REMEDIATION OF POSSIBLE LEAKAGE FROM GEOLOGIC CO_2 STORAGE RESERVOIRS INTO GROUNDWATER AQUIFERS

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By

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I certify that I have read this report and that in my opinion it is fully adequate, in scope and in quality, as partial fulfillment of the degree of Master of Science in Energy Resources Engineering.

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Abstract

Maintaining the long term storage of CO_2 is an important requirement for a large scale geologic CO_2 storage project. Nevertheless, the possibility remains that the CO_2 will leak out of the formation into overlying groundwater aquifers. There are many groundwater remediation technologies available that could be applied for remediating CO_2 leaks. A site specific remediation plan is also important during the site selection process and necessary before storage begins.

Due to the importance of protecting drinking water resources, this study analyzes the optimal remediation scenario for various leakage conditions. The three objectives for remediation considered here are removing any mobile CO_2, reducing the quantity of CO_2 in the reservoir, and reducing the aqueous phase concentration of CO_2. One technique to remediate the leak is to extract the CO_2 in both the gaseous and dissolved phase. Another technique analyzed is to inject water to dissolve the gaseous CO_2 in the groundwater, reduce the overall aqueous concentration, and immobilize CO_2 by capillary trapping. Water injection is similar to the impact of regional flow in the reservoir. The final technique analyzed is the combination of water injection followed by extraction.

The first part of our research was to determine the processes that control the size and shape of the leakage plume in the groundwater aquifer. We used the multiphase flow simulator TOUGH2 with CO_2 leakage from a point source to analyze the plume at various leakage rates. At the depth of most groundwater aquifers the pressure is shallow enough that CO_2 is either in gas phase or dissolved. Due to the large contrast between the density of the groundwater and CO_2, we found that the leakage rate, the quantity of leaked CO_2, and the amount of time that the leak continues have a very important effect on the size and shape of the leakage plume.

The second step was to determine the physical processes that expedite or hinder removal of the CO_2 plume. Important processes include capillary trapping as a result of hysteresis in the relative permeability curves, dissolution, and buoyancy induced flow. We compared the effectiveness of using vertical and horizontal extraction wells to remove the CO_2. We next examined another remediation technique where we inject water to dissolve the gaseous CO_2 and reduce the overall concentration and increase capillary trapping. With an injection well, the main factor controlling the dissolution of CO_2 was the residual gas saturation and the injection well flow rate. Also, the spatial extent of the gaseous CO_2 impacted the amount dissolved over time. Finally, we determined that water injection makes later extraction difficult because it displaces the CO_2 from the initial leakage point.

We also conducted a sensitivity analysis to examine the impacts on the effectiveness of the remediation when there is a heterogeneous layered reservoir and when the leak is allowed to continue after the remediation begins. The low permeability layers reduce the extent of the gravity tongue and allow for more effective remediation for the larger leakage cases analyzed. Allowing the leak to continue does not have a significant impact on the remediation effectiveness if the extraction well is able to remove more CO_2 than is leaking.

Based on the simulations analyzed for this study, multiple conclusions can be made on the effectiveness of various remediation scenarios. With one vertical extraction well the optimal scenario for the larger leakage cases is a multistep extraction process that removes mobile CO_2 from the areas with high gas saturation first. Water injection is very effective at quickly reducing the mobile phase CO_2 with tradeoffs between injection rate and increases in pressure. The most effective scenario over a longer time period includes injection for a short time followed by extraction from four vertical wells. To reduce the CO_2 most rapidly, four injector wells with high flow rates and one extraction well is the most effective for the large leakage cases. Finally, formulating the scenario very quickly after leakage is stopped leads to the most cost effective scenario.

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Chapter 1

1. Introduction

Based on research by the Intergovernmental Panel on Climate Change, the increase in global temperatures over the recent decades can be attributed to human emissions of anthropogenic greenhouse gases. Carbon dioxide (CO_2) is one of the main forms of greenhouse gasses emitted from energy production. Carbon capture and storage (CCS) is considered as a viable option for significantly reducing anthropogenic CO_2 emissions to the atmosphere from large point sources such as coal-fired or natural gas power plants. CCS starts with separation of CO_2 from the exhaust gas of large point sources or precombustion capture of CO_2. The CO_2 is compressed and transported to the storage site for injection. Potential storage sites include geologic formations with structural trapping with a cap rock with low permeability to prevent CO_2 from reaching the surface. However, leakage through this caprock via wells or faults and fractures is possible. Leakage degrades the benefit of reducing emitted greenhouse gases, could result in forfeiture of carbon credits under a carbon trading system and, if not controlled, could ultimately result in the closure of the carbon storage project. Also, if the CO_2 leaks into a groundwater aquifer utilized for drinking water or agricultural purposes it may pose human health risks or damage crops. Currently there are four commercial CO_2 storage projects worldwide, none of which have negatively affected groundwater quality. This chapter provides a brief background on the geologic storage of CO_2, possible CO_2 leakage pathways, possible leakage impacts, the current regulatory framework, and a summary of remediation options.

1.1. Geologic Storage Options and Comparison to the Location of Major Drinking Water Aquifers

One main option for geologic storage of CO_2 is in deep saline (non-potable) aquifers which are prevalent in the United States and in many locations around the world (Benson et al., 2005). Deep saline aquifers are estimated to have the largest storage potential, greater than oil and gas reservoirs and unmineable coal seams. The distribution of the principal groundwater aquifers corresponds closely with the deeper saline aquifers considered for geologic storage. Figure 1-1 shows the 30 principal groundwater aquifers in the US that account for 94% of total groundwater withdrawals (Reilly et al., 2008). Figure 1-1 also shows the distribution of deep saline aquifers that have been considered as a potential site for geologic storage of CO_2 (NETL Atlas, 2007). The red boxes in each figure emphasize the correspondence of the main groundwater aquifers with the deep saline aquifers considered for geologic storage.

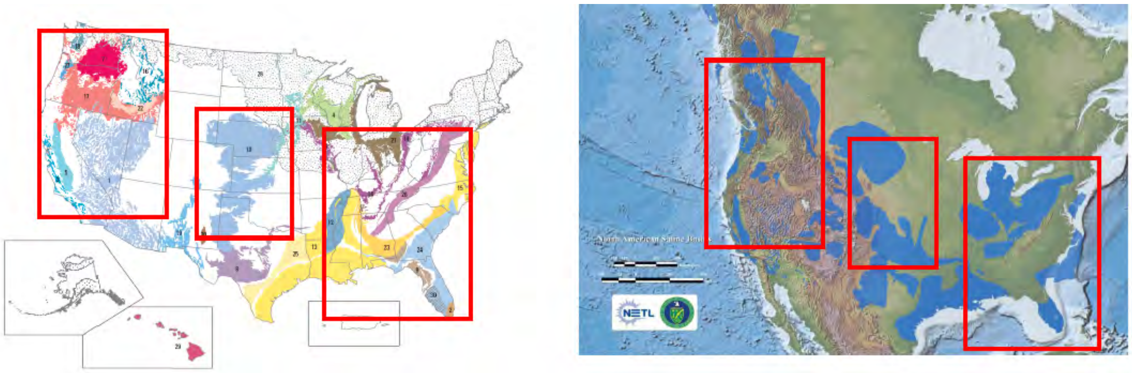


Figure 1-1. Thirty Principal Groundwater Aquifers (Reilly et al., 2008) and Deep Saline Aquifers (NETL Atlas, 2007)

1.2. Leakage Pathways

There are several possible leakage pathways that could allow for movement of the CO_2 and displaced brine from the storage site to an overlying groundwater aquifer. The three main possible leakage pathways are wells, faults and fractures, and spillage beyond the limits of the confining layer of the storage formation.

1.2.1. Wells

Poorly constructed and completed wells that penetrate the confining layer are potential leakage pathways. Among these wells include injection wells, abandoned wells, and oil and gas producing wells from deeper producing formations (Figure 1-2).

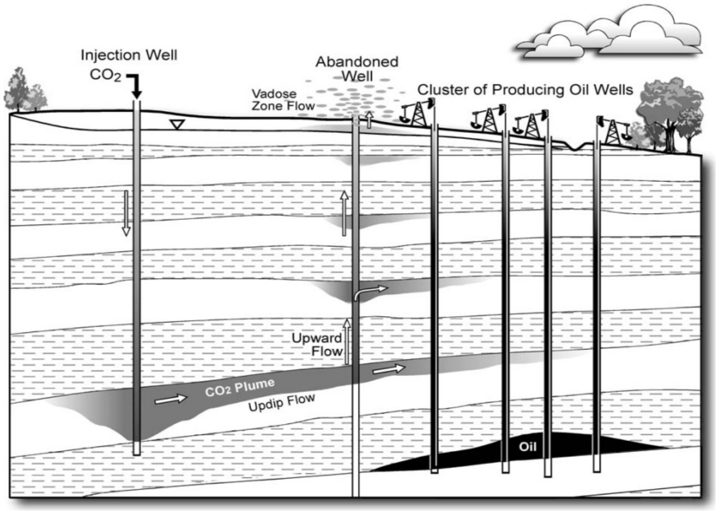


Figure 1-2. Possible Well Leakage Pathways (Gasda et al., 2004)

If CO_2 leaks out of the storage formation through another leakage pathway such as a fault or fracture, then it may intersect a well and continue to move upward. The potential for well leakage is dependent on the depth of the wells, the number of wells in the vicinity of the storage project, the age of the wells, the well construction materials, and for wells that have been abandoned the technology that was used to plug the well (Gasda et al. 2004).

1.2.2. Faults and Fractures

Faults and fractures are features found in rocks that form when the rock is subjected to regional tectonics, sediment compaction, and subsidence (Figure 1-3).

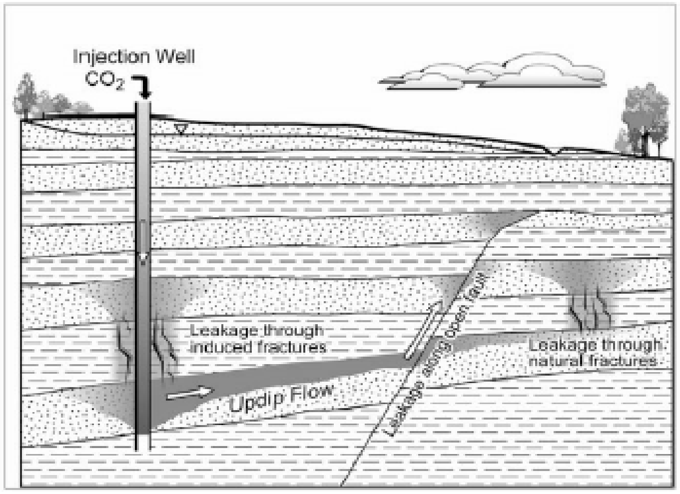


Figure 1-3. Possible Natural Leakage Pathways (Bachu and Celia, 2009)

Injection and withdrawal of fluids alters the pore pressure in the rock as well as the effective rock stress. This can result in the expansion or contraction of the reservoir and existing fractures may open or close. If pressures exceed the minimum rock stress, then the rock may fail and new fractures may form. Faults and fractures may serve as pathways for CO_2 leakage from the storage reservoir if they slice through the confining layer. Many models have been developed to look at the impacts of faults on the movement of the leaking CO_2 plume (Chang and Bryant, 2009).

1.2.3. Spillage out of the Confining Structure

The final possible leakage pathway includes spillage of CO_2 or brine beyond the lateral limits of the confining layer. This type of leakage is the least likely to occur if the geologic storage site is properly characterized. Also, in many cases there will be multiple confining layers above the primary confining layer that will help mitigate the movement of the CO_2.

1.3. CO_2 Leakage Impacts

There are some key aspects of CO_2 that are relevant to understanding the challenges of remediation. CO_2 is less dense than water and due to buoyancy forces will migrate upwards until it reaches a geologic barrier. Also, once the CO_2 dissolves in the formation water it forms carbonic acid which reduces the pH of the groundwater, and could lead to increased levels of trace metals such as arsenic and lead (Wang and Jaffe, 2004). The concentration of trace metals dissolved in the groundwater depends not only on the pH, but also the redox condition and the abundance and type of minerals present in the rock.

A decrease in pH can be accompanied by an increase in trace metal concentrations in the groundwater from desorption of metals from ion exchange sites found on mineral surfaces and the dissolution of the minerals (Zheng et al., 2009). The change in the trace metal concentrations depends on the magnitude of the pH change, solubility and ion exchange capacity of the minerals, buffering capacity of the rock, and redox conditions found in the aquifer. Increases in the concentration of trace metals in the groundwater such as arsenic and lead could pose a human health risk if ingested from consuming contaminated water or agricultural products. Kharaka et al. (2008) detected increased acidity and mobilization of trace metals as well as iron and manganese from an artificial leak of CO_2 into shallow groundwater in Bozeman, Montana. Figure 1-4 shows that there are already many areas where groundwater has arsenic levels above the maximum contaminant level specified by the EPA at 5 µg/L (Reilly et al., 2008). For this reason, in areas susceptible to trace metal contamination it is also important to reduce the aqueous CO_2 concentration to minimize the reduction in pH and limit the possible increases in trace metal concentrations.

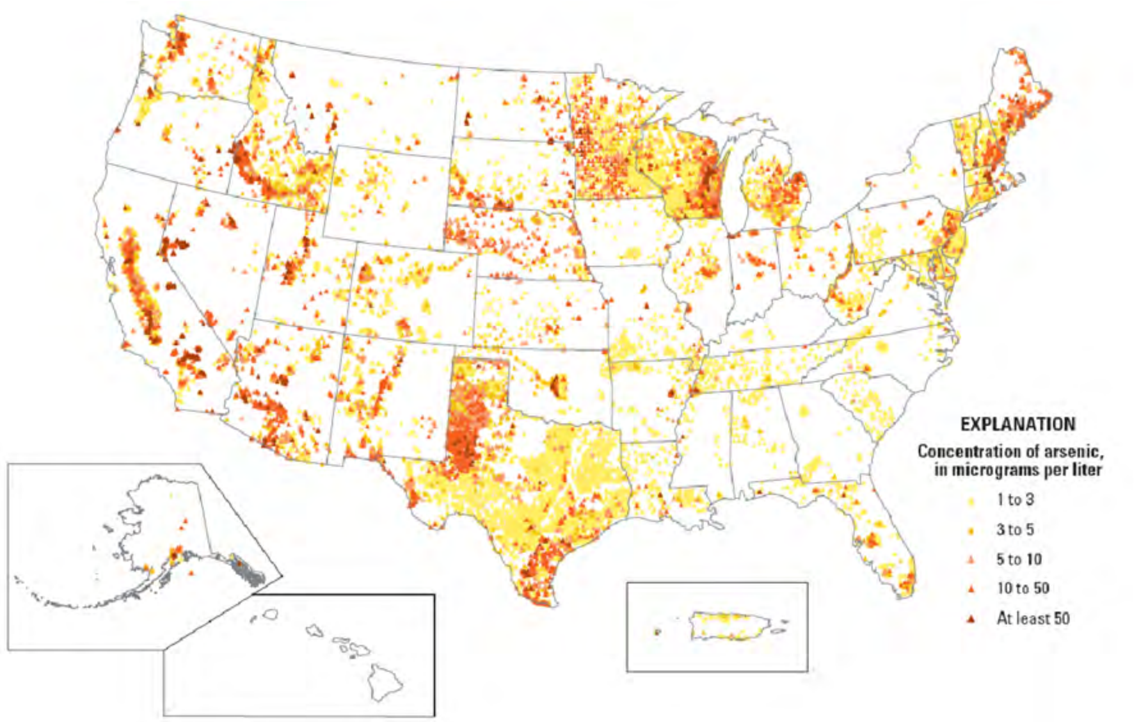


Figure 1-4. Groundwater Arsenic Samples Collected from 1973-2001 (Reilly et al., 2008)

In terms of physical impacts, a large plume of gaseous CO_2 in a shallow groundwater aquifer could interfere with groundwater extraction and conveyance systems because these systems are usually designed to only pump liquids. Groundwater production wells, pumps and pipelines might need to be replaced by alternative devices that are able to extract and transport groundwater with gaseous CO_2.

Another potential impact on groundwater could result if the injected CO_2 displaces saline groundwater from the injection zone into a shallow aquifer. The displaced saline groundwater could contain high concentrations of dissolved ions and trace metals that could potentially mix with the shallow groundwater. Natural CO_2 seeps or leaks are sometimes accompanied with brine displacement and in some cases it is the brine that leads to the greater impact on reducing the groundwater quality (Keating et al., 2009).

1.4. Regulatory Framework

The US Environmental Protection Agency (EPA) Underground Injection Control (UIC) program regulates all underground injection operations. The EPA proposed in July 2008 new federal requirements under section 1421(d)(1) of the Safe Drinking Water Act (SDWA) to regulate the underground injection of CO_2. Underground injection of all fluids except for natural gas storage is regulated by the EPA Underground Injection Control (UIC) program under the SDWA. The proposed rule is based on the existing regulatory framework for injection of other regulated fluids, but takes into account the additional aspects of CO_2 storage to fully protect Underground Sources of Drinking Water (USDW). USDWs include formations that are currently being used for drinking water and any formations that can be expected to be used in the future. The formation must also contain water with less than 10,000 mg/L of total dissolved solids and which can produce a sufficient quantity of water to supply a public water system (40 CFR 144.3) to be considered a USDW. The EPA has proposed a new class of wells, Class VI, for permanent CO_2 storage. Motivation for creating a new injection well classification include: CO_2 is buoyant making it easier to escape from the injection zone; it is corrosive when dissolved in water; mobile in the subsurface; and geologic storage projects will likely inject large volumes of CO_2 over several decades (EPA, 2008). Class VI wells cannot be used for experimental purposes, are not for hydrocarbon recovery, are below the lowermost USDW, and cannot be used to inject hazardous or nonhazardous waste.

The EPA is proposing minimum technical criteria for geologic site selection and characterization, fluid movement, area of review (AoR), corrective action, well construction, operation, and mechanical integrity testing. The sections that follow address the technical criteria for the AoR and the corrective action in the new proposed regulation in greater detail. These two areas deal both with technological considerations to mitigate leakage and also to remediate any possible leakage events.

1.4.1. Area of Review

The AoR is defined as "the region surrounding the geologic sequestration project that may be impacted by the injection activity. The AoR is based on computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream" (EPA, 2008). This takes into account both the horizontal and vertical extent of the area potentially influenced by CO_2 injection. Within the AoR the owner/operator must identify all well penetrations in the confining layer and in the injection zone and determine if they have been properly plugged. Due to the much larger size of CO_2 storage projects, EPA is proposing that the project proponent base the AoR on multiphase flow models and not on a fixed radius as with other classes of wells. It is important to realize that most injection operations in the US take up less than 0.5 km^2 where as CO_2 storage projects for 500 MW coal power plants could easily take up more than 50 km^2 (Schnaar and Digiulio, 2009). AoR calculations need to be reevaluated at least every 10 years and more frequently if there is significant difference between the monitoring results and modeling predictions.

1.4.2. Corrective Action

Corrective action is defined as "the use of Director approved methods to assure that wells within the AoR do not serve as conduits for the movement of fluids into USDWs." The owner/operator will need to compile and review casing, cementing, and plugging information for each well in the AoR that penetrates the confining layers. Wells that require corrective action to prevent the endangerment of USDWs need to be identified. Corrective action techniques will either be applied prior to injection or on a phased basis throughout the storage project in advance of the pressure increase reaching that location. This phased approach reduces the initial financial burden of remediating wells far from the injection point and also allows for newer technology to be continually used for protecting USDWs. The corrective action techniques listed include drilling out improperly plugged wells and re-plugging them, remedial squeeze cementing, and plugging abandoned wells that were never plugged. There is no mention of remediating transmissive faults or fractures in the confining zone because the EPA requires that these features be absent as stated in the draft rule. A rigorous site selection and characterization process must be performed by the project proponent to ensure that these features are not present.

1.5. Groundwater Remediation Options

From a review of the current research on the remediation of CO_2 leakage from geologic storage reservoirs it is clear that very little research has been dedicated to remediating groundwater from CO_2 intrusion. The majority of the current research on remediating leaks focuses on mitigating leaking wells such as work done by Watson and Bachu (2008). In a technical report on remediation options for halting seepage from a geologic CO_2 storage reservoir, pumping the contaminated groundwater and treating it at the surface is suggested as a possible method for groundwater remediation (Kuskraa and Gosdec, 2007). Some work has looked at detecting changes in groundwater quality near a long term Enhanced Oil Recovery (EOR) project, but no strong correlation was found between CO_2 use for EOR and water quality (Smyth et al., 2008). In an overview of options for remediation of leakage from geologic storage formations, Benson and Hepple (2005) propose three groundwater remediation methods: passive, active, and methods to remediate secondary contamination from the CO_2 intrusion.

More relevant research has analyzed vadose zone remediation from CO_2 intrusion using Soil Vapor Extraction (SVE) (Zhang et al., 2004). SVE includes the drilling of multiple vertical or horizontal wells in the contaminated zone. Then air pumps and vacuum pumps are installed to extract the contaminants. Often, impermeable surface covers are added so that ambient air from the ground surface does not flow directly to the pumping well. The effectiveness of this technology to remediate CO_2 leakage in the vadose zone was modeled using a multiphase simulator. Different combinations of horizontal wells, vertical wells, and vertical and horizontal wells were modeled. Also, the effect of an impermeable surface cover was modeled. The half life of the CO_2 plume with SVE methods was compared to the natural attenuation of the CO_2 plume by the soil system. The modeling showed that compared to natural attenuation, SVE methods are very effective at reducing the half life of the CO_2 plume. The most effective reduction in the half life was found using both horizontal and vertical pumping wells. The removal was also improved with the addition of the impermeable surface cover.

There are no studies to date that focus on the remediation of CO_2 from groundwater aquifers. However, there are many groundwater treatment technologies that could be used for remediating impacts from CO_2 intrusion into groundwater including: 1) simple dilution; 2) CO_2 extraction; 3) pH buffering; 4) pump and treat systems; 5) reactive barriers; 6) air sparging. There are decades of experience using these techniques for hazardous waste remediation (Khan et al., 2004). When CO_2 dissolves in water it forms carbonic acid (H_2CO_3) which is mildly corrosive, but is also forms large amounts of bicarbonate (HCO_3^-) which is innocuous to human health and smaller amounts of carbonate (CO_3^{2-}).

One method of groundwater remediation is to dilute the concentration of CO_2 and reduce the mobile phase CO_2 by injecting water into the formation near the leakage plume. First, enough water needs to be injected to dissolve all of the CO_2 in gas phase. Second, additional water needs to be injected to raise the pH by increasing the amount of carbonic acid that dissociates into bicarbonate. The amount of CO_2 that can be dissolved per kg of water injected is also dependent on the increase in pressure in the formation from the water injection. There is also the option of extracting the CO_2 from the initial leakage plume in the groundwater aquifer. Extraction could also occur after injecting water and dissolving all of the CO_2 that was present in the mobile gas phase. Once the extracted water reaches the surface and the pressure decreases the dissolved CO_2 will exsolve from the water.

As mentioned above, when CO_2 dissolves in water it lowers the pH due to the formation of carbonic acid. The pH is an important controlling factor on the rates of adsorption and desorption for many trace metals such as lead and arsenic found in the subsurface. Recent reservoir modeling has shown that CO_2 intrusion can lead to significantly increased levels of both lead and arsenic in the groundwater when the surface reactions of desorption and adsorption are incorporated with the flow modeling (Zheng et al., 2009). More advanced technologies are needed to remediate the impact of the increased concentration of trace metals in the groundwater. Three groundwater remediation technologies that could effectively reduce the secondary effects of the CO_2 leakage are pump and treat systems, reactive barriers, and air sparging. None of these technologies have been used previously to remediate impacts on groundwater from CO_2 leakage, but have been used extensively for other contaminants in groundwater.

1.5.1. Pump and Treat Systems

Installing a pump and treat system is the most common technology that has been used for groundwater remediation. The process involves installing extraction wells in the contaminated aquifer and pumping out the groundwater. The groundwater is then treated at a surface facility to remove the contaminants. After treatment the groundwater is injected back into the aquifer, discharged to a surface water body, or sent to a sewage plant. Pump and treat systems can be very expensive because of the capital cost of installing multiple extraction wells, constructing the surface treatment plant, and purchasing the pumps needed to extract the large volumes of water pumped from the aquifer. Pumping large volumes of groundwater is needed to hydraulically control the contaminent plume and also because the contaminant is often dilute in the groundwater. It can take a long time to treat the groundwater, resulting in large operating and maintenance costs over the lifetime of the remediation project. However, if the groundwater is highly contaminated pump and treat systems may be the best option for remediation.

1.5.2. Reactive Barriers

Reactive barriers are a newer technology for remediating groundwater. The reactive barriers rely on the natural fluid movement in the subsurface. In most cases there is a general direction of regional flow in an aquifer that can be lower than 1 m/yr and greater than 20 m/yr. The flow velocity is dependent on many factors including elevation, precipitation, and surface water bodies (Alley et al., 2002). A reactive barrier is built downstream of the contaminant plume. As the contaminant passes through the barrier it is either trapped or transformed into a harmless substance. The materials used to construct the reactive barrier are dependent on the specific groundwater contaminant. If the groundwater is contaminated with arsenic and lead a reactive barrier filled with activated carbon or zeolite would adsorb the trace metals (Mulligan et al., 2001). Based on the amount of contamination, the adsorptive material may need to be replaced every few years.

A permeable reactive trench is the simplest form of reactive barrier and it needs to extend across the entire width of the plume. A funnel and gate system is another more complicated barrier system for large plumes when one trench may not be effective. This system consists of multiple cutoff walls that funnel the groundwater towards a reactive wall referred to as the gate. If the groundwater contaminated is very deep, then reactive barriers may be impractical and costly to build.

1.5.3. Air Sparging

Air sparging is often used to remediate volatile organic compounds (VOC)s that are dissolved in the groundwater, trapped in the pore space in the saturated zone, or adsorbed onto the soil (Khan et al., 2004). The main process involves injecting air into the groundwater to volatize the groundwater contaminants and encourage biodegradation. The increased levels of oxygen will raise the redox potential, which may cause trace metals in the water to be adsorbed onto ion exchange sites on mineral surfaces or precipitate as a separate mineral phase.

1.5.4. Brine Intrusion Remediation

The displacement of brine from the storage formation into groundwater also poses a possible risk. Brine has high concentrations of salts and possibly some dissolved species such as arsenic. Contaminated water with high concentrations of salt (NaCl) can lead to difficulties with the precipitation/coprecipitation of metals as carried out in the traditional water treatment process. Precipitation uses the addition of chemicals to alter dissolved contaminants to an insoluble phase and coprecipitation is when the contaminant is adsorbed onto another species which is then precipitated. To remove the insoluble contaminant, flocs held together by ionic interactions are formed and then skimmed from the surface. A high concentration of NaCl creates water with high ionic strength which can destabilize the flocculation of the insoluble contaminants. For the treatment of brine intrusion, the dissolved salts may need to be removed from the water before starting the primary treatment process.

1.6. Research Focus

After evaluating the remediation options available, three objectives were chosen as the most important for reducing the effects of CO_2 on the groundwater. The first objective is to reduce the mobile phase CO_2 and reduce the increase in the extent of the leakage plume. The second objective is to remove the CO_2 from the aquifer in both gas and aqueous phase. The third objective is to reduce the aqueous phase concentration and minimize the decrease in pH from the formation of carbonic acid. Minimizing the drop in pH may decrease the amount of secondary contamination from the CO_2 leakage. Three techniques chosen from the remediation options to meet these objectives include: CO_2 extraction in both aqueous and gas phase, water injection, and a combination of water injection and extraction. The treatment of fluid produced from the aquifer to remove CO_2 or any other contaminants is not analyzed here.

Chapter 2

2. CO_2 Leakage

Although there are some diffuse naturally occurring leaks of CO_2 into groundwater aquifers in the US, the characterization of the leakage plumes in the groundwater through field data collection is limited (Lewicki et al. 2006). The four commercial scale CO_2 geologic storage projects have not negatively affected overlying groundwater. Due to this lack of characterization and experience with large concentrated leaks of CO_2 into groundwater aquifers, it was determined that an analysis of the main physical processes controlling the leakage, as well as the impacts of the leakage rate, the duration of the leakage, and the total leakage amount on the shape and size of the leakage plume was required before analyzing remediation scenarios. This chapter provides an overview of the simulations, presents the leakage cases that were used for the analysis of various remediation techniques, and investigates the processes that control the flow of the CO_2 and brine.

2.1. Simulation Overview

The multiphase flow simulator TOUGH2 with the ECO2N fluid property module was used to simulate the various leakage cases (Pruess et al., 1999; Pruess, 2005). The TOUGH2 algorithm solves the mass balance equations over a finite volume V_n (Eq. 2-1). Refer to the nomenclature for a definition of each term.

$$\frac{d}{dt}\int_{V_n} \boldsymbol{M^K dV_n} = \int_{V_n} \boldsymbol{F^K} \cdot \boldsymbol{n d\Gamma_n} + \int_{V_n} \boldsymbol{q^K dV_n} \tag{2-1}$$

The right side of the mass balance equation is the net flux and any sink or source terms. The left side is the accumulation term of mass (M) for each component (k) into the volume over time. The mass for each component is equal to the sum of the concentration of each phase β such as gas or aqueous (Eq. 2-2).

$$\mathbf{M}^{k} = \boldsymbol{\phi} \sum_{\beta} \mathbf{S}_{\beta} \boldsymbol{\rho}_{\beta} \mathbf{X}_{\beta}^{K} \tag{2-2}$$

The advective mass flux F^k across the surface Γ_n is the sum of the fluxes for each individual phase (Eq. 2-3).

$$\boldsymbol{F}^{K} = \sum_{\beta} \boldsymbol{X}_{\beta}^{K} \boldsymbol{F}_{\beta} \tag{2-3}$$

The advective flux can be defined by the multiphase version of Darcy's law of flow of fluid in porous media (Eq 2-4).

$$\mathbf{F}_{\beta} = -\mathbf{k} \frac{\mathbf{k}_{r\beta} \boldsymbol{\rho}_{\beta}}{\boldsymbol{\mu}_{\beta}} (\nabla \mathbf{P}_{\beta} - \boldsymbol{\rho}_{\beta} \mathbf{g}) \tag{2-4}$$

In Equation 2-4, k is the absolute permeability, k_r is the relative permeability, μ is the viscosity, and g is the acceleration due to gravity. P is the sum of pressure in the reference phase either gas or aqueous and the capillary pressure between the reference phase and the phase analyzed (Eq 2-5).

$$\mathbf{P}_{\beta} = \mathbf{P}_{\mathbf{ref}} + \mathbf{P}_{\mathbf{cap}\beta} \tag{2-5}$$

The confined groundwater aquifer is modeled with both a 2D radial axisymmetric grid (Figure 2-1) and a 3D Cartesian grid (Figure 2-2). The aquifer is 100 m thick and confined at the top with an impermeable layer. The top of the groundwater aquifer is 100 m below the ground surface and it is 80 m below the water table. The radius of the CO_2 leakage zone is 5 m in the radial grid. The leakage zone is a 5 m square block in the 3D Cartesian grid. This simulates a conceptual model for leakage from a leaking abandoned well.

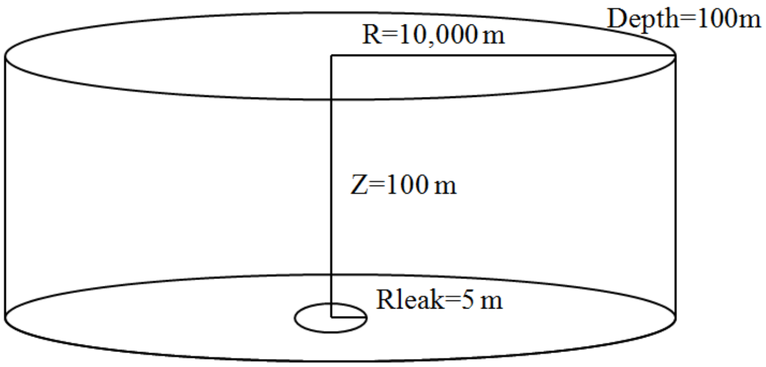


Figure 2-1. 2D Radial Axisymmetric Grid

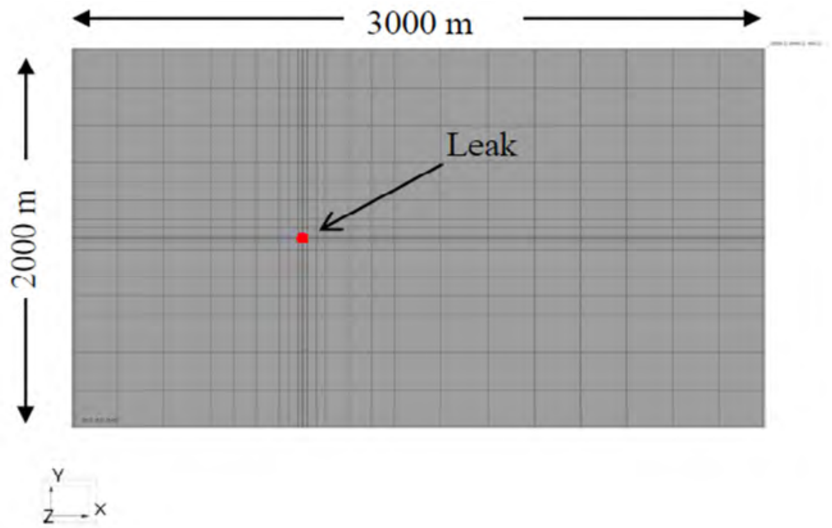


Figure 2-2. 3D Cartesian Grid

The reservoir is homogeneous and anisotropic with k_r=100 md, k_x=k_y=100 md, and k_z=10 md. The porosity is 15% and the NaCl mass fraction is 0.01 (0.171 NaCl molality). A 2D radial grid was chosen because it allows for very high resolution near the leakage point. It also has a large radial area which reduces the impact of the vertical boundary on the simulation. A 3D grid is necessary for analyzing horizontal wells and scenarios with multiple injection or extraction wells.

2.1.1. Pressure and Temperature Profile

There is a hydrostatic pressure gradient with the pressure at the top of the aquifer equal to 0.884 MPa (d=0 m) and 1.864 MPa at the base of the aquifer (d=100 m) (Eq. 2-6).

$$\mathbf{P}(d) = \mathbf{8.84 \times 10^5} + (g \cdot \rho \cdot d)\ [\mathbf{Pa}] \tag{2-6}$$

There is also a temperature gradient of 0.03°C/m which leads to a range of temperature from 23°C at the top to 26°C at the base of the aquifer. The temperature is assumed to be 20°C at the surface (Eq. 2-7).

$$\mathbf{T}(d) = \mathbf{20} + \mathbf{0.03} \cdot d\ [\ ^{\circ}\mathbf{C}] \tag{2-7}$$

2.1.2. *Capillary Pressure Curves*

The van Genuchten capillary pressure curve was used for the simulation (van Genuchten, 1980).

$$P_{cap} = -P_0\left([S^*]^{-1/\lambda} - 1\right)^{1-\lambda} \quad (2\text{-}8)$$

$$\text{subject to } -P_{max} \le P_{cap} \le 0$$

$$S^{*} = (S_l - S_{lr})/(S_{ls} - S_{lr}) \quad (2\text{-}9)$$

In Eq. 2-8 we set $\lambda = 0.457$, $S_{lr} = 0$, $S_{ls} = 0.999$, $P_{max} = 1\text{x}10^7$ Pa, and $P_0 = 1.96\text{ x}10^4$. Figure 2-3 is the capillary pressure on a logarithmic scale in terms of the gas saturation up until the maximum capillary pressure of 1x10^7 Pa.

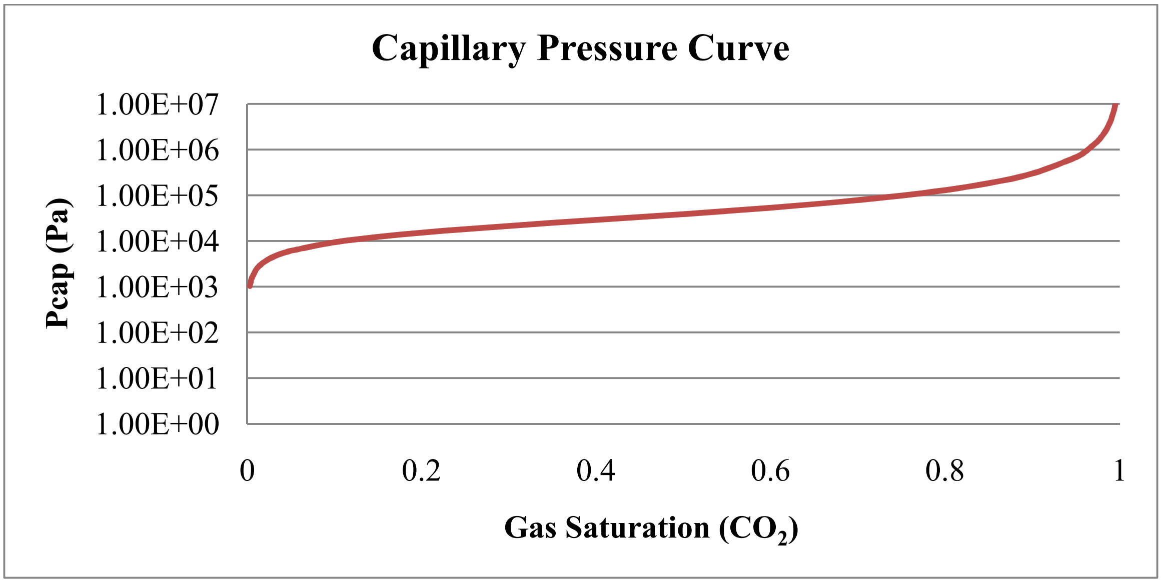


Figure 2-3. Capillary Pressure Curve

2.1.3. *Relative Permeability Curves*

The van Genuchten-Mualem Model was used for the relative permeability curves in the simulations (Mualem, 1976; van Genuchten, 1980) (Eq 2-10 through Eq. 2-13).

$$k_{rl} = \begin{cases} \sqrt{S^{*}}\left\{1 - \left(1 - [S^{*}]^{1/\lambda}\right)^{\lambda}\right\}^2 & \text{if } S_l < S_{ls} \\ 1 & \text{if } S_l \ge S_{ls} \end{cases} \quad (2\text{-}10)$$

$$k_{rg} = \begin{cases} 1 - \mathrm{k_{rl}} & if\ S_{gr} = 0 \\ (1 - \hat{S})^2(1 - \hat{S}^2) & if\ S_{gr} \geq 0 \end{cases} \tag{2-11}$$

$$\text{subject to } 0 \leq \mathrm{k_{rl}}, \mathrm{k_{rg}} \leq 1$$

$$S^{*} = (S_l - S_{lr})/(S_{ls} - S_{lr}) \tag{2-12}$$

$$\hat{S} = (S_l - S_{lr})/(1 - S_{lr} - S_{gr}) \tag{2-13}$$

We set $\lambda = 0.457$, $S_{lr} = 0.3$, $S_{ls} = 1.0$, and $S_{gr} = 0.05$ (drainage), 0.15 (imbibition). Initially during the leakage process the residual gas saturation is set at 5% and the relative permeability curves follow the drainage curves with red for gaseous CO_2 and purple for water in Figure 2-4. After the leak is stopped the residual gas saturation is increased to 15% and the imbibition curves with green for gas and purple for water are used to simulate the trapping of CO_2 during the remediation processes. This represents the effect of hysteresis in relative permeability curves for the multiphase flow of fluid in the groundwater aquifer.

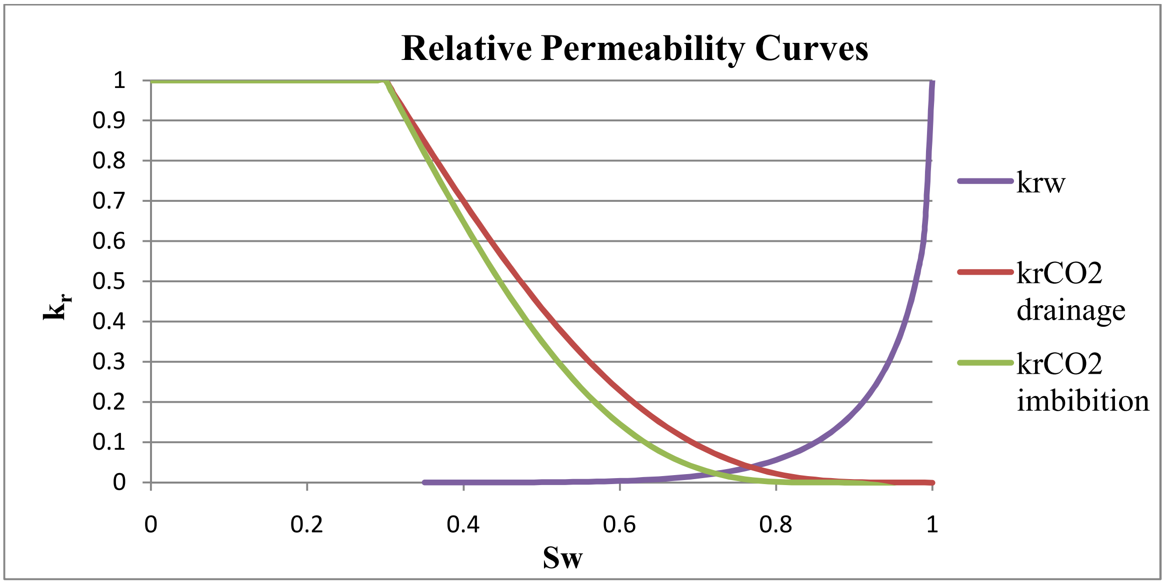


Figure 2-4. Relative Permeability Curves

2.2. Leakage Cases

To better understand the factors that control the size and shape of the CO_2 leakage plume in a homogeneous groundwater aquifer, five leakage cases were run with various leakage rates for a period of five years. Table 2-1 lists the leakage rate in kg/s and in metric tons/year, the total leakage quantity in metric tons, and the percent of the total geologically stored CO_2 at the site that leaks into the groundwater. For the rest of the discussion, one ton refers to one metric ton or 1000 kg. The percentages are based on a total amount stored of 100 Mt of CO_2 which corresponds with storage of 4 Mt of CO_2 per year from a 500 MW coal plant for 25 years (Ansolabehere et al., 2007). Even the largest leakage case analyzed of 50,000 tons is only 0.05% of the total amount of CO_2 stored. Leakage was simulated by imposing a constant mass flux into the base of the aquifers to mimic a leaking wellbore. The CO_2 was water saturated at the base of the system, which corresponds to a mass fraction of 0.006% of water in the CO_2 phase. Water saturated conditions are reasonable given that the leaking CO_2 would have migrated through an extensive amount of water saturated rocks as it migrated from the injection depth to the base of the shallow aquifer.

Table 2-1. Five Leakage Case Parameters

Case	Leakage Rate (kg/s)	Leakage Rate (tons/year)	Total Leakage Quantity (tons)	Percent of Total Stored
Case 1	0.006342	200	1,000	0.001%
Case 2	0.015855	500	2,500	0.0025%
Case 3	0.03171	1,000	5,000	0.005%
Case 4	0.06342	2,000	10,000	0.01%
Case 5	0.3171	10,000	50,000	0.05%

The final gas saturation for each of the five CO_2 leakage cases is shown in Figure 2-5. The radial scale of 225 m is the same for each case except for Case 5 (50,000 tons) which is shown with a radial scale of 450 m due to the large accumulation of CO_2 at the top of the aquifer.

The leakage is allowed to continue for five years because this is considered an appropriate amount of time before the leak is detected and the poorly sealed well is plugged. This assumption is based on annual or biannual monitoring of the storage site which will likely be included with any geologic CO_2 storage permit (EPA, 2010).

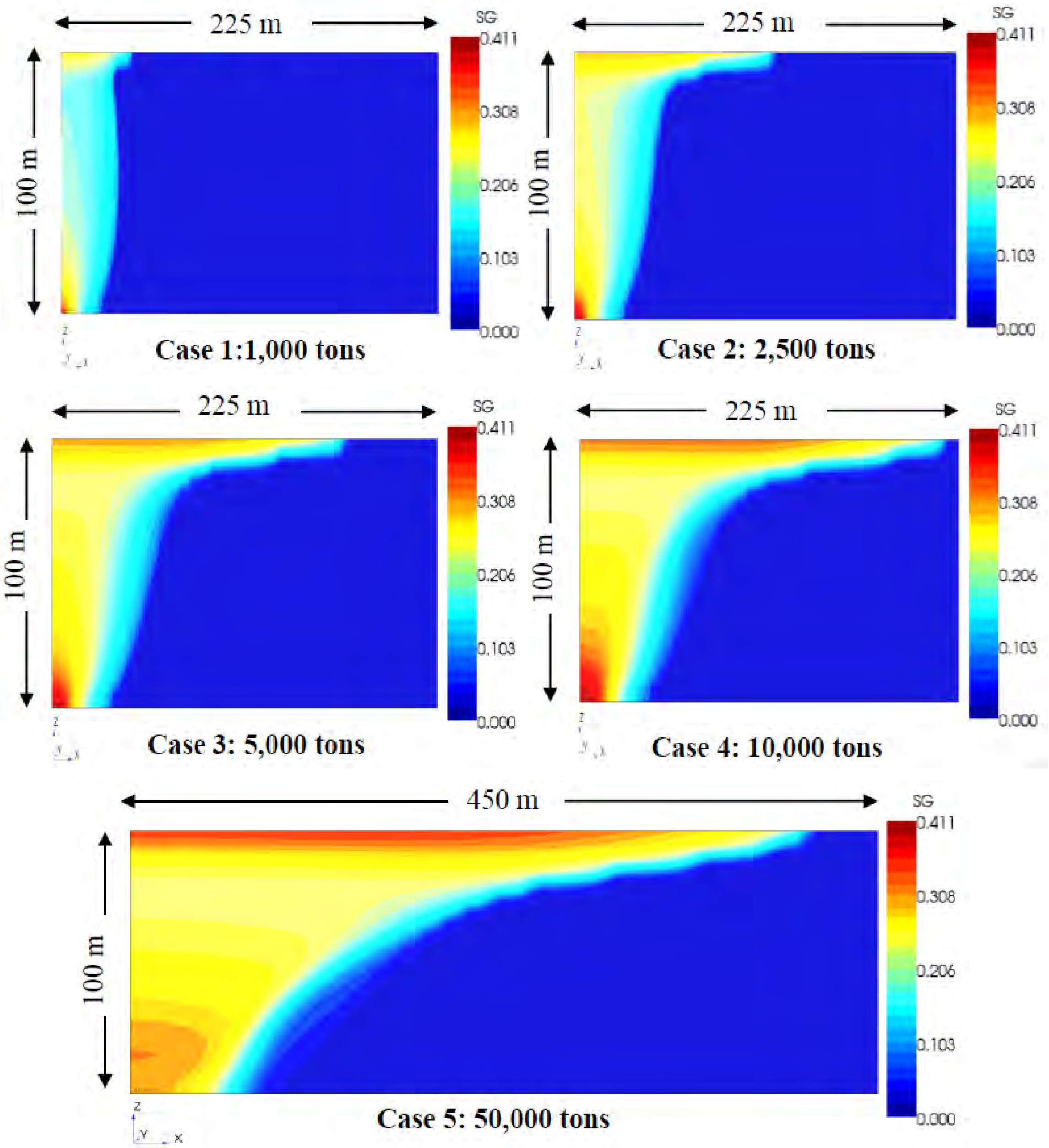


Figure 2-5. Five Leakage Cases

The amount of time that the leakage continues has a significant impact on the final leakage plume. For the smallest leakage rate considered for Case 1 of 200 tons per year, if the well leaks for 12.5 years instead of 5 years the result is the leakage plume shown in Figure 2-6. Although the total quantity leaked is the same as Case 2 at 2,500 tons, the extent of the gravity tongue becomes greater the longer the leak is allowed to continue. The plume extends much farther from the leakage point by 175 m and the gas saturation at the top has increased from 0.32 to 0.42 compared with Case 2 after five years.

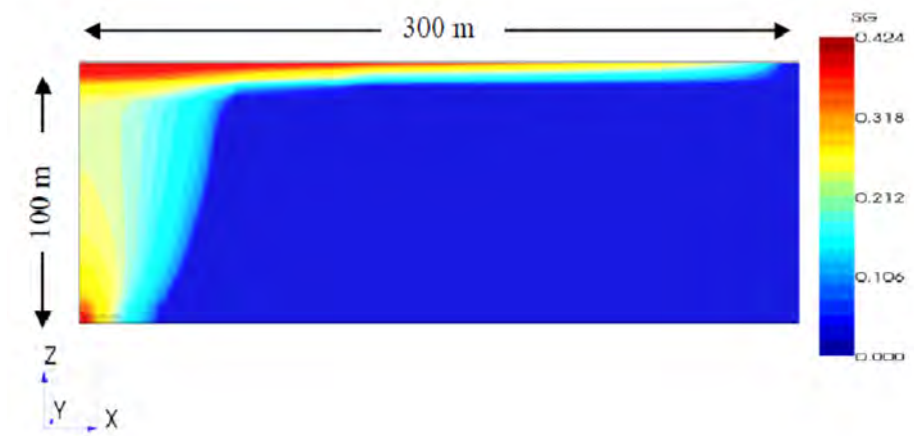
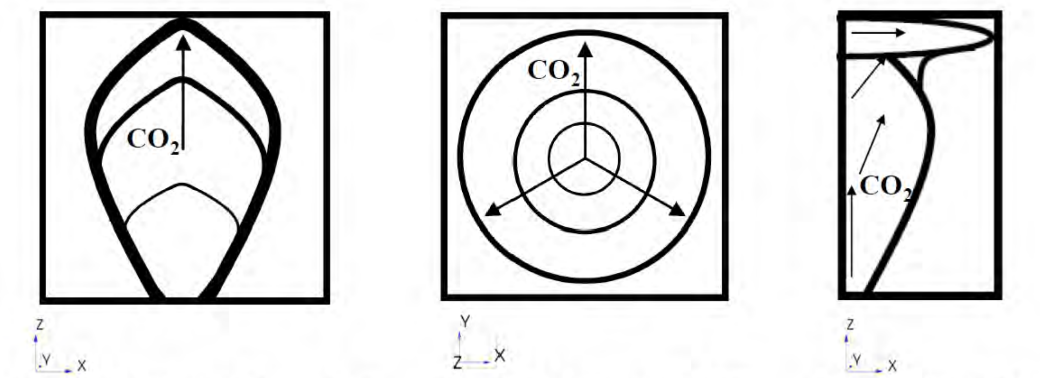


Figure 2-6. Case 1 Leakage Rate of 200 tons/year for 12.5 years

2.3. Processes Dictating Flow of CO_2 and Brine

The movement of CO_2 in the groundwater aquifer during leakage and remediation is complex and depends on the interplay of many factors. These factors include gravity effects, capillary forces, and viscous forces as well as the impacts from dissolution/exsolution of the CO_2 with the water. The leakage plume can be divided into the primary leakage plume in the groundwater aquifer and the secondary leakage plume which is formed at the confining layer at the top of the aquifer.



Primary: CO_2 Buoyancy Driven Flow **Secondary: CO_2 Spreading at Top** **Final CO_2 Plume (Cross Section)**

Figure 2-7. CO_2 Leakage Processes

The first image in Figure 2-7 depicts the initial movement of gaseous CO_2 into the groundwater aquifer dependent on buoyancy and viscous driven flow. As the CO_2 rises it also spreads in the radial direction due to viscous forces. The second image in Figure 2-7 shows that when the CO_2 begins to accumulate at the confining layer at the top of the groundwater aquifer the CO_2 spreads along the top forming a so called gravity tongue. The third image in Figure 2-7 is the cross section of the combination of the primary leakage plume and the secondary accumulation plume in a 2D radial coordinate system. The combination of these two plumes leads to a bifurcated gas saturation gradient along the depth of the reservoir.

The two main processes depicted in Figure 2-7 are seen clearly in the resultant leakage plume from the simulations. First, the primary plume formed when CO_2 rises to the top of the aquifer is evident in all leakage plumes. When the total leakage is greater than 2,500 tons over the five year period, significant spreading occurs as the plume reaches the top of the aquifer. At the top it accumulates below the confining layer, forming the bifurcated plume with a non-monotonic saturation gradient along the depth of the reservoir. This secondary accumulation plume begins to spread away from the leakage site as the leakage rate increases, forming large gravity tongues. For Case 5 (50,000 tons) the gravity tongue extends up to a radius of 425 m and a total area impacted of 0.57 km^2. For Case 1 (1,000 tons) with only 2% of the leakage rate of Case 5 the total area impacted is 0.0055 km^2 which is 1% of the area impacted for Case 5. The area of the gravity tongue at the top of the aquifer for all five cases is shown in Figure 2-8. As the total leakage increases the area that is impacted increases linearly, meaning that more leakage leads to greater contamination. With larger areas affected the likelihood that the plume intersects a groundwater extraction well either for drinking water or agricultural purposes also increases.

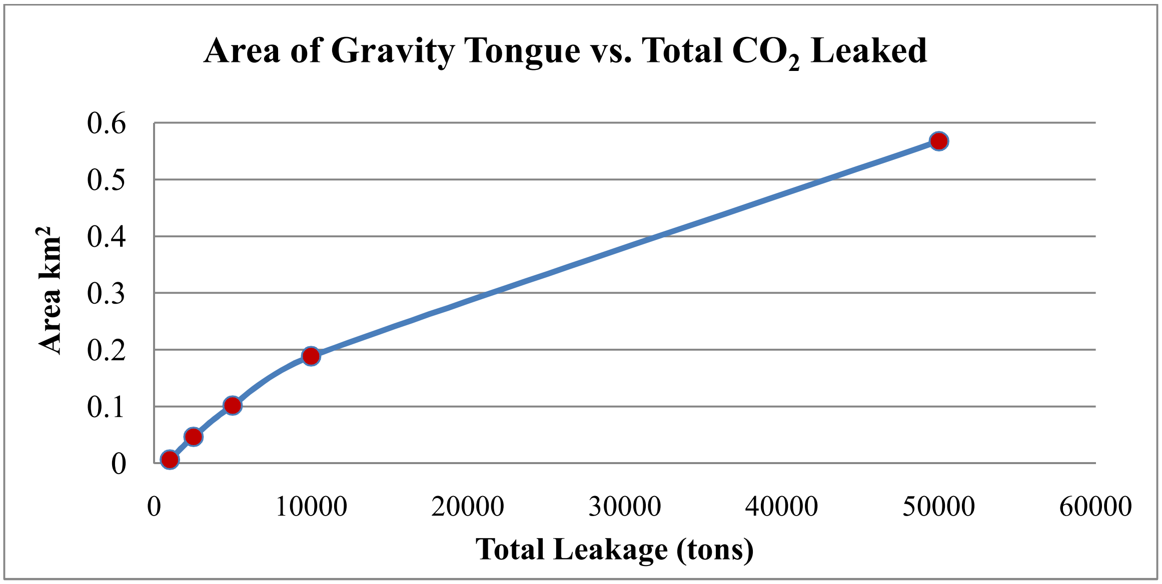


Figure 2-8. Area of Gravity Tongue vs. Total CO_2 leaked

The two areas with the highest CO_2 gas saturation are near the leakage point at the base of the aquifer and in the top 10 m of the reservoir in the secondary plume. The gas saturation near the leakage point is on average 38% and at the top it ranges from 25% to 36% directly above the leak and drops off rapidly to zero at the leading edge. The gas saturation at the top of the aquifer for all cases is shown in Figure 2-9. The areas with the highest mobile phase CO_2 saturations are the most important for consideration during remediation and for containment of the CO_2 leakage plume.

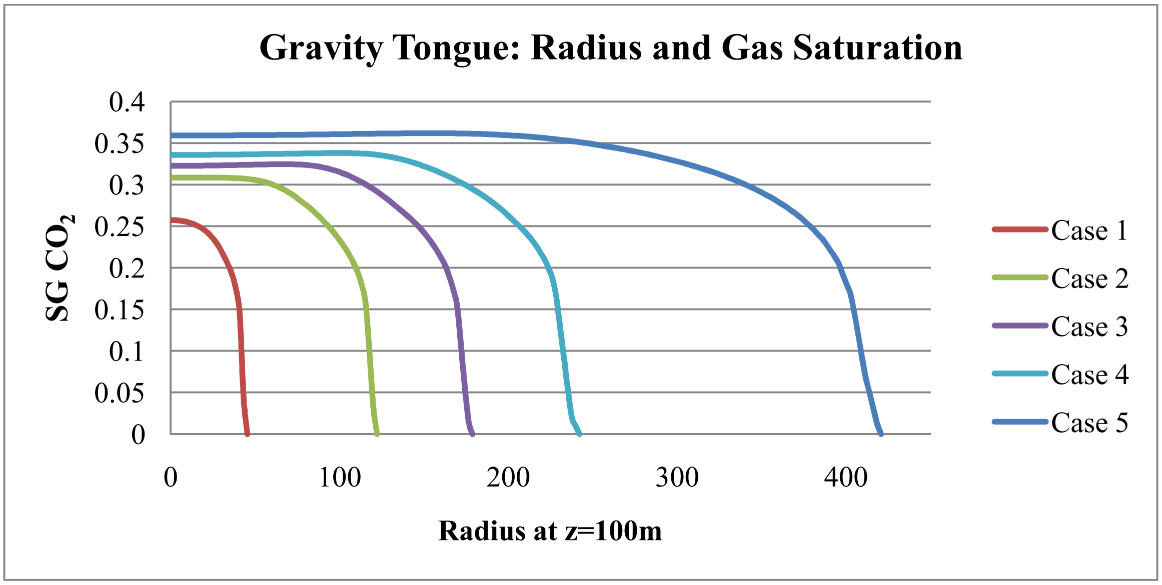


Figure 2-9. Gravity Tongue: Radius and Gas Saturation at the top of the aquifer

A large mass fraction of the leaked CO_2 is in aqueous phase dissolved in the brine. TOUGH2 with the ECO2N fluid property module uses the solubility model from Spycher and Pruess (2005) to determine the aqueous phase mass fraction. Based on this solubility module with 0.171 NaCl molality, a maximum temperature of 26 ºC, and a maximum pressure of 1.86 MPa, the maximum mass fraction of CO_2 that can dissolve in the brine is 0.0246 (0.55 aqueous CO_2 molality). At this depth the density of gaseous CO_2 is approximately 30 kg/m^3 and the density of brine is 1000 kg/m^3. To estimate the mass in aqueous phase, consider one cubic meter of pore space in the reservoir with a gas saturation of 20%. In this cubic meter: 0.2 m^3 x 30 kg $CO_{2(gas)}$/ m^3 = 6 kg of CO_2 will be in gas phase and 0.8 m^3 x 1000 kg/m^3 x 0.0246 kg $CO_{2(aq)}$/kg brine =19.68 kg of CO_2 will be in aqueous phase for a total of 25.68 kg CO_2/m^3. This corresponds to 23.4% of the CO_2 mass in gas phase and 76.6% of the CO_2 mass in aqueous phase. If the saturation increases, the mass fraction in gas phase will increase and the mass in the aqueous phase will decrease.

Figure 2-10 shows the mass fraction of CO_2 in the aqueous phase over the five year leakage period. The mass fraction in aqueous phase increases until the CO_2 reaches the confining layer at the top. The time to reach the confining layer ranges from 2.23 years for Case 5 (50,000 tons) to 4.13 years for Case 1 (1,000 tons). After the CO_2 reaches the top, the mass of CO_2 in gas phase begins to increase because the gas saturation increases. The gas saturation increases because the CO_2 is accumulating in the secondary plume increasing the size of the gravity tongue instead of dissolving in the water. The mass fraction in aqueous phase after five years of leakage ranges between 71% for Case 5 and 79% for Case 1, all very close to the estimated value. The aqueous mass fraction for Case 5 (50,000 tons) is lowest because the accumulation of CO_2 at the top in the gravity tongue is the largest.

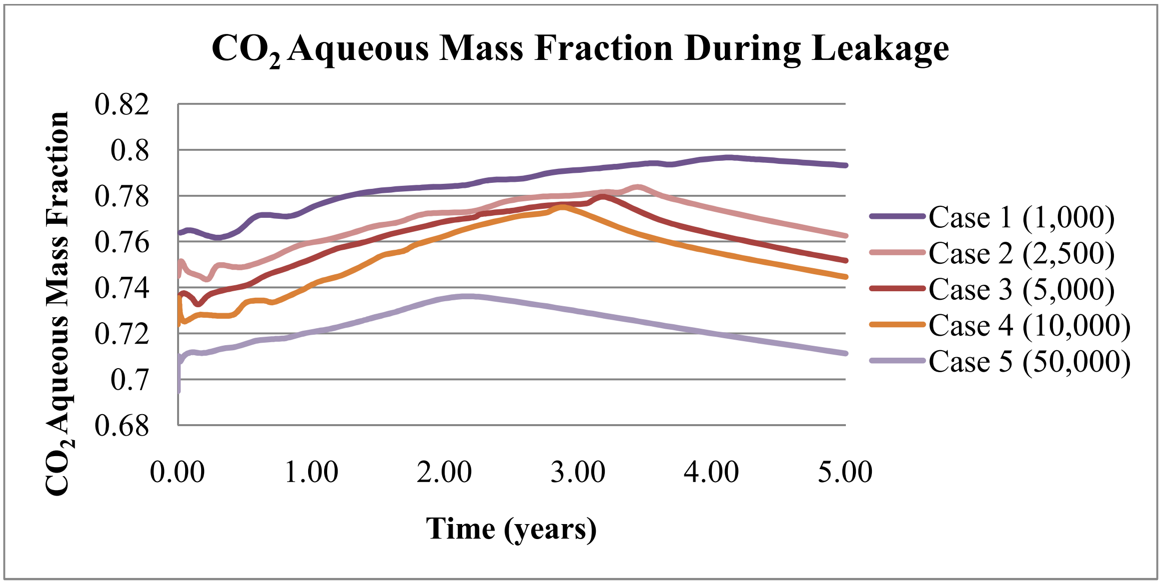


Figure 2-10. Aqueous Mass Fraction During Leakage

Chapter 3

3.Remediation

For the purpose of this study, the primary objectives of remediation are to remove or reduce the mobile CO_2, reduce the total quantity of CO_2 in the reservoir, and lower the aqueous phase concentration of CO_2. Both passive and active remediation methods are considered. Passive methods include monitoring of the site but do not include any further action to mitigate the impacts from the leakage plume. It is possible that the remediation requirements will only dictate reduction to a set contaminant concentration. If so, passive methods may be effective in reducing the concentration below the standard possibly with the benefit of regional flow. The three active methods considered include extracting fluid from the aquifer with a vertical or horizontal extraction well, injecting water into the leakage plume, and a combination of injection and extraction wells. In theory it is possible with an extraction well to achieve all three remediation objectives. Water injection into the leakage plume could reduce the mobile CO_2 through dissolution but it cannot reduce the quantity of CO_2 in the aquifer. However, it could be effective in reducing the aqueous concentration of CO_2 if more water is injected than required to dissolve all the CO_2. Water injection followed by extraction, or simultaneous injection and extraction could also achieve all objectives, but may lead to more difficulties.

3.1. Remediation Processes

During remediation, water flowing into the leakage plume and changes in pressure are two processes that strongly affect the movement of CO_2 and the fraction of CO_2 in gas and aqueous phase. An extraction well can draw water into the CO_2 plume towards the lower hydraulic head in the well. Also, water injection directly leads to water flowing into the CO_2 plume. The pressure in the system will decrease when an extraction well is added and increase from water injection depending on the well parameters. Based on the importance of these two processes for all the remediation techniques, they are further analyzed here.

3.1.1. *The Effects of Changes in Pressure*

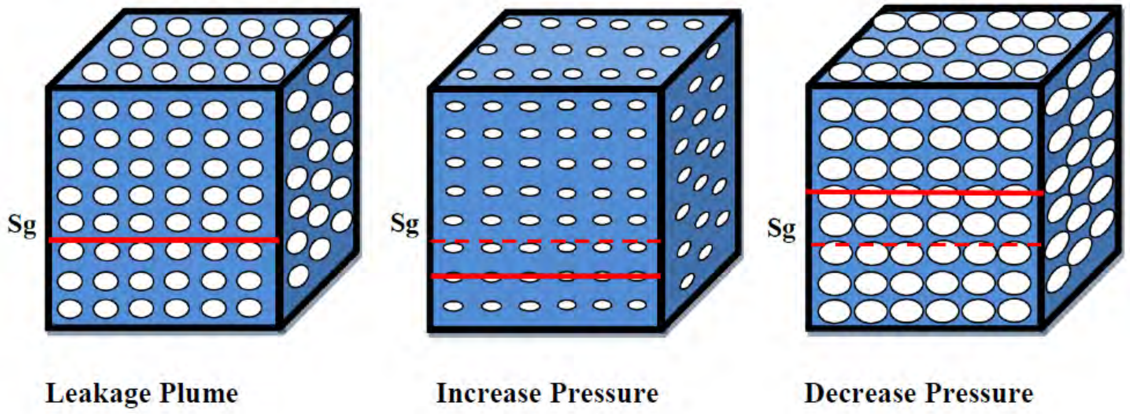


Figure 3-1. Pressure Effects on the Leakage Plume

In Figure 3-1 the white circles represent separate phase CO_2 in the groundwater, the dashed red line is the original gas saturation, and the solid red line is the resultant saturation profile. The amount of CO_2 dissolved in the groundwater is proportional to the salinity which is held constant and the reservoir pressure. When the pressure is increased more CO_2 dissolves in the groundwater, the density of CO_2 increases, and consequently the gas saturation decreases. When the pressure is decreased CO_2 comes out of the aqueous phase, density decreases, and the gas saturation increases.

3.1.2. *The Effects of Water Flowing into the Leakage Plume*

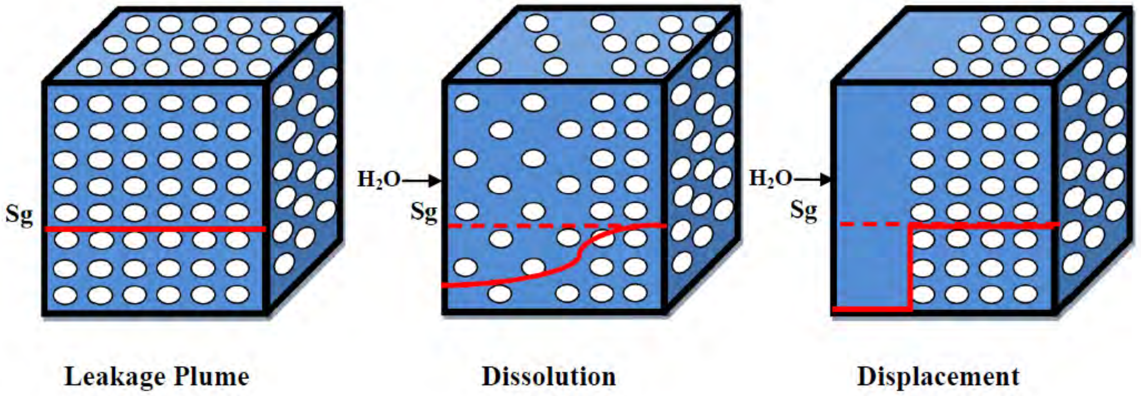


Figure 3-2. Effects of Water Flowing into the CO_2 plume

When water is injected into the CO_2 leakage plume, two main processes take place concurrently as shown in Figure 3-2. First, some of the CO_2 will dissolve in the injected water until it is saturated with CO_2. Once the injected water is fully saturated with CO_2 it will begin to displace any remaining gaseous CO_2 that is above the residual gas saturation. The residual gas saturation is trapped due to large capillary forces in the smallest pores in the rock. The only method to remove this CO_2 is to dissolve it in water unsaturated with CO_2.

3.2. Passive Remediation Method

Before beginning an analysis of active remediation methods, the effectivenss of passive methods in reducing leakage impacts is evaluated. To analyze passive remediation, the leaking well was first plugged and the unhindered movement of the leakage plume was simulated for a five year period for Case 3 (5,000 tons leaked). The plume after being shut in for five years is shown in Figure 3-3. The black dashed line is the comparison with the extent of the plume after five years of leakage.

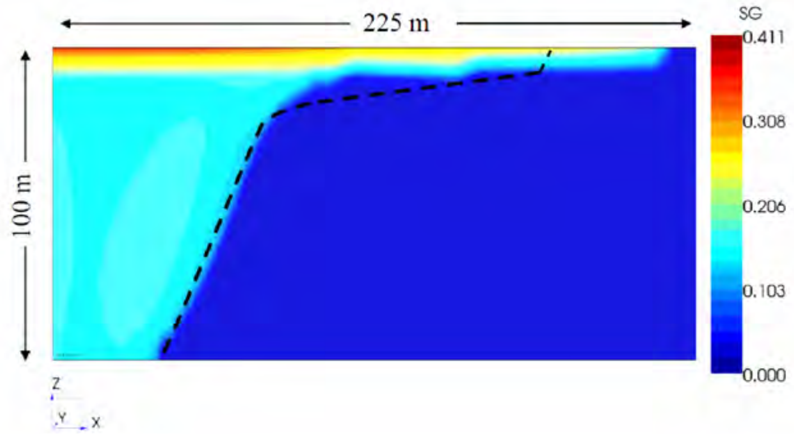


Figure 3-3. Passive Method after five years for Case 3 (5,000 tons)

Over five years the gas migrates upward towards the base of the confining layer, extending the gravity tongue farther into the reservoir by 50 m. The gas saturation at the top of the reservoir increases from 32% to 38%. Some of the gas is capillary trapped in the pores near the bottom of the aquifer, leading to consistent gas saturation in the primary plume at the residual gas saturation of 0.15. The trapping is due to hysteresis in the drainage and imbibition curves. Also the pressure is able to stabilize and lowers once the leakage stops, slightly reducing the aqueous concentration of CO_2 due to the lower solubility of CO_2 at lower pressures. The mass dissolved in the water and in the gas phase over the five year period is shown in Figure 3-4. After a slight increase at the beginning, the mass in the gas phase decreases from 1246 tons to 1064 tons over the five years due to dissolution of CO_2.

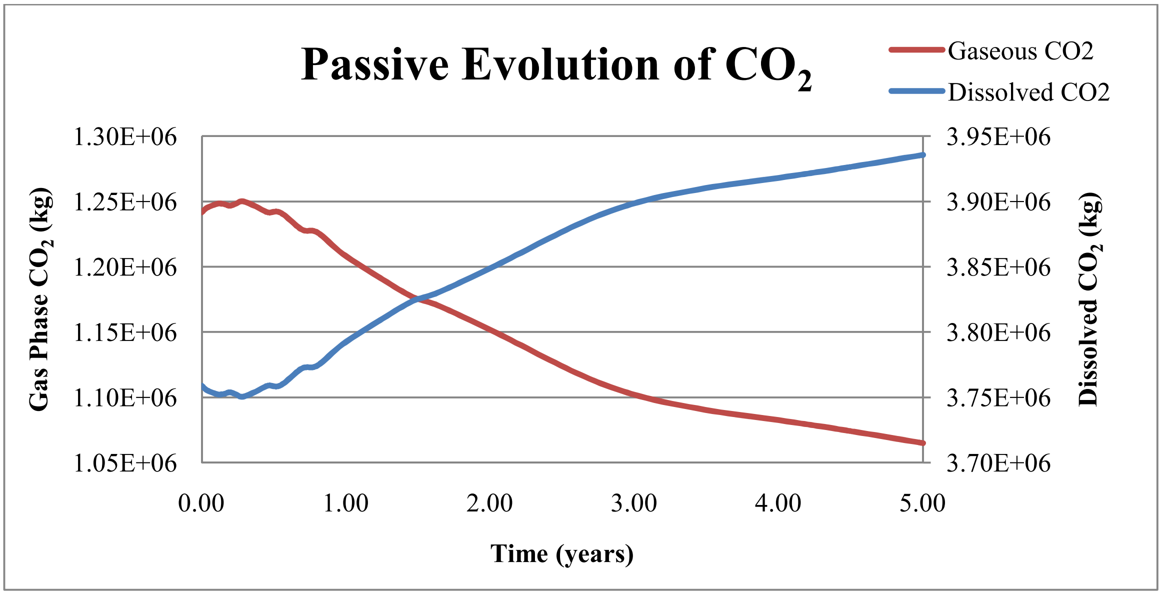


Figure 3-4. Passive Evolution of CO2 in Gas and Aqueous Phase

This method is effective at passively moving all the mobile gas to one location, but increasing the size of the gravity tongue and the area impacted are a major deterrent to using only passive methods. It is minimally effective at reducing the amount of mobile CO_2 by 15% from an initial mass fraction of 0.243 to a final of fraction 0.213. If it continues at this rate it will take approximately 35 years after plugging the well for all of the CO_2 to dissolve. It is more likely that the rate of CO_2 dissolving will decrease over time. After five years the gas is either capillary trapped in the pores or in the gravity tongue where the relative permeability to water is very low. The effectiveness of passive remediation may increase if there is regional flow in the aquifer, especially if it is high. Regional flow may increase the amount of undersaturated water flowing into the leakage plume which may in turn increase the rate of dissolution.

3.3. Active Remediation Methods

It is clear that the passive method is very ineffective at meeting any of the three remediation objectives over a reasonable time period. The need for active methods to reduce the amount of mobile CO_2 more quickly and the total amount of CO_2 in the aquifer is evident. The three active methods of remediation examined here are extraction wells, injection wells, and the combination of extraction and injection wells. The first step of all the active remediation processes is to plug the leaking well and stop the flow of CO_2 into the reservoir. Cases where the leak is allowed to continue are analyzed in a sensitivity analysis. To compare the effectiveness of each active method an optimization of the various operation parameters such as well screening depth, well extraction rate or injection flow rate, and number of injection or extraction wells is carried out.

3.4. Remediation with Extraction Wells

After the leak is stopped, the first step is to drill a vertical or horizontal well that penetrates the leakage plume. Based on the leakage plume size and shape, the well is screened to the optimum depth. Extraction of fluid begins immediately. The well will operate until the amount of CO_2 remaining in the reservoir is small or meets specific remediation requirements. The well is operated with a constant bottomhole pressure that is set at the top of the uppermost screened section. This corresponds to the amount of hydraulic head reduction in the wellbore below the water table, which is initially 80 m at the top of the aquifer. Any water extracted is aerated at the surface to exsolve the remaining CO_2. This water could be re-injected into the aquifer or may need to be treated to remove any secondary contaminants such as trace metals. Reducing the amount of produced water decreases the cost of the extraction process and can be achieved by extracting as much CO_2 in gas phase as possible and then only extracting water that is fully saturated with CO_2.

The extraction wells operate with the deliverability well model found in the TOUGH2 Users Guide (Pruess et al., 1999) with a prescribed flowing bottomhole pressure constraint (P_{wb}) and a productivity index PI (Coats, 1977). The mass production rate for each phase from a grid block where the phase pressure is greater than the wellbore pressure is defined by Eq. 3-1.

$$\mathbf{q}_\beta = \frac{\mathbf{k}_{r\beta}}{\mu_\beta}\rho_\beta \cdot \mathbf{PI} \cdot \left(\mathbf{P}_\beta - \mathbf{P}_{wb}\right) \tag{3-1}$$

The productivity index (PI) for steady radial flow is given by Eq. 3-2 with Δz_l the layer thickness (5 m for all cases), $(k\Delta z_l)$ the permeability thickness product in each layer, r_e the effective well radius, r_w the well radius, and s the skin factor (Coats 1977; Thomas 1982). The PI for all wells was set at 1.48×10^{-12} based on Eq. 3-2.

$$(\boldsymbol{PI})_l = \frac{2\pi(k\Delta z_l)}{ln({}^{r_e}/_{r_w})+s-1/2} \tag{3-2}$$

The rate of production for each mass component (K) summed over the two phases is given by Eq. 3-3.

$$\widehat{\boldsymbol{q}}^K = \sum_\beta \boldsymbol{X}_\beta^K \boldsymbol{q}_\beta \tag{3-3}$$

For wells screened through multiple layers, the well bore pressure is corrected to account for the gravity effects from the multiphase flow in the well. The pressure in the lower layer is obtained by the pressure in the layer immediately above by using Eq. 3-4 with $l = 1$ at the base of the well to $l = L$ at the top of the well where the pressure is set at P_{wb}. In Eq. 3-4 g is the acceleration of gravity and ρ_l^f is the flowing density in the tubing opposite to the layer.

$$\boldsymbol{P}_{wb,l} = \boldsymbol{P}_{wb,l+1} + \frac{g}{2}\left(\boldsymbol{p}_l^f\Delta z_l + \boldsymbol{p}_{l+1}^f\Delta \boldsymbol{z}_{l+1}\right) \tag{3-4}$$

For example, if the wellbore pressure is set to zero then the volumetric production rate of each phase in the layer is given by Eq. 3-5.

$$\mathbf{r}_{l,\beta} = \left(\frac{\mathbf{k}_{r\beta}}{\mu_\beta}\right)_l (\mathbf{PI})_l \mathbf{P}_{l,\beta} \tag{3-5}$$

This well model is used for both vertical and horizontal extraction wells for all cases analyzed in the following sections.

3.4.1. *Extraction Well Remediation Processes*

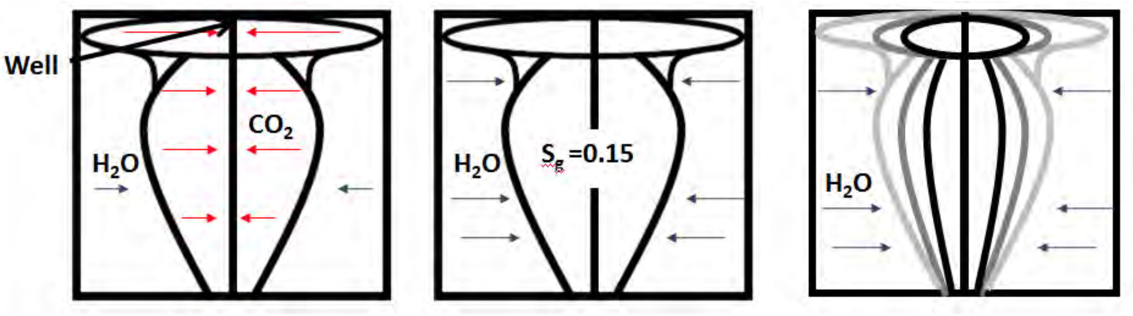


Figure 3-5. Extraction Well Remediation Processes

Based on the principles of multiphase flow, the main processes that will occur once the extraction well is added can be determined. The three images in Figure 3-5 depict the three main processes that will occur during the extraction process. First, the highly mobile phase CO_2 in the areas with high gas saturation will flow rapidly into the well due to the large pressure gradient between the injection well and the aquifer from the hydraulic head drop in the well. Also, because the pressure is dropped significantly in the well more CO_2 will come out of solution into the mobile phase from the leakage plume. Second, after initially producing the mobile gas, the remaining gas will be trapped in the pores at the residual gas saturation of 0.15. Finally, to remove the trapped gas it must be dissolved by unsaturated water flowing towards the well. Based on the low relative permeability for water in the areas with high gas saturation such as the gravity tongue, the water will bypass these areas and they will be the last to be fully dissolved and extracted.

3.4.2. *Remediation with Vertical Extraction Wells*

The first method analyzed is drilling a vertical extraction well into the center of the leakage plume. The extraction well is operated with a constant hydraulic head (pressure) at the top of the well which ranged from 5 m to 50 m for the cases analyzed. Due to the similarity between many of the five cases, each remediation technique was only analyzed for a subset of the leakage cases and primarily for Case 1 with 1,000 tons and Case 3 with 5,000 tons to compare the effects of the gravity tongue on the remediation effectiveness.

Case 1: 1,000 tons

The first aspect to optimize is the vertical extraction well screening depth. A simple analysis may lead to the conclusion that screening the well the entire depth of the aquifer would lead to the fastest extraction rate because the most area would be affected by the well. Fully screening the well (Z_w=100 m) was analyzed for Case 1, which has the smallest leakage of 1,000 tons. The pressure at the top of the well at z=100m was set to 0.198 MPa which corresponds to a hydraulic head of 10 m. The amount of CO_2 remaining in both the gas phase, aqueous phase, and the total amount remaining is shown in Figure 3-6.

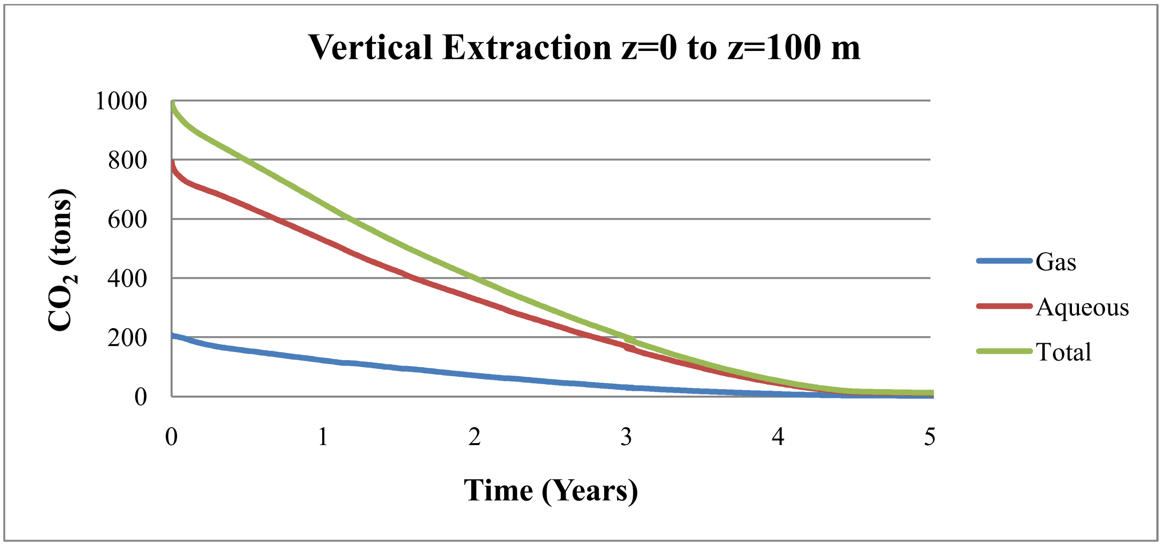


Figure 3-6. Case 1: Vertical Extraction z=0 to z=100 m

Over the five year extraction period 99% of the CO_2 is removed and only 11 tons of CO_2 remains in the aquifer. The tons of CO_2 removed per year decreases significantly after four years of extraction because much of the water produced is not fully saturated with CO_2. The total flow rate of mass from the well over the five years is shown in Figure 3-7. The flow rate is very large for a short time at the beginning because the gas moves rapidly into the well. However, after the initial high flow of gaseous CO_2 the flow rate drops off significantly because some gas is still being produced which has a low density but high volume. Over time as the gas flow rate decreases, the amount of water produced increases. The flow rate increases more steadily after three years when water begins to bypass the plume.

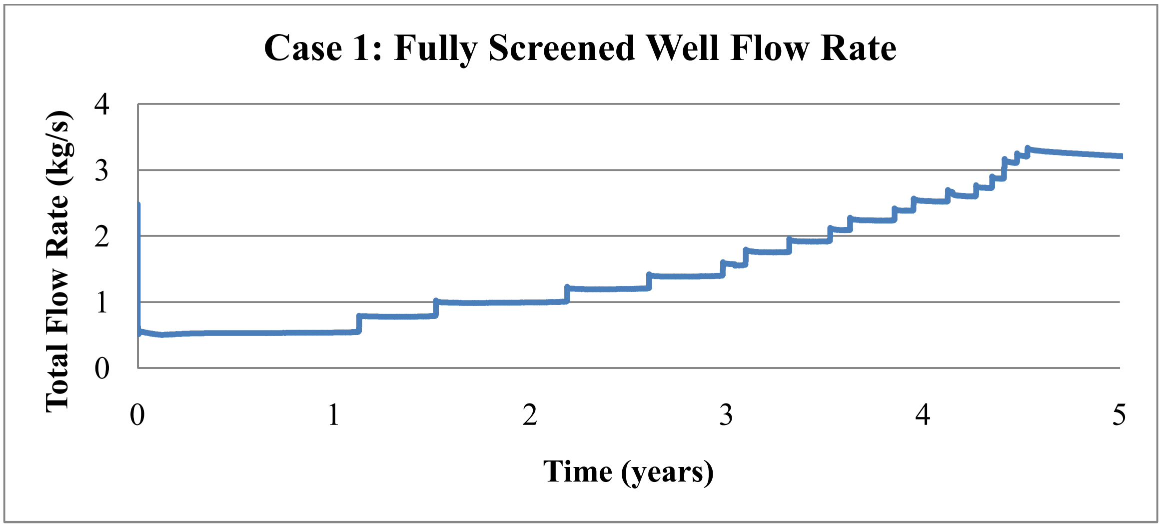


Figure 3-7. Case 1: Fully Screened Well Flow Rate

The water is able to bypass the plume at the base of the aquifer because the rapid flow rate of CO_2 gas from the high gas saturation pocket above the leakage plume leaves an area with relatively lower gas saturation. The water avoids flow in the areas with high saturation due to the low relative permeability to water. The CO_2 plume after three years of extraction is shown in Figure 3-8. The low saturation of gas phase CO_2 is evident in the lower 10m of the aquifer which leads to water bypass of the plume.

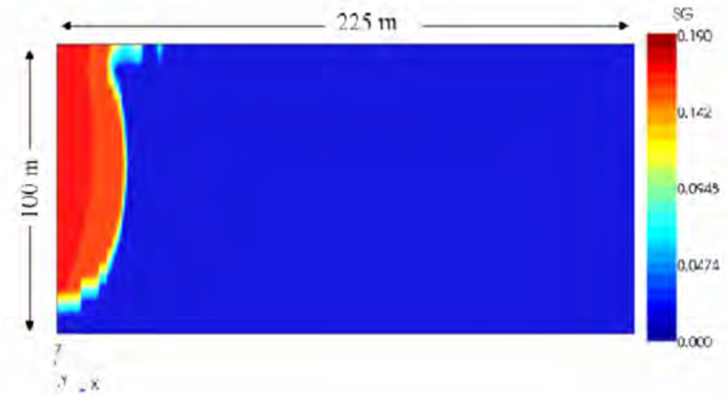


Figure 3-8. Case 1: Fully Screened Well at 3 years

Even after three years, some of the gaseous CO_2 in the leakage plume is still mobile and continues to flow into the well. After 4.5 years, all the remaining gas phase and aqueous phase CO_2 is in the small accumulation plume evident after leakage at the top of the aquifer. This corresponds with the time when the removal of CO_2 flattens (Figure 3-6) and when the well flow rate stabilizes (Figure 3-7). The total mass of brine and CO_2

produced estimated based on the flow rate from the well over the five years is 2.41×10^8 kg or approximately 2.41×10^5 m^3 (Figure 3-9). This is a very large amount of water that may need to be treated if high concentrations of trace metals are present.

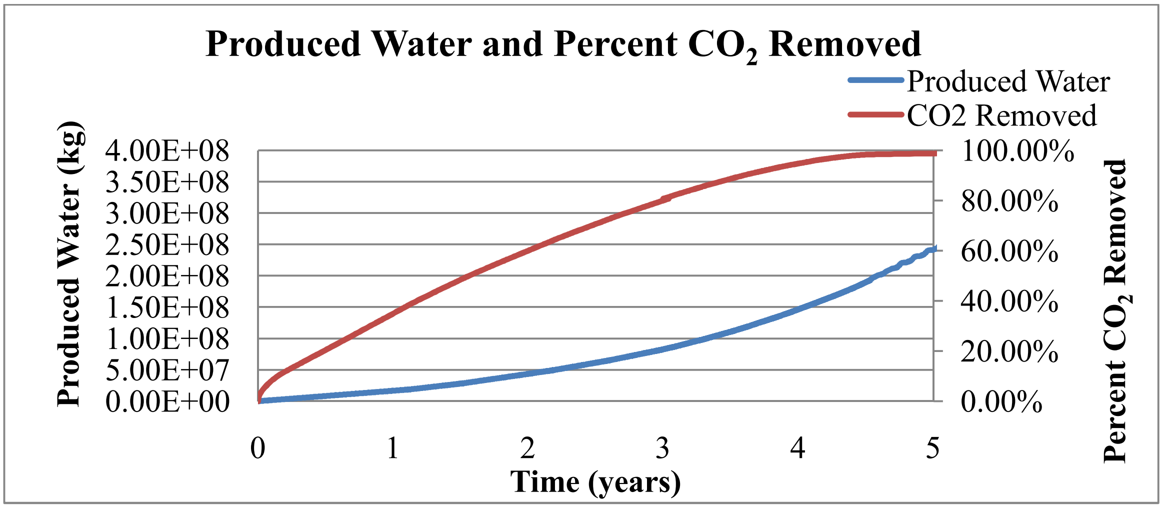


Figure 3-9. Case 1: Produced Water and CO_2 Remaining

Partially screening the well may avoid the bypass of the plume evident after three years of remediation with the fully screened well and also reduce the total amount of water produced. We analyzed adding an extraction well screened from z=10 m to z=100 m (Z_w=90m) with the same pressure drop of 0.198 MPa at z=100 m. The total amount of CO_2 remaining with Z_w=90m compared with Z_w=100m is very similar over the entire five year period with only a difference of 16 tons at the end (Figure 3-10).

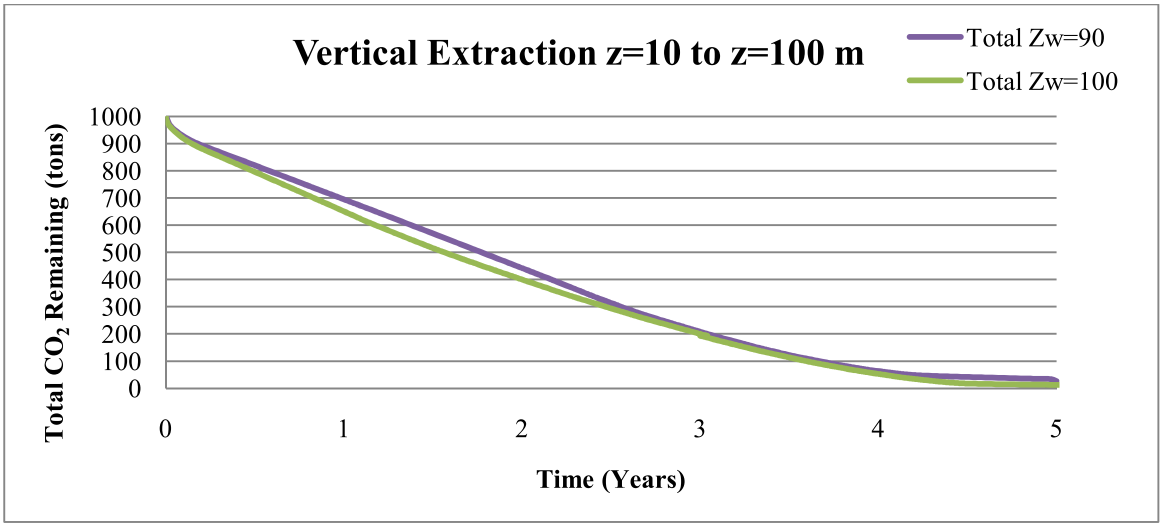


Figure 3-10. Case 1: Vertical Extraction with well screened from z=10m to z=100 m

However, the amount of produced water over the five year period has reduced 9.3% from the fully screened well to a total of 2.20×10^8 kg for the partially screened well.

The difference is very clear when looking at a comparison between the flow rate for the two wells over the remediation time period (Figure 3-11). For the case with the partially screened well the flow rate at the beginning is smaller. Less gas is produced at the beginning because the well does not intersect directly the large pocket of gas above the leakage site. The result is that the amount of time that mostly gas is produced increases from 1.13 years for Z_w=100m to 2.38 years for Z_w=90m. The water flow rate stabilizes earlier at four years for the partially screened case. It stabilizes earlier because it reaches a point when there is CO_2 trapped in the small accumulation plume and in the bottom 10m of the aquifer. This CO_2 is very difficult to extract due to water bypass. If the well is screened over a shallower depth such as from z=30m to z=100m more of the CO_2 will remain at the base of the aquifer. For this reason, partially screening the well from z=10m to z=100 m is seen as the optimal scenario for small leakage cases.

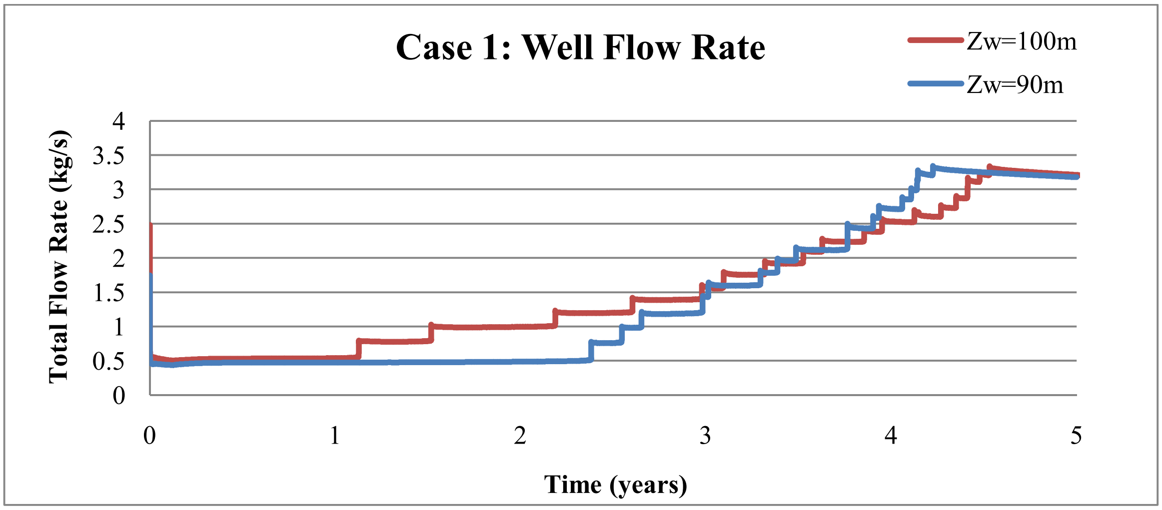


Figure 3-11. Case 1: Well Flow Rate Z_w=90m and Z_w=100m

Case 3: 5,000 tons

Screening the well the entire depth of the aquifer was not as effective for cases with CO_2 leakage greater than 2,500 tons where a large gravity tongue had formed. When the well is screened over the entire depth, the water bypass evident in the small leakage cases becomes much more pronounced. Much of the production from the well is water after

1.5 years. If water is bypassing the CO_2 plume very little CO_2 is removed for each kg of produced water. For example the flow fraction of gas from the top 5 m of the aquifer for Case 3 (5,000 tons) over a three year period with a constant pressure of 0.296 MPa (20 m of hydraulic head) is shown in Figure 3-12.

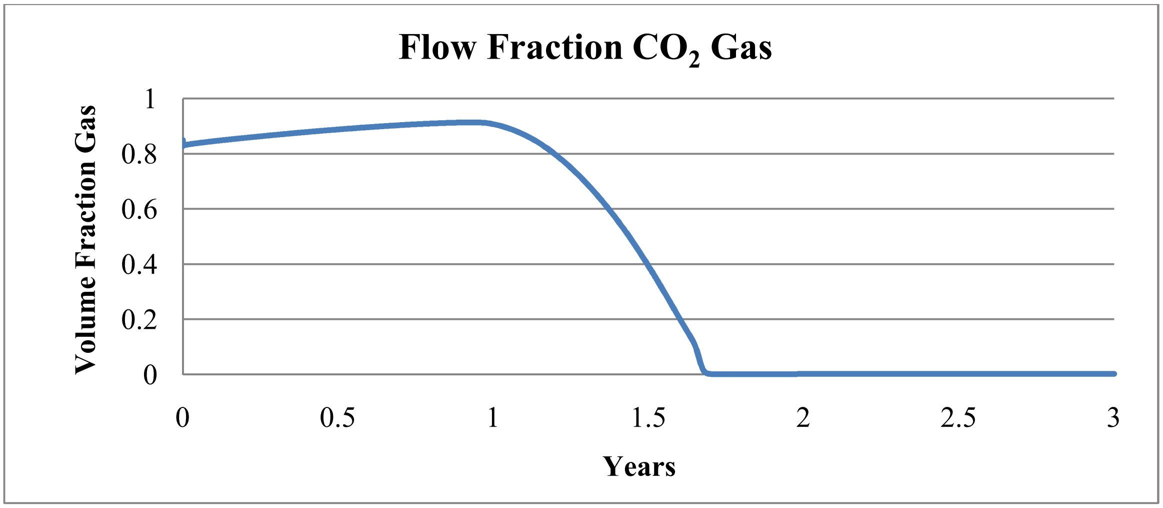


Figure 3-12. Volumetric Flow Fraction CO_2 Gas for Case 3 from Top 5 m of Aquifer

Focusing extraction on certain depths to reduce bypass was tested as an alternative approach. The option considered is to extract first from the areas with high gas saturation to reduce differences in the saturation along the depth of the aquifer. This also meets the first objective to reduce the mobile phase CO_2. Then, once a consistent saturation distribution at the residual gas saturation level is reached, begin extraction with a well screened the entire depth of the aquifer to reduce the total mass of CO_2.

Based on the concept for first extracting the mobile CO_2, the following three step process was analyzed for Case 3 (5,000 tons). From a practical perspective, varying the well screening depth could be achieved by first screening the well the entire depth of the aquifer and then inserting packers to isolate sections utilized during each step. Also, shallow wells are relatively inexpensive and three separate wells could be drilled next to each other.

Multiple extraction well hydraulic heads were analyzed for Case 3 over two years to determine the optimum hydraulic head for the large leakage cases. A hydraulic head of 20 m (0.296 MPa) is shown to be optimal because it allowed for a high flow rate without greatly increasing the amount of mobile CO_2 in the leakage plume (Table 3-1). Increasing the amount of mobile CO_2 may lead to more capillary trapping which could hinder CO_2 extraction.

Table 3-1. Hydraulic Head Comparison

Hydraulic Head	**50 m**	**25 m**	**20 m**
Pressure	0.59 MPa	0.345 MPa	0.296 MPa
CO_2 Remaining	4370 tons	4220 tons	4180 tons

The purpose of the first phase of extraction is to remove all of the mobile CO_2 in the main part of the plume and immediately above the leakage zone. The extraction well was screened from z=40 m to z=90 m with 20 m of hydraulic head (0.296 MPa) at z=90 m. The plume after three years of extraction is depicted in Figure 3-13.

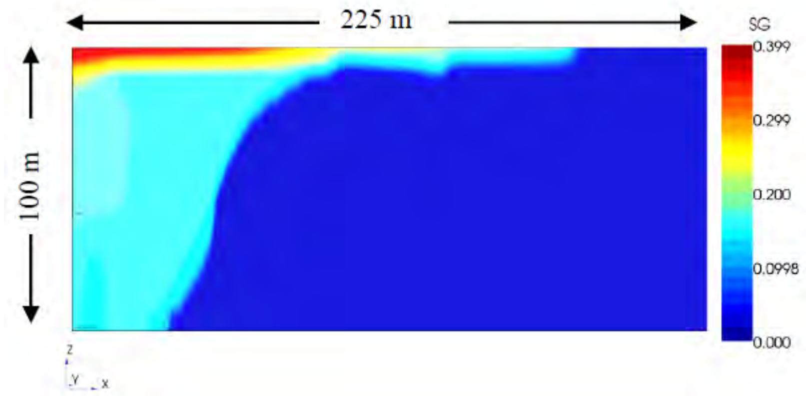


Figure 3-13. Case 3: Extraction with well screened from z=40 m to z=90 m after three years

After three years all the remaining mobile CO_2 is in the secondary plume at the top of the aquifer. This plume looks very similar to the passive remediation case after five years. However, the gravity tongue has not increased in diameter and the amount of CO_2 in the gravity tongue has decreased. To remove the mobile gas remaining in the gravity tongue packers are placed at z=95 m and z=100 m to isolate the top zone. Extraction from the top of the well is operated with 20 m of hydraulic head for 325 days until most of the mobile gas is removed. Figure 3-14 depicts the leakage plume at 160 days and at 325 days. There is very little CO_2 near where the well was screened previously in the middle of the aquifer. Once the well is removed the pressure increases and the gaseous CO_2 saturates the water.

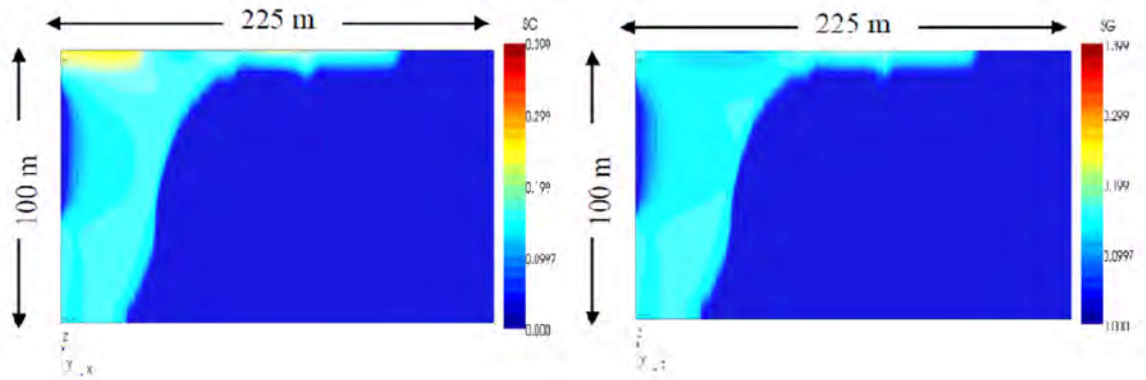


Figure 3-14. Case 3: CO_2 Plume after 160 and 325 days with extraction from the top of the well

The saturation in the gravity tongue drops from 39.9% to an average of 16% during the 325 days of extraction. Now the reservoir is at consistent gas saturation close to the residual of 15%. The third stage is screening the well over the entire depth of the aquifer with 20 m of hydraulic head. However, even during this third phase the extraction of CO_2 is very slow with approximately 240 tons removed per year. Figure 3-15 shows the gas phase, aqueous phase, and total remaining CO_2 over the three step process. The gas removal rate speeds up during the second phase and the aqueous phase stabilizes. The extraction rate during the third step is the largest but most of the production is the aqueous phase CO_2 because the gas phase is trapped and very little is mobile.

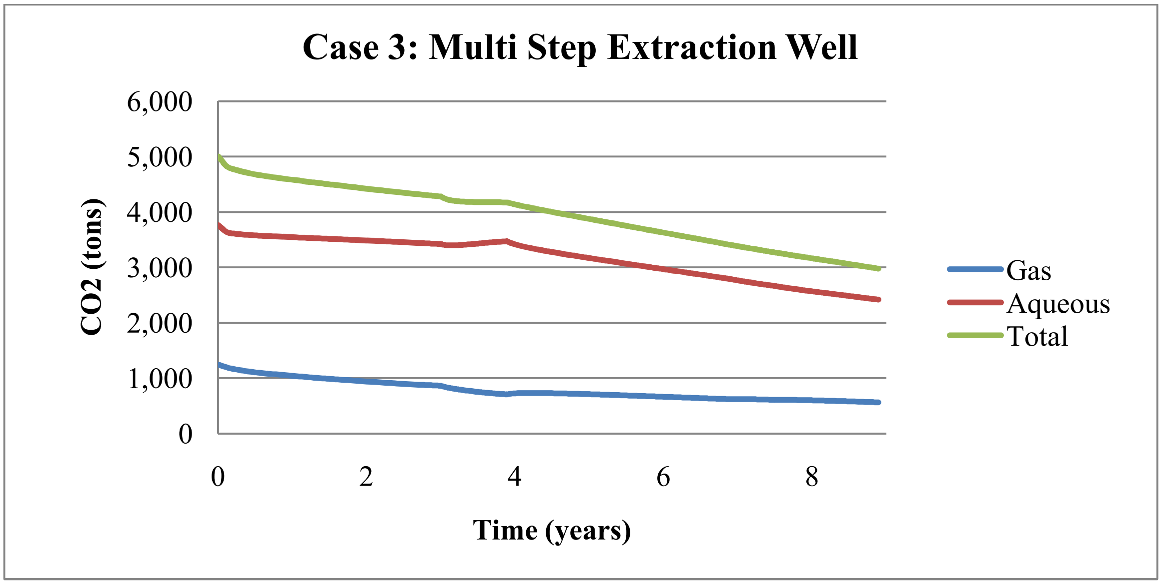


Figure 3-15. Case 3: Multi Step Extraction Well

If the flow rate for the third step of 240 tons per year continues, this three step process will result in a total remediation time frame of approximately 21 years. Although this was determined to be a relatively efficient scenario by reducing the amount of water bypass the remediation time frame is very long consequently other options are considered.

3.4.3. Remediation with Horizontal Extraction Wells

As was shown in the previous cases, the large thin plumes of CO_2 (gravity tongues) lead to difficulties for vertical extraction wells. Also, even if vertical extraction wells are effective for removal of smaller plumes, large volumes of water is co-produced and must be managed. To overcome the ineffectiveness of vertical extraction wells, we examine the use of horizontal wells for removing the plumes of CO_2. The extraction processes for horizontal wells are similar to those for the vertical extraction wells however mobile gaseous CO_2 will not flow downwards to a horizontal well unless the pressure gradient induced by pumping overcomes the buoyancy forces. Over time as the well continues to produce, it will lead to a larger pressure drop along the depth that may overcome the buoyancy forces.

To analyze horizontal wells a 3D Cartesian grid must be used. For the 3D grid the resolution near the well is coarser than for the 2D radial axisymmetric cases, grid cells are cubes instead of cylinders, and the leakage zone is slightly smaller. For these three reasons the resulting shape of the leakage plume for the same amount of total leakage and leakage rate looks slightly different compared to the 2D radial axisymmetric case. The main difference is that less accumulation has occurred at the top of the reservoir over the five year period. The leakage plumes after five years of leakage for Case 3-3D (5,000 tons, 1,000 tons/year) and Case 4-3D (10,000 tons, 2,000 tons/year) are shown in Figure 3-16 and Figure 3-17.

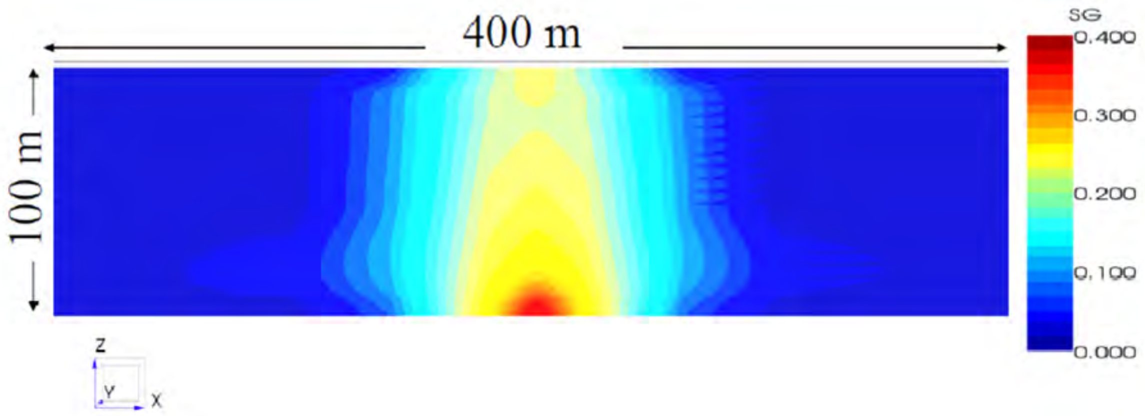


Figure 3-16. Case 3-3D: 5,000 tons

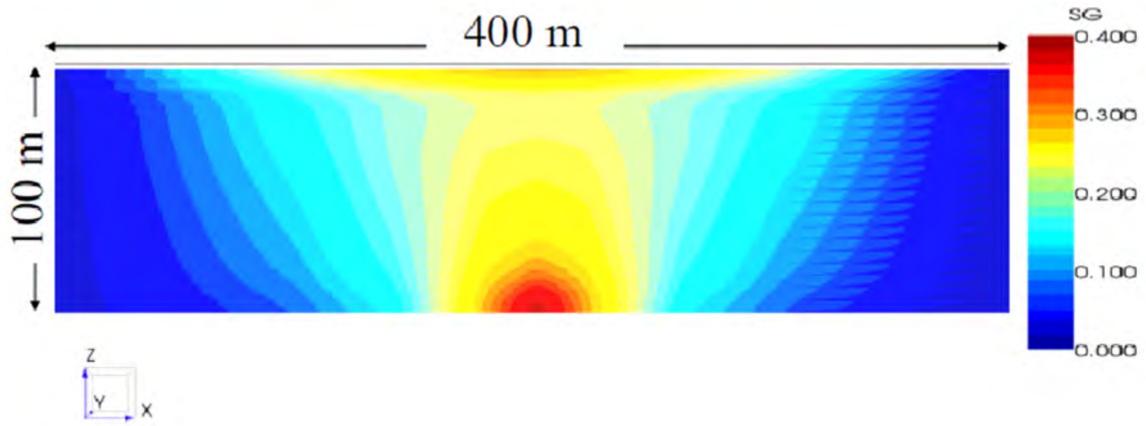


Figure 3-17. Case 4-3D: 10,000 tons

The effectiveness of remediation with horizontal extraction wells is analyzed for Case 3-3D and Case 4-3D. With the 3D grid, Case 3-3D (5,000 tons) has a very small secondary accumulation plume at the top of the aquifer (Figure 3-16). The maximum gas saturation of 37.4% is at the base of the aquifer directly over the leakage site. Case 4-3D with twice as much leakage (10,000 tons) has a gravity tongue that is 400 m in diameter with a maximum gas saturation of 31% (Figure 3-18). For the same leakage with the 2D grid the diameter of the gravity tongue is 500 m with a maximum gas saturation of 33% (Figure 2-9). The remediation effectiveness for Case 3-3D with no gravity tongue and for Case 4-3D with a large gravity tongue are compared to analyze the effects of a gravity tongue on horizontal well extraction efficiency.

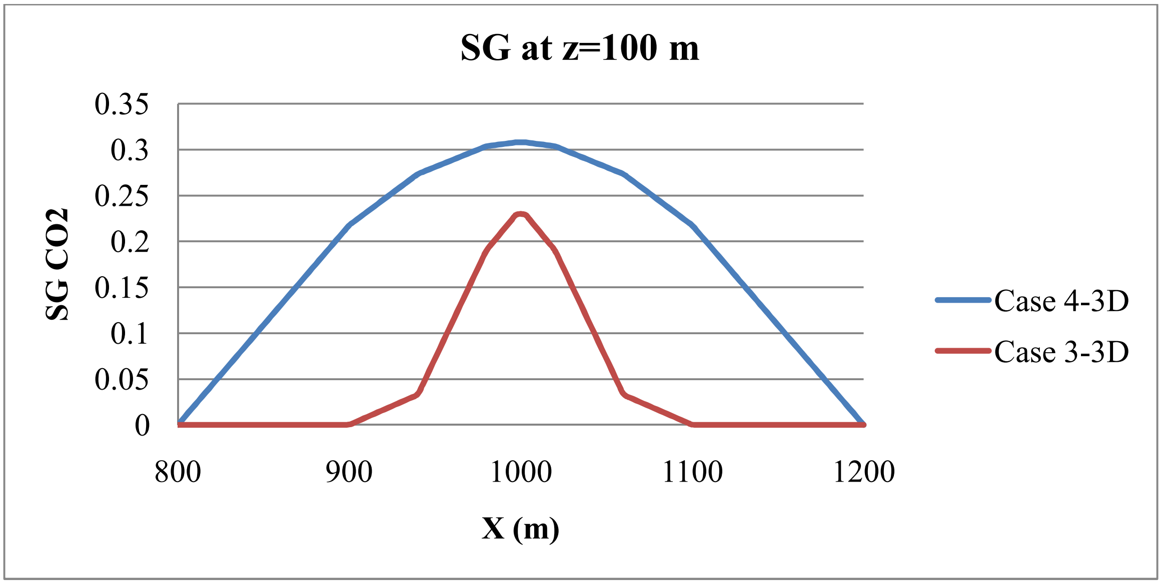


Figure 3-18. Case 3-3D and Case 4-3D: Gas Saturation at the z=100m

Horizontal extraction wells are centered over the leakage zone (x=1000 m and y=1000 m). The width of the mobile CO_2 gas plume from the base of the aquifer up until the gravity tongue begins for both Case 3-3D and Case 4-3D is approximately 100 m. For this reason the length of the horizontal extraction well is 100 m from (x, y) = (950, 1000) to (x, y) = (1050, 1000). Based on symmetry the same results would be achieved if the well runs along the y axis. The horizontal extraction wells are operated with a pressure constraint similar to the vertical extraction wells. The pressure is held constant at x=950 m and is consistent along the length of the horizontal well. Based on the analysis for the vertical extraction wells a pressure of 0.296 MPa was used for the horizontal extraction wells.

With a horizontal extraction well, the depth of the well is an important parameter to optimize. To achieve the first objective to reduce the mobile gas phase, the horizontal extraction well needs to be placed close enough to the secondary plume of CO_2 at the top of the reservoir to capture the CO_2. However, due to the lack of vertical penetration the extraction well needs to be deep enough to also capture the main CO_2 leakage plume.

Case 3-3D: 5,000 tons

For Case 3-3D (5,000 tons) two horizontal extraction well depths, one placed in the middle of the aquifer at z=50 m and one placed at the top of the aquifer at z=90 m were analyzed for a 10 year period. The total amount of CO_2 remaining is shown in Figure 3-19.

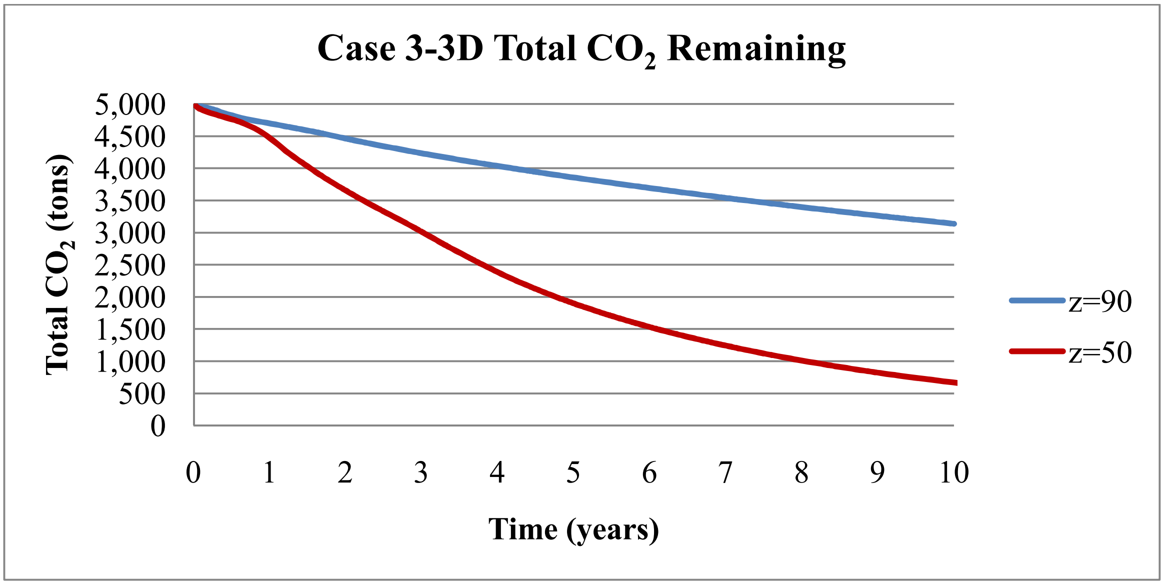


Figure 3-19. Case 3-3D Total CO_2 Remaining for two extraction depths

From Figure 3-19 it is evident that a horizontal well at the center of the aquifer at z=50 m is most effective at removing CO_2 and achieving the second remediation objective. For the first year of remediation the amount removed with both wells is the same. After this point, the well at the top continues at the same removal rate and removes 37% of the CO_2 after 10 years. The extraction rate for the well at z=50 m increases after the first year. At this time the pressure drop from the extraction well has led to a negative pressure gradient that extends vertically to z=70 m. The CO_2 removal rate decreases after nine years and results in a total of 86% removed over the 10 year time frame.

After five years of leakage of 1,000 tons per year 736 tons or 15% of the CO_2 is in gas phase. Figure 3-20 shows that the well in the middle of the aquifer at z=50 m is also more effective at reducing the mobile CO_2 with only 12 tons or 1.6% of the original amount in gas phase remaining at the end of the 10 year period. With the well at the top of the aquifer at z=90 242 tons or 33% of the original amount in gas phase remains at the end of the 10 year period. For the well at the top 24% of the CO_2 produced is gas phase CO_2. This is higher than for the well at the middle where only 17% of the CO_2 produced is gas phase CO_2.

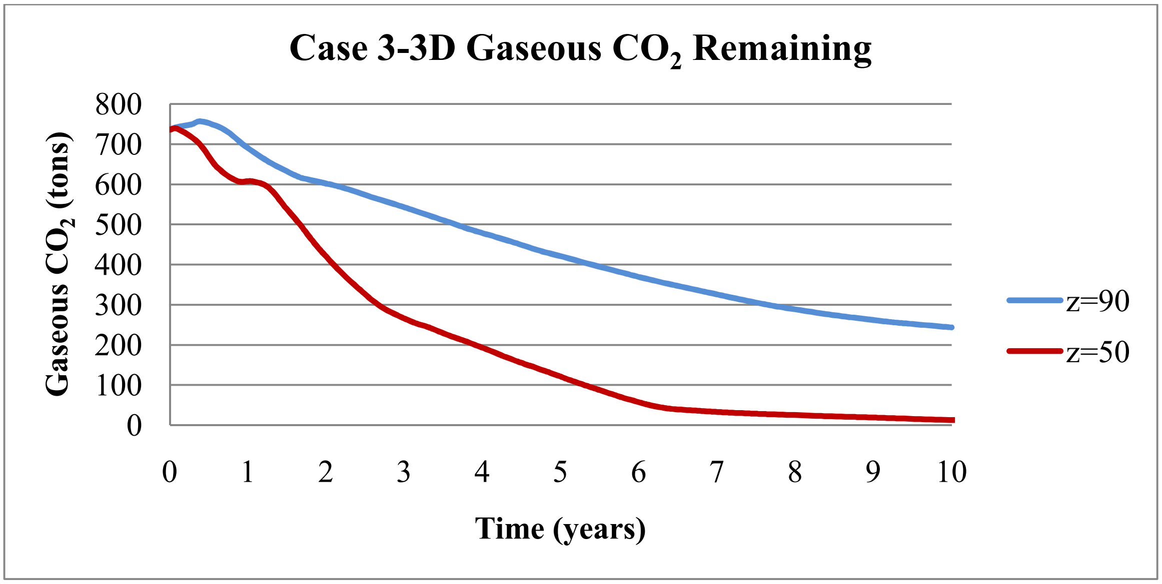


Figure 3-20. Case 3-3D Gaseous CO_2 Remaining for two extraction depths

The amount of CO_2 that is in gas phase increases slightly during the first 30 days of extraction for the well at the middle and during the first 140 days for the well at the top. The increase is due to the pressure drop in the well which leads to a reduction in the density of the gas phase CO_2 and a decrease in the solubility of CO_2 in brine.

The gas saturation in the leakage plume after five years and ten years of remediation are shown for both the case with the well in the middle at z=50 m and the well at the top at z=90m in Figure 3-21 and in Figure 3-22. These figures provide a third measure of comparison of the effectiveness of remediation between the two horizontal extraction depths. Although the well at the middle at z=50 m was shown to both reduce the total amount of CO_2 and the amount of gaseous CO_2 most effectively, there is still mobile CO_2 at the top of the aquifer after five years of extraction. While the well at the top at z=90m is not as effective at removing CO_2 in either gas or aqueous phase, the mobile CO_2 at the top is removed within two years. Based on this analysis, before choosing the horizontal extraction well depth even for plumes without large gravity tongues the multiple remediation objectives need to be balanced based on relative importance.

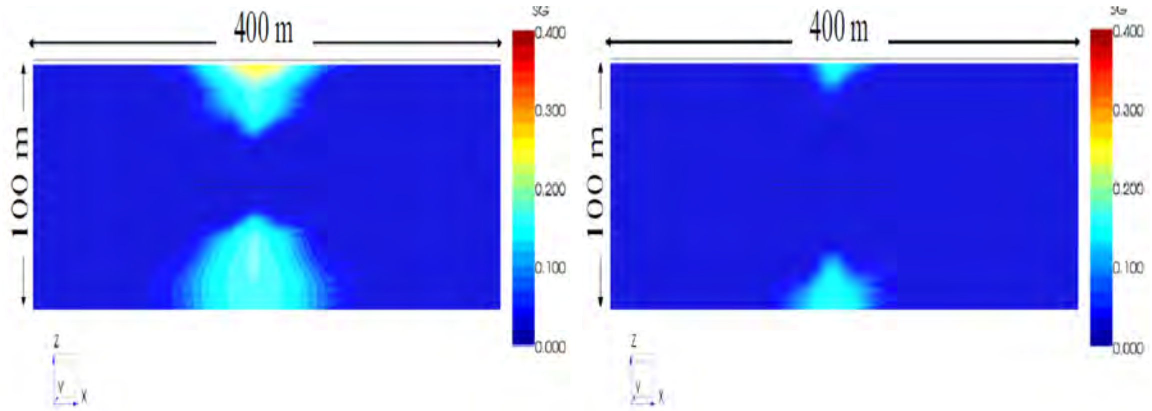


Figure 3-21. Case 3-3D SG after 5 years and 10 years with well at z=50 m

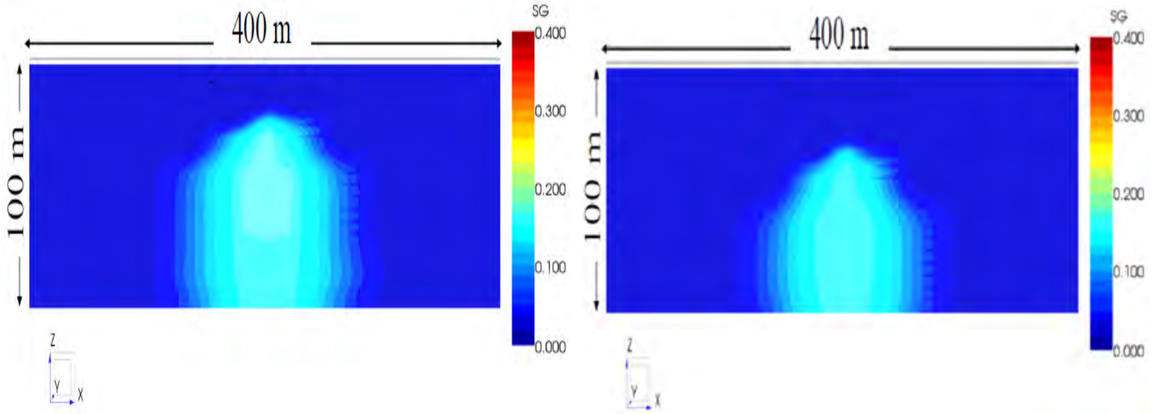


Figure 3-22. Case 3-3D SG after 5 years and 10 years with well at z=90 m

Case 4-3D: 10,000 tons

Next, the optimal depth of the horizontal well was analyzed for Case 4-3D with 10,000 tons of leaked CO_2 and a large gravity tongue that extends 400 m. The remediation was run for 15 years to account for the fact that twice as much CO_2 had leaked for this case compared with Case 3-3D. All the horizontal wells are operated with a constant pressure constraint of 0.296 MPa. Figure 3-23 shows the total amount of CO_2 remaining with wells placed at z=90 m, z=80 m, z=70 m, z=50 m, and z=30 m. More depths were analyzed to better understand the tradeoff between reducing the total amount of CO_2 and reducing the mobile phase CO_2.

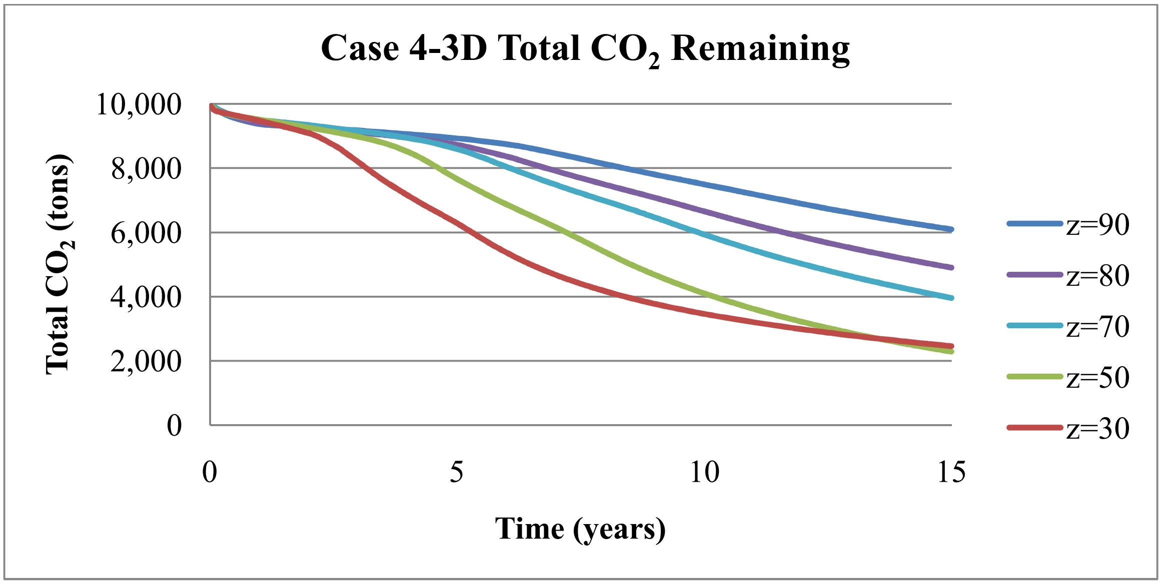


Figure 3-23. Case 4-3D Total CO_2 remaining with various horizontal well depths

The well at z=50 m leads to the highest removal of CO_2 with only 2,290 tons remaining after 15 years. The well at z=30 m leads to a very similar total extraction but has slightly more CO_2 remaining at 2,450 tons. The extraction rate for the well at z=30m is much faster than all the other well depths up until leveling off at 12 years. This is due to the fact that the pressure drop in the well is the most different from the initial pressure before remediation begins. The difference between the well hydraulic head of 20 m compared with the initial hydraulic head of 150 m is 130 m of hydraulic head or approximately 1.37 MPa. After 12 years continuing to extract from the well at z=30 m is very ineffective because the remaining CO_2 is at the top of the aquifer out of reach of the pressure gradient formed by the well.

It is very interesting that up until two years the amount of CO_2 removed is the same for all five horizontal well extraction depths. This can be explained by looking at the amount of gaseous CO_2 remaining for each of the five well depths (Figure 3-24). Over the first two years most of the production from the well is the highly mobile gas phase CO_2 which has a large volume but low density. After two years the only gas phase CO_2 removed is from dissolution from water flowing into the leakage plume due to the pressure drop in the well for the wells in the lower 50 m. Wells in the upper 30 m of the aquifer reduce the gaseous CO_2 at the same rate for the first six years. Between three and six years the reduction in the amount of gaseous CO_2 becomes very small for the wells in the upper 30 m of the aquifer. This is because these wells are mostly removing the gas phase CO_2 that is being exsolved from the water due to the drop in pressure and not from water dissolving the CO_2.

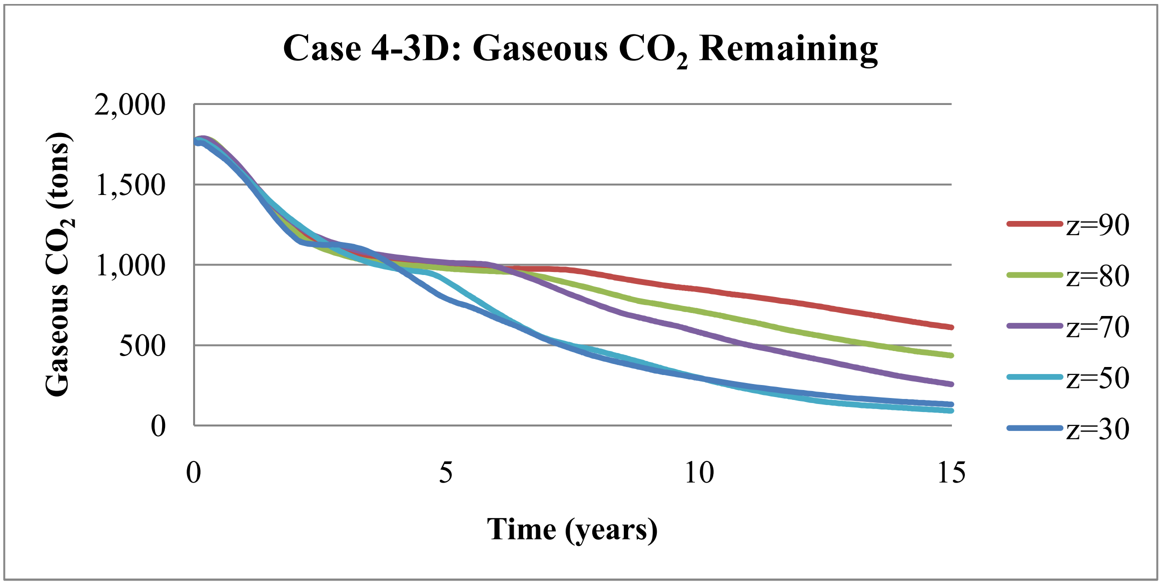
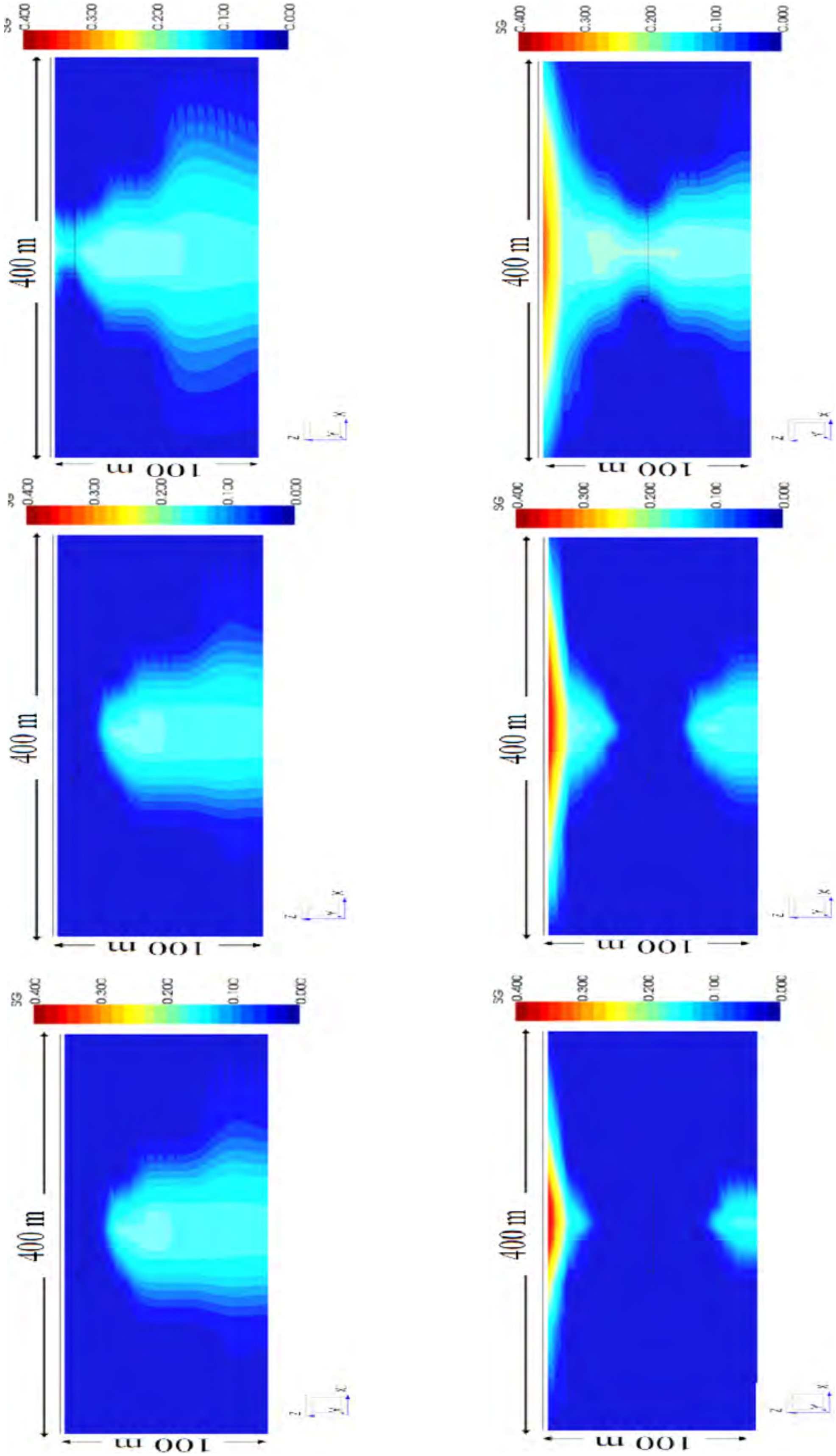


Figure 3-24. Case 4-3D Gaseous CO_2 Remaining with various horizontal well depths

The total decrease in gaseous CO_2 and in the total CO_2 over the 15 years period is linearly related to the extraction well depth if the well is at z=50m or above. Because the pressure constraint is the same for all five extraction wells, the difference with the initial pressure increases linearly as the depth of the well is lowered. The pressure in the leakage plume would naturally decrease to return to hydrostatic after the leakage is stopped. Both the pressure drop from the extraction well and the pressure recovery after injection stops leads to the pressure drop in the leakage plume.

Finally, looking at the plume of CO_2 for Case 4-3D after 5 years, 10 years, and 15 years with a horizontal extraction well at z=50 m and z=90m emphasizes the added difficulty for remediation if a large gravity tongue forms from accumulation at the top.


400 m
100 m
SG
0.400
0.300
0.200
0.100
0.000
Z
Y
X

After five years the well at z=90 m has reduced all the mobile phase CO_2 and is close to removing all of the trapped CO_2 in the gravity tongue. After 10 years the remaining leakage plume looks very similar to the smaller leakage case after 10 years with a large amount of CO_2 remaining in the main leakage plume. The difference after five additional years is minimal because much of the water produced is not saturated with CO_2. The well at z=50 m is much less effective at removing the mobile CO_2 in the gravity tongue compared with Case 3-3D. A large amount of mobile CO_2 is still in the gravity tongue after 5 years, 10 years, and 15 years of extraction. The width of the gravity tongue does decrease over the 15 year period from 400 m to 350 m with the well at z=50 m.

3.4.4. Comparison of Remediation Effectiveness with Total Leaked

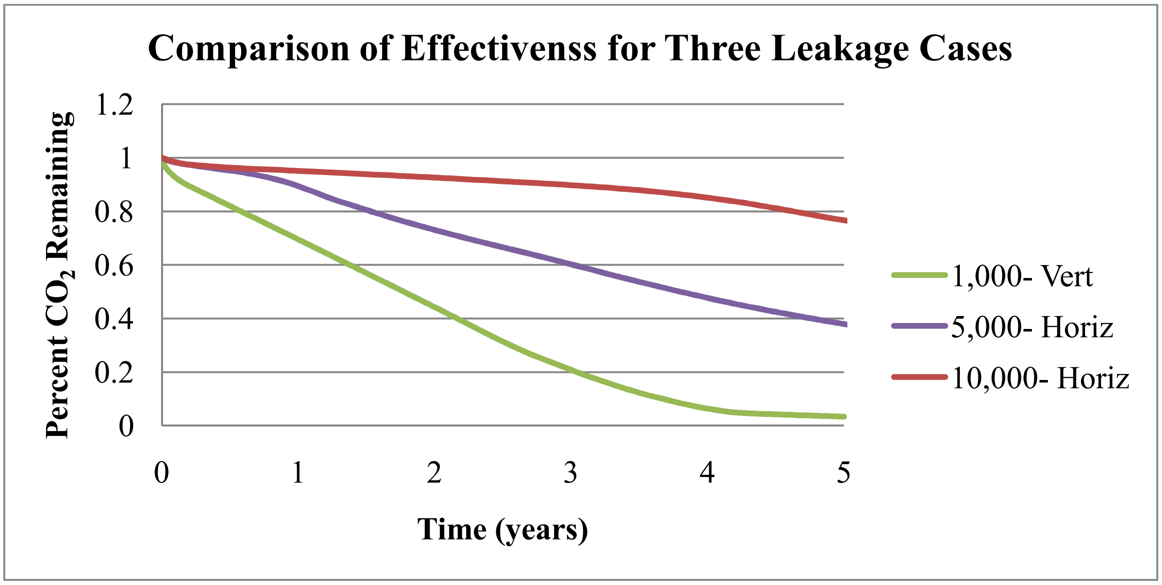


Figure 3-25. Comparison of Four Extraction Scenarios for Three Different Cases

Figure 3-25 shows the percent of CO_2 remaining for three different extraction scenarios and three different leakage quantities over five years: Case 1 (1,000 tons) vertical well screened from z=10 m to z=100 m, Case 3-3D (5,000 tons) horizontal well at z=50m, and Case 4-3D (10,000 tons) horizontal well at z=50 m. From this figure it is very clear that the larger the total quantity leaked the more difficult the removal. The partially screened vertical extraction well for Case 1 (1,000 tons) is the most effective over the five year time frame with only 3% remaining after five years. The second most effective is the horizontal well at z=50m for Case 3-3D (5,000 tons) with 38% remaining after five years.

Finally, the largest leakage case analyzed, Case 4-3D (10,000 tons) has significantly less effective percentage removal rate with 77% remaining after five years. These three remediation scenarios using an extraction well were chosen as the most effective from all the various cases analyzed.

3.5. Remediation with Injection Wells

The second remediation technique is to inject water into the aquifer with the goal of immobilizing the CO_2 by dissolving the CO_2 plume. The main processes involved when the water is injected are displacement of CO_2 due to viscous forces, capillary trapping at the residual CO_2 saturation, dissolution, and gas saturation decreases due to the pressure increase from injection. Water injection achieves the first remediation objective which is to reduce the quantity of mobile CO_2 gas in the reservoir. It does not reduce the overall mass of CO_2. If more water is injected after all the CO_2 is dissolved in the water, the concentration of CO_2 in the dissolved phase can be reduced due to advective mixing and diffusion. A reduction in aqueous concentration could lead to a reduction in the risk of increasing the concentrations of trace metals such as arsenic and lead.

The water injected is reservoir water with a 0.01 mass fraction of NaCl to limit the additional cost of acquiring a large amount of water. The water will be extracted far away from the leakage point so that it is not saturated with CO_2. The injection well is placed in the center of the leakage plume and is screened the entire depth of the aquifer to access the most mobile CO_2.

3.5.1. Injection Well Remediation Processes

Based on the concepts of multiphase flow, the main processes that will occur with the addition of an injection well can be formulated. As the water flows into the leakage plume it dissolves the gas phase CO_2. The first image in Figure 3-26 shows a cross section of the gas saturation in the leakage plume after a period of water injection. Also with water injection, the aqueous phase CO_2 will be displaced shown in the second image. The displacement of the aqueous phase CO_2 is an important secondary process because it increases the extent of the leakage plume. The third image shows the top view of the gas saturation depicting the donut shape that is formed from the dissolution of the gas phase closest to the injection well.

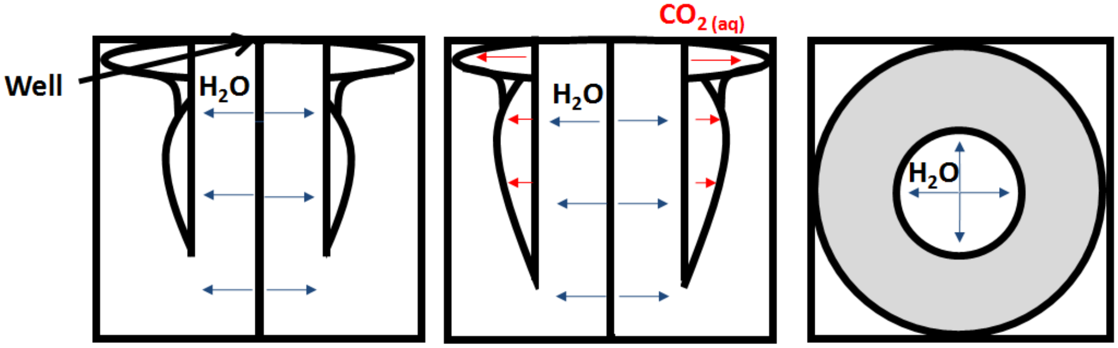


Figure 3-26. Injection Well Remediation Processes

3.5.2. Vertical Injection Well

The vertical injection well is operated with a constant flow rate and is distributed over the thickness of the aquifer by the permeability (kr=100 md) times the height of the grid block (5 m). The vertical injection well is screened the entire depth of the aquifer and is placed at the center of the leakage plume. Since this is a homogeneous anisotropic reservoir the flow rate into each grid block is uniform. For the injection well the flow rate has a significant impact on the period of time that it takes to dissolve the gas phase CO_2. The first flow rate examined is 25 kg/s and corresponds with 1.25 kg/s into the 20 grid blocks that are 5 m high.

Case 3 (5,000 tons):

The effectiveness of the injection well for dissolving the gas phase CO_2 was first analyzed for Case 3 (5,000 tons) with a large gravity tongue. The two images in Figure 3-27 are the gas saturation in the leakage plume after 2 days of water injection and after 33 days of water injection at the rate of 25 kg/s. All of the CO_2 is dissolved after 54 days of water injection. The first image in Figure 3-27 shows how the water injection front moves at a relatively constant speed along the entire depth. There is a slight lag in the top 10 m where the gas saturation is very high, the relative permeability to water is low, and the water wants to bypass this zone. For the first 28 days of water injection the maximum gas saturation in the gravity tongue remains at 33% and then lowers at a steady rate.

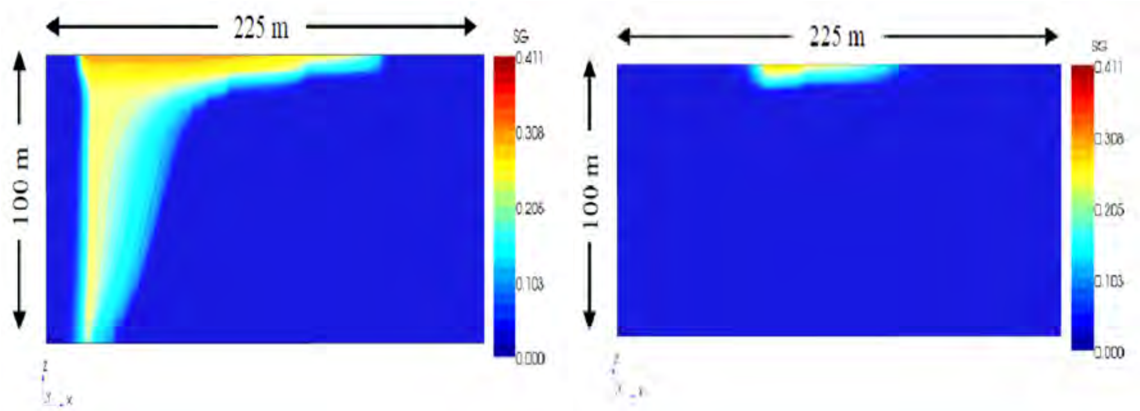


Figure 3-27. Case 3: Injection well (25 kg/s) after 2 days and 33 days

The mass fraction of CO_2 in the aqueous phase at the center of the leakage plume (z=50 m) along the radius of the plume at the beginning before injection starts, after 10 days, after 21 days, and after 54 days of injection is shown in Figure 3-28.

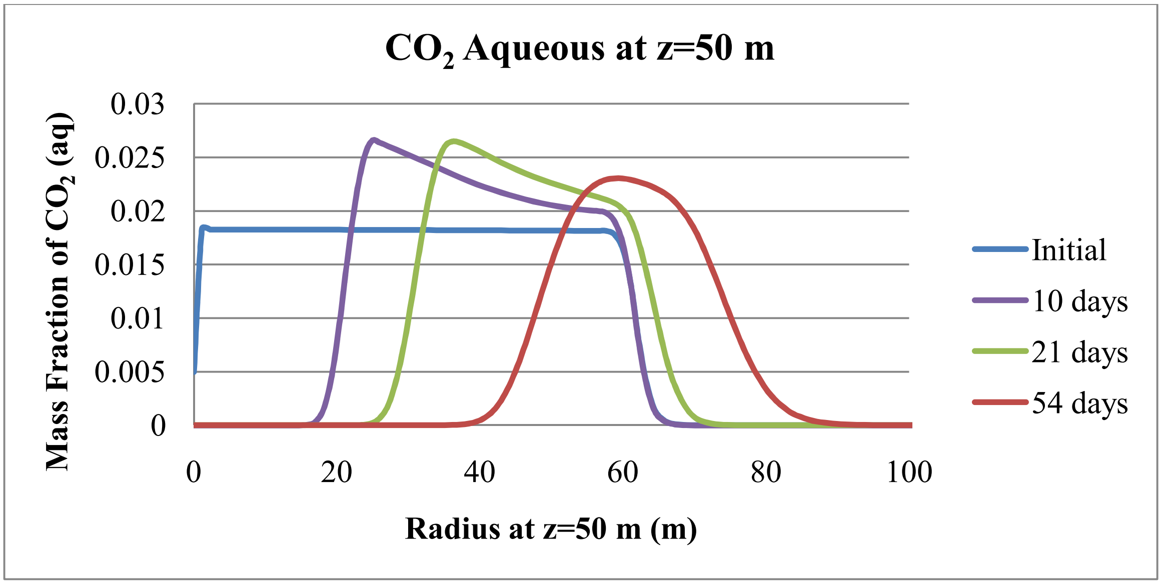


Figure 3-28. Mass Fraction of CO_2 Aqueous at z=50 m over 54 days of injection

The initial mass fraction is very consistent along the width of the plume as shown by the blue line. The CO_2 mass fraction in the aqueous phase increases during injection at the injected water front. This is because the pressure increases significantly from injection allowing for more CO_2 to dissolve in the brine. Also, the injected water over the 54 day period does not mix with the CO_2 saturated water but displaces it away from the injection point. The outer boundary of the aqueous CO_2 plume at z=50 m is displaced from a radial distance of 64 m to form a donut shape with an interior radius of 38 m and an exterior radius of 84 m. The displacement of the outer boundary only occurs during the last 44 days of injection. The leading edge of the gravity tongue at the z=100 m is displaced very little because CO_2 is still being dissolved and not displaced.

The pressure increase at z=50 m and at a radial distance of 50 m from the injection well is from 1.4 MPa to 2.75 MPa over the 54 day period (Figure 3-29). It is stable until the water injection front reaches r=50 m at 7 days. Once the water reaches r=50m the pressure increases rapidly with a slope of 0.0622 MPa/day until 16 days. This corresponds to the time when the water is dissolving the gas phase CO_2. After dissolving the CO_2 the pressure increase is a third of the previous rate at 0.0196 MPa/day.

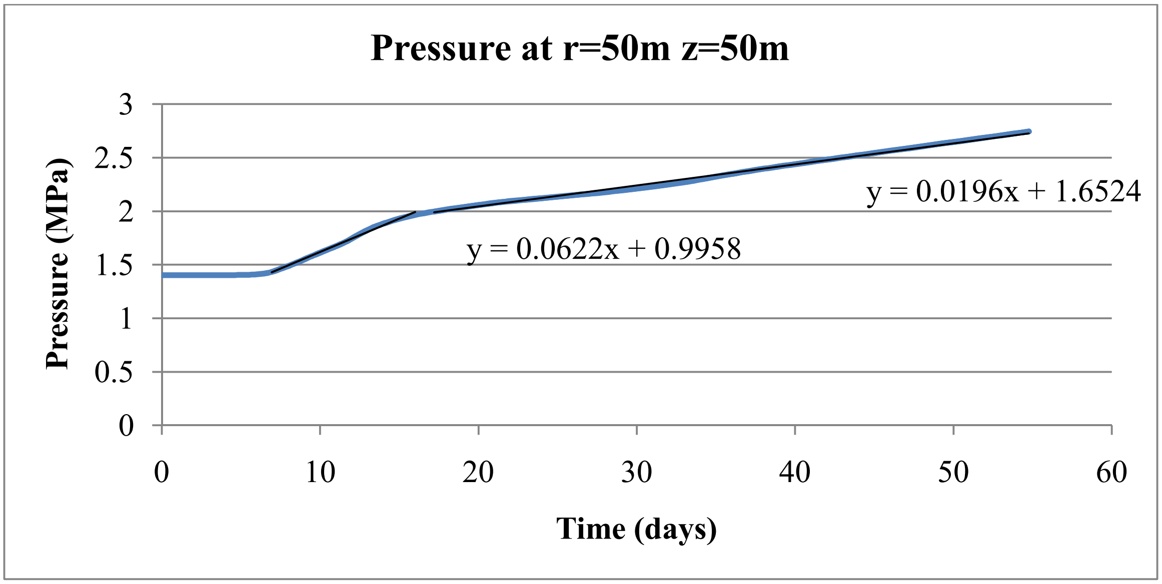


Figure 3-29. Pressure at z=50m and r=50 m over 54 days of water injection

If injection continues for five years instead of 54 days, the maximum CO_2 aqueous mass fraction decreases from 0.022 to 0.0058 as shown in Figure 3-30. This achieves the third objective of reducing the aqueous phase concentration and reducing the risks from increased pH levels. However, the extent of the plume increases significantly from 90 m to 450 m in the radial direction. If secondary contamination is an issue, then it expands the extent of any secondary contamination even if it is at a lower concentration. Also, the width of the donut shaped plume has increased and now extends from 130 m in the radial direction to 450 m. However, the grid size has increased from a cylinder with a thickness of 0.2 m near the leakage zone to a cylinder with a thickness of 9.1 m at 450 m. This change in grid size could also influence the change in aqueous phase concentrations.

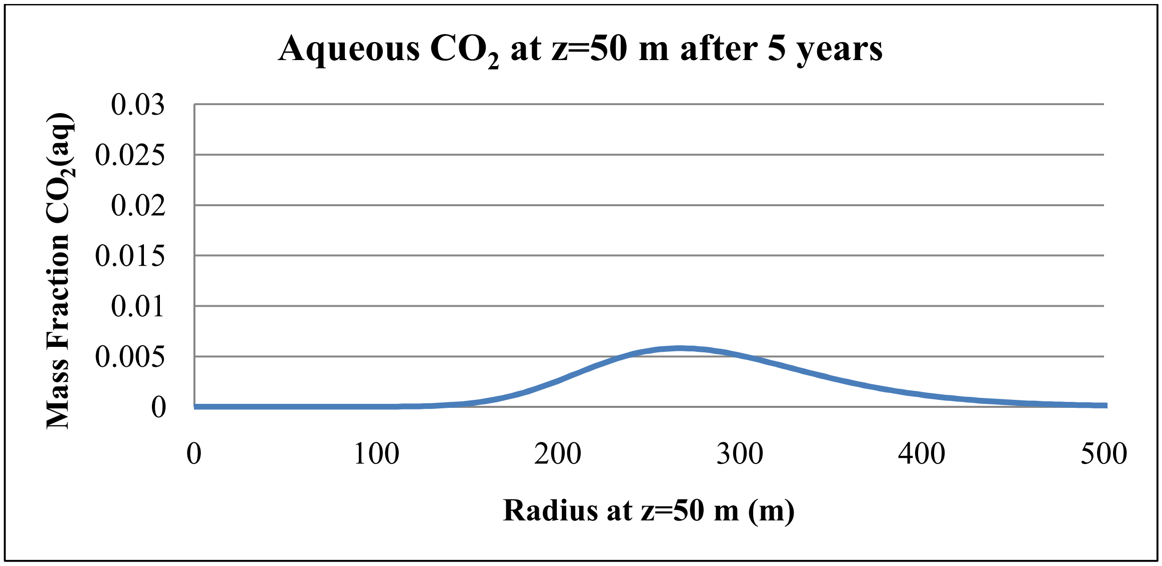


Figure 3-30. Aqueous CO_2 at z=50 m after 5 years

The case presented illustrates that injection can be effective for reducing the mobile CO_2. However, the pressure build up was too large and could fracture the reservoir. Therefore lower flow rates were investigated. The flow rate of water injection has a significant impact on the time to dissolve the gas phase CO_2. Two different flow rates of 25 kg/s and 5 kg/s are shown in Figure 3-31.

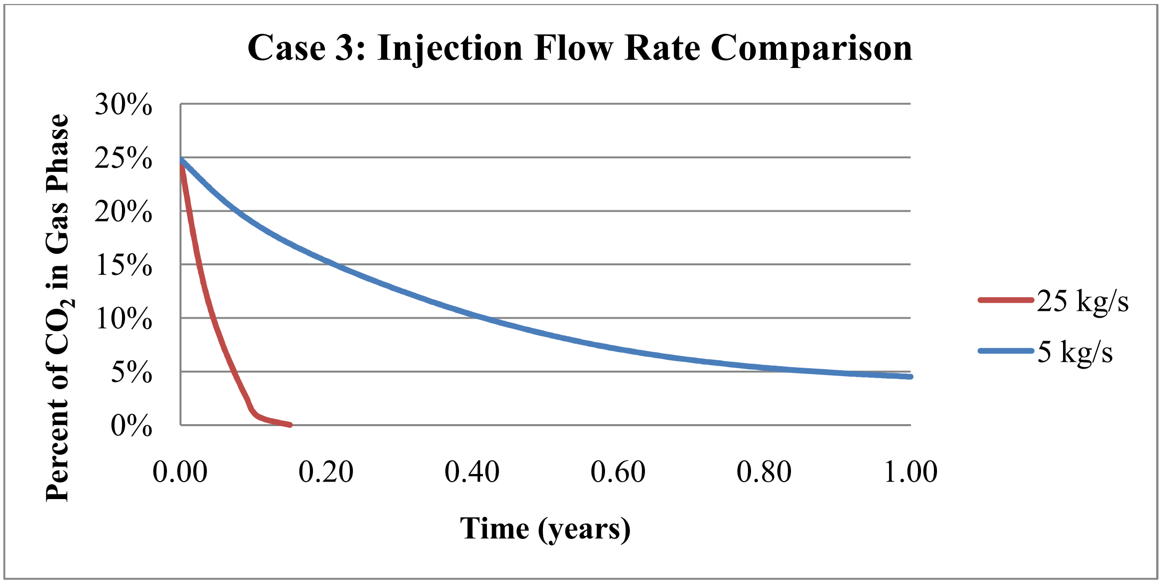


Figure 3-31. Mass Fraction in Gas Phase with 25 kg/s and 5 kg/s

As was previously mentioned with a flow rate of 25 kg/s the mobile phase CO_2 is dissolved in 54 days. A flow rate that is one fifth of that rate at 5 kg/s leads to 5% remaining in gas phase after 1 year. This is almost seven times as long as the total time to dissolve the CO_2 with the higher flow rate. Hence, the time to dissolve the plume is not linearly related to the flow rate. Although a slower flow rate will result in a longer period of time to dissolve the CO_2, the pressure increase is much less. Over the year of injection at a distance of 50 m from the injection well and at z=50 m the pressure increases from 1.4 MPa to 1.71 MPa with a slope of 0.0009 MPa/day.

Case 1 (1,000 tons):

The effectiveness of water injection was also analyzed for Case 1 with 1,000 tons total leaked and a very small amount of accumulation at the top. The results on the leakage plume are similar as for Case 3 (5,000 tons) except that they occur much more rapidly. With a flow rate of 25 kg/s all of the CO_2 is dissolved within 5 days, ten times as fast as for Case 3 which had five times as much leakage. The gas saturation in the leakage plume is shown in Figure 3-32 after two days and after three days of injection.

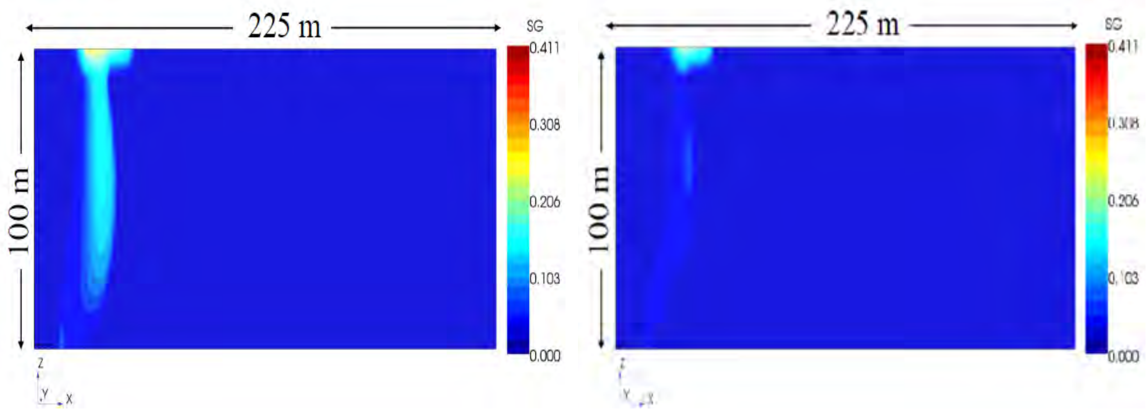


Figure 3-32. Case 1 (1,000 tons) 25 kg/s after two days and three days

After only two days of injection most of the mobile CO_2 has dissolved in the main plume. A small amount of mobile CO_2 remains in the small accumulation plume at the top of the aquifer. The mobile CO_2 at the top is the last to be dissolved as seen in the second image in Figure 3-32. Five days is very rapid achievement of the first objective of reducing the mobile phase CO_2. The injection flow rate has a large impact on the dissolved CO_2. The images in Figure 3-33 show the dissolved CO_2 after 80 days for 25 kg/s and 5 kg/s.

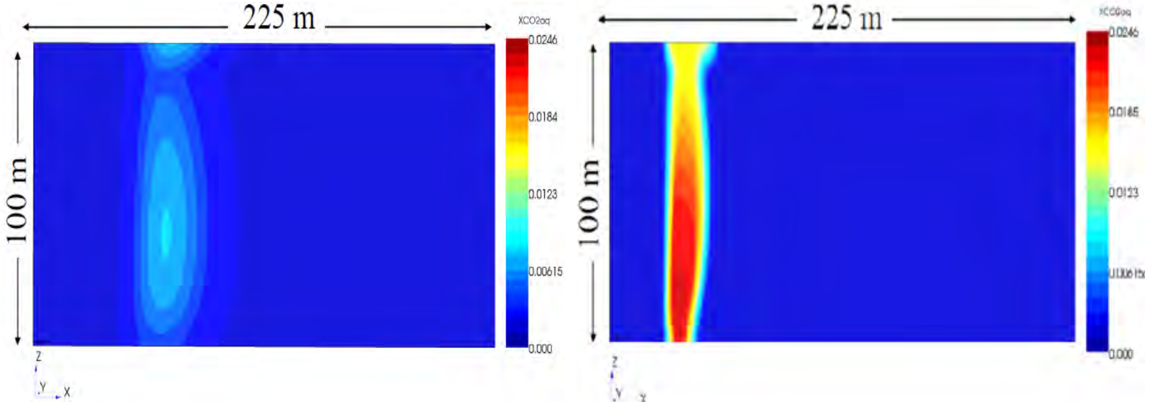


Figure 3-33. Aqueous Phase CO_2 after 80 days of injection with 25 kg/s and 5 kg/s

The two main differences are the extent of the plume in the radial direction and the maximum mass fraction of CO_2 in the water. For the case with very high injection rate of 25 kg/s the plume has been displaced from a cylinder 38 m wide at z=50m to a donut shape with an internal radius of 25m and an external radius of 120 m. With a lower flow rate of 5 kg/s the plume has been displaced much less with an internal radius of 20 m and external radius of 52 m at z=50 m. On the other hand the aqueous phase concentration is much higher in the case with the lower flow rate. The maximum at the base of the aquifer where the pressure is highest is a mass fraction of 0.0246. For the higher flow the maximum concentration in the middle of the aquifer is 0.0061 which is one fourth as much with the low flow rate.

The reduction in the percent of CO_2 in gas phase for Case 1 for the two different flow rates is shown in Figure 3-34. This trend is very similar to the trend for the higher leakage case with 5,000 tons. Again, a slower leakage rate does not correspond linearly with an increase in the amount of time to dissolve the CO_2. If the decrease in gas phase for the low flow rate during the first 17 days continued instead of slowing, then all the CO_2 would be dissolved in 25 days. This would be exactly five times as long as the amount of time to dissolve the CO_2 with a five times larger flow rate. After 17 days with a flow rate of 5 kg/s the remaining gas saturation is primarily at the residual saturation of 15%. One conclusion is that the time to dissolve gas above the residual saturation is linearly related with the flow rate.

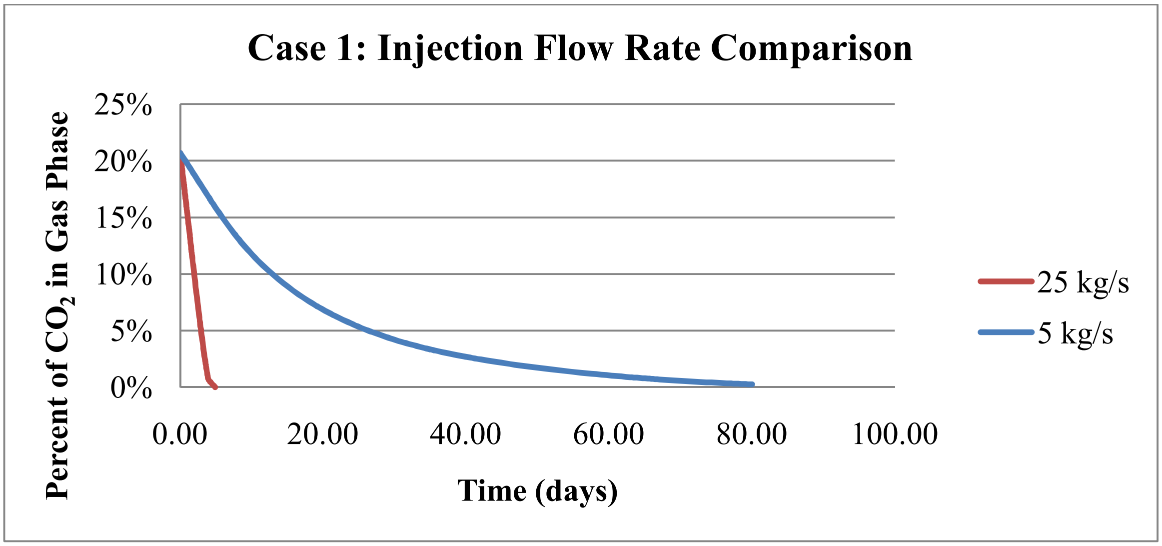


Figure 3-34. Case 1 Injection Flow Rate Comparison for 5 kg/s and 25 kg/s

The tradeoffs between the two flow rates analyzed are either highly concentrated CO_2 in a small area with a lower pressure increase or lower concentrations in a larger area with a higher pressure increase. Considering secondary impacts that are most impacted by pH change a more dispersed plume over a larger area would be preferable. However, considering the overall area affected a much slower flow rate may be better and will also reduce the pressure increase. Water injection is very effective at rapidly dissolving the CO_2 with 5 days required for the low leakage case of 1,000 tons and 54 days required for the leakage case with 5,000 tons with a flow rate of 25 kg/s. As an emergency method, water injection may be the most effective before a long term scenario is designed and implemented. However, after water injection stops the amount of CO_2 in gas phase will increase as the pressure drops returning to hydrostatic. If for Case 1 after injecting water at a flow rate of 5 kg/s for 80 days the well is shut in for 2.5 years, then the amount in gas phase will be 61 tons or approximately 30% of the original amount

3.6. Water Injection and CO_2 Extraction

Although it is possible to immobilize and dissolve all of the CO_2 with a high flow rate of water in a short period time, dissolving all the CO_2 could make subsequent extraction more difficult for two reasons. First, the CO_2 is displaced away from the initial leakage site during injection. As was shown in the previous section the dissolved CO_2 forms a donut shaped plume with an outer radius dependent on the flow rate and the duration of water injection. Second, part of the reason that the CO_2 dissolves is because the pressure increases from the water injection increasing the solubility of CO_2. Once an extraction well is added the pressure drops again and the dissolved CO_2 returns to mobile gas phase but farther away from the leakage site in the donut shaped plume.

Many injection and extraction scenarios are analyzed for their effectiveness in meeting the three remediation objectives of quickly reducing mobile phase CO_2, reducing the total mass of CO_2 in the aquifer, and lowering the aqueous phase concentration of CO_2. The scenarios are also compared based upon the extent the CO_2 plume is displaced during injection and the amount of CO_2 that exsolves when the pressure drops during extraction.

The remediation scenarios can be divided into scenarios with injection followed by extraction from one well, injection followed by extraction from multiple wells, and injection and extraction taking place concurrently from multiple wells. The various scenarios are analyzed with a 2D radial axisymmetric grid if only one well is used or with the 3D Cartesian grid if multiple wells are included. The effectiveness of the remediation technique is analyzed for the case with one well with Case 1 (1,000 tons), Case 3 (5,000 tons), and the cases with multiple wells for Case 3-3D (5,000 tons), and Case 4-3D (10,000 tons).

3.6.1. Injection and Extraction Remediation Processes

The processes that control the flow of CO_2 in the aquifer are a combination of the processes from extraction and injection. However, the importance of each process can change if they are occurring at the same time. During injection the main processes are dissolution of the CO_2, displacement of the aqueous phase CO_2, and increases in the solubility of CO_2 with the pressure increase. Extraction processes include exsolution from the drop in pressure, rapid movement of mobile phase CO_2, capillary trapping, and dissolution of CO_2 into water flowing into the well. When injection and extraction occur at the same time the overall pressure disturbance is very important on determining whether more CO_2 will dissolve into the water due to solubility increases or come out of solution from an overall drop in pressure. Also, the correlation between the location of the pressure disturbance and the plume is very influential on the ratio of CO_2 in aqueous or gas phase. If the drop in pressure from the extraction well leads to exsolution of CO_2, more CO_2 will be capillary trapped at the residual gas saturation. If this CO_2 is trapped far away from the extraction well it will be slow to remove because only dissolution can lead to its removal.

3.6.2. Injection followed by Extraction with One Well

The simplest injection and extraction scenario includes one injection well which switches to an extraction well after the injection period ends. The first scenario analyzed starts with the initial condition after the injection of 25 kg/s for 54 days for Case 3 (5,000 tons). At this point all of the CO_2 is dissolved and has been displaced away from the leakage zone to form a donut shaped plume with an interior radius of 38 m and an exterior radius of 84 m at z=50 m (Figure 3-28). The extraction well is at the center of the interior ring of dissolved CO_2 at r=0 m with a well radius of 0.1m. The extraction well is screened from z=90 m to z=100 m to reduce the area impacted by the pressure drop. The pressure constraint at the top of the extraction well is 0.149 MPa or approximately 5 m of hydraulic head. Figure 3-35 shows the gas saturation after 62 days and 365 days of extraction from the top 10 m of the aquifer.

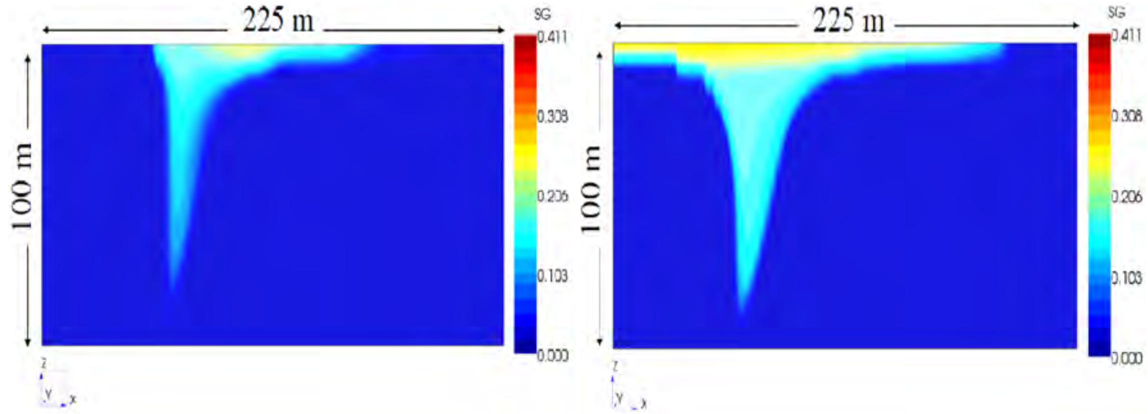


Figure 3-35. Case 3: Extraction after injection at 62 days and 365 days

After 62 days of extraction 60 tons of CO_2 or 5% of initial amount of CO_2 in gas phase after leakage has come out of solution and returned to gas phase. CO_2 exsolves first along the top of the aquifer where the pressure is lowest. CO_2 also exsolves from the region with the highest aqueous concentration on the inner edge of the donut shaped plume. This region has the highest aqueous phase concentration because it experienced the largest increase in pressure from the injection well. After 180 days of extraction CO_2 begins to reach the extraction well and starts being removed from the aquifer. The amount of CO_2 that returns to gas phase continues to increase both along the top of the aquifer and in the main leakage plume. This is clear from the comparison between the gas saturation at 62 days and 365 days shown in Figure 3-35.

Gaseous CO_2 in the main leakage plume is capillary trapped at the residual saturation of 15%. Note that different relative permeability curves may be required to take into consideration the CO_2 returning to gas phase. The impacts of exsolution on capillary trapping and residual saturation is a current research topic and there is little consensus on the overall effects and will not be discussed further here. For these studies, the process is modeled with the same relative permeability curves as the imbibition process because the version of TOUGH2 used for these simulations does not allow for multiple or hysteretic relative permeability curves.

The extraction well also leads to a change in the aqueous phase concentration in the areas where the gas comes out of solution and where it is flowing into the well. The two images in Figure 3-36 show the aqueous phase concentration after 62 days and 365 days of extraction, the same intervals as the gas saturation images in Figure 3-35. The maximum aqueous phase mass fraction remains at 0.0246 over the 365 day period. The area with the maximum concentration decreases to only the bottom 30 m of the main leakage plume. The aqueous phase concentration increases in correspondence with the gas flowing to the well in the top 10 m of the aquifer.

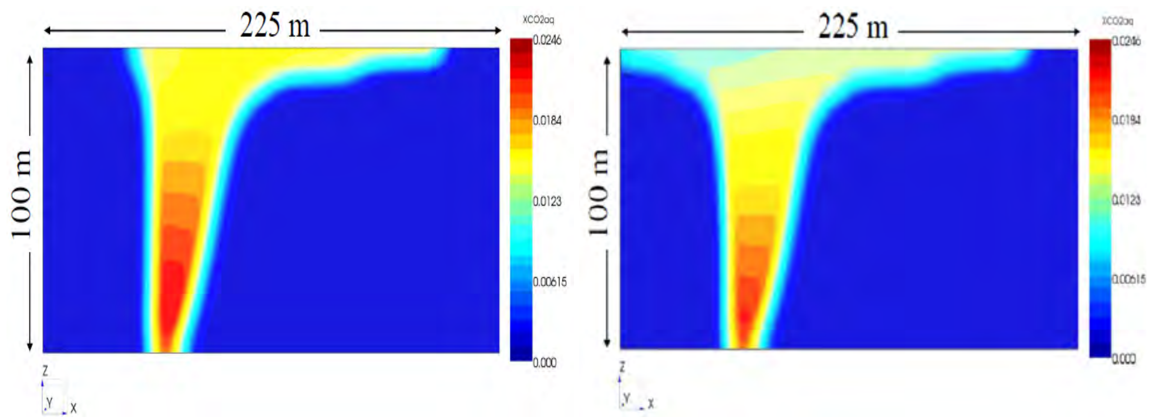


Figure 3-36. Case 3: Aqueous phase concentration after 62 and 365 days of extraction

The pressure drop is the main driver of the decrease in aqueous phase concentration. The pressure at z=50 m after injection and after 365 days of extraction is shown in Figure 3-37. The initial pressure after injection is 2.037 MPa at r=0 m and falls off to 2.029 MPa at r=100m. After extraction the pressure is 1.377 MPa at r=0 m, jumps to 1.403 MPa at r=63 m, and then drops to 1.393 MPa at r=73 m, forming a mound. This is due to exsolution of the CO_2 which drives water out of the pores, leading to a pressure build up in the aqueous phase. Before CO_2 leakage and remediation, the hydrostatic pressure at z=50 m is 1.374 MPa, very close to the final pressure at r=0 m.

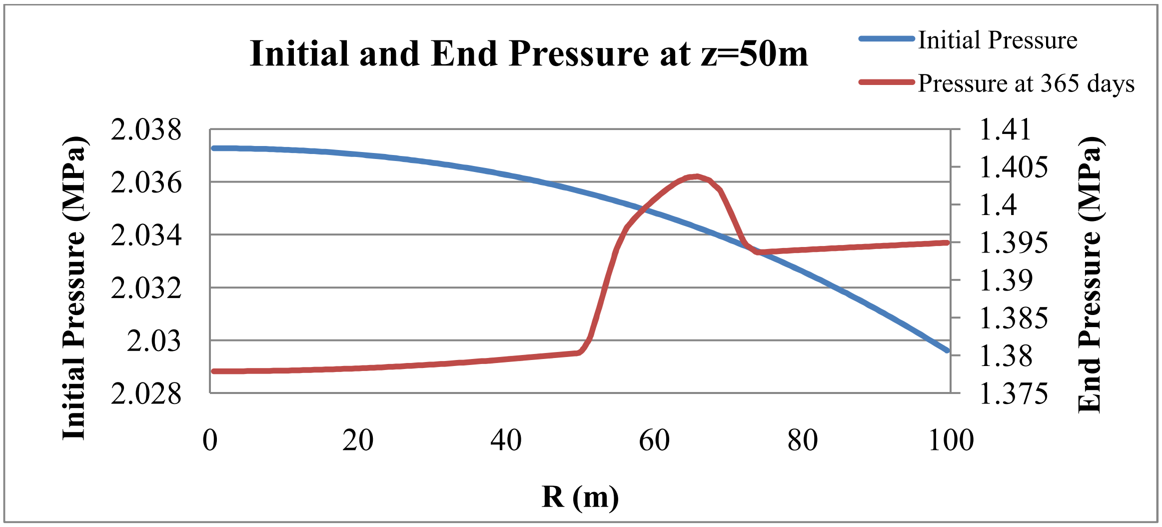


Figure 3-37. Initial and End Pressure at z=50 m

Due to the fact that CO_2 has been displaced 38 m away from the extraction well after injection, the well produces a significant amount of water before producing any CO_2 in either gas or aqueous phase. The flow fraction of gas from the top 5 m of the well is shown in Figure 3-38. The mobile phase CO_2 begins to become the majority of the production after the CO_2 reaches the extraction well at 170 days, climbing to 58% after 365 days. Producing a large amount of gas limits the amount of additional produced water that needs to be handled and leads to efficient CO_2 extraction.

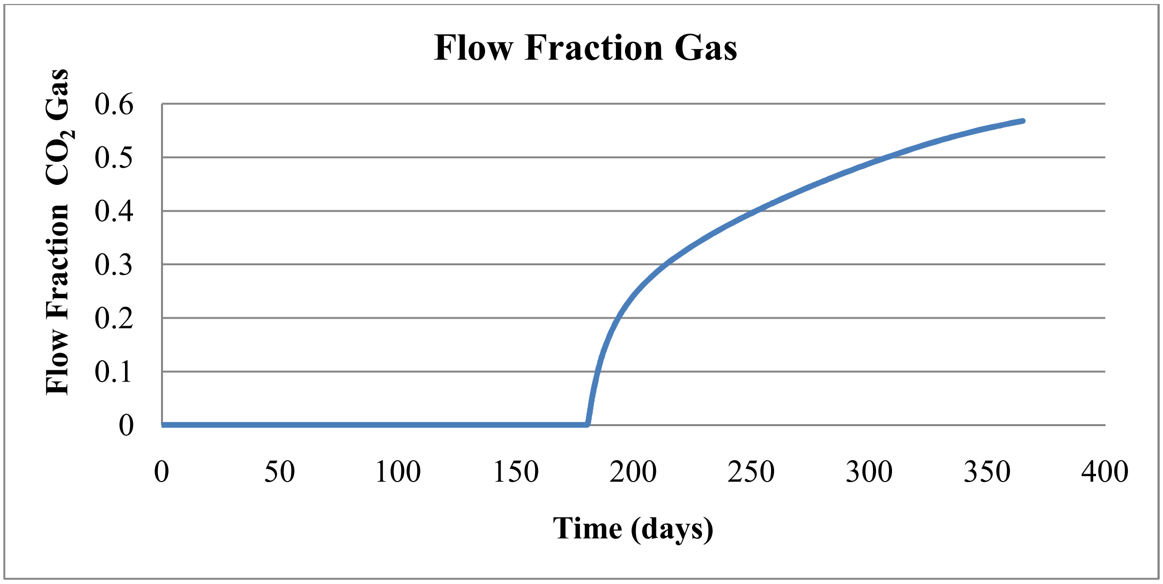


Figure 3-38. Flow Fraction Gas

This simple case with one well used both for injection and then extraction is not very effective at reducing the total amount of CO_2 in the aquifer. The amount of CO_2 remaining in gas phase, aqueous phase, and the total over the entire injection and extraction period is shown in Figure 3-39. The amount of CO_2 that returns to gas phase after one year of extraction is 708 tons. This is less than the initial 1201 tons of CO_2 in gas phase after leakage. The total amount of CO_2 is reduced by 94 tons to 4,906 at the end of the one year period.

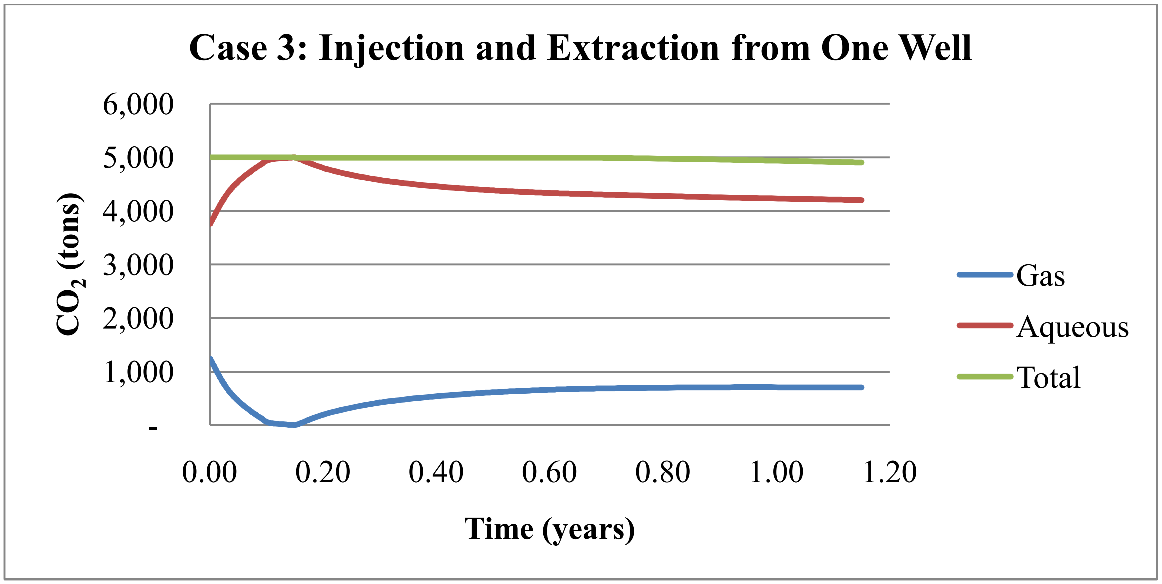


Figure 3-39. Case 3: Injection and Extraction from One Well

Although this simple case is not very effective for remediation of CO_2, it is helpful for understanding the processes that take place with the combination of injection and extraction. Also, it exemplifies the secondary effects that need to be avoided for effective remediation using the combination technique. These secondary effects include the displacement of CO_2 with water injection and the exsolution of CO_2 with the pressure drop. The addition of multiple wells complicates the flow dynamics even further due to the more complex pressure profile.

3.6.3. Injection followed by Extraction from Multiple Wells

The next technique analyzed includes injection from one well followed by extraction from multiple wells that are placed to most effectively remove CO_2 from the aquifer. To analyze a multiple well scenario, the 3D Cartesian grid must be used. Case 4-3D with 10,000 tons of leaked CO_2 and a large gravity tongue is used to analyze the effectiveness of the multiple well scenarios. The first insight from the previous analysis is that although injection does displace the plume it also concentrates the CO_2 into a smaller volume. Figure 3-40 shows the original aqueous phase concentration in the leakage plume and in the leakage plume after an injection of water. The injection well is placed at the x=1000 m and y=1000 m and is screened the entire depth of the aquifer. The injection well flow rate is 15 kg/s of brine and is operated for an 80 day period. The original width of the aqueous phase of the plume after leakage at z=50 m is approximately 400 m, the blue line in Figure 3-40. Then after injection for 80 days the aqueous phase plume increases slightly in width and forms a donut shaped plume, the red line in Figure 3-40.

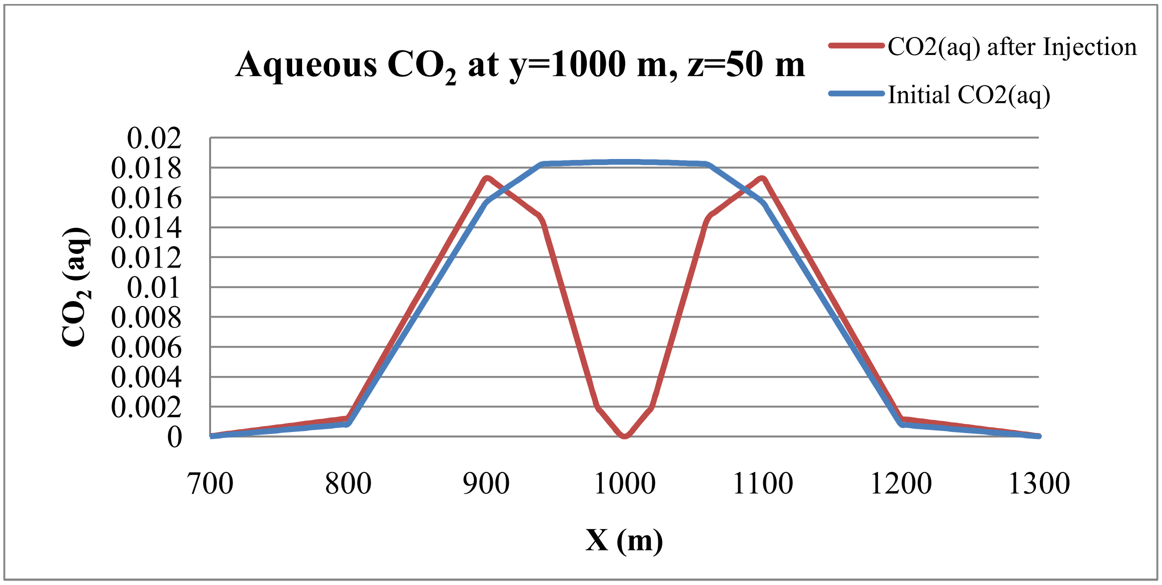


Figure 3-40. Aqueous CO_2 at y=1000 m, z=50 m along the x axis

For simplification we can assume that the plume is a cylinder and ignore the gravity tongue at the top of the aquifer. The initial volume of the aqueous phase if modeled as a cylindrical plume with a diameter of 400 m is 1.257 $x10^7$ m^3. The volume of the donut shaped plume after 80 days of injection with an interior radius of 50 m and an exterior radius of 205 m is 1.242 $x10^7$ m^3, a difference of 1.49 $x10^5$ m^3. Now that the plume is more concentrated in a smaller volume, four extraction wells are added at the interior edge of the donut shaped plume at (x=950, y=1000), (x=1050, y=1000), (x=1000, y=950), and (x=1000, y=1050). The well configuration is shown in Figure 3-41.

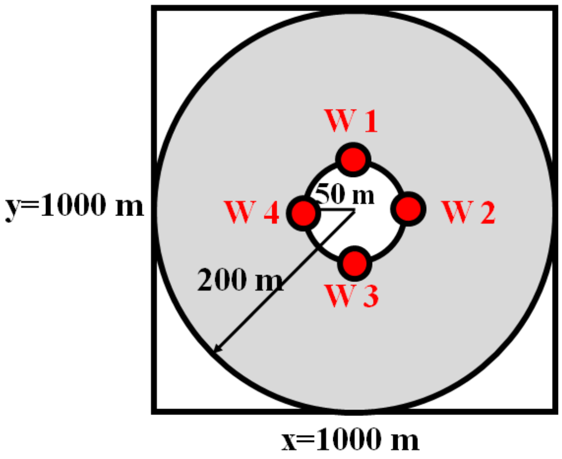


Figure 3-41. Configuration of the Four Extraction Wells

The wells are screened the entire depth of the aquifer and operated with a constant pressure constraint of 0.296 MPa at z=100 m for 15 years. The scenario with four extraction wells operating after water injection is very effective at reducing the total quantity of CO_2 in the aquifer. The gas phase, aqueous phase, and total CO_2 is shown in Figure 3-42. After only 10 years of total operation, only 228 tons of CO_2 remain in the aquifer which is 2.28% of the total leaked.

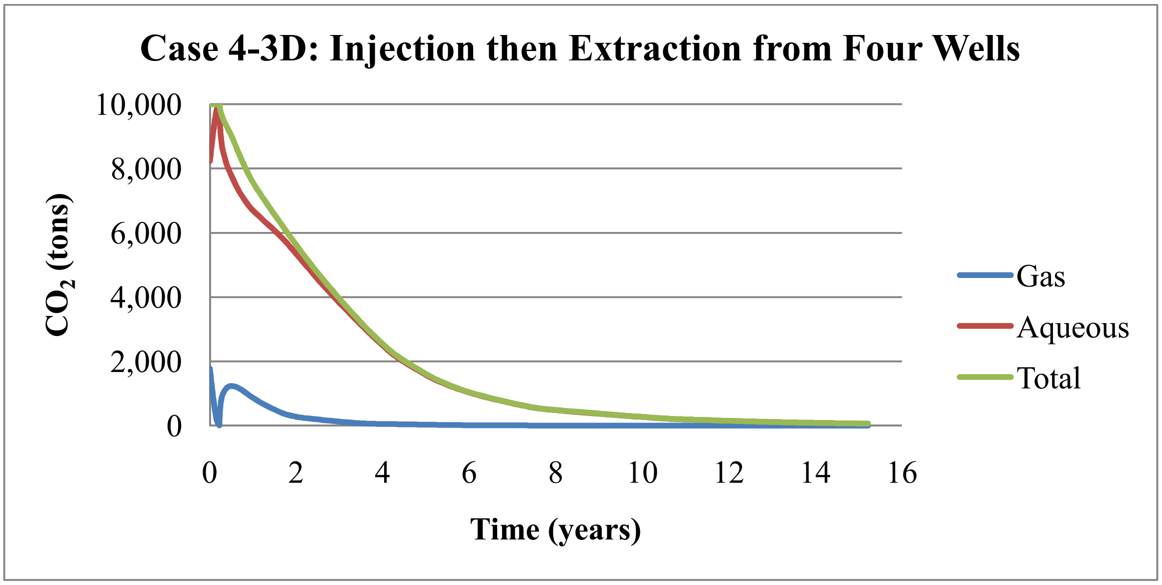


Figure 3-42. Case 4-3D Injection then Extraction from Four Wells

An additional five years of operation only leads to 150 more tons removed. This scenario is much more effective at reducing the total amount of CO_2 than any of the previous scenarios presented for cases with a large gravity tongue. The aqueous phase concentration at z=100 m after injection at the beginning of extraction and after five years of extraction is shown in Figure 3-43.

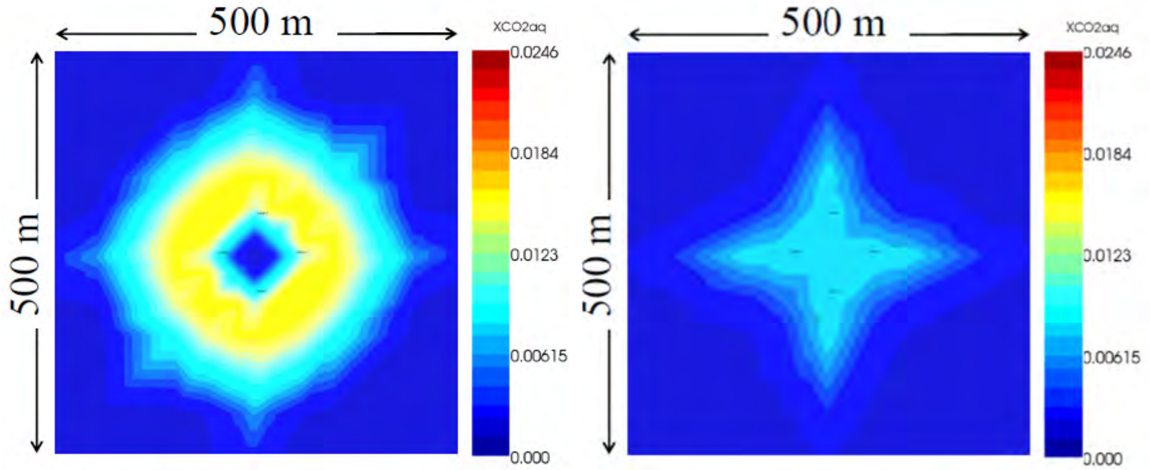


Figure 3-43. Case 4-3D: Aqueous phase after injection for 80 days (left) and after five years of extraction (right) at z=100 m

The donut shaped plume is very evident in the first image with the very low aqueous phase concentration in the center near the injection well. The width of the aqueous phase plume is greatest at the top of the aquifer. The plume is not entirely circular due to the rectangular grid blocks. The second image shows the extent of the reduction in the size and the concentration of the aqueous phase plume. The wells draw the CO_2 back into the center of the plume and extract primarily dissolved CO_2. The star shape is formed partially because the CO_2 that returns to gas phase has the highest saturation near the extraction wells where the pressure is lowest. Water flowing towards the low pressure zone formed by the four wells avoids the areas with high gas saturation and dilutes aqueous concentration in the water between them. The gas saturation at the top of the aquifer after two years and five years of extraction is shown in Figure 3-44. The scale for these images is from SG=0.2 to SG=0.0 to better depict the changes in saturation. From the first image it is clear that the highest gas saturation is at the well location and that the water is bypassing these zones. The star shape is also due to grid effects.

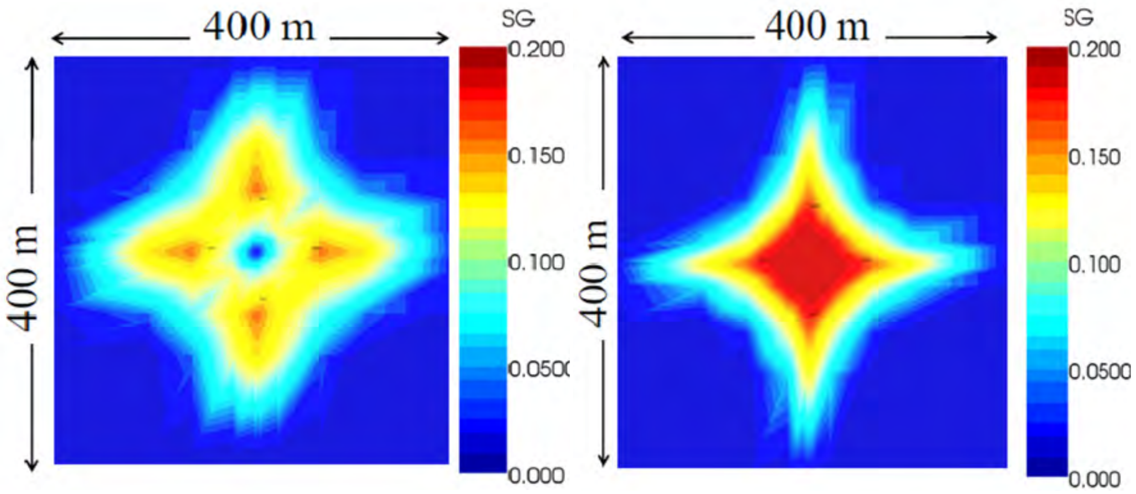


Figure 3-44. Case 4-3D: Gas phase after two years and five years of extraction at z=100 m

The 80 days of water injection is done as an emergency technique and has little overall benefit on CO_2 removal. Another case that was analyzed included the same four extraction wells operating without previous injection. With this case 100 more tons of CO_2 remains in the aquifer after 15 years of remediation. Also, the amount of CO_2 in gas phase is slightly larger by 40 tons throughout the entire remediation period. If the long term remediation plan is defined immediately after leakage is stopped, then the additional cost of the injection well may be unnecessary. Water injection may still be beneficial to allow time to characterize the leak and formulate the remediation technique. Without water injection, after the leak is stopped the CO_2 will rise to the top of the aquifer, increasing the size of the large gravity tongue and hindering later extraction.

3.6.4. Injection and Extraction Concurrently from Multiple Wells

The final combination method is simultaneous injection and extraction using multiple wells. The injection wells maintain the high pressure to keep the CO_2 in solution and flowing into the wells. This configuration of wells with continuous injection and extraction is known as a five spot well pattern (Hurst, 1951). For this case, the extraction well is at the center of the leakage plume and the injectors are around the outer boundaries and operate continuously. Multiple injection well flow rates and two different distances from the extraction well were analyzed for Case 4-3D (10,000 tons) to determine the optimal scenario.

The extraction well in all scenarios is screened from z=10 to z=100 m and has a constant pressure constraint of 0.198 MPa (10 m hydraulic head) at z=100 m. The partial well screening of the extraction well reduces the bypass of the main leakage plume from water flowing into the base of the well. The injection wells are screened over the entire thickness of the aquifer. The three injection well flow rates analyzed are 5 kg/s, 2.5 kg/s, and 1 kg/s. The wells are either 200 m apart (D_w=200 m) or 300 m apart (D_w=300 m), with the center at x=1000 m, y=1000 m. The two separate well configurations are shown in Figure 3-45.

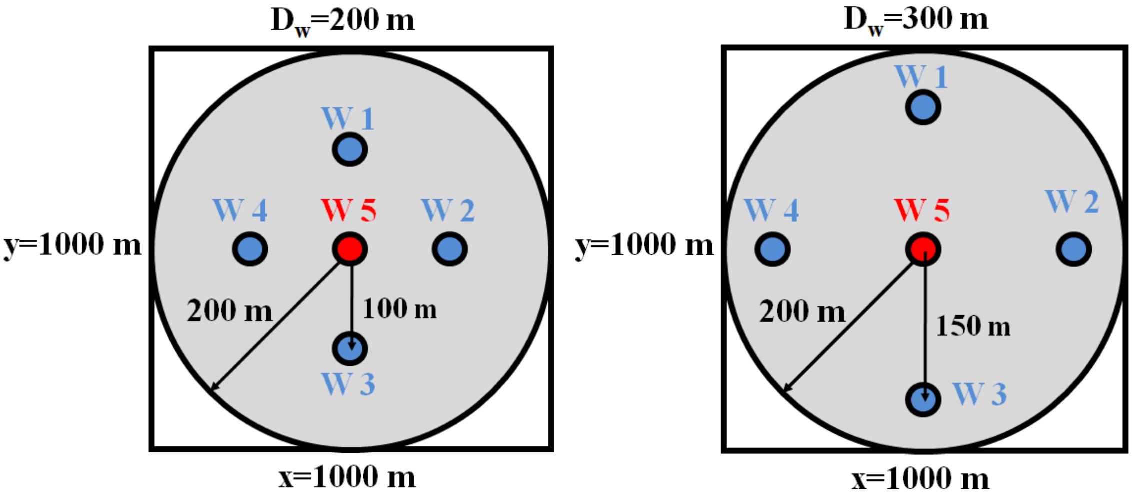


Figure 3-45. Well Spacing: D_w=200 m and D_w=300 m

Table 3-2 lists the type, x location, y location for all five wells for both D_w=200 m and D_w=300 m.

Table 3-2. Five Spot Well Spacing

D_w=200 m	**W1**	**W2**	**W3**	**W4**	**W5**
Type	Injector	Injector	Injector	Injector	Producer
X	1000 m	1100 m	1000 m	900 m	1000 m
Y	1100 m	1000 m	900 m	1000 m	1000 m
D_w=300 m	**W1**	**W2**	**W3**	**W4**	**W5**
Type	Injector	Injector	Injector	Injector	Producer
X	1000 m	1150 m	1000 m	850 m	1000 m
Y	1150 m	1000 m	850 m	1000 m	1000 m

The first spacing analyzed is with the wells closer together forming a square with a width of 200 m (D_w=200 m). The total removed for the three different flow rates of 5 kg/s, 2.5 kg/s, and 1 kg/s at a D_w=200 m is shown in Figure 3-46.

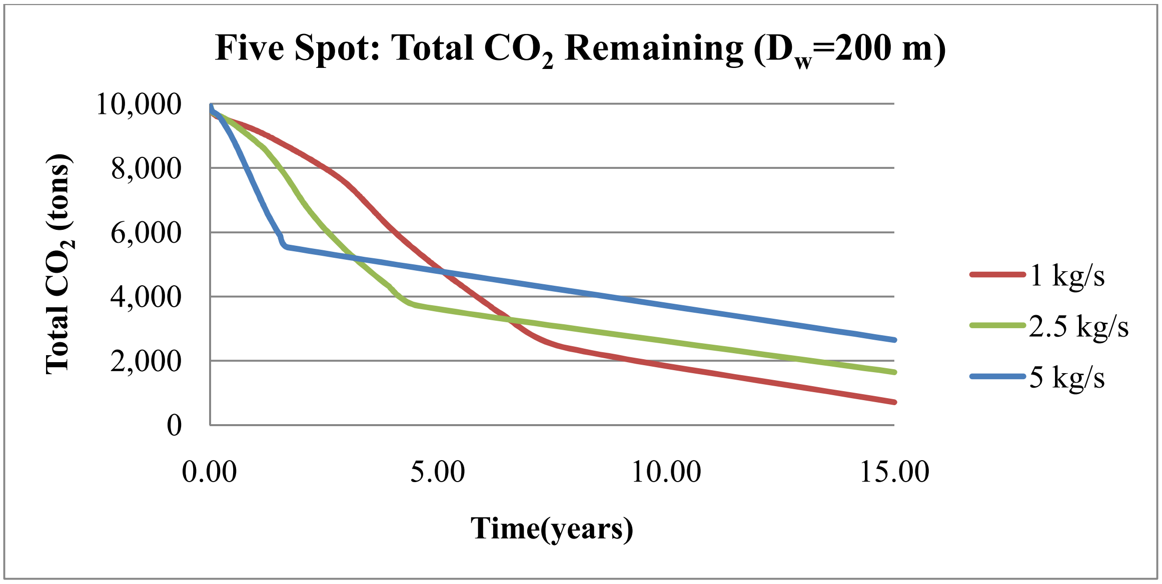


Figure 3-46. Five Spot: Total CO_2 Remaining (D_w=200 m)

It is clear that the lower injection rate leads to a more effective recovery of CO_2 from the aquifer. The total remaining after 15 years with a flow rate of 5 kg/s is 2,650 tons of CO_2 for a total reduction of 73.5%. This is less effective than one horizontal extraction well at z=50 m that reduced the CO_2 to 2,290 tons over 15 years. With half as much flow into the injection wells, at a flow rate of 2.5 kg/s, the total remaining is 1,650 tons, 1,000 tons less than with the higher flow rate. Reducing the injection rate to only 1 kg/s leads to the most effective removal with only 716 tons remaining after 15 years. Based on fitting a line to these three points, each 1 kg/s reduction in flow rate for each well leads to an additional 475 tons of CO_2 removed over the 15 year period. Also, a lower flow rate requires less total water injected, with only 1.89 Mt of water for 1 kg/s compared with 9.46 Mt of water for 5 kg/s.

The opposite correlation may have been more expected where the higher flow rate leads to the greater removal. More closely analyzing the total remaining at each time can provide insight to why this result is found. The flow rate of CO_2 removal can be divided into three sections. The initial flow rate is around 1000 tons/year for all cases. This flow rate lasts for 0.05 years with 5 kg/s, 0.86 years with 2.5 kg/s, and 2.14 years for 1 kg/s. The length of time that this flow rate occurs corresponds well with the period when the gas phase CO_2 is most rapidly being reduced. Figure 3-47 shows the gaseous CO_2 remaining over the 15 year remediation period.

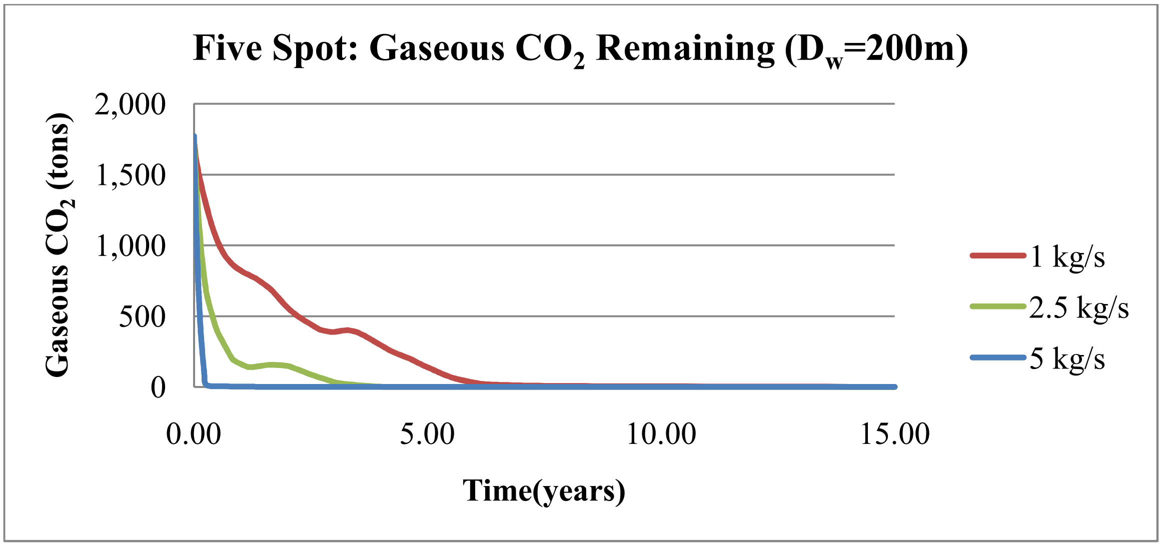


Figure 3-47. Five Spot: Gaseous CO_2 Remaining (D_w=200 m)

The gas phase is reduced both from dissolution into the injected water and from removal with the extraction well. The fraction that dissolves of the total reduction that takes place immediately after injection starts is 71% with 5 kg/s, 49% with 2.5 kg/s, and 25% with 1 kg/s. It is less effective to dissolve the CO_2 than to extract it in gas phase over a longer time period at this spacing. The second flow rate of CO_2 removal is 2,600 tons/year for 5 kg/s, 1,620 tons/year for 2.5 kg/s, and 1,220 tons/year for 1 kg/s. This second slope lasts longest for the lowest flow rate of 1 kg/s. The final CO_2 removal flow rate for all cases is approximately 220 tons/year.

The second well spacing analyzed is shown on the right in Figure 3-45 where the wells form a square that is 300 m wide (D_w=300 m). The total CO_2 remaining over the 15 years of remediation is shown in Figure 3-48 for the three different flow rates of 5 kg/s, 2.5 kg/s, and 1 kg/s. With the injection wells 50 m farther away from the extraction well at the center of leakage plume, the higher flow rate leads to more CO_2 removed over the 15 year time frame. However, the difference in the amount remaining for the three flow rates over the 15 years is very small with 730 tons for 1 kg/s, 657 tons for 2.5 kg/s, and 620 tons for 5 kg/s. The effectiveness of the remediation is higher for the flow rates of 2.5 kg/s and 5 kg/s and slightly worse for 1 kg/s with the larger well spacing.

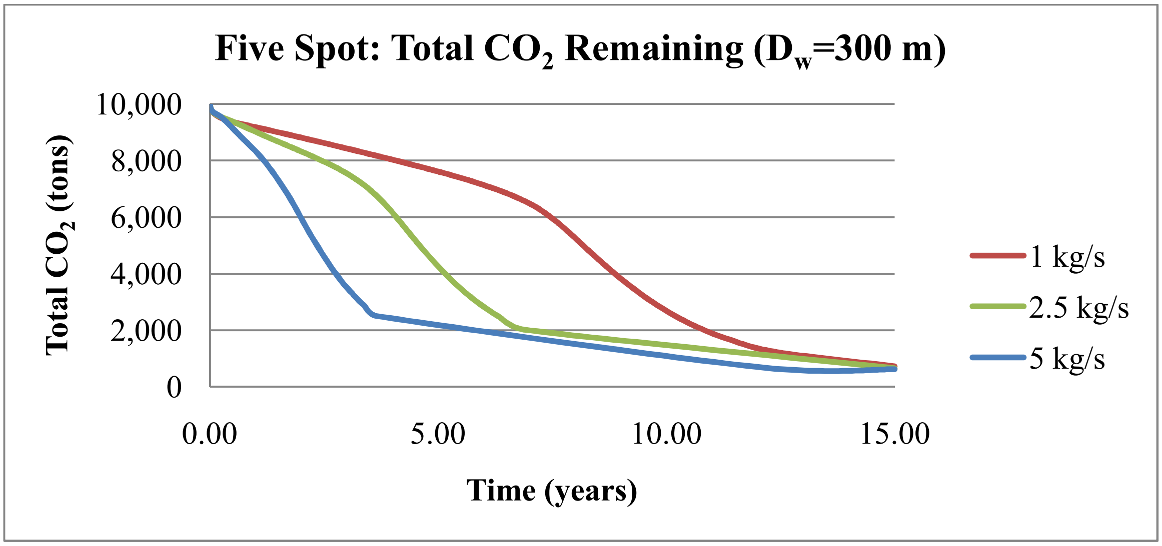


Figure 3-48. Five Spot: Total CO_2 Remaining (D_w=300 m)

The larger well spacing creates a shallower pressure gradient between the injection wells and the extraction well, allowing for more CO_2 to be in gas phase. Also, the injected water has to move through more of the leakage plume before it reaches the extraction well. This allows it to dissolve more CO_2 than with the smaller well spacing. The second flow rate of CO_2 removal for the flow rates at a closer spacing is very similar to the second flow rate with the larger spacing, but the time when it begins and ends is very different. The high CO_2 removal rate of approximately 2,600 tons/year with a flow rate of 5 kg/s lasts for 3.4 years instead of 1.5 years with the closer spacing. With the flow rate of 5 kg/s, 71% of the CO_2 is removed in the first 3.4 years which is very effective. The CO_2 removal rate drops to 200 tons/year after 3.4 years. Based on the comparison between the two well spacing distances, the larger spacing should be chosen with the high flow rate of 5 kg/s if rapid CO_2 removal is the most important. The closer well spacing with the lowest flow rate should be chosen if extracting 9.46 Mt of water from the aquifer for use with the higher flow rate is expensive and difficult. The difference between smaller spacing with low flow rate and the larger spacing with high flow rate after 15 years is only an additional 96 tons of CO_2 remaining.

Chapter 4

4.Sensitivity Analysis

It is important to look at other factors that may influence CO_2 leakage plumes as well as the effectiveness of the various remediation techniques. The first sensitivity analysis studies the impact of one form of aquifer heterogeneity, low permeability layers, in the groundwater aquifer on CO_2 leakage and remediation. Heterogeneous layers in sedimentary rocks are common in the subsurface and are formed due to variations in the grain size of the sediments and the processes that led to their deposition. Low permeable rocks include sands and silts with moderate to high clay contents.

The second sensitivity analysis studies the effects on the remediation effectiveness if the leaking well is not plugged and continues to leak during remediation. If the leak continues to flow, the well will need to remove more CO_2 than the amount leaking to reduce the amount of CO_2 in the aquifer. Also, water injection may not be as effective because water will need to be continually injected to dissolve the leaking CO_2 until the leak is plugged. There are many techniques available to plug abandoned wells, but they are expensive and may not be completely successful at stopping the flow of CO_2 on the first attempt. To effectively plug the leak the exact location of the leakage will need to be determined which may be difficult to do initially after the leak is observed. For these reasons there is a possibility that the leak will continue for some time even after it is detected.

These two different sensitivity analyses provide two separate types of information that may affect the formulation of the remediation scenario. First, heterogeneous low permeability layers may influence the locations and type of wells chosen, but cannot be controlled for by the entity overseeing the remediation. However, allowing the abandoned well to continue to leak for an extended period of time may be allowable if it does not significantly hinder the remediation of the CO_2 leakage plume. This result may provide more flexibility when designing the remediation scenario immediately after the leak is observed. It is very unlikely that the leak will be allowed to continue indefinitely.

4.1. Heterogeneous Layered Cases

The first sensitivity analysis studies the impacts of low permeable layers in the groundwater aquifer. A simplified layered system was modeled to provide some insight into the effects of heterogeneity. For the homogeneous cases analyzed previously the entire groundwater aquifer had a relative permeability of 100 md in the horizontal direction and 10 md in the vertical direction. The anisotropic permeability ratio of kh/kv=10 was preserved in the heterogeneous layered model.

The heterogeneous layered model uses a 2D radial axisymmetric grid. The thickness of the grid blocks alternates between 3 m for the low permeability layers and 7 m for the main aquifer. The permeability values of the three layers are (kr=8 md, kz=0.8 md), (kr=50 md, kz=5 md), and (kr=200 md, kz= 20 md). There are 10 layers corresponding to 70 m of aquifer with kr=200 md, 5 layers corresponding to 15 m of aquifer for kr=8 md, and 5 layers corresponding to 15 m of aquifer with kr=50 md. The arithmetic mean permeability is kr=148.7 md in the horizontal direction. The harmonic mean permeability in the vertical direction is kz=3.96 md . Figure 4-1 depicts the 2D heterogeneous model with dark gray for kr=8 md, green for kr=50 md, and light gray for kr=200 md.

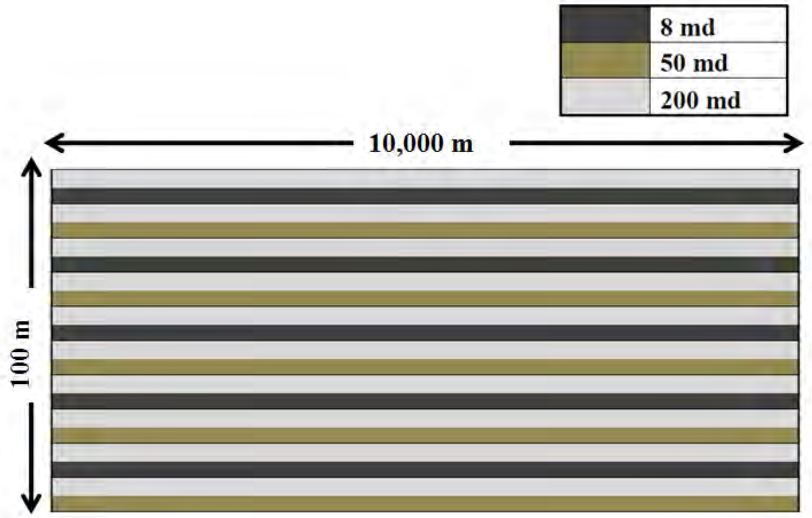


Figure 4-1. Heterogeneous Layered 2D Model

All the other reservoir parameters and initial conditions are the same as the homogeneous case with 15% porosity, a NaCl mass fraction of 0.01, an initial hydrostatic pressure gradient, and a temperature gradient from 23°C to 26°C. Figure 4-2 shows the CO_2 leakage plumes for the five leakage cases after five years of leakage.

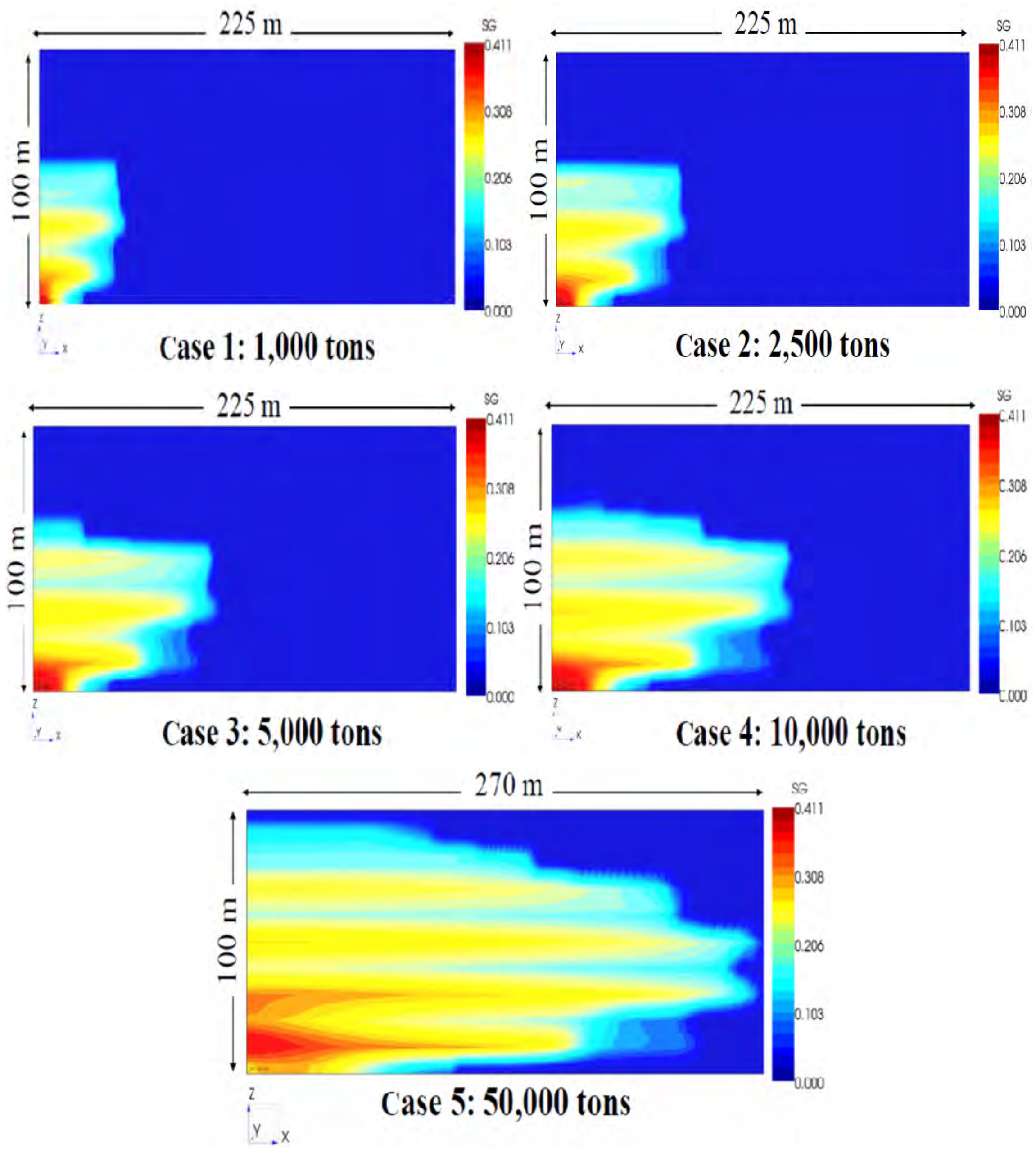


Figure 4-2. Heterogeneous Layered Leakage Cases

The heterogeneous model is simplified because it does not have separate capillary pressure curves for the three layers with different absolute permeability. If they did have different capillary pressure curves the effect of heterogeneity is likely to be greater than for the cases studied here. The leakage plumes after five years of leakage at the same leakage rate look significantly different from the homogeneous model cases. Even for the largest leakage rate of 10,000 tons/year, the CO_2 has not reached the top of the groundwater aquifer after five years. For a leakage rate of 10,000 tons/year with the homogeneous model, a gravity tongue at the top of the aquifer with a radius of 425 m had formed after five years of leakage. Instead of accumulating at the top, the gas phase CO_2 accumulates below each layer with the lowest vertical permeability of kz=0.8 md. It permeates first through this low permeability layer directly above the leakage zone at r=0 m. As the leakage rate increases the height of the plume and the width of the plume also increase. However, the width of the plume does not increase linearly with the leakage rate as was shown with the homogeneous cases. The larger the width of the plume, the longer it takes to remove CO_2 that is farther away from the extraction well.

The gas saturation at the base of the aquifer is higher for all of the leakage cases with the heterogeneous low permeability layers. The gas saturation along the depth of the aquifer after five years of leakage at r=0 m is shown in Figure 4-3 with z=0 m corresponding to the base of the aquifer.

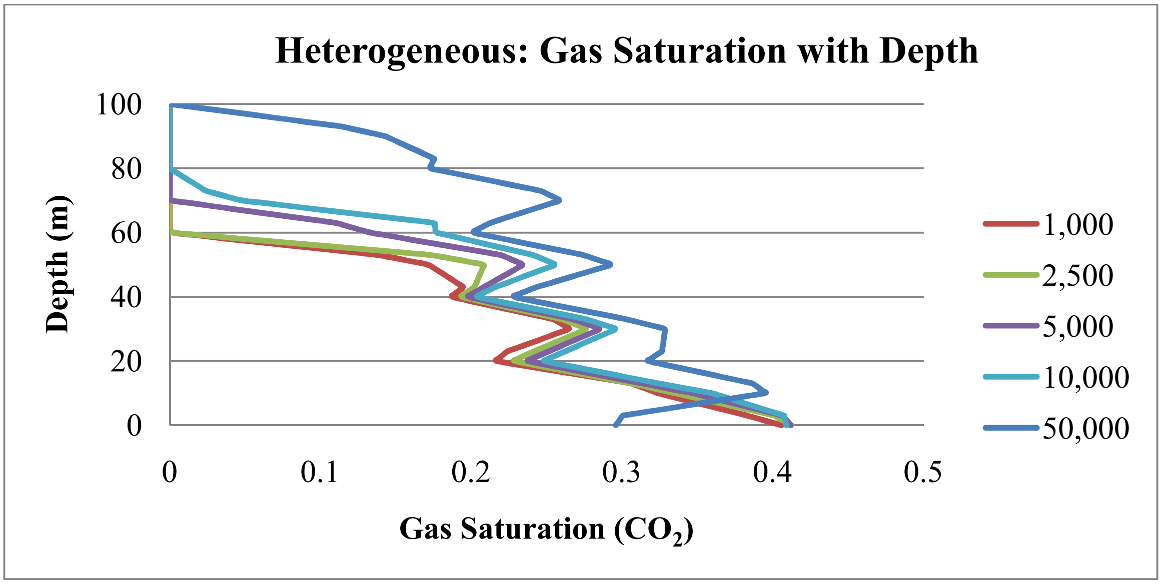


Figure 4-3. Heterogeneous Cases: Gas Saturation with Depth at r=0

The CO_2 gas saturation in the bottom 3 m of the aquifer is the same for Case 1 (1,000 tons) through Case 4 (10,000 tons) at SG= 0.41. For Case 5, the highest gas saturation is slightly higher in the aquifer between z=8 m and z=12 m. It is very interesting that the gas saturation along the lower 40 m of the aquifer is the same for Case 1 through Case 4. The height of the gas plume is the same for Case 1 (1,000 tons) and Case 2 (2,500 tons) at 60 m, but begins to increase for Case 3 (5,000 tons) to 70 m and for Case 4 (10,000 tons) to 80 m. The peaks in the gas saturation seen along the depth occur at the top of each high permeability zone with kz=20 md immediately before the layer with kz=0.8 md begins. The high variation in the gas saturation along the depth may complicate the remediation process. For the homogeneous case the highest gas saturations were only immediately above the leakage zone and in the secondary accumulation plume at the top.

The aqueous phase concentration along the depth of the aquifer shows much less variation as compared with the gas saturation as shown in Figure 4-4. The maximum aqueous phase mass fraction of 0.0246 seen for Case 1 through Case 4 is the same as with the homogeneous model. However, in the bottom 10 m of the aquifer for Case 5 (50,000 tons) the aqueous phase mass fraction peaks at 0.039. This high mass fraction is due to the large pressure buildup from leaking 10,000 tons/year into a layer with kz=5 md. The pressure decreases slightly with height leading to the decrease in aqueous concentration.

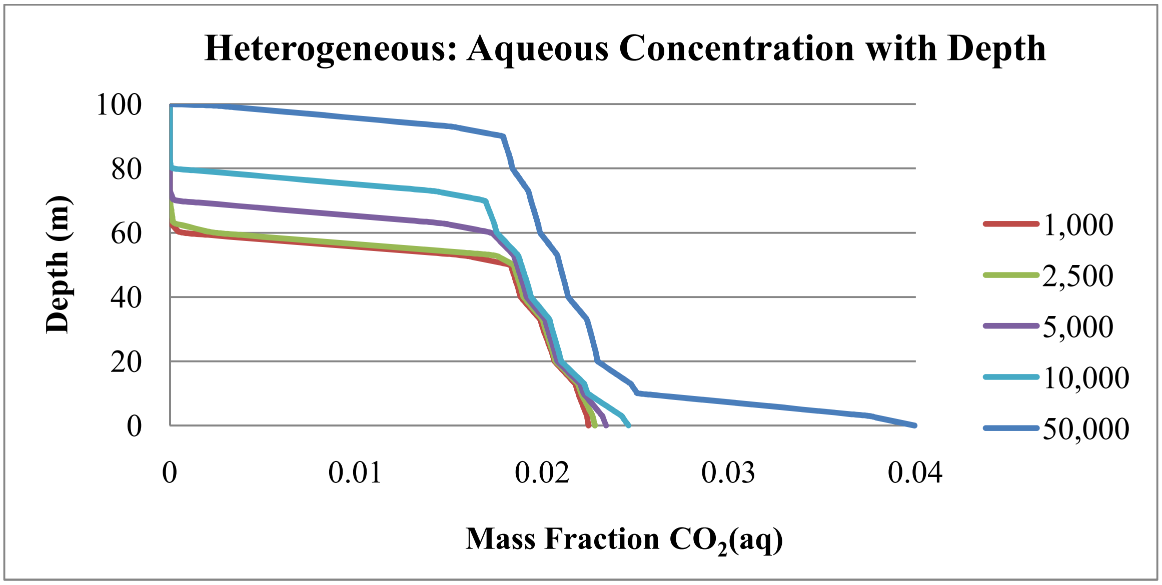


Figure 4-4. Heterogeneous Cases: Aqueous Concentration with Depth at r=0

The final comparison between the homogeneous and heterogeneous leakage cases is the total amount of CO_2 in gas phase and aqueous phase at the end of five years of leakage. Figure 4-5 plots the gas phase CO_2 and the aqueous phase CO_2 compared with the total amount that has leaked. The circles mark the five leakage cases for both heterogeneous and homogeneous. With the heterogeneous model as shown by the purple and green line, more CO_2 is in aqueous phase and less in gas phase. The difference increases with more CO_2 leakage and is greatest for Case 5 (50,000 tons) with 37,344 tons of CO_2 in aqueous phase with the heterogeneous model compared with 35,565 tons of CO_2 with the homogeneous model. Overall these differences are a very small fraction of the total dissolved.

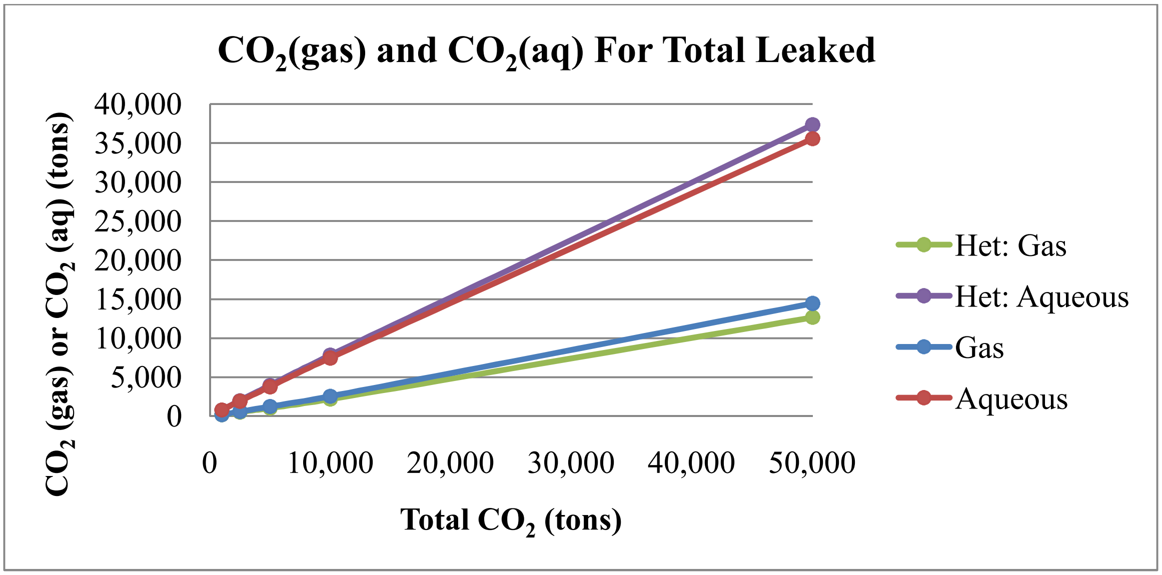


Figure 4-5. CO_2(gas) and CO_2(aq) vs. Total Leaked

The effects from the leakage of CO_2 on the groundwater aquifer are reduced when low permeability layers are present primarily because the extent of the plume is less. This leads to a smaller amount of water that is contaminated by the CO_2 or by any of the secondary contaminants such as trace metals. From the remediation analysis with the homogeneous model it is evident that the gas phase is reduced most quickly from the aquifer with an extraction well. With more CO_2 in aqueous phase the remediation may be more difficult and may lead to more produced water with dissolved CO_2. However, because the width of the plume is less with the heterogeneous layers extraction may be more effective over a shorter time period.

4.1.1. Heterogeneous Layered Case Remediation

The next step of the sensitivity analysis is to compare the effectiveness of CO_2 leakage remediation techniques between the heterogeneous layered cases and the homogeneous cases. The technique of one vertical extraction well is used to compare the two models that both use the 2D radial axisymmetric grid. The screening of the vertical extraction well is the main difference between the two techniques and is due to the significantly shorter heterogeneous leakage plumes.

The first comparison is for Case 1 with the smallest total leakage of 1,000 tons of CO_2 between the heterogeneous permeability and homogeneous permeability. The extraction well added is operated with a constant pressure constraint of 0.296 MPa similar to the homogeneous case and is screened from the base of the aquifer at z=0 m to z=40 m. The well screening height of 40 m is where the highest mobile phase CO_2 is present for Case 1 with the heterogeneous permeability. Case 1 with the heterogeneous permeability is compared with the homogeneous permeability for Case 1 with a partially screened vertical extraction well screened from the base of the aquifer at z=10 to the top of the aquifer at z=100 m. Figure 4-6 shows the comparison of the extraction rates for the homogeneous and heterogeneous cases over a 3.5 year operation period. The extraction well is slightly more effective with the homogeneous Case 1 than with the heterogeneous Case 1 at reducing the total CO_2 in the aquifer. The difference between the two cases becomes larger after three years. With the heterogeneous permeability 200 more tons of CO_2 remains in the aquifer after 3.5 years of extraction. The main reason behind the difference is that it is very difficult to remove the CO_2 that is trapped in the low permeability layers. These low permeability layers account for 12 m of the 40 m of the screened well. Screening the well over a larger depth does not improve the effectiveness because the CO_2 between 40 m and 60 m is removed effectively by the well screened to 40 m.

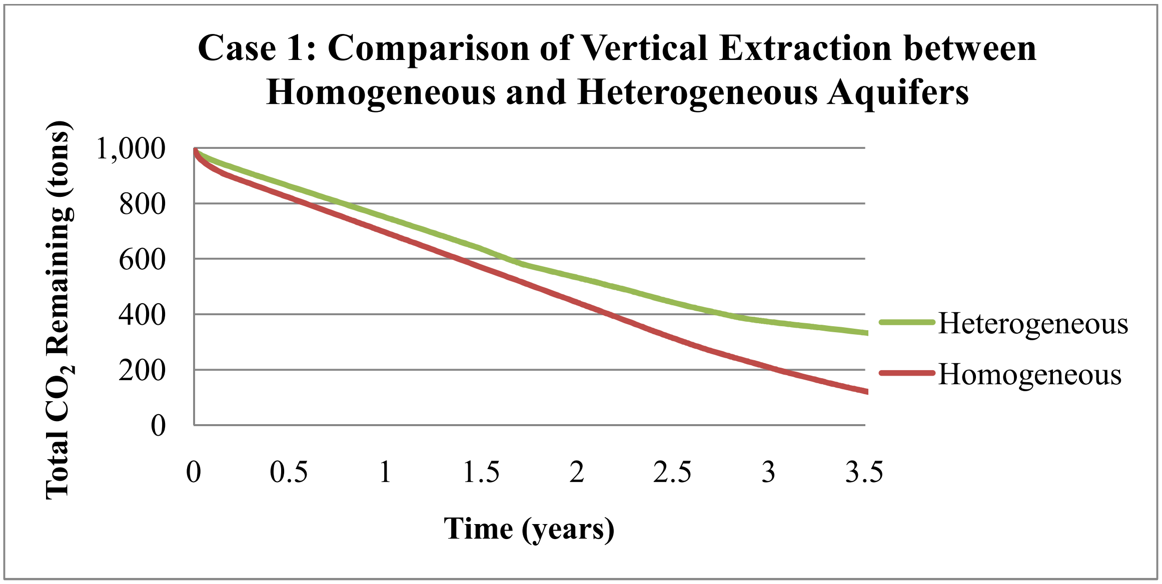


Figure 4-6. Case 1: Comparison of Vertical Extraction between Homogeneous and Heterogeneous Aquifers

The second comparison is between the homogeneous and heterogeneous aquifers for Case 3 (5,000 tons) with multistep extraction well screenings. The difference between the leakage plumes with the homogeneous and heterogeneous aquifers for Case 3 is greater compared with Case 1. For the homogeneous aquifer for 5,000 tons of leakage a gravity tongue has formed with a radius of 180 m. The largest radius of the leakage plume for heterogeneous aquifer for Case 3 at z=50 m is only 98 m, about half of the distance for the homogeneous aquifer for Case 3.

The first step of the multistep extraction is a well screened from z=0 m to z=70 m. The well is operated with a constant pressure constraint of 0.296 MPa for a period of three years. After this time, the well is screened from z=0 m to z=50 m because there is no CO_2 remaining above 50 m after three years of extraction. The well is operated with the shortened screening for five more years with a constant pressure constraint of 0.296 MPa. The three step process for the homogeneous case starts off with a well screened from z=40 m to z=90 m for three years, then from z=95 m to z=100 m for 325 days, and finishes with a well screened from z=0 m to z=100 m for five years all with a pressure constraint of 0.296 MPa. Figure 4-7 compares the extraction over the eight year period between the heterogeneous and homogeneous aquifers with the two different multistep well screening scenarios. Based on this comparison it is easier to remove CO_2 from the heterogeneous reservoir compared to the homogeneous reservoir.

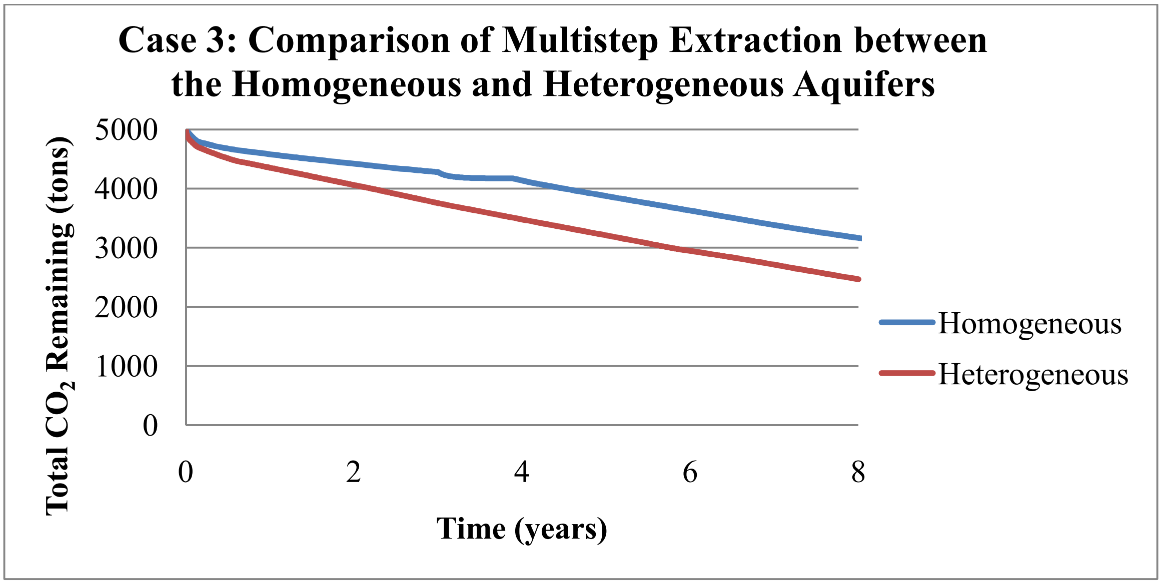


Figure 4-7. Case 3: Comparison of Multistep Extraction between Heterogeneous and Homogeneous Aquifers

This is opposite to the result found for the smaller leakage rates, where it was more difficult to remove CO_2 from the heterogeneous aquifer. The main reason for the difference in performance between the two extraction scenarios for 5,000 tons of leakage is due to the difference in the width of the plume as mentioned previously. The gas saturation in the plume after three years of operation with the first well screening depth of 70 m is shown in the first image in Figure 4-8. All the mobile phase CO_2 has been removed and the gas saturation is consistent at the residual saturation. The second image in Figure 4-8 shows the gas saturation after five more years of extraction with the second well screening depth of 50 m. The width of the plume at the largest point is still 98 m but the height of the plume has decreased along the entire width. The plume is bypassed by water flowing into the lower high permeable layer between 3 m and 10 m, but not to the same extent as was seen with the homogeneous reservoir.

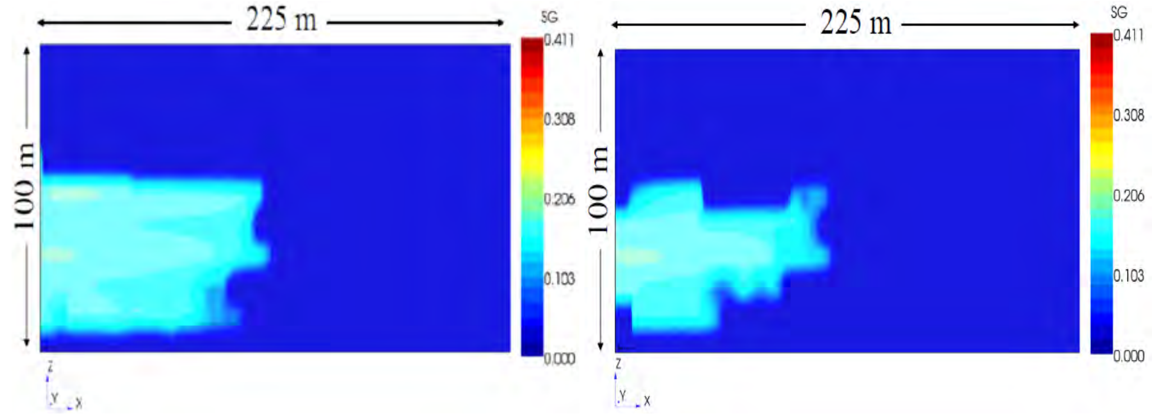


Figure 4-8 Case 3 Heterogeneous Aquifer: Two Step Extraction at 3 yrs and 8 yrs

The final analysis looks at remediation effectiveness for Case 5 (50,000 tons) between the heterogeneous and homogeneous model. The plume with 50,000 tons of leakage and the homogeneous permeability has a gravity tongue with a radius of 425 m and very high gas saturation. The greatest width of the leakage plume for Case 5 with the heterogeneous aquifer is 270 m at z=50 m. The high gas saturation is at the base of the aquifer close to the leakage zone. The extraction method for Case 5 with the homogeneous model includes a well that is screened from z=50 m to z=100 m with a constant pressure constraint of 0.296 MPa. This well screening limits the water bypass that is very pronounced with such a large gravity tongue. The Case 5 extraction process with the heterogeneous aquifer includes a well that is screened from z=3 m to z=10 m to remove the highly mobile gas in this zone with a constant pressure constraint of 0.596 MPa (50 m of hydraulic head). The second part of the well is screened from z=23 m to z=80 m with a pressure constraint of 0.296 MPa. The difference in pressure between the two wells is less than if the well was flowing only water. The smaller increase in pressure between the two wells is because almost 60% of the production from the well is gas phase CO_2 with a very low density of approximately 30 kg/m^3. The pressure constraint at the top of the bottom section of the well is only 42.8% of the hydrostatic pressure increase between z=80 m and z=10 m. This corresponds to approximately 40% of volume of the fluid above the bottom section of well in water and 60% of the volume in CO_2 gas.

Figure 4-9 shows the amount of CO_2 remaining over two years of operation for the homogeneous and heterogeneous aquifer for Case 5. The removal rate is very high for both wells, but the well performs better for the heterogeneous case with removal of 3,555 tons/year compared with only 3,355 tons/year with the homogeneous model. If the flow rate observed over the two years continues, then it will take 14 years to remove all of the CO_2 from the heterogeneous reservoir compared with 15 from the homogeneous reservoir. The difference in flow rate between the two cases decreases over time. This is because more of the CO_2 that remains in the aquifer is either capillary trapped or in aqueous phase far away from the extraction well for both the heterogeneous and homogeneous reservoirs.

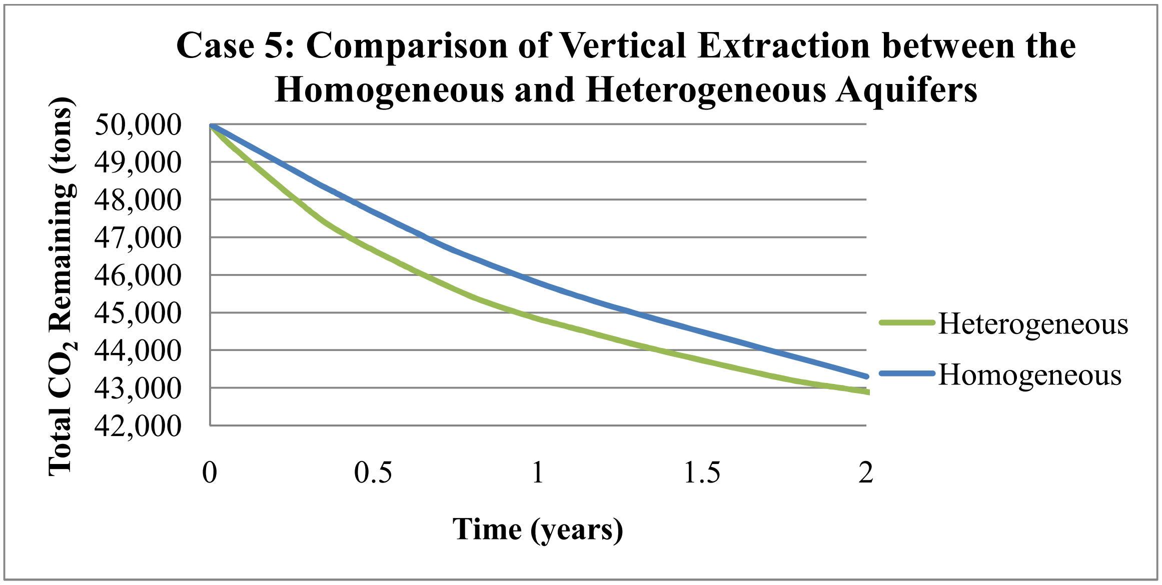


Figure 4-9. Case 5: Comparison of Vertical Extraction between the Homogeneous and Heterogeneous Aquifers

After two years of extraction some mobile CO_2 remains in the plume in the top 30 m as seen in Figure 4-10. However, the majority of the plume is at the residual gas saturation. At the base of the aquifer where the gas saturation was very high after leakage stopped, there remains very little gas phase CO_2. This CO_2 flows rapidly into the bottom section of the well. After producing primarily gas, the bottom section of the well is producing primarily water with aqueous phase CO_2. The second image in Figure 4-10 shows the aqueous phase concentration after two years of extraction. The aqueous phase concentration is highest at the base of the aquifer where the pressure is greatest. Aqueous phase CO_2 remains where the gas has been extracted near the lower screening of the well and in the top 10 m of the aquifer. The aqueous phase CO_2 is very low near the upper section of the well due to the lower pressure in the well. To remove the remaining aqueous phase CO_2 a significant amount of water will need to be produced. For example, if the CO_2 removal continues at the most efficient rate at the highest aqueous phase mass fraction of 0.0246, then to remove the remaining 42,890 tons of CO_2 1.743 million tons of water will be produced.

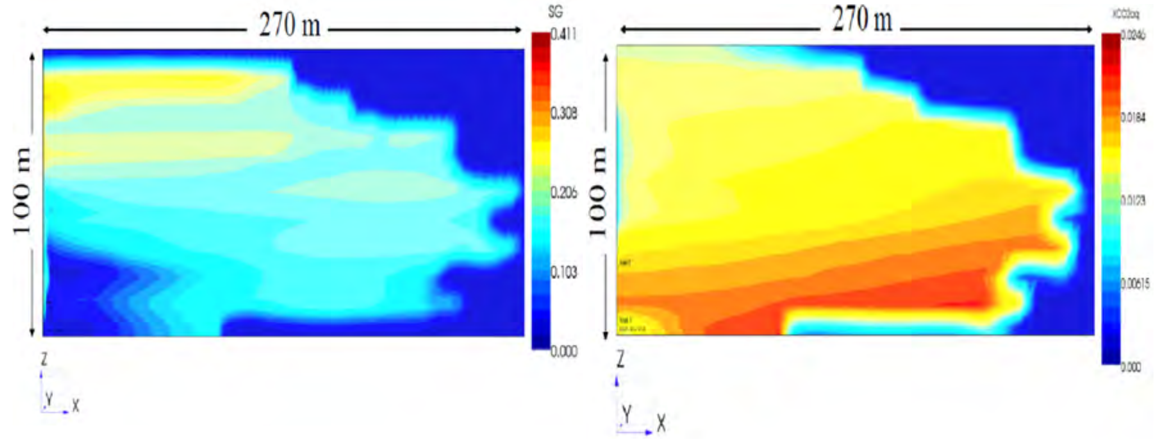


Figure 4-10. Case 5-Het: Gas and Aqueous Phase with Zw=70 m after 2 years

Based on the comparison between the three cases with both a homogeneous and heterogeneous permeability, low permeable layers ease the removal of CO_2 for the larger leakage cases. However, even if low permeable layers are present in the groundwater aquifer, the remediation still will take a long period of time and large amounts of water will be coproduced.

4.2. Leak Continues During Remediation

The second sensitivity analysis studies the impacts of allowing the leak to continue to flow during remediation. As previously mentioned there are many possible reasons why the leak may not be plugged immediately after detection. Allowing the leak to continue unabated will lead to large gravity tongues even for small leaks such as 200 tons/year for Case 1. Figure 2-6 shows that allowing the leak of 200 tons/year to continue unabated for 12.5 years the radius of the gravity tongue increases from 50 m to 300 m.

Case 1 with a leakage rate of 200 tons/year is used for the second sensitivity analysis. An extraction well added at the center of leakage zone and is partially screened from z=10 m to z=100 m. This partial screening was found to be most effective for this case when the leak is plugged. The extraction well is operated with a constant pressure constraint of 0.296 MPa over a 10 year period. The gas phase CO_2, the aqueous phase CO_2, and the total CO_2 remaining during the 10 year remediation period are shown in Figure 4-11.

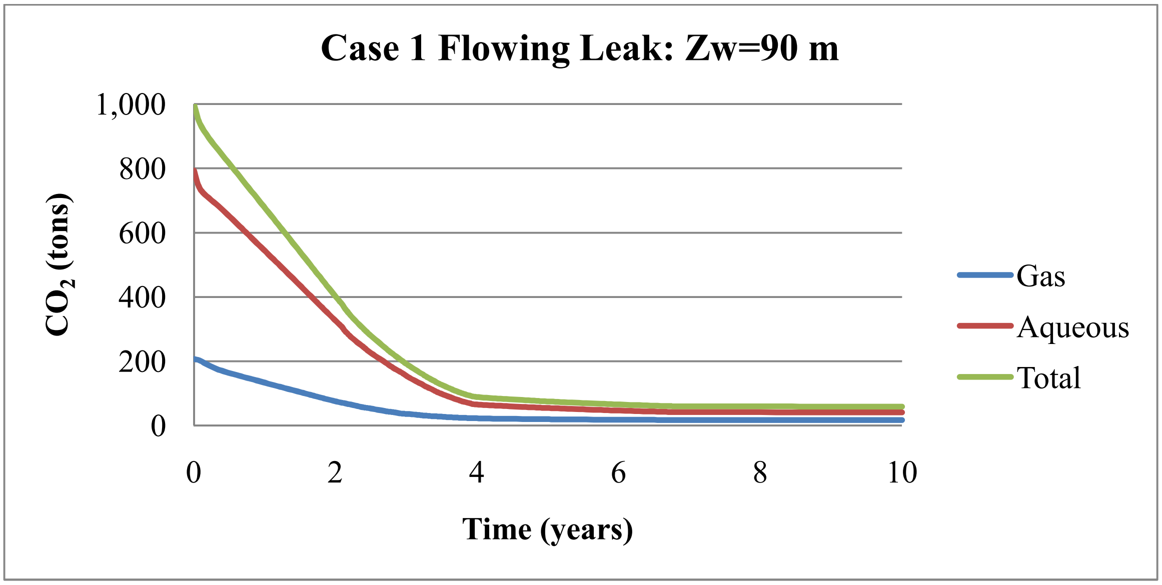


Figure 4-11. Case 1 (Zw=90 m): Continuous Leak of 200 tons/year

The extraction well removes more CO_2 than is leaking over the entire ten year period. This is clear because the amount of CO_2 never increases. The removal rate is very high in the first 3.5 years at 443 tons/year and the CO_2 remaining drops to 127 tons. The removal rate drops to 281 tons/year from 3.5 years to 4 years, then to 210 tons/year from 4 years to 6.5 years and finally to 201 tons/year until the remediation ends. During this last stage the well is extracting the same amount of CO_2 that is leaking into the aquifer. The remaining amount of CO_2 is constant at 60 tons over the last 3.5 years. The reduction in the aqueous phase follows closely with the reduction in the total CO_2.

The reduction in removal rate can be correlated with the changes in the location of the remaining CO_2 over the 10 year period. The first image in Figure 4-12 shows the gas saturation in the plume after 1 year of extraction. The gas saturation in the bottom 10 m of the aquifer remains very high even with the addition of the extraction well. The removal of CO_2 in the top 90 m looks very similar to the case when the leak was plugged before remediation began. The second image shows the gas saturation at three years when the water begins to bypass the main leakage plume between z=20 m to z= 45 m. This corresponds well with a reduction in the CO_2 removal rate. Some CO_2 remains in the secondary accumulation plume at the top of the aquifer, similar to the plugged leak case.

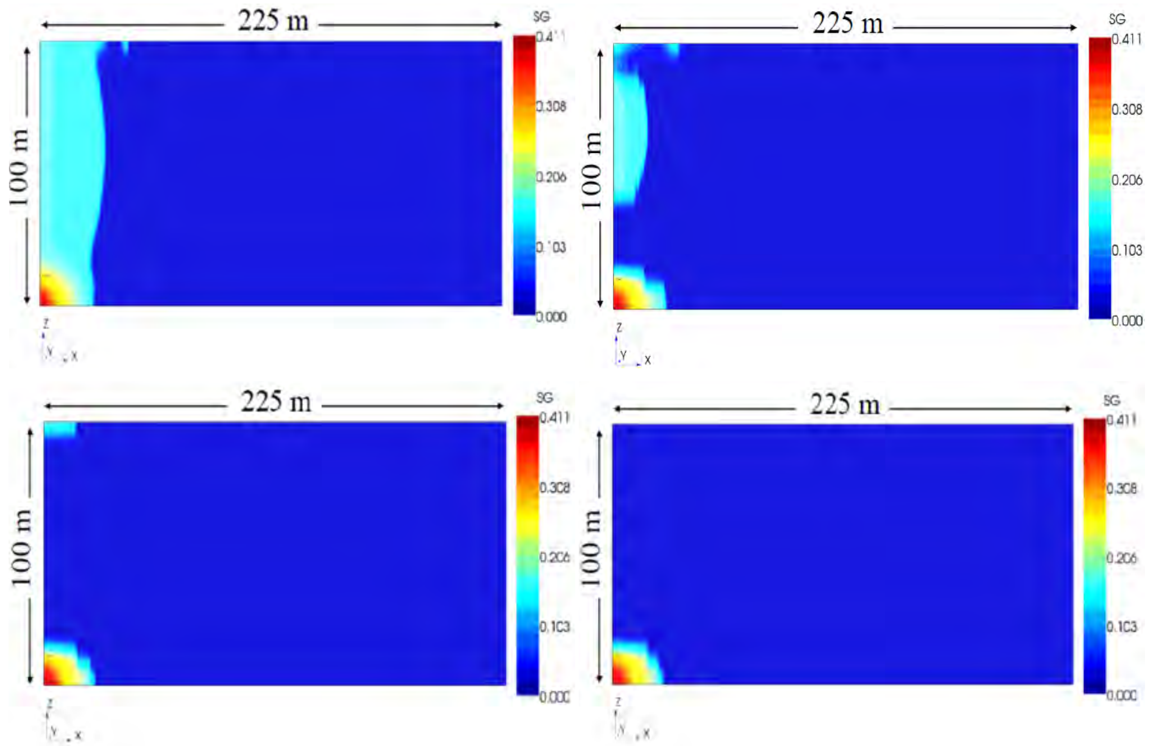


Figure 4-12. Case 1 Continuous Leak: 1 year, 3 years, 6 years, and 10 years

The third image shows the gas saturation at 6 years when the last amount of CO_2 not in the bottom 10 m is being removed. After this time and up until 10 years as shown in the fourth image, the CO_2 is only in the bottom 10 m of the aquifer directly above the leakage zone. This zone remains at the same gas saturation over the entire 10 year period.

In comparison with the case when the leak is plugged with the same well screening depth, allowing the leak to continue only has a negative impact on the reduction of the total CO_2 after 4 years of extraction. The difference after five years of remediation is only very minimal with 60 tons of CO_2 remaining with the flowing leak and 36 tons remaining with plugging the leak (Figure 4-13).

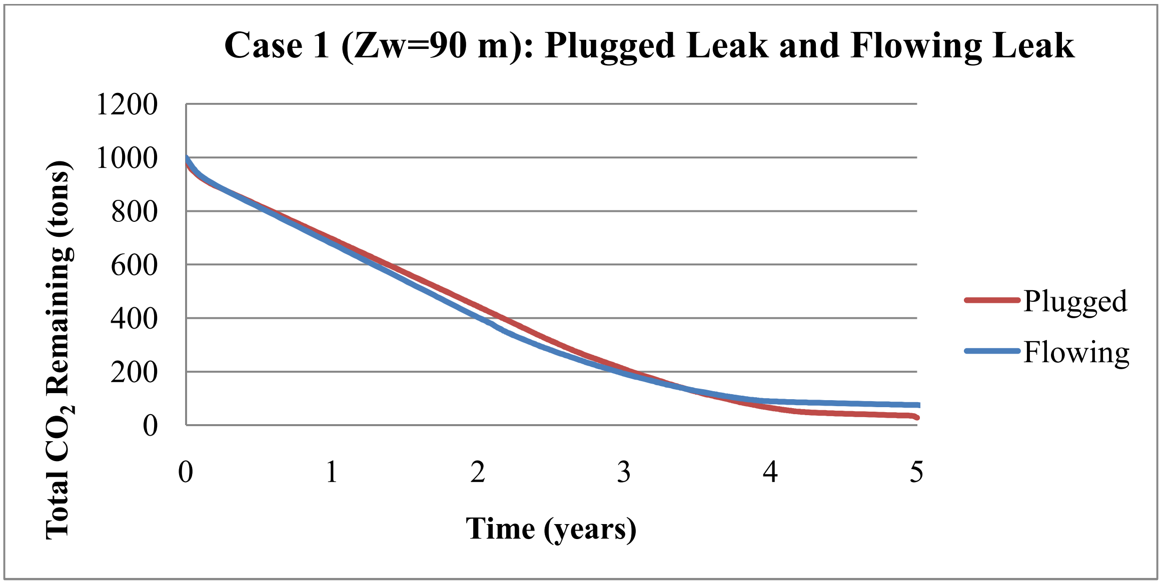


Figure 4-13. Case 1 (Zw=90 m): Plugged Leak and Flowing Leak Total CO_2

Based on this comparison for small leakage rates such as 200 tons/year, allowing the leak to continue to flow during the remediation does not significantly reduce the effectiveness of the vertical extraction well. Once the only CO_2 remaining in the aquifer is directly above the leakage zone, packers could be added to reduce the screened depth to the bottom 10 m. This will reduce the amount of produced water and lower costs. However, if the well is not able to remove more CO_2 than is leaking for larger leakage rates such as 10,000 tons/year, then allowing the leak to continue will lead to more CO_2 in the groundwater aquifer and possibly more remediation difficulties.

Chapter 5

5. Conclusion

As large scale demonstration projects of Carbon Capture and Storage (CCS) come closer to development in the US, the need for formulating groundwater remediation scenarios in case of a possible leakage event from a geologic storage site is very important. The large leakage of oil and gas from the Deepwater Horizon oil rig into the Gulf of Mexico that started April 20, 2010 provides an example that preparation for a possible leakage event is important for reducing impacts. Plugging the leak from the well has shown to be very difficult because there was little contingency plan in place before the explosion and no experience with plugging leaks at great depths. The longer the leak continues the greater the effects on the wildlife, the water and soil quality, and the fishing industry.

Leakage of CO_2 into groundwater aquifers may degrade valuable groundwater resources, may pose a risk to human health if hazardous trace metals dissolve into groundwater, and may interfere with agricultural activities. Based on a review of the literature, very little research has investigated methods for remediating leakage of CO_2 into groundwater aquifers. Although there is a significant amount of experience from remediation of other contaminants present in groundwater, CO_2 poses many unique difficulties that warranted a detailed analysis. Many simulations were performed to understand the influence of leakage rate, total leakage quantity, and leakage duration on the CO_2 leakage plume size and shape. The impact of heterogeneity in the reservoir on the leakage plumes was also analyzed.

Multiple remediation techniques have been compared based on their effectiveness in meeting three remediation objectives. The first remediation objective is to reduce the mobile phase CO_2 to contain the extent of the contamination. The second objective is the removal of both gas phase and aqueous phase CO_2 from the groundwater aquifer. The third objective is to reduce the aqueous phase concentration of CO_2 in an attempt to reduce any secondary contamination from the leakage. These three remediation objectives were chosen because they were seen as the most important in reducing the overall effects of the leakage. The scenarios were also compared based on scenario objectives such as reducing the time required to remediate, limiting the number of wells drilled, minimizing coproduced water, and the limiting the amount of water injected. Meeting these scenario objectives was seen as a measure of cost reduction.

Three techniques were analyzed for remediating the CO_2 leakage including vertical and horizontal extraction wells, water injection wells, and a combination of injection and extraction wells. A sensitivity analysis was performed to study the impacts of low permeable layers on the remediation effectiveness. Also one case was run where the leak was allowed to continue to flow during remediation of the CO_2 leakage plume. The following two sections provide the main conclusions from the CO_2 leakage analysis and from comparison of the multiple remediation techniques. The final section poses some options for future work in this area.

5.1. CO_2 Leakage

The size, shape, and distribution of CO_2 in the aquifer are controlled by multiple fluid flow processes and impacted by the leakage rate, total amount leaked, and leakage duration. During the period when CO_2 leaks into the aquifer migration is dominated by buoyancy, leading to rapid migration of CO_2 to the top of the aquifer and spreading beneath the confining layer. The resultant bifurcated cone-shaped plume has high gas saturation directly above the leakage zone and in the gravity tongue that is formed at the top of the aquifer. The leakage plume can be separated into the main leakage plume formed due to buoyancy and the secondary leakage plume due to accumulation beneath the confining layer. The CO_2 leakage rate determined the width of the main leakage plume and the radius of the secondary plume at the top of the aquifer. For each leakage rate analyzed from 200 tons/year to 10,000 tons/year with homogeneous permeability the CO_2 reached the top of the aquifer over the five year leakage period. The radius of the gravity tongue varied from 50 m for the smallest case to 425 m for the largest leakage case. Also, the area of the gravity tongue was found to increase linearly with increased leakage rate, meaning that more leakage leads to a larger area contaminated. For the cases with low permeability layers in the aquifer, CO_2 only reached the top of the aquifer after five years for the highest leakage rate of 10,000 tons per year. Also with the heterogeneous reservoir, the width of the leakage plume did not increase linearly with increased leakage rate.

The leakage duration impacted the radius of the gravity tongue more than the total amount leaked. Longer leakage durations led to significantly larger gravity tongues without a major difference seen in the width of the main leakage plume. The total amount leaked slightly impacted the fraction of CO_2 in gas and aqueous phase. For the highest total leakage of 50,000 tons for Case 5 the fraction in gas phase was higher at 29% compared to 24% for the lower leakage rates. The large amount in aqueous phase is due to the very low density of CO_2 at this depth. Even with 20% gas saturation only 6 kg will be in gas phase of the 830 kg of total mass in one cubic meter of pore space. The low permeability layers led to less CO_2 in gas phase for all the leakage rates compared to the homogeneous reservoir by a small fraction.

5.2. Remediation of CO_2 Leakage

Remediating large accumulations of CO_2 in groundwater aquifers is challenging due to complex multi-phase flow behavior. The bifurcated saturation gradient makes it difficult to extract CO_2 efficiently from one vertical extraction well screened the entire depth of the aquifer. The area with high gas saturation directly above the leakage zone is quickly depleted of gas phase CO_2 when an extraction well is added. This allows for water to bypass the main portion of the plume and leads to inefficient removal of CO_2. This study suggests that a multi-stage extraction process is more efficient for removing CO_2 from the aquifer. The optimal scenario with one vertical extraction well is to partially screen the well or include a multistep well screening process, first removing CO_2 from the zones with the highest gas saturation and then fully screening the well to remove the aqueous phase CO_2.

Produced water is an added difficulty from CO_2 removal. The aqueous phase mass fraction at this depth is approximately 0.0246. If the fluid removed is fully saturated with $CO_{2,}$ then 40 tons of water will need to be coproduced per each ton of CO_2 removed.

After only two years of production from the extraction well, the amount of gaseous CO_2 drops to zero and the well is primarily producing water with aqueous phase CO_2. The efficiency of the removal decreases over time when it becomes more difficult to remove the trapped gas phase CO_2 and the fluid is not fully saturated.

Injecting reservoir water into the gaseous leakage plume is the most effective measure to quickly reduce the mobile phase CO_2. Water injection can dissolve all the CO_2 in less than 55 days with very high injection rates. The gravity tongue is the last part of the plume to be dissolved. The time to dissolve the CO_2 increases with lower flow rate, but the pressure increase is much less. Water injection also displaces the aqueous phase CO_2 away from the initial leakage point forming a donut shaped plume. The aqueous phase concentration increases in the donut shaped plume due to the large pressure increase from the water injection. If more water is injected than required to dissolve the gaseous CO_2, then the aqueous phase concentration is decreased. However, injecting more water displaces the aqueous plume farther into the reservoir.

Horizontal extraction wells are more effective than vertical extraction wells for larger leakage plumes at reducing the total mass of CO_2 in the aquifer. A horizontal well at the middle of the aquifer is the most effective at removing CO_2 over a longer time frame. However, to remove the mobile CO_2 in the gravity tongue a horizontal extraction well must be placed in the top 20 m of the aquifer.

The most effective scenarios to remove CO_2 from leakage plumes with large gravity tongues combine injection and extraction from multiple wells. The scenario with the highest percentage removal rate begins with water injection into the center of leakage plume for a short period of time. After injection ends, CO_2 is removed with four extraction wells. Continuous water injection and extraction in a five spot pattern was also shown to be effective for large leakage cases. For a closer well spacing of the four injectors and one producer in the five spot pattern, a lower water injection flow rate led to the most effective extraction. With a larger well spacing the higher flow rates performed better than the lower flow rate.

With low permeability layers for the higher total leakage cases the extraction of CO_2 and removal of the mobile phase was slightly more effective. The difference in the distribution of CO_2 and the shape of the plume between the homogeneous and heterogeneous models is greatest for the larger leakage cases. Instead of forming large gravity tongues at the top of the aquifer, the gas phase CO_2 accumulated below each layer with the lowest permeability. Removal of CO_2 with one vertical extraction well was still difficult due to trapping at the residual saturation in the low permeability layers.

Finally, allowing the leak to continue for ten more years during remediation did not significantly reduce the effectiveness of the remediation for the low leakage case. The extraction well was able to remove more CO_2 than was leaking for the low leakage cases. The highest CO_2 removal rate was 3,355 tons/year so any leakage greater than that would lead to increased effects on the groundwater and more difficult remediation. It is still highly suggested that the leak is plugged as part of the remediation, because continuous operation of the extraction well will be costly and lead to large amounts of produced water.

Remediation of CO_2 leakage into a groundwater aquifer is a challenging activity that will vary for each leakage event based on the leakage rate of CO_2, the time before the CO_2 leak is stopped, and the permeability distribution in the aquifer. To reduce risks and decrease remediation difficulties, annual groundwater monitoring of all aquifers overlying the leakage area is recommended. Also, pressure monitoring may detect leaks on the magnitudes analyzed in this study. Catching leaks earlier leads to smaller leakage plumes which are significantly easier to remediate especially if the large gravity tongue has not yet formed.

5.3. Future Research Needs

All the leakage cases analyzed modeled leakage from an abandoned well that connected with the storage zone. There is also the possibility that CO_2 will leak through a fault or fracture. Fault and fractures pose many more difficulties for remediation compared with point source leaks. First, it may be very difficult to stop the leak from the fault or fracture. Also, the leak may be more diffuse over a larger area and specific areas to remediate may be difficult to determine. Possible remediation options that could be analyzed include forming a hydraulic barrier to effectively stop the leaking fault or fracture. Another possible option would be adding a horizontal well that runs along the entire length of the leak. More research on remediating leakage from faults and fractures would provide more insight on this challenge.

Another aspect that was not analyzed fully includes incorporating regional flow in the groundwater aquifer. Regional flows range from less than 1 m/year to over 20 m/year based on the specific hydraulic gradient present in the aquifer. High regional flow on the order of 10 m/year may act similar to water injection and change what techniques may be optimal. Also, if regional flow is present the extent of the contamination will increase each year that the CO_2 is not removed. A hydraulic barrier from a row of water injection wells may be able to halt the continued spreading of the contamination due to regional flow.

Coupling these remediation techniques with a reactive transport simulator that takes into account the adsorption and desorption of trace metals will provide further methods of comparison. Although some methods may be best for removal of CO_2 and reduction of the mobile phase, these same scenarios may lead to greater areas contaminated by secondary contaminants such as lead and arsenic.

Finally, a field scale experiment would significantly improve the understanding of the remediation effectiveness of various techniques. Field scale experiments require a large amount of preparation both with permitting and experimental set up. However, the benefits from studying the leakage of CO_2 and remediation of CO_2 in an actual groundwater aquifer are extensive. The results may provide support for the conclusions reached in this analysis or may lead to new conclusions on which methods are most effective.

Nomenclature

Abbreviations

AoR	Area of Review
CCS	Carbon Dioxide Capture and Storage
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
Mt	million metric tonnes (10^9 kg)
MW	megawatt of power (10^6 W)
NETL	National Energy Technology Laboratory
SDWA	Safe Drinking Water Act
SG	Gas Saturation
SVE	Soil Vapor Extraction
ton	metric ton (1000 kg)
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
VOC	Volatile Organic Carbon

Symbols

d	depth from top of aquifer (m)
D_w	distance between wells in five spot pattern (m)
F	mass or energy flux (kg/m^{2}s)
g	vector of acceleration due to gravity (9.8 m/s^2)
k	absolute permeability of rock formation (md)
$k_{r\beta}$	relative permeability of phase β (liquid of gas)
k_r	permeability in the radial direction (md)
k_x	permeability in the x direction (md)
k_y	permeability in the y direction (md)

k_z	permeability in the vertical direction (md)
M^K	mass of component K (kg)
$\boldsymbol{n}$	inward-pointing normal vector
p	fluid pressure (Pa)
P_{cap}	capillary pressure (Pa)
PI	Productivity Index (Coats, 1977)
P_{max}	maximum capillary pressure (Pa)
P_{ref}	pressure in the reference fluid (Pa)
P_{wb}	well bore pressure (Pa)
Q	volumetric flow rate (m^3/s)
q	mass flow rate (kg/s)
ρ_l^f	flowing density in layer l (kg/m^3)
r_e	effective well radius (m)
$r_{l.b}$	volumetric production rate (m^3/s)
r_w	well radius (m)
S	saturation of each phase
S_{gr}	residual gas saturation
S_{lr}	irreducible liquid saturation
V_n	finite volume (m^3)
X_β^K	mass fraction of a component K in phase β
x	distance from the bottom of the aquifer (m)
z_l	height of each layer (m)
Z_w	height of well screening (m)

Greek Symbols

Δ	change in value
□	gradient
Γ	closed surface of volume
λ	fitting parameter for capillary pressure (van Genuchten, 1980)
μ	fluid viscosity (Pa-s)
ϕ	porosity of reservoir

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