TOPICAL REPORT: RESERVOIR ENGINEERING OPTIMIZATION STRATEGIES FOR SUBSURFACE CO_2 STORAGE

Type of Report: Topical Report

Reporting Period Start Date: December 8, 2009
Reporting Period End Date: September 30, 2013

Principal Authors of this report:
Blayde McIntire, University of Utah
Brian McPherson, University of Utah

Date Report was Issued: December 31, 2013

DOE Award Number DE-FE0001812

Submitting Organization:
University of Utah
Department of Civil and Environmental Engineering
Salt Lake City, Utah 84112 USA

DISCLAIMER

Abstract

The purpose of this report is to outline a methodology for calculating the optimum number of injection wells for geologic CCS. The methodology is intended primarily for reservoir pressure management, and factors in cost as well. Efficiency may come in many forms depending on project goals; therefore, various results are presented simultaneously. The developed methodology is illustrated via application in a case study of the Rocky Mountain Carbon Capture and Storage (RMCCS) project, including a CCS candidate site near Craig, Colorado, USA. The forecasting method provided reasonable estimates of cost and injection volume when compared to simulated results.

Table of Contents

Executive Summary

The long-term success of Carbon Capture and Storage (CCS) as an industry depends on effective risk management and cost efficiency. Reservoir pressure-buildup associated with injection induces minor seismic events in all subsurface reservoirs, and thus such will necessarily be an outcome of CCS operations, too. Perhaps the simplest approach is to modulate injection rates to maintain bottom hole pressure (BHP) below the theoretical fracture pressure of the reservoir that is assumed to be 80% of the lithostatic pressure.

A reservoir model was created for simulating numerous injection well configurations for a typical CCS field operation. Due to time constraints, 10 m injection cells (in the model grid) were chosen to balance error and computational efficiency. Results of this study include plots of injection volume versus number of injection wells, or "injection curves," for a broad range of reservoir parameters evaluated in a comprehensive sensitivity analysis. One injection well proved to inject the least amount of fluid of the tested well configurations. In all cases, the largest injection coincided with the most wells. Injectivity was most sensitive to permeability; injection volume changed by nearly an order of magnitude for an order of magnitude change in permeability. Effects of less sensitive parameters were summarized by their effects to the permeability injection curves. A cost function was developed and applied to all results from the sensitivity analysis to determine cost efficiency. The full set of results may be interpolated to forecast an optimal number of wells for most scenarios. Generally, the optimal number of wells that facilitates the lowest cost of CO_2 per tonne is between four and eight wells. Injection scenarios with a single injection well proved to be the least efficient.

The optimization methodology developed here was applied to a site near Craig, Colorado, under the auspices of the Rocky Mountain Carbon Capture and Storage (RMCCS) project. All results suggest potential subsurface storage may be maximized by careful BHP management through optimized well placement strategies. In this case study, injections were simulated for several well configurations, and results were consistent with the generalized analysis.

Perhaps the most important outcome of this work is a set of recommendations for future work necessary for improving optimization. Specifically, error imposed by injection cell sizing, especially with numerous injection wells, requires extensive future research. Here, only results from single-well injection were evaluated and discussed. Future analyses would benefit from assigning correction coefficients (to model results) to account for cell-sizing bias. However, telescoping grids with very small injection cells may be used whenever possible to ensure more robust results. Other optimization techniques should be investigated, especially if horizontal wells or other special well types are possible. Specifically, horizontal injection wells may provide lower reservoir pressures and therefore higher injection rates. Yet another approach is to optimize well spacing in the Enhanced Oil Recovery (EOR) process where injection and production wells reside within the same field.

This report is based on the MS Thesis research study performed by the senior author, and thus is organized in the original chapters of that thesis.

Narrative

CHAPTER 1

INTRODUCTION

1.1 Overview

Carbon Capture and Storage (CCS), also known as CO_2 sequestration, is an emerging technology under investigation for its ability to reduce greenhouse gas concentrations in the atmosphere. Specifically, storage in deep subsurface reservoirs is a particularly appealing option because of the high potential storage capacity. It is understood that geological subsurface injection and storage may lead to increased subsurface overpressures and associated induced seismicity. The National Academy of Sciences recently published a report that cites CCS as a technology that "may have potential for inducing larger seismic events" and therefore, the study of pressure regimes resulting from large-scale fluid injections is of great importance (National Research Council, 2012). Subsurface pressures may be simply managed with smaller injection volumes. However, for CCS to have its desired impact on emissions reduction, many large-scale CO_2 injection operations would be necessary. While the risks associated with induced seismicity may never be fully mitigated, several ways to reduce risk are possible. Overpressures may be reduced by selecting reservoirs with favorable injection characteristics, including high permeability and high porosity. Unfortunately, if CCS is to be a viable approach, nonideal reservoirs and injection sites will be needed. For these nonideal reservoirs, it is even more important to manage reservoir pressures.

The National Academy study utilizes an inherent assumption that CCS sites will use one injection well, or at least will necessarily require exceedingly high injection rates. Analogous oil fields, in contrast, use many production wells to avoid localized pressure anomalies. The research presented here examines pore pressure and injectivity for a range of injection (well) configurations, for the sake of designing an optimized CCS strategy through the use of multiple wells. The first step in the study was to develop a conceptual model, then a numerical model based on that conceptual model, with specific attention paid to grid resolution. Second, generic trends relating the number of wells to injectivity are identified through a sensitivity analysis. Parameters tested for their relative roles are: permeability, porosity, compressibility, reservoir thickness, reservoir depth, heterogeneity, simulation time, and injection fluid composition. A cost-optimization function is then applied to the results of the sensitivity analysis to identify the optimal number of injection wells for a range of injection scenarios. With the methodology and results presented here, it is possible to forecast injection volumes, project cost, and the optimal number of wells for a proposed CCS project. This process is illustrated with a case study of the Rocky Mountain Carbon Capture and Storage (RMCCS) project, a CCS candidate site near Craig, Colorado, USA. The intent of this methodology is to aid the site selection process, streamline decisions, and increase the overall effectiveness of CCS in the future.

1.2 Literature Review

Reservoir overpressurization, especially due to fluid injection, has been directly linked to seismicity. Raleigh *et al.* (1976) investigated fracture mechanics with the use of field measurements. Their work began after fluid injection was believed to be the cause of earthquakes near Rangely, Colorado as early as 1966. By monitoring down-well pore pressures and seismic activity during injection periods, they determined that effective stress was greatly reduced during injection. Hydraulic fracturing occurs at the point where shear stress overcomes effective stress. Similarly, Majer and Peterson (2007) concluded that injecting additional fluid into a geothermal system is directly linked to seismicity near The Geysers, California.

Understanding in-situ pressure at a given site is important for determining when seismicity might occur. Nonhydrostatic pressure anomalies have three main causes, at minimum (Osborne and Swarbrick, 1997). These three causes are: changes in compressive stress, fluid volume change, and fluid movement. Although fluid injection is not explicitly mentioned, all three of these processes may be associated with injection as well as other mechanisms. Injection is most closely related to fluid volume change. Osborne and Swarbrick assumed that the primary volume change is associated with thermal expansivity. Later models such as Hurwitz *et al*. (2007) and Reid (2004) simulated fluid expansion due to geothermal intrusions, and heat flow in general, as injection. Pore compaction and expansion may also be a source of fluid volume change; for example, McPherson and Bredehoeft (2001) assigned an injection term to represent changes in specific storage associated with fluid volume changes associated with compaction. Heat flow models have been more widely studied than other injection modeling techniques and provide analogies for fluid injection.

Besides the simplest methods of pressure mitigation discussed previously, other pressure management strategies have been the subject of recent work. Zhou and Birkholzer (2011) investigated pressure buildup in closed, partially-closed, and open systems. They use case studies of the Illinois Basin as an open system, and the San Joaquin Basin as a partially closed system. Conclusions drawn suggest that pressure is reduced in open systems because fluid is allowed to flow out of the domain. Closed or partially-closed systems create larger pressure buildup because fluid cannot as easily flow out of the model domain. However, leaky seals can serve as a mechanism to reduce pressure over time. Injectivity may still be the overall controlling factor in either scenario. The Illinois Basin case study required 1,200 years of simulated time before reaching capacity due to low injection rates. Pressure buildup over time is analyzed by Zhou *et al.* (2008). Pressure anomalies within complex, up-dip, open systems are discussed by Nicot (2008), who uses 50 wells with very high injection rates to instigate a pressure pulse, but the overall pressure buildup proved to be small. Closed systems are the subject of Economides and Economides (2010). Partially closed systems are discussed by Cavanagh and Wildgust (2011). Buscheck *et al.* (2012) investigate another method of pressure mitigation through brine production. Included in their research is a sensitivity analysis of well spacing. They illustrated that pressure is a function of well spacing, but did not offer an optimal well spacing. Hawkes *et al.* (2005) mention injecting into reservoir "sweet spots" and the use of horizontal injection wells to avoid hydraulic fracturing. Four corrective measures for mitigating overpressure are identified by Guenan and Rohmer (2011): 1) stop injection with natural recovery; 2) extract CO_2 at the injection well; 3) extract brine at a distant well while stopping CO_2 injection; and 4) extract brine at a distant well with ongoing injection. Of the four, the first option proved the most efficient.

Useful analogies are drawn from work in groundwater withdrawal. Theis (1935) first derived the analytical solution to groundwater drawdown at any radius from a producing well. His solution assumed an unconfined aquifer and infinite lateral extents. Others have derived similar equations for other aquifer boundary conditions, but always for groundwater drawdown. These solutions are useful for the case of water injection too, however. Drawdown is, by definition, a representation of a change in head. Pressure buildup is a change in head in the opposite of drawdown. These findings make it possible to build upon groundwater withdrawal studies. A few studies have investigated optimizing withdrawal through well placement and rates (Gorelick and Vasco, 1984; Ratzlaff *et al.*, 1992; Tiedeman and Gorelick, 1993).

Many sequestration models have been used to investigate the subsurface effects of CO_2 injection since the mid-1990s. Law *et al.* (1996) completed a preliminary study for a proposed injection site in Alberta, Canada. Their sensitivity analysis found that permeability is the most influential parameter for injectivity if reservoir overpressurization is to be avoided. In the process, they developed an equation for injectivity that included many parameters, but only included one injection well. Li *et al.* (2005) investigated the concept of breakthrough pressure and leakage potential at the Weyburn, Canada site. Many sites have been investigated for CO2 sequestration. Koornneef *et al.* (2012) have summarized the knowledge base which has been achieved by these studies. Hydraulic fracturing has been cited as the primary risk associated with a few projects. Michael *et al.* (2010) provides insight into three large injections that are currently underway at Sleipner, Snøhvit, and In Salah. One of the findings of the report is that there is a need for more experience with numerous injection wells as a method for risk mitigation. Another Sleipner application is found in the best-practices manual of Chadwick *et al.* (2008). Later, Chadwich *et al.* (2009) completed a sensitivity analysis for several important reservoir parameters with focus on flow and pressure evolution. Other injection sites are detailed in Malek (2009) and Michael *et al.* (2009). Both of these are of interest because they use multiple injection wells. Preliminary studies at Gorgon in Australia (Malek, 2009) found that hydraulic fracturing can be avoided with a nine-well injection pattern.

Incorporating coupled poroelasticity models with injection well configurations will be the subject of future research. Previous works provide the building blocks for this research. Hsieh (1996) modeled the head change and deformation due to fluid withdrawal. This provides a method that could easily be coupled with pressure regimes to calculate ground surface displacement. Hydrothermal systems related to volcanism are presented by Hurwitz *et al.* (2007). Their poroelasticity equations provide an analogy of what can be expected during injection. Vasco *et al.* (1988) took a somewhat different approach by back-calculating subsurface deformations from known ground surface deformations. Pressure calculations could also be derived with this technique to provide a check against modeled pressures.

1.3 Hypotheses

Four hypotheses are evaluated here. Throughout the course of this report, they are either proved or disproved. First, it is hypothesized that simulated pressure regimes and injection volumes are dependent on injection cell size. Balancing accuracy and computational efficiency is important to the modeling process. Within a numerical reservoir model, grid resolution or cell size in the vicinity of injection wells has profound effects on both. It is hypothesized that injection cell size will impose quantifiable bias on simulation results. Pressure and injectivity forecasts are especially sensitive to cell size. The approach of this study is to compare injectivity values and pressure regimes for several different injection cell sizes. Results are compared to an analytical model before making a statement on the error imposed by each of the tested sizes. An injection cell size is chosen to balance accuracy and computation time.

Second, it is hypothesized that injectivity is most sensitive to changes in permeability of all reservoir parameters. Several reservoir parameters are investigated for their impact on injectivity, via sensitivity analysis. Among all deep saline reservoir parameters, it is hypothesized that injectivity is most sensitive to permeability. Injection volume is primarily a function of permeability, and the number of injection wells is also important. Accordingly, injection volume will exhibit less sensitivity to other parameters.

Third, it is hypothesized that an optimal number of wells exists for any injection scenario. The primary goal of this research is to prove that, for CO_2 injection into deep saline formations, injecting CO_2 through more than one well will result in lower pressures and will therefore reduce the potential to induce seismicity compared to single well injections. Conversely, more wells should allow for larger injection volumes before reaching the hydraulic fracture pressure. It is hypothesized that an optimal well configuration exists for any scenario that will optimize the relationship between injection volume and project cost. A useful cost function is identified. The relationship is applied to the previously developed injection curves to calculate an optimal number of wells for each scenario developed in the sensitivity analysis.

Fourth, it is hypothesized that results from the sensitivity analysis may be used to forecast results for other, case-specific models. With the numerous injection curves and optimization results, interpolation should give decent estimates for other models. A demonstration is provided in the form of a case study. For the case study site, the analysis approach is used to estimate injection volume, project costs, and the optimal number of wells. Simulations are conducted on the case study model to test all estimates.

1.4 Conceptual Model

The initial conceptual model is that of a simple, homogeneous, single-phase (water only) reservoir. The code selected to simulate this simple model is TOUGH2 (Pruess, 1991), a simulation package used extensively to simulate subsurface fluid flow. However, its grid-size limitation is not practical for the size of domain needed for this study. A multiple processor version, TOUGH-MP, is used to allow for grids with hundreds of thousands of cells. A generalized 3D, single-phase model is used to investigate pressure buildup and injectivity values with water injection. First, a sensitivity analysis is completed for several important model parameters. The tested values have been chosen to represent feasible reservoir values. Results are then compared to results of simulated multiphase flow with CO_2 injection to quantify how much error may be attributed by using water as the injection fluid (in a single-phase system). Later, the methodology is applied in a case study.

Model dimensions and parameters are chosen to represent a typical deep saline formation that has sufficient lateral extent to be modeled as an open system. No-flow boundaries are used for the top and bottom of the single layer to mimic extremely low-permeability seals. Injection is simulated in the middle of the formation thickness at 2,000 m depth. The formation is 100 m thick and the perforation zone is the middle 20 m of the layer. For this generic model, the parameters are both homogeneous and isotropic. The base case permeability was chosen to be 1E-15 m^2 and porosity was initially set at 10%. These parameters provide a less-than-ideal injection scenario in which localized overpressures exist. Theoretically, these conditions necessitate use of multiple injection wells to reduce the risk of induced seismicity. Simulation time was set at one year for all cases bar the sensitivity analysis on simulation time. Rock compressibility was set to zero for the base case.

Pressure is the factor of interest for injection simulations. Injection rates were maximized to achieve pressures just below the fracture pressure. Hydraulic fracturing is often assumed to occur between 70 and 90% of the lithostatic pressure (du Rouchet, 1981). For the purposes of this study, 80% of lithostatic is used. Using the rock density of 2,650 kg/m^3, the formula to calculate the lithostatic pressure is simply the product of density, gravity, and depth. Injection rates are maximized to maintain the maximum reservoir pressure just below the fracture pressure. In TOUGH-MP, this is done by interpolating between two sets of injection rates and resulting pressures. The relationship between injection rate and maximum pressure is perfectly linear.

1.5 The Principle of Superposition

Interactions between wells are of utmost importance in finding the most effective well configurations. The governing principle is known as pressure superposition (Freeze and Cherry, 1979). This relationship is depicted in Figure 1, which shows the combined pressure regime from two wells. The two wells are located at 40 m and 140 m on the horizontal axis. Dotted lines depict the theoretical pressure regimes from a single well if it were modeled individually. The principle states that the combined pressure regime from two wells is simply a linear function of the two individual pressure regimes. All pressures are relative to hydrostatic, or in other words, it investigates ΔP rather than absolute pressure. The combined predicted line adds the individual ΔP values from each of the wells at every point in the model. These results are confirmed with a TOUGH2 simulation of the same model. The predicted and simulated results are identical.

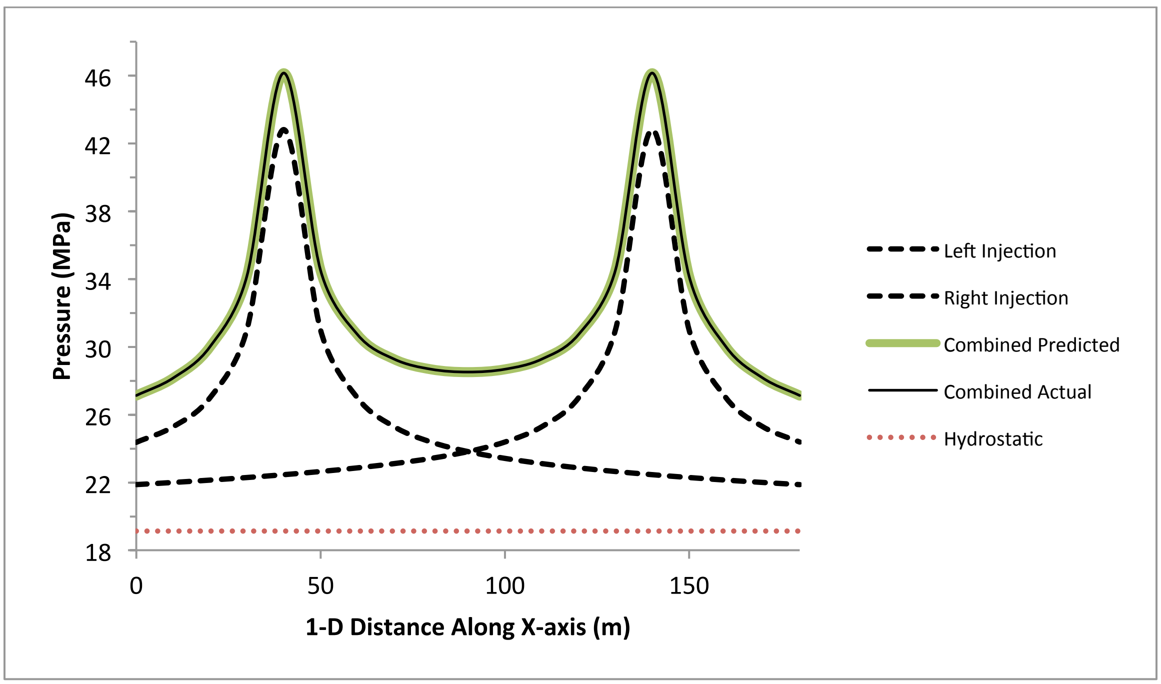

Figure 1. Pressure superposition example showing hydraulic communication between two injection wells.

These results have major implications for modeling interwell relationships, at least for most situations. First, it gives insight into which well configurations may be the most effective for a given number of wells. Theoretically, the distance between wells should be maximized in order to maximize the injection. In what shall be deemed the “maximum perimeter pattern,” wells are placed at even intervals around the perimeter of an available plot of land. This is in contrast to the traditional “infill patterns” that are typically employed in oil field operations which place a single well in the interior of a pattern. Such a well configuration is necessary to optimize operations that include both injection and production. However, the conceptual model presented here includes injection only. By the principle of superposition, an interior well never benefits the pressure regime, and therefore will only serve to decrease injection.

Figure 2 shows a comparison of the maximum perimeter and infill patterns with 16 wells each. The infill pattern places four wells on the interior and 12 wells on the edge of the available land area. Typically, five- or nine-spot patterns are used for infill patterns where a single interior well is used. A 16-well infill pattern is not used in practice, but serves as an appropriate example here. The maximum perimeter pattern places all 16 wells evenly around the perimeter of the area.

With identical injection rates, the disparity in pressure distribution between the two patterns is obvious. The infill pattern results in a much larger area of high pressure on the interior of the area. Therefore, if the bottom hole pressure (BHP) was capped at (limited to) the same pressure for each pattern, the maximum perimeter pattern would allow for larger injection volumes. Simulations have proven that the infill pattern does not inject as much fluid. All simulations utilize the maximum perimeter pattern unless otherwise specified.

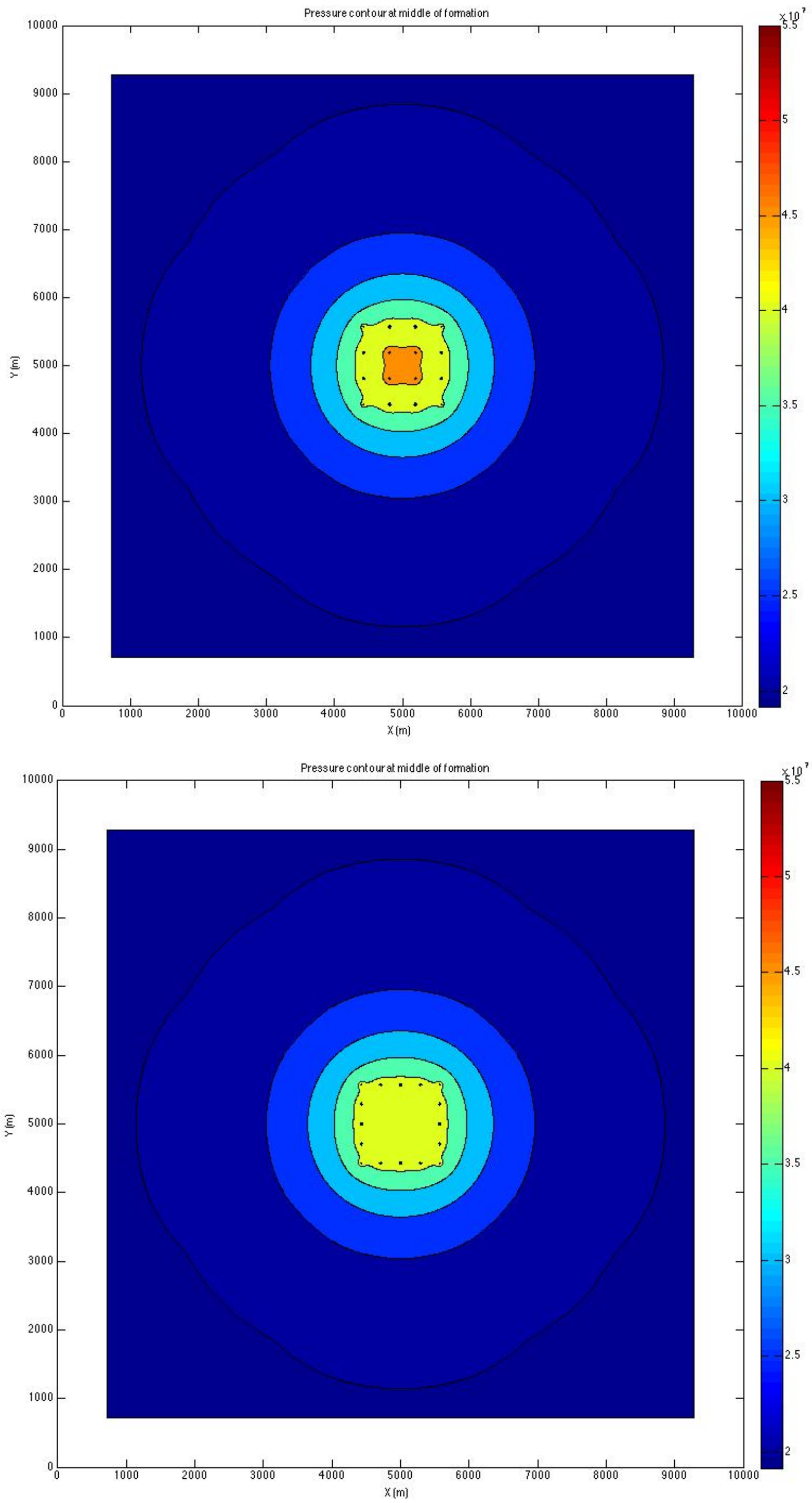

Figure 2. Comparing pressure contours (Pa) at the middle of the formation for the a) 16-well infill pattern and b) 16-well maximum perimeter pattern.

1.6 Approach

Well spacing is not the most critical factor for reservoir management. In simplest terms, the best well spacing is the maximum possible, to avoid superposition and inject the most fluid. However, a better approach is to optimize injection by combining many permutations of well spacings and well patterns.

The approach used here assumes that for every CCS project, only a definitive, limited amount of land might be available. This is more pertinent to actual injection scenarios. For example, a project might have a certain amount of land available and the goal is to optimize injection for that land area. Under this premise, injections are simulated for one, two, three wells, and so on to develop an “injection curve” showing injection volume versus the number of wells. Each well configuration places wells in the maximum possible perimeter pattern. Unique curves are developed for square plots of land sized 2.5, 5, 10, 20, 40, 80, 160, 320, 500, and 1,000 acres. First, curves are developed for each of the base case parameters. The sensitivity analysis then yields general trends for how the base case injection curves may be impacted by the range of each tested parameter. Cost optimization curves are developed by applying economic dependencies to the injection curves. For any injection scenario, interpolations using the full set of curves provide a simple tool for prediction of injection volumes, project costs, and the optimal number of wells.

CHAPTER 2

SENSITIVITY ANALYSIS ON GRID RESOLUTION

2.1 Overview

Lateral grid resolution is a very complex issue. The objective of this analysis is to find a balance between computational efficiency and accuracy. Injection cells are located in the 1,000 acre center of each model to correspond with the largest area of land that was tested. Beyond the injection cells, the grid-size increases (or "telescopes outward") with each successive cell outward being 1.5 times larger than the previous. Ideally, the injection cells would be as small as a wellbore. However, because many different well configurations are tested on the grid, it is not practical to use extremely small cells on the interior of the model. It is imperative that the entire swath of injection cells be the same size such that results are comparable between different scenarios. By comparing results from different sized cells, it is possible to investigate the amount of error that is generated by using injection cells that are larger than a wellbore. A method for quantifying the error between cell pressure and BHP is discussed by Peaceman (1978). The Peaceman (1978) method calculates the correct BHP using cell size and simulated injection cell pressure. With this method, it is possible to assign correction coefficients to pressure and likewise to injection volumes. Those results are not discussed further here. Rather, for simplicity, rough estimates of error are drawn from simulated injection volumes.

Single well injections were simulated with several different interior cell sizes: 1 m, 10 m, 50 m, and 100 m. Cells as small as 1 m are thought to be representative of an actual wellbore size. Although an actual wellbore may be smaller than 1 m in diameter, it was not practical to model anything smaller for the sensitivity analysis due to computational limitations. The initial analysis showed that there is in fact a large disparity in results for different cell sizes. The smaller 1 m injection cells allow an injection rate of 1.48 kg/s while the 10 m cells allow 2.72 kg/s with one injection well to reach the fracture pressure, an increase of nearly 84%. Larger cell sizes result in even more error (Figure 3). However, 1 and 10 m cells appear to have similar relationships with well spacing. An analysis with 2.5 acres shows that these two cell sizes have almost identical relationships, although they are offset by as much as 84% (Figure 4). These results suggest major implications for any sort of fluid injection modeling.

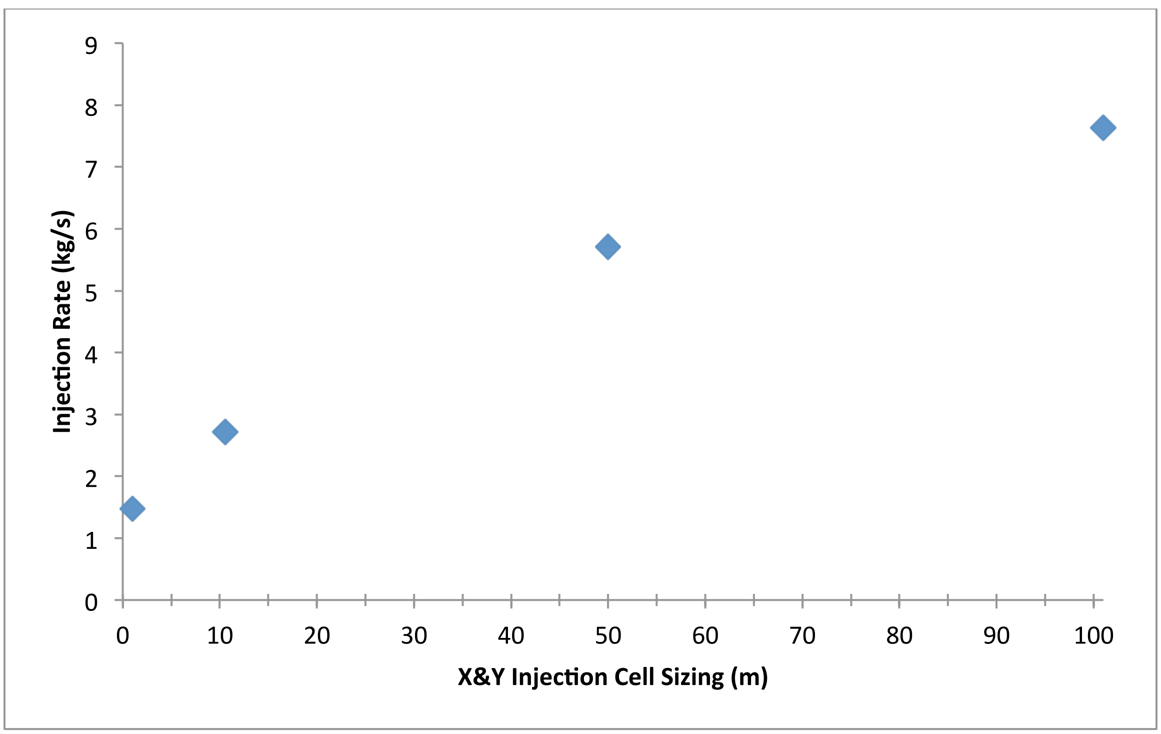

Figure 3. One-well injection rates with various lateral cell sizings show increasing injection rates with increasing cell sizes.

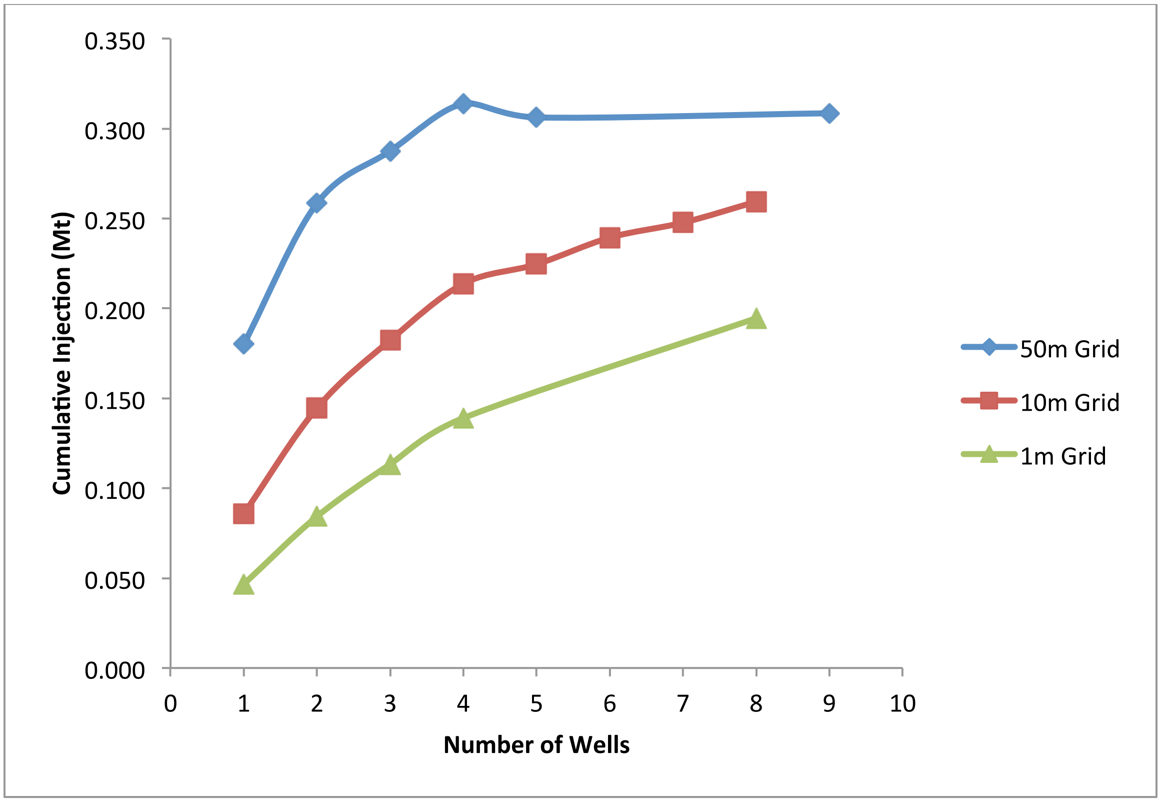

Figure 4. Injection relationships with 2.5 available acres illustrate similar relationships for 1 and 10 m cells, but not larger cells.

2.2 Sensitivity Analysis

The next step in this analysis is to evaluate localized pressures near the injecting well for different cell sizes. Grids with the same 1 and 10 m cells were evaluated with 0.5, 1.0, and 2.0 kg/s injection rates. Results of this sensitivity analysis (Figure 5) indicate that the grid with 10 m cell size does not sufficiently illustrate localized pressure gradients at the injection location. This particular error is uniform for all three rates when comparing the difference between simulated and hydrostatic pressures. For example, with an injection rate of 2.0 kg/s, the grid with 1 m cell size results in a pressure change from 19.13 MPa to 50.12 MPa, or ΔP = 30.99 MPa. The 10 m cell size grid induces a pressure change from 19.13 MPa to 36.10 MPa, or ΔP = 16.97 MPa (45% less). Similarly, the other injection rates result in errors of 45% when comparing ΔP

relative to hydrostatic. Second, Figure 5 shows that the error caused by the 10 m cell size grid is essentially not present in the next cell adjacent to the injector (10 m away). Errors are exhibited only in the injecting cells. Another observation is shown in Table 1 where 1D pressure regimes are given for several grid formats. Pressures from the smaller 1 m grid are compared to pressures from the larger 10 m grid. In both cases, the injection cell is located at 0 m. Additionally, the average pressure value of 10 adjacent 1 m cells is calculated. The simulated injection cell pressure of the 10 m grid is nearly the same as the average of the pressure values from the surrounding 10 cells of the 1 m grid.

The next step in the analysis is to quantify the amount of error caused by assigning different (larger) cell sizes. One approach is to compare numerical results to an analytical solution. Matthews and Russell (1967) investigated analytical solutions to many different injection scenarios, all of which are derived from the diffusion equation. The most useful model for this application appears to be:

$$\Delta P = \frac{162.6 q \mu B}{kh}\left[\log \frac{kt}{\emptyset \mu c r_w^2} - 3.23\right] \qquad (1)$$

where ΔP is the change in pressure due to injection (psi)); q is the injection rate (bbl/d); μ is fluid viscosity (cP); B is the formation volume factor (assumed to be 1); k is permeability (mD); h is the formation thickness (ft); t is the simulation time (hrs); $\emptyset$ is porosity (fraction); c is rock compressibility (psi^{-1}); and r_w is the lateral radial distance from the injection well (ft). Constants are used to modify the diffusion equation for typical field units. The values of these variables are summarized in Section 1.4. In the analysis, the injection rate was increased to 2 kg/s (1449 bbl/d), a much larger rate, to amplify visible results compared to smaller injection rates. The lateral distance to the well is varied to induce a lateral pressure distribution. For the analytical solution, the

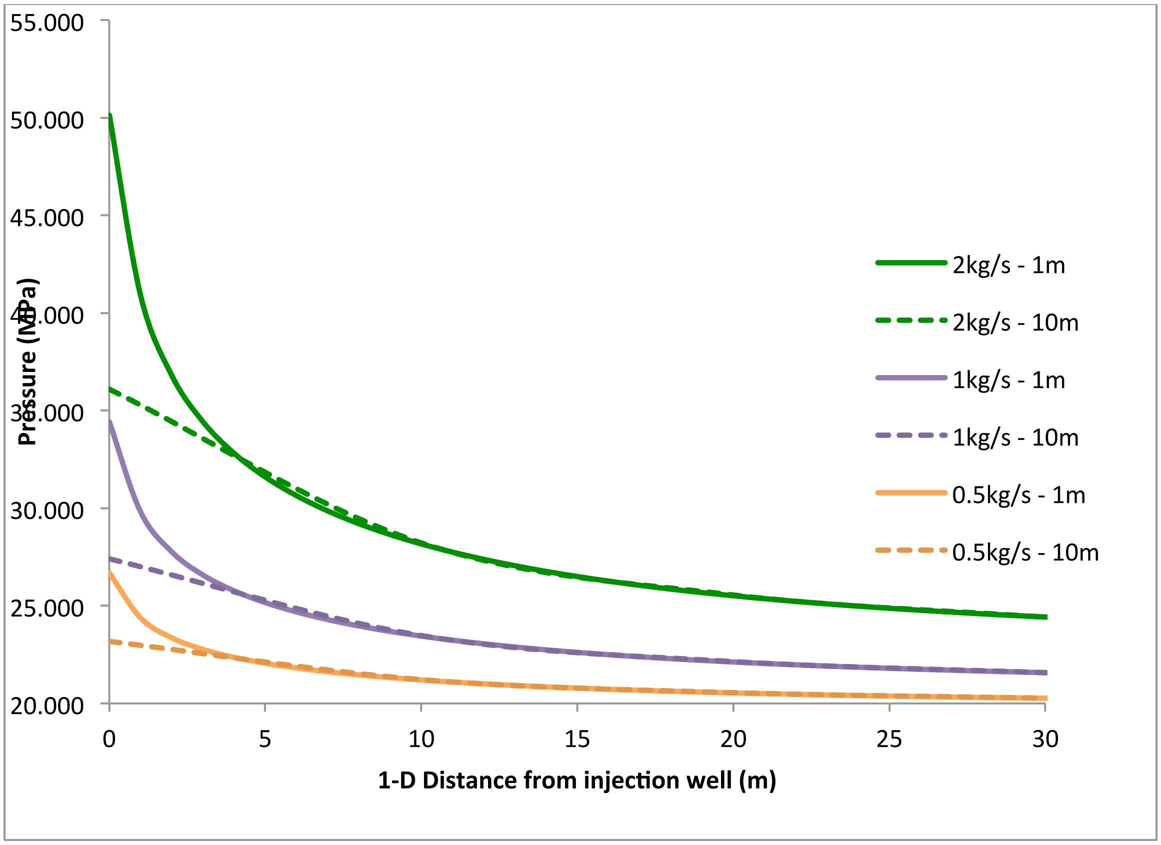

Figure 5. Grid size sensitivity for three injection rates.

Table 1. Approximating 10 m grid pressures as an average of 10 adjacent 1 m cells.

Distance from Injector (m)	1m Grid Pressure (Mpa)	10m Grid Pressure (Mpa)	Average of surrounding 10 - 1m cells
-5	25.165		
-4	25.771		
-3	26.582		
-2	27.772		
-1	29.829		
0	**34.417**	**27.415**	**27.696**
1	29.829		
2	27.772		
3	26.582		
4	25.771		
5	25.165		

water viscosity is assumed to be a function of temperature only, and therefore is assigned a value of 0.36235 at reservoir conditions. The only remaining variable is compressibility. TOUGH2 defaults compressibility to zero, which cannot be used for the analytical solution because the result is an undefined number. This will be discussed in some detail subsequently.

This particular analytical model has a few key assumptions and limitations. Similar to the simulation model to which it is compared, the analytical model assumes single-phase fluid flow with an incompressible fluid in a homogeneous reservoir. Notably, this solution is to be applied only to a laterally-infinite reservoir. Through use of a very large grid, the simulation model effectively employs this same assumption. A major difference between the analytical and simulation models is the perforation zone, the portion of the wellbore in the reservoir which has been opened to fluid injection. The analytical model assumes that the entire reservoir is perforated whereas the simulation model has only perforated the middle 20 m of the reservoir within the injection cell.

Results of several simulations were compared to the corresponding analytical solution in an effort to determine which injection cell size is most accurate (Figure 6). In addition to the 1 m and 10 m cells, 0.1 m injection cells were simulated. These smaller cells are more similar in size to an actual wellbore. Because all previous analyses have assumed a partial perforation zone rather than a fully perforated reservoir like the analytical model, full and partial perforations are simulated and compared. Several permutations of cell sizing and perforation interval are compared to the analytical solution with injection rates of 2 kg/s through a single well in the middle of the domain for one-year simulation duration. However, because TOUGH2 assumes zero rock compressibility, a value of effective compressibility was back-calculated from one of the simulations. For this, the simulation with 0.1 m injection cells and full reservoir perforation was chosen as the benchmark. This permutation was thought to be the

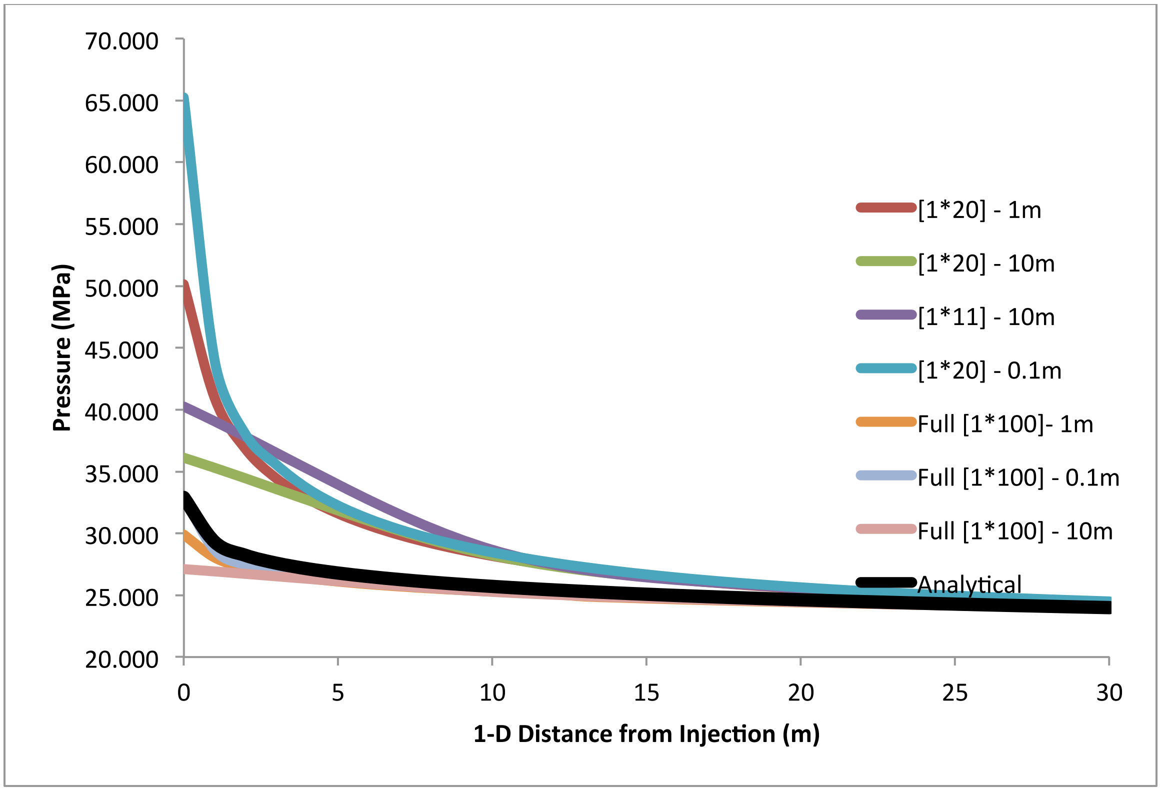

Figure 6. Comparison of several pressure regimes to the analytical solution. Bracketed numbers indicate first the number of injection cells and second the z-dimension perforation (m). Dimensions after the dash indicate x- and y-dimension cell sizing.

closest in dimension to the analytical model. The "goal seek" function of Excel © was used to match the injection cell pressures of this simulation model to results of the analytical model. Rock compressibility was then back-calculated and identified to be 4.13E-09 Pa^{-1}, an extremely high value for compressibility. The back-calculated value may compensate for other parameters from the analytical solution that do not exactly match the modeled parameters.

An important observation is that injection cell size, as well as perforation size, can have a dramatic effect on pressures in the vicinity of a well. Smaller injection cells appear to be more effective for quantifying even the most extreme pressure gradients in the vicinity of the injecting well that courser grids cannot capture. This concept is illustrated by the results summarized in Table 1.

As might be expected, simulations which utilized fully-perforated reservoirs were much more similar to the analytical solution than the simulations with partially-perforated reservoirs. In each case, partially-perforated injection interval simulations resulted in much higher local pressures than their fully-perforated counterparts. This is thought to be due to (1) smaller injection cell volumes (for the same injection rate), and (2) pressure migrating both vertically and horizontally. Specifically, with respect to (1), it is intuitive that injecting the same amount of fluid through a smaller volume will result in higher pressures. With respect to (2), the pressure gradient is steeper for partially perforated reservoirs compared to fully perforated reservoirs because the pressure plume can spread vertically as well as horizontally. In a fully perforated reservoir, fluid is injected all along the vertical axis; therefore, no vertical plume spreading occurs. A consequence of vertical spreading in partially perforated reservoirs is that the pressure in the adjacent lateral cell is lower. Such is not the case in fully perforated reservoirs where the pressure can only spread laterally, and the pressure gradient is lower.

Additionally, all of the pressure regimes converge in 30 m. Therefore, if more injecting wells are added, and assuming they are more than 30 m apart, the pressure plumes will behave similarly with respect to pressure superposition between wells regardless of cell size.

These findings are checked in ECLIPSE, a Schlumberger reservoir simulation software. The check is performed for several of the simulations, for sake of 1) checking the pressure regimes with another simulator, for consistency, and 2) to confirm that the value of calculated rock compressibility is consistent for a separate simulator. The original model with 10 m cells and partial perforation was tested and compared to the analytical solution, along with the following additional permutations: 1 m partial perforation and 1 m full perforation. All of these were tested with the back-calculated compressibility value of 4.13E-09 Pa^{-1}. For an additional reference, the 1 m partial perforation simulation was tested with the Eclipse default compressibility value (4.934E-10 Pa^{-1}) rather than the TOUGH2 back-calculated value. Results are shown in Figure 7. The figure indicates that the results are consistent between the TOUGH2 and ECLIPSE codes. Both partial and full perforations yield similar results, save for a slight offset between all TOUGH2 and ECLIPSE values that are most likely due to slightly different values for some default parameters. Although 0.1 m cell sizes were not tested, it follows that the results would be similar. The single default compressibility simulation shows that the lower back-calculated compressibility value gives lower pressure values.

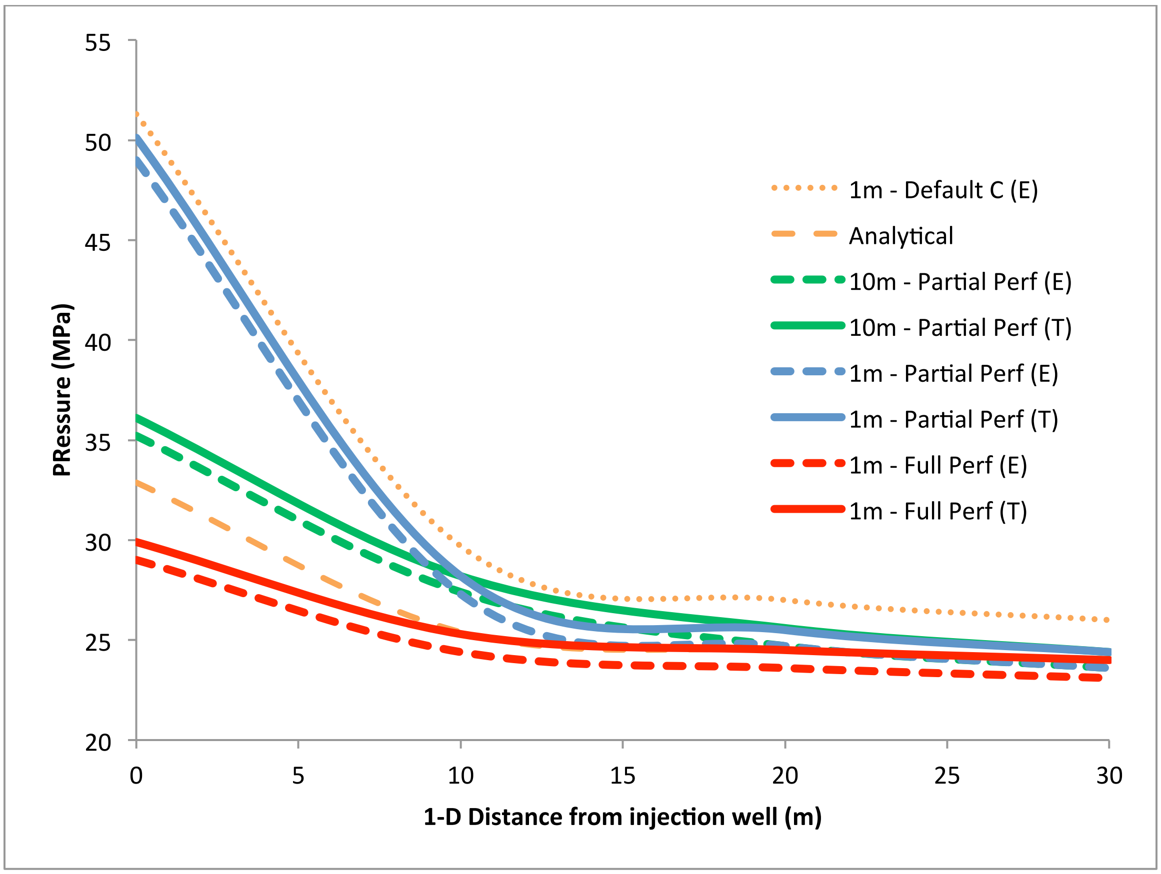

Figure 7. ECLIPSE check of several cases from the cell sizing analysis. Parentheses indicate results from either ECLIPSE (E) or TOUGH2 (T).

2.3 Conclusions

The grid sensitivity analysis provides many useful conclusions. First and most importantly, the selection of injection cell sizing is critical. Injectivity model results depend on the sizes of grid cells and simulated perforation zones. It is recommended that an injection cell sensitivity analysis be completed for every injection model and compared to an analytical solution, if possible. Otherwise, if computational efficiency is not an issue, smaller injection cells should be used to more closely mimic a wellbore.

However, for this study, simulation time is an important consideration in completing all sensitivity analyses. For sake of expediency, all simulations utilize the grid with 10 m cells and a partially-perforated injection zone. This grid is the most efficient of all tested, and gives similar results to finer grids; most importantly, the relative results between permutations of the sensitivity analysis will suffice, rendering the analysis effective. However, specific limitations of this grid for the analysis include: (1) maximum pressure values may be lower with this coarse grid, as it is effectively gives an average pressure over a larger region (Table 1) and cannot capture extreme pressure gradients in the vicinity of an injection well; (2) its partial perforation provides a different pressure gradient than a full perforation in the vicinity of the injection well, due to vertical spreading of the pressure plume. A redeeming quality of this model is that its pressure values match the values from simulations with smaller cell sizes within 30 m (Figure 6). As such, pressure regimes between injection wells are similar regardless of the injection cell sizing. The injectivity values will exhibit some error, but being that the purpose of this study is to investigate interwell relationships rather than give an accurate injectivity value, this error is not important. In summary, local grid refinements may be necessary to predict injection values accurately in future work, but the interwell relationships are regardless of grid cell sizes.

CHAPTER 3

SENSITIVITY ANALYSIS ON INJECTIVITY

3.1 Permeability

It is hypothesized that permeability is the governing factor affecting injectivity. To test this hypothesis, a range of feasible reservoir permeability has been evaluated in a series of injection simulations. Based on typical sedimentary rocks, the range selected is between 1E-16 and 1E-13 m^2 on the low and high end of the spectrum, respectively. Values below this threshold yield such little injectivity that they are not useful to investigate. Higher permeability results in such high injectivity that any well spacing relationships are irrelevant. The chosen range is thought to represent the most common values for saline reservoirs that may be chosen for injection operations. Of course, there may be cases that lie outside of this range. The purpose of this sensitivity analysis is to show the relationships between injectivity and permeability so that other values may be interpolated from the findings. Other reservoir parameters are tested for their sensitivity in a similar manner to either confirm or disprove the hypothesis.

This study is also meant to evaluate optimal well configurations. It has been established that numerous injection wells will always result in lower reservoir pressures compared to a single well, if the cumulative injection volume is the same. Similarly, numerous wells inject larger volumes than a single well if the maximum reservoir pressure is capped at (limited to) a specific value. For the purposes of this study, this cap is the fracture pressure of the rock, 42 MPa under the base case reservoir conditions. In the following, first the relationship between permeability and injectivity for a single injection well is analyzed. From that, the resulting relationship is adapted for many injection scenarios, including permutations of available acreage, number of wells, and permeability. The resulting plots are deemed "injection curves."

Figure 8 depicts the permeability vs. injectivity relationship for a single well. It shows a very well-correlated power regression fit. Permeabilities are separated by an order of magnitude, and are graphed on a log scale. The left of the curve, corresponding to low permeability, shows low injectivity and changes slowly. The right of the curve, corresponding to high permeability, increases sharply. These changes are relative; when permeability is changed by an order of magnitude, the injectivity also changes by nearly an order of magnitude.

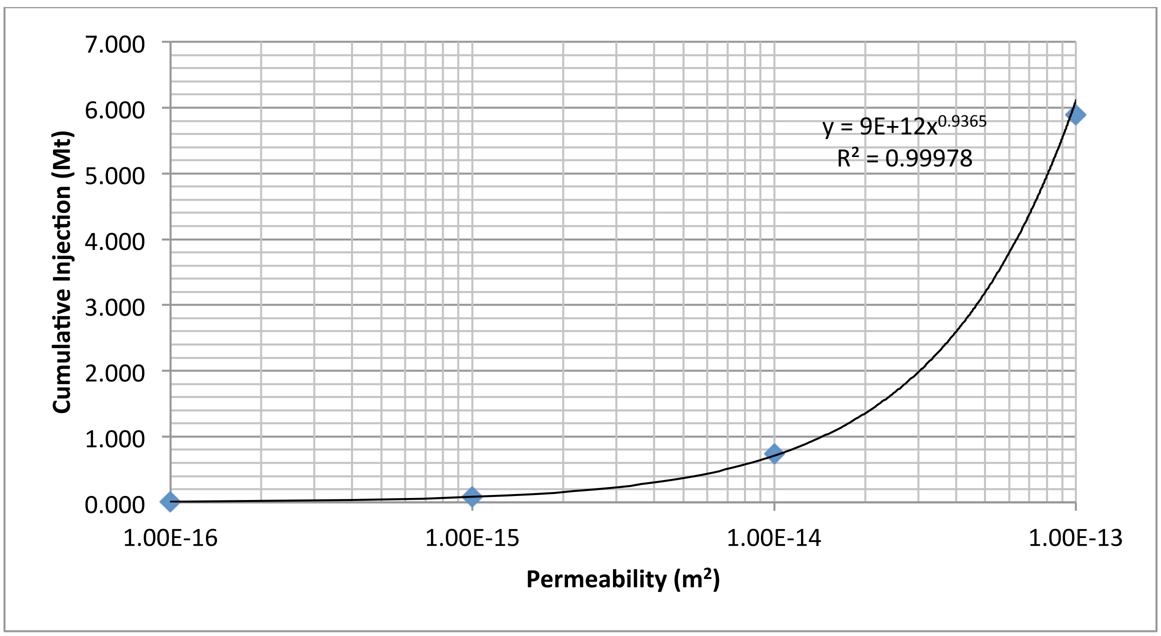

Figure 8. Injection sensitivity to permeability change for a single well.

If the vertical axis is converted to a log scale, the result is a linear trend line: a log-log relationship (Figure 9). Relatively, results for different permeability values exhibit the same sensitivity throughout the tested range. High permeability is the most sensitive because it involves the largest impact on injection volumes. Some of these simulations resulted in larger injections than most current CCS operations. The highest tested permeability, 1E-13 m^2, injected nearly 6 Mt for the one-year simulation. Even the next lowest value of tested permeability, 1E-14 m^2, required injection of 0.74 Mt during the simulated year, to reach the pressure limit. These large volumes suggest that injectivity may not be the limiting factor in such high permeability reservoirs. Rather, economic or other practical factors will limit the injection volumes. Injectivity remains the limiting factor for low permeability reservoirs that are known to accept much less fluid.

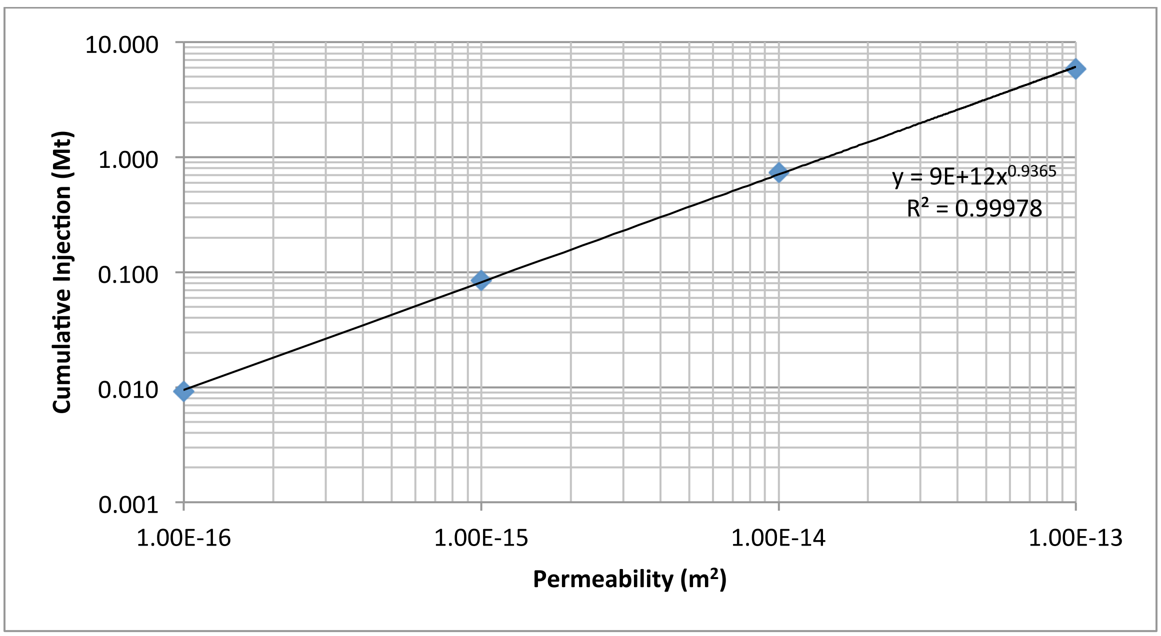

Figure 9. Injection sensitivity to permeability change for a single well (log-log scale).

Next, well configuration and permeability relationships are investigated by developing injection curves for each permutation. Wells are distributed in a "maximum perimeter pattern," defined as even spacing along the perimeter of the available acreage.

Previous results suggest that this is the most effective well distribution to manage reservoir pressures. Figures 10 to 13 provide the injection curves for the tested range of permeability for the single injection well analysis. The slope of the injection curve is the basis for determining the optimal number of wells. Specifically, the point at which the injection curve slope changes dramatically is hypothesized to be the optimal point for a given model.

The lowest permeability model results are plotted in Figure 10. The simulations may be characterized by very low injectivity, even with many wells. Curve slopes are fairly straight because the low permeability inhibits interaction between wells. The optimal number of wells may be as many wells as possible. When less acreage is available, however, this may not be possible. Slopes flatten out as the interaction between wells increases.

Figure 11 provides a plot for results of the base case permeability (1E-15 m^2) model. Injection volumes are much higher and hydraulic interactions between wells are more evident due to higher permeability. Adding additional wells, especially as many as 32 wells in the 1,000 acre case, may not prove beneficial. Similar to results for the 1E-16 m^2 model (Figure 10), decreases in the injection curve slope occur sooner for smaller acreage. Between eight and 12 wells may be the optimal point (Figure 11).

For the 1E-14 m^2 permeability case (Figure 12), the pattern is similar to that of the previous two cases. The injection volumes required to maintain the cap pressure are again higher, similar to the single well analysis. Higher permeability allows for more fluid mobility and more interaction between wells. Any more than ten wells would be a disadvantage as the amount of injection only slightly increases, but the cost of drilling

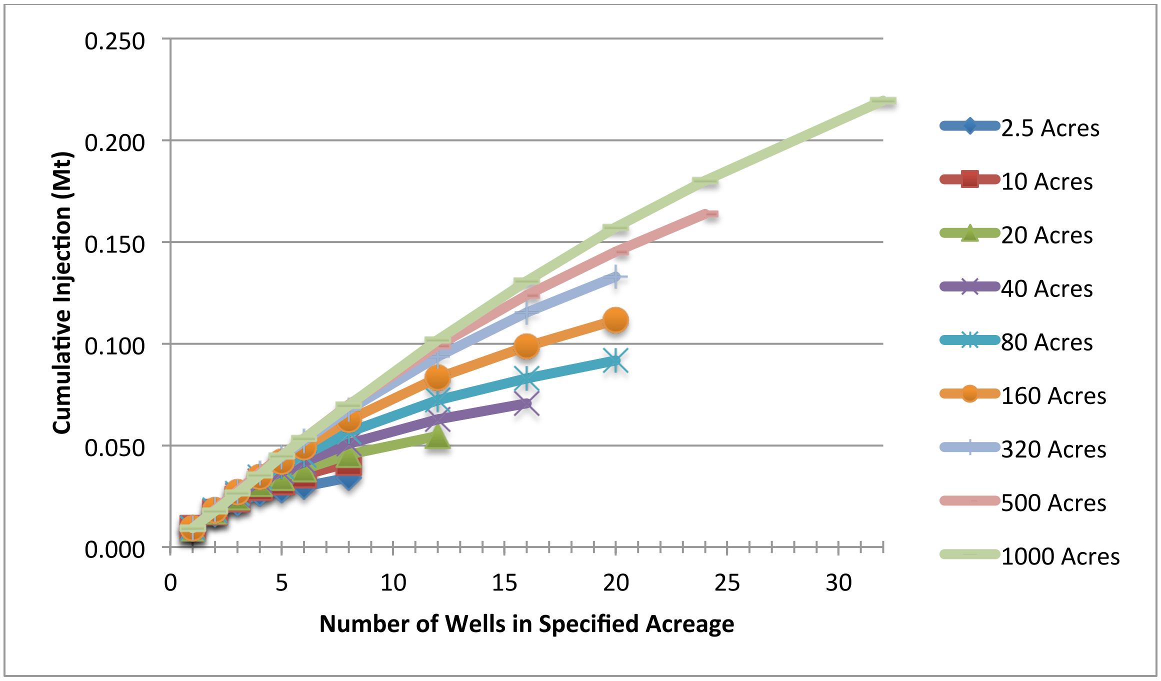

Figure 10. 1E-16 m² permeability injection curve showing the relationship between injection volume and number of wells for each acreage.

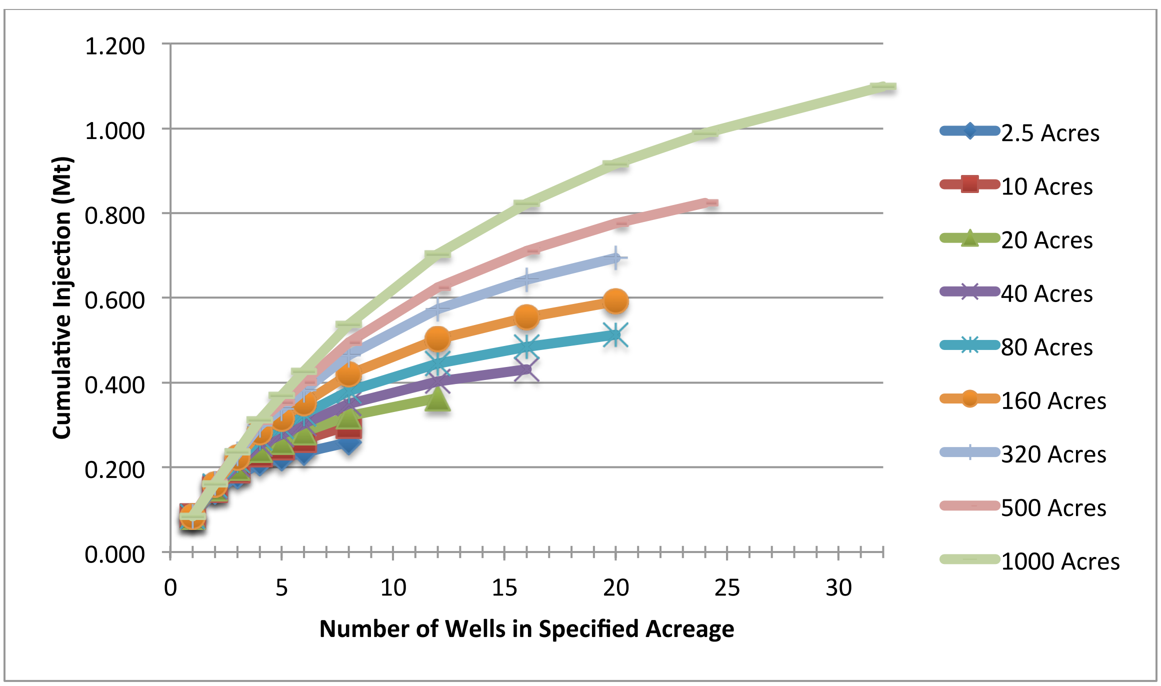

Figure 11. 1E-15 m² permeability (base case) injection curve showing the relationship between injection volume and number of wells for each acreage.

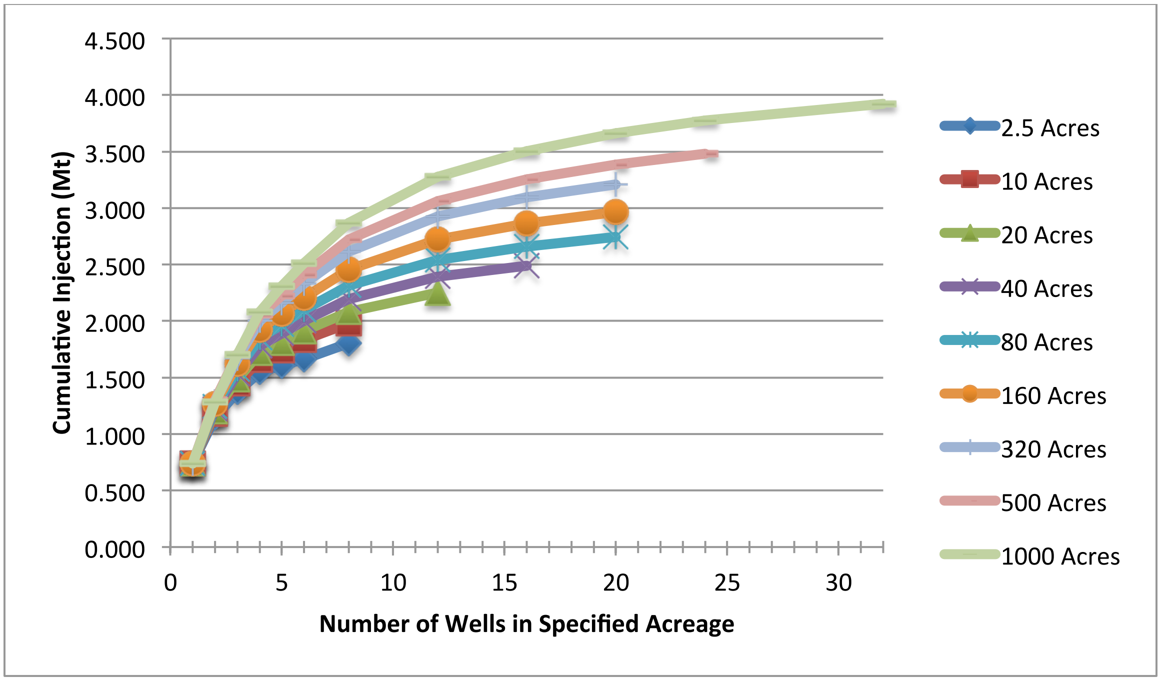

Figure 12. 1E-14 m² permeability injection curve showing the relationship between injection volume and number of wells for each acreage.

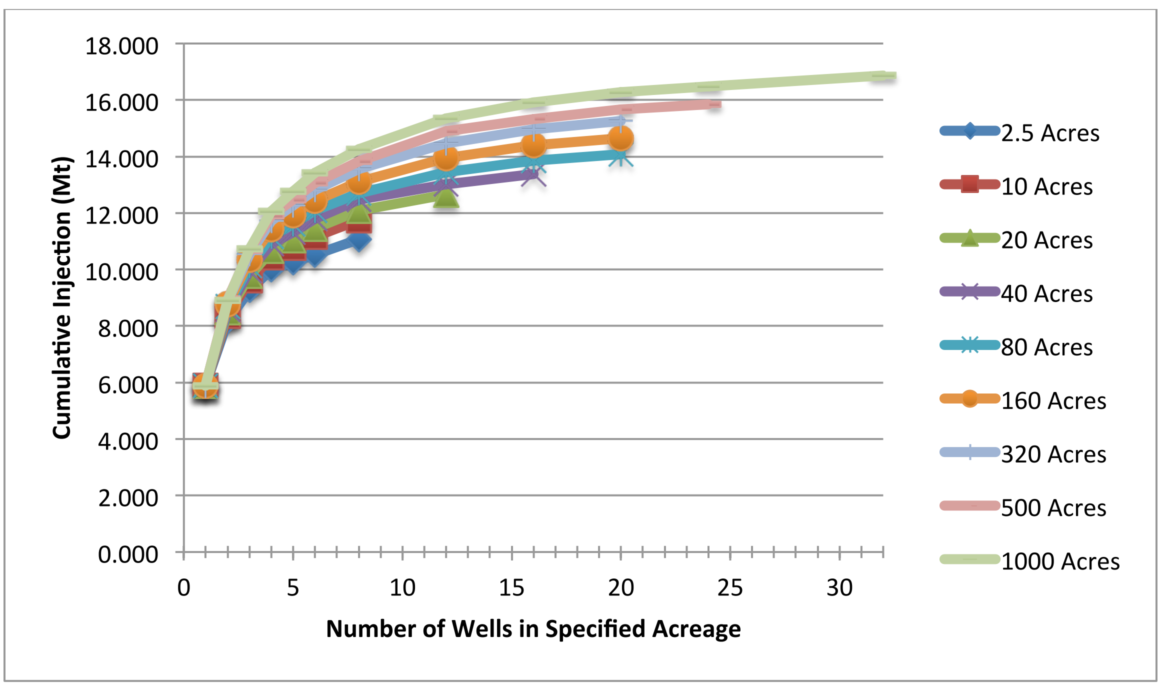

Figure 13. 1E-13 m² permeability injection curve showing the relationship between injection volume and number of wells for each acreage.

increases. These results (Figure 12) suggest that the optimal number of wells may be between four and seven.

The highest permeability simulations (Figure 13) are characterized by extremely high fluid mobility and hydraulic interactions between wells. As previously discussed, a single well may be more than adequate as it facilitates injection of nearly 6 Mt. Additional wells are only somewhat beneficial as the injection slightly increases. Based on the resulting injection curves (Figure 13), the optimum number may be between three and five wells. At the point of slope change, the cumulative injections are over 10 Mt for a single year and injectivity would not be the limiting factor. Results for the permeability sensitivity analysis are summarized in the Appendix.

3.2 Porosity

Porosity sensitivity is first investigated under otherwise base case conditions for a single well. Injection is compared for the porosity range of 5 to 20%, extending from the base case of 10%. The chosen range is representative of most typical saline reservoirs. Relationships for reservoirs with porosity outside of this range may be estimated (interpolated) from these results. Similar to the single well permeability analysis, porosity sensitivity results in a power regression fit (Figure 14). The resulting curve shapes differ, however. While injection is more sensitive to changes near the high end of the permeability range, the opposite is true for porosity; thus, the curves are oppositely cambered. Injection drops off quickly at the low end of the porosity range. This suggests that capacity is the factor mostly influenced by porosity. Porosity is the fraction of pore space in a reservoir, and therefore determines how much fluid can be stored. Lower porosity simulations are capacity-limited, and therefore exhibit significant impact. On the other hand, higher porosity cases are not capacity limited and show less sensitivity. The effect is that on the high end of the porosity range, increasing porosity does little. On

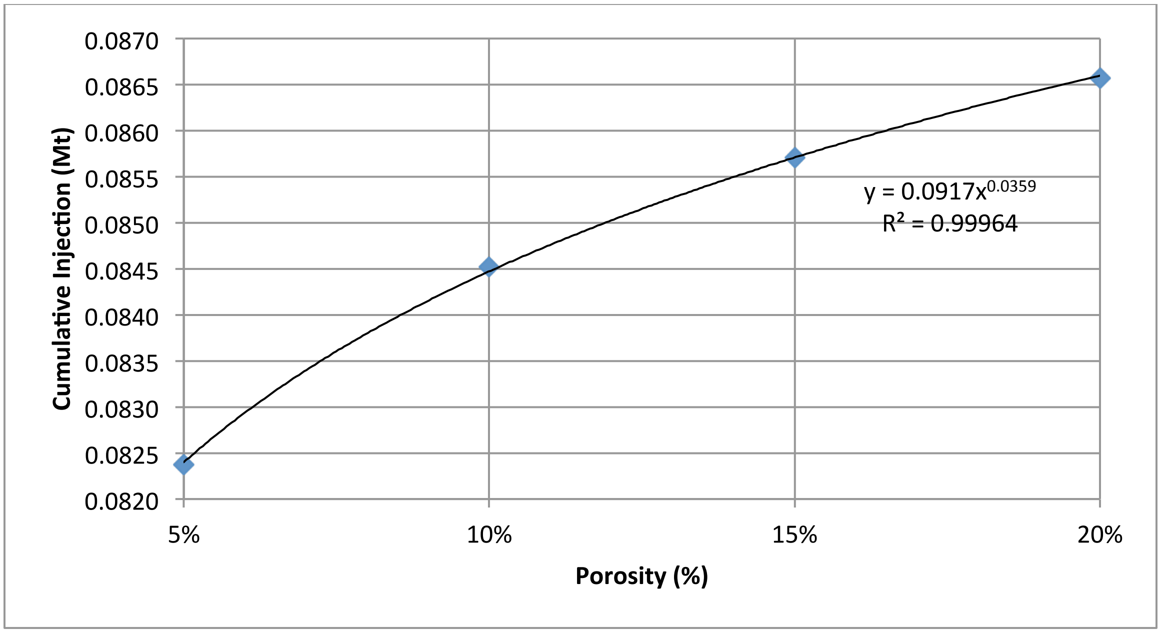

Figure 14. Injection sensitivity to changes in porosity for a single well.

the lower end of the range, small changes in porosity have more pronounced effects on injectivity and pressure.

Resulting injected mass (before reaching the cap/limit pressure) ranged from 0.0824 to 0.0866 Mt for 5 and 20% porosity, respectively, about a 5% difference. For a large injection operation, it is assumed that a reservoir selected would have at least 10% porosity. This would effectively avoid the most sensitive region of the possible porosity range (<< 10%). Therefore, a realistic injection scenario would not be very sensitive to porosity. For example, the 10% porosity model accommodated 0.0845 Mt injection, or about 2.5% less than the 20% porosity simulation. Although a 5% porosity reservoir is not likely to be chosen for injection operations, the analyses include it in the range to illustrate injection relationships.

Next, porosity sensitivity was compared to permeability sensitivity for a single well (Figure 15), to characterize the combined effects of porosity and permeability. The same permeability range from the previous permeability sensitivity analysis is employed.

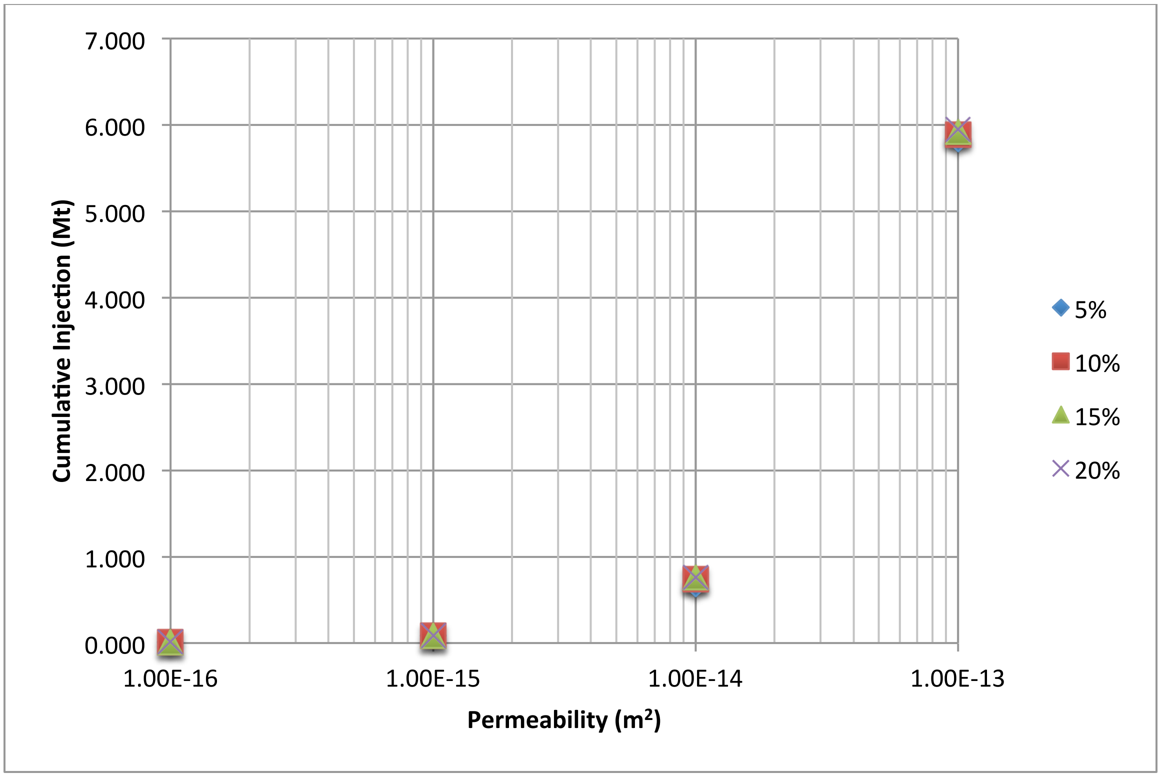

Figure 15. Comparing injection sensitivity to porosity and permeability for a single well.

From the Figure 15, permeability is a more important parameter. It illustrates that changes in permeability impact the injection volume by orders of magnitude, while porosity impacts maximum possible injection by only a few percent.

The sensitivity analysis is intended to elucidate the impacts of porosity on the injection curves associated with differing well spacing and permeability. Model permutations of differing porosity values are tested using the 80-acre case with base case permeability (Figure 16). This particular model (its resulting injection curve, specifically) was chosen because it lies in the middle of the range of resulting injection curves. Figure 16 illustrates that maximum possible injection increases as porosity increases and as the number of wells increases. Where the effect was only a few percent for a single well, adding wells only increases this spread. With 20 wells, the deviation from the base case is 13% for the lowest tested porosity and 16% for the highest porosity.

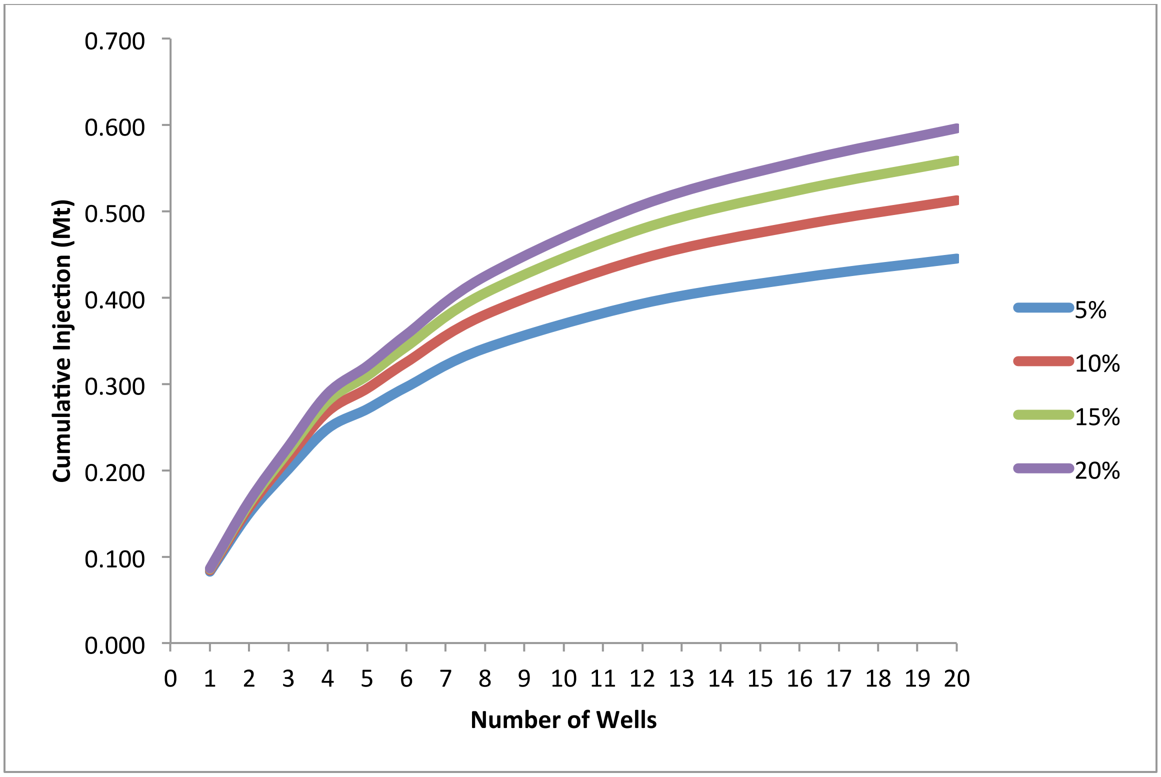

Figure 16. Injection curves for the 80-acre case showing relationships between injection volume and number of wells for each porosity value.

The combined effects of porosity, number of wells, and permeability may require extensive future work. The importance of such work should not be understated, but may be out of the scope of this research. Results for the porosity sensitivity analysis are summarized in the Appendix. The following are general conclusions to illustrate the range of porosity sensitivity and how it might affect previously developed permeability injection curves.

(1) The porosity sensitivity for a single well is generally small. Lower porosity always results in less maximum possible injection, and higher porosity results in higher maximum possible injection. Most scenarios result in small departures from the base case, but may be more depending on the combined effects of porosity, number of wells, and permeability.

(2) Intuitively, injection volume rises with additional wells. With less available land, the sensitivity is less, while the opposite is true with more available land. This is most likely due to injection volumes and the relation to capacity; more fluid takes up more space and therefore porosity becomes an important factor.

(3) Both the lower and higher permeabilities of 1E-16 m^2 and 1E-14 m^2, respectively, appear to be more sensitive to porosity changes than the base case.

(4) The highest permeability, 1E-13 m^2, is much less sensitive to porosity.

3.3 Compressibility

Pore compressibility is tested over a wide range, perhaps much larger than the range of values expected under reservoir conditions. The following values were tested in the sensitivity analysis, and an explanation is provided for each:

(1) The highest compressibility value, 4.13E-09 Pa^{-1}, is assumed based on the grid cell sizing sensitivity analysis. Recall that this value was back-calculated from simulation results and used for the analytical solution.

(2) The value of 4.93E-10 Pa^{-1} is the default value assigned by ECLIPSE.

(3) The next highest value, 2.81E-10 Pa^{-1}, is suggested by Hart and Wang (2010), who detail an experimental procedure to find several poroelastic constants for several rocks. Of particular interest, they tested Berea Sandstone with a vast range of effective stress scenarios. The value 2.81E-10 Pa^{-1} is the drained compressibility of the sandstone with 0.4 MPa of effective stress. This drained compressibility is larger than what is expected from pore compressibility, and the effective stress is much smaller than what is expected under reservoir conditions. This value represents an extremely high, perhaps unrealistic, compressibility value for sandstone.

(4) The value 7.00E-11 Pa^{-1} was also chosen from Hart and Wang (2010). This value is the result of 35.7 MPa of effective stress under drained conditions, a value of effective stress that is more likely to occur under reservoir conditions. However, it does represent drained compressibility, and is higher than the corresponding pore compressibility.

(5) The value 3.00E-11 Pa^{-1} was chosen in an attempt to match the resulting injection volumes from default compressibility in TOUGH2, but is also in the range of pore compressibility from Hart and Wang (2010). Therefore, this final value can be interpreted as the most realistic value. It also the closest to the TOUGH2 default of zero.

The chosen compressibility range should encompass most reservoirs, and others can be interpreted from the analysis results.

Sensitivity of reservoir pressure development to compressibility is analyzed under otherwise base conditions for a single well. Figure 17 shows the maximum possible injection values (without reaching pressure cap/limit) for each of the compressibility values listed above. These are compared to previous results with default (zero) compressibility, although the default was not capable of being plotted on the logarithmic scale. Unlike the porosity and permeability curves, the compressibility curve fits a nearly-exponential trend rather than a power regression fit. An outlier is the highest compressibility value of 4.13E-09 Pa^{-1}. As hypothesized, this value allows for much higher injection than other values, and thus may be unrealistic. Other values lie within a small range of injection volumes. For example, the extreme high end of Berea Sandstone compressibility facilitated an injection volume of 0.0856 Mt, while the default compressibility allowed for 0.0845 Mt. Compressibility values below 1E-10 Pa^{-1} are very similar to the default with errors of less than 1%. For comparison, the default value

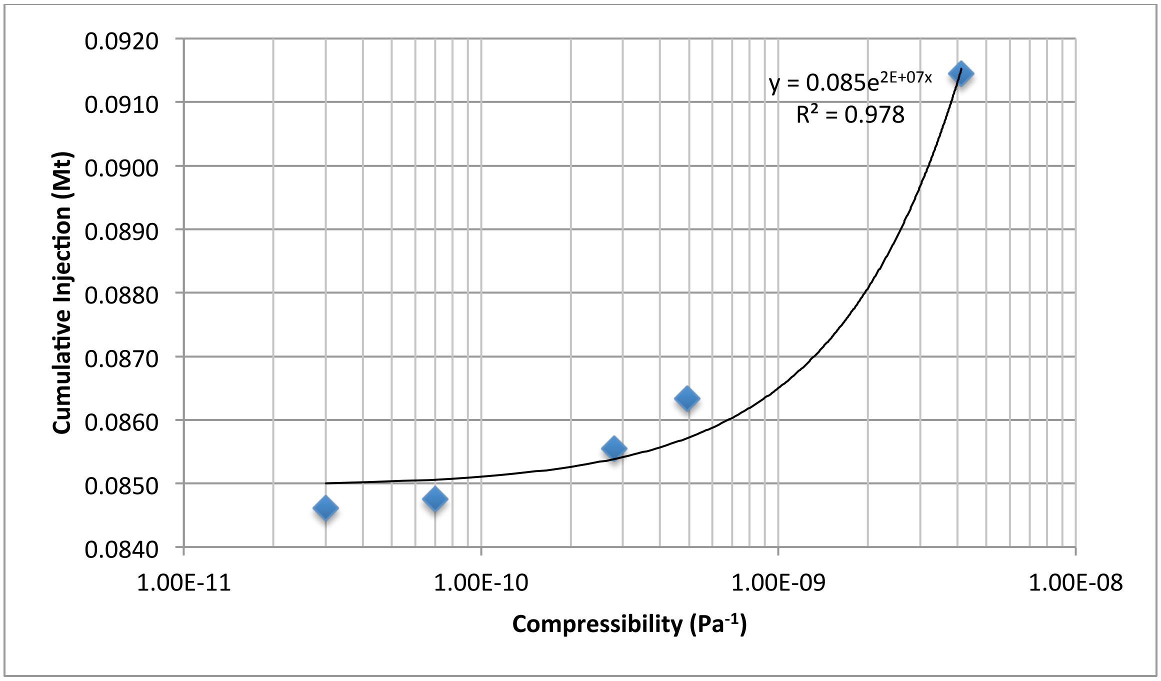

Figure 17. Injection sensitivity to changes in pore compressibility for a single well.

permitted injection of 0.0845 Mt, just .0001 Mt more than the realistic pore compressibility value of 3.00E-11 Pa^{-1}. Therefore, at least for a single well, it appears that the default may be used with negligible error.

Also part of the single-well analysis, the permeability and compressibility sensitivities were compared with respect to their impact on injectivity. Figure 18 illustrates the combined effects of permeability and compressibility. Permeability is the more significant parameter. The outlier again appears to be the back-calculated compressibility value, which allows noticeably larger injection. If a highly compressive reservoir is chosen as the subject of an injection operation, it may be necessary elucidate the combined effects of permeability and compressibility. The other tested compressibility values are far less significant with respect to their impact on maximum possible injection, especially realistic reservoir values which deviate from the default by less than 1% across the entire range of permeability.

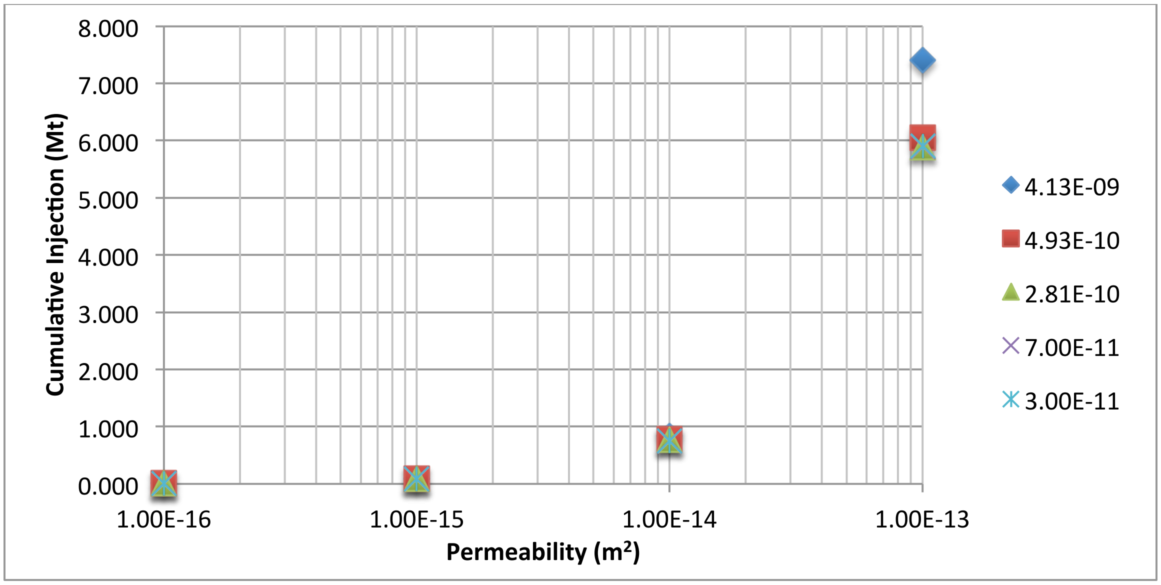

Figure 18. Comparing injection sensitivity to pore compressibility and permeability for a single well.

Compressibility relationships are applied to the 80-acre injection case (see curve on Figure 19). This has been done to illustrate the impact of additional wells. Not all compressibility values from the single well analysis were used, however. The highest compressibility was chosen to show its extreme sensitivity. Values representing Berea Sandstone were also chosen: 2.81E-10 Pa^{-1} represents its absolute maximum compressibility, and 7.00E-11 Pa^{-1}, which is higher than most pore compressibility values, but shows a larger deviation to the default than does 3.00E-11 Pa^{-1}. The following figure gives merit to the conclusion that most sandstones may use the default compressibility value without much error. Even with 20 wells, the 7.00E-11 Pa^{-1} curve is very similar to the default curve. Again, it appears that the highest compressibility is an outlier. Otherwise, there is little spread between the tested compressibility values.

In summary, model results suggest that realistic reservoir compressibility ranges should not have much of an effect on injectivity. Conservatively, the error may be as much as 5% with 7.00E-11 Pa^{-1} compressibility and numerous wells. This compressibility

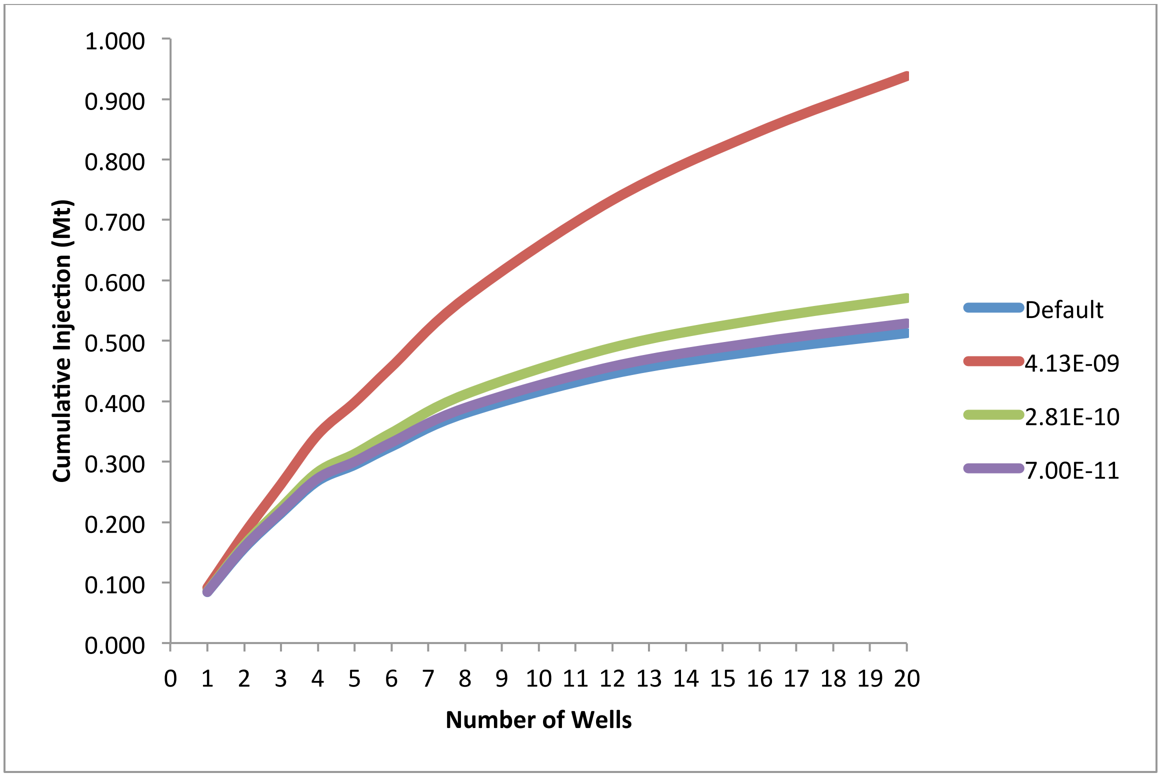

Figure 19. Injection curves for the 80-acre case showing relationships between injection volume and number of wells for each compressibility value.

value is also conservatively high from what is discussed by Hart and Wang (2010). Pore compressibility near 3.00E-11 Pa^{-1} appears to be the norm in their study. Interpolating values from this analysis indicates that such values would result in very little deviation from the TOUGH2 default compressibility value of zero. In practice, it is viable to use this default value under most conceivable scenarios. There is a caveat for high compressibility rocks, which may be able to accommodate much larger volumes. Results for the compressibility sensitivity analysis are summarized in the Appendix.

3.4 Injection Depth

Injection depth depends on where the target formation lies. For CCS operations, this depth must be enough to maintain CO_2 in a supercritical state. The CO2 phase diagram indicates that temperatures must remain above 31.1°C and pressures above 7.38 MPa for supercritical conditions. Of these two parameters, pressure is the most variable factor and corresponds to a depth of about 800 m. For simplicity, water (single-phase) will be the only fluid in this analysis. The upper boundary of 800 m must still be used, however, because anything above that is not useful for converting water injectivity to CO_2 injectivity (e.g., later in the study). The base case depth is 2,000 m. The middle of the reservoir where the perforation zone lies is centered around 1,950 m. Depths range from 1,000 m (950 m injection) to 3,000 m (2,950 m injection) for the sensitivity analysis. Deeper injections are possible but may not be practical with respect to cost. The shallowest injection is still within the supercritical depth range for CO_2 with a slight margin of safety.

Several parameters must be changed in the model to constitute the change in injection depth (Table 2). First, the hydrostatic pressure is changed with depth ($p = \rho_{water}gh$). Water is assumed to have a density of 1,000 kg/m^3. Next, the reservoir temperature is changed as a function of depth. Surface temperature is assumed to be 20°C with a temperature gradient of 30°C/km, typical for the western U.S. Finally, the fracture pressure of the rock also changes as a function of depth. Accordingly, the maximum allowable pressure due to injection will change. This formula is the product of 80% of the lithostatic pressure, or $p = \rho_{rock}gh*0.8$. From the analytical solution for pressure change, viscosity is the only parameter which changes with depth because it is a function of temperature.

Table 2. Variables that change as a function of injection depth

Depth (m)	Hydrostatic Pressure (MPa)	Reservoir Temperature (°C)	Fracture Pressure (MPa)
950	9.32	48.5	21
1950	19.13	78.5	42
2950	28.94	108.5	63

Because all of these formulas are variable with depth, it may be easy to predict the injection relationships with depth as an offset from the base case. The single-well sensitivity analysis shows this offset (Figure 20). On the low end of the range, 1,000 m (950 m injection) accommodates about 35% of the base case (1,950 m). The upper end, 3,000 m (2,950 m), accommodates nearly 200% of the base case. This trend has been confirmed for cases with additional wells. The 80-acre injection curve example is shown in addition to the single-well sensitivity (Figure 21). For every injection scenario, the cumulative injection is multiplied nearly by these same offsets. Slight errors are present in the 80-acre example, and may be attributed to two primary reasons. First, the fracture pressure has been rounded to the nearest whole number. Therefore there is slight error for a single well, which may be compounded for more wells. This error is insignificant, though, because the fracture pressure is only used to illustrate the concept and need not be precise. Second, the injection depths are not round numbers and therefore are not perfect multiples of each other.

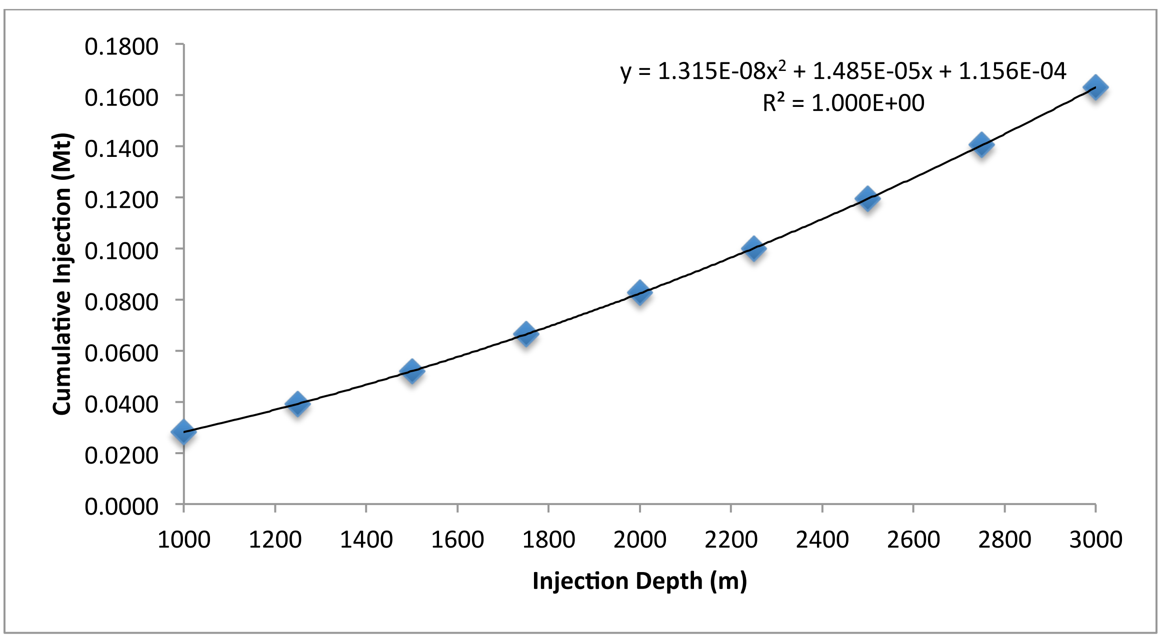

Figure 20. Injection sensitivity to changes in injection depth for a single well.

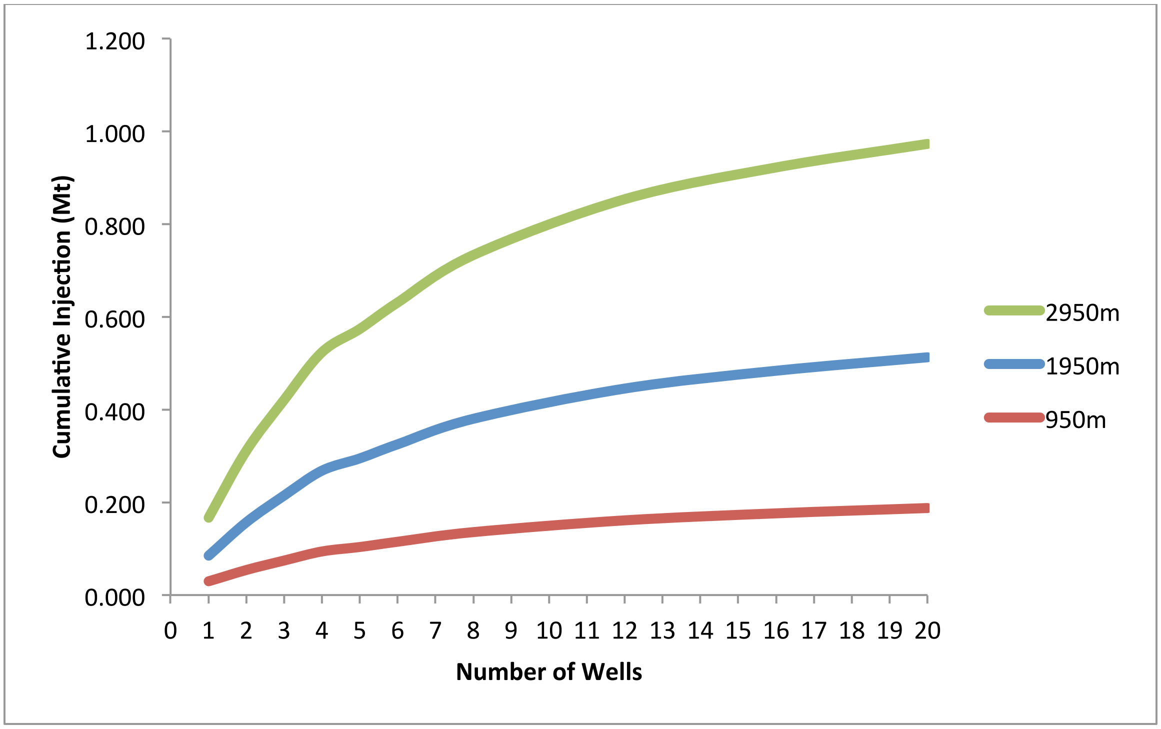

Figure 21. Injection curves for the 80-acre case showing relationships between injection volume and number of wells for each injection depth.

These results may possibly be duplicated for any scenario. The relationship to the base case can be simplified to: 1,000 m accommodates 33%, 1,500 m accommodates 66%, 2,500 m accommodates 150%, and 3,000 m accommodates 200%. Each value from the injection curves may be modified by these values. A figure similar to those indicated by Figures 15 (combined porosity-permeability analysis) and 18 (combined permeability-compressibility analysis) has not been generated because permeability is the more sensitive parameter. Results for the injection depth sensitivity analysis are summarized in the Appendix.

3.5 Layer Thickness

Reservoir thickness is tested at 50 m, 150 m, and 200 m for comparison with the base case of 100 m. Values not within this range may be simply interpolated from the results given here. Layer thickness appears only once in the denominator of the analytical solution for pressure change due to injection. Therefore, increasing the thickness should reduce the impact on pressure buildup and vice versa for decreasing thickness. The relationship should be linear and therefore predictable. Injection volume, although closely tied to pressure, is not as easily predicted, but will also have a linear relationship with layer thickness.

Results from the sensitivity analysis are highly predictable and are very similar to the injection depth sensitivity analysis. Permeability is the more significant parameter with respect to impacting maximum possible injection. Figure 22 provides results for the single-well analysis with respect to layer thickness. Half of the base case thickness (50 m) is capable of injecting nearly 66% of the original maximum injection mass, and 200 m thickness results in nearly 166% of the base case injection. This trend is also shown with the 80-acre injection curve example (Figure 23).

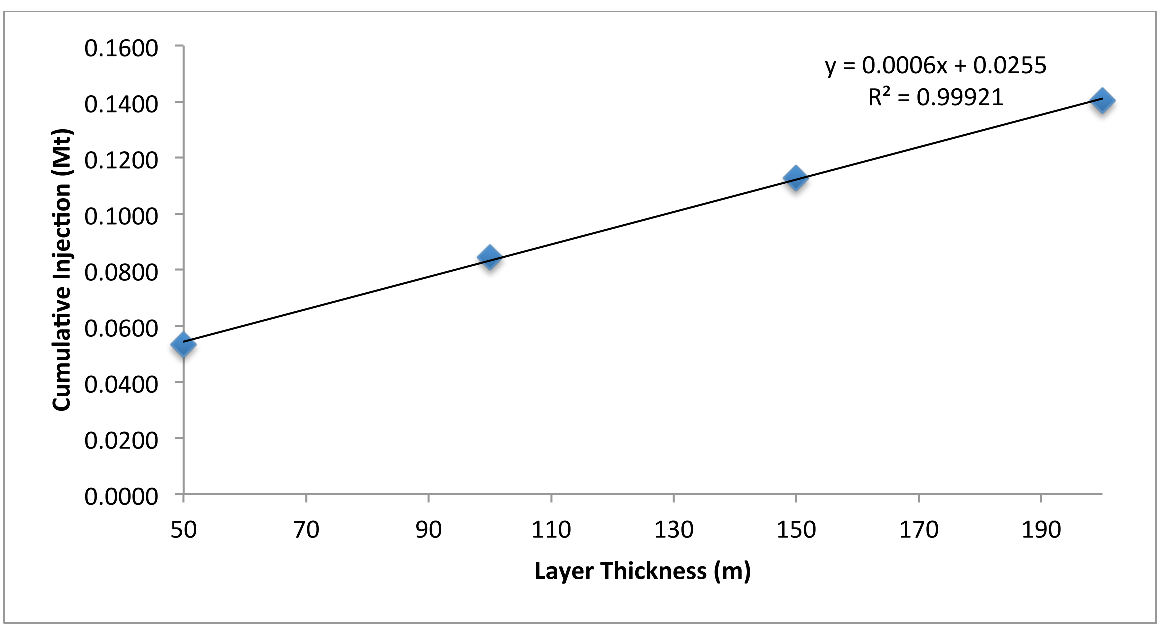

Figure 22. Injection sensitivity to changes in reservoir thickness for a single well.

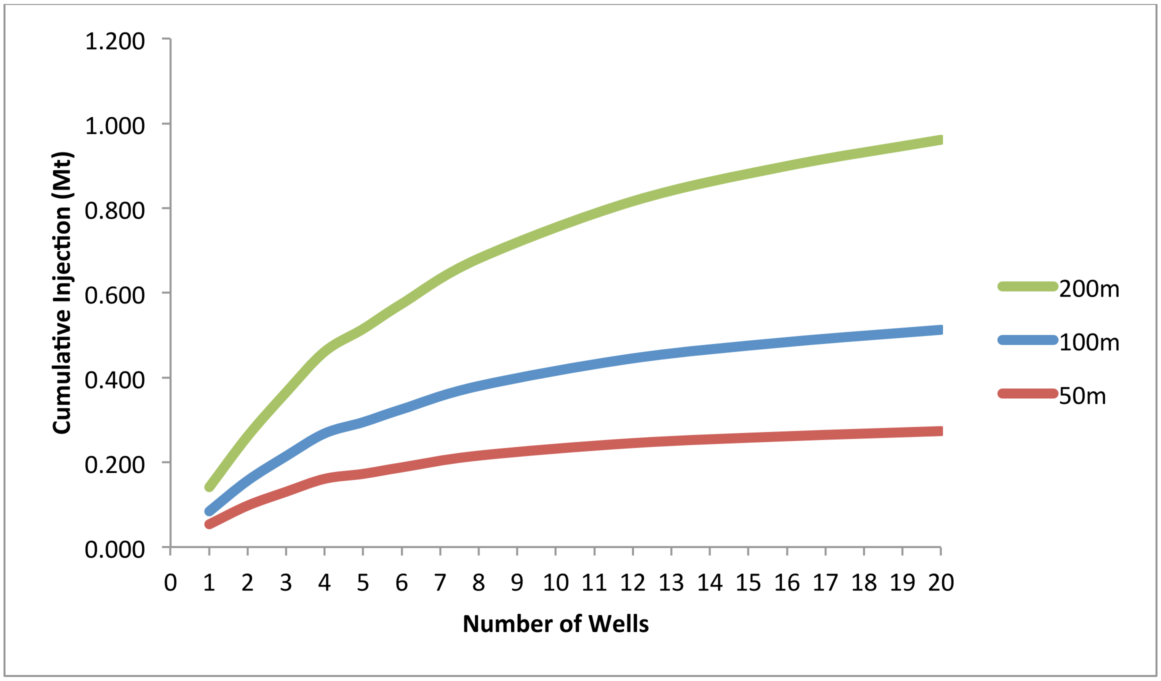

Figure 23. Injection curves for the 80-acre case showing relationships between injection volume and number of wells for each reservoir thickness.

Base case values are amplified or suppressed, but the curve slopes remain unchanged. Offsets are slightly less with lower permeability and more with higher permeability, about 5-10% per order of magnitude change in permeability. Results for the layer thickness sensitivity analysis are summarized in the Appendix.

3.6 Heterogeneity

Heterogeneity may be one of the most difficult properties to estimate for a deep saline reservoir. Normally, only a few test wells are drilled to characterize properties. Between test wells, properties are interpolated using geostatistical methods. Such advanced modeling is beyond the scope of this research. Instead, a completely random permeability heterogeneity field was assigned by the methods of Pruess *et al.* (1999). The random permeability ranged from 5E-16 to 5E-15 m^2. The overall reservoir permeability averaged 1.94E-15 m^2, nearly double the base case value.

It has been shown that an order of magnitude change of permeability nearly changes the injection by an order of magnitude as well. Therefore, it is expected that doubling the permeability should nearly double the injection volume. However, the results are hard to interpret because of the random permeability distribution. The inherent randomness is obvious from the 80-acre injection curve example (Figure 24).

The general trend is that the injection is slightly higher, but not doubled as expected. Certain scenarios result in nearly double the injection, while others are much lower than the homogeneous case. This is a consequence of the constant injection rate approach. If a low permeability cell is located at or near the point of injection it will severely impact the overall simulation. Low permeability cells govern the injection rate as each other well must also use that rate. A pressure managed injection rather than a rate managed one would not have this problem. Wells located near areas of low permeability would not affect the rates of the other wells.

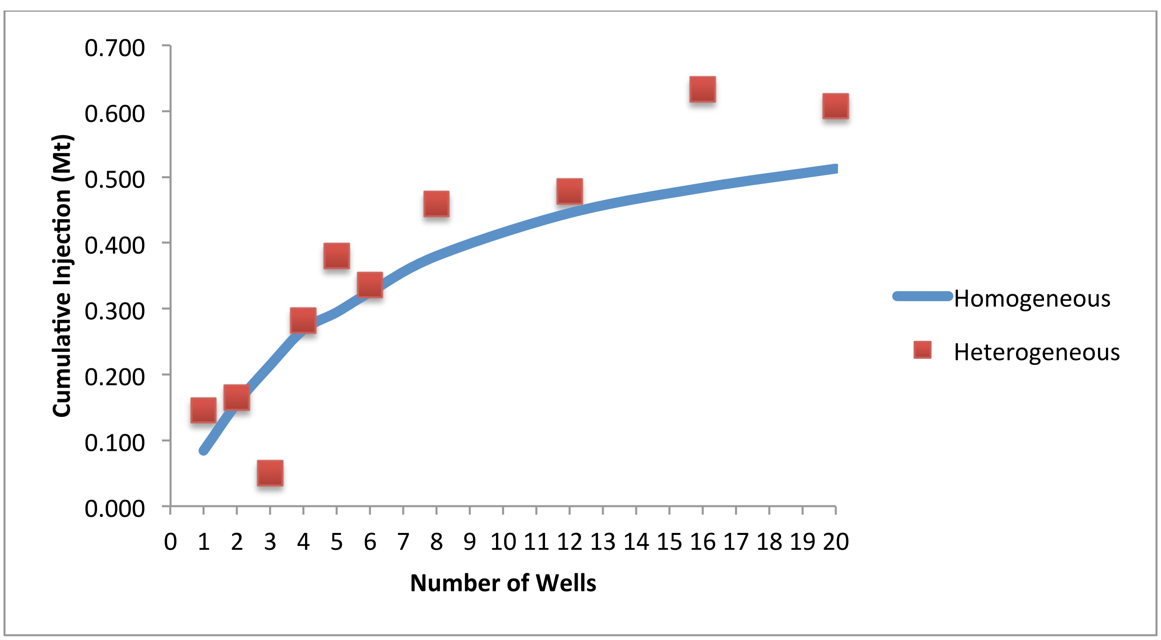

Figure 24. Injection curves for the 80-acre case showing relationships between injection volume and number of wells for homogeneous and heterogeneous cases.

The scenario presented here may not be realistic, but it does illustrate two important concepts. First, injection locations must be chosen carefully in a heterogeneous reservoir. Drilling into a low permeability zone may provide much lower injectivity than expected. Second, it may be appropriate to predict the behavior of a heterogeneous reservoir from its average permeability. The general trend from the 80-acre injection curve is similar to what is expected from the average permeability. Simulated values may be slightly lower than approximated if a low permeability zone resides near the injection cells. Results for the heterogeneity sensitivity analysis are summarized in the Appendix.

3.7 Time

Until this point, all analyses have been conducted with one-year simulations. Most large-scale CCS projects will be much longer than one year and possibly decades in length. Smaller demonstration projects could be a year or less. The range of tested simulation periods ranged from a few hours to 20 years. First, the pressure buildup over time for a single well was investigated (Figure 25). Like the other single-well pressure analyses, the injection rate was fixed at 2 kg/s. Most of the pressure increase occurred within the first few hours. A quasi-static state was reached within the first year; only small increases in pressure developed from that point onward. Figure 25 shows the BHP response over time to the 2 kg/s injection rate.

Maximum allowable injection rates are almost an inverse of the pressure figure. The injection rate is higher with shorter simulations, and lower with longer simulations, to reach the same fracture pressure of 42 MPa. The resulting plot (Figure 26) is what a realistic pressure controlled injection may resemble. The injection rate would be high in the beginning and slowly drop as the pressure builds. Integrating under the curve yields the cumulative injection. For simplicity, this variable injection rate approach has been

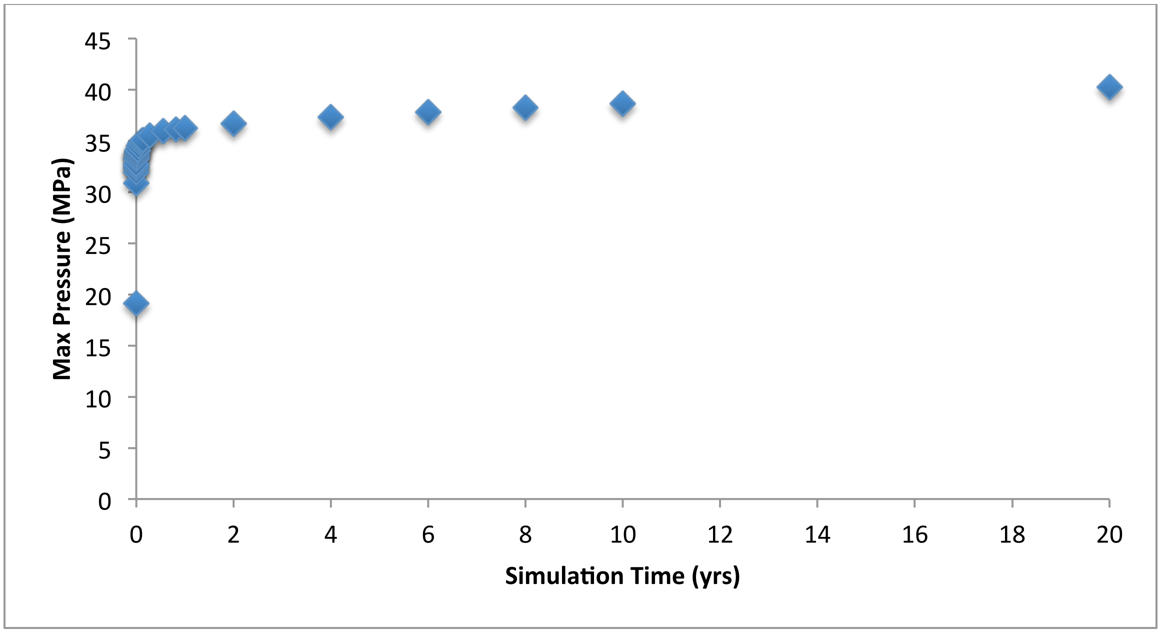

Figure 25. Pressure vs. time for 2kg/s fixed rate injection

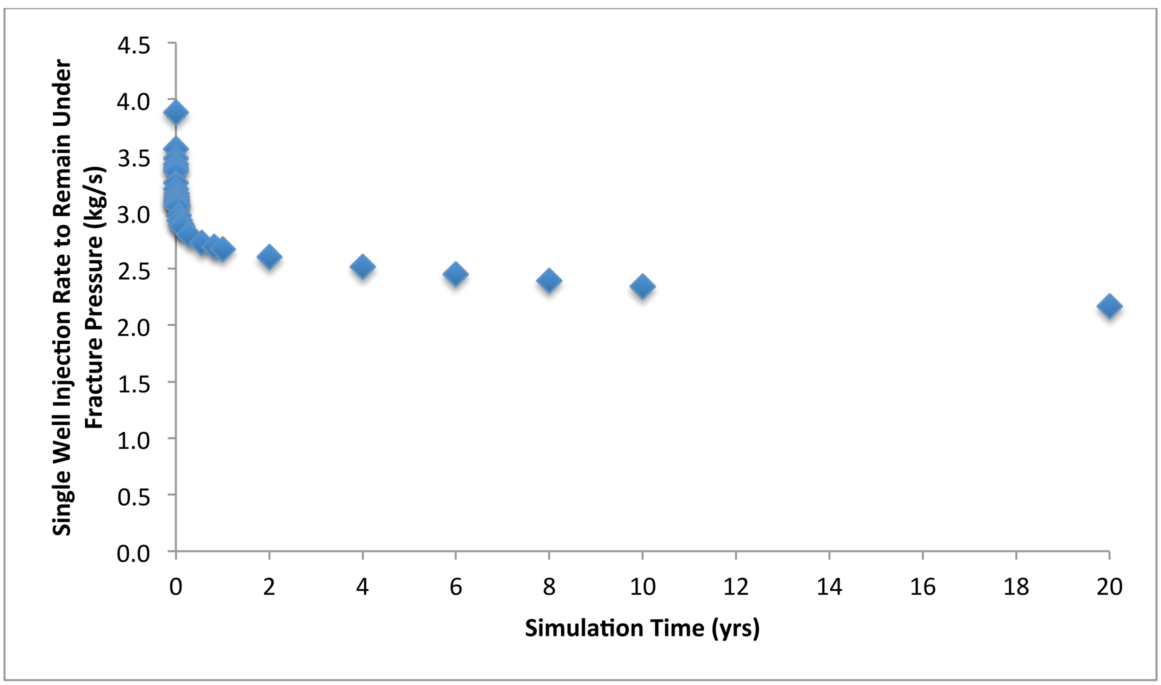

Figure 26. Maximum allowable injection rate to reach the theoretical fracture pressure as a function of simulation time.

avoided in previous analyses and only fixed rates have been used. In doing so, the cumulative injection is lower than it would be with the variable rate. For example, a 20-year simulation would use the maximum allowable rate of about 2.17 kg/s over the entire simulation for the fixed rate approach. A theoretical BHP-controlled well may use injection rates as high as 4 kg/s initially and the rate would slowly drop to 2.17 kg/s by the end of the 20 years. Looking at the cumulative injection plot in Figure 27, the theoretical slope is much steeper initially and gradually decreases to match the slope of the fixed rate at 20 years. The result is slightly less injection with the fixed injection rate. Errors are generally only a few percent. For all subsequent model analyses, fixed injection rates are used for simplicity and consistency.

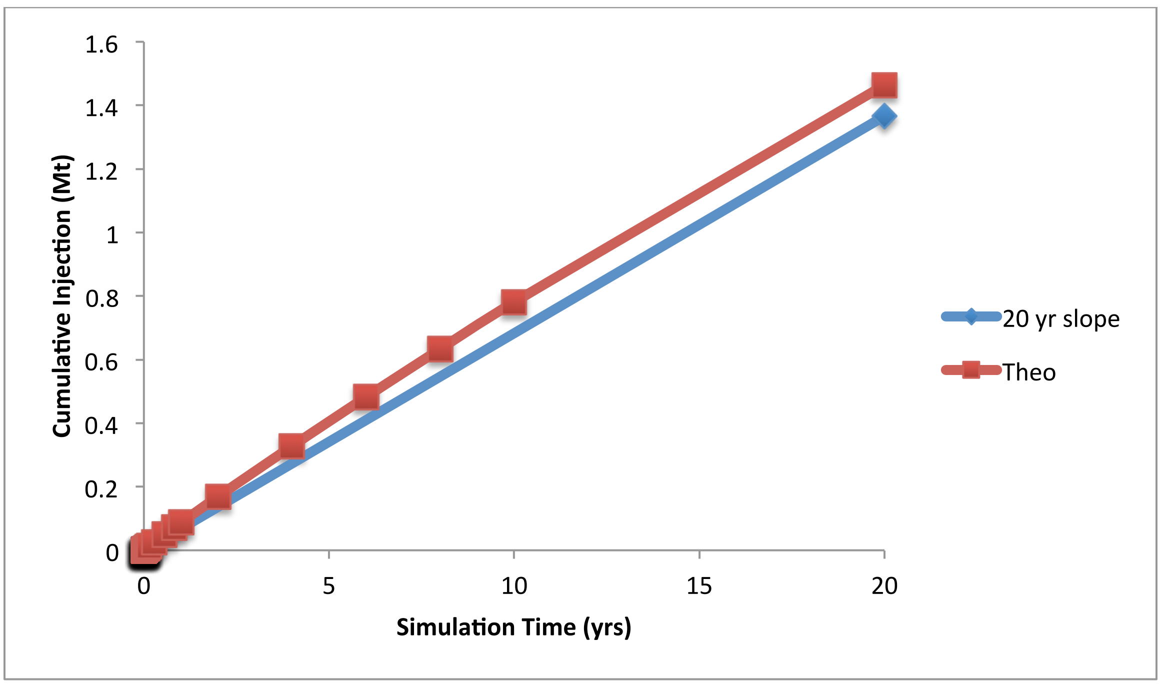

Figure 27. Comparing injection slopes from the 20-year fixed rate and the more realistic theoretical slope which changes over time.

Following procedures of previous sensitivity analyses, simulation time was varied for the 80-acre injection case. A range of simulation times from five days to 10 years is computed first (Figure 28). Each curve is then plotted on separate axes so that the slopes are more easily illustrated (Figures 29-34). Shorter simulations exhibited less interaction between wells as the pressure plumes had not propagated far from each well. The optimal number of wells may be as many as possible, as suggested by relatively straight (slopes) injection curves.

Longer simulations resulted in more hydraulic interaction between wells. Tighter groupings of wells, as in the case of 2.5 acres, have more hydraulic communication sooner. Less dense groupings are more impacted by longer simulations. Base case simulations show little interaction between wells for the 1,000 acre case. However, longer simulations significantly increase the superposition effect. The one-year injection rate is much higher than the 10-year injection rate in this case.

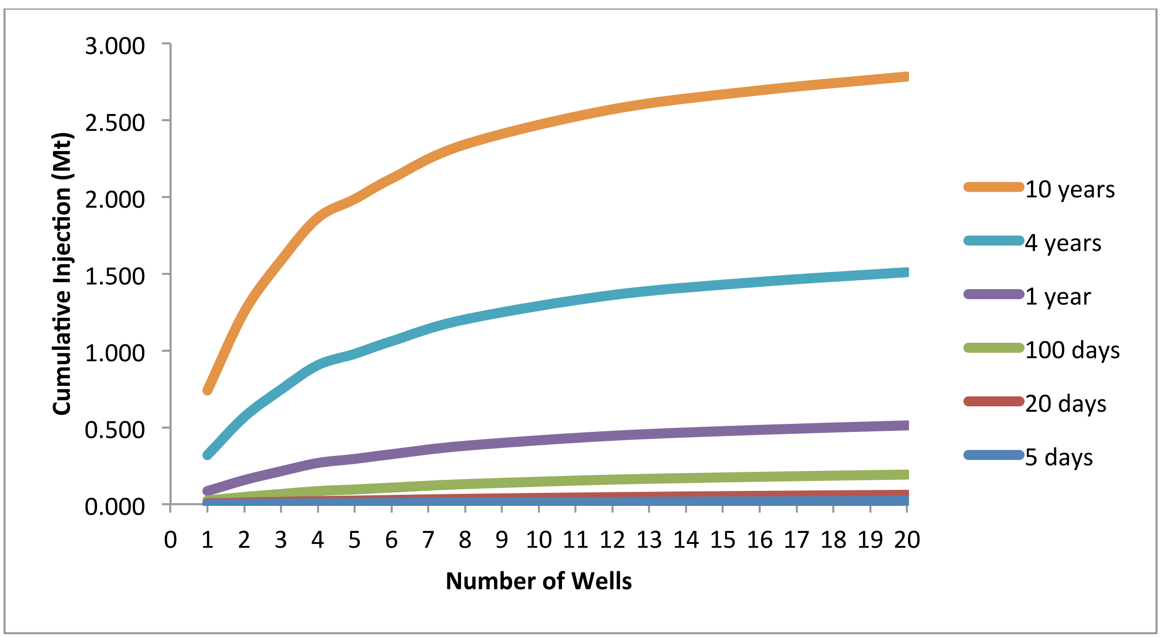

Figure 28. Injection curves for the 80-acre case showing relationships between injection volume and number of wells for each simulation time.

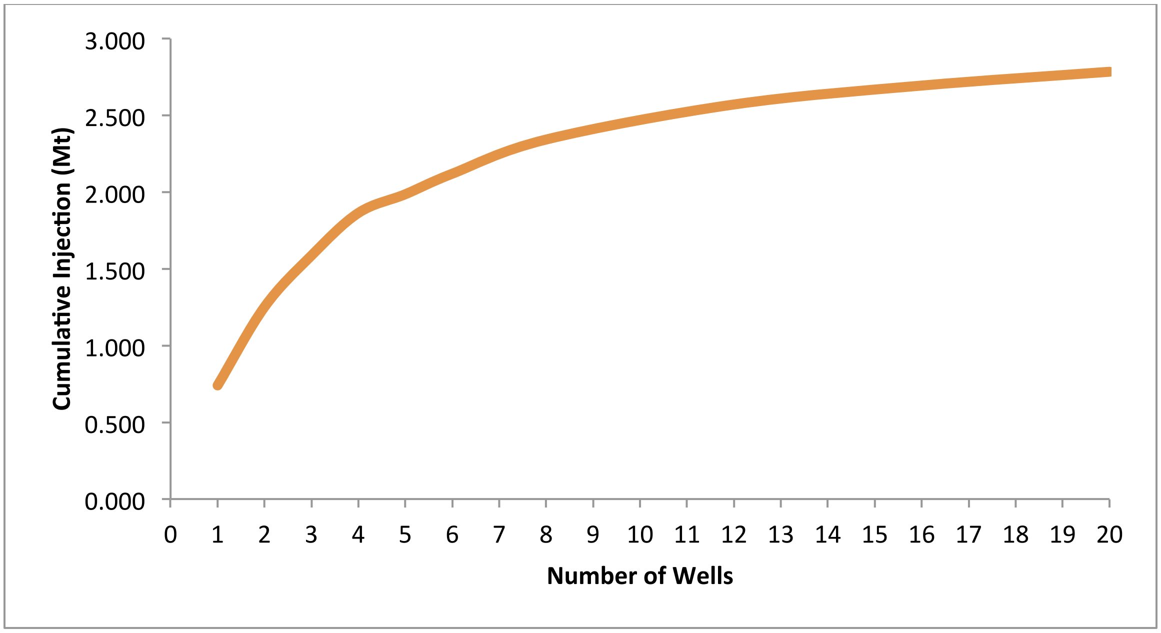

Figure 29. Injection curve for the 80-acre case showing the relationship between injection volume and number of wells for 10 years of simulation time.

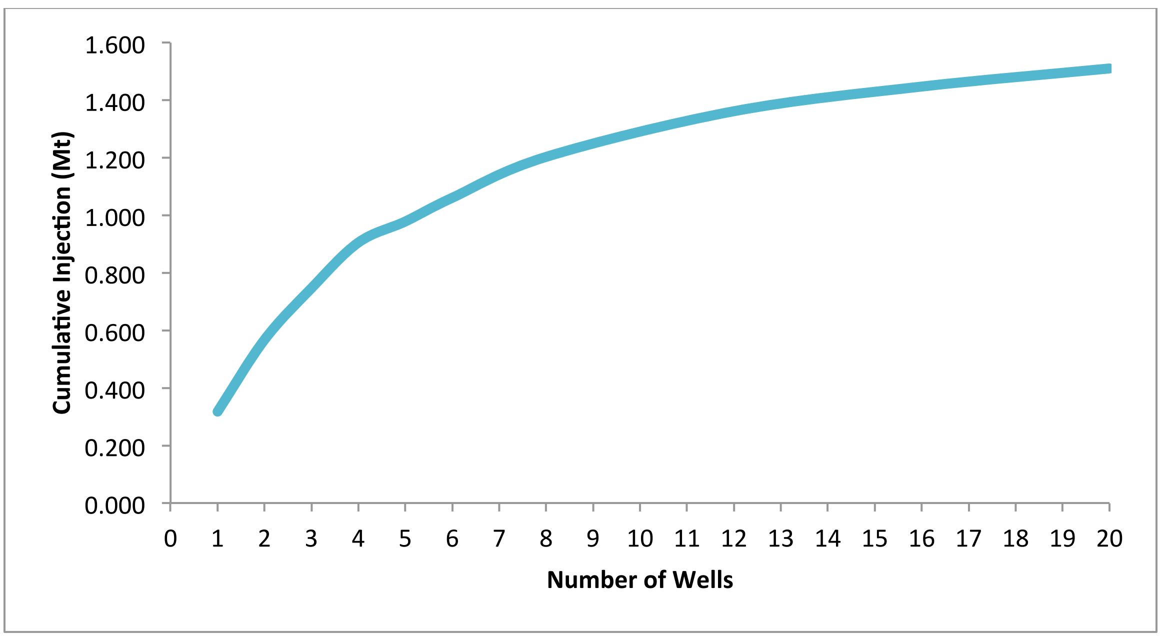

Figure 30. Injection curve for the 80-acre case showing the relationship between injection volume and number of wells for four years of simulation time.

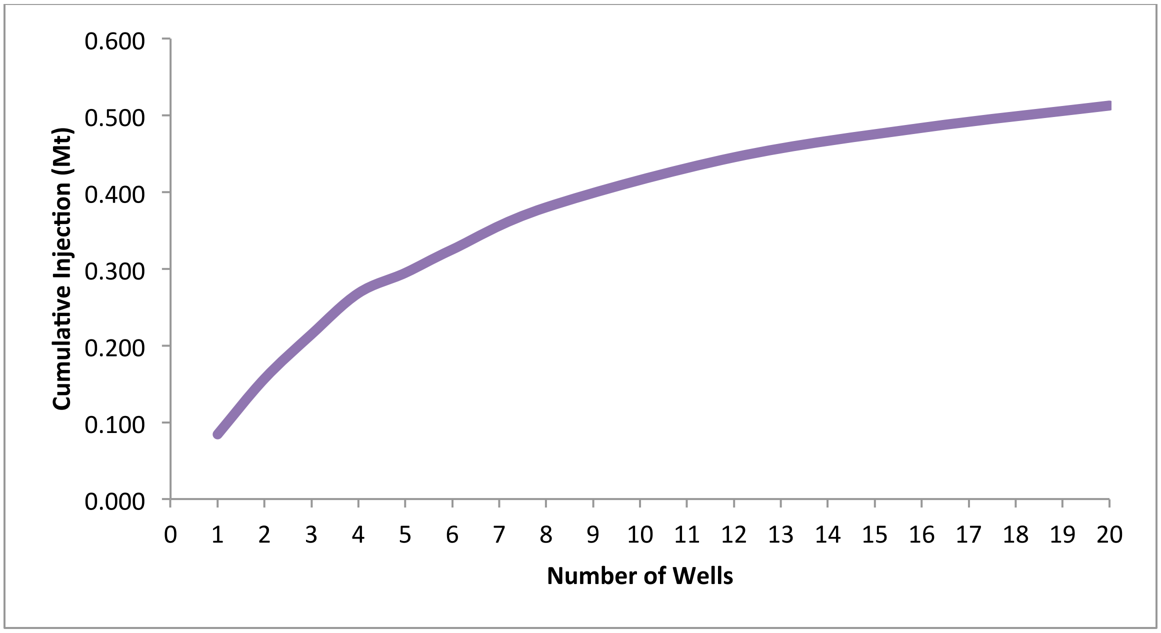

Figure 31. Injection curve for the 80-acre case showing the relationship between injection volume and number of wells for one year of simulation time.

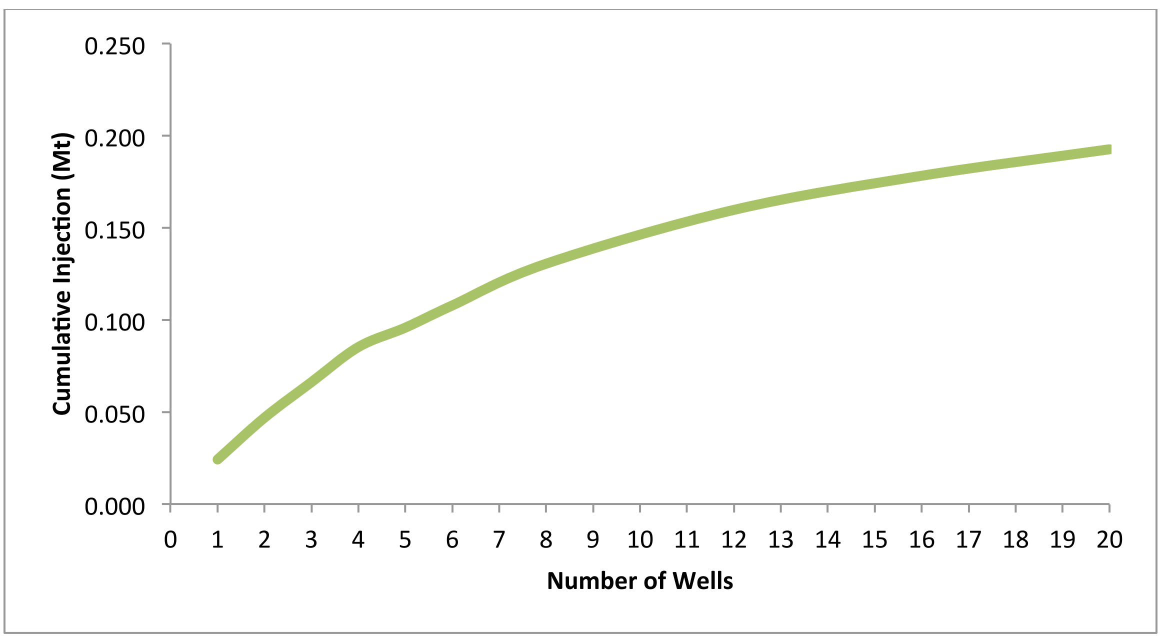

Figure 32. Injection curve for the 80-acre case showing the relationship between injection volume and number of wells for 100 days of simulation time.

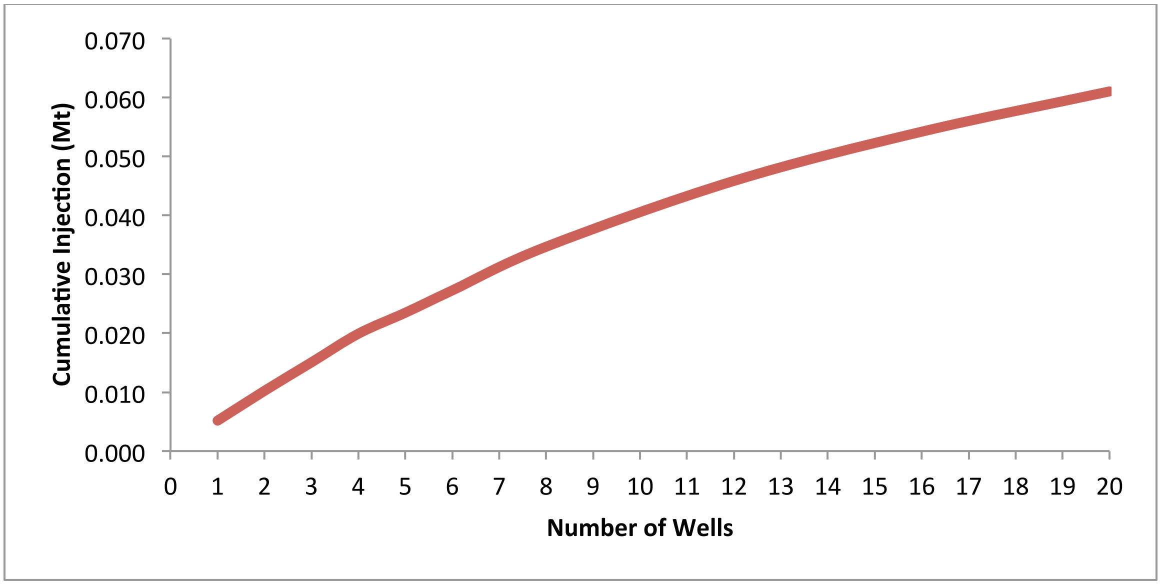

Figure 33. Injection curve for the 80-acre case showing the relationship between injection volume and number of wells for 20 days of simulation time.

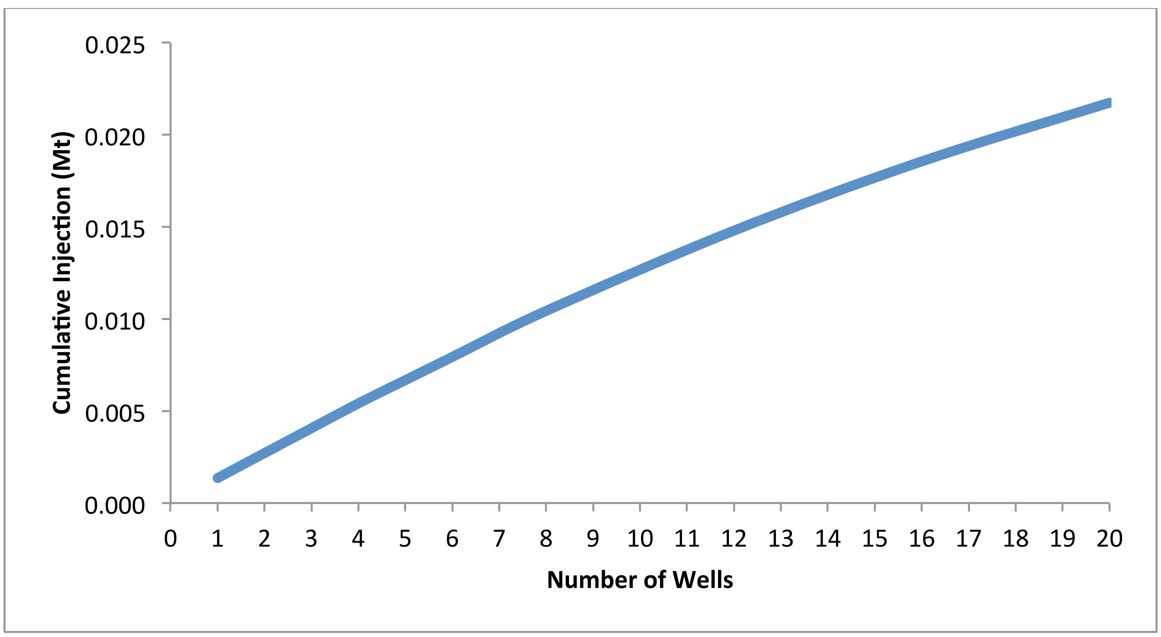

Figure 34. Injection curve for the 80-acre case showing the relationship between injection volume and number of wells for five days of simulation time.

Simulation time and permeability are related when multiple wells are considered. They essentially work in the same way by dictating the extents of pressure plume and fluid migration. The model assigned lowest permeability, 1E-16 m^2, results in much less pressure propagation. It takes much longer for hydraulic interactions between wells to occur. Higher permeability simulations show noticeable interactions in the one-year simulations. After one year, the pressure superposition is such that the optimal point may only be a few wells.

Long simulation times, tight well spacings, and high permeability all may shift the optimal point toward fewer wells as hydraulic communication is more pronounced for more wells. The opposite conditions suggest that more wells are required. Results for the simulation time sensitivity analysis are summarized in the Appendix.

3.8 CO_2

In an attempt to show the extent to which the previous single-phase (water only) models may represent multiphase conditions, CO_2 injection simulations were included as part of the sensitivity analysis. Injections were simulated using an appropriate equation-of-state algorithm published by Pruess (2005), ECO2N, a module of TOUGH2 that was designed for CCS modeling. The input files for previous models were slightly altered for the sake of using the CO2 equation of state, which utilizes four primary variables instead of three. For the single-phase (water only) equation of state, the primary variables are reservoir pressure, air mass fraction, and reservoir temperature. The CO2 equation of state requires reservoir pressure, salt mass fraction, CO_2 mass fraction, and reservoir temperature. The initial CO_2 concentration was assigned as zero. Salt mass fraction was calculated from a commonly used value for brine reservoir salt concentration – 50,000 ppm. Salt was initially specified as aqueous with the option of precipitation or dissolution as a function of saturation levels. Although the module allows for decreased permeability with salt precipitation, this option was not used. Therefore, only porosity was permitted to be affected in all simulations. Density, viscosity, and specific enthalpy are functions of temperature, pressure, and composition. However, all simulations were assigned as isothermal.

A recent study of linear relative permeability suggests that the Brooks-Corey relative permeability function may be the most useful for this application (Moodie, 2013).

First, BHP as a function of time is plotted (Figure 35). The plot is, essentially, an inverse of the same water injection plot, with pressures being higher initially before reaching a quasi-static state at a lower pressure. This is thought to be due to low relative permeability while supercritical CO_2 concentrations are initially low. It should be noted that the one-year injection rate will likely slightly over predict the maximum injection mass for a pressure-controlled well because of this initial pressure high. Although not easily seen on the plot, pressures begin to slowly rise after approximately one year. At this time, solid salt is observed in the group of cells surrounding the injection cell.

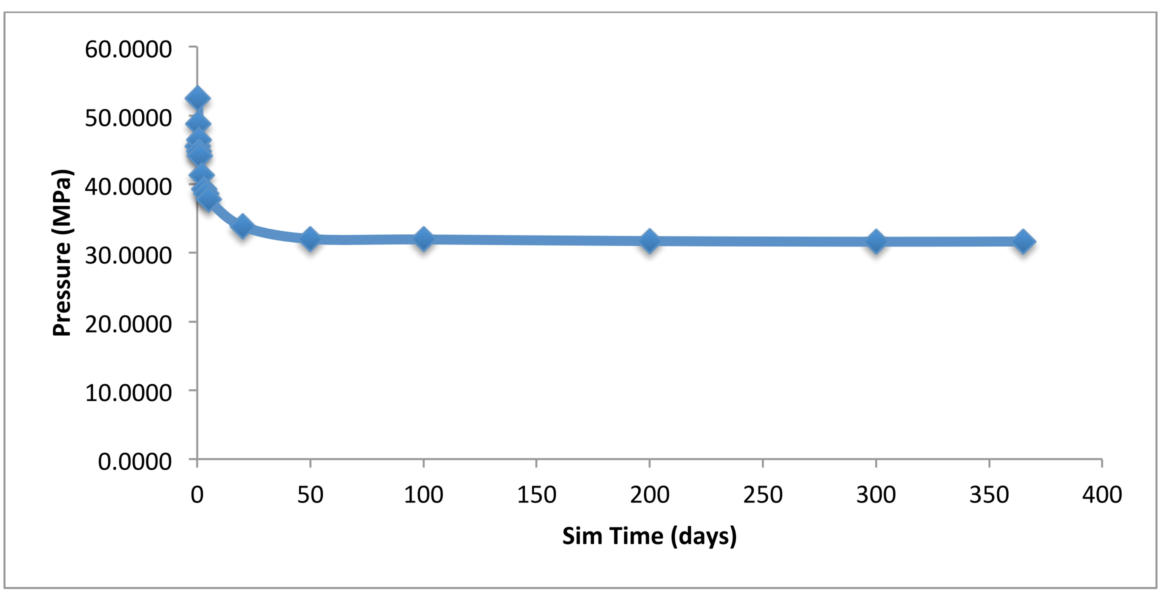

Figure 35. BHP over time resulting from 2kg/s CO_2 injection with a single well.

Figure 35 shows the resulting pressure at the injection cell from a 2kg/s injection for several time steps. Compared to water-only injection, the CO_2 injection exhibits lower pressures except for the initial high pressure. This is due to capillary pressure from the in-situ brine being replaced by CO_2. An outcome of CO_2 compressibility is a shallower slope on the plot of pressure vs. distance from the injector (Figure 36). Interactions between wells should be more extreme with CO_2 than with water injection, although the single-well pressures may be lower.

Figure 37 shows results comparing water injection and CO_2 injection for the 80-acre case, similar to other sensitivity analyses. As hypothesized, CO_2 exhibits more hydraulic interaction between wells because of its higher mobility compared to water. Fewer wells are able to accommodate more CO_2 than their water-injecting counterpart due to decreased local pressure-buildup near the injection well (Figure 36). For up to four injection wells, the slopes of the two lines (CO2 vs. water) are nearly parallel. More wells, however, suggest increased hydraulic communication and do not benefit injectivity. The trend appears in other scenarios as well. Faster pressure propagation and higher one-well injection rates appear to be the main differences for CO_2 compared to water injections. As a result, injection volumes are higher until enough wells are added where interactions between wells significantly reduce the injection rates. CO_2 injection curves are marked by abrupt changes in slope. The slope change is generally more extreme than for water injection and may happen with fewer wells. Previously developed water injection curves must serve as acceptable surrogates since not all CO_2 injection curves have been developed due to time constraints. Results for the CO_2 injection sensitivity analysis are summarized in the Appendix.

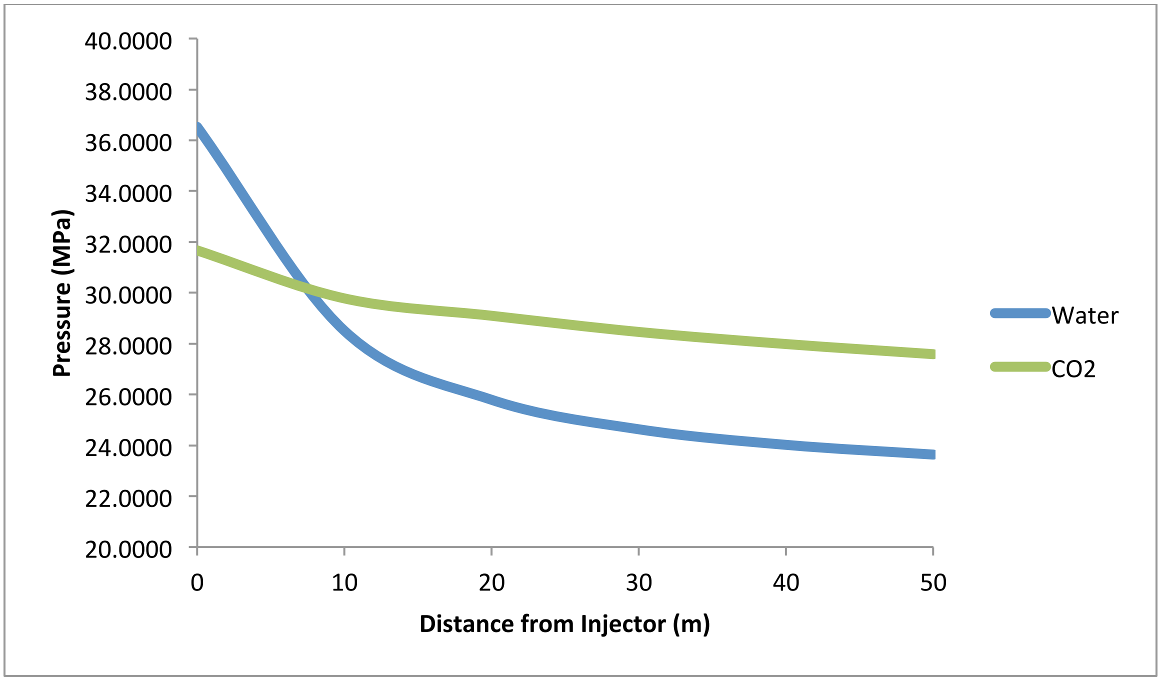

Figure 36. Comparison of lateral pressure distributions from water and CO_2 injection with the same injection rate of 2 kg/s.

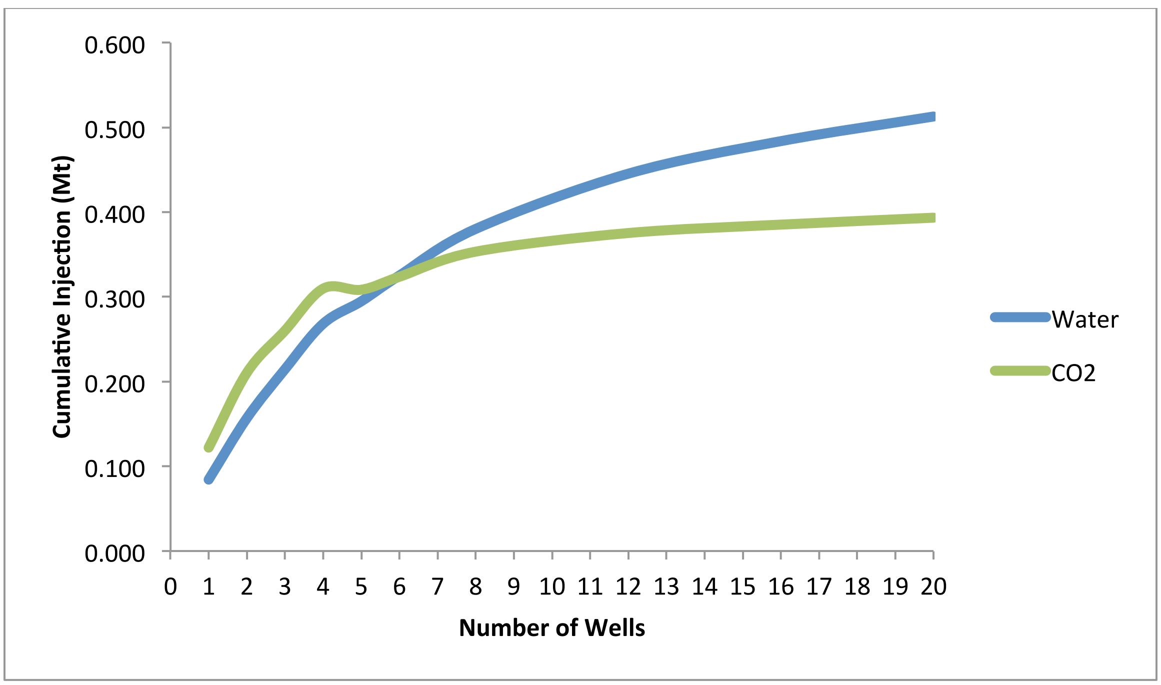

Figure 37. Comparing injection curves for the 80-acre case for water and CO2 injection to investigate relationships between injection volume and number of wells.

CHAPTER 4

COST OPTIMIZATION

4.1 Overview

Financial requirements provide the most significant barrier to large-scale implementation of CCS. Initial models and demonstration projects have proven to be extremely expensive. Costs of CCS are estimated on a continuous basis, and can be represented by a number of equations. For example, Bock *et al.* (2003) lumped together many required costs in a fashion that is very useful for this application. Bock *et al.* (2003) compiled several equations that relate injectivity, number of wells, and overall cost. Their equations, along with monitoring, verification, and accounting (MVA) costs, are adapted to injectivity relationships which were previously derived in the sensitivity analyses presented in Chapter 3. Perhaps more difficult to constrain are the benefits of such high-cost endeavors. Without opportunity for traditional market mechanisms, the benefit of CCS may come in the form of carbon tax credits or the like. Two primary results from this cost analysis include: 1) the optimum number of injection wells to minimize the cost of CO_2 per tonne for any scenario, and 2) the maximum possible injection volume and associated cost for any scenario. Therefore, depending on the project goals, it is possible to identify the benefit in these two ways.

Perhaps the most important outcome of Bock *et al.* (2003) and later by McCoy and Rubin (2005) is a prediction of the necessary number of wells to achieve a desired injection volume. Once the number of wells is determined, economic equations are applied to the injectivity values. A key figure from McCoy and Rubin (2005), presented in Figure 38 here, schematically illustrates the approach.

The generic sensitivity analysis provided by this report has parameterized the McCoy and Rubin "Injectivity Model" for many key variables. Now this "Cost Model" is applied to injectivity values from that analysis. It is not possible to make a direct comparison between their injectivity and cost because their injectivity model assumes a fixed volume of CO_2. A calculation of the number of necessary wells may be useful in some respects, but is very different than the goal of this research. Also, their injectivity relationship assumes no hydraulic communication between wells, which is unrealistic except in rare geological conditions.

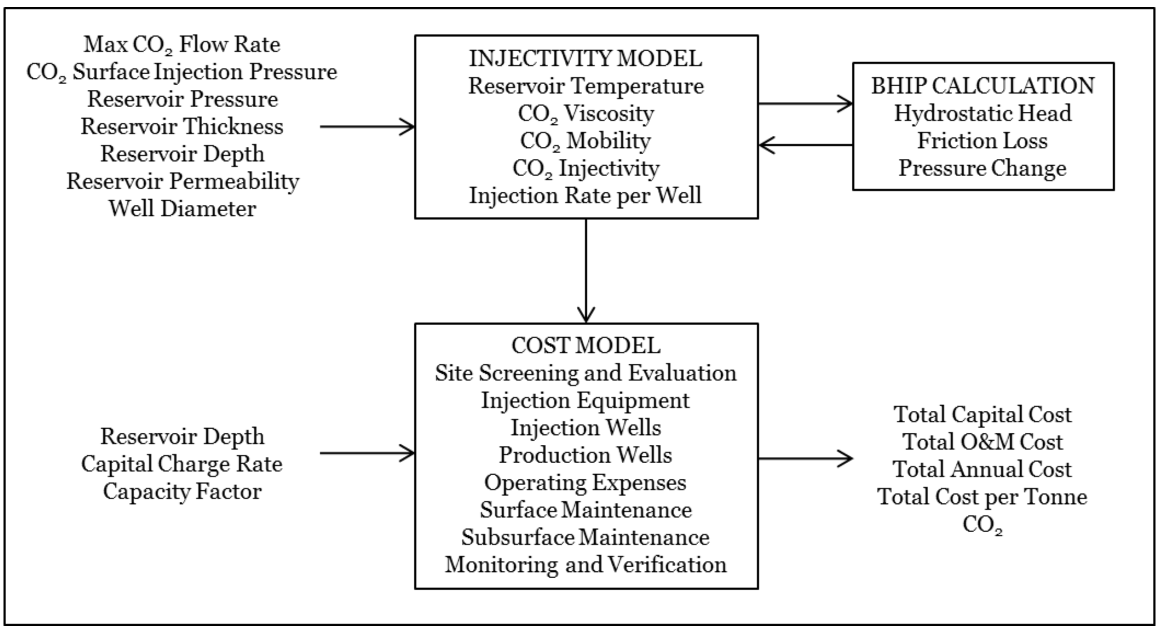

Figure 38. Conceptual model adapted from McCoy and Rubin (2005) illustrating the process to calculate project costs.

4.2 Methods

Details of costs have been compiled from numerous sources by Bock *et al.* (2003). Although the injectivity model has been solved differently, the costs are useful. Several of the equations are solved in terms of total costs per well which renders them easily adaptable to the previously developed injection curves. Other costs are functions of injected CO_2 volume. Site screening costs are a fixed rate applied to each scenario. Combined, these functions give useful representations of optimization and maximization. Their cost of capture function is not included, however. An assumption is that capture technologies and techniques have vastly improved in the past 10 years, whereas other parts of the system have been previously perfected by the oil and gas industry and have seen little change. For a report on the cost of capture, see WorleyParsons (2011). The report shows a wide range in capture cost for several types of power generation plants. Also included are monitoring, verification, and accounting (MVA) costs that are associated with activities during and postinjection. All MVA costs are adapted from the Phase III CO_2 sequestration demonstration project budget (SWP, 2013). A summary of the included MVA costs is given in Table 3. The combined cost function appears simple and straightforward, including only the transportation, storage, and MVA costs to avoid the disparity between types and sizes of power plants.

Costs may be separated into three separate categories so that several economic relations can be drawn. The first category, one-time capital costs, includes site screening, injection equipment, MVA equipment, and well drilling. Site screening costs are detailed by Smith *et al.* (2001). For sake of expediency, it is assumed that their total screening cost figure, $1.685M for all cases, is sufficient for the purposes of this paper, albeit it is over a decade older than this study. Although it is possible that techniques and therefore costs have changed since that paper was published, a key assumption is that an inflation term is the only necessary modifier. Injection equipment costs are derived from the

Table 3. Summary of included capital and annual MVA costs adapted from Phase III demonstration project (SWP, 2013).

ONE-TIME CAPITAL	**Costs**
Miscellaneous Equipment Costs	$250,000
GPS Stations	$50,000
Passive Seismic Geophone	$200,000
Tilt Meters	$15,000
Total One-Time Capital MVA Costs	$515,000
Conversion from 2013 to 1999 dollars	$367,857
YEARLY O&M	**Costs/Year/Mile^2**
VSP	$150,000
3D Seismic	$150,000
Passive Seismic	$10,000
Soil Flux Surveys	$10,000
Eddy Covariance Flux Surveys	$5,000
Tracers	$50,000
InSAR	$15,000
GPS	$2,000
Tilt	$2,000
Basic Fluid Sampling (Reservoir)	$15,000
Basic Fluid Sampling (USDW)	$15,000
Total Annual MVA Costs	$424,000
Conversion from 2013 to 1999 dollars	$302,857

equation in Table ES-5 in Bock *et al.* (2003), revised and retyped as Table 4 in this report. This equation, however, is specific to their problem and must be modified. The constant, 7,389, is the mass flow rate in tonnes per day (Table 4). It is replaced by the appropriate mass flow rate for each scenario in the modified equation. Other constants in the equipment cost equation modify units and interpolate between values between those given by EIA (2000).

MVA costs are divided among two sections: 1) one-time capital costs and 2) yearly O&M costs (Table 3). One-time capital costs are comprised of equipment costs. Miscellaneous equipment includes: an eddy covariance tower and analyzer for broad CO_2

Table 4. Capital and O&M cost functions adapted from Bock *et al.* (2003) enabling costs to be calculated by the number of wells for each injection scenario.

Parameter	Unit	Value
CAPITAL COSTS		
Injection Equipment (Flowlines & Connections)	$/well	43,600*(Mass_Rate/(280*#Wells))^0.5
YEARLY O&M COSTS		
Normal Daily Expenses	$/well	6,700
Consumables	$/well	17,900
Surface Maintenance (Repair & Services)	$/well	13,600*(Mass_Rate/280*#Wells))^0.5
Subsurface Maintenance (Repair & Services)	$/well	5,000*Well_Depth/1219

and CH_4 flux measurements, a 3D anemometer for use with the eddy covariance equipment, a soil flux chamber and analyzer for spot CO_2 flux measurements, an ion chromatograph for water sample analysis, and a network for data storage and acquisition. Also included for detecting surface deformation are three permanent GPS stations and three permanent surface tilt meters. To detect microseismicity by means of passive seismic data collection, one permanent down-well geophone is included. Drilling costs are the last in the category. They are calculated on a per-well basis with the use of this regression equation:

$$y = 0.0888e^{0.0008x} \qquad (2)$$

where y is cost ($M) and x is injection depth (m). This equation can be found in Figure ES-2 from Bock *et al.* (2003).

Pipeline cost has been assigned to its own category, in the form of annualized capital costs. Unlike previously discussed capital costs, Bock *et al.* (2003) annualized pipeline costs for 20 years at a 15% capital charge rate. Pipeline costs are very large compared to other costs. By annualizing these (rather than including them with the one-time capital costs), the first-year costs are lower. With this, well optimization is not improperly skewed toward more wells since most of the simulations are only one year in length. The calculation is a function of mass flow rate (Figure 39). It has been developed for a 12-inch pipe and relative to 100 km of pipeline distance. Both of these parameters would be unique for each project. Pipe diameter in particular would greatly affect cost. In practice, the diameter would be calculated for the mass flow rate, meaning that each injection scenario presented in this paper would require a different pipe diameter. It is estimated that this diameter is appropriate for injections in the range of 2 to 4 Mt per year. This is comfortably within the range that has been simulated, with many simulations lower and a few higher than this rate. For sake of consistency and comparison, the 12-inch pipe relationship was used for all scenarios. The points in Figure 39 have been fitted with a regression equation relating cost per tonne and mass flow rate. Although there are no points with less than 1 Mt on the curve, it is assumed that lower mass flow rates would also obey this equation. Further, it is assumed that their pipeline pressure of 15.2 MPa is appropriate and does not require further compression en route. At an ambient temperature of 25°C, this pressure is within the supercritical range for CO_2 and has been shown to result in good transport quality (Bock *et al.*, 2003).

Yearly Operations and Maintenance (O&M) costs comprise the final category. These are summarized in Tables 3 and 4. Random expenses have been grouped into two groups, daily costs and consumables, at $6,700 and $17,900 per well, respectively. These figures are derived from averages of what has been seen in existing oil field operations. Surface maintenance costs employ a similar equation to that of injection equipment. The constant, 7,389, has been replaced by the appropriate mass flow rate in each scenario. The subsurface maintenance equation comes from EIA (2000). Only the depth is

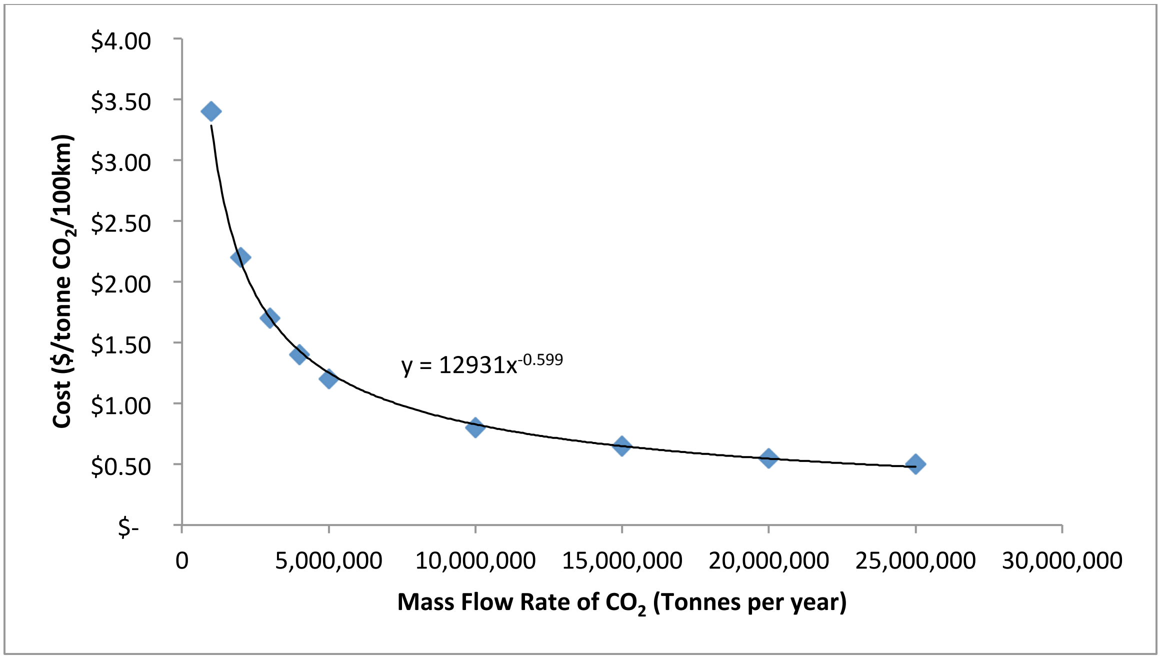

Figure 39. Total annualized pipeline costs including construction and O&M costs presented as a function of mass flow rate, adapted from Bock *et al.* (2003).

changed in this equation. It is assumed that all of these equations remain valid, and that the costs are only to be modified by inflation. Annual MVA costs are calculated in cost per year per square mile, and are scaled appropriately for the respective land area (Table 3). For the purpose of this report, relationships are assumed to be linear with respect to land area. Vertical seismic profiling (VSP) is a method for mapping subsurface layers and fluid plumes. Here, costs are given for a single transect one mile in length. Similarly, 3D seismic is a process that maps the subsurface. Generally, surveys are conducted in a grid pattern for a given area. Passive seismic, soil flux surveys, and eddy covariance flux surveys all require yearly operations and maintenance fees. Two-phase tracers are injected with the fluid to monitor water and CO_2 breakthrough at distant wells. InSAR is an aerial imaging technique that detects surface deformation. The associated cost is for the purchase of two separate images for deformation calculations. GPS equipment and tilt meters, also used for calculating surface deformation, require annual operations and maintenance fees. Fluid sampling takes place in both the target reservoir and adjacent underground sources of drinking water (USDW) to ensure that aquifers are not polluted by injection. Sampling costs are approximated per square mile.

As previously discussed, the "Injectivity Model" from Bock *et al.* (2003) has already been solved for many injection scenarios. The model developed in this paper has output injection rates and volumes. The "Cost Model" with the addition of the SWP (2013) MVA costs has been applied to these results in a cost analysis spreadsheet which contains several user options that may be altered in somewhat of a sensitivity analysis.

Project life span is the first adjustable parameter. Default for this parameter is one year. When altered, the spreadsheet will calculate the first-year costs as well as the full project-life-span costs. However, it should be noted that the latter may be skewed due to incorrect injection rates. All simulations, with the exception of the 'Time' sensitivity analysis (section 3.7), have been one-year injections. Using the one-year injection rates for anything other than a one year project will give incorrect injection volumes, and therefore incorrect costs. For this reason, it is recommended that this parameter remain at the default. Projects of various lengths may be seen in the 'Time' sensitivity analysis (section 3.7). These simulations have correct injection rates for each given project length. Depth to injection may also be altered in the spreadsheet, although again the injection rates will not be correct. See the 'Injection Depth' sensitivity analysis for 1,000 m and 3,000 m depth injection volumes as compared to the default of 2,000 m (section 3.4). Pipeline length may be altered to change the pipeline costs relative to the 100km benchmark. Site screening, daily expenses, and consumables may also be changed, but the default values are recommended. All MVA costs may be altered in a separate tab. Perhaps the most relevant parameter is inflation rate. It has been assumed that all of the cost equations have remained consistent from 2003 until the time of this paper. It is not clear whether or not any of the regression equations have changed, so the most valid method for updating them is with inflation. Bock *et al.* (2003) used 1999 dollars for their studies. As of 2013, the cumulative inflation rate was 40% (CPI Inflation Calculator, Bureau of Labor Statistics. Accessed August 2013, http://www.bls.gov/data/inflation_calculator.htm). Both the first-year cost and total-project cost have been calculated with and without inflation.

4.3 Results

Total-project costs rise with more wells and larger injections. The goal of optimization is to find the point where the cost per tonne of CO_2 is lowest for the total storage capacity requirement. A major goal of this work is to confirm the hypothesis that a single injection well is not ideal. It has been proven from an injection context, and now the same is shown with respect to costs. An example for base case parameters and the 80-acre injection curve is shown in Figure 40.

A single well is one of the more inefficient configurations for two reasons. First, due to the smaller volume of CO_2 injected, the unit price of CO_2 is high. Second, the capital costs are not shared among other wells, but fall solely on the single well. In general, it appears that the optimal number of wells (with respect to cost) lies between four and eight wells for many of the scenarios that have been tested. This coincides with the most extreme change in slope on the injection curve. See, for example, Figure 40. In this particular injection curve, the slope flattens substantially between four and eight wells. Notice that the cost curve ($/tonne) reaches a minimum during the same span. Although more fluid is injected with additional wells, eventually, the benefits of lower unit CO_2 cost are overridden by costs for drilling, equipment, and maintenance. It is possible that certain projects will not prioritize such optimization, but rather have a fixed budget or amount of CO_2. This study will likely still be useful to find the most efficient injection scenario for the project parameters by selecting the appropriate injection curve.

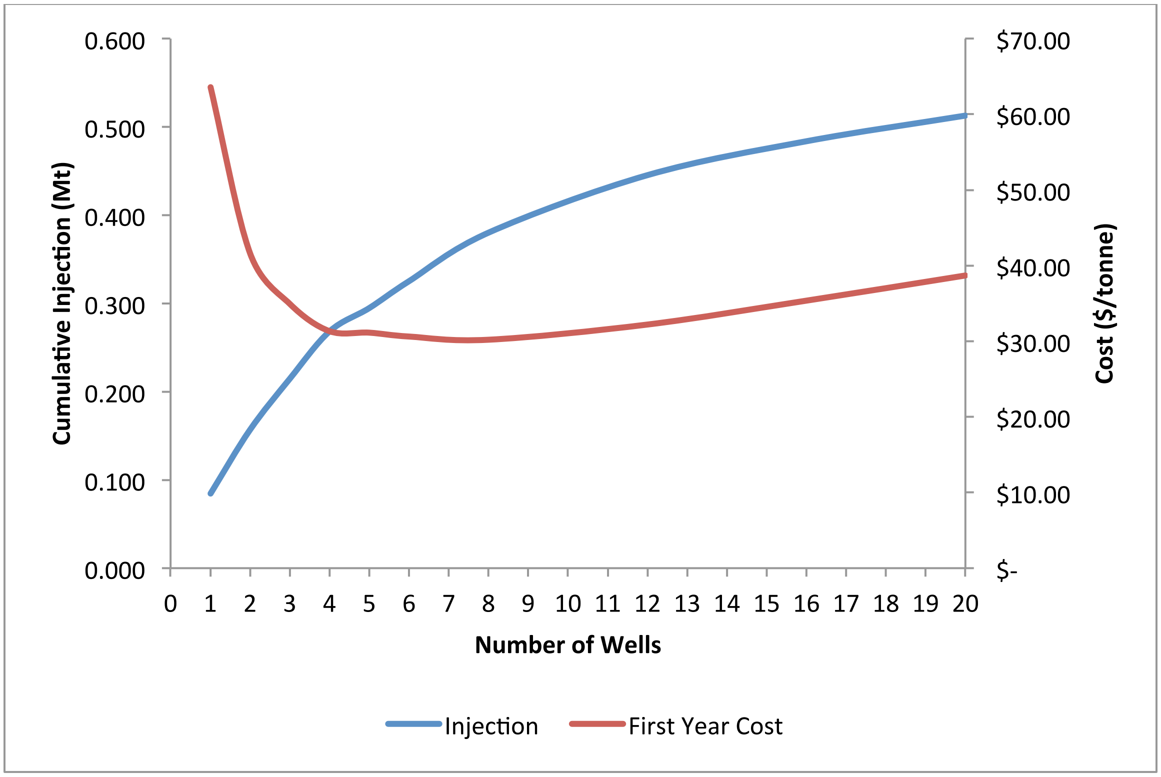

Figure 40. Cost optimization and injection curves for the base case 80-acre example depicts the optimal point between four and eight wells.

Optimization curves are developed for each scenario in the generic sensitivity analysis. A tabular form of results for the full sensitivity analysis are located in the Appendix. Overall, the results are intuitive, beginning with available land area.

- Smaller acreages have optimal points shifted toward fewer wells and are marked by higher unit costs of CO_2. The smallest acreage, 2.5 acres, shows an optimal point near four wells. Larger acreages shift the optimal point toward more wells with 1,000 acres showing 20 wells as the lowest cost per tonne. Pressure superposition between wells expresses these findings.
- Less hydraulic interaction between wells, e.g., for lower permeability reservoirs, results in straighter injection curves, and therefore, the

optimal point corresponds to more wells. The opposite is true with more interaction between wells.

- Porosity only offsets the injection curve without much change to its slope; the optimal point should not change.
- Except for extremely high and unrealistic values, compressibility has little effect on cost, injection volume, or optimization.
- Depth to injection plays a major part in the cost equations. Injection volumes are very different between 1,000 m and 3,000 m depth. Because of the unit price disparity combined with the additional costs of drilling and maintenance, 1,000 m sees an optimal point near eight wells while 3,000 m is optimal with four.
- Layer thickness shows a slightly different effect of superposition. Thinner layers, such as the tested 50 m layer, do not allow for vertical spreading of the pressure plume and may also have an optimal number of wells closer to four. Both the 100 m and 200 m layers showed optimal points between four and eight wells.
- Simulation time yields significant sensitivity for the optimal point. With simulations shorter than one year, the optimal number of wells may be as many as possible because the effect of superposition is small. After one year, the optimal point stabilizes between four and eight wells.
- The effects of permeability heterogeneity are highly variable but may be roughly predicted using the average reservoir permeability.

These results are developed with water as the injection fluid. An analysis with CO_2 as the injection fluid confirms that water injection yields results qualitatively similar to multiphase results. CO_2 proves to be slightly more mobile than water and therefore, the hydraulic communication among wells is generally more significant. The optimal point may be shifted closer to four wells with CO_2, for most reservoirs.

4.4 Discussion

There are several pieces of the cumulative cost equation that may skew the optimization results. First, the injectivity model has been completed with water rather than CO_2 as the injected fluid for all but the CO_2 sensitivity analysis. Due to its compressibility, injecting CO_2 may well lead to larger injections because of smaller pressure buildups. Another possibility is that very low relative permeability and capillary pressure will lead to smaller injection volumes. Yet another is that the increased mobility will cause larger interactions between wells and therefore larger pressures and lower injectivity. This must be analyzed on a case-by-case basis. Other concerns are associated with the fundamental cost model. Capital costs may introduce bias because they typically are very large; specifically, with fewer wells, the burden is more for each well and the cost per tonne is higher. Costs such as site screening, injection equipment, MVA equipment, drilling, and pipeline construction make up a large portion of the total project cost. These were somewhat arbitrarily chosen; perhaps other studies will not include all of the same capital costs or perhaps they include additional costs that are not listed here. Higher capital costs would skew the optimization point toward more wells, while lower capital costs skew the point toward fewer wells. The pipeline cost equation, for example, calculates cost per 100 km. Shorter pipelines would reduce the cost for smaller amounts of CO_2, possibly making it more beneficial to use fewer wells. Longer pipelines would do the opposite by completely disincentivizing smaller injections. Therefore, the optimal point may shift toward more wells. A sensitivity analysis on this concept may be necessary.

Cost estimates of this generic analysis compare fairly well with previous studies. Bock *et al*. (2003) used a base case aquifer with 2.2E-14 m^2 permeability. The cost for injection was $2.93 per tonne. Their high cost scenario for a 8.0E-16 m^2 permeability aquifer was $11.71 per tonne. McCoy and Rubin (2005) used a 1,460 m deep, 14 m thick reservoir with an average permeability of 6.3E-15 m^2. With 4.67Mt/year of injection, the cost ranged from $0.60-$32.40 per tonne. This study indicates that it is feasible to see these higher costs especially with low permeability and low injection rates. McCoy (2008) found a range of $0.35 to nearly $9 per tonne for storage alone with four case studies, all of which had injection rates of 5 Mt/year. The median transport cost was $1.65 per tonne. Additionally, McCoy suggested that site characterization costs could potentially be much higher than the previously suggested $1.685M. An IPCC special report summarized costs from several studies in Australia, Europe, and USA (IPCC, 2005). Storage costs were found to be between $0.50 and $8.00 per tonne. In comparison, the favorable reservoir conditions tested here were capable of costs well below $10 per tonne. Others, such as the 1E-16 m^2 permeability case, resulted in costs as high as $500 per tonne. Such unfavorable reservoirs were not tested in other studies, but are given here to show the full range of reservoir conditions.

Keeping the assumptions and limitations of this method in mind, the findings and procedures can be a useful tool for predicting costs, injectivity, and the optimal number of wells. Engineering judgment is imperative in drawing from all of the conclusions that have been presented throughout this study. Interpolations between the given values are necessary. Additionally, results must be adjusted for biases and shortcomings that have been discussed.

CHAPTER 5

CASE STUDY

5.1 Overview

A case study is utilized to test and confirm results of the generic analyses. The specific goal is to illustrate how the methodology may be applied to proposed CCS projects. Depending on project goals, it is possible to optimize a given scenario in several ways. Injection curves developed in Chapter 3 illustrate relationships between injectivity and number of injection wells. Chapter 4 outlines a method for optimizing injection volume or cost per tonne of CO_2. To demonstrate the full methodology, first a model is developed for a specific site, discussed below. Porosity and permeability fields are parameterized, and cell-sizing results are tested by refining the simulation grid to investigate 1) resulting pressure regimes, and 2) the impact on injectivity. The next step in the methodology is to identify a portion of the grid that may be used to determine optimum well configurations. In an actual CCS scenario, this would be a portion of land that may be feasibly used for an injection site. Terrain, ease of access, land ownership, and proximity to model boundaries are all considered in selecting the appropriate plot of land. Finally, injection simulations are performed on the desired portion of the model. Several well configurations are tested and used with the calibrated cost optimization function. Results are compared to those of the appropriate generic analysis. If the generic results correctly forecast injectivity, cost, and optimum number of wells, then the generic results and methodology may indeed be adapted to other CCS projects.

The case study site is a major geologic fold structure near Craig, Colorado. This site was characterized and evaluated for CCS readiness most recently (2009-2013) by the Rocky Mountain Carbon Capture and Sequestration (RMCCS) project, a multi-agency collaboration led by the University of Utah and sponsored by the U.S. Department of Energy (rmccs.org). The three-year project used a budget of approximately $11M USD to characterize the Dakota Sandstone, Entrada Sandstone, and Weber Sandstone formations of the Sand Wash Basin (Figure 41).

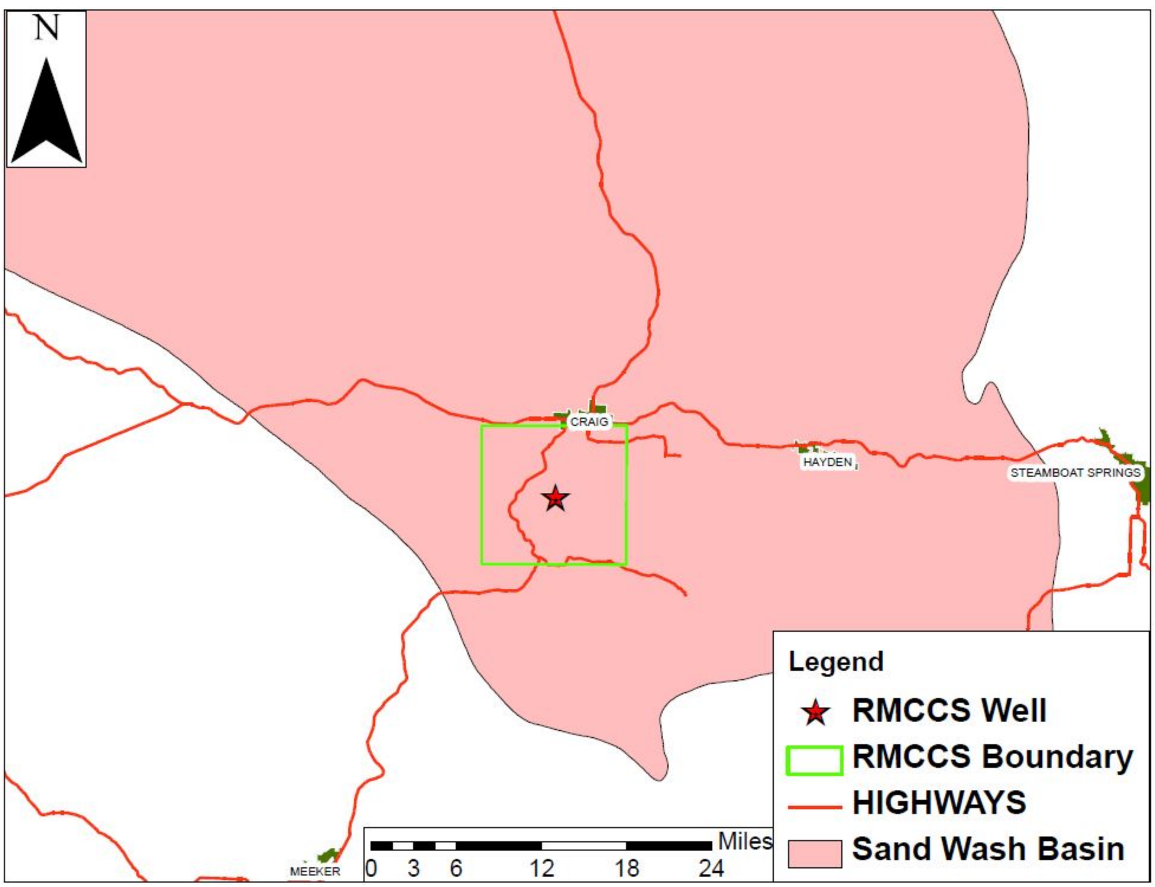

Figure 41. RMCCS site overview.

The Dakota and Entrada Formations are widespread throughout the Rocky Mountain Region and could potentially provide several opportunities for large-scale CCS projects. A single 2,925 m deep well was drilled for the purposes of collecting seismic data. Core samples were collected and tested by several different entities, including TerraTek, CoreLab, and the University of Utah. From these collected data, several geologic models were created by the collaborative team. Original models were created for the purpose of storage capacity estimations. These same models are adapted for the purposes of this case study.

5.2 Site Characteristics

The three target formations are sandstones within the Sand Wash Basin. At the well location, the formation tops are 2,500 m for the Dakota and 2,725 m for the Entrada. Both are approximately 60 m thick with effective seals above and below. The Weber Formation was not reached with the seismic well. Core samples were collected from each layer that was reached. A single data point was collected from the Dakota and none were collected from the Weber. Dozens of points were collected from the Entrada, however. Due to the more abundant data in the Entrada, it is used as the target formation for this report.

Entrada porosity ranged from 3.6 to 12.1%; the mean was 7.63%. Permeability ranged from 0.1E-15 to 19.8E-15 m^2 with a mean of 5.92E-15 m^2 (SWP, 2013). These findings compare reasonably with previous studies. Otto and Picard (1976) found that the Entrada has several different facies. Of these facies, the sandstones had a mean porosity of 15.9% in eastern Utah. The permeability has been tested in several oil fields in Utah to be close to 1E-13 m^2. The grain size is fine- to medium-grained sand on the Wentworth (1922) scale. However, there are other facies within the Entrada that have smaller grain sizes and have porosities between 1 and 9%. Wright *et al.* (1962) also studied Entrada grain size and found the mean to be between 0.125 and 0.25 mm, corresponding to a fine- to medium-grained sand. The Dewey Bridge Member has a mean that is much smaller, between 0.004 and 0.125 mm. The lower end of the range corresponds to a fine silt on the Wentworth (1922) scale. It appears that depositional environment and geographic location have a major impact on the Entrada properties. Porosity and permeability could also be highly variable. There is a major lack of data in Northwestern Colorado, but based on data from previous works, it is feasible that the Entrada is slightly less porous and permeable than it is in Utah where most of the data have been taken. The porosity and permeability at the RMCCS site is on the low end of the range, but considering what has been measured in the Dewey Bridge Member, it is feasible.

5.3 Model

Prior to this work, a full basin scale model was developed for storage capacity estimation. A four-mile radius circular clip of the model was taken around the characterization well for simulation purposes. Both of these models contain only porosity fields. Therefore, an equation was used to relate porosity and permeability in order to populate the model with a permeability field. Perhaps the most well-known relationship, the Kozeny-Carman equation has been used and tested many times over (Kozeny, 1927; Carman, 1937; and Carman, 1956). Although empirical data exist from the core data, the Kozeny-Carman equation is thought to be more reliable than a simple empirical regression. Below is a version of the equation:

$$k = \frac{\emptyset^3}{5{S_o}^2[1-\emptyset]^2} \qquad (3)$$

where k is permeability (m^2), Ø is porosity (fraction), and S_o is the surface area per volume of the particles (m^{-1}). The unknown parameter, S_o is back-calculated by fitting the equation to empirical data. The fit is checked with an approximation for spherical particles, $S_o = 6/d$, where d is the mean diameter (Ingebritsen *et al.*, 2006). Of course, the particles are not perfect spheres, but the approximation is used as a check once the mean particle size is found. Figure 42 shows the calibration of calculated and empirical data. The value of S_o was varied until the best fit was found. At that point, the mean size was calculated to be 0.0171 mm. The size represents a medium silt on the Wentworth (1922) scale, which is smaller than a typical sandstone, but still in the range of what is found in the Entrada Formation. Being that the porosity and permeability from the core analysis are also on the lower end of the range for Entrada, the method is assumed to be valid.

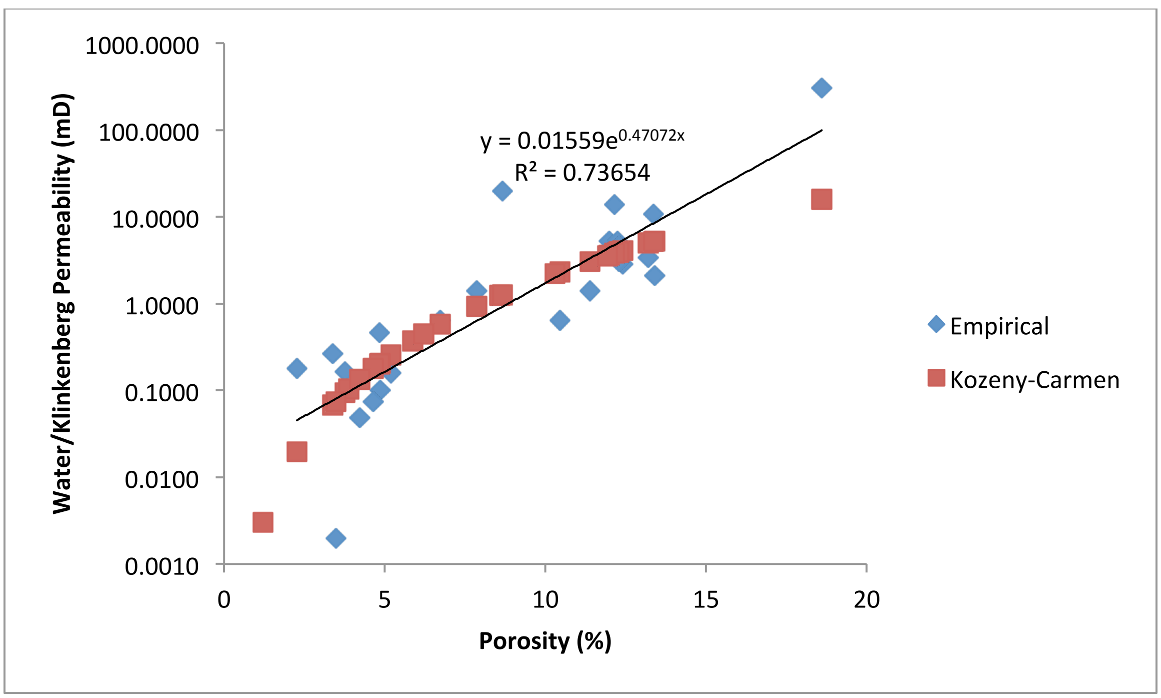

Figure 42. Kozeny-Carman calibration with core data with S_o=3.5E+05 m^{-1} and d = 0.0171 mm.

The Kozeny-Carman equation was accepted with S_0 = 3.5E+05 m^{-1} to be applied to the porosity model for development of the permeability field. The relationship is not ideal for developing a model, but for academic purposes, it is used in this report. Modeled porosity ranged from 1.5 to 24.3% with a mean of 8.0%. The calculated permeability field had a range of 0.006 to 40.6E-15 m^2 with a mean of 2.2E-15 m^2. The permeability distribution on the simulation model is shown in Figure 43. These values are comparable to the base case values from the generic analysis, thus allowing forecasts of results.

ECLIPSE is used for simulations since the model had been created with PETREL. Both codes are from the Schlumberger Inc. suite of subsurface flow software. Several assumptions are made so that the model behaved similar to previous TOUGH2 model. No-flow boundaries are used to avoid the complications of modeling the reservoir as an infinite aquifer. However, the model domain is sufficiently large that boundary effects should be very small if the pressure plume does in fact reach the edge of the domain.

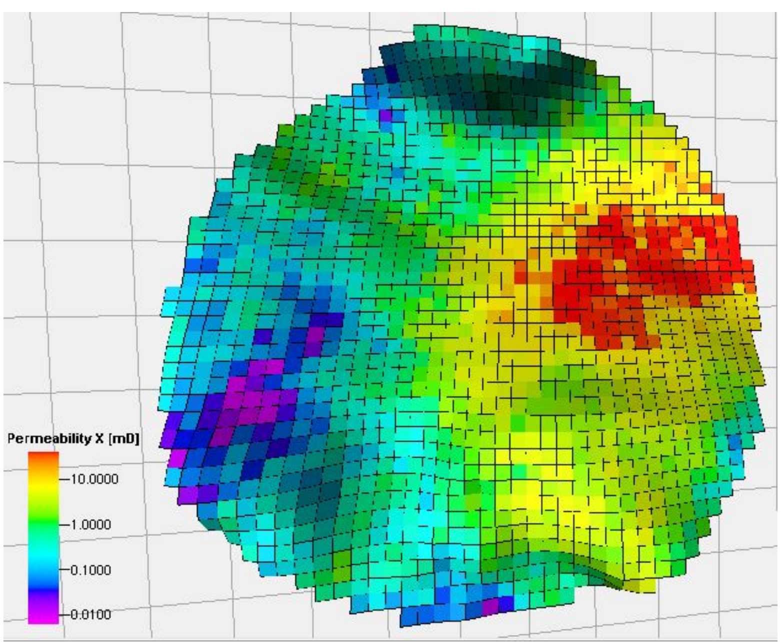

Figure 43. Permeability field on the simulation model.

Initial pressure conditions are hydrostatic. With depth as the reference, the fracture pressure of the rock is calculated to be 56.65 MPa and the reservoir temperature is 101.72°C. The initial brine concentration is 50,000 ppm. Solid salt precipitation is enabled. No gas phase is present at the initiation time. Unlike the TOUGH2 code, there is a very simple bottom hole pressure (BHP) control option on wells that holds the simulation at a specified maximum pressure. Injections were not interpolated from the maximum pressure as done previously. Rather, the injection volumes and rates were exported at the end of the simulation. The middle 20 m of the reservoir is perforated to mimic the previous analysis. Relative permeability is taken from the ECLIPSE example file for the CO2STORE module (Pruess, 2005). Upon visualizing the relative permeability function, the curves most resemble the Brooks-Corey curves.

5.4 Injection Location

A major assumption of this work is that injection operations must take place on a finite parcel of land; thus limiting the spacing between wells. By the principles of superposition, placing wells as far apart as possible would provide the best pressure regime. However, it is not practical or feasible to use a large area of land for an injection site. The generic analysis has developed relationships between available land area and injectivity. In theory, the correct curve can be adapted for the actual available area of land to predict the optimal number of wells and anticipated injection volumes. To illustrate the application of this methodology, a parcel of land has been identified on the simulation model that could plausibly serve as an injection site.

The objective of this site selection was to identify an area of land that could serve as an injection location in a real injection operation, but that also may be used with the PETREL simulation model. Ideally, the site would be of large enough area to accommodate numerous wells to draw comparisons with the TOUGH2 analyses. State or Federal property is specifically targeted because then, theoretically, the land would not have to be purchased from a private owner. Preferably, the injection site would be situated in a high permeability area and near the center of the model domain.

With these guidelines, a 500-acre parcel of land was chosen around the center of the model (Figure 44). The decision was made for several reasons. First, a 500-acre square fit very well within the state-owned land that was situated in the middle of the domain. Any larger and the site would infringe on private land; any smaller and the hydraulic interactions would not be optimized for the available space. Being in the middle of the domain, there are fewer complications caused by the pressure plume reaching the boundaries. Also, the choice of 500-acres allows for comparisons to the generic 500-acre analysis. The efficacy of the generic analysis can be tested by this case study.

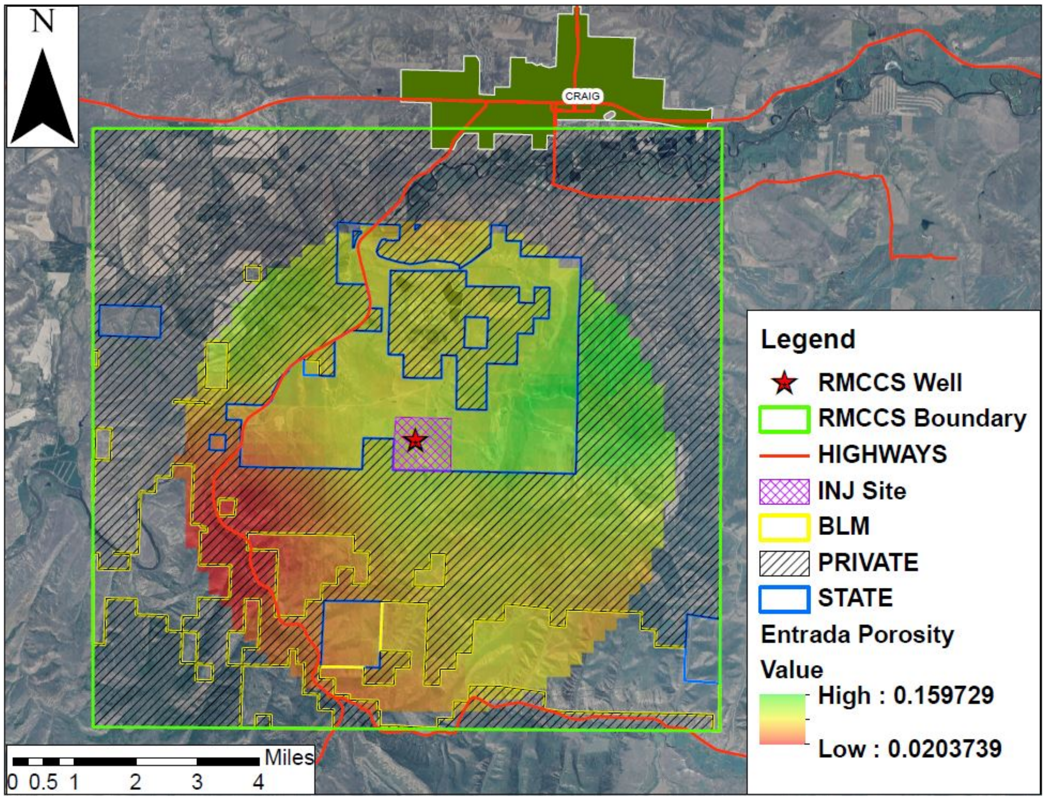

Figure 44. Porosity distribution and land ownership on the simulation grid.

The injection area is situated near a fairly high permeability portion of the model. Average porosity of the vertical cells is shown in the figure because permeability on a log scale gave a misleading color scale in ArcGIS. The permeability is not as high there as the northeast corner of the domain, but was selected over that area for practical reasons. The high permeability area to the northeast is closer to both the model boundary and ongoing mining operations. A test well was drilled in the middle of the domain, and therefore, the porosity and permeability values are more certain within its vicinity. Also, assuming that the power plant in the north-center of the grid is used as a source of CO_2, the pipeline distance is minimized by this site.

5.5 Grid Resolution

The simulation grid originally contained 300 m cells in the x- and y-directions. This is much larger than suggested by the previous cell sizing analysis. In the z-direction, the cells are much smaller, in most cases no more than a few meters thick. The lateral cell sizes were refined to test the effect of cell sizing on injectivity similar to what was previously done. Included in the analysis are the existing 300 m cells, 100 m cells, and 10 m cells. Simulations were attempted on 1 m cells, but were not completed due to extremely long simulation times. Injections took place in the center of the domain through a single cell representing one well.

Results suggest that injectivity is very sensitive to injection cell sizing (Figure 45). This is a function of the volume of the injecting cell. Larger cell volumes result in lower pressures and smaller cells result in higher pressures, as expected. However, the results of injection volumes are not intuitive. Smaller cells inject larger volumes of CO_2 than the larger cells. This may be explained by Darcy's Law (Equation 4).

$$Q = \frac{-kA}{\mu}\left(\frac{P_2 - P_1}{L}\right) \quad (4)$$

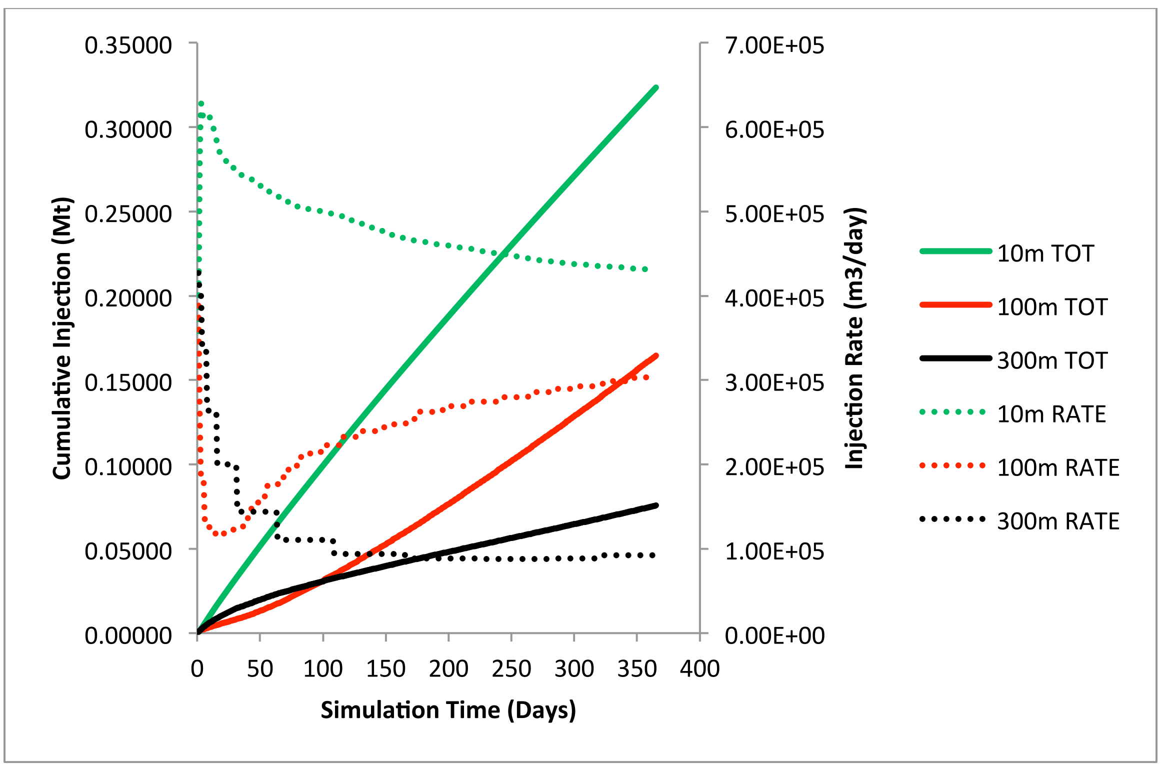

Figure 45. Injection rate and total injection volume for the cell sizing analysis.

This form of the law includes flow rate (Q), permeability (k), cross-sectional area (A), viscosity (□), initial pressure (P_1), final pressure (P_2), and length (L). Examining the pressure change in one dimension, the smaller cells have higher pressure at the injecting cell and also a higher pressure gradient (Figure 46). By Darcy's law, a higher pressure gradient over the same distance should result in higher flow. It may be that smaller cells allow for the fluid to move away from the well at a higher rate resulting in larger injections. Also, precipitation occurred in many of the 10 m cells, but never with the larger cells because they never reached saturation. The smaller 10 m grid refinement is used with the proceeding injection analysis. It is the most accurate and realistic option without sacrificing computational efficiency. Results can also be more easily compared to the TOUGH2 analysis that used 10 m cells. In practice, it may be necessary to use even smaller cell sizes to get accurate injection numbers.

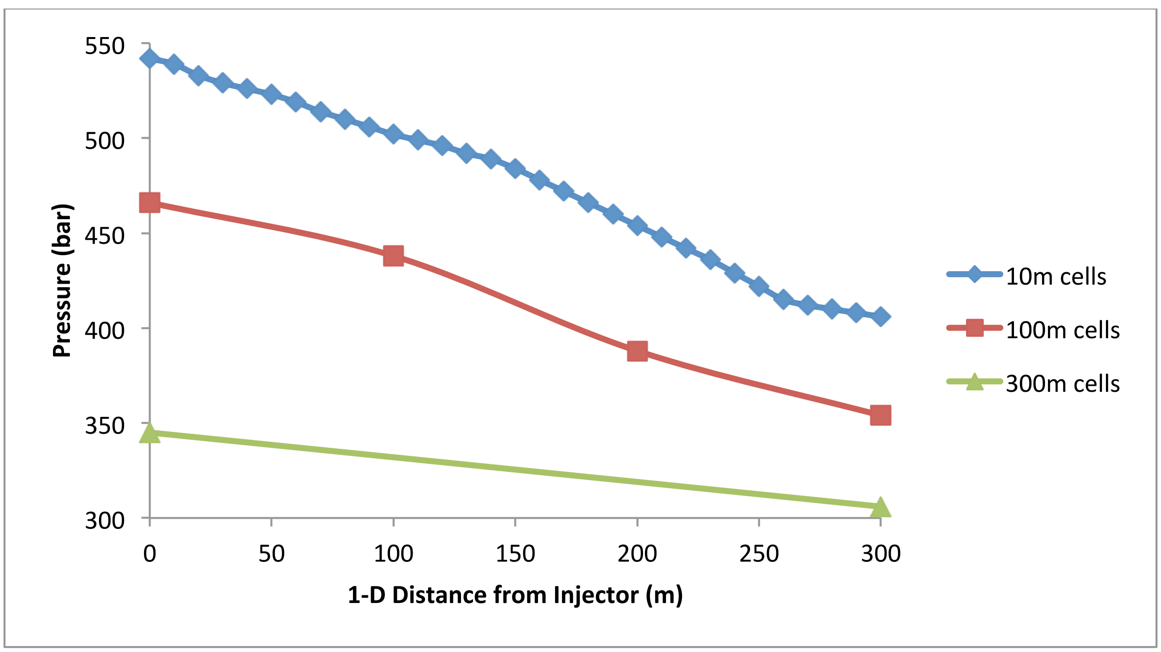

Figure 46. One-dimensional pressure distribution for the cell sizing analysis.

As previously mentioned, 10 m cells give fairly accurate numbers, but are still much larger in volume than an actual wellbore. Grids smaller than 1 m and telescoping outward to larger cells are recommended near a well. For the purposes of this report, extreme grid refinement is not practical or necessary. Accuracy is not the primary goal. Rather, the goal of this work is to develop general relationships and a methodology for well optimization. These goals are achieved with 10 m cells.

5.6 Well Configurations and Cost Optimization

Similar to the TOUGH2 analysis, various well placement patterns are tested on the RMCCS model. Well configurations consisting of one, two, three, four, five, six, eight, and 12 wells are tested to comply with the previous methods. The generic analysis included as many as 24 wells, but those configurations are not tested here as the results were extraneous for well optimization. Wells are placed in the maximum perimeter pattern which evenly distributes the wells around the perimeter of the 500-acre injection site. In addition, the traditional oil field five- and nine-spot patterns are simulated for sake of comparison. The goal is to develop an injection curve showing cumulative injection for the tested well configurations and also calculate an optimal number of wells using the cost-optimization function. Cost functions are all the same as previous analyses. Pipeline length is assumed to be 100 km to be consistent with the previous analysis. It is unknown whether or not the power plant to the north would be used as a CO_2 source. As a caveat, if it were used, the pipeline construction costs would be much lower, shifting the optimal number of wells to fewer wells.

Results show similar relationships to what was found from the generic analysis (Figure 47).

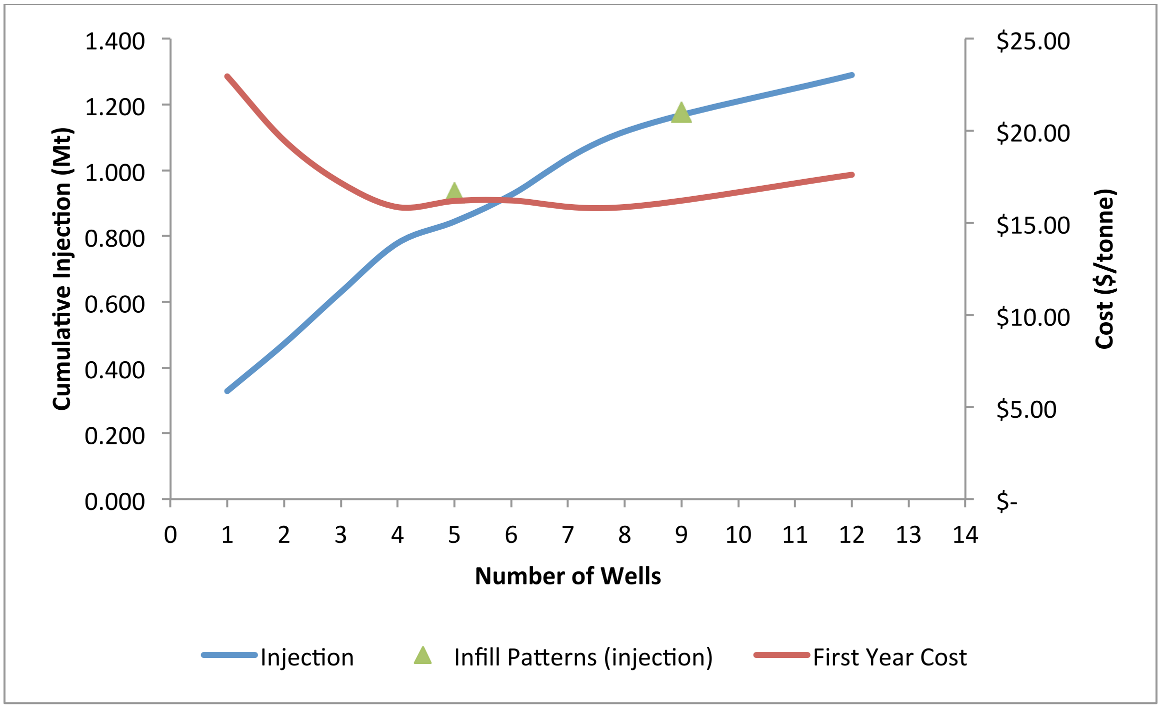

Figure 47. Injection volume and cost optimization for the case study model.

A single well injects the least amount of CO_2 and is the least efficient scenario. The lone well develops localized high pressures near the injection well which limits the injection volume (Figure 48). Because of the small volume of CO_2 injected and high capital costs, the cost per tonne of CO_2 is high. As more wells are added, the localized high pressures persist in the well vicinity but larger injections are possible as effects of pressure superposition between wells are small until five wells. There the injection slope changes; the change is also reflected in the cost optimization. Again it appears that there is an optimal point between four and eight wells where the cost per tonne of CO_2 is lowest. With fewer than four wells, the costs are negatively impacted by high capital costs and low injection volumes. With any more than eight wells, the higher injection volumes are offset by the additional costs of drilling and operations of the wells. Tabular results for injectivity and cost are located in the Appendix.

Opposite of what was seen in the generic analysis, the five-spot pattern (0.9310 Mt) injects more than the five-well maximum perimeter pattern (0.8439 Mt). The result does not necessarily oppose the previous result, but rather it speaks to the impacts of heterogeneity and well placement. Superposition and well spacing are the controls in a homogeneous reservoir.

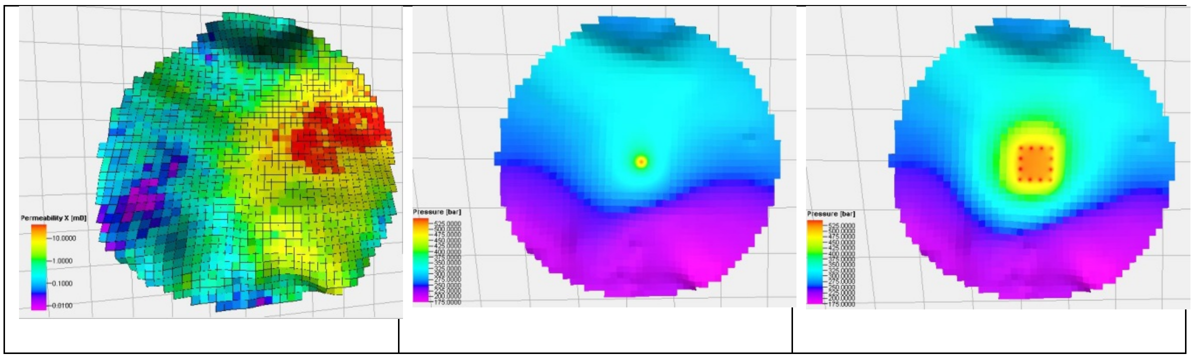

Figure 48. Visualization of permeability values and pressure contours on the simulation model. a) Permeability distribution, b) one-well pressure regime, and c) 12-well pressure regime.

A heterogeneous reservoir on the other hand is controlled by the parameters of each injection cell. Likely, the five-spot pattern injected into cells with favorable characteristics compared to the five-well maximum perimeter pattern. Uncertainty is more important with fewer wells. This can be illustrated by Figure 49, which was developed for storage capacity estimations but can be adopted for injectivity (obtained via written communication between the University of Utah and Dr. Si-Yong Lee). The storage capacity (and likewise injectivity) range is the widest for a single well as the estimation relies solely on the properties within that one location which may or may not be representative of the reservoir average. With more wells, the uncertainty is minimized as the average parameter values for the injection cells approaches the average reservoir values.

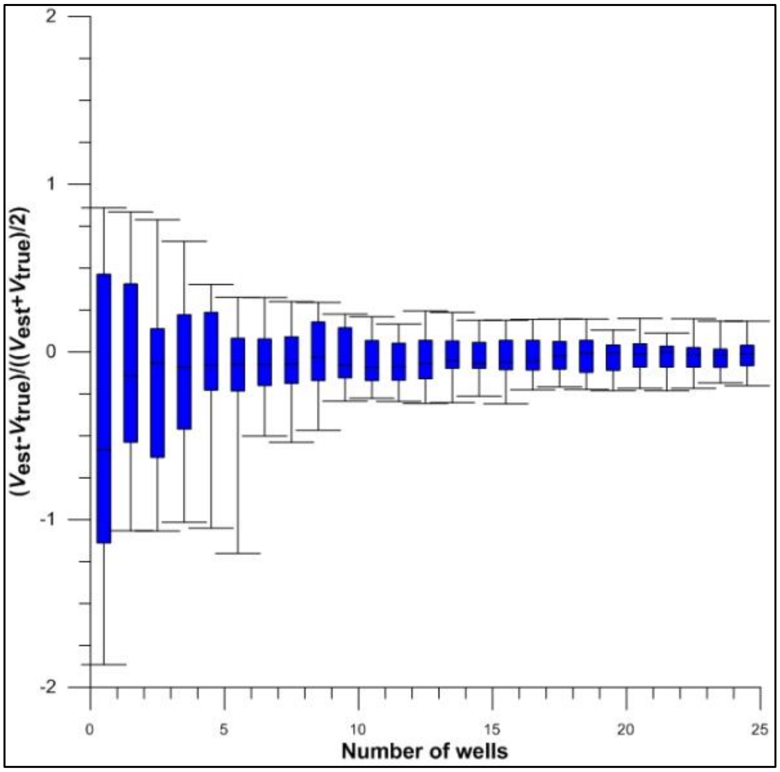

Figure 49. Storage capacity uncertainty vs. number of wells. Provided by Dr. Si-Yong Lee, 2013, written communication.

Following these results, the nine-spot infill pattern injected 1.1771 Mt, falling directly on the smoothed line. Realistically, if a nine-well maximum perimeter pattern was tested, the injection would most likely be above the line which directly connects the points for eight and 12 wells. Previous results suggest that the slope of the line is always steeper with fewer wells and flattens as more wells are added. Therefore, it is hypothesized that the nine-well maximum perimeter pattern would inject slightly more than the traditional nine-spot pattern as predicted from the generic analysis. This result illustrates that uncertainty is reduced with more wells and the results can be more easily predicted.

5.7 Discussion

A goal of the case study is to evaluate the efficacy of the generic analysis for its use toward proposed CCS projects. The findings must be easily adapted to give decent estimates of injection volume, cost, and well optimization. Parameters from the RMCCS simulation model are used with relationships from the generic analysis to estimate results, and then the estimated results are compared to simulated results.

The following are the most important parameters from the Craig model: depth to injection is 2,750 m, average porosity is 8.0%, average permeability is 2.2E-15 m^2, and layer thickness is 62 m. These are used along with the 500-acre curves. Due to the higher average permeability of 2.2E-15 m^2, the injection may as much as double the base case (1E-15 m^2) values. Heterogeneity and lower permeability cells specifically may somewhat dampen the effect of the higher average permeability. Porosity will not have much effect as it is close to the base case 10% porosity. The effect should be less than 5% change in injection volume. Interpolating for depth, the Craig model injection should be just slightly less than double the injection of the base case 2,000 m injection. The thickness being about two-thirds of the base case thickness should decrease the injection by about 25%. With these combined adjustment factors, the Craig model injection values should be between two and three times higher than the generic curve.

Examining the generic 500-acre injection curve along with the newly developed Craig model injection curve, it appears that the prediction is fairly accurate (Figure 50). Most values are about two times larger for the Craig model. The curve shapes are also similar. The cost-optimization function shows that eight wells are optimal for the generic model while the Craig model shows that four wells are optimal (Figure 51). This can be explained by the deeper injection wells and therefore higher costs of drilling in the case study model. This shifts the optimal point toward fewer wells. Costs are lower for the Craig model because more CO_2 is injected. It is concluded that findings from the generic analysis can be adapted to other models to give reasonable estimates of injection volumes, costs, and well optimization.

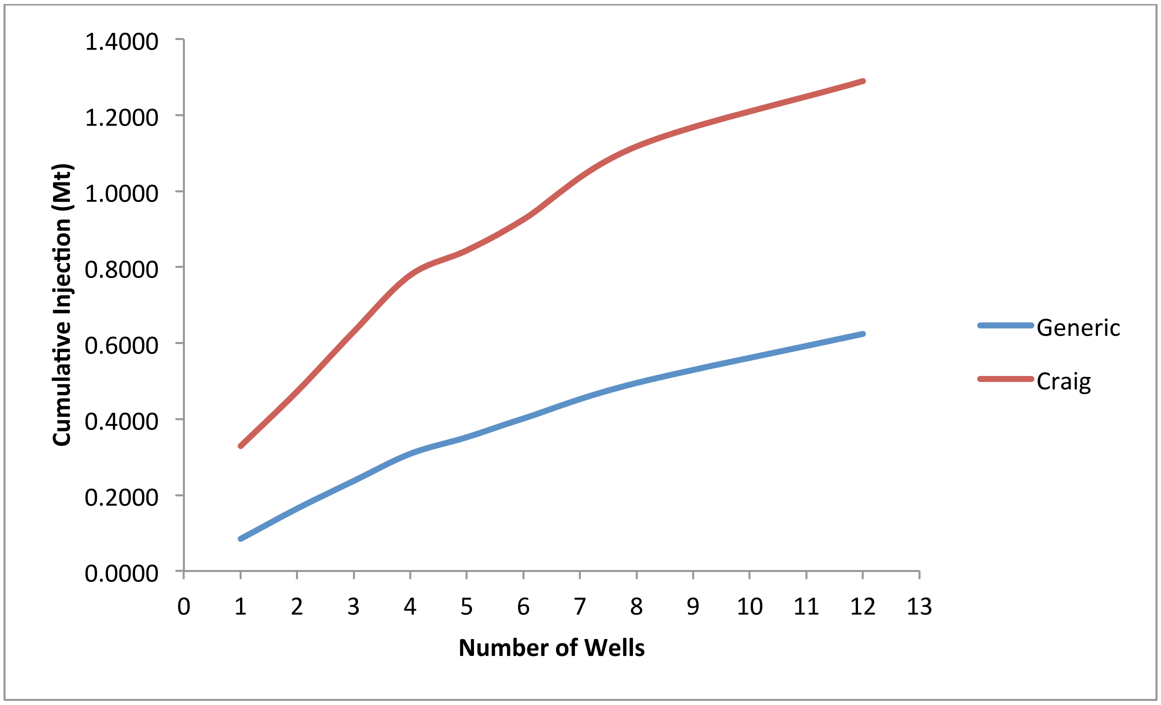

Figure 50. Generic model and Craig model injection curves.

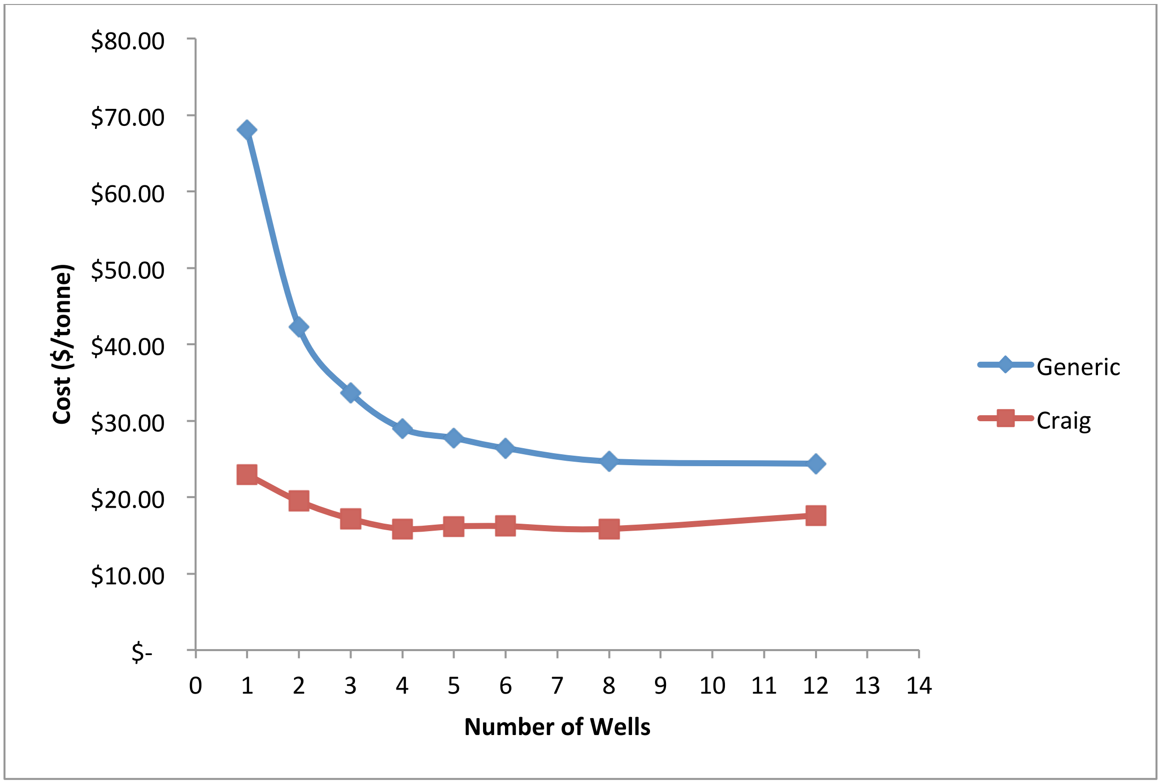

Figure 51. Generic model and Craig model cost optimization curves.

CONCLUSIONS

Presented in this report is a methodology for calculating the optimum number of injection wells for Carbon Capture and Storage operations. It is intended to serve as another of several methods for reducing the risk of induced seismicity caused by hydraulic fracturing. This method differentiates from other pressure management strategies in its ability to make sequestration projects as efficient as possible. Efficiency may come in many forms depending on project goals; therefore, various results are presented simultaneously. Utilizing this paper and its results as guidelines, preliminary estimates for any proposed injection scenario can be made for injection volume, project costs, and the optimal number of wells to be used to give the lowest cost per volume of injected CO_2.

As is the case with any modeling application, quantifying uncertainty is important for understanding the results presented here. A grid resolution sensitivity analysis was completed to determine the amount of error caused by using injection cell sizes (specifically, those larger than a wellbore). Ideally, very small cell sizes should be used for the injection cells to achieve accurate results. Most applications must include a compromise between accuracy and computational efficiency, however. Such is the case here where 10 m lateral cell sizes were chosen. It was concluded from the grid resolution sensitivity analysis that this choice would artificially facilitate larger injection volumes (rates) due to larger cell volumes accepting injected fluid, but that the pressure regimes between wells should not be impacted. The volume offset for a single well was approximately 84% between 1 m and 10 m cell sizes. Furthering the investigation on uncertainty, a sensitivity analysis was completed for injection volume. Injection curves were created to show the relationship between injectivity and number of wells over a realistic range of values for each parameter in the sensitivity analysis. Of the tested parameters, it was determined that permeability is the most sensitive in the range of realistic reservoir values. Permeability injection curves formed the base for which the other parameters were compared.

Cost functions were applied to the injection curves to calculate transportation, storage, and MVA costs for each scenario. One-time capital costs, annualized capital costs, and yearly O&M costs all factored into the calculations. Notably absent were capture costs, inasmuch as these are beyond the scope of this report. Total costs and cost per tonne of CO_2 were forecasted. The latter is the most useful in identifying the optimal, or most efficient, number of wells. Generally, it was found that between four and eight wells result in the lowest cost per tonne.

To illustrate the full methodology, a case study of the Rocky Mountain Carbon Capture and Storage project near Craig, Colorado, was presented. First, the most significant parameter values were identified. Then, a realistic 500-acre injection site was chosen. Injections were simulated for several well configurations and results compared well with the generic analysis. Injection volume, project cost, and the optimal number of wells were predicted by interpolating the generic results to match the case study parameters. The interpolation suggested that the injection volume should be between two and three times larger than the base case 500-acre injection curve with the optimal point residing between four and eight wells. Simulation results showed that the injection was nearly double and four wells were optimal.

Further research may build upon the work of this report to add to the CCS knowledge base. Error imposed by injection cell sizing, especially with numerous injection wells, requires extensive future research. Here, only results from single-well analyses were discussed. Future analyses would benefit from assigning correction coefficients to results to account for the cell sizing bias. However, telescoping grids with very small injection cells should be used whenever possible ensure more accurate results. For further accuracy, increasingly complex models should be subjected to a methodology similar to what is detailed in this report. Other optimization techniques should be investigated. Utilizing horizontal injection wells may provide lower reservoir pressures and therefore higher injection rates. Yet another approach is to optimize well spacing in the Enhanced Oil Recovery (EOR) process where injection and production wells reside within the same field.

The methodology and results of this paper can be used to provide rough estimates of optimization and injectivity for a broad range of injection scenarios. Future CCS projects may benefit from utilizing the process in site selection and planning. This and many other forms of optimization are needed to contribute to the overall goal of reducing atmospheric carbon concentrations.

REFERENCES

Bock, B., R. Rhudy, H. Herzog, M. Klett, J. Davison, D.G.D.L.T. Ugarte, and D. Simbeck, 2003. Economic Evaluation of CO_2 Storage and Sink Enhancement Options (Final Report to USDOE). TVA Public Power Institute, Muscle Shoals, TN.

Buscheck, T. A., Y. Sun, M. Chen, Y. Hao, T.J. Wolery, W.L. Bourcier, and R.D. Aines, 2012. Active CO2 Reservoir Management for Carbon Storage: Analysis of Operational Strategies to Relieve Pressure buildup and improve injectivity. *International Journal of Greenhouse Gas Control* 6: 230–245.

Carman, P.C., 1937. Fluid Flow Through Granular Beds. *Transactions*, Institution of Chemical Engineers, London 15: 150-166.

Carman, P.C., 1956. Flow of Gases Through Porous Media. Butterworths, London.

Cavanagh, A. and N. Wildgust, 2011. Pressurization and Brine Displacement Issues for Deep Saline Formation CO_2 Storage. *Energy Procedia* 4: 4814–4821.

Chadwick, A., R. Arts, C. Bernstone, and F. May, 2008. Best Practice for the Storage of CO_2 in Saline Aquifers-Observations and Guidelines from the SACS and CO2STORE Projects. Ltd, Amersham, UK. Keyworth, Nottingham: *British Geologic Survey Occasional Publication No. 14.*

Chadwick, R. A., D.J. Noy, and S. Holloway, 2009. Flow Processes and Pressure Evolution in Aquifers During the Injection of Supercritical CO_2 as a Greenhouse Gas Mitigation Measure. *Petroleum Geoscience* 15(1): 59–73.

du Rouchet, J., 1981. Stress Fields, a Key to Oil Migration. *AAPG Bulletin* 65: 74-85.

Ehlig-Economides, C., and M.J. Economides, 2010. Sequestering Carbon Dioxide in a Closed Underground Volume. *Journal of Petroleum Science and Engineering* 70(1-2): 123–130.

Energy Information Administration (EIA), 2000. Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/cost_indices/c_i.html.

Freeze, R. A., and J. A. Cherry, 1979. Groundwater. Prentice- Hall, Englewood Cliffs, N.J.

Gorelick, S.M. and C.I. Voss, 1984. Aquifer Reclamation Design: The Use of Contaminant Transport Simulation Combined with Nonlinear Programing. *Water Resources Research* 20(4): 415-427.

Guénan, T. Le and J. Rohmer, 2011. Corrective Measures Based on Pressure Control Strategies for CO_2 Geological Storage in Deep Aquifers. *International Journal of Greenhouse Gas Control* 5(3): 571-578.

Hart, D.J. and H.F. Wang, 2010. Variation of Unjacketed Pore Compressibility Using Gassmann's Equation and an Overdetermined Set of Volumetric Poroelastic Measurements. *Geophysics* 75(1): N9-N18.

Hawkes, C., P. Mclellan, and S. Bachu, 2005. Geomechanical Factors Affecting Geological Storage of CO_2 in Depleted Oil and Gas Reservoirs. *Journal of Canadian Petroleum Technology* 44(10): 52-61.

International Panel on Climate Change (IPCC), 2005. IPCC Special Report on Carbon Dioxide Capture and Storage. Cambridge University Press, Cambridge, United Kingdom and New York, United States.

Hsieh, P. A., 1996. Deformation-Induced Changes in Hydraulic Head during Ground-Water Withdrawal. *Ground Water* 34(6): 1082–1089.

Hurwitz, S., L. B. Christiansen, and P. A. Hsieh, 2007. Hydrothermal Fluid Flow and Deformation in Large Calderas: Influences from Numerical Simulations. *Journal of Geophysical Research* 112(B2).

Ingebritsen, S., W. Sanford, and C. Neuzil, 2006. Groundwater in Geologic Processes. Cambridge University Press, Cambridge, United Kingdom. Second Edition.

Koornneef, J., A. Ramirez, W. Turkenburg, and A. Faaij, 2012. The Environmental Impact and Risk Assessment of CO2 Capture, Transport, and Storage – An Evaluation of the Knowledge Base. *Progress in Energy and Combustion Science* 38(1): 62-86.

Kozeny, J., 1927. "Ueber kapillare Leitung des Wassers im Boden." Sitzungsber Akad. Wiss., Wien, 136(2a): 271-306.

Law, D.H.S. and S. Bachu, 1996. Hydrogeological and Numerical Analysis of CO2 Disposal in Deep Aquifers in the Alberta Sedimentary Basin, *Energy Conversion and Management* 37(6-8): 1167-1174.

Li, S., M. Dong, Z. Li, S. Huang, H. Qing, and E. Nickel, 2005. Gas Breakthrough Pressure for Hydrocarbon Reservoir Seal Rocks: Implications for the Security of Long-Term CO_2 Storage in the Weyburn Field. *Geofluids 5*(4): 326-334.

Majer, E.L. and J. E. Peterson, 2007. The Impact of Injection on Seismicity at The Geysers, California Geothermal Field. *International Journal of Rock Mechanics and Mining Sciences* 44(8): 1079-1090.

Malek, R., 2009. Results of Due Diligence Study Phase 3.5 on Feasibility of Gorgon CO2 Sequestration Petroleum in Western Australia, *Western Australian Department of Mines and Petroleum*, pp. 13–17.

Matthews, C.S. and D.G. Russell, 1967. Pressure Buildup and Flow Tests in Wells. Society of Petroleum Engineers. New York.

McCoy, S.T. and E.S. Rubin, 2005. Models of CO_2 Transport and Storage Costs and Their Importance in CCS Cost Estimates. Fourth Annual Conference on Carbon Capture and Sequestration. DOE/NETL Conference Proceedings, May 2-5 2005.

McCoy, S.T., 2008. The Economics of CO_2 Transport by Pipeline and Storage in Saline Aquifers and Oil Reservoirs. PhD Dissertation, Carnegie Mellon University, Pittsburgh, PA.

McPherson, B. J. O. L., and J.D. Bredehoeft, 2001. Overpressures in the Uinta Basin, Utah: Analysis Using a 3-D Basin Evolution Model. *Water Resources Research* 37(4): 857-871.

Michael, K., S. Bachu, B. E. Buschkuehle, K.Haug, and S. Talman, 2009. Comprehensive Characterization of a Potential Site for CO_2 Geological Storage in Central Alberta, Canada. In: Carbon Dioxide Sequestration in Geological Media—State of the Science, M. Grobe, J.C. Pashin, and R.L. Dodge (Editors). *AAPG Studies in Geology* 59: 227-240.

Michael, K., A. Golab, V. Shulakova, J. Ennis-King, G. Allinson, S. Sharma, and T. Aiken, 2010. Geological storage of CO2 in saline aquifers—A review of the experience from existing storage operations, *International Journal of Greenhouse Gas Control,* 4(4): 659-667.

Moodie, N.D., 2013. Fundamental Analysis of Relative Permeability and Heterogeneity on Carbon Dioxide Storage and Plume Migration. MS Thesis, University of Utah, Salt Lake City, UT.

Nicot, J.P., 2008. Evaluation of Large-Scale CO_2 Storage on Fresh-Water Sections of Aquifers: An Example from the Texas Gulf Coast Basin. *International Journal of Greenhouse Gas Control 2*(4): 582–593.

National Research Council (NRC), 2012. Induced Seismicity Potential in Energy

Technologies. The National Academy Press, Washington, DC.

Osborne, M. J. and R. E. Swarbrick, 1997. Mechanisms for Generating Overpressure in Sedimentary Basins; A Reevaluation. *AAPG Bulletin* 81: 1023-1041.

Otto, E.P. and M.D. Picard, 1976. Petrology of Entrada Sandstone (Jurassic), Northeastern Utah. In: Rocky Mountain Association of Geologists – 1976 Symposium: 231-245.

Peaceman, D., 1978. Interpretation of Well-Block Pressures in Numerical Reservoir Simulation. *Society of Petroleum Engineers Journal 18*(3): 183–194.

Pruess, K., 1991. TOUGH2—A General-Purpose Numerical Simulator for Multiphase Fluid and Heat Flow. *Rep. LBL-29400*, Lawrence Berkeley Lab., Berkeley, CA.

Pruess, K., 2005. ECO2N: A TOUGH2 Fluid Property Module for Mixtures of Water, NaCl, and CO_2. *Rep. LBL-57592*, Lawrence Berkeley Lab., Berkeley, CA.

Raleigh, C. B., J. H. Healy, & J. D. Bredehoeft (1976). An Experiment in Earthquake Control at Rangely, Colorado, *Science*, v. 191 (4233), p. 1230-1237.

Ratzlaff, S.A., M.A. Mustafa, and F. Al-Khayyal, 1992. Optimal Design of Ground-Water Capture Systems Using Segmental Velocity-Direction Constraints. *Ground Water* 30(4): 607-612.

Reid, M. E., 2004. Massive Collapse of Volcano Edifices Triggered by Hydrothermal Pressurization. *Geology* 32(5): 373-376.

Smith, L.A., N. Gupta, B.M. Sass, T.A. Bubenik, C. Byrer, and P. Bergman, 2001. Engineering and Economic Assessment of Carbon Dioxide Sequestration in Saline Formations. Presented at the First National Conference on Carbon Sequestration, May 14-17, 2001, Washington D.C.

Southwest Partnership on Carbon Sequestration (SWP), 2013, Written Communication per Project Proposal Documentation Submitted to US Department of Energy.

Theis, C.V., 1935. The Relation Between the Lowering of the Piezometric Surface and the Rate and Duration of Discharge of a Well Using Groundwater Storage. *American Geophysical Union Transactions 16:* 519-524.

Tiedeman, C. and S.M. Gorelick, 1993. Analysis of Uncertainty in Optimal Groundwater Contaminant Capture Design. *Water Resources Research* 29(7): 2139-2153.

Vasco, D. W., L. R. Johnson, and N. E. Goldstein, 1988. Using Surface Displacement and Strain Observations to Determine Deformation at Depth, With an Application to Long Valley Caldera, California, *Journal of Geophysical Research* 93(B4): 3232-3242.

Wentworth, C.K., 1922. A Scale of Grade and Class Terms for Clastic Sediments. *Geology* 30: 377-392.

WorleyParsons, 2011. Economic Assessment of Carbon Capture and Storage Technologies: 2011 Update. Report commissioned by the Global CCS Institute, Canberra, Australia.

Wright, J.C, D.R. Shawe, and S.W. Lohman, 1962, Definition of Members of Jurassic Entrada Sandstone in East-Central Utah and West-Central Colorado. *AAPG Bulletin* 46(11): 2057-2070.

Zhou, Q., J.T. Birkholzer, C.F. Tsang, and J. Rutqvist, 2008. A Method for Quick Assessment of CO2 Storage Capacity in Closed and Semi-Closed Saline Formations. *International Journal of Greenhouse Gas Control 2*(4): 626-639.

Zhou, Q. and J. Birkholzer, 2011. On Scale and Magnitude of Pressure Build-Up Induced by Large-Scale Geologic Storage of CO_2. *Greenhouse Gases: Science and Technology* 1: 11–20.

APPENDIX

Table 5. Injectivity and cost results for all 1E-16 m^2 permeability cases

2.5 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,043,702.44	$ 331.94	$ 4,261,183.41	$ 464.72
2	0.008	0.016	$ 3,652,688.63	$ 222.99	$ 5,113,764.08	$ 312.19
3	0.007	0.022	$ 4,201,200.75	$ 195.35	$ 5,881,681.06	$ 273.49
4	0.007	0.026	$ 4,733,600.40	$ 181.08	$ 6,627,040.57	$ 253.51
5	0.006	0.028	$ 5,227,251.39	$ 187.36	$ 7,318,151.95	$ 262.30
6	0.005	0.030	$ 5,720,540.57	$ 192.64	$ 8,008,756.80	$ 269.70
8	0.004	0.034	$ 6,714,681.00	$ 196.26	$ 9,400,553.41	$ 274.77

10 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,047,251.55	$ 332.33	$ 4,266,152.16	$ 465.26
2	0.009	0.017	$ 3,670,631.12	$ 212.31	$ 5,138,883.57	$ 297.23
3	0.008	0.023	$ 4,229,307.02	$ 181.16	$ 5,921,029.83	$ 253.63
4	0.007	0.029	$ 4,773,672.13	$ 163.25	$ 6,683,140.98	$ 228.55
5	0.006	0.032	$ 5,276,695.44	$ 165.00	$ 7,387,373.62	$ 231.00
6	0.006	0.035	$ 5,783,915.46	$ 163.96	$ 8,097,481.65	$ 229.54
8	0.005	0.041	$ 6,787,464.69	$ 164.45	$ 9,502,450.57	$ 230.23

Table 5. Continued.

20 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,051,983.69	$ 332.84	$ 4,272,777.16	$ 465.98
2	0.009	0.017	$ 3,678,195.30	$ 210.52	$ 5,149,473.42	$ 294.73
3	0.008	0.024	$ 4,246,283.98	$ 174.77	$ 5,944,797.57	$ 244.68
4	0.008	0.031	$ 4,797,264.72	$ 155.13	$ 6,716,170.61	$ 217.18
5	0.007	0.034	$ 5,305,708.62	$ 154.80	$ 7,427,992.07	$ 216.72
6	0.006	0.038	$ 5,817,887.72	$ 152.24	$ 8,145,042.81	$ 213.13
8	0.006	0.046	$ 6,830,557.11	$ 150.02	$ 9,562,779.95	$ 210.03
12	0.005	0.055	$ 8,797,430.25	$ 160.68	$ 12,316,402.35	$ 224.95

40 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,061,447.97	$ 333.88	$ 4,286,027.16	$ 467.43
2	0.009	0.018	$ 3,692,827.22	$ 207.38	$ 5,169,958.11	$ 290.33
3	0.008	0.025	$ 4,268,381.31	$ 168.70	$ 5,975,733.84	$ 236.19
4	0.008	0.033	$ 4,826,427.81	$ 147.41	$ 6,756,998.94	$ 206.37
5	0.007	0.037	$ 5,341,752.27	$ 144.78	$ 7,478,453.17	$ 202.69
6	0.007	0.042	$ 5,860,364.92	$ 140.53	$ 8,204,510.89	$ 196.74
8	0.006	0.051	$ 6,884,713.49	$ 135.51	$ 9,638,598.88	$ 189.71
12	0.005	0.063	$ 8,868,442.55	$ 140.92	$ 12,415,819.56	$ 197.29
16	0.004	0.071	$ 10,812,391.44	$ 153.17	$ 15,137,348.02	$ 214.44

Table 5. Continued.

80 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,080,376.55	$ 335.94	$ 4,312,527.16	$ 470.32
2	0.009	0.018	$ 3,715,593.57	$ 205.75	$ 5,201,831.00	$ 288.05
3	0.009	0.026	$ 4,297,979.81	$ 164.24	$ 6,017,171.74	$ 229.94
4	0.009	0.034	$ 4,862,145.26	$ 141.59	$ 6,807,003.37	$ 198.22
5	0.008	0.040	$ 5,386,113.50	$ 136.32	$ 7,540,558.90	$ 190.84
6	0.008	0.045	$ 5,911,366.41	$ 130.59	$ 8,275,912.97	$ 182.83
8	0.007	0.056	$ 6,948,221.17	$ 123.16	$ 9,727,509.64	$ 172.43
12	0.006	0.072	$ 8,950,825.91	$ 124.17	$ 12,531,156.27	$ 173.83
16	0.005	0.083	$ 10,911,033.79	$ 131.45	$ 15,275,447.30	$ 184.04
20	0.005	0.092	$ 12,853,995.94	$ 139.98	$ 17,995,594.31	$ 195.97

Table 5. Continued

160 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,118,233.69	$ 340.07	$ 4,365,527.16	$ 476.10
2	0.009	0.018	$ 3,755,991.56	$ 206.07	$ 5,258,388.19	$ 288.50
3	0.009	0.027	$ 4,344,385.47	$ 161.64	$ 6,082,139.66	$ 226.30
4	0.009	0.034	$ 4,900,002.41	$ 142.69	$ 6,860,003.37	$ 199.77
5	0.008	0.042	$ 5,447,913.24	$ 129.49	$ 7,627,078.53	$ 181.29
6	0.008	0.049	$ 5,981,239.62	$ 122.07	$ 8,373,735.47	$ 170.90
8	0.008	0.063	$ 7,031,575.25	$ 112.50	$ 9,844,205.35	$ 157.50
12	0.007	0.083	$ 9,059,348.51	$ 108.93	$ 12,683,087.91	$ 152.51
16	0.006	0.099	$ 11,040,622.84	$ 111.76	$ 15,456,871.97	$ 156.46
20	0.006	0.111	$ 12,998,495.54	$ 116.65	$ 18,197,893.76	$ 163.30

Table 5. Continued.

320 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,193,947.97	$ 348.33	$ 4,471,527.16	$ 487.66
2	0.009	0.018	$ 3,833,312.92	$ 209.09	$ 5,366,638.09	$ 292.73
3	0.009	0.027	$ 4,424,773.62	$ 162.27	$ 6,194,683.06	$ 227.18
4	0.009	0.036	$ 4,995,520.87	$ 137.68	$ 6,993,729.22	$ 192.75
5	0.009	0.044	$ 5,542,006.30	$ 125.66	$ 7,758,808.82	$ 175.92
6	0.009	0.052	$ 6,081,557.47	$ 116.99	$ 8,514,180.46	$ 163.78
8	0.008	0.068	$ 7,143,823.02	$ 105.58	$ 10,001,352.23	$ 147.82
12	0.008	0.094	$ 9,197,094.91	$ 98.18	$ 12,875,932.88	$ 137.46
16	0.007	0.115	$ 11,203,500.07	$ 97.14	$ 15,684,900.09	$ 136.00
20	0.007	0.133	$ 13,179,157.55	$ 99.11	$ 18,450,820.58	$ 138.75

Table 5. Continued

500 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,279,126.55	$ 357.62	$ 4,590,777.16	$ 500.66
2	0.009	0.018	$ 3,918,510.48	$ 213.72	$ 5,485,914.67	$ 299.21
3	0.009	0.027	$ 4,512,072.62	$ 164.39	$ 6,316,901.67	$ 230.15
4	0.009	0.037	$ 5,083,650.99	$ 138.98	$ 7,117,111.38	$ 194.57
5	0.009	0.045	$ 5,633,835.36	$ 125.61	$ 7,887,369.50	$ 175.85
6	0.009	0.053	$ 6,177,102.39	$ 115.95	$ 8,647,943.34	$ 162.32
8	0.009	0.070	$ 7,245,067.50	$ 103.49	$ 10,143,094.50	$ 144.89
12	0.008	0.099	$ 9,311,876.09	$ 94.10	$ 13,036,626.52	$ 131.75
16	0.008	0.124	$ 11,330,160.74	$ 91.56	$ 15,862,225.04	$ 128.19
20	0.007	0.145	$ 13,319,542.17	$ 91.72	$ 18,647,359.03	$ 128.40
24	0.007	0.164	$ 15,288,844.80	$ 93.33	$ 21,404,382.73	$ 130.66

Table 5. Continued.

1000 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.009	0.009	$ 3,515,733.69	$ 383.42	$ 4,922,027.16	$ 536.79
2	0.009	0.018	$ 4,145,642.43	$ 234.07	$ 5,803,899.40	$ 327.70
3	0.009	0.027	$ 4,738,153.63	$ 178.35	$ 6,633,415.08	$ 249.70
4	0.009	0.035	$ 5,308,583.31	$ 149.88	$ 7,432,016.64	$ 209.83
5	0.009	0.045	$ 5,869,215.43	$ 131.26	$ 8,216,901.60	$ 183.77
6	0.009	0.053	$ 6,414,975.94	$ 120.05	$ 8,980,966.32	$ 168.07
8	0.009	0.070	$ 7,479,962.65	$ 107.23	$ 10,471,947.71	$ 150.12
12	0.008	0.102	$ 9,564,134.41	$ 93.94	$ 13,389,788.17	$ 131.51
16	0.008	0.131	$ 11,600,846.44	$ 88.61	$ 16,241,185.02	$ 124.06
20	0.008	0.157	$ 13,607,224.32	$ 86.60	$ 19,050,114.05	$ 121.24
24	0.008	0.180	$ 15,590,400.80	$ 86.53	$ 21,826,561.12	$ 121.14
32	0.007	0.220	$ 19,514,858.86	$ 88.87	$ 27,320,802.40	$ 124.42

Table 6. Injectivity and cost results for all 1E-15 m^2 permeability cases

2.5 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,792,660.65	$ 45.00	$ 5,309,724.91	$ 63.00
2	0.071	0.142	$ 4,564,342.24	$ 32.05	$ 6,390,079.14	$ 44.87
3	0.060	0.179	$ 5,188,390.92	$ 28.99	$ 7,263,747.29	$ 40.59
4	0.052	0.210	$ 5,775,519.96	$ 27.51	$ 8,085,727.95	$ 38.51
5	0.044	0.221	$ 6,286,479.28	$ 28.45	$ 8,801,070.99	$ 39.83
6	0.039	0.235	$ 6,807,783.04	$ 28.91	$ 9,530,896.26	$ 40.48
8	0.032	0.259	$ 7,827,287.76	$ 30.26	$ 10,958,202.86	$ 42.37

10 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,796,209.76	$ 45.04	$ 5,314,693.66	$ 63.06
2	0.074	0.148	$ 4,590,555.32	$ 31.11	$ 6,426,777.44	$ 43.55
3	0.064	0.192	$ 5,241,675.13	$ 27.29	$ 7,338,345.19	$ 38.21
4	0.058	0.230	$ 5,849,188.81	$ 25.39	$ 8,188,864.34	$ 35.54
5	0.049	0.247	$ 6,374,891.83	$ 25.85	$ 8,924,848.56	$ 36.19
6	0.044	0.266	$ 6,907,380.77	$ 26.00	$ 9,670,333.08	$ 36.40
8	0.037	0.298	$ 7,948,839.72	$ 26.66	$ 11,128,375.61	$ 37.32

Table 6. Continued.

20 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,800,941.90	$ 45.10	$ 5,321,318.66	$ 63.14
2	0.075	0.151	$ 4,608,044.05	$ 30.61	$ 6,451,261.67	$ 42.86
3	0.066	0.199	$ 5,271,835.15	$ 26.50	$ 7,380,569.21	$ 37.09
4	0.060	0.242	$ 5,891,088.20	$ 24.38	$ 8,247,523.48	$ 34.13
5	0.052	0.261	$ 6,424,043.42	$ 24.64	$ 8,993,660.79	$ 34.50
6	0.047	0.283	$ 6,963,329.98	$ 24.63	$ 9,748,661.97	$ 34.48
8	0.040	0.321	$ 8,017,453.75	$ 24.98	$ 11,224,435.25	$ 34.97
12	0.030	0.364	$ 10,021,467.02	$ 27.53	$ 14,030,053.83	$ 38.55

40 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,810,406.19	$ 45.21	$ 5,334,568.66	$ 63.30
2	0.077	0.154	$ 4,631,234.29	$ 30.12	$ 6,483,728.00	$ 42.17
3	0.069	0.207	$ 5,309,448.07	$ 25.68	$ 7,433,227.30	$ 35.95
4	0.064	0.255	$ 5,942,428.26	$ 23.32	$ 8,319,399.57	$ 32.65
5	0.055	0.277	$ 6,483,514.90	$ 23.40	$ 9,076,920.86	$ 32.75
6	0.051	0.303	$ 7,032,013.39	$ 23.19	$ 9,844,818.75	$ 32.47
8	0.044	0.349	$ 8,102,007.10	$ 23.21	$ 11,342,809.94	$ 32.49
12	0.034	0.402	$ 10,125,438.56	$ 25.17	$ 14,175,613.98	$ 35.24
16	0.027	0.432	$ 12,084,574.28	$ 28.01	$ 16,918,403.99	$ 39.21

Table 6. Continued

80 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,829,334.76	$ 45.44	$ 5,361,068.66	$ 63.61
2	0.078	0.157	$ 4,663,126.65	$ 29.74	$ 6,528,377.31	$ 41.63
3	0.072	0.215	$ 5,355,906.05	$ 24.96	$ 7,498,268.46	$ 34.94
4	0.067	0.268	$ 6,003,051.65	$ 22.38	$ 8,404,272.31	$ 31.33
5	0.059	0.295	$ 6,554,146.62	$ 22.24	$ 9,175,805.27	$ 31.13
6	0.054	0.325	$ 7,112,010.42	$ 21.87	$ 9,956,814.58	$ 30.62
8	0.048	0.380	$ 8,199,916.14	$ 21.57	$ 11,479,882.60	$ 30.20
12	0.037	0.445	$ 10,244,452.78	$ 23.00	$ 14,342,233.90	$ 32.21
16	0.030	0.484	$ 12,219,515.16	$ 25.26	$ 17,107,321.22	$ 35.36
20	0.026	0.513	$ 14,171,384.63	$ 27.64	$ 19,839,938.48	$ 38.69

Table 6. Continued.

160 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,867,191.90	$ 45.88	$ 5,414,068.66	$ 64.24
2	0.080	0.160	$ 4,714,027.64	$ 29.47	$ 6,599,638.69	$ 41.26
3	0.074	0.223	$ 5,423,533.86	$ 24.29	$ 7,592,947.40	$ 34.01
4	0.071	0.284	$ 6,086,735.86	$ 21.47	$ 8,521,430.21	$ 30.05
5	0.063	0.316	$ 6,651,302.52	$ 21.07	$ 9,311,823.53	$ 29.49
6	0.059	0.352	$ 7,220,391.46	$ 20.53	$ 10,108,548.04	$ 28.74
8	0.052	0.419	$ 8,331,024.70	$ 19.89	$ 11,663,434.58	$ 27.84
12	0.042	0.503	$ 10,406,693.15	$ 20.71	$ 14,569,370.41	$ 28.99
16	0.035	0.554	$ 12,401,301.07	$ 22.40	$ 17,361,821.50	$ 31.37
20	0.030	0.592	$ 14,366,036.59	$ 24.28	$ 20,112,451.22	$ 33.99

Table 6. Continued.

320 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,942,906.19	$ 46.78	$ 5,520,068.66	$ 65.50
2	0.081	0.163	$ 4,801,209.44	$ 29.51	$ 6,721,693.22	$ 41.31
3	0.077	0.232	$ 5,528,324.90	$ 23.84	$ 7,739,654.86	$ 33.37
4	0.075	0.299	$ 6,207,801.99	$ 20.75	$ 8,690,922.78	$ 29.05
5	0.068	0.338	$ 6,787,695.43	$ 20.08	$ 9,502,773.60	$ 28.11
6	0.064	0.382	$ 7,371,593.86	$ 19.32	$ 10,320,231.40	$ 27.05
8	0.058	0.464	$ 8,508,881.42	$ 18.34	$ 11,912,433.99	$ 25.68
12	0.048	0.573	$ 10,624,587.72	$ 18.54	$ 14,874,422.81	$ 25.96
16	0.040	0.643	$ 12,646,800.73	$ 19.66	$ 17,705,521.02	$ 27.53
20	0.035	0.695	$ 14,629,018.38	$ 21.05	$ 20,480,625.74	$ 29.47

Table 6. Continued.

500 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 4,028,084.76	$ 47.79	$ 5,639,318.66	$ 66.91
2	0.082	0.164	$ 4,892,151.52	$ 29.81	$ 6,849,012.13	$ 41.73
3	0.079	0.237	$ 5,630,380.29	$ 23.76	$ 7,882,532.41	$ 33.26
4	0.077	0.309	$ 6,319,458.07	$ 20.48	$ 8,847,241.30	$ 28.68
5	0.070	0.352	$ 6,909,628.74	$ 19.62	$ 9,673,480.23	$ 27.47
6	0.067	0.401	$ 7,505,115.22	$ 18.70	$ 10,507,161.31	$ 26.18
8	0.062	0.495	$ 8,661,048.54	$ 17.50	$ 12,125,467.96	$ 24.50
12	0.052	0.624	$ 10,806,622.94	$ 17.32	$ 15,129,272.11	$ 24.24
16	0.044	0.710	$ 12,849,877.21	$ 18.10	$ 17,989,828.10	$ 25.33
20	0.039	0.776	$ 14,850,460.05	$ 19.13	$ 20,790,644.07	$ 26.79
24	0.034	0.825	$ 16,817,995.70	$ 20.40	$ 23,545,193.98	$ 28.56

Table 6. Continued.

1000 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 4,264,691.90	$ 50.60	$ 5,970,568.66	$ 70.84
2	0.080	0.160	$ 5,113,746.00	$ 31.87	$ 7,159,244.39	$ 44.61
3	0.079	0.236	$ 5,863,760.25	$ 24.84	$ 8,209,264.34	$ 34.78
4	0.078	0.312	$ 6,565,021.80	$ 21.06	$ 9,191,030.52	$ 29.49
5	0.074	0.369	$ 7,190,650.41	$ 19.46	$ 10,066,910.58	$ 27.25
6	0.071	0.426	$ 7,800,668.79	$ 18.30	$ 10,920,936.31	$ 25.61
8	0.067	0.538	$ 8,986,138.75	$ 16.71	$ 12,580,594.25	$ 23.40
12	0.059	0.703	$ 11,183,324.25	$ 15.91	$ 15,656,653.95	$ 22.28
16	0.051	0.822	$ 13,269,505.97	$ 16.14	$ 18,577,308.36	$ 22.60
20	0.046	0.916	$ 15,302,336.69	$ 16.71	$ 21,423,271.37	$ 23.40
24	0.041	0.988	$ 17,297,308.75	$ 17.50	$ 24,216,232.25	$ 24.50
32	0.034	1.099	$ 21,228,375.36	$ 19.32	$ 29,719,725.50	$ 27.05

Table 7. Injectivity and cost results for all 1E-14 m^2 permeability cases

2.5 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 5,571,422.30	$ 7.55	$ 7,799,991.22	$ 10.58
2	0.572	1.145	$ 6,637,809.43	$ 5.80	$ 9,292,933.21	$ 8.12
3	0.458	1.374	$ 7,389,874.91	$ 5.38	$ 10,345,824.87	$ 7.53
4	0.387	1.549	$ 8,057,775.79	$ 5.20	$ 11,280,886.11	$ 7.28
5	0.322	1.608	$ 8,593,078.37	$ 5.34	$ 12,030,309.71	$ 7.48
6	0.278	1.666	$ 9,125,474.95	$ 5.48	$ 12,775,664.92	$ 7.67
8	0.225	1.802	$ 10,208,044.20	$ 5.67	$ 14,291,261.87	$ 7.93

10 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 5,574,971.41	$ 7.56	$ 7,804,959.97	$ 10.58
2	0.592	1.183	$ 6,690,488.91	$ 5.65	$ 9,366,684.47	$ 7.91
3	0.483	1.449	$ 7,478,570.88	$ 5.16	$ 10,469,999.23	$ 7.23
4	0.414	1.658	$ 8,175,807.20	$ 4.93	$ 11,446,130.08	$ 6.90
5	0.348	1.740	$ 8,732,079.45	$ 5.02	$ 12,224,911.23	$ 7.03
6	0.305	1.833	$ 9,296,437.85	$ 5.07	$ 13,015,012.99	$ 7.10
8	0.248	1.981	$ 10,383,299.86	$ 5.24	$ 14,536,619.80	$ 7.34

Table 7. Continued.

20 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 5,579,703.55	$ 7.57	$ 7,811,584.97	$ 10.59
2	0.603	1.206	$ 6,723,439.34	$ 5.58	$ 9,412,815.08	$ 7.81
3	0.496	1.487	$ 7,525,790.08	$ 5.06	$ 10,536,106.11	$ 7.08
4	0.429	1.717	$ 8,241,321.79	$ 4.80	$ 11,537,850.50	$ 6.72
5	0.362	1.810	$ 8,806,334.53	$ 4.87	$ 12,328,868.35	$ 6.81
6	0.319	1.913	$ 9,378,506.27	$ 4.90	$ 13,129,908.78	$ 6.86
8	0.260	2.080	$ 10,478,332.92	$ 5.04	$ 14,669,666.08	$ 7.05
12	0.188	2.251	$ 12,519,712.34	$ 5.56	$ 17,527,597.27	$ 7.79

40 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 5,589,167.84	$ 7.58	$ 7,824,834.97	$ 10.61
2	0.612	1.224	$ 6,755,285.54	$ 5.52	$ 9,457,399.76	$ 7.73
3	0.511	1.532	$ 7,583,928.52	$ 4.95	$ 10,617,499.93	$ 6.93
4	0.445	1.782	$ 8,315,436.13	$ 4.67	$ 11,641,610.58	$ 6.53
5	0.377	1.887	$ 8,890,416.48	$ 4.71	$ 12,446,583.07	$ 6.60
6	0.334	2.005	$ 9,474,195.00	$ 4.72	$ 13,263,873.00	$ 6.61
8	0.274	2.195	$ 10,590,232.21	$ 4.82	$ 14,826,325.09	$ 6.75
12	0.199	2.392	$ 12,649,070.90	$ 5.29	$ 17,708,699.26	$ 7.40
16	0.156	2.493	$ 14,621,920.83	$ 5.87	$ 20,470,689.16	$ 8.21

Table 7. Continued.

80 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 5,608,096.41	$ 7.60	$ 7,851,334.97	$ 10.65
2	0.622	1.244	$ 6,799,320.24	$ 5.46	$ 9,519,048.34	$ 7.65
3	0.525	1.575	$ 7,649,300.29	$ 4.86	$ 10,709,020.40	$ 6.80
4	0.462	1.848	$ 8,399,561.98	$ 4.54	$ 11,759,386.77	$ 6.36
5	0.394	1.968	$ 8,986,019.60	$ 4.57	$ 12,580,427.44	$ 6.39
6	0.350	2.099	$ 9,578,582.82	$ 4.56	$ 13,410,015.95	$ 6.39
8	0.289	2.316	$ 10,712,991.41	$ 4.63	$ 14,998,187.97	$ 6.48
12	0.212	2.540	$ 12,788,668.01	$ 5.03	$ 17,904,135.22	$ 7.05
16	0.166	2.660	$ 14,774,155.07	$ 5.55	$ 20,683,817.10	$ 7.78
20	0.137	2.748	$ 16,732,338.37	$ 6.09	$ 23,425,273.71	$ 8.53

Table 7. Continued.

160 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 5,645,953.55	$ 7.65	$ 7,904,334.97	$ 10.72
2	0.633	1.266	$ 6,863,861.79	$ 5.42	$ 9,609,406.50	$ 7.59
3	0.541	1.623	$ 7,737,562.02	$ 4.77	$ 10,832,586.83	$ 6.68
4	0.481	1.924	$ 8,509,384.14	$ 4.42	$ 11,913,137.79	$ 6.19
5	0.413	2.063	$ 9,110,940.72	$ 4.42	$ 12,755,317.00	$ 6.18
6	0.368	2.209	$ 9,713,598.29	$ 4.40	$ 13,599,037.60	$ 6.16
8	0.307	2.458	$ 10,869,160.65	$ 4.42	$ 15,216,824.90	$ 6.19
12	0.227	2.721	$ 12,968,610.99	$ 4.77	$ 18,156,055.39	$ 6.67
16	0.179	2.863	$ 14,966,687.85	$ 5.23	$ 20,953,362.99	$ 7.32
20	0.148	2.963	$ 16,931,680.62	$ 5.71	$ 23,704,352.87	$ 8.00

Table 7. Continued.

320 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 5,721,667.84	$ 7.76	$ 8,010,334.97	$ 10.86
2	0.644	1.288	$ 6,965,390.33	$ 5.41	$ 9,751,546.47	$ 7.57
3	0.557	1.671	$ 7,863,611.16	$ 4.71	$ 11,009,055.62	$ 6.59
4	0.501	2.002	$ 8,658,599.57	$ 4.32	$ 12,122,039.40	$ 6.05
5	0.432	2.161	$ 9,274,741.71	$ 4.29	$ 12,984,638.39	$ 6.01
6	0.388	2.329	$ 9,892,269.82	$ 4.25	$ 13,849,177.75	$ 5.95
8	0.327	2.613	$ 11,069,838.84	$ 4.24	$ 15,497,774.38	$ 5.93
12	0.244	2.925	$ 13,198,419.42	$ 4.51	$ 18,477,787.19	$ 6.32
16	0.193	3.095	$ 15,212,254.33	$ 4.92	$ 21,297,156.06	$ 6.88
20	0.161	3.211	$ 17,184,996.84	$ 5.35	$ 24,058,995.58	$ 7.49

Table 7. Continued.

500 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 5,806,846.41	$ 7.87	$ 8,129,584.97	$ 11.02
2	0.650	1.300	$ 7,065,541.80	$ 5.43	$ 9,891,758.52	$ 7.61
3	0.567	1.701	$ 7,979,255.91	$ 4.69	$ 11,170,958.27	$ 6.57
4	0.513	2.052	$ 8,789,459.99	$ 4.28	$ 12,305,243.98	$ 6.00
5	0.445	2.223	$ 9,414,420.04	$ 4.23	$ 13,180,188.06	$ 5.93
6	0.401	2.408	$ 10,043,708.34	$ 4.17	$ 14,061,191.67	$ 5.84
8	0.340	2.720	$ 11,238,232.01	$ 4.13	$ 15,733,524.82	$ 5.78
12	0.255	3.065	$ 13,385,275.56	$ 4.37	$ 18,739,385.78	$ 6.11
16	0.203	3.254	$ 15,409,426.96	$ 4.74	$ 21,573,197.75	$ 6.63
20	0.169	3.387	$ 17,391,183.59	$ 5.13	$ 24,347,657.03	$ 7.19
24	0.145	3.479	$ 19,343,469.75	$ 5.56	$ 27,080,857.65	$ 7.78

Table 7. Continued.

1000 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.738	0.738	$ 6,043,453.55	$ 8.19	$ 8,460,834.97	$ 11.47
2	0.642	1.284	$ 7,282,846.26	$ 5.67	$ 10,195,984.77	$ 7.94
3	0.568	1.705	$ 8,220,320.54	$ 4.82	$ 11,508,448.75	$ 6.75
4	0.521	2.084	$ 9,054,801.26	$ 4.35	$ 12,676,721.76	$ 6.08
5	0.461	2.307	$ 9,723,489.50	$ 4.21	$ 13,612,885.30	$ 5.90
6	0.419	2.513	$ 10,366,742.46	$ 4.12	$ 14,513,439.44	$ 5.77
8	0.359	2.870	$ 11,588,508.71	$ 4.04	$ 16,223,912.19	$ 5.65
12	0.273	3.275	$ 13,770,135.59	$ 4.20	$ 19,278,189.83	$ 5.89
16	0.219	3.505	$ 15,816,028.85	$ 4.51	$ 22,142,440.40	$ 6.32
20	0.183	3.665	$ 17,811,331.29	$ 4.86	$ 24,935,863.80	$ 6.80
24	0.157	3.777	$ 19,773,753.87	$ 5.23	$ 27,683,255.42	$ 7.33
32	0.123	3.926	$ 23,647,726.46	$ 6.02	$ 33,106,817.05	$ 8.43

Table 8. Injectivity and cost results for all 1E-13 m^2 permeability cases

2.5 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 9,597,320.12	$ 1.63	$ 13,436,248.17	$ 2.28
2	4.097	8.194	$ 11,085,828.21	$ 1.35	$ 15,520,159.50	$ 1.89
3	3.093	9.279	$ 11,977,460.99	$ 1.29	$ 16,768,445.38	$ 1.81
4	2.500	10.001	$ 12,713,094.21	$ 1.27	$ 17,798,331.90	$ 1.78
5	2.053	10.266	$ 13,279,359.88	$ 1.29	$ 18,591,103.83	$ 1.81
6	1.755	10.528	$ 13,843,445.08	$ 1.31	$ 19,380,823.11	$ 1.84
8	1.385	11.080	$ 14,976,598.21	$ 1.35	$ 20,967,237.49	$ 1.89

10 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 9,600,869.23	$ 1.63	$ 13,441,216.92	$ 2.28
2	4.191	8.382	$ 11,164,234.48	$ 1.33	$ 15,629,928.27	$ 1.86
3	3.204	9.612	$ 12,103,681.22	$ 1.26	$ 16,945,153.70	$ 1.76
4	2.610	10.439	$ 12,870,725.15	$ 1.23	$ 18,019,015.21	$ 1.73
5	2.157	10.783	$ 13,461,834.02	$ 1.25	$ 18,846,567.63	$ 1.75
6	1.862	11.171	$ 14,065,188.04	$ 1.26	$ 19,691,263.26	$ 1.76
8	1.469	11.748	$ 15,200,464.05	$ 1.29	$ 21,280,649.67	$ 1.81

Table 8. Continued.

20 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 9,605,601.37	$ 1.63	$ 13,447,841.92	$ 2.28
2	4.239	8.478	$ 11,206,896.03	$ 1.32	$ 15,689,654.44	$ 1.85
3	3.260	9.781	$ 12,169,969.08	$ 1.24	$ 17,037,956.72	$ 1.74
4	2.666	10.665	$ 12,953,474.09	$ 1.21	$ 18,134,863.72	$ 1.70
5	2.209	11.043	$ 13,554,628.51	$ 1.23	$ 18,976,479.91	$ 1.72
6	1.910	11.462	$ 14,166,498.89	$ 1.24	$ 19,833,098.44	$ 1.73
8	1.511	12.088	$ 15,314,411.11	$ 1.27	$ 21,440,175.55	$ 1.77
12	1.054	12.652	$ 17,382,177.14	$ 1.37	$ 24,335,048.00	$ 1.92

40 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 9,615,065.65	$ 1.63	$ 13,461,091.92	$ 2.29
2	4.291	8.583	$ 11,257,261.39	$ 1.31	$ 15,760,165.95	$ 1.84
3	3.322	9.967	$ 12,246,336.38	$ 1.23	$ 17,144,870.94	$ 1.72
4	2.729	10.915	$ 13,048,205.40	$ 1.20	$ 18,267,487.57	$ 1.67
5	2.266	11.328	$ 13,659,145.59	$ 1.21	$ 19,122,803.83	$ 1.69
6	1.964	11.785	$ 14,281,284.84	$ 1.21	$ 19,993,798.78	$ 1.70
8	1.559	12.470	$ 15,444,319.99	$ 1.24	$ 21,622,047.98	$ 1.73
12	1.085	13.025	$ 17,506,277.07	$ 1.34	$ 24,508,787.89	$ 1.88
16	0.836	13.378	$ 19,503,482.90	$ 1.46	$ 27,304,876.05	$ 2.04

Table 8. Continued.

80 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 9,633,994.23	$ 1.64	$ 13,487,591.92	$ 2.29
2	4.342	8.684	$ 11,315,468.19	$ 1.30	$ 15,841,655.47	$ 1.82
3	3.383	10.149	$ 12,329,901.88	$ 1.21	$ 17,261,862.63	$ 1.70
4	2.791	11.162	$ 13,150,235.41	$ 1.18	$ 18,410,329.58	$ 1.65
5	2.323	11.615	$ 13,772,406.27	$ 1.19	$ 19,281,368.78	$ 1.66
6	2.013	12.079	$ 14,394,489.16	$ 1.19	$ 20,152,284.82	$ 1.67
8	1.587	12.695	$ 15,533,153.62	$ 1.22	$ 21,746,415.07	$ 1.71
12	1.121	13.453	$ 17,654,258.15	$ 1.31	$ 24,715,961.42	$ 1.84
16	0.866	13.853	$ 19,663,309.04	$ 1.42	$ 27,528,632.65	$ 1.99
20	0.704	14.082	$ 21,620,918.53	$ 1.54	$ 30,269,285.94	$ 2.15

Table 8. Continued

160 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 9,671,851.37	$ 1.64	$ 13,540,591.92	$ 2.30
2	4.396	8.793	$ 11,395,434.52	$ 1.30	$ 15,953,608.33	$ 1.81
3	3.450	10.349	$ 12,437,968.94	$ 1.20	$ 17,413,156.51	$ 1.68
4	2.859	11.437	$ 13,279,110.08	$ 1.16	$ 18,590,754.11	$ 1.63
5	2.388	11.940	$ 13,915,433.86	$ 1.17	$ 19,481,607.41	$ 1.63
6	2.073	12.437	$ 14,545,625.86	$ 1.17	$ 20,363,876.21	$ 1.64
8	1.639	13.112	$ 15,698,966.59	$ 1.20	$ 21,978,553.23	$ 1.68
12	1.162	13.948	$ 17,838,721.86	$ 1.28	$ 24,974,210.61	$ 1.79
16	0.900	14.393	$ 19,858,159.70	$ 1.38	$ 27,801,423.58	$ 1.93
20	0.732	14.643	$ 21,820,191.47	$ 1.49	$ 30,548,268.06	$ 2.09

Table 8. Continued.

320 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 9,747,565.65	$ 1.66	$ 13,646,591.92	$ 2.32
2	4.452	8.904	$ 11,513,609.42	$ 1.29	$ 16,119,053.19	$ 1.81
3	3.518	10.554	$ 12,584,781.94	$ 1.19	$ 17,618,694.71	$ 1.67
4	2.931	11.723	$ 13,448,392.01	$ 1.15	$ 18,827,748.82	$ 1.61
5	2.454	12.271	$ 14,096,289.57	$ 1.15	$ 19,734,805.39	$ 1.61
6	2.136	12.817	$ 14,739,210.89	$ 1.15	$ 20,634,895.24	$ 1.61
8	1.694	13.555	$ 15,907,733.02	$ 1.17	$ 22,270,826.23	$ 1.64
12	1.207	14.479	$ 18,068,101.30	$ 1.25	$ 25,295,341.82	$ 1.75
16	0.935	14.956	$ 20,093,885.46	$ 1.34	$ 28,131,439.64	$ 1.88
20	0.763	15.255	$ 22,067,863.34	$ 1.45	$ 30,895,008.68	$ 2.03

Table 8. Continued.

500 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 9,832,744.23	$ 1.67	$ 13,765,841.92	$ 2.34
2	4.486	8.973	$ 11,625,119.38	$ 1.30	$ 16,275,167.14	$ 1.81
3	3.561	10.684	$ 12,714,526.50	$ 1.19	$ 17,800,337.10	$ 1.67
4	2.977	11.908	$ 13,593,265.53	$ 1.14	$ 19,030,571.74	$ 1.60
5	2.496	12.478	$ 14,246,521.32	$ 1.14	$ 19,945,129.85	$ 1.60
6	2.177	13.064	$ 14,899,852.74	$ 1.14	$ 20,859,793.84	$ 1.60
8	1.731	13.845	$ 16,078,674.45	$ 1.16	$ 22,510,144.23	$ 1.63
12	1.242	14.907	$ 18,274,768.10	$ 1.23	$ 25,584,675.34	$ 1.72
16	0.959	15.338	$ 20,285,315.19	$ 1.32	$ 28,399,441.27	$ 1.85
20	0.783	15.665	$ 22,265,781.28	$ 1.42	$ 31,172,093.79	$ 1.99
24	0.660	15.844	$ 24,205,204.63	$ 1.53	$ 33,887,286.48	$ 2.14

Table 8. Continued.

1000 Acres			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	5.888	5.888	$ 10,069,351.37	$ 1.71	$ 14,097,091.92	$ 2.39
2	4.461	8.922	$ 11,842,524.27	$ 1.33	$ 16,579,533.98	$ 1.86
3	3.578	10.735	$ 12,968,582.12	$ 1.21	$ 18,156,014.97	$ 1.69
4	3.015	12.060	$ 13,878,687.06	$ 1.15	$ 19,430,161.88	$ 1.61
5	2.553	12.767	$ 14,572,971.98	$ 1.14	$ 20,402,160.78	$ 1.60
6	2.239	13.435	$ 15,248,494.64	$ 1.13	$ 21,347,892.49	$ 1.59
8	1.783	14.261	$ 16,436,525.21	$ 1.15	$ 23,011,135.29	$ 1.61
12	1.279	15.351	$ 18,635,124.11	$ 1.21	$ 26,089,173.75	$ 1.70
16	0.995	15.924	$ 20,682,404.09	$ 1.30	$ 28,955,365.73	$ 1.82
20	0.815	16.292	$ 22,671,822.70	$ 1.39	$ 31,740,551.78	$ 1.95
24	0.687	16.497	$ 24,616,732.14	$ 1.49	$ 34,463,425.00	$ 2.09
32	0.527	16.876	$ 28,497,546.88	$ 1.69	$ 39,896,565.63	$ 2.36

Table 9. Injectivity and cost results for porosity sensitivity cases.

80 Acres – 5% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.082	0.082	$ 3,817,690.98	$ 46.35	$ 5,344,767.37	$ 64.88
2	0.075	0.150	$ 4,635,372.33	$ 30.85	$ 6,489,521.26	$ 43.18
3	0.067	0.201	$ 5,309,223.00	$ 26.36	$ 7,432,912.19	$ 36.90
4	0.062	0.248	$ 5,941,397.09	$ 23.91	$ 8,317,955.93	$ 33.47
5	0.054	0.271	$ 6,483,662.89	$ 23.94	$ 9,077,128.05	$ 33.51
6	0.049	0.296	$ 7,031,830.47	$ 23.72	$ 9,844,562.65	$ 33.20
8	0.043	0.341	$ 8,100,528.48	$ 23.73	$ 11,340,739.88	$ 33.23
12	0.033	0.393	$ 10,122,097.00	$ 25.75	$ 14,170,935.79	$ 36.05
16	0.026	0.423	$ 12,083,497.55	$ 28.58	$ 16,916,896.57	$ 40.01
20	0.022	0.445	$ 14,025,374.72	$ 31.50	$ 19,635,524.61	$ 44.10

Table 9. Continued.

80 Acres – 10% porosity (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,829,334.76	$ 45.44	$ 5,361,068.66	$ 63.61
2	0.078	0.157	$ 4,663,126.65	$ 29.74	$ 6,528,377.31	$ 41.63
3	0.072	0.215	$ 5,355,906.05	$ 24.96	$ 7,498,268.46	$ 34.94
4	0.067	0.268	$ 6,003,051.65	$ 22.38	$ 8,404,272.31	$ 31.33
5	0.059	0.295	$ 6,554,146.62	$ 22.24	$ 9,175,805.27	$ 31.13
6	0.054	0.325	$ 7,112,010.42	$ 21.87	$ 9,956,814.58	$ 30.62
8	0.048	0.380	$ 8,199,916.14	$ 21.57	$ 11,479,882.60	$ 30.20
12	0.037	0.445	$ 10,244,452.78	$ 23.00	$ 14,342,233.90	$ 32.21
16	0.030	0.484	$ 12,219,515.16	$ 25.26	$ 17,107,321.22	$ 35.36
20	0.026	0.513	$ 14,171,384.63	$ 27.64	$ 19,839,938.48	$ 38.69

Table 9. Continued.

80 Acres – 15% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 3,837,972.81	$ 44.78	$ 5,373,161.93	$ 62.69
2	0.081	0.161	$ 4,682,039.18	$ 29.02	$ 6,554,854.86	$ 40.62
3	0.074	0.222	$ 5,381,809.32	$ 24.23	$ 7,534,533.04	$ 33.92
4	0.070	0.280	$ 6,038,906.18	$ 21.55	$ 8,454,468.66	$ 30.18
5	0.062	0.309	$ 6,596,082.40	$ 21.31	$ 9,234,515.36	$ 29.84
6	0.057	0.343	$ 7,160,637.77	$ 20.86	$ 10,024,892.87	$ 29.20
8	0.051	0.405	$ 8,261,225.57	$ 20.38	$ 11,565,715.80	$ 28.53
12	0.040	0.480	$ 10,320,501.62	$ 21.51	$ 14,448,702.27	$ 30.11
16	0.033	0.525	$ 12,305,172.79	$ 23.46	$ 17,227,241.91	$ 32.84
20	0.028	0.559	$ 14,264,188.52	$ 25.53	$ 19,969,863.93	$ 35.74

Table 9. Continued.

80 Acres – 20% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 3,841,782.45	$ 44.49	$ 5,378,495.43	$ 62.29
2	0.082	0.164	$ 4,694,026.49	$ 28.57	$ 6,571,637.08	$ 40.00
3	0.076	0.228	$ 5,400,947.39	$ 23.71	$ 7,561,326.35	$ 33.20
4	0.072	0.289	$ 6,065,175.94	$ 20.98	$ 8,491,246.31	$ 29.37
5	0.064	0.321	$ 6,627,225.50	$ 20.66	$ 9,278,115.71	$ 28.93
6	0.060	0.357	$ 7,196,818.46	$ 20.15	$ 10,075,545.84	$ 28.20
8	0.053	0.425	$ 8,306,810.32	$ 19.56	$ 11,629,534.44	$ 27.38
12	0.042	0.507	$ 10,378,847.08	$ 20.46	$ 14,530,385.92	$ 28.64
16	0.035	0.558	$ 12,371,525.47	$ 22.19	$ 17,320,135.66	$ 31.06
20	0.030	0.596	$ 14,336,537.34	$ 24.05	$ 20,071,152.28	$ 33.67

2.5 Acres – 5% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.082	0.082	$ 3,781,016.87	$ 45.90	$ 5,293,423.62	$ 64.26
4	0.049	0.197	$ 5,730,557.01	$ 29.03	$ 8,022,779.82	$ 40.64
8	0.030	0.240	$ 7,767,455.40	$ 32.38	$ 10,874,437.56	$ 45.34

Table 9. Continued.

2.5 Acres – 10% porosity (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,792,660.65	$ 45.00	$ 5,309,724.91	$ 63.00
4	0.052	0.210	$ 5,775,519.96	$ 27.51	$ 8,085,727.95	$ 38.51
8	0.032	0.259	$ 7,827,287.76	$ 30.26	$ 10,958,202.86	$ 42.37

2.5 Acres – 15% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 3,801,298.70	$ 44.35	$ 5,321,818.18	$ 62.09
4	0.054	0.218	$ 5,802,130.06	$ 26.67	$ 8,122,982.08	$ 37.34
8	0.034	0.270	$ 7,862,987.18	$ 29.09	$ 11,008,182.06	$ 40.73

2.5 Acres – 20% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 3,805,108.34	$ 44.07	$ 5,327,151.68	$ 61.70
4	0.056	0.223	$ 5,821,701.50	$ 26.07	$ 8,150,382.11	$ 36.50
8	0.035	0.279	$ 7,889,653.90	$ 28.27	$ 11,045,515.47	$ 39.57

Table 9. Continued.

1,000 Acres – 5% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.082	0.082	$ 4,253,048.12	$ 51.63	$ 5,954,267.37	$ 72.28
8	0.059	0.472	$ 8,847,467.40	$ 18.76	$ 12,386,454.36	$ 26.27
32	0.027	0.854	$ 20,881,109.92	$ 24.46	$ 29,233,553.89	$ 34.24

1,000 Acres – 10% porosity (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 4,264,691.90	$ 50.60	$ 5,970,568.66	$ 70.84
8	0.067	0.538	$ 8,986,138.75	$ 16.71	$ 12,580,594.25	$ 23.40
32	0.034	1.099	$ 21,228,375.36	$ 19.32	$ 29,719,725.50	$ 27.05

1,000 Acres – 15% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 4,273,329.95	$ 49.86	$ 5,982,661.93	$ 69.80
8	0.072	0.574	$ 9,057,909.27	$ 15.78	$ 12,681,072.98	$ 22.09
32	0.040	1.266	$ 21,439,780.48	$ 16.94	$ 30,015,692.68	$ 23.72

Table 9. Continued.

1,000 Acres – 20% porosity			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 4,277,139.59	$ 49.53	$ 5,987,995.43	$ 69.35
8	0.075	0.600	$ 9,106,890.17	$ 15.19	$ 12,749,646.24	$ 21.26
32	0.044	1.401	$ 21,599,613.62	$ 15.41	$ 30,239,459.06	$ 21.58

Table 10. Injectivity and cost results for compressibility sensitivity cases.

80 Acres – 0 Pa^{-1} (default)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,829,334.76	$ 45.44	$ 5,361,068.66	$ 63.61
2	0.078	0.157	$ 4,663,126.65	$ 29.74	$ 6,528,377.31	$ 41.63
3	0.072	0.215	$ 5,355,906.05	$ 24.96	$ 7,498,268.46	$ 34.94
4	0.067	0.268	$ 6,003,051.65	$ 22.38	$ 8,404,272.31	$ 31.33
5	0.059	0.295	$ 6,554,146.62	$ 22.24	$ 9,175,805.27	$ 31.13
6	0.054	0.325	$ 7,112,010.42	$ 21.87	$ 9,956,814.58	$ 30.62
8	0.048	0.380	$ 8,199,916.14	$ 21.57	$ 11,479,882.60	$ 30.20
12	0.037	0.445	$ 10,244,452.78	$ 23.00	$ 14,342,233.90	$ 32.21
16	0.030	0.484	$ 12,219,515.16	$ 25.26	$ 17,107,321.22	$ 35.36
20	0.026	0.513	$ 14,171,384.63	$ 27.64	$ 19,839,938.48	$ 38.69

Table 10. Continued.

80 Acres – 4.13E-09 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.091	0.091	$ 3,871,841.73	$ 42.33	$ 5,420,578.42	$ 59.27
2	0.090	0.181	$ 4,760,145.47	$ 26.31	$ 6,664,203.66	$ 36.83
3	0.088	0.263	$ 5,513,320.47	$ 20.99	$ 7,718,648.65	$ 29.38
4	0.086	0.345	$ 6,219,738.21	$ 18.03	$ 8,707,633.49	$ 25.24
5	0.080	0.398	$ 6,826,039.13	$ 17.14	$ 9,556,454.78	$ 24.00
6	0.076	0.457	$ 7,434,534.78	$ 16.27	$ 10,408,348.69	$ 22.78
8	0.071	0.571	$ 8,616,470.84	$ 15.09	$ 12,063,059.17	$ 21.13
12	0.061	0.733	$ 10,798,960.16	$ 14.74	$ 15,118,544.22	$ 20.63
16	0.053	0.847	$ 12,872,441.82	$ 15.21	$ 18,021,418.55	$ 21.29
20	0.047	0.938	$ 14,899,708.13	$ 15.88	$ 20,859,591.38	$ 22.24

Table 10. Continued.

80 Acres – 2.81E-10 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 3,837,184.35	$ 44.84	$ 5,372,058.08	$ 62.77
2	0.081	0.162	$ 4,685,505.68	$ 28.89	$ 6,559,707.96	$ 40.44
3	0.075	0.224	$ 5,387,486.95	$ 24.07	$ 7,542,481.74	$ 33.70
4	0.071	0.283	$ 6,047,335.79	$ 21.37	$ 8,466,270.11	$ 29.91
5	0.063	0.313	$ 6,606,095.11	$ 21.10	$ 9,248,533.16	$ 29.54
6	0.058	0.348	$ 7,172,279.88	$ 20.62	$ 10,041,191.83	$ 28.87
8	0.051	0.411	$ 8,275,395.14	$ 20.12	$ 11,585,553.19	$ 28.17
12	0.041	0.489	$ 10,339,820.76	$ 21.15	$ 14,475,749.06	$ 29.62
16	0.033	0.535	$ 12,327,143.62	$ 23.02	$ 17,258,001.07	$ 32.23
20	0.029	0.571	$ 14,287,856.29	$ 25.03	$ 20,002,998.81	$ 35.05

Table 10. Continued.

80 Acres – 7.00E-11 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.085	0.085	$ 3,831,578.69	$ 45.26	$ 5,364,210.17	$ 63.37
2	0.079	0.159	$ 4,671,076.10	$ 29.43	$ 6,539,506.54	$ 41.20
3	0.072	0.217	$ 5,364,557.79	$ 24.71	$ 7,510,380.90	$ 34.59
4	0.068	0.273	$ 6,016,000.32	$ 22.08	$ 8,422,400.44	$ 30.91
5	0.060	0.300	$ 6,569,278.96	$ 21.90	$ 9,196,990.54	$ 30.66
6	0.055	0.332	$ 7,129,684.15	$ 21.49	$ 9,981,557.81	$ 30.09
8	0.049	0.389	$ 8,221,683.59	$ 21.14	$ 11,510,357.02	$ 29.59
12	0.038	0.458	$ 10,271,749.73	$ 22.45	$ 14,380,449.62	$ 31.43
16	0.031	0.498	$ 12,250,145.82	$ 24.59	$ 17,150,204.15	$ 34.43
20	0.026	0.529	$ 14,204,362.48	$ 26.86	$ 19,886,107.47	$ 37.60

2.5 Acres – 0 Pa^{-1} (default)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,792,660.65	$ 45.00	$ 5,309,724.91	$ 63.00
4	0.052	0.210	$ 5,775,519.96	$ 27.51	$ 8,085,727.95	$ 38.51
8	0.032	0.259	$ 7,827,287.76	$ 30.26	$ 10,958,202.86	$ 42.37

Table 10. Continued.

2.5 Acres – 4.13E-09 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.091	0.091	$ 3,835,167.62	$ 41.93	$ 5,369,234.67	$ 58.71
4	0.066	0.263	$ 5,949,976.60	$ 22.63	$ 8,329,967.24	$ 31.68
8	0.043	0.345	$ 8,072,554.56	$ 23.43	$ 11,301,576.38	$ 32.80

2.5 Acres – 2.81E-10 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 3,800,510.24	$ 44.41	$ 5,320,714.33	$ 62.17
4	0.055	0.219	$ 5,808,260.46	$ 26.48	$ 8,131,564.64	$ 37.07
8	0.034	0.273	$ 7,871,579.71	$ 28.82	$ 11,020,211.60	$ 40.35

2.5 Acres – 7.00E-11 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.085	0.085	$ 3,794,904.58	$ 44.83	$ 5,312,866.42	$ 62.76
4	0.053	0.213	$ 5,785,204.45	$ 27.20	$ 8,099,286.23	$ 38.08
8	0.033	0.263	$ 7,840,148.53	$ 29.83	$ 10,976,207.95	$ 41.77

Table 10. Continued.

1,000 Acres – 0 Pa^{-1} (default)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 4,264,691.90	$ 50.60	$ 5,970,568.66	$ 70.84
8	0.067	0.538	$ 8,986,138.75	$ 16.71	$ 12,580,594.25	$ 23.40
32	0.034	1.099	$ 21,228,375.36	$ 19.32	$ 29,719,725.50	$ 27.05

1,000 Acres – 4.13E-09 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.091	0.091	$ 4,307,198.87	$ 47.10	$ 6,030,078.42	$ 65.93
8	0.087	0.699	$ 9,287,056.79	$ 13.28	$ 13,001,879.51	$ 18.59
32	0.069	2.224	$ 22,412,745.46	$ 10.08	$ 31,377,843.64	$ 14.11

1,000 Acres – 2.81E-10 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.086	0.086	$ 4,272,541.49	$ 49.92	$ 5,981,558.08	$ 69.89
8	0.073	0.582	$ 9,074,204.54	$ 15.58	$ 12,703,886.35	$ 21.81
32	0.041	1.311	$ 21,494,291.42	$ 16.39	$ 30,092,007.98	$ 22.95

Table 10. Continued.

1,000 Acres – 7.00E-11 Pa^{-1}			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.085	0.085	$ 4,266,935.83	$ 50.41	$ 5,973,710.17	$ 70.57
8	0.069	0.551	$ 9,012,291.84	$ 16.36	$ 12,617,208.57	$ 22.91
32	0.036	1.156	$ 21,303,493.44	$ 18.42	$ 29,824,890.82	$ 25.79

Table 11. Injectivity and cost results for injection depth sensitivity cases.

80 Acres – 1,000 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.029	0.029	$ 3,388,400.69	$ 116.05	$ 4,743,760.97	$ 162.47
2	0.027	0.054	$ 4,093,673.07	$ 75.79	$ 5,731,142.29	$ 106.11
3	0.025	0.074	$ 4,712,674.00	$ 63.31	$ 6,597,743.60	$ 88.63
4	0.024	0.094	$ 5,304,488.68	$ 56.41	$ 7,426,284.16	$ 78.98
5	0.021	0.104	$ 5,830,111.65	$ 56.26	$ 8,162,156.31	$ 78.77
6	0.019	0.115	$ 6,361,710.13	$ 55.34	$ 8,906,394.19	$ 77.48
8	0.017	0.136	$ 7,406,655.97	$ 54.57	$ 10,369,318.36	$ 76.40
12	0.013	0.161	$ 9,407,344.42	$ 58.39	$ 13,170,282.19	$ 81.75
16	0.011	0.176	$ 11,358,555.75	$ 64.46	$ 15,901,978.05	$ 90.25
20	0.009	0.188	$ 13,293,054.06	$ 70.84	$ 18,610,275.68	$ 99.18

Table 11. Continued.

80 Acres – 2,000 m (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,829,334.76	$ 45.44	$ 5,361,068.66	$ 63.61
2	0.078	0.157	$ 4,663,126.65	$ 29.74	$ 6,528,377.31	$ 41.63
3	0.072	0.215	$ 5,355,906.05	$ 24.96	$ 7,498,268.46	$ 34.94
4	0.067	0.268	$ 6,003,051.65	$ 22.38	$ 8,404,272.31	$ 31.33
5	0.059	0.295	$ 6,554,146.62	$ 22.24	$ 9,175,805.27	$ 31.13
6	0.054	0.325	$ 7,112,010.42	$ 21.87	$ 9,956,814.58	$ 30.62
8	0.048	0.380	$ 8,199,916.14	$ 21.57	$ 11,479,882.60	$ 30.20
12	0.037	0.445	$ 10,244,452.78	$ 23.00	$ 14,342,233.90	$ 32.21
16	0.030	0.484	$ 12,219,515.16	$ 25.26	$ 17,107,321.22	$ 35.36
20	0.026	0.513	$ 14,171,384.63	$ 27.64	$ 19,839,938.48	$ 38.69

Table 11. Continued.

80 Acres – 3,000 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.167	0.167	$ 4,231,753.91	$ 25.37	$ 5,924,455.47	$ 35.51
2	0.155	0.311	$ 5,182,294.45	$ 16.67	$ 7,255,212.23	$ 23.33
3	0.140	0.421	$ 5,934,577.88	$ 14.10	$ 8,308,409.03	$ 19.74
4	0.131	0.524	$ 6,631,683.45	$ 12.66	$ 9,284,356.83	$ 17.73
5	0.115	0.574	$ 7,204,369.67	$ 12.55	$ 10,086,117.54	$ 17.58
6	0.105	0.631	$ 7,784,726.23	$ 12.34	$ 10,898,616.72	$ 17.27
8	0.092	0.733	$ 8,909,334.63	$ 12.15	$ 12,473,068.48	$ 17.01
12	0.071	0.854	$ 10,992,899.53	$ 12.88	$ 15,390,059.34	$ 18.03
16	0.058	0.922	$ 12,985,995.62	$ 14.08	$ 18,180,393.87	$ 19.71
20	0.049	0.973	$ 14,949,688.18	$ 15.37	$ 20,929,563.45	$ 21.51

2.5 Acres – 1,000 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.029	0.029	$ 3,351,726.59	$ 114.79	$ 4,692,417.22	$ 160.71
4	0.018	0.073	$ 5,138,510.60	$ 70.48	$ 7,193,914.84	$ 98.68
8	0.011	0.091	$ 7,139,259.30	$ 78.71	$ 9,994,963.03	$ 110.19

Table 11. Continued.

2.5 Acres – 2,000 m (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,792,660.65	$ 45.00	$ 5,309,724.91	$ 63.00
4	0.052	0.210	$ 5,775,519.96	$ 27.51	$ 8,085,727.95	$ 38.51
8	0.032	0.259	$ 7,827,287.76	$ 30.26	$ 10,958,202.86	$ 42.37

2.5 Acres – 3,000 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.166	0.166	$ 4,193,712.72	$ 25.19	$ 5,871,197.80	$ 35.26
4	0.103	0.412	$ 6,350,347.76	$ 15.40	$ 8,890,486.86	$ 21.57
8	0.063	0.505	$ 8,447,390.66	$ 16.72	$ 11,826,346.93	$ 23.41

1,000 Acres – 1,000 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.029	0.029	$ 3,823,757.84	$ 130.96	$ 5,353,260.97	$ 183.35
8	0.024	0.192	$ 8,074,709.38	$ 41.96	$ 11,304,593.14	$ 58.75
32	0.013	0.427	$ 20,090,542.42	$ 47.05	$ 28,126,759.38	$ 65.87

Table 11. Continued.

1,000 Acres – 2,000 m (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 4,264,691.90	$ 50.60	$ 5,970,568.66	$ 70.84
8	0.067	0.538	$ 8,986,138.75	$ 16.71	$ 12,580,594.25	$ 23.40
32	0.034	1.099	$ 21,228,375.36	$ 19.32	$ 29,719,725.50	$ 27.05

1,000 Acres – 3,000 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.166	0.166	$ 4,665,743.97	$ 28.02	$ 6,532,041.55	$ 39.23
8	0.129	1.030	$ 9,793,644.14	$ 9.50	$ 13,711,101.79	$ 13.31
32	0.063	2.001	$ 22,212,942.99	$ 11.10	$ 31,098,120.19	$ 15.54

Table 12. Injectivity and cost results for layer thickness sensitivity cases.

80 Acres – 50 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.053	0.053	$ 3,616,021.65	$ 67.74	$ 5,062,430.30	$ 94.84
2	0.049	0.098	$ 4,380,633.39	$ 44.77	$ 6,132,886.74	$ 62.68
3	0.044	0.131	$ 5,019,346.89	$ 38.46	$ 7,027,085.65	$ 53.84
4	0.040	0.161	$ 5,626,050.43	$ 34.93	$ 7,876,470.60	$ 48.91
5	0.035	0.173	$ 6,145,904.65	$ 35.58	$ 8,604,266.51	$ 49.81
6	0.031	0.188	$ 6,677,528.33	$ 35.52	$ 9,348,539.67	$ 49.73
8	0.027	0.216	$ 7,723,249.66	$ 35.79	$ 10,812,549.52	$ 50.10
12	0.020	0.245	$ 9,712,166.62	$ 39.60	$ 13,597,033.27	$ 55.44
16	0.016	0.261	$ 11,653,614.71	$ 44.58	$ 16,315,060.59	$ 62.41
20	0.014	0.274	$ 13,581,553.62	$ 49.63	$ 19,014,175.07	$ 69.48

Table 12. Continued.

80 Acres – 100 m (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,829,334.76	$ 45.44	$ 5,361,068.66	$ 63.61
2	0.078	0.157	$ 4,663,126.65	$ 29.74	$ 6,528,377.31	$ 41.63
3	0.072	0.215	$ 5,355,906.05	$ 24.96	$ 7,498,268.46	$ 34.94
4	0.067	0.268	$ 6,003,051.65	$ 22.38	$ 8,404,272.31	$ 31.33
5	0.059	0.295	$ 6,554,146.62	$ 22.24	$ 9,175,805.27	$ 31.13
6	0.054	0.325	$ 7,112,010.42	$ 21.87	$ 9,956,814.58	$ 30.62
8	0.048	0.380	$ 8,199,916.14	$ 21.57	$ 11,479,882.60	$ 30.20
12	0.037	0.445	$ 10,244,452.78	$ 23.00	$ 14,342,233.90	$ 32.21
16	0.030	0.484	$ 12,219,515.16	$ 25.26	$ 17,107,321.22	$ 35.36
20	0.026	0.513	$ 14,171,384.63	$ 27.64	$ 19,839,938.48	$ 38.69

Table 12. Continued.

80 Acres – 200 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.141	0.141	$ 4,120,268.63	$ 29.30	$ 5,768,376.09	$ 41.03
2	0.131	0.262	$ 5,037,360.84	$ 19.26	$ 7,052,305.18	$ 26.96
3	0.122	0.365	$ 5,799,067.43	$ 15.88	$ 8,118,694.40	$ 22.24
4	0.115	0.461	$ 6,498,915.19	$ 14.09	$ 9,098,481.27	$ 19.73
5	0.103	0.515	$ 7,086,150.72	$ 13.76	$ 9,920,611.01	$ 19.27
6	0.096	0.574	$ 7,677,280.33	$ 13.38	$ 10,748,192.46	$ 18.73
8	0.085	0.681	$ 8,819,668.36	$ 12.95	$ 12,347,535.71	$ 18.13
12	0.068	0.816	$ 10,934,615.38	$ 13.40	$ 15,308,461.53	$ 18.76
16	0.056	0.899	$ 12,952,350.09	$ 14.40	$ 18,133,290.13	$ 20.16
20	0.048	0.961	$ 14,933,100.68	$ 15.53	$ 20,906,340.95	$ 21.75

2.5 Acres – 50 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.053	0.053	$ 3,579,347.54	$ 67.05	$ 5,011,086.55	$ 93.88
4	0.030	0.121	$ 5,409,116.45	$ 44.76	$ 7,572,763.03	$ 62.66
8	0.018	0.141	$ 7,396,002.23	$ 52.27	$ 10,354,403.12	$ 73.18

Table 12. Continued.

2.5 Acres – 100 m (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,792,660.65	$ 45.00	$ 5,309,724.91	$ 63.00
4	0.052	0.210	$ 5,775,519.96	$ 27.51	$ 8,085,727.95	$ 38.51
8	0.032	0.259	$ 7,827,287.76	$ 30.26	$ 10,958,202.86	$ 42.37

2.5 Acres – 200 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.141	0.141	$ 4,083,594.53	$ 29.04	$ 5,717,032.34	$ 40.66
4	0.092	0.370	$ 6,246,846.93	$ 16.89	$ 8,745,585.71	$ 23.65
8	0.058	0.461	$ 8,351,945.96	$ 18.12	$ 11,692,724.35	$ 25.37

1,000 Acres – 50 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.053	0.053	$ 4,051,378.79	$ 75.90	$ 5,671,930.30	$ 106.26
8	0.040	0.324	$ 8,489,416.78	$ 26.20	$ 11,885,183.49	$ 36.68
32	0.019	0.600	$ 20,450,830.63	$ 34.09	$ 28,631,162.88	$ 47.72

Table 12. Continued.

1,000 Acres – 100 m (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 4,264,691.90	$ 50.60	$ 5,970,568.66	$ 70.84
8	0.067	0.538	$ 8,986,138.75	$ 16.71	$ 12,580,594.25	$ 23.40
32	0.034	1.099	$ 21,228,375.36	$ 19.32	$ 29,719,725.50	$ 27.05

1,000 Acres – 200 m			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.141	0.141	$ 4,555,625.78	$ 32.40	$ 6,377,876.09	$ 45.36
8	0.115	0.921	$ 9,638,138.21	$ 10.47	$ 13,493,393.49	$ 14.66
32	0.063	2.021	$ 22,231,827.83	$ 11.00	$ 31,124,558.96	$ 15.40

Table 13. Injectivity and cost results for simulation time sensitivity cases.

80 Acres – 100 days			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.024	0.024	$ 3,353,292.22	$ 37.99	$ 4,694,609.11	$ 53.19
2	0.023	0.047	$ 4,069,973.97	$ 23.79	$ 5,697,963.55	$ 33.31
3	0.022	0.066	$ 4,698,580.38	$ 19.46	$ 6,578,012.53	$ 27.24
4	0.021	0.085	$ 5,300,474.03	$ 17.04	$ 7,420,663.65	$ 23.86
5	0.019	0.096	$ 5,837,358.80	$ 16.70	$ 8,172,302.32	$ 23.38
6	0.018	0.108	$ 6,378,434.00	$ 16.21	$ 8,929,807.60	$ 22.69
8	0.016	0.130	$ 7,441,232.51	$ 15.62	$ 10,417,725.51	$ 21.87
12	0.013	0.160	$ 9,466,686.40	$ 16.24	$ 13,253,360.97	$ 22.73
16	0.011	0.178	$ 11,435,337.14	$ 17.58	$ 16,009,471.99	$ 24.61
20	0.010	0.193	$ 13,383,182.65	$ 19.03	$ 18,736,455.72	$ 26.65

Table 13. Continued.

80 Acres – 1 year (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,829,334.76	$ 45.44	$ 5,361,068.66	$ 63.61
2	0.078	0.157	$ 4,663,126.65	$ 29.74	$ 6,528,377.31	$ 41.63
3	0.072	0.215	$ 5,355,906.05	$ 24.96	$ 7,498,268.46	$ 34.94
4	0.067	0.268	$ 6,003,051.65	$ 22.38	$ 8,404,272.31	$ 31.33
5	0.059	0.295	$ 6,554,146.62	$ 22.24	$ 9,175,805.27	$ 31.13
6	0.054	0.325	$ 7,112,010.42	$ 21.87	$ 9,956,814.58	$ 30.62
8	0.048	0.380	$ 8,199,916.14	$ 21.57	$ 11,479,882.60	$ 30.20
12	0.037	0.445	$ 10,244,452.78	$ 23.00	$ 14,342,233.90	$ 32.21
16	0.030	0.484	$ 12,219,515.16	$ 25.26	$ 17,107,321.22	$ 35.36
20	0.026	0.513	$ 14,171,384.63	$ 27.64	$ 19,839,938.48	$ 38.69

Table 13. Continued.

80 Acres – 4 years			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.318	0.318	$ 4,677,919.42	$ 58.90	$ 6,549,087.18	$ 82.46
2	0.284	0.567	$ 5,706,387.95	$ 40.23	$ 7,988,943.13	$ 56.33
3	0.249	0.746	$ 6,490,958.44	$ 34.78	$ 9,087,341.82	$ 48.69
4	0.226	0.905	$ 7,204,345.63	$ 31.83	$ 10,086,083.89	$ 44.57
5	0.196	0.978	$ 7,779,448.11	$ 31.80	$ 10,891,227.36	$ 44.53
6	0.177	1.061	$ 8,362,049.05	$ 31.53	$ 11,706,868.67	$ 44.15
8	0.150	1.203	$ 9,485,840.72	$ 31.54	$ 13,280,177.01	$ 44.16
12	0.113	1.362	$ 11,561,239.82	$ 33.96	$ 16,185,735.75	$ 47.55
16	0.090	1.447	$ 13,546,350.89	$ 37.44	$ 18,964,891.24	$ 52.41
20	0.076	1.510	$ 15,504,139.73	$ 41.07	$ 21,705,795.62	$ 57.49

Table 13. Continued.

80 Acres – 10 years			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.739	0.739	$ 5,505,305.03	$ 29.80	$ 7,707,427.04	$ 41.72
2	0.626	1.251	$ 6,671,098.90	$ 21.33	$ 9,339,538.46	$ 29.86
3	0.529	1.586	$ 7,507,302.49	$ 18.93	$ 10,510,223.49	$ 26.50
4	0.466	1.864	$ 8,247,726.11	$ 17.70	$ 11,546,816.56	$ 24.78
5	0.397	1.986	$ 8,830,418.96	$ 17.78	$ 12,362,586.55	$ 24.90
6	0.353	2.120	$ 9,419,130.25	$ 17.77	$ 13,186,782.36	$ 24.88
8	0.293	2.343	$ 10,548,470.12	$ 18.01	$ 14,767,858.17	$ 25.22
12	0.214	2.571	$ 12,617,163.69	$ 19.63	$ 17,664,029.17	$ 27.48
16	0.168	2.694	$ 14,599,884.41	$ 21.68	$ 20,439,838.17	$ 30.35
20	0.139	2.784	$ 16,556,205.58	$ 23.79	$ 23,178,687.81	$ 33.30

2.5 Acres – 100 days			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.024	0.024	$ 3,316,618.11	$ 37.58	$ 4,643,265.36	$ 52.61
4	0.016	0.065	$ 5,127,362.46	$ 21.55	$ 7,178,307.44	$ 30.17
8	0.010	0.083	$ 7,139,325.15	$ 23.61	$ 9,995,055.21	$ 33.05

Table 13. Continued.

2.5 Acres – 1 year (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,792,660.65	$ 45.00	$ 5,309,724.91	$ 63.00
4	0.052	0.210	$ 5,775,519.96	$ 27.51	$ 8,085,727.95	$ 38.51
8	0.032	0.259	$ 7,827,287.76	$ 30.26	$ 10,958,202.86	$ 42.37

2.5 Acres – 4 years			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.318	0.318	$ 4,641,245.31	$ 58.44	$ 6,497,743.43	$ 81.81
4	0.183	0.732	$ 6,903,935.55	$ 37.71	$ 9,665,509.77	$ 52.80
8	0.110	0.877	$ 9,016,783.03	$ 41.14	$ 12,623,496.24	$ 57.60

2.5 Acres – 10 years			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.739	0.739	$ 5,468,630.92	$ 74.00	$ 7,656,083.29	$ 103.60
4	0.390	1.561	$ 7,916,964.68	$ 50.73	$ 11,083,750.55	$ 71.02
8	0.227	1.819	$ 10,059,816.91	$ 55.30	$ 14,083,743.67	$ 77.42

Table 13. Continued.

1,000 Acres – 100 days			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.024	0.024	$ 3,788,649.36	$ 42.92	$ 5,304,109.11	$ 60.09
8	0.022	0.178	$ 8,088,320.22	$ 12.45	$ 11,323,648.31	$ 17.44
32	0.015	0.473	$ 20,306,743.69	$ 11.75	$ 28,429,441.17	$ 16.45

1,000 Acres – 1 year (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 4,264,691.90	$ 50.60	$ 5,970,568.66	$ 70.84
8	0.067	0.538	$ 8,986,138.75	$ 16.71	$ 12,580,594.25	$ 23.40
32	0.034	1.099	$ 21,228,375.36	$ 19.32	$ 29,719,725.50	$ 27.05

1,000 Acres – 4 years			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.318	0.318	$ 5,113,276.56	$ 64.38	$ 7,158,587.18	$ 90.13
8	0.200	1.596	$ 10,357,357.48	$ 25.95	$ 14,500,300.47	$ 36.34
32	0.080	2.561	$ 22,550,437.55	$ 35.22	$ 31,570,612.57	$ 49.30

Table 13. Continued.

1,000 Acres – 10 years			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.739	0.739	$ 5,940,662.17	$ 80.39	$ 8,316,927.04	$ 112.55
8	0.363	2.905	$ 11,406,128.75	$ 39.27	$ 15,968,580.24	$ 54.97
32	0.126	4.019	$ 23,460,301.91	$ 58.37	$ 32,844,422.67	$ 81.71

Table 14. Injectivity and cost results for permeability heterogeneity sensitivity cases.

80 Acres – Homogeneous (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,829,334.76	$ 45.44	$ 5,361,068.66	$ 63.61
2	0.078	0.157	$ 4,663,126.65	$ 29.74	$ 6,528,377.31	$ 41.63
3	0.072	0.215	$ 5,355,906.05	$ 24.96	$ 7,498,268.46	$ 34.94
4	0.067	0.268	$ 6,003,051.65	$ 22.38	$ 8,404,272.31	$ 31.33
5	0.059	0.295	$ 6,554,146.62	$ 22.24	$ 9,175,805.27	$ 31.13
6	0.054	0.325	$ 7,112,010.42	$ 21.87	$ 9,956,814.58	$ 30.62
8	0.048	0.380	$ 8,199,916.14	$ 21.57	$ 11,479,882.60	$ 30.20
12	0.037	0.445	$ 10,244,452.78	$ 23.00	$ 14,342,233.90	$ 32.21
16	0.030	0.484	$ 12,219,515.16	$ 25.26	$ 17,107,321.22	$ 35.36
20	0.026	0.513	$ 14,171,384.63	$ 27.64	$ 19,839,938.48	$ 38.69

Table 14. Continued.

80 Acres – Heterogeneous			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.146	0.146	$ 4,142,875.16	$ 28.43	$ 5,800,025.23	$ 39.81
2	0.082	0.165	$ 4,696,923.33	$ 28.47	$ 6,575,692.66	$ 39.86
3	0.017	0.050	$ 4,537,963.92	$ 89.86	$ 6,353,149.48	$ 125.81
4	0.070	0.281	$ 6,042,412.79	$ 21.48	$ 8,459,377.91	$ 30.07
5	0.076	0.380	$ 6,782,859.38	$ 17.83	$ 9,496,003.14	$ 24.96
6	0.056	0.336	$ 7,141,019.11	$ 21.26	$ 9,997,426.76	$ 29.76
8	0.057	0.459	$ 8,383,436.30	$ 18.28	$ 11,736,810.82	$ 25.60
12	0.040	0.478	$ 10,317,442.73	$ 21.57	$ 14,444,419.82	$ 30.19
16	0.040	0.633	$ 12,515,489.53	$ 19.76	$ 17,521,685.34	$ 27.66
20	0.030	0.607	$ 14,357,771.40	$ 23.64	$ 20,100,879.97	$ 33.10

Table 15. Injectivity and cost results for CO_2 injection sensitivity cases.

80 Acres – Water (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,829,334.76	$ 45.44	$ 5,361,068.66	$ 63.61
2	0.078	0.157	$ 4,663,126.65	$ 29.74	$ 6,528,377.31	$ 41.63
3	0.072	0.215	$ 5,355,906.05	$ 24.96	$ 7,498,268.46	$ 34.94
4	0.067	0.268	$ 6,003,051.65	$ 22.38	$ 8,404,272.31	$ 31.33
5	0.059	0.295	$ 6,554,146.62	$ 22.24	$ 9,175,805.27	$ 31.13
6	0.054	0.325	$ 7,112,010.42	$ 21.87	$ 9,956,814.58	$ 30.62
8	0.048	0.380	$ 8,199,916.14	$ 21.57	$ 11,479,882.60	$ 30.20
12	0.037	0.445	$ 10,244,452.78	$ 23.00	$ 14,342,233.90	$ 32.21
16	0.030	0.484	$ 12,219,515.16	$ 25.26	$ 17,107,321.22	$ 35.36
20	0.026	0.513	$ 14,171,384.63	$ 27.64	$ 19,839,938.48	$ 38.69

Table 15. Continued.

80 Acres – CO_2			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.122	0.122	$ 4,032,101.77	$ 33.13	$ 5,644,942.47	$ 46.38
2	0.105	0.210	$ 4,868,548.20	$ 23.14	$ 6,815,967.48	$ 32.40
3	0.087	0.260	$ 5,505,704.53	$ 21.16	$ 7,707,986.34	$ 29.62
4	0.077	0.310	$ 6,124,080.37	$ 19.77	$ 8,573,712.51	$ 27.68
5	0.062	0.308	$ 6,593,004.53	$ 21.38	$ 9,230,206.34	$ 29.93
6	0.054	0.324	$ 7,107,914.23	$ 21.96	$ 9,951,079.92	$ 30.74
8	0.044	0.353	$ 8,131,953.64	$ 23.02	$ 11,384,735.10	$ 32.22
12	0.031	0.375	$ 10,078,346.66	$ 26.85	$ 14,109,685.32	$ 37.60
16	0.024	0.385	$ 11,993,456.26	$ 31.14	$ 16,790,838.76	$ 43.59
20	0.020	0.393	$ 13,903,957.77	$ 35.35	$ 19,465,540.88	$ 49.48

2.5 Acres – Water (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 3,792,660.65	$ 45.00	$ 5,309,724.91	$ 63.00
3	0.060	0.179	$ 5,188,390.92	$ 28.99	$ 7,263,747.29	$ 40.59
4	0.052	0.210	$ 5,775,519.96	$ 27.51	$ 8,085,727.95	$ 38.51
8	0.032	0.259	$ 7,827,287.76	$ 30.26	$ 10,958,202.86	$ 42.37

Table 15. Continued.

2.5 Acres – CO_2			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.122	0.122	$ 3,995,427.66	$ 32.82	$ 5,593,598.72	$ 45.95
3	0.061	0.183	$ 5,205,170.01	$ 28.39	$ 7,287,238.01	$ 39.75
4	0.050	0.199	$ 5,735,101.47	$ 28.87	$ 8,029,142.06	$ 40.41
8	0.025	0.200	$ 7,628,764.40	$ 38.23	$ 10,680,270.16	$ 53.53

1,000 Acres – Water (base case)			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.084	0.084	$ 4,264,691.90	$ 50.60	$ 5,970,568.66	$ 70.84
4	0.078	0.312	$ 6,565,021.80	$ 21.06	$ 9,191,030.52	$ 29.49
8	0.067	0.538	$ 8,986,138.75	$ 16.71	$ 12,580,594.25	$ 23.40
32	0.034	1.099	$ 21,228,375.36	$ 19.32	$ 29,719,725.50	$ 27.05

1,000 Acres – CO_2			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.122	0.122	$ 4,467,458.91	$ 36.70	$ 6,254,442.47	$ 51.38
4	0.111	0.443	$ 6,892,815.88	$ 15.57	$ 9,649,942.24	$ 21.80
8	0.082	0.655	$ 9,208,785.42	$ 14.06	$ 12,892,299.59	$ 19.69
32	0.030	0.975	$ 21,059,453.57	$ 21.60	$ 29,483,234.99	$ 30.24

Table 16. Injectivity and cost results for the RMCCS case study

RMCCS Case Study			First Year Costs			
Injection Wells	Injection/well (Mt/yr)	Total Injection (Mt)	Total Expense (1999 dollars)	Expense ($/tonne)	Total Expense (w/ inflation)	Expense ($/tonne)
1	0.3285	0.3285	$ 5,387,429.18	$ 16.40	$ 7,542,400.86	$ 22.96
2	0.2362	0.4724	$ 6,572,565.16	$ 13.91	$ 9,201,591.22	$ 19.48
3	0.2099	0.6297	$ 7,723,515.97	$ 12.27	$ 10,812,922.36	$ 17.17
4	0.1946	0.7786	$ 8,817,162.62	$ 11.32	$ 12,344,027.67	$ 15.85
5-Spot	0.1862	0.9310	$ 9,888,234.85	$ 10.62	$ 13,843,528.80	$ 14.87
5	0.1688	0.8439	$ 9,757,754.09	$ 11.56	$ 13,660,855.73	$ 16.19
6	0.1542	0.9252	$ 10,717,117.89	$ 11.58	$ 15,003,965.05	$ 16.22
8	0.1397	1.1175	$ 12,657,131.84	$ 11.33	$ 17,719,984.57	$ 15.86
9-spot	0.1308	1.1771	$ 13,571,102.87	$ 11.53	$ 18,999,544.02	$ 16.14
12	0.1075	1.2895	$ 16,221,561.13	$ 12.58	$ 22,710,185.59	$ 17.61