Resolving the Link between Porosity and Permeability in Carbonate Pore Systems

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ABSTRACT

In carbonate reservoirs, permeability prediction from porosity alone is often difficult due to complex pore systems leading to poor porosity-permeability relationships. The main objective of this paper is to resolve the porosity-permeability relationships by understanding the effects of rock texture, pore type as well as compaction/dissolution. Over 500 core plugs were studied from 5 different carbonate reservoirs across the Middle East. The data set available included laboratory-measured Helium porosity and gas permeability. The textures of the samples were analyzed in thin-section photomicrographs and were classified as grainy, muddy and mixed. The pore types were defined as interparticle, intercrystalline, moldic, intraparticle and vuggy. The texture information was plotted in the porosity-permeability domain. Clear trends were seen in the data improving the relationships between porosity and permeability. Different textures gave distinct porosity-permeability trends. The extent of the trend was controlled by the degree of compaction and dissolution. Conclusive relationships between permeability and textural rock properties were clearly found in carbonates, which can provide better permeability predictions from porosity. Rock texture was the main parameter important for the understanding of the porosity and permeability characteristics of the studied carbonate reservoirs.

INTRODUCTION

Core laboratory measurements can have a major impact on the reservoir modeling process [1] but often yield unrepresentative results that raise questions about the effectiveness of the core data in the reservoir model and its calibration. This is partly related to the lack of understanding of reservoir heterogeneity and to the unrepresentative selection of plug samples. Hence, the petrophysical data that is obtained is often left unexplained and with no possibility to link macroscopic measurements to fundamental microscopic properties and geological heterogeneities in the core [2].

As common carbonates have complex and multimodal pore systems, variation of permeability at single porosity can be very large (three to five orders of magnitude). This leads to poor porosity-permeability relationships [3] and imposes a challenge in classifying carbonates into rock types for proper permeability prediction. The porosity-permeability relationships can be resolved by additional information about the pore system, which is mainly related to the rock microstructure (texture) being grainy, muddy or mixed. The microstructure information can be obtained from thin-section photomicrographs. The microstructure (or micro-texture) of the rock has significant pore geometrical properties regarding flow of liquids through the core and thus largely define absolute permeability.

In this study, plug samples were selected to represent statistical distribution of porosity and textures in the cores. The porosity was initially derived from dual energy CT scanning [4] while the different textures were identified in the core X-ray CT images (see figure 1). The microstructure information of the plugs was confirmed from thin-section photomicrographs, and was plotted in the porosity-permeability domain. Samples with grainy microstructure gave high permeability whereas muddy samples showed lower permeability for the same porosity. The porosity and permeability data were fitted into unique trends based on the micro-textural analysis. The different trends were mainly controlled by the different rock microstructures whereas the extent of the trend was due to different diagenesis processes (e.g. cementation and compaction).

PERMEABILITY AND TEXTURE

Carbonate rocks can be geologically categorised based on their microstructures or textures. The microstructure and texture are used interchangeably to describe the rock content, which can basically be identified from a thin-section photomicrograph. Carbonate structures may be classified as grainy, muddy or mixed [5]. Grainy carbonate contains grains only. Muddy carbonate contains matrix only (mud). Mixed carbonate contains both grains and matrix. In this perspective, the Dunham [6] classifications of grainstone and rudstone, for instance, fall into the grainy class, while the mudstone and wackstone would fall into the muddy classification. Floatstone and packstone may be defined as mixed. In all these classes, the presence of cement and the effect of compaction/dissolution can be noticed. The aim of this texture-based classification is to realize the effects of grain size distribution and amount of micrite matrix on the flow characteristics in a porous carbonate. The understanding of these parameters can help establish a sound basis for potential correlations between microscopic and macroscopic properties. Such correlations in the porosity-permeability domain can greatly enhance the ability to predict permeability from porosity and texture. Figure 2 gives an overview of the effects of rock texture on permeability. Within the grainy texture, porosity and permeability can vary with grain size, grain compaction and presence of cement. Sample #1 has the lowest poroperm data because of cementation and compaction. Sample #2 has the highest permeability, which is the result of large grains and their uniform size distribution. Its porosity is moderate because of the large grains. Sample #3 has moderate permeability and high porosity because of the smaller grain sizes. The mixed texture samples have lower permeability values over the same porosity range. This is caused by the micrite content in the samples that maintain good porosity but lower permeability because of its small particle sizes and associated small pores. In the grainy samples the flow is mainly controlled by the interparticle porosity within the grainy structure, whereas, in the mixed samples, the flow is controlled by both the grainy and muddy structures, and is supressed by the intercrystalline porosity within the muddy structure. This explains the drop in permeability for the mixed samples at the same porosity. The muddy texture samples have the lowest permeability values over the same porosity range. This is obviously caused by the fact that permeability is only controlled by the intercrystalline porosity within the small micrite particles in the muddy structure.

TEXTURE-BASED POROSITY-PERMEABILITY RELATIONSHIPS

Five carbonate reservoir cores (A, B, C, D & E) were evaluated to understand the porosity-permeability relationships. Each cored interval ranged from 300 to over 500 feet, and some of the cores represented more than one formation. The cores were mainly limestone with highly varying porosity (~5% to 30%) and permeability (~0.01 mD to 1000 mD). One and a half inch (1.5”) diameter plug samples were statistically selected to represent all the cored intervals. Figure 3 to figure 7 present the conventionally measured helium porosity and gas permeability data on the selected plugs. The porosity and permeability data for each plug were associated with the sample texture that was identified from the corresponding thin-section photomicrograph. Figure 3 shows two distinct porosity-permeability trends from the analysed core in reservoir A. The textures of the samples were classified as grainy and muddy. No mixed texture was detected in the core. The grainy texture was dolomite while the muddy texture was calcite. Both textures revealed a rather large porosity range, which was the result of different degrees of leaching and compaction. The different textures had clear effects on the porosity-permeability relationships as well as on the capillary pressure (Pc) curves. The grainy samples showed higher permeability range with lower entry pressures. Figure 4 shows two distinct porosity-permeability trends from the analysed core in reservoir B. The textures of the samples were classified as grainy and mixed. No muddy texture was detected in the core. The grainy texture was oolitic grainstone while the mixed texture contained micrite matrix within the grainy structure. The different textures had clear effects on the porosity-permeability relationships as well as on the capillary pressure curves. The mixed samples gave lower permeability trend caused by the micrite matrix. The grainy samples had high porosity while the mixed samples gave large porosity range, which was the result of different porous micrite fractions in the samples. Figure 5 presents core data from a tight formation in reservoir C. The samples showed mixed structure with single porosity-permeability trend. Large porosity and Pc variations were caused by different degrees of compaction and cementation. Only few samples were analysed because of the poor physical condition of the core. Figure 6 shows texture-based poroperm relationships with unique average Pc curves from each trend in reservoir D. Five different trends were obtained: Grainy texture 1 (grainstone cemented), grainy texture 2 (rudstone cemented), grainy texture 3 (grainstone highly cemented), mixed texture 4 (packstone) and muddy texture 5 (wackstone cemented). The reservoir was well cemented, which had negative impact on the porosity of the samples. Figure 7 depicts different poroperm trends with unique average Pc curves in reservoir E. Four different trends were identified: Grainy with highest porosity and permeability, mixed with highest porosity range and lower permeability, leached muddy texture with lower permeability and large porosity range that is caused by different dissolution degrees, and muddy cemented texture, which gave the least porosity/permeability values.

DISCUSSION

The analysed samples and their porosity-permeability relationships are believed to be representative to the reservoir properties. This was possible by applying statistical sample selection [4,7,8] based on high-resolution dual energy CT imaging of the entire cores. In all the five reservoirs, it was possible to establish relationships between porosity and permeability in accordance to textural variation. The grainy, mixed and muddy textures seem to be the main controlling parameters in this relationship. Figure 8 plots all the reservoir poroperm data from figure 3 to figure 7. We can see distinct porosity-permeability trends in relation to the three identified textures. This result is very interesting and confirms the strong relationship that exists between permeability and rock texture. It is important to note that the often seen poroperm data cloud is not obtained in any of the analysed cores. All the poroperm data characteristics were classified and understood based on the rock textures. Although the rock microstructure appears to be the main control of flow we should also notice the effects of the porosity type. For instance, a muddy carbonate may have ‘touching vug’ porosity with a very high permeability.

Textural variations are best seen in thin-section photomicrographs but they can also be noticed in X-ray CT images (as in figure 1). This would allow plugging locations to be initially selected in the reservoir cores based on different CT textures. This would then provide the link between the plug poroperm trends and the different textures in the cores enabling permeability to be upscaled (from the porosity log) to the entire whole core intervals; this application was demonstrated in [7]. CT images can detect different textures while thin-sections confirm the geological contents. The different textures can be incorporated in reservoir rock typing as fundamental geological features of carbonate rocks. Grainy samples tend to show higher permeability and lower entry capillary pressures. If core CT images are not available, textures can be derived from facies analysis from core description. This texture-based technique can be implemented in logs if a reservoir facies model is established, which can correlate log response to facies in uncored wells.

CONCLUSIONS

Representative samples were analysed from five different carbonate reservoirs in the Middle East. The sample’s textures were identified from thin-section photomicrographs and were plotted in the porosity-permeability domain. Conclusive relationships between permeability and textural rock properties were clearly found in carbonates, which can provide better permeability predictions from porosity. The following can be concluded from the results in this study,

1. Three different textures (grainy, muddy & mixed) were identified in the reservoirs.
2. Distinct porosity-permeability trends were obtained for the different textures.
3. The extent of the trend was controlled by compaction, cementation and dissolution.
4. Similar textures within the different reservoirs gave similar permeability range.
5. Prediction of permeability is possible from porosity and rock texture.
6. The different rock textures gave distinct capillary pressure curves. This would make textural analysis a fundamental tool for rock typing.

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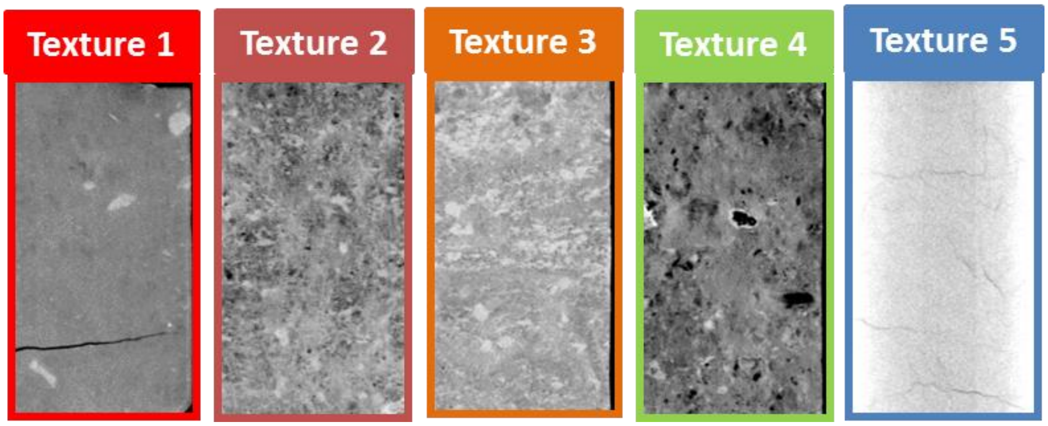

Figure 1 Example CT textures that can be identified in full-diameter 4-inch core

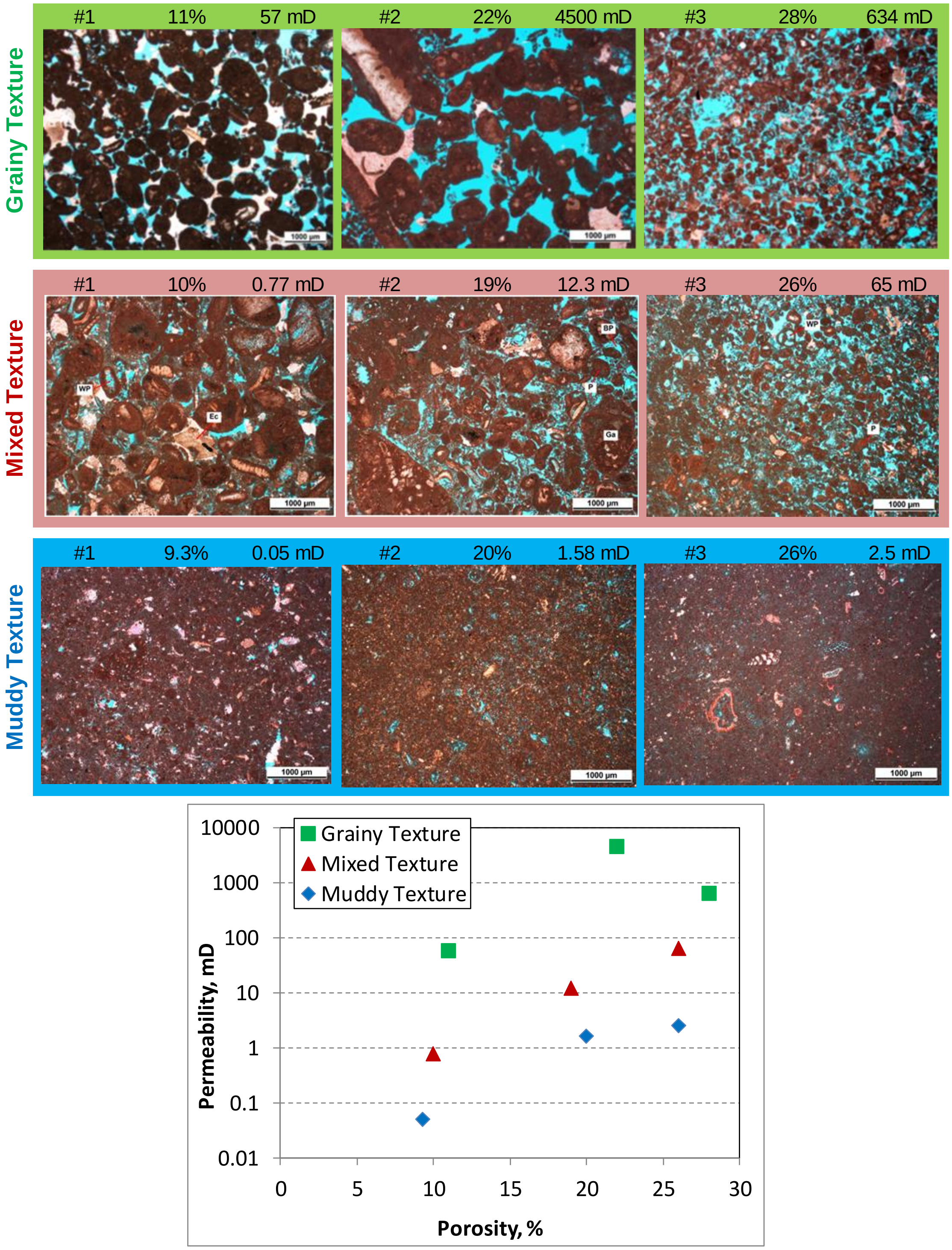

Figure 2 Permeability variation with rock texture/structure. Each sample is represented by its number, thin-section photomicrograph, porosity and permeability. Over the same porosity range, grainy samples tend to give the highest permeability values, while the muddy samples show the lowest permeability values. The mixed samples fall in between the grainy and the muddy samples in the poroperm plot.

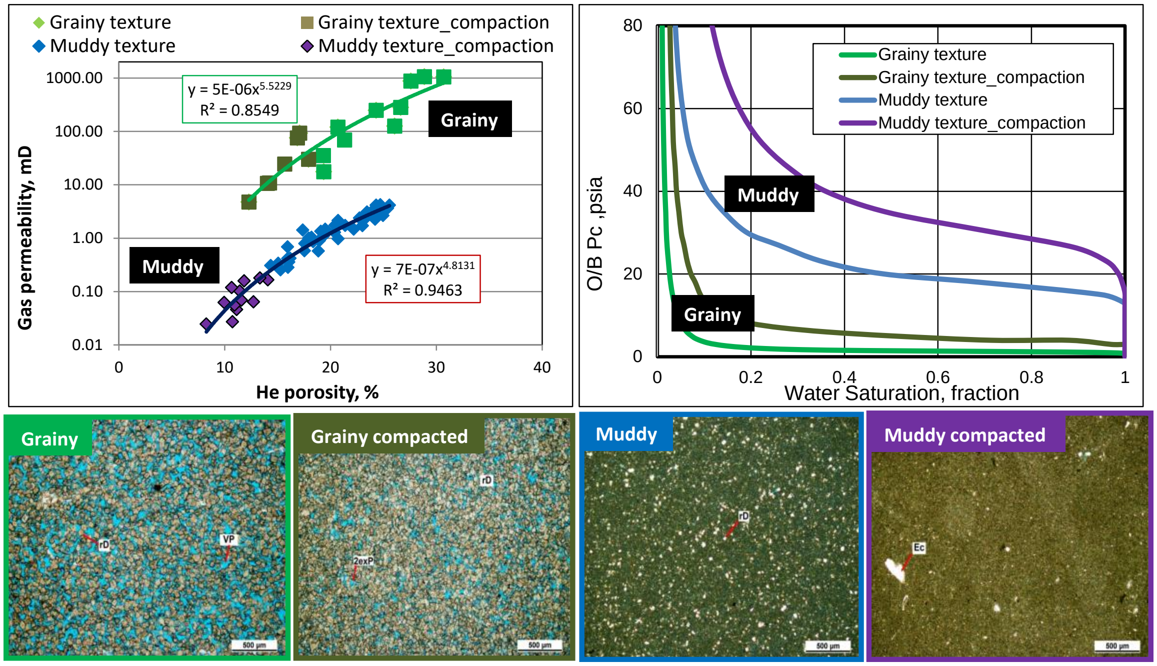

Figure 3 Grainy and muddy textures in reservoir A. Distinct poroperm trends with unique Pc curves

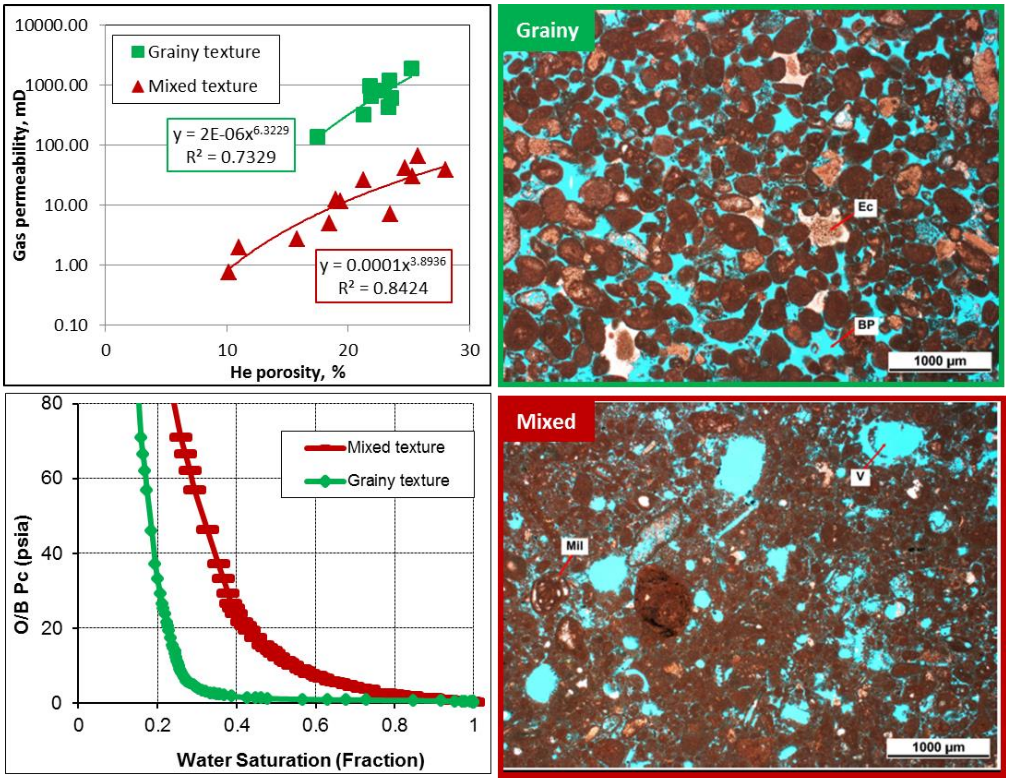

Figure 4 Grainy and mixed textures in reservoir B. Distinct poroperm trends with unique Pc curves. The thin-section photomicrographs and the Pc curves are shown for the average porosity samples.

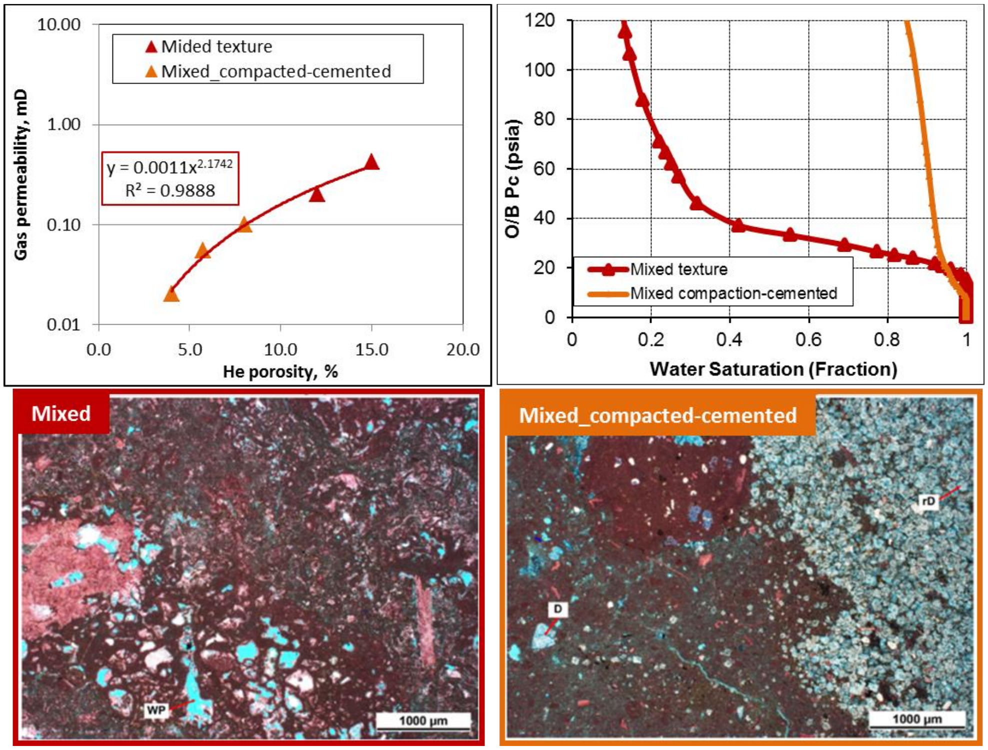

Figure 5 Mixed textures in reservoir C. Single poroperm trend with varying porosity and Pc curves caused by different degrees of compaction and cementation.

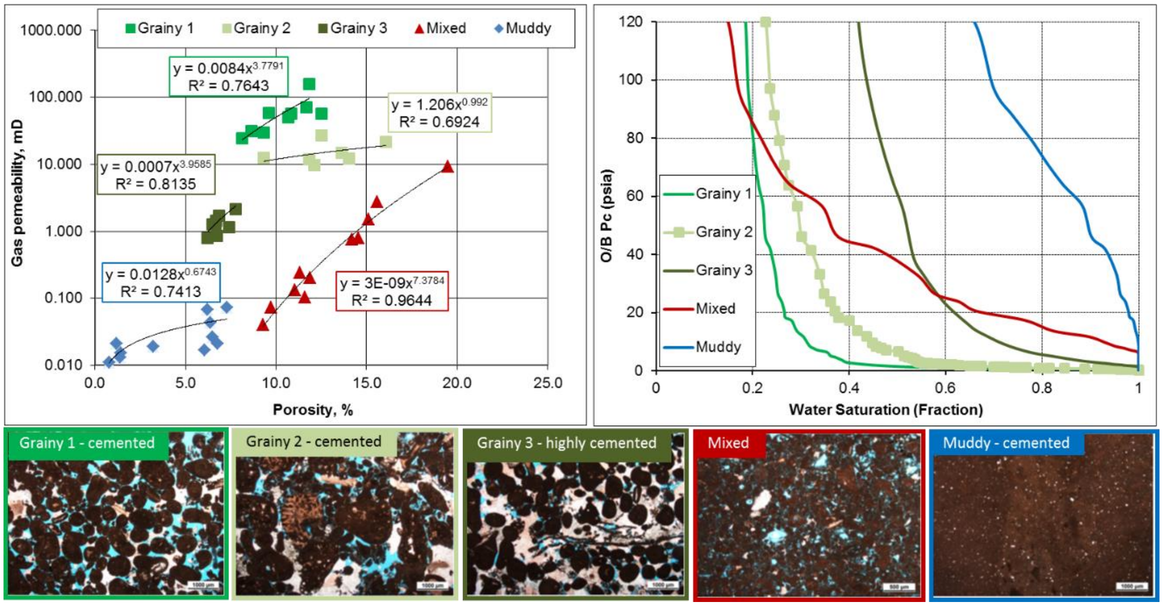

Figure 6 Texture-based poroperm trends with unique average Pc curves in reservoir D. Grainy texture 1 (grainstone cemented), grainy texture 2 (rudstone cemented), grainy texture 3 (grainstone highly cemented), mixed texture (packstone), muddy texture (wackstone cemented).

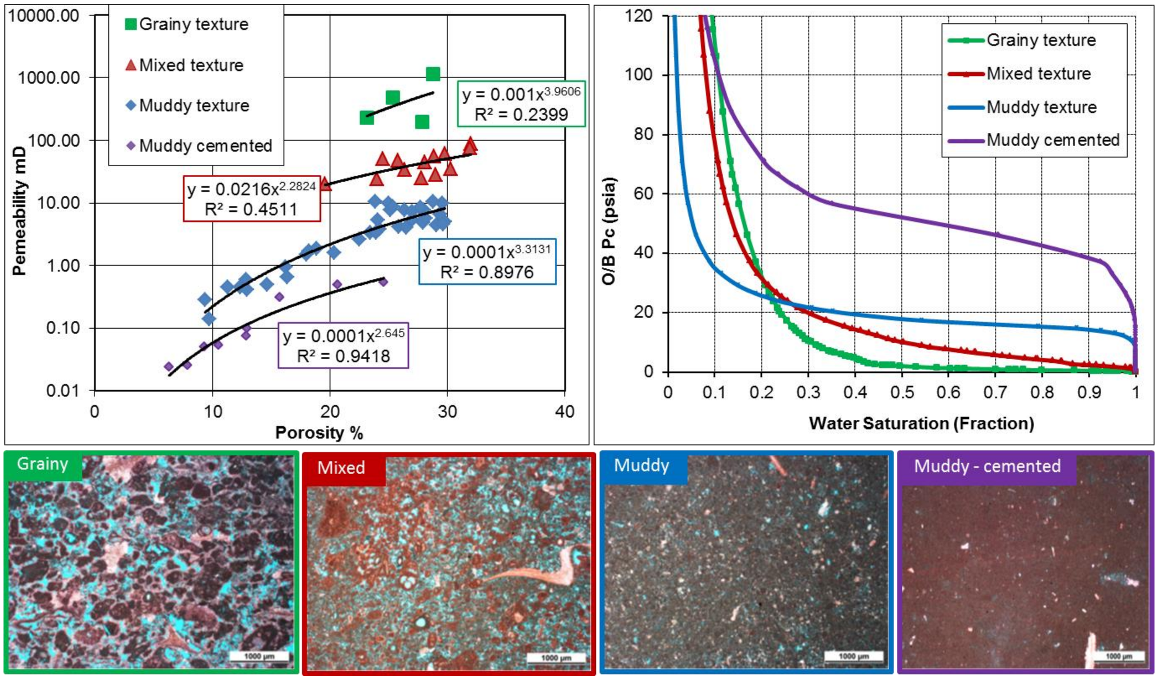

Figure 7 Texture-based poroperm trends with unique average Pc curves in reservoir E.

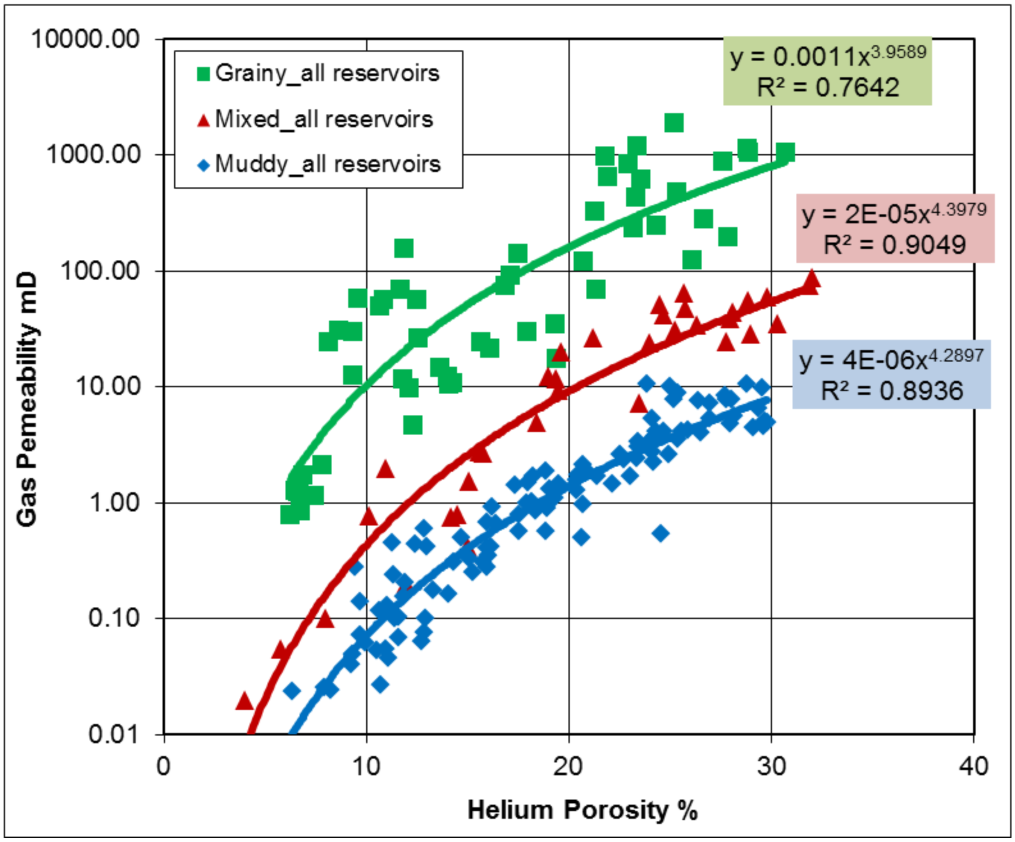

Figure 8 Texture-based poroperm trends for all samples in the five different reservoirs (A, B, C, D & E)