SAND2008-6482C

Using Saline Aquifers for Combined Power Plant Water Needs and Carbon Sequestration

by

Peter H. Kobos[1,*], Malynda A. Cappelle[1] , Jim L. Krumhansl[1], Thomas Dewers[1],
David J. Borns[1], Patrick V. Brady[1], Andrea McNemar[2]

[1]Sandia National Laboratories; [2]National Energy Technology Laboratory
[*]Staff Economist, Phone (505) 845-7086, phkobos@sandia.gov

28th USAEE/IAEE North American Conference,
New Orleans, LA, December 3 – 5, 2008.

Abstract

A methodology was developed to test the feasibility of linking coal-fired power plants, deep saline aquifers for carbon sequestration, and produced water treatment technologies for use as cooling water. A case study examines the San Juan Generating Station (SJGS) with the Morrison Formation Aquifer in the San Juan Basin in Northwest New Mexico. The framework was developed into a dynamic simulation model to examine scenarios regarding varying levels of carbon dioxide (CO_2) sequestration from the power plant, water recovery rates from the formation, and variable costs associated with the whole system's components. The Phase I work identified the high-level results of a combined CO_2 sequestration and brackish water treatment for cooling case study. Phase II continues to address several key model parameters that may substantially alter the initial findings such as CO_2 injection rates, CO_2 fate and transport in the aquifer, and the system's economics. The results presented here indicate that a coupled carbon dioxide sequestration and extracted water for treatment and use in a power plant may be feasible. However, the applicability of the coupled system relies on several unique site and case-specific aspects of the power plant and geologic systems that will greatly affect the physical and economic challenges associated with the overarching system.

1. Introduction: Energy, Water and Carbon Sequestration Systems

The U.S. Department of Energy's National Energy Technology Laboratory is developing a suit of projects that address energy and water resources used for thermoelectric power generation. A number of collaborative projects are underway that address alternative sources of water with potential for power plant cooling in water-stressed regions of the United States. In some regions of the country, saline aquifers have the potential to provide alternative supplies to supplement the growing water needs for all types of uses.[1] At the same time, saline aquifer formations have captured the attention of carbon sequestration researchers, including those who developed the Carbon Sequestration Atlas of the United States and Canada (NETL, 2007). A better understanding is needed of the saline water resources when considering them for both purposes. Injecting CO_2 into an aquifer may pressurize the aquifer and potentially alter formation properties and/or induce leakage. Synchronous pumping of groundwater water and so relieving overpressure could become a potential solution, while at the same time providing a valuable resource if this water could be treated and made available for use in a power plant for cooling purposes.

Three key areas of analysis were developed to address this multidisciplinary issue; a geotechnical assessment (geochemical and subsurface geomodeling), a suite of water treatment options, and a systems-level analysis to bring together the physical and economic considerations throughout the geo- and power plant-system. One geotechnical question is whether the injected CO_2 will change the chemistry of the water to the point that it affects the economic viability of water treatment options. A critical issue throughout the study is to ensure the CO_2 will not be released once it is sequestered. A second issue to be examined is how the carbon sequestration system may be managed to minimize potential deleterious effects on the aquifer or reservoir itself. Additionally, several water treatment and desalination issues need to be addressed as they relate to the quality of the treatment concentrate and disposal options. Each of these three areas of interest must be adequately addressed and integrated to determine the relative cost-effectiveness of using saline waters in power plant systems.

2. Modeling Impacts of Underground CO_2 Sequestration in San Juan Basin Aquifers

How can planners co-locate coal-fired power plants in the Southwest (USA) in such a way to both develop underground CO_2 sequestration while simultaneously making use of the region's limited groundwater resources? The first part of this study was to identify appropriate aquifers to address this question for the energy-rich San Juan Basin of northwest New Mexico. Suitable formations in the region have been identified as those close to the San Juan Generating Station, about ten miles west of the town of Farmington, NM (e.g., Allis et al., 2003, NatCarb, 2007).

The next step involved evaluating whether injecting CO_2 into representative formations would initiate deleterious chemical changes. Time frames of interest for the geochemical modeling range from around 100 years for activities related to current power production technologies; out to 350 years, after which the build up of atmospheric CO_2 may no longer be a as significant an issue (e.g., the air-sea-earth system will have equilibrated to the present CO_2 levels). A vast body of literature has been developed to address chemical consequences, however, these studies typically deal with time spans of many millennia, and not the sort term changes of interest to this study (see Pruss et al., 2003; and Xu et al., 2003; 2004; 2005; 2007).

For this study, geochemical changes were calculated using REACT (Bethke, 1998). The program calculates a combination of minerals that would equilibrate with a specific mix of groundwater (plus CO_2 in this case) and minerals when the components are reacted in a closed container (a “box model”).

2.1. Identification of Potential Host Formations

The San Juan Basin contains numerous wells for hydrocarbon production, providing evidence for the existence of adequate underground permeability (Craigg, 2000). The youngest rocks in Northwest New Mexico are a thick deposit of several thousand feet thick of Tertiary sandstones and shales filling the central and eastern part of the San Juan basin which overlie thousands of feet of transgressive and regressive Cretaceous marine clastics, which in turn overly nonmarine Jurassic lacustrine, fluvial, eolian and deltaic deposits. These include the sandstones, conglomerates and shales of the Morrison Formation (Fm.). These in turn overlie the Permian Hermosa shallow water limestones and other marine sediments.

The power plant site sits on the western margin of the basin. East of the site, the basin deepens so rapidly that younger rocks (Jurassic & Cretaceous) become potentially attractive sequestration targets. West of the site the younger rocks were eroded away when the early Rocky Mountains formed, and the remaining Cretaceous is less than 1000 feet thick. Thus, to the west it is older Paleozoic rocks, such as the Hermosa, which are found at depths attractive for CO_2 sequestration. With this general geologic picture in mind, the “NatCarb” database (NatCarb, 2007) was queried to find wells that were deeper than 2500 feet, within ~35 miles of the site, and which had salinities less than 15,000 TDS (so that desalinization could be carried out economically). Table 1 presents water chemistries from wells which met these criteria. Values for several trace constituents - K^+ (10 ppm), SiO_2(aq) (6 ppm), Al^{+++} (0.005 ppm), and Fe^{+++} (0.0005 ppm) were included to initiate modeling but did not influence conclusions of this study.

Table 1. Selected Formation Water Chemistries

Formation/Water Source	**TDS (ppm)**	**pH**	**Na (ppm)**	**Ca (ppm)**	**Mg (ppm)**	**Cl (ppm)**	**SO_4 (ppm)**	**HCO_3 (ppm)**
FRUITLAND	13,602	8.4	4,050	44	27	1,460	5.6	8,015
MESAVERDE/POINT LOOKOUT	4,447	7.9	1,572	87	28	2,500	4.2	256
GALLUP - SS/ in Mancos	9,145	8.4	3,378	8	7	4,060	7.7	1,684
DAKOTA	2,083	8.6	741	16	10	356	1.4	959
MORRISON	5,947	7.9	1,491	313	49	58	3,764	272
HERMOSA/PARADOX	4,213	8.0	2,654	368	49	425	9.0	708

2.2. Selection of the Morrison

Although individual well data revealed several possibilities (Table 1), the Morrison Fm. has already been recognized as having potential for CO_2 sequestration, (Stone, 2002, TBEG, 2008). Additionally, the Morrison Fm. is sufficiently buried so that much of the brackish water resource lies below the 2500 foot depth limit. Geographically, the sufficiently deep sections of the Morrison Fm. underlies much of the San Juan Basin, including locations closer to the Fruitland formation coal mines which power the existing power plants, which increases its suitably as a sequestration target.

2.3. Geochemical Modeling

Modeling impacts of CO_2 injection requires a quantitative description of groundwater chemistry (Table 1), formation mineralogy (Table 2) and in some cases rates of mineral reactions (Table 3). Although the current study deals with the Morrison Fm., due diligence dictates that other aquifers should also be modeled in order to assess if conclusions for the Morrison were highly sight-specific or of general validity. Models were set up with 1 kg of rock (proportioned among the various appropriate minerals for that formation -Table 2) would react with one liter of brackish water for that formation (Table 1) plus 125 grams of CO_2. The amount of CO_2 was chosen so that pressure would be in the range for compatible pumping of CO_2 as a high-density fluid. The simplest approach is to model equilibration between CO_2, aqueous solution and the mineral assemblage. However, it is more realistic to 'suppress' the appearance of minerals that are unlikely to appear in the time frame of interest (~ 100 - 350 years) to account for sluggish silicate mineral- water reaction kinetics. Reaction kinetics of feldspars, quartz, clay minerals and some carbonate minerals are explicitly accounted for in some modeling runs. Calcite, sulfates and simple hydroxides are taken to react so rapidly that they equilibrate immediately with brines.

Table 2. Proportions of different minerals in modeled formations

Mineral	**% in Fruitland**	**% in Dakota Mesa Verde Mancos**	**% in Morrison**	**% in Hermosa (sandy units)**
Quartz SiO_2	55%	70 % (Balance)	60% (Balance)	35% (Balance)
K-Feldspar $KAlSi_3O_8$	5%	0	5%	5%
Albite (Na-Feldspar) $NaAlSi_3O_8$	5%	0	5%	0
Calcite $CaCO_3$	5% as cement	5% (as cement)	5% (as cement)	30%
Dolomite $CaMg(CO_3)_2$	0	0	0	5%
Illite $K_{0.6}Mg_{0.25}Al_{2.3}Si_{3.5}O_{10}(OH)_2$	10%	5%	5%	10%
Chlorite ("Ripidolit-14A") $Fe_2Mg_3Al_2Si_3O_{10}(OH)_8$	0	0	5%	5%
Low-Fe-Mg Smectite $Na_{0.15}Ca_{0.02}K_{0.2}Mg_{0.9}Fe_{0.45}Al_{1.25}Si_{3.75}O_{10}(OH)_2$	5%	5%	5%	0
Kaolinite $Al_2Si_2O_5(OH)_4$	10%	15%	10%	10%
Siderite $FeCO_3$	5%	0	0	0

For the Morrison (as well as the other formations) the modeling evaluated five water chemistries (Table 4), and four mineralogic profiles (Table 5) that would be 'observed' after the systems had been allowed to react for various amounts of time. The five water chemistries are:

1. Water chemistry and mineralogy resulting when initial formation water (Table 1) is allowed to equilibrate with minerals presumed to be in that formation. This serves as a check that brackish water is not grossly out of equilibrium with the formation mineralogy before addition of carbon dioxide, with small changes from initial mineral amounts (Table 4,Column 2; Table 5, Column 2).
2. Water chemistry which results solely from aqueous reactions when carbon dioxide is added to initial fluid; (Table 4, Column 3).
3. Water chemistry and formation mineralogy resulting after 100 years of contact time (Table 4, Column 4; Table 5, Column 3).
4. Water chemistry and formation mineralogy resulting after 350 years of contact time (Table 4, Column 5; Table 5, Column 4).
5. Water chemistry and formation mineralogy after long times, upon equilibration between minerals and carbonated solutions (Table 4, Column 6; Table 5, Column 5).

Table 3. Kinetic parameters (*) used in modeling rock – carbonated brine interactions.

Mineral	**Rate - moles per cm^2 per second**	**Surface Area - cm^2 per gram**
Quartz	**1.26×10^{-18}**	**37**
K-feldspar	**1.00×10^{-16}**	**100**
Calcite	**1.60×10^{-13}**	**2,000**
Kaolinite	**1.00×10^{-17}**	**5,000**
Illite	**1.00×10^{-18}**	**5,000**
Ripidolit-14A	**1.00×10^{-17}**	**1,000**
Dolomite (Disordered)	**1.60×10^{-13}**	**2,000**
Smectite-low-Fe-Mg	**1.00×10^{-18}**	**10,000**
Albite	**1.00×10^{-16}**	**50**

***** Most rate constants and specific surface areas in Table 3 came from recent Lawrence Berkeley National Laboratory (LBL) publications: (Pruss et al., 2003 and Xu et al., 2003, 2004, 2005, 2007).

Table 4. Morrison Water Chemistry, Changes in groundwater chemistry and mineralogy with CO_2 injection

All values in parts per million	Test Water Equilibrates with rock no CO_2	Test Water plus CO_2 - no rock	Test Water plus CO_2 and rock for 100 years	Test Water plus CO_2 and rock for 350 years	Test Water equilibrates fully with CO_2 and rock
Aluminum	0.061	0.004	0.008	0.007	0.004
Calcium	10.5	278	1,767	1,609	404
Carbon	32	30,210	30,700	30,510	22,220
Chlorine	70.8	63.0	62.8	62.8	65.1
Iron	0.003	0.000	29.7	27.1	7.3
Magnesium	5.8	43.6	178	505	786
Potassium	2.6	8.9	77	173	5,845
Silicon	3.2	2.4	21.8	21.7	2.4
Sodium	1,516	1,326	1,343	1,393	194.2
Sulfate	2,995	3,351	2,096	2,660	963
pH	8.70	3.49	4.84	4.88	5.31

Table 5. Morrison Formation, mineralogy after modeled reaction scenarios.

	grams at start of calculation	grams after 100 years	grams after 350 years	grams after full equilibration
Reactants	**remaining**			
Albite	45	45	44	0.0
Calcite	45	39	40	13.2
Illite	45	45	44	0.0
K-feldspar	45	45	44	20.5
Kaolinite	90	91	93	158
Quartz	540	540	540	619
Ripidolit-14A	45	44	42	0.0
Smectite-low-Fe-	45	44	43	0.0
New Minerals	N/A			
Siderite	N/A	0.34	1.36	20.7
Goethite	N/A	0.022	0.077	1.63
Dolomite-disordered	N/A	0	0	58.5
Dawsonite	N/A	0	0	35.3
Alunite	N/A	0	0	5.97
Clinoptil-Ca	N/A	1.00	3.20	0.00
Gypsum	N/A	2.53	0	0.00

2.4. Summary of Geochemical Modeling Results

Short term changes for the Morrison mineralogy are not large and represent a net loss of solids (several grams in 1 kg of total initial rock mass). Calcite dissolution is typically the most pronounced change and can result in calcium sulfate (“gypsum”) precipitation, along with a smaller amount of a calcium zeolite known as clinoptilolite. The silica and aluminum for this reaction come from dissolution of feldspars and clays, which also slightly elevates concentrations of Mg, K and Fe and raises pH from 3.5 to about 4.9.

In contrast, if the CO_2-enriched fluids and formation minerals fully equilibrate (on the order of thousands of years), extensive water-mineral reactions are anticipated. Amounts of quartz and kaolinite increase, while other primary minerals are much diminished. In their place substantial amounts of siderite [$FeCO_3$], disordered dolomite [$CaMg\ (CO_3)_2$] and dawsonite [NaAl CO_3 (OH)2] appear – all of which can sequester carbon dioxide. Relative to the initial water chemistry the greatest changes are elevated potassium and magnesium and lower sodium (with dawsonite formation) and sulfate (with alunite, [$KAl_3(SO4)_2(OH)_6$] precipitation).

With regard to the broader modeling effort that evaluated all six formations (Table 1), the most rapid reactions will always be those involving carbonate minerals (calcite >> dolomite (disordered) and siderite), resulting in small increases in formation porosity (and presumably permeability). Changes in total dissolved solids are typically small so that desalinization needs would not differ significantly from what would already be needed to treat the *in situ* brackish waters. A caveat here would be a situation where circulating fluids might come in contact with clay minerals and participate in a calcium-for-sodium ion exchange process. This, in turn could lead elevated sodium concentrations *and* calcite dissolution.

There are potential concerns when using these brines which include the possibility of sulfate, iron, and silica mineral scale-up during desalinization. Another limiting factor is that, as little appreciable mineral sequestration is predicted to occur on the century time-scale (due in large part to sluggish silicate-water reaction kinetics), any activity which transports CO_2-bearing brines back to the surface in this time scale would release CO_2 content back into the atmosphere, defeating the original purpose. Over the long term (thousands of years) sequestration purposes, substantial volumes of CO_2 can be sequestered in mineral forms in formations with abundant sources of aluminum and iron. As a result, formations such as the Morrison (with appreciable clays and feldspars) could be the better choice for long term CO_2 sequestration than higher porosity and permeability "clean" quartzose sandstones.

2.5. Hydrogeological Modeling of CO_2 injection

One method used to assess the feasibility of subsurface storage of carbon is numerical reservoir simulation. In this analysis, the TOUGH2 reservoir simulator (Pruess et al., 1999) with the recently developed ECO2N equation of state for CO2-brine-salt multiphase system (Pruess, 2005), is used to constrain carbon sequestration in tandem with coal-fired power plants like the SJGS in the northern San Juan Basin of New Mexico. The analysis focuses on the Morrison Fm. Case suggested by the chemical modeling and is limited to the first 30 years of injection.

2.6. Geologic Framework (Earth) Model

A first step in the development of a numerical sequestration simulator for the SJGS is to create a geologic framework, or earth, model, to represent the relevant rock strata in the subsurface. Stone and Mizell (1978) compile petroleum well log data in the San Juan Basin, for the purpose of modeling groundwater flow. Formation boundary locations from well log data are combined in a three dimensional earth model using the C-Tech MVS^{TM} software. Point data are 'kriged' to create boundary surfaces which constrain formation geometries. Figure 1 depicts well locations and a NS cross section produced from kriging formation boundaries from well logs given in Stone and Mizell (1978). The layered sequence is discretized into blocks for use with the TOUGH2 reservoir simulator. We examine a north-south oriented simulation domain here as it follows the regional structural trend of extension fractures in this portion of the San Juan Basin (Lorentz and Cooper, 2003) and thus the trend of highest hydraulic conductivity.

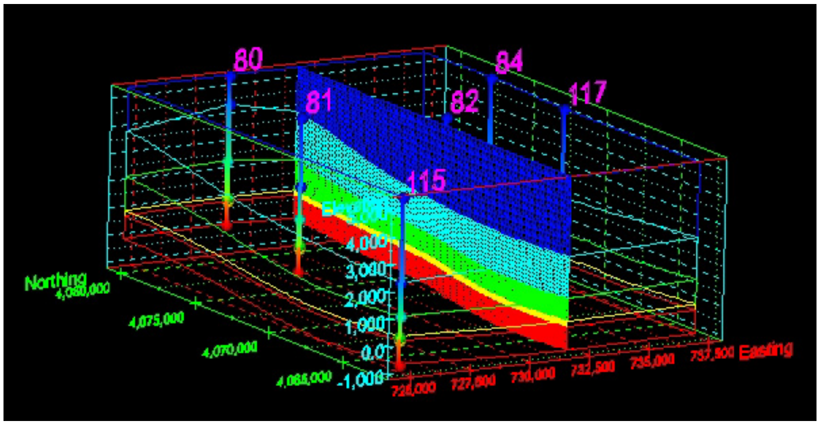
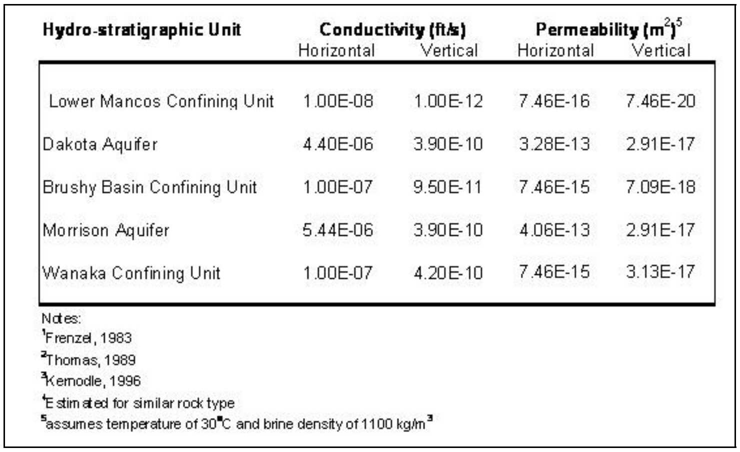


Figure 1. Locations of petroleum wells and formation tops used to construct the "shallow Morrison" geologic framework model. Shown also is a North-South cross section used to derive the finite difference grid for the reservoir simulations of CO_2 injection into the Morrison Fm. Vertical exaggeration is 5X. Coordinate grid is UTM NAD27 Zone 12. (Red depicts Morrison; Yellow is Dakota/Burro Canyon; Green is the Niobrara; Light Blue is the remaining Mancos, and Darker Blue represents the remaining Cretaceous and Tertiary overburden).

2.7. Hydrogeologic Model

For assessing the spatial and temporal dynamics of the shallow Morrison system, the analysis must adequately capture the hydrogeologic properties of the SJGS subsurface. Hydro-stratigraphic units of Thomas (1989) are used in this study, shown in the right column of Table 5 below. These include the lower Wanakah confining layer, the so-called Morrison aquifer (Recapture and Westwater Canyon members), the Brushy Basin confining unit, the overlying Dakota aquifer, and the lower Mancos confining unit (also known regionally as the Niobrara Group). Lithologically, the aquifers are interbedded sands, muds and shales, while the confining units are mostly mudstones and shales. Permeability values listed in Table 5 and used in the reservoir simulations were determined by the cited authors by calibrating groundwater models against available well and recharge data.

Table 5. Hydrologic stratigraphic units, hydraulic conductivities, and absolute permeabilities used in TOUGH2 model for CO2 injection into the Morrison Aquifer.



Hydro-stratigraphic Unit	**Conductivity (ft/s)**		**Permeability (m^2)^5**	
	Horizontal	Vertical	Horizontal	Vertical
Lower Mancos Confining Unit	1.00E-08	1.00E-12	7.46E-16	7.46E-20
Dakota Aquifer	4.40E-06	3.90E-10	3.28E-13	2.91E-17
Brushy Basin Confining Unit	1.00E-07	9.50E-11	7.46E-15	7.09E-18
Morrison Aquifer	5.44E-06	3.90E-10	4.06E-13	2.91E-17
Wanaka Confining Unit	1.00E-07	4.20E-10	7.46E-15	3.13E-17

Notes:
[1] Frenzel, 1983
[2] Thomas, 1989
[3] Kernodle, 1996
[4] Estimated for similar rock type
[5] assumes temperature of 30°C and brine density of 1100 kg/m^3

2.8. Modeling CO_2 Sequestration with TOUGH2

To model CO_2 injection, migration, and phase partitioning with the TOUGH2 reservoir simulator, we require parameters for the multiphase flow properties, porosities, and densities for the hydrogeologic layers. Briefly, the analysis used a porosity of 13% for the Morrison Formation; other parameters to describe multiphase flow in clastic sands, mudstones and shales were taken from Pruess (2005). The modeling activities includes developing a simulation mesh to consist of a coarse 500 meter-spaced grid with a finer grid (progressively down to 1 m spacing) surrounding an injection well centered at 407500 meters Northing and 73250 Easting, roughly corresponding to the location of the SJGS. Vertical grid resolution was taken to be one layer of 50 meters to represent the bottom of the Mancos Fm, one layer of variable thickness (~50 m) to represent the Dakota Fm, one layer (~50 m) to represent the Brushy Basin Member of the Morrison Fm, 4 consecutive layers of 50 meters each to represent the upper Westwater Canyon Member of the Morrison Fm Aquifer, followed by three layers of 40, 9, and 1 meters respectively, to represent the bottom of the Morrison Aquifer. The bottom 4 layers in the Morrison Aquifer were determined thusly to allow injection horizons of 1, 10, or 100 meters.

2.9. Simulation Results

Using the earth-model derived mesh, we have run simulations of CO_2 injection into the Morrison Aquifer beneath the SJGS, varying injection rate in order to obtain estimates of migration distances, pore pressure generation, phase partitioning, and gas saturations. In Figure 2, gas saturations are plotted as a function of time for a model simulation of CO_2 injection within a 1-meter horizon at the base of the Morrison Aquifer. The injection rate was taken to be 0.317 kg/s. The plume of CO_2 spreads with time, showing minimal effect of the southerly dips of the layers in the plane of the cross section. The grid is shown by the blue-background figure at the top of Figure 2.

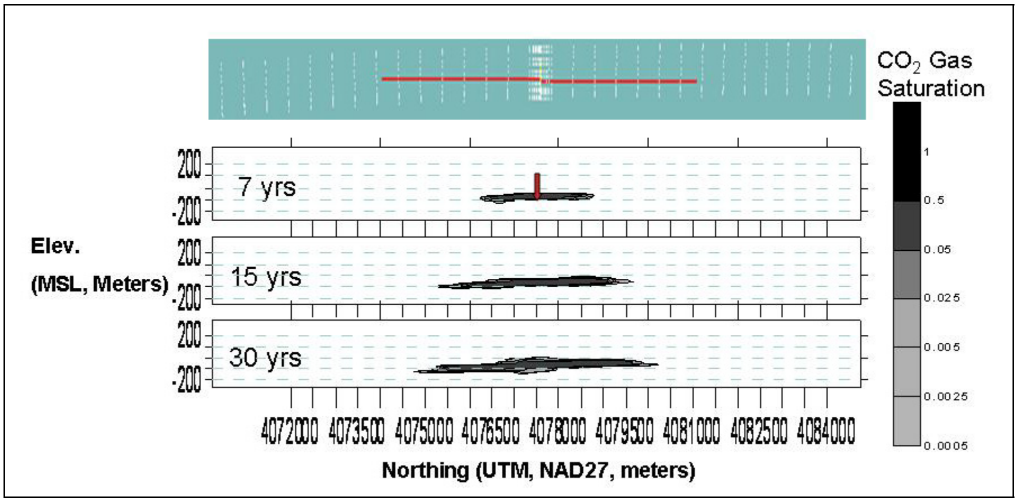


Figure 2. Simulations of CO_2 gas migration following injection (red arrow) at 7, 15, and 30 years.

Figure 3 shows a modest over-pressure of a few megapascals (MPa) being generated at the injection horizon during the TOUGH2 simulation after 30 years, shown by the blue points lying against a hypothetical hydrostatic pore pressure gradient of 10 MPa/km, typical for the average pore solution densities in this area. This is compared to profiles of vertical and maximum horizontal stresses for the San Juan Basin (calculated assuming a 222 kg/m^3 average wetted bulk density and a maximum horizontal to vertical stress of 0.7 typical for the San Juan Basin) plotted in Figure 3. Also plotted by the thin line is the critical pore pressure necessary to open shear fractures at this depth in the Morrison, taken from a simple Mohr-Coulomb failure criteria with an internal friction angle of 30^o. The generated excess pore pressures from injection are too small to cause shear fracture initiation, which would occur at an induced pore pressure of about 20 MPa at this depth, and are far too small to cause hydrofracturing. If hydrofracturing were anticipated, this would be of concern, as generated hydrofractures would likely be vertically oriented at this location (i.e., perpendicular to the least horizontal principal stress) and could propagate up to reach the overlying confining layer, possibly adversely affecting cap rock integrity.

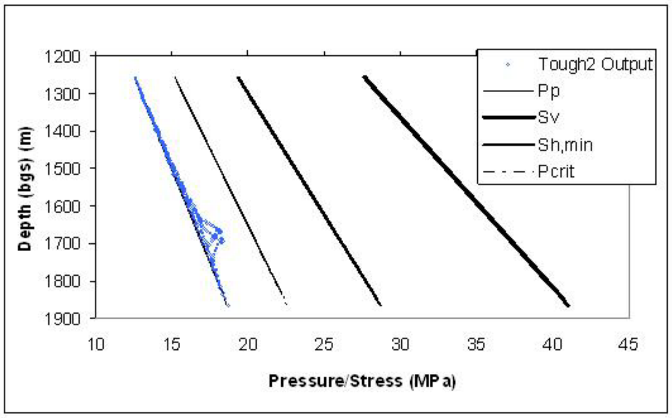


Figure 3. Induced pore pressure (blue dots) from TOUGH2 simulation of Fig. 2 plotted as a function of depth below ground surface, as compared to critical pore pressure for shear failure (thin black line), minimum horizontal stress (slightly thicker black line), and vertical stress (thickest black line).

2.10. Plume Migration, Injection Rates, and Aquifer Storage

Plume Migration

Plume migration distances, correlating to breakthrough times in water production wells, can be determined from sets of numerical experiments discussed above, with varying injection rates and lengths of wellbore perforated intervals. For the Morrison example, the formation dip yields only a slight influence on migration (i.e., only a little more CO_2 migrates in the up-dip direction than down), so the analysis will neglect the effect of formation dip on migration distances at this time. This effect does become more pronounced as injection rates increase. Figure 4 shows migration distances as a function of time (up to 30 years of migration) for the shallow Morrison case. At small injection rates, distances increase roughly linearly with time, but as injection rates increase, the behavior is more parabolic (shown by the cubic curve fits in the figure). In part this is due to a greater residual saturation seen in the Morrison at the higher injection rates, but also is due to some CO_2 migrating into the lower Wanakah Formation.

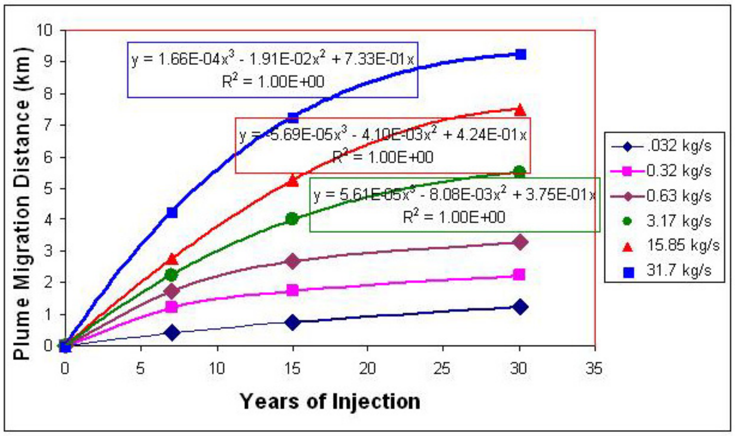


Figure 4. CO_2 gas migration distance as a function of injection time.

Injection Rates

The above simulation results suggest that minimal overpressure might result from CO_2 injection at reasonable rates. To explore the bounds on injection rates with regard to geomechanical and other considerations, numerical experiments designed to examine near well-bore pressure as a function of injection rates were run using a 3D radial injection scenario taken from an example in Pruess (2005), using Morrison-constrained parameters. Although not shown here, the simulations suggest that an injection rate of approximately 200 kg/s (~17,280 tonnes/day) should be used as a cap on the injection rate in order to not cause near wellbore damage from induced shear fracturing.

Considerations of wellbore integrity and stability are an issue with safe injection pressures. Ogden (2002), quoting Hendricks (1994), gives a practical upper limit on safe injection rates per well as 2,500 tonnes per day (~29 kg/s), limited by the friction induced by flow in the wellbore, and other pipe-flow physical constraints. For a 100m injection interval and using Morrison Formation parameters, this would translate to a bottom hole flowing pressure of at most a few MPa for virtually all depths of interest. Thus the wellbore flow physics and current wellbore design constraints limit the maximum available injection rate for CO_2 into the Morrison, not geomechanical considerations. For comparison, Sleipner-magnitude rates are approximately 32 kg/s (Bickle et al., 2007).

CO_2 Mass Storage Capacity for the "Shallow" Morrison Case

Conservation of mass considerations show that CO_2 storage in a volume of reservoir filling with a pancake-like CO_2 plume geometry with thickness t_f and radius L, can be expressed as

$$M_{total} = \phi(S_g \rho_g + S_w \rho_w X_{CO2(aq)})\pi L^2 t_f$$

where ϕ is average porosity, S_g is average gas saturation, $X_{CO2(aq)}$ is average mass fraction of CO_2 in aqueous solution, ρ is density of CO_2 gas (g) or brine solution (w) at formation conditions (we ignore mineral sequestration for the short simulation time scales). Plotting the total amount of CO_2 stored in the simulated aquifer as a function of the square of the migration distance (Figure 5) suggests a linear relationship between total CO_2 storage and square of the migration distance, as in the equation. The size of the Morrison formation, injection rate, and potential 30 year plume migration parameters are used in the system dynamics assessment model.

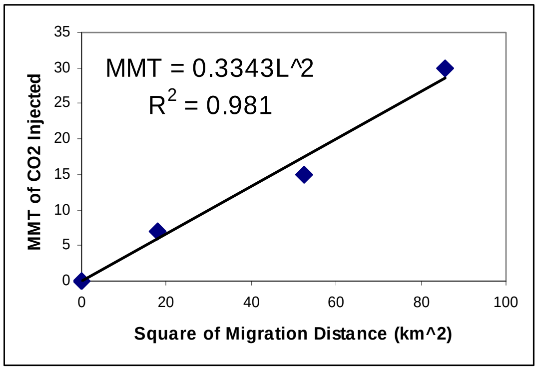


Figure 5. Total mass of carbon dioxide stored in the Morrison Aquifer plotted as a function of plume migration distance.

3. Evaluating Water Treatment Technologies to Treat Saline Water for Power Plant Use

Water supply availability throughout the United States may become a central issue when considering expanded power demands requiring already stressed supplies. A key to alleviating potential competition for water sources is to further refine the paring of water sources with the specific type of demand. Power plants, for example, may have the financial and other resources required to treat saline water from geological aquifers thereby supplementing their current water resources. Population growth, drought, power generating technologies, carbon dioxide capture systems and water desalination technologies may all be extremely region-specific. It is the confluence of these factors, however, that will determine the relative water stress due to water supply and demand imbalances.

3.1. Freshwater Needs for Thermoelectric Power Plants and Carbon Capture Technology

As the demand for electricity increases, water consumption by thermoelectric power plants will likely increase. Thermoelectric power plants utilize water for cooling steam and account for 39% of the freshwater withdrawals and 3.3% of the freshwater consumption in the US (DOE/NETL, 2007a; 2007b). Additionally, carbon capture and sequestration (CCS) technologies were shown to increase water consumption by up to 100% and decrease overall electrical generation efficiency by approximately 32% (DOE/NETL, 2007a).

3.2. Summary of San Juan Generating Station Water Consumption & Non-Fresh Water Applicability

The total net summer electrical capacity in the state of New Mexico is 7,102 MW (EIA, 2006). For context, the San Juan Generating Station's (SJGS) total generating capacity of 1,848 MW represents approximately 25% of this total. The SJGS consumes 22,400 acre-ft/year, primarily for its cooling towers (NETL/EPRI Report, 2006). The New Mexico-based utility company PNM anticipates an increase in its electrical demand 50–75 MW/year over the next ten years. Following current design practices, this growth may require an additional 600–9,300 acre-ft/year of fresh water for the power station.

The majority (90%) of the water consumption at the SJGS is used to supply the cooling towers. The San Juan River is the primary water source, which like other surface waters, is low in total dissolved solids (TDS). The cooling towers at the SJGS operate at approximately 10 cycles of concentration (water is recirculated up to ten times in the cooling towers) prior to being 'blown down'. The 'blow down' water is treated (distilled by brine concentrators) and reused throughout the SJGS plant.

Expansion at the SJGS (and other power plants) will require additional water if wet cooling towers are to be used, whereas non-fresh water will require desalination before using it in the SJGS. This may increase the amount of flow to evaporation ponds. Dry cooling towers could be employed, however, there is an energy penalty as well as the potential for operational problems.

3.3. Cooling Tower Water Chemistry Recommendations

The water used in cooling tower water chemistry is an important factor in power plant design. Limits on the use of the waste water are based on the metallurgy of the piping system, materials of construction of the cooling tower itself, and regulations. Many alternative sources of water (brackish, produced water, waste water) will have elevated levels of chloride and other problematic constituents such as organic constituents, calcium and silica. Waters with a higher TDS count may require different and likely more expensive operating and maintenance (O&M) costs, but they offer the possibility of extending plant life in water-stressed regions.

3.4. San Juan Generating Station Produced Water Study

A detailed study by NETL/EPRI examined the potential of the SJGS to used produced water from the oil and gas industry. In this study, 'Option 10' was determined to be the most feasible, in terms of economics, and for its ability to minimize additional evaporation pond construction. For the purposes of the dynamic simulation assessment model, the analysis employs the High Efficiency Reverse Osmosis (HERO) process for desalination. The capital and annual operating costs for desalination alone (without including any gathering costs) were estimated to be $14.1 million and $2.98 million, respectively. This option would recover 1,255 gpm (approximately 2,000 AF/yr). Using this option results in a treatment cost of $4.52 per 1,000 gallons of recovered water.

3.5. Using Brackish Groundwater Aquifer for CO_2 Sequestration Activities

There is some debate over how CO_2 injection will be regulated by either state and/or federal authorities. Current regulations in the Underground Injection Control (UIC) program are set up to protect drinking water sources. These are defined as brackish waters with a TDS level below 10,000 mg/L. In July 2008, EPA published the Federal Requirements Under the UIC Program for CO_2 Geologic Sequestration Wells Proposed Rule for public review and comment. For the analysis presented here, the initial work begins with a TDS level less than this 10,000 mg/L limit for the purposes of the Morrison formation example. This formation was chosen for the initial analysis due to its location and the amount of information already available. Having this information allowed the analytical framework to determine which parameters were applicable to the analysis. Ongoing work within this project will look at additional formations and locations with TDS levels greater than the 10,000 mg/L limit.

3.6. New Water Formation Chemistry for Cooling Tower Make-up

The initial findings indicate that none of the available brackish waters in this study’s region could be used economically in their raw state (without treatment) for cooling tower make-up. This is primarily due to the fact that cooling tower systems require chlorides to be below 1,000 mg/L. Even if one were to replace the cooling system with a system that could work with higher chloride waters, there would be a substantial increase in the amount of evaporation ponds or other process equipment required to maintain a zero liquid discharge facility.

3.7. Summary of Desalination Options Studies for the Model

Once the potential aquifers had been studied for their geochemical properties and water quality restrictions were known, several desalination (reverse osmosis) options were studied using a simple spreadsheet analysis. The options studied were:

Option A: No concentrate disposal
Option B: 59.5 acre evaporation ponds for concentrate disposal
Option C: 3,000 ft injection pipeline & well for concentrate disposal
Option D: HERO+Brine concentrator retrofit

These options are shown schematically in Figure 6. Each of the options studied required calculations for the capital and O&M costs. Most of the calculations are based on the USBR Desalting Handbook (USBR, 2003). Similar to the NETL/EPRI 2006 report, it was determined that the best option for the SJGS would be Option D.

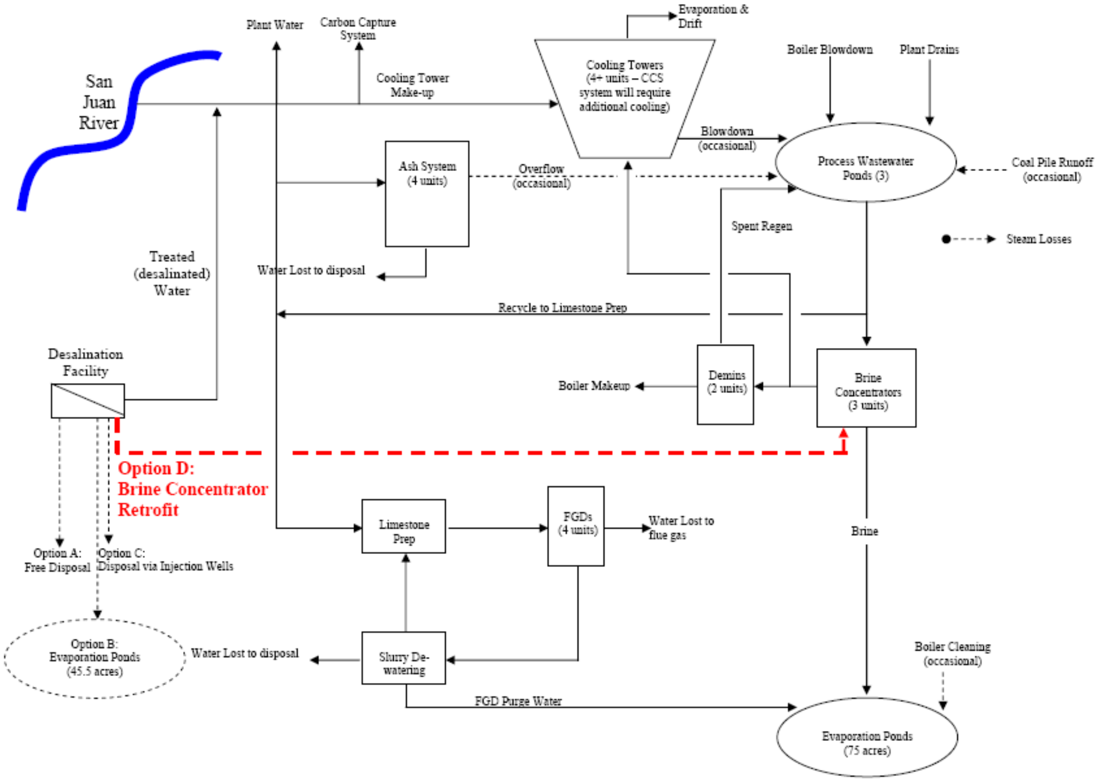


Figure 6. San Juan Generating Station Simplified Water Flow Diagram. (Adapted from the NETL/EPRI 2006 report).

The base case costs are given in Table 7. This list of costs is for a 1.3 million gallon per day (MGD) desalination facility and compares each of the treatment options considered. The total cost of Option D (including desalination facility and brackish water gathering) is $5.31 per 1,000 gallons of treated water; the cost of desalination alone is $2.72 per 1,000 gallons of treated water.

Table 7. Summary of Desalination Costs – Base Case

	Option A	Option B	Option C	Option D
Total Cost of Treatment				
Annualized Total Capital	$ 2.90	$ 5.05	$ 3.23	$ 2.59
Annual O&M	$ 2.16	$ 2.19	$ 2.17	$ 2.73
Total Cost (O&M+cap)	**$ 5.06**	**$ 7.24**	**$ 5.39**	**$ 5.31**
Cost of Desalination only (i.e. no ponds, no GW pumping)				
Annualized Total Capital	$ 1.59	$ 1.59	$ 1.59	$ 1.28
Annual O&M	$ 1.19	$ 1.19	$ 1.19	$ 1.43
Total Cost (O&M+cap)	**$ 2.78**	**$ 2.78**	**$ 2.78**	**$ 2.72**

4. Regional Assessment Framework: Systems Analysis Capability and Framework

The goal of the regional assessment is to illustrate the high-level issues associated with the suite of technologies applied to an existing power plant for both carbon sequestration and using brackish water from a saline aquifer. This assessment builds from the geochemical/hydrogeological modeling, and water treatment analyses to develop a systems model for scenario mapping.

The analysis first assesses the geologic carbon sequestration information applied to a modest sized power generating station, such as the San Juan Generating Station in New Mexico. From there, analysis includes CO_2 sequestration systems into a saline aquifer combined with a water utilization system to exploit the potential extracted brackish water. Conceptually, this system may be relatively straightforward. However, beginning with this concept and then moving to a rudimentary analysis, and then on to an increasingly detailed study hinges on several key engineering, geological and economic challenges to more adequately address the system's overall feasibility.

To address the feasibility issue, a dynamic simulation model incorporates the stocks and flows associated with this system (e.g., electricity production, CO_2 flows, water flows and treatment costs, etc.) and the economics associated with these components. This model allows interested parties the ability to perform 'what if' scenario analyses in real time. For example, the model can address the question, 'What if the level of CO_2 capture increases from 50% to 90%? What will the electricity costs look like?' Similar scenario questions can be addressed for different power plant configurations, geological formations used for CO_2 sequestration, and brackish water pumping treatment technologies. Figure 7 illustrates the foundation for the analysis, which continues to develop more refined characteristics and assumptions used for the power plant, carbon sequestration, geological system, and brackish water extraction and treatment systems.

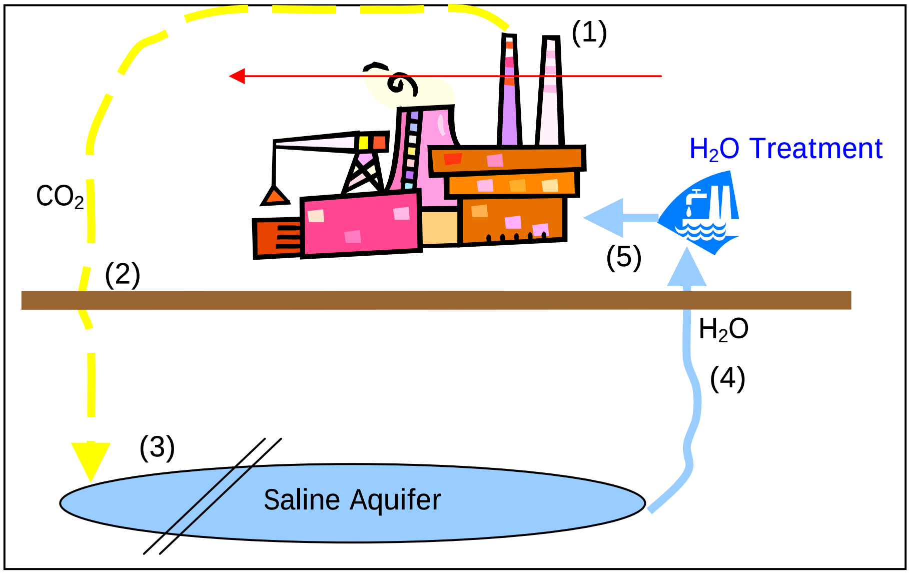


Figure 7. Conceptual Design of a Combined Power Plant with Carbon Dioxide Sequestration while Using Water from a Saline Aquifer.

Figure 7 illustrates each facet of the combined power/water/CO_2 sequestration/water treatment and use system using a number designation for general subsystems of the analysis. The following descriptions explain how the dynamic simulation model incorporates these components, and describes the potential next steps to further refine the assessment model.

4.1. Power Plant and Carbon Dioxide Sequestration

Section '(1)' shown in Figure 7 details the power plant and carbon capture and sequestration systems. The study begins with the SJGS near Farmington, NM. This power plant is a coal-fired electricity generating station with four boilers associated with the generators representing a combined 1,848 MW of installed capacity. According to the eGRID database, each of the four boilers (and their respective cooling towers) consumes 0.02 cubic feet of water per kilowatt hour (kWh) per boiler (EPA, 2006). Scaling up to the full plant size, this represents a water consumption rate of around 0.52 gallons/kWh. Additionally, the percent capture level for CO_2 was adopted from existing literature for the 0, 30, 50, 70, and 90% levels of capture (NETL, 2007).[1] Table 8 further illustrates the performance, economic and CO_2 capture metrics associated with different percentage capture levels for CO_2.[2]

Table 8. Performance and Techno-economic metrics associated with capturing and sequestering carbon dioxide for the test case model.

Percent of CO_2 Captured →	**0**	**30**	**50**	**70**	**90**
Power Plant Rating, % Decrease from Base 1,848 MW	0	10.34	19.52	30.17	43.01
Additional costs of electricity (cents/kWh)*	0	3.19	4.52	6.20	7.80
Carbon Dioxide Captured and Sequestered (million metric tonnes, MtC)	0	3.95	6.58	9.22	11.85

* Capture, Piping and Wells costs.

4.2. Hydrological Assumptions

Section '(2)' shown in Figure 7 addresses the high-level geophysical aspects of sequestering CO_2 in a geological formation and the subsequent (assumed) volume of displaced water. The base case of the analysis uses a shallow location in the Morrison formation to illustrate the scale of the sequestration and potential volumes of displaced water. The Morrison formation, as described and highlighted in the geochemical component of this analysis, may be a candidate to sequester CO_2 while at the same time serve as a source of non-traditional brackish waters for power plant cooling.

---

[1] NETL, 2007. Summary metrics adapted from Table ES-1, "Summary of Technical and Economic Performance for Retrofitting a Pulverized Coal-Fired Plant."

The analysis begins by using the hydrostatic pressure assumption calculated using the volumes available within the formation to store CO_2.[3] Thus, every gram of CO_2 injected underground displaces approximately 1.52 cm^3 of water.[2]

4.3. CO_2 Sequestration and Brackish Water Volume Analysis

The potential for CO_2 to displace formation water was developed using the information underlying Figure 3. The methodology uses a CO_2 density-depth relation, e.g. Clark (1966) or Bentham and Kirby (2005). While the pressures involved with this test case framework lie within the supercritical range of the CO_2 density-vapor curve analysis, the dynamic simulation model allows users to adjust the potential density of CO_2 based on attributes of the formation under consideration.

The representative depth for the initial formation location is 1750 meters (~5500 feet), where assuming an initial hydrostatic pressure, this would equate to 170 bars.[4] The working framework calculates that approximately 400 gallons of water may be displaced for every tonne of CO_2 sequestered under these types of conditions. However, number of gallons calculated is highly conditional and site specific to the point that it should be considered a starting point for a more detailed analysis, and ideally, field testing to validate the reliability of this assessment and subsequent relationship over time. In addition, the interactive effects of CO_2 dissolution into the brine may affect both the geochemical aspects of the resource, as well as the potential storage (CO_2) and extracted water volumes.

4.4. Brackish Water Extraction

Section '(4)' of the system's framework calculates the displaced water volumes due to sequestering the CO_2. Under the working assumptions to illustrate the methodology, the Morrison formation may have a theoretical yield of displaced waters on the order of several trillion gallons. This may represent 60+ years' worth of water supply for the San Juan Generating Station at its current rate of consumption. There are, however, substantial technical and economic hurdles that need to be overcome in order to use this water resource in addition to further refining of the assessment framework.

4.5. Water Treatment

Section '(5)' completes the analytical framework by developing the cost to extract and treat brackish water for the San Juan Generating Station. The base case analysis employs option D described in Table 7. Table 9 summarizes these 5 components and their respective working assumptions and results underlying the dynamic simulation model.

---

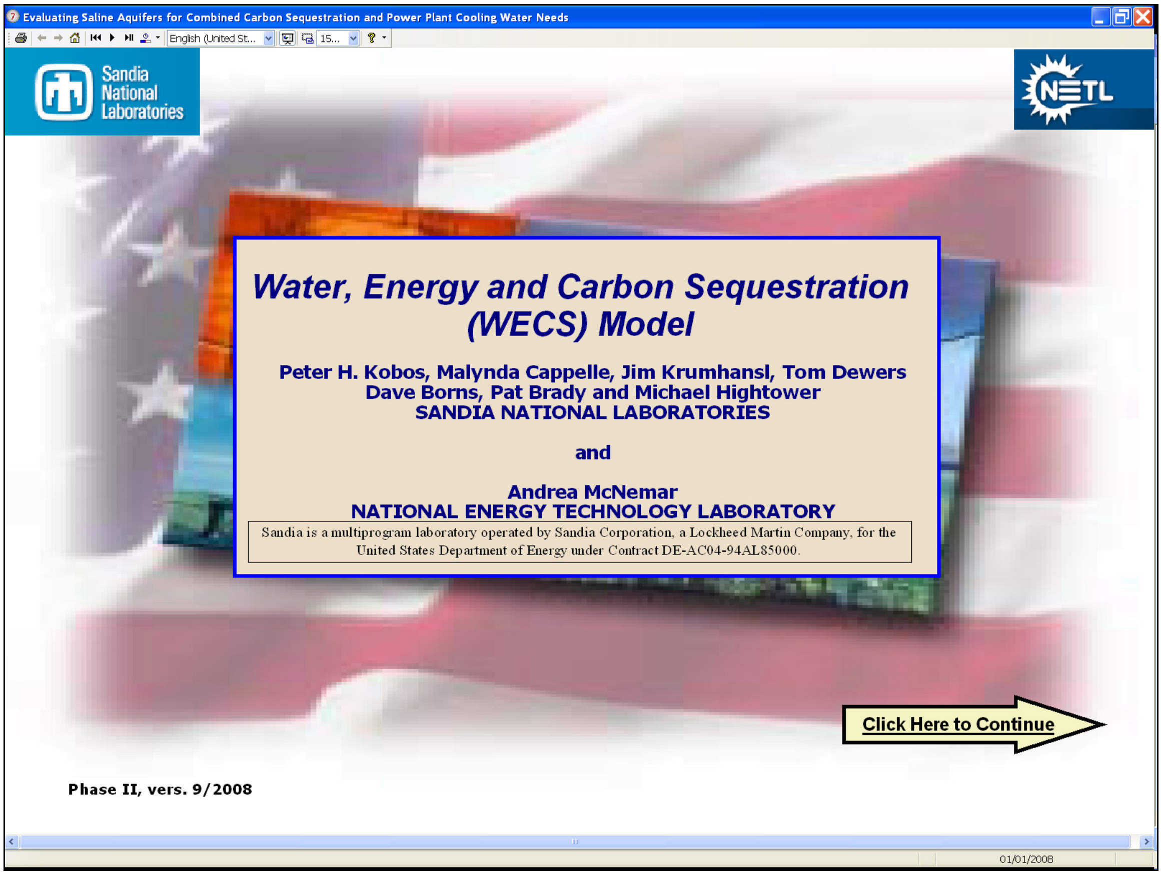
[2] Special thanks to Tom Dewers and Jim Krumhansl for their assistance with the working CO_2 to potential H_2O displacement calculations.

Table 9. Test Case and Working Model Methodology.

Section	**Description**	**Assumption**	**Units**	**Notes**
1	**Power Plant**	1848	MW	San Juan Generating Station
	Capacity Factor	72	%	EPA, 2006 (eGRID)
	Carbon Dioxide Capture	50	%	Adjustable capture %
	CO_2 Emissions	14,512,417.5	tons/year	EPA, 2006 (eGRID)
	CO_2 Sequestered	6,582,722	tonnes/year	tonnes sequestered (or 2,500 tonnes/da maximum per well).
2	**Saline Aquifer Formation**	3,343	mmt	Morrison Formation, CO_2 storage volume, Calculated using TOUGH2. Million metric tonnes.
	Representative Depth	5,700	feet	Calculated using TOUGH2
	Years' worth of CO2 storage capacity	500+	Years	volume / tonnes sequestered
3	**Saline Water displaced**	170	bar	hydrostatic pressure assumption/approximation, TOUGH2 analysis.
	CO_2 displacing H_2O	1.52	Cubic centimeters of H_2O per gram of CO_2	Based on the Density of CO_2 vapor curve and work described in Clark, 1966 and Bentham and Kirby, 2005
4	**H2O displaced and Demand**	402	Billion gallons total	Potential water volume assuming 30% recovery
	Annual H2O displaced	792	Million gallons / year	---
	Power Plant cooling towers' H2O demand	6.4	Billion gallons / year	27.6 ft3/second, EPA, 2006 (eGRID); ~17.8 million gallons/day
	Years' worth of H2O supply	60+	Years	---
5	**Desalination Costs – Base Case**	5.31	$ / thousand gallons	Option D, HERO+BC option (~$6.40 using a ~5,500ft deep well)

Section '(5)' in Figure 7 outlines the desalination technologies used in the base case for the model. These technologies, and their associated costs, are outlined in Table 7. The High Efficiency Reverse Osmosis system with a Brine Concentrator (HERO+BC) system was adopted for the base case. The other technology and cost options for desalination can be introduced and analyzed in the model as well.

4.6. The Water, Energy and Carbon Sequestration (WECS) Model Prototype



Water, Energy and Carbon Sequestration (WECS) Model

Peter H. Kobos, Malynda Cappelle, Jim Krumhansl, Tom Dewers
Dave Borns, Pat Brady and Michael Hightower
SANDIA NATIONAL LABORATORIES

and

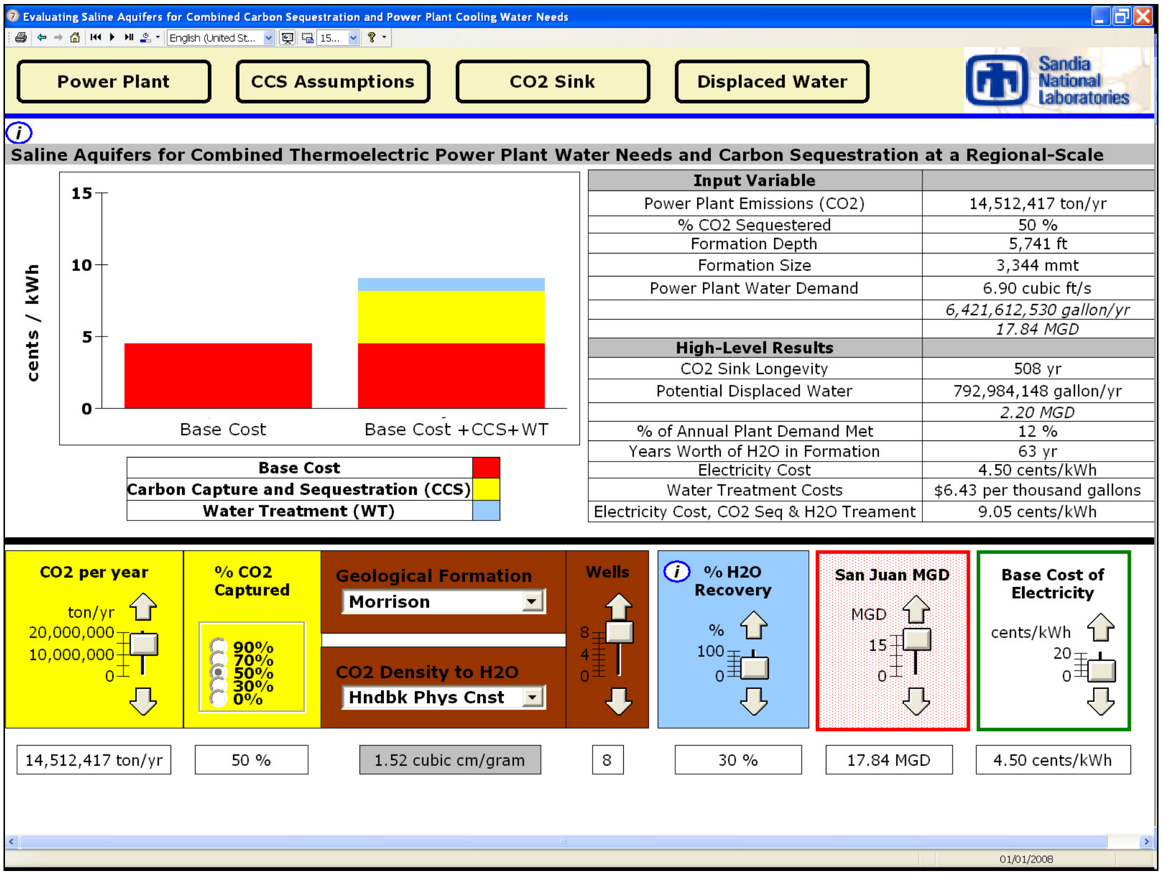
Andrea McNemar
NATIONAL ENERGY TECHNOLOGY LABORATORY

Sandia is a multiprogram laboratory operated by Sandia Corporation, a Lockheed Martin Company, for the United States Department of Energy under Contract DE-AC04-94AL85000.

Phase II, vers. 9/2008

Figure 8. Prototype Front Screen of the Phase I Dynamic Simulation Model for the Water, Energy and Carbon Sequestration Integrated Modeling Assessment.

Figure 8 illustrates the prototype model’s interactive interface. This interface allows users to adjust select attributes of the power plant, CO_2 capture, geological storage, water demand and electricity cost systems. Changing these attributes allows for sensitivity analyses across the four respective systems outlined in Figure 7.



Saline Aquifers for Combined Thermoelectric Power Plant Water Needs and Carbon Sequestration at a Regional-Scale

Base Cost	🟥
Carbon Capture and Sequestration (CCS)	🟨
Water Treatment (WT)	🟦

Input Variable	
Power Plant Emissions (CO2)	14,512,417 ton/yr
% CO2 Sequestered	50 %
Formation Depth	5,741 ft
Formation Size	3,344 mmt
Power Plant Water Demand	6.90 cubic ft/s
	6,421,612,530 gallon/yr
	17.84 MGD
High-Level Results	
CO2 Sink Longevity	508 yr
Potential Displaced Water	792,984,148 gallon/yr
	2.20 MGD
% of Annual Plant Demand Met	12 %
Years Worth of H2O in Formation	63 yr
Electricity Cost	4.50 cents/kWh
Water Treatment Costs	$6.43 per thousand gallons
Electricity Cost, CO2 Seq & H2O Treament	9.05 cents/kWh

CO2 per year: ton/yr, 20,000,000, 10,000,000, 0 — 14,512,417 ton/yr

% CO2 Captured: ○ 90% ○ 70% ● 50% ○ 30% ○ 0% — 50 %

Geological Formation: Morrison

CO2 Density to H2O: Hndbk Phys Cnst — 1.52 cubic cm/gram

Wells: 8, 4, 0 — 8

% H2O Recovery: %, 100, 0 — 30 %

San Juan MGD: MGD, 15, 0 — 17.84 MGD

Base Cost of Electricity: cents/kWh, 20, 0 — 4.50 cents/kWh

Figure 9. Prototype Front Screen of the Dynamic Simulation Model for the Water, Energy and Carbon Sequestration (WECS) Integrated Assessment Modeling as of late Summer 2008.

4.7. Sensitivity Analysis: Water Recovery Scenario Framework

Figure 9 illustrates a base case scenario analysis from which model users can develop numerous sensitivity analyses. For example, the base case scenario assumes the power plant may capture 50% of its CO_2 emissions. Varying the level of CO_2 captured changes the maximum lifetime of the geological formation for CO_2 sequestration. This in turn changes the percent the extracted water may meet the power plant's demand, and the economics associated with the system as a whole. The sliders enable model users to change the volume of CO_2 captured per year, the number of injection wells that need to be developed, the geological formation under consideration, the density of CO_2 at depth to displace water at that depth, the percent of recoverable brackish water from the saline aquifer, the water demand by the cooling towers at the San Juan Generating Station in million gallons per day (MGD), and the hypothetical cost of electricity. Table 10 illustrates the variability in these scenarios across different percent levels of capturing CO_2 from the power plant.

Table 10. Carbon Capture, Water Treatment and Electricity Cost Scenarios.

Percent of CO_2 Captured →	**0**	**30**	**50**	**70**	**90**
CO_2 Sink Longevity (years)	n/a	847	508	363	282
Displaced Water (million gallons /year)	n/a	476	793	1,110	1,427
Annual Plant Cooling Towers' Demand Met (%)	n/a	7	12	17	22
Years Worth of H_2O in Formation (years)	n/a	63	63	63	63
Water Treatment Costs ($ per thousand gallons)	n/a	11.33	7.37	5.66	4.71
Electricity Cost, CO_2 Seq., Pipelines, injection wells & H_2O Treatment (cents/kWh)*	n/a	8	9	11	12

n/a: not applicable, * Preliminary cost calculations, assuming a 100 km pipeline.

The results given in Table 10 show that as the percent of CO_2 increases, the potential to displace brackish water also increases. Similarly, the percent of annual water demands of the power plant may also increase when the volumes of CO_2 sequestered increase with a commensurate increase in displaced brackish water. One of many key assumptions to further study and verify (or bound) are the actual displacement of water by the potential CO_2 plume. The communication between the CO_2 plume and the brackish water is such that water would not be displaced for many years. Therefore, we assume brackish water production is driven by pumping rather than any reliable CO_2 push. This would effectively make the full system two projects in one: a CO_2 sequestration system in an injection well, with a brackish water extraction and treatment system in another well that may not connect within the aquifer for some time.

A final, important caveat to note concerns the number of CO_2 injection wells. Specifically, preliminary runs of the TOUGH2 reservoir modeling of the Morrison Fm. accepting CO_2 assume a one well scenario (this analysis continues to develop). The analysis assumes each well can inject 2,500 tonnes of CO_2 per day. At this level, this represents approximately 7% of the San Juan Generating Station's annual CO_2 emissions. Up to 8 wells would be required to sequester 50% of the total annual CO_2 emissions. Thus, if one were to implement this coupled system with one initial CO_2 injection well, the potential displaced water would meet approximately 2% of the plant's annual water demands based on sequestering only 7% of the plant's total CO_2. Hence, the costs, flow rates and years worth of CO_2 capacity and water supply could change drastically depending on many factors including the engineering of the CO_2 sequestration system, the geosystem's characteristics, and the institutional barriers associated with using a water resource, albeit a currently untapped one, for the purposes of carbon dioxide sequestration.

Acknowledgements

Sandia National Laboratories and the authors would like to thank the National Energy Technology Laboratory, and Tom Feeley and Andrea McNemar in particular, for funding the research in the areas of Energy-Water Program Management and Research. Thanks also go to Mike Hightower for his guidance, and Jason Heath for his ongoing participation.

References

Allis, R.G., Chidesy, T.C., Morgan, C., Moore, J., White, S.P.. (2003). CO_2 sequestration potential beneath large power plants in the Colorado Plateau-southern Rocky Mountain region, USA, Proceedings 2ng Annual Conference on Carbon Sequestration, Alexandria VA, May 5-8, 2003 (Sponsored by the US Department of Energy).

Bentham, M. and G. Kirby. (2005). CO_2 storage in saline aquifers. Oil and Gas Science and Technology, v. 60, pp. 559-567.

Bethke, C.M. (1998). The Geochemist's Workbench: A Users Guide to Rxn, Act2, Tact, React, and Gtplog, University of Illinois Hydrology Program.

Bickle, M., Chadwick, A., Huppert, H., Hallworth, M., and Lyle, S. (2007). Modelling carbon dioxide accumulation at Sleipner: Implications for underground carbon storage. Earth and Planetary Science Letters 255, pp. 164-176.

Clark, S.P., Jr. (1966). Handbook of Physical Constants, Geological Society of America Memoir 97, Published by the Society, GSA Publishers, NY, NY., 587

Craigg, S.D. (2000). Geologic Framework of the San Juan Structural Basin of New Mexico, Colorado, Arizona, and Utah with emphasis on Triassic through Tertiary Rocks, US Geological Society Professional Paper 1420, 70 pp.

Department of Energy / National Energy Technology Laboratory (DOE/NETL). (2007a). *Estimating Freshwater Needs to Meet Future Thermoelectric Generation Requirements: 2007 Update Forecasts*. DOE/NETL-400/2007/1304, <http://www.netl.doe.gov/technologies/coalpower/ewr/pubs/ 2007WaterNeedsAnalysis-UPDATE-Final_10-10-07b.pdf>

Department of Energy / National Energy Technology Laboratory (DOE/NETL). (2007b). "Power Plant Water Usage and Loss Study", August 2005, revised May 2007. <http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/WaterReport_Revised%20May2007.pdf>

Energy Information Administration (EIA). (2008). State Electricity Profiles. http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html As of June 2008.

Environmental Protection Agency (EPA), 2006. eGRID2006 Version 2.1 Plant File (Year 2004 Data), As of March 3, 2008.

Envvironmental Protection Agency (EPA), 2008. Regulatory Development. http://www.epa.gov/safewater/uic/wells_sequestration.html#regdevelopment As of September 26, 2008.

Frenzel, P.. (1983). Simulated changes in ground-water levels related to proposed development of Federal coal leases, San Juan Basin, New Mexico. USGS Open File Report 83-949. 63p.

General Accounting Office (GAO). (2003). "Freshwater Supply: States' View of How Federal Agencies Could Help Them Meet the Challenges of Expected Shortages." July 2003 <http://www.gao.gov/new.items/d03514.pdf>

Gozalpour, F., Ren, S., and Tohidi, B. (2005). CO_2 EOR and Storage in Oil Reservoirs. Oil and Gas Science and Technology – Rev. IFP 60, pp. 537-546.

Kernodle, J. (1996). Hydrogeology and steady-state simulation of ground-water flow in the San Juan Basin, New Mexico, Colorado, Arizona, and Utah. USGS Water Resources Investigations Report 95-4187. 117p.

Kobos, P.H., Aragon, M.J., Krumhansl, J.L., Borns, D.J., Hightower, M.M. and A. McNemar. (2008). Study of the Use of Saline Aquifers for Combined Thermoelectric Power Plant Water Needs and Carbon Sequestration at a Regional-Scale: Phase I Report. SAND2008-4037.

Lorentz, J., and Cooper, S. (2003). Tectonic setting and characteristics of natural fractures in Mesaverde and Dakota reservoirs of the San Juan Basin. New Mexico Geology, 25, pp. 3-15.

McCabe, W., Smith, J., and P. Harriott. (1993). Unit Operations of Chemical Engineering, 5th Edition. McGraw-Hill, Inc., 1993.

Murphy, J. (2007). "Power Plant Cooling and FGD MakeUp Water Quality Requirements." US

NatCarb, 2007. http://www.natcarb.org/ and http://drysdale.kgs.ku.edu/natcarb/eps/natcarb_alpha_content.cfm) as of Spring 2008.

National Energy Technology Laboratory (NETL), 2007. Carbon Sequestration Carbon Sequestration Atlas of the United States and Canada As of September 26, 2008. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/index.html

National Energy Technology Laboratory (NETL), 2007. Carbon Dioxide Capture from Existing Coal-Fired Power Plants. DOE/NETL-401-110907. (Final Report (Original Issue Date, December 2006)), Revision Date, November.

Ogden, J. (2002). Modeling infrastructure for a fossil hydrogen energy system with CO_2 sequestration. Sixth Greenhouse Gas Control Technologies Conference, Kyoto, Japan.

Perry, R. and D. Green. (1997). Perry's Chemical Engineer's Handbook, 7th Edition. McGraw-Hill, Inc.

PNM. (2008). www.pnm.com As of June 2008.

Pruess, K., Oldenburg, C., and Moridis, G. (1999). TOUGH2 User's Guide, Version 2. Lawrence Berkeley National Laboratory, LBNL-43134, 198 p.

Pruess, K; Xu, TF; Apps, J; Garcia, J. (2003). Numerical modeling of aquifer disposal of CO_2 SPE Journal; March 2003; v.8, no.1, p.49-60.

Pruess, K. (2005). ECO2N: A TOUGH2 fluid property module for mixtures of water, NaCl, and CO_2. Lawrence Berkeley National Laboratory, LBNL-43134, 66 p.

Stone, W., and Mizell, N. (1978). Basis subsurface data compiled for hydrogeologic study of the San Juan Basin, northwest New Mexico. New Mexico Bureau of Mines and Mineral Resources, Open File Report 89, 74 p.

Stone, J.W. (2002). Groundwater and Energy Development in the San Juan Basin, New Mexico's Energy, Past and Present, Policy, Production, Economics, and the Environment, Decision-Makers Field Conference, 2002, San Juan Basin, (http://geoinfo.nmt.edu/publications/decisionmakers), Brister, B.S. and Price, G.L., editors, Chapter 1, p. 35-38.,

Texas Bureau of Economic Geology (TBEG). (2008). Sequestration of Greenhouse Gases in Brine Formations; "Morrison Formation, San Juan Basin" web page at: http://www.beg.utexas.edu/environqlty/co2seq/0morrison.htm As of September 2008.

Thomas, B. (1989). Simulation analysis of the ground-water system in Mesozoic rocks in the Four Corners Area, Utah, Colorado, Arizona, and New Mexico. USGS Water Resources Investigations Report 88-4086, 87p.

United States Bureau of Reclamation (USBR) (2003). Desalting Handbook for Planners, 3rd Edition. USBR.

Viessman, Jr., W. and M. Hammer. (1998). Water Supply and Pollution Control, 6th Edition. Addison-Wesley.

Xu, TF; Apps, JA; Pruess, K; Yamamoto, H. (2007). Numerical modeling of injection and mineral trapping Of CO_2 with H_2S and SO_2 in a sandstone formation, : Chemical Geology; Aug 15 2007; v.242, no.3-4, p.319-346.

Xu, TF; Apps, JA; Pruess, K. (2003). Reactive geochemical transport simulation to study mineral trapping for CO2 disposal in deep arenaceous formations - art. no. 2071, Journal of Geophysical Research – Solid Earth; Feb. 4; v.108, no.B2, p.2071-2071.

Xu, TF; Apps, JA; Pruess, K. (2005). Mineral sequestration of carbon dioxide in a sandstone-shale system: Chemical Geology; April 25 2005; v.217, no.3-4, p.295-318.

Xu, TF; Apps, JA; Pruess, K. (2004). Numerical simulation of CO{sub 2} disposal by mineral trapping in deep aquifers, Applied Geochemistry; June 2004; v.19, no.6, p.917-936**.**

---

[1] This paper builds heavily from several works, including the Phase I report by Kobos et al., 2008.

[2] The pipeline, piping at the well location, and well costs may add \$4/tonne/CO_2 to the overall costs of sequestration.

[3] For example, NatCarb builds from example conditions of 8,000 feet deep, 140° F, and 3,500 pounds per square inch (psi). Assuming a column of water 33 feet high gives a pressure of around on atmosphere (1 bar), this example indicates NatCarb works off of hydrostatic pressure for the well depth [(8,000 feet / 33 feet) * 14.7 (psi/bar)] = 3,563 pounds per square inch (psi). The NatCarb example approximates the pressure to 3,500 psi, which corresponds to (3,500 (psi/bar) / 14.7 (psi)) = 238 bars. Using this assumption, the density of CO_2 given is 48.55 lbs mass per cubic foot. Therefore, one calculates the volume displacement relationship of sequestered CO_2 to H_2O as: (1,000g/kg*48.55 lbs / 2.2046 lbs/kg)) / ((2.54^3)*12ˆ3) cm^3 per ft^3) = 0.777 g (CO_2) / cm^3 (H_2O). In this particular case given the different temperatures and depths associated with this location in the Morrison formation, the subsurface pressures used in the TOUGH2 modeling were approximately 170 bar, 1700-1750 meters, 30 degrees C/km geothermal gradient, and 0.1 bar/meter hydrostatic gradient, and building from the works of Clarke, 1966, and Bentham and Kirby, 2005. The resulting displacement for a CO_2 density of approximately 0.65 equates to ~1.52 cubic centimeters of water per gram of CO_2.

[4] The hydrostatic pressure using the Handbook of Physical constants was developed in Phase I of the analysis. Phase II is further refining the pressure using TOUGH2 modeling and therefore the overarching results of the analysis will likely change in subsequent work to reflect this different working hydrostatic pressure calculation.