GHGT-12

Evaluation of the effectiveness of injection termination and hydraulic controls for leakage containment

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Abstract

One of the greatest concerns that the public has with large-scale adoption of CCS technology is the potential risk of carbon dioxide leakage from sequestration reservoirs. Among other things, addressing these concerns will require developing intervention and remediation strategies that can be quickly and effectively implemented should leakage occur. The three main methods proposed for remediation of leakage from carbon storage reservoirs are: (1) termination of CO₂ injection activities, (2) injection of a chemical or biological sealant to act as a flow barrier [1] or (3) the development of hydraulic barriers [2, 3, 4]. Creating hydraulic barriers relies on the injection of water in the overlying aquifer with or without injection or production of fluid from the injection reservoir in order to manipulate the pressure field to stop or reverse leakage. Here we first investigate the effectiveness of passive remediation (stopping CO₂ injection), and then determine its effectiveness in combination with a variety of different hydraulic controls such as injection of water above the fault, injection of water below the fault and production of brine in the lower reservoir.

Regardless of when the leak is detected, simulation results show that passive remediation (stopping injection) almost immediately reduces the leakage rate by an order of magnitude. Depending on the degree of residual trapping, leakage can be even further reduced. For example, with a maximum residual CO₂ saturation of greater than 20%, leakage rates drop by another factor of 4 or more. In many cases stopping injection may reduce the leakage to the extent that it is small that it reaches an acceptable level. However in the case where further reductions are desired, for example, in order to completely stop leakage, the implementation of hydraulic controls may be necessary. The most effective method for completely stopping leakage is to inject water into the overlying aquifer near the breach in the caprock. Drawbacks of using this method alone is that while it stops leakage during water injection, leakage resumes after the cessation of water injection. In order to prevent leakage from continuing after water injection ends, the CO₂ plume in the injection reservoir must be displaced away from the bottom of the fault zone. Displacing the CO₂ plume away from the fault is accomplished by injection of water below the fault while injecting water above the fault, and by producing reservoir brine on the opposite side of the CO₂ plume. Reservoir brine production helps pull mobile CO₂ away from the bottom of the fault. In this study, production rates are established by balancing water injection...
rates, therefore reducing costs and surface storage issues associated with leakage remediation. The most effective hydraulic controls for stopping CO\textsubscript{2} leakage combine brine extraction from the storage reservoir with water injection into the overlying aquifer and storage reservoir near the fault.

Overall this study demonstrates that temporally limited, multi-stage remediation strategies using a combination of stopping injection and hydraulic controls can permanently terminate leakage while having the additional benefit of dissolving most of the CO\textsubscript{2} in the overlying aquifer into the resident brine. This finding should provide assurances to industry, policy makers, and the public that intervention measures can quickly and effectively mitigate the risks of leakage should leakage occur.

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Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords: CO\textsubscript{2} sequestration; leakage; remediation; hydraulic barriers; intervention; simulation; numerical model

1. Introduction

There are two main forces that could drive CO\textsubscript{2} and brine leakage from a storage reservoir. The first is the pressure build up in the storage reservoir due to CO\textsubscript{2} injection. Carbon dioxide injection will typically increase the pressure in the reservoir to levels higher than that of the overlying aquifer(s). If a permeable flow path exists in the seal between the injection reservoir and overlying aquifer (e.g. abandoned well or fault zone), fluid will migrate from the high pressure injection reservoir to the lower pressure aquifer(s). The second risk of CO\textsubscript{2} leakage is due to the buoyancy of CO\textsubscript{2} relative to the resident reservoir fluid. Typically, supercritical CO\textsubscript{2} is less dense than the surrounding reservoir fluid; this gravity driven buoyancy force is capable of driving CO\textsubscript{2} from the storage reservoir.

If a leak in a sequestration reservoir is identified, it is important to evaluate the risks, operational and economic costs, and environmental impacts of the leakage in order to determine if remediation is necessary and/or feasible. Several remediation strategies have been proposed, these generally fall into one of four categories: (1) hydraulic barriers and pressure management [2, 3, 4], (2) production and removal of CO\textsubscript{2} from the storage reservoir [6], (3) biological barriers [1] and (4) emplacement of sealants and other physical barriers [7]. Hydraulic barriers rely on the manipulation of pressure fields in the overlying aquifer and storage reservoir by either injecting water or producing reservoir fluids in order to stop and possibly reverse leakage. Measures can also be taken to change the injection plume geometry or pressure conditions in order to prevent future leakage after the cessation of remediation intervention. Production of CO\textsubscript{2}, likely from the original injection well, removes much of the mobile CO\textsubscript{2} in the storage reservoir. This reduces long-term leakage significantly but can have large financial consequences if the CO\textsubscript{2} must be reinjected in another storage reservoir or if penalties are incurred for venting the CO\textsubscript{2} back into the atmosphere. Biological barriers, sealants and other physical barriers attempt to alter the permeability of the fault zone by introducing gels, grouts or other materials that have the ability to fill the pore spaces through which CO\textsubscript{2} is escaping from the storage reservoir.

In this study, simulation models are employed to analyze and characterize the behavior of CO\textsubscript{2} leaking from a storage reservoir through a subseismic fault. In this model, CO\textsubscript{2} is injected into a lower reservoir capped by an impermeable seal, above the seal is an aquifer. As the CO\textsubscript{2} plume migrates through the injection reservoir, it reaches a fault zone which provides a pathway for fluid connectivity between the reservoir, caprock and overlying aquifer. After developing a detailed understanding of the leakage process, timing, pressure and saturation conditions, different intervention options are evaluated. These options include CO\textsubscript{2} injection termination and hydraulic controls such as, water injection in the overlying aquifer above the fault, injection of water in the lower reservoir below the fault, and reservoir fluid production away from the CO\textsubscript{2} plume.
2. Methods and model development

2.1. Simulation model development

All simulations are performed with TOUGH2, a fully implicit numerical simulator designed to model nonisothermal, multiphase, multicomponent flow in porous and fractured media [8]. TOUGH2 was run with the fluid property module ECO2N [9]. In order to accurately model the simultaneous drainage and imbibition processes that take place during remediation activities, a specialized TOUGH2 source code was used in order to properly model hysteresis. Details of the implementation of hysteresis can be found in [5].

The simulation model is 2.5 km by 2.5 km by 100 m, with a structured grid geometry (Figure 1). The grid is locally refined around the injection well and fault zone. The smallest grid cells are one meter wide in the fault and three meters wide at the injection well. The largest grid cells are 500 m wide near the model boundaries. The lower reservoir has a thickness of 68 m, the caprock is 12 m thick and the overlying aquifer is 20 m thick. The storage reservoir and overlying aquifer both have permeabilities of 28 mD and porosities of 10%. The caprock has a permeability of 0.2 nanodarcy and a porosity of 5%. The fault zone geometry was constrained using published scaling relationships starting with the initial assumption that the fault zone is subseismic and therefore has a displacement less than 10 m. The fault is three meters wide and 500 m long. For simplicity, the permeability structure that typically exists in fault zones in sedimentary rocks [10] is ignored and a single permeability value is assigned to the fault zone. The distance of the fault from the injection well is 500 m. In order to model a basin scale reservoir, the model boundary cells have volume factors of 10^5.

The aquifer and reservoir porosity, permeability and characteristic capillary pressure curves are modeled after the Arqov sandstone as described in [11]. The characteristic capillary pressure curves for the fault and caprock are determined by scaling the Arqov capillary behavior using the Leverett function. The characteristic relative permeability curves are Corey’s Curves with S_{fr}=0.2 and S_{gr}=0. The reservoir temperature and pressure conditions are established based on typical values for a reservoir located at a depth of roughly 1600 m below the water table. Prior to remediation initiation, CO$_2$ is injected at a constant rate of 7.9 kg/s (0.25 Mt/yr) into the lower reservoir over a completion interval of 0 m to 55 m from the bottom of the reservoir.

![Figure 1. Grid geometry model used for TOUGH2 simulations. Note the height of the system is scaled 10x greater than the x and y directions.](image)

3. Residual trapping

An important factor in plume stabilization, and thus remediation effectiveness, is the extent of CO$_2$ residual trapping. To evaluate the influence of residual trapping, the commonly used Land trapping method [12], shown in Equation 1 and Equation 2, is implemented in the ECO2N simulation module.
These equations describe the relationship between the residual trapping coefficient ($S_{\text{max}}$), the initial CO$_2$ in the pore spaces ($S_i$), and amount of CO$_2$ that is residually trapped ($S_{\text{trapped}}$). Trapping coefficient and residual trapping measurements have been measured in lab and field settings [13]. Krevor et al. [14] measured Land trapping coefficients in four cores from different sandstone formations and found that core-averaged CO$_2_{\text{rmax}}$ (here referred to as $S_{\text{rmax}}$) values ranged from 0.21 to 0.33 with typical values around 0.3. Other laboratory experimental studies [15, 16] used a variety of methods for relating initial and residual saturation values; these studies yielded similar results. Residual trapping values were also measured in a carbon storage reservoir as a part of the CO2CRC Otway demonstration project [17]. Results from this project estimated that the residual CO$_2$ saturation in the reservoir was between 11-20% [18]. Typical gas saturation values of 20-50% in the reservoir, and a $S_{\text{rmax}}$ trapping coefficient of 0.3, leads to residual trapping values between 13-25%. Based on these studies, a $S_{\text{rmax}}$ value equal to 0.3 was assigned for all of the remediation model scenarios in the following sections. Details of the Land trapping implementation are described in [5].

3.1. Base case leakage scenario

Prior to the development of intervention methods, it is useful to examine the character of leakage through a fault zone as a function of time. Carbon dioxide is injected at a constant rate of 7.9 kg/s. As CO$_2$ is injected in the reservoir, water (i.e. reservoir fluid/brine) is displaced, driving water up the fault. This flux of water into the overlying aquifer will result in a pressure increase in the overlying aquifer. The aquifer pore volume, permeability, and distance of leak from monitoring well will determine if the pressure increase from the water flowing into the aquifer is high enough to be detectable [19]. The immediate pressure increase at the base of the aquifer in the fault zone is illustrated in Figure 2. In this model scenario the pressure increase is on the order of hundreds of kilopascals, which is likely to be detectable with current measurement tools [19, 20].

Following this initial period when only water leaks up the fault, the CO$_2$ injection plume eventually reaches the fault after 3.4 years. The pressure drops briefly when CO$_2$ begins to migrate up the fault. As the relative permeability of water drops precipitously during drainage, the cumulative fluid flow (i.e. both water and CO$_2$) drops. As the CO$_2$ plume continues to advance in the lower reservoir, the rate of leakage continues to increase as does the pressure at the top of the fault. Leakage increases due to three factors: 1) the increasing relative permeability to CO$_2$ as the saturation in the fault increases; 2) the length of fault exposed to the plume increases until the CO$_2$ plume covers the entire base of the fault zone; and 3) the thickness of the plume underneath the fault continues to increase for many years, increasing the buoyancy force driving CO$_2$ up the fault zone.

The rate of leakage reaches a nearly steady value within 10 years after it begins. Timing and rates change dramatically depending on reservoir, fault and aquifer conditions but the key stages of leakage are: (1) water/brine leakage, (2) CO$_2$ leakage increasing at a decreasing rate and (3) approximately steady-state leakage. These stages are observed in all cases when the fault is not in the immediate vicinity of the injection well, when the permeability of the fault zone is not influenced by injection activities, and when boundary conditions are nearly infinite.
3.2. Leakage intervention

The most immediate action that can be taken after a leak is identified is to stop CO₂ injection in the well(s) nearest the fault. If this is not sufficient to stop leakage or reduce leakage rates below acceptable levels, additional measures such as using hydraulic barriers or producing CO₂ from the injection well can be implemented. Through injection and production activities, it is possible to increase dissolution of CO₂, change the direction of fluid flow in the fault zone, push CO₂ away from the fault zone at the base of the caprock, and manipulate the CO₂ plume geometry throughout the injection reservoir. The extent and duration of leakage intervention will be dependent on the fault, reservoir and overlying aquifer properties. Many leakage scenarios may only require minimal remediation such as injection shutoff to terminate leakage, while some leakage scenarios may require extended remediation and monitoring for many years. All of the intervention options presented in this study have been examined through a lens of practicality and feasibility of implementation. As a result, active remediation strategies (i.e. injection and production) are limited to a decade, pressure build up from fluid injection was evaluated, and basic cost analysis ruled out the use of elaborate well injection and production patterns that have been suggested by other authors [2,6].

Since the effectiveness of remediation is likely to be highly dependent on when the leak is detected, two initial leakage scenarios were examined. The first scenario is that detection occurs after five years of CO₂ injection, almost immediately after leakage begins. In the homogenous base model described earlier, just over 5,000 tons of CO₂ leaked into the upper aquifer, or roughly 0.5% of the total CO₂ injected into the system. This includes CO₂ in both the supercritical and aqueous phase. The extent of the leakage plume in the overlying aquifer is a 100 m wide and 300 m long plume of supercritical CO₂. In 10 year intervention scenario, intervention begins after 10 years of CO₂ injection. The total amount of CO₂ leaked in this scenario is 76,000 tons, or roughly 3% of the total CO₂ injected. The leakage plume in the aquifer above the storage reservoir is 500 m wide and 800 m long.

4. Injection shutoff

Shutting off CO₂ injection is able to reduce the source of the pressure build up in the storage reservoir, allowing the increased pressure in the reservoir to dissipate over time, which leads to decreasing leakage rates. Figure 3 shows the dramatic decrease in the amount leakage after injection shutoff for the two different detection scenarios.
compared with no injection shutoff. In the 5 year detection scenario, injection shutoff reduces the mass of CO$_2$ leaked after 50 years by 99.8% and in the 10 year detection scenario the reduction in total CO$_2$ leaked is 98.7%.

5. Hydraulic controls

If stopping injection fails to reduce CO$_2$ leakage below the required threshold then additional intervention methods can be implemented. This section will provide detailed procedures and results for implementing hydraulic controls. All intervention methods begin after 5 years of CO$_2$ injection and CO$_2$ injection is terminated prior to beginning any further remediation. For each intervention strategy two different models are evaluated. The first model has a fault permeability of 10 mD, roughly half of the reservoir permeability but eight orders of magnitude higher than the caprock permeability. The second model has a fault with a permeability of 100 mD, approximately four times higher than the reservoir permeability and nine orders of magnitude higher than the caprock permeability. These two models enable analysis the influence of fault permeability on both leakage behavior and remediation effectiveness.

5.1. Water Injection into an overlying aquifer

Water injection into the overlying aquifer creates a region of higher pressure at the top of the fault. This zone of higher pressure can reduce or reverse the hydraulic gradient causing leakage. As a result, this method is able to completely stop and, in some cases, reverse the CO$_2$ leakage in the fault. The other benefit of injecting water into the overlying aquifer is that it may be possible to dissolve much of the CO$_2$ that has leaked into the aquifer, thereby reducing the mobility and concentration of supercritical CO$_2$.

The length of the fault will determine the well geometry (vertical or horizontal) necessary to create a region of high pressure above the fault. A vertical well will concentrate the pressure buildup to a single point. Horizontal wells are able to extend the pressure build up over a larger area, reducing the pressure increase at any one point and thus reducing the risk of hydraulic fracturing or induced seismicity. All of the models examined in this study use vertical injection wells completed only in the top 5 meters of the overlying aquifer.
In order to show the influence of water injection rate on leakage through the fault zone, a number of simulations were run with injection rates varying from 1 kg/s to 5 kg/s at the top of the aquifer, directly above the fault in the base case model. In all cases water injection is terminated 10 years after the initiation of hydraulic controls. Figure 4 compares the impact of four different injection rates on the total leakage percent of CO₂ in the aquifer and the percent of CO₂ in the aquifer that is dissolved in water. This figure shows that water injection not only has the potential to decrease the cumulative amount of CO₂ in the overlying aquifer, but even at the lowest injection rates over 90% of the CO₂ in the overlying aquifer becomes dissolved in water. It is important to note that in these simulations the salinity of the storage reservoir and overlying aquifer was set to zero, increasing salinity decreases the capacity for CO₂ dissolution in the system.

Remediation is more effective at higher injection rates and thus injection rates should often be set as high as possible in order to maximize the efficacy and reduce the duration of remediation. However, caution is required when choosing an injection rate because the geomechanical effects must also be taken into account. The rate of pressure build up in the vicinity of the well will be highly dependent on aquifer properties such as permeability, porosity, and aquifer height. In this model setup, with a vertical injection well, an aquifer permeability of 28 mD and an aquifer height of only 20 m, injection rates higher than 2 kg/s exceed 150% of initial pore pressure. Prior to water injection, it will be necessary to characterize the fault zone and the regional stress regime in order to estimate the injection threshold above which induced seismicity or slip along the fault would become a significant risk.

Leakage in the homogeneous system can be quickly stopped by injecting water into the overlying aquifer as shown by the examples in Figure 4; however leakage eventually resumes after water injection ends regardless of the injection rate. Thus, injection of water in the aquifer will usually act as a temporary containment method to stop leakage while the risks and benefits of other options are being evaluated.

Figure 4. a. (left) Comparison of the influence of different injection rates on the cumulative leakage percent of CO₂ in the upper aquifer. The leakage percent is calculated by dividing the total mass of CO₂ in the aquifer by the total mass of CO₂ injected into the system. In all cases, the injection rate is constant for the first 10 years, after which injection stops. b. (right) Percent of CO₂ in the overlying aquifer that is in the gas phase CO₂ (i.e. not dissolved).

5.2. Reservoir brine production

A major limitation of water injection in the overlying aquifer is that it has minimal influence on the CO₂ plume in the injection reservoir. As a result, gravity driven equilibration of the injection plume continues to slowly drive CO₂ up the fault zone after water injection is terminated. One option to reduce buoyancy driven leakage is to produce reservoir water/brine in order to displace the CO₂ plume away from the fault zone.

The first step in fluid production remediation is to determine the ideal placement of a production well in the injection reservoir. Early scoping studies found that producing brine anywhere on the fault-side of the CO₂ injection plume increased the long term CO₂ leakage. Production in this region displaced more CO₂ from under the fault
while decreasing the pressure below the fault. This was good in the short term for preventing leakage up the fault but after the cessation of remediation there remained a large column of CO₂ below the fault that subsequently leaked up the fault in the following decades.

With the results from this scoping work, it was determined that the most effective production well location was on the opposite side of the plume from the fault. This production well could either be a horizontal or vertical well located at the bottom of the injection reservoir. Figure 5 illustrates the reduction in leakage of CO₂ using water injection activities with reservoir fluid production (dotted lines) and without reservoir fluid production (solid lines). In these simulations, fluid production is balanced with water injection (above the fault in the overlying aquifer) which was set to 2 kg/s for 10 years in the cases shown in Figure 5. The production well was placed 750 m away from the original CO₂ injection well, far enough from the plume such that CO₂ was never extracted from the storage reservoir during brine production. While brine production alone is insufficient to stop leakage into the overlying aquifer, it contributes to the long term CO₂ leakage reduction.

Simultaneous injection and production addresses some of the financial and logistical concerns associated with hydraulic remediation strategies. In order to limit the costs of water storage and multiple water sources, all of the cases examined in this study have total production rates equal to total injection rates, or an extraction ratio of one [2]. This assumption relies on the ability to inject reservoir water into the aquifer, which may not always be possible—or may require filtration or treatment—depending on the salinity, chemistry, and current and future utility of the reservoir and aquifer fluids.

5.3. Water injection below the caprock

The second option to prevent gravity driven leakage following remediation termination is to inject water below the fault in order to push the CO₂ plume away from the vicinity of the fault zone and reduce the mobility of CO₂ by dissolution into the injected water. The initiation of water injection below the fault must take place sometime after the injection above the fault has stopped the leakage and re-saturated the fault with brine. This prevents water injection in the reservoir from displacing more CO₂ up the fault zone. In these simulations, water is first injected above the fault with brine produced at the same rate as injection (2 kg/s). After two years of injection above the fault, injection below the fault begins. The water injection well in the storage reservoir is located directly below the water injection well in the overlying aquifer. This placement allows both injection methods to be performed using only one well perforated at two different intervals, one below the caprock and one above the caprock. Water injection below the fault is set to the same rate as water injection above the fault (in this case 2 kg/s). When water injection below the caprock begins, the rate of fluid production increases to 4 kg/s to match the combined water injection rates below and above the caprock. After ten years, all injection and production is terminated.

The combination of water injection above and below the fault with concurrent reservoir fluid production makes it possible to completely terminate leakage in the homogeneous model for decades (Figure 5), and significantly reduce leakage for centuries. Figure 5 compares the efficacy of different stages of remediation for different fault permeability scenarios. The character of the CO₂ leakage is very similar for the different fault permeabilities. However, the leakage rates are higher when the permeability of the fault is larger, as would be expected. It is important to point out that for the 10 mD fault, when only injection shutoff was implemented, the leakage rates after 100 years drops to roughly 30 tons/year, or 0.003 %/year, resulting in a cumulative leakage of 12,213 tons of CO₂ in 100 years. For the 100 mD fault, the highest leakage rates are roughly 300 tons per year after 100 years with a cumulative leakage percent of roughly 8% of the total CO₂ injected into the system after 100 years.
5.4. Long term leakage behavior

In homogeneous systems, while some small amount of CO$_2$ continues to leak slowly from the storage reservoir after cessation of remediation, intervention methods are very effective. As shown in Figure 6, leakage rates drop quickly and continue to decline with time. While leakage still occurs, it is very small and decreasing in an exponential fashion as the injected CO$_2$ plume stabilizes due to secondary trapping mechanisms. As a result of this exponential decline in leakage rate, the cumulative amount of leakage stabilizes after several centuries. For a 10 mD fault, by stopping injection the cumulative leakage is less than 2% of the injected CO$_2$ after 500 years. The addition of hydraulic controls can reduce the cumulative leakage to less than 1% of the injected CO$_2$. For example, the combination of water injection above and below the fault with CO$_2$ injection shutoff drops the cumulative amount of leakage to less than 0.8%, and less than 0.0025 %/year is leaking after 500 years. If no intervention occurred then after only 40 years the total amount of CO$_2$ leaked into the aquifer would be around 655,110 tons.
detected after 5 years of CO2 injection, and these intervention methods are implemented, the total mass of CO2 in the aquifer after 500 years is 14,000 tons and much of this CO2 is dissolved in water.

All of the leakage rates post-injection shutoff were significantly lower than the leakage rates when CO2 injection was taking place. In these models, the pressure build up in the reservoir due to injection causes much more leakage than the buoyancy instability between the CO2 and reservoir fluid.

![Figure 6. Long-term comparison of different stages of remediation for a 10 mD fault zone showing the leakage rates (right) and leakage percent values (left) as a function of time.](image)

6. Conclusion

Leakage intervention and remediation requires a balance of engineering efficacy, geomechanical assessment and cost-benefit analysis. Injection shutoff or passive remediation is the fastest, easiest, and likely the cheapest method to quickly reduce leakage from the storage reservoir. Usually injection shutoff alone is not able to completely stop leakage. If passive remediation is not sufficient, various hydraulic controls such as water injection or reservoir fluid production can be employed to further reduce leakage rates and trap mobile CO2. Water injection is a very effective remediation technique because it: (1) increases the pressure in the overlying aquifer relative to the base of the fault which can quickly stop leakage, (2) is able to push some amount of leaked CO2 back down the fault, (3) is able to dissolve large quantities of CO2 in the vicinity of the water injection and finally, (4) does not require injection directly into the fracture, which is likely to be required if a chemical or biological sealant is used. In some cases, water injection alone may be enough to stop current and future CO2 leakage, especially when the leak is detected early, before a large amount of CO2 has accumulated below and above the fault. Additional hydraulic controls such as reservoir fluid production and water injection below the caprock increase rates of dissolution and thus trapping of CO2 in the storage reservoir. These findings should provide assurance to industry, policy makers, and the public that intervention measures can quickly and effectively mitigate potential leakage from carbon sequestration reservoirs.

Acknowledgements

This project was supported by the Stanford University Department of Energy Resources Engineering and the Stanford Center for Carbon Storage. This work is part of a larger project, “Assessment of Leakage Detection and Intervention Scenarios for CO2 Sequestration,” supported by the CCP3; a joint industry project sponsored by BP, Chevron, Eni, Petrobras, Shell, and Suncor.
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