Carbon Sequestration with Enhanced Gas Recovery: Identifying Candidate Sites for Pilot Study

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Abstract

Depleted natural gas reservoirs are promising targets for carbon dioxide sequestration. Although depleted, these reservoirs are not devoid of methane, and carbon dioxide injection may allow enhanced production of methane by reservoir repressurization or pressure maintenance. Based on the favorable results of numerous simulation studies, we propose a field test of the Carbon Sequestration with Enhanced Gas Recovery (CSEGR) process. The objective of the field test is to evaluate the feasibility of CSEGR in terms of reservoir processes such as injectivity, repressurization, flow and transport of carbon dioxide, and enhanced production of methane. The main criteria for the field site include small reservoir volume and high permeability so that increases in pressure and enhanced recovery will occur over a reasonably short time period. The Rio Vista Gas Field in the delta of California's Central Valley offers potential as a test site, although we are currently looking broadly for other potential sites of opportunity.

Introduction

With their proven records of gas recovery, demonstrated integrity against gas leakage, existing infrastructure of wells and pipelines, and land use history of gas production and transportation, depleted natural gas fields are attractive targets for carbon sequestration by direct carbon dioxide (CO_2) injection. The International Energy Agency (IEA) estimates 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 (Reichle et al., 1999). Although target gas reservoirs for carbon sequestration are depleted in methane (CH_4) with pressures as low as 20–50 bars, they are not devoid of methane. Prior studies have suggested that additional methane can be recovered from depleted natural gas reservoirs by CO_2 injection (van der Burgt et al., 1992; Blok et al., 1997; Oldenburg et al., 2001). The idea is to inject CO_2 at some distance from producing wells and take advantage of the repressurization of the reservoir to produce additional CH_4. The augmented methane production can be used to offset the cost of CO_2 injection. We have termed this process CSEGR, or Carbon Sequestration with Enhanced Gas Recovery.

Although simulations of CO_2 injection into depleted natural gas reservoirs have been carried out (e.g., van der Burgt et al., 1992; Oldenburg et al., 2001), field testing of CSEGR has not yet been done to validate results of these simulations. This is an important next step in the development of this concept. Moreover, some critical issues for the success of the process are best studied in the field, including injectivity of liquid-like CO_2 at pipeline pressures (~150 bars), cooling due to phase change and Joule-Thomson effects as injected CO_2 flashes and expands into the relatively low-pressure depleted gas reservoir. A well designed field test can address these issues in addition to those already studied by numerical simulations such as flow bypassing and early breakthrough of CO_2 to production wells, and mixing of CO_2 with CH_4 that reduces the quality of produced gas.

In order to address the critical issues and thereby further evaluate the feasibility of CSEGR, we propose a pilot study that consists initially of a Phase I field test of CO_2 injection into a natural gas reservoir. Subsequent phases of the pilot study may involve varying injection and production schedules and the use of multiple injection and production wells to optimize CSEGR. The purpose of this paper is to outline the objectives of the Phase I field test of CSEGR, discuss the expected processes, discuss the test approach including monitoring strategies, and present some criteria for site selection.

Objectives

The broad objective of the CSEGR pilot study is to evaluate feasibility of the concept. The CSEGR process consists of collecting CO_2, for example by scrubbing CO_2 from flue gases at fossil-fueled power plants or collecting by-product CO_2 from refineries, pressurizing the CO_2 to supercritical conditions for transport in a pipeline, transporting the CO_2 to a depleted natural gas reservoir, injecting the CO_2 into the reservoir, and enhancing the production of CH_4 from the reservoir. After some period of enhanced CH_4 recovery, the production wells would be sealed and the reservoir would be filled with CO_2 up to initial reservoir pressure. The injected CO_2 would then be sequestered in the gas reservoir just as CH_4 was stored over geologic time prior to its production as an energy resource. A schematic illustrating the CSEGR process for a gas-fired power plant is shown in Figure 1.

As discussed above, CSEGR consists of many steps and processes that are subject to practical and theoretical limits and constraints. To make progress in assessing the feasibility of CSEGR, we are proposing a phased approach to the pilot study that begins with Phase I comprising an assessment of the process feasibility of CSEGR. By process feasibility, we refer to the physical practicality in terms of reservoir processes as opposed to gas transportation, CO_2 availability, land-use, or economic and policy considerations. The key processes to be tested are: (1) injectivity of CO_2 in a gas reservoir; (2) effects of CO_2 injection pressure on injectivity and flow; (3) cooling around the injection well due to phase change and Joule-Thomson effects; (4) flow of CO_2 within the reservoir; (5) mixing of CO_2 and CH_4 in the reservoir; and (6) repressurization and production of CH_4.

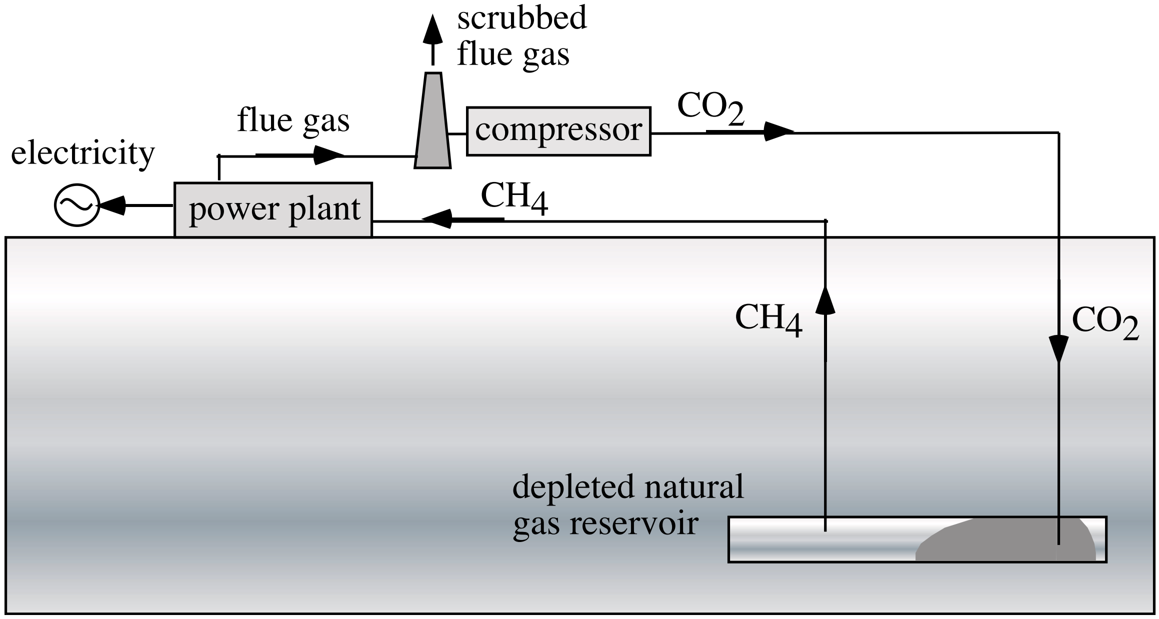

Figure 1. Schematic of the CSEGR process for a gas-fired power plant.

In order to assess the key processes, we propose a limited field test that involves injecting CO_2 from tanker trucks into a relatively small and high-permeability gas field or a depleted compartment of a larger reservoir. The reason for seeking a small reservoir or compartment is to be able to realize measurable pressure increases and CO_2 transport over reasonable time periods by using a limited amount of CO_2. High permeability is desirable to achieve high injectivity and to reduce the expected travel and repressurization times. The pressure of the gas reservoir should be relatively low (< 50 bars) to test injectivity into a reservoir at subcritical conditions for CO_2 distinct from the better understood supercritical injections associated with enhanced oil recovery (EOR) (e.g., Bondor, 1992). We envision a test where CH_4 pressure in the production well will increase due to CO_2 injection, and CO_2 and/or injected gas tracers will break through at the production well indicating transport over the course of a month or so of injection.

Results of the pilot study will be considered favorable for full-scale CSEGR if injectivity of CO_2 is sufficiently high, if pressure at the production well increases upon injection prior to breakthrough, and if relatively pure methane can be produced prior to breakthrough. The pilot test will also provide the opportunity to test and validate numerical simulation techniques used for CSEGR studies.

Expected Reservoir Processes

The critical temperature and pressure of CO_2 are approximately 31 ˚C and 74 bars respectively (Vargaftik et al., 1996). As such, CO_2 will be supercritical upon injection into the formation due to relatively high pipeline pressures (~150 bars). Within the Phase I field test, we expect to observe strong cooling due to (1) flashing of supercritical liquid-like CO_2 to gas, and (2) Joule-Thomson cooling as the CO_2 gas expands in the low pressure reservoir. In addition, we expect the CO_2 to dry the formation, another potential heat consuming process. Given that the formation and residual gas and liquid are at somewhat elevated temperature ($T > 40$ ˚C), heat will be available for the expanding gas. Eventually however, the temperature around the well may become quite low leading to the possibility of hydrate formation and associated decreases in injectivity. Pure carbon dioxide hydrate can form at approximately 0˚C at 20 bars pressure (Haneda et al., 2000).

Assuming there is sufficient permeability, the injected CO_2 will flow in the reservoir due to pressure gradient and gravitational effects. If there is liquid CO_2 immediately around the wellbore, it will flow strongly downward through the gas reservoir due to its large density. Once flashed to gas, CO_2 is also notably denser than CH_4 at all relevant pressures (see Figure 2) and will tend to flow downwards, displacing the native CH_4 gas and repressurizing the reservoir. Because CO_2 gas is more viscous than CH_4 (see Figure 3), the displacement will be stable.

Nevertheless, the displacement process will be miscible, and the gases will mix over time by molecular diffusion. For gases however, the repressurization is much faster than the mixing by molecular diffusion. This can be seen by examining the pressure diffusivity

$$D = \frac{T}{S} = \frac{\frac{k\rho g}{\mu} b}{\rho g b(\alpha + \phi \beta)} = \frac{\frac{k}{\mu}}{(\alpha + \phi \beta)} \qquad (1)$$

(e.g., Freeze and Cherry, 1979) where T is transmissivity, S storativity, k permeability, ρ is fluid density, g is acceleration of gravity, b is the layer thickness, μ is fluid viscosity, α is formation compressibility, ϕ is porosity, and β is fluid compressibility. Choosing representative values for porosity, permeability, and sandstone compressibility ($\phi = 0.35$, $k = 1 \times 10^{-12}$ m^2, $\alpha = 1 \times 10^{-8}$ Pa^{-1}), and reasonable values for methane at 50 ˚C and 60 bars ($\mu = 1.3 \times 10^{-5}$ Pa s, $\beta = 1.7 \times 10^{-7}$ Pa^{-1}), we obtain a pressure diffusivity of 1.1 m^2 s^{-1}. A similar result is obtained if properties of CO_2 are used. Regardless of the CO_2-CH_4 mixture composition, pressure diffusivity will be at least 10^4 times larger than gaseous molecular diffusivity, which is on the order of 10^{-5} m^2 s^{-1}, or smaller.

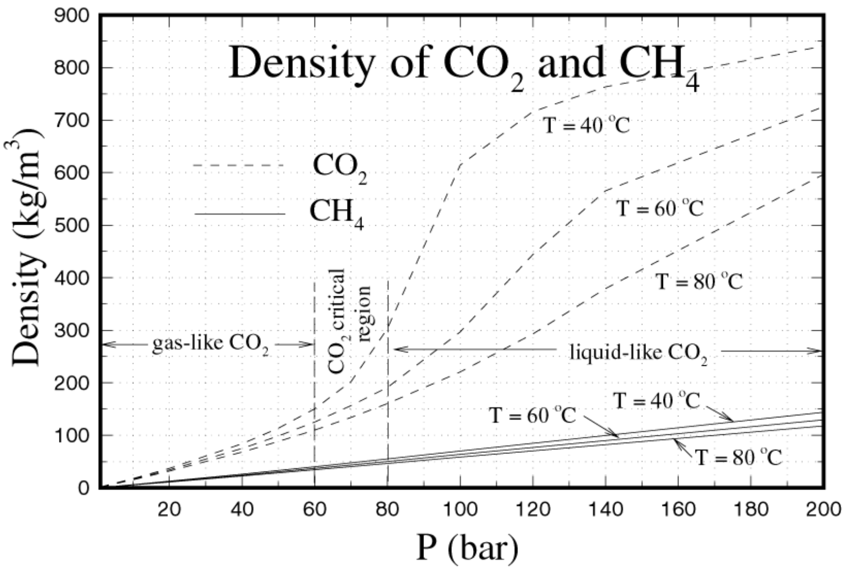

Figure 2. Density of CO_2 and CH_4 as a function of pressure for various temperatures based on data from Vargaftik et al. (1996).

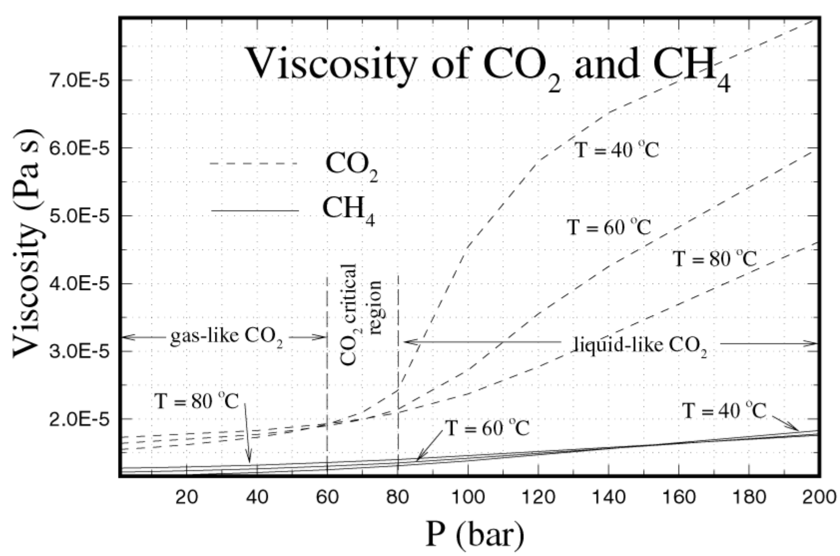

Figure 3. Viscosity of CO_2 and CH_4 as a function of pressure for various temperatures based on data from Vargaftik et al. (1996).

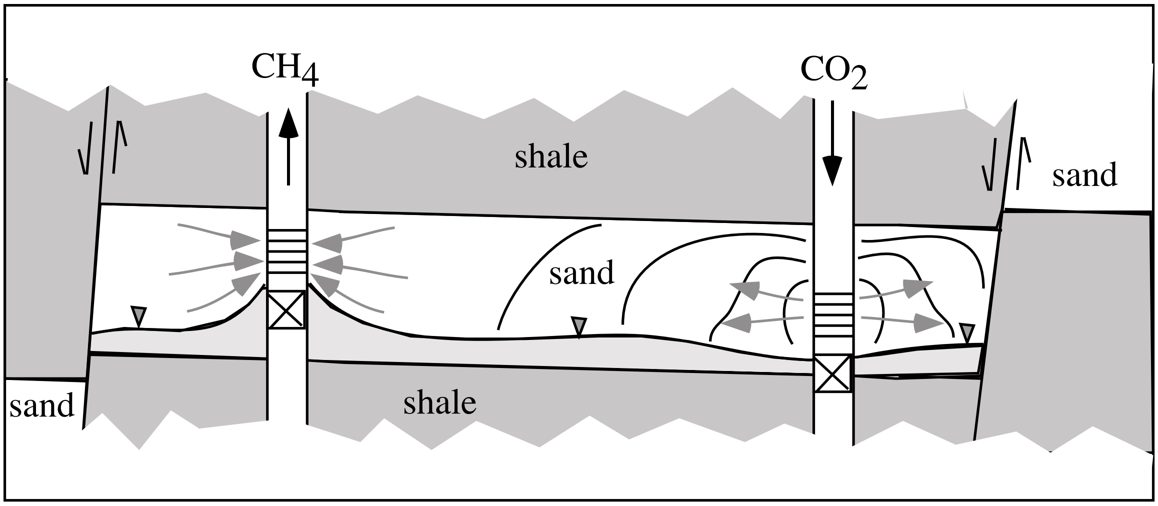

Figure 4. Cross section schematic of CO_2 injection and enhanced production of CH_4.

The reservoir processes of CO_2 injection and enhanced CH_4 production are shown schematically in Figure 4. As observed in the Figure and in numerical simulations (Oldenburg et al., 2001), CO_2 injection can deflect the water table, giving rise to repressurization at a large distance from the injection well. Also, the tendency for CO_2 to flow downwards due to density effects can be exploited in CSEGR by injecting CO_2 low in the reservoir and producing CH_4 at higher levels as is done to minimize water coning. In the proposed field test, the injection and production wells will be independently controlled and monitored to test the effects of pressurization, flow, and transport on gas injection and production.

We have carried out preliminary simulations of injection of CO_2 into a depleted natural gas reservoir under isothermal conditions (Oldenburg et al., 2001). A single representative result after 10 years of CO_2 injection with simultaneous constant-pressure production of CH_4 from the upper right-hand side of the two-dimensional homogeneous anisotropic reservoir is shown in Figure 5. The produced gas at this time (t = 10 yrs) contains about 10% CO_2 by mass. Briefly, the reservoir porosity is 0.35, Y-direction permeability is 10^{-12} m^2, Z-direction permeability is 10^{-14} m^2, the reservoir is dipping to the left (i.e., water table is horizontal), and other details can be found in Oldenburg et al. (2001).

Heterogeneity in the formation may lead to preferential flow paths for the injected CO_2. This phenomenon may be favorable for injectivity and carbon sequestration in that it allows greater amounts of CO_2 to be injected. However, preferential flow may lead to early breakthrough and is therefore detrimental to enhanced gas recovery. Furthermore, the development of larger gas composition gradients and subsequent mixing by molecular diffusion is enhanced by preferential flow.

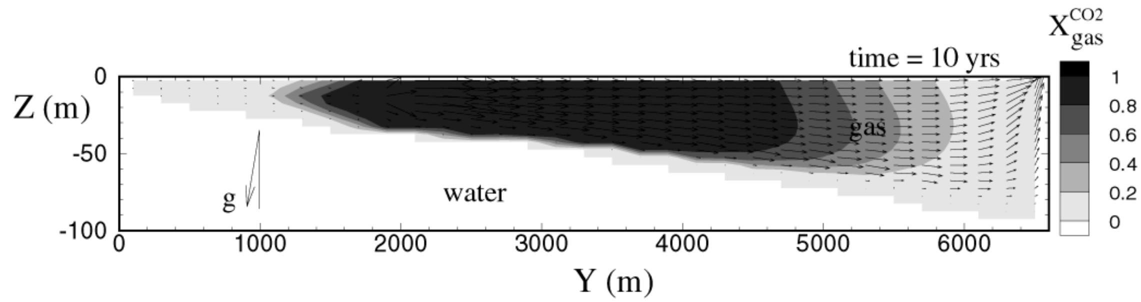

Figure 5. CO_2 gas mass fraction and gas velocity vectors after 10 years of CO_2 injection.

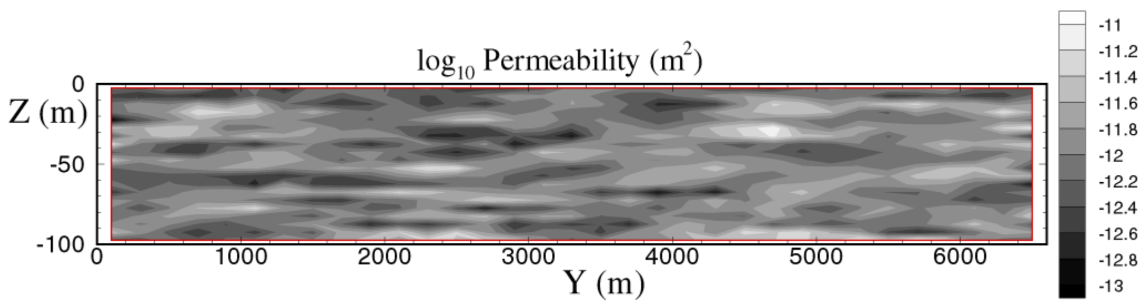

Figure 6. Representative heterogeneous permeability field.

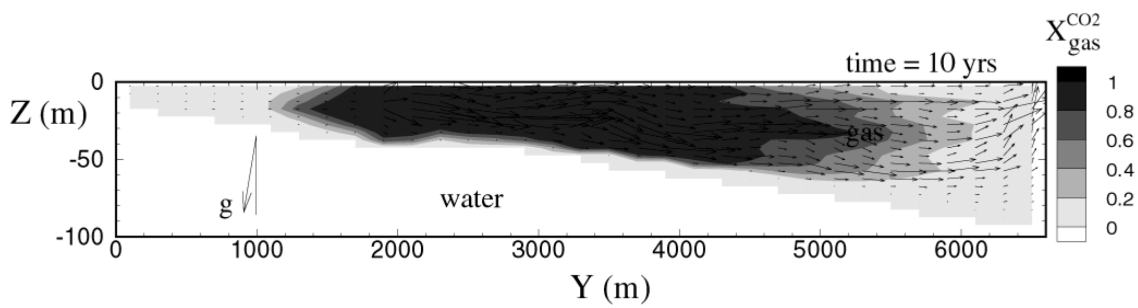

Figure 7. CO_2 mass fraction in the gas and gas velocity vectors after 10 years of CO_2 injection into a heterogeneous reservoir.

We have simulated the injection of CO_2 into depleted natural gas reservoirs with heterogeneous permeability. A representative case that has permeability varying over two orders of magnitude with a log normal distribution with 1000 m correlation length in the *Y*-direction and no *Z*-direction correlation is shown in Figure 6. The resulting CO_2 gas flow field of Figure 7 shows that preferential flow occurs in the high-permeability regions, but that the overall CO_2 transport is similar to the homogeneous permeability case of Figure 5. To remedy large preferential flow near the injection well in practice, various established approaches may be useful such as water and foam injections.

Monitoring Approach

Assuming the site selected for the Phase I field test consists of one injection well and one production well, access to the target formation will be limited. Four different monitoring approaches will be used.

1) Wellhead pressures, temperatures, and gas compositions will be continuously monitored in the two wells. All three types of measurements are crucial to the CSEGR process. At the injection well, we want to observe whether injectivity is compromised due to hydrate formation or other processes. At the production well, the pressure and gas composition are particularly interesting for monitoring the effectiveness of the enhanced gas recovery.
2) Downhole injection well pressure and temperature surveys will be conducted before, during and after the injection period. These will be used to determine the extent of cooling associated with gas injection and provide another constraint to validate reservoir simulations.
3) Stable isotopes of carbon and oxygen will be used to track migration of the injected CO_2. In addition, a combination of nonreactive and partioning tracers will be used to assess flow paths, the extent of formation drying and CO_2/water/rock interactions.
4) Depending on the outcome of ongoing geophysical modeling of CO_2 and CH_4 filled reservoirs, we may employ crosshole electromagnetic or seismic approaches in nearby boreholes, if feasible.

Criteria for Site Selection

Given the objectives and processes relevant to the Phase I field test, we seek the following characteristics for the field test site: (1) a depleted natural gas reservoir with pressures less than 50 bars; (2) weak to nonexistent water drive; (3) high permeability (>100 md); (4) small area (< 1 km^2) and thickness (< 10 m); (5) at least two idled wells or wells that can be screened in the target formation and that are relatively closely spaced; (6) easy access by tanker trucks. The Phase I field test is conceived as being revenue-neutral for the participating producer, with shared access to all of the data that are collected.

Rio Vista Site

The Sacramento Valley of California has a large number of dry gas fields that have been under production for many decades. Current production rates of the largest of the fields are now a small fraction of the peak values and reservoir pressures are highly depleted. High water cuts or low production rates have led to idling of many of wells or producing them at very low rates. As discussed by Oldenburg et al. (2001), the Rio Vista Gas Field, the largest dry gas field in California, is a logical candidate for CSEGR.

The Rio Vista Gas Field is located approximately 75 km northeast of San Francisco and approximately 20 km from a 680 MW gas-fired power plant that produces 2.2 x 10^9 m^3 (1 bar, 15.5 ˚C) or 4.15 x 10^9 kg (4.15 MT) of CO_2 annually (Figure 8). Since 1936 the Rio Vista Gas Field has produced from 365 wells 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]). Assuming a CH_4 density of 0.678 kg m^{-3} (1 bar, 15.5 ˚C), this volume corresponds to a mass of 6.3 x 10^{10} kg. Production peaked in 1951 with annual production of 4.4 x 10^9 m^3 and has declined steadily since then (Cummings, 1999). The Rio Vista reservoir has an elongated dome-shaped structure extending over a 12 by 15 km^2 area, with reservoir rocks consisting of alternating layers of sands and shales deposited in deltaic and marine environments with contemporaneous normal faulting trending NW through the field (Figure 9). The most important of these is the Midland Fault. The Domengine formation shown in Figure 9 has been the most productive reservoir 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. In some gas-bearing strata, displacement along the faults has created structural traps. A small compartment created as a structural trap may be suitable for the needs of the Phase I field test.

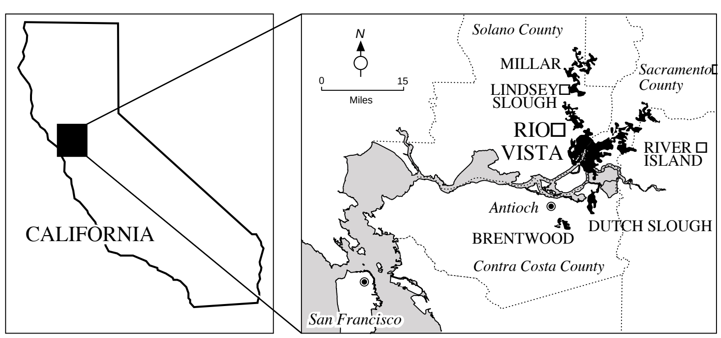

Figure 8. Rio Vista Gas Field area map showing gas fields in black.

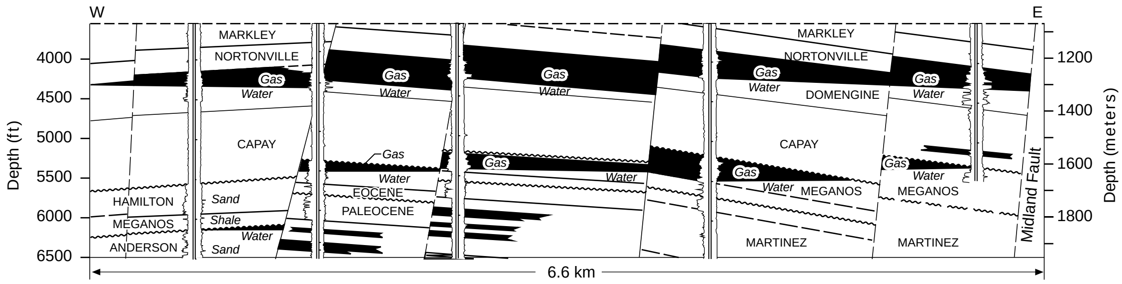

Figure 9. East-west cross section of the Rio Vista Gas Field modified from Burroughs (1967).

Conclusions

Prior reservoir simulation studies show favorable results for CSEGR in terms of the feasibility of reservoir repressurization and enhanced production of CH_4. While simulations demonstrate that reservoir heterogeneity promotes early breakthrough, standard techniques for controlling preferential flow may be used in the field where required. Our simulations for a particular system, combined with the inherently favorable attributes of CO_2 in general, such as a comparatively high density and viscosity, suggest that CSEGR is feasible. Further progress in evaluating the feasibility of CSEGR requires field testing. We propose a Phase I field test to investigate the reservoir processes involved in injecting high-pressure CO_2 into depleted natural gas reservoirs. Key processes will be the injection of CO_2 and associated cooling of the formation, flow and transport of CO_2 gas through the reservoir, repressurization of the reservoir, and the enhanced production of CH_4. The Rio Vista Gas Field in California is a promising target for the field test, however, we will consider other locations if they have better potential to satisfy the objectives of the pilot study.

Acknowledgments

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