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, several results related to subtask 1.1 are given. In this period, most of our research centered on how to estimate the dispersivity at the field scale. Simulation studies (Solano *et al.* 2001) show that oil recovery for enriched gas drives depends on the amount of dispersion in reservoir media. But the true value of dispersion, expressed as dispersivity, at the field scale, is unknown. This research investigates 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 the dispersivity that is unaffected by fluid flow direction. Layering in permeable media tends to increase the observed dispersivity in well-to-well tracer tests, also known as transmission dispersivity, but leaves the echo dispersivity unaffected. A collection of SWTT data is analyzed to estimate echo dispersivity at the SWTT scale. The estimated echo dispersivities closely match a published trend with length scale 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.

A third type of dispersive mixing is local dispersivity, or the mixing observed at a point as tracer flows past it. Numerical simulation results show that the local dispersivity is always less than the transmission dispersivity and greater than the echo dispersivity limits. 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.

Regarding Task 2, two results are described: 1) An experimental study of N_2 foam finds the two steady-state foam-flow regimes at elevated temperature and with acid, adding evidence that the two regimes occur widely, if not universally, in foam in porous media. 2) A simulation finds that the optimal injection strategy for overcoming gravity override in homogeneous reservoirs is injection of large alternating slugs of surfactant and gas at fixed, maximum attainable injection rates. A simple model for the process explains why this strategy works so well. Before conducting simulations of SAG displacements, however, it is important to analyze the given foam model using fractional-flow theory. Fractional-flow theory predicts that some foam processes will give foam collapse immediately behind the gas front. In simulations, numerical dispersion leads to a false impression of good sweep efficiency. In this case simply grid refinement may not warn of the inaccuracy of the simulation.

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OBJECTIVES

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.

RESULTS AND DISCUSSION

TASK 1: REDUCE MMP WITH GAS ENRICHMENT

This last period, most of our research focused on subtask 1.1 to estimate the level of dispersivity at the field scale. As was shown by Solano *et al.* 2001, the oil recovery for enriched-gas drives is highly sensitive to the level of dispersion. Thus, it is important to determine the level of mixing found in a reservoir. We use data from single-well tracer tests (SWTT) for this purpose. The SWTT is performed by injecting a bank of a mixture of reactive and non-reactive tracer 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 alone. 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 any significant flow from external sources absent, the spreading of non-reactive tracer concentration measured at the injection source represents the echo dispersion.

Layered permeable media simulations. All numerical simulations in this paper assume the following:

- 1) 1-D radial (or Cartesian) and homogenous system (single layer), constant porosity;
- 2) Single-phase flow (aqueous phase flow);
- 3) Incompressible fluid and rock;
- 4) Non-reacting, non-partitioning aqueous-phase tracer;
- 5) Constant-potential external boundary condition; and,
- 6) Constant-rate injection/production at the wellbore.

We used the UTCHEM reservoir simulator developed at The University of Texas at Austin to generate a transmission history by performing an injection and production on a two-dimensional, layered permeable medium with permeabilities ranging from 200 to 1400 md. Each layer was assumed to be homogenous with a local dispersivity equal to 0.46 m. Figure 1.1 shows the history match of the transmission history data, which gives an effective dispersion of 2.47 m.

Figure 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. We performed a history match of the concentrations, now measured at the former injector.

Both history matches were single-variable regressions. Note that, as we discussed above, the transmission dispersivity is substantially greater than the echo value.

UTCHEM requires input values for longitudinal and transverse dispersivity. These 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. In all simulation cases, the input transverse dispersivity was zero; the input dispersivity was the quantity adjusted in the history matching. Note that the echo and input dispersivities are equal in Figs. 1.1 and 1.2. See Mahadevan (2001) for more details of the simulations.

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. But all SWTT's used a material-balance tracer that is not affected by the residual oil saturation. We use the material-balance tracer histories from the 59 tests to analyze echo dispersivity.

From 59 published SWTT histories, we ignored 24 for either lack of adequate information about injection/production times or for obviously bad concentration data. This leaves 35 SWTT's to be analyzed.

We fit the 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 for simulating fluid flow in permeable media.

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. 1.3). The median of echo dispersivities is 0.46 m (Fig. 1.4). The plot shows that there is significant variance of echo dispersivities at the same distance traveled.

The estimated echo dispersivities are compared with the measured field dispersivities (Fig. 1.5). If the permeable media were layered, there should be a significant difference in the values of echo and field dispersivities from Arya *et al.* (1998). The results in Fig. 1.5 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 distance to be investigated.

Dispersion induced by stochastic permeability fields. Stochastic permeability fields are permeability fields whose properties have been assigned according to statistical functions that specify the mean, variability and degree of inter-relationship (autocorrelation) of the property. A stochastic permeability field can be generated by gridding the reservoir medium into several grid blocks, which can be assigned permeabilities according to the autocorrelation function of permeability and the heterogeneity.

Permeability fields were developed for a two-dimensional reservoir medium 312 m long and 6 m thick in a Cartesian coordinate system. The system was divided into 1024 blocks in the horizontal direction (length) and 8 grid blocks in the vertical direction

(thickness), with 8192 grid blocks. The permeability assignments were made according to the stable semi-variogram using a fast Fourier transform program with horizontal permeability correlation length of 804 m in the horizontal direction, uncorrelated in the vertical direction, coefficient of variation of horizontal permeability equal to 0.145, and an exponent of one.

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 very large vertical permeability to simulate vertical equilibrium with respect to the pressure distribution. Tracer concentration distributions for individual realizations of the first two cases are in Figs. 1.6 and 1.7.

Case 1 - The vertical permeability is equal to zero in this case. The tracer concentration profiles are shown in Fig. 1.6. The amount of mixing is indicated by the different shades of gray on the contour plot. The plots show layered behavior and little mixing.

Case 2 - The vertical permeability is equal to the horizontal permeability in this case. The tracer concentration contour plots are shown in Fig. 1.7. The plots show that there is more mixing when the vertical permeability is greater than zero.

Both echo and transmission dispersivities are estimated for several distances of travel in the stochastic realizations. They are calculated for a given realization and plotted against the distance traveled in logarithmic coordinates. The vertical permeability is varied from zero to 10000 md (an artificially large value chosen to create vertical equilibrium with respect to the fluid pressure) and the simulations were conducted to estimate the echo, transmission and local dispersivities with injected fluid travel distance.

To try and apply these results to the SWTT data, we introduce the *local* dispersivity. The local dispersivity is a measure of the dispersion that exists at a point as fluid flows by the point (concentration histories). We estimate the local dispersivity by fitting an analytical result (given in Mahadevan (2001)) to concentration histories at every point in the simulation.

The results from simulation studies on stochastic permeable media are in Figure 1.8. This figure shows the variation of estimated dispersivities (transmission, echo and local) with travel distance (for one realization of the permeability field) with varying vertical permeability. Three different cases are considered where vertical permeability equals 0 md, vertical permeability equal to horizontal permeability and finally vertical permeability equal to 10000 md. 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 the transmission dispersivity shows a trend similar to the field dispersivity data from Arya *et al.* (2001) with a unit slope and the echo dispersivity is unaffected by distance traveled. The local dispersivity also follows the same 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 raised to $k_v = k_h$, the echo dispersivity trend shows a slope greater than zero and the transmission dispersivity trend slightly less than unit slope. Nearly all the local dispersivity generally fall 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.

When the vertical permeability is increased to 10000 md the echo and transmission dispersivities show a trend that is similar to the trend for the case with $k_v = k_h$. 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. 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. Since there are only three cases shown, it is possible that the case (realistic case from field) with small, but non-zero, vertical permeability would have the local, echo and transmission dispersivities equal.

These stochastic results and the results from the single-well tracer tests suggest that dispersivity values may be in the region where oil recoveries are highly sensitive to dispersion (Solano et al. 2001). If this is the case, it will be difficult to make accurate numerical simulations as the numerical dispersion may dominate over the true dispersion.

TASK 2: INCREASE SWEEP EFFICIENCY WITH FOAM

A number of studies of foams made with N_2 gas find that at steady state foam exists in two regimes depending on injected gas volume fraction, i.e. foam quality f_g (Alvarez *et al.*, 2001; Rong, 2002). An example is shown in Fig. 2.1. In the high-quality regime (upper-left portion of figure), pressure gradient is nearly independent of gas injection rate. In this regime foam properties are controlled by bubble coalescence and capillary pressure, and bubble sizes change drastically as a function of gas-injection rate. Foam mobility can be shear-thinning, Newtonian or shear-thickening at fixed foam quality in this regime. In the low-quality regime (lower-right portion of figure), pressure gradient is nearly independent of liquid injection rate. Theory suggests that the high-quality regime should be more sensitive to factors that affect foam stability and to permeability than the low-quality regime, and experiments bear this out in part (Rong, 2002).

This pattern of two strong-foam regimes is observed with a variety of surfactant formulations and gases, in porous media varying from consolidated cores to sandpacks and beadpacks, and over a wide range of injection rates (Alvarez *et al.*, 2001; Rong, 2002). The difference between these two regimes is important, because their rheology and ability to divert flow between layers differing in permeability is very different. But it was not clear if the two regimes apply universally to foams. In particular, studies at elevated temperature are rare (Osterloh and Jante, 1992).

A study primarily of foam for acid diversion in well stimulation provides additional evidence that the two flow regimes apply widely, if not universally, to strong foams at steady state. In this study a foaming surfactant formulated for acid well stimulation was tested at room temperature, and the same formulation tested at 220°F with acid. The results are shown in Figs. 2.1 and 2.2. In Fig. 2.1, at fixed foam quality, the data suggest a power-law exponent of approx. 0.5 in the high-quality regime and 0.3 in the low-quality regime: i.e., shear-thinning behavior in both regimes. Similarly, in Fig. 2.2, at fixed foam quality, the data suggest a power-law exponent of approx. 0.5 in the high-quality regime and 0.35 in the low-quality regime: i.e., shear-thinning behavior in both regimes. Foam is weaker at the higher temperature, as expected. Both figures are in

agreement with earlier studies of the two flow regimes (Alvarez *et al.*, 2001; Rong, 2002).

Miscible-gas foam field trials have employed a variety of injection strategies, with mixed results. Using simulation, we have compared foam-injection strategies in homogeneous reservoirs with a variety of foam models.

The optimal injection strategy for overcoming gravity override with foam in a homogeneous reservoir is alternating injection of separate, large slugs of gas and liquid (SAG injection) at fixed, maximum-allowable injection pressure. 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. Fig. 1 shows one such comparison. Fig. 2.1(a) shows foam injection at fixed injection rate. This process has reached steady state, and foam will advance no further no matter how long it is injected (Shi and Rossen, 1998). Figs. 2.1(a) and (b) compare fixed-rate injection with a maximum pressure rise of 350 psi with fixed-injection-pressure injection with that same rise in injection-well pressure. Figs. 2.1(c) and (d) are a similar comparison for a 50-psi injection-pressure rise. In each case, a SAG process with a large slug of surfactant followed by gas injection at fixed injection pressure gives the best sweep efficiency. This same result obtains with a variety of foam simulation models.

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. A process with one large SAG cycle gives somewhat better sweep efficiency than that with more SAG cycles.

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. Fig. 2.2 shows an example.

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. Liquid should likewise be injected at maximum allowable injection pressure; this puts liquid most rapidly into the reservoir and minimizes segregation during liquid injection.

Remarkably, differences between foam models (corresponding, e.g., to 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.

If fractional-flow theory indicates that foam both forms and collapses within the shock front in a SAG displacement (Zhou and Rossen, 1995), the preceding paragraph 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 apparent sweep efficiency may not degrade much upon grid refinement. The only obvious symptom of the artifact is that injectivity increases without bound upon increasing grid refinement, as illustrated in Fig. 2.3

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

and the dried-out region near the injection well. Fig. 2.4 shows the assumptions of this simple model. The model leads to a single family of curves to describe all SAG processes in all cylindrical homogeneous reservoirs. Fig. 2.5 compares the model predictions to simulation for one case.

This model implies that in the ideal SAG process (represented in the model assumptions) 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.

The model further implies that 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.

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 good sweep efficiency in simulation (Fig. 2.3). 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 simulations with various foam models.

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Figure 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.

Figure 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.

Figure 1.3. Echo dispersivities estimated from SWTT data plotted against the distance traveled (twice the distance of penetration) in the reservoir.

Figure 1.4. 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.

Figure 1.5. The comparison between field measured dispersivity and echo dispersivity values for field-scale permeable media. Data from Arya et al. (1998).

Figure 1.6. Concentration contour plots for continuous tracer injection into a stochastic permeable medium. The medium is 30 ft long and 20 ft thick. Each grid block size is 1 ft by 1 ft. 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.

Figure 1.7. Concentration contour plots for continuous tracer injection into a stochastic permeable medium. The medium is 30 ft long and 20 ft thick. Each grid block 1 ft by 1 ft. 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. 1.6. The injection is 1.1 pore volumes.

Figure 1.8. Variation of estimated dispersivity with distance traveled in the stochastic permeable medium (single realization), with increasing values of kV . The data points are the local dispersivity values estimated at all the grid blocks in the reservoir. The upper solid lines are transmission dispersivities; the lower lines are echo dispersivities.

Fig. 2.1. 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 at room temperature: 0.5 vol% solution of commercial surfactant formulated for foam-acid diversion. Horizontal numbers are values of pressure gradient along contours. Vertical numbers are values at the individual steady-state measurements.

Fig. 2.2. 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: same surfactant as in Fig. 2.1, with acid at 220°F.

Fig. 2.1. Water saturation in a 2D cylindrical reservoir using the foam model of Fisher *et al.* (1990) (*cf.* Shi, 1996) with 0.02% surfactant concentration. a) continuous foam injection ($f_w=0.2$, total injection rate = 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. Production well maintained at 2000 psi.

a) 0.1 PV (1st liquid slug)

b) 0.3 PV (end of first cycle)

c) 0.4 PV (2nd liquid slug)

d) 0.45 PV (during second gas slug)

e) 0.6 PV (end of second cycle)

Fig. 2.2. 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. This injection pressure is insufficient for good sweep efficiency, and gas migrates to the top of the reservoir. Then, 0.1 PV liquid is injected at 31.4 ft³/d, followed by 0.2 PV gas injected at 2050 psi. With the higher injection pressure, gas sweeps the reservoir more evenly, in spite of the poor sweep of gas and gravity slumping during the first cycle. Production well maintained at 2000 psi.

Fig. 2.3 Top: Water saturation after 0.01 PV gas injection into a large surfactant slug in a 2D cylindrical reservoir based on the fixed- P_c^* model (Zhou and Rossen, 1995; Rossen *et al.*, 1999; Shi, 1996) with 50*10, 200*10 and 500*30 grid blocks. Gas is injected at 2050 psi. Fractional-flow theory predicts that this foam would collapse completely during gas injection in a SAG process. Sweep efficiency does not appear to decrease with increasing grid refinement, however. The symptom of numerical inaccuracy in this case is the fact that injection rate *does* depend on grid refinement, without any apparent limit (bottom figure). In other words, if one trusts only to plots of sweep efficiency, even grid refinement may not warn the user of the numerical inaccuracy of the simulations.

Fig. 2.4. Schematic of the idealized model for SAG displacements.

Fig. 2.5. Top: 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. Bottom: Displacement front position after 0.2 PV, 0.4 PV and 0.6 PV of gas injection into the same rectangular reservoir using the idealized model. Gas is injected at 50 psi above reservoir pressure.