Hydraulic controls on injection of carbon dioxide into deep saline aquifers

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Abstract

Sequestration of carbon dioxide in geologic formations, both deep aquifers and depleted petroleum reservoirs, has the potential to significantly reduce the atmospheric emissions of that greenhouse gas. Injection into a deep saline formation differs from injection into a hydrocarbon reservoir in that there is no produced fluid from the aquifer and the hydrogeologic characterization of both the receptor formation and the cap or seal is much more uncertain. Hydraulic control may reduce the risks and increase the safety of CO\(_2\) sequestration. While the applicability to a particular site is strongly dependent on the local conditions, the injection of brine above the confining layer can reduce the vertical migration and enhance the lateral spreading of the carbon dioxide.

1 Introduction

Sequestration of carbon dioxide in geologic formations is a promising way of reducing emissions of the greenhouse gas (cf. Herzog, 2001; Bachu, 2000; Zweigel and Gale, 2000). While the impacts to the receptor formations are minimal, the largest concern regarding geologic storage of CO\(_2\) is the unplanned escape of the gas. Though carbon dioxide is not usually considered hazardous, in concentrations greater than 10,000 ppm it is toxic to humans, and at sites such as Mammoth Mountain, CA, natural CO\(_2\) releases have deforested 400 hectares of conifers (Farrar et al., 1999). An effective geologic sequestration effort will require the responsible
management of carbon dioxide injection and storage.

Both deep saline formations and depleted oil and gas reservoirs are potential classes of candidate formations. Saline formations offer greater total volume and are more widely available (Herzog, 2001; Bachu, 2000); also, there are no concerns over contaminating a potential future resource. Injection into a saline aquifer, however, has some distinct differences from injection into a depleted petroleum reservoir. First, the geology of such a receptor formation will not be characterized as well as a former petroleum field that has been producing for many years. Second, while one may reasonably presume that the integrity of the seal or trap for a hydrocarbon reservoir is high, the quality of a confining layer overlying a saline aquifer will be unknown. Last, there would typically be no produced fluid for injection into a saline formation, which means that injection of CO$_2$ will raise the pressure above its natural condition. In sum, injection of carbon dioxide into a saline formation is characterized by a much higher degree of uncertainty than injection into a depleted oil or gas reservoir.

Additional hydraulic manipulation may help overcome some of the drawbacks and reduce the risks associated with carbon dioxide sequestration. In particular, the injection of brine above the stratum confining the target formation may retard the vertical migration of CO$_2$ and enhance lateral spreading.

2 Methodology

To investigate the utility of hydraulic control as a mechanism for reducing the potential impacts of carbon dioxide escape near the injection well, we consider three injection scenarios.

1. Injection of CO$_2$ at 20 kg/s (equivalent to the emissions from a 200 MW power plant) for eight years into the target formation with an undisturbed confining layer that presents a uniform capillary barrier to vertical migration.

2. Injection of CO$_2$ at 20 kg/s for eight years into the target formation with the presumption that the confining layer is not an effective capillary barrier. In this scenario, capillary pressure effects are ignored.
3. Injection of CO$_2$ at 20 kg/s for eight years into the target formation, again neglecting capillary pressure, with the simultaneous injection of brine at 40 kg/s (approximately 600 gallons per minute) above the confining layer to reduce carbon dioxide escape. The brine is presumed to be withdrawn from the same well but deep enough that the extraction does not affect the flow field.

These three scenarios are intended to represent, respectively, an ideal injection, a possible injection failure, and an attempt to reduce the risks of injection through hydraulic manipulation. These scenarios are not intended to be exhaustive, but rather to provide insight into possible outcomes of carbon dioxide sequestration and the feasibility of hydraulic control on CO$_2$ injection.

The geometry of all simulations is presented in Figure 1. In the model, top and bottom no-flow boundaries are imposed at depths of 60 and 960 meters, respectively. A hydrostatic pressure distribution is specified at a radial distance of approximately five kilometers. The target formation ranges from a depth of 800 to 850 meters and is bounded above and below by confining layers, each ten meters thick. In each of these scenarios the focus is on the target formation, and no geologic heterogeneity beyond the upper and lower confining units is considered. Also, to keep the emphasis on the hydraulic regime around the injection well and to simplify the simulations, the temperature is held constant at 60°C. Prior to injection, the pressure of the brine varies hydrostatically, ranging from 7.9 to 8.4 MPa in the target formation. Such a pressure distribution, coupled with the constant temperature of 60°C, implies that the injected CO$_2$ will be in a supercritical state (the critical point of carbon dioxide is 7.3 MPa and 31.1°C). Under these conditions, carbon dioxide has a density of approximately 250 kg/m$^3$ and a viscosity around $2 \times 10^{-5}$ Pa-s. This density leads to a strong buoyancy effect, and the low viscosity means that the resistance to flow is much less for the CO$_2$ than for the resident brine, which has a density of 1020 kg/m$^3$ and a viscosity near $5 \times 10^{-4}$ Pa-s at 60°C.

The permeability and porosity of the target formation are 100 mD and 10%, respectively. These values are consistent with the range of values for the two formations in the Alberta Basin studied by Bachu (in Hitchon, 1996). Note that there is significant variation in these parameters among potential injection sites; e.g., the
Frio Formation, near Houston, Texas, has a permeability of 1000 mD and a porosity of 25% (Hovorka et al., 2000). The permeability of the confining layers is 0.1 mD, a factor of 1000 less than the target formation, and the porosity is 10%.

The injection scenarios are explored with the TOUGH2 simulator, version 2.0 (Pruess et al., 1999), with the EWASG package (Battistelli et al., 1997). This code facilitates the simulation of the multiphase flow of brine and CO₂, accounting for carbon dioxide dissolution in the aqueous phase. While the EWASG package was originally designed for geothermal reservoirs, not CO₂ injection, the thermodynamic relationships employed by the package are appropriate for the goals of this work.

Relative permeability is modeled with a Corey relationship (Corey, 1954 in Pruess et al., 1999):

\[
\begin{align*}
  k_{r,aq} &= \phi^4 \\
  k_{r,CO_2} &= 1 \phi^2 \phi^2
\end{align*}
\]

(1a)

(1b)

where

\[
\phi = \frac{S_{aq} \phi \phi \phi \phi}{S_{aq,r} \phi \phi \phi}
\]

(2)

In (2), \(S_{aq}\) is the brine saturation, \(S_{aq,r}\) is the residual brine saturation and \(S_{CO_2,r}\) is the residual carbon dioxide saturation. In these simulations, the former is set to 30%, and the latter to 5%. For the set of scenarios incorporating capillary pressure effects, we use Leverett’s function (Leverett, 1941 in Pruess et al., 1999) to describe the relationship between brine saturation and capillary pressure:

\[
P_{cap} = P_0 \phi \phi \phi \phi (S^n)
\]

(3)

where \(\phi\) is the surface tension of water, and the function, \(f(S^n)\) is given by

\[
f(S^n) = 1.417 (1 \phi \phi \phi \phi) 2.120 (1 \phi \phi \phi \phi)^2 + 1.263 (1 \phi \phi \phi \phi)^3
\]

(4)

where

\[
S^n = \frac{S_{aq} \phi \phi \phi}{S_{aq,r} \phi \phi}
\]

(5)
The scaling factor, $P_0$, related to the inverse of the pore size, is $5 \times 10^7 \ (1/m)$ for the confining layers and $5 \times 10^5 \ (1/m)$ for the aquifers. Figure 2 presents a plot of the two capillary pressure-saturation relations. As shown in the figure, the values used here correspond to an effective entry pressure of approximately 0.5 MPa for the confining layers, similar to the value used in Weir, et al. (1996).

3 Results

Figure 3 presents a gray-scale image of total carbon dioxide mass (both separate phase and dissolved in brine) per unit volume of the porous medium at the end of eight years of injection for the first scenario — the case with an intact capillary barrier. This figure indicates that most of the carbon dioxide is trapped by the confining layer, but a small amount near the injection well, where pressures are highest, is able to overcome the entry pressure and migrate through the layer. In contrast to this behavior, Figure 4 shows the CO$_2$ distribution after approximately eight years of injection for the second scenario — the case ignoring capillary effects. This figure shows that the CO$_2$ migrates upward through the confining layer and escapes to the surface. Figure 5 presents the distribution of carbon dioxide after eight years of injection for the third scenario. In this case, as in the second scenario, the confining layer is modeled as an ineffective capillary barrier and capillary effects are ignored. Brine is injected above the confining layer at a rate of 40 kg/s. As the figure shows, the brine injection succeeds in suppressing the upward migration of CO$_2$ in the vicinity of the injection well. The CO$_2$ moves out radially and is kept beneath the confining layer until the buoyancy force overcomes the additional pressure due to the injected brine. Without a capillary barrier, however, after a sufficiently long time, the CO$_2$ will migrate through the confining layer. Figure 6 shows the CO$_2$ distribution for the third scenario after eight years of injection, followed by forty years of subsequent migration. At this point, about 9% of the injected CO$_2$ has migrated to a depth less than 460 m. A shadow of near-residual CO$_2$ remains at depth; between 460 and 960 m depth, the maximum gas saturation, found in the confining layer, is 10%.
4 Discussion

Figures 3 and 4 readily identify the importance of a capillary barrier for CO$_2$ sequestration in a saline aquifer. If the seal does not have a significant entry pressure, buoyant carbon dioxide will migrate through the confining layer, even if the permeability is low. Unfortunately, the quality and uniformity of a capillary barrier is difficult to determine in the field. Consequently, a failure may not be detected until after injection has begun. As shown in Figure 5, the hydraulic control of carbon dioxide injection may provide an additional level of safety. The increased brine pressure above the confining layer in the vicinity of the injection well reduces the upward migration of CO$_2$ and forces it to move laterally. This enhanced radial expansion of the carbon dioxide means that if it does break through the confining layer, there will be a larger volume of water into which it can dissolve before reaching a sensitive aquifer or the ground surface. Injection of brine may also prove useful in preventing localized CO$_2$ escape elsewhere in the target formation, such as through an abandoned well-bore or fracture in the confining layer. If such a leak is detected, brine could be injected to create a local pressure field forcing flow away from the area. Of course, CO$_2$ escape is not the only concern associated with carbon dioxide injection. Migration of brine (both resident and injected) must also be considered. Indeed, unwanted brine movement may present larger problems in some instances. Also, the pumping of brine for hydraulic manipulation has associated capital and energy costs, and these must be weighed versus the benefits.

5 Conclusions

Injection of CO$_2$ into a saline formation is characterized by a much higher level of uncertainty than injection into a depleted oil and gas reservoir. To ensure the safety of such a carbon sequestration operation, additional measures beyond CO$_2$ injection and monitoring may need to be undertaken. Brine injection above the confining layer can prevent vertical migration of CO$_2$ near the injection well and enhances the radial expansion of the carbon dioxide plume. Though the applicability to a particular site will be strongly dependent on the local conditions, the exploratory simulations presented here demonstrate that hydraulic manipulation may
reduce the risks associated with the injection of carbon dioxide into a saline aquifer.

References


Zweigd, P., and Gale, J., Storing CO\textsubscript{2} underground shows promising results, EOS Transactions, 81(45), 529-534, 2000.
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Figure 1. Schematic of geology around the point of carbon dioxide injection.

Figure 2. Capillary pressure-saturation relationships for aquifers and conning layers in the first scenario.

Figure 3. Distribution of carbon dioxide (mass of CO$_2$ per volume of porous medium) after eight years of injection for the first scenario.

Figure 4. Distribution of carbon dioxide (mass of CO$_2$ per volume of porous medium) after eight years of injection for the second scenario.

Figure 5. Distribution of carbon dioxide (mass of CO$_2$ per volume of porous medium) after eight years of injection for the third scenario.

Figure 6. Distribution of carbon dioxide (mass of CO$_2$ per volume of porous medium) after eight years of injection and forty years of subsequent migration for the third scenario.
Figure 1:
Figure 2:
Figure 3:
Figure 4:
Figure 5:
Figure 6: