ELSEVIER

Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 1 (2009) 2573–2580

Energy Procedia

www.elsevier.com/locate/procedia

GHGT-9

Risk of Leakage versus Depth of Injection in Geological Storage

Michael A. Celia[a], Jan M. Nordbotten[a,b], Stefan Bachu[c], Mark Dobossy[a], Benjamin Court[a]

[a]*Department of Civil and Environmental Engineering, Princeton University, Princeton, NJ 08544 US*
[b]*Department of Mathematics, University of Bergen, Bergen, NORWAY*
[c]*Alberta Research Council, Edmonton, Alberta CANADA*

Abstract

One of the outstanding challenges for large-scale CCS operations is to develop reliable quantitative risk assessments with a focus on leakage of both injected CO_2 and displaced brine. A critical leakage pathway is associated with the century-long legacy of oil and gas exploration and production, which has led to many millions of wells being drilled. Many of those wells are in locations that would otherwise be excellent candidates for CCS operations, especially across many parts of North America. Quantitative analysis of the problem requires special computational techniques because of the unique challenges associated with simulation of injection and leakage in systems that include hundreds or thousands of existing wells over domains characterized by layered structures in the vertical direction and very large horizontal extent. An important feature of these kinds of systems is the depth of each well, and the fact that the number of wells penetrating different formations decreases as a function of depth. As such, one might reasonably expect the risk of leakage to decrease with depth of injection. With the special computational models developed to simulate injection and leakage along multiple wells, in layered systems with multiple formations, quantitative assessment of risk reduction as a function of injection depth can be made. An example of such a system corresponds to the Wabamun Lake area southwest of Edmonton, Alberta, Canada, where several large coal-fired power plants are located. Use of information about both the existing wells and the local stratigraphy allows a realistic model to be constructed. Leakage along existing wells is assumed to follow Darcy's Law, and is characterized by a set of effective permeability values. These values are assigned stochastically, using several different methods, within a Monte Carlo simulation framework. Computational results show the clear trade-off between depth of injection and risk of leakage. The results also show how properties within the different formations affect the risk profiles. In the Wabamun Lake area, one of the formations has the highest injectivity, by far, while having a moderate number of existing wells. Its moderate risk of leakage, as compared to injections in formations above and below, shows some of the key factors that are likely to influence injection design for large-scale CCS operations.

Key Words: CO_2 geological storage, well leakage, risk assessment, injection depth, analytical models, carbon capture and storage, Monte Carlo simulations

doi:10.1016/j.egypro.2009.02.022

1. Introduction

When considering geological storage of CO_2, the main environmental concern is usually leakage of the injected CO_2, as well as possible leakage or large-scale displacement of the resident brine. One potentially important leakage pathway is associated with the century-long legacy of oil and gas exploration and production, which has resulted in many millions of wells being drilled [1]. Those wells are often drilled through otherwise excellent caprock formations overlying permeable reservoirs. Because a successful CO_2 storage operation requires a competent caprock formation overlying the injection formation, these oil and gas wells may compromise the efficacy of storage operations by providing preferential flow pathways through the caprock. This is especially true in North America, where many millions of oil and gas wells have been drilled since the late 1800's (Figure 1).

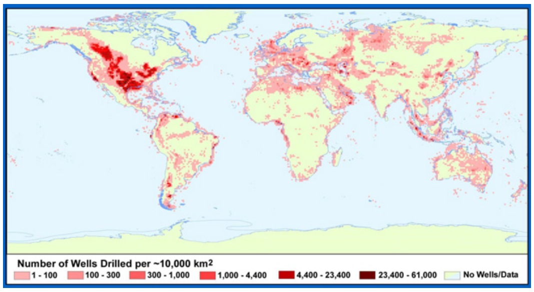

Figure 1: Worldwide density of wells [1].

Gasda et al. [2] analyzed the spatial density of wells that perforate a particular formation in the Alberta Basin, Canada. Their results indicated that tens to hundreds of wells might be contacted by a typical CO_2 plume. If the area of concern is expanded to include regions of possible brine migration and leakage, the number of wells of concern increases further. For a large-scale injection operation that continues over several decades, the domain that needs to be analyzed will be on the order of thousands of square kilometers. Within that domain, the vertical structure, particularly the major layers of permeable (aquifer) and essentially impermeable (caprock or aquitard) formations must be taken into account (see, for example [3]). Furthermore, within this domain, many hundreds of wells may exist, each with a different depth of penetration, and with properties that are largely unknown. The uncertainty of the key parameters associated with existing wells, coupled with the underlying complexity associated with the physics and mathematics of two-phase flow, make this a computationally challenging problem. To overcome computational limitations of existing multi-phase simulators, a new set of models has been developed that can solve this type of problem, where large domains with many vertical layers are populated with many wells along which fluid may leak under large-scale injection of CO_2. The basic components of such a model can be found in Nordbotten et al. [3,4,5] and Nordbotten and Celia [6,7,8]. Simple example applications of different parts of the model can be found in those papers as well as in Celia et al. [9] and Bachu and Celia [10].

In the present work we demonstrate the application of this overall modelling approach for a chosen field site in Alberta, Canada. The location corresponds to an area where four large coal-fired power plants currently operate, emitting collectively about 30 million tonnes (Mt) of CO_2 per year [11]. We use detailed stratigraphic descriptions and actual locations and depths of 1,344 wells over a study area of 2500 km^2. We use the model to demonstrate the most important characteristics of the problem, including the importance of vertical structure in the stratigraphic sequence, the nature of leakage in such systems, and the importance of injection location within the vertical sequence. In particular, we demonstrate how leakage risk is reduced as a function of depth of injection. We also consider injectivity and limits on injection rates based on estimated fracture pressures.

2. Computational Model

The computational model used in this work is based on a set of analytical and semi-analytical solutions for CO_2 injection [6], leakage along segments of wells [4] and upconing in the vicinity of leaky wells [7]. These individual components are integrated into an overall solution algorithm that can accommodate an arbitrary number of layers and an arbitrary number of potentially leaky wells. The combined algorithm is described in [8].

2.1. CO_2 Plume Evolution

The fundamental building block of the model is a solution for a single injection well in a horizontal, confined, homogeneous aquifer. The model uses the assumption of a sharp macroscopic interface between the CO_2 and the resident brine. This assumption is justified by the large density contrast between the two fluids, which leads to a strong gravity segregation. Associated with the sharp interface assumption is the assumption that both fluid phases are very close to vertical equilibrium, so that the pressure distribution in the vertical direction is approximated as the (hydro)static pressure. This is often referred to as the vertical equilibrium assumption. Both of these assumptions are used in [6], where a similarity solution is derived for the system. Among other things, the CO_2 plume is shown to increase in radial distance away from the injection well in proportion to the square root of time. Similarly, the pressure perturbation that drives the flow of both the CO_2 plume and the brine also expands proportional to the square root of time, but at a much greater rate. Examples of applications of these equations may be found in Nordbotten and Celia [7, 8], Bachu and Celia [10] and Kavetski et al. [12].

2.2. Leakage along wells

Leakage along wells is treated as Darcy flow, using the two-phase extension of Darcy's Law. While we recognize the complicated flow paths that can be associated with leakage along wellbores, especially at the small scale, we focus our modelling on mathematical descriptions across relatively large lengths along a well. In addition, we assume that most of the leakage will take place outside the well casing, along the complex zone that involves cement and residual drilling fluids in the annular space, as well as possible damaged rock zones caused by the drilling process. We lump all of these materials, and the complex flow paths through them, into a bulk 'effective' permeability that represents the ability of fluid to flow along a well. The permeability is meant to apply, in bulk, over a length along the well that corresponds to the thickness of a caprock formation. With reference to the schematic of flow and leakage given in Figure 2, each potential leaky well is characterized by an effective permeability assigned to each segment of the well that crosses an individual caprock formation.

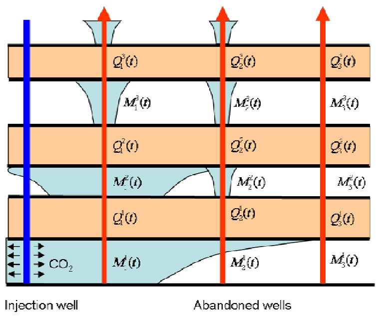

Figure 2: Schematic of flow and leakage in a multi-layer system from [12].

2.3. Interface Upconing

The third important part of the simulation package we have developed is a solution that describes so-called upconing of the CO_2-brine interface around a leaky well. The idea is that when a well is leaking, the flow of fluid along the well represents a net loss of mass in the formation from which the leakage is occurring (for example, the injection formation). This causes a local decrease in pressure around the well, which induces the interface to move upward, reducing the thickness of the CO_2 plume in the vicinity of the leaky well. If the thickness goes to zero locally at the well, then both brine and CO_2 can flow along the well. If the thickness of the plume remains greater than zero, then only CO_2 will flow along the well. And if the CO_2 plume has not yet reached the well, then only brine can leak along the well.

Our approach is to use an improved analytical solution to the interface upcoming problem, as derived in [7]. The solution uses existing interface thickness, pressure, and leakage conditions to determine the thickness of the CO_2 plume at a leaky well. If the thickness goes to zero, then an additional calculation is performed to determine the fraction of flow along the well that originates from each of the two fluids, CO_2 and brine. This is then used in the remainder of the calculations for the overall pressure and CO_2 fields.

2.4. Overall Computational Model:

These three major pieces, described in Sections 2.1, 2.2, and 2.3, form the core of our model. Details about how these are put together, the way discrete time-stepping is imposed, and other considerations are described in Nordbotten et al. [4, 8]. We note that, contrary to traditional numerical models for these kinds of problems, our model has no spatial grid but rather uses analytical solutions in space that are associated with the physical features of the problem, specifically the wells and the permeable layers. However, because of the nonlinearity of the underlying equations, discrete time steps are required. Because of the discretization in time, we refer to the overall solution process as a semi-analytical algorithm.

3. Site Description

We have identified a field location southwest of Edmonton, Alberta, Canada where a large-scale CCS activity might reasonably take place in the future. Here four large coal-fired power plants currently emit about 30 million tonnes of CO_2 per year (Mt CO_2/yr) [11]. The location of the site is shown in Figure 3. Data have been collected for site characterization in the area outlined in the figure, with the area being 50 km x 50 km. Within that area, 1,344 existing oil and gas wells have been identified. The locations of these wells are also shown in Figure 3. These wells have variable characteristics, including depth of penetration and age. We have also identified the general stratigraphic sequence in the area, which consists of alternating permeable and impermeable layers, with the permeable layers corresponding to sandstones in the higher layers and carbonates in the lower layers. The impermeable caprock formations are shales. The characteristics of the permeable layers, including number of wells, are summarized in Table 1.

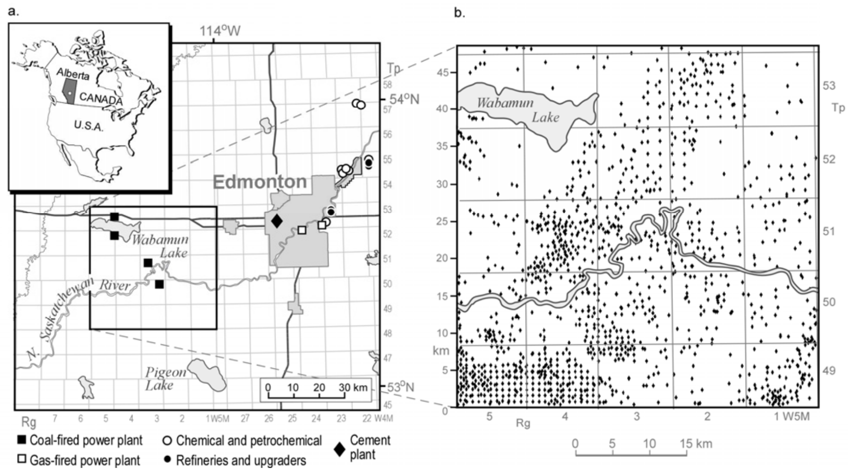

Figure 3: Wabamun Lake area study site in the Alberta Basin, Canada.

The average slope of the different formations across the area was determined by examination of well logs associated with the different wells, and estimation of vertical locations of the different formations. In general, the slopes are less than 1%. When considered in the context of the analysis presented by Gasda et al. [13], we conclude that the buoyant movement of the CO_2 injection plume due to caprock slope will be insignificant during the entire period of injection. As such, the assumption of horizontal formations may be seen as reasonable.

The permeable layers have associated with them a number of small-scale (core-plug) measurements of permeability. These have been aggregated into formation averages [11] as shown in Table 1. We use these estimates directly in our simulations. All caprock formations are assumed to be impermeable, except for possible flows along the existing wells. We have assigned an effective compressibility for CO_2 and brine corresponding to the average compressibility of brine. We take the domain size to be 50 km x 50 km, and assign lateral boundary conditions as fixed pressure conditions, with the values held constant at the initial values, which are taken to be hydrostatic conditions within all formations. Initially all formations are saturated with brine.

Table 1: Characteristics of permeable layers. Shaded rows correspond to formations into which injection is simulated. Data in columns marked with * are from [11].

Aquifer Name*	Top depth	Thickness [m]*	Intrinsic permeability [milliDarcy]*	Wells ending in layer	Maximum injection rate [$MtCO_2$/year]	Wells reached by CO_2 plume after 50 years
Belly River	728.8	56	86	1237	2.8	197
Cardium	1051.8	15	7	1155	0.1	23
Viking	1287.8	30	53	900	1.7	200
Mannville	1461.8	65	7	895	1.0	43
Nordegg/Banff	1537.8	80	4	733	0.7	13
Wabamun	1628.8	160	4	138	1.1	1
Nisku	1881.8	72	170	39	21.4	31
Keg River	2506.8	22	3.5	11	0.2	0
Pika	2844.8	14	16	2	0.6	0
Basal Sandstone	2964.8	38	23	1	2.6	1

Each of the 1,344 existing oil and gas wells within the domain are assigned a finite depth, based on well logs and records. Depending on the depth, any given well will perforate a sequence of caprock formations, and eventually end in a specific formation. We have collectively grouped all of the wells based on the deepest formation penetrated. Table 1 shows this information. We see, for example, that about 900 wells perforate the caprock of the Viking Formation, 733 perforate the caprock of the Nordegg/Banff Formation, and then there is a large drop, to 39 wells, penetrating the Nisku Formation. As must be the case, the number of wells perforating the caprock formation above any given permeable formation decreases as one proceeds deeper into the vertical succession.

The key property assigned to each well segment is the effective permeability. This property is problematic in that we are unaware of any measurements of effective permeability along well segments, with the exception of the recent work of Crow et al. [14]. However, recent analyses of well characteristics indicative of potential well leakage by Watson and Bachu [15, 16] provide guidance to identifying those wells that might be of better quality than others. Watson and Bachu considered a set of attributes for each well in Alberta, inclusive of the study area, including number of perforations, treatment of producing intervals, and abandonment type, and developed a scoring system, summarized in Table 2, meant to represent an overall measure of how likely the well is to leak readily. In our earlier work we had used assumed probability distributions for effective well permeability to assign permeability values to each vertical segment of each well (see, for example, [9] or [12]). Those distributions were bi-modal lognormal distributions with one mode corresponding to intact cement and the other corresponding to degraded cement regions. For the current application, we have used both of these approaches described below.

When assigning effective permeability values to segments of a particular well, we have allowed for two different approaches. The first assumes that all segments along a given well have permeability values that are independent and uncorrelated. As such, each segment is chosen independently from the given probability distribution. The second approach assumes that the quality of materials in a given well is uniform along the entire well, which means that the effective permeability values are completely correlated. In this case, one value of effective permeability is chosen from the probability distribution, and that value is assigned to all segments of the well. The results shown herein assume full correlation of the permeability values along a given well.

Within the Wabamun Lake domain, we have considered injection of CO_2 in a single injection well and single injection layer. All scenarios use a vertical injection well located in the center of the domain, with different scenarios associated with different depths of the injection well.

Table 2: Mapping of well score to mean effective well permeability (data in columns marked with * from [16]).

Deep Leakage Potential*	Score range*	Well effective permeability mean
Low	< 2	$10^{-14.5}$ to $10^{-14.3}$
Medium	2 to 6	$10^{-14.3}$ to $10^{-13.9}$
High	6 to 10	$10^{-13.9}$ to $10^{-13.5}$
Extreme	> 10	$10^{-13.5}$ to $10^{-11.5}$

4. Results

To demonstrate the impact of depth of injection on leakage risk, we consider initially injection into three of the formations in the vertical sequence: the Nordegg Formation, has a mean top depth of 1537.8 meters and a mean thickness of 80 meters; the Nisku Formation, at a mean top depth of 1881.8 meters with mean thickness of 72 meters; and the Basal Sandstone Formation, at a mean top depth of 2964.8 meters with mean thickness of 38 meters. A few key characteristics of these formations, as summarized in Table 1, are the following. Nordegg has a large number of wells that penetrate its caprock formation, its permeability is rather low, and it is not very thick. As such, it has relatively low injectivity (see Table 1), and with its large number of wells it may not be a very good target for injection. The Nisku Formation has many fewer penetrations of its caprock as compared to the Nordegg Formation, it is relatively thick and has fairly high permeability. As such, it appears to be a good candidate for injection. Finally, the Basal Sandstone Formation has only one well penetrating its caprock, so it is expected to have minimal leakage risk.

To show how injections into each of these three formations behave, we inject CO_2 into each of the formations based on the maximum allowable injection pressure. According to injection regulations in Alberta, the maximum bottom hole injection pressure is 90% of the estimated fracture pressure for the formations. We use a fracture pressure gradient of 20 kPa/m, as used in [11]. For each injection scenario, we use two different input distributions for well-segment permeabilities. The first, corresponding to Table 2, maps the scoring system developed by Watson and Bachu [15, 16] into permeability values, and the second uses a bi-modal lognormal distribution with intact cement assumed to have a mean permeability of 0.1 milliDarcy (from [17]) and degraded cement to have a mean of 1 Darcy. Both modes have a variance of one order of magnitude and a weighting of 50%. All simulations use permeabilities along each well segment that are uncorrelated spatially but fully correlated vertically. One thousand simulations are run for each case, and the statistics of the leakage profiles after 50 years of injection are displayed in our results.

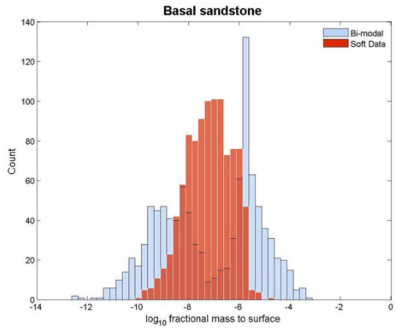

Figure 4: Histogram of CO_2 leakage to surface layer, Basal Sandstone injection.

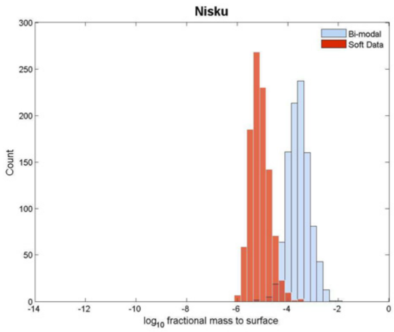

Figure 5: Histogram of CO_2 leakage to surface layer, Nisku injection.

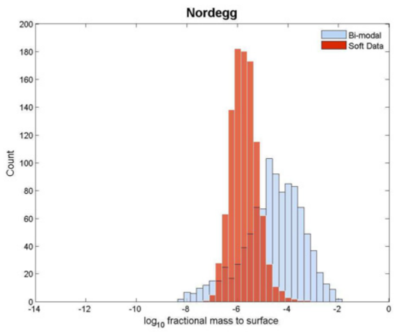

Figure 6: Histogram of CO_2 leakage to surface, Nordegg injection

The flexibility of our model allows us to examine many aspects of the systems, including leakage of both CO_2 and brine in all layers at all times, and propagation of the pressure field into all layers at all times. To illustrate one particular aspect of the system behavior, we display here the amount of CO_2 the leaks into the top layer of the model, which we take to correspond to estimates of CO_2 leakage into shallow zones of the subsurface. Histograms of leakage over the 1,000 runs for each injection case are displayed in Figures 4, 5, and 6.

The results show that, as expected, the lowest risk of leakage is associated with injection into the Basal Sandstone Formation (Figure 4). Because there is only one potentially leaky well in that system, the statistics of the input distribution are reflected in the leakage distributions. We also see, as with the other simulations, that the bi-modal lognormal permeability distribution produces consistently higher leakage estimates than the mapped Watson and Bachu scores [15, 16] because the wells closed to the center of the domain have a low score, which limits the potential leakage. For the Basal Sandstone Formation, leakage is estimated to be less than one-thousandth of the injection mass after 50 years of injection. As such, one would want to inject as much CO_2 as possible into this formation. While our injection strategy is very simple – use of a single vertical injection well – CO_2 storage in this relatively thin formation with moderate permeability is limited by injectivity. More complex injection scenarios, including multiple and/or horizontal wells, are expected to increase the injectivity associated with this formation.

The Nisku Formation has much higher injectivity than the Basal Sandstone Formation, and as such should be considered as the best formation for overall amount of mass of CO_2. The high injection rates that can be achieved (Table 1) lead to a large plume after 50 years of injection. Of the 39 wells that penetrate the caprock above the Nisku Formation, 31 of them are contacted by the CO_2 plume after 50 years. This leads to a higher probability of CO_2 leakage, as illustrated in Figure 5. The bi-modal lognormal distribution again leads to higher leakage rates, and the overall risk of leakage from the Nisku Formation is 2 to 3 orders of magnitude higher than that of the Basal Sandstone Formation. Notice that while the injection location can be chosen in Basal Sandstone to avoid the single well, there is no such choice in Nisku, as the size of the resulting plume means that existing wells cannot be avoided.

The final results in this triplet are for injection into the Nordegg Formation, as shown in Figure 6. As with the other cases, the lognormal distribution again leads to higher risks of leakage. However, while the Nordegg Formation has an order of magnitude more wells penetrating its caprock as compared to the Nisku Formation, the leakage risk is actually lower than for the Nisku Formation. This somewhat surprising result is explained by the low injectivity of the Nordegg Formation – much less CO_2 can be injected into this formation, and the resulting plume size is much smaller than the plume in the Nisku Formation. This results in the number of potentially leaky wells being contacted by the CO_2 in the Nordegg Formation being relatively small (13), thereby leading to relatively little leakage. While this is a good result in terms of leakage risk, it also shows that this formation is not very useful because its injectivity is much too low.

While not shown here, we find different results for the leakage of brine through the leaky wells. As would be expected, injecting into the Basal Sandstone Formation results in the smallest brine leakage rates. However, when comparing the brine leakage resulting from a Nisku injection to that from a Nordegg injection, we find that the normalized brine leakage rate for Nordegg is much higher than that of Nisku. This difference is because the pressure pulse that drives brine leakage expands much more quickly than the CO_2 plume that drives CO_2 leakage. While the CO_2 plume reaches 20 *fewer* wells in Nordegg than in Nisku, the pressure pulse reaches 694 *more* wells, resulting in greater normalized leakage rates. However, we note that this result is strongly influenced by the spatial boundary conditions that are imposed on the 50 km by 50 km domain. Clearly for the Nisku simulations a larger domain is required, and this may change the results of the brine leakage analysis.

5. Conclusions

We have shown that a specialized model, based on a semi-analytical solution framework, can provide quantitative risk assessment evaluations, including insights into how leakage risk changes as a function of depth of injection. In the Wabamun Lake area southwest of Edmonton, Alberta, Canada, where several large coal-fired power plants are located, several different formations could be used for CO_2 storage. Which set of these formations would ultimately be chosen depends on the properties of these formations as well as the number of wells that penetrate the caprock of each of the formations. At this specific field location, the two most promising formations for injection are the Nisku and the Basal Sandstone Formations. The Basal Sandstone Formation has the strong advantage that it has only one well that penetrates its caprock in the 2,500 km^2 domain that was investigated. As such, leakage is minimal and could be monitored and controlled most easily. However, the injection rate is constrained by the relatively low permeability and moderate thickness of the formation. The limitation comes from imposition of a maximum injection pressure, based on estimates of fracture pressure. The Nisku Formation has the highest injectivity, by far, because of its relatively high permeability and its relatively large thickness. While the total number of wells in the Wabamun Lake area exceeds 1,300, only 39 of those wells penetrate the Nisku Formation. However, because the plume that evolves under maximum injection rates fills much of the modeled domain, most of those wells are contact by the CO_2 plume after 50 years of injection, and all of the wells are influenced by the pressure build-up. This leads to a risk of leakage that is several orders of magnitude larger than the risk associated with injection into the Basal Sandstone Formation.

These results highlight a few of a large set of interesting questions associated with design of injection well fields. Which set of formations to choose, where to place the injection wells to control plumes and minimize the number of passive wells contacted by the plume, how to think about horizontal well designs, and how to factor risk reduction into an overall strategy that will ultimately involve options to pipeline captured CO_2 to other locations, form some of the interesting design questions and options. Decisions will require flexible models that can seamlessly integrate different computational approaches, both numerical and semi-analytical, so that the dominant processes and leakage pathways can be captured properly. We believe that such a framework can be developed, and that large-scale injection designs can be pursued successfully in a risk-based framework. Such models can inform decision makers as well as regulators.

Acknowledgements

This work was supported in part by BP and Ford Motor Company through the Carbon Mitigation Initiative at Princeton University.

References

1. Intergovernmental Panel on Climate Change (IPCC), Special Report on CO_2 Capture and Storage. Cambridge University Press, Cambridge, UK, and New York, NY, USA, 2005.
2. S.E. Gasda, S. Bachu and M.A. Celia, Env. Geol. No. 46:6-7 (2004) 707.
3. J.M. Nordbotten, M.A. Celia and S. Bachu, Water Resour. Res. 40:4 (2004) W04204.
4. J.M. Nordbotten, M.A. Celia, S. Bachu, S. and H.K. Dahle, Env. Sci. Technol. 39:2 (2005) 602.
5. J.M. Nordbotten, M.A. Celia and S. Bachu, Transport in Porous Media 58:3 (2005) 339.
6. J.M. Nordbotten and M.A. Celia, J. Fluid Mech. 561 (2006) 307.
7. J.M. Nordbotten and M.A. Celia, Water Resour. Res. 42 (2006) W08433.
8. J.M. Nordbotten and M.A. Celia, Env. Sci. Technol. (2008) in press.
9. M.A. Celia, S. Bachu, J.M. Nordbotten, D. Kavetski and S.E. Gasda, Proc. 8th Int. Conf. Greenhouse Gas Control Technologies, Trondheim, Norway, June 19-22, 2006, CD ROM, Elsevier , (2006).
10. S. Bachu and M.A. Celia, AGU Monograph *The Science and Technology of Carbon Sequestration*, 2008, in press.
11. K. Michael, S. Bachu, B.E. Buschkuehle, K. Haug and S. Talman, AAPG Studies 59 *Carbon Dioxide Sequestration in Geological Media – State of the Art*, 2008, 1.
12. D. Kavetski, J.M. Nordbotten and M.A. Celia, Proc. XVI Conf. Computational Methods in Water Resources, Copenhgen, Denmark, June 19-22, 2006.
13. S.E. Gasda, J.M. Nordbotten and M.A. Celia, IES Journal A: Civil and Struct. Eng. No. 1:1 92008) 2.
14. W. Crow, B. Williams, J.W. Carey, M. Celia and S. E. Gasda, Proc. 9th Int. Conf. Greenhouse Gas Control Technologies, Washington, D.C., November 16-20, 2008.
15. T.L. Watson and S. Bachu, Paper SPE 106817, 2007.
16. T.L. Watson and S. Bachu, Paper SPE 112924, 2008.
17. J.W. Carey, M. Wigand, S.J. Chipera, G. WoldeGabriel, R. Pawar, P.C. Lichtner, S.C. Wehner, M.A. Raines and G.D. Guthrie, Int. J. Greenhouse Gas Control 1:1 (2007), 75.