Measurement of aperture distribution, capillary pressure, relative permeability, and in situ saturation in a rock fracture using computed tomography scanning

Stephanie P. Bertels and David A. DiCarlo
Department of Petroleum Engineering, Stanford University, Stanford, California

Martin J. Blunt
Centre for Petroleum Studies, Imperial College, London, England, United Kingdom

Abstract. We develop an experimental technique that uses computed tomography (CT) scanning to provide high-resolution measurements of aperture distribution and in situ saturation along with capillary pressure and relative permeability for the same rough-walled fracture. We apply this technique to an induced fracture in a cylindrical basalt core undergoing water drainage. We find that the sum of the water and gas relative permeabilities is much <1 at intermediate saturations and the water relative permeability shows a sharp change over a narrow range of average water saturation. In situ saturation maps show channeling of gas and significant retention of the wetting phase (water). The capillary pressure initially increased and then decreased with decreasing water saturation. Although this type of capillary behavior is atypical for unsaturated flows, we find that the sizes of the gas-filled apertures are consistent with the measured capillary pressure.

1. Introduction

Fluid flow in geologic media is often dominated by the highly permeable pathways provided by rock fractures and joints [Bear et al., 1993]. There are several circumstances when multiple fluid phases may flow simultaneously through fractured soil and rock. Examples include oil and water flows in petroleum reservoirs during water flooding, vapor/liquid transport in geothermal reservoirs, the flow of nonaqueous phase liquids, water and gas in contaminated soil, and gas/water flows in underground storage sites for nuclear wastes. The present theory of multiphase flow in fractures has been taken from work on granular porous media and, in many cases, remains unsubstantiated by experimental work. To improve our understanding of the controlling mechanisms and key parameters for flow and transport in fractures, experimental studies of multiphase flow in single fractures are needed. In particular, the determination of aperture distribution, capillary pressure, relative permeability, and in situ saturation for the same fracture would provide insight into the mechanics of two-phase flow in fractures as well as providing a comprehensive data set for comparison with theoretical and numerical models.

1.1. Fracture Aperture

Early models of fluid flow were based on the assumption that fractures could be adequately represented as flat parallel plates with a constant aperture equal to the mean aperture of the rough-walled fracture [de Marsily, 1986]. However, theoretical and experimental studies have shown that the distribution and size of apertures within a fracture impact fluid flow [Brown, 1987; Tsang and Witherspoon, 1981].

Several different experimental techniques have been used to characterize the void geometry or aperture distribution of fractures. Brown and Scholz [1985] and Gentier [1986] both used linear profilometry to scan the open surfaces of a fracture. The two halves were scanned and then matched using reference points. The aperture distribution was computed by knowing the distance between the two halves. Pyrak-Nolte et al. [1987] used Wood's metal to make casts of natural fractures under different stress conditions and demonstrated that contact area and void space change with normal stress. Gentier et al. [1989] studied two-dimensional images of the fracture surface made by the injection of translucent epoxy resins. When the resin cooled, the fractures were taken apart, and a translucent resin cast of the pore space remained. Light attenuation was used to estimate the thickness of resin and thus fracture aperture. Gale [1987] injected a room temperature curing epoxy into a fracture under negative pressure. After the epoxy hardened, the fracture plane was sectioned. The resin-filled fracture was polished on a surface grinder and photographed and digitized to provide a direct measurement of aperture distribution, which was found to be approximately lognormal.

All the methods above are destructive and hence make it difficult to study the effects of fluid flow and aperture distribution on the same fracture, unless all the displacement experiments are performed first. Moreover, the apertures for different stress conditions cannot be measured on a single sample. It is thus desirable to have a method of determining fracture aperture distribution that is nondestructive and does not require the separation of the two fracture faces. Kumar et al. [1997] used nuclear magnetic resonance imaging (NMRI) to measure fracture apertures in induced fractures in a limestone and granite core. They found that the aperture distribution for the limestone sample had an approximately normal distribu-
tion. Dijk and Berkowitz [1999] also used NMRI to measure aperture distribution in an induced limestone fracture with a resolution of 180 μm. Detwiler et al. [1999] studied the accuracy and precision of measuring apertures in analogue fractures made from two sheets of textured plate glass using light transmission and obtained an estimated root-mean-square error of 2 μm.

Johns et al. [1993] investigated the use of X-ray computed tomography (CT) as a tool for detecting and characterizing the variability in aperture thickness of natural fractures in crystalline rock cores. The authors developed a correlation between the observed CT response and the thickness of simulated fractures of known dimension. This correlation was applied to a sequence of CT scans along the length of a granite core to obtain measurements of the fracture aperture field with a precision (1 standard deviation) of 50 μm. Keller et al. [1999] used the method of Johns et al. [1993] with a new generation of CT scanner to determine fracture aperture distribution for granite and sandstone cores. Keller et al. found an approximately lognormal aperture distribution and reported apertures down to 35 μm but reported no estimate of the accuracy.

1.2. Measurement of Flow Properties

When multiple fluid phases are present in a porous medium or rock fracture, the presence of one phase will interfere with the flow of all the other phases. Relative permeability quantifies the decrease in permeability due to phase interference and depends on the saturation of each phase. It is generally accepted that when the fluids are immiscible, Darcy’s law can be applied to each phase individually [Dullien, 1992], giving

\[ q_i = -k_i \frac{k_{ri}}{\mu_i} (\nabla P_i - \rho_i g), \]

where \( q_i \) is the Darcy flux in phase \( i \), \( k \) is the intrinsic permeability, \( k_{ri} \) is the relative permeability, \( \mu_i \) is the viscosity, \( P_i \) is the fluid pressure, \( \rho_i \) is the density, and \( g \) is acceleration due to gravity.

In many cases, the fracture relative permeability has been modeled as being equal to phase saturation, \( k_{ri} = S_i \). This assumption stemmed from Romm’s [1966] study of two-phase flow of water and kerosene in artificial parallel-plate fractures. However, his experiment was designed to obtain a large degree of phase separation by lining the glass plates with waxed paper and adding waxed paper strips through the length of the plates as spacers. Thus it is not surprising that Romm [1966] measured linear relative permeabilities, but this is not necessarily representative of two-phase relative permeabilities in real fractures with a variable aperture distribution.

Merrill [1975] conducted steady state relative permeability experiments similar to Romm’s but without the waxed paper strips on glass plates and sandstone blocks. Once the pressure drop was recorded, the experiment was stopped, the nonwetting phase was displaced, and the volume was recorded to determine saturation. Merrill [1975] found that wetting phase saturations clustered around a value of ~0.72 and 0.62 for the glass plates and sandstone fracture, respectively, for almost the whole range of flow rates and fractional flows studied.

Both Pieters and Graves [1994] and Nicholl and Glass [1994] also observed behavior that deviated from straight-line relative permeabilities in their experiments. Pieters and Graves [1994] performed displacement experiments to obtain relative permeability ratio and determined saturations from videotaped im-

ages. The images showed channeling and a large amount of fingering prior to breakthrough. Nicholl and Glass [1994] measured wetting phase relative permeability on analogue fractures made from two sheets of textured plate glass and found that relative permeability was proportional to the saturation of the wetting phase to the third power. Both aperture and saturation measurements were calculated from light attenuation.

Persoff and Preuss [1995] measured relative permeability for natural rock fractures and transparent replicas of natural fractures using gas and water. Relative permeability was plotted against mass flow rate ratio. The experiment showed that significant phase interference occurred and that multiphase flow occurred even at the highest and lowest mass flow rate ratios. Relative permeabilities in this experiment did not fit a linear or Corey-type (power law) model.

Reitsma and Kueper [1994] developed a laboratory technique to measure capillary pressure for an induced, rough-walled rock fracture under different states of normal stress. The method was applied to a single, rough-walled fracture in limestone using oil and water as the nonwetting and wetting phases, respectively. The fracture was initially saturated with the wetting phase. One face of the fracture was connected through a porous barrier to a burette that was used to control the pressure of the wetting phase while the pressure of the nonwetting phase was held constant. Capillary pressure was plotted against the volume of wetting phase imbibed or displaced by nonwetting phase.

Tokunaga and Wan [1997] measured flow in layers of wetting fluid on a single fracture surface of a Bishop Tuff. A probe tensiometer [Tokunaga, 1997] measured the matric potential of the fluid flowing on the rock surface. It was shown that flow at the rate of 2–40 m/d occurred through connected layers of wetting fluid that were between 2 and 70 μm thick. This work indicates that flow of the wetting phase through fracture roughness can be significant, even if the center of the fracture is gas-filled.

Theoretically, percolation models suggest an opposite extreme to linear relative permeabilities. The percolation-like models of both Pruess and Tsang [1990] and Rossen and Kumar [1992] showed that in a two-dimensional lattice, two randomly distributed phases can never both be connected. This means that one of the relative permeabilities is always zero and there is no multiphase flow unless the fracture aperture distribution is correlated or gravitational segregation occurs. Flow of wetting layers would also allow multiphase flow but at very low relative permeabilities of the wetting phase.

1.3. Objective

To recap, previous experimental studies have shown a huge variability in multiphase fracture properties. They range from no phase interference [Romm, 1966] to considerable phase interference where multiphase flow does occur over a range of flow rate ratios [Merrill, 1975; Pieters and Graves, 1994; Nicholl and Glass, 1994; Persoff and Preuss, 1995] to some theoretical models which suggest that there is essentially no multiphase flow in uncorrelated media [Pruess and Tsang, 1990; Rossen and Kumar, 1992]. The question is, What is the typical multiphase behavior in real fractured systems? We wish to study displacements at low flow rates, typical of natural circumstances, for a fracture with a representatively variable fracture aperture. We will relate macroscopic flow parameters to in situ measurements of saturation and identify the typical features of fracture relative permeability curves that should be captured.
by modeling studies. A key feature missing from previous experimental work has been a reliable measurement of in situ saturation against which capillary pressure and relative permeability may be plotted. In this work, we use CT scanning to provide aperture distribution and in situ saturation measurements. Combined with flow measurements, we can relate saturation pattern changes to changes in relative permeabilities and capillary pressure.

2. Experimental Design and Procedures

2.1. Sample Preparation

In order to measure the effects due to fracture flow independent of the matrix we used a core with an impermeable matrix. Keller [1997] experienced variability in CT response due to changes in the mineralogy of the impermeable granite cores he studied. As a result, basalt was chosen for this work because of its impermeability ($k < 10^{-24}$ m$^2$) and relatively homogeneous mineralogy. Over 1.524 m of Columbia River basalt core, provided by Pacific Northwest National Laboratory, was screened in the CT scanner to find sections of core that were homogeneous and suitable for use in the experiment.

A fracture was induced because of the difficulty associated with coring a single fracture located centrally down the length of the core. Two thin steel bars were positioned in small notches along the length of the core on either side. A load was applied to the bars using a uniaxial compression device in order to induce a single fracture. The technique produced fractures that were well aligned centrally and parallel to the core. The samples were banded at the time of fracture initiation, and the sample selected for use in the experiment was sealed in place along the sides using a liquid steel resin epoxy. This prevented fluid flow from short circuiting along the sides and ensured that fracture aperture remained constant during the experiments. The core chosen for use in the experiment was 4.5 cm in diameter and 11.8 cm in length. It should be noted that the method of inducement resulted in edge damage which produced large aperture regions near the sides of the fracture. Although these features may not be that common in single-plane natural fractures, the intersection of two or more fractures can create connected larger aperture channels in naturally fractured systems. The use of induced or fabricated fracture replicas in the context of fracture flow experiments both serve to mimic the essential elements of a natural fracture while addressing the limitations of experimental design. The work presented in this paper should be viewed in this context.

2.2. Flow Cell Design

In this experiment, the two phases chosen were nitrogen and water. In order to measure the inlet and exit pressures of both phases and to prevent capillary end effects the two fluids must enter and exit the core separately. This was achieved by using end caps similar to those used by Persoff and Pruess [1995] with alternating gas and water entry paths. Figure 1 shows an exploded view of one of the end caps. The gas entered the fracture through six channels in an aluminum mold, which was epoxided flush with the end of the fractured core. The water entered the fracture through a porous mortar, which filled the spaces between the channels and intimately contacted the fracture end. Space was left between the end plate and the mortar so that the water would cover the entire surface of the mortar in order to assure even distribution of the wetting phase. In order to bypass the pressure drop across the mortar, pressure was measured through a separate mortar-filled tensiometer directly in contact with the fracture. In addition to segregating the flow paths...
the end cap prevents a discontinuity in capillary pressure, which would result in capillary end effects.

The mortar was composed of a mixture of sand, cement, and water in a ratio of 5:1:0.5 by weight. The sand was sifted to fall between a 48 and 60 mesh. For a capillary barrier to work effectively the entry pressure of the barrier must be greater than the greatest capillary pressure achieved during a capillary pressure experiment. This will prevent gas from breaching the barrier. The entry pressure of the mortar was measured to be 31 cm of water, and the permeability was measured to be $1.4 \times 10^{-12}$ m$^2$. It was anticipated that this would be sufficient for the expected range of capillary pressures. Before assembling the end caps, all no-flow edges and the circumference of the aluminum core holder were sealed with epoxy to prevent any short-circuiting of the flow.

The flow cell was designed to measure the inlet and outlet capillary pressures as well as the pressure difference in each phase using four differential pressure transducers. Two of the transducers measured inlet and outlet capillary pressures, and the remaining two measured the difference in phase pressure from inlet to outlet in each phase. In addition, four manometers, reading phase pressure directly at both inlet and outlet, provided a means to calibrate the transducers and were used to obtain accurate pressure readings at each steady state interval. The measurements of pressure drop in each phase and inlet and outlet capillary pressures obtained from the transducers were plotted every 5 s in order to determine when the system had reached steady state. After steady state had been reached for a period of at least 6 hours, the individual phase pressures at inlet and outlet were recorded directly from the manometers, which had a resolution of 0.5 mm of water. Gas pressure taps were included in the gas line immediately adjacent to the fracture flow cell. Water pressure measurements were read from the tensiometers located adjacent to the fracture ends in the capillary end caps.

In an effort to minimize capillary end effects the outlet capillary pressure was adjusted to be equal to the inlet capillary pressure in order to have capillary pressure equal across the fracture plane. Capillary pressure control was achieved at the outlet by allowing the gas to exit to barometric pressure and adjusting the liquid pressure by raising and lowering the height of the liquid outlet.

Water was injected by means of two Isco 500D syringe pumps with a Series D pump controller acting in continuous flow mode (0.3% full scale flow rate accuracy). A 500 psi back pressure device was used to stabilize the flow and to minimize the effect of the 5 psi fluctuations which occur when the controller switches from one pump to the other. Gas was delivered using a Brooks 5850E mass flow controller with a capacity of 200 mL/min and an accuracy of 1% full scale at standard temperature and pressure.

### 2.3. Measurement of Fracture Aperture Distribution

We use CT scanning to obtain the aperture distribution and saturation distributions during the flow experiment. CT scanning has been used by many researchers [Wellington and Vinegar, 1987; Warner et al., 1989; Lenormand et al., 1990; Peters and Afzal, 1992] to construct a three-dimensional image of fluids in porous media from a series of two-dimensional slices through the system. For a discussion of the theory of CT scanning, see Kak and Slaney [1988]. In this study, a Picker Synergyview 1200X fourth generation scanner was used to image the rock and fluids. Care must be taken in the design of any apparatus to be imaged in the CT scanner. The geometry of the scanner is cylindrical, and the X-ray source rotates around the object being scanned in a circular path. Thus the reconstruction process is better able to resolve cylindrical objects. Objects that contain sharp corners are subject to artifacts in the images that radiate from the corners into the object. For this reason, a cylindrical core was chosen. Additionally, it is important to avoid high-density contrasts and high-density materials. When a polychromatic X-ray beam passes through an object, photons of lower energy will be attenuated more than higher energy photons. This phenomenon is called beam hardening [Kak and Slaney, 1988] and results in reconstructed CT values which are elevated at the edges of the object being scanned. In order to limit the effects of beam hardening we encased the core in an aluminum sleeve which moved the largest effects of the hardening away from the core. In choosing the settings for scanning shown in Table 1 we attempted to maximize our image quality while minimizing the time required between scans. A low current was chosen to avoid over heating the X-ray tube while a high-energy beam resulted in better penetration. For this experiment, the current was set at 80 mA while the tube voltage was set to 140 kV, and the scan time was 3 s.

The fractured core was attached to a motorized stage that could move the core longitudinally (y direction) through the scanner. The fracture plane within the core was aligned horizontally (in the x-y plane). Each scan of the core produced a CT image in the x-z plane that consisted of a matrix of $512 \times 512$ pixels (pixel size of $0.31 \times 0.31$ mm) with attenuation values in Hounsfield units. Hounsfield units are X-ray attenuation coefficients scaled linearly such that $CT(gas) = -1000$, $CT(water) = 0$ [Hounsfield, 1973]. Scans of beam thickness of 3 mm were taken every 2 mm along the core (y direction), producing 59 images for our core of 11.8 cm. Allowing for reconstruction and cooling of the tube, a complete set of 59 scans can be completed in ~1 hour.

Figure 2 shows one of the 59 scans through the dry core. In this experiment, many apertures are smaller than the size of one pixel, but the fracture is visible in the image as the CT number is reduced around the fracture due to the presence of gas rather than rock. We use the method of Johns et al. [1993] to convert the CT number reduction into an aperture at every position in the x direction. As pixels surrounding the fracture are also influenced by the presence of the fracture, a cumulative response is obtained by integrating across the observed CT valley. The total reduction in CT number caused by the fracture at x position $i$ is calculated by subtracting the observed CT numbers from the mean CT number of the rock and integrating over the z direction. Mathematically, this is expressed as

$$I(i, j) = \sum_{k=1}^{k_{\text{max}}} [mCT(i) - CT(i, j, k)],$$

### Table 1. Picker 1200x Scanner Parameter Values

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field size</td>
<td>16 cm</td>
</tr>
<tr>
<td>Matrix size</td>
<td>$512 \times 512$</td>
</tr>
<tr>
<td>Scan angle</td>
<td>$90^\circ$</td>
</tr>
<tr>
<td>Thickness</td>
<td>3 mm</td>
</tr>
<tr>
<td>Voltage</td>
<td>140 kV</td>
</tr>
<tr>
<td>Current</td>
<td>80 mA</td>
</tr>
<tr>
<td>Scan time</td>
<td>3 s</td>
</tr>
<tr>
<td>Resolution</td>
<td>ultrahigh resolution</td>
</tr>
</tbody>
</table>
where \( i, j, \) and \( k \) are the indices in the \( x, y, \) and \( z \) directions, \( I \) is the integrated CT number, \( CT \) is the CT number, \( m_{CT} \) is the mean CT number of the rock and \( k_{\text{max}} \) is the number of pixels integrated over. The integrated CT number accounts for the decrease in apparent density caused by the presence of the gap between the two rock faces. Since CT numbers less than the mean CT can also be caused by variations in the rock CT number, the integration algorithm searched for the largest reduction in CT number. From this point the integration proceeded outward and stopped on either side when the CT value became equal or greater than the mean CT value. By performing the integration over a limited number of points around the gap, variations in the rock CT number away from the fracture were not incorporated in the integrated CT number.

Within 2 mm of the fracture edge there was not enough basalt to do the integration. Thus, in these regions we were unable to obtain any data using the CT scanner. Epoxy filled in most of the fracture within 2 mm of the edges, but there still exists the possibility of unobserved aperture and water that can contribute to flow along the edges.

We calibrate the method by measuring the integrated CT number for fractures of known dimension. Calibration standards were produced by cutting a basalt core in half along the cylindrical axis and polishing the surfaces using a final grind of 5 \( \mu m \) aluminum oxide to give a random roughness of \( \sim 2-3 \mu m \). Flatness was estimated at 1 \( \mu m \) or less using a Mahr clock gauge and Loh sphereometer ring. Calibrated shim stock, varying in thickness from 0.025 to 1 mm, was used to establish fractures of known aperture.

Systematic and random errors were found to affect the accuracy and precision of the method. The largest systematic effects are beam hardening, which causes the CT numbers to be elevated near the edges of the core, and blurring of the CT numbers in the \( x \) direction. The largest random effects include the CT uniformity of the rock. Random variations of the rock’s CT value create random errors in the integrated CT number and the measured aperture. We discuss each factor in turn.

Figure 3 plots the mean of 10 pixels of basalt above and below the fracture versus horizontal position for all 59 slices. From this graph it is clear that the mean rock CT value decreases radially inward due to beam hardening. The method employed by Johns et al. [1993], Keller [1997], and Keller et al. [1999] uses a single CT number for the entire slice, irrespective of radial distance. As a result, the curves generated from each slice will shift up and down around that constant mean CT number as radial position changes. This results in fracture apertures being underestimated on the edges of the core be-
cause the background value of the rock at that radial distance is much higher than the constant mean, and conversely, apertures will be overestimated in the center. To account correctly for beam hardening, we performed the integration by subtracting the value of mean CT that corresponded to the radial position from a parabolic fit of the mean CT data shown in Figure 3 rather than using one mean CT value for the whole slice.

Using this mean CT profile, integrated CT numbers were calculated along the $x$ direction for 21 scans (3 different scan positions and 7 different apertures) of the calibration standards. Figure 4 plots the mean of the integrated CT numbers against aperture. A linear least squares fit was determined, the slope of which reflects the difference in the basalt-gas CT attenuation coefficients. Fracture aperture is determined by calculating the size of the dip using the integrated CT number described above and applying the least squares fit to determine aperture.

To establish the accuracy and precision of this method, apertures were calculated at all positions along the $x$ direction from the CT images of the calibration standards. No systematic variations in the average aperture were found, although the random variations in the apertures were greater near the edges of the scans (where beam hardening plays a larger role). The greatest precision was found at the center of the most uniform sections of basalt where the calculated apertures had a standard deviation of 10 $\mu$m. For a particular aperture, all of the calculated apertures taken together had a standard deviation of 25 $\mu$m. This standard deviation was roughly equal for all apertures from 0.025 to 1 mm.

The main source of precision error was the natural variations of the basalt, which caused the mean CT value to vary randomly along the $y$ direction (from slice to slice) by $\sim 20$ Hounsfield units, thus creating variations in the integrated CT number. Additionally, when small vugs occurred near the fracture, an enhanced integrated CT number was observed.

We have one final note on the blurring of the CT images. It is observed that even though the aperture is $<1$ pixel in size, because of the large CT contrast between rock and gas, the effect of the aperture is noticed up to 5 pixels (1.5 mm) in the $z$ direction. Presumably, this smearing also occurs in the $x$ direction, thus smoothing out the observed aperture field. As the apertures of our standards were constant, the magnitude of the smearing cannot be determined from our calibrations. However, since there is less density contrast in the $x$ direction than the $z$ direction, the smearing should be much less in the $x$ direction.

### 2.4. Measurement of Saturation

Having scanned the fracture at 100% gas saturation, the core was filled with carbon dioxide and subsequently saturated with water through the injection of over 500 pore volumes. Once completely saturated with water, the core was scanned again to provide endpoint CT values for 100% water saturation. It is assumed that the CT number varies linearly with water saturation from 0 (gas-filled) to 100%, and the saturation was calculated using

$$S_w(i, j) = \frac{\sum_k [CT_w(i, j, k) - CT_g(i, j, k)]}{\sum_k [CT_w(i, j, k) - CT_g(i, j, k)]},$$

where $CT_w$ is the water-filled CT number, $CT_g$ is the gas-filled CT number, $CT$ is the measured CT number, and the sum is over the $z$ direction. In order to estimate the precision error associated with this method, regions of the fracture that were assumed to remain water filled (the portion of the large center region where the apertures were $\sim 0.1$ mm) were compared between the water-saturated condition and the first interval of the drainage. In these regions we calculate an average saturation $S_w = 1.00$, with a standard deviation of 0.12. The deviations appear to be random and are most likely due to the resolution and repeatability of the scanner. This precision er-
The hydraulic aperture was calculated using the cubic law \[
\delta = \left( \frac{12 \mu Q}{w \Delta P_w} \right)^{1/3},
\] where \(\delta\) is the hydraulic aperture, \(\mu\) is the viscosity of water, \(L\) is the length of the fracture, \(Q\) is the volumetric flow rate, \(w\) is the width of the fracture (4.5 cm), and \(\Delta P_w\) is the pressure drop in the water phase. When there was no variation in hydraulic aperture with flow rate, the core was assumed to be saturated. At this point, the average measured hydraulic aperture was 143 \(\pm\) 3 \(\mu\)m (error is the standard deviation of the mean) for the four flow rates stated above, with no dependence on the magnitude of the flow rate. The core was scanned again to provide endpoint CT values for saturation. The water flow rate was set to 5 mL/min, and gas was introduced into the core at a flow rate of 2 mL/min. The gas lines were cleared of all water and the gas flow rate was increased to 5 mL/min. The outlet capillary pressure was adjusted to match the inlet capillary pressure. Once steady state was achieved and held for at least 6 hours, the core was scanned to determine saturation, and phase pressures for the inlet and outlet were recorded from the manometers.

In some cases, inlet and outlet capillary pressures could not be adjusted to be exactly equal. The average capillary pressure for the fracture was calculated by averaging the difference in phase pressures, read from the manometers, at the inlet and outlet.

Relative permeabilities are calculated in a similar manner to the method proposed by Persoff and Preuss [1995]. When the core is fully saturated, we find the product of the absolute permeability \(k\) and an effective flow area \(A\) from a rearrangement of Darcy’s Law:
\[
kA = \frac{Q \mu L}{\Delta P}.
\]
For multiphase flow, we use the measured pressure and flux of both the gas and water phases to find the relative permeability of each phase \(k_{ri}\),
\[
k_{ri} = \frac{\mu_i Q_i L}{\Delta P A_i},
\]
with \(kA\) being determined from (6). The experiment began with both phases injected at a flow rate of 5 mL/min. Gas flow was increased holding the water flow rate constant over five different intervals until the maximum gas flow rate of 200 mL/min was achieved. In order to remain in the realm of realistic flow rates the water flow rate was then reduced for seven more intervals while the gas rate was held constant at 200 mL/min. The breakdown of each steady state interval is shown in Table 2.

### Table 2. Breakdown of Experimental Results by Steady State Interval

<table>
<thead>
<tr>
<th>Interval</th>
<th>Water Flow Rate (Q_{w0}) mL/min</th>
<th>Gas Flow Rate (Q_{g0}) mL/min</th>
<th>Gas:Water Flow Ratio</th>
<th>Water Inlet Pressure (P_{w0}), cm Hg water</th>
<th>Water Outlet Pressure (P_{w0}), cm Hg water</th>
<th>Gas Inlet Pressure (P_{g0}), cm Hg water</th>
<th>Gas Outlet Pressure (P_{g0}), cm Hg water</th>
<th>Average Pressure Drop (\Delta P_{w}), cm Hg water</th>
<th>Average Capillary Pressure (P_c), cm water</th>
<th>Water Relative Permeability (k_{rw})</th>
<th>Gas Relative Permeability (k_{rg})</th>
<th>Average Water Saturation (S_w)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>5.00</td>
<td>5.00</td>
<td>1</td>
<td>22.0</td>
<td>25.5</td>
<td>0.2</td>
<td>8.0</td>
<td>3.60</td>
<td>0.314</td>
<td>0.006</td>
<td>1.0</td>
<td>0.090</td>
</tr>
<tr>
<td>1</td>
<td>5.00</td>
<td>5.00</td>
<td>1</td>
<td>21.4</td>
<td>24.9</td>
<td>0.2</td>
<td>25.0</td>
<td>3.75</td>
<td>0.317</td>
<td>0.023</td>
<td>0.814</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>5.00</td>
<td>5.00</td>
<td>1</td>
<td>21.5</td>
<td>26.2</td>
<td>0.2</td>
<td>25.6</td>
<td>4.80</td>
<td>0.311</td>
<td>0.056</td>
<td>0.803</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>5.00</td>
<td>5.00</td>
<td>1</td>
<td>22.2</td>
<td>29.0</td>
<td>1.5</td>
<td>27.7</td>
<td>7.00</td>
<td>0.287</td>
<td>0.104</td>
<td>0.786</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>5.00</td>
<td>200</td>
<td>0.8</td>
<td>26.5</td>
<td>37.4</td>
<td>3.8</td>
<td>34.1</td>
<td>11.35</td>
<td>0.232</td>
<td>0.170</td>
<td>0.762</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>5.00</td>
<td>40</td>
<td>0.0</td>
<td>18.1</td>
<td>28.6</td>
<td>3.8</td>
<td>25.4</td>
<td>11.05</td>
<td>0.154</td>
<td>0.230</td>
<td>0.746</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>5.00</td>
<td>40</td>
<td>0.0</td>
<td>16.0</td>
<td>24.2</td>
<td>2.2</td>
<td>19.2</td>
<td>8.40</td>
<td>0.082</td>
<td>0.300</td>
<td>0.738</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>5.00</td>
<td>40</td>
<td>0.0</td>
<td>16.0</td>
<td>21.8</td>
<td>4.9</td>
<td>16.9</td>
<td>5.75</td>
<td>0.048</td>
<td>0.337</td>
<td>0.715</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>5.00</td>
<td>40</td>
<td>0.0</td>
<td>15.7</td>
<td>21.0</td>
<td>4.8</td>
<td>16.0</td>
<td>5.05</td>
<td>0.034</td>
<td>0.352</td>
<td>0.698</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>0.33</td>
<td>300</td>
<td>1.0</td>
<td>15.7</td>
<td>19.4</td>
<td>4.0</td>
<td>15.4</td>
<td>3.70</td>
<td>0.010</td>
<td>0.370</td>
<td>0.693</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>0.10</td>
<td>200</td>
<td>0.6</td>
<td>15.5</td>
<td>19.9</td>
<td>4.9</td>
<td>15.1</td>
<td>4.30</td>
<td>0.005</td>
<td>0.380</td>
<td>0.669</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>0.05</td>
<td>200</td>
<td>0.5</td>
<td>15.3</td>
<td>19.2</td>
<td>4.2</td>
<td>15.1</td>
<td>3.90</td>
<td>0.001</td>
<td>0.380</td>
<td>0.625</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>0.01</td>
<td>200</td>
<td>0.5</td>
<td>15.3</td>
<td>18.4</td>
<td>4.0</td>
<td>14.8</td>
<td>3.30</td>
<td>0.0005</td>
<td>0.396</td>
<td>0.585</td>
<td></td>
</tr>
</tbody>
</table>

### 3. Experimental Results and Discussion

#### 3.1. Fracture Aperture Distribution

The aperture map is shown in top view in Figure 5. Flow enters from the left and exits from the right. Most of the central portion of the fracture contains apertures of the order of 100 \(\mu\)m, but large aperture regions up to 3 mm are visible on
either edge of the fracture, possibly resulting from the method of fracture initiation.

The distribution of fracture aperture appears to be bimodal, as shown by the histogram of the logarithm (base 10) of the fracture aperture distribution in Figure 6. In general, the lower peak corresponds to the center of the fracture, and the upper peak corresponds to the edges. The arithmetic mean, sometimes referred to as the mechanical aperture, is 336 μm with a standard deviation of 434 μm, reflecting the presence of the larger channels along the side of the core. As described in the procedure, the hydraulic aperture was measured to be 143 μm and is lower than the mechanical aperture. This is due to the large central region of small apertures that forces the bulk of the flow to follow the channels along the sides of the fracture.

3.2. Saturation

Saturation maps were constructed for each interval of the experiment. As in the aperture map, flow enters from the left of the map and exits at the right. Figure 7 shows the saturation maps for the first, sixth, and last intervals. The displayed saturations are cut off at 0 and 1, although for some pixels the saturation was measured to be <0 or >1 due to precision errors discussed earlier. As the ratio of gas to liquid flow rates increased, the average water saturation always decreased. All of the saturation maps show significant channeling of the gas in the large aperture regions. The channel at the bottom of each map is invaded at the first interval at a capillary pressure of 3.6 cm of water and an average water saturation of 0.831. The channel at the top of each map is invaded at interval 11 at a capillary pressure of 4.3 cm of water and an average water saturation of 0.669.

3.3. Relative Permeability

Table 2 gives a breakdown of the experimental results in each steady state interval. The viscous pressure drop increases during the period where gas flow rate was increased and decreases during the period when the water flow rate was decreased. The relative permeability of each phase was calculated from the measured phase pressures using the method outlined in the experimental procedure. Figure 8 is a plot of relative permeability versus average water saturation. The dashed lines are the often used linear relative permeabilities ($k_r = S_r$).

![Aperture Map](image)

**Figure 5.** Map view of fracture aperture distribution.

![Histogram](image)

**Figure 6.** Histogram of the logarithm (base 10) of the fracture aperture distribution.
By definition, the water relative permeability equals 1 when the fracture is fully saturated ($k_{rw} = 1$ when $S_w = 1$). From Figure 8 we see that $k_{rw}$ drops sharply as gas invades the largest regions of the fracture and is not close to the linear relative permeability. In the first interval, $k_{rw} = 0.3$ since gas has already occupied a highly conducting channel (see Figure 7a). Then $k_{rw}$ continues to fall as the water saturation decreases and is only $5 \times 10^{-2}$ when the experiment ends. Here the water is confined to the smallest aperture regions (see Figure 7c). The experiment ended at this point as the capillary barrier failed, and lower flow rates of water were not possible. However, notice that the average water saturation is 0.585, which is still very high, indicating that with a variable fracture aperture, complete desaturation of the system is difficult since the wetting phase clings to the narrowest regions and can become poorly connected.

The gas relative permeability $k_{rg}$ is small in the first interval since the gas channel in Figure 7a is barely connected. At the end of the experiment (Figure 7c) $k_{rg} \approx 0.4$, still significantly lower than 1 as the gas does not occupy the whole fracture. The sum of the relative permeabilities is $<1$ ($k_{rg} + k_{rw} < 1$) throughout the displacement, indicating significant phase interference. For most of the saturation range studied, $k_{rg} + k_{rw}$ is approximately constant at around 0.4.

Qualitatively, the relative permeability curves are similar to those observed by Merrill [1975], where a sharp change in $k_{rw}$ was observed over a narrow range of $S_w$. Furthermore, there is evidently strong retention of the wetting phase, and we find neither linear nor power law forms for the gas or water relative permeabilities.

3.4. Capillary Pressure-Saturation

The capillary number is defined as [Dullien, 1992]

$$N_c = \frac{\mu Q}{\sigma A},$$

where $N_c$ is the capillary number, $\mu$ is the water viscosity, $Q$ is the water flow rate, $A$ is the cross-sectional area of the fracture (estimated as the hydraulic aperture multiplied by the fracture width), and $\sigma$ is the interfacial tension between the two fluids.
The experiment was conducted for a range of flow rates that results in capillary numbers ranging from $10^{-3}$ to $10^{-6}$, typical of many natural fracture flows [Bear et al., 1993]. Despite these low flow rates, however, from Table 2 it can be seen that the viscous pressure drop across the fracture is $2–8$ times larger than the capillary pressure. This means that both viscous and capillary forces influence the displacement.

Figure 9 shows the capillary pressure as a function of average water saturation for the fracture. As discussed earlier, the increasing gas:water flow ratio caused the fracture to be in drainage (decreasing in water saturation) during the experiment. While the gas flow rate was increased, the capillary pressure increased with decreasing water saturation, which is the typical behavior for porous media. A maximum can be seen at a capillary pressure of 11.35 cm of water. At this point when the gas rate was held constant and the water rate is decreased, the capillary pressure decreased with decreasing water saturation, with a slight increase at the eleventh interval. A decreasing capillary pressure with decreasing wetting phase saturation is atypical for porous media, but as discussed below, it may be common for fractures.

Consider what happens when the capillary pressure is raised.
incrementally in a porous medium in which the pore space (and the water and gas) is extremely well connected. As the phases are well connected, the capillary pressure at the ends of the medium will be equal to the capillary pressure throughout the medium, and the water will be displaced by gas in the largest pore spaces in which water remains. If all displacements are piston-like, the radius of the pores \( r_p \) being drained at a particular capillary pressure \( P_c \) is given by the Young-Laplace equation \( r_p = \frac{2\sigma}{P_c} \), assuming a zero gas/water contact angle. All of the pores with radii greater than \( r_p \) will be filled with gas, and all of the pores with radii smaller than \( r_p \) will be filled with water. Figure 10 shows schematically the gas-filled and water-filled pores in a perfectly connected porous medium (or, alternatively, a bundle of capillary tubes). As the capillary pressure is increased, the water saturation necessarily has to decrease.

Our experiment differs from the above ideal case in two important ways. First, the pore space in a fracture is poorly connected due primarily to the reduced dimensionality (two-dimensional (2-D) versus 3-D) of the system. Second, in our experiment, instead of controlling the capillary pressure, we controlled the flow rates of gas and water (and thus the ratio of the gas and water relative permeabilities). The saturation and the capillary pressure at the ends of the fracture are then measured.

Figure 11 shows the measured gas-filled and water-filled apertures at the last interval of the experiment (lowest saturation). The number of gas-filled apertures was calculated by summing the gas saturation of apertures of a particular bin size. Unlike Figure 10, Figure 11 shows that at this particular interval, gas has filled some of the apertures of sizes from 0.1 to 3 mm. The larger the aperture, the more likely it is to be filled by gas, but there is clearly not a sharp cutoff.

Why is there such a distribution of gas-filled apertures in a fracture? There are at least three factors that would promote this type of behavior. First, the lack of connectivity may leave large apertures water-filled. For a fracture at a particular capillary pressure (and ignoring in-plane curvature), apertures of size

\[ a = 2\sigma/P_c \]

will have gas enter them if and only if gas can reach them. If small apertures surround a large aperture region, the region will remain water-filled. Second, curvature of the water/gas interface within the aperture plane can greatly affect the capillary entry pressures of each aperture, with a concave interface increasing the entry pressure and a convex interface decreasing the entry pressure \([Glass et al., 1998]\). Third, in cocurrent flow in fractures, viscous forces can make the capillary pressure vary greatly along the fracture even if the capillary pressure at the ends is equal. If there is a constriction in a water pathway, there will be a large viscous pressure drop across the constriction, and the capillary pressure necessarily has to be smaller upstream from the constriction than it is downstream. Likewise, if there is a constriction in a gas pathway, the capillary pressure has to be greater on the upstream side. This possible variation in capillary pressure will fill a range of aperture sizes.

Between each interval the apertures that fill with gas should be roughly determined by the capillary pressure, although there will be a broad range that fills due to the above reasoning. Figure 12 shows which pores are gas-filled at the first, sixth, and last intervals of the experiment. At the first interval the capillary pressure is 4.3 cm of water, and using (10), apertures of 0.34 mm and greater will fill with gas if possible. Most of the gas filling is in apertures \(>0.3 \text{ mm} \) (logarithm of \(-0.5\)). At the sixth interval the capillary pressure is 11.05 cm of water, corresponding to an aperture of 0.13 mm (logarithm of \(-0.9\)), and a higher proportion of the smaller apertures have become

---

**Figure 10.** Histogram of gas- and water-filled pores for a “well-connected” lognormal porous medium. This is equivalent to the bundle of capillary tubes model.
gas-filled. At the last interval the capillary pressure has decreased to 3.3 cm of water, and many more apertures >1 mm have become gas-filled. Although it cannot be observed in Figure 12, between the sixth and last intervals the number of apertures of <0.1 mm that were gas-filled decreased from 73 to 55. This corresponds to retraction of the gas and refilling of water in these small pores as the capillary pressure decreased. Larger apertures were filled in the later intervals because of the opening of the top channel for gas flow. Once the gas reaches this large aperture region, smaller capillary pressures are needed to empty further portions of this large aperture region. Thus the observed pressure-saturation behavior is, in fact, consistent with the observed aperture filling.

This suggests that the pressure-saturation curve for fractures may depend on the method of measurement. Consider what happens when a large aperture region is encountered when the

Figure 11. Histogram of observed gas and water-filled apertures for the fracture at the last interval (lowest water saturation). This differs greatly from the well-connected case in Figure 10.

Figure 12. Histogram of observed gas-filled apertures for the fracture at the first, sixth, and last intervals. At low capillary pressures (first and last intervals) more large apertures become gas-filled. At high capillary pressure (sixth interval) more medium and small apertures become gas-filled.
fracture is emptied by controlling the capillary pressure and when the fracture is emptied by controlling the saturation (which is closer to our experiment). When controlling (and always increasing) the capillary pressure, the contact with a large aperture region will cause an abrupt and large decrease in saturation as the whole region will suddenly empty. When controlling (and always decreasing) the saturation, the contact with a large aperture region will result in larger radii of curvature water/gas interface and a decrease in capillary pressure. The capillary pressure will increase again only after the region completely empties.

4. Conclusions and Recommendations for Future Work

An improved technique for determining fracture aperture for CT images was developed that accounts for the variation in mean CT number due to beam hardening. The distribution of fracture aperture appears to be bimodal with an arithmetic mean of 332 μm and a standard deviation of 496 μm, reflecting the presence of larger channels along the side of the core.

High-resolution measurements of in situ saturation were made along with capillary pressure and relative permeability for a single fracture for gas/water drainage. The sum of the liquid and gas relative permeabilities is much less than 1 at intermediate saturations, and \( K_w \) shows a sharp change over a narrow range of \( S_w \). In situ saturation maps show channeling of gas and significant retention of the wetting phase (water).

The capillary pressure curve shows nonmonotonic behavior. Examination of the saturation maps indicates that decreases in the capillary pressure with increasing gas saturation are due to the local rearrangement of fluid under the influence of both capillary and viscous forces. This suggests that a macroscopic capillary pressure, based theoretically on considerations of capillary equilibrium, may be inadequate for describing fracture flow.

Although the use of a porous mortar provided intimate contact to the wetting phase, it limited the range of flow rates that could be tested because of its relatively low entry pressure. In future experiments, a porous plate with a high gas entry pressure could be machined to fit into the holes in the aluminum mold and sealed into place using an epoxy. Alternatively, a design similar to that used by Persoff and Pruess [1995], employing a fluted porous plate, could also be tested.

This experimental method could be extended to fracture sets to observe flow at the intersection of fractures. It could also be applied to single fractures in different orientations or under different states of normal stress. It could be extended to sandstone cores to explore matrix-fracture interaction. In this case, the core would need to be scanned in an unfractured and fractured state to establish both matrix and fracture endpoint saturations. Finally, both imbibition and drainage curves should be measured for each fracture to explore the effects of hysteresis.

Acknowledgments. We thank Robert Glass and the anonymous reviewers for their helpful comments. Financial support for this work was provided by the U.S. Department of Energy under grant DE-FG-22-96BC14851 and the Stanford University Gas Injection Affiliates Program (SUPRI-C) during the course of this work.

References


Reitsma, S., and B. H. Kueper, Laboratory measurement of capillary


S. P. Bertels, Golder Associates Ltd., 500-4260 Still Creek Drive, Burnaby, British Columbia, Canada V5C 6C6, (sbertels@golder.com)

M. J. Blunt, Centre for Petroleum Studies, Imperial College, Prince Consort Road, London SW7 2BP, England, UK, (m.blunt@ic.ac.uk)

D. A. DiCarlo, Department of Petroleum Engineering, Stanford University, Stanford, CA 94305-2220, (dicarlo@pangea.stanford.edu)

(Received August 20, 1999; revised October 2, 2000; accepted October 2, 2000.)