Modelling Long Term CO_2 Storage in Saline Aquifers

Abubakar Mohammed
School of Mechanical Engineering,
University of Leeds, Leeds, United Kingdom

Gabriel A. Ekoja
Institute of Petroleum Engineering,
Heriot-Watt University, Edinburgh, United Kingdom

Akinola A. Adeniyi
School of Mechanical, Material, and Manufacturing Engineering,
University of Nottingham, Nottingham, United Kingdom

Abdulkadir B. Hassan
Department of Mechanical Engineering,
Federal University of Technology, Minna, Nigeria

Abstract

Deep saline aquifers provide a large storage for CO_2. To ensure for long timescale storage, CO_2 is usually injected into the saline aquifers. It is important to understand how a storage will behave based on the injection rate of the CO_2, such as knowledge of the gas migration pattern, saturation pattern among others. Selection of simulation tools usually depends partly on software capabilities. In this work, three computational applications (Eclipse 300, CO2STORE module, and Front Sim) were used with flow simulation of a ten year period at an injection rate of over 140,000 sm^3/day. A recommendation is made of the application suitable for an oil field with likelihood of large pressure variation, gas breakout, hysteresis and imbibition.

Keywords: CO_2 Storage, Saline Aquifers, Eclipse 300, Front sim, CO2STORE.

1. Introduction

One of the proposed methods for reducing the amount of CO_2 into the atmosphere is to capture CO_2 from power stations and inject into the subsurface. In particular deep saline aquifers provide a large storage area worldwide. A problem in simulating CO_2 injection, as with many other reservoir processes, is that if we construct detailed models with many grid cells, the time scale for flow simulation is prohibitive. In oil reservoirs, streamline simulation is often used to overcome this drawback. A pressure solve is performed at one time step, and streamlines are traced throughout the model. The injected fluid is then advanced along the streamlines. FrontSim is a streamline simulation software, which is part of the Eclipse software. This program cannot simulate all the physical processes which take place when CO_2 is injected into a reservoir. However, because it is powerful and runs relatively fast, it is very useful for determining the migration of CO_2 in a complex geological model. A more accurate method for simulating CO_2 injection is to use Eclipse 300, which is the compositional version of Eclipse. The module CO2STORE has been specially designed for CO_2 storage, and can take account of dissolution of CO_2 in water. Obviously a complex program like this takes longer to run than a streamline simulation. This paper will aim to compare both software to find out which is more accurate to use whether the FrontSim on detail geological model less physics or Eclipse300 on coarse model with less geology and more physics.

1.1 Numerical modelling of CO_2 storage in saline aquifers

The key objective for introducing CO_2into saline aquifers is to ensure that injected CO_2 remains in the subsurface over along timescales.

CO_2 storage in deep saline aquifers can be achieved in four ways: either as a dense mobile free phase, as a trapped residual saturation, as dissolved in the formation water or precipitated as carbonate mineral.TheCO_2 transport processes that are relevant to CO_2 storage in the subsurface are the advection, buoyancy and diffusion. The advection is the movement of CO_2 caused by pressure gradient; buoyancy is caused by the density differences between the gas/liquid phases and diffusion which is caused by concentration gradients. Ukeagbu et al [1] reported that advection is the dominant transport mechanism during injection period, while the flow is mainly buoyancy driven during the post-injection period. The modelling involves several processes, the interaction of which may be described by complex mathematical equations. Consequently, numerical modelling tools have been frequently employed in the study of CO_2 storage. Many scholars [2-4] investigated various aspects of CO_2 storage in saline aquifers and generally adopted one of the two approaches: black-oil and compositional modelling as the way forward.

1.2 Black-Oil Approach

Black-oil reservoir simulators are used in the investigations. Typically, oil is assigned the properties of the water phase and gas is assigned the properties of CO_2. Properties for the phases (e.g. viscosity and density) are user-supplied, based on established correlations and/or laboratory data. Al-Abri [2] examined the effects of varying different properties of a homogeneous aquifer on the fate of injected CO_2. He used rock properties similar to the Utsira formation, the target formation used by *Statoil* for CO_2 storage in the Sleipner field in Norway. He noted, by conducting a grid refinement study, that simulation models with coarse grid blocks overestimate the amount of dissolved CO_2.Mo and Akervoll [5] modelled hysteresis in the gas relative permeability curve and noted a decrease in the amount of trapped CO_2 with a reduction in permeability anisotropy. In this anisotropic flow, less CO_2 is trapped in a homogenous model than in a heterogeneous model. They also concluded that the dissolution of CO_2 in brine is the most dominant mechanism of CO_2 storage in saline aquifers provided that the vertical communication in the aquifer allows for the convective mixing of the CO_2plume into the brine phase. Ide *et al.* [6] extended the work by Mo and Akervoll on the trapping of CO_2 as a residual phase by brine and concluded that viscous-dominated displacements, coupled with increasing capillary pressures and aquifer inclinations, serve to enhance CO_2trapping.

1.3 Compositional Approach

These studies take into account the various components that can exist in the gas and liquid phases. The bulk of studies fall into this category. Two subgroups are identified, based on whether mineral trapping is considered or not.

1.3.1 Without mineral trapping:

This approach does not take into account the geochemical reactions between CO_2 and the host rock. Ghanbari*et al.* [3] examine CO_2 storage in homogeneous and heterogeneous saline aquifers and concluded that aquifers that maximize solubility trapping are best for storing CO_2. In heterogeneous formations, low vertical to horizontal permeability ratios promote lateral migration of CO_2, thus increasing the brine surface area contacted by CO_2 and consequently enhancing solubility trapping. It seems however, that buoyancy-driven flow occasioned by density differences improves solubility in homogeneous formations. Doughty [7] and Flett*et al.* [8] direct their attentions to quantifying the contribution of residual trapping to storage of CO_2. While Doughty concludes that hysteres is should be modelled in problems involvingCO_2 storage for more accurate results, Flett*et al*[8] noted that highly heterogeneous aquifers delay trapping ofCO_2 as a residual phase and have the added advantage that they can delay reliance on the formation seal provided they possess sufficient injectivity.

1.3.2 With mineral trapping: Other compositional

This approach examines the geochemical effects due to injection of CO_2. Gunter *et al* [4] suggested that Silicaclasticaquifers make for better CO_2 mineral traps than carbonate aquifers, while Xu*et al*[9] noted that under' favourable conditions', the amounts of CO_2 stored as minerals may be comparable with dissolution. Pruess*et al.* [10] quantified the contribution of mineral trapping for various formations. Kumar *et al*[11] and Ozah*et al*[12] focus more on the relative importance of CO_2 trapping at the pore scale, but noted that the contribution of mineral trapping is small even over long timescales. Given that most simulations in this work are carried out for only 20 years, mineral trapping is not taken into account.

1.4 The Streamline Simulation Method

The streamline simulation method solves a 3D problem by decoupling it into a series of 1D problems, each one solved along a streamline. Unlike finite difference (FD) simulation, streamline simulation relies on transporting fluids along a dynamically changing streamline-based flow grid, as opposed to the underlying Cartesian grid.The result is that large time step sizes can be taken without numerical instabilities, giving the streamline method a near-linear scaling in terms of CPU efficiency vs. model size [13]for very large models, streamline-based simulators can be one to two orders of magnitude faster than FD methods. The time step size in streamline methods is not limited by a classic grid throughput condition but by how far fluids can be transported along the current streamline grid before the streamlines need to be updated. Factors that influence this limit include nonlinear effects like mobility, gravity, and well rate changes[14].

This paper compares simulations of CO_2 injection into a fine-scale heterogeneous model using Eclipse 300, CO2STORE module, and Front Sim. Also, the heterogeneous model will be upscale and coarse model simulated using Eclipse 300.This will be to determine whether it is more accurate to use Front Sim on a fine grid or CO2STORE on a coarse grid.

2.0 Methodology

2.1 Geological Model

Detailed 3D heterogeneous and homogenous geological models were constructed for both the Front Sim and Eclipse300. The homogenous model of dimensions 20 X 20 X 20(8000 blocks)was constructed to test the simulation. Two detailed 3D heterogeneous models were constructed with one very heterogeneous and with many grid cells of 75 X 100 X 80 (600,000 blocks) and another up scaled fine version of the model to 33 X 50 X 80 (152,000 blocks). Both of these models were run on the Front Sim for duration of ten years and a tan injection rate of 143,000 sm^3/day (one–tenth of the injection rate of the Sleipner project in Norway). The fine model of 33 X 50 X 80 was run on Eclipse300 using the CO2STORE option and was then upscale to coarse model of 25 X 33X20 (16,500 blocks) and was also simulated using the same option in Eclipse300. The simulation on Eclipse300 was also done at the same injection rate and duration.

2.2 Simulations

In the Front Sim simulation, water was used in place of oil and the PVT properties of water was used to replace the PVT properties of oil as given in table 1. Gas was given the PVT properties of CO_2 as shown in table 2. The relative permeability was calculated using Pruess*et al* [10] and the capillary pressure from the well-known Brooks and Corey correlation[15].The same relative permeability properties were used in both soft wares. The PVT properties for the CO_2 and water were defaulted in the Eclipse300 CO2STORE.Two vertical wells were drilled in both simulations. One injector well and one producer well. The producer well was shut to avoid any production. The wells were placed in the same position for the homogenous case in both the Front Sim and Eclipse300 and in high permeability zone and down the dip. Perforation was done at the bottom layers far from the cap rock. Also, the same style was employed in positioning the fine heterogeneous grids in both the Front Sim and Eclipse300. CO_2 was injected for a period of ten years in both simulations. The control mode for both simulations was by rate. The mean sea temperature of 38^oC was used and a typical hydrostatic pressure was assumed

2.3Fluid Properties

The only fluid phase in the reservoir before CO_2 injection is the saline water. The PVT properties of CO_2 and brine were obtained from using web calculator. Table 1 and 2 present the properties of brine and CO_2 used in the Front Simsimulation.

Table 1. The PVT Properties of Brine used in the Simulation

Pr (Mpa)	Rs (rm^3/sm^3)	Bw (rm^3/sm^3)	Viscosity (Mpa.s)
1	3.126	1.02414	0.4648
10	20.436	1.04500	0.4672
13	22.632	1.04688	0.4680
15	23.537	1.04734	0.4685
17	24.248	1.04753	0.4690
19	24.860	1.04759	0.4695
21	25.413	1.04757	0.4701
22	25.674	1.04754	0.4703
25	26.408	1.04740	0.4711
28	27.091	1.04721	0.4719
31	27.735	1.04698	0.4720

Table 2. The PVT Properties of CO_2 used in the Simulation

Pr (Mpa)	Bg (rm^3/sm^3)	Viscosity (Mpa.s)
1	0.1153900	0.01692
10	0.0070271	0.02301
13	0.0041750	0.03318
16	0.0031536	0.04521
20	0.0027008	0.05610
24	0.0024897	0.06396
30	0.0023094	0.07324
32	0.00222666	0.07595
40	0.00213890	0.08567

2.4 Relative Permeability and Capillary Pressure

The capillary pressure was model using Brooks and Corey type ref were employed in this study and relative permeability method of Prues et al [10] were used.

$$k_{rw} = \sqrt{S^*}\left[1 - \left(1 - [S^*]^{1/m}\right)^m\right]^2 \quad (1)$$

$$k_{rg} = \left(1 - \acute{S}\right)^2\left(1 - \acute{S}^2\right) \quad (2)$$

Where, $S^* = (S_w - S_{wr})/(1 - S_{wr})$ and
$S^* = (S_w - S_{wr})/(1 - S_{wr} - S_{gr})$, S_{wr} is irreducible water saturation (set to 0.1), S_{gr} is residual gas saturation (set to 0.05), and mis 0.6269. Hysteresis in the gas relative permeability curve was not modelled. Capillary pressure, Pc, was modelled using the approach of Brooks' and Corey[15] given as:

$$Pc = PdS^{-1/\lambda} \quad (3)$$

Where *P*d is pore entry pressure (Pa), *S*e is effective water saturation defined as *S*e = $(S_w - S_{wr})/(1 - S_{wr},)$ and $\lambda$is shape parameter for the capillary pressure curve. Parameters *P*d and λ have been set as 10 Pa and 2 respectively, based on a similar study by Kopp*et al.* [16]. Figure 1 shows the graph of K_{rg}, K_{rw} and $P_{c.}$

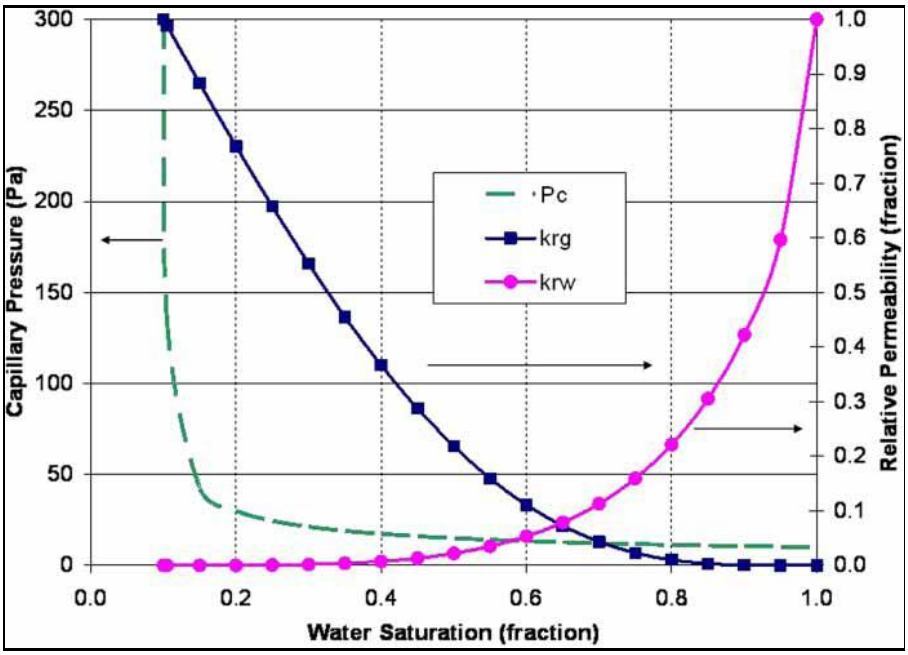

Figure1.The capillary pressure and relative permeability curves used in the simulation.

3. Results

3.1Homogenous Model Results:

The field gas injection total for both Front Sim and Eclipse300 was the same at the end of the injection period. A total of $1x10^9 sm^3$ of gas was injected in both Front Sim and Eclipse300 at the end of the injection period as shown in Figure4.The average field pressure in the Front Sim is higher than that of the Eclipse300 with the Front Sim field average pressure at the end of the injection period being 780barand that of Eclipse300 is 580bar. The Front Sim shows and increment of over 200bar for the same injection period and rate.

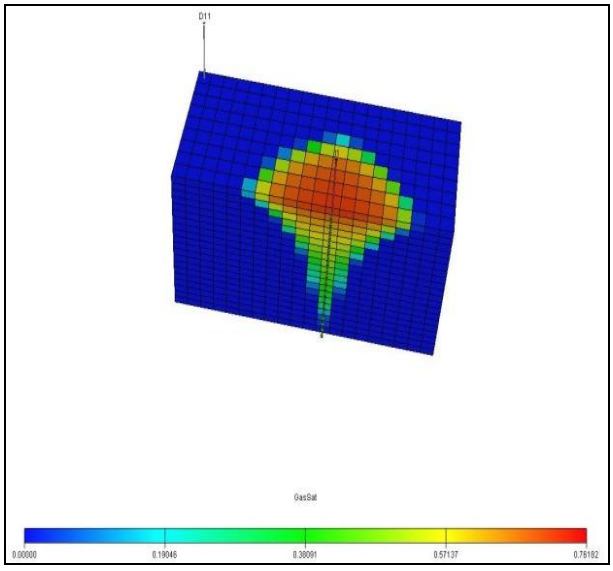

Figure 2. Eclipse300 Homogenous Model: showing Gas saturations at the end of the injection period

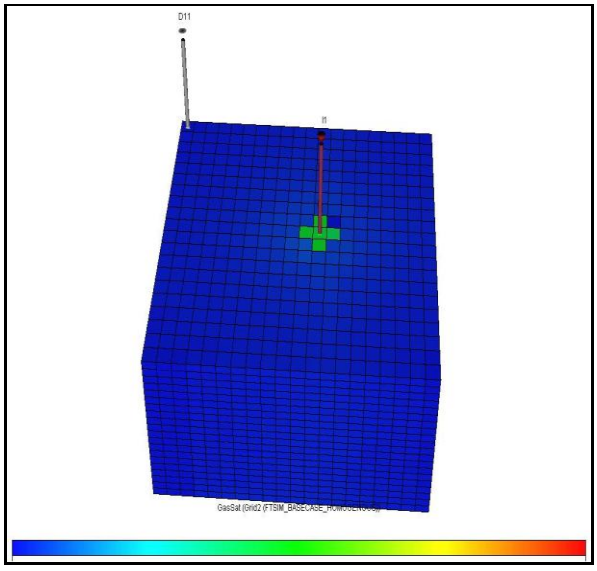

Figure 3. FrontSim Homogenous Model: showing Gas saturations at the end of injection period.

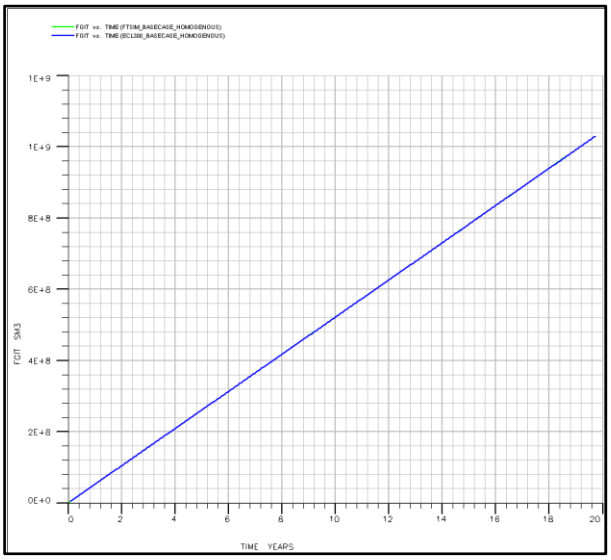

Figure 4. Field Gas Injection Total for the Homogenous Model

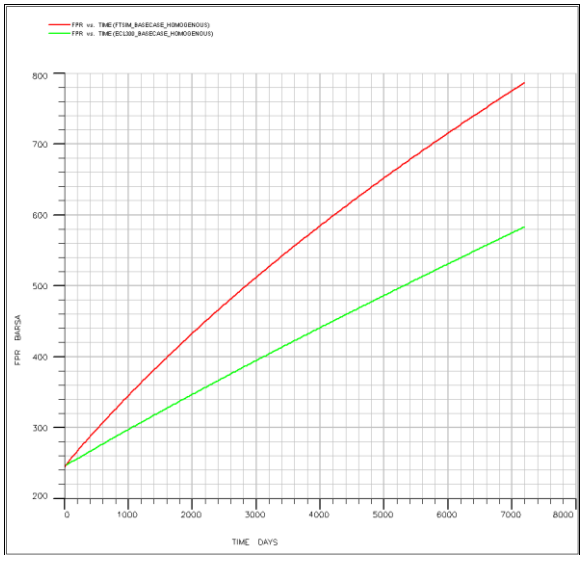

Figure 6. Graph showing pressure profile for both Front Sim& Eclipse300 in the Homogenous model

3.2Heterogeneous Model Results

3.2.1 Front Sim Heterogeneous Model Results:

After the injection, the CO_2 spreads from the vertical well bore (Figure 7) displacing formation brine and at the same time absorbing water from the formation brine. This movement is caused by the pressure gradients. It flows away from the high pressure injection point in a l direction towards the area of low pressure, this is in accordance with Darcy's law for flow in porous media. The CO_2 continues to rise upward as plume since it is less dense than the formation brine until it encounters a low permeability streak. The distribution of the CO_2 is controlled by the degree of heterogeneity in the permeability. The CO_2 preferentially migrates upwards along higher permeability along the formation Figure 8.

The bottom hole pressure profile of the injector as shown in Figure10, has risen from 260 bar to 346 bar. The rapid rise in the well pressure is a function of the compressibility of the fluids and rock, and is dependent on the well type and length of completion. The bottom hole pressure gradually increases as the saturation of CO_2 increases by the injection of more CO_2. The change in pressure at the well will have an impact on the pressure at the caprock, which is important as this will affect the seal integrity. No information was provided on the fracture pressure.

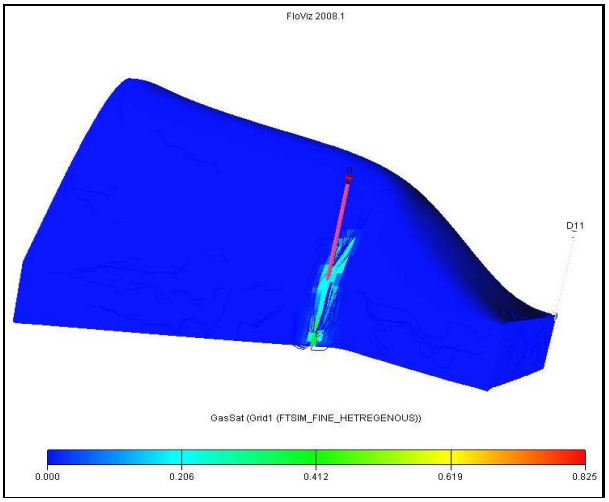

Figure 7. Gas saturations at the end of the first year of injection Front Sim fine model

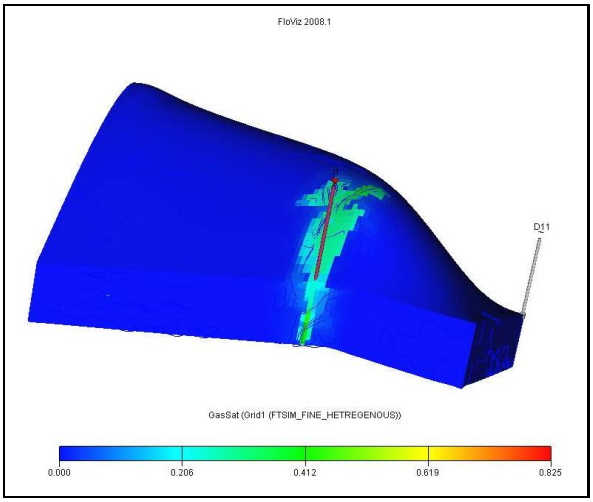

Figure 8.Gas saturation at the end of the injection period Front Sim fine model

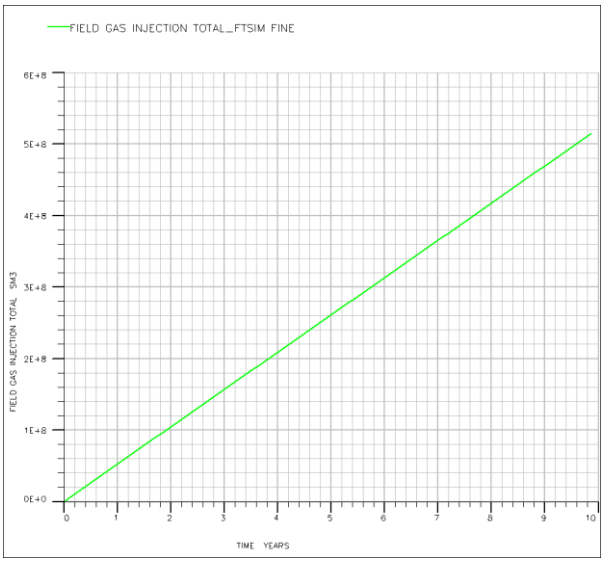

Figure 9. Total gas injected with time Front Sim fine model. After 10 years 5.14 x 10^8 sm^3 of gas has been injected.

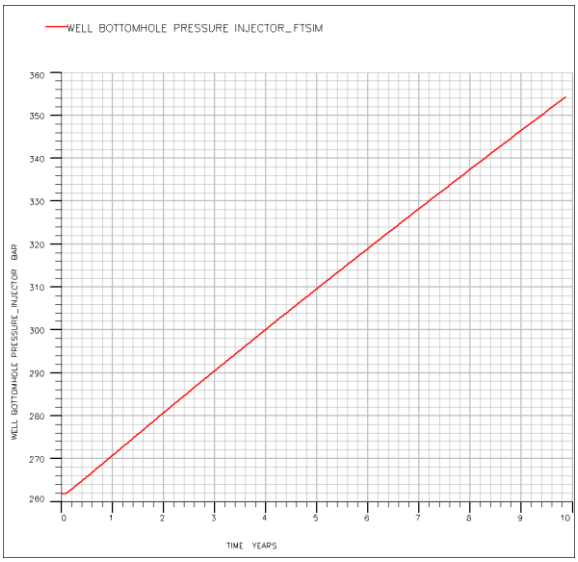

Figure 10. Well Bottom hole Pressure for the Front Sim injector well

3.2.2 Eclipse300 Coarse Model Results

After the injection the CO_2 spreads from the vertical well bore Figure 11 and 12displacing formation brine and spreading through a wider area than the Front Sim fine grid and showing more gravity effect than the Front Sim fine grid. This movement is caused by the pressure gradients. It flows away from the high pressure injection point in a radial direction towards the area of low pressure, this is in accordance with Darcy's law for flow inporous media. The CO_2 continues to rise upward as plume since it is less dense than the formation brine until it encounters a low permeability streak. The distribution of the CO_2 is controlled by the degree of heterogeneity in the permeability. The CO_2 preferentially migrates upwards along higher permeability along the formation.

Figure13 shows the total gas injected with time. After 10 years, 5.14 x 10^8 sm^3 of gas has been injected same as that of the Front Sim fine grid. Figure 14shows the well bottom hole pressure profile for the injector in Eclipse300 coarse model. The pressure rose from an initial value of 316bars to a maximum of 338 within the injection period of ten years. The rapid rise in the well pressure is a function of the compressibility of the fluids and rock, and is dependent on the on the well type and length of completion. The bottom hole pressure gradually increases as the saturation of CO_2 increases by the injection of more CO_2. The initial sharp spike in the well bottom hole pressure is due to the fact that the low relative permeability of CO_2 at the start of injection. The change in pressure at the well will have an impact on the pressure at the caprock, which is important as this will affect the seal integrity. No information was provided on the fracture pressure.

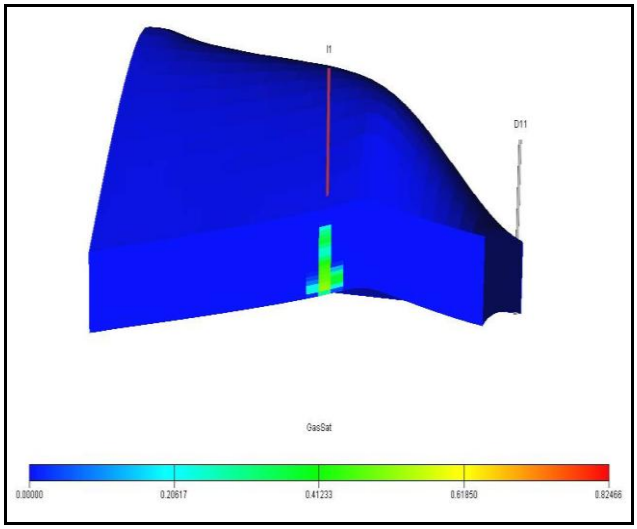

Figure 11. Gas saturation at the end of the first year of injection for the eclipse coarse model

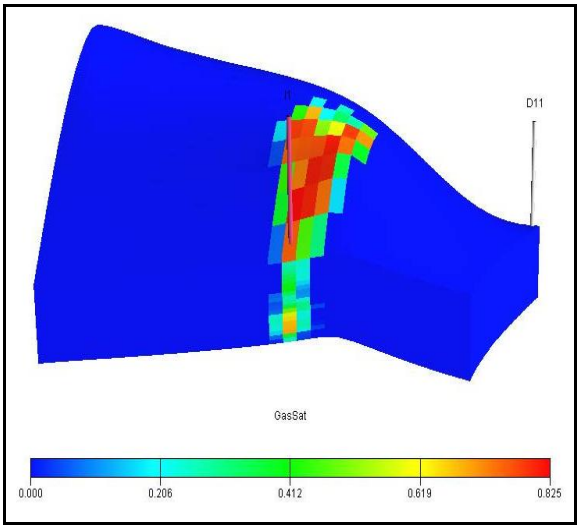

Figure 12.Gas saturation at the end of the injection period for the eclipse coarse model.

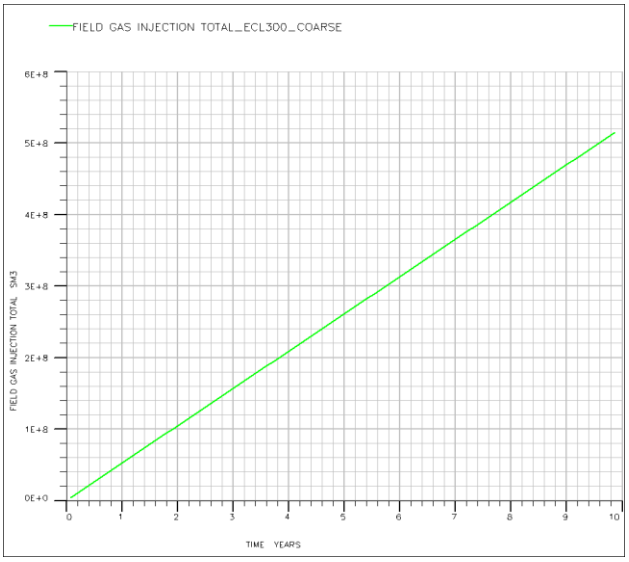

Figure 13. Total gas injected with time eclipse coarse model

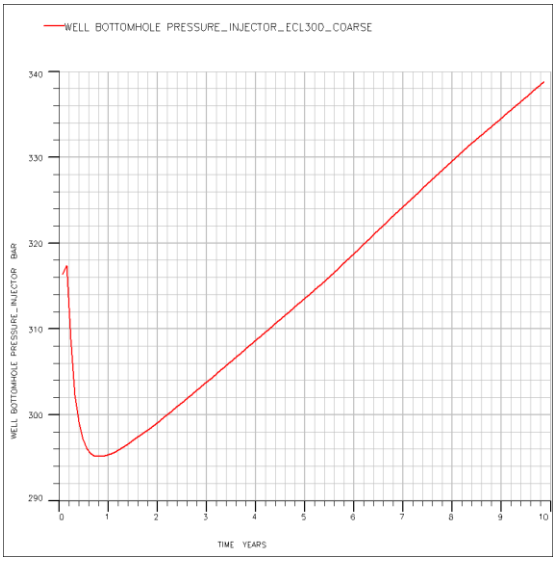

Figure 14 Well Bottom hole Pressure for the Eclipse300 coarse injector well

3.3Gas Migration Patterns

Figure15.showsthat during the transportation or migration of CO_2 more mobile CO_2 are present in the gas phase than trapped. 18 x 106 kg-m are present in the mobile phase at the end of the injection period while 2.40 x 106 kg-mare trapped as against the 1.6 x 106 kg-m dissolved in the brine which leads to the increase in density of brine as shown in Figure 16.

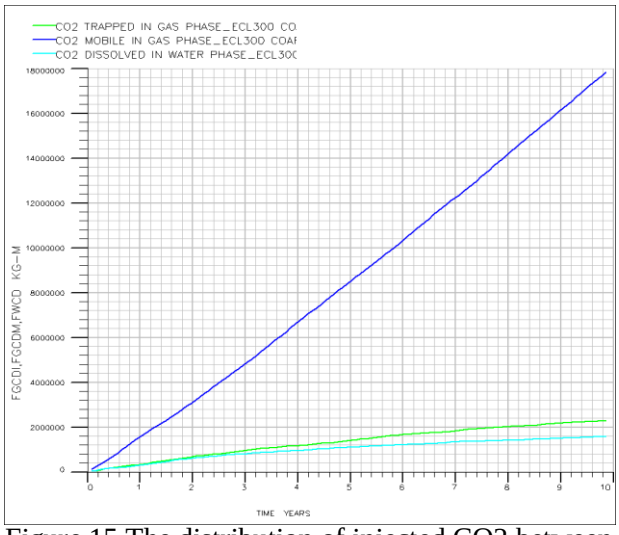

Figure 15.The distribution of injected CO2 between the gaseous and aqueous phase

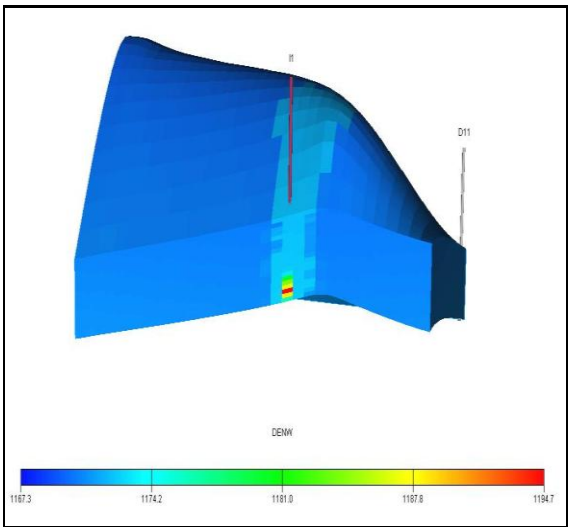

Figure 16.The increase in density of brine at the end of the 2nd and 10th year.

4. Discussion

Simulation results shows that the injection of CO_2 at the same rate in all cases, produced the same total of CO_2 injected, this is due to the fact that the areal extent of all the model is the same irrespective of the software used and the injection rate is constant.

From the result of the very fine grid with detailed geology and less physics in the Front Sim simulation the well bottom hole pressure in Front Sim is higher and it increases almost at constant rate from the point of injection. The fluids are advancing along the streamline from the injection point which is at higher pressure to low pressure cells in the model along the high permeability streak. The spread of the CO_2 from the point of injection shows little impact of gravity on it rather it seems to be diffusing along the streamline with high permeability. This shows that for displacements where gravity plays an important role and components move in directions that are not in alignment with the streamline, the simulation cannot be expected to provide accurate results. The simulation of the coarse model in Eclipse300 gave more detailed on the physics of the simulation. The spread of CO_2 from the point of injection is in radial form with CO_2 migrating along the path with high simulation and with good vertical communication. The impact of gravity is more pronounced in this simulation more than that in the Front Sim simulation of the fine grid. The CO_2 displaces the brine and also somewhere dissolved in the brine and increasing the density of the brine and also the chemistry. The amount of CO_2 trapped in this study is more than the one dissolved and more mobile CO_2 is present in the gas phase.

The difference in the migration pattern spotted in the simulation may be due to numerical dispersion and the CO_2 has a larger surface area in the coarse grid to travel than in the fine grid. The fine grid cell cannot be simulated on the coarse grid due to memory allocation and the complexity involved in the mechanism of the injection of CO_2 , and as the grid cells were increased the speed of simulation on the Eclipse300 tends to be very slow. The Fronts simulation of the very fine grid cells shows better speed and good memory allocation and leads to reduced computational cost. Thus it allows high resolution of heterogeneity and not adversely affected by numerical dispersion when modelling field –scale computation.

5. Conclusions

The examples and analysis presented in this simulation studies show that no one technique is the best to accurately model a field, but preferences can be given depending on the objective of studies. CO_2 injected into aquifers can be stored in either gas-like CO_2 rich phase or dissolved in aqueous phase. The streamline simulation shows that:

- The method works well for very heterogeneous system if the displacement is assumed to be dominated by convection only since it is not able to account for gravity.

- The streamline provides fast, accurate, and robust solutions to displacements that are dominated by reservoir heterogeneity. It captured the impact of heterogeneity on the flow field.
- The speed of the method makes it an ideal tool for statistical reservoir forecasting where hundreds of geostatical images can be processed in a fraction of time required by the compositional reservoir simulator.
- Computational cost is reduced and hence man hour not wasted.
- If the aim is to model an entire field with geological detail and large area model then Front Sim would give an accurate result but if it is to model just a portion of the field with less geological detail and the physics is important the Eclipse300 is suitable for such.
- In area where the physics is of important or more complex like in the case of large pressure variation, gas breakout, hysteresis, imbibitions etc. the Front Sim should be used as a guide or pre-processing step to an intermediate model that will be passed onto Eclipse300 for further analysis and predictive runs.

References

Ukaegbu C, Gundogan O, Mackay E, Pickup G, Todd A, and Gozalpour F. Simulation of CO_2 storage in a heterogeneous aquifer. SPE 2009 p. 251-252.

Al-Abri, M. CO_2sequestration in saline aquifers. MSc Thesis, Institute of Petroleum Engineering, Heriot-Watt University, Edinburgh EH14 4AS, 2003.

Ghanbari, S., Al-Zaabi, Y., Pickup, G. E., Mackay, E.,Gozalpour, F., and Todd, A. C. Simulation of CO_2 storagein saline aquifers. Chem. Eng. Res. Des., 2006, 84(A9), 764–775.

Gunter,W. D., Perkins, E. H., and Hutcheon, I. Aquiferdisposal of acid gases: modeling of water-rock reactions for trapping of acid wastes. Appl. Geochem., 2000, 15,1085–1095.

Mo, S. and Akervoll, I. Modeling long-term CO_2 storage in aquifer with a black-oil reservoir simulator. Paper SPE93 951 presented at the 2005 SPE/EPA/DOE Exploration and Production Environmental Conference, Galveston, Texas, USA, 7–9March 2005.

Ide, S. T., Jessen, K., and Orr Jr, F. M. Storage of CO_2 in saline aquifers: effects of gravity, viscous, and capillary forces on amount and timing of trapping. J. Greenhouse Gas Control, 2007, 1, 481–491.

Doughty,C. Modeling geologic storage of carbon dioxide: comparison of non-hysteretic and hysteretic characteristic curves. In Proceedings of the TOUGH Symposium, Lawrence Berkeley National Laboratory, Berkeley, CA,USA, 15–17May 2006.

Flett, M., Gurton, R., and Weir, G. Heterogeneous saline formations for carbon dioxide disposal: impact of varying heterogeneity on containment and trapping. J. Petrol.Sci. Eng., 2006, 57, 106–118.

Xu,T.,Apps, J. A.,andPruess, K.Numerical simulation of CO_2 disposal by mineral trapping in deep aquifers. Appl.Geochem., 2004, 19, 917–936.

Pruess, K., Xu, T., Apps, J., and Garcia, J. Numerical modeling of aquifer disposal of CO_2. SPE J., 2003, 8(1),49–60.

Kumar, A., Ozah, R., Noh, M., Pope, G. A., Bryant, S., Sepehrnoori, K., and Lake L.W. Reservoir simulation ofCO_2 storage in deep saline aquifers. SPE J., 2005, 10(3),336–348.

Ozah, R. C., Lakshminarasimhan, S., Pope, G. A., Sepehrnoori, K., and Bryant, S. L. Numerical simulation of the storage of pure CO2 and CO2–H2S gas mixtures indeep saline aquifers. Paper SPE 97 255 presented at the 2005 SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, 9–12 October 2005.

R.O.Baker, F. Kuppe, S.Chugh, R.Bora and S. Stojanovic. Full field modelling using streamline-based simulation: four case studies. SPE 2002,126-127.

Batycky, R.P., Blunt, M.J., and Thiele, M.R. A 3D field scale streamline-Based reservoir simulator: SPERE 1997 246.

Bielinski, A**.** Numerical simulation of CO_2sequestration in geological formations. PhD Dissertation, University of Stuttgart, Stuttgart, Germany, 2006.

Kopp, A.,Bielinski, A., Ebigbo, A., Class, H., and Helmig, R. Numerical investigation of temperature effects during the injection of carbon dioxide into brine aquifers. Proceedings of the 8th International Conference on Greenhouse gas control technologies,Trondheim,Norway,2006.