PROCESS MODELING OF CO_2 INJECTION INTO NATURAL GAS RESERVOIRS FOR CARBON SEQUESTRATION AND ENHANCED GAS RECOVERY

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ABSTRACT

Injection of CO_2 into depleted natural gas reservoirs offers the potential to sequester carbon while simultaneously enhancing CH_4 recovery. Enhanced CH_4 recovery can partially offset the costs of CO_2 injection. With the goal of analyzing the feasibility of carbon sequestration with enhanced gas recovery (CSEGR), we are investigating the physical processes associated with injecting CO_2 into natural gas reservoirs. The properties of natural gas reservoirs and CO_2 and CH_4 appear to favor CSEGR. In order to simulate the processes of CSEGR in detail, a module for the TOUGH2 reservoir simulator that includes water, brine, CO_2, tracer, and CH_4 in nonisothermal conditions has been developed. Simulations based on the Rio Vista Gas Field in the Central Valley of California are used to test the feasibility of CSEGR using CO_2 separated from flue gas generated by the 680 MW Antioch gas-fired power plant. Model results show that CO_2 injection allows additional methane to be produced during or after CO_2 injection.

INTRODUCTION

Depleted natural gas reservoirs are potentially important targets for carbon sequestration by direct carbon dioxide (CO_2) injection. The accumulation and entrapment of a light gas such as methane (CH_4) testifies to the integrity of natural gas reservoirs for containing gas for long periods of time. By virtue of their proven record of gas production, depleted natural gas reservoirs have demonstrated histories of both (i) available volume, and (ii) integrity against gas escape. The IEA (International Energy Agency) has estimated that as much as 140 GtC could be sequestered in depleted natural gas reservoirs worldwide (IEA, 1997) and 10 to 25 GtC in the U.S. alone (Riechle et al., 2000). These aspects of natural gas reservoirs for carbon sequestration are widely recognized.

Less well recognized is the potential utility of CO_2 injection into natural gas reservoirs for the purpose of enhancing CH_4 production by simple repressurization of the reservoir. The pressure support provided by the CO_2 is similar to the proven cushion gas concept used in the gas storage industry wherein expansion of cushion gases upon natural gas withdrawal aids in production from the storage reservoir (Carrière et al., 1985; Laille et al., 1988). The concept of enhancing CH_4 production is important because it can partially offset the costs of CO_2 sequestration. This concept was first described by van der Burgt et al. (1992) and Blok et al., (1997), who used reservoir simulation to evaluate how quickly the injected CO_2 would mix with the produced natural gas. Based on the simulations they concluded that enhanced production was possible for some period before the extent of mixing was too great. Nevertheless, little attention has been given to this option for sequestration, primarily due to concerns about degrading the quality of the produced gas.

The purpose of this paper is to further explore the physical processes involved in CSEGR. To accomplish this, numerical simulations of CO_2 injection and enhanced gas recovery were carried out on a model system based on the Rio Vista Gas Field in California's Central Valley. The proposed source of CO_2 in this study is flue gas from the 680 MW power plant at Antioch, California, 20 km from Rio Vista. To carry out the simulations, we have developed capabilities for the TOUGH2 reservoir simulator (Pruess et al, 1999) for modeling gas reservoirs. Through simulations of the injection process, we show that repressurization of the methane is possible and significant quantities of methane that would otherwise be left in the reservoir can be produced while carbon dioxide is being injected.

PROCESS DESCRIPTION

CSEGR involves the injection of CO_2 into depleted gas reservoirs with simultaneous or subsequent production of repressurized CH_4. The processes of gas-phase mixing by advection, dispersion, and molecular diffusion, which will tend to mix the gaseous components and deteriorate the quality of the natural gas, are dependent on the properties of natural gas reservoirs and of the gases. Pressures in depleted natural gas reservoirs are approximately 20–50 bars, with temperatures 27–120 °C. The large volume and large areal extent of gas reservoirs decrease the potential for mixing by dispersion over practical time scales. In Table 1 we present properties of CO_2 and CH_4 relevant to CSEGR. Note that CO_2 is denser and more viscous than CH_4, and will generally be subcritical but may be supercritical in deep depleted reservoirs. The large density of CO_2 relative to CH_4 means that CO_2 will tend to migrate downwards relative to CH_4. The larger viscosity of CO_2 ensures that displacement of CH_4 by CO_2 will be a favorable mobility ratio displacement, with less tendency for the gases to finger and intermix than in displacements such as water floods in oil reservoirs. Pressure diffusivity is typically three–five orders of magnitude larger than molecular diffusivity, making repressurization occur much faster than mixing by molecular diffusion. In summary, the properties of gas reservoirs and CO_2 and CH_4 appear to favor the feasibility of CSEGR.

Table 1. Properties of CO_2 and CH_4 from Vargaftik (1975).

Property	CO_2	CH_4
Molecular weight	44 g/mole	16 g/mole
Critical point	31 °C, 73 bar	-83 °C, 46 bar
Density	880 kg/m^3 (50 °C, 300 bar) 140 kg/m^3 (50 °C, 60 bar)	193 kg/m^3 (50 °C, 300 bar) 39 kg/m^3 (50 °C, 60 bar)
Viscosity	0.085 cp (50 °C, 300 bar) 0.019 cp (50 °C, 60 bar)	0.023 cp (50 °C, 300 bar) 0.013 cp (50 °C, 60 bar)
Diffusivity (at 273 K, 1 bar)	1.42 x 10^{-5} m^2/s (in air)	1.53 x 10^{-5} m^2/s (in CO_2)

MATHEMATICAL MODEL

In order to model gas reservoir processes, we have developed a module called EOS7C (Oldenburg and Pruess, 2000) for simulating gas and water flow in natural gas reservoirs within the TOUGH2 framework (Pruess et al., 1999). The module handles five components (water, brine, non-condensible gas, tracer, and methane) along with heat. The non-condensible gas can be selected by the user to be CO_2, N_2, or air. EOS7C is an extension of the EOS7R (Oldenburg and Pruess, 1995) and EWASG (Battistelli et al., 1997) modules. The EOS7C module is currently restricted to the high-temperature "gas-like" conditions for CO_2 as opposed to the high-pressure "liquid-like" conditions. Advection of gas and liquid phases is governed by a multiphase extension of Darcy's law. Molecular diffusion in the gas and liquid phases is currently modeled using a Fickian approach. The main gas species partition between the gas and liquid phases according to their temperature- and pressure-dependent solubilities (Irvine and Liley, 1984; Cramer, 1982; Pritchett, 1981), while the gas tracer volatilization is controlled by a Henry's coefficient input by the user. The selection of N_2 or air in place of CO_2 will allow the module to be used for simulating gas storage processes, including the use of inert cushion gases. Because it is a module of TOUGH2, EOS7C includes all of the multiphase flow capabilities of TOUGH2, including the ability to model water drives and gas-liquid displacements that may be present in gas reservoirs.

APPLICATION TO RIO VISTA GAS FIELD

In this section, we investigate by numerical simulation the process of CSEGR at the Rio Vista Gas Field. Rio Vista is the largest gas field in California and has been under production since 1936 (Burroughs, 1967). It is located approximately 75 km north of San Francisco in the Sacramento Basin and has an elongated dome-shaped structure extending over a 12 by 15 km area (see Figure 1). The reservoir rocks are Upper Cretaceous to Eocene and consist of alternating layers of sands and shales deposited in deltaic and marine environments. Normal faulting occurred contemporaneously with sedimentation, creating a set of sub-parallel faults trending NW through the field. The most important of these is the Midland Fault (Figures 1 and 2). In some gas-bearing strata, displacement along the faults has created structural traps. In others, particularly the thicker gas bearing sands, the smaller faults do not play as important a role in defining reservoir structure.

Since 1936 the Rio Vista Gas Field has produced over 9.3 x 10^{10} m^3 of natural gas (at standard conditions of 1 bar, 15.5 °C [14.7 psi, 60 °F]) from 365 wells. Production peaked in 1951 with annual production of 4.4 x 10^9 m^3 and, as shown in Figure 3, has declined steadily since then (Cummings, 1999). Production decline is caused by decreasing reservoir pressures and increased water production, particularly on the western boundary of the field.

The Domengine formation shown in Figure 2 has been the most productive pool in the Rio Vista Gas Field. It occurs at an average depth of 1150 to 1310 m with an average net thickness of 15 to 100 m. The initial reservoir pressure and temperature were approximately 120 bars and 65 C. Other generalized reservoir properties are provided in Table 2. As shown in Figure 2, the Domengine is laterally continuous across the Rio Vista Gas Field with vertical confinement provided by the Nortonville and Capay Shales. Its western boundary is controlled by the presence of the watertable at a depth of 1325 m. For the purpose of this study we focused on CO_2 sequestration and enhanced gas recovery in the Domengine formation to the west of the Midland Fault (see Figure 4).

The source of CO_2 considered in this study is the 680 MW gas-fired power plant located in Antioch, California (20 km from Rio Vista). This plant produces 2.2 x 10^9 m^3 (1 bar, 15.5 °C) or 4.15 x 10^9 kg of CO_2 annually. At this rate, a simple volumetric replacement of all of the natural gas produced from Rio Vista since 1936 suggests that approximately 80 years of sequestration capacity are available.

The simplified 2-D model system based on the Rio Vista Gas Field is shown in Figure 4. The model system is a 1 km wide cross-section with vertical dimensions 100 m and horizontal extent 6600 m of the western flank of the dome, corresponding to 1/16 of the actual length of the reservoir. The model reservoir has a roof sloping at 0.78 ° and closed right-hand side. The bottom of the gas reservoir is a horizontal water table. Note that in all simulations presented here, water drive is turned off by closing all the lower boundaries of the system. Properties of the formation are simplified for this study as shown in Table 3.

Table 2. Relevant properties of Rio Vista model gas reservoir.

Property	Value	Units
Porosity	0.35	-
Y-, Z-direction permeability	1.0×10^{-12}, 1.0×10^{-14}	m^2, m^2
Capillary pressure m, S_{lr}, $1/\alpha$, P_{capmax}, S_{ls}	van Genuchten (1980); 0.2, 0.27, 8.4×10^{-4}, -10^5, 1.	-, -, Pa^{-1}, Pa, -
Relative permeability		
liquid	Van Genuchten model	-
gas	Corey model ($S_{gr} = 0.01$)	-
Molecular diffusivity in gas, liquid	1.0×10^{-5}, 1.0×10^{-10}	$m^2 s^{-1}$, $m^2 s^{-1}$
Temperature	65	°C
Initial pressure at water table	126	bars

The initial condition consists of the water table at $Z = 0$ on the left-hand side of the domain at a pressure of 126 bars, with CH_4 gas and residual water ($S_{lr} = 0.27$) in the pore space above. All simulations were done at isothermal conditions of 65°C. From this initial condition, we simulated the withdrawal of CH_4 at 1/16 the historical rate as shown in Figure 3 for the period 1936–1998.

Following the historical production, we simulated CO_2 injection at a point 15 m below the top of the reservoir at approximately $Y = 2000$ m, and CH_4 withdrawal from the upper right-hand side of the domain ($Y = 6600$ m). In all cases, CO_2 is injected into the reservoir at a rate corresponding to 1/16 the actual production of CO_2 from the 680 MW Antioch gas-fired power plant. An example simulation result is shown in Figure 7 where we show mass fraction of CO_2 along with gas velocity vectors at three different times for the case of CO_2 injection with no CH_4 production. Note the depression of the water table in response to gas injection. As gas is injected, reservoir pressure increases with limited mixing of the gases by advection and diffusion.

Summaries of the simulated pressure evolutions and mass production rates are shown in Figures 5 and 6, respectively. We simulated two different scenarios that start in 1999 (see Table 3). In Scenario I, CO_2 is injected into the reservoir for ten years starting in 1999, as shown in Figure 7. This injection serves to repressurize the reservoir. In the subsequent part of Scenario I, CH_4 is produced for ten years from the repressurized reservoir at a rate corresponding to the 1950–1960 average rate. In Scenario II, CO_2 injection is simultaneous with CH_4 production, where CH_4 is produced at constant pressure. Note in Figure 5 that in Scenario I, 99% pure CH_4 can be produced for about 5 years following CO_2 injection, and that this CH_4 production is at a very large rate. In Scenario II, 99% pure CH_4 can be produced for approximately 10 years during CO_2 injection, although the rate is smaller than in Scenario I (see Figure 6). Note that these simulations have neglected dispersion which would increase gas-phase mixing. Assuming a longitudinal dispersivity of 100 m and 20 years of CSEGR, the dispersive mixing length for these scenarios is on the order of 1 km. This estimate shows that dispersion is an important mixing mechanism, but that over the large length scale in the model gas reservoir, repressurization and production of high quality methane would still be possible. The total additional masses of CH_4 produced by CSEGR for Scenarios I and II are 1×10^9 kg (5.2×10^7 Mcf) and 1.1×10^9 kg (5.7×10^7 Mcf), respectively, as compared to a projected 1.8×10^8 kg (9.4×10^6 Mcf) without CSEGR. Note that these quantities are for the 2-D model system which is 1/16 of the whole gas field.

Table 3. CSEGR scenarios for Rio Vista case study.

Period	Inject	Produce	Rate	Cumulative mass
1936–1998	-	CH_4	Variable (1/16 historical CH_4 production)	-3.5×10^9 kg CH_4
Scenario I. 1999–2009	CO_2	-	8.2 kg/s (1/16 Antioch CO_2 production)	2.6×10^9 kg CO_2
2010–2019	-	CH_4	3.2 kg/s (1950–1960 average rate)	-9.6×10^8 kg CH_4
Scenario II. 1999–2019	CO_2	CH_4	CO_2: 8.2 kg/s CH_4: Variable (constant pressure of 39 bars)	5.1×10^9 kg CO_2 -1.1×10^9 kg CH_4

Finally, we present in Figure 8 a scenario to examine the process of density stratification within the reservoir for the case of no CH_4 production. In this scenario, CO_2 is injected for 10 years and then allowed to migrate as driven by density and pressure gradients. As seen in Figure 8, CO_2 moves downwards due to its greater density relative to CH_4, a process favorable for CSEGR.

CONCLUSIONS

The Rio Vista Gas Field is a potential site for CSEGR. Properties of natural gas reservoirs and of CO_2 and CH_4 are favorable for repressurization without extensive mixing over time scales of practical interest. Simulations of the process of CO_2 injection into a depleted natural gas reservoir carried out with TOUGH2/EOS7C confirm the plausibility of CSEGR as a way to sequester carbon while enhancing methane recovery. Simulations that use realistic estimates of CO_2 produced from the Antioch gas-fired power plant show that with CSEGR, more than five times the mass of methane can be recovered relative to that which would be produced without CSEGR.

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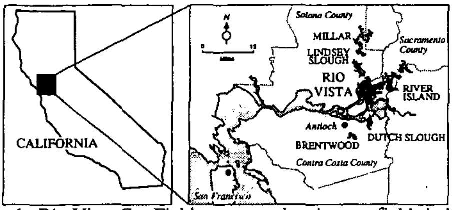

Figure 1. Rio Vista Gas Field area map showing gas fields in black.

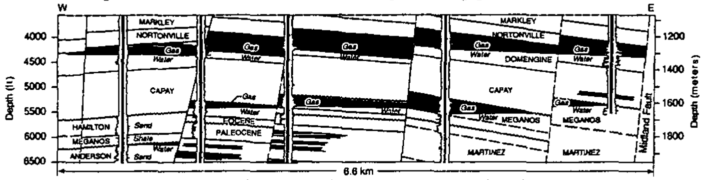

Figure 2. East-west cross section of the Rio Vista Gas Field modified from Burroughs (1967).

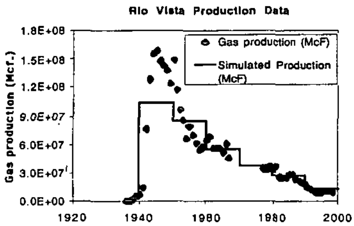

Figure 3. Production history of methane from the Rio Vista Gas Field. Production from model system is 1/16 of the 10-year-averages shown. (n.b., 1 Mcf = 10^3 cf)

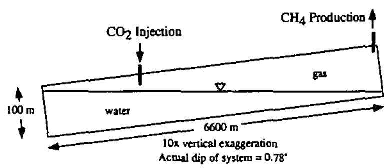

Figure 4. 2-D vertical section used in CSEGR simulations.

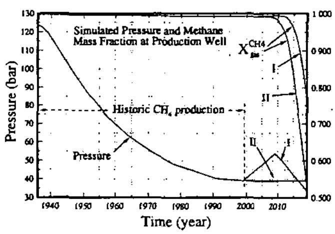

Figure 5. Pressure and CH_4 mass fraction evolution for Scenarios I and II.

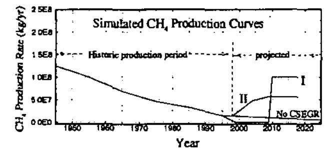

Figure 6. Simulated mass production rates of CH_4 for Scenarios I, II, and projected if no CSEGR.

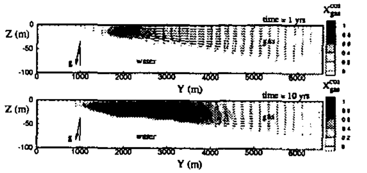

Figure 7. Mass fraction of CO_2 in the gas phase and gas velocity at t = 1 yr and 10 yrs with no CH_4 production.

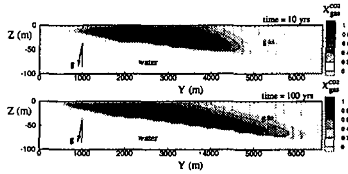

Figure 8. Mass fraction CO_2 in the gas phase and gas velocity at t = 10 yrs and 100 yrs for the case of gravity-driven density stratification following 10 years of CO_2 injection.