DEVELOPMENT OF MORE-EFFICIENT GAS FLOODING APPLICABLE TO SHALLOW RESERVOIRS

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ABSTRACT:

The objective of this research is to widen the applicability of gas flooding to shallow oil reservoirs by reducing the pressure required for miscibility using gas enrichment and increasing sweep efficiency with foam. Task 1 examines the potential for improved oil recovery with enriched gases. Subtask 1.1 examines the effect of dispersion processes on oil recovery and the extent of enrichment needed in the presence of dispersion. Subtask 1.2 develops a fast, efficient method to predict the extent of enrichment needed for crude oils at a given pressure. Task 2 develops improved foam processes to increase sweep efficiency in gas flooding. Subtask 2.1 comprises mechanistic experimental studies of foams with N₂ gas. Subtask 2.2 conducts experiments with CO₂ foam. Subtask 2.3 develops and applies a simulator for foam processes in field application.

Regarding Task 1, significant research was accomplished in the last three and one-half years with over 11 journal and conference publications, many of which have been repeatedly referenced by other researchers. All goals, except one, were accomplished for both Task 1.1 and Task 1.2. The remaining goal on the development of accurate CO₂ MMP correlations is near completion and will be published in a future paper.

Task 1.1 focused on the effect of dispersive processes on oil recovery and how to enrich gas so that the MMP can be reduced. Simulation studies (Solano *et al.*, 2001;

Stalkup, 1990) show that oil recovery for enriched gas drives depends on the amount of dispersion in reservoir media, but the value of dispersion, expressed as dispersivity, at the field scale, is unknown. This research investigated three types of dispersion in permeable media to obtain realistic estimates of dispersive mixing at the field scale. These types are echo dispersivity, which is unaffected by fluid flow direction, transmission dispersivity, which is caused by layering in permeable media, and local dispersivity, which is the mixing observed at a point in the reservoir as tracer flows past.

We analyzed a collection of single-well tracer test (SWTT) data to estimate echo dispersivity at the SWTT scale. The estimated echo dispersivities closely match a published trend with length in dispersivities obtained from groundwater tracer tests. This unexpected result—it was thought that transmission dispersivity should be greater than echo dispersivity—is analyzed with numerical simulation. The agreement between the SWTT echo dispersivities and the field trend suggests that the field data are measuring local dispersivities, which are on the order of 2 ft. All dispersivities appear to grow with length.

The interaction of phase behavior and flow, in the presence of dispersive mixing, was examined for 1-D four-component and twelve-component enriched-gas displacements. Numerical and analytical solutions demonstrated that oil recovery may be substantially increased by gas enrichment above the minimum enrichment for miscibility (MME). For the twelve-component oil, the increase in recovery (displacement efficiency) above the MME was as large as 15% OOIP depending on the level of mixing. The methodology outlined can be used as a screening tool to identify if a significant benefit may exist and further 2-D and 3-D studies are warranted.

We also considered the effect of dispersion on 1-D and 2-D floods for the same twelve-component oil. 2-D effects such as channeling, gravity tonguing, and crossflow can impact the enrichment required for good recovery. The primary result for 1-D enriched-gas floods is that the recovery difference between displacements above the MME and those at or near the MME increases significantly with dispersion. The trend, however, is not monotonic and shows a maximum at a dispersivity of about 4 ft. The trend is independent of relative permeabilities and gas trapping for dispersivities less than about 4 ft. For 2-D enriched gas floods with slug injection, the difference in recovery generally increases as dispersion and crossflow increase. The magnitude of the recovery

differences is less than observed for the 1-D displacements. Recovery differences for 2-D models are highly dependent on relative permeabilities and gas trapping. For water alternating gas (WAG) injection, the differences in recovery increase slightly as dispersion decreases. That is, the recovery difference is significantly greater with WAG at low levels of dispersion than with slug injection.

The main conclusions of this WAG research showed that the richer the gas above the MME, the fewer the number of WAG cycles required for maximum oil recovery at a given WAG ratio. Another significant observation is that over-enrichment above the MME improves recovery the most when the largest permeability layers are at the bottom of the reservoir. Continuous slug injection performed better than WAG when the largest permeability layers are at the bottom of the aquifer, richer gases are used, and the vertical to horizontal permeability ratio is small.

In Task 1.2, our goal was to develop a fast and robust method to estimate MMP and the displacement mechanism for real gas floods. Our research has shown that published methods (Johns and Orr, 1996; Wang and Orr, 2002; Jessen *et al.*, 1998) will not always converge to the correct MMP for a variety of fluid characterizations. This research presents a simplified and robust method for MMP or MME calculation that does obtain the correct MMP. We demonstrate the improvements by calculation of the MMP and MME and the displacement mechanisms for a variety of gas/oil systems.

Regarding Task 2, significant progress was made, resulting in 16 journal and conference publications. Research proceeded along both experimental and numerical tracks. Experiments included foams made with N₂ and with high-pressure CO₂.

Studies of the two steady-state foam regimes with N₂ foam have shown them to be, if not universal, then at least widely occurring in foam. We developed a self-consistent mechanistic explanation for behavior in both regimes, and verified the two regimes in a wide variety of porous media and with different surfactant formulations, at room temperature and elevated temperatures, from published studies and our own experiments. We found that the two regimes persist in the presence of oil. The two regimes differ in their basic behavior, so differentiating between the two regimes is essential to any foam application.

The two flow regimes were identified in previously published studies of dense CO₂ foam, although never both regimes in the same study. Surprisingly, our own

experimental study of dense-CO₂ foam did not find either regime. Instead, examination of dense-CO₂ foam in both Berea core and a sandpack found a regime where pressure gradient decreases with increasing liquid injection rate. Such behavior is conceivable in the context of current understanding of foam, *if* gas trapping were constant (or ineffective) *and* bubble size were constant. We do not yet know if this explanation is correct.

The foam algorithm we have developed can be implemented in either compositional gas-flood simulator UTCOMP or chemical-flood simulator UTCHEM. In addition, our foam model is shown to be similar to that in STARSTM, a widely used commercial foam simulator.

The use of the simulator was key to identifying the optimal injection strategy for overcoming gravity override with foam, in the idealized case of a homogeneous reservoir. The optimal strategy is injection of gas and surfactant solution in large alternating slugs (SAG injection) at the maximum allowable injection pressure. Injection of large alternating slugs of liquid and gas can give long-distance propagation without segregation with remarkably low injection pressures. Fractional-flow theory was key in explaining why the SAG process gives both low mobility at the displacement front and high injectivity, and in why continuous foam injection may lead to either gravity segregation or fracturing if injection pressure is limited. Fractional-flow theory also raises concerns about numerical artifacts in foam simulations with models in which foam collapses completely at a single "limiting water saturation" S_w^* . A model even simpler than fractional-flow theory, one with a single low-mobility front between gas and water banks of infinity mobilities, explains several aspects of gravity segregation in SAG processes.

Application of the simulator to a study of viscous and capillary crossflow in layered media modifies earlier conclusions from our research group about the effects of capillary crossflow on foam effectiveness. Capillary crossflow did not greatly harm diversion with foam.

Toward a fully mechanistic foam simulator, we developed a model for effective gas viscosity in the presence of foam that for the first time accounts for both capillary and viscous forces. The resulting behavior is much more complex than assumed in current mechanistic models. We developed a model for foam generation at layer boundaries that is in agreement with a variety of experimental observations. Since oil reservoirs are

heterogeneous on a wide variety of scales, foam generation at these boundaries can be a significant factor in foam success, especially in preventing vertical migration of gas across layers.

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EXPERIMENTAL

Task 1 includes no experiments. Task 2 comprises a variety of experimental studies, with a corresponding variety of experimental techniques. Details of these techniques are given in the discussion of the activities conducted within the specific subtasks of Task 2.

RESULTS AND DISCUSSION

Task 1: Reduce MMP with Gas Enrichment

Subtask 1.1: Effect of Dispersion on Recovery for Gas Injection Above the MME

Research on Task 1.1 focused on the effect of dispersion on recovery for shallow enriched gas drives. Subtasks include the estimation of the true dispersivity in porous media, the effect of dispersion on one-dimensional four and twelve-component displacements, and the effect of dispersion on two-dimensional recoveries with and without WAG.

Estimation of True Dispersivity in Porous Media

In-situ mixing (dispersion or dispersive mixing) of two miscible fluids of constant mobility and density (tracer flow) is called dispersion. Dispersion in a permeable medium depends on a combination of factors: diffusion, pore-scale velocity gradients, and mechanical mixing in pore bodies. For a heterogeneous permeable medium, the observed dispersion depends on spatial variations in the streamline flow length, which in turn depends on the autocorrelation of permeability of the medium. These effects do not occur independently so that what is observed in a dispersion measurement is a combination of all the above factors.

Tertiary oil recovery processes, such as miscible gas flooding, are used to recover oil from hydrocarbon-bearing reservoirs. Solano *et al.*, (2001) and Stalkup (1990) studied the impact of dispersive mixing on oil recovery of gas drives that were enriched above the laboratory-determined minimum miscibility enrichment (MME). The results from such studies show that for one-dimensional (1-D) enriched gas floods, the oil

recovery for enrichments above the MME decreases *significantly* with increasing dispersion. The recovery difference for 1-D displacements varies from about 7 to 15 percent of the original oil in place (OOIP) for an enrichment increase from 65% to 85% (Solano *et al.*, 2001). For two-dimensional (2-D) enriched gas floods with discontinuous shales, the results are similar to the 1-D displacement and also show significant sensitivity to dispersion.

The research reported in this research is to estimate the dispersion to be expected in a field-scale permeable medium. We consider no effect other than flow through the reservoir scale permeable media. All the discussions in the following paragraphs assume an incompressible, single-phase, constant mobility and density, fluid flowing in a heterogeneous permeable medium.

We study four types of dispersion: *input*, *echo*, *transmission* (Hulin and Plona, 1989) *and local*. Input dispersion refers to the values used in input files to numerical simulation. These do not vary with either time or space and can refer to either longitudinal or transverse dispersivity. Echo dispersion is inferred from averaged tracer concentration made at the point of injection upon reversal of fluid flow direction. Because of the flow reversal, this type of mixing is irreversible. Transmission dispersion is inferred from averaged tracer concentration between separate injection and production points. It involves no fluid flow reversal. Lastly, local dispersion is inferred from a tracer concentration measured at a fixed point in space. There is no averaging. We presume that the local dispersion that governs the oil recovery discussed above, and hence is the "true" dispersivity mentioned. All inferences for the last three are based on the time-evolution of the respective concentration. The principal difference between echo, transmission and local dispersivity is the averaging scale over which it is observed.

Dispersion in Permeable Media

Basic Dispersion Theory

The transport of tracers in the x-direction by molecular diffusion is given by (Levenspiel, 1992)

$$\frac{\partial C}{\partial t} = D \frac{\partial^2 C}{\partial x^2} \tag{1.1}$$

where D is the coefficient of molecular diffusion. In an analogous manner we may consider all the contributions to mixing of fluid flowing in the x-direction to be described by a similar expression, where the longitudinal dispersion coefficient, K_l , replaces the diffusion coefficient, D . Since Eq. 1.1 used Fick's simple law, mixing with constant D is called Fickian mixing.

In dimensionless terms the transport equation (convection-dispersion equation) for a tracer species in a permeable medium becomes, after adding convection and rearranging,

$$\frac{\partial C}{\partial t_D} = \left(\frac{K_l}{vL} \right) \frac{\partial^2 C}{\partial x_D^2} - \frac{\partial C}{\partial x_D} \quad (1.2)$$

where dimensionless time is given by

$$t_D = \frac{qt}{A\phi L},$$

and dimensionless distance by

$$x_D = \frac{x}{L}.$$

With the assumption of one-dimensional, single-phase, incompressible and uni-directional flow, the distribution of tracer concentration in a homogeneous permeable medium is given by the following solution to the convection-dispersion equation (Eq. 1.1), (Lake, 1989)

$$C = \frac{1}{2} \left[1 - \operatorname{erf} \left(\frac{x_D - t_D}{2\sqrt{t_D/N_{Pe}}} \right) \right] + \frac{e^{x_D N_{Pe}}}{2} \left[1 - \operatorname{erf} \left(\frac{x_D + t_D}{2\sqrt{t_D/N_{Pe}}} \right) \right] \quad (1.3)$$

where erf is the error function given as

$$\operatorname{erf}(z) = \frac{2}{\sqrt{\pi}} \int_0^z e^{-z^2} dz, \quad (1.4)$$

and the Peclet number is given by

$$N_{Pe} = \frac{vL}{K_l}.$$

This dimensionless group is a ratio of convection to dispersion. Eq. 1.3 takes the initial tracer concentration to be zero and the injected concentration to be one at $x = 0$ for $t > 0$.

The second term in Eq. 1.3 becomes negligible at large values of t_D or x_D . The solution shows, after neglecting the second term, that the tracer concentration curve resembles an S-shaped curve centered about the position where the concentration is $C=0.5$. Dispersion does not affect the rate of propagation of this mean position of the tracer front, but it does affect the spread of concentration (or mixing) about this point. The mixing length or the distance between the positions where the $C=0.1$ and $C=0.9$ respectively, is given by

$$L_m = 3.625\sqrt{K_l t} \quad (1.5)$$

The longitudinal dispersivity α_l is defined by

$$\alpha_l = \frac{K_l}{|v|} , \quad (1.6)$$

which leads to the following expressions for mixing length and Peclet number:

$$L_m = 3.625\sqrt{\alpha_l |v| t} \quad (1.7)$$

$$N_{Pe} = \frac{L}{\alpha_l} . \quad (1.8)$$

Eq. 1.7 shows that the mixing length is independent of "direction" of velocity; therefore, when flow is reversed the mixing length depends only on the time elapsed (the flowing time), the magnitude of the velocity, and the longitudinal dispersivity. The dispersivity is the main emphasis of this research. This entire formalism is for unidirectional, 1-D flow.

A main issue is how to interpret the dispersivity in flows where the medium is heterogeneous and the flow is not 1-D. In heterogeneous media, of course, the concentration is a function of all the position coordinates as well as time. To use 1-D theory we average the local concentrations in the direction perpendicular to bulk flow. The resulting concentrations are flow-averaged or cup-mixing concentrations. One

consequence of this interpretation is that the dispersivity becomes dependent on scale or travel distance. This is called non-Fickian behavior.

Uncorrelated permeable media

Another way to look at dispersion, borrowing from the theory of diffusion, is of the behavior of a group (ensemble) of particles. Consider the injection of a set of particles at $x = 0$. Assume that the particles take several discrete jumps to reach their respective positions after a time t . There is a bias in the movement of these particles because of the bulk fluid flow, but added to this movement are a series of random jumps. In this case (this occurs when the local transport properties are themselves spatially uncorrelated), the jump that a particle takes is independent of any previous jumps. The particles do not trace back their original path when the flow is reversed, as the reverse jumps taken are also not correlated with each other. Thus, for flow in uncorrelated media, dispersion should be independent of flow reversal: echo and transmission dispersivities should be equal. But real media are far from uncorrelated so we expect some differences.

Layered permeable media

The other extreme from a completely uncorrelated (though still heterogeneous) medium is a uniformly layered medium. Now the transport properties are perfectly autocorrelated in the direction parallel to bulk flow, but perfectly uncorrelated perpendicular to it. If there is no lateral movement, the jumps that the particles take are identical to the previous jumps taken to arrive at that point. The layers in the system have different average permeabilities and the advance of the tracer particles across the whole media depends on the velocity differences between each layer.

When the flow is reversed, the particles trace back their path and reach the inlet at the same time. The reversal of flow cancels out the differences caused by velocity variations and retains only the mixing within each layer. In this case, the transmission dispersivity should be larger than the echo dispersivity (Remember that both dispersivities are inferred from Eq. 1.3 using cup-mixing concentrations).

Past Research

It has been shown (Hulin and Plona, 1989; Hulin *et al.*, 1988) that Fickian dispersion suggests that the medium in which flow is taking place is homogeneous. Hulin and Plona (1989) demonstrated experimentally that non-Fickian dispersion observed in a laboratory experiment became Fickian after the direction of flow was reversed when the tracer was observed at the outlet end (formerly the inlet) of the medium. The experiments demonstrated the reversibility of the portion of spreading of the tracer that resulted only from convection. The other portion, corresponding to echo dispersion, however is irreversible.

Similar experiments with flow reversal were carried out in random packs of monodisperse glass beads to demonstrate the irreversibility of echo dispersion. (Rigord *et al*, 1990). These experiments used a tracer slug that was transported a short distance into the medium, the direction of flow reversed, and the tracer concentration analyzed at the same location where it was originally injected. When the slug is transported a small distance into the sample, the echo dispersivity increases with distance, but at larger distances approached a constant value.

Field-scale studies of mixing have indicated an approximately linear increase of the effective dispersivity with the scale of study, i.e., the mean distance covered by the tracer (Gelharet, 1993; Mercado, 1967). It is not known how much of this dispersivity is reversible.

Single-Well Tracer Tests (SWTT) as Examples of Echo Dispersion

Applications of flow reversal are widely used to measure the residual oil saturation in water-flooded oil reservoirs. A version of the SWTT is performed by injecting a slug of a mixture of reactive and non-reactive tracer dissolved in an aqueous phase followed by a volume consisting only of non-reactive tracer. The non-reactive tracer is used to check for material balance consistency in the aqueous phase. The injection period is followed by a shut-in period in which the reactive tracer reacts. The shut-in is followed by a production period when the injected fluids are produced and the tracer concentrations are measured. With significant flow from external sources absent,

the spreading of non-reactive tracer concentration measured at the injection source represents the echo dispersion.

Results

Layered permeable media simulations

All numerical simulations in this research assume the following:

- 1) Single-phase flow (aqueous phase flow);
- 2) Incompressible fluid and rock with spatially invariant porosity;
- 3) Non-reacting, non-partitioning aqueous-phase tracer;
- 4) Constant potential external boundary condition; and,
- 5) Constant rate injection/production at the well bore,
- 6) The total variation diminishing (TVD) is used in the reservoir simulations to control numerical dispersion.

Before analyzing the SWTT data, we used the UTCHEM reservoir simulator (Reservoir Engineering Research Program 1998) to generate a transmission history by performing an injection and production on a two-dimensional, uniformly layered permeable medium with permeabilities ranging from 200 to 1400 md. Each layer was homogenous with an input longitudinal dispersivity equal to 0.46 m and an input transverse dispersivity equal to 0.046 m. The longitudinal and transverse dispersivities are intended to represent mixing on scales smaller than the resolution of the simulation; in this case, there were 30 cells between injection and production ends and 5 cells vertically. The size of grid block was kept uniform at 0.3048 m vertically and horizontally.

Fig. 1.1 shows the automatic history match of transmission history data obtained at the producer. The automatic history matching is performed using the solution of the convection-dispersion equation (Eq. 1.3) with dispersivity as one of the varying parameters. The history match gives transmission dispersion of 2.47 m.

Fig. 1.2 shows the same results applied to echo dispersivity. For these runs, we injected a tracer front up to breakthrough in a producer and then reversed the flow. Since we do not have an analytic solution for reversed flow, we performed a history match using a 1-D UTCHEM simulation of the concentrations, now measured at the former injector. Note that the transmission dispersivity is substantially greater than the echo

value. The history match in Fig. 1.1 is poorer than that in Fig. 1.2 due to the type of concentration history curve in Fig. 1.1. It has been observed experimentally (Hulin and Plona 1989; Rigord *et al.*, 1990) that concentration history curves for a layered permeable media always produces long tails and is non-Fickian, whereas the concentration history curve for a homogeneous permeable media is Fickian and exactly follows the solution to Eq. 1.3. The echo and input longitudinal dispersivities are equal in Figs. 1.1 and 1.2 indicating that the numerical dispersion in UTCHEM is small and that there is relatively little transverse fluid movement.

Estimation of Echo Dispersivity from Field Data

Test results of 59 SWTT's conducted between 1958 and 1968 are taken from Majoros and Deans, 1980. The tests consist of the injection and subsequent production of tracer back into the well in which they were originally injected. SWTT's were originally conducted to determine the residual oil saturation in water-flooded reservoirs. All SWTTs, however, use a material balance tracer whose propagation is unaffected by the residual oil saturation, except for a minor effect on the tortuosity. We use the material balance tracer histories from the 59 tests to analyze echo dispersivity.

From the 59 published SWTT histories, we ignored 24 for either lack of adequate information about injection/production times or for obviously inappropriate concentration data. This means there was excessively tailing of the concentration, or that the beginning concentration was not the injection concentration. This leaves 35 SWTT's to be analyzed.

We fit the 1-D (single layer) UTCHEM results to the SWTT concentration histories. The injection flow rate, production flow rate, and important reservoir details are available in Majoros and Deans, 1980.

We developed an automatic history-matching program to determine the echo dispersivity from the SWTT data. The program uses UTCHEM to simulate fluid flow in permeable media (Mahadevan, 2000). A schematic of the fitting program is in Fig. 1.3.

The estimated echo dispersivities are plotted against distance traveled; for the SWTT, the distance traveled is twice the distance penetrated. Estimated echo dispersivities range from 0.03 to 2.13 m (Fig. 1.4). The median of the echo dispersivities is 0.46 m (Fig. 1.5). The plot shows that there is significant variance of echo

dispersivities at the same distance traveled. The echo dispersivities appear to increase slightly with distance traveled, but this is anything but certain because of the scatter in the data and because the travel distance is nearly the same for all the SWTTs.

Fig. 1.6 compares the estimated echo dispersivities are compared with measured field dispersivities from Arya *et al.*, 1998. If the permeable media were layered, there should be a significant difference between the values of echo and field dispersivities. The results in Fig. 1.6 were unexpected: we expected the field dispersivities to behave like transmission dispersivities and, hence, be larger than the echo (SWTT) values. However, all dispersivities fall on the same trend. That they fall on the same trend suggests that echo dispersivity data would increase with distance traveled were a larger travel distance to be investigated by the SWTTs. We comment further on why the echo dispersivities agree with the field data in the discussion section. In the next section we perform numerical simulations to explain the results in Fig. 1.6.

Dispersion Induced by Stochastic Permeability Fields

Stochastic permeability fields are fields whose spatially varying permeabilities have been assigned according to statistical functions. The functions specify the mean, variability and degree of inter-relationship (autocorrelation) of the permeability.

Permeability fields were developed for a two-dimensional reservoir medium 312 m long and 6 m thick in a Cartesian coordinate system. The medium was divided into 1024 cells in the longitudinal direction (length) and 8 cells in the transverse direction (thickness). There are 8192 total cells. The permeability assignments were made according to the stable semivariogram using a fast Fourier transform technique (Jennings, 2000). The autocorrelation length is 804 m in the longitudinal direction. Permeability is uncorrelated in the transverse direction, the coefficient of variation of the horizontal permeability is 0.145, and stable semivariogram exponent is one. (We picked these values to match the field trend of dispersivities. See discussion below.)

Two-dimensional cross-sectional simulation studies, using UTCHEM, were conducted with the above-generated permeability fields. Both well-to-well tracer tests and SWTT were conducted on the permeability field. Three different cases were studied in the simulations: one with zero vertical permeability, the second with vertical permeability that is equal to the horizontal permeability and the third with a vertical

permeability equal to 10000 mD (an artificially large value chosen to create vertical equilibrium with respect to the fluid pressure). Tracer concentration profiles for individual realizations of the first two cases are in Figs. 1.7 and 1.8. The concentration field shown is only a 9.15 m by 6 m portion of the field discussed above. The input dispersivities here are 0.46 m in the longitudinal direction, and 0.046 m in the transverse direction.

Case 1 - The vertical permeability is zero in this case. The tracer concentration distribution is in Fig. 1.7. The amount of mixing is indicated by the different shades of gray on the contour plot. The plots show layered behavior and little local mixing.

Case 2 - The vertical permeability is equal to the horizontal permeability in this case. The tracer concentration contour plots are in Fig. 1.8. The plots show that there is more mixing when the vertical permeability is greater than zero.

There is much more mixing in Fig. 1.8 than in Fig. 1.7 an observation that indicates the importance of transverse permeability to mixing. Further discussion follows.

Both echo and transmission dispersivities are estimated in the stochastic realizations. They are calculated for a given realization and plotted against the distance traveled in logarithmic coordinates. The simulations were conducted to estimate the echo, transmission and local dispersivities with injected fluid travel distance.

Local dispersion is estimated from a concentration history sampled at a point, unlike that of echo or transmission dispersion, which are cup-mixing types of sampling.

We recognize that there is a degree of arbitrariness in this selection inasmuch as Eq. 1.3 does not, strictly speaking, apply to multidimensional flow. The procedure would be rigorously accurate if the flow was based on the movement of particles along streamlines, but such particles do not exist in finite difference numerical simulation. Nevertheless, the local dispersivity is measuring how concentration changes at points, without averaging, and is consequently our best estimate of "true" dispersivity. It remains to be seen if this is the dispersivity that controls the attainment of miscibility in IOR displacements. Of course, we can infer as many local dispersivities as there are cells.

The results from simulation studies on stochastic permeable media are in Figs. 1.9 - 1.11. The figures show the variation of estimated transmission, echo and local

dispersivities with travel distance (for one realization of the permeability field) with varying vertical permeability. The upper solid curves are the transmission dispersivities for the three cases and the lower solid curves are the echo dispersivities. The points are the local dispersivities.

For the case of zero vertical permeability (Fig. 1.9) the transmission dispersivity shows a trend similar to the field dispersivity data from Arya *et al.*, (1998) with a unit slope, the echo dispersivity is unaffected by distance traveled. The local dispersivity also follows the latter trend indicating that the echo and local dispersivity are equal in the case of flow with no lateral movement of fluid.

When the vertical permeability is increased to $k_v = k_h$, (Fig. 1.10) the echo dispersivity trend has a slope greater than zero. The transmission dispersivity trend has slightly less than unit slope. Nearly all the local dispersivity generally falls between the echo and transmission dispersivities. All the local dispersivities however do fall between the trend for echo and transmission dispersivities for zero vertical permeability.

For the large vertical permeability case (Fig. 1.11) the echo and transmission dispersivities show a trend that is similar to the trend for the $k_v = k_h$ case. The local dispersivities estimated from this case also generally falls between the trends for echo and transmission dispersivity, but they are, with considerable scatter, closer to the transmission line than in Fig. 1.10. Again, all the local dispersivities however do fall between the trend for echo and transmission dispersivities for zero vertical permeability.

However, we note that the dispersivities are not equal in any of the cases shown as they were in the SWTT data.

Analytical Model for the Flow of Particles in Reservoir Media

In addition to simulation studies, it is possible for the field dispersivity in Fig. 1.6 to be analyzed analytically from the statistics of particle ensembles. This is discussed in this section.

The distribution of tracer particles in a permeable medium is determined by the input dispersivities, the heterogeneity of the permeability of the medium and its autocorrelation structure. The average velocity in the permeable medium determines the position of the tracer concentration front. We can match the field dispersivities with a

theoretical random jump model. The theoretical model has the following measure of heterogeneity:

A coefficient of variation of permeability is given by

$$C_v = \frac{\sigma}{\bar{k}} \quad (1.9)$$

where σ is the standard deviation of the permeability distribution and $\bar{k}$ is the arithmetic average of permeability. The autocorrelation of horizontal permeability is given by stable semivariogram model,

$$\gamma(h) = \sigma^2 \left(1 - \exp \left(- \left| \frac{h}{R} \right|^a \right) \right) \quad (1.10)$$

where h is the lag distance in the x -direction, R is the autocorrelation length, and a is the semivariogram exponent.

The statistical parameters in Eq. 1.10 are estimated by performing a non-linear regression of the echo from the combination of SWTT and field-scale dispersivities. The best-fit autocorrelation model is now given by

$$\gamma(h) = (0.145\bar{k})^2 \left(1 - \exp \left(- \left| \frac{h}{2638} \right|^{1.0} \right) \right) \quad (1.11)$$

The analytical expressions for echo and transmission dispersivity are derived by the application of statistical principles to tracer particle movement in a stochastic permeable medium (Mahadevan, 2000). The expression for transmission dispersivity in a stochastic permeable medium is given by,

$$\alpha = 2RC_v^2 \sum_{k=0}^{\infty} \frac{(-1)^k \left(\frac{\bar{X}}{R} \right)^{ka+1}}{k!(ka+1)(ka+2)} + \left(\frac{\sigma_\epsilon^2}{\Delta x} \right) \quad (1.12)$$

where $\bar{X}$ is the average distance of travel by the tracer particles and Δx is the average jump size of the particle. The last term on the right is the standard deviation of a white noise component (random) in the x -direction (ϵ) divided by the average jump size of the particle.

The expression for echo dispersivity in a stochastic medium is given by the same equation as above except that the average distance traveled by the tracer particles is equal to twice the average distance traveled before reversal of flow.

The fitted value of α indicates that the stable semivariogram model has collapsed to an exponential semivariogram model, one of the simplest representations of autocorrelation structure. The fit of Eq. 1.12 to the field data is shown in Fig. 1.12.

The large value of $R = 2638$ m, which is the autocorrelation length in an exponential model, indicates strong autocorrelation in the flow direction. This is consistent with a current understanding of the distribution of permeability in reservoirs. However, the fitted value of $C_V = 0.145$ is substantially smaller than coefficient of variations of horizontal permeabilities estimated from direct measurements (Jenson *et al.*, 2000). On the other hand, the coefficient of variation used in Eq. 1.12 is the longitudinal variation of velocity, not the vertical variation of permeability, and it may very well be that this value is realistic. Evidently, there is something in the nature of the flow (probably having to do with the vertical permeability) that mitigates the effective vertical heterogeneity of the flow field. The values determined here were used in the simulation realizations of Figs. 1.6-1.11.

Discussion

The most important observation from this work is that the single-well tracer test dispersivities agree with field-measured dispersivities. Although the SWTT values are measured over a small range in travel distance, the agreement suggests that echo dispersivities would grow with travel distance if they were measured over a larger distance. The numerical simulation results suggest this also.

The agreement between SWTT and field-dispersivities is difficult to explain. In the research by Hulin and Plona (1989), the experimental results show that the dispersion length (which is defined in the same way as dispersivity) measured for transmission experiment is at least six times greater for a layered porous media (Massillon sandstone) than a homogeneous medium (Berea sandstone). Although not obvious from their research, the transmission dispersion length for layered porous media (Massillon sandstone) is two times greater than the echo dispersion length for the same travel length. Also recalling the numerical simulation results (Fig. 1.1 and 1.2), which show that for a

layered medium transmission dispersivity is greater than the echo dispersivity for a given length of travel, the field dispersivities are not transmission dispersivities, as we thought. This is because the echo and transmission represent extremes of the dispersive behavior and the SWTT values must be echo dispersivities. The local dispersivities, on the other hand, could be made to agree with echo dispersivities if we were to use smaller values of vertical permeability. It is reasonable that the field dispersivities could be local dispersivities if, in fact, the concentrations being measured in these tests were from points that sampled only one streamline (areally) or one layer (vertically).

One of the more troubling aspects of the research is that the analytical model of dispersivity, which can be made to match the field trend with reasonable parameters, does not show a difference between echo and transmission dispersivities. We think this is because the analytical model assumes that the paths of tracer particles returning to the well are independent of the outflowing path. The other extreme of this assumption, that the return path is perfectly correlated (identical, in fact) with the outflowing path, would lead to zero echo dispersivities and pure streamline flow. Since the numerical simulations results gave echo dispersivities less than the transmission dispersivities, but not zero, it appears that the return paths are correlated with the outflow path, but they are only partially so.

Finally, and returning to the theme with which we started this research, we have not established which of the dispersivities control the approach to miscibility in an enriched gas drive, the "true" dispersivity in the research title. It seems reasonable that the controlling dispersivity would be the local dispersivity since this is mixing at a "point" in the medium (or grid cell size in numerical simulations); all the other dispersivities involve some averaging. This type of mixing is the basis for qualitative arguments for the development of miscibility in all types of developed miscibility processes (Lake, 1989).

Conclusions

- 1) All dispersivities--echo, local and transmission-- are the same for heterogeneous and spatially uncorrelated media.

- 2) For layered heterogeneous media, echo and transmission dispersivities are not the same. Echo, local and input longitudinal dispersivities (in simulation) are equal. The transmission dispersivity grows with length scale.
- 3) For non-layered media, whose permeability is heterogeneous (and autocorrelated) with zero vertical permeability the conclusions in 2 apply.
- 4) For non-layered media, which is heterogeneous (and autocorrelated) with non-zero vertical permeability, all dispersivities grow with travel distance. The local dispersivity is between the echo and transmission and all are greater than the input dispersivity in the simulation.
- 5) The greater the vertical permeability the closer the local dispersivities are to the transmission values.
- 6) The SWTT dispersivities (which must be echo dispersivities) follow the field data trend. Based on the above results, one of the following must be true of the SWTT dispersivities:
 - a. Either the field scale media is homogeneous (which is highly unlikely)
 - b. Or the field data are really local dispersivities (likely)
- 7) The true dispersivity that should be used in reservoir simulators is likely the field (local) dispersivity data.

Effect of Gas Enrichment Above the MME on Oil Recovery in Shallow Enriched-Gas Drives

Enriched gas floods are being conducted in many reservoirs worldwide. In these floods, the objective is to achieve a multicontact miscible (MCM) displacement, by taking advantage of the high local displacement efficiency that is possible when the injection gas is sufficiently enriched with intermediate hydrocarbon components. Because strict MCM behavior occurs only in dispersion-free flow, real field displacements, in which some reservoir mixing is present, will generally show some two-phase flow. Because two-phase flow can reduce recovery (Stalkup 1998; Johns *et al.*, 1993; Walsh and Orr, 1990), it is important to determine the conditions under which those nearly miscible displacements can still be very efficient.

There are several mechanisms that can cause reservoir mixing of a multi-contact miscible solvent and oil. For example, (1) molecular diffusion; (2) convective dispersion;

(3) capillary crossflow; and (4) viscous crossflow can cause mixing. Mixing from viscous crossflow caused by alternating water and gas (WAG) appears to be particularly significant in some reservoirs (Stalkup 1998).

Stalkup investigated the effect of dispersive mixing on recovery for a displacement of 12-component oil by enriched solvent (Stalkup 1998). His study showed that recovery may continue to improve significantly with enrichment above the MME. Other investigators have also examined the effect of diffusion and dispersion as well as capillary and viscous crossflow on mixing a multi-contact miscible injectant and oil into the multiphase region (Fayers and Lee, 1994; Pande *et al.*, 1989; Haajizadeh *et al.*, 1999). Core flood experiments (Chang *et al.*, 1993) and fully compositional simulations (Jerauld, 1998) have shown that recovery can continue to increase significantly as solvent is enriched above the MME.

The main focus of this research is to demonstrate that in the presence of dispersive mixing oil recovery can increase significantly as gas is enriched above the MME. The effect of gas enrichment and mixing on oil recovery is examined for several one-dimensional four-component gas/oil systems where dispersion-free analytical solutions are known. The use of simplified systems allows additional insight into the effects of dispersion and enrichment on recovery. This research examines the displacement mechanisms of the miscible process and the sensitivity of recovery as the enrichment is increased beyond the MME. Numerical dispersion is used to simulate physical dispersion in these one-dimensional displacements by varying the grid block size.

Analytical and Numerical Equations

Analytical and numerical solutions to dispersion-free flow in one-dimension are solved using hyperbolic conservation equations with the assumptions stated by Helfferich (Helfferich, 1981). For simplicity, total volume of both phases is assumed invariant with component mixing, but the approach is easily extended to include volume change on mixing (Dindoruk *et al.*, 1992). Although not shown here, the results presented in this research were duplicated using UTCOMP (Change *et al.*, 1990), a compositional simulator that includes volume change on mixing (Sah, 2000).

The dimensionless conservation equations are

$$\frac{\partial C_i}{\partial t_D} + \frac{\partial F_i}{\partial x_D} = 0, \quad i = 1, \dots, n_c \quad (1.13)$$

where C_i and F_i are defined as

$$C_i = \sum_{j=1}^{n_p} c_{ij} S_j, \quad F_i = \sum_{j=1}^{n_p} c_{ij} f_j, \quad c_{ij} = \frac{x_{ij} / \rho_i}{\sum_{k=1}^{n_c} x_{kj} / \rho_k}. \quad (1.14)$$

The gas phase fractional flow, equilibrium volume and mole fractions, and component densities were calculated using the Peng-Robinson equation of state (Peng and Robinson, 1976) (PREOS). The parameters used in the PREOS for the four-component phase behaviors presented here are given by Johns *et al.* (1993a and 1993b) (Johns 1992).

Analytical solutions for dispersion-free displacements were constructed using the method of characteristics (MOC) to calculate the velocity at which a given composition propagates through the porous medium (Helfferich, 1981; Dumore *et al.*; 1984; Lake, 1989). Shocks occur when solutions become multi-valued (Helfferich, 1981; Johns, 1992; Larson, 1979; Pope, 1980; Wang and Orr, 1998).

Numerical solutions are obtained by solving a discrete form of Eq. 1.13 as described by Walsh and Orr (1990). Because the analytical solutions assume that changes in pressure over the flow length have negligible effect on phase behavior, a fully explicit scheme with single-point upstream weighting is used. That is, the overall composition of component i in grid block k at time level $n+1$ is found from

$$C_{i,k}^{n+1} = C_{i,k}^n + \frac{\Delta t_D}{\Delta x_D} (F_{i,k-1}^n - F_{i,k}^n), i = 1, \dots, n_c \quad (1.15)$$

where Δt_D is the dimensionless time step and Δx_D is the dimensionless grid block size. Lantz showed that numerical dispersion arises in the numerical solution due to truncation errors, which can be described by a one-phase Peclet number (Lantz, 1971). For two immiscible phases the numerical Peclet number is written as (Walsh and Or, 1990)

$$N_{\text{Pe}}^{-1} = \frac{\Delta x_D}{2} \frac{df_g}{dS_g} \left[1 - \frac{\Delta t_D}{\Delta x_D} \frac{df_g}{dS_g} \right]. \quad (1.16)$$

The Peclet number is the ratio of convective to dispersive transport. When the dimensionless time steps are small compared with the grid block size and the fractional flow derivative is approximated as 1.0, Eq. 1.16 reduces to

$$N_{\text{Pe}} = \frac{2}{\Delta x_D} . \quad (1.17)$$

Eq. 1.17 is used in this research to approximate the level of numerical dispersion in the enriched-gas drive simulations by varying the grid block size. Eq. 1.17 generally provides a good representation of the true level of physical dispersion (Stalkup, 1998; Haajizadeh *et al*, 1999). In all simulations shown, a dimensionless time-step size one-tenth of the dimensionless grid block size was chosen.

Mixing in Three-Component Displacements

Many analyses of the mechanisms of miscible floods have been based on the idealized behavior of three-component systems. According to three-component theory, only two types of displacements are possible, vaporizing or condensing gas drives. Both mixing cell arguments and rigorous mathematical approaches show that a three-component displacement can be MCM only if either the injection composition (condensing-gas drive) or the initial composition (vaporizing-gas drive) lies outside the region of tie-line extensions on a ternary phase diagram (Helfferich, 1981; Dumore *et al.*, 1984; Lake, 1989; Larson, 1979).

Fig. 1.13 illustrates the partially miscible (PM), multi-contact miscible (MCM), and first-contact miscible (FCM) regions for an enriched-gas displacement (condensing mechanism) of the specified oil (20% C₃, 80% C₁₆). The minimum enrichment for miscibility (MME) occurs when the injection gas lies on the critical tie-line extension. In Fig. 1.13, the MME occurs at approximately 53% C₃ enrichment on the methane-propane axis of the ternary diagram.

Walsh and Orr have thoroughly analyzed the effect of dispersive mixing on composition paths and recovery for vaporizing gas drives (Walsh and Orr, 1990). Their main conclusion is that dispersion causes a MCM displacement to develop two-phase flow, which reduces recovery. They showed that the shape and size of the two-phase region controls the sensitivity of recovery to the level of dispersion. Recovery in their simulations was more sensitive to the Peclet number for displacements where the angles

between the dilution line (the line that connects the gas and oil compositions) and the tie lines are large.

Fig. 1.14 illustrates the sensitivity of recovery to the Peclet number. At a low Peclet number of 10, which corresponds to a large level of dispersive mixing, recovery is substantially reduced. For a Peclet number greater than 100, the recovery of C_{16} is nearly 100% at the MME. Thus, for slim-tube displacements where the Peclet number is on the order of 1000, recovery in a three-component system is generally very high at the MME. Furthermore, the "knee" in the recovery curve occurs at the MME even for large levels of dispersive mixing.

Mixing in Four-Component Displacements

When more than three components are present, the displacement process can display features of both condensing and vaporizing drives (Johns *et al.*, 1993b; Zick, 1986). Recent mathematical theory has shown that, when a fourth component is added, displacements can be MCM even when the oil or gas lies within the region of tie-line extensions on a quaternary diagram (Dindoruk *et al.*, 1992; Johns *et al.*, 1993b; Johns, 1992; Wang and Orr, 1998; Johns and Orr, 1996). A third key tie line, the crossover tie line, was shown to play an important role in the development of miscibility for combined condensing/vaporizing displacements (CV).

In dispersion-free flow, four-component displacements consist of two back-to-back displacements that are similar to the ternary patterns (Johns, 1992). Fig. 1.15 illustrates a typical composition route on a quaternary diagram, in which the gas and oil contain all four components. The composition route follows a "vertical" surface from the initial oil composition **O** and oil tie line, switches to a "horizontal" surface at the crossover tie line, and then follows along the horizontal surface until the gas tie line and injection gas composition **I** is reached. The crossover tie line is aptly named (Monroe *et al.*, 1990) as it is the only tie line that lies in both surfaces and serves to connect successive pseudoternary displacements. Each pseudoternary displacement can be either vaporizing or condensing. In a CV flood, the downstream portion of the displacement is condensing and the upstream portion is vaporizing.

Multi-contact miscibility in four-component displacements is developed when any of the key tie lines (i.e. the gas tie line, the oil tie line, or the crossover tie line) becomes a

critical tie line as the pressure or enrichment is increased. For CV displacements, the crossover tie line controls the development of miscibility, and therefore, the oil or gas composition does not lie outside of the region of tie-line extensions for MCM flow as it must for ternary displacements (Johns *et al.*, 1993b). The signature of a CV displacement is that component K-values converge towards unity in the upstream direction during the condensing portion of the CV displacement and diverge from unity during the vaporizing portion. Hence, the crossover tie line which connects the condensing and vaporizing displacements is the tie line nearest the critical locus in a partially miscible (PM) displacement.

Effect of Dispersion on Composition Paths

Dispersive mixing causes the composition paths in a gas flood to enter deeper into the two-phase zone, regardless of whether the displacement consists of three components³ or more than three components (Stalkup, 1998; Johns *et al.*, 1993a). Fig. 1.16 shows a phase diagram of a $C_1/C_3/C_6/C_{16}$ quaternary system at 2000 psia and a temperature of 200°F in which oil **O** is displaced by gas **I**₁ (90% C_1 , 10% C_3) (Johns *et al.*, 1993b). Numerical simulations of the PM displacement were made for varying numbers of grid blocks that correspond to Peclet numbers of approximately 10, 100, and 1000. The composition paths from these simulations are plotted in Fig. 1.16 along with the dispersion-free composition path (MOC solution is equivalent to $N_{pe} = \infty$). Oil **O** is a three-component oil that contains only C_1 , C_6 and C_{16} (i.e. oil **O** lies on the bottom ternary face of Fig. 1.16 and contains 20% C_1 , 40% C_6 , and 40% C_{16}).

As stated previously, the dispersion-free composition path must lie on two surfaces, the vertical and horizontal surfaces as illustrated in Fig. 1.15. The composition path for the MOC solution in Fig. 1.16 consists of a sequence of rarefaction waves and shocks that connect compositions **A**, **B**, **C**, and **D**, to oil **O** and gas **I** (see Fig. 1.15) (Johns *et al.*, 1993b). Compositions **B** and **C** lie on the crossover tie line, which is at the intersection of the vertical and horizontal surfaces. Composition **D** lies on the gas tie line and **A** lies on the oil tie line.

Fig. 1.16 shows that the effect of dispersion causes composition paths to deviate from the horizontal and vertical surfaces, and enter deeper into the two-phase zone. That is, the effect of dispersion is to cause the displacement path to follow vertical and

horizontal surfaces more distant from the critical locus (i.e. develop a new "apparent" crossover tie line further from the critical locus). This effect is similar to that seen by Walsh and Orr in three-component systems (Walsh and Orr, 1993) where they state that competition between dispersion and sharpening behavior of the shocks establishes a composition deeper into the two-phase region. Once the composition in the two-phase zone is established, the composition path follows a path similar to that calculated by MOC.

As the Peclet number is reduced, Fig. 1.16 shows that the deviation of the composition path away from the critical locus becomes larger. The maximum possible deviation occurs for a Peclet number of zero when the composition path approaches a dilution (mixing) line between the oil and injected gas. As the Peclet number is increased, however, the composition path approaches the MOC solution, as it should.

Fig. 1.17 shows the saturation and composition profiles for the paths of Fig. 1.16. As dispersive mixing is increased (smaller Peclet number), the size of the two-phase zone is somewhat increased, which causes faster breakthrough of the injected gas, and lower oil recovery. The effect of the same level of dispersion on oil recovery, however, is dependent on the level of enrichment.

Effect of Dispersion on Oil Recovery

The vertical and horizontal surfaces play an important role in the effect of dispersion on oil recovery. The composition paths with dispersion follow vertical and horizontal surfaces that are deeper into the two-phase region than they otherwise would be without dispersion. Thus, recovery is reduced as dispersion is increased for the same level of enrichment.

Fig. 1.18 shows the oil recovery for displacements of oil **O** by gas **I** in Fig. 1.16 as a function of pore volumes injected (PVI). As the Peclet number is decreased (mixing is increased), recovery of the C_6 and C_{16} components in the oil are decreased. The decrease in recovery at the same PVI increases as the Peclet number for the displacement is decreased. That is, the decrease in recovery from a Peclet number of 100 to 10 is greater than the decrease in recovery from a Peclet number of 1000 to 100.

Effect of Dispersion and Enrichment on Oil Recovery

When enrichment of the injected gas is increased, recovery increases but the rate of increase is dependent on the level of dispersive mixing. The sensitivity of dispersion to recovery is dependent, among other things, on several key enrichment compositions.

Fig. 1.19 illustrates the key enrichments for displacement of the three-component oil **O** by an injection gas that consists only of C_1 and C_3 (along the methane-propane axis of Figs. 1.16 and 1.19). Composition **I** in Fig. 1.16 is the same as **I₁** in Fig. 1.19. The MME for the displacement occurs at approximately 39% C_3 enrichment, which is indicated by injection gas **I₂** in Fig. 1.19a (Johns *et al.*, 1993b; Subramanian, 1998). The MME occurs at **I₂** even though the injection gas and oil **O** lie within the region of tie-line extensions (see Fig. 1.19b for a better view of the ternary $C_1/C_3/C_{16}$ face in Fig. 1.19a). This is in contrast to three-component systems where the gas lies on the critical tie-line extension at the MME (see Fig. 1.13).

Displacements of oil **O** by gases with enrichment below the MME are partially miscible floods (PM). As the enrichment is increased beyond the MME multi-contact miscibility occurs (MCM flow). When the gas is enriched to composition **I₄** (47% C_1 , 53% C_3), the gas lies on the critical tie-line extension. Composition **I₄** corresponds to the MME for the three-component displacement shown in Figs. 1.13 and 1.14 (i.e. displacements that contain no C_6). As the gas is enriched further from **I₄**, the gas will lie outside the region of tie-line extensions. Composition **I₆** (39% C_1 , 61% C_3) is eventually reached where the gas is first-contact miscible (FCM) with the oil. Thus, the MCM region from the MME to FCM (**I₂** to **I₆**) can be divided into two regions: MCM1 and MCM2. MCM1 is defined where the injection gas remains in the region of tie-line extensions (from **I₂** to **I₄**), whereas MCM2 occurs when the gas lies outside the region of tie-line extensions (**I₄** to **I₆**) as shown in Fig. 1.19. Composition **I₄**, therefore, is a critical gas enrichment (CGE) that divides the MCM1 and MCM2 regions.

The location of the injection gas with respect to the region of tie-line extensions (i.e. in regions MCM1 or MCM2) is important in the determination of the effect of dispersive mixing on the rate of recovery. Fig. 1.20 gives the recovery calculated from the numerical simulations of oil **O** displaced by gases of various enrichments. As is shown, recovery of C_6 and C_{16} in the oil increases as enrichment is increased. The rate of

increase, however, is dependent on the MME and the CGE. For example, for a Peclet number of 1000, recovery increases significantly to the MME, but the rate of increase slows for enrichments beyond the MME. Such a level of dispersive mixing may be similar to what occurs in slim-tube displacements where a "knee" in the recovery curve occurs at the MME. For displacements with a greater amount of dispersive mixing (i.e. Peclet numbers of 100 and 10), however, the "knee" in the recovery curve occurs at the boundary of MCM1 and MCM2 (at the critical gas enrichment $\mathbf{I}_4$), not at the MME. In fact, the rate of recovery is the greatest in region MCM1 when the displacement occurs at a Peclet number of 10. This effect of dispersion on oil recovery cannot occur for three-component displacements where only one MCM region exists.

In region MCM2, the gas lies outside the region of tie-line extensions where no horizontal surface is possible. Thus, recovery is increased compared to MCM1, because there is less competition between dispersion and the sharpening behavior of the displacement. That is, in MCM1 recovery is less than in MCM2, because the path must follow tie lines along a horizontal surface that takes the displacement further away from the critical locus. The "apparent" crossover tie line in region MCM2, found by the dispersive path, is closer to the critical locus than that of the "apparent" crossover tie line that develops for MCM1. The greater the dispersive mixing (the lower the Peclet number), the more distant the crossover tie line moves from the critical locus and the greater the reduction in recovery. In the limit of dispersion-free flow, there is no crossover tie line in either MCM1 or MCM2 and recovery is 100%.

Effect of Enrichment on Displacement Mechanisms

The conclusion that there is no horizontal surface in MCM2 displacements with dispersion necessarily implies that the mechanism of the displacement must be different in MCM1 as compared to MCM2. Fig. 1.21 shows the K-values for each component in displacements of oil $\mathbf{O}$ by varying levels of gas enrichment. K-values are set to 1.0 in single-phase regions.

Fig. 1.21a shows the K-values for the PM displacement of oil $\mathbf{O}$ by gas $\mathbf{I}_1$ shown in Fig. 1.19b. This displacement shows an hourglass shape indicative of CV behavior. That is, K-values initially converge in the upstream direction (condensing portion) and then diverge (vaporizing portion). As enrichment is increased, the size of the two-phase

region shrinks. At the MME (Fig. 1.21b), the displacement again shows CV behavior, but the importance of the vaporizing portion of the displacement is reduced (i.e. K-values are closer to 1.0 in the vaporizing portion than they are in Fig. 1.21a). The reason for the reduction in vaporizing behavior as enrichment increases is that the horizontal surface shrinks (see Fig. 1.21c for gas I_3 in MCM1), but the vertical surface is essentially the same because the oil composition has not changed. Eventually, at the critical gas enrichment I_4 , the horizontal portion of the displacement no longer exists and the vaporizing behavior disappears (see Fig. 1.21d). Thus, displacements with dispersion in the PM and MCM1 regions exhibit the combined CV behavior, but above the critical gas enrichment I_4 (in region MCM2), the vaporizing portion of the displacement no longer exists and the displacement is purely condensing (see Figs. 1.21d and 1.21e). As enrichment is increased further to I_5 (in MCM2, see Fig. 1.19b), the importance of the condensing behavior decreases (i.e. K-values become closer). Eventually, FCM flow is reached at I_6 and single-phase flow occurs without any condensing or vaporizing behavior. Recovery for FCM flow at 1.2 PVI primarily depends on the level of dispersion (see Fig. 1.20).

Effect of Dispersion on Displacement Mechanism

The displacement mechanism does not change with the level of dispersion. Fig. 1.22 illustrates this for the displacement of oil O by an injection gas at the MME (I_2). As is shown, the K-values for displacements with Peclet numbers from 100 to 10000 give CV behavior. In fact, the CV behavior is accentuated as the Peclet number is increased because the "apparent" crossover tie line found by the dispersive path is closer to the critical locus where K-values are equal to 1.0. Only the size of the two-phase region shrinks as the Peclet number is increased, not the overall magnitude of the K-values. Fig. 1.22 also demonstrates that at the MME the combined CV behavior exists no matter the level of dispersive mixing. Only in the limit of dispersion-free flow where flow is single-phase will CV behavior vanish.

Fig. 1.23 illustrates a similar point for displacements of oil O by an injection gas at the CGE (I_4 that separates regions MCM1 and MCM2). In Fig. 1.23, the size of the two-phase region again shrinks as the Peclet number is increased and the condensing behavior remains. CV behavior does not abruptly appear as the level of mixing is

reduced. In the limit of dispersion-free flow where only single-phase flow exists above the MME, the condensing behavior vanishes.

Effect of Oil Composition on Recovery

The oil composition can significantly affect the nature of the displacement if the new oil composition causes the vertical surface to shift with respect to the critical locus. For oils that lie on the same tie line, however, the nature of the displacement should be similar because the vertical surface will not have changed (Johns *et al.*, 1993b; Johns, 1992; Dindoruk, 1992). Fig. 1.24 illustrates this point for a bubblepoint oil $\mathbf{O}_1$ that contains more methane (about 40% C_1) than oil $\mathbf{O}$ (about 20% C_1), but remains on the original oil tie line as oil $\mathbf{O}$ (see Fig. 1.19). The recovery curves for both oils show the same overall features for displacements with a Peclet number of 100. That is, the "knee" in the recovery curves occurs at the same CGE $\mathbf{I}_4$ that separates the MCM1 and MCM2 regions. The only difference is that the recovery curve for the bubblepoint oil $\mathbf{O}_1$ is more sensitive to enrichment, because a larger and faster methane bank develops with $\mathbf{O}_1$ than with $\mathbf{O}$ (Johns *et al.*, 1993).

Effect of Mixing in a $\text{CH}_4\text{N}_2/\text{C}_{2+}/\text{C}_{5+}/\text{C}_{30+}$ System

The effect of dispersive mixing on the recovery of the displacement depends significantly on the phase behavior. Fig. 1.25 shows a phase diagram of another four-component system used by Johns *et al.* (1993a) to describe a 12-component oil. In this $\text{CH}_4\text{N}_2/\text{C}_{2+}/\text{C}_{5+}/\text{C}_{30+}$ system, regions MCM2 and FCM do not exist for gas compositions on the $\text{CH}_4\text{N}_2/\text{C}_{2+}$ axis of the quaternary diagram. Only PM and MCM1 flow can occur because gas enrichments along the $\text{CH}_4\text{N}_2/\text{C}_{2+}$ axis always lie within the region of tie-line extensions. Nevertheless, the system illustrates that the sensitivity of oil recovery to dispersive mixing can vary greatly depending on the phase behavior.

Fig. 1.26 gives the recovery of C_{5+} and C_{30+} with enrichment at 1.2 PVI for two levels of dispersion. The "knee" in the recovery curve occurs near the MME (29% CH_4N_2 , 71% C_{2+}) for Peclet numbers of 100 and 10. This is different than the recovery curves for the previous four-component system (see Fig. 1.20) where the "knee" occurred at much greater enrichments than the MME (i.e. the "knee" occurred at the CGE).

The reason for the reduced sensitivity of recovery to dispersion above the MME is probably related to the angularity of the tie lines with respect to dilution lines between the oil, the crossover tie line, and the gas. An inspection of the tie lines in Fig. 1.25 reveals that the tie lines angle upward towards the injection gas. This is in contrast to the $C_1/C_3/C_6/C_{16}$ system where the tie lines are reversed.

Discussion

The choice of enrichment examined here is based purely on one-dimensional theory. The one-dimensional theory allows us to examine the impact of dispersion on local displacement efficiency, one of the key components in determining the recovery efficiency. If the displacement efficiency shows little increase with enrichment above the MME, the economic optimum will likely be near or below the MME. Thus, it is useful to examine first how the local displacement efficiency is affected by dispersion. If the benefit were large, other factors such as heterogeneities, gravity, and related sweep factors should be considered to determine the field optimum.

The CV four-component system in Fig. 1.20 exhibits a clearly defined CGE substantially above the MME. The CV system in Fig. 1.26, however, does not have the same behavior. Nevertheless, there may still be some potential benefit to selecting enrichments above the MME even for that system. Because enrichment can be expensive, the economic optimum will likely depend on many factors including the supply of enriching components. In some cases, the economic optimum may be to reduce enrichment below the MME and accept some loss in oil recovery.

The $C_1/C_3/C_6/C_{16}$ system in Fig. 1.20 demonstrates that enriching the injection gas above the MME could substantially increase recovery for certain systems. For real field displacements, however, where many more components exist, flow is more complex and the identification of the CGE may be more difficult. For such multicomponent displacements, it is likely that the MCM region can be divided into many sub-MCM regions because additional crossover tie lines exist (Johns *et al.*, 1993b; Wang and Orr, 1998). Each region may have a different sensitivity of oil recovery to dispersion. Recovery curves for small Peclet numbers may become smoother without the abrupt "knee" evident in Figs. 1.20 and 1.24 (Sah and Johns, 2000).

The research presented here also has implications to the interpretation of recoveries from core-flood and slim-tube experiments. Slim-tube results that identify the "knee" in the recovery curves may be misleading in that the level of dispersive mixing is probably smaller than that in the field (Stalkup, 1998).

The conclusion that displacement mechanisms vary with enrichment levels also has important implications to methods used to estimate the MME and MMP. Multiple mixing cell methods that rely on compositional simulations could be adversely affected by dispersion when the injection gas or pressure used in the simulations is above the MMP or MME (Hearn and Whitson, 1995). In such cases, mixing cell methods that attempt to account for dispersion must recognize that displacement mechanisms may change as the enrichment or pressure is altered. Methods that identify the MME and MMP based on dispersion-free theory may have an advantage in that the effect of dispersion is no longer a variable (Wang and Orr, 1998; Johns and Orr, 1996).

Conclusions

The effect of enrichment and dispersive mixing on oil recovery and the displacement mechanism was considered for one-dimensional displacements in several four-component systems. The results of the study are as follows:

1. Oil recovery for certain systems can be substantially increased above the MME for displacements with Peclet numbers less than 1000.
2. The magnitude of the effect of dispersion and enrichment on recovery depends on the size and shape of the two-phase region considered.
3. The "knee" in the recovery curves can occur at a critical gas enrichment (CGE) much greater than the thermodynamic MME.
4. In four-component systems, the MCM region is divided into two regions by the CGE. Each region exhibits a different sensitivity to dispersion.
5. The displacement mechanism changes from a combined condensing/vaporizing displacement to a condensing one at the CGE.
6. A one-dimensional screening analysis can be used to estimate the potential benefit of enriching above the MME. If a significant benefit exists, further 2-D and 3-D field studies may be warranted to identify the economic optimum.

Mixing in Twelve-Component Displacements

The main focus of this part of the research is to extend the work for four-component systems to displacements of a twelve-component oil by solvents enriched above the MME. The effect of realistic levels of dispersive mixing on the displacement efficiency of the floods are examined. The slope in the recovery curves is used to quantify the effect of dispersion on the displacement efficiency. We also show how dispersion and enrichment affect the CV displacement mechanisms. The displacement mechanisms of the miscible process are exactly quantified for the first time using "dispersion-free" theory. We use numerical dispersion in this research to mimic physical dispersion.

The twelve-component system considered here is the same as that used by Stalkup (1998) and Solano and Johns (2000). The oil contains twelve components and the injection gas contains five. The gas at zero enrichment is a lean gas mixture. The enriched gas at 100% enrichment is a five-component solvent.

Johns and Orr (1996) showed that for a twelve-component displacement there are eleven key tie lines ($n_c - 1$ for a multicomponent system): the oil tie line, nine crossover tie lines, and the gas tie line. The analytical displacement path for "dispersion-free" flow is determined by first finding the key tie lines and then applying geometric constructions to locate the key compositions of the displacement. The composition path for the twelve component system traverses ten ruled surfaces ($n_c - 2$ surfaces for a multicomponent system). Each ruled surface is bounded by the key tie lines. MCM flow is developed when any of the key tie lines becomes a critical tie line as the pressure or enrichment is increased.

Effect of Dispersion on Recovery

Fig. 1.27 gives the recovery calculated from the UTCOMP simulations of the twelve-component oil displaced by gases of varying enrichment. As shown, recovery increases as enrichment is increased, consistent with the results obtained for a four-component system. At a Peclet number of 1000, which corresponds to the level of mixing that may be present in a slim-tube experiment, the "knee" occurs at the MME of about 60% enrichment with solvent. For smaller Peclet numbers, however, the location of the

"knee" shifts towards larger enrichments. At a Peclet number of 10, which is representative of the level of mixing that may occur in a reservoir, the "knee" shifts to an enrichment of about 85% solvent. Fig. 1.28 demonstrates that the shift in the "knee" is approximately linear with the Peclet number, unlike the three- and four-component systems.

Fig. 1.27 also demonstrates that the increase in recovery with enrichment above the MME can be substantial. For example, the oil recovery increases by 7% OOIP from the MME of 60% to the "knee" of about 72%. For a Peclet number of 10, the increase is on the order of 15% OOIP from the MME to the "knee" at about 85%. The slopes of the recovery curves in Fig. 1.27 are plotted in Fig. 1.29. Similar to the four-component case (Fig. 1.30), the slope of the recovery curve at the MME is independent of the level of dispersion.

Displacement Mechanism

Figs. 1.31 and 1.32 show the component K-values for different levels of dispersion and enrichment. The "hour-glass" shapes of the curves in the figures demonstrate that CV behavior exists at all enrichments. Unlike the four-component example, the gas tie line for the twelve-component system remains within the region of tie-line extensions even for injection of pure solvent (see Fig. 1.33). Thus, no MCM2 or FCM region exists for the twelve-component system. The CGE, therefore, cannot be reached and the displacement mechanism for the twelve-component system cannot exhibit purely condensing behavior. Fig. 1.32 also illustrates that as enrichment is increased, the size of the two-phase region shrinks for a constant level of dispersion. The K-values are set to unity in the single-phase regions.

Discussion

The choice of enrichment examined here is based purely on one-dimensional theory. The one-dimensional theory allows us to examine the impact of dispersion on local displacement efficiency, one of the key components in determining the recovery efficiency. When the displacement efficiency shows little increase with enrichment above the MME, the economic optimum will likely be near or below the MME (assuming that the injected gas density and viscosity changes little with enrichment). Thus, it is useful to examine first how the local displacement efficiency is affected by dispersion. If a large

benefit exists, other factors such as heterogeneities, gravity, and related sweep factors should be considered to determine the field optimum.

Conclusions

The effect of dispersive mixing on local displacement efficiency and displacement mechanisms was studied for four and twelve-component displacements. For these systems, the results show:

1. The displacement efficiencies for both the four and twelve-component systems substantially increase as enrichment increases above the MME. The twelve-component system recovery increased by 15% OOIP from the MME (60% solvent) to 85% solvent.
2. The rate of increase in the recovery with enrichment can be greater above the MME than below the MME at dispersive levels (mixing) found in reservoirs. The slope of the recovery curves is independent of the level of dispersion at the MME.
3. The 1-D calculations can be used to identify when a large benefit in recovery with enrichment above the MME may exist. If a large benefit does not exist, the optimum enrichment is likely near or below the MME and further 2-D and 3-D studies may be unwarranted.
4. The fraction of a displacement that is vaporizing or condensing can be quantified by calculating the compositional distances traversed by the displacement path along key ruled surfaces. The procedure can be used to compare the mechanisms between different oil and gas displacements.

Impact of Dispersion on Two-Dimensional Shallow Enriched-Gas Floods

Gas enrichment is an important optimization variable in enriched-gas drives. Recoveries from slimtube experiments often give a sharp bend at the minimum enrichment for miscibility (MME). Above the MME, slimtube recoveries do not increase significantly with enrichment. The optimum enrichment required to maximize recovery on a pattern scale in the field, however, is likely different from the MME. The difference in the optimum enrichment may be largely the result of greater mixing in the reservoir than exists in slimtubes. In addition, enrichment may impact sweep efficiency in 2-D

displacements. Oil and gas mixing in a reservoir can include mechanisms such as molecular diffusion, mechanical dispersion, gravity crossflow, viscous crossflow, and capillary crossflow.

There are several reasons why recovery could increase for enrichments beyond the MME. First, the density and viscosity of the gas will increase with enrichment, which may improve sweep efficiency. Second, mixing can cause an otherwise multicontact miscible flood (MCM) to develop some two-phase flow (Johns *et al.*, 1993; Walsh and Orr, 1990; Pande and Orr, 1989; Lake, 1989). Richer gases mix closer to the critical locus in the two-phase zone, which causes a smaller and slower lean gas bank. A smaller lean gas bank could improve sweep efficiency. Last, richer gases, which mix near the critical locus, decrease "miscible residual oil" by increasing the velocity of the trailing evaporation fronts.

Several authors have examined the effect of mixing and enrichment above the MME on oil recovery. Johns *et al.* (2000a; 2000b) recently considered the effect of dispersion on recovery in one-dimensional displacements. They showed that the "knee" in the recovery curve from slimtube experiments depends on the level of dispersion. For small dispersivities typical of slimtubes, the knee occurs at the MME. For greater levels of mixing, they showed that the knee in recovery could occur at enrichments much greater than the MME.

Chang (Chang *et al.*, 1993) matched coreflood displacements with reservoir simulations at different enrichments. He showed that recovery increased sharply for enrichments above the MME. Chang concluded that the increased recoveries were due to higher displacement and sweep efficiencies as the enrichment level increased. The better sweep efficiency was attributed to increased gas density with enrichment. Jerauld (1998) also observed an increase in recovery above the MME. Giraud *et al.* (1977) observed that the highest recovery occurred at pressures above the minimum miscibility pressure (MMP).

Stalkup (1998) showed that significant additional recovery might be obtained by injecting enriched gases above the MME. A significant increase in recovery occurred for longitudinal dispersivities as low as 0.3 ft when the solvent and water were injected in slugs. He also concluded that mixing of solvent and oil by viscous crossflow during WAG might dominate other mixing mechanisms in the reservoir, i.e. dispersion. Thus, he

suggested that predictions of oil recovery from coarse grid blocks might be accurate as long as the vertical gridding is sufficient to capture the effect of viscous crossflow during WAG. Stalkup also showed that simultaneous grid refinement in horizontal and vertical directions caused numerical dispersion to overestimate the recovery with gas enrichment beyond the MME (Stalkup *et al.*, 1990; Stalkup 1990; Stalkup 1987). Other researchers have also examined the effect of viscous crossflow, capillary pressure, diffusion, gravity, heterogeneities, and numerical gridding on recovery (Lim *et al.*, 1997; Lim, 1993; Fayers, 1992).

Pande (1992) obtained contradictory results from that of Stalkup. For the 2-D cases considered, she showed that the optimal enrichment might be below the MME, not above it. Pande, however, did not examine the effect of gridding or gas trapping on the results. She also used a fluid characterization that exhibited a small sensitivity of displacement efficiency to dispersion making her results sensitive only to sweep efficiency. Nevertheless, her results indicate that the optimal enrichment is highly problem dependent.

This research provides further evidence to support the conclusions of Stalkup (1998). The first part of the research describes the method and model used. The remaining portion of the research investigates how mixing and enrichment above the MME for a variety of cases, including reservoir heterogeneity, WAG, slug injection, relative permeabilities and gas trapping, affect recovery. Only the effect of mixing by dispersion, viscous crossflow, and gravity crossflow are considered. Physical dispersion is mimicked by numerical dispersion.

Methodology

The simulations were performed using the numerical code UTCOMP (Chang 1990), a fully compositional simulator developed at The University of Texas at Austin. UTCOMP uses a volume-based IMPES method to solve the compositional model equations. One advantage of the code for this research is that it includes higher-order total-variation-diminishing methods, which can be used to reduce numerical dispersion effects (Liu *et al.* 1995). UTCOMP also allows for direct input of physical dispersivities.

Table 1.1 presents important properties of the fluids and reservoir properties used in the simulations. Phase behavior was modeled using the Peng-Robinson equation of

state (PREOS) (Peng and Robinson, 1976). All input parameters and fluid properties for the PREOS are similar to those used by Stalkup (1998). The initial oil, which consists of 12-components, has a bubble-point pressure of approximately 4170 psia. Injection gases consist of a lean gas mixed with a five-component solvent to enrichments of 65 and 85 percent. Both of these enrichments are above the MME of about 60 percent.

For all cases, the dimensions of the reservoir are 1000-ft long (x) by 800-ft wide (y) by 20-ft high (z). We used 10 grid blocks in the vertical direction for all 2-D simulations, unless otherwise specified. The injection well (at $x = 0$ ft) and production well (at $x = 1000$ ft) are completed through all vertical grid blocks. The gas injection rate is 151.1 MSCF/day, which corresponds to a fluid velocity of about 1.3 ft/day through the reservoir. The water injection rate is 98.69 bbl/day. The bottom-hole pressure of the production well is constant at 4100 psia (slightly below the bubble point). Average reservoir pressure in the simulations was relatively constant at about 4150 psia so that pressure dependence on recovery can be ignored. An initial water saturation of 0.32 is specified for all grid blocks, independent of heterogeneity.

Both slug and WAG injection are examined in this work. For slug injection, 0.20 HCPV of gas is injected followed by a 1.0 HCPV waterflood. For WAG, 0.3 HCPV of water is injected followed by 0.2 HCPV gas and 0.2 HCPV of water in six alternating cycles. Each cycle therefore, consists of 0.033 HCPV gas and 0.033 HCPV water injection. The six alternating cycles are followed by a 0.5 HCPV waterflood. Total injection of fluids for either WAG or slug injection is 1.2 HCPV.

Two three-phase relative permeability relationships are used: RELPM1 and RELPM2. RELPM1 is based on the two-phase relative permeability curves for oil-water, gas-water, and gas-oil given by Jerauld (1997). A Land-type equation accounts for trapped gas as a function of the maximum gas saturation. These two-phase curves are similar to those used by Stalkup.¹⁰ We used Stone II to compute the three-phase relative permeabilities.

RELPM2 is based on the relative permeability data given by Killough (1987). We adjusted the irreducible water saturation to 0.32 and the oil-water residual oil saturation to 0.128 (see Table 1.1). RELPM2 does not include trapped gas. Additional details of the relative permeability curves used and other model parameters can be found in Solano (2000).

Reservoir Dispersivity

In the simulations, we used numerical dispersion to model mechanical dispersion. Lantz (1970) showed that numerical dispersion arises in the numerical solution due to truncation errors, which can be described by a one-phase Peclet number. For two immiscible phases the numerical Peclet number for 1-D displacements is given by Eqs. 1.16 and 1.17. For convective-dominated flow, numerical dispersivities from Eq. 1.17 are given by $\Delta x/2$. Eq. 1.17 generally provides a good representation of the true level of mechanical dispersion for single-point upstream weighting (Stalkup, 1998; Solano, 2000). In all simulations presented here, the dimensionless time-step was less than one-hundredth of the dimensionless grid-block size in the x-direction to ensure that the time-step size did not contribute to the level of numerical dispersion. We also compared recoveries for different time-step sizes to ensure that the time-step size did not affect the results.

Eq. 1.17 is not valid for higher-order methods, which give non-Fickian dispersion. Nevertheless, higher-order methods are useful to reduce numerical dispersion levels from that of single-point weighting. The dispersivity estimated by a "best fit" of concentration data using two-point upstream weighting is typically about three to four times smaller than numerical dispersivities estimated from single-point upstream weighting (see Fig. 1.34). For example, a dispersivity with single-point weighting of 2.5 ft can be reduced to an effective dispersivity of 0.7 ft with two-point weighting (Stalkup 1998; Solano 2000). For three-point upstream weighting, the dispersivity can be further reduced to about 0.3 ft. For floods above the MME, Solano (2000) demonstrates that the recoveries and saturation and composition profiles for the different weighting methods are similar when the same level of effective dispersion is used.

Although there is considerable disagreement about the true value of dispersivity at the field scale, Stalkup (1998) suggested that dispersivities of about 0.1 to 2 ft might be reasonable. In the simulations presented here, a dispersivity of 2 ft corresponds to about 250 grid blocks in the x-direction. This suggests that a substantial number of grid blocks may be required to model the true level of mechanical dispersion in a reservoir.

Results

Results are presented for eight cases of different reservoir models, injection boundary conditions, and relative permeabilities. Solano (2000) gives color saturation plots for all cases examined here. The cases considered are:

Case 1: 1-D homogeneous, slug injection, RELPM1

Case 2: 1-D homogeneous, slug injection, RELPM2

Case 3: 2-D homogeneous, slug injection, RELPM1

Case 4: 2-D homogeneous, slug injection, RELPM2

Case 5: 2-D w/ discontinuous shales, slug injection, RELPM1

Case 6: 2-D w/ discontinuous shales, WAG, RELPM1

Case 7: 2-D layered model, WAG, RELPM1

Case 8: 2-D layered model, slug injection, RELPM1

Case 1. In this example, oil is displaced in a 1-D horizontal flood (x-direction) by a 0.2 HCPV slug of enriched-gas. The slug of enriched-gas is then driven by water until 1.2 HCPV of total fluid is injected. Fig. 1.35 gives the recovery for two levels of enrichment as a function of dispersion. Dispersion is varied by using 40, 60, 100, 200, and 500 grid blocks. To reduce dispersion further, the same simulations were conducted using two-point and three-point upstream weighting. These results are also presented in Fig. 1.35. For one-point upstream weighting, the range of dispersivity varies from approximately 1.0 ft (500 grid blocks) to 12.5 ft (40 grid blocks).

As expected, recovery increases monotonically as dispersion decreases. That is, recovery increases as the grid-block size is reduced or when higher-order methods are used. For example, for 65 percent enrichment and one-point weighting, oil recovery increases by 10 percent from a dispersivity of 12.5 ft to 1.0 ft. Fig. 1.35 also shows that recovery extrapolated to zero dispersion approaches a value significantly less than 1.0, i.e. calculated analytical to be about 0.75. The reduced recovery at zero dispersion occurs because all of the enriched-gas is trapped prior to complete displacement of the oil (maximum trapped gas in RELPM1 is 0.29). After the injected gas is trapped, oil is displaced only by water, thus leaving behind significant oil.

Fig. 1.36 presents the difference in recovery between displacements at 85 and 65 percent enrichment. The difference generally increases with greater dispersion and with

the use of lower-order methods. Additionally, the extrapolated value of recovery difference is zero when dispersion is zero. The low-dispersion limit is as expected, because recovery should be independent of enrichment for dispersion-free 1-D miscible flow, i.e. method of characteristics limit (Lake 1989). The recovery curve for single-point weighting, however, shows an "anomalous" response, in that a maximum in recovery difference occurs at a dispersivity value of 5.1 ft. The maximum occurs because recovery with 65 percent enrichment has a different sensitivity to dispersion than when 85 percent enrichment is used (Solano, 2000). Johns *et al.*, (2000a) showed that the sensitivity for 1-D displacements with enrichments above the MME depends on the phase behavior, i.e. primarily the compositional direction of the tie lines. The two and three-point weighting curves do not show a maximum because they are obtained at estimated dispersivities less than 5.1 ft.

Fig. 1.37 illustrates more clearly the trend in recovery difference by plotting all 1-D simulations and a few additional points at larger dispersivities on the same dispersivity scale. (The effective dispersivities for two-point and three-point weighting are calculated from Fig. 1.34). Although the dispersivities are only approximate, Fig. 1.37 shows excellent agreement between all weighting methods. The difference in recovery peaks at eight percent near a dispersivity of 4 ft. For the low-dispersivity range (below 4 ft), the recovery difference is very sensitive to dispersion. Above 4 ft, the difference in recovery is not as sensitive to dispersion, but does decrease asymptotically to the high-dispersion limit at about 1.4 percent for case 1. The results for case 2 asymptote to a different value, as will be explained in the discussion of case 2 results. The high-dispersion limit, which corresponds to a single-cell-mixing model, can be approximated analytically or numerically. The composition path for infinite dispersion lies on a line in composition space that connects the oil and enriched-gas compositions (Johns *et al.*, 2000a).

The results also indicate that for slimtube displacements where dispersivity is very small, recovery differences for enrichments beyond the MME are small. For greater levels of dispersivity found in reservoirs (i.e. 0.1 – 2 ft), however, recovery differences are very sensitive to dispersion and could be significant.

Case 2. Case 2 is similar to case 1, except that RELPM2 is used. Fig. 1.38 gives the recovery for two levels of enrichment and each weighting method as a function of dispersion. The behavior is similar to case 1; recovery increases monotonically as

dispersion decreases. For single-point upstream weighting, the increase is about 15 percent for a change in dispersivity from 12.5 ft to 1.0 ft. Unlike case 1, however, the extrapolated recovery is 100 percent at zero dispersion. Recovery is 100 percent because no gas trapping is included in RELPM2, which allows the enriched-gas slug to completely displace the oil in the dispersion-free limit.

The difference in recovery for case 2 is very similar to case 1 (See Figs. 1.36 and 1.39). That is, the recovery difference for single-point upstream weighting shows a maximum. Fig. 1.37 gives the differences in recoveries for case 2 as a function of the estimated dispersivities for each weighting method. The trend for case 2 is nearly identical to that for case 1 at low dispersivities. For large dispersivities, the recovery differences separate and approach different high-dispersion limits (for case 2, the high-dispersion limit is about zero percent). This result suggests that the trend in recovery difference at 1.2 HCPV is relatively independent of relative permeabilities for dispersivities near or below that corresponding to the maximum in the recovery difference, i.e. range of possible dispersivity values for reservoirs.

Case 3. Case 3 is similar to case 1, except that the model is 2-D. Thus, dispersion, viscous crossflow, and gravity crossflow can affect recoveries. Ten grid blocks are used to refine the model in the z-direction. Because the vertical to horizontal permeability ratio is 1.0, a gravity tongue develops at the top of the reservoir and a water tongue moves downward in the reservoir.

The recoveries for the 2-D model are lower than those in the 1-D model because of viscous and gravity crossflow (see Fig. 1.40). That is, recoveries are lower because of reduced sweep efficiency and greater overall mixing of gas with contacted oil. Generally, recoveries tend to increase as dispersion is reduced, although the behavior is not always monotonic. Hence, it is difficult to extrapolate recoveries to zero dispersion.

A plot of recovery differences shows a more distinct trend with dispersion than do the recoveries (see Fig. 1.41). There is a peak in the recovery difference of about 5 percent OOIP. The recovery differences generally decrease as dispersion approaches zero, although that limit is uncertain. This behavior is in some degree similar to the result obtained in the 1-D model because the gas tongue at the top of the reservoir is quasi one-dimensional (Stalkup, 1998). The maximum recovery difference is less than the 1-D

cases because the increase in displacement efficiency with enrichment above the MME is limited to the swept region of the gas tongue.

The trend shown in Fig. 1.41 for the 2-D floods cannot be collapsed to one curve as was done for the 1-D cases. This is because both longitudinal and transverse dispersion are present in 2-D displacements.

Case 4. In this example, RELPM2 is used. Otherwise, case 4 is the same as case 3. Recoveries for this case are relatively constant with dispersion, but much larger than for case 3, i.e. about 60% for case 3 compared with 78% for case 4 (Solano, 2000). The smaller recoveries with case 3 are primarily the result of gas trapping in RELPM1.

Fig. 1.42 shows the difference in recovery between 85 and 65 percent solvent slugs for the 2-D homogeneous model. The recovery difference is much lower than when RELPM1 is used (case 3, see Fig. 1.41). The maximum in recovery difference is also shifted to coarser grid-block sizes than for case 3. Thus, unlike the 1-D examples, the effect of relative permeability and gas trapping on recovery is important. The reason for this is probably related to changes in mobility contrasts, which induces changes in crossflow.

Case 5. We now consider the effect of various heterogeneities on recovery. Fig. 1.43 shows the location of three discontinuous shales in the model. Except for the addition of shales, these displacements occur under the same conditions as for case 3, i.e. RELPM1 and slug injection are used.

In this example, recoveries generally increase monotonically as grid-block size decreases. Recoveries for case 5 are about 5 percent OOIP larger than for case 3 primarily because the shales restrict vertical crossflow and allow for better sweep (Solano, 2000). Fig. 1.44 shows the differences in recovery between the 85 and 65 percent solvents. The recovery differences are generally greater and more sensitive to dispersion than for the case without shales (see case 3, Fig. 1.41). The recovery differences for each weighting method also clearly show a maximum, although they exhibit different trends. The differences in the trends are again probably related to differences in numerical dispersion in the z-direction with each weighting method.

Case 6. This example considers the effect of WAG on recovery differences between the 85 and 65 percent solvents. The same discontinuous shale layers as in case 5 are used. With WAG instead of slug injection, the difference in recoveries increases

somewhat as dispersion decreases (see Fig. 1.45) This trend is opposite of those seen in the previous five cases. In addition, the increase is more significant when the higher-order methods are used. For example, for two-point weighting, the increase in recovery differences is about 2 percent OOIP from 40 to 100 grid blocks. Such a result suggests that crossflow is very important when WAG is used, especially at low values of dispersivity. WAG apparently causes significant mixing independent of the grid-block size used. Stalkup observed similar behavior (Stalkup, 1998).

Case 7. For case 7 the model consists of ten equal-thickness layers of different permeability. The values of permeability are 5, 50, 30, 100, 50, 165, 50, 10, 100, and 40 md from the top of the reservoir to the bottom. The vertical to horizontal permeability ratio is 1.0 for all layers, which allows for maximum crossflow. WAG recoveries for case 7 are smaller than for case 6 by about 3 to 4 percent OOIP, primarily because of decreased sweep (Solano, 2000).

The recovery differences for case 7 increase as dispersion decreases, although the magnitude of the differences are about half of those for case 6 (compare Fig. 1.46 to Fig. 1.45). The increase in recovery difference is about 1 percent OOIP for the range of grid-block sizes examined.

Case 8. This case illustrates how channeling might significantly affect the recoveries with enrichment above the MME. Case 8 is the same as case 7, except that slug injection is used instead of WAG. Fig. 1.47 shows that the recovery differences with slug injection decrease substantially to near zero when three-point weighting is used. The decrease is caused by gas channeling through the largest permeability layer located in the center of the model (see Fig. 1.48). Channeling occurs only when the 85 percent enriched gas and three-point weighting is used because the denser gas reduces gravity crossflow to the top lower permeability layers (these results are similar to Pande (1992)). The three-point weighting method also reduces vertical mixing of the fluids, which enhances the potential for channeling. With WAG (case 7), gas channeling does not occur because significant vertical mixing is present.

Discussion

The interplay between dispersion, viscous and gravity crossflow, heterogeneities, phase behavior, and flow is complex. The results from these interactions are likely very

problem dependent. The results are also complicated by the fact that reservoir dispersivity is scale dependent and the true reservoir value is generally uncertain. Nevertheless, the work presented here offers some important insights.

The 1-D displacements demonstrate that the displacement efficiency depends significantly on dispersion, especially for dispersivities less than about 4 ft. Furthermore, recovery differences between two enrichments are not very sensitive to relative permeability/gas trapping for dispersivities in this same range. Unfortunately, simulations used to determine the enrichment required to maximize recovery on a pattern scale are usually performed with coarse grid blocks, i.e. numerical dispersivities greater than about 10 ft. The results from those simulations are suspect if one believes that reservoir dispersivities are less than about 2 ft as Stalkup (1998) suggests. In addition, the differences in the displacement efficiencies for two enrichments from coarse-grid simulations show greater sensitivity to relative permeability/gas trapping than if finer grids are used.

The 2-D displacements suggest that relative permeability/gas trapping may affect recovery differences over a larger range in dispersivity, including those between 0.1 and 4 ft. Crossflow, which is induced by contrasts in mobility, is sensitive to relative permeability and gas trapping. For systems with a much lower vertical to horizontal permeability ratio, crossflow is reduced and the 2-D displacements will approach the results of the 1-D simulations (Pande and Orr, 1989). For example, when horizontal shale layers are included in the model, the results are more similar to the 1-D displacements (see case 5).

The injection boundary condition may also have a significant affect on the recovery difference above the MME. If WAG is used instead of slug injection, the rate of change in the recovery difference changes sign. That is, the recovery difference increases somewhat, as dispersion becomes small. Thus, when WAG is used, the increase in recovery above the MME with enrichment could be substantial. WAG also tends to reduce the adverse effects of gas channeling on sweep.

Stalkup (1998) suggested that crossflow dominates dispersion effects when WAG is used and that the increase in recovery with enrichment is relatively insensitive to numerical dispersion. He hypothesized that coarse grid blocks could be used to accurately determine the optimum enrichment for maximum recovery. The results

presented here, although similar to Stalkup, are not conclusive in that regard. The differences in recoveries at "field" dispersivities are somewhat sensitive to enrichment, especially when higher-order methods are used. The use of higher-order methods may increase the effect of crossflow in the vertical direction than when single-point upstream weighting is used. A grid refinement study in the z-direction could help to answer some of these questions.

Conclusions

This research has examined the interplay between dispersion, crossflow, heterogeneities, phase behavior and flow. The effect of capillary crossflow and molecular diffusion are not considered. The main conclusions are:

1. Enrichment above the MME can significantly increase oil recovery for 1-D or 2-D displacements, especially when WAG is used. For the cases considered, recovery at larger enrichments is always greater than recovery at smaller enrichments. The magnitude of the increase is likely highly problem dependent. For 2-D displacements, the increase in recovery with enrichment is generally less than for 1-D displacements.
2. For 1-D displacements, the increase in recovery above the MME is highly dependent on the level of dispersion. A maximum in recovery difference occurs at a level of dispersivity below about 4 ft for the cases considered. The increase in recovery is most sensitive to dispersion for dispersivities less than that corresponding to the maximum difference in recovery (4 ft). Recoveries slowly decrease to finite values for dispersivities greater than the maximum.
3. For the two relative permeability models used (one with and one without gas trapping), the trends in recovery differences for the 1-D displacements coincide for dispersivities below that corresponding to the maximum recovery difference, i.e. dispersivities near 4 ft. Relative permeabilities and trapped gas, however, do affect the difference in recovery for dispersivities greater than the value corresponding to the maximum recovery difference.
4. For 2-D displacements, the relative permeabilities and gas trapping models used affect recovery differences over a large range in dispersivity. Relative permeabilities induce contrasts in mobility, which can alter the magnitude of crossflow.

5. The trends with WAG injection are opposite of those with slug injection. That is, recovery differences increase somewhat as dispersion decreases.
6. Heterogeneities that reduce crossflow but allow for good sweep, i.e., horizontal shale layers with otherwise uniform permeability, cause enriched-gas floods to behave similar to the 1-D displacements. That is, recovery differences with slug injection decrease as dispersion is reduced.
7. Gas channeling can occur for layered systems as the gas is enriched above the MME, particularly when the high permeability layer is not at the top of the reservoir and dispersion (i.e. mixing) is small in the vertical direction.

WAG Optimization for Shallow Enriched Gas Floods

Gas enrichment is one of the important optimization variables in water-alternating-gas (WAG) enriched-gas floods. Recoveries from slimtube experiments with continuous gas injection often give a sharp bend at the minimum enrichment for miscibility (MME). Above the MME, slimtube recoveries do not increase significantly with enrichment. The optimum enrichment required to maximize recovery on a pattern scale in the field, however, is likely different from the MME. The difference in the optimum enrichment may be largely the result of greater mixing in the reservoir than exists in slimtubes. In addition, enrichment may impact sweep efficiency in 2-D displacements. Oil and gas mixing in a reservoir can include mechanisms such as molecular diffusion, mechanical dispersion, gravity crossflow, viscous crossflow, and capillary crossflow. WAG in particular causes significant mixing of reservoir and injected fluids, depending on the total volume of the gas injected (slug volume), the WAG ratio, and the number of gas cycles or WAG frequency.

Stalkup (1998) showed that significant additional recovery might be obtained by injecting enriched gases above the MME. A significant increase in recovery occurred for longitudinal dispersivities as low as 0.3 ft when the solvent and water were injected in slugs. He also concluded that mixing of solvent and oil by viscous crossflow during WAG might dominate other mixing mechanisms in the reservoir, i.e. dispersion. Thus, he suggested that predictions of oil recovery from coarse grid blocks might be accurate as long as the vertical gridding is sufficient to capture the effect of viscous crossflow during WAG. Stalkup also showed that simultaneous grid refinement in horizontal and vertical

directions caused numerical dispersion to overestimate the recovery with gas enrichment beyond the MME (Stalkup *et al.* 1990; Stalkup, 1990; Stalkup, 1987). Other researchers have also examined the effect of viscous crossflow, capillary pressure, diffusion, gravity, heterogeneities, and numerical gridding on recovery (Lim *et al.*, 1997; Lim, 1993; Fayers, 1992; Solano *et al.*, 2001a).

Previous research on WAG for immiscible and CO₂ floods has shown that WAG can cause a significant increase in oil recovery primarily because of improved sweep efficiency based on changes in mobility contrasts (Sanchez, 1999; Haajizadeh *et al.*, 2001; Jarrell *et al.*, 2002). WAG may also reduce the amount of gas injection required, although determining the optimum WAG parameters is sometimes difficult and reservoir dependent. WAG efficiency is generally poor when too much gas is injected in each cycle causing a gas tongue at the top of the reservoir to develop owing to gravity segregation. Gas override leads to a reduction in gas sweep efficiency. Oil recovery is also poor when too much water is injected per WAG cycle primarily because water reduces the displacement efficiency compared to gas and a water tongue may develop towards the bottom of the reservoir. Even with these potential difficulties, Sanchez²⁰ reports that 80% of the WAG projects in the United States are profitable, an affirmation of the success and relative robustness of the method.

This research extends much of the previous research to water alternating gas (WAG) processes in enriched gas floods for the case where the gas is enriched above the minimum miscibility enrichment (MME). The objective of this research is to understand the interaction between key WAG, simulation, and reservoir parameters and how they affect miscible oil recovery. Compositional simulations of x-z cross-sections are used to quantify the effects of WAG parameters, numerical dispersion, level of enrichment and heterogeneity on local displacement efficiency and sweep efficiency.

Model Parameters

Numerical simulations were performed using the numerical code UTCOMP (Chang, 1990), a fully compositional simulator developed at The University of Texas at Austin. UTCOMP uses a volume-based IMPES method to solve the compositional model equations. One advantage of UTCOMP is that it allows for direct input of physical dispersivities.

Table 1.2 presents important properties of the fluids and reservoir used in the simulations. Phase behavior was modeled using the Peng-Robinson equation of state (PREOS) (Peng and Robinson, 1976). All input parameters and fluid properties for the PREOS are the same as those used by Solano *et al.* (2001b). The initial oil, which consists of 12-components, has a bubble-point pressure of approximately 4170 psia. Injection gases consist of a lean gas mixed with a five-component solvent to enrichments of 65 and 85 percent (see Table 1.3). Both of these enrichments are well above the MME, which was recently calculated using the analytical procedure of Yuan and Johns (2002) to be around 55%.

For all cases, the dimensions of the reservoir are 1000-ft long (x) by 800-ft wide (y) by 20-ft high (z). The injection well (at $x = 0$ ft) and production well (at $x = 1000$ ft) are completed through all vertical grid blocks. The gas injection rate is 151.1 MSCF/day, which corresponds to a fluid velocity of about 0.3 ft/day through the reservoir. The water injection rate is 98.69 bbl/day, which matches the volumetric gas rate at reservoir conditions. The bottom-hole pressure of the production well is constant at 4100 psia (slightly below the bubble point). Average reservoir pressure in the simulations was relatively constant at about 4150 psia so that pressure dependence on recovery can be ignored. An initial water saturation of 0.32 is specified for all grid blocks, independent of heterogeneity. The vertical to horizontal permeability is 1.0 unless otherwise specified.

Both slug and WAG injection as primary recovery methods are examined in this work. For slug injection, 0.20 HCPV of gas is injected followed by a 1.0 HCPV waterflood. For WAG, a total of 0.2 HCPV gas is injected with water in alternating cycles, followed by waterflood up to 1.2 HCPV. For example for a WAG ratio of 1.0 with six cycles, each cycle consists of 0.033 HCPV gas and 0.033 HCPV water injection, followed by 0.8 HCPV waterflood.

Three-phase relative permeability is based on the two-phase relative permeability curves for oil-water, gas-water, and gas-oil given by Jerauld (1997). A Land-type equation accounts for trapped gas as a function of the maximum gas saturation. These two-phase curves are similar to those used by Stalkup (1998). We used Stone II to compute the three-phase relative permeabilities.

Reservoir Dispersivity

We used numerical dispersion to model mechanical dispersion. Lantz (1970) showed that numerical dispersion arises in the numerical solution due to truncation errors, which can be described by a one-phase Peclet number (Eq. 1.17). Bermudez (2002) outlines in detail how the time-step size was selected for a given grid-block size and also gives additional information on fluid and model parameters.

Although there is considerable disagreement about the true value of dispersivity at the field scale, Stalkup (1998) suggested that dispersivities of about 0.1 to 2 ft might be reasonable. More recently, Mahadevan *et al.* (2002) reported measured dispersivities at the local scale to be similar to Stalkup. In the simulations presented here, a dispersivity of 2 ft corresponds to about 250 grid blocks in the x-direction. This suggests that a substantial number of grid blocks may be required to model the true level of mechanical dispersion in miscible flooding.

Continuous Slug Injection as a Limiting Case

A limiting case of WAG is continuous gas slug injection, which occurs in the limit of zero WAG ratio or when there is only one WAG cycle. Bermudez (2002) presents a detailed research study of slug injection in both homogenous and heterogeneous reservoirs. In this section we present a few key results that are useful to understand results from WAG injection.

2-D pattern-scale simulations with widely varying grid-block sizes show a significant tradeoff in recovery between achieving high local displacement efficiency and sweep efficiency. Fig. 1.49 shows the recoveries at 1.2 HCPVI for a wide range of grid-block sizes for a gas enrichment of 65% solvent. The recovery contours in the figure were smoothed by linear kriging with a nugget variogram to better indicate recovery trends. The shaded regions at the boundaries of Fig. 1.49 indicate the trends in the displacement and sweep efficiencies.

The best recovery (69.2% OOIP) in Fig. 1.49 for the grid-block sizes considered occurs when the displacement has 100% sweep efficiency and high local displacement efficiency, i.e. in the upper left corner of Fig. 1.49 where recovery is most sensitive to the vertical grid-block size. Such a case occurs for 1-D gas floods or for floods with infinite mixing in the vertical direction. The lowest 2-D recovery (50.9% OOIP) occurs at the

lowest local displacement and sweep efficiency, i.e. in the lower-right corner of Fig. 1.49 where the recovery is most sensitive to changes in the horizontal grid-block size. Thus, the oil recoveries vary by nearly 20% OOIP depending on the grid-block sizes used. Such a result indicates that accurate recovery predictions from numerical simulation are generally poor because they depend significantly on the size of the grid blocks used.

The shaded region in the center of Fig. 1.49 corresponds to grid-block sizes often used in numerical simulation of gas floods. Based on measured true dispersivities in the range of 2 ft, simulations in this “operating window” will cause more numerical mixing of reservoir fluids than exists in the reservoir. Furthermore, the contours in the operating window indicate that oil recoveries in this region are most sensitive to vertical refinement of the grid. Thus, the numerical simulations appear to be grid converged in the x-direction.

Fig. 1.50 shows the three-phase saturation profiles at four injection times and grid-block sizes. For a finely gridded vertical model, the displacement efficiency does not significantly affect the recoveries. The gas tongue is thicker for finely gridded vertical models as the number of grid blocks in the x-direction increases. In all cases except for 1-D flow, the water injected during the waterflood (post gas slug injection) preferentially bypasses the gas tongue primarily because of lower water relative permeability caused by gas trapped during the waterflood.

Contour plots of recoveries such as those shown in Fig. 1.49 can be made for other gas enrichments to determine the increase in recovery or “recovery difference” between enrichments. Fig. 1.51 illustrates a recovery difference plot for 85% and 65% enrichment, both of which are well above the MME. As is shown, the recovery differences are relatively constant at about 3 – 5% OOIP, except very near the region where displacements are 1-D. For the 1-D displacements the recovery differences from numerical simulation are the same as those reported by Solano *et al.* (2001b). The nearly constant recovery differences away from the quasi-1-D floods suggest that unlike the previous recovery estimates of Fig. 1.49, a coarse grid can be used to obtain reliable estimates of the recovery differences between two enrichments above the MME.

We also examined with a very fine grid how longitudinal and transverse dispersivities directly input into the simulator affect the recovery trends. Although not shown here, similar trends in the recoveries and recovery differences as those discussed

above were obtained, although the recoveries were very sensitive to small changes in the transverse dispersivity (Bermudez, 2002).

Vertical permeabilities can significantly affect the oil recovery. When the vertical to horizontal permeability ratio is changed from 1.0 to zero, the numerical results are equal to the 1-D recoveries where only the displacement efficiency affects recovery and recovery differences (sweep efficiency for 1-D displacements are always 100%). Because the recoveries and recovery differences are largest for the 1-D case, these results suggest that measuring the vertical permeability at the field scale is important. Vertical permeability estimates, however, are typically only based on a few core plug measurements, which are likely not representative of field scale values.

Incremental recoveries (recovery increase above waterflood) for the 2-D floods with 65% enrichment ranged from -5% to 15% OOIP. All of the positive and large incremental recoveries, however, were for quasi-1D displacements. The incremental recoveries for 85% enrichment were all positive independent of the grid-block size and ranged from 0% to 20% OOIP. Thus, for homogeneous reservoirs, significant over enrichment is required to yield gas flood recoveries above those from waterflood alone, unless vertical communication is poor and displacements are quasi-1D. For displacements in layered reservoirs considered in the next section, incremental recoveries are positive and large with continuous slug injection (approaching nearly 20% OOIP) when the largest permeability layers are at the bottom of the reservoir. Incremental recoveries for the layered case are only slightly negative when vertical permeability is large and the largest permeability layers are at the top of the reservoir.

WAG Injection

In this section, we consider water-alternating-gas (WAG) injection processes for gas floods with gas enrichments above the MME. For all cases the total gas slug size injected during the WAG process is constant at 20% HCPV.

Homogeneous Reservoirs

We first consider a homogeneous reservoir with 100 grid blocks in the horizontal direction (10 ft in length) and 20 grid blocks in the vertical direction (1 ft in height). For this grid numerical dispersion is minimized and the waterflood recovery (without gas injection) is about 60% OOIP. Although homogeneous reservoirs are overly simplistic,

numerical simulations of such models provide important benchmarks for understanding more realistic heterogeneous reservoirs.

Fig. 1.52 shows the oil recovery as a function of the number of WAG cycles and WAG ratio for an enrichment of 65% solvent. The duration (or volume) of each WAG cycle becomes smaller as the number of cycles increase so that the total gas slug size injected is constant at 20% HCPV.

As is shown in Fig. 1.52, the curves for different WAG ratios converge to the recovery for a continuous gas slug, i.e. for one WAG cycle or zero WAG ratio. The recovery for a fixed WAG ratio increases from the continuous slug case as the number of WAG cycles increases until a maximum in the recovery is reached. For example, for a WAG ratio of 1, the optimum number of WAG cycles is between five and six. For a WAG ratio of 2.0, however, the optimum number of WAG cycles is increased to about 10. The figure also shows that as the WAG ratio is increased, the recovery increases as a result of improved waterflood sweep efficiency.

The recovery increases further as the gas is enriched above the MME. Fig. 1.53 shows an increase in recovery of about 4% OOIP from 65% enrichment to 85% enrichment. For 85% enrichment, there is also a maximum in the recovery for each WAG ratio as a function of the number of WAG cycles.

The optimum number of WAG cycles for maximum recovery as a function of WAG ratio is plotted in Fig. 1.54 for both enrichments. As is shown, richer gases require a fewer number of WAG cycles for a fixed WAG ratio, except where both curves converge towards the continuous gas slug case. Alternatively, richer gas floods for a fixed number of WAG cycles require a larger WAG ratio. Thus, one potential cost benefit of over-enrichment above the MME is a reduction in the required number of WAG cycles.

Mobility contrasts and crossflow control how the injected fluids move into the reservoir during WAG. Fig. 1.55 shows the three-phase saturations after injection of 10 WAG cycles for a fixed WAG ratio of 2.0. As the gas is enriched, sweep efficiency improves largely due to reduced gravity crossflow owing to increased gas density.

The recovery differences between 85% and 65% enrichment at a fixed grid-block size are relatively constant between about 2% and 5% OOIP (see Fig. 1.56). There is a

slight downward trend in the recovery differences as the number of WAG cycles is increased. The recovery differences are also somewhat larger for larger WAG ratios.

The incremental recoveries (recovery increase above the waterflood recovery of 60% OOIP) for the 2-D WAG floods with 65% enrichment were higher with WAG than with continuous slug injection. For low WAG ratios (less than 1.0), however, the incremental recoveries are negative (see Fig. 1.52 compared with 60% waterflood recovery). The incremental recoveries for 85% enrichment were all positive (see Fig. 1.53 compared with 60% waterflood recovery).

Heterogeneous Reservoirs

We also consider the affect of grid-block size, vertical permeability, and enrichment on recoveries with WAG injection in a simplified two-layered heterogeneous model, where the ratio of the permeability of the top layer to the bottom layer is given by the permeability contrast ratio k_t/k_b . Although real reservoirs exhibit much more heterogeneity, such a simplified model is useful because it shows likely trends in recoveries for field-scale reservoirs, depending on whether the permeability is higher at the top of the reservoir than at the bottom. For all cases, one layer (either top or bottom) is kept at 100 md, which means that the results can be plotted as a function of the k_t/k_b ratio without losing generality as long as the pressures in each layer are relatively constant. That is, the figures are valid for different layer permeabilities as long as the pressures in each layer do not significantly alter the equilibrium phase calculations.

The results show that the recovery curves are symmetric around $k_t/k_b=1$ for zero vertical permeability (see Fig. 1.57). The curves are symmetric because no crossflow, either gravity or viscous, can occur. The recoveries are lower than those for a homogeneous reservoir, except where they are equal for $k_t/k_b=1$. As the contrast in permeability increases (to either extreme) the recoveries are reduced to about half of the homogeneous case because one half of the reservoir is contacted by fluid (water or gas). The recovery differences are also symmetric (see Fig. 1.58) and large when $k_t/k_b=1$, i.e. for 1-D floods in a homogeneous reservoir.

The recoveries as a function of the permeability contrast in Fig. 1.59 are asymmetric around $k_t/k_b=1$ for nonzero vertical permeabilities, in this case a vertical to horizontal permeability ratio of 1.0. The asymmetry provides a good measure of the

importance of gravity crossflow because viscous crossflow would not cause the asymmetric response at $k_t/k_b = 0.1$ or $k_t/k_b = 10$. The recovery curves are skewed towards larger values for $k_t/k_b = 10$ primarily because of improved waterflood sweep efficiency. When the bottom layer has a larger permeability than the top, the reverse is true and most of the water moves into the bottom layer.

The recovery differences between 85% and 65% gas enrichments are positive and relatively independent of the grid-block sizes used (see Fig. 1.60). The recovery difference is larger for higher k_t/k_b ratios when the vertical to horizontal permeability ratio is 1.0. For a vertical to horizontal permeability ratio of 0.1, however, the recovery differences have a slight downward trend with increasing k_t/k_b (see Fig. 1.61). The conclusion here is that over-enrichment will improve recovery the most when the general trend in the reservoir is that the largest permeability layers are at the bottom of the reservoir.

In some cases it may be better to inject a continuous gas slug instead of using WAG. Fig. 1.62 shows the recovery difference between WAG and continuous slug injection for an enrichment of 65% and a vertical to horizontal permeability ratio of 0.1. At low values of k_t/k_b , WAG recovery is lower than that by continuous slug injection. When the vertical to horizontal permeability ratio is increased to 1.0, however, the recovery difference between WAG and continuous slug injection is large and positive (see Fig. 1.63). Thus, with good vertical communication the use of WAG is generally better than continuous gas slug injection, especially when the largest permeability layers are at the top of the reservoir. For richer gases, the trend in recovery differences is accentuated in that for small k_t/k_b it is always better to inject a continuous gas slug than to use WAG, independent of the vertical to horizontal permeability ratio.

Incremental recoveries for the layered reservoir with WAG were generally positive, especially when the largest permeability layers are at the bottom of the reservoir. For small k_t/k_b , incremental recoveries approached nearly 18% OOIP for 65% enrichment and about 22% OOIP for 85 % enrichment. The incremental recoveries were small and in some cases slightly negative for large k_t/k_b ratios and large vertical to horizontal permeability ratios. Thus, heterogeneity and low vertical to horizontal

permeability ratios improve incremental recoveries in enriched-gas drives, which is probably why WAG floods have been so successful.

Last, Fig. 1.64 shows the recovery contours for different vertical to horizontal permeability ratios, reservoir permeability contrasts, and grid-block sizes. The recoveries are not sensitive to changes in the grid-block size in the x-direction as the vertical permeability increases and the permeability of the bottom most layers of the reservoir decreases.

Conclusions

We have examined the interplay between local displacement and sweep efficiency and reservoir and numerical parameters for WAG processes above the MME, particularly when WAG is used as a primary recovery method. Based on the cases examined, the main conclusions are:

1. Predictions of oil recovery from numerical simulation are highly dependent on the grid-block sizes used. Very fine grids are required for accurate estimates based on measured true dispersivities in the neighborhood of 2 ft.
2. Recovery differences between two gas enrichments above the MME are relatively insensitive to grid-block sizes for continuous slug or WAG injection. Thus, coarse grids can be used with reasonable accuracy to estimate the increase in recovery between two enrichments above the MME.
3. Recoveries for continuous gas slug injection in homogeneous and layered reservoirs are significantly above waterflood recovery when:
 - a. The gas is significantly over-enriched above the MME or;
 - b. Little vertical communication exists so that the flood is quasi-1-D, or;
 - c. The largest permeability layers are at the bottom of the reservoir so that waterflood sweep efficiency is poor and gas more effectively displaces the top layers.
4. For gas floods of homogeneous reservoirs with WAG:
 - a. Recoveries increase as the WAG ratio increases;
 - b. A fewer number of WAG cycles are required to achieve maximum oil recovery as the gas enrichment is increased above the MME;

- c. The incremental recoveries (above waterflood recovery) are generally higher with WAG than with continuous slug injection. For low WAG ratios (less than 1.0) and leaner gases, however, incremental recoveries are negative.
5. For gas floods of layered-reservoirs with WAG:
- a. Over-enrichment above the MME improves recovery the most when the largest permeability layers are at the bottom of the reservoir;
 - b. Continuous slug injection performs better than WAG when the largest permeability layers are at the bottom of the aquifer, richer gases are used, and the vertical to horizontal permeability ratio is small.
 - c. Incremental recoveries (above waterflood recovery) were generally positive and large, especially when the largest permeability layers are at the bottom of the reservoir or when the vertical to horizontal permeability ratio is small.

Subtask 1.2: Robust Calculation of MMP and MME

Task 1.2 focused on the fast estimation of MMP for real crude oils. In particular, we developed a robust method for calculation of MMP that correctly converges to the MMP, unlike previous methods. A second subtask was to characterize the displacement mechanisms that occur in shallow gas floods.

Robust Method for Calculation of MMP for Shallow Gas Reservoirs

Gas enrichment is an important optimization parameter in enriched gas floods. Recoveries from slim tube experiments often give a sharp bend at the MME. Above the MME, slim tube recoveries (or local displacement efficiencies) do not increase significantly with enrichment. This is also true for slim tube recoveries as a function of pressure above the MMP. Thus, the accurate determination of MME or MMP is important in gas flood design.

Pseudoternary diagrams have traditionally been used to explain the behavior of multicontact miscible (MCM) gas drive processes (Hutchinson *et al.*, 1961). Both qualitative mixing cell arguments and more rigorous mathematical approaches show that a ternary displacement can be MCM only if either the oil composition (vaporizing gas drive) or the injection gas composition (condensing gas drive) lies outside the region of

tie-line extensions on a ternary phase diagram (Dumore *et al.*, 1984; Benham *et al.*, 1959. For ternary systems, the MMP is the pressure at which the oil lies on a critical tie-line extension, whereas the MME is found when the gas lies on a critical tie-line extension. Thus, a ternary displacement can be either condensing or vaporizing but not both.

Zick (1986) and Stalkup (1987) found that real oil displacements could have features of both vaporizing and condensing drives (CV). They also found that MMP's and MME's estimated by ternary methods were different than those observed for combined CV drives. Thus, new methods were needed to estimate MMP's and MME's for real systems.

Four primary methods have been used in recent years to calculate MMP's and MME's for real systems: slim tube experiments, compositional simulation, (Stalkup, 1987) mixing-cell models, (Zick) and analytical models (Johns and Orr, 1996; Wang and Orr, 2002; Jessen *et al.*, 1998). Each of these methods, however, has advantages and disadvantages. Slim tube experiments, which use real fluids, are expensive and time consuming to perform and can give misleading results depending on the small level of physical dispersion present. (Johns *et al.*, 1993). Fine-grid compositional simulations and mixing-cell models can suffer from numerical dispersion effects and are also time consuming to perform. Dispersion-free analytical methods are often very fast, but like simulation and mixing-cell models, they rely on an accurate fluid characterization by an equation-of-state (EOS). Because of their improved speed, however, analytical methods offer significant promise for developing improved fluid correlations and for use in compositional streamline simulations.

Monroe *et al.* (1990) first examined the analytical theory for quaternary systems and showed that there exists a third key tie line in the displacement path, called the crossover tie line. Johns *et al.* (1993) also considered quaternary systems and analytically proved the existence of the combined CV mechanism. They showed that the crossover tie line controls the development of miscibility for such systems. They also provided a simple geometric construction to locate the crossover tie line; the crossover tie-line extension must intersect the oil and gas tie lines.

Later, Johns and Orr (1996) showed that the displacement path for dispersion-free flow is controlled by n_c-1 key tie lines, which include the oil tie line, gas tie line, and n_c-3 crossover tie lines. They extended the simple geometric construction to show that

successive key tie lines must intersect and that any one of those key tie lines could control the development of miscibility. Johns and Orr showed that MCM flow is obtained when any one of the key tie lines intersects the critical locus as pressure (MMP) or enrichment (MME) is increased. Furthermore, they showed that the displacement is purely vaporizing when the oil tie line becomes a critical tie line first as pressure is increased. Otherwise, miscibility is controlled by one of the crossover tie lines and the displacement would exhibit a combined CV mechanism. Johns and Orr gave the first multicomponent example calculation of MMP for a displacement of eleven-component oil by pure CO₂.

Wang and Orr (2002) gave calculations of MMP for oils displaced by a multicomponent gas. They used a multidimensional Newton-Raphson scheme to locate the crossover tie lines based on the geometric construction approach of Johns and Orr.¹ They reported convergence difficulties for cases when two successive key tie lines were nearly parallel. They also stated that false solutions were obtained in some cases and that the method often converged slowly. Jessen *et al.* (1998) modified Wang and Orr's method to improve speed and robustness. Their main achievement was the inclusion of fugacity equations in the Newton-Raphson iterations that significantly increased the calculation speed.

This research presents a simplified and robust analytical method for MMP or MME calculation. The approach relies on finding key crossover tie lines for a dispersion-free displacement using method of characteristic theory (MOC). The new method differs from published methods in five ways: 1) the number of model equations and unknown parameters are significantly reduced using a minimum distance function; 2) the number of unknown parameters are further reduced by examination of the solution structure and setting some to zero a priori (this also helps to avoid false solutions); 3) robust singular value decomposition (SVD) is used along with a Marquardt factor to ensure convergence to the MMP or MME; 4) convergence to false (or local) solutions are avoided by a wise choice in the initial guess of the unknown parameters; and 5) an improved negative flash is used to find all tie-line extensions. These five improvements significantly increase the robustness and speed of the analytical method.

We demonstrate the improvements by calculation of the MMP and MME for a variety of gas/oil systems. We also give new analytical solutions for systems where

equilibrium K-values are constant as compositions change. For such systems, we show that the family of intersecting crossover tie lines is not unique and the number of possible solutions increases with the number of components.

Mathematical Model

Johns and Orr (1996) developed the analytical theory for multicomponent gas floods and showed that the extension of successive key tie lines (oil, gas, and crossover tie lines) must intersect in composition space using a simple geometric construction. They also showed that miscibility is obtained for dispersion-free flow when any one of these n_c-1 key tie lines becomes a critical tie line, i.e. a tie line of zero length. Thus, the problem of determining the MME or MMP becomes one of increasing the gas enrichment (or pressure) and determining the lengths of the key tie lines. When a key tie-line length becomes zero, the MME or MMP has been reached.

Minimum Distance Function

Root finding techniques are used to locate the key tie lines. The most important step in any root finding technique is to use a well-behaved function. We use a minimum distance function.

Fig. 1.65 shows two successive tie lines, which according to the analytical theory must intersect when they are key tie lines. We initially follow the same approach as Jessen *et al.* (1998), who write equations for the line segments that connect the equilibrium liquid fraction of one tie line to the equilibrium vapor fraction of the other tie line. The overall composition A and B along each line segment are therefore given by the following linear combinations (see Fig. 1.65)

$$z_k^A = x_k + \alpha^k (K_{k+1} x_{k+1} - x_k) \quad k = 1, \dots, n_c - 2 \quad (1.18)$$

$$z_k^B = x_{k+1} + \beta^k (K_k x_k - x_{k+1}) \quad k = 1, \dots, n_c - 2 \quad (1.19)$$

where α^k and β^k are parameters that vary continuously from zero to one along the line segments. These two line segments must intersect when the tie lines intersect, i.e. they lie in the same plane and the minimum distance between the line segments must be zero.

The distance between any two points A and B along the line segments connecting two key tie lines is (ignoring the last component)

$$d^k = \left(\sum_{i=1}^{n_c-1} (z_{k,i}^A - z_{k,i}^B)^2 \right)^{1/2} \quad k = 1, \dots, n_c - 2 \quad (1.20)$$

Thus, the minimum distance between the two line segments can be easily determined by least squares. From least squares, the minimum distance for d^k is found when

$$\alpha^k = \frac{(b_1 a_{22} - b_2 a_{12})}{(a_{11} a_{22} - a_{21} a_{12})} \quad k = 1, \dots, n_c - 2 \quad (1.21)$$

and

$$\beta^k = \frac{(a_{11} b_2 - a_{21} b_1)}{(a_{11} a_{22} - a_{21} a_{12})} \quad k = 1, \dots, n_c - 2 \quad (1.22)$$

Thus, α^k and β^k are explicitly determined and the number of unknown parameters is significantly reduced. This differs from Jessen *et al.* (1998) who kept them as unknown parameters. Furthermore, the minimum distance function is very well behaved in that it is a “bowl-shaped” function whose values are always greater than or equal to zero. When the minimum distance is zero, the two tie lines shown in Fig. 1.65 intersect.

Further Reduction of Unknown Parameters

Once parameters α^k and β^k are determined, the only remaining unknown parameters are the equilibrium liquid compositions for each crossover tie line. A negative flash of the oil and gas compositions finds the oil and gas tie lines (1989). Thus, there are a total of $(n_c - 3)(n_c - 1)$ unknowns. Some of these unknowns can be set to zero using simple rules based on the analytical solution structure.

For example, consider the displacement of eleven-component oil by five-component gas. The system consists of a total of twelve components because four of the five gas components also exist in the oil. For a twelve-component system, there are a total of nine crossover tie lines that must be found, and thus, there are 99 unknown equilibrium liquid mole fractions. Table 1.4 provides an illustration of the unknown parameters that must be determined for each crossover tie line *CI* through *C9*. In this example, component three in the oil is zero, and thus its corresponding equilibrium liquid mole fraction is also zero in Table 1.4. The twelfth component is not shown in Table 1.4 because the equilibrium mole fractions must sum to unity. Because six equilibrium liquid

components in the oil tie line are not present in the gas tie line, many of the unknowns can be set to zero (based on shock construction theory (Johns and Orr, 1996)). As shown in Table 1.4, fifteen of the unknown equilibrium liquid mole fractions for crossover tie lines C5 to C9 are zero in this example. Thus, the number of unknowns is reduced from 99 to 84. We can also avoid some false (or trivial) solutions by ensuring that each crossover tie line has the expected number of components.

The rules for how to determine which equilibrium liquid compositions are zero are as follows:

1. Sort components in descending order according to their K-values so that component 1 has the highest K-value;
2. Locate the highest K-value component whose equilibrium liquid mole fraction is zero in the gas tie line. The equilibrium liquid mole fractions for that component will be zero for crossover tie-line number $n_c - n_g - 2$ to crossover tie-line number $n_c - 3$, where n_g is the number of components in the gas. When $n_c - n_g - 2 \leq 0$, none of the equilibrium liquid mole fractions can be zeroed.
3. Step 2 is repeated for the next highest K-value component except that the equilibrium liquid mole fractions will be zero for crossover tie-line number $n_c - n_g - 1$ to crossover tie-line number $n_c - 3$. The beginning crossover tie-line number is increased by unity for all subsequent components.

After zeroing, the total number of unknown parameters is then $(n_c - 3)(n_c - 1) - \sum_{i=1}^{n_c - n_g - 2} i$. The decreased number of unknown parameters reduces the potential for finding trivial or false solutions. The root-finding method, which is explained in the next section, will also take less time to implement.

Solution of Equations

We use multidimensional root-finding to locate the key tie lines in composition space. That is, we want to find the solution to the system of equations where

$$d^k = 0 \quad k = 1, \dots, n_c - 2 \quad (1.23)$$

and

$$\sum_{i=1}^{n_c-1} (K_{k,n_c} - K_{k,i}) x_{k,i} + K_{k,n_c} - 1 = 0 \quad k = 2, \dots, n_c - 2 \quad (1.24)$$

Eq. 1.23 states that the minimum distance functions are zero when successive key tie lines intersect. Eq. 1.24 is a restatement of the constraint that equilibrium liquid and vapor mole fractions must sum to one. There are a total of $2n_c - 5$ equations.

Newton-Raphson iteration is used to solve the nonlinear system of equations. The linearized system of equations can be written as

$$\bar{J} \Delta \bar{x} = -\bar{F}(\bar{x}_0), \quad (1.25)$$

where $\bar{x}_0$ is the initial (or subsequent) estimate for the vector of equilibrium liquid mole fractions and $\bar{J}$ is the Jacobian matrix. The Jacobian is developed assuming component K-values are constant. After each iteration, flashes of the resulting compositions from Eqs. 1.25 are done to update the K-values and equilibrium liquid compositions. The initial guess for subsequent iterations is described in the next section.

The system of equations is an underdetermined system because the number of unknowns exceeds the number of equations. Thus, $\bar{J}$ is not a full-rank matrix. An efficient and robust algorithm using singular value decomposition (SVD) has been developed to solve such undetermined systems (Press *et al.*, 2002). We also use a Marquardt's regularization factor that improves convergence when the Jacobian becomes near singular.

Table 1.5 compares the number of unknown parameters and equations for the twelve-component system of Table 1.4 using the simplified method and published methods. The new method significantly reduces the number of equations and unknown parameters from these other methods.

Initial Guess for Improved Robustness and Speed

An important aspect of the simplified method is an improved initial guess for each iteration. The initial guess of equilibrium liquid compositions for the first iteration is determined by solving the pure component problem, where the lightest component in the gas is injected (1996). Following the approach of Wang (1998) and Jessen *et al.*, (1998) the gas composition is then slowly incremented to the actual injection gas composition for each subsequent iteration. The approach differs from Wang in that for the second and subsequent iterations, the equilibrium liquid compositions from Eqs. 1.25 (corrected by flashing the result to obtain $x_{k,i}$) are not used as the initial guess for that iteration. Instead, we use a linear extrapolation from previous solutions. That is, the initial guess for iteration $j+1$ is

$$x_{k,i}^{j+1} = x_{k,i}^j + \left[\frac{x_{k,i}^j - x_{k,i}^{j-1}}{\Delta z_{g,k,i}^j} \right] \Delta z_{g,k,i}^{j+1}, \quad (1.26)$$

where $\Delta z_{g,k,i}^j = z_{g,k,i}^j - z_{g,k,i}^{j-1}$ is the increment in gas enrichment along crossover tie-line k (for species i) for the current iteration j . Eq. 1.26 is used because equilibrium compositions for all key tie lines must continuously increase or decrease with small changes in enrichment (or pressure). Although not done here, higher-order extrapolations could also be used, especially for tie lines near the critical locus.

The advantage of using linear extrapolation to provide a good initial guess for each iteration is twofold. First, rapid convergence to specified tolerances in the minimum distance functions is obtained. Second, false solutions in the equilibrium liquid compositions are often avoided.

Fig. 1.66 shows the number of iterations required to achieve convergence to a tolerance of 1E-8 for the total minimum distance. The total minimum distance is the sum of all minimum distance functions. The example used is twelve-component oil displaced by a five-component gas. The figure shows that convergence with the improved initial guesses is achieved with tens of iterations instead of hundreds of iterations. Hence, speed-up is considerable. The solution at each enrichment (or pressure) takes less than a few seconds for a twelve-component system on a Pentium II PC.

False solutions to the wrong set of key tie lines are also avoided by using the improved initial guess. For example, Fig. 1.67 illustrates that without the improved guess, the calculations converge to false equilibrium liquid compositions. We found that the method of Wang and Orr (2002) and Jessen *et al.* (1998) may converge to these false solutions. Wang (1998) suggests that the false solutions can be recognized by continuity arguments. The improved initial guess presented here provides such a continuity condition.

Improved Negative Flash

The first step in the solution of Eqs. 1.25 is to solve the key tie lines for the pure component gas injection problem. We modified the approach given by Wang (1998) to perform a negative flash to solve for all tie lines that intersect a given composition. We solve for all possible equilibrium liquid mole fractions of selected component j (typically component j is component 1) using

$$\sum_{i=1}^{n_c} \frac{z_i x_j (K_j - 1)(K_i - 1)}{(K_i - 1)z_j + (K_j - K_i)x_j} = 0 \quad (1.27)$$

To find all possible solutions, we first locate the poles of Eq. 1.27 in the interval for x_j between zero and one. Next, we use the modified Newton's and generalized bisection methods (Press *et al.*, 2002) for each subinterval between the poles. This guarantees convergence to all roots of Eq. 1.27 between all poles. Once all values for x_j are found, the remaining equilibrium liquid compositions are found using the standard Rachford-Rice calculations (Rachford and Rice, 1952).

Procedure for MMP and MME Calculation

We summarize the procedure to calculate the MMP or MME below:

1. Find the equilibrium liquid compositions for all key tie lines for displacement of multicomponent oil by single-component gas using the shock construction approach of Johns and Orr (1996). The gas component injected is the lightest component present in the gas. This step provides a known accurate initial guess. The flash calculations are at reservoir pressure if the MME is to be calculated; otherwise, for MMP calculations the pressure should begin at a pressure substantially below the MMP.

2. Dilute the gas in small increments to the required multicomponent gas composition and solve Eqs. 1.25 for each increment. For MME calculation, the dilution path can proceed from a single-component gas to a lean gas and then to an enriched gas. Pressure is fixed in this step.
3. Increase the pressure in small increments for MMP calculation.
4. Calculate the lengths of all key tie lines as the pressure or gas composition is changed. When one of the tie line lengths become zero, i.e. intersects the critical locus, the MMP or MME has been reached. The lengths of the key tie lines are calculated with,

$$l_k = \sqrt{\sum_{i=1}^{n_c} [(K_{k,i} - 1)x_{k,i}]^2} \quad (1.28)$$

Example Calculations of MMP and MME

We consider several widely varying fluid characterizations to demonstrate the robustness of the method. All examples use the Peng-Robinson equation-of-state (PREOS) (Peng and Robinson, 1976).

Fig. 1.68 shows the key tie-line lengths for a simple four-component system previously considered in detail by Johns *et al.*, (1993). They stated that the three-component oil (C₁, C₆, C₁₆) displacement by two-component gas is a CV drive. Fig. 1.68 verifies their results and shows that the crossover tie line becomes a critical tie line first at the MME of about 59.6% C₁ and 40.4% C₃. The oil tie-line length remains constant with enrichment because pressure does not change. The gas tie line has zero length at about 46.6% C₁ and 53.4% C₃. Thus, if the displacement had been considered a condensing drive, the error in the estimated MME would be large (13% C₃ enrichment).

Figs. 1.69 and 1.70 show the calculated tie-line lengths for the seven-component systems considered by Uleberg and Hoier (2002). For lean gas injection they report a MMP of 6909 ± 147 psia as measured by slim-tube experiments. For enriched-gas injection, they estimate the MMP to be 4777.5 ± 73.5 psia. Thus, as expected the MMP is significantly lower when the gas is enriched with solvent. The calculated MMP by the simplified method is in perfect agreement with these values: 7007 psia for lean gas injection and 4838 psia for enriched-gas injection. For lean gas injection, the first crossover tie line controls the development of miscibility and the displacement is a CV

drive. The displacement is also a CV drive for the enriched-gas case, but the third crossover tie line controls the development of miscibility. Thus, we expect the enriched-gas drive to be more condensing than the lean-gas drive. Johns *et al.* (2002) show how to calculate the fraction of a CV drive that is condensing or vaporizing as a function of pressure or enrichment.

Last, we consider a displacement of twelve-component oil by five-component gas, as previously reported by Johns *et al.* (2002) and Solano *et al.* (2001). In this enriched-gas flood, the lean gas from the separator is enriched with a five-component solvent (see Table 1.3). Fig. 1.71 shows all key tie-line lengths as the lean gas is enriched with solvent. After 4% enrichment with solvent, the fourth crossover tie line becomes the shortest key tie line. The fourth crossover tie line eventually has zero length at the MME of 57.2%, which agrees well with the approximate value of 60% reported by Johns *et al.* (2001). Thus, the displacement mechanism is CV.

Discussion

The simplified method for analytical calculation of MMP is much faster than experimental or simulation methods. For the twelve-component system of Fig. 1.71, the calculation from the pure gas solution to the lean gas solution to the MME (at increments of 1% enrichment) took less than five minutes on a Pentium II personal computer or about 2 seconds per increment. Thus, the analytical method has significant potential for improving the characterization of fluids or in providing new correlations. Johns *et al.* (2001) demonstrate the use of the analytical method to quantify the displacement mechanism.

Besides speed, the main advantage of the analytical approach is that the estimated MME and MMP are independent of dispersion. As shown by Johns *et al.* (2001) and Solano *et al.* (2001), dispersion can significantly affect the estimation of MMP or MME for some fluid characterizations. In such cases, estimates of MME or MMP from slim tube experiments are likely too large because recovery trends are affected by physical dispersion.

The main disadvantage with the analytical approach is that a good fluid characterization by an EOS is required (this is also true for simulation methods). Although this is a disadvantage compared to slim tubes, the analytical method could be

used to determine what additional PVT data should be obtained to improve fluid characterizations.

Conclusions

A simplified and robust analytical method for estimation of MMP or MME is presented. The approach relies on finding key crossover tie lines for a dispersion-free displacement using method of characteristic theory (MOC). The new method is very accurate and rapid as evidenced by several example calculations. A windows-based program that calculates the MME or MMP is available from the authors.

Other conclusions are

- The number of model equations and unknown parameters are significantly reduced from previous methods using a minimum distance function. We demonstrate how to reduce the number of unknown parameters by examination of the solution structure a priori and zeroing those unknowns;
- Robust singular value decomposition (SVD) is used along with a Marquardt factor to improve convergence to the MMP or MME;
- A wise choice in the initial guess of the unknown parameters can avoid convergence to false (or trivial) solutions and can also significantly increase the speed of the calculations;
- An improved negative flash is used to find the extensions of all key tie lines that intersect a common point. This reduces the chance of using a false solution as the initial guess for subsequent iterations.
- An analytical solution for constant K-values shows that the number of false solutions increases significantly with the number of system components.

Quantification of Displacement Mechanisms in Shallow Gas Floods

Pseudoternary diagrams have traditionally been used to explain the behavior of multicontact miscible (MCM) gas drive processes (Hutchinson *et al.*, 1961). Both qualitative mixing cell arguments and more rigorous mathematical approaches show that a ternary displacement can be MCM only if either the oil composition (vaporizing gas drive) or the injection gas composition (condensing gas drive) lies outside the region of

tie-line extensions on a ternary phase diagram (Dumore *et al.*, 1984; Benham *et al.*, 1959). For ternary systems, the MMP is the pressure at which the oil lies on a critical tie-line extension, whereas the MME is found when the gas composition lies on a critical tie-line extension. Thus, a ternary displacement can be condensing or vaporizing, but not both, and the compositions, pressure, and temperature determines which key tie line (gas or oil) controls the development of miscibility.

Zick (1986) and Stalkup (1987) found that multicomponent oil displacements could be both vaporizing and condensing drives (CV). They showed that MMP's and MME's estimated by ternary methods could be significantly different than those observed for combined CV drives.

Johns *et al.* (1993) mathematically proved the existence of the combined CV mechanism for four-component systems and gave a method to calculate the dependence of the MMP or MME on the displacement mechanism. In particular, they showed that a key tie line, called the crossover tie line, controls the development of miscibility in CV drives. The MME occurs when the extension of the crossover tie line intersects the extensions of both the oil and gas tie lines as enrichment is increased.

Johns and Orr (1993) showed that the displacement path for multicomponent dispersion-free flow is controlled by $n_c - 1$ key tie lines, which include the oil tie line, gas tie line, and $n_c - 3$ crossover tie lines. They extended the simple tie-line geometric construction to show that successive key tie lines must intersect and that any one of those key tie lines could control the onset of miscibility. MCM flow is obtained when any one of the key tie lines intersects the critical locus as pressure (MMP) or enrichment (MME) is increased. Johns and Orr also showed that the displacement is purely vaporizing when the oil tie line becomes a critical tie line first as pressure is increased. Otherwise, miscibility is controlled by one of the crossover tie lines and the displacement mechanism is CV.

More recent researchers have used the geometric construction of Johns and Orr (1996) to calculate MMP's and MME's for displacements of oils by multicomponent gases. Jessen *et al.* (1998) significantly increased the calculation speed of MMP estimation by inclusion of fugacity equations in the Newton-Raphson iterations. Yuan and Johns (2002) presented a simplified and robust analytical method for both MMP and MME calculation.

Wang and Peck (2000) suggested that the displacement mechanism could be quantified by determining the number of the key tie line that controls miscibility. They also showed a relationship between the number of the critical tie line and the effect of dispersion on local displacement efficiency. Johns *et al.* (2002), however, demonstrated that the critical tie-line number is only a qualitative indicator of the displacement mechanism for CV drives. They proposed a more accurate method to quantify the displacement mechanism and demonstrated the approach for an example four-component system. Others have also examined the sensitivity of local displacement efficiency to dispersion for a variety of systems and displacement mechanisms (Johns *et al.*, 2002; Jessen *et al.*, 2002).

The approach in this part of the research relies on finding key tie lines for a dispersion-free displacement using method of characteristic theory (MOC). The first section shows how to quantify the displacement mechanism for any number of oil or gas components by calculating the displacement path lengths along ruled surfaces bounded by these key tie lines. We then quantify the displacement mechanisms for several multicomponent fluid characterizations. Those calculations give the expected result that the condensing mechanism typically increases as the pressure or enrichment are increased. Last, we examine the sensitivity of the local displacement efficiency at the MMP to dispersion as the condensing fraction of the displacement is increased.

Quantification of the Displacement Mechanism

We use the composition paths and key tie lines determined by the dispersion-free analytical approach to quantify the displacement mechanism. Johns and Orr (1996), who developed the analytical theory for multicomponent gas floods, showed that the composition path during a displacement jumps from one key tie line to the next along ruled surfaces that are nearly planar. (A ruled surface is generated by a sequence of lines, in this case, tie lines). Furthermore, they showed that the extension of successive key tie lines (oil, gas, and crossover tie lines) must intersect in composition space using a simple geometric construction. Miscibility is obtained for dispersion-free flow when any one of these $n_c - 1$ key tie lines becomes a critical tie line, i.e. a tie line of zero length. Thus, the problem of determining the MME or MMP becomes one of increasing the gas enrichment (or pressure) and determining when a key tie-line length becomes zero.

The composition path during a one-dimensional gas flood traverses $n_c - 2$ ruled surfaces. The displacement along each ruled surface is either purely condensing or vaporizing, but not a combination of both. Thus, the compositional distance or length of the paths along each ruled surface is related to the fraction of vaporizing or condensing behavior that occurs in a CV flood. To make the displacement mechanism calculations, we simply sum the path lengths that the displacement takes along each surface, sort them by their displacement mechanism, and compare the relative magnitudes of the displacement mechanisms.

To simplify the calculation, we approximate the compositional path lengths along a ruled surface by the compositional distances between two successive key tie lines. The distances between the successive key tie lines are calculated from the mid-points of the tie lines where the mole fraction of vapor or liquid is 0.50. Thus, the distances along each surface are given by,

$$d_k = \sqrt{\sum_{i=1}^{n_c} (z_{k+1i} - z_{ki})^2} \quad k = 1, \dots, n_c - 2 \quad (1.29)$$

where d_k is the distance between key tie line k and key tie line $k+1$ and z_{ki} is the overall mole fraction of component i on key tie line k at a molar vapor fraction of 0.50. The use of the approximation means that only the key tie lines must be obtained (gas, oil, and crossover tie line), instead of the exact dispersion-free compositional paths.

The approach to quantify the displacement mechanism is best understood by considering four-component systems. For dispersion-free flow, four-component displacements consist of two back-to-back displacements along nearly planar ruled surfaces that are connected through the only crossover tie line of the system. The composition path of the displacement traverses along a “vertical” surface from the initial oil composition on the oil tie line to the crossover tie line. The path then traverses along the “horizontal” surface from the crossover tie line to the gas tie line.

For a four-component system, each displacement along a ruled surface can be either condensing or vaporizing. Thus, in quaternary systems, there can be four different types of drives: purely condensing, purely vaporizing, leading vaporizing/trailing condensing (VC), and leading condensing/trailing vaporizing (CV). For CV drives, the condensing portion occurs at the downstream end of the displacement, i.e. along the

vertical surface, whereas the vaporizing portion occurs at the upstream end, i.e. along the horizontal surface.

For four-component systems, there are only two equations for the path lengths given by Eqs. 1.29, i.e. distances from the oil tie line to the crossover tie line and from the crossover tie line to the gas tie line. The fraction of a CV displacement that is vaporizing (V_m) is therefore given by,

$$V_m = \frac{d_2}{d_1 + d_2} \quad (1.30)$$

where d_1 is the compositional distance from the oil tie line to the crossover tie line (condensing portion along the vertical surface) and d_2 is the compositional distance from the crossover tie line to the gas tie line (vaporizing portion along the horizontal surface). The fraction of the CV displacement that is condensing is therefore $C_m = 1 - V_m$.

The equation used to quantify the displacement mechanism for four-component systems (Eq. 1.30) is easily extended to multicomponent systems. For example, for a twelve-component system there are ten ruled surfaces bounded by the oil, gas, and crossover tie lines. The displacement along each ruled surface is either vaporizing or condensing. Thus, the path lengths (compositional distances) along the ruled surfaces that are vaporizing can be summed to give the total vaporizing path length. Similarly, the path lengths along the ruled surfaces that are condensing are summed to represent the total condensing path length. The ratio of the total vaporizing path length to the length of the entire composition path is a good estimate of the vaporizing fraction of the displacement. That is, the vaporizing fraction for multicomponent displacements is given by

$$V_m = \frac{\sum_{k=1}^{n_c-2} d_{k,v}}{\sum_{k=1}^{n_c-2} d_k} \quad (1.31)$$

where $d_{k,v}$ is nonzero only for vaporizing displacements along a given ruled surface. In general, condensing surfaces occur at the downstream end of the displacement, whereas the vaporizing surfaces occur at the upstream end.

Calculation Procedure

We summarize the procedure to quantify the displacement mechanism below:

1. Find the equilibrium liquid compositions for all key tie lines for the displacement of multicomponent oil by multicomponent gas using the approach of Yuan and Johns (2002).
2. Calculate the path lengths between all key tie lines using Eqs. 1.29 at molar vapor fractions of 0.5.
3. Calculate the lengths of each key tie line with,

$$l_k = \sqrt{\sum_{i=1}^{n_c} [(K_{k,i} - 1)x_{k,i}]^2} \quad (1.32)$$

4. Determine the displacement mechanism along each ruled surface (from one key tie line to the next) by comparing the lengths of each successive key tie line. When the lengths of the key tie lines that bound a ruled surface are longer in the upstream direction (towards the gas tie line), the displacement mechanism along that ruled surface is vaporizing. Otherwise, the displacement mechanism is condensing.
5. Sum the vaporizing and condensing path lengths and use Eq. 1.31 to calculate the vaporizing and condensing fraction of the displacement.

Example Calculations of Displacement Mechanisms

In this section, we quantify the displacement mechanism for a variety of example systems. We first consider the simplest case, a four-component displacement, followed by several multicomponent characterizations of fluids with measured phase behavior (PVT) data. All examples use the Peng-Robinson equation-of-state (Peng and Robinson, 1976) to represent the phase behavior, unless otherwise stated.

Quaternary Displacements

Fig. 1.72 gives the tie-line lengths as a function of enrichment for the four-component system (C_1 , C_3 , C_6 , and C_{16}) previously considered by Johns *et al.* (1993, 2002). The gas enrichment is the percentage of C_3 added to C_1 . As shown in Fig. 1.72, the MME occurs when the crossover tie line becomes a critical tie-line (zero length tie

line) at a gas composition of 59.6% C_1 and 40.4% C_3 . The oil tie-line length does not depend on enrichment because pressure is constant. The gas tie line, however, changes with enrichment, but has zero length at an enrichment of 46.6% C_1 and 53.4% C_3 . Thus, if the displacement had been considered a condensing drive instead of a CV drive, the error in the estimated MME would be large (an additional 13% C_3 enrichment).

Fig. 1.73 shows the path lengths along each ruled surface for the four-component displacements as calculated by Eqs. 1.29. The compositional distance from the oil tie line to the crossover tie line indicates the magnitude of the condensing portion of the displacement, whereas the distance from the crossover tie line to the gas tie line is representative of the vaporizing portion. When the path length traversed on the vertical surface is zero, no condensing mechanism occurs and the displacement is purely vaporizing. A pure vaporizing drive occurs in Fig. 1.73 when the injected gas is 100% methane (at zero enrichment), under which circumstances the four-component displacement becomes a three-component displacement and the crossover tie line merges with the oil tie line (only C_1 , C_6 , and C_{16} are then present). As gas enrichment with C_3 is increased, however, the mechanism becomes CV and the computed path lengths change approximately linearly. The condensing path length increases with enrichment, while the vaporizing path length decreases.

The percentage of the CV displacement that is condensing (or vaporizing) is computed using Eq. 1.30 (see Fig. 1.74). The condensing fraction increases from zero at no enrichment to nearly 90% at the MME. Thus, the displacement mechanism changes significantly with enrichment as is expected.

Multicomponent Displacements

We first consider the seven-component systems reported by Uleberg and Hoier (2002), who report a MMP of 6909 ± 147 psia as measured by slim-tube experiments in which lean gas is injected. For enriched-gas injection, they estimate the MMP to be 4777.5 ± 73.5 psia. Thus, as expected the MMP is significantly smaller when the gas is enriched with solvent. The calculated MMP by Yuan and Johns (2002) is in very good agreement with these values: 7007 psia for lean gas injection and 4838 psia for enriched-gas injection (see Figs. 1.75 and 1.76 for lengths of the key tie lines).

Figs. 1.77 and 1.78 give the lengths of the composition paths along the five ruled surfaces for both the lean and enriched-gas floods. For lean gas injection, the first crossover tie line controls the development of miscibility and the displacement is a CV drive. As shown in Fig. 1.77, the displacement mechanism is primarily vaporizing because the path length between crossover tie line 4 and the gas tie line is much longer than the other path lengths. The fraction of the CV drive that is vaporizing is relatively constant with pressure (between 0.90 and 0.95 in Fig. 1.79), although the vaporizing fraction does decrease slightly with pressure.

The enriched-gas displacements are also CV floods. In this case, however, the third crossover tie line controls the development of miscibility (see Fig. 1.76). Thus, the enriched-gas drive should be more condensing than the lean-gas drive. Fig. 1.79 confirms that this is true since the vaporizing fraction of the CV displacement is between 0.55 and 0.60. Again, the displacement mechanism is relatively insensitive to pressure. Although this system is reported as an enriched-gas flood, the mechanism for oil recovery is slightly more vaporizing than condensing.

Next, we consider displacements of twelve-component oil by five-component gases, as previously reported by Johns *et al.* (2002) and Solano *et al.* (2001). In this enriched-gas flood, lean separator gas is enriched with a five-component solvent (see Yuan and Johns (2002) for gas compositions). Fig. 1.80 shows all key tie-line lengths as the lean gas is enriched with solvent. After 4% enrichment, the fourth crossover tie line becomes the shortest key tie line. The fourth crossover tie line eventually has zero length at the MME near 57.2% enrichment.

Fig. 1.81 gives the percentage of the CV displacement that is condensing (or vaporizing) as the injected gas is enriched with solvent. The condensing fraction increases significantly from about 0.10 to a value of about 0.60 at the MME.

Last, we consider displacements of thirteen-component oil by CO₂. Tables 1.6 – 1.10 give the parameters used to model the phase behavior by the Soave Redlich-Kwong equation-of-state (SRKEOS) (Soave, 1972). Fig. 1.82 shows the lengths of the key tie lines as a function of pressure. The second crossover tie line determines miscibility at the MMP of 2296 psia (the MMP was not measured from slim-tube data).

Fig. 1.83 also gives the lengths of the key tie lines for the same fluid, but after lumping to seven pseudocomponents. We obtained the pseudocomponent model by

tuning to available phase behavior data for this oil (bubble point pressure, differential liberation data, separator flash data, etc.). The MMP for the lumped system, 2233 psia, is slightly smaller than that of the original thirteen-component system. Thus, the error in MMP is small and we would expect the local displacement efficiency (1-D oil recovery) in the absence of dispersion to be nearly the same at the MMP of the thirteen-component system. Fig. 1.84 shows, however, that the lumped system is about 7% more condensing than the original thirteen-component model. This difference in the displacement mechanism could be important for gas floods whose performance are very sensitive to dispersion. We examine the sensitivity of oil recovery to dispersion in the next section. Future work could examine tuning the pseudocomponent model to the condensing fraction of the CV drive.

Effect of Dispersion on Recovery

In this section, we examine the sensitivity of the local displacement efficiency to dispersion, where the oil recovery is computed with one-dimensional simulations as a fraction of the initial hydrocarbon pore volume (HCPV). Solano *et al.* (2001) showed that the effect of physical dispersion on 1-D oil recovery can be accurately modeled by changing the number of grid blocks. The numerical solutions for one-dimensional flow are calculated with The University of Texas at Austin Compositional Simulator (UTCOMP), a compositional simulator that includes volume change on mixing (Chang *et al.*, 1990).

We examine the effect of dispersion on recoveries for the four-component and twelve-component models considered earlier. Fig. 1.85 shows the oil recoveries at 1.2 PVI (Pore Volume Injected) for the simulated four-component displacement for two grids (100 and 1000 grid blocks). Each recovery value in Fig. 1.85 is calculated for different enrichment levels at a pressure equal to the calculated MMP (corresponding to that particular enrichment). The fraction of the displacement that is condensing is determined at each MMP and enrichment.

Fig. 1.85 illustrates that the oil recoveries initially decrease as the condensing fraction of the displacement increases. A minimum in the recoveries is eventually reached beyond which the recoveries increase with the condensing fraction. The minimum occurs when the gas enrichment is about 10 – 15% C₃ and the condensing

fraction is about 0.60. Overall, the condensing displacements are more affected by dispersion. This trend is opposite to that observed by Wang and Peck (2000) who argued that vaporizing displacements may be more sensitive to dispersion than condensing ones. It is more likely that the sensitivity of recovery to dispersion is related to the dispersive distance as defined by Jessen *et al.* (2002).

Fig. 1.85 also shows that recoveries at the greater level of dispersion (100 grid blocks) are much smaller than those with less dispersion (1000 grid blocks). Thus, as Solano *et al.* (2002) explain, it may be necessary to enrich a gas beyond the MME or increase the pressure above the MMP to overcome the adverse impact of dispersion on the local displacement efficiency. Whether over enriching is required or not, depends on many factors, including the sensitivity of the fluid characterization to dispersion as shown in this research and on the level of dispersion itself.

Fig. 1.86 illustrates the oil recoveries at 1.2 PVI for the twelve-component system as a function of the grid sizes and the condensing fraction. This system is much more sensitive to dispersion than the four-component one. The trend in the recoveries is similar to the four-component model, although the minimum occurs at an enrichment of about 20% solvent.

Conclusions

We have developed a simple and fast analytical technique to quantify the drive mechanism and tied it to the computation of the MMP and MME. We showed that the condensing fraction of a displacement increases with increasing enrichment or pressure. An accurate fluid characterization is needed to estimate the MMP or MME and the displacement mechanism if the proposed analytical technique is to be used. As long as lumping is done properly, the reduction in the number of components did not have a major impact on the MMP of the displacement, although the condensing fraction of the displacement mechanism increased more significantly for the system studied. One implication of this observation is that lumped systems could exhibit different sensitivities of oil recovery to dispersion than their original characterizations.

Task 2: Increase Sweep Efficiency with Foam

Subtask 2.1: Laboratory Experiments

Subtask 2.1.1: Mechanistic N₂ Foam Studies

Work on N₂ foam studies comprised two major efforts: examination of the generality and implications of the two steady-state foam-flow regimes, and study of the fractional-flow curve for foam at low water fractional-flow, in conjunction with scale-up of behavior to field-scale application.

Two Steady-State Foam-Flow Regimes

Introduction

P_c* regime. Khatib *et al.* (1988) found that foam stability in porous media is limited by capillary pressure. In studying foam in beadpacks, they identified an abrupt transition from strong foam to no foam (or weak foam) in a very narrow range of capillary pressure around the “limiting capillary pressure,” P_c*. Supporting observations were reported for sandpacks (de Vries and Wit, 1990), Boise sandstone (Persoff *et al.*, 1991) and fired Berea sandstone (Ettinger and Radke, 1992). In the P_c* regime, foam bubbles change size as needed to maintain foam at the limiting capillary pressure. As a result, liquid saturation S_w is constant and equal to S_w*, its value at P_c*. If P_c* and S_w* are independent of flow rates, as in the “fixed-P_c* model” (Rossen and Zhou, 1995), then k_{rw}(S_w) is constant during foam flow; as a result, pressure gradient is proportional to liquid flow rate or liquid superficial velocity U_w and independent of gas flow rate (Persoff *et al.* 1991; Ettinger and Radke, 1992).

Second Flow Regime. Osterloh and Jante (1992) identified two foam flow regimes in a sandpack study. In one regime pressure gradient was reasonably independent of gas flow rate, as predicted by the P_c* model. But in the second regime pressure gradient was reasonably independent of *liquid* flow rate and dependent on gas flow rate. The transition zone between the two regimes was characterized by a specific value of gas fractional flow f_g (gas superficial velocity divided by total velocity), f_g*. Foam "quality" is f_g rescaled from the range from 0 to 1 to the range from 0 to 100%. Fig. 2.1 shows the two regimes and the transition foam quality at f_g* = 0.94. Therefore, f_g > 0.94

corresponds to the “high-quality regime” (also called the “coalescence regime” (Ettinger and Radke, 1992)); foam in this regime obeys the P_c^* model. On the other hand, for the second, “low-quality regime”, the P_c^* model does not apply. Osterloh and Jante pointed out that the transition from one regime to the other likely occurs when the limiting capillary pressure is reached. Fig. 2.2 is a simplified representation of a contour plot like Fig. 2.1, showing important parameters and definitions used throughout this study.

Supporting observations are provided by Parlar *et al.* (1995) (see also Robert and Mack (1995)) and Rossen and Wang (1999), all using Berea cores. Rossen and Wang proposed a model for foam behavior in the low-quality regime. Their model is based in the assumption that bubble size in this regime is fixed (perhaps at roughly pore size), and therefore independent of liquid and gas flow rates. This conjecture is based in the idea that diffusion causes bubbles smaller than the pore size to disappear and, for bubbles smaller than pores, foam-creation processes like snap-off and lamella division are inhibited. Foam with a fixed bubble size is then modeled as a Bingham plastic (Bird *et al.*, 1960) that is trapped or flows depending on pressure gradient.

This assumption of fixed bubble size implies that pressure gradient in the low-quality regime should be a strong function of the porous medium. Pressure gradient is set by bubble trapping, which with bubble size fixed depends primarily on pore geometry and surface tension (Falls *et al.*, 1989; Rossen, 1990a-d); however, surface tension in many cases does not vary greatly with surfactant formulation. For instance, at room temperature, many surfactant formulations give surface tensions with air between about 25 and 40 dyne/cm. Therefore, rock-petrophysical properties should play the key role in determining pressure gradient in the low-quality regime, while surfactant formulation is the most important parameter in the high-quality regime through its effect on foam-coalescence processes. At the time, there was no direct evidence that bubble size is fixed in the low-quality regime.

More recently, Vassenden and Holt (1998) identified two foam-flow regimes in experiments in reservoir core from the Snorre field and crushed Berea sand. They plotted their data as gas relative-permeability curves and defined the two regimes relative to a change in slope in the curves. The transition between the two regimes in the high-permeability sandpack occurred at lower water saturation than in the reservoir core. It is difficult to relate the difference directly to permeability, because different surfactant

concentrations were used in the two experiments. Vassenden and Holt explained the occurrence of the low-quality regime as the effect of viscous pressure gradients on foam films. For foam at the “limiting pressure gradient,” increasing injection rate creates more flow channels in the porous medium; pressure gradient is therefore independent of gas flow rate, and gas relative permeability is proportional to gas flow rate. They also replot the data of several previous studies as relative-permeability curves, and show that these studies also reflect two foam-flow regimes.

Following the lead of Vassenden and Holt, but plotting in the style of Osterloh and Jante, Fig. 2.3 shows a contour plot obtained using data from Khatib *et al.* (1988). Two flow regimes are observed, with f_g^* greater than 0.98. Fig. 2.4 shows data from Chang and Grigg (1999). Their experiments were performed at low foam qualities (f_g between 0.2 and 0.8), and all data reflect the low-quality regime. Lee and Heller’s (1990) data are shown in Fig. 2.5. In this case higher foam qualities were used (f_g from 0.6 to 0.9), and only the high-quality regime was observed. The contours are jagged due to experimental scatter, but the trend of the contours is clearly vertical.

Such contour plots provide important insights into how various parameters affect foam behavior. For instance, Lee and Heller (1990) concluded that foam mobility decreases as foam quality decreases. However, the effect of f_g on foam mobility clearly depends on flow regime, as illustrated in Fig. 2.2. At fixed total flow rate U_T , in the high-quality regime, ∇p increases with decreasing foam quality until f_g^* is reached; then ∇p decreases with further decreases in foam quality in the low-quality regime. The “optimal” foam quality (highest ∇p at fixed U_T) occurs at f_g^* .

Hypothesis. The working hypothesis of this study is as follows:

- In the high-quality regime (vertical contours in Fig. 2.1), P_c^* controls bubble size and therefore gas mobility. The ability of the surfactant to stabilize bubbles is the key to this (coalescence) regime. The porous medium also plays an important role.
- In the low-quality regime (horizontal contours in Fig. 2.1), bubble size is fixed and pressure gradient depends on porous medium and to lesser extent on surface tension, but not on the ability of surfactant to stabilize foam.
- The transition between the two regimes occurs roughly where the contour lines from the high-quality regime intersect the contour lines from the low-

quality regime (Fig. 2.2). Therefore, the transition zone is sensitive to both the nature of the porous medium and ability of surfactant to stabilize foam.

We call this hypothesis for foam the “ f_g^* model.” Fig. 2.6 shows a schematic representation of the flow regimes and the hypotheses proposed for each regime.

The following section describes experimental work carried out as part of this study.

Experimental Approach

Materials. The experiments were carried out in either Berea cores (nominally homogeneous), Antolini cores (sandstone cores with distinct layers, described in detail by Wang (1995)) or silica sand, F-35[®] grade, from U.S. Silica Company (Ottawa, IL). Antolini sandstone features alternating sharply delineated, roughly parallel layers about 1 cm or less in thickness, of larger and smaller grains. Wang's minipermeameter readings in one sample varied from extremes of less than 50 to almost 1000 md, but since layers were at or below the resolution of the minipermeameter, these figures may underestimate the variability of local permeability. In our experiments, cores were cut parallel to the layering, and layers extended the length of the core. All the cores used were 2 inches in diameter. Neither cores nor sand were fired before the experiments. Two types of surfactants were used: PEN-5 surfactant, an octyl ethoxylated alcohol (nonionic surfactant), supplied by Halliburton Service Company (Duncan, Oklahoma), and Bio-Terge AS-40[®] surfactant, a C₁₄₋₁₆ sodium α -olefin sulfonate (anionic surfactant), from Stepan Company (Northfield, IL). In bottle tests Bio-Terge formed the more stable foam at room temperature. The CMC of the Bio-Terge surfactant in this brine at room temperature is about 0.15 wt% (Alvarez, 1998). Brine composition was 3 wt.% NaCl and 0.01 wt.% CaCl₂ in deionized water. Nitrogen was used as the gas phase during the experiments.

Apparatus. A schematic of the apparatus is presented in Fig. 2.7. A Hassler-type coreholder with 4 internal pressure taps was used, with the coreholder placed in a vertical position and with injection from the top. A different Hassler coreholder without pressure taps was utilized in the sand-pack experiment. Liquid and gas meet at a tee before entering the foam generator, which was a Nupro[®] filter body packed with bronze wool.

Foam bubbles were observed upstream and downstream of the core using two Temco (Tulsa, OK) variable-aperture visual cells. The nominal aperture of the downstream visual cell was approximately 30 μm between the opposing glass plates for all the experiments in this study. Large bubbles appear very bright and round. On the other hand, multiple layers of small bubbles appear as a dark, opaque mass. A video camera recorded qualitative bubble texture observed through the visual cell at the outlet of the core. Early in a coreflood, before foam reaches the end of the core, wet, round bubbles may appear in the effluent as an experimental artifact of snap-off at the core outlet (Ransohoff and Radke, 1988). Later, after ∇p rises and levels off in section 4, the drier bubbles in the effluent are thought to reflect the bubble size distribution in the core near the outlet (Ettinger and Radke, 1992).

The core was divided into four sections, of length 1 in., 4 in., 4 in. and 2 in., starting from the inlet. Pressure drop in each section was measured using a Validyne® (Northridge, CA) pressure transducer. A 320-psi diaphragm (DP15-54) was used to measure the pressure drop in the first section. Diaphragms of 500 psi (DP15-56) were used for the remaining sections. Further details of the apparatus are given by Alvarez (1998).

Experimental Procedures. All experiments were carried out at room temperature and 600 psi outlet pressure according to the following procedure:

After placing the given core in the Hassler-type coreholder and vacuum-saturating with brine, brine permeability is determined. After a period of brine injection, injection of surfactant solution and gas begins. Gas and surfactant flow rates are set to obtain a specific foam quality, f_g , at the outlet conditions of 600 psi. Steady state is reached when pressure drop through the core holds constant within a certain range; to ensure steady state, foam is injected at each flow rate for at least 24 hours. After steady state is achieved, liquid flow rate, gas flow rate or both are changed to obtain a new point on a plot such as Fig. 2.1. This process is repeated to obtain as many points as desired.

Pressure drop in each section is used to calculate an average pressure for each section. This average pressure is then used to compute *in situ* gas flow rate in each section using the ideal gas law. Both gas and liquid velocities reported in the contour plots shown below are superficial velocities (Darcy velocities).

If the same core is needed for succeeding experiments, 100 PV of brine are injected to clean the core. Then the core is placed in an oven at 150°F for 48 hr. After that, 20 PV more of brine are injected and permeability and porosity checked to ensure the absence of petrophysical changes. Core permeability changed by no more of 20% in these experiments.

DeltaGraph® software, from DeltaPoint, Inc. (Monterey, CA), was used to construct the contour plots. The software interpolates linearly within triangular regions formed by nearest-neighbor data points; as a result, the contours can be somewhat jagged, and small deviations between closely-spaced data can distort the apparent trend of a contour substantially (*cf.* Fig. 2.5). No attempt to smooth the contours was made, however, to avoid biasing the interpretation of the data. Details are given by Alvarez (1998).

All data reported here were obtained from section 2 of the core. Similar results were obtained using data from core section 3 (Alvarez, 1998).

Strategy. The effects of five different parameters on foam behavior were evaluated in seven experiments. Surfactant type, surfactant concentration, permeability, core layering and flow rates were varied one at the time in order to isolate each effect. With relatively few experiments to probe several factors, these results should be considered preliminary. Table 2.1 shows the working conditions for the seven experiments. Experiments Ug5 and Ug6 were used to evaluate the effect of surfactant type. Surfactant concentration was evaluated in experiments Ug6, Ug7 and Ug8. Bio-Terge surfactant concentration was reduced from its maximum value, in experiment Ug6, to lower values in experiments Ug7 and Ug8; for Ug8 it was well below its CMC (Alvarez, 1998). The effect of permeability was evaluated in experiments Ug6 and Ug11. Experiment Ug12 assessed the effect of core layering. Finally, experiments Ug6 and Ug14 were combined to evaluate the effect of widely varying flow rates.

Experiments Ug6, Ug7, Ug8 and Ug14 were carried out in the same Berea core. Experiment Ug5 used a different, though nominally similar, Berea core.

Results

Fig. 2.8 shows results for experiment Ug5. On this plot each bold-black dot represents one steady-state datum. Two regions were observed, as described first by Osterloh and Jante (1992). However, the transition zone between these regimes is at much lower gas fractional flow than in their experiments. For surfactant PEN-5, pressure gradient is independent of gas velocity for values of f_g greater than about 0.73. On the other hand, for values of f_g less than 0.73 pressure gradient is independent of liquid velocity. This value of $f_g^* = 0.73$ should be taken as a rough estimate and not as a precise value. Experiments after Ug5 used a different, though nominally similar, Berea core (Table 2.1).

The results obtained in experiments Ug6, Ug7 and Ug8 are presented in Figs. 2.9, 2.10 and 2.11, respectively. Bio-Terge surfactant is used and concentration is changed in each experiment; the f_g^* value at the transition between flow regimes is different for each case.

Fig. 2.12 shows the contour plot obtained in experiment Ug11, in a high-permeability medium (sandpack). Two regions are also observed in this case, with a transition f_g^* value similar to the one obtained by Osterloh and Jante in a sandpack at a higher temperature (Fig. 2.1). Experiment Ug12 reveals two regimes also in the more complex, layered Antolini sandstone (Fig. 2.13). Experiment Ug14 (Fig. 2.14) extends experiment Ug6 to lower flow rates; the f_g^* value at the transition between regimes is reduced to 0.6 (*cf.* Fig. 2.9).

A summary of these results is presented in Table 2.1. As mentioned above, all plots shown here were constructed with data from core section 2, but plots with similar trends were obtained using data from section 3 (Alvarez, 1998). Table 2.1 also describes the apparent foam rheology in both flow regimes in each experiment; details are in Alvarez (1998). Behavior is shear-thickening (∇p increases more than proportionately to U_T) in the high-quality regime, and shear-thinning (∇p increases less than proportionately to U_T) in the low-quality regime. Because ∇p contours are vertical in the high-quality regime and horizontal in the low-quality regime, ∇p scales the same with either U_T or U_w in the high-quality regime and with either U_T or U_g in the low-quality regime.

Figs. 2.15 and 2.16 show pictures of foam texture observed at the visual cell downstream of the core in experiment Ug14. Figs. 2.15a through 2.15c were obtained with increasing gas flow rate in the high-quality regime while Figs. 2.16a and 2.16b were obtained with different gas flow rates in the low-quality regime.

The following presentation is divided into results consistent with the f_g^* model and results inconsistent with this model.

Results consistent with the f_g^* model. *Bubble Size.* In the high-quality regime (Fig. 2.15) bubble size increases with increasing gas flow rate, as predicted in the P_c^* model (Khatib *et al.*, 1988) and reported by Ettinger and Radke (1992). This change in bubble size allows gas mobility to rise as gas flow rate increases, thereby holding pressure gradient independent of gas flow rate. On the other hand, in the low-quality regime (Fig. 2.16), smaller bubbles were observed. No gross changes in bubble size were observed upon changing gas flow rates by a factor of 2.5, though no quantitative analysis was attempted. This last observation qualitatively confirms the fixed bubble size assumed in Rossen and Wang's (1999) model for the low-quality regime.

Pressure gradient in the low-quality regime. The three cases with different concentrations of Bio-Terge surfactant (Figs. 2.9, 2.10 and 2.11) show very different behavior in the high-quality regime and different transition foam qualities, but similar ∇p contours in the low-quality regime. This result agrees with the model of Rossen and Wang (1999), in which bubble size is fixed and ∇p depends only on the porous medium and surface tension, which does not vary greatly with surfactant concentration. Pressure gradient is lower in the low-quality regime in a sandpack (Fig. 2.12), as expected, due to larger pores and pore throats.

Effect of Surfactant Concentration. Results obtained in experiments Ug6 through Ug8, reflecting the effect of surfactant concentration, show that the reduction of surfactant concentration below the CMC causes a shift of the transition zone to lower values of f_g^* , from 0.74 for 1 wt.% Bio-Terge to less than 0.4 for 0.05 wt.% Bio-Terge. The reduction in surfactant concentration reduces P_c^* , increasing S_w^* and increasing gas mobility. Therefore, pressure drop is reduced as consequence of the increment on S_w^* and its effect on $k_{rw}(S_w^*)$, as expected from the fixed- P_c^* model. Figs. 2.9, 2.10 and 2.11 show that foam weakens in the high-quality regime as surfactant concentration decreases. Note that ∇p remains significant at low surfactant concentration in Fig. 2.11, reflecting a

decline in P_c^* but not a complete collapse of, or failure to stabilize, foam. Fig. 2.17 shows schematically how decreasing foam strength reduces f_g^* . As mentioned above, ∇p in the low-quality regime is expected to be independent of surfactant formulation. Therefore, the horizontal contours in this regime remain unchanged after reducing surfactant concentration. On the other hand, the vertical lines in the high-quality regime move to the right as foam gets weaker (*i.e.*, liquid velocity at fixed ∇p must increase). The final result is a movement of the intersection point for the two regimes to lower f_g^* .

There is only a subtle change in f_g^* between experiment Ug6, with 1 wt.% Bio-Terge, and experiment Ug7, with 0.25 wt.% Bio-Terge (Figs. 2.9 and 2.10). In the low-quality regime ∇p is the same in both cases, but in the high-quality regime ∇p is higher at the higher surfactant concentration; therefore f_g^* must be higher in experiment Ug6, but experimental scatter, combined with rough plotting approach in these figures, partially obscures this trend in the transition region. The values of f_g^* in Figs. 2.9 and 2.10 are based on extrapolation of contours from well within the high- and low-quality regimes, where they are free of this distortion, into the transition region, as described by Alvarez (1998). Thus experiments Ug6, Ug7 and Ug8 show a monotonic increase in f_g^* with increasing surfactant concentration: subtle differences above the CMC, and large differences below it.

Effect of Permeability. Comparing the results from experiments Ug11 (Fig. 2.12) and Ug6 (Fig. 2.9), with the same surfactant formulation, shows a much higher value of f_g^* in the high-permeability medium. Fig. 2.18 shows a schematic representation of how f_g^* responds to changes in permeability. As discussed above, ∇p in the low-quality regime depends strongly on the porous medium. Bigger pores and therefore lower capillary resistance are expected in the sandpack, giving a lower pressure gradient than in the lower-permeability consolidated core. Therefore, the horizontal ∇p contours in the low-quality regime move upward with increasing permeability (*i.e.*, gas velocity must increase at constant ∇p). The effect of permeability on vertical ∇p contours in the high-quality regime is less clear, but a variety of data (Rossen and Lu, 1997) suggest the net effect of increasing k would be a gentle decrease in ∇p , moving the contour somewhat to the right. The data of Myers and Radke (2000), however, suggest that ∇p contours may

move to the left upon increasing permeability. The final result in either case is an increase in f_g^* as shown in Fig. 2.18.

Effect of Heterogeneity. Two regimes are also observed in the Antolini core (Fig. 13), a heterogeneous medium, with f_g^* greater than in the Berea cores. The average permeability of the Antolini core is lower than the Berea cores (Table 2.1); if the core were homogeneous, this would suggest a lower value of f_g^* . Whether f_g^* should decrease in this case depends on the relative effects of average core permeability, flow diversion and capillary crossflow, as discussed by Alvarez (1998). The result observed is consistent with flow dominated by the higher-permeability layers in this core and little capillary crossflow. How this result would relate to field-scale heterogeneity is not clear. Capillary and viscous crossflow are discussed further later in this report.

Rheology in the Low-Quality Regime. Shear-thinning rheology in the low-quality regime (Table 2.1) is consistent with the fixed-bubble-size model of Rossen and Wang (1999). Both the yield stress of foam (Falls *et al.*, 1989; Rossen, 1990a-d) and the shear-thinning rheology of moving bubbles (Hirasaki and Lawson, 1985) imply shear-thinning behavior in this regime.

Effect of Total Flow Rate. Combining the results of experiment Ug6 and Ug14 (Fig. 2.9 and Fig. 2.14) shows that increasing flow rates increases the value of f_g^* . Fig. 2.19 combines the data from Ug6 and Ug14 (same core, surfactant and surfactant concentration, but different ranges of flow rates). Clearly f_g^* increases with increasing flow rates. Alvarez (1998) computes that f_g^* increases from 0.6 at a combined Darcy velocity of 0.5 ft/day to 0.8 at 2 ft/day. Osterloh and Jante's (1992) plots show a similar trend.

This result derives from the shear-thinning rheology of the low-quality regime, as shown in Fig. 2.20. Upon increasing flow rate, the shift upwards of the ∇p contour in the low-quality regime is greater than the shift to the right in the high-quality regime. The apparent shear-thickening rheology of the high-quality regime, discussed below, also contributes to the effect.

"Chaotic Regime." Fig. 2.11 shows a reduction in pressure gradient as gas flow rate increases at high foam quality (i.e., the ∇p contour curves bend to the left in the high-quality regime). This phenomenon was also reported by Osterloh and Jante (1992), who called this the "chaotic regime." The "chaotic regime" in their experiments occurred

at f_g values greater than about 0.998, where foam is very dry and unstable. In Fig. 2.11 the “chaotic regime” is observed for f_g values greater than about 0.7 but at very low surfactant concentration, arguably conditions too dry for stable foam at this surfactant concentration. It is possible that the “chaotic regime” occurs when a combination of low surfactant concentration, poor foamer or dry conditions destabilizes foam.

Results Inconsistent With the f_g^* Model. Comparison between surfactants. Results for PEN-5 surfactant from experiment Ug5 by themselves fit the trend of other data, but the comparison of PEN-5 with Bio-Terge does not agree with the f_g^* model.

Comparing Fig. 2.9, for experiment Ug6 with 1 wt.% Bio-Terge, with Fig. 2.8, shows that pressure gradient in the high-quality regime is much lower with 0.5 wt.% PEN-5 (note different scales in the figures). Foam is weaker with PEN-5, in agreement with bottle tests (Alvarez, 1998). More troubling, pressure gradient in the low-quality regime is much higher with Bio-Terge than with PEN-5, contradicting the hypothesis that pressure gradient should be largely independent of surfactant formulation in the low-quality regime. As a result, f_g^* is similar for the two cases, where a lower value would be expected for the weaker foam with PEN-5.

The reason for this difference is not clear. It is possible that the different, though nominally similar, Berea core used in experiment Ug5 with PEN-5 surfactant caused this difference. It is also possible that surfactant type alters drag on bubbles in the low-quality regime. Hirasaki and Lawson⁸ reported that foam apparent viscosity is affected by surface-tension gradients and Marangoni effects. Therefore, surfactant type could have some effect on pressure gradient. Apparent foam rheology is quite different in the low-quality regime for the two surfactants used. PEN-5 behaves as a Newtonian fluid (Table 2.1), while Bio-Terge is more like a shear-thinning fluid. However, if Marangoni effects are important, then surfactant concentration should affect pressure gradient with Bio-Terge in the low-quality regime, which was not the case here. At this point, no conclusive explanation can be given.

Rheology in the High-Quality Regime. The shear-thickening behavior found in the high-quality regime (Table 2.1) implies that P_c^* increases as liquid velocity increases: lower mobility implies lower $k_{rw}(S_w^*)$, lower S_w^* , and higher P_c^* . Because ∇p contours are vertical in this regime, this conclusion is independent of foam quality f_g in this regime.

Previous authors (Khatib *et al.*, 1988; de Vries and Wit, 1989; Jimenez at Radke, 1989) find or predict a decrease, not an increase, in P_c^* with increasing flow rates. Osterloh and Jante's data (Fig. 2.1) also indicate shear-thinning behavior in the high-quality regime. We are not sure why our results differ on this point.

Discussion

The results obtained in this study confirm the existence of two foam-flow regimes with several different surfactant formulations and porous media. Which regime is observed in a given study depends on experimental conditions: *cf.* Figs. 2.4 and 2.5. Using the trends reported here, seemingly contradictory data in the literature can be reconciled. In particular, foam rheology depends on flow regime. Shear-thickening behavior may be obtained in the high-quality regime, while shear-thinning behavior is expected in the low-quality regime.

Since f_g^* decreases as permeability is reduced, one could expect a low value of f_g^* in many oil-reservoir rocks, with much lower permeability than those used in this study. Moreover, low foam velocity, expected away from the wellbore, further reduces f_g^* . Thus the P_c^* regime might apply widely in oil-recovery processes.

Steam-foam processes operate in the high-quality regime, at least near the wellbore, because of high injected foam quality. Therefore, reducing liquid flow rate without altering gas flow rate could reduce pressure drop and help prevent fracturing in a process such as high-pressure cyclic-steam injection in Venezuela (Alvarez *et al.*, 1993). This coincides with process goals for steam floods, where steam is injected at the highest flow rate possible in order to place as much heat in the reservoir in the shortest possible time.

The low-quality regime offers the economic advantage that liquid (surfactant) injection rate can be reduced without reducing pressure drop (until one leaves the low-quality regime). In addition, in the low-quality regime, one can take advantage of shear-thinning behavior to give high foam mobility near the wellbore, increasing injectivity. This can be especially important for CO₂ processes where avoiding fracturing is a problem (Jonas *et al.*, 1990).

The f_g^* model implies that gas diversion is better at higher foam quality: a larger fraction of injected gas flows through the less-permeable layer. Fig. 2.21 shows ∇p

contours for two layers with different permeability without crossflow. As discussed above, the horizontal contours in the low-quality regime move upward as permeability increases; the vertical contours in the high-quality regime could move to the left or right, but not far to the right. For injection into two isolated layers in field application, foam quality and injection pressure (f_g and ∇p) are the same in both layers. Higher f_g gives a smaller contrast in flow rates: more gas flows into the low-permeability layer in comparison with injection at lower f_g . Viscous and capillary crossflow between layers could complicate this analysis.

On the other hand, an acid-diversion process depends on diversion of acid after foam is placed in both layers. In this case, it is an advantage to have more foam in the higher-permeability layer before switching injection from foam to acid. This suggests that injection in the low-quality regime is better for acid diversion, because it places more foam in the low-permeability layers.

The effect of the presence of crude oil in these trends is not clear. Since oil decreases the effectiveness of foam (Sufridge *et al.*, 1989; Raterman *et al.*, 1989; Schramm and Novosad, 1992; Myers and Radke, 2000), a weaker foam in the presence of oil might drive the transition between flow regimes to a lower f_g^* values compared with the oil-free case. The effect of oil on the two flow regimes is discussed further below.

Conclusions

The following conclusions derive from this study:

1. Two distinct foam-flow regimes, corresponding to high foam quality and low foam quality, are observed with foams in a wide variety of porous media, with a variety of surfactant formulations and gases.
2. A single model can reconcile seemingly contradictory foam behavior. In this model gas mobility is controlled by trapping and mobilization under wet conditions and by capillary pressure and coalescence under dry conditions.
3. This model correlates the shift in predominance between flow regimes as permeability, foam formulation and flow rates vary.
4. Insights gained from this model can guide selection of foam formulation and foam quality for field application in gas-injection IOR.

Further Studies of the Two Foam-Flow Regimes

Since this initial study, we have discovered additional examples of the two steady-state foam-flow regimes in published studies of CO₂ foam; these are discussed under Subtask 2.1.2 below. We have shown the existence of the two foam-flow regimes at elevated temperature (220°F) in the presence of acid (in a study of foam for acid diversion). Fig. 2.23 compares the same foam formulation at room temperature without acid and at 220°F with acid. Details are in Kam *et al.* (2003).

We have conducted a study of foam application to environmental remediation. The permeabilities of the porous media (sandpacks) were much higher in this study than in most oil reservoirs, but the study stands as a test of the generality of the two foam-flow regimes. In addition, this study comprises one of the most comprehensive studies of the two foam-flow regimes in any context. This study involved a variety of surfactants, concentrations, sandpack permeabilities, and presence and absence of oils of two types. Between the variety of surfactants, concentrations and permeabilities studied, 49 plots like Figs. 2.8 to 2.14 were prepared, allowing twelve comparisons of the effect of surfactant concentration, holding surfactant type and pack permeability fixed, without oil; ten comparisons of the effect of permeability, holding surfactant type and concentration fixed, again without oil; several comparisons of the effect of surfactant type; and four comparisons of the effects of oils of different type and amount, holding surfactant type, surfactant concentration and permeability fixed. The effect of oil is discussed in the next section. Several trends are evident in the comparisons without oil.

The plots of ∇p as a function of flow rates clearly show the two flow regimes. In a few cases the data appear to lie entirely in one regime or the other. In the cases without oil, the results generally, but not perfectly, agree with the trends cited above. Detailed analysis of the data, available in Rong (2002), leads to the following conclusions:

- The two steady-state strong-foam regimes observed for foam in petroleum applications appear to apply in this study as well.
- Surfactant concentration plays a larger role in the high-quality regime than in the low-quality regime, in agreement with the analysis above. In other words, mobility changes little as a function of surfactant concentration in the low-quality regime but is more sensitive to concentration in the high-quality

regime. Twelve comparisons of the effect of surfactant concentration largely support this finding (Rong, 2002).

This suggests that higher surfactant concentration increases the limiting capillary pressure (Khatib *et al.*, 1988; Rossen and Zhou, 1995; Aronson *et al.*, 1994), and stabilizes foam in the high-quality regime. The low-quality regime is less sensitive to the effects of surfactant concentration. As a result, as surfactant concentration decreases, the high-quality regime comes to dominate behavior over a wider range of flow rates.

- Permeability, on the other hand, has a much stronger effect on ∇p in the low-quality regime than in the high-quality regime, in agreement with the analysis above. Ten comparisons of the effect of permeability largely support this finding (Rong, 2002).

In other words, in the high-quality regime foam tends to compensate for differences in permeability, creating beneficial diversion, but much less so in the low-quality regime. As permeability decreases, the high-quality regime comes to dominate behavior over a wider range of flow rates.

- Both the high- and low-quality regimes are sensitive to surfactant choice, in contradiction to the initial conjecture cited in the previous section, but in agreement with the limited data compiled in that study.
- Foam rheology is shear-shinning in the low-quality regime, again in agreement with trends cited above. In the high-quality regime, behavior can be shear-thickening, Newtonian or shear-thinning.

The Effect of Oil on the Two Foam-Flow Regimes

Introduction. Several experimental methods are available for evaluating the stability of foams to oils, including coreflooding, bulk foam stability, micromodel observations, and measurements of interfacial parameters. Foam-oil interaction mechanisms have been proposed based on surface energy principles, and these properties have been subsequently experimentally observed in numerous combinations of foams and oils of a wide variety (Bergeron *et al.*, 1993; Schramm and Novosad, 1992; Myers and Radke, 2000). Three main models have emerged in attempting to predict foam stability to oil, including spreading and entering coefficients, pseudoemulsion film models, and

lamella number (Lau and O'Brian, 1988; Schramm and Novosad, 1990, 1992; Mannhardt, *et al.*, 2000). However, in this study, the objective is to investigate the effect of oils on foam behavior in the two foam-flow regimes. That is, in this study of the variation of pressure gradient in the two regimes, the major concern is how the f_g^* value changes when foam is generated in the presence oil, rather than the detailed mechanism of interaction of oil and foam. However, to reduce the number of experiments and aid in the evaluation of results, the entering and spreading coefficients and lamella number were measured and used to pre-select a range of conditions for the of oils on foam stability. In this study the experimentally observed of variation of pressure gradient was to evaluate the effect of oil on foam stability, which was classified in the categories of no effect, moderate effect, and unstable foam.

The objectives of this study are to

- Investigate the effect of oil to the two foam-flow regimes,
- Evaluate the effect of types of oil, and
- Investigate the effect of fraction of oil on foam flow

Experimental Materials. In this study, two anionic surfactants, Aerosol MA-80I and Dowfax 8390, and three oils, decane (obtained from Fisher Scientific, Fair Lawn, NJ), FC-70, and FC-77 (fluorinated oils obtained from 3M Co., St. Paul, MN) were selected. The fluorinated oils have a lower surface tensions and were expected to have less effect on foam stability. The fluorinated oils are of course not found in oil reservoirs. They represent oils of very different properties from the hydrocarbon (decane), and they also stand in for the chlorinated hydrocarbons often encountered in environmental remediation (without the extreme toxicity in the laboratory). Two sand samples, mesh 20/30 and F-95, were selected and packed in plastic columns to create porous media with two different permeabilities, 5 and 210 darcy.

Experimental Apparatus, Method and Strategy. The same experimental apparatus (sandpack flow system) was used as in the study without oil; this facilitated a direct comparison with the experimental results obtained in the absence of oil. However, introduction of oil required modification of the system and procedures. To maintain constant concentrations over the experiments, the oil, gas, and surfactant are separately injected from the top of column. In these experiments, at least 3 pore volumes of a mixture of oil and surfactant solution were injected into the column before introducing

the gas. After saturating the column with the oil and surfactant solution, gas, oil and surfactant solution are injected at fixed ratios for the desired foam quality. The injection of oil is through a "T" connection after the mixing of the gas and surfactant solution.

The liquid flow rate shown in the sample plot below for the experiments with oil combines the surfactant solution and oil flow rates.

The surface and interfacial tensions of the surfactant solution and oil were measured both before and after mixing. After mixing the surfactant solution with oil, two interfacial-tension measurements were made, that of the initial interfacial tension $\gamma_{ow,i}$, which measures the interfacial tension immediately after mixing, and the pre-equilibrated or equilibrium interfacial tension $\gamma_{ow,e}$, which measures the interfacial tension after mixing and equilibration for 24 hours. The results are summarized in Table 2.2. The entering coefficient, E, which describes oil entering the gas/water interface from the water phase, the spreading coefficient, S, which describes oil spreading on the water/gas interface, and the lamella number, L, which is thought to describe both oil emulsification and foam stability, are also calculated as shown in Table 2.2.

Schramm (1994) in a coreflood experiment suggested that oil saturations between 5 and 20% could cause foam to become unstable. Mannhardt and Svorstol (1999) observed in their experiments that the foam stability is affected by oil at the residual oil saturation above 13%. Hudgins and Chung (1990) suggested that at a residual oil saturation of 23%, the rate of foam generation in porous medium becomes slow. Thus, the residual oil saturation that starts to affect to foam stability is unknown. Therefore, 7% and 22% oil volume fraction in injected liquid are used in this study, in an attempt to be below and above the value that impacts foam stability.

In previous studies, the residual oil saturation is commonly measured. For instance, Myers and Radke (2000), in their coreflood experiment, pre-saturated the 280-md core with decane, and observed that the residual oil saturation (31%) was constant throughout the entire experiment. Unfortunately, one cannot in general keep the residual oil saturation constant during foam generation. In our preliminary studies, for example, the residual oil saturation was 30% before introducing foam into the column but only 5% after the foam-flooding experiment. This higher loss of oil in the current study than in that of Myers and Radke may be due to the higher permeability (210 darcy) of the porous medium, its lower capillary resistance, and the resulting greater removal of residual oil

when foam was generated in porous media. The large change in residual oil over the course of an experiment made the method of Myers and Radke impractical for this study. Instead, the ratio of injected liquid and oil flow rates is fixed.

Results and Discussion. The results of bottle tests of foam stability as well as measurements of surface and interfacial tensions are summarized in Table 2.2. The calculated values of the initial and equilibrium spreading coefficients, S_i and S_e , entering coefficients, E_i and E_e , and lamella numbers, L_i and L_e , are also reported in Table 2.2. Rong (2002) presents detailed experimental results. Fig. 2.24 presents one example comparison of the effects of different oils on foam with one surfactant formulation.

Initial Prediction of Interaction of Oil with Foam from S , E and L . In Table 2.2, the experimental results show that all entering coefficients, including initial and pre-equilibrated values, are positive, i.e., it is thermodynamically favorable for the oil to enter the interface between water and gas. The values of spreading coefficient indicate that FC-70 is non-spreading in either surfactant system. FC-77 is thermodynamically favorable to spread on the surface of both surfactant solutions. Decane will not spread in the MA-80I surfactant solution but will spread on the surface of the Dowfax 8390 solution. FC-70 and FC-77 have lamella numbers less than 1. This suggests that the formation of emulsified droplets is unfavorable for both fluorinated oils. However, it is thermodynamically favorable for decane to emulsify into small droplets, especially when it initially contacts with surfactant Dowfax 8390.

Based on these results, one would predict that the fluorinated oils would have small effect on foam stability. However, decane should decrease the stability of both surfactant foam systems and especially the Dowfax 8390 surfactant system. Therefore, one would expect that decane would weaken the foam strength more than the fluorinated oils, and therefore f_g^* should decrease greatly in the presence of decane but small in the presence of fluorinated oils.

Effect of Oil on Two Foam-Flow Regimes. This study is the first to investigate the effects of oil on the two foam-flow regimes. Rong (2002) shows that the two foam-flow regimes exist using with both surfactants Aerosol MA-80I and Dowfax 8390 in the presence of oil in porous media with permeability of 200 or 5 darcy. However, the degree of effect of the oil on the foam behavior in both regimes depends on several factors.

Effect of oil Type. The effect of oil on foam depends on the interaction between the oil and the surfactant (Suffridge *et al.*, 1989; Meling and Hanssen, 1989). Therefore, both the oil and surfactant properties may be the important factors. The experimental results indicate that the presence of oil has a drastic effect in the high-quality regime but less effect in the low-quality regime. However, the degree of effect depends on the oil type. For both surfactant formulations, the effect of fluorinated oils is smaller than that of decane on the foam stability. The implication is that the foam is more sensitive to decane. Foam stability varies widely in the presence of different oil types as has been observed by some researchers (Suffridge *et al.*, 1989; Schramm and Novosad, 1990, 1992). However, surfactant type is also a contributing factor to the effect of oil presence.

Summary. The following conclusions can be drawn from this study of the interactions between oil and foam. See Rong (2002) for a detailed discussion.

- In the cases examined, the two steady-state foam-flow regimes identified in extensive studies of foam without oil exist also in the presence of oil.
- Oil weakens foam in the high-quality regime more than in the low quality regime. If a surfactant foam is fairly insensitive to the presence of oil, the major effect occurs in the high-quality regime and less effect occurs in the low-quality regime. If a surfactant foam is sensitive to an oil, for instance Dowfax 8390 to decane, foam behavior in the high-quality regime has a large effect, while there is a small to moderate effect in the low-quality regime.
- The interaction between oil and surfactant is one of most important factors to affect foam behavior in both regimes. This suggests that oil type and choice of surfactant type play the key role in the applications of foam in *in-situ* remediation.

Subtask 2.1.2: CO₂ Foam Experiments

Previous Evidence for the Two Foam-Flow Regimes

Our study of CO₂ foam has focused on the existence and implications of the two foam-flow regimes identified for N₂ foams by Osterloh and Jante (1992) and Alvarez *et al.* (2001) (see above). Below is a survey of previous studies of CO₂ foam that can be

reinterpreted in terms of the two flow regimes, and a description of an experimental effort to identify both regimes for the a single foam formulation in a given porous medium. This effort led to identification of a possible third regime, and an attempt to explain this regime mechanistically.

Researchers at the New Mexico Petroleum Recovery Research Center (NMPRRC) have done experimental investigations of CO₂ foam for over a decade (Heller *et al.*, 1985; Syahputra *et al.*, 2000). During most of this time, the existence of two flow regimes was unknown. Therefore an analysis was done of these published experimental results to see whether CO₂ foam shows signs of the two flow regimes.

Two contour plots from data published by researchers of NMPRRC are shown above. One case is from data of Chang and Grigg (1999) (Fig. 2.4). They did a series of steady-state CO₂ foam flow experiments performed under reservoir conditions. They used fired Berea sandstone cores and Chaser CD1045 surfactant. Their experiments were done for total flow rates of 4.2, 8.4, and 16.8 cc/hr with increasing foam quality ranging from 20% to 80%. The contour plot (Fig. 2.4) shows that foam displayed characteristics of the low-quality regime. Data from Lee and Heller (1990) (Fig. 2.5) reflect only the high-quality regime.

There are additional CO₂ foam data from NMPRRC publications that can be analyzed the same way. Heller *et al.* (1985) conducted an experimental study of CO₂ foam mobility with Rock Creek sandstone cores of ½ in diameter and 1 in long. The cores had low permeability, ranging from 4.5 to 15.6 md. The (nonionic) surfactant solution was 0.05%-0.2% Emulphogene BC-720 in brine. Total flow velocity varied from 28-80 ft/day while foam quality was in the range of 70-90%. Huge pressure gradients were observed due to the high flow rates and low permeabilities. When plotted in Fig. 2.25, the data shows the character of the low-quality regime.

In Lee and Heller's (1989) study of CO₂ mobility and surfactant adsorption, they did one set of experiments using a Berea sandstone core to study the effect of foam quality on foam mobility. The permeability of the core was 302 md. The surfactant was 0.1% Shell Enordet X2001 (AEGS, Ethoxylated Alcohol Glyceryl Sulfonate, anionic). Lee and Heller plotted the data in a figure showing mobility with different velocities and foam qualities. These data can be converted into pressure gradient as a function of liquid and gas superficial velocities as in Fig. 2.26. The data reflect the high-quality regime. In

another set of experiments, a low-permeability Baker Dolomite core was used. The permeability was only 6.09 md. The surfactant and its concentration were the same as above. A plot of the data (Fig. 2.27) indicate that all the data are in the high-quality regime.

Yaghoobi and Heller (1994) investigated parameters affecting CO₂ foam mobility in sandstone. The core was about 7 cm long and 3.7 cm in diameter. The core material was fired Berea sandstone. The permeability of cores were 140, 490, and 985 md. Four types of surfactants were used: Chevron Chaser CD1050 (Alkyl Phenol Ethoxlate, nonionic), CD1045, and CD1040 (Alpha Olefin Sulfonate, anionic) and Shell Enordet X2001 (AEGS). Two sets of experiments were done. In the first set, CO₂/surfactant solution ratio was fixed with total velocity varying. In the second set of experiments, at fixed gas flow rate, liquid flow rate was increased with foam quality decreasing from 80% to 49.9%. Then liquid flow rate was fixed and gas flow rates were increased, with foam qualities varying from 80% to 98%. In these cases, sufficient data are provided for constructing a contour plot; pressure-gradient contours are nearly vertical in Figs. 2.28, 2.29 and 2.30 if the data of all experiments for a given surfactant and core are plotted together. These data again demonstrate the characteristics of high-quality foam flow.

Thus both high-quality and low-quality regimes are observed in some CO₂ foam studies. Unfortunately, the data reviewed lie in either high- or low-quality regime, but no single study appears to show both regimes. One objective of this study is to conduct experiments with wider ranges of gas and liquid flow rate and foam qualities to test the existence of two regimes in one set of experiments.

New Experimental Study

Experimental Approach

Experimental Apparatus. The apparatus used here is described in detail by Dong (2001); a schematic is shown in Fig. 2.31. Instead of metering gas directly from a tank, a Ruska pump is used to meter the Dow Corning fluid into the drive side of stainless floating-piston reservoirs. CO₂ is thus displaced into the core. ISCO pumps are used for liquid injection.

A Phoenix Hassler-type core holder was used in all the experiments with consolidated core. The core holder is mounted in the vertical direction and fluids are

injected from the top to the bottom. The holder has a $\frac{1}{4}$ -inch-thick Viton rubber sleeve. In experiments, compressed hydraulic oil is introduced into the gap between the sleeve and the core-holder wall. Then the sleeve is compressed and sealed to prevent radial flow of injected fluid. Along the core holder, there are five pressure taps for pressure measurement. In this study, only three of them were used. They divide the core into four sections. The second and third sections are 4" long. The fourth section is 2" long, while the length of the first section depends on the total length of the core. The core holder has two end caps to seal it after a core is put in. The top end cap is adjustable to accommodate different core lengths.

Unfortunately, a Viton rubber sleeve is not sufficiently resistant to CO₂ diffusion. High-pressure CO₂ would diffuse into the sleeve if there were not a barrier between it and the core. After system pressure is released, the CO₂ inside the sleeve then would expand, or even explode, and the sleeve would be severely damaged.

To prevent CO₂ diffusing into the rubber sleeve, the core needs to be wrapped with layers of aluminum foil and heat-shrinkable Teflon tubing (Dria, 1989). The aluminum foil is Reynolds Wrap® heavy duty aluminum foil. The Teflon tubing (from Zeus Industrial Products, Inc.) is a heat shrinkable FEP roll cover. It is 2" in diameter with wall thickness of 0.02". A layer of Teflon tubing is wrapped immediately around the core. Then two layers of aluminum foil are wrapped outside the tubing. Another layer of Teflon tubing is used to hold the aluminum foil to the core. To make this approach work, there are several potential problems which must be solved.

First, after a 2"-diameter core is wrapped with the aluminum foil and Teflon tubing, it does not fit inside the Viton sleeve. So a smaller core must be used for the experiment. In the experiment, 1.83"-dia. cores were used. Further details on wrapping the core are given below.

Second, if only the core itself is wrapped, CO₂ can still leak where the ends of the core are in contact with the endplates of the core holder (Kibodeaux, 1997). So the endplates and the core must be wrapped together. Therefore the diameter of the endplates needs to be reduced too; otherwise they cannot go through the Viton sleeve. It is important that the diameter of the endplates be milled down to the same as that of the core. Otherwise, the aluminum foil and Teflon tubing would break under high confining pressure at the place where the ends of the core and the endplates meet.

Third, after the core is wrapped, there is no communication between the core and the pressure taps. No pressure measurement is possible without this communication. The communication is established by drilling small holes through the layers of Teflon tubing and aluminum foil. Care should be exercised so that the drill bit does nothing more than to drill through tubing and aluminum and scratch the surface of the core. Then compressed N₂ is injected into the core to blow cuttings out of the pressure port. Brine is also pumped into the core with pressure taps open to make sure that fluid can flow out of the core through the ports. This port-opening procedure occasionally needs to be performed a second time because the Teflon tubing or rubber sleeve extrudes into the space between the pressure-port tubing and the core surface, and effectively seals the pressure port. More details about this drilling process are given below.

A sand-packed cylinder is used as the foam generator (*cf.* Friedmann and Jensen, 1986).

To check the CO₂ flow rates from the Ruska pump, a short length of capillary tube upstream of the foam generator is used to measure CO₂ flow rate (Lee and Heller, 1991). A pressure transducer measures the pressure drop across the capillary tube and verifies the CO₂ injection rate.

Fluids. We used industrial-grade carbon dioxide from Air Liquide Company (4927 E. 5th St., Austin, TX 78702). To suppress swelling of clay in the Berea sandstone, salts were added to the deionized water: 3 wt % of sodium chloride, 0.01 wt % of calcium chloride.

The surfactant solution was prepared by mixing surfactant with brine. Two surfactants were used in the experiments.

Bio-Terge AS 40 (Alvarez, 1998) is a C₁₄₋₁₆ sodium α – olefin sulfonate (anionic surfactant) made by Stephan Company. Its active content is 39.6%. In bottle tests, Bio-Terge forms relatively stable foam (Alvarez, 1998). Its CMC is about 0.18 wt%. The concentration of the surfactant solution in this study is 0.05 wt%. Preliminary experiments indicated that Bio-Terge is not a good foamer with CO₂, at least at low concentration. First, it takes a very long time for foam to propagate. Foam had not propagated to the last section of the core after more than 24 hours of co-injection of surfactant solution and CO₂. Second, foam was unstable when foam quality was either too low or too high. Fluctuation in pressure drop occurred at all foam qualities and slugs

of foam and clear fluid (either CO₂ or surfactant solution) were observed flowing through the upstream view cell. This surfactant was not used further in the experiments. Given that this surfactant is anionic, it is probably not surprising that it was not effective at the low pH of high-pressure CO₂ foam.

The second surfactant used was Chevron Chaser CD 1045 (Tsau and Heller, 1992; Chou, 1991). CD 1045 was provided by Chaser International. This surfactant was developed for CO₂ floods in carbonate reservoirs. Its CMC (critical micelle concentration) falls between 0.075-0.1 wt % of the active surfactant (Tsau and Heller, 1992).

Cores. Berea sandstone came from two sources. Some sandstone rock was purchased directly from Cleveland Quarries Co. in Amherst, OH and some was donated from industry.

Cores are cut into cylinders 1.83 inch in diameter and about 1 foot in length. Initially, unfired Berea was used in corefloods. It was then found that fines migration was a severe problem. A huge pressure drop was built up in the last two sections of a core each time an experiment had been run on the core for 3 or 4 days. The effluent changed to a reddish color about one day after foam injection began, and a precipitate settled out of the effluent. It is suspected that change of color is due to the ion exchange or mineral dissolution in the core (Gabriel and Inamdar, 1983; Vaidya and Fogler, 1992). When Na⁺-rich surfactant solution is injected into the core, some Na⁺ exchanges with ferric and ferrous ions in the core. After they flow out of the core and CO₂ vaporizes, these ions are oxidized by air, and causing the effluent to change color. The precipitation is likely caused by calcium, ferric, aluminum, or magnesium carbonate.

After it was confirmed by repeated experiments that unfired Berea sandstone cores suffered fines migration, fired Berea sandstone cores were used for the experiments (Shaw *et al.*, 1989; Ma and Morrow, 1991; Yaghoobi and Heller, 1994; and Chang and Grigg, 1999). Berea cores are put into a furnace and temperature raised to 650°C and maintained at that temperature for over 12 hrs. To avoid thermal shock, the core was cooled down slowly with the furnace door kept closed.

The effluent from fired Berea sandstone cores did not change color after it flowed out. There was still some precipitation. The effluent was filtered through filter paper and the precipitate collected. When HCl was added to the dry precipitate, most of it dissolved,

and gas was formed. So the precipitate was assumed to be a carbonate salt. Most important, with fired cores, there was no evidence of core plugging from pressure measurements.

Core Preparation. As discussed above, to prevent CO₂ diffusion, the core, together with the two end plates, is wrapped with Teflon tubing and aluminum foil. First, a layer of heat shrinkable Teflon tubing is used to hold the three pieces together. Then two layers of aluminum foil are wrapped around the core. The ends of the aluminum foil are doubly folded so that CO₂ will not come out from the place where they meet. Then another layer of Teflon tubing is wrapped around to hold the aluminum foil in place. Then the core is put into the core holder and end caps are put into place to seal off the core holder.

As mentioned earlier, there is no communication between the core and the pressure taps after it is wrapped using the Teflon tubing and aluminum foil. Small holes must be drilled through these layers so that fluid in the core can transmit its pressure to the transducers. This is accomplished using a hand drill. Bolts sealing the pressure ports are screwed off for the drill bit to reach the core through the pressure tap. The drill bit must be small enough to go through the pressure tap.

Before drilling the holes, axial confining pressure of about 500 psi is applied to hold the core in place. Radial confining pressure should not be exerted because hydraulic oil would flow out through the pressure tap under pressure.

After small holes are drilled, the bolts are screwed tight. Then radial confining pressure is applied. High-pressure N₂ is injected into the core while leaving the pressure taps open. Flow of N₂ would blow out cuttings left from the drilling procedure. Otherwise, these cuttings could clog the pressure transmitting tubing later.

Back-pressure. The back-pressure for the corefloods is set at 1500 psi, well above the critical pressure of CO₂. At the outlet of the N₂ cylinder there is a back-pressure regulator which can adjust the output pressure of the cylinder. N₂ from a high-pressure tank pressurizes the dome of the back-pressure regulator. A liquid is injected into the core while applying back-pressure. The regulator at the N₂ cylinder is then opened slowly to ensure a stable increase in back-pressure. This also protects the transducer across the back-pressure regulator from being over-ranged. During the

process, confining pressure should be increased accordingly to ensure that it is always at least 500 psi higher than the inlet pressure of the core.

After the desired back-pressure is set, the valve in the line between the N₂ cylinder the back-pressure regulator is closed so that the back-pressure stays constant except for slight variations due to temperature change in the laboratory.

Foam Injection. Foam injection is carried out by co-injection of CO₂ and surfactant solution. As mentioned earlier, CO₂ is stored in an accumulator and displaced into the core using a Ruska pump. Surfactant in the cylinder of an ISCO pump is injected into the core directly. The CO₂ and the surfactant solution meet in a tee and then flow into a foam generator. Foam is formed and flows through a view cell. Then it flows into the core. The coreflood effluent exits the system from the outlet of the back-pressure regulator and is collected in a beaker.

Due to the limited volumes of the accumulators and the ISCO pumps, it is necessary to refill of them occasionally. To make this process efficient and cause as little disruption as possible to the experiment, the two accumulators and the two ISCO pumps are connected with three-way valves. When one accumulator or cylinder needs to be refilled, the valves are rotated to the other ones that are used for injection purpose. Then the accumulator and cylinder not in use are free for refilling.

After an experiment is finished, back-pressure is released slowly while maintaining liquid-phase injection. Confining pressure needs to be decreased accordingly, but still held high enough to prevent radial flow of fluids around the core. Liquid injection is stopped after back-pressure reaches atmosphere pressure. Then the end caps of the core are opened and the core is taken out from the core holder. The wrapped Teflon tubing and aluminum foil are taken off from the core and the flow direction in the previous experiment is marked on the core surface.

Results

Two sets of experiments were conducted, using two cores and two surfactant concentrations. Table 2.3 gives the properties of the cores. As shown in the table, there is not much difference between the permeabilities of the two cores. The surfactant for both experiments was Chaser CD 1045 from Chevron Chemical Company, with concentration 0.25 wt % and 0.8 wt % for the respective experiments.

The experiments were conducted at room temperature of about 74°F and elevated pressure. For the purpose of showing how pressure gradient changes with flow rates, CO₂ and surfactant-solution flow rates in the experiment were chosen in such a way that there are several flow rates of one phase for each flow rate of the other phase. The order of the specific tests was randomized to eliminate any systematic effect of hysteresis or slow changes in core properties.

Analysis of Data. To reduce end effects, the pressure drop in the second section of the core was used for data analysis. Figs. 2.32 and 2.33 plot the contour lines of the pressure gradient as functions of superficial velocities of gas and liquid. Contrary to the behavior of N₂ foam shown above, pressure drop increases with increasing gas flow rate at constant liquid flow rate and decreases with increasing liquid flow rate at constant gas flow rate. Clearly these data do not reflect either of the two flow regimes found in N₂ foam and in earlier studies with CO₂ foam.

Comparison of Figs. 2.32 and 2.33 indicates that pressure drop at the same liquid and gas flow rates is higher at higher surfactant concentration, as expected.

One possible reason why CO₂ foam does not show the two distinct regimes as N₂ foam may lie in the fact that CO₂ is very different from N₂ at high pressure. It behaves more like a liquid than a gas at the experimental conditions of this study. Also the interfacial tension between CO₂ and most surfactant solutions is much lower than that between N₂ and surfactants (Tsau and Heller, 1992; Alvarez, 1998). This would not explain the differences with other CO₂ foams shown in Figs. 2.4, 2.5 and 2.25 to 2.30, however.

As discussed above, a review of experimental data from New Mexico Petroleum Recovery Research Center (NMPRC) indicates that one of two flow regimes apparently exists for CO₂ foam at each of their experimental conditions. The failure to identify either regime in this experiment may be due to one of the following reasons. First, the flow-rate range in this experiment is narrower than that in NMPRC due to the limitation of our pumps. Second, the choice of surfactant type and concentration may affect our results. Third, most experiments in NMPRC were done at temperature higher than room temperature and at pressures higher than 1500 psig. Pressure and temperature should not cause much difference to the flow behavior if CO₂ is in a supercritical state. But they do affect interfacial tension to some extent (Lee and Heller, 1991).

Implications of Data. This trend of pressure drop with flow rates, if confirmed by further study, implies beneficial effects for field application of CO₂ foam. In any enhanced oil recovery flood, a certain pressure gradient must be maintained in the reservoir to cause flow to the producing well (Shi and Rossen, 1998a). With CO₂ foam, this can be achieved using a low surfactant-solution injection rate. Thus less of the expensive surfactant is consumed. The cost of a foam project could be lowered in this way.

In an acid-diversion process, it is desirable to inject more acid into the reservoir without fracturing the formation. Our data for CO₂ foam show decreasing pressure gradient as liquid flow rate is increased. So in a foam-assisted acid diversion process, acid flow rate can be increased without any increase in pressure gradient. Thus more acid could be injected into the desired zone in a short time and without the risk of fracturing the formation.

Discussion. Several observations from the experiments deserve more comment and explanation.

First, it took a long time to reach steady state in a brand new core. Steady state was reached much faster if a core had been previously flushed with surfactant solution and CO₂. The mixture of CO₂ and surfactant solution appeared to form a weak acid inside the core and interacted with some minerals of the core. This process evidently takes some time to reach a steady state.

Second, the permeability of a core decreased substantially over about two months of experiments, while there was little change in porosity. Measurements showed that the permeability of both cores decreased by over 100 md after the experiments. Table 2.4 shows the properties of the cores after foam- injection experiments.

Third, cycles of fluctuation in pressure drop were recorded when foam quality was high. A periodic rise and fall in pressure-drop was observed in each section of the core in these cases. One possible explanation is that high gas flow rate resulted in low water saturation in the core, and thus capillary pressure was high. Foam collapsed after capillary pressure reached a critical value. Gas mobility increased drastically and a large amount of gas escaped from the core. Water saturation then increased. Strong foam was formed again and pressure was built up in the core. This sort of cycling was observed by

Khatib *et al.* (1988) in their original study of the limiting capillary pressure. In these cases, the average pressure drop in the cycle is reported in Figs. 2.32 and 2.33.

Conclusions

In this study, an experimental apparatus for high-pressure CO₂ was constructed. Surfactant solution and CO₂ were co-injected to study the flow behavior of foam in Berea sandstone at high pressure and room temperature. Different surfactants at various concentrations were used in the experiments. The conclusions from these experiments are as follows:

1. Foam was readily generated in a range of CO₂ and surfactant-solution flow rates.
2. Foam did not reach steady state when foam quality was either very high or very low. Instead pressure drop cycled during the experiment.
3. Foam generated by higher-concentration (0.8 wt%) surfactant solution was stronger than that of lower-concentration (0.25 wt%) surfactant solution.
4. Data from this study did not show the two distinctive flow regimes as seen for N₂ foam and other CO₂ foams in the literature. Further study is needed to determine the reason for this difference.

Subsequent Experimental Study of CO₂ Foam in Sandpacks

Given the surprising failure to observe the two expected foam-flow regimes in this study, the apparent slow approach to some sort of mineralogical equilibrium between the core and injected fluids, and the slow decrease of core permeability with time, it was suspected that mineral interactions between the acidic injected fluids and the Berea core may have distorted the results. Therefore, a further study was conducted in sandpacks. Details are in Kim (2003). The experimental approach was similar to that above, with the substitution of a sandpack for the Berea core (also obviating the need for the Hassler coreholder). The surfactant was Shell Neodol 25-9 in this study.

The data from this new study (Fig. 2.34) also don't appear to match expected behavior in either regime: specifically, pressure gradient increases with increasing gas injection rate and decreases with increasing liquid injection rate.

Possible Theoretical Explanation for Observations

Given the disagreement with data from earlier studies with supercritical- CO_2 foam, we are unsure whether this reflects some unique aspect of our experiments (somewhat lower temperature and higher permeability than the earlier published studies, different surfactant formulation) or some new physical phenomenon. An ongoing study in our laboratory of N_2 foam with and without polymer in sandpacks at room temperature is also finding behavior roughly similar to that in Figs. 2.32 to 2.34 (Rossen, 2003). This behavior is paradoxical. For instance, gas mobility is inversely related to bubble size. In the high-quality regime, one would expect bubble size to decrease and gas mobility to decrease, not increase, as water superficial velocity increases (Rossen and Zhou, 1995). Bubble size is thought to be constant in the low-quality regime, but still this does not explain decreasing pressure gradient as water saturation increases.

A survey of the literature finds at least two theoretical models for foam in which pressure gradient decreases as water injection rate increases, as in these studies.

de Vries and Wit (1991) published a model for foam in two regimes based on N_2 foam data. In their model, in the regime corresponding to our "low-quality regime," pressure gradient decreases with increasing liquid injection rate as in Fig. 2.34. Our CO_2 foam data follow a trend roughly similar to that in de Vries and Wit's data, when plotted in the unconventional way dictated by their model (*cf.* Figs. 2.35 and 2.36), but at lower pressure gradient. Somewhat lower pressure gradient would be expected because of the lower surface tension on foam films with dense CO_2 v. N_2 .

The foam-viscosity model of Hirasaki and Lawson (1985) predicts that foam viscosity decreases as liquid saturation increases, as long as bubble size does not change with liquid saturation. We conjecture that bubble size *is* fixed in the low-quality regime (Rossen and Wang, 1999; Alvarez *et al.*, 2001), so this condition may be satisfied. Equating a decrease in foam viscosity with a decrease in pressure gradient also requires that gas effective relative permeability not change with changing liquid injection rate. This does not fit models for the low-quality regime, where gas trapping decreases with increases in liquid injection rate. It is possible that our data reflect behavior in the low-quality regime where for some reason gas trapping is either not important or is constant as a function of liquid injection rate.

Hirasaki and Lawson's model is better as a mechanistic explanation than that of de Vries and Wit, which makes *ad hoc* assumptions about transport of liquid and gas as foam flows through porous media. Both models share the implication, however, that as foam of a given bubble size flows through pores, the drag on Plateau borders between bubbles decreases as the water flow rate through those pores increases. (de Vries and Wit's model does not explicitly account for bubble size or Plateau borders, but does allow easier gas flow as water flow rate increases through the gas-filled pores.) If bubble size is fixed, and gas trapping and relative permeability holds constant, then this reduction in gas effective viscosity with increasing liquid injection rate could give the behavior we have observed. It remains to see if those assumptions hold for these experiments.

Subtask 2.2: Mechanistic Foam Simulation

Studies directed toward mechanistic foam simulation were wide-ranging. First, the local-steady-state foam simulator was tested for its ability to represent the two steady-state foam regimes. The basic foam algorithm incorporated into the UTCOMP simulator works also in the chemical-flood simulator UTCHEM, and some of our simulation studies were conducted with UTCHEM. A comparison to the widely used commercial foam simulator STARS™ showed that it is substantially similar to UTCOMP and UTCHEM modified for foam. A detailed study of the numerical artifacts possible in foam simulation was conducted using the UTCHEM simulator.

Important simulator applications include the development of optimal injection strategies for overcoming gravity override in homogeneous reservoirs, and investigation of the competing effects of gravity and capillary crossflow as foam diverts flow between layers differing in permeability.

Parallel to the efforts with a numerical simulator was the extensive application of analytical models. A key breakthrough was the mathematical proof that the pattern of gravity override seen in gas and foam IOR simulations is the inevitable result of standard assumptions of incompressible flow in porous media, and not an empirical pattern that may have important exceptions. Thus one can use the formula, previously based on empiricism, with confidence.

The local-steady-state foam algorithms used in UTCOMP and UTCHEM is remarkably simple. It relies on the overriding control of foam behavior by two key mechanisms, rendering detailed description of other mechanisms unnecessary. Toward development of a fully mechanistic simulator, incorporating all foam mechanisms, we developed an improved model for foam viscosity; critiqued the consensus view that snap-off controls foam generation; and analyzed "population balance" foam models in terms of fractional-flow theory.

Modification of Foam Model to Fit Two Foam-Flow Regimes

Predictive design of foam processes for field application requires a foam simulator that can accommodate the two foam-flow regimes discussed above.

Vassenden and Holt (1998) propose a foam simulation model in which gas mobility is reduced by a factor that is the sum of two exponential functions of water saturation. One function decreases steeply for $S_w > S_w^*$ and controls behavior in the high-quality regime. The second function decreases more gently as S_w increases and controls behavior in the low-quality regime. Together, these functions reproduce the behavior in Fig. 2.1 and those like it.

Earlier, de Vries and Wit (1990) proposed a mathematical model for foams with two regimes, the drier of the two regimes characterized by foam collapse.

The foam model of Rossen *et al.* (1999), called the UT model below for short, was based on the data of Persoff *et al.* (1991), which lie entirely in the high-quality regime. It gives a steep increase in gas mobility as S_w decreases toward S_w^* , and a constant reduction in gas mobility for larger values of S_w . Though derived to represent the coalescence regime, this model also represents the low-quality regime reasonably well, as shown below. Earlier work with this model (Rossen *et al.*, 1999; Rossen and Lu, 1997; Shi and Rossen, 1998a,b) modified the miscible gas-flood simulator UTCOMP (Liu, 1993; Chang *et al.*, 1994) for foam, but the algorithms are transferable to any simulator with facility for multiple phases and a tracer or chemical solute that can represent surfactant. Some results presented here use the same algorithms with the chemical-flood simulator UTCHEM (Delshad *et al.*, 1996; de Blanc *et al.*, 1999), which has previously been modified to accommodate a flowing gas phase.

STARSTTM, developed by the Computer Modeling Group, is a widely used commercial foam simulator (Mohammadi and Coombe, 1991; Mohammadi *et al.*, 1993; Lau and Coombe, 1994; Hanssen *et al.*, 1994; Surgachev *et al.*, 1995a,b; Svorstol *et al.*, 1997; Shrivastava *et al.*, 1999; Martinsen and Vassenden, 1999; Vassenden *et al.*, 1999). It includes an option for population-balance simulation, but is most widely applied using a local-steady-state option that is similar in several respects to the model of Rossen *et al.* (1999). It includes in addition algorithms for the effects of surfactant concentration and oil saturation on foam not currently included in the UT model, that are not examined in this paper.

Cheng *et al.* (2000) show how to fit the parameters of both STARSTTM and the UT model to steady-state laboratory coreflood data to represent both foam-flow regimes. In the process, they define a minimum set of data needed to fit these parameters, and evaluate and illustrate the fits attainable with both models. An abbreviated version of that report appears here. Implications of the second foam-flow regime for foam injectivity and the success of foam in overcoming gravity override and in diverting flow between layers are examined. Earlier simulation studies of these effects were limited to the high-quality regime (Rossen *et al.*, 1999; Rossen and Lu, 1997; Shi and Rossen, 1998a,b).

Throughout this paper we consider only foam behavior in the absence of oil. The effect of oil on foam, though certainly crucial in field application, is complex and only partially understood; see Schramm (1994), Rossen (1996) and Myers and Radke (1999) for further discussion of the effects of oil.

All foam simulators begin with conventional multiphase, multicomponent reservoir simulators. For foam the simulator must include equations for surfactant propagation including adsorption. However this aspect of foam modeling will not be discussed here. The foam model proposed by Rossen *et al.* (1999) modifies the gas relative permeability for the effect of foam:

$$\text{If } S_w < (S_w^* - \epsilon) \text{ or } C_s < C_s^0, \text{ then } k_{rg}^f = k_{rg}^0(S_w) \quad (2.1)$$

$$\text{If } (S_w^* - \epsilon) \leq S_w \leq (S_w^* + \epsilon) \text{ and } C_s = C_s^0,$$

$$\text{then } k_{rg}^f = \frac{k_{rg}^o(S_w)}{\left(1 + \frac{(R'-1)(S_w - S_w^* + \epsilon)}{2\epsilon}\right)} \quad (2.2)$$

If $S_w > (S_w^* + \epsilon)$ and $C_s = C_s^0$,

$$\text{then } k_{rg}^f = k_{rg}^o(S_w)/R' \quad (2.3)$$

where C_s is surfactant concentration in the aqueous phase, C_s^0 is a threshold surfactant concentration for foam formation, k_{rg}^f is effective gas relative permeability modified for foam, $k_{rg}^o(S_w)$ is the gas relative-permeability function in the absence of foam, and S_w^* , ϵ and R' are model parameters. Eqs. 2.1 to 2.3 do not attempt to model the effect of surfactant concentration on foam strength, except to require that surfactant be present for foam formation. This exclusion was designed to minimize the effects numerical dispersion on foam simulation in processes where only a single sharp front in surfactant concentration is expected (Rossen *et al.*, 1999; Cheng, 2002).

In previous applications of this model (Rossen *et al.*, 1999; Rossen and Lu, 1997; Shi and Rossen, 1998a,b), R' is a constant (called R in previous reports), and rheology is Newtonian in the low-quality regime. Here we modify the model of Rossen *et al.* to allow for shear-thinning, by modifying R' according to gas flow rate:

$$R' = R_{ref} \left(\frac{u_g}{u_{gref}} \right)^{(\sigma-1)} \quad (2.4)$$

Here u_g is gas volumetric flux (superficial velocity), R_{ref} is the value of R' at a reference gas volumetric flux u_{gref} , and σ is the conventional power-law exponent. For Newtonian behavior, of course, $\sigma = 1$, and for $\sigma < 1$ behavior is shear-thinning. Note that in this version of the model R' is not a fixed model parameter, but a function of gas flow rate and model parameters R_{ref} and u_{gref} .

S_w^* is the water saturation at which foam collapses. It is a function of surfactant formulation and rock properties but not (by assumption) a function of flow rates. This assumption is equivalent to the "fixed- P_c^* " model (Rossen and Zhou, 1995; Zhou and Rossen, 1995) that fits some (but not all) laboratory coreflood data in the high-quality

regime. S_w^* controls mobility in the high-quality regime, where (if ε is sufficiently small)

$$\nabla p = u_w \frac{\mu_w}{k k_{rw}(S_w^*)}. \quad (2.5)$$

R' controls gas mobility in the low-quality regime (Eq. 2.3). The extent to which R' affects the high-quality regime is not immediately obvious from Eq. 2.2. (2ε) is the range in S_w across which foam collapses (Eq. 2.2).

The dissertation of Cheng (2002) gives detailed instructions for fitting the foam model parameters to data like those in Fig. 2.1.

STARSTTM Foam Simulator

In STARSTTM (Reme, 1999), gas relative permeability is multiplied by a factor FM, which is inversely related to a product of other factors

$$k_{rg}^f = k_{rg}^o(S_w) FM \quad (2.6)$$

$$FM = \frac{1}{(1 + fmmob \ F1 \ F2 \ F3 \ F4 \ F5 \ F6)}. \quad (2.7)$$

FM and fmmob correspond, respectively, to the inverse of the factor by which k_{rg}^f is reduced and to R_{ref} in Eqs. 2.1 to 2.4. Surgachev *et al.* (1995a,b) note that fmmob corresponds to the normalized resistance to flow of a minimum-size bubble, in the absence of factors increasing bubble size. F1, F3, F4 and F6 describe dependencies on surfactant concentration, oil saturation, gas velocity and critical capillary number, which are not examined further this report. Factor F4 represents a shear-thinning effect similar to F5, discussed below, in a different mathematical form.

F2 controls the rise in gas mobility as water saturation decreases to fmdry (Martinsen and Vassenden, 1999):

$$F2 = \left(0.5 + \frac{\arctan[epdry (S_w - fmdry)]}{\pi} \right). \quad (2.8)$$

Although the functional form for this rise in gas mobility differs from that in Eq. 2.2, in both cases gas mobility rises sharply as S_w decreases toward $fmdry = S_w^*$. A large value

of ϵ_{dry} corresponds to a small value of ϵ in Eqs. 2.1 to 2.3, and, as noted, f_{mdry} corresponds to S_w^* in Eqs. 2.1 to 2.3.

F5 alters gas mobility for shear-thinning in the low-quality regime:

$$F5 = \left(\frac{f_{mcap}}{N_{ca}} \right)^{epcap} \quad (2.9)$$

$$N_{ca} \equiv \left(\frac{k}{\sigma_{wg}} \nabla p \right) \quad (2.10)$$

where N_{ca} is capillary number, k is absolute permeability, σ_{wg} is water-gas surface tension, and f_{mcap} and $epcap$ are two model parameters. Shear-thinning in Eq. 2.10 is based on ∇p , whereas in Eq. 2.4 it is related to u_g ; this implies that

$$\sigma = \left(\frac{1}{1 + epcap} \right). \quad (2.11)$$

For Newtonian behavior, $epcap = 0$.

Implicit in the parameters R_{ref} or f_{mmob} is a dimensionless measure of maximum foam bubble density (i.e. per number of pores) times a dimensionless capillary resistance (relative to a reference gas flow velocity) (Surgachev *et al.*, 1995) analogous to that derived by Falls *et al.* (1989) (their equations (24) or (41a)). Although this correspondence may not be exact, this does provide a conceptual link to population balance treatments of foam modeling (Falls *et al.*, 1988; Myers and Radke, 2000) under local steady-state conditions.

The thesis of Reme (1999) gives detailed instructions in how to fit the STARS model parameters to data like Fig. 2.1.

Comparison to Data

Fig. 2.37 shows a fit to the steady-state data of Fig. 2.19 using the STARS™ model, from Reme (1999). Reme uses $k_{rw}(S_w)$ and $k_{rg}^o(S_w)$ functions based on the data of Persoff *et al.* (1991) (*cf.* also Rossen *et al.*, 1999). in the absence of data for this particular core. Fig. 2.38 shows a fit to the data of Fig. 2.1 using the UT model. Osterloh and Jante's (1992) data are sufficient for computing $k_{rw}(S_w)$ (Reme, 1999), and we

assume $k_{rg}^0 = 1$ for all the sandpack data at the low water saturations observed with foam (5 to 7%).

Both models fit the nearly vertical ∇p contours in the high-quality regime and nearly horizontal contours in the low-quality regime. Both show the transition foam quality f_g^* (slope from origin to intersection of the two regimes) increasing as overall flow rate increases, due to shear-thinning behavior in the low-quality regime (Alvarez *et al.*, 2001). In general, one obtains vertical contours in the high-quality regime as $\varepsilon \rightarrow 0$ or $epdry \rightarrow \infty$; contours may not be perfectly horizontal in the low-quality regime because gas mobility depends weakly on S_w through $k_{rg}^0(S_w)$ (Eqs. 2.2, 2.3 and 2.6). This dependence is increased by the algorithms used for shear-thinning (Eqs. 2.4 and 2.9); in other words, contours are more nearly horizontal in this regime if $\sigma = 1$, at the price of failing to reflect shear-thinning rheology. To obtain perfectly horizontal contours one must decouple gas mobility from S_w along a contour; Rossen and Wang (1999) provide a theoretical explanation for such behavior, and Alvarez *et al.* (2001) provide supporting data. The contours are exactly horizontal in Fig. 2.38, for the data of Osterloh and Jante (1992), because k_{rg}^0 does not change with S_w at these low water saturations in a sandpack; this does not reflect a difference between STARSTM and the UT model.

The trends in behavior observed upon changing model parameters reflects the principles explained by Alvarez *et al.* (2001): anything that makes foam stable at higher capillary pressures and lower water saturations (i.e., that reduces S_w^* or $fmdry$) raises ∇p in the high-quality regime but extends the low-quality regime to higher foam qualities; anything that increases the resistance to the movement of bubbles in the low-quality regime (increases R_{ref} or $fmmob$) raises ∇p in the low-quality regime but extends the high-quality regime to lower foam qualities.

Fig. 2.39 illustrates the first of these effects (in reverse) by increasing $fmdry$ in Fig. 2.37 to 0.35; in effect, making foam less stable to drying out. Pressure gradient is reduced in the high-quality regime, compared to Fig. 2.37, and the high-quality regime extends to lower foam qualities. In the remaining low-quality regime, however, ∇p is unaffected by the change.

Fig. 2.40 illustrates the effect of reducing resistance to bubble movement in the low-quality regime (reducing f_{mob} or R_{ref}): ∇p is reduced in the low-quality regime; ∇p is unaffected in the high-quality regime; and the low-quality regime extends to higher foam qualities.

Fig. 2.41 illustrates the effects of reducing $epdry$ (or increasing ϵ): the ∇p contours in the high-quality regime show a noticeable deviation from vertical. Laboratory data with vertical ∇p contours, such as Figs. 2.1, indicate small values of ϵ and large values of $epdry$.

These trends in behavior can be illustrated using $f_w(S_w)$ or relative-permeability plots as well. Reme (1999), for instance, presents an $f_w(S_w)$ plot based on the data of Alvarez *et al.* (Fig. 2.19) and the effects of parameter variation on this plot.

It is noteworthy that the shear-thinning introduced by Eqs. 2.4 and 2.9 affects only the low-quality regime, a fact not immediately obvious from the initial equations. In the high-quality regime, gas mobility is dominated by the abrupt changes in bubble size upon slight changes in water saturation (Eqs. 2.2 and 2.8). The milder effects of shear-thinning have relatively little effect there. Neither STARS™ nor the UT model at this time can account for shear-thinning or shear-thickening effects in the high-quality regime; this would require accounting for variation of S_w^* or f_{mdry} with flow rates. Therefore, while the models both fit one contour in the high-quality regime, they do not fit the other contours quantitatively in Fig. 2.1 (*cf.* Fig. 2.38), with strongly shear-thinning behavior in the high-quality regime, or Fig. 2.19 (*cf.* Fig. 2.37), with moderately shear-thickening behavior in the high-quality regime.

Numerical Artifacts in Foam Simulation

Cheng's dissertation (2001) shows that numerical dispersion of surfactant concentration affects the simulated propagation rate of foam. The effect can be minimized by using smaller grid blocks and other numerical strategies to reduce numerical dispersion. Its effects are small in the studies reported here, but can be significant when grid block sizes are large, as in field simulations.

Cheng also discusses the fluctuations in water saturation observed in the gas bank ahead of foam in foam simulations, as in Figs. 2.42 to 2.44. This is most clear with simulation output plotted in the manner of fractional-flow theory (Lake, 1989) - i.e., as a

contour plot with axes of time and position, as in Fig. 2.44. Cheng shows that the fluctuation in water saturation results from fluctuation in water fractional-flow as individual grid blocks at the foam front drain liquid one at a time. The process can be analyzed by a combination of fractional-flow theory and analysis of the drainage of an individual grid block at the foam front. Once an analytical model is available, one can probe the effect of the artifact. Cheng shows that these fluctuations, though unsightly, have no effect on the progress of the foam displacement.

While these numerical artifacts in simulation of steady foam injection are relatively minor, a significant artifact can completely change the nature of foam injection in a SAG process. This artifact is discussed in the next section.

Application: Optimal Injection Strategy for Overcoming Gravity Override in Homogeneous Reservoirs

Foam can be placed in the reservoir by 1) co-injection of liquid and gas at fixed quality (gas volume fraction), or 2) SAG (surfactant-alternating-gas) injection, where alternating slugs of surfactant solution and gas are injected. For CO₂ projects, SAG processes may be preferred, to minimize corrosion to surface facilities and piping (Shrivastava *et al.*, 1999; Martinsen and Vassenden, 1999). Continuous foam injection should be used if one wants to create and maintain foam in the near-well region, or to ensure that both gas and liquid enter the same zones in a heterogeneous reservoir.

Different foam-injection strategies have been used in field trials due to stratigraphic differences, unexpected foam behavior and operational concerns. Shan (2001) lists 11 foam field trials with CO₂, N₂, air or hydrocarbon-gas foam. Six employed co-injection of gas and liquid, seven SAG injection at fixed flow rates, and two SAG injection at fixed injection pressure. (Some field trials tested more than one method of injection.) Determining optimal injection strategy is a major goal of this work.

For continuous foam injection at fixed injection rate, there is a simple correlation for foam effectiveness in preventing gravity override in homogeneous reservoirs (Shi and Rossen, 1998a). This correlation was verified for foam displacements with a wide range of foam qualities, foam strengths, reservoir geometries and properties, and foam models (Cheng *et al.*, 2000). The correlation indicates that the only way to improve sweep efficiency with continuously injected foam is by raising the injection-well pressure. In

such a process low-mobility foam extends from the displacement front back to the injection well, where most of the pressure drop occurs. The required rise in injection-well pressure could fracture the injection well, rendering a continuous-injection foam process impractical.

Shi and Rossen (1998b) show that foam processes employing SAG injection at fixed injection pressure control gravity override better than continuous foam injection or SAG at fixed injection rate, based on numerical simulations. They limited their study to gas injection following injection of a large (infinite) slug of liquid. The effects of liquid slug size or multiple slugs were not considered.

Here we extend that study of gravity override in homogeneous reservoirs to finite, multiple slugs of liquid and gas, with particular focus on optimal injection strategies for both fluids. Fractional-flow analysis indicates the reasons for the success of this process: most of the well-to-well pressure drop is focused near the displacement front where sweep efficiency is determined. An idealized model based on this concept shows why the process works, why it is relatively insensitive to the details of behavior of the foam formulations, and why real foam formulations may not live up to the ideal process efficiency.

For simplicity, this report focuses on foam mobility in the absence of oil, and “liquid” and “water” are used interchangeably to designate the aqueous phase.

Fractional-Flow Analysis of SAG Processes

Fractional-flow methods are useful in analyzing foam (Zhou and Rossen, 1995; Rossen *et al.*, 1999) and other IOR processes (Lake, 1989). The assumptions made include incompressible phases; Newtonian mobilities; one-dimensional displacement; absence of dispersion, gradients of capillary pressure and viscous fingering; and immediate attainment of local steady state. In spite of its simplifying assumptions, fractional-flow theory was found by others (Martinsen and Vassenden, 1999) to be accurate and useful in analysis of field data in the foam field test at the Snorre field. The application of fractional-flow theory to foam displacements is discussed more fully elsewhere (Zhou and Rossen, 1995; Rossen *et al.*, 1999).

For the purposes of this study, three insights from fractional-flow theory are essential: First, in fractional-flow methods, one plots fractional-flow curves from the

mobilities of the individual phases, and then time-distance diagrams for a given displacement. Fig. 2.45 shows the fractional-flow curves for foam at two surfactant concentrations based on the model of Fisher *et al.* (Fisher *et al.*, 1990; Shi, 1996; Rossen *et al.*, 1999). The time-distance diagrams describe the movement of saturation waves in a one-dimensional (1D) displacement; examples are shown below. Second, during gas injection in a SAG displacement there is a shock front from the high liquid saturation initially present to a point on the fractional-flow curve at extremely low water fractional flow f_w (high foam quality), as illustrated in Fig. 2.45. Only saturations below the point of tangency are actually observed in the displacement. Obtaining steady-state data in this crucial range is extremely difficult, and published data are rare. We use five different foam models below because all current foam models, when applied to SAG processes, are extrapolations based on data taken at higher f_w . All five models we use are reasonable extrapolations from data, but none is definitively correct. These models represent both a range of behavior one might observe with different foam formulations and the uncertainty in extrapolating data to the low values of f_w crucial to SAG processes.

If the fractional-flow curve has a sharp corner at very low f_w (very high foam quality), fractional-flow theory predicts a shock front at the leading edge of the gas bank, from the initial high liquid saturation in the reservoir to a dried-out state of complete foam collapse (Zhou and Rossen, 1995; Rossen *et al.*, 1999). Foam forms, strengthens, dries out and collapses, all within the shock front. There is no low-mobility foam zone in the displacement except in the shock front, which shrinks to insignificance in a field-scale displacement. The time-distance diagram for one such a case is shown below. This sort of behavior can be observed if foam collapses abruptly and completely at the limiting water saturation S_w^* (Zhou and Rossen, 1995; Rossen *et al.*, 1999). In Fig. 2.45, in both cases there is a rounded corner in the fractional-flow curve at low f_w , not a sharp corner, and foam does not collapse completely in the shock front (Rossen *et al.*, 1999).

The third insight from fractional-flow theory concerns the pressure rise during gas injection in a SAG process and is discussed below.

Foam Models

We employ five foam models. Three are based on extrapolations of the data of Persoff *et al.* (1991) (*cf.* Shi, 1996; Rossen *et al.*, 1999), and two on the model of Fisher

et al. (1990), which is in turn based on the data of Lee and Heller (1990) at different surfactant concentrations. For simplicity we refer to the latter two cases simply as the Fisher model. Details are given by Shi (1996) and Shan (2001).

Figs. 2.46 to 2.50 show the time-distance diagrams for these five foam models for gas injection into a large (infinite) slug of surfactant solution in a 1D reservoir initially at 100% saturation. The vertical axis is dimensionless position x_d , i.e. (x/L) in a rectangular reservoir and $(r/R_e)^2$ in a cylindrical reservoir, where x is lateral position and L reservoir length in a rectangular reservoir and r is radial position and R_e outer radius in a cylindrical reservoir. The horizontal axis in each figure is dimensionless time, i.e. pore volumes injected. Thus lines drawn through the origin represent waves moving downstream from the injection point, and the slope of a wave on the plot indicates wave velocity in the porous medium. The width of a wave in the plot represents the width of the wave in the porous medium. The region next to the vertical axis represents the initial state of the core or reservoir. A number in a box or circle, respectively, on these figures represents the total relative mobility (in $(\text{Pa}\cdot\text{s})^{-1}$) for a constant-state region (bounded by solid lines on the plot) or a single characteristic in a spreading wave (dotted line on the plot). In each case the initial saturation (along the vertical axis) is 100% liquid saturation; the mobilities of the initial state differ somewhat between the cases because parameter values specified in the models differ (Shi, 1996; Shan, 2001).

The fixed- P_c^* foam model extrapolated from data of Persoff *et al.* (Fig. 2.46) has a shock front from the initial saturation to a state of complete foam collapse, the latter with enormous mobility ($29540 (\text{Pa}\cdot\text{s})^{-1}$) (Zhou and Rossen, 1995; Rossen *et al.*, 1999). The "2% progressive-collapse" model (Shi, 1996) follows the data of Persoff *et al.* as far as they extend, but at lower f_w foam is assumed to coarsen progressively over a narrow (2%) range in S_w . It (Fig. 2.47) has a narrow moderate-mobility bank ($243 (\text{Pa}\cdot\text{s})^{-1}$), and, behind it, a spreading wave of increasing mobility extending back to the injection well. In the "10% progressive-collapse" model (Shi, 1996) (Fig. 2.48) foam collapses more gradually as a function of water saturation; the moderate-mobility bank is wider and mobilities are lower behind this bank. In the Fisher model based on data for 0.02% surfactant concentration (Shi, 1996) (Fig. 2.49), mobilities are a little lower at the leading edge of the gas bank than in the water bank ahead, but increase rapidly in a spreading wave behind that. In the Fisher model for 0.5% surfactant concentration (Fig. 2.50),

mobilities are extraordinarily low at the leading edge of the gas bank, and stay low except very close to the injection point (horizontal axis).

All of these models assume local steady state rather than attempting to represent the complex dynamics of foam generation and destruction mechanisms (Falls *et al.*, 1988; Friedmann *et al.*, 1991; Kovscek and Radke, 1994). A roughly similar foam model (i.e., local-steady-state, with gas mobility a function of water saturation) was validated by others in simulation of the foam test at the Snorre field (Martinsen and Vassenden, 1999).

Shan (2001) shows that in 1D cylindrical flow the pressure drop between any two characteristics in a plot such as Figs. 2.46 to 2.50 remains constant in time as the wave moves outwards. (This does not apply to the horizontal characteristic at the injection point.) In a SAG process the mobility near the well is very high (Figs. 2.46 to 2.50), so, to a good approximation, in a fixed-injection-rate SAG displacement in a 1D cylindrical reservoir, the pressure drop across the entire gas (foam) bank is also constant in time. Shan (2001) gives examples. This finding has two implications.

First, it provides an analytical expression for the maximum injection pressure during gas injection in a fixed-injection-rate SAG process, as follows. In simulations, the maximum injection-well pressure during gas injection in a fixed-rate SAG process tends to occur near the start of gas injection. Unfortunately, at this point in simulations relatively coarse gridding near the well does not allow accurate resolution of the displacement or the pressure drop. At short times, before gravity override sets in, a 2D SAG process in a homogeneous cylindrical reservoir is essentially a 1D displacement. This implies that the maximum injection pressure during gas injection in a SAG occurs at short times, and is the sum of the pressure drop across the gas bank (which is constant) and the pressure drop across a water bank (which is a maximum when it extends nearly from the injection well to the outer reservoir radius). Both can be estimated analytically (Shan, 2001).

Second, if the foam in the gas bank is relatively weak (Figs. 2.47 to 2.49), the water ahead of the gas bank may account for a significant fraction of the well-to-well pressure drop. Shan (2001) shows several examples.

Mobility During Liquid Injection After Gas

Many studies find that foam does not change the water-relative-permeability function (Bernard *et al.*, 1965; de Vries and Wit, 1990; Holm, 1968; Huh and Handy, 1989), but none of these studies examined specifically the case of post-foam injection of liquid (*cf.* Rossen and Wang, 1999). Moreover, the gas-mobility function does change when liquid injection follows foam: specifically, the liquid slug after foam traps more gas in place than in the models used here. Injection of surfactant solution following foam traps most, but not all, gas in the foam in place, keeping liquid mobility relatively low (Kibodeaux *et al.*, 1994; Rossen and Wang, 1999; Cheng *et al.*, 2001). Liquid mobility following gas injection was a key issue in the SAG field trial at the Snorre field (Blaker *et al.*, 1999; Martinsen and Vassenden, 1999).

Here, the same mobility functions are used during foam injection and gas and liquid injection in SAG processes. Refinement of this assumption must await definitive experimental studies.

Foam Simulator and Numerical Issues

We use UTCOMP, an isothermal, three-dimensional, equation-of-state (EOS) compositional simulator for miscible-gas flooding (Chang, 1990; Liu, 1993), modified for foam as described above, but without shear-thinning in the low-quality regime ($\sigma = 1$). The solution scheme is IMPEC (implicit pressure, explicit phase saturations and compositions). That is, the grid-block pressure is determined implicitly, using explicit dating of saturation-dependent terms which are computed using the physical properties at the previous time step. There is no complex phase behavior in the cases described here; surfactant is soluble only in water, and water and gas are assumed to be insoluble in each other.

Foam is modeled in the simulator by modifying gas relative permeability in the presence of foam, as described above. The water relative-permeability function does not change with foam. Surfactant transport is tracked by treating the surfactant as an aqueous-phase tracer, and there is no density difference between surfactant and aqueous phase. In the simulator, it is assumed that foam generation and propagation can occur at any pressure gradient (*cf.* Rossen and Gauglitz (1990) and Gauglitz *et al.*, 2002) if gas is present and surfactant concentration in the aqueous phase exceeds one-half the injected

concentration. This latter condition is intended to minimize the effects of numerical dispersion (Rossen *et al.*, 1999; Cheng, 2002). For simplicity, we exclude surfactant adsorption from this study.

UTCOMP models cylindrical flow by constructing a pie-shaped grid, where the width of a grid block increases proportionately to the distance from the well (Shan, 2001). In this work, there are 200 grid blocks in the radial direction, and the outer radial boundary is maintained at a fixed pressure of 2000 psi. Gas volumes and flow rates cited below are at the initial reservoir pressure of 2000 psi. Table 2.5 lists reservoir parameters used in the simulations.

Chang (1990) and Liu (1993) recommend the third-order method in UTKOMP with TVD as the best way to reduce numerical artifacts in simulations. We used the third-order method with TVD in all results reported here.

Gravity Override in SAG Processes

Gravity override results from a competition between gravity (and density difference) and lateral pressure gradient (Shi and Rossen, 1998a,b). For a foam process with continuous foam injection, water saturation in the foam bank is nearly uniform and constant (Shi and Rossen, 1998a; Rossen *et al.*, 1999). For a process that perfectly obeys the fixed- P_c^* model, water saturation in the foam bank is absolutely uniform and constant. Foam mobility is very low throughout the foam bank. Especially in a cylindrical reservoir, high velocity and low foam mobility near the injection well cause high injection pressure, which risks fracturing the formation (Kuehne *et al.*, 1990). Moreover, velocity and pressure gradient at the displacement front decrease as the displacement front moves away from the well, promoting gravity override (Shi and Rossen, 1998a).

In contrast, for SAG processes, during gas injection, water saturation declines and mobility increases toward the injection well (Figs. 2.46 to 2.50), helping to avoid fracturing the formation. Fig. 2.51 shows total relative mobility as a function of position after 0.2 PV gas injection into a large bank of surfactant in a cylindrical reservoir using the Fisher model at 0.02% surfactant concentration. The shock front is near the middle of the reservoir at $r = 0.5 R_e$ (or $x_d = 0.25$ on Fig. 2.49). High mobility near the injection well results from drying-out and partial foam collapse there; it is not the result of any shear-thinning rheology, which, as mentioned, has been excluded from this simplified

version of the UT model. There are a low-mobility zone behind the shock front, a high-gas-mobility zone near the well, and a single grid block with extremely low mobility at the shock front. According to Fig. 2.51, a SAG process can employ higher injection rate to prevent gravity override without exceeding the allowed injection pressure, since foam mobility is high near the well during gas injection. With relatively high mobility ahead of and behind the displacement front, a SAG process with fixed injection pressure can focus much of the reservoir pressure drop at the displacement front to fight gravity override. In a SAG process with fixed injection rate, however, decreasing frontal velocity in radial flow reduces pressure gradient at the front and promotes gravity override. Shi and Rossen (1998b) compare continuous foam injection and fixed-injection-rate and fixed-injection-pressure SAG processes in rectangular and cylindrical reservoirs using the Fisher model with 0.02% surfactant concentration. They reported that the fixed-injection-pressure SAG minimizes gravity override and injection time. A wider range of examples, with this and other models, are shown below. In addition, we consider the effects of finite slug sizes below.

Comparison of Gas-Injection Strategies

In this section we assume initially a large (infinite) slug of surfactant ahead of gas in order to compare different gas-injection schemes.

In Fig. 2.52(a), based on the Fisher model with 0.02% surfactant concentration, gas and liquid at 80% foam quality are injected simultaneously into a cylindrical reservoir at a total flow rate 108 ft³/d. In this and following figures, x represents lateral position in a rectangular or (more often) a cylindrical reservoir. At steady state, the position where gas and water segregate completely is about 0.45 R_e and the pressure difference across the reservoir is about 350 psi at that time. At this point the foam bank has stopped advancing into the reservoir (Shi and Rossen, 1998a). Given the uniform, low-mobility foam zone, it takes about 570 days to inject 0.4 PV gas and water. Higher injection rate would allow foam to propagate somewhat further into the reservoir, but at the cost of higher injection pressure, with higher risk of fracturing the formation.

Fig. 2.52(b) and (c) show water saturations after 0.4 PV gas injection for a SAG process at a fixed injection rate of 2205 ft³/d, in which injection pressure rises a maximum of 350 psi, and a SAG process at a fixed injection pressure of 2350 psi. The

case with the fixed, maximum pressure drop (Fig. 2.52(c)) clearly gives better sweep efficiency. Figs. 2.52(d) and (e) show water saturations for a SAG process at a fixed injection rate of $315 \text{ ft}^3/\text{d}$ (7 times lower than in Fig. 2.52(b)) and for SAG process at a fixed injection pressure of 2050 psi (pressure drop 7 times smaller than in Fig. 2.52(c)). The fixed-pressure SAG processes give much better sweep than fixed-rate SAG process at the same maximum injection pressure. Moreover, it takes 104 days and 40 days, respectively, for SAG processes at fixed injection rate and at fixed injection pressure to inject 0.4 PV gas in Figs. 2.52(d) and (e). As in continuous foam injection (Shi and Rossen, 1998a), pressure gradient is the crucial factor in controlling gravity override in SAG processes. The cases with higher fixed injection rate or pressure (Figs. 2.52(b) and (c)) give a better sweep than the cases with lower fixed injection rate or pressure (Figs. 2.52(d) and (e)).

Fig. 2.53 compares different injection strategies based on the Fisher model with 0.5% surfactant concentration. In Fig. 2.53(a), 80%-quality foam is injected at total flow rate of $1 \text{ ft}^3/\text{d}$. At steady state, gas overrides at about $0.46 R_e$, and the pressure drop across the reservoir is about 350 psi. Gas is injected at a fixed flow rate of $120 \text{ ft}^3/\text{d}$ in Fig. 2.53(b) and a fixed injection pressure of 2350 psi in Fig. 2.53(c), respectively. After 0.4 PV gas injection, the injection pressure for SAG process at fixed rate (Fig. 2.53(b)) decreases to 260 psi, which is still high enough to prevent gravity override, so this case gives almost the same sweep efficiency as the SAG process at fixed pressure. It takes 578 days for the SAG process at fixed injection rate to inject 0.4 PV gas (Fig. 2.53(b)), and over 85,000 days to inject the same volume of gas as part of an 80%-quality foam (Fig. 2.53(a)), but only 480 days for the SAG process at fixed injection pressure (Fig. 2.53(c)). Figs. 2.53(d) and (e) show water saturations for SAG processes at a fixed injection rate of $17 \text{ ft}^3/\text{d}$ (7 times lower than in Fig. 2.53(b)) and at a fixed pressure of 2050 psi (pressure drop 7 times smaller than in Fig. 2.53(c)). These two cases give worse sweep due to lower injection rate and injection pressure. Figs. 2.52 and 2.53 show that injection-well pressure plays a larger role in controlling gravity override than details of foam behavior, as discussed further below. Injection rate, however, is sensitive to details of foam behavior.

Figs. 2.54 and 2.55 show similar comparisons for the 2% and 10% progressive-collapse models based on the data of Persoff *et al.* The gas saturation in the gas bank is

about 0.65 with these two models, compared to 0.8 to 0.85 with the Fisher models (Fig. 2.45). Therefore the gas banks have progressed further at 0.4 PV gas injection in Figs. 2.54 and 2.55 (b) and (c) than in Figs. 2.50 and 2.53. Figs. 2.53(d) and 2.54(d) represent 0.2 PV gas injection, unlike the other cases. The fixed-injection-pressure SAG has better sweep than the other two injection strategies at the same maximum injection-well pressure.

Thus a SAG process at fixed injection pressure gives better sweep efficiency than either continuous foam injection or a SAG process at fixed injection rate. If injection rate and injection pressure are sufficiently high, all three processes can succeed (*cf.* Shi and Rossen, 1998a).

Gas Injection into a Finite Liquid Slug

When gas breaks through the surfactant bank in a SAG process, one expects no further improvement in sweep efficiency. Fig. 2.56 illustrates what happens when gas breaks through a finite surfactant slug in a 2D cylindrical reservoir. This and following figures plot both surfactant concentration in the aqueous phase and gas saturation. In all cases, a concentration of 5000 units (half the injected concentration) is sufficient to trigger foam formation (Rossen *et al.*, 1999; Cheng, 2001). In this case, injection of 0.05 PV surfactant solution is followed by gas injected at a fixed injection pressure of 2100 psi. After 0.2 PV gas injection, gas breaks through the surfactant front at about 0.38 R_e , quickly rises and overrides the rest of the reservoir. As in the SAG foam project in the Snorre field (Blaker *et al.*, 1999; Martinsen and Vassenden, 1999), the effectiveness of foam degrades when gas breaks through the surfactant front. Thus, the ability of foam to overcome gravity override cannot extend beyond the front of surfactant bank.

Thus there are two necessary conditions for foam to overcome gravity override: sufficient surfactant solution to sweep the region of interest, and sufficient pressure gradient to avoid gravity segregation in this region. For processes with sufficient pressure gradient, surfactant propagation limits sweep efficiency. For processes with sufficient surfactant, gravity and pressure gradient limit sweep efficiency (Shi and Rossen, 1998b).

Multiple SAG Cycles

Comparison between one SAG cycle and two SAG cycles. Once SAG injection is selected for field application, the slug sizes are important design

considerations. Fig. 2.57 shows surfactant concentration and water saturation after 0.6 PV total injection for one SAG cycle and two SAG cycles, for a SAG process at fixed injection rate. For the case with one SAG cycle, 0.2 PV surfactant solution is injected first at an injection rate of $31.4 \text{ ft}^3/\text{d}$, followed by 0.4 PV gas injection with an injection rate of $1260 \text{ ft}^3/\text{d}$. During injection of the first liquid slug there is no gas in the reservoir, so no liquid slumping occurs initially. For the case with two SAG cycles, 0.1 PV surfactant solution with a flow rate of $31.4 \text{ ft}^3/\text{d}$ is followed by 0.2 PV gas with a flow rate of $1260 \text{ ft}^3/\text{d}$ in the first cycle, followed by a second cycle the same as the first. There is gravity segregation during the injection of the second liquid slug in this process. Fig. 2.57 shows that the process with one SAG cycle gives nearly piston-like displacement while gas override has already occurred at 0.6 PV injection for the process with two SAG cycles. The reason is clear from the surfactant front in Fig. 2.57: the surfactant front propagates further along the top of the reservoir, where override occurs, with only one SAG cycle.

Fig. 2.58 shows water saturations for processes with one SAG cycle and two SAG cycles with fixed injection pressure of gas in both. Liquid is injected at a fixed flow rate of $31.4 \text{ ft}^3/\text{d}$ and gas is injected at fixed pressure of 2200 psi (the maximum injection pressure of the case in Fig. 2.57). After 0.6 PV gas and liquid injection, the process with one SAG cycle gives slightly better sweep efficiency than the process with two SAG cycles.

Thus SAG with fewer, larger slugs gives a somewhat better sweep efficiency than the case with many smaller slugs. The reason, we believe, is a coupling between gravity segregation and surfactant propagation. In the two-SAG-cycle process, surfactant fills the lower portion of the reservoir not penetrated by gas, with water saturation $S_w=100\%$. Where gas sweeps, in this process, $S_w \approx 20\%$, and a given volume of foam requires only $1/5$ as much surfactant solution as a region with $S_w = 100\%$. In other words, a relatively small override zone with $S_w = 100\%$ represents what could have been a much larger region filled with foam. In the two-cycle SAG process, a large portion of the injected surfactant slug lies useless in the override zone. Meanwhile, in Figs. 2.57(a) and 2.584(a), the piston-like sweep with the one-slug process helps to push surfactant ahead and maximizes the propagation of surfactant.

Liquid Slumping and Optimal Gas-Injection Strategy. In principle, liquid slumping only a short distance could deprive the top of reservoir of the surfactant solution needed for foam. Surfactant is treated as an aqueous-phase tracer in the simulator (Rossen *et al.*, 1999), with no change in aqueous-phase density; the only factor to cause gravity slumping here is the large density difference between liquid and gas.

Fig. 2.59 shows the performance of four cases after 0.6 PV injection with two SAG cycles and different gas-injection pressures: 10, 30, 50, and 100 psi above reservoir pressure. The reservoir is initially saturated with surfactant-free water with $S_w=100\%$. The liquid-injection strategy is same for all cases, with a flow rate of $31.4 \text{ ft}^3/\text{d}$. Surfactant-concentration contours and water saturations in Fig. 2.59 illustrate that higher gas-injection pressure gives both better gas sweep efficiency and less surfactant slumping. Comparison of these cases indicates that gas override and surfactant slumping go together. Better sweep of gas, with higher pressure gradient, helps the liquid propagate further along the top of the reservoir.

Thus injecting gas at the maximum allowable injection pressure for SAG processes not only prevents gas override within the surfactant bank, but also decreases surfactant slumping, both of which help gas sweep further.

Redistribution of Liquid During Gas Injection. A worst-case scenario for slumping of the surfactant slug occurs during injection of surfactant into a field with a gas present but no foam. Highly mobile gas can redistribute, facilitating slumping of the surfactant front. Fig. 2.60 shows a two-SAG-cycle process with gas, but no surfactant or foam, initially present in the reservoir ($S_{wi} = 0.8$). The first cycle comprises 0.1 PV liquid injected at a flow rate of $31.4 \text{ ft}^3/\text{d}$, followed by 0.2 PV gas injected at a modest 50 psi above reservoir pressure. The second cycle is same as the first one. During first 0.1 PV liquid injection, severe gas override and surfactant slumping occur, because gas mobility is initially high. However, the following period of gas injection with 50 psi pressure drop across the reservoir partially redistributes surfactant solution, with surfactant solution propagating further along the top of the reservoir. During injection of the second gas slug, liquid again propagates along the top of the reservoir, thus helping to prevent gas override. It appears that foam can push surfactant back toward the top of reservoir to mitigate gravity slumping that occurs during injection of liquid. Thus fixed-pressure SAG

injection with sufficient pressure drop can at least partially heal a process of gravity slumping during liquid injection.

Fig. 2.61 illustrates a case where insufficient injection pressure in a previous SAG cycle led to gravity override. At the end of injection of the first liquid slug, the contour lines of the surfactant concentration are vertical, because (by assumption) surfactant solution has the same density as water. The first gas slug is injected at 2010 psi. Gas largely overrides the liquid slug due to insufficient pressure gradient. Then 0.1 PV surfactant solution is injected into the reservoir. By this point gas override is significant and liquid slumping is starting to deplete the top of the reservoir. Then 0.2 PV more gas is injected at a larger fixed pressure of 2050 psi. During this period, the high pressure gradient pushes liquid back up to the top of reservoir. Gas injection with sufficient pressure gradient can partially reverse gravity slumping during injection of liquid.

Optimal Liquid Injection Strategy. For the SAG project in the Snorre field (Blaker *et al.*, 1999; Martinsen and Vassenden, 1999), the high well pressure experienced during injection of the liquid slug caused fracturing of the formation, with loss of surfactant, and reduced effectiveness of foam. Fortunately, Figs. 2.60 and 2.61 suggest that liquid injection strategy is not crucial to success against gravity override (as long as fracturing is avoided), because even if slumping of surfactant occurs, the following period of gas injection with sufficient pressure gradient can at least partially heal this problem. This is especially important because the mobility of a liquid slug injected after foam is still not fully resolved. Nonetheless, one can still make the following generalization: It is best to inject liquid at fixed pressure, just below fracturing pressure, to accelerate the process and minimize the time for gravity segregation during liquid injection. Shan (2001) shows an example where liquid injection at fixed injection rate doubles the injection pressure, while injection at fixed, lower pressure gives nearly the same sweep efficiency.

Sensitivity to Missing Data at Low Water Fractional Flow

For continuous foam injection in a given reservoir, gravity override depends only on injection-well pressure (Shi and Rossen, 1998a). Shi and Rossen (1998b) suggest that sweep efficiency in fixed-pressure SAG processes may likewise be independent of foam

properties. Fractional-flow theory predicts that the effectiveness of SAG processes depends on foam strength at extremely high foam quality (low f_w) (Zhou and Rossen, 1995; Rossen *et al.*, 1999), but it is difficult to conduct steady-state corefloods at this condition (Kibodeaux and Rossen, 1997). Thus, if process performance were independent of this behavior, it would simplify field process design.

Figs. 2.52 to 2.55 compare the performance of four foams with very different mobilities at low f_w (Figs. 2.47 to 2.50) under similar conditions. These differences in foam models reflect the differences of foam properties between different foam formulations, or the uncertainty in foam behavior at the low f_w that controls SAG floods. The sweep efficiency with continuous foam injection (Figs. 2.52(a) to 2.55(a)) depends only on injection-well pressure, as expected (Shi and Rossen, 1998a). The sweep efficiency of fixed-pressure SAG processes with the same injection pressure is also remarkably similar. For instance, the Fisher foam with 0.5% surfactant concentration is about 100 times stronger than with 0.02% concentration (*cf.* Figs. 2.49 and 2.50), but performance of the foams in fixed-pressure SAG floods at the same injection pressure (Figs. 2.52(c) and 2.53(c), or 2.52(e) and 2.53(e)) is similar.

Injection rate is sensitive to foam strength, however, as noted above. Sweep efficiency with a fixed-injection-rate SAG process also depends more on foam model than with fixed-pressure SAG.

It appears that Shi and Rossen's (1998b) conclusion should be modified slightly as follows: the performance of a fixed-pressure SAG process changes remarkably little with differences between foam models; pressure gradient is a more important factor than details of foam behavior in controlling gravity override in fixed-injection-pressure SAG processes. We propose an explanation below. For now, we note that for the 0.02%-concentration Fisher model a larger fraction of the well-to-well pressure drop is dissipated across the water bank than for 0.5% concentration, because with 0.02% surfactant concentration the foam bank has higher mobility (Figs. 2.49 and 2.50). Therefore, the case with 0.5% surfactant concentration focuses more of the well-to-well pressure drop on the gas displacement front than that with 0.02% concentration.

Sweep with complete foam collapse in shock front. The data of Persoff *et al.* (1991) are also consistent with a model in which foam collapses completely in a shock front at the leading edge of the foam bank (Fig. 2.46) (*cf.* Shi and Rossen (1998a) and

Rossen *et al.* (1999)). In finite-difference simulation, foam cannot form and collapse in a shock front with zero width; the minimum width of the front is one grid block (*cf.* the lowest-mobility grid block in Fig. 2.51). Therefore artificial numerical dispersion is introduced by finite-difference simulation. As the gas front moves across one grid block, or, more precisely, drains the water from one grid block and moves on to the next, foam is created and then collapses as the grid block drains. For the fixed- P_c^* model (Fig. 2.46), there should be no low-mobility bank at all (Zhou and Rossen, 1995), but finite-difference simulation artificially introduces at least one grid block with low mobility.

Comparing the two Fisher models (Figs. 2.52 and 2.53), the one with the narrower low-mobility zone (0.02% concentration) has similar sweep efficiency but much higher injectivity than the case with the broader bank of much lower mobility (0.5% concentration). For a process in which foam collapses in the shock front, the width of the low-mobility bank is one grid block; as gridding is refined, the width of this bank decreases. Sweep efficiency does not at first suffer. Fig. 2.62 shows the sweep efficiency of a foam that obeys the fixed- P_c^* model, with 50, 200 and 500 grid blocks along the radial direction. It is remarkable that gravity override does not worsen more rapidly as the grid block size decreases. An explanation is suggested below.

Nevertheless, the similarity in sweep efficiency masks an artifact in these simulations that is apparent in a plot of injection rate v. time. Fig. 2.63 shows cumulative gas injection for the same three cases. The simulation is not approaching a constant behavior as grid-block size is reduced, but injection rate is increasing with increasing grid refinement, apparently without limit in the range of grid refinements shown. In these simulations, injection rate is regulated largely by the single low-mobility grid block at the leading edge of the gas bank. As the grid-block size shrinks, injectivity increases. This symptom is a warning sign that the simulation as a whole is controlled by numerical dispersion at the gas shock front and is unreliable.

An Idealized Model for SAG Displacements

From the above examples, it appears that the ideal SAG process introduces a spreading wave with low mobility at the front and very high mobility near the injection well (Figs. 2.47 to 2.50). Shan (2001) shows that the pressure drop across the low-mobility displacement front such a spreading wave in 1D cylindrical flow is constant in

time. This observation motivates an idealized model for SAG foam displacements, in which all resistance to flow is concentrated in a narrow zone at the gas displacement front, with infinite mobility ahead of and behind it. The model is shown schematically in Fig. 2.64 and is described fully by Shan.

For a fixed-pressure SAG process a single family of curves for dimensionless lateral position X_D v. dimensionless vertical position Z_D as a function of dimensionless time t_D (Fig. 2.65) describes the displacement front for all displacements. These dimensionless variables are defined as follows:

$$X_D \equiv \frac{\Delta \rho g x}{\Delta P} \quad (2.12)$$

$$Z_D \equiv \frac{\Delta \rho g z}{\Delta P} \quad (2.13)$$

$$t_D \equiv \frac{k \lambda_{rf} \Delta \rho g}{(1 - S_{wf}) \phi \tau} t \quad (2.14)$$

where $\Delta \rho$ is density difference between phases, g gravitational acceleration, x lateral distance from the well (in cylindrical or rectangular coordinates), z vertical distance from the top of the formation, ΔP well-to-well pressure difference, k and ϕ formation permeability and porosity, λ_{rf} and τ the mobility within and thickness of the thin low-mobility displacement front, and t time since the start of injection.

The width τ and mobility λ_{rf} of the low-mobility zone affects the scaling of t_D (and the injection rate), but not the shape of the front. One need not plot $Z_D > 1$, because at these depths gas injection pressure is not sufficient to overcome hydrostatic pressure in the liquid and inject gas into the reservoir. For processes where $\Delta P > \Delta \rho g H$, where H is reservoir height, the displacement maps on to an upper portion of Fig. 2.65 ($Z_D < 1$); an example is shown below. There is no limit to possible (positive) values of X_D .

Gravity override for this idealized fixed-pressure SAG process depends only on density difference between phases ($\Delta \rho g$) and well-to-well pressure difference (ΔP). In the idealized model, for given ΔP , sweep efficiency is independent of the details of foam behavior (i.e., (λ_{rf}/τ)) as long as model assumptions are satisfied: much lower mobility near the leading edge of the gas bank than ahead of the bank or near the injection well.

This explains much of the response of the fixed-injection-pressure SAG process to the different foam models in Figs. 2.52 to 2.55 above.

The model also helps explain the spurious high sweep efficiency observed with the fixed- P_c^* model with abrupt, complete foam collapse (Fig. 2.62). There, a low-mobility zone one grid block wide is provided by numerical dispersion at the displacement front. Nevertheless, the narrow low-mobility zone, a numerical artifact, gives reasonably good sweep efficiency and little deterioration upon refinement of the grid; as noted, the model predicts that the width of the low-mobility zone τ does not affect the shape of the front (*cf.* Fig. 2.62) but does affect injectivity (*cf.* Fig. 2.63). In principle, sweep efficiency must deteriorate eventually with increasing grid refinement, as the pressure drop across the single low-mobility grid block becomes insignificant compared to the pressure drop in the liquid bank.

At the start of the displacement, the front is vertical; it begins to tip over because the pressure difference between gas and water is greater at the top of the reservoir than at the bottom, due to hydrostatic effects present in the liquid but not the gas. A fixed-pressure SAG process is so successful in the idealized case because all that is needed is a well-to-well injection pressure well above the hydrostatic pressure difference in the liquid phase across the reservoir height. Even if ΔP is not much larger than this, and the front starts to tip over, the displacement is aided by the fact that the front moves normal to its direction. Thus even as the front tilts over, the front moves normal to this direction, i.e. downward toward the unswept portions of the reservoir.

In 1D linear or cylindrical flow at fixed injection rate, holding (λ_{rf}/τ) constant, the idealized model indicates that well-to-well ΔP is constant. In 1D linear flow in a spreading-wave SAG process like those in Figs. 2.47 to 2.50, however, pressure drop across the foam bank is not constant with time, because the width of the foam bank increases with time. Shan (2001) shows that ΔP is constant in a fixed-injection-rate SAG process in 1D cylindrical flow, however. This means that the idealized model actually maps better on to SAG processes in cylindrical reservoirs than rectangular reservoirs. In cylindrical flow the gas flow rate increases dramatically as the front moves outward, but the rate of advance of the front is not limited by injection rate, since by assumption mobility is high behind the front.

Comparison With Simulation

Of the foam models in Figs. 2.46 to 2.50, the Fisher model with 0.5% surfactant concentration (Fig. 2.50) best fits the assumptions of the idealized model. Fig. 2.66 shows the displacement front of the Fisher model with 0.5% surfactant concentration in a rectangular reservoir 200 ft long and 30 ft high, with an injection pressure of 2050 psi. For this model, $S_{wf} = 0.15$. Fig. 2.67 shows the predictions of the idealized model at the same PV injection. The displacement fronts are very similar.

Comparison with Fixed-Rate SAG Process

To model a fixed-rate SAG process in the context of the idealized model, one must reduce the injection pressure over time to maintain injection rate fixed. The difference is especially great in cylindrical geometry. Figs. 2.68 and 2.69 compare fixed-rate SAG injection to fixed-injection-pressure SAG in a rectangular and a cylindrical reservoir. In these figures, for simplicity, $S_{wf} = 0$. The dimensionless front shapes are identical for fixed-pressure SAG in rectangular and cylindrical geometries for the same values of X_D , but the PV injected differ in the two geometries. In Figs. 2.68 and 2.69, both processes begin with the same injection pressure, 2016.6 psi, but pressure falls off in the fixed-rate case - so much so that in the cylindrical reservoir (Fig. 2.69) gas stops entering the lower injection interval. The fixed-rate process continues to sweep the entire interval efficiently. In fixed-rate SAG in a cylindrical reservoir, front velocity decreases as it moves radially outward. As a result, injection-well pressure decreases. Now injection pressure cannot compete so well with hydrostatics, and the vertical interval over which gas enters the formation decreases (Fig. 2.69). The gas front actually retreats upwards with time (no account for residual gas saturation is made in the idealized model). The severity of the effect in Fig. 2.69 in part reflects the low injection rate (and maximum injection pressure) selected.

Deviations from Idealized Assumptions

The other foam models do not give as good fit to the idealized model as in Figs. 2.66 and 2.67. All of the models have high mobility near the injection well, in accord with the model assumptions, but not all fit the assumptions that gas-bank mobility is much lower than that of the water bank ahead of it (Figs. 2.47 to 2.49). We believe that if

much of the well-to-well pressure drop is dissipated in the water bank ahead of the foam, less is focused at the displacement front, and sweep efficiency suffers.

Discussion

Both the idealized model and the simulations presented throughout this report assume that injection and production rates can be adjusted as needed to maintain fixed injection and production pressures, with corresponding (potentially large) increases in rates of produced fluids. There may be operational barriers to implementing this strategy in practice. In addition, effects of reservoir heterogeneity and interactions with oil must be considered before field implementation. This work presents an ideal case to guide strategies that must contend with such practical considerations.

Conclusions

The following conclusions derive from our simulation study:

1. A SAG process at fixed injection pressure better controls gravity override in homogeneous reservoirs than either continuous foam injection or a fixed-rate SAG process.
2. Sufficient surfactant slug size and sufficient pressure gradient are both necessary conditions for foam to overcome gas override. Surfactant slug size determines the potential region of sweep and sufficient pressure gradient prevents gravity segregation in this region.
3. The case with one SAG cycle gives somewhat better sweep efficiency than that with more SAG cycles.
4. For cases where gravity override has happened during the first SAG cycle, better injection strategies in the following SAG cycles can reduce surfactant slumping and improve sweep efficiency.
5. Gas should be injected at the maximum allowable injection pressure; this not only increases gas sweep efficiency within the surfactant bank, but also decreases surfactant slumping.
6. Liquid should likewise be injected at maximum allowable injection pressure; this puts liquid most rapidly into the reservoir and minimizes segregation during liquid injection.

7. Differences between foam models (i.e., differences between surfactant formulations) have only a moderate effect on gravity override in SAG processes with the same fixed injection pressure. The differences in sweep observed among foam models may reflect differences in the fraction of the well-to-well pressure drop dissipated in the water bank ahead of foam. Although different foam models give similar sweep efficiency in fixed-pressure SAG injection, they do differ significantly in injection rate.
8. If fractional-flow theory indicates that foam both forms and collapses within the shock front in a SAG displacement, conclusion 7 does not apply. Ironically, in such a case, a finite-difference simulation still gives a low-mobility bank at least one grid block wide. This numerical artifact then provides sweep improvement in the simulation, and the sweep efficiency may not change much upon grid refinement. The symptom of the artifact is that injectivity increases without bound upon increasing grid refinement.

An idealized model, in which all resistance to flow is confined to a narrow bank between high-mobility fluids ahead of and behind the displacement front, matches simulation results if the foam bank has much lower mobility than both the water ahead of it and the dried-out region near the injection well. The following conclusions derive from this model:

9. In the ideal constant-injection-pressure SAG process the well-to-well pressure drop is focused entirely in the displacement front. Then the well-to-well pressure drop need only compete with the hydrostatic pressure difference over the height of the reservoir; thus moderate injection pressures give very good sweep efficiency. In addition, even as the displacement front tilts over from override, it then tends to sweep downward from the override zone.
10. Fixed-rate SAG processes suffer from declining injection pressure, especially in radial flow, making the pressure drop at the front smaller compared to the hydrostatics with which it competes. Severe gravity override can result.
11. Since the idealized model takes no account of details of foam behavior, it explains why sweep efficiency in a fixed-pressure SAG process is relatively insensitive to the details of foam behavior. It also helps explain why even a spurious low-mobility zone, created by numerical dispersion, can by itself

give reasonable sweep efficiency in simulation. If, however, the foam process creates a weak foam, so that the water bank ahead of the foam accounts for a significant portion of the well-to-well pressure drop, then process efficiency suffers somewhat. These inferences are supported by the simulations with five foam models shown here.

Application: Capillary and Viscous Crossflow in Heterogeneous Reservoirs

Introduction

Foam plays two roles in a foam-drive process. It can help in overcoming gravity override (see above), and, in a layered reservoir, it can also divert fluid into intended layers by partially plugging other layers. In a foam-acid diversion process, the goal is that foam, which stays strong in the high-permeability, or undamaged layer, divert subsequently injected acid into damaged or low-permeability layers that need acid. In a gas-diversion process in IOR, the purpose is to increase sweep efficiency by diverting some gas flow from a high-permeability layer into low-permeability layers.

In principle, capillary crossflow can reduce the effectiveness of both foam-acid diversion and foam IOR processes in layered reservoirs. Rossen and Zhou (1995) predict disastrous effects of capillary crossflow on foam in the limit of capillary equilibrium, as discussed below. Capillary equilibrium applies in the limit of long, thin layers with good capillary contact. Therefore capillary crossflow is not expected to affect near-well process like foam-acid diversion. In this section, we address the effect of crossflow on gas diversion in IOR processes. We start with the definition of two types of crossflow occurring in the reservoir.

Capillary Crossflow

Capillary crossflow is caused by a difference in capillary pressure between two neighboring layers with no flow barrier between them. It is best illustrated with capillary-pressure curves for two layers as shown Fig. 2.70. Layer 1 has higher permeability and thus low capillary pressure, while layer 2 has lower permeability and higher capillary pressure (Lake, 1989). For almost any pair of water saturations in the two layers, capillary pressure would be higher in the low-permeability layer. The capillary pressure

at the interface settles at an intermediate value between the two capillary pressures. Thus water flows spontaneously across the interface from the high-permeability layer (at low capillary pressure) into the low-permeability layer (at high capillary pressure), and gas flows in the opposite direction.

At capillary equilibrium, the capillary pressure in the two adjacent layers is equal. This is expected to apply to very thin layers with good capillary contact far from injection well. Whether a finite-length system attains this equilibrium depends on the dimensions of the layers and the ease of transport between the layers. Since the capillary-pressure difference is usually very small (with surfactant, P_c itself is of order of a few psi), for layers of several feet in width, the fluid exchange caused by this capillary crossflow is a slow process. Thus complete capillary equilibrium across two layers may not be attained over reasonable distances.

In a water-flooding process, capillary crossflow drives water into lower-permeability layers from adjacent high-permeability layers, and is beneficial to oil recovery. But in the case of foam, losing water from a high-permeability layer may weaken foam near its boundary with a low-permeability layer and harm gas diversion (Zhou and Rossen, 1995; Rossen and Lu, 1997).

Viscous Crossflow

Viscous crossflow is caused by the pressure difference that arises from reservoir flow along two adjacent layers with no flow barrier between them. It is illustrated schematically for a two-layered system in Fig. 2.71. In this case foam or other low-mobility fluid has advanced more quickly along layer 1 than layer 2. Virtually all the pressure drop in both layers occurs within the foam bank. This leads to a pressure difference between the two layers throughout the foam bank, but especially between the two fronts. Viscous crossflow results from this pressure difference. Without a flow barrier, this viscous pressure difference drives flow of both water and gas across the boundary from layer 1 to layer 2, and the result is the evening-out of two foam fronts. In reality, viscous crossflow itself would reduce the pressure difference from that shown schematically in Fig. 2.71. Since it evens-out the displacement fronts, viscous crossflow is beneficial to gas diversion by increasing sweep efficiency. The same crossflow occurs

in any displacement where a more viscous fluid displaces a less-viscous fluid (Lake, 1989).

Compared to a capillary pressure difference of a few psi that drives the capillary crossflow in Fig. 2.69, the magnitude of the pressure drop across the foam front in Fig. 2.71 could be hundreds of psi; therefore, viscous crossflow is expected to be more significant than capillary crossflow, especially near the displacement fronts. Both capillary and viscous crossflow occur simultaneously across two adjacent layers with an open boundary. Cheng (2001) examines the effect of them both during continuous foam injection into a two-layer system. This report is summarized here.

Two Criteria and Two Time-Frames for Studying Foam Crossflow

While viscous crossflow is beneficial to a foam process, Zhou and Rossen (1995) show that if capillary crossflow is severe, foam effectiveness in diverting flow to lower-permeability layers can be harmed. There are at least two possible harmful effects of capillary crossflow:

1. Foam could be weakened and even break down in a higher-permeability layer due to loss of water, diverting less flow to an adjacent lower-permeability layer.
2. Foam crossflow between adjacent layers could reduce or increase the total injectivity into these two adjacent layers and affect diversion into distant intervals.

Criterion 1 asks if capillary crossflow weakening foam in highest-permeability layer A1 in Fig. 2.72 means that less flow is diverted into adjacent layer A2. Criterion 2 asks if crossflow between layers A1 and A2, both of which have higher permeability than layer D, means less diversion to layer D. These two criteria may seem similar, but, as shown below, they are not identical. The reason is that the same capillary crossflow that weakens foam in a high-permeability layer strengthens foam in the adjacent lower-permeability layer; the net effect on total injectivity into the two layers has to be examined from case to case and is not immediately clear.

In addition, there are two time frames in which crossflow may affect foam diversion:

- A. As the foam front passes, viscous crossflow drives some flow from the layer in which foam is moving fastest (whether the higher- or lower-permeability layer) into adjacent layers in which foam advances more slowly, and evens out the two foam advancing fronts.
- B. Far behind the foam front, where differences in pressure between layers due to viscous pressure gradients are smaller, modest differences in capillary pressure can draw water out of higher-permeability layers into adjacent lower-permeability layers, weakening foam in the higher-permeability layers. This is where capillary crossflow comes in play. The theory of capillary equilibrium assumes there is no viscous pressure difference between layers (Lake, 1989).

In coreflood experiments, Yaghoobi and Heller (1996), and Bertin *et al.* (1999) observed that viscous pressure gradients even-out the advance of foam in adjacent layers with crossflow allowed (i.e., success in time frame A). Later, after foam had passed through both layers of the core (time frame B), Yaghoobi and Heller observed some diversion of water into the lower-permeability layer, and less-effective, but still partially effective, diversion of gas by foam. Rossen and Lu (1997), and Rossen *et al.* (1999) also addressed time frame B, i.e., diversion well behind the foam front, using computer simulations of foams in the high-quality regime and in rectangular 2D reservoirs.

Cheng (2001) uses the above criteria and time frames to examine the effects of both viscous and capillary crossflow in a foam diversion process, using the foam algorithm described above implemented in the UTCHEM simulator. He reaches the following conclusions:

- 1. In flow of foam through adjacent layers, capillary-cross flow does weaken foam in the high-permeability layer, but it does not significantly hurt sweep efficiency between adjacent layers, contrary to the conclusions of Rossen and Lu (1997) and Rossen *et al.* (1999). Viscous crossflow gives an even frontal advance of foam in all case we examined, except one case with extremely slow injection rate and long, narrow layers. Even in that case, the gas bank still sweeps both layers ahead of the foam.
- 2. The overall mobility can be reduced or increased by capillary crossflow, depending on the magnitude of capillary crossflow. This effect can have a small positive or negative effect on diversion from a pair of adjacent layers,

differing somewhat in permeability, to another distant layer. In the cases we examined, the effect is not large.

3. A limited contrast in ranges of permeability, S_w^* , injection rates, and linear layer geometries were tested for crossflow. More factors may need to be tested: foam quality, partially effective shale barriers between layers, permeability anisotropies, gravity effects, different foam models, and radial flow geometry. An important limiting case of capillary crossflow would be foam flow through a natural fracture. This case deserves further study before final conclusions are drawn.
4. Simulations with different extents of grid refinement suggest that the gridding effect on simulation results is insignificant; if anything, relatively coarse grids (layers 5 grid blocks wide) tend to overstate effect of capillary crossflow.

Further details are available in Cheng's dissertation (2001).

Application: Gravity Override in Steady Foam Injection into Homogeneous Reservoirs

Gravity segregation between injected gas and water reduces gas sweep and oil recovery in gas-injection improved oil recovery processes (Lake, 1989). It also afflicts foam IOR processes, as described above. A useful model for gravity segregation is that of Stone (1982) and Jenkins (1984) for steady-state gas-water flow in a homogeneous porous medium. Stone and Jenkins argue that although in the field gas and water are usually injected in alternating slugs, over sufficiently long distances and sufficiently long times the process approximates steady co-injection of the two fluids, which is the focus of their study. Their problem statement begins with the usual assumptions of fractional-flow theory: Newtonian mobilities, incompressible phases, absence of dispersive processes, and instantaneous attainment of local equilibrium.

Stone and Jenkins then go on to postulate that upon injection of gas and liquid the reservoir attains a steady state with three uniform regions with sharp boundaries between them (*cf.* Figs. 2.52a to 2.55a). Based on these assumptions, Stone and Jenkins derive equations for the distance L_g (in a rectangular reservoir) or R_g (in a cylindrical reservoir) that the injected gas-water mixture flows before complete segregation, i.e. segregation

length, of gas and water flow and for the shape of the boundaries separating the three regions in the reservoir. The equation for a rectangular reservoir is as follows:

$$\frac{L_g}{L} = \left(\left(\frac{\Delta \rho g}{\nabla p_m} \right) \left(\frac{L}{H} \frac{k_x}{k_z} \right) \right)^{-1} \quad (2.15)$$

where L is the well-to-well distance, ∇p_m pressure gradient at the well in the "mixed" zone where gas and water flow together (i.e., without segregation; or as foam, in a foam displacement), H is reservoir height, and k_x and k_z are horizontal and vertical permeabilities. The equation for cylindrical reservoirs is

$$2 = \left(\frac{\Delta \rho g}{\nabla p_m(R_g)} \right) \left(\frac{R_g}{H} \frac{k_x}{k_z} \right) \quad (2.16)$$

where $\nabla p_m(R_g)$ is the pressure gradient that *would* be present at radial position R_g in the absence of gravity segregation. With either Eq. 2.15 or 2.16, one can predict the distance at which complete segregation occurs, from the injection rates and mobility functions for gas and water (and foam). No simulation is necessary.

The model of Stone and Jenkins fits simulations of gas-water flow over a wide range of parameter values. Still more remarkably, the model fits gravity segregation in simulation of foam injection as well (Shi and Rossen, 1998a), as long as the standard assumptions of fractional-flow modeling hold. The model fits simulation results in spite of the complexity of foam behavior, the extremely large reductions in gas mobility caused by foam, and the abrupt collapse of foam often observed over a narrow range of water saturation (Khatib *et al.*, 1988; de Vries and Wit, 1990; Fisher *et al.*, 1990; Persoff *et al.*, 1991; Rossen and Zhou, 1995; Aronson *et al.*, 1994; Alvarez *et al.*, 2001). An example model prediction is given in Fig. 2.73. Shi and Rossen (1998b) and Cheng *et al.* (2000) vary injected foam quality, foam strength, foam mechanistic model, flow rates, reservoir dimensions and properties, and even finite-difference grid refinement over a wide range of values with little no deviation from predictions of Stone and Jenkins (*cf.* example simulation result in Fig. 2.74). The model also fits experimental data in a 2D sandpack for gas-water flow (Holt and Vassenden, 1996), and for foam flow as well, if one allows an empirical adjustment to account for an ability of foam to suppress vertical migration in imperfectly homogeneous media (Holt and Vassenden, 1997). "Fit" should

be defined carefully in this context. Finite-difference simulations cannot resolve either the vertical or lateral position of complete segregation, H_g or L_g , to better than the size of one grid block. In the simulations, the regions appear remarkably uniform in saturation. The boundaries between regions appear sharp to within one or two grid blocks, as expected in the presence of numerical dispersion. Shi and Rossen (1998a) compare the extent of gravity override qualitatively with the model predictions, while Cheng *et al.* (2000) and Shan (2001) show agreement between model and simulations to within about 4% in L_g (almost to within grid resolution). The value of H_g cannot be compared directly to the simulations because the predicted override zone is usually thinner than one grid block. It is not clear whether the shape of the boundaries between regions in simulations has been compared quantitatively to the model; in any case quantitative comparisons would be limited by numerical dispersion and grid resolution at the boundaries; *cf.* Fig. 2.74.

The implications of Stone and Jenkins' model (Eqs. 2.15 and 2.16) are profound. The model implies that, for a given reservoir and density difference between phases, the only way to increase the distance gas and water travel together before complete gravity segregation is to increase the lateral pressure gradient in the reservoir, at the cost of increased injection-well pressure. Equivalent improvements are predicted, for instance, from injecting a strong foam at low flow rates, a weak foam at higher rates, or no foam at all at very high rates, to achieve the same value of $(\nabla p)_m$. Moreover, if injection-well pressure is limited, it may be impossible to achieve a desired improvement in vertical sweep. These conclusions, and this section, however, apply only to continuous-injection foam processes. As discussed above, alternating-slug (SAG) foam processes with sufficiently large slugs (larger than those envisioned by Stone and Jenkins) can achieve much better vertical sweep without adversely affecting injection-well pressure.

Uncertain Theoretical Foundation

The Stone and Jenkins' model fits a wide range of simulation results and some laboratory data for gas-water flow with or without foam; however, the theoretical justification for the model is uncertain. Stone (1984) remarks that the process of gravity segregation in 2D flow is similar to gravity segregation in a stagnant porous medium, for which a fractional-flow solution is available (Siddiqui and Lake, 1992); that is, he asserts

that the assumptions in his model can be derived from considering an element of fluid spanning the height of the reservoir, moving away from the injection well in time as shown schematically in Fig. 2.75. It can be seen in two ways that this is not so. First, while a stagnant porous medium is a closed system, the moving element in Fig. 2.75 is open. Lateral velocities differ between and vary within the three regions; therefore, in the override zone gas flows into the element from behind and out of its front face with different velocities. Second, gravity segregation in a stagnant medium may feature two shocks, but also one or two spreading waves (Fig. 2.76). Hence in that case one does not always observe two shocks, with uniform regions between, as in Stone and Jenkins' model.

Jenkins (1984) shows a sample fractional-flow function for gravity segregation in a stagnant medium (like Fig. 2.76) with a shock and a spreading wave, and argues that the average saturations observed in the various zones in 2D flow correspond to the average saturations of any spreading waves predicted from the fractional-flow solution for the stagnant case. This does not explain the observation of two shocks with three uniform regions in the simulations of 2D flow. Moreover, the upper and lower regions in the flow simulations are at their endpoint saturations (or zero saturation of one phase), not at some average saturation of a spreading wave with finite mobility of both phases (*cf.* Fig. 2.74).

Thus, a clearly useful model that fits a wide range of simulation results and has important implications for field application, is without a firm theoretical justification.

New Theoretical Proof

Using a method similar to fractional-flow theory, Rossen and van Duijn (2003) prove that a foam or gas IOR process that obeys the standard assumptions of fractional-flow theory, with injection into a homogeneous porous medium or reservoir, does indeed spontaneously segregate into three uniform regions with shock fronts between them, and the distance to the points of complete segregation fits the equations presented by Stone and Jenkins. This result does not depend on the details of phase mobilities; it is general for any two-phase system for which mobilities are monotonic with saturations. With this result, the model of Stone and Jenkins can be applied with confidence to estimating

gravity override in gas-water IOR as well as foam IOR. Details are in an upcoming publication (Rossen and van Duijn, 2003).

Toward Mechanistic Foam Simulation

The simulation models described above assume local steady state. They successfully reproduce behavior in the two steady-state foam-flow regimes because those two regimes are each dominated by a single, relatively simple mechanism. Fully mechanistic foam modeling, taking into account all foam mechanisms, remains a goal. It is essential when, for instance, foam generation to steady-state strong foam is not assured.

Toward the goal of fully mechanistic foam simulation, studies were conducted of the effective viscosity of gas in foam, and of the mechanisms of foam generation.

Effective Gas Viscosity in Foam

Foam behavior in porous formations is complex. Most gas stays trapped even as foam flows (Gillis and Radke, 1990; Friedmann *et al.*, 1991); in such cases “bubble trains” flow through regions of trapped gas. Therefore bubbles move in geometry not too unlike a constricted tube. Falls *et al.* (1989) split the effective viscosity of flowing gas in foam into two parts: effects of capillary constrictions and viscous drag. They and Rossen (1990a-d) assumed that the quasi-static case is the lower limit to actual ∇p of moving bubbles. To determine this lower limit, Rossen analyzed quasi-static lamella movement through various pore shapes. In this limit, soap films, or lamellae, can make asymmetric jumps even in radially symmetric pores, contributing to the effective yield stress. Examples are given below. The lamella shape can be complex in three dimensions (3D), but the model is straight-forward in 2D.

To determine viscous-drag effects, researchers investigated bubble flow in cylindrical capillary tubes. Bretherton (1961) investigated the pressure drop of isolated slowly moving bubbles. Hirasaki and Lawson (1985) analyzed bubbles with slugs of liquid in between, and then extrapolated to zero liquid thickness between bubbles – i.e., lamellae. Their model allows for surface-tension gradients along the bubble due to drag by liquid on surfactant molecules, and they found this is an important source of viscous drag. Ratulowski and Chang (1989) analyzed bubbles separated by lamellae with Plateau borders but without surface-tension-gradient effects. All these studies suggest that pressure drop across a lamella is proportional to the $2/3$ power of bubble velocity. Wong

et al. (1995) considered isolated bubbles advancing through a tube with polygonal cross-section, with water occupying the corners around the bubble, and found that pressure drop varies with the first power of velocity under some conditions and with the 2/3 power of velocity under others.

A model developed here for the first time addresses both drag and pore constrictions simultaneously (in 2D). The sequence of lamella shapes and positions are determined numerically as a function of time and the pressure drop along a train of bubbles is determined. At low dimensionless velocity, the results confirm the assumptions of Falls *et al.* (1989) and Rossen (1990a-d) that the quasi-static value is lower limit to ∇p . However, in some cases that assumption breaks down, and ∇p can decrease as flow rate increases. Full details are available in the dissertation of Xu (2003) and in a recent publication (Xu and Rossen, 2003).

Model and Assumptions

A wedge-shaped pore in two dimensions is shown in Fig. 2.77. For purposes of calculation, pore depth in the third dimension is W . At the pore corner, a sine function provides a smooth transition between pore walls over a distance ($2 \epsilon L$). Even in angular pores, water occupying the pore corners can effectively round off the pore body as suggested schematically in Fig. 2.77 (Rossen, 1988). The gas is assumed to be incompressible; its advance is regulated by pistons moving at constant velocity, V . We assume that the lamella shape adjusts instantaneously to minimize its area subject to given bubble volume and the positions of its Plateau borders, while the Plateau borders may respond more slowly to bubble advance. We assume the Plateau borders may be treated as points of contact between the lamella and the pore wall.

Both Hirasaki and Lawson (1985) and Ratulowski and Chang (1989) conclude that pressure difference between bubbles in cylindrical tubes scales with the (2/3) power of bubble velocity. The same pressure difference must apply across the lamella, which is a spherical section in their case; this implies that the apparent angle of contact of the lamella with the pore wall (Fig. 2.77) is related to velocity by

$$\cos(\theta_1) = (K V_1)^{2/3} \quad (2.17)$$

$$\cos(\theta_2) = (K V_2)^{2/3} \quad (2.18)$$

where K is a constant. In cylindrical tubes $V_1 = V_2$ and $\theta_1 = \theta_2$; we assume Eqs. 2.17 and 2.18 apply also to dynamic movement in constricted tubes. Ratulowski and Chang (1989) imply that K is of the order of (μ/σ) , i.e. about 0.3 s/m for a water- N_2 foam. Hirasaki and Lawson (1985) imply that K is about one order of magnitude higher; the exact value depends on capillary pressure in the Plateau border. The value implied by the model of Kavscek *et al.* (1995) is highly dependent on pore diameter (if all other parameters hold constant). Wong *et al.* 's (1995) work implies an exponent of 1 in Eqs. 2.17 and 2.18 in some cases, but we do not believe that change would substantially alter what follows.

Eqs. 2.17 and 2.18, along with the volume constraint for an incompressible bubble, pore geometry, velocity of the piston, and the requirement that the lamella is always a circle joining the two Plateau borders, define the problem. Note (Fig. 2.77) that $dx_1/dt = V_1(\cos \beta)$ and $dx_2/dt = V_2(\cos \beta)$. A backwards-difference numerical method was developed and used to calculate sequence of lamella positions and shapes. Pressure drop across lamella (in 2D) is obtained from lamella radius r

$$\Delta p = 2\sigma/r \quad . \quad (2.19)$$

Dimensionless (Δp_D) is Δp divided by capillary entry pressure, $(2\sigma/R_t)$. Rossen (1990a) showed that for a train of incompressible bubbles the time-average pressure drop for one lamella $(\Delta p_D)^{ave}$

$$(\Delta p_D)^{ave} \equiv \int_0^1 (\Delta p_D) \Delta t_D \quad , \quad (2.20)$$

where t_D is time divided by the time required to pass through one pore, is also the population-average Δp per bubble for a long train of bubbles passing through a chain of identical pores. Pressure gradient is then $(\Delta p)^{ave}$ divided by bubble length in the direction of flow.

Results

Three kinds of lamella behavior at the pore body are identified from simulations. They are symmetric jumps, asymmetric jumps and transitional behavior. As dimensionless piston velocity $V_D \equiv (K V)$ increases, asymmetric jumps may change to symmetric jumps either abruptly or through transitional behavior.

In the figures to follow, dimensionless time t_D and piston velocity V_D are as defined above, and dimensionless pressure difference Δp_D and average pressure difference $(\Delta p_D)^{ave}$ are divided by capillary entry pressure (in 2D) (σ/R) , where σ is surface tension.

Three Types of Behavior. Rossen (1990c) showed that in a wide wedge-shaped pore with a sufficiently sharp corner at the pore body (small ϵ), the lamella jumps in the vicinity of the pore corner to an asymmetric shape roughly as shown in Fig. 2.78. The lamella advances smoothly from (a) to (b); then jumps to asymmetric shape (c) and advances smoothly to (d); finally jumps to (e) and advances smoothly to (f). Fig. 2.78 shows this process for a low, but finite, piston velocity. The left-hand figure shows the sequence of lamella shapes, the middle figure the positions of the two Plateau borders as a function of time (splitting apart at the asymmetric jump at (c)), and the right-hand figure the pressure drop across the lamella as a function of time. The integral of the right-hand curve (with the sequence from (e) to (f) partially canceling the sequence from (a) to (b)) is the dimensionless average Δp , $(\Delta p_D)^{ave}$, given by Eq. 2.20. There are slight deviations between Fig. 2.78 and the quasi-static case; in all cases the lamella bulges forward slightly more, and Δp_D is slightly larger, than in the quasi-static case. The jumps are extremely rapid on the time scale shown here but can be resolved with sufficiently small time steps; we used up to 100,000 time steps in the cases shown here.

At higher dimensionless velocities, the asymmetric jump is replaced by a symmetric jump, illustrated in Fig. 2.79. The loss of the sequence from (c) to (d) between Figs. 2.78 and 2.79 reduces the capillary contribution to $(\Delta p_D)^{ave}$, because it replaces a sequence of nearly flat shapes with shapes that are concave and pulling the lamella forwards. The transition between asymmetric and symmetric jumps may be abrupt or gradual, through a sequence of shapes we have named "transitional behavior," illustrated in Fig. 2.80. The middle figure here shows Plateau border positions for several dimensionless piston velocities, in which there is a gradual transition from clearly asymmetric behavior toward symmetric lamella movement. The curve in the middle figure with black dots corresponds to the lamella shapes shown on the left and the Δp_D curve shown on the right.

Transitions Between Behavior. Fig. 2.81 plots $(\Delta p_D)^{ave}$ v. dimensionless piston velocity V_D in pores with several values of ϵ . In all cases, $R/L = 1/8$ and $\beta = 22.5^\circ$ (Fig. 2.77). For $\epsilon \leq 0.08$ (Fig. 2.81 (a)), there is an abrupt change from asymmetric- to symmetric-jump behavior as V_D increases. Since the capillary contribution to $(\Delta p_D)^{ave}$ is significantly smaller for the symmetric jump (Figs. 2.78 and 2.79), this abrupt transition reduces $(\Delta p_D)^{ave}$ discontinuously at the change. The shift in behavior occurs at larger values of velocity as ϵ increases. Close examination of the case $\epsilon = 0.05$ shows that $(\Delta p_D)^{ave}$ is lower at a dimensionless velocity of 0.006 than in quasi-static movement.

Fig. 2.81 (b) plots $(\Delta p_D)^{ave}$ v. V_D for $\epsilon \geq 0.09$. Here there is transitional behavior between asymmetric and symmetric jumps, and the transition moves to smaller velocities as ϵ increases. Where the transition occurs, $(\Delta p_D)^{ave}$ decreases continuously with increasing velocity over a finite range of velocities.

We suspect that the nature of the transition between regimes depends on pore geometry as follows. If the jump to the asymmetric shape occurs after the rearward bubble occupies more than half the pore (*cf.* Fig. 2.78, middle or left-hand plot), then no continuous transitional behavior is possible; the lamella jumps symmetrically or asymmetrically. But if the jump would occur before the rearward bubble occupies half the pore volume, a continuous transition between regimes is possible.

Contributions to Foam Pressure Drop. Falls *et al.* (1989) postulated that total foam pressure drop is the sum of a quasi-static capillary contribution and a viscous drag that is proportional to the (2/3) power of velocity. Fig. 2.82 tests this assumption by subtracting the zero-velocity extrapolation of $(\Delta p_D)^{ave}$ from the total value at low velocities (see Fig. 2.82(a)). Only the case $\epsilon = 0.05$ is shown. The actual viscous contribution is compared to that estimated for the lamella moving through a smooth (2D) pore with the same volume at the same volumetric flow rates as the pore in Fig. 2.77. The viscous contribution is close to that assumed by Falls *et al.* (Fig. 2.82(b)).

Of course, at higher velocities pressure drop deviates strongly from that assumed by Falls *et al.* Most strikingly, pressure drop can decrease with increasing velocity (Fig. 2.81(b)), and the pressure drop across a moving lamella can be less than that at the quasi-static limit (Fig. 2.82(a)).

These results show that a fully mechanistic description of gas effective viscosity with foam is much more complex than current representations have assumed.

Snap-Off and Foam Generation

Recent attempts at fully mechanistic foam generation have assumed that lamellae are created exclusively by a process of "snap-off" at pore throats. We have shown (Rossen, 2000) that this explanation is problematic. However, repeated foam generation by snap-off is possible as gas flows across a sharp boundary in permeability. Details are in Rossen (1999).

This study shows that for permeability contrasts greater than about 4:1 or 5:1, continuous gas-liquid flow across the permeability boundary is blocked. Instead, as gas flows into the higher-permeability zone and capillary pressure falls, snap-off blocks gas flow at the transition; capillary pressure then rises there until either lamellae break or are mobilized by the increasing pressure gradient, and then capillary pressure falls again. This cycle was observed and reported by Falls *et al.* (1988) in their studies in beadpacks. Snap-off also depends weakly on the gas-liquid ratio of injected fluids, with foam generation promoted by low gas fractions. The model explains a variety of experimental observations. For instance, a fourfold difference in permeability required to give snap-off in this way corresponds to a twofold decrease in bead size, in agreement with Ransohoff and Radke's (1988) observation. The dependence on gas fraction predicted by the model agrees with the finding of Falls *et al.* that foam generation at such a boundary ceases with sufficiently dry flow.

Analysis of Population Balance Simulators in Terms of Fractional-Flow Theory

The thesis of Dong (2001) includes a detailed local-steady-state analysis of several foam simulators. The foam model of Vassenden and Holt reproduces the two foam-flow regimes discussed under Task 2.1 above, as does the STARS™ model and the model of Bertin (2000). The population-balance model of Kovscek *et al.* (1995) includes at steady-state only the high-quality regime. (This is understandable, because a plot of the steady-state data used to fit the model reflects only a high-quality regime.)

Fractional-flow modeling, based on the local-steady-state versions of these models, suggest some concern about the nature of the gas bank in a SAG process, and

possible numerical artifacts in simulations of a SAG process. Details are in Dong's thesis (2001).

CONCLUSIONS

Task 1 Conclusions

Task 1.1 focused on the effect of dispersive processes on oil recovery and how to enrich gas so that the MMP can be reduced. Simulation studies (Solano *et al.*, 2001; Stalkup, 1990) show that oil recovery for enriched gas drives depends on the amount of dispersion in reservoir media, but the value of dispersion, expressed as dispersivity, at the field scale, is unknown. This research investigated three types of dispersion in permeable media to obtain realistic estimates of dispersive mixing at the field scale.

The dispersivity from single-well tracer tests (SWTT), also known as echo dispersivity, is dispersivity that is unaffected by fluid flow direction. Layering in permeable media tends to increase the dispersivity observed in well-to-well tracer tests, also known as transmission dispersivity, but should not affect the echo dispersivity.

We analyzed a collection of SWTT data to estimate echo dispersivity at the SWTT scale. The estimated echo dispersivities closely match a published trend with length in dispersivities obtained from groundwater tracer tests. This unexpected result—it was thought that transmission dispersivity should be greater than echo dispersivity—is analyzed with numerical simulation.

Another type of dispersive mixing is local dispersivity, or the mixing observed at a point as tracer flows past. Numerical simulation results showed that the local dispersivity is always less than the transmission dispersivity and greater than the echo dispersivity. It is closer to one limit or the other depending on the amount and type of heterogeneity, the autocorrelation structure of the medium's permeability, and the lateral (vertical) permeability. The agreement between the SWTT echo dispersivities and the field trend suggests that the field data are measuring local dispersivities. All dispersivities appear to grow with length.

The interaction of phase behavior and flow, in the presence of dispersive mixing, was examined for 1-D four-component enriched-gas displacements. Numerical and analytical solutions demonstrated that oil recovery may be substantially increased by gas enrichment above the minimum enrichment for miscibility (MME). The level of increase is dependent on the level of dispersive mixing and the size and shape of the two-phase region.

A critical gas enrichment (CGE) above the MME is defined that separates the multi-contact miscibility region into two regions: MCM1, when the gas lies within the region of tie-line extensions, and MCM2, when the gas lies outside. For enrichments below the CGE (in MCM1), oil recovery can increase significantly with enrichment. Above the CGE (in MCM2), oil recovery is not as sensitive to enrichment for the cases studied. Displacements in the MCM1 region exhibit a combined condensing and vaporizing mechanism, whereas displacements in the MCM2 region are purely condensing.

We also extended the research on four-component systems to displacements of multicomponent oils and gases where the recovery is affected by dispersion and enrichment. In particular, we considered a twelve-component oil displaced by solvents enriched above the MME. For this case, the increase in recovery (displacement efficiency) above the MME was as large as 15% OOIP depending on the level of mixing. The methodology outlined can be used as a screening tool to identify if a significant benefit may exist and further 2-D and 3-D studies are warranted.

A secondary focus of this part of the research was to examine in detail how dispersion affects recoveries and displacement mechanisms for the four and twelve-component systems. We showed that for the case of the four-component model the displacement mechanism changes from a combined condensing/vaporizing displacement (CV) to a strictly condensing one as enrichment increases above the MME. We also showed how to quantify the percentage of the CV displacement that is vaporizing or condensing by calculating the compositional distances between key tie lines identified from "dispersion-free" theory.

Next, we considered two-dimensional floods and the effect of dispersion. 2-D effects such as channeling, gravity tonguing, and crossflow can impact the enrichment required for good recovery.

Numerical simulation is often used to model the effect of physical mixing on oil recovery in miscible-gas floods. Unfortunately, numerical dispersion can cloud the interpretation of the results by artificially increasing the level of mixing in the reservoir.

This part of the research investigated the interplay between various mixing mechanisms, enrichment level, and numerical dispersion. The mixing mechanisms examined are mechanical dispersion, gravity crossflow, and viscous crossflow. UTCOMP

is used to evaluate the effect of these mechanisms on recovery for different grid refinements, reservoir heterogeneities, injection boundary conditions, relative permeabilities, and numerical weighting methods including higher-order methods. For all simulations, the reservoir fluid used is twelve-component oil displaced by gases enriched above the MME.

The results showed that for 1-D enriched-gas floods, the recovery difference between displacements above the MME and those at or near the MME increases significantly with dispersion. The trend, however, is not monotonic and shows a maximum at a dispersivity of about 4 ft. The trend is independent of relative permeabilities and gas trapping for dispersivities less than about 4 ft. For 2-D enriched gas floods with slug injection, the difference in recovery generally increases as dispersion and crossflow increase. The magnitude of the recovery differences is less than observed for the 1-D displacements. Recovery differences for 2-D models are highly dependent on relative permeabilities and gas trapping. For water alternating gas (WAG) injection, the differences in recovery increase slightly as dispersion decreases. That is, the recovery difference is significantly greater with WAG at low levels of dispersion than with slug injection. For the cases examined, the magnitude of recovery difference varies from about 1 to 8 percent of the original oil-in-place (OOIP).

Water-alternating-gas floods (WAG) are commonly used to improve sweep efficiency in heterogeneous reservoirs. There has been little reported in the literature, however, on the effectiveness of WAG processes where the gas is enriched above the minimum miscibility enrichment composition (MME). Thus, the next part of our research task examined in more detail how to optimize WAG processes for enriched gas floods above the MME, particularly as a primary recovery method. Compositional simulations of x-z cross-sections were used to quantify the effects of WAG parameters, numerical dispersion, level of enrichment, and heterogeneity on local displacement efficiency and sweep efficiency.

The main conclusions of this research showed that the richer the gas above the MME, the fewer the number of WAG cycles required for maximum oil recovery at a given WAG ratio. Another significant observation is that over-enrichment above the MME improves recovery the most when the largest permeability layers are at the bottom of the reservoir. Continuous slug injection performed better than WAG when the largest

permeability layers are at the bottom of the aquifer, richer gases are used, and the vertical to horizontal permeability ratio is small.

In Task 1.2, our goal was to develop a fast and robust method to estimate MMP for real gas floods. Local displacement efficiency from gas injection is highly dependent on the minimum miscibility pressure (MMP) or minimum miscibility enrichment (MME). Analytical methods, which are inexpensive and quick to use, have been developed to estimate MMP's for complex fluid characterizations. Published methods (Johns and Orr, 1996; Wang and Orr, 2002; Jessen *et al.*, 1998), however, often require estimation of numerous parameters and little has been written with regard to method robustness. Our research has shown that all of these previous methods will not always converge to the correct MMP for a variety of fluid characterizations. This research presents a simplified and robust method for MMP or MME calculation that does obtain the correct MMP.

The approach relied on finding key crossover tie lines for a dispersion-free displacement using method of characteristic theory (MOC). The new method, however, differs from published methods by significantly reducing the number of equations and unknown parameters, and by providing a fast and robust method that can avoid trivial and false solutions. We demonstrate the improvements by calculation of the MMP and MME for a variety of gas/oil systems and also give new analytical solutions for constant K-value systems that give insight into the nature of the false solutions.

Additional research beyond the goals for Task 1.2 examined the displacement mechanisms that occur in shallow gas floods. Local displacement efficiency in gas floods depends strongly on the minimum miscibility pressure (MMP) or minimum miscibility enrichment (MME). The values for these design parameters depend in turn on the displacement mechanisms, vaporizing, condensing, or a combination of the two known as a condensing/vaporizing (CV) drive. Characterization of the displacement mechanism, however, is currently limited to these broad categories with little reference to the degree to which a CV displacement is condensing or vaporizing. The focus here, therefore, was to present a method to quantify the fraction of a multicomponent gas flood that is vaporizing or condensing as the pressure or gas enrichment is increased.

The approach again relied on finding key tie lines for a dispersion-free one-dimensional displacement using method of characteristic theory (MOC). We quantified

the displacement mechanism for any number of oil or gas components by calculating the displacement path lengths along ruled surfaces bounded by these key tie lines. Several multicomponent fluid characterizations are considered, including a twelve-component enriched-gas flood and a thirteen-component CO₂ flood. The results show that as the pressure or enrichment is increased condensation occurs at the expense of vaporization. We also showed by numerical simulations that the sensitivity of the local displacement efficiency to dispersion depends on the condensing fraction of the displacement.

Task 2 Conclusions

Studies of the two steady-state foam regimes have shown them to be, if not universal, then at least widely occurring in foam: with different surfactant formulations; in sandstones, sandpacks, beadpacks, and carbonates; at room temperature and elevated temperature; with N₂ gas and high-pressure, dense CO₂; with and without oil (though data are few on the two regimes with oil present). We have proposed and presented experimental evidence to support a self-consistent model for both regimes. This model explains the distinct effects of permeability, flow rates and surfactant concentration on the two regimes. The two regimes differ in their basic behavior, including the effects of permeability and surfactant type and concentration, and rheology. Therefore, differentiating between them is essential to any foam application. For instance, diversion between layers is more effective in the high-quality regime, because foam strength in that regime is more sensitive to permeability.

The two flow regimes were identified in previously published studies of dense CO₂ foam, although never both regimes in the same study. Therefore it is surprising that our own experimental study of dense-CO₂ foam did not find the low-quality regime. Instead, examination of dense-CO₂ foam in both Berea core and a sandpack found a regime where pressure gradient decreases with increasing liquid injection rate. We have recently seen similar behavior in an ongoing study of the behavior of foam with and without polymer in sandpacks. Theoretical models of Hirasaki and Lawson and de Vries and Wit predict that effective gas viscosity in the presence of foam decreases as water injection rate increases. These models could explain our laboratory data, *if* gas trapping were constant (or ineffective) *and* bubble size were constant in the experiments. We do not yet know if this explanation is correct.

The foam algorithm we have developed can be implemented in either compositional gas-flood simulator UTCOMP or chemical-flood simulator UTCHEM. Indeed, it can be implemented with the addition of a short section of code into any simulator that can accommodate a surfactant component and gas. The model fits the two steady-state foam-flow regimes. The key mechanisms behind the model parameters are the collapse of foam at a limiting capillary pressure P_c^* , a constant gas-mobility reduction factor (i.e., independent of water saturation) at capillary pressures higher than P_c^* , and shear-thinning rheology in the low-quality regime. Our foam model is shown to be similar to that in STARSTM, a widely used commercial foam simulator.

We have documented the numerical artifacts that can render foam simulations inaccurate and described how to minimize them. In many cases, grids may need to be refined more than in conventional field- or pattern-scale simulations.

The use of the simulator was key to identifying the optimal injection strategy for overcoming gravity override with foam, in the idealized case of a homogeneous reservoir. The optimal strategy is injection of gas and surfactant solution in large alternating slugs at the maximum allowable injection pressure. Propagation of continuously injected foam is limited by gravity segregation relatively near the well, according to the model of Stone and Jenkins. We derived a theoretical proof of the validity of Stone and Jenkins' model that transforms it from an empiricism to a dependable, predictive model, and verified its accuracy with a wide variety of simulations.

Injection of large alternating slugs of liquid and gas, however, can give long-distance foam propagation and high sweep efficiency without segregation, with remarkably low injection pressures. Injection of liquid and gas at steady, maximum injection pressure maximizes sweep efficiency and minimizes liquid slumping. This process is remarkably insensitive to foam behavior, as long as foam does not collapse completely at the limiting capillary pressure P_c^* . This finding may minimize the need to conduct difficult laboratory experiments at extremely low water fractional flow, which would otherwise be needed to predict foam behavior in a SAG process.

A unique aspect of this research program has been the application of fractional-flow theory in parallel with computer simulation. Fractional-flow theory was key in explaining why the SAG process gives both low mobility at the displacement front and high injectivity. Fractional-flow theory also raises concerns about numerical artifacts in

SAG-foam simulations with models in which foam collapses completely at the limiting capillary pressure. Fractional-flow theory explains the origin of the fluctuations in water saturation observed in the gas bank in foam simulations and shows that they are unimportant to overall process predictions (though unsightly). Fractional-flow methods applied to a variety of published simulator models provide insights into those models and highlight concerns about numerical artifacts in simulation. Finally, it is a variant of fractional-flow theory proves why the model of Stone and Jenkins is so accurate over so wide a range of conditions.

A model even simpler than fractional-flow theory, one with a single low-mobility front between gas and water banks of infinite mobility, explains several aspects of gravity segregation in SAG processes: why a successful process requires only a moderate injection pressure; why SAG injection at fixed rates fails; why sweep efficiency in the fixed-injection-pressure SAG process is insensitive to the details of foam behavior; how numerical artifacts make a process in which foam collapses completely at P_c^* deceptively successful; and why this numerical artifact is revealed in an injection rate that increases with increasing grid refinement.

Application of the simulator to a study of viscous and capillary crossflow in layered media modifies earlier conclusions from our research group about the effects of capillary crossflow on foam effectiveness. In the limit of capillary equilibrium, capillary crossflow does tend to create anti-diversion, i.e., diversion of flow into higher-permeability layers. However, our displacement simulations did not approach this limit except in the case of extremely thin, extremely long layers. In such cases viscous crossflow near the foam front caused gas to enter the lower-permeability layers long before capillary crossflow weakened foam in the higher-permeability layer.

Toward a fully mechanistic foam simulator, we developed a model for effective gas viscosity in the presence of foam that for the first time accounts for both capillary and viscous forces. The resulting behavior is much more complex than assumed in current mechanistic models. Other work casts doubt on snap-off as the mechanism of foam generation, as implemented in some simulators. These studies highlight the difficulty of performing fully mechanistic foam simulation.

We developed a model for foam generation at layer boundaries that is in agreement with a variety of experimental observations. Since oil reservoirs are

heterogeneous on a wide variety of scales, foam generation at these boundaries can be a significant factor in foam success, especially in preventing vertical migration of gas across layers.

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TABLES

TABLE 1 - RESERVOIR AND FLUID PROPERTIES			
Reservoir		Fluids	
Porosity, fraction	0.22	Water viscosity , cp	0.34
Absolute permeability, mD	100	Oil viscosity , cp	1.06
Vertical to horizontal permeability ratio	1.0	65% enriched gas viscosity, cp	0.042
Dimensions x-y-z, ft	1000x800x20	85% enriched gas viscosity , cp	0.048
Initial water saturation, fraction	0.32	Water mass density, b/ft ³	62.4
Irreducible water saturation to oil, fraction	0.32	Oil mass density, lb/ft ³	46.5
Residual oil saturation to water, fraction	0.128	65% enriched gas density, lb/ft ³	22.2
Maximum trapped gas in RELPM1, fraction	0.29	85% enriched gas density, lb/ft ³	24.9
Initial pressure, psia	4100	Oil bubble pressure, psia	4170
Initial temperature, °F	182		

Note: Fluid properties at reservoir conditions, 4170 psia, 182 °F

TABLE 1.2 - RESERVOIR AND FLUID PROPERTIES			
Reservoir		Fluids	
Porosity, fraction	0.22	Water viscosity , cp	0.34
Absolute permeability, mD	100	Oil viscosity , cp	1.06
Vertical to horizontal permeability ratio	1.0	65% enriched gas viscosity, cp	0.042
Dimensions x-y-z, ft	1000 x 800 x 20	85% enriched gas viscosity , cp	0.048
Initial water saturation, fraction	0.32	Water mass density, lb/ft ³	62.4
Irreducible water saturation to oil, fraction	0.32	Oil mass density, lb/ft ³	46.5
Residual oil saturation to water, fraction	0.128	65% enriched gas density, lb/ft ³	22.2
Maximum trapped gas in RELPM1, fraction	0.29	85% enriched gas density, lb/ft ³	24.9
Initial pressure, psia	4100	Oil bubble pressure, psia	4170
Initial temperature, °F	182		

Note: Fluid properties at reservoir conditions, 4100 psia, 182°F

TABLE 1.3 - FLUID MOLAR COMPOSITIONS						
Component	Reservoir Oil	Lean Gas	Solvent	Gas 55% (MME) Enrichment	Gas 65% Enrichment	Gas 85% Enrichment
CO2	0.0150	0.0815	0.2120	0.1549	0.1663	0.1924
C1	0.5069	0.8305	0.2770	0.5427	0.4707	0.3600
C2	0.0587	0.0620	0.2050	0.1419	0.1550	0.1836
C3	0.0358	0.0225	0.2560	0.1514	0.1743	0.2210
C4	0.0192	0.0035	0.0500	0.0291	0.0337	0.0430
C5	0.0161					
C6-C7	0.0379					
C8-C10	0.0725					
C11-C14	0.0639					
C15-C19	0.0614					
C20-C29	0.0639					
C30+	0.0487					

Table 1.4-Illustration of unknown parameters for a twelve-component system. The oil tie line, which consists of eleven components, is determined by a negative flash of eleven-component oil. The gas tie line, which consists of six components, is found by a negative flash of five-component gas. The "d" indicates known values from the negative flashes. The "x" indicates unknown values for each crossover tie line (C1 through C9). The "0" indicates equilibrium liquid mole fractions that are zero based on shock construction theory (Johns and Orr, 1996).

	x_1	x_2	x_3	x_4	x_5	x_6	x_7	x_8	x_9	x_{10}	x_{11}
<i>Oil</i>	<i>d</i>	<i>d</i>	0	<i>d</i>	<i>d</i>	<i>d</i>	<i>d</i>	<i>d</i>	<i>d</i>	<i>d</i>	<i>d</i>
<i>C1</i>	×	×	×	×	×	×	×	×	×	×	×
<i>C2</i>	×	×	×	×	×	×	×	×	×	×	×
<i>C3</i>	×	×	×	×	×	×	×	×	×	×	×
<i>C4</i>	×	×	×	×	×	×	×	×	×	×	×
<i>C5</i>	×	×	×	0	×	×	×	×	×	×	×
<i>C6</i>	×	×	×	0	×	×	0	×	×	×	×
<i>C7</i>	×	×	×	0	×	×	0	0	×	×	×
<i>C8</i>	×	×	×	0	×	×	0	0	0	×	×
<i>C9</i>	×	×	×	0	×	×	0	0	0	0	×
<i>Gas</i>	<i>d</i>	<i>d</i>	<i>d</i>	0	<i>d</i>	<i>d</i>	0	0	0	0	0

Table 1.5-Comparison of simplified method with published methods for the example displacement of eleven-component oil by five-component gas (see Table 1.4).

	Unknowns	Equations
Wang and Orr ²	99	99
Jessen <i>et al.</i> ³	286	286
Simplified method	84	19

Table 1.6-Fluid characterization for the displacement of thirteen- component oil by CO₂. Reservoir temperature is 157°F. The acentric factor is not used for phase behavior calculations.

Component	P _c (psia)	T _c (°F)	ω	MW
CO ₂	1070.74	87.91	0.225	44.01
C ₁	666.39	-116.72	0.011	16.04
N ₂	493.13	-232.51	0.031	28.02
C ₂	707.60	90.09	0.099	30.07
C ₃	616.34	206.01	0.154	44.10
iC ₄	529.16	274.98	0.184	58.12
nC ₄	550.81	305.65	0.200	58.12
iC ₅	490.69	369.10	0.228	72.15
nC ₅	488.78	385.86	0.251	72.15
nC ₆	439.78	454.55	0.298	86.18
C ₇₁	316.03	695.92	0.527	161.80
C ₇₂	218.51	979.68	0.824	287.70
C ₇₃	156.29	1286.78	1.125	476.40

Table 1.7-Initial oil and injection gas compositions for the displacement of thirteen-component oil by CO₂ including temperature dependence parameters tuned with the SRKEOS.

Component	Oil	Gas	Ω_A	Ω_B
CO ₂	0.0029	1	0.37659	0.0793
C ₁	0.3097	0	0.31442	0.0858
N ₂	0.0033	0	0.26344	0.0949
C ₂	0.0569	0	0.39289	0.0827
C ₃	0.0543	0	0.42158	0.0785
iC ₄	0.0203	0	0.45760	0.0800
nC ₄	0.0388	0	0.46996	0.0798
iC ₅	0.0234	0	0.50057	0.0804
nC ₅	0.0216	0	0.50414	0.0792
nC ₆	0.0339	0	0.53349	0.0781
C ₇₁	0.2583	0	0.68167	0.0783
C ₇₂	0.1113	0	0.83859	0.0714
C ₇₃	0.0653	0	0.98050	0.0640

Table 1.8-Binary interaction parameters (BIPs) for the displacement of thirteen-component oil by CO₂ using the SRKEOS. All other BIPs are zero.

Component	CO ₂	C ₁	N ₂
C ₁	0.1196		
N ₂	-0.0500	0.0400	
C ₂	0.1193	0.0283	0.029
C ₃	0.1189	0.0274	0.070
iC ₄	0.1186	0.0265	0.094
nC ₄	0.1186	0.0265	0.094
iC ₅	0.1182	0.0257	0.094
nC ₅	0.1182	0.0257	0.094
nC ₆	0.1178	0.0248	0.094
C ₇₁	0.1189	0.0201	0.094
C ₇₂	0.1126	0.0124	0.094
C ₇₃	0.1178	0.0008	0.094

Table 1.9-Fluid characterization for the displacement of thirteen- component oil by CO₂ after lumping to seven pseudo-components.

Component	P _c (psia)	T _c (°F)	ω	MW
CO ₂	1070.74	87.68	0.225	44.01
C ₁	666.39	-116.95	0.011	16.04
N ₂	493.13	-232.74	0.031	28.02
P ₁	621.51	197.97	0.150	44.28
P ₂	468.29	410.17	0.264	78.18
P ₃	286.67	781.12	0.617	199.69
P ₄	172.00	1193.66	1.038	413.20

Table 1.10-Initial oil and injection gas compositions for the displacement of thirteen-component oil by CO₂ after lumping to seven pseudo-components.

Component	Oil	Gas	Ω _A	Ω _B
CO ₂	0.0029	1	0.37659	0.0793
C ₁	0.3097	0	0.31442	0.0858
N ₂	0.0033	0	0.26344	0.0949
P ₁	0.1703	0	0.44219	0.0822
P ₂	0.0789	0	0.51900	0.0794
P ₃	0.3696	0	0.77093	0.0789
P ₄	0.0653	0	0.94002	0.0662

Table 1.11-Binary interaction parameters (BIPs) for the displacement of thirteen-component oil by CO₂ after lumping to seven pseudo-components. All other BIPs are zero.

Component	CO ₂	C ₁	N ₂
C ₁	0.1196		
N ₂	-0.0500	0.0400	
P ₁	0.1188	0.0285	0.070
P ₂	0.1180	0.0274	0.094
P ₃	0.1145	0.0227	0.094
P ₄	0.1094	0.0159	0.094

Table 2.1. Experimental Conditions and Summary of Experimental Results

Experiment	Surfactant	Cs (wt%)	core	K (md)	fg* at transition zone	Power law exponents	
						High-quality regime	Low-quality regime
Ug5	PEN-5	0,5	Berea #1	400	0,73	1,3	1,08
Ug6	Bio_Terge	1	Berea #2	530	0,78	1,28	0,46
Ug7	Bio_Terge	0,25	Berea #2	430	0,73	1,7	0,38
Ug8	Bio_Terge	0,05	Berea #2	535	0,4	2,11	
Ug11	Bio_Terge	1	Sand	3110	0,97		0,35
Ug12	Bio_Terge	1	Antolini	302 (ave)	0,89		0,32
Ug14	Bio_Terge	1	Berea #2	527	0,6	1,69	0,3

Table 2.2 Measurements of Entering (E) and Spreading (S) Coefficients and Lamella Number (N)

Initial Measurements							
Oil	$\gamma_{ow,i}$	γ_{og}	γ_{gw}	E_i	S_i	L_i	Effect on foam
Surfactant: Aerosol MA-80I (2 wt%)							
Decane	2.5	25.3	27.4	4.6	-0.4	1.64	M/Un
FC-70	9.8	20.9	27.4	16.3	-3.3	0.42	M
FC-77	9.3	15.9	27.4	22.6	2.2	0.44	M/Un
Surfactant: Dowfax 8390 (1 wt%)							
Decane	0.2	25.3	49.5	26.1	24.0	36.39	Un
FC-70	26.0	20.9	49.5	54.6	2.6	0.28	M/Un
FC-77	22.5	15.9	49.5	56.1	13.1	0.32	M/Un
Measurements of Pre-Equilibrated Interfacial Tension							
Surfactant: Aerosol MA-80I (2 wt%)							
Oil	$\gamma_{ow,e}$	γ_{og}	γ_{gw}	E_e	S_e	L_e	Effect on foam
Decane	3.0	25.3	27.4	5.1	-0.9	1.27	M/Un
FC-70	10.5	20.9	27.4	17.0	-4.0	0.39	M
FC-77	10.0	15.9	27.4	21.5	1.5	0.41	M/Un
Surfactant: Dowfax 8390 (1 wt%)							
Decane	6.0	25.3	49.5	30.2	18.2	1.20	M/Un
FC-70	24.0	20.9	42.5	45.6	-2.4	0.27	M
FC-77	23.0	15.9	40	47.1	1.1	0.26	M/Un

- Unit = dynes/cm
- M : moderate stability; Un: Unstable

Table 2.3. Properties of Cores Before the CO₂ Foam Experiments

	Length (in)	Diameter (in)	Porosity (%)	Permeability (md)
Core 1	12	1.83	19.6	360
Core 2	11.75	1.83	20.2	366

Table 2.4. Properties of Cores After the CO₂ Foam Experiments

	Length (in)	Diameter (in)	Porosity (%)	Permeability (md)
Core 1	12	1.83	19.1	217
Core 2	11.75	1.83	20.1	229

Table 2.5. Reservoir Parameters Used in Simulations of Optimal Injection Strategy

Reservoir dimensions:	
rectangular (x,z,y)	200 x 30 x 3 ft
cylindrical (r,z)	250 x 30 ft*
Wellbore radius (cyl. reservoir)	0.33 ft
Number of grid blocks	200 x 10**
Absolute permeability	300 md
Porosity	0.25
Reservoir temperature	72°F
Initial reservoir pressure	2000 psi
Fixed p at production well	2000 psi
Water (aq. phase) density	62.4 lb/ft ³
Gas density	9.5 to 10.0 lb/ft ³ ***
Water viscosity	0.7 cp
Gas viscosity	0.0207 cp***
Minimum surfactant	1/2 injected concentration
concentration for foam	(5000 "units" in figures)
Relative-permeability and	see Shan (2001) and Shi
foam-model parameters	(1996)

* except 200 x 30 ft in Fig. 2.66

** except in Fig. 2.62

*** determined by simulator

FIGURES

Fig. 1.1- Estimation of transmission dispersivity for a layered permeable medium. The data points are the simulated concentration history for a two well medium using UTCHEM. The solid line is the best-fit match of the solution of the convection-dispersion (CD) equation to the points. The concentrations for both the simulation and the CD equation are vertically averaged cup-mixing concentrations. The estimated transmission dispersivity of 2.47 m is greater than the input longitudinal dispersivity, 0.46 m, used to generate the production history data.

Fig. 1.2- Estimation of echo dispersivity in a layered permeable medium. The data points are the produced concentration in a simulated single well tracer test (SWTT) plotted against volume produced. The solid curve is the best fit for a one-dimensional, radial UTCHEM simulation. The concentrations are vertically averaged cup-mixing concentrations. The estimated echo dispersivity is 0.46 m, and the input longitudinal dispersivity is 0.46 m.

Fig. 1.3- Flow chart for automatic history-matching routine. UTCHEM, the reservoir simulator, is used as a subroutine. "REGRESSION" is a subroutine that calculates the goodness of fit between the forward and inverse concentration histories.

Fig. 1.4- Echo dispersivities estimated from SWTT data plotted against the distance traveled (twice the distance of penetration) in the reservoir.

Fig. 1.5- Probability plot showing the frequency of occurrence of echo dispersivity values. The median echo dispersivity (0.4 m) is the value below which 50% of the values lie. The values are normally distributed with some bottom truncation.

Fig. 1.6- The comparison between field measured dispersivity and echo dispersivity values for field-scale permeable media. Data from Arya *et al.* (1998). The plot includes lab scale echo and transmission data from paper by Hulin *et al.* (1989).

Fig. 1.7- Concentration contour plots for continuous tracer injection into a stochastic permeable medium. The medium is 9.15 m long and 6 m thick. Each grid block size is 0.305 m by 0.305 m. Permeability in the vertical direction is zero. The dark shades show regions of large concentration and the lighter shades regions of near-zero concentration. Note the sharp changes in concentration from dark to light. The injection time is 1.2 pore volumes.

Fig. 1.8- Concentration contour plots for continuous tracer injection into a stochastic permeable medium. The medium is 9.15 m long and 6 m thick. Each grid block 0.305 m by 0.305 m. Cell permeabilities in the vertical direction are equal to that in the horizontal direction. The dark shades show the regions of large concentration and the light shades regions of near-zero concentration. Note the greater dispersion compared to the case in Fig. 1.7. The injection is 1.1 pore volumes.

Fig. 1.9- Variation of estimated dispersivity with distance traveled in the stochastic permeable medium (single realization) with no vertical permeability. The data points are the local dispersivity values estimated at all the grid blocks in the reservoir. The solid lines are transmission (upper) and echo (lower) dispersivities.

Fig. 1.10- Variation of estimated dispersivity with distance traveled in the stochastic permeable medium (single realization), with $k_v=k_h$. The data points are the local dispersivity values estimated at all the grid blocks in the reservoir. The solid lines are transmission (upper) and echo (lower) dispersivities.

Fig. 1.11- Variation of estimated dispersivity with distance traveled in the stochastic permeable medium (single realization), with $k_v=10000$ md. The data points are the local dispersivity values estimated at all the grid blocks in the reservoir. The solid lines are transmission (upper) and echo (lower) dispersivities.

Fig. 1.12- Best-fit match of the field and laboratory data with the theoretical expressions for echo and transmission dispersivity. The plot includes lab scale echo and transmission data from paper by Hulin *et al.* (1989). The solid line represents the best fit for field data from Arya *et al.* (1998) and the best fit for echo dispersivity data using SWTT.

Fig. 1.13- $C_1/C_3/C_{16}$ ternary diagram showing the regions for partially miscible (PM), multicontact miscible (MCM) and first-contact miscible (FCM) displacements of the oil shown at 2000 psi and 200°F.

Fig. 1.14- Recovery of C_{16} at 1.2 PVI for displacement of the oil in Fig. 1.13 by gas containing C_1 and C_3 for varying levels of dispersive mixing.

Fig. 1.15- Illustration of a typical compositional route in a quaternary system. The composition route follows three key tie lines: the oil tie line, the gas tie line and the crossover tie line (Peng and Robinson, 1976).

Fig. 1.16- Quaternary diagram of $C_1/C_3/C_6/C_{16}$ system at 2000 psi and 200°F. Composition paths for varying levels of dispersive mixing are shown for a partially miscible displacement of oil O by injection gas I.

Fig. 1.17- Composition and saturation profiles for varying levels of dispersive mixing for the partially miscible displacement of oil O in Fig. 1.16.

Fig. 1.18- Recovery of C_6 and C_{16} at different pore volumes injected for varying levels of dispersive mixing for the partially miscible displacement of oil O in Fig. 1.16.

Fig. 1.19- (a) Illustration of the $C_1/C_3/C_6/C_{16}$ quaternary diagram showing regions for partially miscible (PM), multicontact miscible (MCM1 and MCM2) and first-contact miscible (FCM) displacements at 2000 psi, 200°F. The vertical surface traversed by the "dispersion-free" displacement is shown by the shaded area. (b) Expanded view of the $C_1/C_3/C_{16}$ ternary face of the $C_1/C_3/C_6/C_{16}$ quaternary diagram.

Fig. 1.20—Recovery of C_6 and C_{16} at 1.2 PVI for varying levels of dispersive mixing for the partially miscible displacement of oil O. The "knee" in the recovery curves occurs at 53% C_3 enrichment for $P_e=100$ and 10, not at the MME (39% C_3).

Fig. 1.21- Component K-values of the displacement of oil O by injection gas (a) I_1 (b) I_2 (c) I_3 (d) I_4 and (e) I_5 .

Fig. 1.22- Component K-values for displacements of oil O by injection gas I_2 (MME) for Peclet numbers (a) 100, (b) 1000, and (c) 10000.

Fig. 1.23- Component K-values for displacements of oil O by injection gas I_4 for Peclet numbers of (a) 100 and (b) 1000.

Fig. 1.24- Comparison of the effect of dispersion at $N_{Pe} = 100$ on oil recovery at $t_D = 1.2$ PVI for the displacement of a bubblepoint oil O_1 and oil O shown in Fig. 1.19.

Fig. 1.25- Phase diagram of $\text{CH}_4\text{N}_2/\text{C}_{2+}/\text{C}_{5+}/\text{C}_{30+}$ system at 3650 psi, 200°F. The oil composition O and an injection gas composition I are shown.

Fig. 1.26- Recovery of C_{5+} and C_{30+} at 1.2 PVI for different enrichments for the displacement of oil O in Fig. 1.25.

Fig. 1.27- Recovery of oil at 1.2 PVI for varying levels of dispersive mixing for the 12-component system. The "knee" in the recovery curves for Peclet numbers less than 1000 occur at enrichments much higher than the MME (60%). No MCM2 or FCM region exists for this 12-component system.

Fig. 1.28- The location of the "knee" for four-, and twelve-component systems shifts with enrichment, but not for three-component systems.

Fig. 1.29- Sensitivity of recovery to enrichment and dispersion for the twelve-component system. The curves intersect near the MME (60%). The slope is the change in recovery per unit change in enrichment.

Fig. 1.30- Sensitivity of recovery to enrichment and dispersion for the four-component system. The curves intersect near the MME. The slope is the change in recovery per unit change in enrichment.

Fig. 1.31- Component K-values for oil displacements by gas at the MME (60%) for Peclet numbers (a) 100, and (b) 1000. The CV mechanism is evident.

Fig. 1.32- Component K-values for oil displacements at a Peclet number of 100 for three different enrichments of (a) 20%, (b) 60%, and (c) 80%. The CV mechanism is evident for all enrichments. The size of the two-phase region shrinks as enrichment is increased.

Fig. 1.33- Lengths of the oil and gas tie lines for the twelve-component displacements.²³ Smaller lengths with enrichment indicate that the gas tie line is approaching the critical locus. The gas tie line, however, remains within the region of tie-line extensions for all enrichments and is just slightly closer to the critical locus than the oil tie line at 100% enrichment.

Fig. 1.34- Effective 1-D dispersivity for different grid-block sizes and weighting methods. Effective dispersivity is determined by matching the error function solution to fully miscible displacements.

Fig. 1.35- Case 1. Oil recovery at 1.2 HCPVI for the 1-D homogeneous model. A slug solvent of 0.2 HCPV displaces the oil. Both enrichments are above the MME of 60 percent. RELPM1 is used.

Fig. 1.36- Case 1. Difference in recovery between 85 and 65 percent solvent slugs at 1.2 HCPVI for the 1-D homogeneous model. RELPM1 is used. Values for effective dispersivity are shown.

Fig. 1.37- Recovery difference between 85 and 65 percent solvent slug for 1-D homogeneous model. The trends show nearly log normal distribution with dispersivity. At infinite dispersivity, the difference approaches 0.0 for case 1 and 1.4 for case 2.

Fig. 1.38- Case 2. Oil recovery at 1.2 HCPVI for the 1-D homogeneous model. A slug solvent of 0.2 HCPV displaces the oil. RELPM2 is used. The oil recovery at an infinite number of grid blocks is 1.0 because RELPM2 does not include gas trapping.

Fig. 1.39- Case 2. Difference in recovery between 85 and 65 percent solvent slugs at 1.2 HCPVI for the 1-D homogeneous model. RELPM2 is used.

Fig. 1.40- Case 3. Oil recovery at 1.2 HCPVI for the 2-D homogeneous model. A slug solvent of 0.2 HCPV displaces the oil. The effect of grid-block size on recovery is greatly reduced. RELPM1 is used.

Fig. 1.41- Case 3. Difference in recovery between 85 and 65 percent solvent slugs at 1.2 HCPVI for the 2-D homogeneous model. RELPM1 is used.

Fig. 1.42- Case 4. Difference in recovery between 85 and 65 percent solvent slugs at 1.1 HCPVI for the 2-D homogeneous model. RELPM2 is used.

Fig. 1.43- Discontinuous shales in the 2-D cross-section model for cases 5 and 6.

Fig. 1.44- Case 5. Difference in recovery between 85 and 65 percent solvent slugs at 1.2 HCPVI for the 2-D model in Fig. 1.43. RELPM1 is used.

Fig. 1.45- Case 6. Difference in recovery between 85 and 65 percent solvent WAG at 1.2 HCPVI for the 2-D model with shales. RELPM1 is used.

Fig. 1.46- Case 7. Difference in recovery between 85 and 65 percent solvent WAG at 1.2 HCPVI for the 2-D layered model. RELPM1 is used.

Fig. 1.47- Case 8. Difference in recovery between 85 and 65 percent solvent slug at 1.2 HCPVI for the 2-D layered model. RELPM1 is used.

Fig. 1.48- Case 8. Shaded grid blocks indicate those that attained at least a maximum gas saturation of 10 percent (after 1.0 HCVPI). Gas channeling through a high permeability layer in the center of the model reduces sweep efficiency for three-point weighting with 85 percent enriched gas. The gas channeling explains the lower recovery difference with three-point weighting in Fig. 1.47.

Fig. 1.49- Recovery contours as a function of grid-block size for continuous slug injection of 0.2 HCPV lean gas enriched with 65% solvent into a homogeneous reservoir. Oil recovery is at 1.2 HCPVI following a 1.0 HCPV waterflood.

Fig. 1.50- Three-phase saturation profiles at different injection times and grid-block sizes corresponding to selected grids in Fig. 1.49.

Fig. 1.51– Recovery difference between 85% and 65% enrichment as a function of grid-block size for continuous slug injection of 0.2 HCPV gas into a homogeneous reservoir. Oil recovery is at 1.2 HCPVI following a 1.0 HCPV waterflood.

Fig. 1.52- Recovery for different WAG ratios and frequencies for a total gas injection of 0.2 HCPV lean gas enriched with 65% solvent into a homogeneous reservoir. Oil recovery is at 1.2 HCPVI. Grid blocks are 10 ft x 1 ft.

Fig. 1.53- Recovery for different WAG ratios and frequencies for a total gas injection of 0.2 HCPV lean gas enriched with 85% solvent into a homogeneous reservoir. Oil recovery is at 1.2 HCPVI. Grid blocks are 10 ft x 1 ft.

Fig. 1.54- Optimum WAG ratio and frequency for maximum recovery at 1.2 HCPVI in a homogeneous reservoir based on Figs. 1.52 and 1.53.

Fig. 1.55- Three-phase saturation profiles in a homogeneous reservoir after injection of 10 WAG cycles at a WAG ratio of 2.0 corresponding to one case shown in Fig.

1.54.

Fig. 1.56- Recovery difference between 85% and 65% enrichment for different WAG ratios and frequencies for displacements in a homogeneous reservoir. Oil recovery is at 1.2 HCPVI.

Fig. 1.57- Oil recovery in a layered reservoir for zero vertical permeability, 65% enrichment, WAG ratio of 2.0, and seven WAG cycles.

Fig. 1.58- Recovery difference between 85% and 65% enrichment in a layered reservoir for zero vertical permeability, WAG ratio of 2.0, and seven WAG cycles.

Fig. 1.59- Oil recovery in a layered reservoir for vertical to horizontal permeability ratio of 1.0, 65% enrichment, WAG ratio of 2.0, and seven WAG cycles.

Fig. 1.60- Recovery difference between 85% and 65% enrichment in a layered reservoir for a vertical to horizontal permeability ratio of 1.0, WAG ratio of 2.0, and seven WAG cycles.

Fig. 1.61- Recovery difference between 85% and 65% enrichment in a layered reservoir for vertical to horizontal permeability ratio of 0.1, WAG ratio of 2.0, and seven WAG cycles.

Fig. 1.62- Recovery difference between WAG and continuous slug injection in a layered reservoir for 65% enrichment, vertical to horizontal permeability ratio of 0.1, WAG ratio of 2.0, and seven WAG cycles.

Fig. 1.63- Recovery difference between WAG and continuous slug injection in a layered reservoir for 65% enrichment, vertical to horizontal permeability ratio of 1.0, WAG ratio of 2.0, and seven WAG cycles.

Fig. 1.64- Recovery contours for layered reservoir with different vertical permeabilities and grid-block sizes. The WAG ratio is 2.0 and there are seven WAG cycles. The gas enrichment is 65% solvent.

Fig. 1.65- Illustration of minimum distance between two successive key tie lines.

Fig. 1.66- Example of convergence for displacement of twelve-component oil by five-component gas. The number of iterations required to achieve a tolerance of 1E-8 are significantly reduced when the initial guess for the equilibrium liquid compositions for each iteration are determined by linear extrapolation.

Fig. 1.67- Example of convergence to a false set of crossover tie lines. The correct solution continues to increase approximately linearly. Only the equilibrium liquid compositions for crossover tie line 2 and species 2 and 3 are shown.

Fig. 1.68- Example displacement of three-component oil by two-component gas (a four-component system). Input parameters for the PREOS are given by Johns *et al* (1993). The MME occurs when the crossover tie line is zero length at 59.6% C_1 and 40.4% C_3 . Thus, the system is a combined condensing/vaporizing (CV) drive.

Fig. 1.69- Lengths of key tie lines for displacement of seven-component oil by a five-component lean gas (seven-component system reported by Uleberg and Hoier (2002)). The slim tube measured MMP is 6909 ± 147 psia. The calculated MMP by the simplified method is 7007 psia. Crossover tie line 1 controls miscibility and the displacement is CV.

Fig. 1.70- Lengths of key tie lines for displacement of seven-component oil by a five-component lean gas (seven-component system reported by Uleberg and Hoier (2002)). The slim tube measured MMP is 4777.5 ± 73.5 psia. The calculated MMP by the simplified method is 4838 psia. Crossover tie line 3 controls miscibility and the displacement is CV.

Fig. 1.71- Lengths of key tie lines for displacement of twelve-component oil by five-component enriched-gas. The calculated MME occurs when the lean gas is enriched to 57.2% of the solvent. Crossover tie line 4 controls miscibility and the displacement is CV.

Fig. 1.72- Lengths of key tie lines for displacements of three-component oil by two-component gases (a four-component system). Input parameters for the PREOS are given by Johns *et al.* (1993). The MME occurs when the length of the crossover tie line is zero at 59.6% C_1 and 40.4% C_3 . Thus, the system is a combined condensing/vaporizing (CV) drive for all nonzero enrichments. The temperature is 200°F.

Fig. 1.73- Compositional path lengths for displacements of three-component oil by two-component gases (a four-component system). The MME is 59.6% C_1 and 40.4% C_3 . The compositional path length along the condensing portion of the displacements increases with increasing enrichment. The temperature is 200°F.

Fig. 1.74- Drive mechanism for displacement of three-component oil by two-component gas (a four-component system). The MME is 59.6% C₁ and 40.4% C₃. The condensing fraction of the displacements increases with increasing enrichment. At the MME, the displacement is primarily condensing. The temperature is 200°F.

Fig. 1.75- Lengths of the key tie lines for displacements of seven-component oil by a five-component lean gas (seven-component system reported by Uleberg and Hoier (2002). The slim tube measured MMP is 6909 ± 147 psia. The calculated MMP by the analytical method is 7007 psia. Crossover tie line 1 controls miscibility and the displacement mechanism is CV. The temperature is 266°F.

Fig. 1.76- Lengths of the key tie lines for displacements of seven-component oil by a five-component enriched gas (seven-component system reported by Uleberg and Hoier (2002). The slim tube measured MMP is 4777.5 ± 73.5 psia. The calculated MMP by the analytical method is 4838 psia. Crossover tie line 3 controls miscibility and the displacement is CV. The temperature is 266°F.

Fig. 1.77- Compositional path lengths for displacements of seven-component oil by a five-component lean gas (seven-component system reported by Uleberg and Hoier (2002). The MMP is 7007 psia. The temperature is 266°F.

Fig. 1.78- Compositional path lengths for displacements of seven-component oil by a five-component enriched gas (seven-component system reported by Uleberg and Hoier 2002). The MMP is 4838 psia. The temperature is 266°F.

Fig. 1.79- Drive mechanism for displacements of seven-component oil by two five-component gases (seven-component systems reported by Uleberg and Hoier (2002). The MMP for the lean gas system is 7007 psia and 4838 psia for the enriched-gas system. Both systems are primarily vaporizing, but the enriched-gas displacements contain a significant condensing fraction. The temperature is 266°F.

Fig. 1.80- Lengths of key tie lines for displacements of twelve-component oil by five-component gases. The calculated MME occurs when lean gas is enriched to 57.2% of the solvent. Crossover tie line 4 controls miscibility and the displacement is CV. The temperature is 182°F.

Fig. 1.81- Drive mechanism for displacements of twelve-component oil by five-component gases. The MME is at an enrichment of 57.2%. The condensing fraction of the displacement increases significantly with enrichment. The temperature is 182°F.

Fig. 1.82- Lengths of key tie lines for displacements of thirteen-component oil by CO₂. Tables 1.6 - 1.8 give the input parameters using the SRKEOS. The MMP occurs when crossover tie line 2 has zero length at a pressure of 2296 psia. The temperature is 157°F.

Fig. 1.83- Lengths of key tie lines for displacements of thirteen-component oil by CO₂. Tables 1.9 - 1.11 give the input parameters using the SRKEOS. The MMP occurs when crossover tie line 2 has zero length at a pressure of 2233 psia. The temperature is 157°F.

Fig. 1.84- Drive mechanism for the displacements of thirteen-component oil by CO₂ (before and after lumping). After lumping, the condensing fraction of the displacement is increased by approximately 0.10. Both systems show that the condensing fraction of the displacement mechanism increases with increasing pressure. The temperature is 157°F.

Fig. 1.85- Simulated oil recovery versus percent condensing for the four-component system considered in Figs. 1.72 - 1.74. The temperature is 200°F. The MME occurs at 40.4% C₃ enrichment. The enrichments used in the simulations are shown next to the points. The MMP's corresponding to each enrichment are 5604 psia (0%), 5447 psia (1%), 4872 psia (5%), 4251 psia (10%), 3738 psia (15%), 3292 psia (20%), 2907 psia (25%), 2572 psia (30%), 2020 psia (35%), and 2000 (40.4%) psia.

Fig. 1.86- Simulated oil recovery versus percent condensing for the twelve component system considered in Figs 1.80 - 1.81. The temperature is 182°F. The MME occurs at 57.2% enrichment. The enrichments used in the simulations are shown next to the points. The MMP's corresponding to each enrichment are 7798 psia (0%), 7274 psia (10%), 6508 psia (20%), 5591 psia (30%), 4676 psia (40%), 4170 psia (50%), and 4000 psia (57.2%).

Fig. 2.1- Pressure drop as a function of flow rates, from Osterloh and Jante (1992).

Fig. 2.2- Osterloh and Jante's type of plot (schematic); identification of important parameters.

Fig. 2.3- Pressure gradient as a function of flow rates (data from Khatib *et al.*, 1988); pressure gradient in psi/ft.

Fig. 2.4- Pressure gradient as a function of flow rates (data from Chang and Grigg, 1999), pressure gradient in psi/ft.

Fig. 2.5- Pressure gradient as a function of flow rates (data from Lee and Heller, 1990), pressure gradient in psi/ft.

Fig. 2.6- Schematic of effect of various factors on contour plot of two foam-flow regimes. The figure shows contours for several values of ∇p for the same porous medium.

Fig. 2.7- Schematic of experimental apparatus for study of two foam-flow regimes.

Fig. 2.8- Pressure gradient (psi/ft) as function of flow rates in experiment Ug5, (see experimental conditions in Table 2.1).

Fig. 2.9- Pressure gradient (psi/ft) as function of flow rates in experiment Ug6.

Fig. 2.10- Pressure gradient (psi/ft) as function of flow rates in experiment Ug7.

Fig. 2.11- Pressure gradient (psi/ft) as function of flow rates in experiment Ug8.

Fig. 2.12- Pressure gradient (psi/ft) as function of flow rates in experiment Ug11.

Fig. 2.13- Pressure gradient (psi/ft) as function of flow rates in experiment Ug12.

Fig. 2.14- Pressure gradient (psi/ft) as function of flow rates in experiment Ug14.

Fig. 2.15- Bubble size in the high-quality regime, $q_w = 0.17 \text{ cm}^3/\text{min}$ in all pictures, $q_g = 0.75 \text{ cm}^3/\text{min}$ @ 600 psi (in picture a), $q_g = 1.2 \text{ cm}^3/\text{min}$ (in picture b), $q_g = 1.93 \text{ cm}^3/\text{min}$ (in picture c). The circular opening shown is about 1 inch in diameter.

Fig. 2.16- Bubble size in the low-quality regime, $q_w = 0.54 \text{ cm}^3/\text{min}$ in all pictures, $q_g = 0.3 \text{ cm}^3/\text{min}$ @ 600 psi (in picture a), $q_g = 0.75 \text{ cm}^3/\text{min}$ (in picture b). The circular opening shown is about 1 inch in diameter. Opaque regions represent the smallest bubbles.

Fig. 2.17- Schematic representation of f_g^* reduction due to reduction in surfactant concentration.

Fig. 2.18- Schematic representation of change in f_g^* due to permeability increase.

Fig. 2.19- Pressure gradient (psi/ft) as function flow rates data from Ug6 and Ug14.

Fig. 2.20- Effect of shear-thinning behavior on f_g^* (schematic).

Fig. 2.21- Effect of shear-thickening behavior on f_g^* (schematic).

Fig. 2.22- Effect of f_g injected on gas diversion, reservoir represented as two layers with different K.

Fig. 2.23- Top: Pressure gradient (psi/ft) as a function of volumetric fluxes of gas (U_g) and water (U_w) in steady-state strong-foam flow through a sandpack: room temperature, no acid or corrosion inhibitor. Horizontal numbers are contour values, and vertical numbers represent the individual data. Bottom: Pressure gradient (psi/ft) as a function of volumetric fluxes of gas (U_g) and water (U_g) in steady-state strong-foam flow through a sandpack: with acid (no corrosion inhibitor) at 220°F.

No oil; $fg^* = 0.85$ (Dow-210-1)

Decane = 22 %; $fg^* = 0.54$ (Dow-oil -1)

FC-77 = 22 %; $fg^* = 0.68$ (Dow-oil-2)

Oil Type	No oil		decane		FC-77	
fg^*	0.85		0.54		0.68	
Regime	L	H	L	H	L	H
u_w or u_g	u_g	u_w	↑	↑↑↑	=	↑↑
Δf_g^*			decrease		decrease	

“L”: low-quality regime; “H”: high-quality regime

*Comparing the effect in the two flow regimes is based on the change from oil free experiment. The symbol represents the shift in u_w (high-quality regime) or u_g (low-quality regime) for a given ∇P contour. “=” no effect; “↑” small effect; “↑↑” moderate effect; “↑↑↑” large effect

Fig. 2.24- Example of the effect of presence of oil and oil type (with injected oil volume fraction = 22%); surfactant = Dowfax 8390; concentration = 1 wt%; permeability = 210 darcy. See Rong (2002) for details.

Fig. 2.25- Contour plot of pressure gradient (psi/ft) based on data from Heller *et al.* (1985); relatively low foam quality.

Fig. 2.26- Contour plot of pressure gradient (psi/ft) based on data from Lee and Heller (1990); relatively high foam quality.

Fig. 2.27- Contour plot of pressure gradient (psi/ft) based on data from Lee and Heller (1990); relatively low foam quality.

Fig. 2.28- Contour plot of pressure gradient (psi/ft) based on data from Yaghoobi and Heller (1994); surfactant: CD1050; relatively high foam quality.

Fig. 2.29- Contour plot of pressure gradient in psi/ft for data from Yaghoobi and Heller (1994); surfactant: CD1040; relatively high foam quality.

Fig. 2.30- Contour plot of pressure gradient (psi/ft) for data from Yaghoobi and Heller (1994); surfactant: Enordet; relatively high foam quality.

Fig. 2.31- Schematic of experimental apparatus for CO₂ foam experiments.

Fig. 2.32- Pressure gradient in psi/ft as a function of superficial velocities; surfactant CD1045, 0.25 wt %; Berea sandstone, 360 md.

Fig. 2.33- Pressure gradient in psi/ft as a function of superficial velocities; surfactant CD1045, 0.8 wt%; Berea sandstone, 366 md.

Fig. 2.34- Laboratory data for foam made with dense CO₂ (2000 psi back-pressure, room temperature) and Shell Neodol 25-9 surfactant in a sandpack, plotted in manner of Alvarez *et al.* (2001). Each dot represents a steady-state datum.

Fig. 2.35- New data for dense CO₂ foam (2000 psi back-pressure, room temperature) and N₂-foam data of de Vries and Wit (1990) plotted in manner dictated by theory of de Vries and Wit. Note that magnitude of pressure drop ΔP in our data is smaller than in de Vries and Wit. See also Fig. 2.36.

Fig. 2.36- New laboratory data for CO₂ foam at 2000 psi back-pressure at room temperature, plotted in the manner of the theory of de Vries and Wit (1990); *cf.* Fig. 2.35. The trends look similar, but the values on the horizontal axis are lower.

Fig. 2.37- Fit to data of Fig. 2.19 using parameters of STARST™ foam model: $f_{mdry} = 0.316$, $f_{mob} = 54985$, $ep_{dry} = 20000$, $f_{mcap} = 0.0000246$, $ep_{cap} = 1.1215$.

Fig. 2.38- Fit to data of Fig. 2.1 using parameters of UT model: $S_w^* = 0.06$, $R_{ref} = 65000$, $\varepsilon = 0.001$, $\sigma = 0.3475$, $u_{gref} = 0.4604$ ft/d.

Fig. 2.39- Effect of changing f_{mdry} to 0.35 on model fit of Fig. 2.37.

Fig. 2.40- Effect of changing fmmob to 33000 on model fit of Fig. 2.37.

Fig. 2.41- Effect of changing epdry to 1000 on model fit of Fig. 2.37.

Fig. 2.42- Comparison between fractional-flow (exact) and simulation solutions for water saturation after 0.2 PV foam injection for a foam displacement using the UT foam model, illustrating fluctuations in water saturation in the gas bank ahead of the foam; from Cheng (2001).

Fig. 2.43- Water saturation in the gas bank as foam enters the second grid block in a foam simulation using the UT foam model. The final two dotted curves listed at the bottom of each column in the legend correspond to the fractional-flow (exact) solution at 0.1 and 0.145 PV.

Fig. 2.44- Time-distance diagram for water saturation S_w and water fractional flow f_w as foam enters the first 5 grid blocks during a foam injection into a 100% brine-saturated core. In this sort of plot computer output is plotted in the same manner as in fractional-flow theory. "I" is the initial condition (100% brine); "J" is the foam bank, and "GB" the gas bank ahead of the foam. Both S_w and f_w should be uniform in the gas bank, but the sudden release of water as foam enters each new grid block sends a wave of high f_w and slightly elevated S_w into the gas bank. From Cheng (2001).

Fig. 2.45- Fractional-flow curves for two different surfactant concentrations based on the Fisher model. Dotted line represents shock front for gas injection into surfactant bank with 0.02% surfactant concentration.

Fig. 2.46- Time-distance diagram for gas injection into large slug of surfactant: fixed- P_c^* model based on data of Persoff *et al.* (1991). Foam collapses completely at the shock front at the leading edge of the gas bank.

Fig. 2.47- Time-distance diagram for gas injection into a large slug of surfactant: 2% progressive-collapse model. There is a narrow region of uniform mobility followed by a spreading wave.

Fig. 2.48- Time-distance diagram for gas injection into a large slug of surfactant: 10% progressive-collapse model.

Fig. 2.49- Time-distance diagrams for gas injection into a large slug of surfactant: Fisher model with 0.02% surfactant concentration.

Fig. 2.50- Time-distance diagrams for gas injection into a large slug of surfactant: Fisher model with 0.5% surfactant concentration.

Fig. 2.51- Total relative mobility after injection of 0.2 PV gas injection into a large slug of surfactant for a SAG process in a 1D cylindrical reservoir; Fisher model with 0.02% surfactant concentration (Fig. 2.49); simulation result.

Fig. 2.52- Water saturation in a 2D cylindrical reservoir using the Fisher model with 0.02% surfactant concentration. a) continuous foam injection ($f_w=0.2$, $q_t=108$ ft³/d, maximum pressure drop=350 psi); b) gas is injected at fixed rate of 2205 ft³/d, maximum pressure drop=350 psi; c) gas is injected at fixed pressure of 2350 psi; d) gas is injected at fixed rate of 315 ft³/d, maximum pressure drop=50 psi; e) gas is injected at fixed pressure of 2050 psi.

Fig. 2.53- Water saturation in a 2D cylindrical reservoir using the Fisher model with 0.5% surfactant concentration. a) continuous foam injection ($f_w=0.2$, $q_t=1$ ft³/d, maximum pressure drop=350 psi); b) gas is injected at fixed rate of 120 ft³/d, maximum pressure drop=350 psi; c) gas is injected at fixed pressure of 2350 psi; d) gas is injected at fixed rate of 17 ft³/d, maximum pressure drop=50 psi; e) gas is injected at fixed pressure of 2050 psi.

Fig. 2.54- Water saturation in a 2D cylindrical reservoir using the 2% progressive-collapse model. a) continuous foam injection ($f_w=0.2$, $q_t=16$ ft³/d, maximum pressure drop=225 psi); b) 0.4 PV gas is injected at fixed rate of 1604 ft³/d, maximum pressure drop=225 psi; c) 0.4 PV gas is injected at fixed pressure of 2225 psi; d) 0.2 PV gas injected at fixed pressure of 2050 psi (different gray scale; saturations are similar to other cases).

Fig. 2.55- Water saturation in a 2D cylindrical reservoir using the 10% progressive-collapse model. a) continuous foam injection ($f_w=0.2$, $q_t=16$ ft³/d, maximum pressure drop=225 psi); b) 0.4 PV gas is injected at fixed rate of 922 ft³/d, maximum pressure drop=225 psi; c) 0.4 PV gas is injected at fixed pressure of 2225 psi; d) 0.2 PV gas injected at fixed pressure of 2050 psi (different gray scale; saturations are similar to other cases).

Fig. 2.56- a) Surfactant concentration and b) water saturation after injection of 0.2 PV gas at 2100 psi into 0.05 PV surfactant solution in 2D cylindrical reservoir using the Fisher model with 0.02% surfactant concentration. On the left-hand plot, a surfactant concentration of 5000 units (medium gray) is sufficient to trigger foam formation.

Fig. 2.57- Surfactant concentration (top) and water saturation (bottom) for SAG processes at fixed injection rate in a 2D cylindrical reservoir using the Fisher model with 0.02% surfactant concentration. a) One SAG cycle: 0.2 PV liquid is injected at 31.4 ft³/d, then 0.4 PV gas is injected at 1260 ft³/d; b) Two SAG cycles: 0.1 PV liquid is injected at 31.4 ft³/d, followed by 0.2 PV gas injected at 1260 ft³/d, followed by a second cycle the same as the first.

Fig. 2.58- Surfactant concentration (top) and water saturation (bottom) for SAG processes at fixed injection rate in a 2D cylindrical reservoir using the Fisher model with 0.02% surfactant concentration. a) One SAG cycle: 0.2 PV liquid is injected at 31.4 ft³/d, then 0.4 PV gas is injected at 2200 psi; b) Two SAG cycles: 0.1 PV liquid is injected at 31.4 ft³/d, followed by 0.2 PV gas injected at 2200 psi, followed by a second cycle the same as the first.

Fig. 2.59- Surfactant concentration (top) and water saturation (bottom) for SAG processes in a 2D cylindrical reservoir with different gas-injection pressures using the Fisher model with 0.02% surfactant concentration. All cases have two SAG cycles with the same liquid-injection strategy, but different injection pressure for gas. In the contour plots of surfactant concentration, the second contour from the right indicates 5000 units, the minimum concentration for foam formation.

Fig. 2.60- Water saturation and surfactant concentration after injection of slugs for SAG processes in a 2D cylindrical reservoir. Gas is initially present in the reservoir, with 80% initial water saturation. 0.1 PV surfactant is injected at 31.4 ft³/d, followed by 0.2 PV gas injected at 2050 psi. The second cycle is same as the first.

Fig. 2.61- Surfactant concentration (top) and water saturation (bottom) for SAG process in a 2D cylindrical reservoir using the Fisher model with 0.02% surfactant concentration. 0.1 PV liquid is injected at 31.4 ft³/d, followed by 0.2 PV gas injected at 2010 psi. Then, 0.1 PV liquid is injected at 31.4 ft³/d, followed by 0.2 PV gas injected at 2050 psi.

Fig. 2.62- Water saturation after 0.01 PV gas injection into a large surfactant slug in a 2D cylindrical reservoir based on fixed- P_c^* model with 50*10, 200*10 and 500*30 grid blocks. Gas is injected at 2050 psi.

Fig. 2.63- Cumulative-injection profiles for the cases in Fig. 2.62.

Fig. 2.64- Schematic of the idealized model for SAG displacements.

Fig. 2.65- Universal dimensionless progress of gas injection in the idealized model for fixed-injection-pressure SAG displacement.

Fig. 2.66- Water saturation after 0.2 PV, 0.4 PV and 0.6 PV gas injection into rectangular reservoir using Fisher model with 0.5% surfactant concentration in simulator. Gas is injected at 50 psi above reservoir pressure.

Fig. 2.67- Displacement front position after 0.2 PV, 0.4 PV and 0.6 PV of gas injection into rectangular reservoir of Fig. 2.66 using the idealized model. Gas is injected at 50 psi above reservoir pressure. Other parameters are listed in Table 2.5.

Fig. 2.68- Displacement-front positions during gas injection into a large surfactant slug in rectangular reservoir using the idealized model. a) Gas is injected at 5 ft³/d and the maximum pressure is 16.6 psi above reservoir pressure. b) Gas is injected at fixed pressure 16.6 psi above reservoir pressure.

Fig. 2.69- Displacement front positions during gas injection into a large surfactant slug in cylindrical reservoir using the idealized model. a) Gas is injected at 3.5 ft³/d and the maximum pressure is 16.6 psi above reservoir pressure. b) Gas is injected at fixed pressure 16.6 psi above reservoir pressure.

Fig. 2.70- Schematic plot of capillary-pressure difference across two layers driving crossflow. Capillary-pressure function from Kovscek *et al.* (1995).

Fig. 2.71- Schematic of viscous crossflow.

Fig. 2.72- Schematic of reservoir with adjacent layers (A1, A2) differing moderately in permeability, with distant layer (D) differing greatly in permeability.

Fig. 2.73- Example of three zones in reservoir predicted by Stone and Jenkins model for foam injection using parameters based on data from Persoff *et al.* (1991).

Fig. 2.74- Example of gravity segregation in finite-difference simulation of continuous foam injection into a rectangular reservoir, from Shan (2001). Gray scale indicates water saturation: white = override zone, gray = mixed (foam) zone, black = underdrive zone. In this case complete gravity segregation occurs at $L_g \approx 0.5$, in agreement with the model of Stone and Jenkins. The foam model used here, and the Stone model prediction, is not identical to that in Fig. 2.73.

Fig. 2.75- Schematic of the assumption made by Stone (1982) that a moving vertical fluid element within a reservoir maps the segregation problem in horizontal flow on to a segregation problem without horizontal flow.

Fig. 2.76- Schematic of function $F(S)$ that governs gravity segregation without horizontal flow (Siddiqui and Lake, 1992). Parameter values are those for N_2 and water from Persoff *et al.* (1991). If the reservoir is initially at $S = 0.8$ (water saturation $S_w = 0.68$), there is a shock front moving from the bottom of the reservoir, which has saturation $S = 1$ ($S_w = .8$) (dotted line), but a spreading wave moving down from the top at $S = 0$ ($S_w = 0.2$).

Fig. 2.77- Pore-geometrical parameters in model for effective viscosity of foam.

Fig. 2.78- Asymmetric jump as lamella traverses pore.

Fig. 2.79- Symmetric jump as lamella traverses pore at higher velocity.

Fig. 2.80- Transitional behavior.

Fig. 2.81- Relation of dimensionless average pressure drop $(\Delta p_D)^{ave}$ to dimensionless velocity V_D for discontinuous transition and the continuous transition. a) Discontinuous transition from asymmetric to symmetric jump. b) Transitional behavior (same pore geometry except for larger ϵ (Fig. 2.77)).

Fig. 2.82- Split of $(\Delta p_D)^{ave}$ into quasi-static and viscous portions as postulated by Falls *et al.* (1989). Fit of viscous portion to (1/3)-power law at low velocity and low drag.