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GEOLOGIC CO_2 SEQUESTRATION IN A BASALT RESERVOIR: CONSTRAINING PERMEABILITY UNCERTAINTY WITHIN THE COLUMBIA RIVER BASALT GROUP

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ABSTRACT

This study investigates the feasibility of industrial-scale CCS operations within the Columbia River Basalt Group (CRBG) with an emphasis on understanding the implications of site-scale permeability uncertainty. We develop a Monte Carlo-style numerical modeling experiment in which CO_2 sequestration is simulated within 50 stochastically generated and spatially correlated permeability distributions. Results from this research illustrate that reservoir-scale permeability uncertainty significantly impacts both the accumulation and distribution of CO_2. After 20 years of injection at constant pressure, the total volume of CO_2 injected in each simulation ranges from 2.4 MMT to 40.0 MMT. Interestingly, e-type calculations show that the mean CO_2 saturation over the ensemble of 50 simulations is concentric around the injection well with the CO_2 migrating 900 m away from the injection well, suggesting that ensemble behavior does not seem to be controlled by the anisotropic permeability correlation structure. These results indicate that *a priori* knowledge of permeability correlation structure is an important operational parameter for the design of monitoring, measuring, and verification strategies in highly heterogeneous CCS reservoirs.

INTRODUCTION

Among the principal challenges of this century is the stabilization of the climate, and it is widely accepted that doing so requires a dramatic reduction in anthropogenic CO_2 emissions (e.g. Matter et al., 2009). One promising technological solution is carbon capture and sequestration (CCS), which involves the storage of anthropogenic CO_2 in deep geological (>800 m) formations because they have the potential to store tens of millions of metric tons of CO_2. Recent developments at the CarbFix CCS pilot in Iceland (Aradóttir et al., 2012) and the Wallula Basalt Pilot Project located in eastern Washington (McGrail et al., 2017) have shown that basalt reservoirs are highly effective for permanent mineral trapping on the basis of CO_2-water-rock interactions. Specifically, pilot-scale basalt CCS at the CarbFix project showed 95% permanent CO_2 mineralization within two years of injection (Matter et al., 2016). However, despite the effectiveness of trapping CO_2 via mineralization, the volumes injected in both pilot projects (270 tons CO_2 at CarbFix, 1000 tons CO_2 at Wallula) are far from the scales required to mitigate climate change. Upscaling from a pilot project to an industrial-scale CO_2 injection requires a detailed characterization of the subsurface, which introduces a significant amount of uncertainty associated with reservoir parameters, which affect the injectivity, capacity, and confinement of the target reservoir (Chadwick et al., 2008). For flood basalt reservoirs this can be challenging because it is generally accepted that plausible constraints on *in situ* permeability distributions are unknowable at reservoir scale. Moreover, uncertainty in permeability distributions at any scale, especially site-scale or larger can have a substantial impact on the results of hydrogeologic models, as well as, numerical model-based risk assessment (NETL, 2011). In order to understand the implications of permeability uncertainty in basalt-hosted CCS reservoirs, this study interrogates the feasibility of industrial-scale CCS operations within the Columbia River Basalt Group (CRBG).

METHODS

We use TOUGH3 (Jung et al., 2017) compiled with ECO2M (Pruess, 2011) to simulate a one-well, constant-pressure CO_2 injection scenario operating within the Columbia River Basalt Group at depths of 775 – 875 m. The 3-D model domain is discretized within 5,000 m × 5,000 m × 1,250 m volume, which represents ground surface to 1,250 m depth. Within this model domain, the Wallula Pilot Project borehole is centrally located, and borehole geology is reproduced in 50 spatially correlated and equally probable synthetic reservoirs. This domain is discretized into 530,000 grid blocks with dimensions of 50 m × 50 m × 25 m. Previous studies have shown the permeability within the CRBG can range over 13 orders of magnitude (Jayne and Pollyea, 2017), and, as a result, it is generally accepted that plausible constraints on *in situ* fracture-controlled permeability distributions are unknowable at reservoir scale. To account for the wide range of fracture-controlled permeability within the CRBG, injection-zone permeability is modeled by sequential indicator simulation to generate 50 equally probable and spatially correlated permeability distributions (Deutsch and Journel, 1998). In this approach, the permeability distributions reproduce the permeability correlation model developed by developed by Jayne and Pollyea (2017), which shows regional-scale, 5:1 spatial anisotropy with direction of maximum spatial correlation oriented N40^{o}E. The CO_2 injection scenario is simulated within each synthetic reservoir for 20-years at constant pressure.

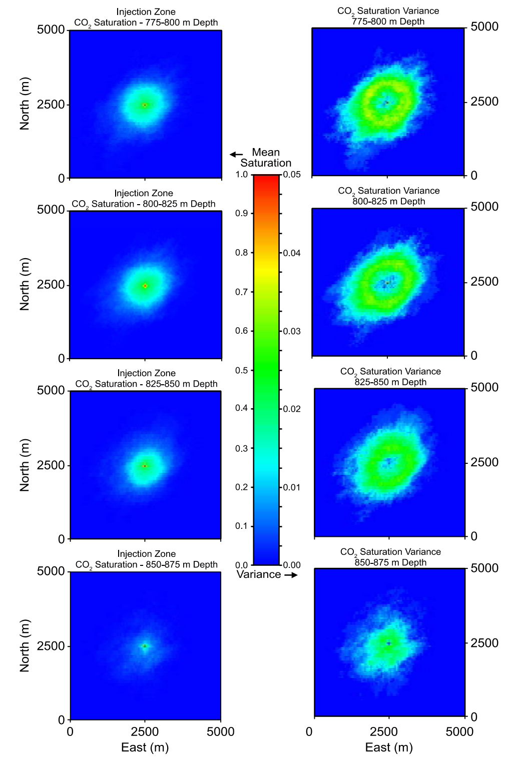

Figure 1. E-type estimates for (N=50) 20-year CO_2 injections. Average free-phase CO_2 saturation over all 50 simulations for the injection zones are shown on the left and the variance over all 50 simulations is shown on the right.

RESULTS

For each analysis, the simulations are referred to by an integer index (1-50). In order to maintain consistency and facilitate comparison each analysis includes simulation 20 because the total mass of CO_2 injected for this simulation is close to the ensemble mean. The e-type estimates (grid cell mean and variance) for the ensemble of 50 simulations are presented in Figure 1. To compare the range CO_2 volume injected throughout this modeling study, 3D plots of CO_2 plumes from four different realizations are presented in Figure 2 to illustrate the minimum volume (run 33), maximum volume (run 43), and average volume (runs 11 and 20) after 20 years. In order to evaluate the thermal effects of free-phase CO_2 flow within the target reservoir, Figure 3 illustrates the change in temperature from pre- to post-CO_2 injection within the model domain.

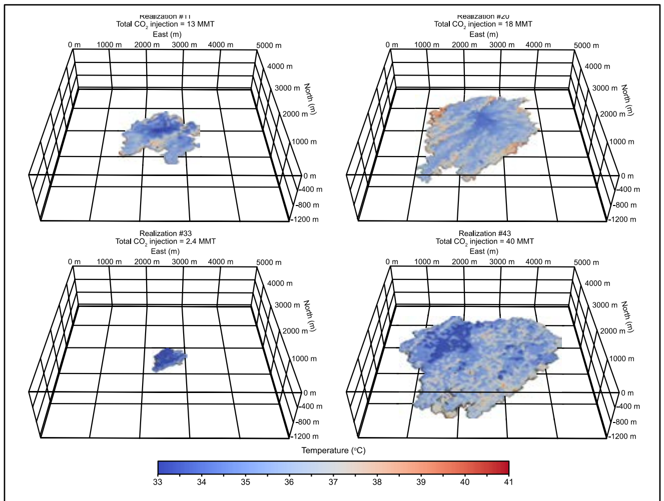

Figure 2. Four different realizations after a 20-year CO_2 injection, isosurface represents the edge of the CO_2 plume, each plume is contoured by temperature.

DISCUSSION

The complete ensemble simulation results (e-type estimates) for free-phase supercritical CO_2 saturation after 20 years of injection are shown in Figure 1. The ensemble mean results (Fig. 1, left column) are similar to those of McGrail et al. (2012), which uses a radially-symmetric, homogeneous grid to simulate an annual injection of 0.8 million metric tons (MMT) supercritical CO_2 into the Grande Ronde formation to show CO_2 migrates ~1,000 m from the injection well after 30 years. While the ensemble mean behavior of CO_2 from this study is similar to the results from McGrail et al. (2012), the variability in this study reveals drastically different results. The variance of CO_2 saturation over all 50 simulations is shown in Figure 1, which illustrates an 'ellipse' of variability extending up to ~1,800 m away from the injection well. The longitudinal axis of the ellipse trends N40°E, which is the direction of maximum spatial correlation. This result suggests that the uncertainty of CO_2 migration within CRBG basalt is strongly governed by the permeability correlation structures. The variability over all 50 simulations is not only obvious in the shape of the individual plumes (Figure 2) and the ensemble variance (Figure 1), but also in the total volume injected in each simulation. The total volume of CO_2 injected into each of the 50 equally probable synthetic reservoirs ranges from a nominal 2.4 MMT (0.12 MMT yr^{-1}) to 40 MMT (2 MMT yr^{-1}). The plume shape and size are also highly variable over the ensemble; Figure 2 illustrates the isosurface at 1% gas saturation for four individual realizations. This variability over the ensemble of simulations has important implications for monitoring, measuring, and verification (MMV) practices. The results presented here show that the average CO_2 plume behavior may exhibit characteristics of an isotropic permeability distribution, but the variability over all 50 simulations is significant, and warrants a site-specific monitoring program.

Results from this study also indicate that the thermal monitoring at CO_2 sequestration sites may be an effective MMV strategy. For example, the areas that show the largest increase in temperature are near the edges of the CO_2 plume, where CO_2 dissolution into formation water releases heat. This process is called "heat of dissolution" because CO_2 dissolution is an exothermic reaction (Pruess, 2005). In the results shown here, the change in reservoir temperature from pre- to post-injection shows that temperature within the reservoir changes +/- 4°C as a result of the CO_2 injection, and this effect is most pronounced at the lateral extent of the plume (Figure 3). In contrast, areas that show the largest decrease in temperature are near the injection well, which is caused by Joule-Thomson expansion. In this process, temperature change is associated with the expansion of a gas (Roebuck et al., 1942). During CO_2 injections, the CO_2 is injected at a high pressure and begins to expand and cool as it migrates away from the injection well (Oldenburg, 2007). The competing effects of the heat of dissolution and Joule-Thomson expansion are shown in Figures 2 and 3. The isosurfaces in Figure 2 are contoured by temperature to illustrate characteristic thermal features of a large-scale CO_2 injection, specifically heating at the plume edge and cooling within the plume interior. As the CO_2 migrates away from the wellbore due to the pressure gradient imposed by the injection, the CO_2 begins to expand and cool, but at the edges of the plume the CO_2 is dissolving into the reservoir water and giving off enough heat to overcome Joule-Thomson cooling resulting in a net increase in temperature. Conversely, near the wellbore after some time the water becomes saturated with CO_2 and no more CO_2 will dissolve. At this point, Joule-Thomson cooling dominates resulting in a net decrease in temperature near the well (Figure 3A - C and E). This result suggests that the competing effects of dissolution heating and Joule-Thomson cooling may be an effective strategy to monitor breakthrough. In particular, the heat of dissolution effect may be used to predict CO_2 breakthrough at monitoring wells within the reservoir. As the CO_2 dissolves into the reservoir water and releases heat, both the CO_2 and reservoir water experience an increase in temperature. This results in a thermal anomaly that migrates throughout the reservoir slightly ahead of the free phase CO_2 plume.

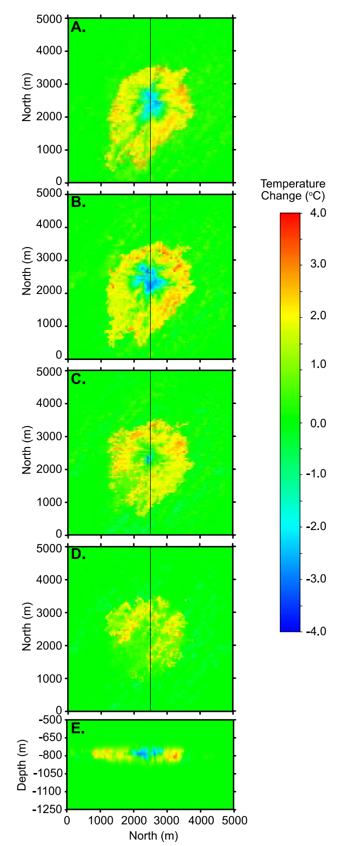

Figure 3. Change in temperature between pre-CO_2 injection temperatures to post-CO_2 injection temperatures for a single realization (20). Panels A-D represent the 4 injection layers within the model domain. E. A vertical north-south profile through the center (indicated by the black lines in A-D) of the model domain.

CONCLUSION

Basalt formations have been gaining recognition as potential reservoirs for carbon capture and sequestration. Upscaling field-scale experiments (i.e. Wallula Pilot Borehole) is required if CCS is to be used as a way to mitigate climate change. However, there are a number of uncertainties associated with upscaling to an industrial-scale CO_2 injection, particularly in the context of fracture-controlled reservoir permeability. This study investigates the uncertainty of a large-scale CO_2 injection into a highly heterogeneous basalt reservoir by focusing on the effects of spatially distributed permeability on CO_2 plume migration. The primary results from this study suggest that: (1) ensemble behavior is not governed by the spatial correlation structures, (2) the ensemble variance is strongly controlled by the spatial correlation structures, (3) for equally-probable permeability distributions, the volume of CO_2 that can be injected over 20 years can range from 2.4 – 40 MMT, and (4) the thermal effects of a CO_2 injection may be an effective MMV strategy. These results illustrate the uncertainty associated with highly heterogeneous flood basalt reservoirs and a CCS project would require extensive reservoir characterization and a unique monitoring, measuring, and verification plan.

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