

Numerical simulations of CO₂ injection into a porous sandstone formation

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Abstract

CO₂ is sequestered in geological formations by three trapping mechanisms: solubility, mineral and hydrodynamic trapping. This is to capture and securely storage the CO₂ emissions produced by human activities from reaching the atmosphere. For this to happen the injectivity of the formation needs to be evaluated, for which formation permeability and flow properties are important factors to be determined. Also, relative permeability and residual saturation should be estimated when two phase flow is injected, e.g. brine and CO₂.

In this paper it was attempted to simulate numerically a core flooding lab experiment conducted to investigate injectivity of a sandstone sample. The experiment consisted of primary drainage displacement (brine displaced by CO₂) followed by primary imbibition (CO₂ displaced by brine) flood. The production profiles at both injection phases were estimated and the differential pressure across the sample was recorded.

ANSYS software was implemented in this study to construct a 3D core sample with similar size to the one tested in the lab. A fine grid mesh was generated for the model. Both injection phases were simulated numerically using the lab data. The pressure drop across the sample and the velocity profiles were extracted. Also, the relative permeability of the two phases was estimated. The results showed a fairly good agreement with those obtained from the lab experiments. The results are presented and interpreted.

Keywords: CO₂, modelling, relative permeability, ANSYS, CFX.

1 Introduction

The progression of fluid modelling has continued to be applied to the increasing field of carbon dioxide sequestration which is becoming more and more



prevalent due to the global issue of greenhouse gas emissions (Cooper *et al.* [1]). With this, a key parameter is the relative permeability of the carbon dioxide in relation to the brine which dictates the flow within the reservoir. The residual saturations associated with this data controls the storage capacity of the formation and determines the volume of water which will be unmoved during the injection of the CO₂.

Laboratory experiments have been effective in concluding the accuracy of the use of core flooding experiments to determine the relative permeability of gas through water; particularly achieving great accuracy in calculating residual saturations of the two phases (Mulyadi *et al.* [2]). However, these experiments are costly and time consuming. Hence, numerical simulations have been performed in the past and are becoming more common to gain the required information. Various numerical simulations have accurately determined the two phase flow through tight gas sand using the FLUENT fluid modelling tool of CFX-F3D (Khlaifat *et al.* [3]). However, this was limited to very low porosity and permeability formations and is not applicable in the injection of CO₂ which generally occurs into sandstone aquifers (Cooper *et al.* [4]).

With the use of ANSYS and the modelling solver CFX, the relative permeability of CO₂ injection into a porous media can be modelled. This will enable the high cost and time associated with the use of laboratory equipment to be reduced by conducting only few lab experiments for validation purposes.

With the application of the Darcy equation, the volume of fluid which is produced and the differential pressure which is witnessed across the sample can be combined to determine the relative permeability. This is applied to a laminar, isothermal and incompressible fluid model across a porous sandstone core.

This paper will outline the process undertaken to develop this model and also compare the results between the laboratory experiments undertaken and the final numerical modelling.

2 Laboratory data

In this study the data corresponding to a sandstone core sample which was tested in the lab for injection studies were used for numerical simulations using CFX. The experiments carried out using a core flooding rig. The sample has a diameter of 38 mm and a length of 79 mm and has a porosity of about 20%. The in-situ Brine Permeability of the sample was measured to be 165 mD.

The two stage unsteady-state experiments consisted of primary drainage displacement, followed by a primary imbibition flood of CO₂ being displaced by the brine solution. The experiment was carried out at a pore pressure and overburden of 2580 psi and 6725 psi, respectively. The test was conducted at a temperature of 83°C and the formation salinity was 30,000 ppm.

During the drainage and imbibition stages of the experiment, approximately 15 pore-volumes of the appropriate injection fluid were pumped through the sample. This was at a rate of 300cc/hour for the carbon dioxide and 200cc/hour for the brine solution.



Figure 1(a) presents the cumulative produced volume of brine with Figure 1(b) showing the differential pressure observed across the sample. The pressure volume of fluid which was produced as well as the measured pressure differential was utilised in order to calculate the relative permeability which has been plotted in Figure 2.

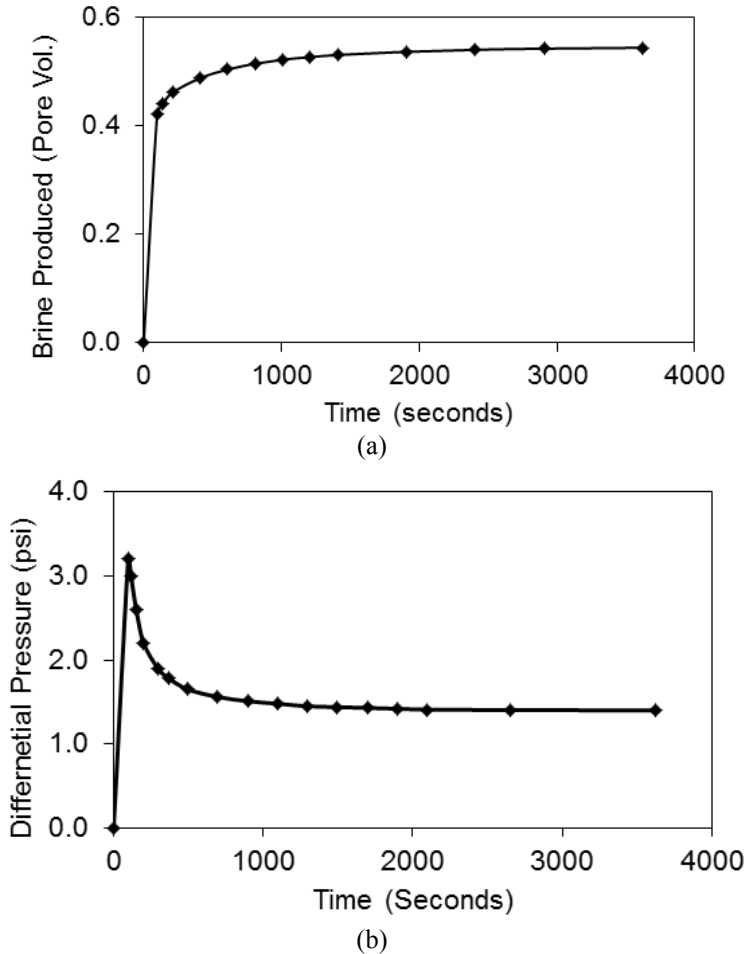


Figure 1: Cumulative produced volume of brine (top) and pressure differential across the sample (bottom).

The irreducible saturations which were determined from the core flooding experiment was $S_{wr}=45.57\%$ during the drainage process and $SCO_2, r=20.45\%$ during imbibition process.

The above information used in section 4 in order to perform numerical analysis to simulate lab experiment.

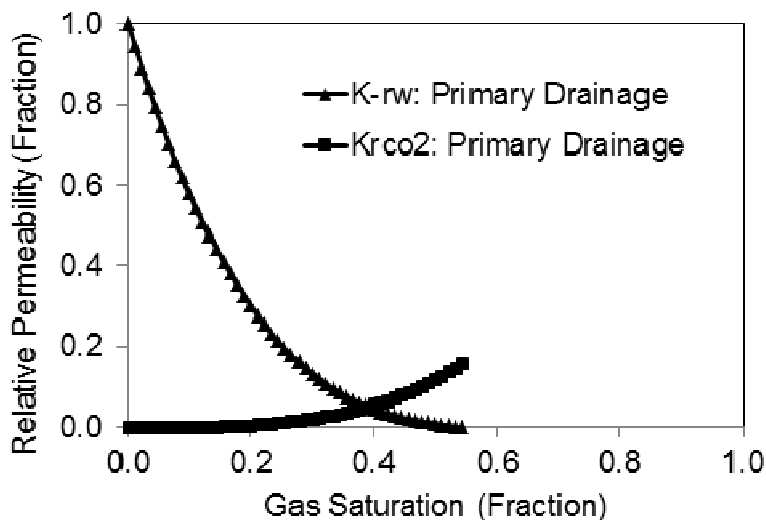


Figure 2: Relative permeability of the tested sample.

3 CFX modelling

The CFX3D module in the ANSYS commercial software was used for numerical simulations of injection into a porous media in this study.

To solve the system the continuity and momentum equations must be outlined to determine the interfacial forces between the phases and porous media. These equations are expressed in the following forms (Khlaifat *et al.* [5]):

$$\frac{\partial}{\partial t}(\phi S_{\alpha} \rho_{\alpha}) + \nabla \cdot (\phi S_{\alpha} \rho_{\alpha} U_{\alpha}) = 0 \quad (1)$$

$$\frac{\partial}{\partial t}(\phi S_{\alpha} \rho_{\alpha} U_{\alpha}) + \nabla \cdot (\phi S_{\alpha} (\rho_{\alpha} U_{\alpha} X U_{\alpha} - \tau_{\alpha})) = \phi S_{\alpha} (B_{r\alpha} - \nabla P_{\alpha}). \quad (2)$$

In above equations α denotes the phase, ϕ is porosity, ρ_{α} is phase density, S_{α} is the saturation, U_{α} is the velocity vector, τ_{α} is the viscous stress tensor, $B_{r\alpha}$ is the interfacial momentum transfer between the rock and the phase.

The total saturation of the two phases is 100%:

$$S_w + S_g = 1. \quad (3)$$

These equations enable the system to be solved between the cells over the individual transient time periods.

In CFX the porous media is defined using two terms of viscous and inertial loss, which are added into the fluid flow equations. The source term including these terms is defined as (Rasouli and Rasouli [6]):

$$S_i = - \left(\sum_{j=1}^3 D_{ij} \mu v_j + \sum_{j=1}^3 C_{ij} \frac{1}{2} \rho |v_j| v_j \right). \quad (4)$$

Here S_i is the source term for the i^{th} (x , y , or z) momentum equation, and D and C are prescribed matrices. This momentum sink contributes to the pressure gradient in the porous cell, creating a pressure drop that is proportional to the fluid velocity in the cell. For a homogenous porous media equation (5) simplifies to:

$$\frac{\Delta p}{l} = - \left(\frac{\mu}{\alpha} v + C \frac{1}{2} \rho v^2 \right). \quad (5)$$

This equation calculates the pressure drop per unit length in a porous media with permeability α (or viscous resistance $K=1/\alpha$) and inertial resistance C for a fluid with viscosity μ and density ρ flowing at a mean velocity v .

4 Numerical simulations

An ideal homogeneous material, laminar flow regime, and an isothermal and incompressible fluid were assumed for the purpose of this simulation. The boundary conditions defined included the inlet, outlet and no-slip wall.

The model has a similar size to the core sample tested in the lab (see section 2). A coarse size mesh including 3264 elements was used initially to reduce computational time during the refining stage, before a fine mesh made up of 53808 cells and 57246 nodes was used for the final modelling process. A medium smoothing as well as a proximity and curvature analysis of the mesh was used to increase the accuracy and reliability of the results. A view of the finer meshed model is shown in Figure 3. This is an accurate depiction of the core plug used in the laboratory with the same dimensions and pore volume making up the base of the model.

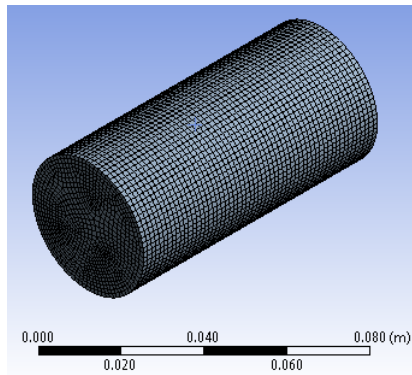


Figure 3: Core geometry and model mesh.

The boundary conditions were set in order to mimic the laboratory experiment. The inlet was initiated as a uniformly distributed pressure of 1MPa, while the outlet was left at atmospheric pressure. The differential pressure of the

subsonic, homogenous and incompressible fluid was measured across the two points during the modelling process.

The permeability and resistance loss coefficient used in this study were $1 \times 10^{-12} \text{ (m}^2\text{)}$ and $1 \times 10^{12} \text{ (m}^{-1}\text{)}$, respectively. These values found to produce a sample model being representative of the tested sample in the laboratory. While the model was initialised at 99% water saturation and 1% air before being injected a flow of carbon dioxide. This is due to the model not performing accurately to initially fully saturated water sample.

5 Results and discussions

Figure 4 shows the contours of fluid velocity (in this case the carbon dioxide as an example) along a plane which has been sliced through the middle of the core plug.

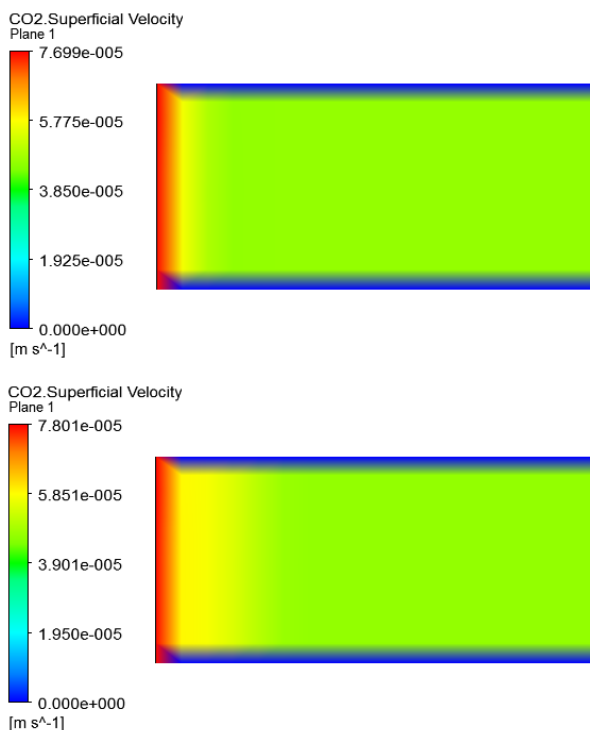


Figure 4: Contours of CO₂ velocity across the sample at 50 seconds (above) and 150 seconds (below).

From Figure 4, it is seen that the velocity of the gas decreases moving from the centre of a sample towards both walls. This is due to the non-slip wall condition which has been applied to the sample. This means that the velocity of

any fluid along the outer wall of the core will be equal to zero due to the attraction between the fluid and the sample.

It is also evident that as the saturation is increasing (from 50 seconds to 150 seconds in the figure) as it invades a larger proportion of the core that the velocity is also increasing. This is due to the relative permeability of the two fluids interacting and the results are as expected from the assumptions made with the modelling process.

Although this may not be accurate to real life conditions as with any gas flow through a core, some slippage may exist at the surface. This would lead to a small fluid velocity being present at the boundary instead of the absolute zero experienced in the numerical simulation.

In Figure 5 the volume fraction of CO₂ after 50 (top) and 150 (below) seconds are shown. The result show that as time evolves CO₂ penetrates into the formation and displaces the water phase.

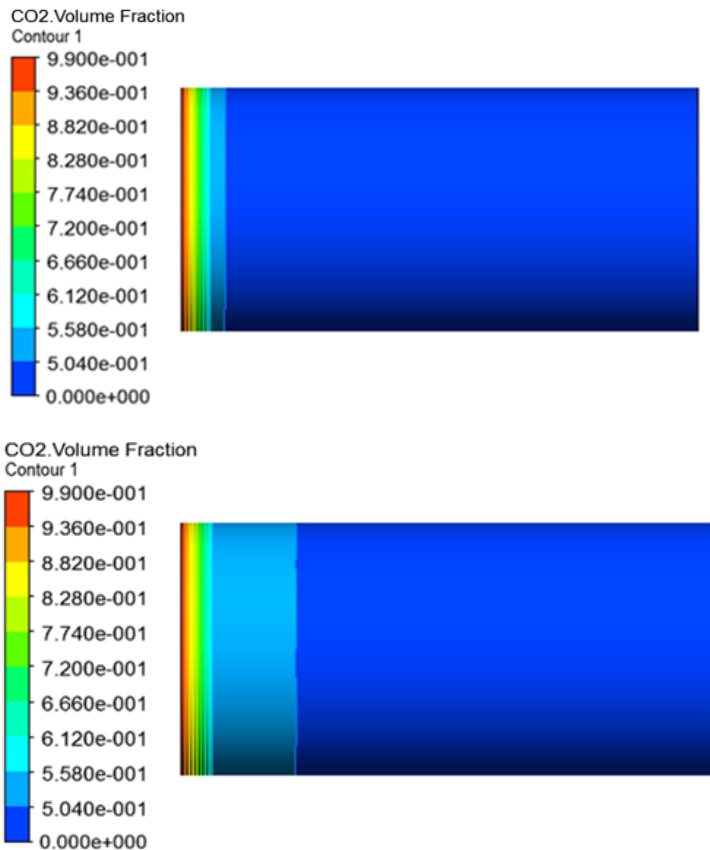


Figure 5: CO₂ volume fraction at 50 (top) and 150 seconds (below).

In figure 6 the initial pressure drop along the axial length of the core sample from inlet (left) to the outlet (right). As it is seen, and expected, the pressure reduces gradually moving to the outlet. As the time is increase the pressure drop begins to decrease as the sample changes from saturated with brine to carbon dioxide.

The CO₂ saturations along the sample length at various times have been extracted from numerical simulations and the results are plotted in Figure 7.

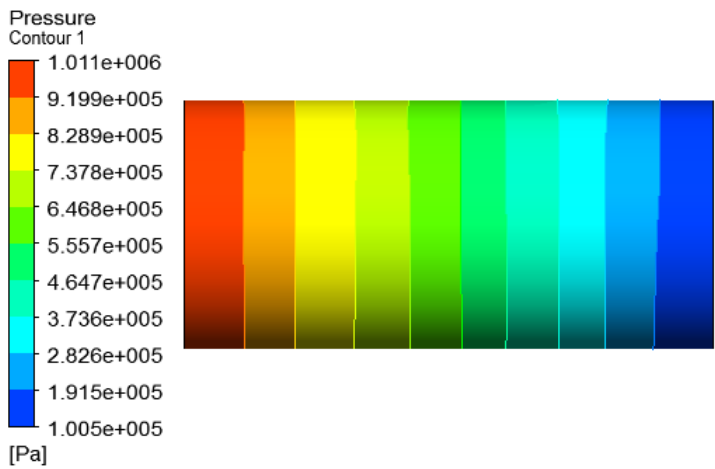


Figure 6: Pressure contours along the sample length.

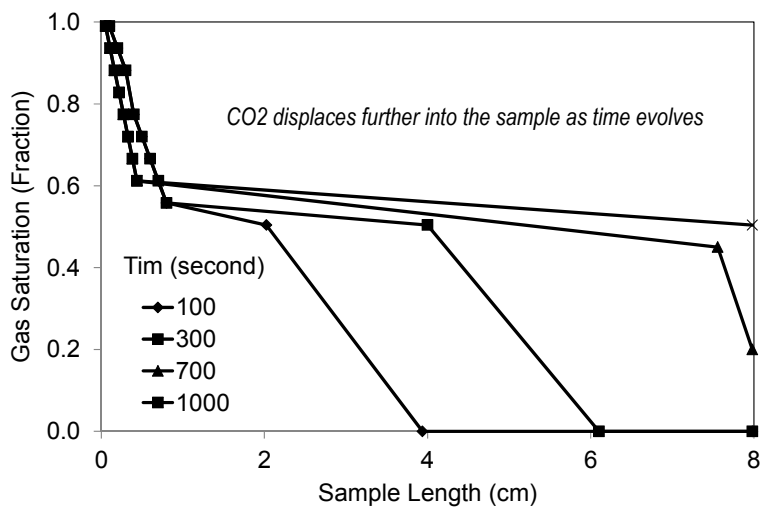


Figure 7: Initial pressure distribution (above) and CO₂ saturations along the sample length at various times (below).

From this figure it is seen how CO_2 displaces into a longer length of the sample had it been given more time and hence displaces more brine solution which can be seen in figure 8.

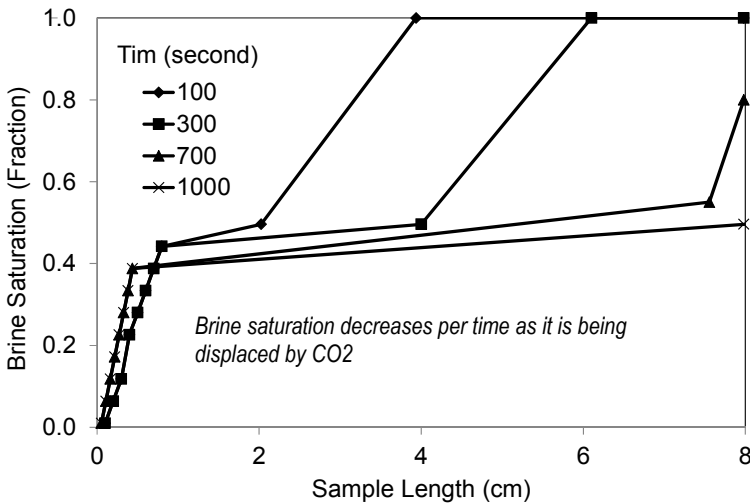


Figure 8: Brine saturation along the sample length at various times.

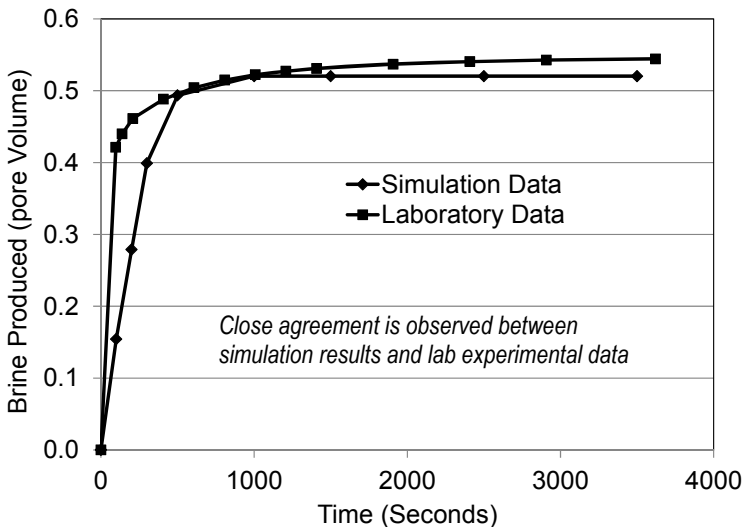


Figure 9: Cumulative produced volume of brine.

Figure 9 shows the simulation results of fraction of cumulative produced volume of Brine. The results of lab experiments are also plotted in this figure which presents a very close agreement with those of numerical simulations. The

production of brine as a fraction of the total pore volume of 18.8cm^3 shows the correlation between the simulation and laboratory experiment.

The results of the simulation are highly sensitive to the resistance coefficients and these have been able to manipulate the rate at which the carbon dioxide is filtered through the system. The front of the CO_2 which is injected through the sample is highly linear and does not necessarily follow the changing trend of the laboratory experiments. This may be due to the lack of capillary pressure data, but due to the highly porous nature of the sample the consequences of this would be minimised.

Also, due to the small pressure differential across the sample after the core flooding is started in comparison to the initial conditions, this plot from the laboratory experiment cannot be recreated.

The irreducible saturation of the water phase has been matched accurately and is a key to determining the storage volume of carbon dioxide within a porous underground formation. This gives the user confidence that the simulation models are correlated to laboratory experiment and can be used for different samples and even larger scale simulations of bulk fluid movement of injecting carbon dioxide.

However, in order to make these results even more accurate in the early time steps of the numerical simulation, an additional number of the more complex components in CFX3D would have to be considered. This would include temperature effects, capillary pressure data and also the effects of turbulent gas flow through the sample to generate a more comprehensive model used for a wider range of investigations.

6 Conclusions

The laminar flow of carbon dioxide through brine solution in a porous media was modelled using the CFX3D as a module of ANSYS. The numerical simulation was able to accurately reconstruct the laboratory experiment of carbon dioxide injection into a brine saturated sandstone core sample. This was evident in the correlation between the rates of brine produced and the movement of the carbon dioxide flood front through the sample.

However, this is an initial study into the application of the software into the feasibility for determining relative permeability with ANSYS and CFX. Hence for future works the complexities of non-Darcy flow, compressible fluids and capillary pressure will need to be investigated to provide a more accurate and robust system of producing relative permeability for new samples. If this can be achieved, the cost and time saved for laboratory experiments will be reduced with accurate results still able to be produced.

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