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The effect of sandstone microfabric upon relative permeability end points

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Abstract

The nuances of relative permeability curves are commonly considered to be the product of variations in pore structure and wettability. Extrapolation of the results of a few flow tests into an entire reservoir for simulation purposes assumes that wettability does not change much over most of the reservoir and that the porous microstructure is relatively random and homogeneous. However, there is an increasing body of research indicating that the distribution of porosity is never random or homogeneous. Sandstone fabrics are a mixture of close-packed domains and packing flaws. This characteristic structure imparts a characteristic structure to the pore network that, in turn, defines fluid flow behavior (both single- and multiphase). Packing flaws are zones of oversized pores and pore throats with great spatial continuity. In lithified sandstones, virtually all of the single-phase flow occurs within packing flaws. The close-packed zones have much smaller pores and pore throats, and along with microporosity, tend to retain irreducible water. Results from a variety of quartz-rich sandstone reservoirs indicate that the domainal structure of porosity exerts a major influence upon S_{or} and S_{wi} values observed in unsteady-state tests. The sample set is limited to quartz-rich reservoir sands with an induced water-wet condition. However, the results demonstrate the linkage between pore fabric and relative permeability end points, and may ultimately permit one to extrapolate those properties as a function of depositional fabric. © 1999 Elsevier Science B.V. All rights reserved.

Keywords: porous medium; clastics; heterogeneous fabric; relative permeability; image analysis

1. Introduction

Knowledge of both the state of wetting and the homogeneity of wetting through a reservoir is critical to fully understand and predict the course of hydrocarbon production. Application of theory and laboratory results to natural media is not straightforward even in the most texturally and compositionally homogeneous reservoirs. Quartz-rich, relatively equigranular sandstone is a logical choice for moving from highly controlled macroscopic laboratory experiments to investigations of multiphase fluid behavior in natural systems. Complications observed in such systems can only be magnified in other more complex rock types. The research discussed below concentrates on the behavior of a suite of quartz-rich reservoir sandstones that differ in grain size, depositional fabric, and diagenetic state.

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The samples were taken from six different quartz-rich reservoir sandstones located in the North Sea and North America (Table 1). Modal grain size ranges from 112–450 μm (very fine to medium sand) and total porosity ranges from 11–22%. Prior to thin sectioning, each sample was subjected to an unsteady-state relative-permeability test using the Johnson–Bossler–Naumann method. Native oil was extracted using a mixture of solvents and the cores were dried. Prior to testing, the samples were completely saturated with brine. The extraction of native fluids very probably ensured an initial water-wet condition. Using metering pumps, the cores were injected with oil until only trace amounts of water were produced and then reinjected with water until only trace amounts of oil were produced. The data set is limited to samples with an induced water-wet condition. Again, complications observed in such samples can only be magnified in other more complex wettability conditions.

1.1. The structure of sandstone

All sandstones consist of a complex three-dimensional network of pores linked by pore throats. Output from flow tests represents a volume average of microscopic events occurring at pore or subpore level. A host of possible microscopic processes can interact with a spectrum of possible porous geometries to produce an observed product. Therefore, deducing the role of wettability in even fairly homogeneous quartz-rich sandstones requires evaluation of a large and complex set of possibilities or evaluating data under a set of simplifying assumptions. One such assumption is the relative homogeneity of the porous medium. In this paper, we show that variations in the porous microstructure can be linked to the results of the interactions of single and multiphase fluids in such sandstones. Specifically, the microstructure within the sample set is variable enough to strongly influence the end points observed in unsteady state tests.

1.2. Relative permeability

The term 'relative permeability' has gained some acceptance in petroleum engineering although there is ongoing controversy on how it should be measured and even whether or not the property is really related in a basic physical sense to the permeability associated with Darcy's Law. However, there is general agreement that the state of wetting at pore surfaces has a strong effect on the outcome of flow tests purporting to quantify the relative permeability function, and most importantly in the context of flow tests, the end points: irreducible water saturation (S_{wi}) and residual oil saturation (S_{or}).

1.3. The capillary microstructure

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids (Andreson, 1986). Wettability effects act in concert with the porous microstructure. Capillary behavior is associated with the sizes of pore throats, and the ratio of throat size

Table 1

Core measurements and calculations from the Northern Hemisphere set of quartz-rich sandstones

Sample	P_T (% BV)	TOP (%)	Md (μm)	E (μm)	E' (μm)	P_{EX}	P_{CP}	P_{UR}	P_{EFF}	P_I	SWP	SIP	S_{WI}	S_{OR}
S1	21.6	23.33	165	215	590	10.75	12.58	−1.73	2.88	36.44	130.57	8.35	38.2	16.5
S2	16.5	18.46	268	343	781	9.63	8.83	−1.96	3.06	39.82	79.10	4.27	34.3	2.6
S3	22.3	21.07	215	282	656	9.60	11.47	1.23	3.76	26.19	126.29	4.79	41.5	6.0
S4	22.0	20.44	450	392	800	12.11	8.33	1.56	4.29	35.55	51.79	3.44	23.2	10.3
S5	19.8	9.93	150	169	384	6.47	3.46	9.87	3.22	16.41	184.26	6.82	47.1	17.4
S6	12.7	12.66	157	168	376	7.94	4.72	0.04	3.94	31.50	100.12	13.38	27.5	37.2
S7	21.7	16.22	230	327	560	8.49	7.73	5.48	3.81	21.57	129.07	5.43	38.2	10.4
S8	17.2	14.77	197	268	575	7.96	6.81	2.43	3.55	25.64	125.91	6.16	40.3	16.6
S9	11.0	4.83	112	115	309	3.58	1.25	6.17	1.80	16.18	213.05	8.25	47.5	18.8
S10	11.4	10.34	131	142	319	7.03	3.31	1.06	3.46	31.32	112.41	15.54	29.1	40.9

to pore size is especially important. It may be possible to construct a medium wherein modifications in capillary structure can mimic results that, under other circumstances, can be due to changes in wettability. Given a well-sorted sandstone with grains in hexagonal closest packing (or the equivalent packing slightly randomly perturbed), wetting phenomena probably have the strongest influence on the behavior of mutually immiscible phases in that medium. However, there is an increasing body of research indicating that the pore structure in natural sandstones is never homogeneous (Bryant et al., 1993; Prince et al., 1995), and that the characteristic structure of porosity exerts a strong influence upon the petrophysical character of the rock (Ehrlich et al., 1997; Prince, 1999). The objective of this report is to show that this characteristic pore structure can have a strong influence on variations in S_{wi} and S_{or} in sands that are virtually identical in terms of mineral composition, where any variations in the character of grain surfaces is minor.

2. Theoretical basis for a heterogeneous sand fabric

Graton and Fraser (1935) developed a theory for the textural control of permeability in sands and sandstones based on observations of the structure of monolayers of spheres of a single size. They deduced that the process of sedimentation would favor the spontaneous aggregation of close-packed domains because these had the lowest potential energy. Many such clusters of grains would form and grow in the sedimenting system. However, no long-range process exists to align the internal fabric among close-packed domains. Therefore as the close-packed clusters grow, they eventually begin to impinge on one another and compete for the remaining space. Thus a compromise zone, a packing flaw, develops between clusters. Such zones contain oversize pores connected by large pore throats. Graton and Fraser speculated that such zones would constitute circuits that would largely control permeability. Their choice of spheres of uniform size and shape was done deliberately in such that a system might be thought to generate the most homogeneous grain (and pore) fabric. They recognized that if such heterogeneity existed there, then it had to exist in grain aggregates where grain size and shape both vary.

These zones of compromise packing were later defined as ‘packing defects’ or ‘packing flaws’ by solid state physicists who were using aggregates of spheres in order to understand the physical properties of ionic crystals. They showed that packing flaws were critical in the growth of crystals, strongly controlled the strength of the crystals, that packing flaws strongly controlled the strength of the crystals, and had a major effect on a host of other physical properties. Apropos to our interests is the demonstration that packing flaws (excepting point defects) propagate throughout the solid with individual flaws terminating only upon intersection with another flaw. This produces a three-dimensional network with great spatial continuity — the ‘permeability circuits’ discussed by Graton and Fraser (1935). In terms of the flow of mutually immiscible phases, this sort of structure can lead to the spatial segregation of the non-wetting phase in the packing flaws and a large part of the wetting phase located in the close-packed domains.

3. Empirical evidence

A large body of evidence has accumulated which supports the conjectures of Graton and Fraser. This evidence has four aspects: (1) relationships between aspects of porosity observed in thin section and capillary pressure data obtained from associated core plugs, (2) direct detection of packing flaws via Fourier analysis of thin-section imagery, (3) prediction of end points via image analysis from thin section, and (4) observation of phase segregation during flow tests monitored with X-ray tomography. All support the concept that the domainal structure of sandstone has a dominant influence upon the macroscopic phase separation of mutually immiscible fluids.

3.1. Petrographic image analysis, pore types and capillary pressure

Ehrlich and Horkowitz (1984) reported the existence of strong correlations between parameters measured from thin section and permeability and other physical properties. The variables represent a large number of aspects of the size and shape of the patches of porosity observed in section and are strongly correlated with each other. Principal component analysis showed that these variables were associated with less than 10 eigenvectors, suggesting that a relatively small number of porosity features were involved. Ehrlich et al. (1991) described a way for deriving ‘pore types’ from a subset of image analysis variables derived from erosion/dilation differencing. The pore types correlate strongly with physical properties and can be easily associated with the kinds of porosity subjectively identified by experienced petrographers.

McCreesh et al. (1991) demonstrated that pore types can be precisely related to mercury capillary pressure curves and calculated the amount of porosity associated with each pore type that fills in each pressure increment. Pores of a given type tend to dominate specific pressure intervals. Large pores commonly (but not always) fill at low pressures. They demonstrated that the low-pressure (large throat size) ''plateau'' on a mercury injection curve is caused by the filling of circuits composed of pores of like size and shape.

3.2. Direct detection of packing flaws

Direct detection of the circuits hypothesized by McCreesh et al. (1991) was demonstrated by Prince et al. (1995) using Fourier transforms of binary images of porosity digitized from thin section (Fig. 1). The images combine high resolution (pixel size < 4 μm) with a large coverage area (up to 8 cm^2). A 2-D Fourier transform is used to quantify the spatial density (packing) of image features (pores). The resulting 2-D and radial power spectra clearly showed spatial heterogeneity over a wide range of scales. Prince et al. (1995) discussed the results in terms of the theory of Graton and Fraser (1935) and also demonstrated that porosity associated with packing flaws not only survives compaction but, at low values of porosity, is dominant.

Depending upon the size of the image, a radial power spectrum can quantify the spatial density of image features at scales ranging from 8 μm to 10 mm (Fig. 2). In terms of image area, most of the grains are in a close-packed configuration, producing a characteristic modal grain size peak on the radial power spectrum (Fig. 2). The difference in packing between close-packed and loose-packed domains gives rise to a subsidiary peak. The discontinuity between the two, shown at E in Fig. 2, is usually found at approximately 1.2–1.3 times the modal grain size.

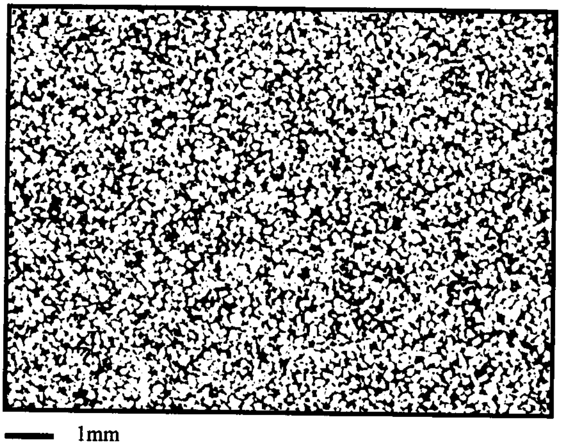


Fig. 1. A binary image of porosity from a clean, well-sorted orthoquartzite. As with many texturally mature sandstones, there was a close agreement between total plug porosity ($P_T = 26.2\%$) and total optical porosity (TOP = 25.8%).

To directly image packing flaws, the transform is low-pass filtered using the spatial discontinuity at E as a cut-off. The transform is inverted to create a smoothed version of the original image lacking high-frequency information associated with pore/grain shape and size. The synthetic image is overlain upon the original to highlight the packing flaws (Fig. 3).

The equivalence between porosity in packing flaws and those pore types associated with low pressure filling in mercury injection experiments was shown by Riggert (1994) and Carr (1996). Further work demonstrates that virtually all of the fluid flow in sandstones is confined to the network of packing flaws (Prince, 1999; Prince and Ehrlich, 1998). The contrast between close-packed and loose-packed domains is only one facet of a structural hierarchy arrayed over a wide range of spatial scales. Some of this structure is associated with ‘efficient’ packing flaws that, as discussed below, have important physical significance. Others represent the differences in pore size associated with changes in grain size as well as changes in the size, shape, and orientation in

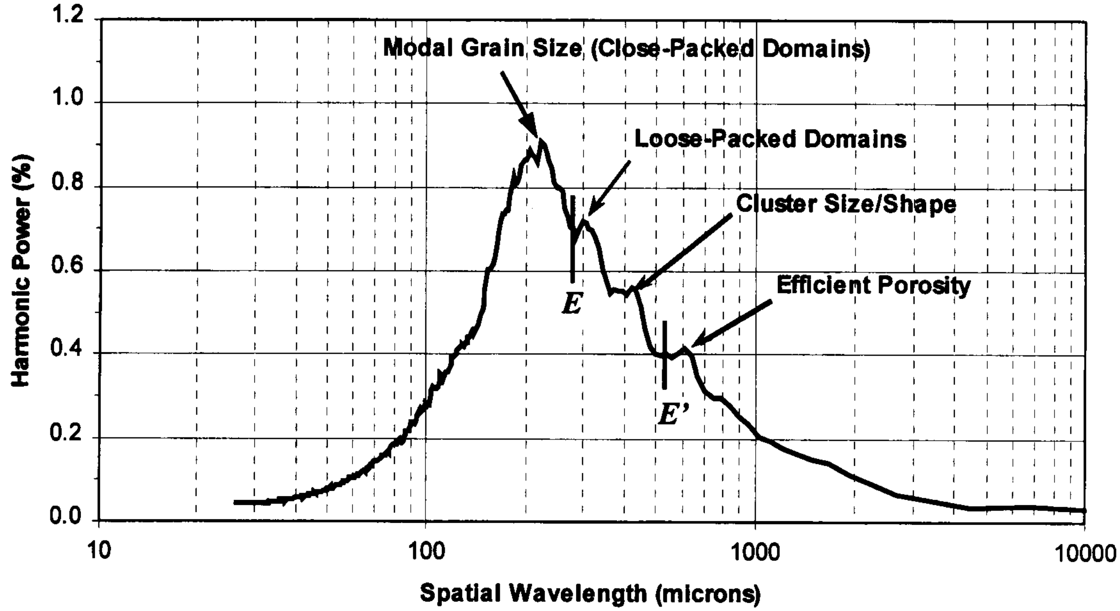


Fig. 2. A radial power spectrum of the image in Fig. 1.

packing flaws under the influence of depositional hydrodynamics and bioturbation.

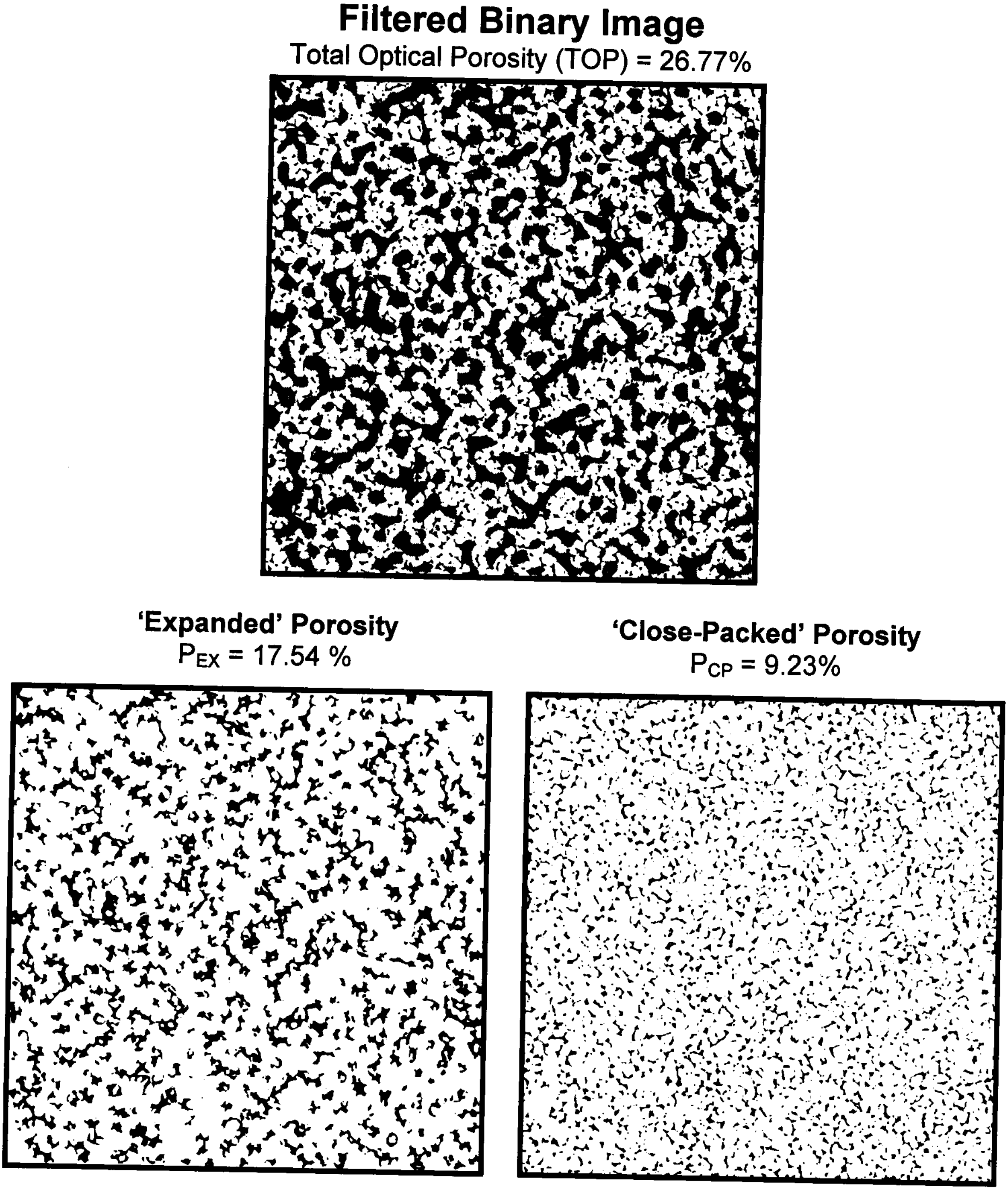
3.3. Thin section porosity and end points

A strong statistical relationship between pore types (as well as other erosion/dilation variables) and the end points of unsteady state relative permeability curves was demonstrated by Coskun and Wardlaw (1993, 1994, 1995, 1996) from two suites of samples: one from a North American Reservoir and another from a North Sea reservoir. One sample set was from a water-wet reservoir and the other was from a reservoir of mixed wettability. Precision of estimates (R^2 generally greater than 0.8) were the same for each sample set. These pioneering results demonstrated that the characteristics of the microstructure affect the end points, but could not shed light on the underlying cause(s) of the relationship.

The conjectures of Graton and Fraser (1935) supply a context to explain these relationships. The image-based Fourier procedures that are the basis of the present investigation were designed as an empirical test of their conjectures. Using digital image analysis techniques, we can recognize several levels of the structural hierarchy in sandstones and use the information to predict relative permeability end points from thin section. The image analysis techniques allow us to subdivide porosity into three fundamental components: 'expanded porosity' (P_{EX}) associated with packing flaws, 'close-packed porosity' (P_{CP}) found in well-packed domains, and 'unresolved porosity' (P_{UR}) porosity below the resolution of the digital image (herein, less than 4 μm in diameter).

As illustrated in Fig. 3, the spectral demarcation between close-packed and loose-packed domains provides an effective means to subdivide porosity into P_{EX} and P_{CP}. P_{EX} represents large, well-connected pores (packing flaws) forming a network of high permeability circuits. At the other end of the scale, P_{UR} is primarily associated with intragranular microporosity and small asperities on grain surfaces. In effect, P_{CP} represents a multiphase transition zone between the largest pore features (P_{EX}) with the greatest affinity for non-wetting fluids, and the smallest pore features (P_{UR}) with the greatest affinity for wetting phases.

Pore size within packing flaws is functionally related to grain size and to the degree of lithification (Prince, 1999). However, regardless of the grain size or total porosity, the pore size ratio between P_{EX}



Filtered Binary Image

Total Optical Porosity (TOP) = 26.77%

'Expanded' Porosity

P_{EX} = 17.54 %

'Close-Packed' Porosity

P_{CP} = 9.23%

Fig. 3. Using the close-packed/loose-packed discontinuity (E) as a limit, the original image is filtered to subdivide porosity into 'Expanded' porosity associated with packing flaws, and 'Close-Packed' porosity associated with close-packed grain clusters.

and P_{CP} remains relatively fixed at approximately 2:1 (Prince, 1999). The spatial discontinuity used to image P_{CP} and P_{EX} is generally found at 1.2–1.3 times the modal grain size, thus at deposition, the size of P_{CP} pores is defined by the grain size distribution of the sand. The process of lithification (compaction, dewatering, and cementation) tends to alter this relationship progressively reducing both pore size and total porosity (Prince and Ehrlich, in press; Prince, 1999). However, if we hold total porosity constant, coarse-grained sands have larger P_{CP} pores than those found in fine-grained sands. This means that under equivalent experimental conditions, the P_{CP} in fine-grained sand should have a greater relative affinity for wetting fluids than the equivalent porosity in a coarse-grained sand.

Together, P_{CP} and P_{UR} represent the portion of the pore network that has the greatest affinity for the wetting phase. However, the influence of P_{CP} must be inversely scaled by grain size. With this information, we can create a new variable — scaled well-packed porosity (SWP), that is more closely aligned with the variation in S_{wi} (Table 1).

$$\mathrm{SWP} = \mathrm{Md}(\phi)\left[\left(\left(P_{CP}+P_{UR}\right)/P_{T}\right)\times 100\right]$$

where Md = modal grain diameter (in millimeters) and $\mathrm{Md}(\phi) = (-1)\log_2(\mathrm{Md})$, a common logarithmic measure of grain diameter.

There appears to be a linear relationship between SWP and S_{wi} (Fig. 4). Note that the line of best fit does not pass through the origin, but intersects the abscissa at a water saturation of approximately 20%. This suggests that about 20% of the relatively immobile water is present within the packing flaws both as a thin hygroscopic coating on grain surfaces and as thicker films adhering to surface irregularities such as solution and fracture pits on the grain surfaces. This wetting film should also be found at the invaginations between crystal faces and at the junctions between adjacent grains — features similar to the corners in experiments with triangular tubes (Mason and Morrow, 1991).

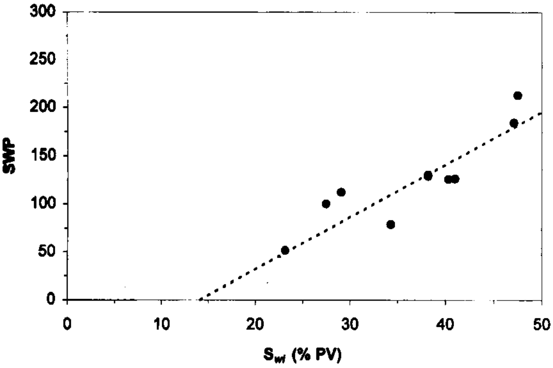


Fig. 4. The relationship between SWP and S_{wi} as indicated by a set of quartz-rich sandstones representing several reservoirs in North America and the North Sea.

We can also subdivide P_{EX} into 'efficient' and 'inefficient' packing flaws. Packing flaws are not homogeneous. In all of the samples examined there is a subset of packing flaws that are exceptionally large, well-connected and hydrodynamically efficient. 'Efficient porosity' (P_{EFF}) can be recognized as a subsidiary peak or plateau on a radial power spectrum, and the discontinuity between efficient and inefficient packing flaws is generally located at wavelengths 2.5–3.5 times the modal grain size (E' in Fig. 2). The discontinuity is equivalent to E in that it provides a means to filter the image and quantify both P_{EFF} and inefficient flaws ($P_{I} = P_{EX} - P_{EFF}$). Again, P_{I} must be scaled to account for the textural properties of the sandstone.

Accordingly, we can define another variable: scaled inefficient porosity (SIP), which is more closely aligned with the variation in S_{or}:

$$\mathrm{SIP} = P_{I}\log(E')$$

where $P_{I} = [(P_{EX} - P_{EFF})/P_{T}] \times 100$ and E' = spatial discontinuity between inefficient and efficient porosity.

The results, listed in Table 1, and shown in Fig. 5, suggest that there is a strong linear relationship between SIP and residual oil saturation. As in Fig. 4, the intercept term suggests that as SIP gets very small, there is always a small proportion of flawed porosity that is water-wet.

3.4. Direct observation of phase segregation during flow tests

The effect of sandstone microstructure on multiphase flow is increasingly observed by research engineers and physicists. Packing flaws should preferentially carry oil and close-packed domains should

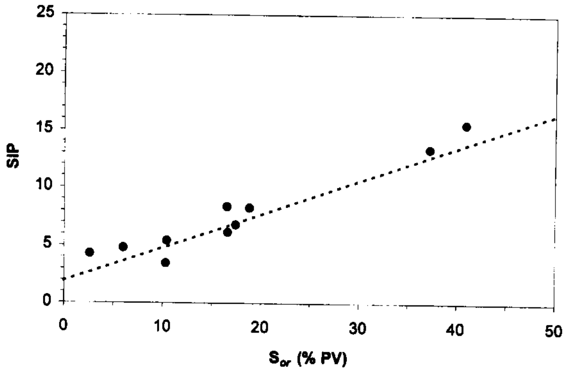


Fig. 5. The relationship between SIP and S_{or} in quartz rich sandstones.

be relatively water rich producing a small scale 'zebra striping'. Liang et al. (1995), using CT scans in conjunction with flow experiments on laminated sandstone observed that oil saturation varied considerably on a lamina to lamina scale. This reflected spatial variability within a single plug of S_{wi}, S_{or}, and recovery efficiency. Thus, the results of the flow experiment depend strongly on the relative amounts of water rich and oil rich lamina. Accordingly, they state: "Considerable care is needed when interpreting capillary-dominated (low flow rate) two-phase flow experiments because the details of the small-scale petrophysical properties play a significant role." If a porous medium is uniform, emplacement of a gel should reduce both oil and water permeability; but experimental evidence contradicts this. Huang et al. (1995) performed a series of experiments aimed at understanding the reasons for the greater reduction of water permeability compared to oil permeability after the emplacement of a gel. They state: "Results from our experiments suggest that segregation of oil and water pathways through a porous medium (on a microscopic scale) may play the dominant role in the disproportionate permeability reduction." A frequent question is whether variations in the heterogeneous microfabric are macroscopically relevant. Formally, the sort of microstructure described above is termed as "spatially correlated" or "quasi-regular" medium. Sahimi (1995), in a series of numerical modeling experiments on single-phase flow through porous media, showed that this sort of "microscopic" fabric gives rise to "a rich variety of macroscopic transport regimes that are absent from uncorrelated systems." MacAlister et al. (1993) relate X-ray CT scanning to relative permeabilities. They observed phase separation within cores leading them to conclude: "This raises fundamental questions about the meaning of laboratory-derived relative permeabilities when non uniform fluid distributions are significant."

4. Discussion

All sandstones carry a characteristic fabric consisting of the juxtaposition of close-packed clusters separated by zones of loose-packing. Close-packed domains contain relatively smaller pores and pore-throats and so, have an affinity for the wetting phase. Loose-packed domains have been demonstrated to possess larger pores connected by larger pore throats. They form the major pathways for fluid flow and virtually all of the non-wetting phase (Prince, 1999). Both wetting and non-wetting phases can occupy the loose-packed circuits. As an oil column increases, buoyant forces will progressively inject the non-wetting phase into the close-packed circuits until residual water is bound by wetting effects as a film on pore walls. Such water will represent an immobile fraction. In the presence of an extremely long oil column, the non-wetting phase will probably enter close-packed porosity. We surmise that most of this non-wetting phase saturation within close-packed porosity will remain immobile during subsequent imbibition.

Packing flaws are not homogeneous and can be subdivided into inefficient and efficient classes. In terms of area, most of the packing flaws have a relative dilation of 20–30% of the modal grain size. Embedded within the 'normal' packing flaws are 'over-expanded' high-efficiency pathways with a spacing of 2.5–3.5 times the modal grain size. The evidence indicates that the residual non-wetting phase is associated with the 'normal' packing flaws, while the mobile non-wetting phase is associated with the high-efficiency tube-like pathways. The intimate proximity of these tubes to the surrounding normal loose-packed grains probably may explain the observed distribution of residual oil blobs in artificial media constructed from glass beads. Morrow et al. show photographs of residual oil blobs (Fig. 11, Morrow et al., 1988) in which the spatial density of the blobs is approximately 3–4 grain diameters.

The results discussed above should not be interpreted to mean that microstructure contrasts in the case of a uniform wetting state can control the values of end points. Other investigations must be performed on native state cores using the natural fluids under reservoir conditions to explore the degree of generality of our limited observations.

We have recently observed physical confirmation of another of Graton and Frasers (1935) hypotheses concerning the controls on the spatial density of expanded fabric. They surmised that the thickness of a zone of expanded porosity is a function of the degree of cohesiveness of a sand/water interface prior to the deposition of more sand on top of it. The inference is that the waning of a depositional event along with the continuing action of a steady-state current (no net deposition or erosion) allows uppermost section of the depositional unit to reach a greater degree of consolidation. In a typical deltaic reservoir sandstone, bedding features range from subparallel laminae a few grains thick to relatively large cross-bedded units up to several meters thick. The larger units that are commonly the most prominent bedding features in sandstone complexes probably represent an areally extensive water-sediment interface of relatively long duration (days, weeks, and months), and so develop a high degree of cohesion. The sudden deposition of a new layer on top of this cohesive surface will create a chaotic compromise zone at the interface with a greater proportion of expanded and over-expanded porosity. The thickness of this compromise zone should be a function of its position in the bedding hierarchy.

Evidence of this hierarchy can be found in partially oil-stained core. The prominent subhorizontal bedding surfaces generally have the thickest oil stain in the base of the overlying bed and the thickness of the oil-stained zone usually decreases with the size of the bedding feature until there is no staining between bundles of laminae. If this conjecture can be proved with more rigor, then it would appear that the segregation of the immiscible phases occurring at the small scale described herein may also occur at greater scales — and so must be taken into account in the attempt to simulate the response of the reservoir to production.

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