counter-current water imbibition. Water was supplied at the core face until no further change in water saturation was measured. The voxel-by-voxel water saturation, S_w , of each cross-sectional area was computed from

$$S_w = \frac{CT_{owr} - CT_{or}}{\phi (CT_w - CT_o)} \quad (2)$$

where ϕ is the independently measured porosity from Eq. 1, the subscript *owr* refers to rock containing oil and water, the subscript *w* denotes the bulk water phase.

For the tests with $S_{wi} \neq 0$, images of the dry air-saturated cores were taken first. Then the core was 100% saturated with water and a second set of images was acquired. Thereafter, oil was injected into the core to establish initial water saturation; when the initial water saturation was established, a third set of images were taken.

3. RESULTS

Results are described in order of increasing complexity, that is, from outcrop cores and simple fluids to field cores and crude oil. In total, 18 experiments were conducted.

3.1 Water/Air/Outcrop Core

We first performed a water imbibition test with a dry outcrop diatomite core to characterize spontaneous water imbibition behavior under strongly water-wet conditions. This also served to verify that the experimental apparatus was operating properly. The test temperature was 25 °C and initial water saturation was zero. The viscosity ratio of displacing phase to displaced phase is greater than unity and a piston-like displacement was expected (Zhou *et al.*, 2001). The experimentally measured recovery is presented in Fig. 4. Because water wets diatomite strongly as compared to air, the water imbibition rate was very fast. It took about 270 minutes to reach a final gas recovery of 0.79 PV which is less than the value of 0.94 reported by Zhou *et al.* (2001). This case will provide a base line for studying water imbibition under different viscosity ratios of displacing phase (water) to displaced phase (oil).

3.2 Water/nC₁₀/Outcrop Core

Under this circumstance nC₁₀ was used as the initial phase (non-wetting). The tests were run at T=25, 48, and 88 °C, respectively. Initial water saturation was again zeroing to provide a constant well-defined initial condition. No backpressure was applied and the confining pressure was about 1.4 MPa (200 psia). The same core was used for the

three tests. We assumed that the core was initially water-wet and that any wettability shift introduced by contacting the rock surface directly with decane was negligible. Regardless, any wettability change associated with the procedure is constant from experiment to experiment, as the core, brine, and oil are identical. The experiments were conducted from low to high temperature progressively. At the termination of each test, the oil and water in the core were removed by heating the core at about 50 °C under vacuum. After the core was dry, it was re-saturated with oil at the next test temperature; the oil volume was measured at room temperature using an ISCO pump and material balance. Note that the oil production was also measured at room temperature. The water saturation within the core was calculated after correction for thermal expansion of oil and water phases. Rock thermal expansion was not incorporated because all tests are isothermal and the effect was thereby constant.

The oil recovery by spontaneous counter-current water imbibition for the tests with normal decane is also presented in Fig 4. At room temperature, both water imbibition rate and the extent of oil recovery are somewhat low; the final oil recovery is about 0.27 PV, suggesting weak water-wetness (WWW) at 25 °C. However, both imbibition rate and the extent of recovery increase with increase in temperature systematically. The final oil recovery is about 0.57 PV for 48 °C and 0.67 PV for 88°C. A water imbibition curve obtained from a strongly water-wet (SWW) outcrop diatomite core at 22 °C (Zhou *et al.*, 2001) is also presented in this figure for comparison. It shows that the recovery curve at 88°C is more close to that obtained for a SWW core. This indicates that wettability alteration to increased water-wetness may occur as temperature increases (Al-Hadhrami and Blunt, 2000). This phenomenon is in agreement with the results obtained from Berea sandstone by Tang and Morrow (1997) and from carbonate rocks by Dangerfiedl and Brown (1985). In addition, the decrease in oil viscosity contributes to the increased rate of oil recovery.

3.3 Water/Blandol/Outcrop Core

A modestly viscous mineral oil (blandol) was used as an oil phase to study the effect of temperature on water imbibition under a circumstance of viscosity ratio of water to oil phase less than one. The test temperatures were 57, 120, and 180 °C, respectively. The viscosity ratio of displacing phase (water) to displaced phase (oil) was about 0.062 at 57°C, 0.15 at 120 °C, and 0.217 at 180 °C. In order to prevent the formation of live steam, a backpressure of 4.1 MPa (600 psia) was employed at the outlet of the water-circulation loop; a confining pressure of 5.5 MPa (800 psia) was applied. After the backpressure regulator, a water-cooled condenser reduces the temperature of the produced liquids before they reached the oil/water separator. Blandol oil was difficult to remove from the core following an experiment. A fresh core was used at each test temperature.

Similar to the results with n-decane/water, spontaneous imbibition recovery of blandol increases with temperature, as summarized in Fig. 5. The final oil recovery is about 0.49 PV at 57 °C, 0.53 PV at 120 °C, and 0.62 PV at 180 °C. The time to achieve residual oil saturation is about 9,000 minutes at 57 °C, and about 5,000 and 4,000 minutes

at 120 and 180 °C, respectively, indicating a faster water imbibition rate at high temperatures.

3.4 Water/PAO40/Outcrop Core

A mineral oil with a viscosity of about 400 cp at room temperature was used next as the oil phase. The test temperatures were 120 and 180 °C, respectively. Initial water saturation was again zero. A backpressure that varied between 2.8 to 4.1 MPa (400-600 psia) and a confining pressure of 5.5 MPa (800 psia) were employed. Similar to tests with blandol, a different core was used for each temperature.

Figure 6 shows the imbibition curves for PAO40 tests. Again, both water imbibition rate and the extent of oil recovery increase significantly with temperature as observed previously. The final oil recovery increases from 0.39 to 0.49 PV as temperature increases from 120 to 180 °C. At 120 °C, an apparent induction time of 300 min is observed prior to the onset of recovery. Induction time is defined as a time before water begins to imbibe into a core; it is usually observed when the viscosity ratio of displacing to displaced phase is far less than unit, or the displacing phase weakly wets the core (Zhou *et al.*, 1995 and Tang and Firoozabadi, 2001). Here, induction is likely related the period of time required to wash a small amount of oil from the face of the core so that water can access the rock matrix directly and imbibe. There is no induction time at 180 °C where the mineral oil viscosity is roughly 5 mPa-s, as shown in Fig. 2. Figure 6 also contrasts recovery versus time as determined by produced oil volume and X-ray CT. Note the pleasing agreement among the two methods of conducting material balance.

Figure 7a presents the one-dimensional water saturation profile versus time for PAO40/water imbibition at 180 °C as measured by X-ray CT. Water begins to imbibe instantly and reaches the far end of the core in about 400 min. A diffuse water-advancing front is obvious during the early imbibition period consistent with previous observations (Zhou *et al.*, 2001). Water saturation builds quickly at the inlet reaching 0.58 PV at 200 minutes. Thereafter, the water saturation close to the inlet increases slowly to roughly 0.7 in about 1000 min. Likewise, the water saturation far from the inlet gradually increased with time during this period. The water saturation profile changes little after 2275 min.; however, the water saturation distribution along the core is not uniform at the end of spontaneous imbibition. The region of high water saturation near the core inlet indicates low connectivity of oil; hence, oil relative permeability is probably low. Combined with the somewhat elevated oil viscosity, flow resistance is high. The nonwetting phase has difficulty exiting the interior of the core. Figure 7b presents water saturation distribution (CT-Images) versus time at the cross section $X_D=0.64$ for the water/PAO40 system at 180 °C. Note that black shading corresponds to S_w equal to 0 and that white corresponds to S_w equal to 0.7. The diffuse nature of the imbibition front is apparent through the relatively slow increase in water saturation. The distribution of water saturation at the cross-section is relatively uniform consistent with the homogeneous porosity distribution in outcrop samples as shown in Fig.1a.

3.5 Water/Crude Oil/Outcrop Core

To increase system complexity in a logical fashion, a heavy crude oil was used next as the oil phase in outcrop cores. The test temperatures were 42, 120, and 180 °C, respectively for cores with $S_{wi}=0$ and was 180 °C for a core with $S_{wi}=21.7\%$. A separate core was used for each test. Because the crude oil is very viscous at room temperature, the oil and coreholder were heated to 80°C to accelerate the oil injection process. After the core was saturated with the crude oil, the core was heated or cooled to test temperature and allowed reaching thermal equilibrium. Each core was aged with oil at the test temperature for 1 to 2 days before it was subjected to water imbibition. Because the oil is very viscous at room temperature, the oil flow from the tubing to the oil/water separator was slow. This caused inaccuracy in the collection of oil in the separator and a time-shift error in volumetric. Thus, we accounted for the imbibition rate and recovery strictly from CT-images. The final oil recovery from the volumetric method, however, was used to check the CT data.

Figure 8a shows the oil recovery curves for the crude oil at the various temperatures. When $S_{wi}=0$, oil recovery at 42 °C is about 0.03 PV. However, as the temperature was increased from 42 to 120 and 180 °C, the water imbibition rate and oil recovery increased significantly. The final oil recovery is about 0.42 PV at 180 °C. Compared to the oil recovery for PAO40 at 180°C in Fig. 6, both final oil recovery and water imbibition rate are lower for the water-crude oil/outcrop core system. As Fig. 2 teaches, crude oil and PAO40 viscosity are nearly equal at this temperature. This indicates a possible adsorption of polar oil components from the crude oil onto rock surfaces that reduces water-wetness slightly in this case (Kovscek *et al.*, 1993). At $T=180$ °C, the water imbibition rate for the core at $S_{wi}=21.7\%$ is initially ($t < 1500$ min) similar to the core at $S_{wi}=0$. Thereafter, water imbibition rate remains low for the core with initial water saturation, indicating a less capillary driving force. Fig. 8b shows the water saturation vs. time for cores with and without initial water saturation at $T=180$ °C. It shows that water saturation for the core with initial water saturation remains higher all the time. Thus, the capillary force is weak for the core with initial water saturation, especially at the later period of the test. Figure 9 shows the water saturation profiles along the core for the test at 180 °C. Again, water enters the core instantaneously and the imbibition front is relatively diffuse. However, water advance is slower compared to previous cases; it took about 4,000 min to reach a stable water saturation profile. Similar to PAO40, water saturation along the core is not uniform at the end of the experiment. Near the inlet the final water saturation is 0.55 PV while near the outlet it is roughly 0.35 PV.

3.6. Field Core

Four field cores from the same diatomite reservoir as the crude oil sample were used for the remaining tests. Two of them (F-a, and F-15), from a depth of 920 ft, were used at $T=43$, 120, and 180 °C and zero initial water saturation. Another two cores (F-25 and F-1) from different depth were used for experiment at 180 °C with $S_{wi}=27$ -30%. Core F-25 is from a depth of 920 ft and core F-1 is from a depth of 650 ft.

3.6.1. $S_{wi}=0$

The first test (with core F-a) at $T=43^{\circ}\text{C}$ did not show any water imbibition. This core was then heated to 120°C and allowed reaching a thermodynamic equilibrium. Then it was subjected to water imbibition. The second core (F-15) was used at 180°C . All three of these tests were conducted at $S_{wi}=0$. At $T=180^{\circ}\text{C}$, two tests with initial water saturation (F-25 with $S_{wi}=30\%$ and F-1 with $S_{wi}=27.1\%$) were conducted. Figure 10 shows the recovery data for the crude oil/field core ensemble. For the tests without initial water saturation (cores F-a and F-15), the water imbibition is nearly zero at $T=43^{\circ}\text{C}$ (a reservoir temperature), even after 12,000 minutes. However, when the temperature was increased to 120°C , water did imbibe. About 0.22 PV oil was produced by spontaneous water imbibition at 120°C . Compared to outcrop, the final oil recovery is lower. This indicates, possibly, that field cores are less water wet than outcrop cores. When the temperature increased further to 180°C and a new experiment was conducted, the water imbibition rate at times less than 500 min increased significantly. The rate decreased somewhat in the later period, but it is still greater than rates for the 120°C case. The final oil recovery is about 0.43 PV. Figures. 11a and 11b show the water saturation profile along the core versus time at $T=120$ and 180°C , respectively. At 120°C , the waterfront stopped advancing at X_D equal to 0.6; whereas at $T=180^{\circ}\text{C}$, the waterfront reached the far end of the core. Final water saturation at the core end is about 0.35 PV. Reduction in oil viscosity from 12 cp at 120°C to 4.5 cp at 180°C and an increase in water-wetness from 120 to 180°C may contribute to the improved recovery behavior among these two temperatures. Similar to the previous cases, the final water saturation at 180°C is not uniform. Figure 12 shows water saturation images versus time as obtained by CT for the cross section $X_D=0.35$. Again, dark shading indicates low S_w while light indicates high S_w . Due to core heterogeneity, the water saturation is not uniform and water has not yet swept all of the cross-sectional area. It is apparent that water advance through some of the bedding layers is responsible for a major portion of the imbibition response. Note the white shading in this area compared to the darker shading in the remainder of the cross section increases with time.

3.6.2. $S_{wi}\neq 0$

To establish the initial water saturation, the coreholder was heated to 80°C , to reduce oil viscosity, and then oil was pumped into the brine-saturated core. After oil breakthrough, the flow direction was reversed and oil was injected until no further water was produced. The produced water was collected and used to estimate the initial water saturation. The core F-25 was aged for 10 days at room temperature; core F-1 was aged only 2 days at room temperature. At the end of spontaneous imbibition, the cores were subjected to a forced imbibition. The inlet pressure was about 4.03 MPa (585 psia) and outlet pressure was about 3.89 MPa (565 psia). Hence, the pressure drop across the core was about 138 kPa (20 psi). Forced water imbibition continued for about two days until no further oil was produced. The relevant results are shown in Fig.10. The total oil

recovery by spontaneous water imbibition is about 27% of OOIP for core F-25 and about 40% of OOIP for core F-1. After the cores were subjected to forced water imbibition, the oil recovery increased to about 52% of OOIP for core F-25 and 54% of OOIP for core F-1 quickly (<400 min). Thus, forced displacement is effective for the diatomite system; however, the pressure gradient is roughly 1.8 MPa/m (80 psi/ft). For a reservoir system, the imposed pressure gradient will obviously be less and oil production will occur by both spontaneous and forced water imbibition.

From the imbibition curves for $T=180\text{ }^{\circ}\text{C}$ (cores F-1, F-15, and F-25), we could not conclude a systematic effect of initial water saturation on water imbibition. This may be caused by heterogeneous feature of the field cores. However, with respect to residual oil saturation, we found the residual oil saturation is less for the core with initial water saturation (see Fig. 13). The S_{or} is about 0.46 PV for core F-1, 0.51 PV for core F-25, and 0.58 PV for core F-15, respectively. With forced water imbibition, the S_{or} could be as low as 0.35 PV. One may imply that the presence of initial water saturation is favorable to reduce residual oil saturation in cases such as these. Our companion work on the pore network properties of diatomite should shed light on the possible reasons for this behavior (Ross and Kovscek, 2002).

The water saturation profile along the core for core F-25 ($S_{wi}=30\%$) experiment is presented in Fig. 14. The dashed lines are for forced water imbibition. This figure shows that (1) the water-front is even more diffuse than what was observed for the experiments without initial water saturation, and (2) the forced water imbibition (following free imbibition) does not result in a clearly definable water front moving through the core.

4. SUMMARY OF EXPERIMENTS

All experiments followed a linear trend (not shown) when plotted as the average aqueous phase saturation versus the square root of time, as expected (Handy, 1960). The slope is proportional to the imbibition potential of each fluid/rock system (Akin *et al.*, 2000) and is useful in sorting the macroscopic results. Table 1 summarizes all experiments by listing the best-fit slope of the line obtained by plotting average water saturation versus $t^{0.5}$. All lines are forced through the initial saturation. Fortunately, the outcrop sample permeabilities are all nearly equal allowing generalization without considering the role of permeability. Also tabulated is the nonwetting phase residual saturation to spontaneous imbibition, S_{orsi} . The air-water/outcrop system exhibits the largest imbibition potential (IP) consistent with low gas viscosity and the extreme preference of the solid surface for water as opposed to air. For each fluid system (water/ $n\text{C}_{10}$, water/blandol, water/PAO40, water/crude oil), an increase in temperature results in more rapid recovery consistent with reduced oil viscosity as temperature increases. Similarly, at a fixed temperature, the recovery rate decreases as the ratio of wetting to nonwetting phase viscosity decreases. Presence of initial water saturation also shows a less imbibition potential value.

In general, results for experiments with crude oil lag behind those for the white mineral oils even when crude and mineral oil viscosity are similar at 180°C and the difference in permeability among field and outcrop is considered. This indicates possible interaction of crude oil constituents with rock that alters wettability toward mixed wetness in a fashion; perhaps, similar to that suggested by Kovscek *et al.* (1993). Residual oil saturation to spontaneous imbibition is largest in the crude oil systems. Nevertheless, the residual oil saturation to spontaneous imbibition for a specific fluid system decreases as temperature increases. Forced displacement following spontaneous imbibition significantly reduced oil saturation in the water-crude oil/outcrop system. This indicates that a substantial portion of the oil phase remains continuous at the end of spontaneous recovery that could be recovered during forced imbibition.

5. DISCUSSION

Experimental results as a function of temperature appear to exhibit some influence from changing wettability state. However, the viscosity and mobility ratios and interfacial tension are also a function of temperature and must be considered before any inferences can be made regarding wettability. Research on rock wettability through spontaneous imbibition tests has been extensively performed (Morrow and Mason, 2001). Spontaneous imbibition tests, as conducted here, provide not only final recovery data, but also the imbibition rate and pattern of water invasion. A more precise characterization of wettability is possible as compared to the Amott Index (Amott, 1959) that is based only on spontaneous and forced imbibition end points. Wettability is assessed through the construction of dimensionless groups that include water and oil mobilities, capillary and viscous forces, core dimensions, permeability, and porosity.

Several scaling groups for counter-current imbibition have been proposed (Zhou *et al.*, 2001, Zhang *et al.*, 1996, and Wang, 1999). In this work, we used Zhou *et al.*'s scaling group (Zhou *et al.* 2001) to examine our experimental results. It explicitly incorporates the mobility ratio. Given the extreme variations in viscosity and mobility with temperature, it is most appropriate. Beginning from the equations of motion in

porous media and restricting them to counter-current conditions, it was derived:

$$t_D = \sqrt{\frac{k}{\phi}} \frac{\sigma}{L_c^2} \sqrt{\lambda_{rw}^* \lambda_{rnw}^*} \frac{t}{\sqrt{M^*} + \frac{1}{\sqrt{M^*}}} \quad (3)$$

where $\lambda_r^* = k_r^* / \mu$ is a characteristic mobility for the wetting (w) and non-wetting (nw) phases and $M^* = \lambda_{rw}^* / \lambda_{rnw}^*$ is a characteristic mobility ratio, and σ is interfacial tension. End-point relative permeabilities are used for calculating λ_r^* and M^* . Numerical values of k_{ro}^* and k_{rw}^* are set equal to 0.16 and 0.60, respectively, consistent with refs (Zhou *et*

al., 2001 and Schembre and Kovscek, 2001). The characteristic length scale, L_c , is expressed as

$$L_c = \sqrt{\frac{V_b}{\sum \frac{A_i}{l_i}}} \quad (4)$$

where V_b is the bulk volume of the rock sample, A_i is the area of a face open for imbibition in the i direction and l_i is the distance from the open face to the no-flow boundary in the i direction.

The interfacial tension varies with temperature. Unfortunately, a high-temperature tensiometer was not available. Measured, at room temperature, IFT were extrapolated to the temperature of interest via the corresponding states relationship (Reid, 1987).

$$\sigma(T) = \sigma(T_r) \left(\frac{1 - T_{r1}}{1 - T_{r2}} \right)^{1.22} \quad (5)$$

where $T_r (=T/T_c)$ is the reduced temperature. For blandol and PAO40, the critical temperature is obtained from correlation (Pedersen *et al.*, 1989).

$$T_c = 24.279T_b^{0.588} SG^{0.36} \quad (6)$$

where T_b is the normal boiling temperature and SG is the specific gravity. Table 3 summarizes IFT measurements and extrapolations.

Figure 15 presents the results from renormalizing the spontaneous imbibition behavior of the outcrop/white mineral oil systems. Scaled results appear to separate into two groups. The water/air/outcrop and water/PAO40/outcrop systems fall into one group. In a dimensionless time of roughly 2 these systems achieve residual non-wetting phase saturation. This is consistent with prior results of counter-current imbibition in very strongly water wetting diatomite outcrop (Zhou *et al.*, 2001). The second requires a dimensionless time of order 10 to come to residual oil saturation. Note that with the exclusion of the water/nC₁₀ at 48° C and water/blandol at 57° C data sets, the second group of results collapses well. In the future, we intend to repeat these particular fluid systems at the specified temperature to determine whether some experimental error or inaccuracy exists. Nevertheless, the existence of two distinct groups within the dimensionless data indicates that core samples are not uniform with respect to wettability. Evidently, the air/water/outcrop and PAO40/water/outcrop systems are more strongly water wet than the remaining systems. This is consistent with the fact that cores were drawn from two different blocks of the same outcrop that were quarried at different times and locations.

We also attempted to scale the water imbibition data for crude oil tests and the results are presented in Fig. 16. We assumed the interfacial tension between crude oil and water is about 30 mN/m at 120 °C and 20 mN/m at 180 °C, respectively. Obviously, the experimental data for crude oil/water/outcrop core system are similar to those shown

in Fig. 15. However, the scaled data for crude oil/water/field core do not show a consistent trend and not collapsed. Further study of water imbibition for crude oil/water/field rock system is underway to explain these trends.

6. CONCLUSIONS

Temperature affects water imbibition and oil recovery from oil-filled diatomite cores significantly. Imbibition rate increases and the residual oil saturation to spontaneous imbibition decreases systematically with increasing temperature. The experimental results indicate that improvement in recovery with temperature occurs through both a more favorable mobility ratio and wettability alteration. The significant reduction in oil viscosity as a function of temperature decreases the mobility ratio and this effect always favors an increase in the rate of spontaneous imbibition. Wettability alteration toward a more water-wet state with increase in temperature, as evidenced by a decrease in S_{or} , also favors imbibition. However, there is competition between the increase in water-wetness and decrease in interfacial tension with temperature. Over the range of temperatures examined here, the decrease in interfacial tension is a lesser effect as compared to wettability change.

An interesting observation from the CT images is that water saturation within the cores was not uniform, and became more nonuniform as the viscosity ratio of water to oil became much less than one. Water saturation at the completion of spontaneous recovery was high near the inlet and decreased with distance from the inlet. In this regard, some portion of the oil phase remained continuous at the end of spontaneous imbibition. Forced displacement, following spontaneous imbibition recovered significant oil. In field core, recovery increased from roughly 30 % of OOIP following spontaneous recovery to 50% with forced displacement.

7. NOMENCLATURES

A	area, cm^2
CT	CT number, Hounsfields
$I P$	imbibition potential, $\text{min}^{-0.5}$
k, k_r	permeability and relative permeability, md
L	length, cm
M	mobility ratio
PV	pore volume
S	saturation, fraction
T	temperature, $^{\circ}\text{C}$
T_b	boiling temperature, K
T_c	critical temperature, K
t	time, min
X_D	dimensionless length, fraction
V	volume, cm^3
ϕ	porosity, fraction
μ	mPa.s
σ	interfacial tension, mN/m
λ	mobility

Subscripts

a	air
o	oil
r	rock
w	water

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Table 1 Core Properties and Test Conditions

Core^a	k md	φ %	L cm	S_{wi} %	T °C	Non-wetting phase	μ_n mPas	S_{or,si} PV	IP min^{-0.5}
O-1	2.5	67	7.0	0	22	air	0.018	0.21	0.053
O-2	2.7	65	7.0	0	25	n-C10	0.93	0.73	0.0059
O-2	2.7	65	7.0	0	48	n-C10	0.62	0.43	0.0091
O-2	2.7	65	7.0	0	88	n-C10	0.24	0.33	0.016
O-3	2.9	67	3.5	0	57	blandol	9.0	0.51	0.0064
O-4	2.5	67	6.5	0	120	blandol	1.7	0.47	0.0073
O-5	2.3	65	7.0	0	180	blandol	0.7	0.38	0.012
O-6	2.5	67	6.5	0	120	PAO40	12.6	0.61	0.010
O-7	2.5	67	6.5	0	180	PAO40	4.7	0.51	0.018
O-8	3.9	63	6.5	0	42	Crude	640	0.97	0.00040
O-9	2.6	65	6.5	0	120	Crude	18.2	0.66	0.0042
O-10	2.7	67	6.4	0	180	Crude	4.5	0.48	0.0062
O-11	2.1	70	6.0	22	180	Crude	4.5	0.49	0.0053
F-a	0.8	55	6.5	0	43	Crude	640	1	0
F-a	0.8	55	6.4	0	120	Crude	18.2	0.88	0.00020
F-15	1.1	58	4.5	0	180	Crude	4.5	0.57	0.0045
F-1	1.5	69	5.1	27	180	Crude	4.5	0.46	0.0028
F-25	1.2	60	4.0	30	180	Crude	4.5	0.51	0.0025

Note: a-O and F denote outcrop and field core, respectively.

Table 2 Brine Composition for Diatomite Reservoir Brine, mg/L

Na⁺	Ca⁺⁺	Mg⁺⁺	Cl⁻	HCO₃⁻	SO₄⁻	TDS	pH
2884	56	3	3575	1494	108	8100	7.5

Table 3 Estimation of Interfacial Tension (mN/m) at Elevated Temperatures

Temperature, °C	22 (measured)	48	57	88	120	180
n-C ₁₀ /water (mN/M)	50	46	44	38	32	22
blandol/water (mN/M)	42	38	37	33	29	21
PAO40/water (mN/M)	40	37	36	32	28	22

Figure 1: Porosity images for outcrop and field diatomite cores.

Figure 2: Viscosity of crude oil and mineral oils vs. temperature.

Figure 3: Schematic of experimental

Figure 4: Spontaneous water imbibition in air or oil (n-C₁₀) filled outcrop diatomite core.

Figure 5: Spontaneous water imbibition in oil filled outcrop diatomite core at elevated temperatures: blandol.

Figure 6: Spontaneous water imbibition in oil filled outcrop diatomite core at elevated temperatures: PAO 40

Figure 7a: Water saturation profile for water imbibition in oil filled outcrop core at $T=180^{\circ}\text{C}$: PAO40.

Figure 7b: Water saturation vs. time at $X_D=0.64$ for PTO40/outcrop diatomite core at $T=180^{\circ}\text{C}$.

Figure 8a: Water imbibition in outcrop diatomite core at elevated temperatures: crude oil.

Figure 8b: Water imbibition in outcrop diatomite core with zero and non zero initial water saturation at T=180°C: crude oil.

Figure 9: Water saturation profile for water imbibition in oil filled outcrop core at $T=180^{\circ}\text{C}$: crude oil.

Figure 10: Water imbibition in oil filled field core at elevated temperatures: crude oil

Figure 11a: Water saturation profiles for water imbibition in oil filled field core at $T=120^{\circ}\text{C}$: crude oil

Figure 11b: Water saturation profile for water imbibition in oil filled field core at $T=180^{\circ}\text{C}$: crude oil.

Figure 12: Water saturation distribution at $X_D=0.35$ vs. imbibition time for crude oil/field diatomite core at $T=180^\circ\text{C}$.

Fig.13: Change in average water saturation vs. time for water imbibition in oil filled field core at $T=180^\circ\text{C}$: crude Oil.

Figure 14: Water saturation profile for water imbibition in oil filled field diatomite core at $T=180^\circ\text{C}$ and $S_{wi}=30\%$: crude oil.

Figure 15: Scaled spontaneous water imbibition in oil filled outcrop diatomite core at elevated temperatures using t_{D2} : mineral oils.

Figure 16: Scaled spontaneous water imbibition in oil filled diatomite cores at elevated temperatures using t_D :crude oil.

MECHANISMS OF PRIMARY HEAVY OIL RECOVERY

Mechanisms of Solution Gas Drive in Viscous Oils

Yi Tak Leung

1. INTRODUCTION

Primary production in some heavy-oil reservoirs in Canada and Venezuela has been found to be higher than that estimated by conventional calculations. There have been studies done to determine the reason for this unexpected phenomenon and they are discussed in the literature review. 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” (1995). This foamy appearance is due to its high content of bubbles dispersed in the oil, but is not directly the cause for high oil recovery.

There already have been studies performed demonstrating the positive effects of increasing flow rates on recovery. This corresponds to decreases in gas-phase mobility and thus gas relative permeability. A reduction in gas-phase relative permeability is the most likely cause for increased recovery. The motivation, through the process of experimentation, is to better understand the effects of high viscosity and differing depletion rates on relative permeability of the fluids in the system, particularly gas relative permeability.

Estimated recovery of oil and production forecasts are dependent upon knowledge of reservoir parameters. By having more knowledge of this heavy-oil mechanism, better predictions and more informed decisions can be made. Knowledge of optimal flow rates can then be used to obtain the best recovery and total cumulative production before other secondary or tertiary methods are implemented. Relative permeability plays an important role in determining optimal flow rates and should be researched further.

The objective of this work is to characterize 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.

2. LITERATURE REVIEW

Smith (1988) was the first to address this issue of anomalous behavior in heavy-oil reservoirs during primary production. He hypothesized that the oil and gas flowed together, where the gas is in the form of small bubbles interspersed throughout the oil. This simultaneous flow of oil and gas has a lower apparent viscosity as compared to oil alone, thereby increasing productivity. Smith also looked at the theory of sand production creating “wormholes”, thereby increasing permeability in the neighborhood of the wellbore. It has been documented that initially, some new primary production wells produce oil at high sand cuts, which decreases as production continues until finally the sand cut stabilizes. This sand production is believed to increase the permeability near the wellbore, contributing to a negative skin. Smith determined that this still would not account for the drastic increase in total recovery. He also theorized that the asphaltenes in the oil could act as nucleation sites for bubbles to form.

Claridge and Prats (1995) go one step further, basing an entire model on the process of asphaltene adsorption. They performed simulations but did not actually do laboratory experiments to confirm their theory where the asphaltenes coat the gas bubble preventing bubble growth and coalescence. Thus, the bubbles stay small enough to travel with the oil. This continual adsorption of asphaltenes onto the bubble’s surface causes the oil viscosity to decrease.

Experiments were later done by Bora *et al.* (1997) using micromodels to test several theories. The main objective of their experiments were to determine the effects of asphaltenes, pressure depletion rates, and sand wettability on the process of solution gas drive. Their use of micromodels, though not as representationally accurate as the use of cores or sandpacks, permits them to examine pore-scale events. One concern about their apparatus design is the structure of their micromodels. They used a very symmetric and structured design probably not representative of the rough grains and tortuosity of the pores and throats encountered at the pore-scale. We should be cautious if we are to extrapolate their findings to processes that happen in the actual reservoir. They found that the asphaltenes tended to increase the supersaturation pressure and decrease the amount of bubble coalescence, but the asphaltenes did not increase the number of nucleation sites. They then found that higher depletion rates tended to keep bubbles dispersed as they flowed to the outlet and the effect of wettability on the depletion process was negligible.

Possibly from the same results as Bora *et al.* (1997), Maini (1999) presents a mechanistic model of foamy solution gas drive with possible explanations for the improved performance and recovery. In his mechanistic model, he compares the foamy flow and conventional solution gas drive. The main difference happens after nucleation and growth of bubbles up to pore size. The bubbles will continue to grow, staying immobile in the conventional solution gas drive process until it forms a continuous gas-phase by coalescing with other nearby bubbles. Once the continuous gas-phase is formed, it will then flow towards the producing end. But in the foamy flow situation, the bubbles will flow with the oil once it reaches a certain size. This bubble size is dictated by the equilibrium of capillary forces and viscous forces. As the bubbles flow,

coalescence is offset by the breakup of bubbles keeping them dispersed. This results in a low gas oil ratio and high recovery. He then did experiments with micromodels and sandpacks to support his theories. Maini (1999) also notes the independence of wettability on the solution gas drive process. Since the solution gas drive process seems to be independent of wettability, we can extend and simplify our experiments by using an oil-gas system rather than go through the complicated process of conducting three-phase (water-oil-gas) experiments. As to be expected, in Maini's (1999) sandpack experiments, the increase in flow rate corresponds to a higher pressure gradient, which leads to reduced coalescence, increased bubble dispersion and higher recoveries. Also, an increase in oil viscosity meant that these high recoveries could still be obtained at lower depletion rates, as compared to the lower viscosity oils.

A more representational experiment was done by Urgelli *et al.* (1999) using a sandstone core to investigate gravity and depletion rate effects. They found that recovery was lower when the core was in a horizontal position as compared to when it was in a vertical position. This was further compounded by the fact that there was higher gas saturation found at the top of the core. It was not determined whether this gas-phase was continuous. In any event, results indicate that there can be a gravity effect. These findings compete with the idea that small bubbles remain entrained in the oil. It should be noted that oil with viscosity 1500 cp was used. In their depletion rate tests, they found that higher depletion rates corresponded to higher oil recovery.

In contrast to the results of Urgelli *et al.* (1999), Pooladi-Darvish and Firoozabadi (1999) did similar experiments using a sandpack with light and heavy-oil and found that gas mobility in heavy-oil was much less than in light oil. Intuitively, this makes sense. The heavy-oil with higher viscosity will of course inhibit gas mobility. Other findings include, a lack of microbubble gas-phase flow with the oil and lack of increased liquid mobility upon nucleation of bubbles. So contrary to Claridge and Prats (1995), the evolution of gas-phase, did not increase liquid mobility. But Claridge and Prats (1995) specifically indicated asphaltenes as the reason for increased liquid mobility. The presence of asphaltenes in the heavy-oil used by Pooladi-Darvish and Firoozabadi (1999) is not known. Pooladi-Darvish and Firoozabadi (1999) then did simulations, varying relative permeability functions to fit experimental results. They found that there was a very large decrease in relative permeability to gas for the heavy-oil case as compared to the light-oil case.

Tang and Firoozabadi (1999) set out to disprove the idea of foamy oil as the reason for increased recovery. Their experiments compared recovery of mineral oil and crude oil. The mineral oil is taken to not have the ability to be in a foamy state. They found that the increased recovery was not due to the results of the oil's ability to be foamy, but rather the effect of low gas mobility. They then formulated a mathematical model to determine the relative permeability of gas and oil, but they cannot compare these relative permeability values to other independent measurements (to ensure that their mathematical model was accurate).

Kumar *et al.* (2000) takes the next step by changing depletion rates and observing its effect on gas mobility in an unconsolidated sandpack. They then match their experimental results using Eclipse-100 Black Oil Simulator to obtain gas relative permeability. They found that gas relative permeability decreases as depletion rate increases.

3. APPARATUS SETUP

The equipment is setup as in Fig. 1. The sandpack holder is 16 inches long, 2 inches in diameter, and has 11 pressure ports attached to it⁹. 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), which 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 CO₂ 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.

4. EXPERIMENTAL PROCEDURE

The sandpack holder is initially packed with clean Ottawa sand with grain sizes ranging between 75-150 μm . Before the inlet cap is placed back on, some glass wool is added to the top of the sand to prevent sand movement and slumping. The apparatus is then pressure tested to determine whether or not the O-ring on the inlet cap was sheared during the closing process. If the O-ring is sheared, then the sandpack holder will leak. If the sandpack does not leak, then it is flushed with CO₂ for approximately 20 minutes to displace any air in the system. The dry sandpack is then locked into place on the positioning table in the CT scanner. The sandpack will remain immobile after the first scan of the dry image is taken. The tubing for the pressure ports, inlet and outlet are then connected and a dry image of the sandpack is taken with the CT scanner. The settings used in the CT scanner are shown in Table 1.

Saturation of the mineral oil with CO₂ is done in the piston accumulator. The amount of gas needed in solution is first determined from the GOR we desire and the volume of live oil we wish to create. This amount of gas is then converted into a corresponding pressure that the gas will exist at when the gas is at a volume equivalent to that of the piston accumulator's, via the real gas law. CO₂ is then injected into the

accumulator until pressure stabilizes to our calculated value. A liquid pump (LDC Analytical constaMetric 3200 Solvent Delivery System) is used to inject the dead oil into the accumulator. The oil is situated above the piston while water is used below the piston as the displacement fluid. There are only 2 orifices, one at the top for the oil and one at the bottom for the water. Once the oil has been injected, the valve is closed and an ISCO pump is connected to the water side and is used to bring the pressure in the accumulator above saturation pressure. This system is left for several days to equilibrate while the pump is left on constant pressure mode to keep the system consistently pressurized. Prior to injecting the live oil, several samples are taken from the piston accumulator and tested to determine whether the live oil is truly at the target GOR.

The liquid pump is used to inject the dead oil, which saturates the sandpack. Once oil begins to be produced at the outlet, then the back pressure regulator (BPR), located at the outlet of our system, is set to the same pressure as the pressure we wish to start the experiment at. We also try to saturate the live oil at this pressure. A total of 1.5 pore volumes of dead oil is injected to achieve a saturated state. The pressurization of the sandpack using the BPR removes any gas pockets that the injection fluid may have missed displacing. Any CO₂ left still in the system will dissolve into the oil and be produced out. Absolute permeability of the sandpack to oil can be determined at this point. Once the 1.5 pore volumes of dead oil has been injected, flow to the inlet of the sandpack is then switched from dead oil to live oil. The ISCO pump is set to slow constant flowrate injection and should displace the dead oil with piston-like displacement. 1.5 pore volumes of live oil is injected into the sandpack and an image of the sandpack fully saturated with live oil is taken. Once injection of the live oil has finished, the inlet is valved off and the ISCO pump is then connected to the bottom (outlet orifice) of the outlet accumulator while the other end of the accumulator goes to the effluent orifice of the sandpack. This outlet accumulator system is then brought up to the same pressure as that of the sandpack and the outlet valve is switched from the BPR to the outlet accumulator. The ISCO pump is then set to constant refill mode, which begins the depletion experiment. Throughout the experiment, the effluent is monitored for gas bubbles. Pressure measurements at all 11 pressure ports are recorded and CT images are taken at various time intervals. The experiment is concluded when effluent is all gas and it appears that no more oil is produced.

5. RESULTS

Three experiments have been conducted so far. All the experiments have used Kaydol and CO₂, with the live oil containing a GOR of roughly 43 vol/vol. The following are details of data processing and observations for each experiment.

The following formulas are used to determine porosity and gas saturation in the sandpack from raw CT data:

$$\phi = \frac{CT_{oilwet} - CT_{dry}}{CT_{oil} - CT_{gas}}$$

$$S_g = 1 - \frac{CT_{obj} - CT_{dry}}{CT_{oilwet} - CT_{dry}}$$

All CT values have the units of Hounsfield. CT_{dry} denotes the CT value of the dry sandpack. CT_{oilwet} is for the fully oil saturated sandpack while CT_{obj} is for the image being processed. CT_{gas} is the CT value for pure gas, in our case CO_2 with a value of – 1000 Hounsfield. CT_{oil} is the CT value for pure oil, in our case Kaydol with a value of – 182 Hounsfield.

Kaydol Experiment 1: This first experiment was not conducted exactly according to the procedure as previously outlined. For this first experiment, a volume of Kaydol was allowed to saturate with a large amount of CO_2 at a pressure of 600 psi for several days. It was initially hope that the GOR would be high, around 110 vol/vol (from Fig. 2), but the GOR measurements obtained at the end of the experiment indicated a GOR of 44.3 vol/vol. The experiment began at 615 psi using a constant volumetric depletion rate of 0.160 mL/min (0.035 PV/hr). From Fig. 3, we see that compressibility of the liquid accounts for the steep pressure drop of 5.03 psi/min above the bubble point pressure. Once the bubble point pressure of 300 psi is reached, we enter a zone of supersaturation, where pressure drop is still dependent on liquid compressibility, until pressure reaches 266 psi. The pressure then rebounds back to 276 psi and then slowly decreases at a gentler slope, which is dependent on gas compressibility. The GOR value correlates well with the saturation pressure in Fig. 2. The first bubble seen in the CT scan and from the outlet tubing was observed at the same time of 1:22:00 into the experiment. Strangely, the pressure difference between the inlet and outlet does not drop until 1:39:00. From CT images, we can conclude that mobilization of the gas happened soon after the gas nucleated. Looking at Fig. 6, we can deduce that this gas production is from a continuous gas phase because of the sharp increase in fractional flow of gas soon after production of the first gas bubble. This suggests that gas entrained in oil flow, where the gas does not act as a free phase, is unlikely as the latter scenario would be indicated by a gradual increase or a constant fractional flow of gas for a period of time soon after the first bubble. The experiment was stopped after 17 hours.

Looking at the CT images of the sandpack, we immediately see a problem with packing in the upper right corner. Glass wool was not used in the sandpack for this experiment because it was not foreseen that slumping would be a problem. For subsequent experiments, a disk of glass wool with a diameter 2 mm smaller than that of the inlet cap and a thickness of 3 mm is used as a cushioning device to reduce movement of sand and slumping.

It was decided that the sandpack should be repacked for the 2nd experiment. This time, an over-ambitious attempt was made to prevent sand movement. The handle of a large screwdriver was used to compact the sand as the sandpack was being filled. A disk of glass wool was placed over the sand before the inlet cap was inserted. The intermittent manual reciprocating compaction led to an undesirable heterogeneous pack with areas of alternating high and low porosities.

Kaydol Experiment 2: The experimental procedure for this experiment is congruent with the process described in the experimental procedure section. The target GOR was set to 44 vol/vol and samples of the live oil were taken after saturation to determine GOR. The GOR was found to be 43.8 vol/vol. Initial pressure at the beginning of the experiment was 650 psi and the depletion rate is ten times slower than Kaydol Experiment 1. Depletion rate for this experiment was 0.016 mL/min (0.0035 PV/hr). The pressure drop in the liquid expansion region is 0.502 psi/min. Since Kaydol is again used in this experiment and the GOR is similar to the last experiment, we expect to see a bubble point close to 300 psi. Because of this estimated bubble point, we decreased the frequency for pressure measurements below 500 psi. Unfortunately, the pressure rebound was found to be in the vicinity of 420 psi. Pressure drop in the gas expansion region was 0.0463 psi/min. The first gas seen in the CT images is at 5:31:00. Unlike the last experiment, the first bubble seen at the outlet end is at a much later time (36:00:00) as compared to time when gas is seen in the CT image. The critical gas saturation for the slow rate case is much higher. The regions of high gas saturation resemble the shape of the heterogeneities. From the CT images, gas nucleation and growth happens in the locations of high porosity. The capillary pressure in these areas are lower, thus facilitating growth of gas bubbles, whereas the low porosity regions may have proportionately a larger amount of gas nucleation due to the numerous crevices but the growth of these nucleated bubbles is hindered by higher capillary pressure. In Fig. 11, the gas first nucleates near the center of the sandpack and growth of the gas is fairly equal in directions to both the outlet and inlet. In Experiment 1, it is clearly seen that the gas preferentially nucleates and grows near the outlet. Fractional flow of gas at the outlet was unable to be obtained due to a failure of the video camera.

The discrepancy of bubble point pressure between the first experiment and the second experiment is strange and the only plausible reason to explain it is that Kaydol is an industrially obtained oil. The properties may differ somewhat from batch to batch because there are no stringent guidelines. Since the time period between Experiments 1 and 2 was two months, it is possible that the Kaydol used in both experiments came from different batches. In association to this, it is quite possible that the saturation properties for the oil changed from batch to batch. The bubble point for the second experiment was confirmed to be 425 psi, by doing a volumetric expansion on the remaining saturated oil in the piston accumulator. Since the bubble point pressures are so different between experiments, we decided that to conduct Experiment 1 again, this time using the same oil as for Experiment 2. The oil was resaturated with CO₂ and such a method would guarantee the same bubble point pressure between Experiments 2 and 3.

Kaydol Experiment 3: The same sandpack was used in Experiment 3 as in Experiment 2. Again 1.5 pore volumes of dead oil was injected into the depleted sandpack (the status of the sandpack at the end of Experiment 2). The system was brought up to 600 psi and live oil was injected into the sandpack. The depletion rate is the same as in Experiment 1. As expected, the bubble point pressure is almost exactly the same for Experiment 3 as for Experiment 2. Pressure depletion rate in the single phase liquid zone is 4.6 psi/min and 0.27 psi/min in the gas expansion region. The results between Experiment 1 and Experiment 3 are very similar besides the difference in bubble point pressure. Gas

nucleation is seen in the CT images at 00:44:17 and gas production from the outlet is at 00:47:49. Again, in this fast depletion rate case, mobilization of the continuous gas phase happens soon after gas formation. This leads to a low critical gas saturation. Looking at Figs. 3, when gas nucleates and is produced, we are situated near the peak of the differential pressure curve. As more free gas is produced, the differential pressure drops.

Figure 5, illustrates the difference in supersaturation between the slow and fast depletion rate experiments. The average pressure in the lower rate experiment dips lower and rebounds higher than that of Experiment 3. There are two possible reasons for this behavior. The first, models show a constant rate with reduced number of bubbles displaying a larger supersaturation, while a higher depletion rate with constant number of bubbles will also show a larger supersaturation (Arora and Kovscek, 2001). These two effects compete and if the number of bubbles dominate over the depletion rate, then we would see a larger supersaturation in Experiment 2 as opposed to Experiment 3. Another possible reason is due to the heterogeneity in the sandpack. This heterogeneity affects capillary pressure, especially when the depletion rate is slow, so that viscous forces are low. This capillary pressure could trap the gas, leading to a higher supersaturation. When the gas finally is able to mobilize and coalesce, it may do so abruptly causing a large rebound in pressure.

There have been difficulties calculating gas saturations because of anomalous CT numbers in the region of gas formation. The CT number inside the gas bubbles are larger than the saturated CT number and for pixels immediately adjacent to these gas bubbles, the CT numbers are lower than the dry CT numbers. This leads to gas saturations in certain areas which are less than zero and greater than one. Methods to work around this are currently being looked at.

6. CONCLUSION AND FUTURE WORK

With the experiments so far, it is shown that depletion rate does have an effect on the apparent supersaturation and critical gas saturation. The ability to apply these results to relative permeability remains elusive, but using normalized gas saturations for the relative permeability calculations may yield some results.

The objectives and motivation remain the same thus far. No one has tried to obtain a concrete analytical definition of how relative permeability is affected by viscosity and depletion rates of oil. The objective of the laboratory experiments will be to use the experimental results and try to formalize an analytical model relating flow rate of heavy-oil at their respective viscosity's with relative permeability curves, in particular the gas relative permeability curve. Quantifying effects of viscosity and depletion rate on critical gas saturation and apparent supersaturation would also be useful.

This understanding is important because gas and oil relative permeability have significant effects on the solution gas drive mechanism in heavy-oil reservoirs. We see this from Darcy's Law. By decreasing gas relative permeability, flow rate of gas decreases thereby enabling more gas to stay in the system prolonging the energy in the

reservoir, and creating a solution gas drive mechanism that is more effective than expected.

At least two more experiments are planned for the future. This time, the effect of oil viscosity will be examined. Two mineral oils will be used, PAO-40 and PAO-100, with viscosity of 900 cp and 2500 cp, respectively. The experiments will be conducted at the slow depletion rate of 0.016 mL/min (0.0035 PV/hr) and the sandpack will be repacked so that it is more homogeneous. Revisiting Experiment 2 with a homogeneous sandpack would also be beneficial in the comparison studies.

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Table 1 – CT Scanner Settings

Pilot scan	Off	MA	124
Field of View	48 cm	Focal Spot	LARG
Image Matrix	512 x 512	Anode Speed	Low
Sampling	1024	X-Ray Filter	3
Scan Rotation	398 degrees	Fast Process	Off
Scan Speed	6	Dyn Ref	On
Slice Thickness	10 mm	Dyn Cal	on
Algorithm	7		
Resolution	High		
Set KV	140		

Table 2 - Experiment Properties

	Experiment 1	Experiment 2	Experiment 3
Porosity	0.33	0.2	0.2
Permeability (D)	20	5	5
GOR (vol/vol)	44.3	42.0	43.3
Depletion rate (mL/min)	0.16	0.016	0.16

Figure 1 – Apparatus for primary depletion experiments.

Figure 2 – Saturation pressure for Kaydol. The gas is CO₂.

Figure 3 – Average pressure vs. time.

Figure 4 – Delta P vs. time.

Figure 5 – Average pressure vs. volume expanded.

Figure 6 – Fractional flow of gas at outlet for Experiment 1.

Figure 7 – Fractional flow of gas at outlet for Experiment 2.

Figure 8 – Experiment 1 Porosity.

Figure 9 – Experiment 2 & 3 Porosity.

For the next 3 figures, the outlet is on the left side.

Figure 10 – Gas saturation in sandpack (Experiment 1).

Figure 11 – Gas saturation in sandpack (Experiment 2).

Figure 12 – Gas saturation in sandpack (Experiment 3).

Figure 13 – Gas saturation bar.

A Study of the Effect of Viscosity on Gas Bubble Coalescence in Viscous Oils

Omar Hayat

1. INTRODUCTION

Primary production from heavy-oil reservoirs operating under a solution-gas-drive mechanism exhibits unexpectedly high primary recovery with slower pressure decline rate, lower than expected producing gas oil ratios, and higher oil production rates (Bora *et al.*, 1997).

Heavy-oil reservoirs in Canada and Venezuela exhibit this phenomenon. The process of solution gas drive involves nucleation of gas bubbles as the pressure in the reservoir falls below the bubble point. It is postulated these small bubbles are trapped and tend to remain dispersed in the oil due to the large viscosity of the continuous oil phase. Initial development of many of these reservoirs under solution-gas drive has a great economic advantage because implementation of traditional thermal methods can be avoided or delayed, resulting in cost saving. At Frog Lake, Alberta Canada a study (Huang *et al.*, 1997) concluded that cold production, the simultaneous production of oil and sand with the aid of progressive cavity pumps, can produce heavy oil (12° API, 20,000 to 50,000 cp) without the introduction of any external thermal energy. Another study in the Hamaca area of the Orinoco Belt in Eastern Venezuela (Mirabal, 1997) attributed the high productivity found in the reservoir to foamy-oil behavior of the crude. It was reported that primary production mechanism of the Hamaca reservoirs is controlled by the in-situ formation of a non-aqueous oil foam under solution gas drive conditions, improving oil mobility, therefore leading to high well productivity. The contribution of foamy-oil behavior as a primary production mechanism is up to 10% of the OOIP in the Hamaca Area (Mirabal *et al.*, 1996).

Several of these reservoirs are said to have shown a “foamy oil” behavior. This “foam” is oil continuous with the gas fraction close to solution gas-oil ratio and the consistency of a “chocolate mousse” at the wellhead. This kind of reservoir shows abnormally high production rate as well as effective recovery factor (Urgelli *et al.*, 1999).

To explain the above phenomenon a number of mechanisms have been suggested (Pooladi-Darvish and Firoozabadi, 1999) which can be divided into two main categories. Geomechanical effects such as sand dilation and development of wormholes comprise the first category. The second category suggests that the special properties of the flowing fluids, the gas and heavy oil, are the main reasons for high production. Both of these categories are not mutually exclusive and are described in some detail below.

The first theory postulates that this favorable behavior of heavy-oil reservoirs driven by solution-gas-drive is because of sand production. Economical production of heavy oil is possible by allowing formation sand to be produced along with the fluid. Dusseault (1993) shows that heavy oil (10-15° API) in cohesionless sandstones (>30% porosity) can be exploited by permitting sand to enter the wellbore along with fluids. He showed that with 1-3% sand production the flow rate goes up from 0.3 – 2 m³/d to 5-15 m³/d. This higher rate with sand production is attributed to four major factors enhanced drainage radius, grain movement, gas bubble expansion, and continuous pore deblocking.

The second theory suggests that sand production is not the predominant mechanism responsible for high oil rates and recoveries in heavy oils. It focuses more on the way the two phases i.e. oil and gas interact. According to this theory retention of the evolved gas phase in a dispersed form in the oil would lead to maintaining the reservoir energy. Although Dake (1978) does not explicitly discuss heavy oils he has shown that to obtain a high primary recovery, as much gas as possible should be kept in the reservoir. Maintaining the cumulative gas oil ratio (the ratio of cumulative gas production to cumulative oil production) as low as possible, helps keep the gas in the reservoir. By keeping the gas in the reservoir the total reservoir system compressibility is large and results in greater cumulative production for a given pressure drop.

The second category, is the focus of this research. Smith (1986) argues that it is certainly the case that extensive sand production modifies the reservoir in the vicinity of the casing, but it has been shown in the laboratory that no amount of sand remolding or fines removal would increase the permeability to the extent observed in pressure analysis. It is more likely that the laboratory determined core permeabilities are overestimates of the undistributed in-situ values and it is most commonly observed that the fines migration in the reservoir leads to reservoir plugging and not reservoir cleaning.

It is now an accepted fact that in the solution gas drive process, the main source of energy driving the oil towards the wellbore is the evolution and expansion of the gas initially dissolved in the oil (Bora *et al.*, 1997). The role of the gas bubbles in the oil displacement process is a focus of many research efforts, for the simple reason that understanding the pore level physics of how these bubble nucleate, grow, and coalesce is the key to developing better oil recovery techniques from heavy oil reservoirs.

In studying the bubble nucleation and growth process, research efforts have been directed towards trying to examine directly the pore level events by using micromodels. These micromodels are mostly made of glass and in some cases etched out in silicon. Such visualization experiments have also been accompanied by numerical simulation of the experiments. Li and Yortsos (1995) carried out experiments of bubble growth by pressure depletion in 2-D etched-glass micromodels and in Hele-Shaw cells (bubble growth in bulk liquid). The work also included development of a pore network numerical model to simulate the growth of multiple gas clusters under various conditions. Du and Yortsos (1999) also studied the dependence of critical gas saturation (gas saturation at which the onset of bulk gas flow occurs) on the geometric parameters of the porous media in detail. Bora and Maini (1997) carried out a series of flow visualization

experiments to examine the pore scale behavior of the solution gas drive process in heavy oils.

Experimental and modeling effort has also focused on understanding the nucleation mechanism for the gas bubbles. There are two models explaining the nucleation of bubbles. One is instantaneous nucleation (IN), which states that all the bubbles nucleate at essentially the same time and do not originate from preexisting bubbles trapped in crevices or the roughness of pore walls. Firoozabadi and Kaschiev (1995) did significant work to explore IN. The progressive nucleation process assumes that the bubbles are released from sites such as crevices or roughness on pore walls with poor liquid wetting properties that become activated when the local supersaturation exceeds the capillary pressure of the site (Li *et al.*, 1995).

The most important issue, however, is the understanding of bubble coalescence in porous media. The presence of dispersed gas bubbles in the oil during pressure depletion results in increased production rates in heavy oil reservoirs. Bora *et al.* (1997) made several observations about bubble coalescence. They described bubble coalescence as a three-step process. According to them, first, the bubbles have to come close to each other. This occurs naturally during migration of the bubbles in fast depletion tests and growth of adjoining bubbles by diffusion in slow depletion tests. When the bubbles are close enough and collide, the second step of the coalescence process begins. This involves draining and thinning of the liquid film separating the two bubbles. This thinning can be a slow process, which requires a finite length of time. According to them whether or not bubbles will coalesce depends whether the hydrodynamic forces pull the two bubbles apart before the liquid film has drained to a critical film thickness. At critical thickness the final step leads to coalescence of two adjoining bubbles.

George and Kavscek (1999) developed an apparatus to allow the use of silicon-wafer micromodels over a wide range of pressures, as required for solution gas drive experiments. Expected pore-level phenomena, such as snap-off and “breathing” of liquid films were successfully observed. Visual observations of gas bubble formation and evolution at a nucleation site were recorded. Experimental results indicated that oil-phase viscosity affects the rate at which pressure changes during pressure decline. Viscosity was also found to affect possibly the ability of bubbles to coalesce.

Building on that, Arora and Kavscek (2000) developed a mechanistic population-balance model to describe solution gas drive behavior in viscous oils and address the question of gas-bubble microstructure. The objective of this work was to incorporate pore-level bubble nucleation, growth, and transport mechanisms into a continuum displacement model consistent with standard simulation of multi-phase flow in porous media and to verify the theoretical predictions by comparison to experimental results. The results for the IN and PN models were compared to experimental data reported elsewhere for light oil and to new data for viscous oils. It was found that PN model matches the experiments somewhat better, but is more demanding computationally.

The work presented in this paper is directed towards developing a better understanding of solution gas drive behavior in heavy oils. While there is experience and data from micromodels and numerical simulation, the pore-level physics needs to be explored further. An interesting phenomenon observed in previous micromodel experiments was the effect of viscosity on bubble coalescence (George, 1999). A study by Kumar and Pooladi-Darvish (1999) on the effects of viscosity and diffusion coefficient on the kinetics of bubble growth in heavy oil, reported that the effect of oil viscosity on bubble growth can be ignored. It concluded that viscous forces and in general hydrodynamic forces have little or no effect on bubble growth in heavy oils at late times. This observation was based on studying the numerical model for growth of a single bubble in heavy oil and light oil for gradual decline in pressure. These seemingly different observations make it all the more necessary to explore the effect of viscosity on bubble coalescence in porous media.

The objective of this work is to understand the effect of viscosity on the coalescence of gas bubbles trapped in narrow throats filled with heavy oil. Bubble coalescence is divided into two broad time regimes, an earlier time regime, after nucleation, when coalescence is diffusion dominated and a later time regime when coalescence is governed by pressure gradient across the bubbles, pushing them together.

The earlier, diffusion dominated time regime, is explored by borrowing from the work of Firoozabadi *et al.* (1995). The effect of viscosity on diffusion dominated bubble coalescence is studied in detail.

A physical model is developed to study the effect of viscosity on bubble coalescence in a narrow, non-circular throat filled with oil, at a later time. The model computes the time required for the oil lens between the bubbles to drain, which are being pushed together by pressure gradient across the bubbles. The computed time for coalescence is compared with visual data from micromodel and capillary tube experiments.

2. DIFFUSION DOMINATED BUBBLE COALESCENCE

Once the bubbles nucleate, they grow in size by diffusion of dissolved gas in oil. Bubbles nucleating in close vicinity therefore coalesce by growing in size through diffusion.

Firoozabadi *et al.* (1995) suggested that bubble nucleation rate J , and growth, G , can be represented by the following general expressions:

$$J(t) = A \exp[-B / s^2(t)] \quad (1)$$

$$G(t) = (\omega + \nu) K s^\omega(t) t^{\nu-1} \quad (2)$$

In the above Eqs. A and B are the kinetic and thermodynamic constants of bubble nucleation, K is the kinetic constant of bubble growth, ω and ν are positive numbers of the order unity, s is supersaturation and is defined as

$$s(t) = p_e(t) - p(t), s \geq 0 \quad (3)$$

P_e is the liquid pressure at which liquid and gas phases are at equilibrium, and P is the pressure in the liquid, which maybe supersaturated. However for calculations in this paper, we considered a constant value of s .

Firoozabadi used $\omega = 1/2$ and $\nu = 1/2$ to derive an expression for Kinetic constant K. Here as we are considering diffusive growth of the bubble trapped in narrow pore, and so $\omega = 2/5$ and $\nu = 2/5$ is used to approximate the restraint in growth from the pore walls. Based on the derivation presented by Firoozabadi, an expression for K is derived for new values of ω and ν .

$$K = \frac{5}{4} K' [st]^{0.1} \quad (4)$$

$$\text{where } K' = \left[\frac{RT D k_s}{2P_b} \right]^{\frac{1}{2}} \quad (5)$$

In Eq. 5, R is the gas constant, T is temperature, D is diffusion coefficient, K_s is solubility constant and P_b is bubble point pressure.

The diffusion coefficient can be calculated using the empirical correlation of Hayduk and Minhas (1982) according to this correlation, the mutual diffusion coefficient is given by

$$D_{AB} = 13.3 \times 10^{-8} \frac{T^{1.47} \mu^\varepsilon}{V_A^{0.71}} \quad (6)$$

The above expression is used to calculate diffusion of an infinitely dilute solution of A in B. Which implies that each A molecule is in an environment of essentially pure B. This may need correction of calculated diffusion coefficient. However according to Reid *et al.* (1987), D_{AB} can be assumed to be a representative diffusion coefficient even for concentrations of A up to 5 and perhaps 10 mole percent. Therefore in this work, D_{AB} is used to represent D in Eq. 5. Here CO_2 is the solute dissolved as a solution gas in oil that acts as a solvent where μ is viscosity, V_A is molar volume and ε is given by

$$\varepsilon = \frac{10.2}{V_A} - 0.791$$

From Tyn and Calus (1975), molar volume can be calculated from the following relationship

$$V_A = 0.285 V_C^{1.048}$$

Equation 2 can be solved for radius r , as

$$\frac{dr}{dt} = (\omega + \nu) K s^\omega(t) t^{\nu-1} \quad (7a)$$

After integration the expression for the radius of the bubble is

$$r = 2.5K'[st]^{0.5} \quad (7b)$$

The values for different parameters used to make the calculations are given in Table 1. Values of different parameters are chosen for illustrative purposes only.

Table 1: Parameters for Calculation of Diffusive Bubble Growth

Parameters	Values
R	8.3124 J/mol K
T	298K
K _s	5x10 ⁻⁶ cm ² /sec
P _b	1500 psi
S	90 psi
ω	2/5
v	2/5

Figures 1 and 2 show the variation of diffusion coefficient with viscosity and change in bubble radius with time respectively, as more and more gas diffuses into the bubble. Result shows strong dependence of diffusion coefficient on viscosity of the solute. It drops significantly for higher viscosity oils. Bubble growth follows the same trend and show strong dependence on oil viscosity.

3. PRESSURE INDUCED BUBBLE COALESCENCE

At a later time after bubble nucleation and the onset of gas flow, coalescence is mainly controlled by pressure gradient across the bubble that pushes them together, until they come close enough to coalesce. A physical model is developed to describe the coalescence of gas bubbles trapped in the originally oil filled pores in reservoir media. Consider Fig. 3a to understand the geometry of the trapped bubbles in the pore, this geometry is the basis for developing the model.

The following assumptions are made to develop this model: Oil is the wetting phase and gas is the non-wetting phase and there is no aqueous phase present. The pore has a square cross-sectional area. This is a valid assumption because real pores in porous media have corners. Pore geometry is shown in Fig 4. Bubbles are acted on by the oil-phase pressure gradient and diffusional bubble growth at this stage is slow enough to be neglected. Pore cross-sectional areas in our models are also square. The flow out of the oil lens is through the four pore corners, and oil films that line the straight section of the

bubble-pore wall interface are thin enough to be ignored in flow calculations. Any effect of gravity is ignored considering the very small pore diameters in reservoir media. Finally we assume that no thin-film forces are present to stabilize gas-oil interfaces.

The problem is solved for one of the trapped bubbles and the solution is valid for the second bubble by virtue of symmetry. Fig 3b shows the geometry of flow lines as the two trapped bubbles move towards each other under the pressure gradient across the bubble. At the plane of symmetry the flow lines interact to generate a stationary flow plane with respect to the z-axis. At this point the problem becomes analogous to a “squeeze film”. Denn (1980) explores the problem of a squeeze film in detail.

In the problem under discussion, gas bubbles move towards the symmetry plane and the oil flows out through the four corners. Figure 3b shows the geometry of the flow problem. The boundary Conditions for the problem illustrated in Fig 3 are that,

$$v_z = v_r = 0 \quad (8)$$

at the symmetry plane.

The oil-gas bubble interface moves towards the symmetry plane, with velocity $V(t)$. Therefore at the moving surface $z = H(t)$:

$$v_z = V(t) \quad (9a)$$

$$v_r = 0 \quad (9b)$$

Solving the Navier stokes creeping flow equation for the above boundary conditions, the following expressions for v_z , v_r and V_t are reached (Denn, 1980).

$$v_z = -3V(t) \left[\frac{z}{H(t)} \right]^2 \left[1 - 2z/3H(t) \right] \quad (10)$$

$$v_r = [3rzV(t) / H^2(t)] \left[1 - z/H(t) \right] \quad (11)$$

$$V(t) = - dH/dt = [2F/3\pi\mu R^4] H^3 \quad (12)$$

In the above equations, $H(t)$ is the distance between the symmetry plane and the bubble front at time t , v_z is the velocity of fluid in z-direction, v_r is the velocity of fluid in the radial direction, $V(t)$ is the velocity of the moving bubble, μ is the viscosity of the fluid, F is the imposed force, responsible for bubble movement, and R is the radius of the bubble.

At this point, boundary conditions and the flow equations are established for this problem.

The task now is to calculate the expression for time t , needed for the two bubbles each of radius R and separated by distance H_0 , to drain the oil lens so that coalesce may occur. The answer comes from Stefan equation (Denn *et al.*, 1980), derived for the squeeze-film problem using the boundary conditions and flow equations described above:

$$H(t) = \left[(1/H_0^2) + (4Ft/3\pi\mu R^4) \right]^{-1/2} \quad (13)$$

Solving for t gives

$$t = (3\pi\mu R^4/4F) [1/H^2 - 1/H_o^2] \quad (14)$$

In the above equation R, H and H_o can be measured and quantified from visual micromodel experiments. The viscosity of the oil, μ , can be readily measured. The only unknown that needs some mathematical treatment is the imposed force F.

In short, F is simply the pressure difference times the cross-sectional area of the pore and is given by

$$F = (\Delta P - \Delta P_c) \pi R^2 \quad (15)$$

Where ΔP is the total pressure gradient across the bubble and ΔP_c is the pressure gradient of oil in four pore corners. The resistance to flow in the pore corners opposes thinning of the lens.

The expression for the term ΔP_c can be calculated from the expression for flow resistance coefficient β , given by Ransohoff and Radke (1988),

$$\Delta P_c = (q\mu\beta L) / (a^2 A_w) \quad (16)$$

where q is the volumetric oil flow rate through the corners, β is the dimensionless flow resistance coefficient, L is the length of the bubble, and A_w is the area of the corners occupied by the oil.

The volumetric flow rate q out of the oil lens is given by

$$q_w = \int_0^{H(t)} 2\pi R v_r dz \quad (17)$$

Substituting Eq. 11 for v_r and integrating, we obtain

$$q_w = [6\pi R^2 V(t) / H^2(t)] [z^2/2 - z^3/3H(t)] \quad (18)$$

Putting in the limits from 0 to H(t), Eq. 18 reduces to

$$q_w = \pi R^2 V(t) \quad (19)$$

Substituting Eq. 12 for V(t) gives;

$$q_w = 2FH^3(t) / 3\mu R^2 \quad (20)$$

Putting the value of q_w back into the expression for ΔP_c , Eq. 16, we obtain

$$\Delta P_c = (2F H^3(t)\beta L) / (3 a^2 R^2 A_w) \quad (21)$$

Where a is the interfacial radius of curvature as shown in Fig 2b. Substituting F with $(\Delta P - \Delta P_c) \pi R^2$ in the above expression gives

$$\Delta P_c = [(2\pi H^3(t)\beta L) / (3 a^2 A_w)] [\Delta P - \Delta P_c] \quad (22)$$

Let $\lambda = [(2\pi H^3\beta L) / (3 a^2 A_w)]$ and rearranging the above equation

$$\Delta P_c = [\lambda(t)/(1+\lambda(t))] \Delta P \quad (23)$$

At this point we have established a relationship between ΔP and ΔP_c and can find the time required to drain any lens. The next step is to establish the values for each of the remaining parameters. Once this is done, calculations can be made for comparison with experimental findings.

Values of parameters are established from experimental observations. The pressure gradient across the bubble, ΔP can be obtained by measuring the gradient across the entire micromodel and equating the $\Delta P/L_{\text{model}}$ with $\Delta P/L_{\text{pore}}$. For example the micromodel used here is a 1.6-inch square with pressure drop of about 70 psi across its length. The ratio $\Delta P/L_{\text{model}}$ for this model is about 44.45 psi/in, for a typical pore of length 100 μm the value of ΔP is about 0.2 psi.

Ransohoff and Radke (1988) have computed the value of β as a function of surface viscosity, pore half angle, contact angle, and degree of roundedness in both graphic and tabular form. For this problem, a no slip condition is assumed and the value for sharp corners is used (degree of roundedness, $R_0 = 0$). From Ransohoff and Radke, for surface viscosity = 0, $\beta = 93.93$. See Fig 4b for the geometry of the problem.

The value for interfacial radius, a , can be calculated from the work of Ransohoff *et al.* (1987). This work tabulates the values for the equilibrium dimensionless interfacial entry curvature, $C_{\text{dm}} = C_m R$, in a variety of noncircular cross sections, where R is the local radius for the largest inscribed circle of the capillary. For the case under discussion, it is the radius of the throat. As the throat is assumed to have a square cross-section, $C_{\text{dm}} = 1.89$ from Ransohoff *et al.* Interfacial radius a is related to C_m by simple relationship $a \cong 1/C_m$. For typical pore radius of 10 μm , $a = 5.3 \mu\text{m}$.

The area wetted by the oil at the four corners, A_w is related to interfacial radius a by simple expression $A_w = 4[a^2 - \pi a^2/4]$. For typical pore dimensions mentioned above, A_w equals 24.02 μm^2 .

Its clear that value of β will remain independent of pore geometry for this problem because of the assumption that the throat has sharp corners. Other parameters are dependent on pore geometry and will change from one case to another. The procedure to evaluate them, however, remains unchanged.

4. MICROMODEL EXPERIMENT

The experimental apparatus consists of a micromodel, pressure vessel, optical equipment and a system of hardware that controls fluid flow and pressure [George, 1999]. The micromodel is a 5 cm by 5 cm etched pore pattern in silicon-wafer, which is anodically bonded to a borosilicate glass plate. Figure 5a is an optical micrograph of the model. Figure 5b is a SEM micrograph of the model and shows the shape and pattern of the pore network. Note the pore wall roughness and sharp unrounded pore corners.

In order to perform solution gas drive experiments at elevated pressure, a pressure vessel is designed to house the micromodel. The pressure vessel has an operating pressure of 1000 psig. It has a thick sapphire window located directly above the micromodel. See Fig. 6 for pressure vessel configuration. Confining fluid is present on both surfaces of the micromodel.

A microscope is positioned on top of the vessel and pore events in the micromodel can be observed through the sapphire window of the pressure vessel. Kaydol, a 200 cP mineral oil, was saturated with CO₂ at the desired pressure for a minimum of 20 hours. If the micromodel contained air, CO₂ was injected and allowed to sweep the micromodel and displace the air. The upstream pressure was increased to the desired injection pressure, and the injection of live liquid was initiated. Sufficient time was allotted for the micromodel to fill with the liquid, and for some fluid to exit the micromodel. The three-way valve on the downstream side of the pressure vessel was turned such that the outlet of the micromodel was connected to the syringe pump. The pump was then run until the outlet pressure reached the inlet pressure. The valve on the upstream side of the pressure vessel was shut. At this point the volume between the valve and the syringe pump, including the porous medium, pressure gauges, and tubing was closed. Once the inlet and outlet pressure equilibrated ($\Delta p = 0$), the syringe pump was run in refill mode at a low flow rate, to provide a controlled volume expansion.

The upstream and downstream pressures were recorded against time, and the VCR recorded pore-level visual observations. These visual observations are used to verify the physical model developed in this work.

5. RESULTS OF CALCULATIONS FOR MICROMODEL EXPERIMENT

Equations derived previously are used to calculate the time for coalescence of gas bubbles trapped in a narrow pore. The geometrical dimensions used are taken from a particular micromodel experiment see Fig 7. The results are plotted in Fig 7 for the parameters tabulated in Table 2.

Table 2. Parameters for Calculation of Coalescence in a Micromodel.

Parameter	Value
Viscosity, μ	220 cP
Bubble Length, L	100 μm
Bubble Radius, R	10 μm
Interfacial Radius, a	5.29 μm
Wetting Area, A_w	24.02 μm^2
Pressure Gradient, ΔP (across bubble)	0.2 psi

The time required for the bubble to travel from its initial position to the plane of symmetry is calculated. There are no chemical agents present in the viscous mineral oil to stabilize the interface and prevent coalescence. Thus coalescence is assumed to occur when the bubble interfaces (gas-oil) touch. The time interval for coalescence is found by computing time versus interface position according to Eq. 14 from the initial position to 1 μm of separation. We then extrapolate the solution to an interface separation zero. At very small thickness of the oil lens, the squeeze film approximation of this problem breaks down and infinite coalescence times are predicted. With this procedure the calculated time for coalescence is roughly 34s, whereas the experimentally measured time is 32s. The two agree well.

The dependence of time for coalescence on viscosity of oil is in agreement with observed high recoveries for heavy oil reservoirs under solution gas drive. These heavy oil reservoirs are able to maintain their high-energy state because gas bubble coalescence is delayed by viscous oil. The more time these bubbles take to coalesce the more time is available for the reservoir to stay energetic and produce at high rates, resulting in higher productivity and higher recovery. Any surface agents present in the crude oil enhance the effect of viscosity by further preventing coalescence.

6. CAPILLARY TUBE EXPERIMENT

Micromodel experiments as employed here, have one significant flaw for the problem that is being analyzed. The problem is with the control of events within a micromodel. It is hard to capture frequently a situation where one can observe bubble coalescence under pressure gradient across the bubble. Capillary tube experiments provide a suitable alternative without compromising the basic assumptions made, to solve the problem.

Triangular capillaries with sharp corners were used to conduct the experiments. The experimental setup is shown in Fig 8. The Capillary tube is held vertical with its lower end immersed in the beaker filled with the oil. An oil lens is introduced from the top of the capillary using a syringe. The trapped air between oil bank at the bottom of the capillary and the oil lens simulates the gas bubble trapped in narrow pore. The oil in the lens drains itself by flowing down the capillary corners, across the bubble, into the beaker. As shown in the Fig 8, the problem set up is practically the same as for the micromodel experiments. The time it takes for the oil lens of given length to drain completely is calculated. This is the time that a bubble required to reach the plane of symmetry, as described in the previous section. In other words this is the time for coalescence of two bubbles trapped in a narrow pore. Experiments were repeated for a set of oils with different viscosity.

The effect of gravity has to be considered as the capillary tubes are held in a vertical position during the drainage of the oil lens. The force pushing the bubble up, therefore is given by

$$F = (\Delta P - \Delta P_c + \rho_o g h) \pi R^2$$

ρ_o is the density of the oil, g is gravity and h is the length of the bubble. In the above equation the net imposed pressure ΔP can be calculated by the following expression

$$\Delta P = (\rho_o - \rho_g) g h$$

Where ρ_g is the density of the gas. As gas density is negligible compared to oil density, F , can be written as

$$F = (2\Delta P - \Delta P_c) \pi R^2$$

The rest of the equations are the same as were used to calculate the time for coalescence in case of micromodel experiment. The next section describes some of the results from the experiments and their comparison to the calculations made using the physical model.

7. RESULTS OF CALCULATIONS FOR CAPILLARY TUBE EXPERIMENT

Effort is made to maintain the height of the oil lens (i.e., the distance between the bottom of the oil lens and the top of the oil bank at the bottom of the capillary) and the length of the oil lens itself is roughly the same for every experiment. The upper interface of the oil lens remains stationary during the drainage and its acts as a plane of symmetry. A set of five different visocities was tested and the results compared with the physical model in Fig. 9.

The following equation was used to calculate the time for coalescence in this case.

$$t = C_f \times (3\pi\mu R^4/4F) [1/H^2 - 1/H_o^2]$$

where C_f is the correction factor based on the correlation between experimental results and the physical model. It has a value of 1.63.

Effect of viscosity on time for coalescence is apparent and it takes longer for bubbles trapped in high viscosity oils to come close and coalesce.

8. CONCLUSIONS

The effect of viscosity on bubble coalescence in heavy oils is studied .It is shown that viscosity of oil has a profound effect on coalescence dynamics at both earlier and later time regimes.

In the earlier time stage when the coalescence occurs primarily owing to bubble growth by diffusion, high viscosity of the oil slows down diffusion of dissolved solution gas in the oil thus reducing the rate of bubble growth. This result in longer time for coalescence for bubbles trapped in more viscous oils. This is shown by making calculations for the rate of growth of bubbles trapped in oils with different viscosity.

At a later stage coalescence is governed by the pressure gradient across the bubbles, pushing them together, draining the oil lens between the bubbles and finally resulting in coalescence. Intuitively it should be hard to drain the highly viscous oil between the bubbles and this is verified by using a physical model based on a rather simple set of equations.

At this stage, the physical model is capable of predicting the effect of viscosity on coalescence, but it needs improvement to predict accurately the time for coalescence. Ideally it should be able to predict the time for coalescence without using the correction factor C_f , coming from the experimental observations. This may require an even closer look at the physics of the model.

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Fig 1 Variation in diffusion coefficient with viscosity.

Fig 2 Variation in radius of the bubble with time

Figure 3 a) Geometrical configuration of two gas bubbles moving towards each other in a narrow pore.
b) Schematic representation of fluid flow and how the plane of symmetry acts as a static plate.

a

b

Figure 4 a) Cross-sectional view: wetting-liquid distribution in a square throat with the trapped gas bubble in it.
 b) Geometry of the corner flow problem. Showing the half angle, α , the contact angle, Ψ and the primary radius of curvature, a . Flow is in the positive z -direction into the plane of the figure.

Figure 5 a) Optical micrograph of the micromodel.
 b) SEM micrograph of the micromodel.

Figure 6 Exploded view of the pressure vessel components

Figure 7. Video shots of bubble coalescence in a micro model with 220 cP White oil.

Figure 8 Experimental setup for capillary tube experiments.

Physical Model of bubble coalescence

Figure 9. Experimental observations and results from physical model. Dotted lines show the experimental observations, solid lines are results from the physical model.

INSITU COMBUSTION

Chapter 17 (Reservoir Engineering Section)

INSITU COMBUSTION

William E. Brigham and Louis M. Castanier

This chapter is going to be the combustion part of the SPE handbook.
This is an advanced draft and will be published in 2003.

Chapter 17 (Reservoir Engineering Section)

Insitu Combustion

William E. Brigham and Louis Castanier

1. INTRODUCTION

Insitu Combustion (ISC) is the oldest thermal recovery technique. It has been used for over nine decades with many economically successful projects. Nevertheless, it is regarded as a high-risk process by many, primarily because of many failures of early field tests. Most of those failures came from application of a good process (ISC) to the wrong reservoirs or to the poorest prospects. An objective of this chapter is to clarify the potential of ISC as an economically viable oil recovery technique for a variety of reservoirs. This chapter is a summary containing a description of ISC, a discussion of laboratory screening techniques, an illustration of how to apply laboratory results to field design, a review of performance prediction methods, a discussion of operational practices and problems, and an analysis of field results. For a more complete review, the work of Sarathi¹, Prats² and Burger *et al.*³ should be consulted.

2. PROCESS DESCRIPTION

In situ combustion is basically injection of an oxidizing gas (air or oxygen-enriched air) to generate heat by burning a portion of the resident oil. Most of the oil is driven toward the producers by a combination of gas drive (from the combustion gases), steam and water drive. This process is also called fire flooding to describe the movement of a burning front inside the reservoir. Based on the respective directions of front propagation and air flow, the process can be forward, when the combustion front advances in the same direction as the air flow, or reverse, when the front moves against the air flow.

2.1. Reverse Combustion

This process has been studied extensively in laboratories and has been field tested. The idea is that it could be a useful way to produce very heavy oils with high viscosity. In brief, it has not been successful economically for two major reasons.

First, combustion started at the producer results in hot produced fluids that often contain unreacted oxygen. These conditions require special, high-cost tubulars to protect against high temperatures and corrosion. More oxygen is required to propagate the front compared to forward combustion, thus increasing the major cost of operating an insitu combustion project.

Second, unreacted, coke-like heavy ends will remain in the burned portion of the reservoir. At some time in the process the coke will start to burn and the process will revert to forward combustion with considerable heat generation but little oil production. This has occurred even in carefully controlled laboratory experiments.

In summary reverse combustion has been found difficult to apply and economically unattractive.

2.2. Forward Combustion

As only forward combustion is practiced in the field we will only consider this case. Forward combustion can be further characterized as “dry” when only air or enriched air are injected or “wet” when air and water are co-injected.

2.2.1. Dry Combustion

The first step in dry forward insitu combustion is to ignite the oil. In some cases auto-ignition occurs when air injection begins if the reservoir temperature is fairly high and the oil reasonably reactive. This often occurs in California reservoirs. Ignition has been induced using down hole gas burners, electrical heaters, and/or injection of pyrophoric agents or steam injection. Ignition will be discussed in more detail later.

After ignition the combustion front is propagated by a continuous flow of air. Rather than an underground fire, the front is propagated as a glow similar to the hot zone of a burning cigarette, or to hot coals in a barbecue. As the front progresses into the reservoir, several zones exist between injector and producer as a result of heat and mass transport and the chemical reactions. Figure 17.1⁴ is an idealized representation of the various zones and the resulting temperature and fluid saturation distributions. In the field there are transitions between zones, however the concepts illustrated provide insight on the combustion process.

2.2.2. Zone Definitions

Starting from the injector, seven zones have been defined:

- A. The burned zone is the volume already burned. This zone is filled with air and may contain small amounts of residual unburned organic solids. As it has been subjected to high temperatures, mineral alterations are possible. Because of the continuous airflow from the injector, the burned zone temperature increases from injected air temperature at the injector to combustion front temperature at the combustion front.

A. Burned Zone	E. Steam Plateau
B. Combustion Zone	F. Water Bank
C. Cracking Region	G. Oil Bank
D. Evaporation and
Visbreaking Region	H. Initial Zone

Figure 17.1 Schematic Diagram Of Temperature And Saturation Profiles And Zones In Insitu Combustion⁴

- B. The combustion front is the highest temperature zone. It is very thin, often no more than several inches thick. It is in this region that oxygen combines with the fuel and high temperature oxidation occurs. The products of the burning reactions are water and carbon oxides. The fuel is often misnamed coke. In fact it is not pure carbon but a hydrocarbon with H/C atomic ratios ranging from about 0.6 to 2.0. This fuel is formed in the thermal cracking zone just ahead of the front and is the product of cracking and pyrolysis which is deposited on the rock matrix. The amount of fuel burned is an important parameter because it determines how much air must be injected to burn a certain volume of reservoir.
- C/D. The cracking/vaporization zone is downstream of the front. The crude is modified in this zone by the high temperature of the combustion process. The light ends vaporize and are transported downstream where they condense and mix with the original crude. The heavy ends pyrolyze, resulting in CO_2 , CO , hydrocarbon gases and solid organic fuel deposited on the rock.
- E. The steam plateau. This is the zone where some of the hydrocarbon vapors condense. Most of those condense further downstream as the steam condenses. The steam plateau temperature depends on the partial pressure of the water in the gas phase. Depending on the temperature the original oil may undergo a mild thermal cracking, often named visbreaking that usually reduces oil viscosity.
- F. A water bank exists at the leading edge of the steam plateau where the temperature is less than steam saturation temperature. This water bank decreases in temperature and saturation downstream, with a resulting increase in oil saturation.
- G. The oil bank. This zone contains most of the displaced oil including most of the light ends that result from thermal cracking.
- H. Beyond these affected areas is the undisturbed original reservoir. Gas saturation will increase only slightly in this area because of the high mobility of combustion gases.

2.2.3. Wet Combustion

A large amount of heat is stored in the burned zone during dry forward insitu combustion (Fig. 17.1), because the low heat capacity of air cannot transfer that heat efficiently. Water injected with the air can capture and advance more heat stored in the burned zone.

During wet combustion injected water absorbs the heat from the burned zone, vaporizes, moves through the burning front and condenses, expanding the steam plateau. This results in faster heat movement and oil displacement.

Depending on the water/air ratio, wet combustion is classified as: (1) incomplete when the water is converted into superheated steam and recovers only part of the heat from the burned zone, (2) normal when all the heat from the burned zone is recovered, and (3) quenched or super wet when the front temperature declines as a result of the injected water.

When operated properly, water assisted combustion reduces the amount of fuel needed, resulting in increased oil recovery and decreased air requirements to heat a given volume of reservoir. Up to a 25% improvement in process efficiency can be achieved⁵. Determination of the optimum water/air ratio is difficult because of reservoir heterogeneities and gravity override that can affect fluid movement and saturation distributions. Injecting too much water can result in an inefficient fire front, thus losing the benefits of the process.

Some authors recommend, as a best practice, injecting water at high rates to achieve “partially quenched combustion”. This method has limited application. A high temperature burn is preferred but is difficult to achieve with oils that are not highly reactive. Injecting large amounts of water can lower combustion temperatures resulting in a greater fraction of oil burned and higher costs for oxygen. At the same time these types of burns only partially oxidize the oil. This partial oxidation results in a much more viscous liquid, which in turn lowers the flow rate. So, in brief, if water injection is used, great care should be taken to assure that liquid water never reaches the high temperature combustion front. A discussion of heat and material balance calculations that include chemical reactions and the effect of injected air and water, is presented later in some detail.

3. LABORATORY STUDIES

In situ combustion mechanisms are largely a function of oil composition and rock mineralogy. The extent and nature of the chemical reactions between crude oil and injected air, as well as the heat generated, depend on the oil-matrix system. Laboratory studies, using crude and matrix from a prospective ISC project, should be performed prior to the design of any field operation.

3.1. The Reactions

The chemical reactions associated with ISC are complex and numerous. They occur over a broad temperature range. Most researchers group them into three classes in ascending temperature ranges:

- Low temperature oxidation (LTO) - heterogeneous gas/liquid reactions producing partially oxygenated compounds and few carbon oxides.
- Medium temperature reactions - cracking and pyrolysis of hydrocarbons to form fuel.

- High temperature oxidation (HTO) - heterogeneous H/C bond breaking reactions in which the fuel reacts with oxygen to form water and carbon oxides.

A more recent and more accurate kinetics model has been developed⁶. Only two reactions are used, but in addition the geometry of the reacting residual fuel in the pore spaces is taken into account as indicated in Figure 17.2. This figure represents the fuel remaining on two sand grains at different times in the combustion process, as discussed by Mamora *et al.*⁶ The crude oil oxidation consists of two stages, low temperature oxidation forming an oxygenated hydrocarbon fuel, and high temperature combustion of this fuel. A detailed description of the different reaction regimes is outside the scope of this handbook; some practical comments on the role of LTO, however, are appropriate at this stage.

Figure 17.2. Schematic Diagram Of Varying-Fuel-Geometry⁶.

Low temperature oxidation (LTO) can be described as oxygen addition to the crude oil. LTO yields water and oxygenated hydrocarbons such as ketones, alcohols, and peroxides. A good description of LTO can be found in Burger and Sahuquet.⁷ LTO generally increases original oil viscosity, boiling range and density. LTO increases the amount of fuel. LTO is promoted by low air flux in the oxidation zone. Poor crude oxidation characteristics can also play a role. In heavy oil reservoirs (API gravity $< 20^\circ$), LTO tends to be more pronounced when oxygen rather than air is injected in the reservoir⁸.

Research has shown that, for heavy oils, LTO reactions must be minimized. Figure 17.3 shows the oxygen uptake as the temperature of a typical heavy oil is raised linearly with time. Notice the negative temperature gradient region where oxygen rate uptake decreases with temperature increase. If the temperature of the ISC process stays at or below the negative temperature gradient region, the oil displacement efficiency will be very low. This is because LTO increases the oil viscosity and fuel content.

Figure 17.3. Schematic of dry combustion temperature profile showing the general effect of temperature on oxygen uptake rate for heavy oils and the negative temperature gradient region⁸.

The injected air flux in a heavy oil project should be maintained at a value well above the value needed to maintain the reactions in the high temperature oxidation regime. LTO generally has almost no effect on light oils in terms of mobility or recovery despite the fact that light oils are more susceptible to LTO than heavy oils.

Fuel deposition determines the feasibility and economic success of a combustion project. It occurs at intermediate temperatures after the LTO reactions. Numerous studies have been conducted aimed at understanding fuel formation and deposition at intermediate temperatures. The oil type and chemical structure determine the rate and extent of the different reactions. Catalytic effects from the matrix and/or injected solutions of metals may affect the type and amount of fuel formed. Again all laboratory experiments must include not only the crude to be tested but also representative core material from the reservoir of interest.

3.2. Kinetics

Kinetics of combustion reactions can be defined by how fast the chemical reactions occur and how much of the oil is affected. It is important to study kinetics for several reasons:

- Characterization of oil reactivity
- Determination of ignition conditions
- Insight on the nature of the fuel and its combustion characteristics

- Use of kinetic parameters as input for possible numerical simulation of the process.

As crude oils contain hundreds of different compounds, it is impossible to accurately represent all the reactions occurring during ISC. Even if it were possible to detail all the reactions, the use of such information in numerical models would be impossible because of cost and computer limitations. Consequently we will concentrate on useful simple models describing ISC reaction kinetics that have been published in the literature. Most studies use the Arrhenius reaction expressions defined as follows. The model assumes a functional dependency on fuel concentration and oxygen partial pressure. It is given by,

$$R_c = \frac{dC_f}{dt} = K p_{O_2}^a C_f^b \quad (17.1)$$

where

R_c = reaction rate of the crude, $kg / m^3 sec$

C_f = the concentration of fuel, kg / m^3

p_{O_2} = oxygen partial pressure, Pa

K = reaction rate constant, $(kg / m^3)^{1-b} / (Pa)^a sec$

The exponent constants, a and b , are the orders of the reactions with respect to oxygen partial pressure (a), and fuel concentration (b). Data shows that “a” ranges between 0.5 and 1.0, while “b” is close to 1.0. The reaction rate constant, K , is based on the Arrhenius constant, expressed as a function of temperature, as follows,

$$K = A \exp(-E / RT) \quad (17.2)$$

where

A = Arrhenius constant $(kg / m^3)^{1-b} / (Pa)^a sec$

E = activation energy, kJ/mole

T = absolute temperature, °K

R = universal gas constant, kJ/mole °K

When using literature values one has to be careful because the parameters in Eqs. 17.1 and 17.2 vary depending on the system of units used.

A variety of experimental techniques can be used to determine the kinetics of ISC reactions. Among those are differential thermal analysis, thermogravimetric analysis, accelerating rate calorimetry and effluent analysis. The additional references contain several descriptions of various methods and results.

The effluent analysis method, also called the ramped temperature method is quantitative and consists in heating a sample of oil and rock while flowing oxygen (for oxidation) or nitrogen (for pyrolysis) through the sample. The kinetic parameters can be

calculated from effluent gas evolution with temperature, and chemical analysis of post test cores. Details of the analysis techniques can be found in the references.^{3,6,9}

3.3. Combustion Tube Studies

Although the kinetic studies can provide useful insight on ISC reactions, combustion tube experiments are mandatory to determine the parameters needed to design and implement field projects. These data are used to make predictions of field test performance. As Sarathi¹ points out, “Combustion tube studies are the necessary first step in the design of an ISC project.”

Combustion tubes aim at representing a small volume of the reservoir. They are usually packed with native reservoir cores or representative samples of matrix material and oil, placed in vertical position to minimize gravity effects and heated to reservoir temperature. Ignition is usually started at the top by electrical heaters and the combustion front is propagated downward. This allows propagation of a combustion front and the associated chemical reactions at conditions close to those in a reservoir.

Temperature profiles, pressures, gas and liquids injection and production rates, and composition histories at the inlet and outlet are recorded. ISC tube runs are unscaled and direct correlation of combustion tube results to the field is not possible. However, as long as the runs are performed with reservoir rock and fluids at reservoir conditions, the reactions of fuel deposition and combustion will be similar in both tube and reservoir. Tube runs will not provide information on ISC sweep efficiency. They adequately model the chemistry of the process but not the flow behavior in the reservoir, and only partially model the heat transfer processes. Flow behavior in the reservoir is affected by gravity override, well spacing and geometry and reservoir heterogeneities, and tube runs cannot reproduce these phenomena. Heat transfer from the tube to the surroundings can be much higher than reservoir heat losses.

Two different schools of thinking exist on this heat transfer problem. Many experimenters use strip heaters around the tube to lower the temperature gradient between the tube and the surroundings. This reduces heat losses and allows front propagation at fluxes similar to those in the field. It can, however, lead to overestimation of water/oil ratios in wet combustion if the strip heaters provide too much energy to the system, as they often do. Information on front cooling by injected water may also be masked by the heaters. As a result, the extent of the steam plateau may not be correct. Most of these types of experiments are bulky and time consuming and require extensive instrumentation.

The other solution is to increase the air flux and minimize heat losses by insulation alone. This may slightly overestimate air requirements and fuel content but is much simpler and easier to operate. As a result, it is widely used. Description of various setups for combustion tube studies have been provided.^{5,6,10,11,12}

The information that can be acquired from tube runs includes:

- Fuel burned
- Air required to burn a unit volume of reservoir
- Atomic H/C ratio of burned fuel
- Excess air and oxygen utilization
- Air/Fuel ratio
- Oil recovery from the swept zone
- Optimization of water/air ratio in wet combustion
- Composition of produced fluids
- Front temperature and stability

This last information is quite important in heavy oils to determine if the process is operating properly in the desired high temperature regime. If high temperature cannot be achieved in ideal laboratory conditions it is likely that field results would be worse.

3.3.1. Data Analysis

The following is a simple analysis of data from tube runs. It assumes that the combustion occurs at high temperature where the fuel exclusively combines with oxygen to produce water and carbon oxides. The stoichiometric equation¹³ is then:

$$CH_n + \left[\left(\frac{2m+1}{2m+2} \right) + \frac{n}{4} \right] O_2 = \left(\frac{m}{m+1} \right) CO_2 + \left(\frac{1}{m+1} \right) CO + \left(\frac{n}{2} \right) H_2O \quad (17.3)$$

where n = hydrogen/carbon atomic ratio of fuel
 $m = CO_2 / CO$ concentration ratio produced

The other symbols indicate the various components in the chemical balance equation.

This equation is only an approximation of the process. It neglects LTO reactions, oxygen/minerals reactions and water/organic fuel reactions. Alternate analysis when some of these reactions are important are detailed in Sarathi¹ based on information provided by Moore and Mehta of the University of Calgary. Assuming Eq. 17.3 to be valid the apparent H/C ration, n , can be estimated from the concentration of exhaust gases and the injected oxygen concentration¹³.

$$n = \frac{4[O_2 - CO_2 - CO/2 - (O_2)_{\text{prod}}]}{CO_2 + CO} \quad (17.4)$$

where $(O_2)_{\text{prod}}$ = Oxygen concentration produced

It is prudent to normalize the concentrations by making a balance on the nitrogen, which in these conditions can be considered inert. The basic chemical equation is then:

$$CH_n + aO_2 + RaN_2 = bCO_2 + dCO + fH_2O + RaN_2 \quad (17.5)$$

where R is the molar ratio of nitrogen to oxygen in the feed gas and a, b, d , and f are stoichiometric coefficients similar to those in Eq. 17.3.

The range of the ratio, n , for high temperature reactions should be from 0.5 to 2. Calculation of an unusually high value of n indicates that low temperature oxidation is important. In the very early stages of field projects high “ n ” values are often observed because of the solubility of the combustion gases, particularly CO_2 , in the oil.

Once n and m are known, the amount of air required to burn one unit weight of fuel is found from Eq. 17.3. The heat generated by burning a unit weight of fuel can be calculated by simple addition of the heat generated by each reaction as described in the stoichiometric equation (Eq. 17.3). The calculation of heat produced must take into account the production of carbon monoxide. The following formula¹³ can be used to estimate heating values of fuels as a function of n and m .

$$H_c = \frac{m(174,000)}{(m+1)(n+12)} + \frac{52,500}{(m+1)(n+12)} + n \frac{61,500}{(n+12)} \quad (17.6)$$

where

H_c = heating value, Btu/lb fuel

To convert to Joules/kg multiply by 2,326.

The air required to burn a given volume of reservoir is of course a very important design parameter and one of the keys to the economics of the combustion process. This is directly calculated from the experimental data by dividing the amount of oxygen consumed by the volume swept during the tube run. The mass of fuel burned in a unit volume of reservoir can be calculated from the oxygen consumed by a unit volume and applying Eq. 17.3. All the other relevant parameters can be estimated^{13,14}. It is prudent to perform multiple laboratory tube runs prior to field implementation.

4. COMBINING MATERIAL AND HEAT BALANCE CALCULATIONS

Many useful and reasonably accurate calculations can be made on ISC to predict the behavior of a proposed project. These ideas will be explained in the following diagrams and example calculations. They start with a very simple heat balance, and are then extended to more closely represent what happens in the laboratory and reservoir.

4.1. First Assumptions

Start by assuming no combustion data is available to get an initial idea of the feasibility of a project. This preliminary work gives the engineer a sound basis to decide whether further work has economic promise. Assume a sandstone formation with a

porosity of 22%, a temperature of 100°F, a 24° API oil at a saturation of 65%, and an injection pressure of 300 psia. Also assume the CO_2 / C_{atomic} ratio, m , will be,

$$m = \frac{CO_2}{CO} = 20 \quad (17.7)$$

This is a reasonable ratio to assume, based on both laboratory and field experience. Since there is no tube run data, generalized correlation curves¹³, Figs. 17.4 and 17.5, will be used to calculate expected results. From Fig. 17.4, the fuel availability, W , for 24° API crude is,

$$W = 0.95 \text{ lb } C / 100 \text{ lb Rock} \quad (17.8)$$

Figure 17.4. Fuel Availability vs Oil/Gravity¹³

The apparent H/C atomic ratio (n) of the fuel is also needed. This is a function of the combustion front temperature¹³ as shown on Fig. 17.5. Selected data from the graph are listed in Table 17.1.

Figure 17.5. H/C ratio vs. combustion temperature¹³.

Table 17.1 Effect of Temperature on H/C Ratio, 21.8° API Crude

H / C Ratio, n	Comb. Temp (°F)
0.40	1,000
0.80	800
1.40	700
2.40	600

These data for 21.8° API crude are close enough to 24°API crude for initial estimates.

4.2. Calculate Initial Heat Balances and Temperatures

Start by assuming all heat generated is used to heat the rock formation through which the combustion front has moved. This assumption is incorrect, but simplifies understanding of the mathematics and concepts involved in heat balance calculations. A sketch of the temperature profile generated is shown in Fig. 17.6. Corrections to this heat balance calculation will be discussed later.

Assuming 1.0 ft^3 of rock formation burned and the front temperature is 1000°F , from Eq. 17.8, and Table 17.1, we get,

$$\begin{aligned}\frac{\text{lb Fuel}}{100 \text{ lb Rock}} &= \frac{\text{lb Carbon}}{100 \text{ lb Rock}} + \frac{\text{lb Hydrogen}}{100 \text{ lb Rock}} \\ &= 0.95 + \frac{0.95(0.40)}{12} = 0.9817\end{aligned}\quad (17.9)$$

Quartz weighs about 164 lb/ft^3 . The amount of fuel for a cubic foot of formation equals

$$\frac{(0.9817)(164)(1 - 0.22)}{100} = 1.256 \text{ lb Fuel/ft}^3 \text{ Rock} \quad (17.10)$$

Figure 17.6 Idealized Temperature Profile Assuming All Heat Stays In The Burned Zone.

Using the heat of combustion, Eq. 17.6, with the appropriate parameters, it becomes,

$$\begin{aligned}H_c &= \frac{(20)(174,000)}{(21)(12.4)} + \frac{52,500}{(21)(12.4)} + \frac{(0.4)(61,500)}{12.4} \\ &= 15,550 \text{ BTU/lb Fuel}\end{aligned}\quad (17.11)$$

Thus the total heat generated is,

$$\frac{\text{Heat generated}}{\text{ft}^3 \text{ Rock}} = (15,550)(1.256) = 19,530 \frac{\text{BTU}}{\text{ft}^3 \text{ Rock}} \quad (17.12)$$

Next, calculate the temperature rise of the formation behind the front by performing a heat balance to see if it matches the temperature assumed. Since, for practical purposes, the only fluid in the formation behind the front is air, which has a very small volumetric heat capacity, we only need to calculate a heat balance on the sandstone itself. A good equation for average sandstone heat capacity is¹³,

$$c_s = \frac{T_1 + 2000}{10,000} + \frac{T_2 - T_1}{20,000} \quad (17.13a)$$

$$= 0.21 + \frac{1000 - 100}{20,000} = 0.255 \text{ BTU/lb-}^\circ\text{F} \quad (17.13b)$$

where T_1 = Initial reservoir temperature, $^\circ\text{F}$,
 T_2 = Final reservoir temperature, $^\circ\text{F}$

From a heat balance calculation, the reservoir sand temperature is as follows,

$$T_2 - 100 = \frac{19,530}{(0.255)(164)(1 - 0.22)} = 598.7$$

or $T_2 = 699^\circ\text{F}$ (17.14)

The result from Eq. 17.14 does not agree with the assumed temperature of 1000°F . Calculations using other assumed temperatures result in calculated temperature values shown in Table 17.2.

Table 17.2 Assumed and Calculated Temperatures as a Function of H/C Ratios

Assumed Temperatures ($^\circ\text{F}$)	H / C Ratio	Calculated Temperature ($^\circ\text{F}$)
1000	0.40	699
800	0.80	802
700	1.40	939

The tabular data is graphed as circles in Figure 17.7. The two temperatures match at 801°F. This is the calculated combustion front temperature if all the heat generated is used to heat the formation behind (upstream of) the combustion front.

Figure 17.7. Assumed and calculated combustion zone temperatures.

4.3. Correction for Water of Combustion

These results don't include all the processes occurring in the reservoir. First, the water formed by combustion will condense beyond the combustion front, absorb some heat of combustion and reduce the heat of the formation behind the combustion front. This effect can be calculated as follows.

From Eq. 17.9, 0.0317 lb of H_2 are formed per 100 lb of rock at 1000° F. Assuming that a pound of steam will release 1,000 BTU when cooling from combustion temperature and condensing (This number is not exactly correct, but is adequate for

estimation purposes.) the amount of heat carried forward by the steam is calculated using concepts similar to Eqs. 17.10 and 17.12,

$$\begin{aligned} \text{Heat carried ahead by steam} &= 0.0317 \left(\frac{18}{2} \right) \frac{(1000)(164)(1 - 0.22)}{100} \\ &= 365 \text{ BTU/ft}^3 \text{ Rock burned} \end{aligned} \quad (17.15)$$

In this equation, 18/2 is the ratio of molecular weight of water and hydrogen. The heat given up by the steam is 1000 BTU/lb, and the other numbers are similar to those in Eq. 17.10. Thus, the calculated temperature is lower than it was in Eq. 17.14 as shown below,

$$T_2 - 100 = \frac{19,530 - 365}{(0.255)(164)(1 - 0.22)} = 587.5$$

or, $T_2 = 688^\circ \text{F}$ (17.16)

Other temperatures were calculated similarly and the results, graphed as triangles in Figure 17.7, show a corrected combustion temperature of 788°F. At this temperature the H/ C ratio is 0.85 as indicated in Figure 17.8 below.

Figure 17.8. H/C atomic ratio versus combustion temperature¹³

4.4. Calculating the Volume and Temperature of the Steam Plateau

No calculations on the steam plateau were necessary in the above calculations. The steam plateau temperature and volume directly affect the volume of oil moved as a result of the combustion process. To calculate these terms, use the H/C ratio of 0.85 and calculate the partial pressure of the water as follows.

The fuel composition is $CH_{0.85}$. From Eq. 17.3 the moles of oxygen used per mole of fuel are,

$$\begin{aligned} O_2 &= \frac{2m+1}{2m+2} + \frac{n}{4} = \frac{2(20)+1}{2(20)+2} + \frac{0.85}{4} \\ &= 1.189 \text{ moles } O_2 \end{aligned} \quad (17.17)$$

Combustion products are calculated in a similar way,

$$CO_2 = \frac{m}{m+1} = \frac{20}{21} = 0.952 \quad \text{Moles } CO_2 \quad (17.18)$$

$$CO = \frac{1}{m+1} = \frac{1}{21} = 0.048 \quad \text{Moles } CO \quad (17.19)$$

$$H_2O = \frac{n}{2} = \frac{0.85}{2} = 0.425 \quad \text{Moles } H_2O \quad (17.20)$$

$$N_2 = \left(\frac{79}{21} \right) (O_2) = \frac{79}{21} (1.189) = 4.473 \quad \text{Moles } N_2 \quad (17.21)$$

The operating pressure is 300 psia. The partial pressure of H_2O in the combustion gas is,

$$\begin{aligned} p_{\text{water}} &= \frac{0.425(300)}{0.952 + 0.048 + 0.425 + 4.473} \\ &= 21.6 \text{ psia} \end{aligned}$$

From steam tables, the saturation temperature for 21.6 psia is 232°F. This is the temperature of the steam plateau.

The volume of the steam plateau is a function of the amount of H_2O formed. Knowing that there are 0.95 lb C/100 lb rock burned, and knowing from Figure 17.8, that the H/C ratio is 0.85, an equation similar to Eq. 17.10 yields the amount of water formed per cubic foot of rock burned.

$$\begin{aligned} \text{Water formed} &= 0.95 \left(\frac{0.85}{12} \right) \left(\frac{18}{2} \right) \frac{(164)(1-0.22)}{100} \\ &= 0.775 \frac{\text{lb } H_2O \text{ Formed}}{\text{ft}^3 \text{ Rock burned}} \end{aligned} \quad (17.22)$$

Thus the total heat carried forward by the water formed, is,

$$\begin{aligned}\text{Heat carried by steam} &= 0.775 (1,000) \\ &= 775 \text{ BTU/ft}^3 \text{ rock burned}\end{aligned}\quad (17.23)$$

Using Eq. 17.13a, the heat capacity of the formation is,

$$c_s = 0.21 + \frac{232 - 100}{20,000} = 0.2166 \text{ BTU/lb-}^\circ\text{F} \quad (17.13c)$$

The amount of heat needed to raise a cubic foot of sand from 100°F to 232°F, from a heat balance, is,

$$\begin{aligned}\Delta H &= \frac{0.2166 \text{ BTU}}{\text{lb-}^\circ\text{F}} \left[\frac{164(1 - 0.22) \text{ lb}}{\text{ft}^3} \right] (232 - 100)^\circ\text{F} \\ &= 3,701 \text{ BTU/ft}^3\end{aligned}\quad (17.24)$$

Thus the volume of rock heated by condensing steam is Eq. 17.23 divided by Eq. 17.24,

$$\text{Volume of steam heated rock} = \frac{775}{3,701} = \frac{0.209 \text{ ft}^3 \text{ Steam zone}}{\text{ft}^3 \text{ Rock burned}} \quad (17.25)$$

A sketch of the resulting temperature profile is shown in Figure 17.9.

Figure 17.9. Idealize Temperature Profile With Steam Plateau Ahead of Combustion Front.

4.5. Calculating Effects of Injected Air and Water

Further corrections are needed to the temperature profile in Figure 17.9. Injected air will partially cool the burned zone, rise in temperature as it approaches the combustion front, and carry heat forward. This will have little effect on the combustion kinetics or the amount of heat generated by combustion; so, in essence, this amount of energy is merely carried forward to extend the size of the steam plateau.

A sketch of this idea is shown in Figure 17.10 below. In this sketch, the area marked 1 is the temperature profile behind the burning front; Area 2 is the steam plateau, which is now larger than calculated before because of the heat carried forward by the combustion gases.

Figure 17.10. Schematic of Combustion Temperature Profile Including Cooling by Injected Air.

This temperature profile can be approximated as indicated in Figure 17.11 where the profiles of the burned zone and steam plateau are treated as square waves that have been adjusted so that the total heat in Areas 1 and 2 are the same as in Figure 17.10.

Figure 17.11. Idealized Temperature Profile Including Injected Air Cooling.

There are several reasons for using this square wave concept. One is that it makes it easier to calculate heat losses to be expected from either a laboratory or field combustion operation using superposition calculations similar to those discussed by Ramey¹⁵ as seen in Prats' Thermal Recovery Monograph². These references also indicate that the heat losses calculated using Figure 17.11 are quite adequate.

When wet combustion is used, the temperature behind the front tends to be a sharp front, as shown in Figure 17.11. As a result, heat and material balances of the sort discussed next, can be used to calculate the movement of the resulting cooling front, burn front, and steam plateau.

The amount of air injected per cubic foot of rock burned and the heat capacity of air are needed to calculate this heat transfer process for dry combustion. The volume of combustion gas should also theoretically be calculated, but normally this isn't necessary, for its volume is nearly identical to the air volume. Further its heat capacity is nearly the same – remember that most of the combustion gas is nitrogen.

The moles of air injected are calculated by adding the O_2 from Eq. 17.17 to N_2 from Eq. 17.21,

$$\text{Air injected} = 1.189 + 4.473 = \frac{5.662 \text{ Mole air}}{\text{Mole fuel}} \quad (17.26)$$

Combining a heat capacity for air of 7.00 BTU/lb Mole - °F with previously determined factors of 0.95 lb of carbon burned for 100 lb rock, 164(1 - 0.22) pounds of rock per cubic foot of rock, 12 lb of carbon per mole, a combustion zone temperature of 788°F (Figure 17.7), and the results of Eq. 17.26 yields the amount of heat carried forward by the injected air as follows.

$$\begin{aligned} \frac{\text{Heat carried by air}}{\text{Cubic ft rock burned}} &= \left(\frac{0.95}{100} \right) \left[\frac{(164)(1 - 0.22)}{12} \right] (5.662)(7.00)(788 - 100) \\ &= \frac{2761 \text{ BTU}}{\text{ft}^3 \text{ Rock burned}} \end{aligned} \quad (17.27)$$

This heat extracted behind the burned zone is deposited into the steam plateau. The resulting size of the steam plateau can be calculated in a way similar to Eq. 17.25 by adding the heat carried by the combustion gas to that by the water, as follows,

$$\text{Vol of steam heated rock} = \frac{775 + 2761}{3701} = 0.901 \text{ ft}^3 \quad (17.28)$$

This calculation shows the condensing steam front is far enough ahead of the combustion front to displace oil efficiently and it is unnecessary to have the combustion front cover the entire reservoir to get good recovery. Recovery can be estimated by knowing the

amount of fuel burned, by estimating the residual oil saturation in the steam plateau, and by estimating the sweep efficiency of the process.

4.6. Heat Losses

An estimate of heat losses using the superposition concepts seen in Prats' Thermal Recovery Monograph² based on Ramey's¹⁵ work, will make the calculations just presented more accurate. These estimates are particularly important if a laboratory heat balance indicates significant heat losses. The temperature profiles just calculated assuming no heat losses can be used to make a first estimate of heat losses and a recalculated steam plateau size. This is a reasonable way to handle the heat balance. Since all heat transferred was assumed to be in the steam plateau, any reduction in that transferred heat because of losses will reduce the amount of heat in the plateau.

As the size of the steam zone and the size of the calculated heat losses are interdependent, iterative calculations are necessary until the assumed and calculated heat balances match. This will usually require only two to three iterations.

Data used in the previous calculations were based on generalized predictions of combustion behavior, i.e., the amount of fuel per cubic feet of formation, and the H/C ratio of the fuel. If combustion tube runs are made in the laboratory, those parameters are known and can be used in the calculations. In addition, accurate temperature and saturation profiles versus time will allow reasonably accurate heat balance calculations to determine the heat losses from the experiment. As an alternative, reasonable assumptions about the heat losses can be used to check the heat balance calculations and indicate if there is significant experimental error.

Computer assisted tomography, CAT, scanner measurements produce the most accurate saturation histories. Alternatively, accurate measurements of temperature profiles and accurate oil, water and gas production data also make it possible to estimate reasonable saturation histories. These are the major sources of error in the overall heat balance calculations, but are fairly small compared to the amount of heat stored in the hot matrix.

5. DESIGN CONSIDERATIONS

Conditions favoring the use of ISC rather than steam include the following: 1) high reservoir pressure where steam is not efficient, 2) potential for severe well bore heat losses (i.e., depth, offshore, permafrost), 3) reservoir clay swelling in contact with fresh water, 4) limited water supply and 5) environmental regulations prohibiting steam generation.

Like any other injection process, the design of ISC projects must consider injection pressure limitations and reservoir flow resistance. These are especially important in heavy oil reservoirs where combustion must occur in the high temperature

regime to be successful. The minimum air flux needed to maintain high temperatures at the front is estimated to be 0.125 ft/day (0.04 m/day).¹⁴ As the burn zone growth is directly proportional to the injected air, the maximum air injection rate determines the minimum lifetime of the project. Ways to increase the air injection rate are often needed, especially in heavy oil reservoirs. They may include reduced well spacing, cyclic steaming of injectors and producers and an increase in injection pressure. These factors will determine the compressor pressure and volume output.

There has often been some controversy over whether ISC projects should be developed using patterns or line drives. Many early projects were started as pilots with a single injector. Usually this resulted in an inverted five-spot pattern. These pilots behaved contrary to plan with the combustion front moving in only one direction because of permeability variations, gravity effects, well spacing differences or a combination of these factors.

Attempts to correct the unbalanced flow included stimulating unresponsive wells and limiting withdrawal rates of wells that producing excessive volumes of combustion gas. Generally these efforts did not have the desired effect.

In retrospect, this reservoir behavior makes sense. Once a combustion front is even slightly asymmetric, the higher temperature and thus higher mobility will cause greater flow in that direction. Thus the flow will become more asymmetric, finally resulting in flow principally in only one direction.

Since it is often difficult to decide, a priori, which direction the major flow will take, operating plans should remain flexible until field performance indicates what injection scheme best utilizes the flow directions.

For the above reasons many of the more successful ISC projects have been line drive operations that start near the top of the reservoir and move downdip. In such an operation, the direction of the fire front is known. The operating engineers can then plan their completion and operating history in a rational way that will mirror the front movement and breakthrough history. This operating practice can be seen in most of the successful ISC field projects that will be discussed later.

6. PERFORMANCE PREDICTION

Predicting the production response to ISC has been the topic of various studies. Complete numerical simulation of ISC is difficult because of the complex reactions and the thin burning front that requires small grid blocks for representation. Simulators range from tank models to complex three-dimensional simulators. In addition to simulation, empirical models, hybrid models and correlation methods have been developed. A discussion of some of these methods follows.

The easiest method is essentially a tank balance¹⁴ adapted by Prats². The oil and water produced are given by,

$$N_p = \phi V_b (S_{oi} - S_f) + 0.4 S_{oi} (V_p - V_b) \quad (17.29)$$

and

$$W_p = V_b \phi (S_{wi} + S_{wf}) \quad (17.30)$$

Where	S_{oi}	=	initial oil saturation, fraction
	S_f	=	oil saturation burned, fraction
	V_b	=	volume burned, m^3
	N_p	=	oil produced, m^3
	W_p	=	water produced, m^3
	ϕ	=	porosity, fraction
	V_p	=	volume of the pattern, m^3
	S_{wf}	=	water saturation resulting from the combustion process, fraction
	S_{wi}	=	initial water saturation, fraction

If the volumes are in acre-feet and the production terms are in barrels, a multiplication factor of 7,758 must be used. The estimate of 40 percent of the oil in place produced from outside the burned volume is an empirical value based on experience. This is the 0.4 term in Eq. 17.29.

Figure 17.12, presented by Gates and Ramey¹⁶, combines laboratory results and field observations from the Belridge ISC projects. It shows the effect of initial gas saturation on the oil recovery history. Oil production rates and instantaneous air/oil ratios can be estimated from the slopes of the curves. At late times the above two techniques give similar results.

Brigham *et al.*¹⁷ used data from dry combustion field tests to obtain two empirical correlations. Those are presented in Figs. 17.13 and 17.14. The terms in the ordinates are: ΔN_p , cumulative incremental oil produced; N_i , original oil in place; ΔN_b , fuel burned; and N , oil in place at start of the project.

In addition to original oil saturation, S_o , thickness, h , oil viscosity, μ_o , and porosity ϕ ; the abscissas include, a_i , cumulative air injected, N , oil in place at start of the project, and e_{o2} , fraction oxygen utilization. The second correlation, Figure 17.14, is the most accurate except for oils of less than 10 cp viscosity where the first correlation should be used. These correlations were generated from small scale floods, thus they would not be expected to be accurate for large scale pattern flooding. However, the narrative in the previous section points out that pattern flooding is generally not the best

Fig. 17.12. Gates and Ramey Method.¹⁶

Figure 17.13. First Satman correlation¹⁷

17.14. Second Satman correlation¹⁷

7. OPERATING PRACTICES

In addition to the standard field equipment for oil production, ISC requires particular attention to air compression, ignition, well design, completion, and production practices.

7.1. Compressors

Air compression systems are critical to the success of any ISC field project. Failures of the past can often be traced to poor compressor design, faulty maintenance or operating mistakes. A detailed discussion of compressors and sizing considerations appears in Chapter 7 of the Facilities Section of this handbook. Other discussions are available in Sarathi¹.

The factors to be considered when selecting compressors include peak air requirements, injection pressure, capital cost, power requirements, operation and maintenance costs and other relevant technical and economic parameters specific to the field considered. Compressor terminology varies among manufacturers. It is best to obtain a complete description including compressor, driver, interstage cooling system, and all ancillary equipment including control and safety systems from each vendor being consulted.

Air compression causes high temperatures because of the high c_p / c_v ratio of air. Compressor design must consider these high temperatures to ensure continuous, sustained operations free from the corrosive effects of air and the explosion hazards of some lubricating fluids. Mineral oils are not recommended. Synthetic lubricants withstand the higher temperatures and offer lower volatility and flammability than conventional lubricants.

7.2. Ignition

Ignition and maintenance of high combustion temperatures, especially in heavy oil projects, are the most critical factors of an ISC project. Shallcross¹⁸ presented a complete review of ignition methods. The following is a summary of this study.

Ignition can occur spontaneously if the oil is reactive, the reservoir temperature high enough, and the reservoir is reasonably thick. Various models have been proposed to determine the time for spontaneous ignition^{19,20}.

When spontaneous ignition does not occur or is not desired (i.e., in heavy oil reservoirs where it is important to maintain high combustion temperatures), the most appropriate ignition method to use depends on the reservoir and the equipment available on site.

Down hole gas-fired burners allow good control of the temperature of injected gases and may be operated at a greater depth than other methods. The disadvantages include the need to run multiple tubing strings in the injection wells. Some particles, such as soot, may be carried into the formation if the gas does not burn cleanly.

Catalytic heaters run at lower temperatures but are sometimes prohibitively expensive. Electrical heaters can be lowered with a single cable, and can provide excellent temperature control. They can be reused repeatedly. There is, however, a depth limitation because of electrical power losses in the cable.

Chemically enhanced ignition does not have a depth limitation but may require handling and storage of dangerous materials. Fuel packs are not recommended because of poor temperature control and nonuniform ignition across the entire reservoir thickness. Well damage from elevated temperatures and plugging by particulate matter may occur.

Steam may be used to locally increase reservoir temperature and facilitate auto ignition. It suffers from depth limitation because of wellbore heat losses, but when the conditions are right it can be a very simple and effective method for ignition.

The additional references include details of design and implementation of the above methods.

7.3. Well Design and Completions

ISC wells must be designed to account for several factors amplified by the combustion process, namely high temperature, corrosive environment and sand and clay control. Safe operations should be the primary concern.

Typical well designs for injection and production are shown in Figs. 17.15 and 17.16¹. Completion type and design depends on the reservoir being considered. Laboratory testing for sand control and completions can help to determine the best completion technique for a given field. Care has to be taken to properly cement the wells. There are cement formulations that are stable at high temperatures²¹. Open hole completions may be used in conjunction with slotted liners, screens, gravel packs or various other sand and clay control methods. To maximize productivity, producing wells should be completed toward the bottom of the zone of interest to take advantage of gravity drainage and avoid hot gases as long as possible. Rat holes have been used successfully in certain heavy oil combustion projects to increase the effect of gravity drainage²².

TYPICAL AIR INJECTOR

Figure 17.15. Typical injection well design¹

TYPICAL PRODUCING WELL COMPLETION

Figure 17.16. Typical production well design.¹

7.4. Injection and Production Practices

Safe air injection requires that the surface injection equipment and the injection well are free of hydrocarbons. All lubricants used in compression and down hole operations should be synthetic or non hydrocarbon types. All equipment, tools, lines, tubing, work strings and injection strings must be clean and hydrocarbon free. Personnel at all levels should be aware of the importance of preventing hydrocarbons in the injection wells. As a safety measure to protect injection wells if the compressor is shut down, a system to prevent backflow of oil from the formation must be present at every injection well.

Downhole temperatures in producing wells increase as displaced oil, hot water and steam fronts reach the well. Producers are preserved by downhole cooling and proper material selection. Figure 17.17 provides an estimate of the water requirements to maintain bottom hole temperature no higher than 250°F as a function of oil and water production rate and formation flowing temperature. Significant additional oil recovery can be obtained from hot wells with downhole cooling, especially if the well is completed in the lower section of the producing zone to maximize gravity segregation in the reservoir. In many cases, after the combustion front has moved through the well it is possible to convert the former producer to a new air injector, thus realizing significant cost reductions over the life of the project.

Monitoring is crucial for proper combustion operations. In addition to testing individual producers for oil and water rates, injected fluids must be measured. Also, produced gases must be measured and analyzed to determine the efficiency of the combustion operation. Down hole temperature measurements are essential to calculate the size and location of the burned zone. Flow line temperatures can indicate thermal stimulation or down hole problems.

Combustion projects generate waste water, flue gases and pollutants from compression and oil handling equipment. Local pollution disposal regulations must be consulted prior to the design of any insitu combustion operation.

In general, environmental problems are similar to those posed by steam injection. The produced water may contain H_2S and/or CO_2 which may require special handling and anti-corrosion equipment. Flue gases may contain hydrocarbons, H_2S , CO_2 , CO and other trace amounts of sulfur gases. Table 17.3¹ summarizes the various pollution control systems suitable for combustion projects and their recommended applications. Sarathi¹ also provides detailed descriptions of the various types of systems and their uses. Some other problems that can be encountered are sand production, corrosion, emulsions, well failures or compressor failures.

Figure 17.17 Water needed to cool hot wells¹

8. FIELD EXPERIENCE

In situ combustion has been used in the field since 1920. In the U.S. over 230 projects have been implemented. Many of those were technically and economically successful. Unfavorable reservoir and fluid characteristics, poor design and engineering or operational problems caused failures. Most of the failed projects were small pilot projects implemented in unfavorable reservoirs. Worldwide, combustion accounts for about 10% of the oil produced by thermal methods. Steam injection accounts for the rest and is discussed in Chapter 16. Twenty nine projects were active as of 1998¹. Most of the projects outside of the U.S. are large heavy oil projects while the current trend in the U.S. is to use ISC in deep, lighter oil reservoirs where water flooding or steam flooding are not effective. Brief comments on these projects follow.

8.1. Heavy Oils

For oil with 20° API gravity or less, 19 projects using ISC were active in 1998. Some general comments apply:

- Most of these projects last a long time; projects initiated in the 1960's are still active. Economics of successful projects are favorable even as compared to steam and water flooding²³.
- All of the successful projects operate in the high temperature mode.

- Gravity override and channeling do occur. Gravity drainage of the hot oil is an important mechanism and should be maximized. Frequently, improved production of oil continues after the air injection has been terminated.
- Line drive projects, starting at the top of the reservoir and moving downward, exhibit superior performance compared to repeated pattern projects.
- Most of the projects failed when air injection was attempted in different layers of the reservoir at the same time. Air injectivity is a critical parameter and injectivity contrasts between layers is usually too difficult to overcome.

Table 17.3. Application of Pollution Control Systems to a Fireflood Project¹

Equipment	Gas Treated	Pollutant Removed	Method	Suggested Application
Flare stack	Flue gas	None	Vent to atmosphere	Flue gas meets air quality regulations
Flare stack with flame burner	Flue gas	H/C ⁽¹⁾ , CO ⁽¹⁾ , S-gases ^(1,2)	Burn	Flue gas with enough H/C to support combustion (>200Btu/Scf)
Thermal incinerator	Flue gas	H/C, CO, S-gases ^(1,2)	Burn	Flue gas not suitable for a flare with burner or a catalytic incinerator (heat value > 85 Btu/Scf but < 200 Btu/Scf)
Catalytic incinerator (excess air)	Flue gas	H/C, Co, S-gases ⁽²⁾	Burn	Flue gas with heat value < 85 Btu/Scf
H ₂ S scrubber	Flue gas	H ₂ S ⁽⁴⁾	Chemical reaction	Flue gas containing H ₂ S but acceptable amounts of other S gases
SO ₂ scrubber	Incinerator exhaust	SO ₂ ⁽⁴⁾	Chemical reaction	When H ₂ S removed from flue gas is inadequate or impractical
<ol style="list-style-type: none"> 1. Removal efficiency may be poor 2. S-gases are converted to SO₂ 3. May increase amount of CO For flue gas with heat values > Btu/Scf 4. Typical removal efficiency is 90-95%. 				

As a detailed description of all or even a few of the projects is outside the scope of this narrative, the reader can find additional information on several current projects in the following references:

- Projects in Romania: Suplacu de Barcău is the world's largest combustion project. It started in 1964 and is operated in a line drive mode from the top downward. Videle and Balaria are other ISC projects.^{24,25}
- In India, Balol, started as a pilot in 1990, was expanded to the whole field. Designed as a wet combustion project, the water injection rate had to be cut in half because of too much cooling. This project was also changed from patterns to updip line drive because of premature breakthrough in the producers.^{26,27}
- Projects in Russia, Kazakhstan, and Azerbaijan, are not very well described in western literature.²⁸
- The Albanian project of Kasnice is described in Marko.²⁹
- Batrum in Canada is a successful Mobil project using horizontal wells as producers. Eyehill field is another Mobil project with horizontal wells.^{27,30} Wabaska also uses the same concept of horizontal wells as producers.³¹ This technology has been used in Canada since 1993.

Cyclic applications such as pressure up and blow down, have been described^{31,32}. This operational technique allows production from very low mobility oil fields or tar sands where fracturing or cyclic steaming are needed prior to air injection. The Wabaska project is a cyclical combustion project with horizontal wells. This type of pressure up, blow down, technique has also been successfully implemented at Wolf Lake³². Air was injected until the front arrived at the producers. When the front reached a given producer, this well was shut down and cooling water circulated. When all the producers were shut down, injection was stopped and the producers reopened to blow down the reservoir. This process was repeated for several cycles. Operating combustion in this fashion allows production from fields where injectivity is low because of a high crude viscosity at reservoir conditions.

U.S. projects at Bellevue and Midway-Sunset have been described.²⁷ More details on the Midway-Sunset project can be found in Hoffmann.³³ Ramey, *et al.*²² describe the Belridge project as an economic success.

Insitu combustion in heavy oil reservoirs has been successful in both the dry and wet mode. Dry combustion early in the life of the project is the preferred method to form the desired high temperature regime. When the process is well established, moderate amounts of water can be added to improve efficiency. Quenched or super wet combustion seems to have limited success except when used at the end of a field operation to scavenge the heat remaining in the rock.

Another operating variation includes the use of enriched air or pure oxygen. Oxygen enriched combustion presents technical and economic advantages for reservoirs with high pressure or very low injectivity. It has been successfully demonstrated in the field.^{34,35} More detailed literature covering the special handling methods and additional precautions needed for enriched air injection is listed in the additional references.

Commercial application of the oxygen technology has been limited because of oil price variations.

8.2 Light Oils

In situ combustion is used in light oil reservoirs for a variety of processes:

- To reduce the viscosity of unconventional light oils such as Demjen in Hungary³⁶ or Niemangu in China¹. In these cases, thermal effects are important. In the case of Demjen, a catalyst had to be injected to promote combustion. Iron was used to increase the amount of fuel burned because the light oil by itself was not depositing enough fuel to sustain combustion. The oil is parafinic and almost solid at reservoir temperature despite an API gravity of 32°.
- To produce from light oil reservoirs where water flooding or other enhanced oil recovery methods are not attractive. Combustion is used to generate flue gases for reservoir pressure maintenance and production by gravity drainage. Thermal effects are only minor for this process. An interesting case is the West Hackberry double displacement process³⁷ in which the gas cap is expanded for gravity drainage to recover residual oil after waterflood.
- To burn thin, light oil reservoirs. Combustion is successful in tight carbonate reservoirs, located in the Dakotas, such as Medicine Pole Hill, Buffalo, West and South Buffalo³⁸ and Horse Creek.³⁹ In those cases, combustion allows exploitation of thin reservoirs with large well spacing.

8.3. Screening Guidelines

In situ combustion is a complex process. It combines effects of steam drive, hydrocarbon miscible and immiscible flood, immiscible gas drive and hot and cold water flood. Because of its complexity there is a misconception that combustion has a low probability of success. The truth is that combustion is an economically attractive, proven recovery process, capable of economically recovering a large fraction of the oil in place.

In situ combustion can be applied to many different reservoirs. Some suggested screening guidelines are:

- Nature of the Formation : The rock type is not important provided that the matrix/oil system is reactive enough to sustain combustion. As in any drive process, high permeability streaks are detrimental. Swelling clays may be a problem in the steam plateau area.
- Depth: Depth should be large enough to ensure containment of the injected air in the reservoir. There is no depth limit, except that this may affect the injection pressure.
- Pressure: Pressure will affect the economics of the process, but does not affect the technical aspects of combustion.
- Temperature: Temperature will affect auto ignition but is otherwise not critical.

- Reservoir Thickness: Thickness should be greater than about 4m (15 ft)^{2,3} to avoid excessive heat losses to surrounding formations. Very thick formations may present sweep efficiency problems because of gravity override.
- Permeability: This has to be sufficient to allow injection of air at the designed air flux. The air injectivity is especially important for heavy oil reservoirs. Conditions are favorable when kh/μ is greater than about 5md m/cp.³
- Porosity and Oil Saturation: These have to be large enough to allow economic oil recovery. The product, ϕS_o , needs to be over about 0.08 for combustion to be economically successful.
- Oil Gravity: This parameter is not critical. Insitu viscosity has to be low enough to allow air injection and resulting oil production at the design rate.
- Oil Nature: In heavy oil projects the oil should be readily oxidizable at reservoir and rock matrix conditions. This relationship must be determined by laboratory experiments. The same laboratory experiments can also determine the amount of air needed to burn a given reservoir volume. This is key to the profitability of the process.

9. CONCLUSIONS

In situ combustion can be applied to a wide array of reservoirs. In fact it is the only thermal method that can presently be applied to deep reservoirs, though deep downhole steam generation is being tested. It can be used at any stage of reservoir depletion. It can be used in special situations such as offshore or in arctic regions. Because of the lack of heat losses at the surface and in the injection wells, it is the most thermally efficient thermal recovery method. The injectant (air) is readily available. Combustion allows wider well spacing than steam. Economic results are comparable to those of steam injection.

Several aspects of operating ISC projects are important. First is the large compression ratios and associated costs required to inject air into the formation. Second is planning and design requirements for a combustion project that are more difficult than steam. Third is extensive laboratory work to assess fuel availability, air requirements and burning characteristics of the crude that are required before designing insitu combustion projects. Fourth is the high degree of technical sophistication, and careful monitoring needed to ensure proper operation of a project. Fifth is the limitation of numerical simulation and other techniques that makes predictions of recovery more difficult than most other enhanced oil recovery methods.

Considerable improvements in the application of insitu combustion have been made since the early projects. New developments, such as application to light oil reservoirs, injection of gases at high oxygen concentrations, and the use of horizontal wells are reviving interest in ISC. This process deserves consideration for many reservoirs including those in hostile environments or not amenable to other recovery methods.

10. NOMENCLATURE

A	Arrhenius constant, $(kg / m^3)^{1-b} / (Pa)^a \text{ sec}$
a	Order of reaction with respect to oxygen, dimensionless
a_i	Cumulative air injected, scf
b	Order of reaction with respect to fuel concentration, dimensionless
C_f	Fuel concentration, kg / m^3
c_p	Heat capacity at constant pressure, BTU/lb $^{\circ}F$
c_s	Heat capacity of sandstone, BTU/lb $^{\circ}F$
c_v	Heat capacity at constant volume, BTU/lb $^{\circ}F$
E	Activation energy, kJ / mole
e_{o_2}	Oxygen utilization efficiency, fraction
H_c	Heating value of fuel, BTU/lb
h	Vertical thickness of reservoir, ft
K	Reaction rate constant, $(kg / m^3)^{1-b} / (Pa)^a \text{ sec}$
m	CO_2 / CO concentration ratio produced, dimensionless
N	Oil in place at the start of the project, $b b l$
ΔN_b	Fuel burned, $b b l$
N_i	Initial oil in place, $b b l$
N_p	Oil produced, m^3
ΔN_p	Cumulative incremental oil produced, $b b l$
n	Hydrogen/carbon atomic ratio of fuel, dimensionless
O_2	Oxygen concentration, injected
$(O_2)_{\text{prod}}$	Oxygen concentration produced,
p_{O_2}	Oxygen partial pressure, Pa
R	Universal gas constant, $kJ/\text{mole } ^{\circ}K$
R_c	Reaction rate of the crude, $kg / m^3 \text{ sec}$
S_f	Oil saturation burned, fraction
S_o	Oil saturation, fraction
S_{oi}	Initial oil saturation, fraction
S_{wf}	Water saturation resulting from the combustion process, fraction
S_{wi}	Initial water saturation, fraction
T	Absolute temperature, $^{\circ}K$
T_1	Initial temperature, $^{\circ}F$
T_2	Final temperature, $^{\circ}F$

V_b	Volume of reservoir burned, m^3
V_p	Volume of the pattern, m^3
W	Fuel availability, lb /100 lb rock
W_p	Water produced, m^3

Greek Letters

ϕ	Porosity, fraction
μ_o	Oil viscosity, cp

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Upgrading Via In-situ Combustion

L. M. Castanier and W.E. Brigham

ABSTRACT

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 very beneficial process.

In-situ combustion has long been used as an enhanced oil recovery method. For heavy oils, numerous field observations shown upgrading of 2 to 6 degrees API for heavy oils undergoing combustion (Ramey, 1992) . During in-situ combustion of heavy oils, temperatures of up to 700 degrees C can be observed at the combustion front. The purpose of this note is try to examine the changes caused by the various reactions occurring during combustion with emphasis on the upgrading potential for various oil types. We will first describe the process with an emphasis on the temperature changes and chemical reactions which can either upgrade or degrade the oil in terms of its API gravity and viscosity. In the second part, we present results from three combustion tube runs aimed at sulfur removal. We will end by discussing possible in-situ upgrading strategies using combinations of in-situ combustion and other improved recovery methods.

1. BACKGROUND AND PROCESS DESCRIPTION

In-situ combustion is injection of an oxidizing gas (air or oxygen enriched air) to generate heat by burning a portion of the oil. Most of the oil is driven toward the producers by a combination of gas drive (from the combustion gases) and steam and water drive. This process is also called fire flooding to describe the movement of the burning front inside the reservoir. Based on the respective directions of front propagation and air flow, the process can be forward, when the combustion front advances in the same direction as the air flow, or reverse, when the front moves against the air flow.

As only forward combustion is practiced in the field we will only consider this case. Forward combustion can be further characterized as “dry” when only air or enriched air is injected or “wet” when air and water are co-injected.

Air is injected in the target formation for a short time, usually a few days to a few weeks and the oil in the formation is ignited. Ignition can be induced using down hole gas burners, electrical heaters, and/or injection of pyrophoric agents (not recommended)

or steam injection. In some cases auto-ignition occurs when the reservoir temperature is fairly high and the oil reasonably reactive. This often occurs in California oils.

After ignition the combustion front is propagated by a continuous flow of air. As the front progresses into the reservoir, several zones can be found between the injector and the producer as a result of heat and mass transport and the chemical reactions occurring in the process. Figure 1 (Wu and Fulton, 1971) shows a schematic representation of the locations of the various zones and temperature and fluid saturation distributions. In the field there are transitions between all those zones so Fig. 1 is only an idealized representation.

Starting from the injector seven zones can be defined:

- (A) The burned zone is the volume already burned. This zone is filled with air and may contain small amounts of residual unburned organic solids. As it has been subjected to high temperatures, mineral alterations are possible. Because of the continuous air flow from the injector to the burned zone, temperature increases from injected air temperature at the injector to near combustion front temperature near the combustion front. There is no oil left in this zone.
- (B) The combustion front is the highest temperature zone. It is very thin, often no more than several inches thick. It is in that region that oxygen combines with the fuel and high temperature oxidation occurs. The products of the burning reactions are water and carbon oxides. The fuel is often misnamed coke. In fact it is not pure carbon but a hydrocarbon with H/C molar ratios ranging from about 0.6 to 2.0. This fuel is formed in the thermal cracking zone just ahead of the front and is the product of cracking and pyrolysis which is deposited on the rock matrix. The amount of fuel burned is an important parameter because it determines how much air must be injected to burn a certain volume of reservoir. One should note that the fuel burnt is the heaviest part of the oil. As we will see later it is formed by the steam distillation, cracking and pyrolysis.
- (C) The cracking/vaporization zone is downstream of the front. The oil remaining in that zone is the residual oil left behind the steam plateau. The crude is modified in this zone by the high temperature of the combustion process. The light ends vaporize and are transported downstream where they condense and mix with the original crude. The heavy ends pyrolyse, resulting in CO_2 , hydrocarbon gases and solid organic fuel deposited on the rock.
- (D) The steam plateau is next downstream. Most of the oil is displaced forward. The immobile oil undergoes steam distillation. Further downstream some of the hydrocarbon vapors condense, mostly as the steam condenses. The steam plateau temperature depends on the partial pressure of the water in the gas phase. Depending on the temperature the original oil may undergo a mild thermal cracking, often named visbreaking, in this zone. That usually reduces the oil viscosity.

- (E) At the leading edge of the steam plateau, where the temperature is less than steam saturation temperature, a water bank is formed which decreases in temperature and saturation as we look downstream, with a resulting increase in oil saturation.
- (F) An oil bank is next. This zone contains most of the oil displaced from upstream, including most of the light ends that resulted from the thermal cracking upstream.
- (G) Beyond lays the undisturbed original reservoir. Gas saturation will only increase slightly in this region because of the high mobility of combustion gases. The production mechanism in this area is gas drive from the combustion products.

2. CHEMICAL REACTIONS

Chemical reactions are of two main categories. Oxidations occur in the presence of oxygen while pyrolysis is caused mainly by elevated temperatures.

Oxidation can be of two different natures (Mamora, 1993). In general at low temperatures oxygen combines with the oil to form oxidized hydrocarbons such as peroxides, alcohols or ketones. This generally increases the oil viscosity but could increase oil reactivity at higher temperature. When oxygen contacts the oil at higher temperature, combustion occurs resulting in production of water and carbon oxides. Pyrolysis is the chemical alteration of hydrocarbons under the effect of heat. The reactions depend on the chemical structure of the oil and can be dehydrogenation where the number of carbon atoms in the molecule remains the same, cracking which reduces the number of carbon atoms or condensation which increases the number of carbon atoms. Dehydrogenation is usually preponderant for short chain hydrocarbons while cracking is the main reaction for longer chain molecules. At temperatures over 500 degrees centigrade, the products of pyrolysis are light hydrocarbons and a coke like residue.

In the steam plateau, the composition of the oil will change (Venkatesan and Shu 1984; Aksinat, 1983). Sulfur removal by formation of H₂S often occurs at this stage. Figure 2 (Monin and Audibert, 1984) shows the effect of steam and of the rock matrix on the changes in composition of two oils heated to 300°C. One can notice a decrease in asphaltene content and the formation of a solid coke like substance called pyrobitumen.

Distillation allows transport and production of the light fractions of the oil (Lim *et al.*, 1992) leaving behind the heavy ends. These heavy ends often contain the majority of undesirable compounds which may contain sulfur or metals.

Of all the reactions that can occur during in-situ combustion, only low temperature oxidation can increase the viscosity of the oil. (Moore *et al.*, 1994) If the fireflood is conducted properly low temperature oxidations are minimized because most of the oxygen injected is consumed at the burning front.

Abu Khamsim *et al.* (1985) presented a good literature review of fuel formation and pyrolysis during in-situ combustion. They also present results of experiments aimed at understanding fuel formation. They emphasized the importance of distillation and of the nature of the crude. They found that fuel formation started with distillation followed by visbreaking and pyrolysis. They confirmed that the fuel left is mainly composed of the heavy fractions of the oil.

From a multi-year study (Castanier and Brigham, 1996) we know that water soluble metallic additives cause changes in the nature and the amount of fuel formed during in-situ combustion. These changes appear to depend on the type of oil used. Various crude oils are affected differently by different additives. The efficiency of various metals as additives does not follow the usually cited order for cracking reactions of coke $Cu < V < Fe < Cr = Zn < Ni$. For the cases studied, iron and tin seem to be the additives which best increase fuel deposition and promote combustion. Unfortunately no additive was found as yet to decrease fuel lay down. This method was successfully used in the field in Hungary (Racz *et al.*, 1985) using iron to increase fuel content.

3. EXPERIMENTS FOR SULFUR REMOVAL

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 light Middle East 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. A schematic of the equipment is shown in Fig. 3 (after Mamora *et al.*, 1993). 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.

3.1. Run Without Additive

Temperature profiles are shown on Fig. 4. One can observe some fluctuations and an average front temperature of about 450°C. Figure 5 shows the effluent gas composition. Again fluctuations are seen and the oxygen utilization is poor with an average of 7 mole % fraction of oxygen produced. This shows that the combustion is not efficient and not enough fuel is burned. Figure 6 shows the front locations and fuel concentrations as a function of time. Again, wide fluctuations in the amount of fuel burned are observed. The original oil contained 6% by weight of sulfur, the average sulfur content of the produced oil was about 3%. Most of the removed sulfur was found as sulfuric acid in the produced water.

3.2. Runs with Water Soluble Metallic Additives

Tin chloride and Iron nitrate were dissolved in the water at 5% by weight concentration. The experimental procedure and parameters were similar to those of the previous run. As the behavior of both runs was similar we will only present in detail the results of the run where tin chloride was used.

The temperature profiles as a function of time are shown on figure 7. The average front temperature was 500°C . This represents an increase of about 50° over the run without additive. Figure 8 shows the produced gas composition. The combustion was stable with only minor fluctuations. Almost all of the oxygen injected was consumed . Fuel concentration (Fig. 9) was also stable at a value around 0.04 grams per cubic centimeter of the pack. This run was stopped after 4 hours because a leak developed in the thermal well.

The run with iron nitrate was made after repairing the leak and the results were similar to the run made with tin chloride. In both cases, the amount of sulfur in the produced oil was reduced to less than 1% by weight from the original 6%. Although it was necessary to use metallic additives to promote fuel deposition and obtain a good burn of this light oil, sulfur removal by in-situ combustion appears promising. We can also postulate that heavy metals, sometimes present in the oil, can be removed in a similar manner.

3.3. Possible In-Situ Upgrading Strategies

Forward in-situ combustion is already an effective in –situ upgrading method. Field improvements in gravity by as much as 6° have been mentioned in the literature. In the following we will present some hybrid methods that could be used to further upgrade the oil in-situ.

In a recent article (Moore *et al.*, 2001), a method of upgrading Athabasca bitumen was proposed. It consists in a combination of low temperature oxidation followed by higher temperature oxidation. They showed that dividing the oxidation process into two steps can result in an overall reduction of viscosity. Low temperature oxidation will occur during the first step, and by raising the temperature the pre oxidized oil will react more easily at higher temperature, and cracking of the heavy oxygenated compounds will become easier.

This process can be achieved, for example, by injecting air and then by following the air slug with steam to raise the temperature. Xia and Graves (2001) describe experiments combining air injection and horizontal wells. Using SARA (Saturates, Aromatics, Resins, Asphaltenes) analysis they show significant upgrading of bitumen during their three dimensional experiments. From a bitumen of 1 million Mpas viscosity they produce oil of viscosity between 500 and a 1000 Mpas. The I gravity improved by

up to 8 degrees API. The SARA analysis showed a dramatic increase in saturates for the produced oil. Although direct application of these laboratory results to the field is difficult, such technology deserves further research.

Another possible in-situ upgrading technique involves a combination of solvent injection and combustion. Cyclic oil recovery has numerous advantages both technically and economically. It can also be easily optimized in a given oil reservoir. We propose cyclic injection of solvents, either gas or liquid, followed by in-situ combustion of a small part of the reservoir to increase the temperature near the well bore but also to clean the well bore region of all the residues left by the solvents. Alternate slugs of solvent and air will be injected and production will occur after each solvent slug injection and after each combustion period. The process can be repeated until an economic limit is reached. One important fact to note is that both solvent injection and in-situ combustion have been proven to be effective in a variety of reservoirs, however, the combination of the two methods has never been tried to our knowledge.

We expect that in most cases, the amount of solvent to be injected will be a small fraction of the pore volume of the reservoir considered. By mixing with the oil the solvent will decrease the viscosity of the mixture below the viscosity of the original oil. The improvement in oil production can be estimated using an approach similar to the one used by Boberg (1998) for steam cycling and taking into account only the change of viscosity caused by the solvent. Production after the injection of the first slug of solvent can thus be easily estimated.

At the end of the first solvent cycle, one can expect some damage to the near wellbore area. Most significant will be the precipitation and/or deposition of heavy hydrocarbons such as asphaltenes or paraffins. The produced oil is expected to be slightly upgraded by the solvent cycle. Unlike the classic well to well in-situ combustion, we would only try to improve near well bore conditions by burning the solid residues left after the solvent cycle. The amount of air (or oxygen) to be injected can easily be determined by laboratory experiments and numerical simulation or simple calculations. The benefits of using combustion at this stage are expected to include:

- Productivity improvement through removal of the heavy ends left from the solvent cycle.
- Possible deactivation of the clays near the well bore due to the high temperature of the combustion.
- Reduced viscosity of the oil due to temperature increase.
- Effect of CO_2 production causing swelling and viscosity reduction of the oil
When CO_2 partial pressure is high enough
- pressure maintenance

One must note that combustion burns only the heaviest part of the crude and hence the upgrading already observed during the solvent cycle should be maintained and even improved. A soak period will probably be necessary at the end of the air/oxygen injection to ensure that all of the oxygen injected will have reacted in the reservoir and

will not be produced during the subsequent production cycle. The recovery predictions at this stage of the process will be difficult and probably require a fine grid thermal/compositional simulation. It is however possible to obtain some estimates based on simple correlations such as Brigham, *et al.* (1981), or to perform simple analytical approximations similar to the well known steam cyclic models (Boberg, 1998).

The process can be repeated by alternating solvent injection and near well in-situ combustion as long as the economics warrants it. Optimization of slug sizes and duration needs to be addressed to ensure maximum economic efficiency. Reservoir conditions will, of course, dictate these parameters.

4. CONCLUSIONS

Because of the nature of the process, in-situ combustion is a viable in-situ upgrading method. For heavy oils significant upgrading occurs by the fact that the heavy ends are burned while most of the light ends are produced. The use of water soluble metallic additives allows in-situ combustion of light oils. This can be quite beneficial for removal of sulfur or other metals. More research is needed in that area. Several possible new in-situ upgrading technologies have been discussed. They include use of steam and air injection, combinations of horizontal wells and air injection and combinations of in-situ combustion with solvent injection. All of those techniques should be further examined for technical and economic feasibility.

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Fig. 1. In-Situ Combustion: Schematic Diagram of Temperature and Saturation Profiles and Zones (After Wu and Fulton, 1971).

Fig. 2. Chemical alteration of heavy crudes after 200 h heating at 350°C; atmosphere of helium at about 4 Mpa, or atmosphere at 18-20 Mpa containing argon or water vapor. Oil density at 25°C is 999 kg/m³ for Oil A and 946 kg/m³ for oil B. Oil B contains essentially no sulfur. (a) Material balance (in weight percent of the initial crude oil). (b) Composition of oil fractions C_{12+} .

Fig. 3. Schematic diagram of kinetic and combustion tube apparatus.

Fig. 4. Average gas saturation in the core versus time for an oil withdrawal rate of $1.44 \text{ cm}^3/\text{day}$ ($5.1 \times 10^{-5} \text{ ft}^3/\text{day}$), IN population balance model. The number of bubbles nucleated is $10,000 \text{ bubbles/ft}^3$ of rock ($0.353 \text{ bubbles/cm}^3$).

Fig. 5. Gas bubble size with time for an oil withdrawal rate of $1.44 \text{ cm}^3/\text{day}$ ($5.1 \times 10^{-5} \text{ ft}^3/\text{day}$), IN population balance model. The number of bubbles nucleated is $10,000 \text{ bubbles/ft}^3$ of rock ($0.353 \text{ bubbles/cm}^3$).

Fig. 6. Plot of average pressure versus time illustrating the effect of varying the expansion rate, IN population balance model. The number of bubbles nucleated is 10,000 bubbles/ft³ of rock (0.353 bubbles/cm³).

Fig. 7. Match of the IN bubble population balance model to the experimental pressure data of Firoozabadi *et al.*²⁴. Withdrawal rate is 1.44 cm³/day (5.1x10⁻⁵ ft³/day).

Fig. 8. IN population balance model prediction of average gas saturation along length of core. Withdrawal rate is $1.44 \text{ cm}^3/\text{day}$ ($5.1 \times 10^{-5} \text{ ft}^3/\text{day}$).

Fig. 9. Match of the IN bubble population balance model to the experimental pressure data of Firoozabadi *et al.*²⁴. Withdrawal rate is 7.2 cm³/day (2.5×10^{-4} ft³/day).

RESERVOIR DEFINITION

Integrating Production History into Reservoir Models Using Streamline-Based Time-of-Flight Ranking

Y. Wang and A. R. Kovscek

ABSTRACT

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. An example using 500 distinct reservoir models demonstrates computational efficiency and also shows that the method easily selects the most appropriate permeability fields. Flow simulations confirm that selections are satisfactory.

1. INTRODUCTION

Geostatistical techniques are used primarily to generate realistic equally-probable numerical reservoir models that honor known geological information. However, significant uncertainty exists in the detailed distribution of reservoir properties such as permeability (Deutsch and Srinivasan, 1996) because the known data is relatively sparse. If flow simulation is performed on various realizations to predict reservoir performance, the geological reservoir model uncertainty, in turn, is transferred into uncertainty of simulation results. In many instances, the variability in flow simulation results among geostatistical realizations is large.

When no production history is available, uncertainty in reservoir performance can be evaluated by conducting flow simulations on various geostatistical models. Approaches to speed up the process of comprehensive flow simulation on a great number of models have been discussed in the literature. Deutsch and Srinivasan (1996) reviewed three categories of methods for ranking geostatistical reservoir models. They are: (1) statistical methods, (2) methods based on approximations to flow simulation, and (3) flow-simulation-based methods for a simpler process, e.g., on coarsened models. In the

second category, Ballin *et al.* (1992) selected models for comprehensive simulation by using a fast simulator to rank realizations. The fast simulation can be, for example, a tracer simulation or a simplified flow model. To address further the issue of uncertainty, Cruz *et al.* (1999) introduced the concept of a quality map that is obtained by running flow simulation many times with a single well at varying locations. A number of quality maps can be generated for different geostatistical models, and uncertainty can be evaluated. The quality map can be then used for decision-making. This method can be computationally intensive.

If production history is present, integration of the data with geostatistical realizations can reduce uncertainty. In turn, future reservoir performance should be better predicted. However, no general and computationally efficient method for production data integration exists currently. Barker *et al.* (2000) discussed the application of three approaches to constraining geological realizations to production data: rejection sampling, pilot-point method, and Markov Chain Monte Carlo (MCMC). The latter two approaches use inverse modeling techniques in conjunction with finite difference based flow simulator. In general, on the order of thousands of flow simulations were needed to achieve tens of matched models for all three methods. Similar to the pilot point method, the sequential-self-calibration technique has been adapted to the inverse problem of integrating multiwell transient pressure and production data with reservoir models (Wen *et al.* 1998a, b). On the other hand, Yoon *et al.* (2000) presented a multiscale approach to production-data integration using streamline models. In their method, multiscales of coarseness within reservoir descriptions are used to account for the varying resolving power of different production data. A scale by scale inversion of production response is achieved with an increase in computational efficiency. A streamline simulator is used for flow simulation and a streamline approach is used to compute the sensitivities of production data to reservoir model parameters.

In other work, Wang and Kovscek 2000 proposed a streamline approach for history-matching production data (Wang and Kovscek, 2000). Streamline properties are used in the inverse method to obtain the permeability changes needed to match production data. The method works in two steps: (1) the error between measured and computed producer water cut is related to an error in effective permeability of streamlines; and (2) the perturbation in streamline effective permeability is computed analytically and mapped into a change of permeability for individual grid cells. This method applies well in water-flood cases with few or no infill wells to be matched. A streamline flow simulator, 3DSL (Batycky *et al.*, 1997), is used for forward flow simulation in the history matching process, but a standard finite difference based simulator could also be used. Agarwal and Blunt (2001) applied this same method to cases with gravity and compressibility. Data from a North Sea Field was used to test the technique with reasonable history match and prediction of future performance. In both cases, the history-matched reservoir models were not constrained to geological information. Subsequently, Caers *et al.* (2001) combined Wang and Kovscek's method with a Gauss Markov random function (GMrf) technique to constrain reservoir models jointly to production data and geological information. Other streamline-based history-

matching methods are discussed in literature (Gupta *et al.*, 1994; He *et al.*, 2001; Vasco *et al.*, 1998; Wen *et al.*, 1998).

It is commonly known that both the history matching process and geostatistics are inherently non-deterministic. It is not appropriate to use only one geologically constrained and history-matched reservoir model to characterize reservoir performance. It is desirable to have a suitable number of such models so that the uncertainty of the prediction can be evaluated. Even though the method of Caers *et al.* (2001) is efficient in generating a reservoir model that honors both the production history and geology, the generation of many such models may still be computationally involved. Thus, we propose a rejection sampling type approach to rank or sort geostatistical realizations. This provides an additional process to constrain our streamline-based history matching method (Wang and Kovscek, 2000) to observed geology. Further, it provides a means to select rationally a subset of reservoir models that honor observed production data from a larger suite of realizations.

It is proposed here that a reservoir model be obtained by unconstrained history matching to the known production as shown by Wang and Kovscek (2000). Then a desired number of reservoir models are generated using geostatistical methods (*e.g.* Deutsch and Journel, 1992). These geostatistical models are thus consistent with any known geology, whereas the unconstrained history match provides a model consistent with production. Next, streamlines and their time-of-flight (SL-TOF) distributions are computed (Blunt *et al.*, 1996) for the unconstrained history-matched model and the reservoir models to be ranked. Full flow simulation is not required for this step. The SL-TOF distribution of each geostatistical model is then compared to that of the history-matched model. The models are ranked based on the SL-TOF cdf errors. This ranking is proven below to be the same as the ranking in terms of water-cut error at corresponding producers. Errors in the flow-rate, pressure and cumulative oil production are ranked in a similar way. We proceed by first defining a number of terms and then turn to the task of correlating the distribution of time of flight among streamlines to observed water-cut behavior. A synthetic example is used to illustrate the method.

2. TERMINOLOGY

Before continuing, some terms are defined so that the discussion can be concise.

PVI: Pore volume injected. In this context, it refers to displaceable pore volume replaced by water.

SL-TOF: Streamline time of flight. More precisely, it refers to the dimensionless time of flight. SL-TOF is equivalent to the pore-volume-injected (PVI) along the streamline.

cdf: Cumulative distribution function. The cdf characterizes the probability that the value of a variable is less than a particular value. It is the integral of the probability density function.

CFS: Comprehensive flow simulation on a reservoir model.

M: Mobility ratio. The endpoint mobility of the displacing phase divided by the displaced phase endpoint mobility.

SL: Streamline.

Water-cut/fractional-flow: The injected-phase fractional-flow or injected component concentration at a producer. The two terms are used interchangeably.

CIPP: Cumulative initial-phase production, that is, cumulative oil production.

The ideal set-up for our method requires information in the following two categories, First, known geology, including direct measurements of reservoir properties at discrete locations. Therefore, many equal-probable reservoir models can be generated using any appropriate geostatistical approach. Secondly, known well production history, including water-cut and injection data. The ideal cases are incompressible water flooding and tracer flow study.

3. EXHAUSTIVE SIMULATION AND ERROR CORRELATION

Streamline trajectories and other properties are correlated with permeability distribution, and so streamline properties bear on reservoir performance. The various TOF of streamlines that connect an injector and producer can be summarized as a cdf. Intuitively, the streamline time of flight (SL-TOF) cdf is correlated with water-cut history. Similarly, flow rate and pressure distribution at one time correlates with that at other times. As cumulative initial-phase production can be computed from water-cut and flow-rate, a term that is equivalent to CIPP, equivalent CIPP, can be computed by combining SL-TOF cdf and flow-rate. Compared to the comprehensive flow simulation, computation of streamlines, SL-TOF cdf, and equivalent CIPP takes significantly less execution time. Substantial computational work can be saved if reservoir models are ranked (i.e., rejected) according to streamline properties rather than simulation results. However, the direct correlation between ranking realizations with streamline properties and with CFS must be established. This is the purpose of the remainder of this section. First, exhaustive simulations on 51 geostatistical realizations are conducted. One realization is used as "truth". Unit and unfavorable mobility ratio flow simulations are performed to explore the variation in results among the models and truth. Phenomenologically, a direct correlation between SL-TOF cdf and producer water cut is shown. Second, a brief theoretical explanation is given that confirms the correlation.

3.1. Correlation of TOF Results

Throughout, we refer to the difference between a realization and truth as "error". Within streamline computations, errors include SL-TOF cdf, flow rate, pressure drop, and equivalent CIPP. The error of a physical term of a model with respect to that of the reference model is computed as follows. Take the SL-TOF cdf error as an example. Compute the SL-TOF distributions for the reference model and the model to be checked. Discretize the two distributions at identical TOF values. Then the error is the average of the absolute values of the differences at all the discrete points. Therefore, each type of the error of a model is quantified by a single value.

To verify the correlation of errors numerically, fifty-one models, represented by permeability fields, are generated using sequential-Gaussian simulation (SGSIM) (Deutsch and Journel, 1998) with fixed permeability values at well locations as shown in Table 1. Each permeability field is 50 by 50 grid-blocks. Table 2 lists the other details of the flow simulations. Each model is ranked compared to the truth case for three pairs of error type: SL-TOF cdf and water-cut from CFS, flow-rate from SL simulation and flow-rate from CFS, and equivalent-CIPP and CIPP. Streamline properties for ranking models are always computed for unit mobility ratio. A confined five-spot pattern is used for all displacements

Results for forward simulations with $M=1$ and $M=2.5$ cases are presented below. For unit mobility ratio, total flow-rate in CFS is constant and the same as that in the ranking method. Streamlines do not vary in time. The only concern is the correlation of water-cut from CFS and SL-TOF cdf. Figure 1a shows the correlation between SL-TOF cdf error and water-cut error for $M=1$. Figure 1b shows the correlation between SL-TOF cdf error rank and water-cut error rank. The correlation coefficients are both above 0.97. The error among models correlates well between CFS and unit-mobility ratio streamlines. Importantly, the relative rank also correlates. Models that are far from the truth case produce large error whether computed from CFS or strictly from SL-TOF.

For mobility ratio $M=2.5$ Figs. 2a, 2b, and 2c show the correlation between SL-TOF cdf error and fractional-flow error from CFS, between the error of the equivalent flow-rate in ranking and the error in flow-rate from CFS, and between the error of equivalent-CIPP and error of CIPP from CFS, respectively. Figure 2d shows the correlation of error rank between each pair. The correlation coefficients are all above 0.97 as shown in Fig. 2. Therefore, the correlation is almost perfect in terms of both error and error rank. Again, the relative rank correlates among these pairs of errors.

In Fig. 1, SL-TOF cdf error and fractional flow-error correlate with unit slope for $M=1$. That is, the difference in performance between two reservoir models is gauged from either the difference in water-cut curves or the difference in the distribution of SL-TOF. For non-unit mobility ratio, the slope is not unity. However, as shown in Fig 2, the errors among CFS and SL calculations correlate linearly with a bias close to zero. Properties, such as TOF and streamline geometry, computed for unit mobility ratio are

indicative of the results on the same permeability field when the displacement is not unit mobility.

3.2. Correlation--Theoretical Development

The correlation of different error pairs is made obvious by the substantial flow simulation results and ranking results as shown in Figs. 1 and 2. The equations derived below give a quantitative explanation of this correlation.

For unit mobility ratio cases, streamline trajectories and the pressure distribution are constant. Flow is equivalent to miscible displacement or tracer injection. Due to the fact that each streamline carries the same amount of flow, the amount of injectant that is produced increases by $1/n$ (where n is the number of streamlines) when each streamline breaks through. The SL-TOF cdf also increases by $1/n$ when each streamline breaks through. Therefore, the SL-TOF cdf is the same as the fraction of injected phase produced. As shown in Fig. 3, the SL-TOF cdf agrees with fractional-flow very well at all producers for a confined five-spot pattern where permeability heterogeneity is present.

The same argument holds for non-unit mobility ratio cases because the breakthrough of each streamline contributes an incremental amount to the water cut if each streamline carries the same flow-rate. However, in the ranking process, the error SL-TOF cdf is computed under unit mobility ratio while the error of water-cut in simulation result is computed under true (non-unit) mobility ratio. Therefore, we need to show that the SL-TOF cdf error for unit mobility case is linearly correlated with the SL-TOF cdf error for non-unit mobility case that is equivalent to the water-cut at the same mobility ratio.

Assume n streamlines are launched between an injector-producer pair. A streamline can be treated as the center of a streamtube. Throughout this discussion, streamline and streamtube are used interchangeably. Equations are derived, first for unit and then for non-unit mobility ratio, by treating streamtubes as non-communicating layers and following the work of Dykstra and Parsons (1950) (Dykstra and Parsons, 1950; Lake, 1989).

For unit mobility ratio and piston-like displacement, the total PVI when the first streamtube breaks through is the same as the dimensionless TOF of the first streamline,

τ_{D1} ,

$$\tau_{D1} = \frac{v_1 + \sum_{i=2}^n v_i x_{fDi}}{V} = \frac{v_1 + v'}{V} \quad (1)$$

where v_i is the pore volume of the streamtube i , x_{fDi} is the dimensionless position of the displacement front in streamtube i , V is the total pore volume, and v' is total swept pore

volume of all but the first streamtubes, which is defined as

$$v' = \sum_{i=2}^n v_i x_{fD} = V' x_{fD} \quad (2)$$

where x'_{fD} is the pore- volume averaged displacement front of those streamtubes, and V' is the total pore volume of all but the first streamtubes as defined below.

$$V = \sum_{i=1}^n v_i = v_1 + \sum_{i=2}^n v_i = v_1 + V' \quad (3)$$

Each streamline carries the same volumetric rate q . Hence, the flow-rate of the first streamline is q and that of the rest is $(n-1)q$. For homogeneously distributed porosity, the following can be obtained from material balance

$$\frac{v'}{v_1} = \frac{(n-1)q}{q} = n-1 \quad (4)$$

Combining the Eqs. 2-4, we obtain

$$v_1 = \frac{1}{1 + (n-1)/x'_{fD}} V, \quad v' = \frac{n-1}{1 + (n-1)/x'_{fD}} V \quad (5)$$

Plug Eq. 5 into Eq. 1 and rearrange,

$$x'_{fD} = \frac{n-1}{n - \tau_{D1}} \tau_{D1} \approx \tau_{D1}, \quad \forall \text{ large } n \quad (6)$$

Then

$$v_1 = \frac{\tau_{D1}}{n} V, \quad v' = (1 - \frac{\tau_{D1}}{n}) V \quad (7)$$

For non-mobility ratio, the dimensionless position of the displacing front can be expressed in terms of mobility ratio and the dimensionless distance of displacing front for unit mobility case

$$x^*_{fD} = \frac{M}{M-1} \left\{ 1 - \sqrt{1 + x'_{fD} \left(\frac{1}{M^2} - 1 \right)} \right\} \quad (8)$$

where superscript * denotes the non-unit mobility ratio case.

The PVI at the first streamtube breakthrough is

$$\tau^*_{D1} = \frac{v_1 + v' x^*_{fD}}{V} \quad (9)$$

Plug Eqs. (7) and (8) into (9) and simplifying for large n , we obtain

$$\tau^*_{D1} = \frac{M}{M-1} \left\{ 1 - \sqrt{1 + \tau_{D1} \left(\frac{1}{M^2} - 1 \right)} \right\} \quad (10)$$

For moderately favorable or moderately unfavorable mobility ratios, this approximation is accurate. For example, τ_{D1} and τ_{D1}^* are 0.425 and 0.335 respectively in the simulation result on a permeability field for $M=2.5$. The τ_{D1}^* computed using the above formula is 0.330.

Given the difference in τ_{D1} from that of the reference model, τ_{D1}^R , for unit mobility ratio, the formula to compute the error of τ_{D1}^* from τ_{D1}^{*R} can be derived from Eq. 10,

$$\Delta\tau_{D1}^* = \tau_{D1}^* - \tau_{D1}^{*R} = \frac{1}{M-1} \left[\sqrt{M^2(1-\tau_{D1}^R) + \tau_{D1}^R} - \sqrt{M^2(1-\tau_{D1}) + \tau_{D1}} \right] \quad (11)$$

where $\Delta\tau_{D1}^*$ is the error of dimensionless TOF of streamtube l . Superscript R denotes the reference.

Note that $\Delta\tau_{D1} = \tau_{D1} - \tau_{D1}^R$ where $\Delta\tau_{D1}$ is the error of dimensionless TOF of streamtube l at unit mobility-ratio, and let $c = M^2(1-\tau_{D1}^R) + \tau_{D1}^R$, we obtain

$$\Delta\tau_{D1}^* = \frac{\sqrt{c}}{M-1} \left[1 - \sqrt{1 - \frac{(M-1)(M+1)}{c} \Delta\tau_{D1}} \right] = a(1 - \sqrt{1 - b\Delta\tau_{D1}}) \quad (12)$$

where $a = \frac{\sqrt{c}}{M-1}$, $b = \frac{(M-1)(M+1)}{c}$ with c defined above. The terms a , b , and c are all constant. Based on $0 < \tau_{D1}^* < 1$, we know that $|b\Delta\tau_{D1}| < 1$. Using a power series expansion, we obtain

$$\Delta\tau_{D1}^* = a \left[\frac{1}{2}(b\Delta\tau_{D1}) + \frac{1 \times 1}{2 \times 4}(b\Delta\tau_{D1})^2 + \frac{1 \times 1 \times 3}{2 \times 4 \times 6}(b\Delta\tau_{D1})^3 + \dots \right] \quad (13)$$

Usually, $|b\Delta\tau_{D1}|$ is small and the higher order terms can be omitted, thus

$$\Delta\tau_{D1}^* \approx \frac{ab}{2} \Delta\tau_{D1} = \frac{M+1}{2\sqrt{M^2(1-\tau_{D1}^R) + \tau_{D1}^R}} \Delta\tau_{D1} \quad (14)$$

Therefore the relationship between $\Delta\tau_{D1}^*$ and $\Delta\tau_{D1}$ is approximately linear. Their absolute values are mutually rank-preserving, i.e., the error rank in $\Delta\tau_{D1}^*$ is the same as that in $\Delta\tau_{D1}$. This correlation is confirmed by Fig. 2.

The above equations are derived for the first-breakthrough streamline. This relation also holds for other streamlines. That is, the difference of the i^{th} streamline breakthrough-time of two given reservoir models at mobility ratio M is a linear function of that when computed using $M=1$. The errors computed for different mobility ratios are rank preserving. As the fractional-flow at a producer is the same as the SL-TOF cdf at the real mobility ratio, the error of the fractional-flow at true mobility ratio and the error

of SL-TOF cdf computed using $M=1$ is also rank preserving. To compute the fractional-flow error, a CFS is required. However, the only computational effort required to compute the SL-TOF cdf errors is equivalent to that of one time-step of a full simulation. Obviously, the SL-TOF cdf error ranking is a tremendous savings of computation. This savings is due to conversion of the complexity in the temporal coordinate as in water cut history to complexity in the spatial coordinate as in SL-TOF spatial distribution. The conversion is possible because they are highly correlated.

4. STREAMLINE-BASED RANKING – ALGORITHM

As elaborated above, the error rank in SL-TOF cdf, flow-rate, pressure, and equivalent-CIPP are correlated with error in the fractional-flow, flow-rate, pressure, and CIPP as computed by CFS, respectively. The ranking procedure requires computation of the pressure field and streamlines only once for each model. Above, the difference in results was computed between a realization and some reference. Below differences (i.e. errors) in SL-TOF are computed between a realization and a history-matched model.

The ranking procedure is as follows:

- Start from an initial reservoir model and perform a history-matching process (Wang and Kovscek, 2000) to obtain an unconstrained history-matched reservoir model.
- For the history-matched model and each of the models to be ranked, compute pressure distribution for unit mobility ratio, compute streamlines geometries, and then compute SL-TOF cdf for each producer. We used Pollock's method to compute streamline geometries (Pollock, 1998).
- For each of the reservoir models, compute the difference between its SL-TOF cdf, or the other quantities of interest, and that of the history-matched model. This computation is performed for each injector-producer pair.
- Rank the reservoir models based on the error type of interest. For instance, if we desire to match the fractional-flow at all the producers, then SL-TOF cdf ranking should be used. Also, combinations of the three terms can be used for ranking. For example, flow-rate and fractional-flow can be combined in ranking to indicate fits in cumulative oil production. Some combinations make more physical sense than the others. The following four pairs are perfectly correlated as proven above: (1) SL-TOF cdf and fractional-flow in CFS; (2) flow-rate in ranking and the flow-rate in CFS; (3) pressure in ranking and the pressure in CFS; and (4) equivalent CIPP and CIPP.
- Select a suitable number of models within a specified maximum error and run CFS on them to evaluate the match in simulation results.

The selected models can be then used to predict future reservoir performance and to evaluate the uncertainty of this prediction.

5. EXAMPLE APPLICATIONS

In the examples below, we concentrate on heterogeneity in the permeability field. Five hundred reservoir models are generated by the geostatistical routine, SGSIM (Deutsch and Journel, 1998). They are conditioned to the permeability values at wells as listed in Table 1. 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. Note that any reservoir simulator might be used here. The choice of 3DSL is based on its rapid execution times and availability. Two cases, one with unit mobility ratio and the other with unfavorable mobility ratio ($M=2.5$), are tested and presented below.

5.1. Five-Spot, $M=1$

First, the reference production history is obtained by running a CFS on a phantom reference reservoir model (Fig. 4a) with the simulation parameters shown in Table 2. This model is not available in practice and here is used only to obtain production data. Then starting from another initial model generated by SGSIM, the fast streamline-based history matching method is used to generate a history-matched model. No geological constraints are applied while history matching. Figure 4 shows the phantom reference reservoir model and the history-matched model as expressed by permeability distributions. Figure 5 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.

The error 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, and therefore, only the ranking results in SL-TOF cdf are discussed in this case. After ranking, CFS was conducted on the five best-matched models. Figure 6 shows these fractional-flow curves and the reference fractional-flow curve. The match is satisfactory. Figure 7 shows the fractional-flow of five worst matched models. The difference between the best and worst is obvious.

5.2. Five-Spot, $M=2.5$

The production history is generated by the same method and the same phantom reference model as in the previous case, but with end-point mobility ratio equal to 2.5. Simulation parameters are listed in Table 2. A history-matched permeability field is obtained in the same way as for the previous case. This permeability field is very similar to that in Fig 4 (b). The same ranking procedure is performed. The ranking result in fractional-flow error is very similar to that of the first case. Thus, we concentrate here only on the match in equivalent CIPP to avoid repetition. Figure 8 shows the CIPP (in

PVI) versus time (in PVI) of the five best-matches as well as the five worst-matches to the reference data.

Figure 9 shows the permeability fields of the best and worst matched models in SL-TOF cdf and equivalent-CIPP. The model shown in Fig 9a and other models that are best-matched in TOF cdf have a common feature—there is a high permeability region connecting the injector in the center to Producer 1 at the lower-left corner of the model. This results in earlier breakthrough of the injected-phase at Producer 1 as shown in Fig. 6. This trend is also observed in the reference model in Fig 4a. On the contrary, the worst-matched models have a low-permeability barrier between this injector-producer pair as shown in Fig. 9b.

While the SL-TOF cdf indicates the correlated heterogeneity of the permeability distribution, the equivalent-CIPP represents swept-area, and the average permeability between each injector-producer pair. Figure 9c shows the model that is best-matched in equivalent-CIPP. The permeability is relatively high in the lower-left quarter of the model. It agrees with the reference and the history-matched model in Fig. 4. Other well-matched models have the same feature. However, in the worst-matched models (Fig. 9d, the permeability in this region is relatively low.

6. DISCUSSION

The method just described has the potential to reduce greatly the uncertainty in the prediction of future reservoir performance. Consider again a confined five-spot pattern after 0.585 PV of water has been injected. The simulation parameters are the same as the $M=2.5$ case, except that a new reference permeability field is used to generate synthetic production data. At 0.585 PVI, the average water-cut of the four producers is about 0.3. Again, 500 reservoir models are ranked based on the match to SL-TOF cdf following the procedure above and using water-cut data only up to 0.585 PVI. Figure 10 shows the best matches to the partial production history. Evidently, the match to the history is very accurate and the future prediction is satisfactory. Figure 11 shows the reference permeability field and the five models selected as best matching the production history up to 0.585 PVI. The common feature among the models is the lack of a high permeability channel or streak connecting the injector in the center to any of the producers at the four corners. This results in a fairly uniform breakthrough time for each producers of about 0.5 PVI, as shown in Fig. 10.

We observed, not surprisingly, that the accuracy of predicting reservoir future performance is a monotonically increasing function of the amount of production history used to select the models. To ensure satisfactory prediction, production history up to the point of an average water-cut of 0.3 was needed to select models with accuracy. This translates roughly to 0.6 PV, or more, of injection.

The remainder of this discussion is devoted to issues related to error distribution and computational efficiency. It is observed from the ranking results that the error of each term follows approximately a normal distribution. Therefore, the criteria for selecting good models or rejecting bad models can be expressed by a constant k . That is, models that have errors k times standard deviation lower than the average error are accepted, while the rest are rejected. Given that the distribution is normal, the percentage of models that prove acceptable can be determined solely by k . If the number of desired models within a tolerance is known, then the number of models to rank is easily determined. For instance, we can choose those models whose error is two standard deviations lower than the average error. The probability for this selection is 2.23 percent given the normal distribution and the skewness correction, if needed. Take the fractional-flow and the cases above as an example. The mean of the error in SL-TOF cdf is $\mu = 0.0736$ and the standard deviation is $\sigma = 0.0149$. Set the criteria for accepting a model as $\mu - 2\sigma = 0.0438$. Eleven out of the 500 (2.2%) models sampled meet the criteria. Table 3 gives the number of models that meet the selection criteria when a different number (50, 100, 150, 200, 250, 300, and 500) of models are ranked. Therefore, once the number of models to be selected and the criteria are determined, the number of models needed for sorting is also determined. Obviously, once a suitable number of models are generated and ranked, increasing the number does not contribute significantly to error reduction. For this study, 300~500 is a suitable number.

The computational work in terms of CPU time for the two cases is listed in Table 4. The jobs were run on a 600MHz DEC machine. The difference between the two cases lays in the history matching part. The history matching procedure requires, in each iteration, a flow simulation to check the error and the streamline inverse process to modify the permeability (Wang and Kovscek, 2000). Six to eight iterations are usually needed to obtain a satisfactory match to the production history. Each iteration takes about 8 seconds for unit mobility ratio case, and 39 seconds for non-unit mobility ratio for a 50 by 50 grid. Sorting one model involves solving the pressure field, computing a sufficient number of streamlines and their TOF distributions. However, this procedure is exceptionally fast. It takes about one second for each model for a 50 by 50 case. Generating a model using SGSIM takes negligible CPU time. As shown in Table 4, sorting 500 models (50 by 50 grid-blocks) takes about ten minutes all together. On average, each model takes about 1.1 seconds for unit mobility ratio case and 1.4 seconds for non-unit mobility ratio case. However, if CFS is run on each model with the same number of grid-blocks (50 by 50) to compute the error, it takes about 6 seconds for unit mobility ratio case and up to 35 seconds for the non-unit mobility ratio case, to ensure accurate results. Therefore, the proposed ranking method is, on average, a magnitude faster than if the CFS is used for ranking. The ranking method would appear even more efficient compared to CFS if a finite-difference based simulator was used for forward simulation. While the CPU time consumed by sorting increases with the number of models, the cost for history-matching is fixed and independent of the number of models to be sorted.

It is worth-noting that the computational work is an approximately linear function of the number of grid-blocks, n . More specifically, the computation time of the ranking procedure and streamline inverse part of the history-matching process is strictly linear with respect to n , while the flow simulation part of history-matching is approximately proportional to $n \lg n$. For instance, the CPU time for ranking five hundred models with 10,000 grid-blocks takes 40 minutes for unit mobility ratio case and 55 minutes for $M=2.5$ case. If a full flow simulation is used to compute the errors of a model and to rank the model, the computational effort is at least proportional to $n \lg n$. Disregarding the computation for history-matching, the ranking effort is equivalent to one or two time-steps of the full flow simulation.

Currently, the algorithm does include a number of assumptions or limitations: no gravity effects, two-phase flow, incompressible or slightly compressible fluid or rock, uniform initial condition, and some accurate production history showing injected phase breakthrough available. Further study is underway to relax these assumptions. For instance, it appears to be well suited for three-dimensional cases with slight gravity.

7. CONCLUSIONS

This study revealed the linear correlation between each of the following pairs of streamline computed and reservoir flow properties: (1) SL-TOF cdf and producer water cut, (2) unit mobility flow-rate or pressure at one time and that in comprehensive flow simulation, and (3) equivalent-CIPP and CIPP. These correlations are proven approximately via analytical expressions and confirmed numerically. Based on this observation, a streamline based ranking algorithm is proposed. Functionally, it is a conversion of matching in the temporal coordinate to matching in the spatial coordinate. For instance, matching of the producer water cut versus time is converted to matching the desired SL-TOF distribution. This conversion substantially speeds up the matching process. For unit mobility ratio, such as in a tracer flow study, it is shown that the fractional-flow curve is the same as the SL-TOF cdf. In this case, the history-matching process is not necessary. That is, the reference fractional-flow curve can be directly used as reference SL-TOF cdf. In general, the computational effort is equivalent to only two time-steps of a comprehensive flow simulation of the same model. More importantly, the computational work for calculating streamlines scales linearly with the number of grid-blocks.

It is observed that the distribution of the difference in results between a realization and the reference reservoir model is approximately a normal distribution. Therefore, the number of models that must be sampled to obtain a given number of acceptable models (i.e., within a specified range of the reference) can be estimated accurately. For instance, it is known that about two percent of the models to be ranked have errors two standard deviations lower than the average error.

8. NOMENCLATURE

k	permeability, L^2
k_{rw}, k_{ro}	relative permeability of water and oil
M	end point mobility ratio
n	number of streamlines
q	flow-rate, L^3/t
s_o, s_w	oil and water saturation
v, V	pore volume of streamtube(s), L^3
x_{fD}	dimensionless distance the displacing front has traveled along a streamline
τ_D	dimensionless time of flight

Subscripts:

D	dimensionless
f	displacing front
$1, 2$	streamline index

Superscripts:

R	reference
•	non-unit mobility ratio case

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Table 1. Constant permeability values at well locations for sgsim.

Location (m)		Permeability (md)	Description
x	y		
5	5	620.08	Lower-left corner, Producer 1
495	5	750.62	Lower-right corner, Producer 2
245	245	302.39	Center, Injector
5	495	574.27	Upper-left corner, Producer 3
495	495	656.00	Upper-right corner, Producer 4

Table 2. Case description/parameters.

Case	Grid	bloc k-size			ϕ	q m3/day	S_{wc}	S_{or}	k_{rw}^0	k_{ro}^0	viscosity (cp)		k_r eqns	M
		dx	dy	dz							water	oil		
Compute Correlation	50x50x1	10.0	10.0	2.0	0.2	300.0	0.0	0.0	1.0	1.0	1.0	1.0	Set 1	1.0
							0.2	0.2	0.2	0.8	1.0	10.0	Set 2	2.5
							0.2	0.2	0.2	0.8	1.0	40.0	Set 2	10.0
							0.2	0.2	0.2	0.8	1.0	100.0	Set 2	25.0
Case 1	50x50x1	10.0	10.0	2.0	0.2	300.0	0.2	0.2	0.2	0.8	1.0	40.0	Set 2	10.0
	100x100x1	5.0	5.0	2.0	0.2	300.0	0.2	0.2	0.2	0.8	1.0	40.0	Set 2	10.0
	200x200x1	2.5	2.5	2.0	0.2	300.0	0.2	0.2	0.2	0.8	1.0	40.0	Set 2	10.0
Case 2	50x50x1	10.0	10.0	2.0	0.2	300.0	0.2	0.2	0.2	0.8	1.0	10.0	Set 2	2.5

$$\text{Set 1: } k_{rw} = k_{rw}^0 (S_w - S_{wc}), \quad k_{ro} = k_{ro}^0 (S_o - S_{ro})$$

$$\text{Set 2: } k_{rw} = k_{rw}^0 \left(\frac{S_w - S_{wc}}{1 - S_{or} - S_{wc}} \right)^2, \quad k_{ro} = k_{ro}^0 \left(\frac{1 - S_{or} - S_w}{1 - S_{or} - S_{wc}} \right)^2$$

Table 3. Errors of selected models.

# models ranked	50	100	150	200	250	300	500	600
Mismatch of the selected models	0.0430	0.0419	0.0349	0.0349	0.0342	0.0342	0.0342	0.0342
		0.0430	0.0419	0.0419	0.0345	0.0344	0.0344	0.0344
			0.0430	0.0430	0.0349	0.0345	0.0345	0.0345
					0.0419	0.0349	0.0349	0.0349
					0.0430	0.0366	0.0366	0.0366
						0.0419	0.0405	0.0401 *
						0.0430	0.0418	0.0405
							0.0419	0.0418
							0.0420	0.0418 **
							0.0430	0.0419
							0.0436	0.0420
								0.0430
								0.0433 **
								0.0436
# models selected	1	2	3	3	5	7	11	14

*—100x100 grid blocks; **—200x200 gridblock

Table 4. Computational work/CPU times.

Case	CPU (sec)			Total CPU	
	History Matching	Sorting 1 Model	Sorting Model	(sec)	(min)
5 spot. 50x50, M=1	64	0.95	475		
5 spot, 50x50, M=2.5	234	0.95	709	11.8

Fig. 1. Error-error plots, unit mobility ratio case, five-spot pattern.

(a) fractional-flow error vs TOF error

(b) Q simulation-error vs Q ranking-error

(c) CIP error vs Equivalent-CIP error

(d) CFS error rank vs SL error rank

Fig. 2. Error-error plot for unfavorable mobility ratio $M=2.5$, five-spot pattern.

Fig. 3. Streamline TOF cdf versus fractional flow at producer, $M=1$.

Fig. 4. Permeability fields, $M=1$ synthetic example
(a) reference model; and (b) unconstrained history-matched model.

Fig. 5. History-matched fractional-flow, 5 spot, $M=1$.

Fig. 6. Fractional-flow of five best matched models, $M=1$.

Fig. 7. Fractional-flow of five worst matched models, $M=1$.

Fig. 8. Cumulative production of initial-phase, 5 best and 5 worse matched models, $M=2.5$.

Fig. 9. Best and worst matched permeability fields.
 (b) best matched in water-cut, (b) worst matched in water-cut,
 (c) best matched in CIP, (d) worst matched in CIP.

Fig. 10. Production history of five best-matched models, $M=2.5$, five-spot pattern. A history match is obtained for time less than 0.585 PVI. Subsequent data is prediction.

Fig. 11. Permeability fields for partial water-cut example.
 (a) reference, (b) to (f) best matched fields.

Pore Microstructure and Fluid Distribution in a Diatomaceous Reservoir

C.M. Ross and A.R. Kavscek

ABSTRACT

This study was undertaken to improve our understanding of fluid distribution and flow behavior by quantifying pore type, pore body size, shape attributes, and throat sizes of pore networks in diatomaceous reservoir rock. This work is a first step toward providing a means of integrating different measurement types and establishing an interpretive tool for understanding laboratory results and field behavior. This project lays the groundwork for developing a predictive tool that can be utilized to generate input for reservoir simulator studies.

The pore microstructure of 11 diatomite samples from Lost Hills Field (Kern Co., CA) and one quarry sample was quantified using image analysis of photomicrographs collected with a Scanning Electron Microscope (SEM) in backscattered electron (BSE) mode. Six distinct pore types were identified ranging from small, irregularly shaped pores to large moldic and intraskeletal pores as well as large interconnected, intergranular pores. The throat size average and size range for each pore type was established by combining image analysis information with high-pressure mercury injection measurements. Once this relationship is determined, the pore body size and throat size serve as the basis for a predictive model allowing capillary pressure curves and fluid saturations to be calculated from pore type data.

In this study, the relationship between pore types, fluid flow, and fluid distribution indicate a dual porosity system. Permeability is primarily controlled by three pore types, which represent 1 to 28% of the total core porosity and 0.67 to 9.75% of the total volume. Fluid saturation models were developed to provide an accurate means of calculating oil and water saturations as well as their distribution within the pore network for both the reservoir and core samples. From the model, we found that the most permeable pore types have oil saturations that are 5 to 35% lower than reservoir saturations. This indicates that the oil is moveable and can be swept from permeable pore types. Alternatively, there was no net change in saturations for the remaining pore types between core- and log-derived saturations. For these pore types, spontaneous imbibition is the most likely production mechanism. The smallest pore type is predominately water filled with oil saturation values of about 32% in both the reservoir and core samples.

The proportion of each pore type can be predicted from wireline log data and used as input for the predictive capillary pressure model and fluid saturation models. This allows the models to be applied to the rest of the field providing data for field development decisions and simulator input.

1. INTRODUCTION

Virtually all recovery processes for diatomite and other low permeability reservoirs rely on either spontaneous or forced imbibition. Wells are usually hydraulically fractured to overcome low matrix permeabilities, thereby improving injectivity as well as productivity. These fractures increase the contact area between boreholes and the reservoir. Injection pressure for diatomite must be limited, because the fields are relatively shallow, the permeabilities are very low, and diatomites often have low cohesive strength. Thus for any process involving water injection, the role of matrix to fracture transfer via imbibition is important in determining oil recovery.

The rate and extent of water flow during spontaneous and forced imbibition depends primarily on the capillary pressure versus water saturation curve, the initial water saturation, relative permeability curves, and the viscosity of the nonwetting and wetting fluid phases. In turn, the above rock properties depend on factors such as pore structure, pore connectivity, pore throat to body size aspect ratio, wettability, and interfacial tension. Pore type, pore roughness, and connectivity are especially important to imbibition, because water simultaneously moves in the corners or crevices of pores, advances in a piston-like fashion, and fills pore bodies cooperatively (Lenormand and Zarcone, 1984; Lenormand, *et al.*, 1988).

Prior work on diatomites has focused on establishing the macroscopic effects of these more microscopic factors. The main tools have been experiments to monitor the extent of imbibition in tight rocks samples with X-ray CT (Akin *et al.*, 2000; Zhou *et al.*, 2002). In strongly water-wet samples of diatomite, capillary forces are significant and partially offset low formation permeability. Similarly, experimental imbibition results in a combination with a scaling analysis teach that the Leverett J-function for diatomite is greater than that for sandstones (Schembre *et al.*, 1998). Limited qualitative, microscopic characterization of diatomite using mercury porosimetry and SEM images indicates that pore structure and pore roughness are varied (Akin *et al.*, 2000). Many pathways for water are available and these might either aid or hinder the imbibition process.

Thus, a first order solution to improving oil recovery from diatomite is to develop a quantitative understanding of the relationship between pore structure, permeability, porosity, wettability, and macroscopic oil transport. An equally important understanding remains to be developed of how pore structure and other properties evolve with stress and silica diagenesis. Any of these tasks are monumental and beyond the scope of a single study. Nevertheless, we have begun characterizing quantitatively the pore structure of diatomites and their variability from two-dimensional (2D) images collected from epoxy-impregnated polished samples. The resulting pore types are used to model high-pressure mercury injection data and fluid saturations. These models further our understanding of fluid flow behavior at the pore level in diatomaceous reservoirs and are scalable to the field level in that these models can be applied via wireline log analyses.

2. BACKGROUND, SAMPLING, AND AVAILABLE DATA

Twelve opal-A diatomite samples were analyzed in this study; eleven samples are reservoir diatomites and one sample is from a coastal quarry. The quarry sample is from Grefco quarry (Santa Barbara Co., CA) and consists of relatively pure biogenic material deposited during the late Miocene (Mohnian) in the Santa Maria Basin (Graham and Williams, 1985). The quarry sample serves as a relatively pure diatomite end member and helps relate current and previous laboratory studies, conducted using readily available quarry samples, to reservoir diatomites (Akin *et al.*, 2000; Schembre *et al.*, 1998).

The remaining 11 samples are from well OB-7 in Lost Hills Field. These samples are from the uppermost unit of the Monterey Formation, the Belridge Diatomite Member, consisting of biogenic silica (opal-A), clay, and detrital silt as well as sand. The late Miocene (Mohnian) Belridge Diatomite is a thick section of diatomites and diatomaceous shales that occur in the central portion of the San Joaquin Basin and may be included as a facies within the Reef Ridge Member of the Monterey Formation (Graham and Williams, 1985). Although Lost Hills Field was originally discovered in 1910 and production began in 1913, aggressive development of the field did not occur until the mid-1980's following advancements in hydraulic fracturing (Wallace and Pugh, 1993). Waterflood development began in 1991 to further improve recovery and slow subsidence rates (Wallace and Pugh, 1993). The original oil in place (OOIP) is estimated at 2.6 billion barrels (Perri *et al.*, 2000). To date, only 5% of the OOIP or approximately 135 million barrels of oil have been produced (Perri *et al.*, 2000).

Due to the variability in diatomite composition within Lost Hills Field, diatomites are classified as sandy diatomites, clayey diatomites, and clean diatomites based upon their composition and properties (Fossum and Fredrich, 2000). Four sandy diatomites, four clayey diatomites, and three clean diatomites were provided for study (Table 1). The quarry sample is classified as "quarry diatomite" and is considered an extreme member of the clean diatomite class from Lost Hills Field, as shown by the continuum between reservoir and quarry data in the porosity and permeability plot (Fig. 1).

Conventional core data, high-pressure (60,000 psi) mercury injection measurements, wireline log data, core plugs, additional core material, and SEM mounts were provided for ten reservoir samples. Much of this data and sample material was also available for the quarry sample, except for wireline log data and fluid saturation data. For sample 1450.00, only core data and an SEM mount were available.

3. PORE MICROSTRUCTURE

Characterization of pore microstructure and its variability improves our understanding of oil, water, and gas transport within diatomite reservoirs. Image analysis allows us to identify pore types and quantify their size range. By modeling capillary pressure behavior and fluid saturation, we are able to further our understanding of

reservoir dynamics on the pore level with the potential to apply this knowledge to the entire field via wireline log data.

3.1. Image Analysis

For each sample, a small amount of core material was cleaned and impregnated with epoxy, first under vacuum and then under pressure (up to 1500 psi). We estimate that pores as small as 0.04 μm or less should be filled at this pressure. After the epoxy hardened, the samples were finely polished to provide an optically flat surface for subsequent BSE-SEM imaging. Photomicrographs were collected using a JEOL JSM-500LV SEM with a BSE detector and an EDAX X-ray spectroscopy system. Uncalibrated BSE images of polished surfaces are relative electron density maps where epoxy-filled pores have the lowest average electron density and are dark in the grayscale images. Silica, carbonate, and pyrite have increasingly higher electron densities and are correspondingly brighter within an individual image (Fig. 2).

70 to 100 images from each sample were collected at a magnification of 500X. At 500X, large pores in the sandy diatomite samples could be imaged while theoretically detecting pores as small as 0.1 μm . Each image covers a 237.6 by 177.6 μm area and is represented by a matrix of 2048 by 1600 pixels. In most samples, the rare occurrence of high porosity views (often associated with large pores; e.g., Fig. 2) increased the number of images needed to generate stable SEM porosity averages. (For comparison, typically 15 to 30 images are collected at 40 to 200X for sandstone and carbonate reservoirs Ehrlich *et al.*, 1991) In the limited area visible at 500X, it is difficult to distinguish between naturally occurring fractures and those induced during coring and sample preparation; therefore, fractures were not imaged.

Each grayscale image was segmented into a binary image (Fig. 2) consisting of black pore pixels and white non-pore pixels, based upon visual inspection of the image as well the grayscale histogram. Incomplete epoxy impregnation of larger pores and surface roughness can interfere with the thresholding process causing pixels to be misclassified, which is corrected by “painting” the appropriate pixels either white or black. For the study samples, the amount of porosity resolved at 500X ranges from 5.77 to 18.12% (Table 1). In this study, SEM porosity represents only 9.3 to 28.9% of the measured core porosity. The remaining porosity is either too small to be resolved at the study magnification or matrix pores were not filled with epoxy. For each portion of this study, we found that the unresolved porosity does contribute to permeability, capillary pressure modeling, and fluid saturation modeling. Therefore, permeability, capillary pressure, and fluid saturation analyses were performed with the detected pore types alone.

Binary pore images were processed using erosion-dilation (E-D) procedures that measure the size, shape, and connectivity of pores as viewed in two dimensions (2D) (Ehrlich *et al.*, 1991). In particular, E-D subdivides the porosity into smooth and roughness components and records the size distribution and relative abundance of each component. The smooth component is equivalent to either a circular or ellipsoid pore body, whereas the roughness components are portions of the pore that deviate outside of the smooth

component (Ehrlich *et al.*, 1991). In images with interconnected 2D pores, the largest pore body will be attributed to smooth porosity and the remaining porosity (as well as smaller pore bodies) will be attributed to roughness components based upon their size¹⁰. A pattern recognition algorithm then determines smooth and roughness components that occur together in constant proportion (Ehrlich *et al.*, 1991). Attributes that occur in constant proportion are considered different 2D slices of a three-dimensional (3D) pore type (Ehrlich *et al.*, 1991; Gratton and Fraser, 1935). The algorithm also determines the number of 3D pore types and their relative abundance within each study sample.

3.2. Pore Types

The pore classification procedure identified six distinct pore types in the study samples (Fig. 3), determined the smooth and roughness size and shape characteristics of each pore type, and the proportion of SEM porosity contributed by each pore type per sample (Table 2). The pore body width range is the size range of 2D cross sections through the pore body (smooth porosity; Table 3) (Ehrlich *et al.*, 1991a; Ehrlich *et al.*, 1991b). The average minimum pore body diameter, as determined from E-D smooth and roughness measures, serves as a 3D pore size measure and is used to rank the pore types by size (Table 3). Pore Type 1 (PT1) is the smallest detected pore type whereas the largest pore type is Pore Type 6 (PT6).

Pore type 6 consists of relatively large, well-connected intergranular pores that occur in sandy diatomite samples, 1450.00, 1516.80, and 1526.85 (Tables 1-3). PT6 occurs in interstitial spaces between very fine-grained sand to coarse-grained silt grains in regions that lack pore-occluding matrix material (Fig. 3). Due to the irregularity of the pore body shapes and the high degree of connectivity as observed in 2D, PT6 primarily consists of moderate- to large-scale roughness features (82%; $\geq 0.457\mu\text{m}$). The larger scale roughness features are associated with somewhat smaller, interconnected pore bodies rather shape irregularities within a single pore.

In comparison, the other large pore type, PT5, consists mainly of smooth porosity (71%; $0.456\text{--}120\mu\text{m}$) with 3% moderate roughness components ranging from 0.229 to $0.342\mu\text{m}$ and 26% large scale roughness components ($\geq 3.649\mu\text{m}$), that are deviations from either a spherical or ellipsoid pore shape. PT5 is primarily composed of moldic pores (Fig. 3) as well as relatively large intraskeletal pores (diatom and foraminifer; Fig. 2) and occasionally equant intragranular pores. In Fig. 3, the example image for PT5 is the largest pore observed in this study and has a minimum pore width of about $120\mu\text{m}$. Typically, PT5 consists of smaller pores ranging in diameter from 10 to $25\mu\text{m}$. PT5 is most abundant in the remaining sandy diatomite sample, 1484.95 (Tables 1-2). Although classified as a sandy diatomite via wireline log analysis, sample 1484.95 does not contain much sandy and silty detrital material and occurs as an outlier in the porosity-permeability plot (Fig. 1; Table 1). The bulk density of this sample was most likely increased by gypsum (observed bridging fractures and replacing matrix material), thereby causing this sample to be misclassified via log analysis. Alternatively, the misclassification could be attributed to the thin interbedded nature of diatomites.

The remaining pore types are comparatively small with an average minimum pore body diameter ranging from 0.82 to 1.74 μm (Table 3). Pore type 4 consists of small intergranular pores that occur between irregularly shaped silt grains (Fig. 3) and are primarily found in sandy diatomite samples, except for one clayey diatomite sample, 1707.00 (Table 1-2). These irregularly shaped pores have a small proportion of smooth porosity (31%; 1.482-4.332 μm) with a broad size range of roughness features (0.115-1.254 μm) that comprise 69% of PT4.

The remaining three pore types are, for the most part, abundant in clean and clayey diatomite samples. Pore type 3 is composed of small- to moderate-sized intraskeletal pores, primarily occurring in test fragments as well as some whole tests (Fig. 3). The shape characteristics for PT3 are bimodal with smooth porosity (24%) sizes of 0.114 to 0.456 μm and 1.142 to > 4.334 μm (Table 3). The smaller sized pores occur in broken test fragments, tests that have their surface exposed, and cross sections of the test walls (Fig. 3). The larger pores occur within the tests. These two pore sizes occur together in constant proportion and are, therefore, classified as a single pore type. Samples 1553.65, 1880.00, and Quarry1 contain the highest percentage of PT3 (42-44% SEM porosity; Table 2). The roughness component of PT3 ranges in size from 0.114-3.648 μm .

Pore type 2 consists of small equant pores (1.35 μm ; Table 3) that occur in regions that are relatively devoid of matrix porosity (Fig 3). Of the pore types in this study, PT2 is unique due to their relative isolation from neighboring pores. These low porosity areas are associated with somewhat linear fabric disruptions in the matrix and may be compaction features. PT2 is most abundant in the clean diatomites with an average of 46% of the SEM porosity (Tables 1-2). In the other diatomite types, PT2 comprises an average 32% of the SEM porosity for clayey diatomites, 24% of the quarry sample, and an average of 14% for sandy diatomites (Tables 1-2).

The last pore type, PT1, is the smallest pore type that was detected at 500X magnification (0.82 μm ; Table 3) and consists of 44% smooth porosity with small roughness elements (0.114-0.912 μm). In sandstone and carbonate studies, the smallest pore type typically consists of pores that are 1 to 2 pixels wide, do not survive past the first E-D cycle, and are unable to distinguish shape characteristics (Ehrlich *et al.*; 1991; Ross *et al.*, 1995). In this study, PT1 has a multiple E-D cycle size range (0.114-2.508 μm ; Table 3) due to the higher magnification and image resolution (i.e., pixel density). PT1 consists of very small intraskeletal and intramatrix pores as well as very small intraparticle pores. PT1 occurs in each diatomite type (Tables 1-2).

3.3. Pore Types, Porosity, and Permeability

The need to characterize pore networks in diatomaceous reservoirs is due in part to the complex relationship between porosity and permeability ($r = -0.14$; Fig 1) as well as capillary pressure and aqueous-phase saturation (Akin *et al.*, 2000). For any given porosity value, permeabilities have a range of two to three decades. Comparison of SEM porosity with permeability does not provide an improvement on this relationship

($r = -0.16$; Table 1). This indicates that the type of porosity (i.e., pore type distribution) is more important in determining permeability than either the total amount of porosity or the amount of SEM porosity.

The six pore types were grouped according to their relationship to permeability. Pore types that do not correlate positively to permeability and, therefore, do not contribute significantly to permeability are PT1, PT2, and PT3. Each of these pore types have either low or negative correlations with permeability (PT1, $r = 0.17$; PT2, $r = -0.78$; PT3, $r = -0.52$). Although PT2 has a particularly strong negative relationship with permeability (Fig. 4), it does not indicate that pores classified as PT2 decrease permeability. Rather, it is the association of PT2 with low porosity regions (Fig. 3), which serve as permeability barriers, that causes this negative relationship with permeability. In fact, the presence of these relatively non-porous permeability barriers as indicated by PT2 provides good predictor of permeability [$\log(K) = 1.626 - 3.890(PT2)$; $R^2 = 0.74$]. PT1 has a complex relationship with permeability depending upon the diatomite type. In clean and clayey diatomites, PT1 does not contribute to permeability; however, PT1 has a strong positive relationship with permeability in sandy and quarry diatomite samples (Fig. 4).

The remaining pore types have positive relationships with permeability (PT4, $r = 0.35$; PT5, $r = 0.51$; PT6, $r = 0.47$). Individually, these pore types do not have a strong predictive relationship with permeability. By summing the relative abundance of these pore types, the correlation between permeability and pore type information increases ($r = 0.66$; Fig. 5). If PT1's contribution to permeability is added for sandy and quarry diatomite samples, this relationship improves significantly ($r = 0.84$; Fig. 5) and provides a good predictive relationship [$\log(K) = 0.244 + 1.893(\text{permeable PT})$; $R^2 = 0.77$]. In these samples, porosity volumes of 0.67 to 9.75%, that represent only 1.2 to 28% of the total core porosity, control permeability.

4. CAPILLARY PRESSURE MODEL

The size range of pore throats (i.e., constrictions connecting pore bodies) associated with each pore type is determined by modeling mercury injection measurements using the pore type distributions for each sample (McCreesh *et al.*, 1991). Capillary pressure data reveals the volume of porosity accessed through throats of a given size. By using the pore type distribution to predict saturation changes within the capillary pressure curves, the pore body and throat size relationship can be established. In addition, the resulting series of equations can be used to construct synthetic or predicted capillary pressure curves.

Six inflection points were selected based upon the location of significant slope changes in the capillary pressure curves provided for 11 study samples. For each sample, the change in saturation between inflection points was regressed against the proportion of pore types ($R^2 = 0.73-0.95$). The resulting series of equations serve as the capillary pressure model (Table 4). In the model, the coefficients summed for each pore type (column) should approach unity (1) if all of the porosity attributed to the pore type is

being filled. On average, 96% of the total porosity is filled according to the model (Table 4). Actual values ranged from 77 to 114% indicating that additional samples may be needed to characterize some pore types fully.

The range of throat sizes associated with each pore type is determined using the model (Tables 4-5). For example, the throat size range for PT1 is 0.0018 to 0.236 μ m. The average throat size is a weighted average based upon each pore type's relative saturation and throat size range for each pressure interval. In sandstone and carbonate studies, average pore body widths are typically 2 to 15 times larger than their average throat diameter and may be as much as 600 times larger (Ross *et al.*, 1995; McCreesh *et al.*, 1991; James, 1995; Bowers *et al.*, 1994). In diatomites, the size ratio between average pore body and throat diameter range is often much smaller (e.g., 1.6 for PT3, 1.4 for PT4, and 0.8 for PT5; Table 5).

By definition, pore throats cannot be larger than pore bodies as shown for PT5. In light of this, the applicability of throat and/or pore size averages developed on conventional sandstone and carbonate reservoirs should be reassessed. In perfectly aligned sphere packs, multiple throat sizes and multiple pore body sizes per unit pore (pore type) occur depending upon the packing pattern (Ciftcioglu *et al.*, 1988). Further work is needed to establish the optimal averaging method to characterize pore body and throat sizes in diatomites. If the data warrants, multiple pore body and throat sizes should be attributed to each pore type for both interpretation and network modeling applications.

Synthetic capillary pressure curves were constructed by converting the saturations predicted by the equations into cumulative form (McCreesh *et al.*, 1991). The resulting values are plotted with the measured capillary pressure curve to determine the accuracy of the model (Fig. 6). All of the synthetic capillary pressure curves show good agreement with the measured curves ($r = 0.98-1.0$). Sample 1642.25 shows the greatest discrepancy between the measured and predicted capillary pressure curves (Fig. 6). This sample contained many small fractures that were not imaged as discussed previously. If the fractures were induced by either coring or sample preparation, the predicted capillary pressure curve better indicates reservoir behavior. If the fractures are naturally occurring, the predicted curve indicates the capillary pressure behavior of the matrix.

For sample 1450.00, capillary pressure measurements were not available. The capillary pressure model allows a synthetic curve to be constructed using pore type information alone (Fig. 6). Once calibrated, the model allows the limited number of capillary pressure measurements to be extended to any sample with enough material for image analysis sample preparation. Capillary pressure modeling provides an alternative when sample materials fail during measurement and when measurements are particularly time consuming and costly (Ross *et al.*, 1995). In addition, this technique is particularly useful when pore type proportions are predicted using wireline log response, which allows the model to be applied to the entire reservoir interval throughout the field without performing additional measurements and without the expense of collecting cores (Ross *et al.*, 1995; Callender *et al.*, 1998). In this study, additional samples and measurements are needed to develop a field-wide model for Lost Hills. It may also be possible to develop a

diatomite model for California reservoirs; this would require substantially more samples and data from dozens of fields.

Oil saturations determined from wireline log data should be comparatively unaffected by drilling operations, but log-derived saturations have a much lower resolution compared to plug data. Despite the decreased resolution and reduced impact of drilling, the same relationship between pore types and oil saturation was found using log-derived saturations (Fig. 8). This relationship indicates that the oil saturation decreases as the proportion of permeable pore types increases. The study well, OB-7, is only 20 ft from a water injection well, 10W-9, that has been in operation since 1994 (Wilt *et al.*, 1995); the permeable pore types were likely swept by injection water.

Crosswell electromagnetic survey results indicate that the proximity to the injector well did not affect the oil saturations above the injection interval (~1510 ft) (Wilt *et al.*, 1995) where two of the more permeable samples originate (1450.00 and 1484.95). By comparing data from 10W-9 (drilled in 1994) and OB-7 (drilled in 1999), a 5% reduction in oil saturation was observed between 1540 and 1750 ft, whereas a 4 to 6% increase in oil saturation was observed in diatomite intervals below 1790 ft (Wilt *et al.*, 1995). Wilt and others (Wilt *et al.*, 1995) were especially interested in intervals containing high percentages of opal-A (i.e., not sandy diatomites) because of their higher oil saturations as indicated by their higher resistivities. Their observations correspond to the distribution of fluids as determined in this study.

In order to better understand the distribution of fluids within individual pore types, saturation models were developed for both core- and log-derived fluid saturations. Each model was constructed using 11 equations with known saturations for each sample and six unknowns as the saturation coefficients for each pore type. The resulting coefficients are presented in Table 6 for fluid saturations in core samples (S_{wc} and S_{oc}) and in the reservoir (S_{wl} and S_{ol}). Using pore type proportion data from either image data or predicted from wireline log data, fluid saturations can be calculated. For the study samples, core fluid saturations are more accurately predicted ($r = 0.92$ - 0.94) than log-derived fluid saturations ($r = 0.85$ - 0.87). Figures 9-10 provide an alternative way of displaying the resulting saturation coefficients.

The saturation coefficients may be compared between models. For example, the oil saturations of PT4, PT5, and PT6 are higher in the reservoir (34-73%) than observed in core samples (13-59%; Figs. 9-10). The lower oil saturations of core- versus log-derived values may be due in part to flushing of the core by drilling, expulsion (drainage) of the oil during handling, shrinkage of the oil due to out gassing, and expansion of the core once confining stress was removed (Bilodeau, 1995). There was not a net change in saturation for the remaining pore types, PT1, PT2, and PT3.

For demonstration purposes, the core saturation model will be treated as if it were a waterflood model based on laboratory measurements. In this case, we would conclude that 5% of the oil was flushed from PT6, 34% from PT5, and 14% from PT4 during the tests. The actual volume of oil produced during the waterflood could be calculated based upon the SEM porosity and pore type distribution. In this manner, researchers could better compare laboratory results with respect to different production mechanisms (e.g.,

waterflood, steamflood, CO₂ flood, etc.). This knowledge may be applied to the rest of the reservoir via simulations by predicting pore types from wireline logs and applying the physical models that were developed based upon core data. Intervals could be targeted with the optimal production mechanism based upon their pore network configuration.

5. CONCLUSIONS

1. Image analysis techniques originally developed for sandstone and carbonate reservoir characterization are applicable to diatomaceous reservoir description. Although their mean pore body size is small, pore types in diatomites carry significant information about the pore network and their influence on physical properties as well as fluid flow and distribution.
2. Permeability is more accurately predicted using pore type criteria than core porosity values. Permeability prediction using core porosity has a range of two to three decades whereas the pore type-based relationships with permeability has only a one-decade range.
3. The amount and distribution of fluids within the pore network can be determined using pore type characterization. In this case, we found that the more permeable pore types contain oil saturations of 34 to 73% in the reservoir and 13 to 59% in core plugs. These comparisons can be used in conjunction with laboratory measurements to further our understanding of multiphase fluid behavior.
4. Pore type 2 exhibits a strong relationship with many reservoir quality measures such as permeability ($r = -0.78$) and oil saturation ($r = 0.83$).
5. Pore typing studies provide input parameters for equations modeling physical properties such as permeability, capillary pressure, imbibition potential, formation factor, and relative permeability. Some of these parameters include throat size and distribution, pore body size and distribution, number of pores per unit area, and surface area. Predicting pore types from wireline log data extends the applicability of these parameters beyond the original sample set.
6. Some aspects of diatomite topology and morphology differ from those of conventional sandstone and carbonate reservoirs. Due to the small pore dimensions and extreme heterogeneity within diatomite samples, three to five times more images are needed to produce stable SEM porosity values, compared to conventional reservoir types.
7. Additional samples are needed to better characterize the pore network variability within the Lost Hills diatomite reservoir and to serve as a training set in order to predict pore type distribution using wireline log data.

6. APPLICATIONS AND FUTURE WORK

Pore typing may be the key to understanding diatomite reservoir behavior and integrating disparate data collected across a variety of different length scales. For example, samples can be characterized with respect to their pore type, size, and connectivity information as well as macroscopic flow properties such as permeability and relative permeability (Zhou *et al.*, 2002; Etris, 1991). Likewise, samples can be correlated with their log response. Hence, pore type can be inferred from log data. Then, flow behavior from reservoir regions that have only been logged can be identified from pore characteristics.

In addition to further refinement of pore types presented here, our work continues in the implementation of pore network for opal-A diatomites. Diatomite network simulators can be used to probe flow physics and oil production as well as estimate relative permeability. Studies are underway on opal-A samples from Midway-Sunset Field. We have begun to compare the pore structure of opal-CT samples with opal-A diatomites. Another potential research direction is to study the effects of stress and compaction upon pore networks of diatomites.

7. NOMENCLATURE

2D	=	two dimensions, area
3D	=	three dimensions, volume
$\emptyset$	=	porosity, % volume
BSE	=	back-scattered electron
BVO	=	bulk volume oil, % volume
BVW	=	bulk volume water, % volume
K	=	permeability, md
OOIP	=	original oil in place, barrels
PT	=	pore type, proportion
r	=	correlation coefficient
R^2	=	regression coefficient
SEM	=	scanning electron microscope
S_{oc}	=	oil saturation, core (% pore volume)
S_{ol}	=	oil saturation, log (% pore volume)
S_{wc}	=	water saturation, core (% pore volume)
S_{wl}	=	water saturation, log (% pore volume)
X	=	times, magnification

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Table 1. Study Samples and Measured Core Properties

DEPTH (ft)	ROCK TYPE	SEM $\emptyset$ (% area)	$\emptyset$ (% vol)	K (md)	SO (% $\emptyset$)	SW (% $\emptyset$)	BVO (% vol)	BWW (% vol)
1341.12	Clayey	14.72	56.1	1.1	46.3	51.9	25.97	29.12
1341.23	Clayey	12.27	55.4	0.9	46.3	51.9	25.65	28.75
1450.00	Sandy	10.34	46.3	43.42	36.7	63.3	16.99	29.31
1484.95	Sandy	5.77	62.2	30.4	35.3	57.5	21.96	35.77
1516.80	Sandy	14.25	49.3	21	38.1	60.2	18.78	29.68
1526.85	Sandy	9.74	46.2	2.8	54.3	45.7	25.09	21.11
1553.65	Clayey	9.91	52.5	1	49.1	45.8	25.78	24.05
1642.25	Clean	11.36	61.7	1.1	50.1	47.1	30.91	29.06
1706.00	Clayey	12.73	48.2	2.1	58.4	40.7	28.15	19.62
1801.00	Clean	10.65	59.4	1.2	61.3	38.4	36.41	22.81
1880.00	Clean	8.43	54.9	0.4	56.2	40.3	30.85	22.12
Quarry1	Quarry	18.12	76.6	14.8				

Table 2. Proportion of SEM Porosity Attributed to Each Pore Type

Sample	PT1	PT2	PT3	PT4	PT5	PT6
1341.12	0.4407	0.1794	0.1775	0.0942	0.0884	0.0197
1341.23	0.2186	0.3753	0.2294	0.0832	0.0444	0.0491
1450.00	0.2161	0.0813	-0.0247	0.2632	0.0779	0.3862
1484.95	0.2838	0.1312	0.1452	0.0594	0.3609	0.0194
1516.80	0.0749	0.0426	0.0002	0.3061	0.0386	0.5376
1526.85	-0.0418	0.2811	0.1178	0.2307	-0.0141	0.4262
1553.65	0.0320	0.3874	0.4157	0.0436	0.0747	0.0466
1642.25	0.3404	0.3994	0.0599	0.1153	0.0320	0.0530
1706.00	0.0900	0.3437	0.2357	0.3198	0.0078	0.0029
1801.00	0.0461	0.4589	0.4255	-0.0030	0.0707	0.0017
1880.00	0.0539	0.5304	0.3360	0.0455	0.0415	-0.0072
Quarry1	0.1487	0.2370	0.4420	0.0803	0.0772	0.0148

Table 3. Pore Body Attributes for Each Pore Type

Pore Type	Average Minimum Pore Body Width (μm)	Pore Body Width Range (μm)
PT1	0.82	0.114 - 2.508
PT2	1.35	0.230 - > 4.334
PT3	1.64	0.114 - 0.456; 1.142 - > 4.334
PT4	1.74	1.482 - 4.332
PT5	4.02	0.456 - 120
PT6	6.50	2.510 - > 4.334

Table 4. Capillary Pressure Model

Throat Radius (μ)		PT1	PT2	PT3	PT4	PT5	PT6
$\geq$	9.9441		0.0267			0.0512	0.0162
9.9440 -	1.5364			0.0173	0.0030	0.0151	0.0070
1.5363 -	0.2361			0.4974	0.7701		
0.2360 -	0.0718	0.3510	0.3954	0.4847		0.8893	0.6613
0.0717 -	0.0220	0.3142	0.3933				0.2936
0.0219 -	0.0018	0.1615	0.2711				0.1625
	sum	0.8267	1.0865	0.9994	0.7731	0.9556	1.1406

Table 5. Throat Size Attributes for each Pore Type

Pore Type	Average Minimum Pore Body Width (μm)	Pore Body Width Range (μm)	Average Throat Radius (μm)	Throat Radius Range (μm)
PT1	0.82	0.114 - 2.508	0.0631	0.0018 - 0.236
PT2	1.35	0.230 - > 4.334	0.0734	0.0018 - 0.236
PT3	1.64	0.114 - 0.456; 1.142 - > 4.334	0.5244	0.0718 - 9.944
PT4	1.74	1.482 - 4.332	0.6042	0.2361 - 9.944
PT5	4.02	0.456 - 170	2.2409	0.0718 - >9.944
PT6	6.50	2.510 - > 4.334	0.7843	0.0219 - >9.944

Table 6. Fluid Saturation Models

Saturation	PT1	PT2	PT3	PT4	PT5	PT6
S_{wc}	68	29	47	42	68	71
S_{oc}	33	66	54	59	13	29
S_{wl}	69	24	57	27	53	66
S_{ol}	31	76	43	73	47	34

Fig. 1 Porosity and permeability values measured on 12 study samples (black) and over 1000 core plugs from Lost Hills well OB-7 (gray) and Grefco Quarry (open circles) near Lompoc, CA.

Fig. 3 Representative binary images of the six pore types. Each image is 237.6 by 177.6 μm .

Fig. 2 Grayscale image (left) and its corresponding binary image (right) after segmentation. The CaCO_3 foraminifer test is 60 by 110 μm . SEM porosity for this view is 17.16%.

Fig. 4 Measured permeability versus proportion of PT1 (left) and PT2 (right).

Fig. 5 Measured permeability versus proportion of PT4, PT5, and PT6 summed (left) and permeable pore types with contributions from PT1 added for sandy and quarry diatomite samples (right).

Fig. 6 Measured (line) and predicted (dots) mercury injection curves for each study sample.

Fig. 7 Measured oil saturation from core plugs versus pore type 2 (left) and permeable pore types (PT1 in sandy and quarry samples, PT4, PT5, and PT6; right).

Fig. 8 Oil saturation from wireline log data versus pore type 2 (left) and permeable pore types (PT1 in sandy and quarry samples, PT4, PT5, and PT6; right).

Fig. 9 Oil (black) and water (gray) saturations per pore type within the reservoir.

Fig. 10 Oil (black), water (dark gray), and unfilled (light gray) saturations per pore type within core samples.

Improving Reservoir Definition Through Integration of Multiscale Petrophysical Data

Liping Jia and Anthony Kovscek

1. INTRODUCTION

In this research, integration of multi-scale data is studied in order to improve reservoir definition. There are three different scales of data considered, which are pore-scale, core-scale, and well-scale data. Pore network modeling is used to integrate pore-scale and core-scale data. A neural network analysis is proposed to correlate wireline logs with pore-scale data. Integration of different scale petrophysical data can supply more accurate input for reservoir simulation, which can provide more accurate ultimate oil recovery and other predictions for the reservoir.

A diatomite reservoir is chosen to study in this report because of its low permeability and large volumes of oil in place. The method is equally applicable to sandstones, chalks, and other carbonates. The available data for reservoir study include well log, core scale measurement, pore type proportions and production data. Because these measurements are made at different length scales and the correlation among them is generally not known, it is likely that interpretation of the reservoir and its performance is inconsistent. Therefore, it is suggested integrating all the petrophysical data available be accomplished when formulating a reservoir model. In this report, it is considered how to better link pore type proportion, core scale permeability and relative permeability measurements with well log data. The outline of approach is shown in Fig. 1.

Pore network modeling is a technique to model multiphase flow at the small scale and to predict average properties, such as permeability, capillary pressure, relative permeability and ultimate oil recovery. A pore network model is developed to calculate permeability for Lost Hills core samples. Image analysis of petrographic thin sections is applied to obtain the pore size, pore type, and proportion, throat size, type, and proportion. Six pore types are acquired from analysis of diatomite core samples from Lost Hills reservoir and six throat types correspond to each pore type. The pore-scale information will be the input of the pore network modeling. A three-dimensional pore network model is developed and used to predict the permeability for different core samples. In order to calculate absolute permeability, the pore network is filled with a single fluid first. Under steady state flow of incompressible fluid, a mass conservation equation for each pore body is developed. The conductance of a throat is calculated using Poiseuille's law for flow in a pipe. After the pressure distribution for each pore body is obtained, the total flow rate flowing through the pore network model can be calculated. Then Darcy's law is applied to calculate absolute permeability. Relative permeability and capillary pressure calculations are under development. The preliminary results are shown in Table 1. The samples we choose include sandy, clayey and clean diatomite lithologies.

Figure 1 Outline of approach

The samples of depth 1341.12 ft and 1706.00 ft are clayey diatomite. The samples of depth 1450.00 ft and 1516.80 ft are sandy diatomite. The sample of depth 1880.00 ft is clean diatomite. The porosity and permeability data in second and third column are from the lab measurement. The permeability (meas.) is air permeability. Permeability (calculate) is from pore network modeling study for water/brine flow.

Table 1. Preliminary results for diatomite

Sample (ft)	Porosity (meas.)	K (meas.)	K (calculate)
1341.12	0.561	1.1	1.656
1450.00	0.463	43.42	1.7546
1516.8	0.493	21.0	1.0047
1706.00	0.482	2.1	3.537
1880.00	0.549	0.4	2.046

In order to anchor the results from pore network modeling, spontaneous imbibition experiments are performed, on both outcrop core samples and field core samples from the Lost Hills reservoir. The important idea of laboratory measurements is to relate these measurements to the well log and reservoir scales. Therefore, scaling-up groups for counter-current and co-current imbibition are also investigated.

The objectives of experimental study are to obtain the saturation profile and rate of imbibition in order to determine fluid displacement mechanisms during counter-

current and co-current water imbibition into air- and oil-filled cores. X-ray CT scanning is used for visualization of displacement patterns. The diatomite outcrop sample is a well-characterized porous medium and has no initial oil or water saturation. The rock is consolidated and almost pure white indicating little silt or mud. Some evidence of bedding planes is visible to the naked eye. However the field samples contain connate water and residual oil, which creates difficulties for the experiment. The entire length of the core is imaged because we scan along the direction of flow using an apparatus designed specially for imbibition study, shown in Fig. 2. A single slice provides us with a picture of the progress and saturation pattern of imbibition. Different viscosity fluids are used for outcrop experiments in order to observe viscosity effects. For field sample experiment, crude oil is applied to simulate the reservoir condition as much as possible. The whole setup is kept close to reservoir temperature for experiments with field cores and room temperature for outcrop experiments.

Figure 2 Schematic of imbibition cell set up for countercurrent imbibition

From the results for outcrop experiments, it is shown that the water front is relatively sharp initially and becomes more diffuse as the front moves through the core. One set of images for an outcrop experiment is shown in Fig. 3 (Note the saturation scale on the right). To summarize the outcrop sample experimental results, imbibition performance as gauged by speed of recovery and amount recovered decreases as the non-wetting phase viscosity increases. Water movement through the cores becomes increasingly diffuse with viscosity also. From the field sample results, it is noticed that the displacing front is no longer obvious and becomes more diffuse. It takes much longer to imbibe water for field core experiment even with higher temperature. The recovery for a field sample experiment is lower than the results for outcrop experiment.

Figure 3 CT-derived water saturation images of counter current water/blandol imbibition in diatomite. Time is given in minutes beneath the image. Viscosity of blandol is 25 cp.

In order to scale-up the experimental results to predict the reservoir behavior, a theoretical analysis of the flow characteristics of imbibition processes was also conducted. A new set of scaling groups for counter-current and co-current imbibition is acquired. Both the simulation and the experimental data are used to verify the new scaling group, which shows that the new dimensionless time that can improve significantly the scaling of spontaneous imbibition in low permeability porous media. The new scaling is used to correlate experimental and simulation results. It improves correlation significantly by taking end-point fluid-phase mobilities and the mobility ratio into account. The scaling also explains the empirical observation that water/oil imbibition time scales inversely with the geometric mean of water and oil viscosity, whereas water/air imbibition scales inversely with water viscosity. The field sample results are still under investigation and will be reported soon.

2. FUTURE WORK

The pore network model will be used to calculate relative permeability and capillary pressure curves for diatomite. The field sample experiments need to be completed and analyzed. The scaling group for co-current imbibition needs to be verified using simulation data and experimental data if possible. The correlation between pore network model and wireline logs will be studied also. A novel method will be developed to integrate core-scale data with wireline log and pore network modeling results. An accurate and consistent data set will be generated to be used in simulation study, which will give us more accurate prediction of ultimate oil recovery for diatomite reservoirs. The study will also be extended to other kinds of reservoirs as well.