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The Impact of Rock Wettability in Fractured Reservoirs Behavior

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"Through the use of refined grids the water filling fracture regime can be observed in reservoir simulation for water-wet rocks."

Introduction

Fractures can have a great impact on reservoir behavior and, therefore, earlier the influence is determined, better is the management process. The rate at which water may transfer from the fracture to matrix system can vary according primarily by the rock wettability, matrix permeability and fracture intensity (Narr et al, 2006). Matrix-to-fracture transfer functions in reservoir simulation assume that fractures are instantaneously filled with water. However, this effect cannot be observed for some conditions, such as water-wet rocks. Rangel-German et al, 2010, introduce these observations by laboratorial experiments. So, depending on rock wettability, it could result in upscaling issues given the presence of imbibition forces in water-wet rocks which are not well represented in dual porosity numerical models. The purpose of this study is to show the impact of rock wettability in simulation flow response and upscaling procedures, for fractured reservoirs. The relative permeability curves used for this work are a combination of real field data and synthetic data (Ligero and Schiozer, 2014).

Methodology

Figure 1 shows the methodology. The first step is to define a fine grid model to use as reference solution for reservoir flow response. To avoid upscaling issues relative to geometric properties, which is not the focus of this work, the geological scenario is based on a synthetic refined model following Warren and Root's assumptions (orthogonal system of continuous and uniform fractures) for fractured reservoirs. The next step consists in applying a conventional upscaling procedure Oda, 1985) to discrete fracture networks in order to obtain the effective block fracture permeability for the coarse dual porosity model. The dual porosity model is then used to compare the reservoir flow response with reference solution. This approach is applied for seven cases by applying small changes to critical parameters (fracture spacing, aperture and injection rate). These seven cases are then applied for each wettability scenario, with the purpose of validating our results by using different scenarios. All scenarios are fractured reservoirs type II (fractures provide essential permeability).

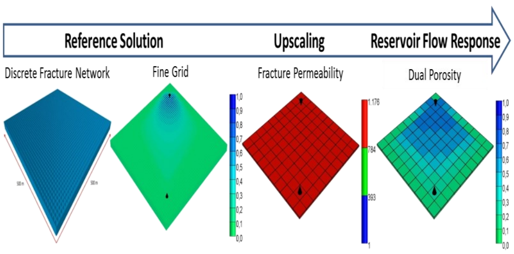

Figure 1: Simplified Methodology

Application and Results

For all the cases, fracture porosity is assumed as 0.1%, matrix porosity as 15% and matrix permeability as 10 mD. The matrix porosity is homogeneous and isotropic. The refined model measures 500 x 500 x 2 m³ and the grid cell 1 x 1 x 2 m³. The coarse model (dual porosity flow model) has a grid cell of 50 x 50 x 2 m³. The relative permeability for fractures is assumed as two straight-lines functions with endpoints at zero and 100% saturation. Figure 2 shows a close-up in water front near the injector well and the respective rock type for the reference solution. Is noticed that this is a water filling fracture regime as the matrix has higher water saturation in the initial stage. For the oil-wet case (Figure 3) the water saturation is more expressive in fracture system. The intermediate-wet example, which is not illustrated, presents a similar flow behavior compared to oil-wet case. For water-wet cases the imbibition process for water injection is more expressive (faster water advance in matrix) than for intermediate-wet and oil-wet rocks given the preference for water to be in contact with water-wet rock over oil-wet rocks. So, for intermediate-wet and oil-wet rocks the oil recovery from the matrix is mainly controlled by viscous and drainage forces and the matrix-fracture transfer fluid is largely dependent on matrix permeability. The matrix-fracture fluid transfer is more relevant in water-wet rocks due to the importance of imbibition forces in matrix oil recovery.

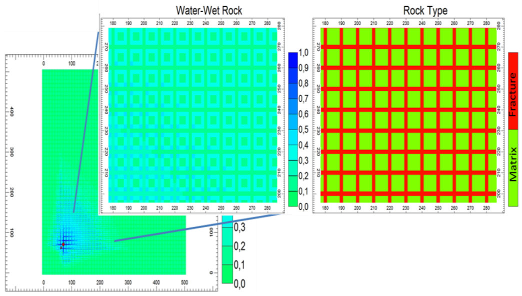

Figure 2: Water front for the water-wet rock

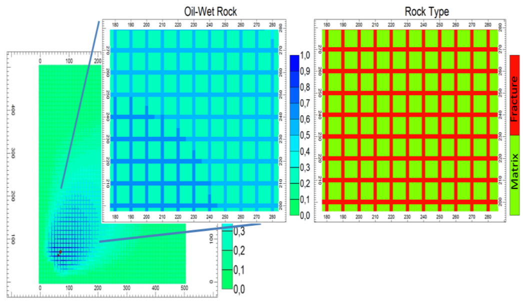

Figure 3: Water front for the oil-wet rock

Figure 4 shows the oil recovery factor for oil-wet and water-wet scenarios, as example. The oil recovery factor also shows that water-wet scenarios have a large sensitivity to parameters changes, comparing to oil-wet scenarios. The matrix recovery factor for oil-wet cases is mainly controlled by viscous forces due to an imposed pressure gradient. For water-wet cases, the matrix recovery factor is mainly controlled by spon-

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"Dual porosity flow models assume that fractures are instantaneously filled with water, leading to upscaling issues especially for water-rocks."

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taneous imbibition wherein the water from the fractures imbibes into the matrix by capillary pressure. This behavior for water-wet characteristics is due to the positive capillary pressure for all range of water saturation. Thus, for oil-wet scenarios, water will not displace spontaneously oil from the matrix and only the oil from the fractures and from matrix-fracture pressure gradients will be displaced. This explains the small oil recovery and the small sensitivity to the selected parameter changes for oil-wet scenarios.

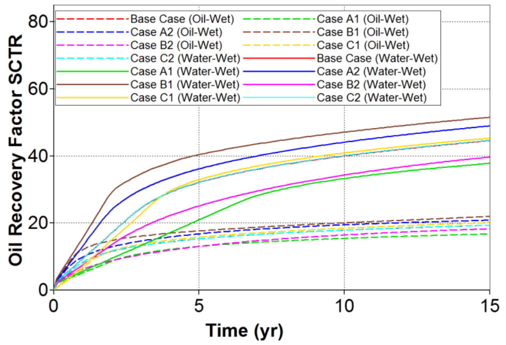

Figure 4: ORF for all scenarios

Figure 5 shows the oil recovery. These results show that the differences between the coarser and reference solution after upscaling to a dual porosity flow model is smaller for the oil-wet and intermediate-wet cases than for water-wet cases. Figure 6 shows these differences for ORF considering all scenarios. We see that the increase of rock preference for water leads to a larger difference between the dual porosity model and the reference solution, based in oil recovery factor. The relevance of imbibition forces explains the larger difference in upscaling procedure for water-wet cases.

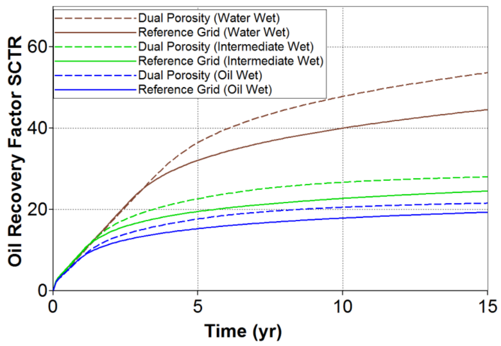

Figure 5: ORF for upscaling comparison analysis

Considerations

Through the use of refined grids, the water filling fracture regime can be observed in reservoir simulation for water-wet rocks. This behavior leads to a great impact in reservoir flow response given its higher imbibition rates comparing to oil-wet and intermediate-wet rocks, but

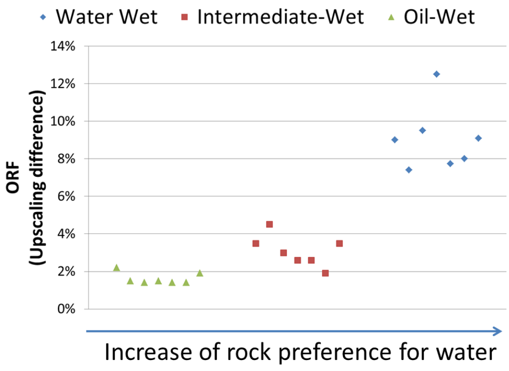

Figure 6: Differences between the dual porosity flow simulation and the reference solution, based in ORF, considering all cases

also leads to upscaling issues relative to dual porosity flow model limitations, as dual porosity flow models assume that fractures are instantaneously filled with water. So, even applying the conventional upscaling procedure under an "ideal" geometric case, the fine and coarse grid for water-wet cases are not matched because of the differences in dynamic behavior which came mainly from the relevance of imbibition forces in water-wet rocks.
This work shows that the increase of rock preference for water can lead to upscaling limitations due to dual porosity flow model assumptions for water displacement in fracture system. Despite his absence from commercial simulators, the time-dependent shape factors can consider the partially immersed fractures behavior. Nevertheless, a time-dependent matrix-fracture fluid transfer term can be applied in commercial software's.

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Manuel Gomes Correia is a researcher from UNISIM, and is currently working with upscaling procedures and reservoir simulation applied to naturally fractured carbonate reservoirs.