INJECTION OF CO_2 INTO AN UNCONFINED AQUIFER LOCATED BENEATH THE COLORADO PLATEAU, CENTRAL UTAH

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SUMMARY Some geothermal fields, for example Ohaaki and Ngawha in New Zealand, contain significant amounts of CO_2. In a post Kyoto protocol world it may be financially advantageous to capture and dispose of the CO_2 in a permanent manner rather than releasing it to the atmosphere. CO_2 sequestration in geological formations is an active area of investigation at present and techniques developed in non-geothermal situations may be applicable in geothermal situations. While this paper is not concerned with disposal of CO_2 in a geothermal setting the methods are applicable in such a case. We have developed a regional scale, two-dimensional numerical model of a non-dome-shaped such structure on the Colorado Plateau that includes the major physical and chemical processes induced by injection of CO_2. Ignoring water-rock reactions, CO_2 returns to the surface after about 250 years and about 40% remains sequestered after 1000 years. However, coupling water-rock reactions to transport calculations shows significantly more CO_2 is sequestered, with dawsonite and calcite being the most important sequestration minerals.

1. INTRODUCTION

This paper summarizes work investigating the injection of CO_2 into geological structures that are not dome shaped and thus do not provide the conventional reservoir-trap geology usually considered necessary for the development of a gas reservoir. Although such structures are open, they may however, provide very long flow paths between the injection point and the surface, allowing the permanent sequestration of the injected CO_2 as a mineral or dissolved in the groundwater.

We investigate one such geological structure using a two-dimensional numerical model of an unconfined reservoir to study the long-term behaviour of CO_2 injected in the reservoir. Using the reactive chemical transport code ChemTOUGH2 (White 1995) the model is able to represent the major physical and chemical processes induced by injection of CO_2 into the reservoirs including transport in the liquid and gas phases, the effect of dissolved CO_2 on brine density, and the reaction between the CO_2 plume and the reservoir rocks.

2. GEOLOGICAL SETTING

The geology beneath Hunter Power Plant, located on the San Rafael Swell, is an example of a structure that, although not dome shaped, may provide a suitable CO_2 sequestration site. The San Rafael Swell is a major physiographic feature in east-central Utah. It represents a broad, basement-involved, asymmetrical anticline that trends north-northeast to south-southwest. The San Rafael Swell is one of numerous Laramide-age (middle to late Paleocene to early Oligocene) structures on the Colorado Plateau.

The site is considered an important test case as there are two power plants within 15 km with a combined capacity of 2000 MW producing 15 million tones of CO_2 emissions per annum. The sedimentary sequence shown in Figure 1 contains potential reservoir and seal formations at over 1 km depth beneath the power plant, but the regional dip exposes some of these formations at the surface some 40 to 50 km away.

A review of the properties of likely reservoirs and capping structures in this region identified several potential targets for the injection of CO_2 gas on the cross-section; 1) Navajo Sandstone, 2) Wingate Sandstone, 3) White Rim Sandstone, and 4) Redwall Limestone. Of these, only the Redwall Limestone is not exposed on the crest or *flanks* of the uplift.

3. HYDROLOGICAL MODEL

The regional topography and precipitation pattern give a pressure gradient roughly along the cross-section of Figure 1, with pressures highest in the west. Regional flow is from the high ground of the Wasatch Plateau in the west towards the Green River in the east.

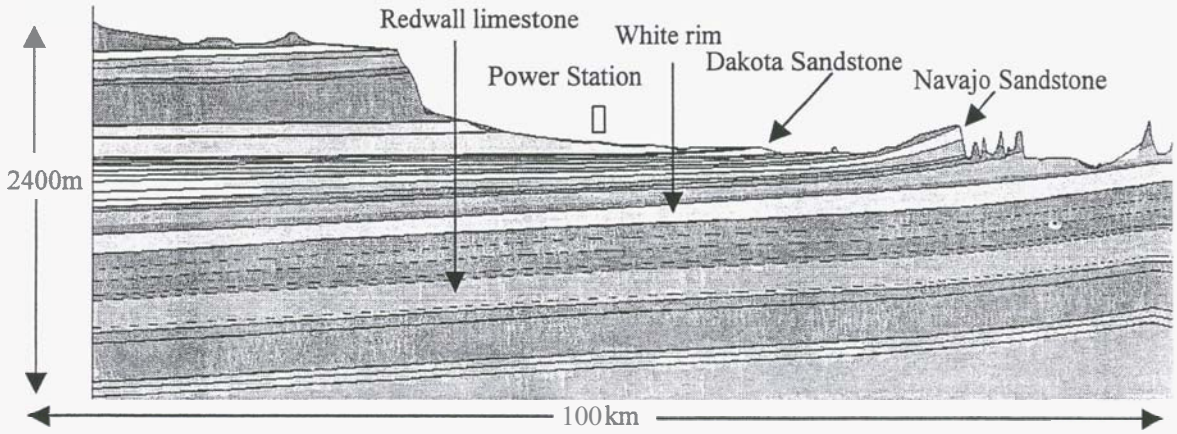

Figure 1: Geology on the cross-section beneath the Hunter Power-plant, Central Utah

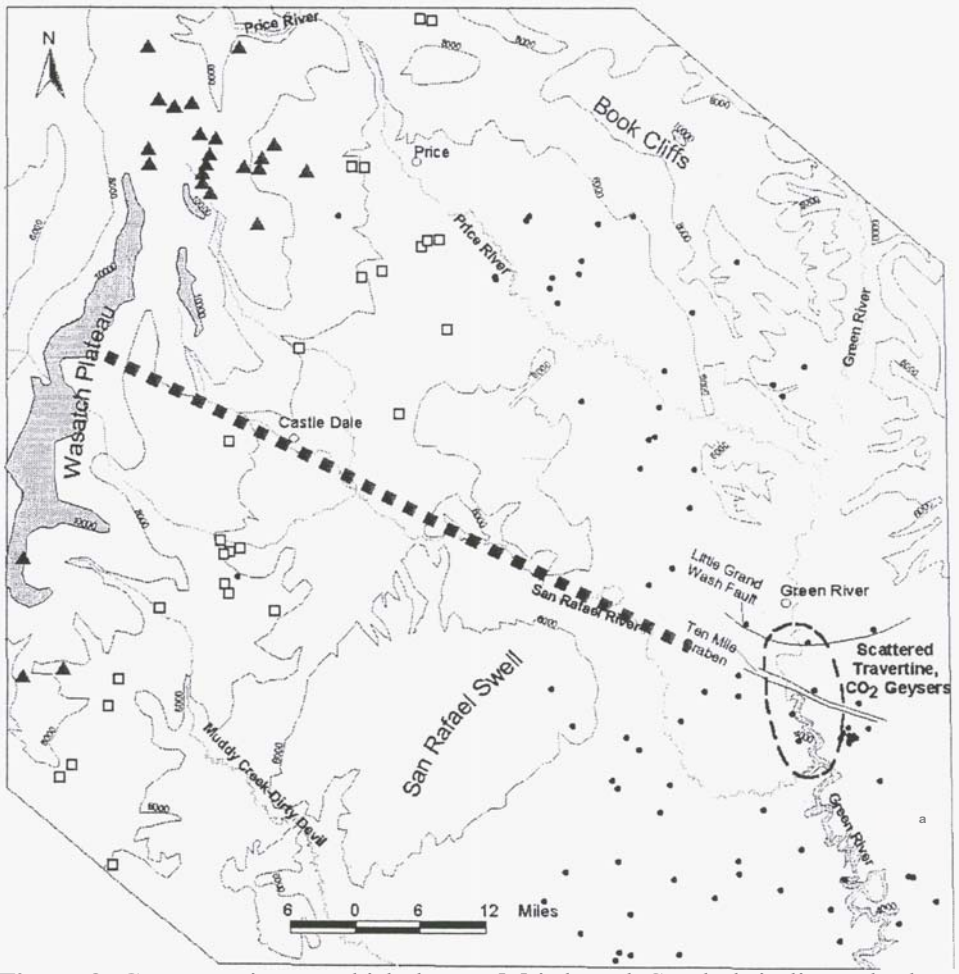

Figure 2: Cross-section on which the **model** is based. Symbols indicate the location of pressure data points used in calibrating the model. Data points on the East San Rafael Swell are to the east of the cross-section and provide a boundary condition on the eastern boundary of the slice. Filled **triangles** on the Wasatch Plateau **are** the locations of downhole pressure data that provide a constraint on the west side of **the** cross-section. The lateral pressure gradient is about 10 MPa (100 bar).

Previous modelling studies simulated the formation of the natural CO_2 reservoirs at Farnham Dome on the Colorado Plateau (Allis *et al.* 2001, White *et al.* 2001, White *et* al. 2002) and established reservoir parameters required for gas reservoir formation.

On the eastern boundary of the model we set boundary pressures to those of a hydrostatic column with the water table depth determined from pressure measurements in the area while on the western boundary pressures are either hydrostatic or no flow across the boundary is enforced.

4. NUMERICAL MODEL

Two TOUGH2/ChemTOUGH2 integrated finite difference models of the cross-section shown in Figure 1 have been developed. In the first model (Model A), we have used a fine grid in the vicinity of the injection wells to resolve better the early part of the injection period when pressure gradients are large. Resolution in the second model (Model B) is reduced in order to keep the computer time requirements for modeling the CO_2-brine-rock interactions manageable. These models and the parameters used in the modeling are discussed in detail in White et *al.* (2003).

4.1 Boundary Conditions

Boundary conditions for the numerical model are determined largely from the hydrological model discussed above and they can be summarized as

- Atmospheric pressure at the surface
- *20* cm precipitation on low (below 2000 masl) area with 2% infiltration
- 100 cm precipitation in the west decreasing to 20 cm at the base of the Wasatch Plateau with 15% infiltration
- Constant pressure on the eastern boundary
- Constant pressure on western boundary during sequestration simulations. No flow through this boundary during steady state calculations.
- No fluid flow through the base of the model
- Heat flow at the base of the model is set to match the typical terrestrial heat flow for the region.

5. SEQUESTRATION SCENARIOS

Sequestration scenarios investigated fall into two groups. The first group used Model A and the TOUGH2 (Pruess 1991) simulator to model the injection of CO_2 into several reservoirs and tracked the location of the CO_2 over a period of 1000 years. Chemical reactions between the reservoir brine and the host rock were ignored. Reservoirs investigated were the Navajo Sandstone, White Rim Sandstone, Wingate Sandstone and Redwall Limestone aquifers.

The second group used the ChemTOUGH2 (White 1995) simulator and investigated the effects of water-rock interactions on CO_2 sequestration, firstly modeling reactions between a brine with a constant CO_2 partial pressure and reservoir rock and then a reactive transport simulation using Model B.

In all flow simulations reported CO_2 is injected for 30 years at 0.15 kg/s per meter of cross-section thickness. This rate corresponds to about 5 million tomes / year (approximately equal to the emissions fkom a 600 MW coal fired power station) into a section 100 meters wide.

5.1 Model A Simulations

The Redwall Limestone proved unsuitable for long-term sequestration of CO_2 as unrealistic injection pressures were required to inject into the medium permeability (2 mD) inferred for this reservoir. Figure 3 shows the fraction of injected CO_2 that has not returned to the atmosphere over time. Clearly neither the Wingate nor Navajo formations are suitable for long-term sequestration of CO_2. In both formations CO_2 begins to reach the surface before injection is completed. Even in the case of the White Rim Sandstone there is significant leakage from the target reservoir and a larger volume of rock is exposed to CO_2 than just the White Rim sandstone formation .

Of the investigated reservoirs, only the White Rim formation may provide containment of injected CO_2 for the hundreds to thousands of years required for mineral sequestration reactions to complete. However, the geochemical situation is much more complex than has been assumed in Model A. Transport of reaction products in the reservoir, changing reservoir temperature, mineralogy and partial pressure of CO_2 all mean a full reactive transport model must be used.

5.2 Model B Simulations

We have included sufficient geo-chemical complexity to represent the interaction of a simplified reservoir mineralogy (Table 1) with a CO_2 rich brine. To achieve this we used the lower spatial resolution of Model B. However it retains a reasonable resolution with over 1300 elements. The fate of injected CO_2 was traced for 1000 years as the geo-chemical calculations described earlier in this section suggest most sequestration reactions will be well advanced in this time. Details of parameters used for water-rock reaction rates and the kinetic model used for these reactions is provided in White et *al.* (2003).

Mineral	Chemical composition	Volume (%)	Surface area (m^2/dm^3)	k_{25} (moles $m^{-2}s^{-1}$)	E_a (KJ/mol)
Quartz	SiO_2	77	7.7	$1.26x10^{-14}$	87.5
K-feldspar	$KAlSi_3O_8$	0.60	0.060	$1.00x10^{-12}$	67.83
Kaolinite	$Al_2Si_2O_5(OH)4$	2.25	22.5	$1.00x10^{-13}$	62.76
Calcite	$CaCO_3$	1.80	0.180	$1.60x10^{-9}$	41.87
Dolomite	$CaMg(CO_3)_2$	0.0	25.0	$0.60x10^{-9}$	41.87
Siderite	$FeCO_3$	0.0	25.0	$0.60x10^{-9}$	41.87
Illite	$K_{0.6}Mg_{0.25}Al_{1.8}(Al_{0.5}Si_{3.5}O_{10})(OH)_2$	0.0	25.0	$1.00x10^{-14}$	58.62
Albite-low	$NaAlSi_3O_8$	0.60	0.060	$1.00x10^{-12}$	67.83
Smectite-Na	$Na_{0.290}Mg_{0.26}Al_{1.77}Si_{3.97}O_{10}(OH)_2$	2.25	22.5	$1.00x10^{-14}$	58.62
Anorthite	$CaAl_2Si_2O_8$	0.66	0.06	$1.60x10^{-12}$	18.40
Dawsonite	$NaAlCO_3(OH)_2$	0.0	25.0	$1.60x10^{-9}$	41.87
Porosity		15.0			

Table 1 Reaction rates and surface areas of primary and secondary minerals included in the reservoir

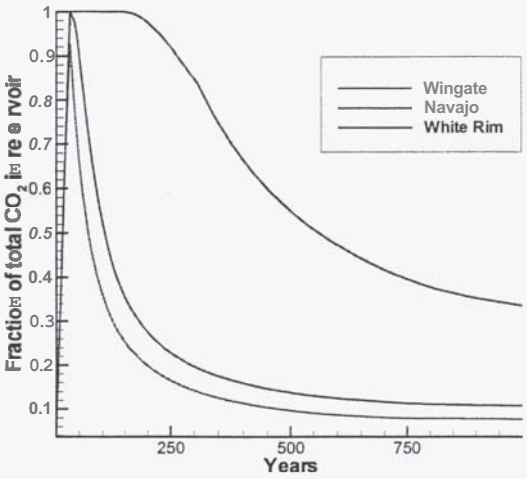

Figure 3: Fraction of total injected CO_2 remaining sub-surface as a function of time for three potential sequestration sites ignoring water-rock reactions (i.e. Model A).

Initial chemical conditions were calculated by firstly assigning the mineralogy specified in Table 1 to model elements, setting the reservoir fluid to a **0.3** M NaCl brine (based on water analyses from exploration wells in the San Rafael Swell region.) and then allowing the brine to react with the reservoir for 1000 years. This modified the original mineralogy slightly and provided initial conditions for the fluid reservoir throughout the reservoir. The initial brine composition in the White Rim sandstone is given in Table 2.

pH	Cl	SO4	HCO3	SiO_2	Al	Ca	Mg	K	Na	Fe	HS
11.7	10394	0.0	0.1	1442	0.0	3280	0.03	109	6709	0.0	0.1

CO_2 was then injected into the White Rim formation for **30** years at the same rate as used in the non-reactive modeling (Model **A).** The chemistry and flows in the system were then simulated for a total of 1000 years.

The location of the gas at the conclusion of the simulation period is **shown** in Figure 5. Low permeability formations, primarily the Moenkopi and Chinle formations, have channeled the gas over thirty kilometers horizontally. There is some leakage into shallower permeable formations and the formation of secondary CO_2 reservoirs above the major concentration of gas in the White Rim and Black Box formations. Although it is not obvious from Figure *6,* about 10% of the gas has escaped out the top boundary of the model.

Injected CO_2 dissolves in the reservoir brine to form a low pH fluid, this reacts with the feldspars in the reservoir and precipitates kaolinite together with the carbonate minerals calcite and dawsonite. These three secondary minerals have been observed as pore-filling minerals likely related to an influx of CO_2-rich fluids in the Springerville natural CO_2 field, eastern Arizona (Moore *et al.* **2003).** Figures 6-**8** show the change in the amount of feldspars throughout the model domain 950 years after injection begins. There is some dissolution of anorthite throughout the domain but it is largest in the area affected by the injected CO_2. K-feldspar is dissolved only in the low pH region formed by the interaction of injected CO_2 with the reservoir brine. Albite is initially supersaturated in some regions and there is some precipitation of albite where these regions are not affected by the injected CO_2. Albite is dissolved in the region affected by the injected CO_2. Figures 10-12 show the location of the precipitated minerals. These are largely confined to the two-phase, low pH region shown in Figure 5 although they are not found throughout this region. Calcite does not form shallower than 1500 masl while dawsonite and kaolinite does not form deeper than **1600** masl. Dawsonite is not found in the Moenkopi or Chinle capping rocks.

Figure 12 shows the fate of the injected CO_2 950 years after injection began and these results are summarized in Table **3.** It is not possible to directly compare the results of Model **A** (Figure

4) and Model B (Figure 13) as the coarse grid of Model B does introduce some errors into the calculation reducing the calculated leakage to the surface. In the long term, the effect of this discretization error is to overestimate the amount of CO_2 sequestered by about 10%. To make clear the effect of including water-rock reactions, also plotted in Figure 13 are the results of running the Model B grid using TOUGH2 rather that ChemTOUGH2. The effect of including water-rock reactions is not simply to reduce the surface leakage by the amount of CO_2 sequestered in a mineral phase as precipitation of carbonate minerals also reduces the partial pressure of CO_2 reducing flows driven by pressure gradients. Although only 13% of the injected CO_2 is sequestered as a mineral surface leakage is reduced by 60 %.

	sequestration	mineral sequestration
Gas phase	36 %	31 %
Dissolved	34 %	31 %
Calcite	7 %	
Dawsonite	6 %	
Leakage	17 %	38 %

beginning of injection.

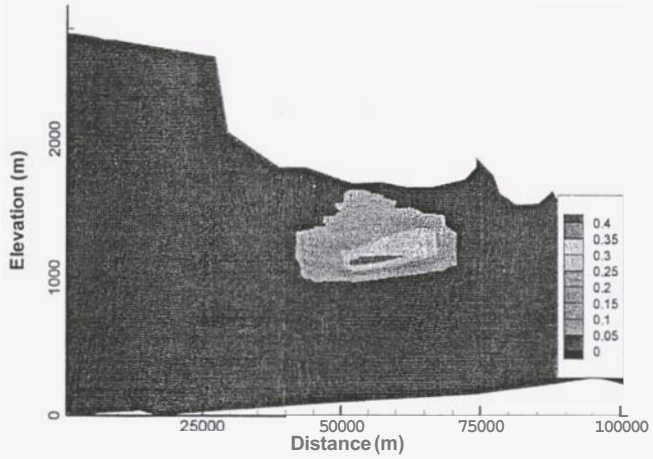

Figure 5: Gas saturation 950 years after beginning of CO_2 injection (Model B).

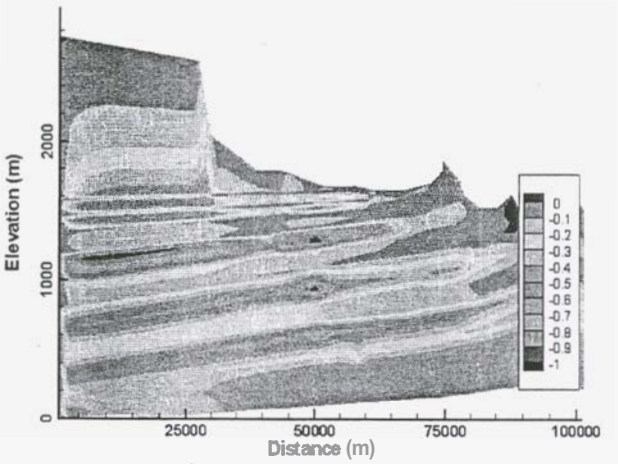

Figure 6: Change in anorthite density 950 years after the beginning of CO_2 injection (M dm^{-3}); (Model B).

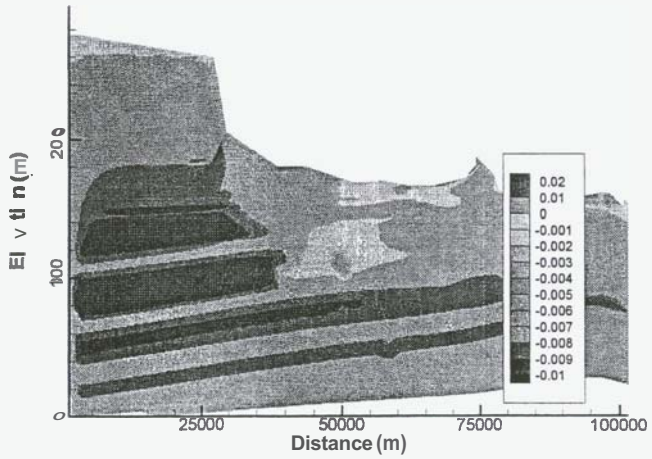

Figure 7: Change in **albite density 950 years after the beginning** of CO_2 **injection** (Mdm^{-3}Model B).

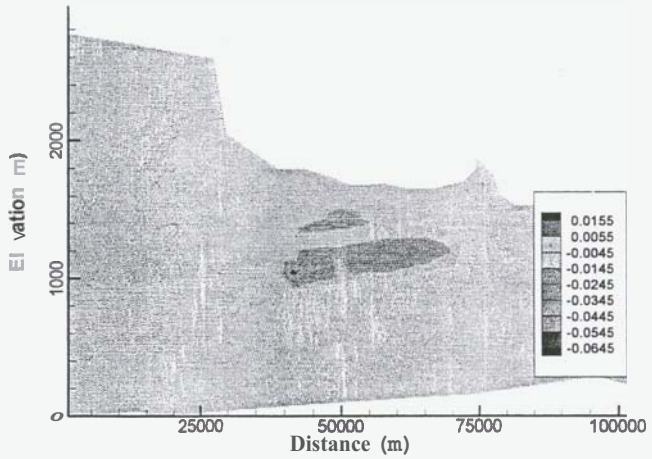

Figure 8: Change in K-feldspar density 950 years after the beginning of CO_2 injection (M dm^{-3}), (Model B).

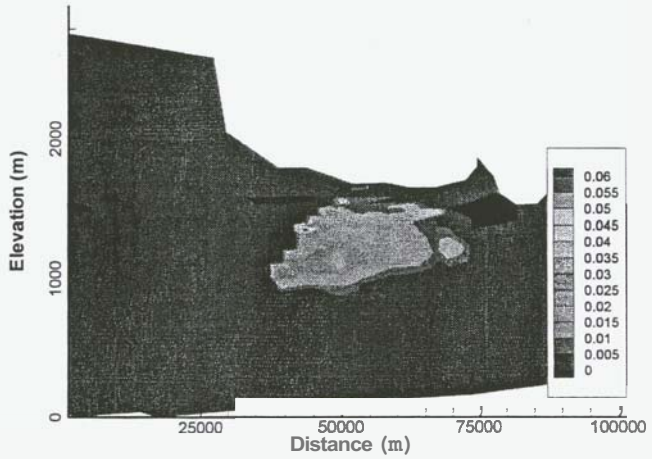

Figure 9: Change in calcite density 950 years after the **beginning of C02 injection (M dm^{-3}); (Model** B).

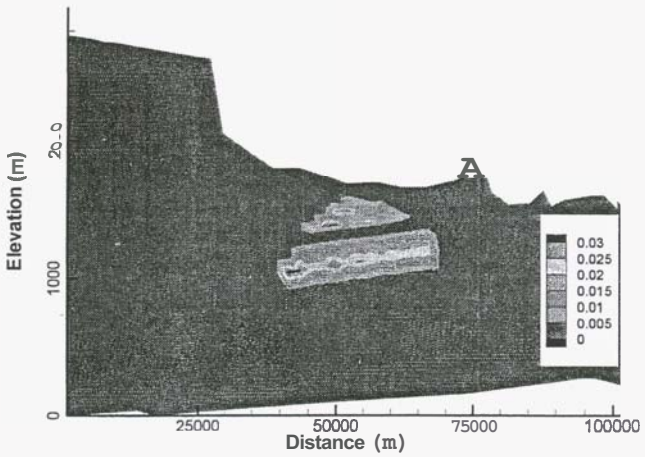

Figure 10: Change in dawsonite density 950 years after the beginning of CO_2 injection (M dm^{-3}; Model B).

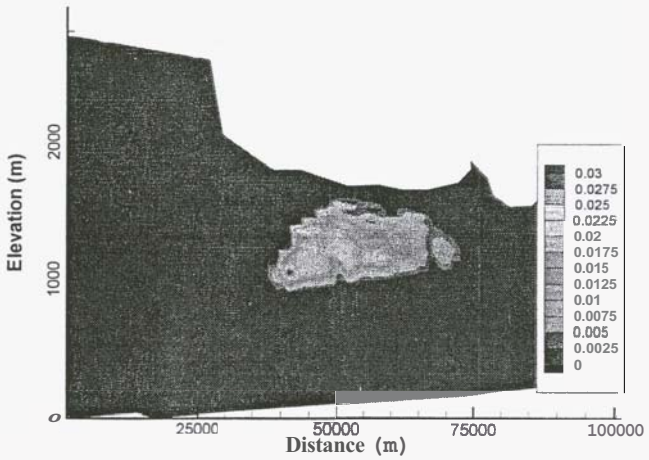

Figure 11: Change in kaolinite density 950 years after the beginning of CO_2 injection (M dm^{-3}; Model B).

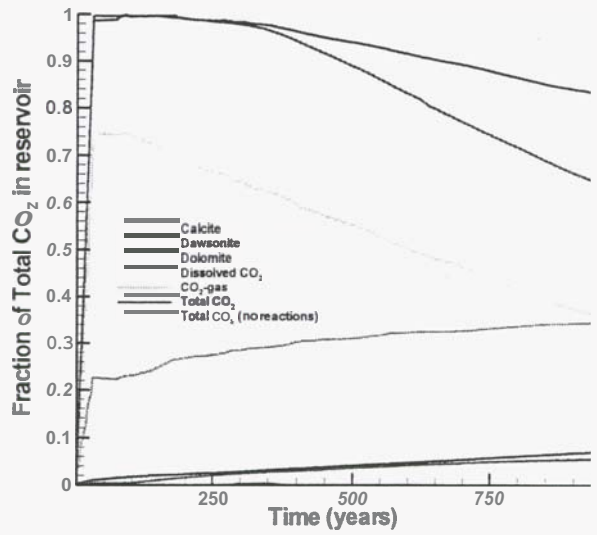

Figure 12: Location of CO_2 within the reservoir as a function of time. The difference between Total *C02* and 1.0 is the fraction of C 0 2 leakage to the atmosphere.

6. SUMMARY AND CONCLUSIONS

The capacity of White Rim sandstone for sequestration (assuming a 100 meter wide cross-section) is approximately 50,000 x100×200×22 = 2.2×10^{10} kg or sufficient to sequester about 150 years of injected CO_2 (White *et al.* 2003).

CO_2 is sequestered as a mineral or dissolved in reservoir fluid. In fact, a much larger volume of rock is 'seen' by the injected CO_2 than is contained in the White Rim formation (see Figure 6) and there should be ample volume of rock to sequester all the injected CO_2 providing flow to the surface is sufficiently slow.

More detailed modeling of injection into the White Rim Sandstone that included water-rock interactions was carried out. This found that 1000 years after the **30** year injection period began approximately 21 % of the injected CO_2 was permanently sequestered as a mineral, 52% was beneath the ground surface as a gas or dissolved in the groundwater and 17% had leaked to the surface. Leakage to the surface was continuing. Running model B ignoring water-rock interactions for a longer simulation period found gas ceased leaking to the surface at 1500 years. At this stage, by extrapolating Figure 12, we estimate at least 70% of the injected gas is permanently sequestered

A note of caution must be added to these estimates as some of the key parameters governing the results are not well known. In particular the composition and properties of the reservoir and seal units are not well known and nor are the mineral reaction rates or surface areas ***in a field setting.*** Better grid resolution is also required in the reactive transport model.

7. REFERENCES

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