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Enhanced Natural Gas Recovery by Carbon Dioxide Injection for Storage Purposes

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Abstract

Injection of CO_2 into depeleted (or producing) natural gas reservoirs is one option available for geosequestration of CO_2. The simulation models presented in this paper outline what factors are favourable for enhanced gas recovery and subsequent CO_2 storage. The models show that treatment of high velocity flow effects is important. Low permeability, isotropic, homogeneous reservoirs were shown to the most favourable situation. Injection at high flow rates late in the life of the gas reservoir was also shown to be favourable.

Introduction

In depleted natural gas reservoirs, a large amount of natural gas may remain in place after the reservoir has been naturally depleted by gas production wells. To produce this remaining gas, one possibility is to inject CO_2 into the reservoir in an enhanced gas recovery (EGR) process, sweeping out additional natural gas and simultaneously storing CO_2 underground at the same time. When CO_2 is injected into a depleted reservoir it will flow through the reservoir increasing the reservoir pressure and displacing the natural gas. After a period of time, the injected CO_2 will make its way to the production wells. In an EGR process the breakthrough (i.e. arrival) time of the CO_2 at the production wells is very important. Once breakthrough occurs, natural gas production drops significantly and CO_2 production rises significantly.

The risks posed by this mixing of CO_2 and natural gas are thought to be one of the reasons that CO_2 EGR projects are very uncommon (though the K12-B project in the Netherlands [1] is one example of a commercial EGR project.), while enhanced oil recovery (EOR) using CO_2 is a relatively common process. It has been suggested by Oldenburg and Benson [2] that mixing between CO_2 and natural gas will be limited due to the high density and viscosity of CO_2 relative to methane. The density difference will create a favourable mobility ratio with a diminished tendency to inter-finger into the methane. In addition to this the density difference will give the CO_2 a tendency to sink within the reservoir.

As a consequence of this, it has been suggested that it is advantageous to locate the CO_2 injection depth below the natural gas production depth [2], [3]. This is so that the injected CO_2 can pressurise the reservoir without being produced itself. If injection were to take place above production, gravity would act to pull the CO_2 towards the production wells, resulting in earlier breakthrough times. It is also advantageous to place the injection wells as far away from the production wells as possible. This is because in a gas reservoir, the repressurisation will occur very quickly, whereas the actual flow of the fluid will take some time. By having a wide separation between injection and production, flow at the producer will be increased and breakthrough of CO_2 will be delayed for as long as possible.

The numerical simulation studies presented in this paper aim to identify reservoir and fluid parameters that make a CO_2 EGR process effective. The simulation models also assess what factors need to be taken into account when simulating such the CO_2 EGR process.

Literature Review

Oldenburg and Benson [2] considered mixing and noted that the density and viscosity of the CO2 are greater than those of the methane at reservoir conditions, which significantly reduces the risks of mixing. This article also examines the effect of heterogeneities in the permeability distribution and concludes that they result in early breakthrough due to high permeability pathways in the reservoir.

Jikich et al. [4] studied several parameters involved in CO_2 injection into gas reservoirs. These include injector length (at a constant pressure), brine saturation, the time at which injection takes place and the pressure used for injection.

Jikich et al. found that for a given injection pressure, there is some optimal injector length (this could be a function of the injection pattern being used) that maximises CO_2 storage. Increased injector length was found to have a detrimental effect on methane production. Increasing the injection pressure results in considerably increased CO_2 storage. The case of having horizontal injection wells was considered, where a 160 acre pattern was used with the injector located in the centre. Jikich et al. concluded that the use of horizontal wells aids CO_2 storage, but lowers methane recovery slightly. It is concluded that injecting CO_2 at the start of methane production accelerates production until breakthrough, but has a detrimental effect on total methane production at breakthrough.

Al-Hashami et al. [3] investigated the effects of CO_2 solubility in formation water, the effects of diffusion, delayed injection from the start of the gas recovery project and the effects of increased CO_2 injection rate (under a limited production flow rate). They found that solubility causes delayed breakthrough of CO_2 into the production stream causing an increase in storage, but has little effect on incremental methane recovery. Diffusion coefficients below $10^{-6}m^2/s$ were found to have negligible impact on results.

This paper summarises a portion of a thesis completed by the first author [5] and aims to complement the existing literature on this topic by providing a comprehensive analysis of the parameters which influence the CO_2 EGR process.

Method

The problem of assessing the role of various reservoir, well and fluid parameters in the CO_2 EGR process was approached through numerical simulation using an industry standard finite difference flow simulator. All simulation models in the study were run using the GASWAT option in the fully implicit formulation of the E300 compositional simulator (a part of the ECLIPSE suite [6]).

A base case reservoir model was constructed and was similar to the one outlined by Al-Hashami et al. [3], with some minor changes. The base model has a square horizontal cross section and with dimensions of 5000ftx5000ftx100ft. Permeability and porosity were chosen as 100mD and 0.2 respectively. No anisotropy or heterogeneity was considered in the base case. The reservoir was set at 212^{o}F.

The base case simulation has a single injection well and a single production well, each of which are in opposing corners of the reservoir. Both wells are vertical in orientation.The injector perforates the bottom 20 feet of the reservoir, whereas the producer perforates the top 20 feet. This is done to try to take advantage of the fact that CO_2 has a higher density than methane at reservoir conditions, causing an under running effect.

The injection well is set to inject carbon dioxide at a flow rate of 10000 MSCF/day with a bottom hole pressure (BHP) limit of 4500 psia. The production well is set to produce at a bottom hole pressure of 550psia, with a gas flow rate limit of 10000 MSCF/day. The breakthrough point is defined in this work as the point at which 10% production rate (on a molar basis) is CO_2.

The characteristic properties of the reservoir fluids (water, methane, carbon dioxide such as the critical values of temperature and pressure, Lohrenz Bray Clark viscosity coefficients and acentric factor were generated by the PVTi module of ECLIPSE, which has libraries of standard fluids. The Peng-Robinson equation of state (EOS) (with the modifications for solubilities suggested by Soreide and Whitson [7] that are implemented in the GASWAT option) was used in the calculation of PVT properties of all fluids.

The Modified Brooks Corey method of the form outlined by Lake [8] was used to define relative permeability curves for the gas and water phases. Corey exponent values n_g and n_w of 2 and 3 were chosen for the gas and water relative permeability curves respectively (with endpoint relative permeabilities of 1 in both cases).

A wide range of model runs were performed with variations of this base case model. Simulations were compared at the point in time when injected CO_2 arrives (breaks through) at the production well. The full simulation study in described in reference [5]. A selection of these results is presented in the following section.

Results

Forchheimer Flow Equations

By default, the E300 module of Eclipse uses Darcy's law, equation 1.

$$u = -\frac{k}{\mu}\frac{\partial p}{\partial x} \quad \text{(1)}$$

to model fluid flow, where u is the Darcy velocity, k is the permeability, μ is the fluid viscosity, p is fluid pressure and x represents position. This equation has the inherent assumption that the in porous media flow higher order momentum terms may be neglected. The simulator however also has the option of enabling the high velocity Forchheimer equation, equation 2.

$$-\frac{\partial p}{\partial x} = \frac{\mu}{k}u + \beta\rho u^2 \quad \text{(2)}$$

where ρ is the fluid density and β is the Forchheimer parameter. Use of this option was investigated because gas flows near wells can often be at high velocity, making the extra momentum terms become significant.

Using the Forchheimer equation resulted in a significant change in breakthrough results. Breakthrough time was increased by 14.4% compared to the base case, methane production reduced by 2.6% and CO_2 storage increased by 14.5%. The most likely explanation is that the extra momentum terms result in more resistance to the flow, meaning that a higher injection pressure is required to maintain a given flow rate.

Horizontal Wells

In order to examine the effects of having horizontal wellbores in place of vertical ones as in the base case, simulations were run for horizontal well lengths of 495ft, 659ft, 824ft and 989ft (injectors are the same size as producers for each simulation). The injection and production wells are completed in the top and bottom rows of cells such that they are in opposite corners of the reservoir, running parallel to each other. The well setup is shown in Figure 1.

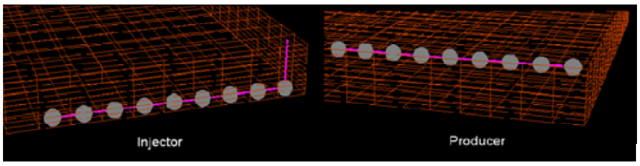

Figure 1.Horizontal injector and producer well configuration.

Comparing the shortest horizontal well case (495ft) to the base case, it was found that breakthrough time is 25.4% lower, methane production is 8.6% higher, CO_2 storage is 25.4% lower, reservoir pressure is 20.6% lower. As horizontal well length increases to the maximum simulated length (989ft), breakthrough time reduces (to 30.1% lower), methane production increases (to 10.3% higher), CO_2 storage reduces (to 30.1% lower), and reservoir pressure decreases (to 24.6% lower).

This result at first seems contradictory to the simulations of Jikich et al. [63 in which horizontal injection raised storage and lowered methane recovery. The likely reason for this is that Jikich et al.'s investigation was carried out at a constant bottom-hole pressure, whereas this one was carried out with a specified injection flow rate (and therefore a variable bottom hole pressure). Having constant injection pressure means that the longer the well, the more of the reservoir is exposed to that pressure, the higher the reservoir flowrate is and the higher the average reservoir pressure will be.

Permeability Magnitude

Two simulations were run to investigate the effect of the magnitude of the permeability on breakthrough results. The first was for a permeability of 10mD and the second for a permeability of 1mD.

Lowering permeability to 10mD increased breakthrough time by 140%, increased CO_2 storage by 141%, reduced methane production by 18%, caused an 86% increase in average breakthrough reservoir. This phenomenon results from increased resistance to flow increasing reservoir pressure.

Permeability Anisotropy

Reservoirs can exhibit a permeability distribution with a horizontal component that can be anywhere between 1 and 1000 times greater than the vertical component. To examine these effects, simulations were run for horizontal to vertical permeability ratios of 10:1 and 100:1 using a horizontal permeability of 100mD.

These simulations resulted in breakthrough times that increased by 5.3% and 13.4% respectively (compared to the base case), methane production that dropped by 1.3% and 3.3% respectively, CO_2 storage that increased by 5.4 and 13.5% respectively, and average reservoir pressure increases of 4% and 10%.

Increased anisotropy results in more resistance to flow in the vertical direction. Since injection is taking place downdip of production, the gases need to make their way up through the layers of low vertical permeability, meaning that a greater pressure is required for a given flow rate, raising average reservoir pressure, yielding the above results. From these results, it would seem that anisotropy is undesirable for CO_2 EGR. This is because the operation will take longer and the reduction in methane production will allow less CO_2 to be stored after breakthrough has occurred.

Permeability Hetereogeneity

Real reservoirs can have a heterogeneous permeability distribution. In order to examine the effects of this, two synthetic heterogeneous permeability dstributions were generated using a Sequential Gaussian Simulation as described by Deutsch and Journel [9]. A log normal permeability distribution with a mean of 100.8mD and a standard deviation of 81.6mD was used.

Results from the first of these distributions are presented. In this case the permeability variogram has a range of 50 cells in the horizontal plane and 5 cells in the vertical direction. This distribution has connected channels of high permeability and large clusters of low permeability.

Both distributions have an average anisotropy ratio of 10:1, so the percentage change in CO_2 storage etc. is measured against simulation with the same anisotropy, but no heterogeneity. The simulated breakthrough time for this case reduced by 8.7%, CO2 storage dropped by 8.8%, reservoir pressure increased by 0.2%, and methane production dropped by 17.4%. These effects are related to the change in CO2 sweep efficiency which is presented graphically in Figure 2.

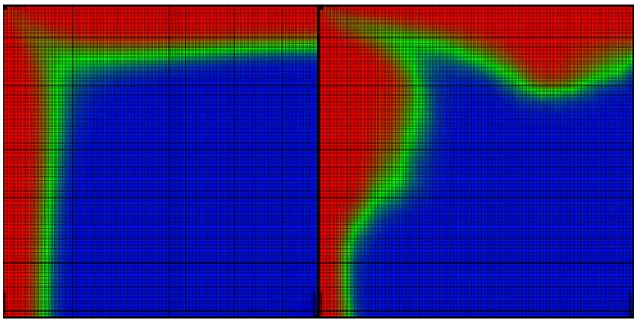

Figure 2. CO_2 sweep (full CO_2 saturation shown in blue, full methane saturation in red) for homoegenous case (left) and heterogeneous case (right).

Reservoir Geometry

To assess the impact of reservoir geometry additional models were created with parabolic and slanted geometries. The three-dimensional nature of these models means that there will be additional gravitional effects in these models which will impact reservoir pressure and sweep efficiency. These model geometries are shown graphically in Figure 3.

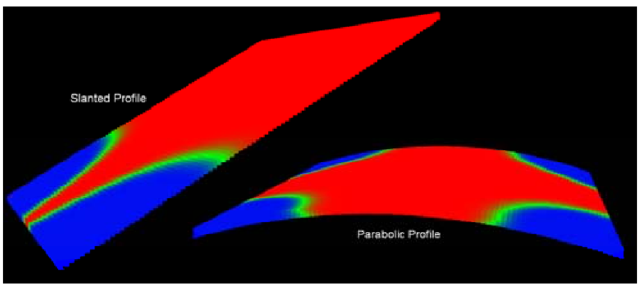

Figure 3. Slanted and parabolic reservoir geometries with CO_2 saturations during the injection process.

In the parabolic geometry two sides of the reservoir remain straight and parallel to one another and the top of the reservoir between these two sides follows a parabolic profile. For this geometry, the producer is placed in the centre of the reservoir and one injector is placed at each of the corners. Total injection and production limits are imposed with each injection well now limited to a flow rate of 2500 MSCF/day. Displacements of 100 ft, 200 ft and 400 ft between the top and bottom of the reservoir were considered.

The second geometry is a slanted profile that simply tests the effect of gravity on the solution. Reservoir dip angles of 10, 15, 20, 25, 30, 35, 40 and 45 degrees from the horizontal were considered. The injection wells are at the two lower corners, whereas the production well is at the centre of the highest edge of the reservoir. Each injector is limited to an injection flow rate of 5000 MSCF/day.

For the parabolic profile the results were compared against those of a case with the same well configuration but with a flat reservoir geometry. Results showed a 17.5% lower breakthrough time, 3.5% less methane production, 17.7% less CO_2 storage, and a 10.5% lower average reservoir pressure. The impact of the geometry is best illustrated by the comparison of the CO_2 sweep in the flat and parabolic models shown in Figure 4. In the parabolic model the flow is subject to significant gravitational effects, and it will tend to flow preferentially into the lower regions of the reservoir instead of flowing towards the top. This causes an improved sweep in the lower regions, raising the sweep efficiency.

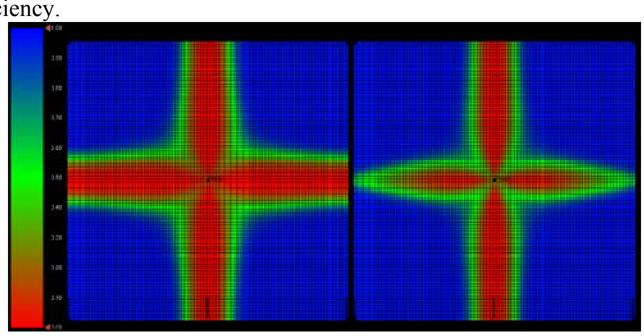

Figure 4. CO_2 sweep in flat (left) and parabolic (right) models.

In the slanted reservoir cases the well configuration (i.e. production at the centre of the upper edge, and injection at the two corners of the lower edge) gives a better sweep efficiency than the base case which improves methane production. The effect of gravity however increases the bottom hole pressure required at the injection wells to enable them to push injected CO_2 from the lower side of the reservoir to the upper side. This in turn increases the average reservoir pressures observed in these simulations.

Simulation	Breakthrough Time %	Methane Production %	CO2 Storage %	Average Reservoir Pressure %
No Slant	-3.96	11.64	-4.00	-6.87
10 Degrees	4.65	0.24	4.68	3.09
15 Degrees	6.19	0.47	6.23	4.02
20 Degrees	7.72	0.38	7.77	5.06
25 Degrees	9.42	0.19	9.48	6.25
30 Degrees	11.52	0.09	11.58	7.66
35 Degrees	14.21	0.21	14.27	9.35
40 Degrees	17.70	0.62	17.77	11.42
45 Degrees	22.24	1.32	22.31	14.01

Table 1. Performance of slanted reservoir cases compared the original base case. The "no slant" case has the same well configuration as the slanted cases (which have a different well configuration to the base case).

Injection Timing

A set of simulation models were used to explore how the CO_2 EGR process was affected by the timing of the start of the CO_2

injection. Figure 5 shows that CO_2 storage was maximised by injecting later in the life of the reservoir, i.e. when the gas reservoir was more depleted. When injection begins, the sweep patterns are very similar in each case, however in the cases where the reservoir is more depleted, pressure at breakthrough is lower and thus the reservoir fluids are less dense. This pressure drop only has a minor effect on methane production, but causes a major decrease in CO_2 storage due to the relative volumes of methane and CO_2 in place at the point of breakthrough. Economic analysis of all injection options was performed by Feather in [5]. In this case injecting CO2 earlier in the life of project may be economically optimal, depending on the economic assumptions made, even though this does would not store the maximum possible amount of CO_2.

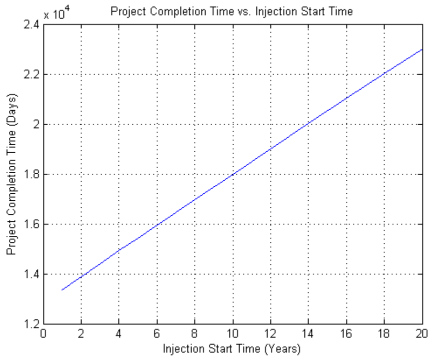

Figure 5. CO_2 storage as a function of the start of CO_2 injection.

Flow Rate Dependence

Methane production and CO2 storage were simulated for injection flow rates of 1000 MSCF/day to 20000 MSCF/day. Figure 6 shows that the CO2 storage achieved is strongly dependent on CO2 injection rate. Methane production is adversely affected (by a much smaller amount) by increasing injection rate. The reason for this is that a greater injection pressure is required to maintain a greater injection flow rate, while production pressure remains the same. This causes an increase in average reservoir pressure which results in the increased storage.

For a higher injection flow rate, the flow is more dominated by pressure gradients than by gravitational effects and thus the flow front of the CO2 is more vertical. When breakthrough occurs, coning will be observed from the under-running section and thus the flatter (more vertical) the flow front (see Figure 7), the more delayed breakthrough will be in terms of the distance into the reservoir that the CO2 penetrates. As a result, the higher flow rate case will result in greater sweep efficiency.

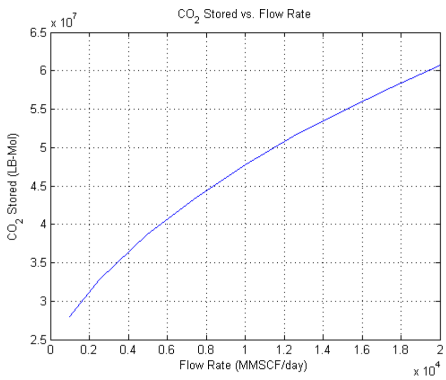

Figure 6. CO_2 storage as a function of injection rate.

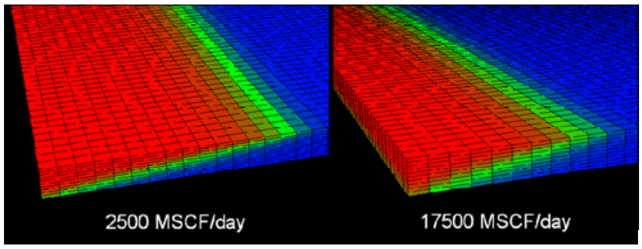

Figure 7. CO_2 sweep at injection rates of 2500 MSCF/day and 17500 MSCF/day (full CO_2 saturation in blue, full methane saturation in red).

Conclusions

The parameters of greatest importance when it comes to overall production and CO_2 storage at breakthrough are the sweep efficiency and the reservoir pressure. Higher reservoir pressure acts to improve CO_2 storage, but decreases natural gas production. Improved sweep efficiency acts to improve both CO_2 storage and natural gas production.

Through comparisons to the base case simulation, it was found that the use of high velocity flow equations and taking account of permeability heterogeneity have a significant impact on simulation results.

Use of vertical wells and the presence of dip (slope) in the reservoir geometry were identified as favourable for CO_2 EGR. Permeability anisotropy and permeability heterogeneity were both found to be favourable for EGR. It was also found that the injection pattern used can have a significant influence on both production and storage.

Injection as late as possible in the depletion of the gas reservoir, and at the maximum possible rate, improves CO_2 storage without adversely impacting methane production.

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