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Modeling Studies of CO_2 Injection for Imaging and Characterizing Faults in Geothermal Systems

Curtis M. Oldenburg[1], Andrea Borgia[1], Rui Zhang[2], Yoojin Jung[1], Kyung Jae Lee[1],
Christine Doughty[1], Thomas M. Daley[1], Nikita Chugunov[3], Bilgin Altundas[3]

[1]Energy Geosciences Division 74-316C, Lawrence Berkeley National Laboratory, Berkeley, CA 94720

[2]University of Louisiana at Lafayette, Lafayette, LA

[3]Schlumberger-Doll Research, Cambridge, MA

cmoldenburg@lbl.gov, aborgia@lbl.gov, rxz1961@louisiana.edu, yoojinjung@lbl.gov, kyungjaelee@lbl.gov, cadoughty@lbl.gov, tmdaley@lbl.gov, nchugunov@slb.com, baltundas@slb.com

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ABSTRACT

We have carried out a modeling project aimed at assessing the utility of using supercritical carbon dioxide ($scCO_2$) injection to enhance fault characterization in geothermal systems. The methods we used in the study included numerical simulations of push-pull CO_2 injection using TOUGH2/ECO2N, including inversion, sensitivity, and data-worth analyses using iTOUGH2, dynamic range assessment of well-logging tools for high-temperature systems, and simulation of seismic monitoring using a finite difference code based on the SPICE codes. The prototypical enhanced geothermal system (EGS) site we focused on is the single-fault (Brady's-type) system at Desert Peak, Nevada, but we also investigated data-worth at a conjugate fault system based on the Dixie Valley geothermal system. Results of simulations of CO_2 push-pull injection into a single dipping fault modeled after the Desert Peak site show that CO_2 migrates upward in the fault gouge against the hanging wall with limited entry into the damage zone because $scCO_2$ is non-wetting relative to the liquid phase. During the pull phase, mostly water is produced because upward buoyancy puts the CO_2 out of reach of fluid drawdown in the well. Using the simulated pressures and saturations of CO_2 and brine in the fault gouge, we analyzed the feasibility of well logging and active seismic monitoring to detect the CO_2 and contribute to characterizing the fault. Dynamic range effective medium modeling of various high-temperature well-logging tools suggests that neutron capture is the most promising approach in the cased-hole environment provided there is enough salinity contrast, e.g., as could be facilitated by pre-flush with high-salinity brine. As for active seismic monitoring, the time-lapse crosswell geometry produces the strongest signal with time-lapse differences of 1-10% resulting from CO_2 migration in the fault gouge. The pressure transient of CO_2 injection into a single fault shows unique traits due to the multiphase flow conditions developed by CO_2 injection. Fault gouge permeability can be estimated from pressure transient data. CO_2 injection into a dual fault system (conjugate fault) such as that at Dixie Valley results in CO_2 entering both limbs of the fault, with CO_2 migration and pressure dissipation in the faults controlled by the permeability of surrounding damage and matrix components of the fault zone. We carried out data-worth analysis for hydraulic data from a dual fault system such as that at Dixie Valley, and we determined that pressures in the gouge at approximately one-half the depth of the injection point are the most valuable observation data to forecast CO_2 distribution in the faults. In summary, modeling and simulation of CO_2 push-pull hydraulic well testing with sensitivity and data-worth analysis, crosswell active seismic monitoring, and well logging suggest that these approaches are complementary and capable of providing useful characterization information for fault zones in EGS systems.

1. INTRODUCTION

Faults and fractures, either natural or a result of stimulation, are needed to provide permeability for sustainable geothermal energy production from high-temperature liquid-dominated geothermal systems in crystalline rocks. But one or two large fractures or faults may dominate fluid production and thereby provide poor thermal sweep through the geothermal resource. In order to design an effective fracture stimulation or to evaluate existing fractures and faults in geothermal systems, fracture and fault characterization is needed for both the natural and stimulated faults and fractures. We carried out a modeling project to assess the feasibility of using $scCO_2$ injection into faults at geothermal sites to enhance field characterization. The idea is that CO_2 injected into faults will create a significant contrast for active seismic and well-logging imaging, while also providing a pressure-transient response, the combination of which would assist in characterizing the fracture or fault system. In this brief paper, we summarize our results in evaluating the use of CO_2 injection into faults and fractures as a way of improving enhanced geothermal system (EGS) reservoir characterization.

Theory and empirical evidence (e.g., Majer et al., 1997, Tura et al., 2013, and Zhang et al., 2015) suggested that $scCO_2$ will provide contrast for monitoring by seismic and well-logging approaches, and we expected that a $scCO_2$ push-pull injection-production sequence can provide useful well-test information about the fault hydraulic properties. There are several properties of $scCO_2$ that make it a promising contrast and hydraulic well-test fluid for EGS: (1) $scCO_2$ is much more compressible than water at downhole in situ conditions, creating variations in stiffness tensor and correspondingly in effective seismic velocity; (2) $scCO_2$ is non-wetting and will therefore tend to stay in the fault/fracture plane and fault gouge without entering the fine-grained matrix; (3) $scCO_2$ is less viscous than ambient brine, facilitating fracture/fault permeation; (4) $scCO_2$ is denser than other gases (such as nitrogen or air) thereby decreasing the buoyant rise of the CO_2 plume in vertical faults and fractures.

In this brief paper, we summarize the research we carried out to assess the utility of a workflow involving CO_2 injection in a push-pull manner into faults at EGS sites in order to enhance the characterization of the fault zone. In the workflow, well logging and active seismic monitoring complement one another, and are together complemented by pressure-transient and data-worth analysis to inform monitoring locations and parameters that can provide the most value for characterizing the fault during the push-pull process.

2. SIMULATION OF CO_2 INJECTION AND PRODUCTION

Simulation of CO_2 injection and production provides the fundamental synthetic data needed to evaluate effectiveness of well logging and active seismic methods for enhancing the characterization of faults and fracture zones by CO_2 injection. Simulations of the push-pull injection and production of CO_2 were carried out using TOUGH2/ECO2N (Pruess et al., 2012; Pan et al., 2016) in an idealized fault. A conceptual sketch illustrating a well intersecting a fault with idealized CO_2 plume in the fault zone is shown in Figure 1a. Figure 1b shows the detail of the model domain and discretization around the fault zone with 40× horizontal exaggeration. The boundary for the model domain is assumed closed to fluid flow at the top and open to fluid flow on the sides and at the bottom. Here for brevity, we present only a snapshot of results in Figure 2 which shows that (i) CO_2 permeates the slip plane and gouge zone, (ii) does not enter the matrix appreciably, (iii) moves upward due to buoyancy, and (iv) accumulates under the upper side of the hanging wall due to buoyancy. Additional results and further details of our CO_2 injection modeling have been presented in Borgia et al. (2015; 2017a,b) and Oldenburg et al. (2016; 2018).

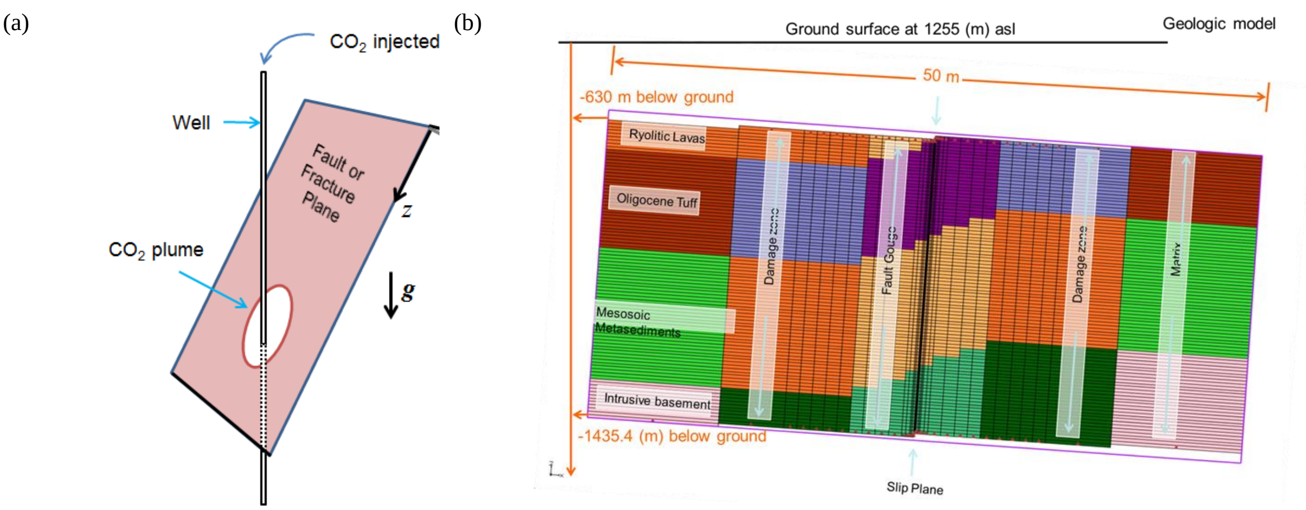

Figure 1. Conceptual model for injection of CO_2 into a dipping fault. (a) Sketch of coordinate system (the fault plane is parallel to the *x-z* axes) along with idealized circular CO_2 plume, and (b) conceptual model and grid for the Desert Peak 2D model with 40× horizontal exaggeration. The 2D-fault has slip-plane (10^{-2} m in thickness), gouge (5 m on both side of slip plane), damage zone (10 m on both sides of gouge) and intact matrix (10 m on both side of damage zone). The different rocks change their hydrogeologic parameters if they are a part of the damage zone, gouge, and slip plane. Geology is after Faulds and Garside (2003).

3. WELL LOGGING

Well logging provides a direct method of characterizing the fault zone following injection of CO_2 into the fault. In the workflow being evaluated here, well logging could be conducted on a similar schedule as active seismic monitoring, i.e., before, and soon after the CO_2 push-pull test, assuming access to the well can be provided between fluid-transfer events. The high-temperature of EGS sites (T > 175 ºC) limits the number of tools available for wireline well logging, and requires the use of so-called "hostile environment" (high-temperature) versions of the tools. Dynamic range calculations and analyses of fault-zone saturations forecasted by our modeling work (see Section 2) suggest that induction logging (electrical conductivity) and neutron capture monitoring might be feasible for tracking injected CO_2 in fault gouge. More details of the analyses of well logging as part of the CO_2 push-pull workflow in this project were presented previously (Oldenburg et al., 2016; 2018; Borgia et al., 2017a, b).

4. MODELING OF ACTIVE SEISMIC MONITORING

We simulated active seismic monitoring to address the question of whether CO_2 injected into faults and fractures can enhance detectability by active seismic approaches, and if so, can active seismic methods be used to characterize the fault or fracture zone. At the heart of this question is whether the CO_2 injection causes enough contrast in elastic properties over enough volume to affect seismic wave propagation at a level that is resolvable by the measurements. The model system we have used for modeling studies to address these questions is the same as used for the push-pull injection simulations, namely the single-dipping fault (Brady's type) Desert Peak system as shown schematically with velocity model in Figure. 3a.

(a) (b)

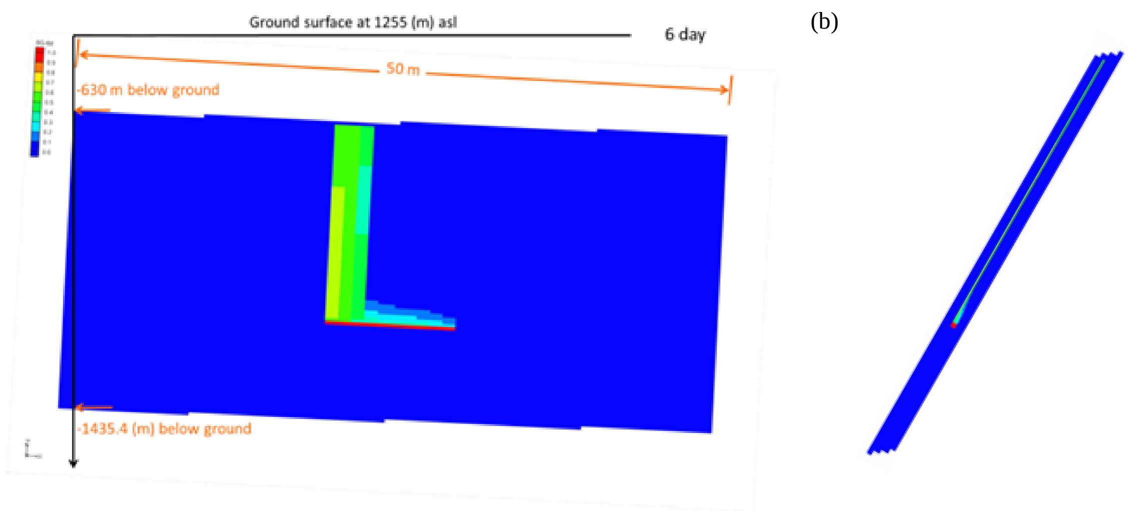

Figure 2. CO_2 saturation simulation results after six days of injection of CO_2 injection into a "Brady's-type" normal fault with 60° of dip. Fault gouge and slip plane are homogeneous in hydrogeologic properties. Note how the CO_2 plume develops against the hanging wall of the fault not entering the damage zone in the short time of the simulation. (a) 6 days, and (b) the same results with no horizontal exaggeration.

Our approach was to simulate active seismic imaging using finite difference solutions to wave propagation equations as implemented in a code originally from SPICE (http://www.spice-rtn.org/library/software.1.html) which was modified at LBNL for parallel processing, choice of boundary conditions, and for consideration of fracture properties. We assumed here that changes due to fluid injections in fractures can be treated as an equivalent isotropic porous region (with modified velocity). Details of the methods in the numerical model are provided in Oldenburg et al. (2018), and Zhang et al. (in prep.).

We modeled an active source which will send out seismic waves through the target zone to be reflected by the interfaces of rock volumes with different velocities or by discrete discontinuities such as fractures. By assessing properties of the modeled reflected waves on the free surface or within specific seismic monitoring boreholes, we can infer effective rock properties as would be done in a field experiment. In order to model seismic wave propagation in isotropic porous media, estimates of the bulk fluid- and rock-mixture properties are needed. We used an accurate equation of state model to estimate CO_2 and water properties to calculate mixture elastic properties for various rock types (Altundas et al., 2013). We assumed homogeneous fluid mixing (the typical Gassmann relation) rather than a more complex patchy saturation model. A profile of the velocity model we used is shown in Figure 3b. As shown, there is an overall upward decrease in P-wave velocity in the layered volcanics of the system. Superimposed on this variation is the CO_2-induced change in P-wave velocity arising from the CO_2 saturations modeled by TOUGH2/ECO2N (e.g., see also Figure 2).

Detection of change in seismic data is one goal, however the correct spatial localization of change is a separate goal that requires seismic "imaging." Imaging is a data and numerical processing activity that places seismic energy, recorded using an arbitrary geometry with an arbitrary velocity model, in its correct subsurface location. Reverse time migration (RTM) (e.g. Baysal, et al., 1983) is one imaging method. To enhance the characterization of the fault zone via seismic imaging, we carried out RTM of the synthetic crosswell active seismic monitoring data using the method of Zhu, et al. (2014). Figure 4 shows the active seismic monitoring conceptual velocity model corresponding to CO_2 saturations, *P*, and *T* from the TOUGH2/ECO2N simulations and source and receiver configuration in crosswell setting around the fault. An example of seismograms from one source receiver at one time (forming a wavefield "snapshot") is shown in Figure 4b. Figure 5 shows the seismograms corresponding to pre- and post CO_2 injection, and their difference (bottom). Corresponding RTM images and their difference (bottom right-hand image) can be seen in Figure 5. As shown, the difference in RTM shows a dipping structure that represents the fault where CO_2 saturation appears to be high. This result demonstrates the possibility that CO_2 injection along with active seismic imaging can be used to locate and orient faults at EGS sites into which CO_2 is injected.

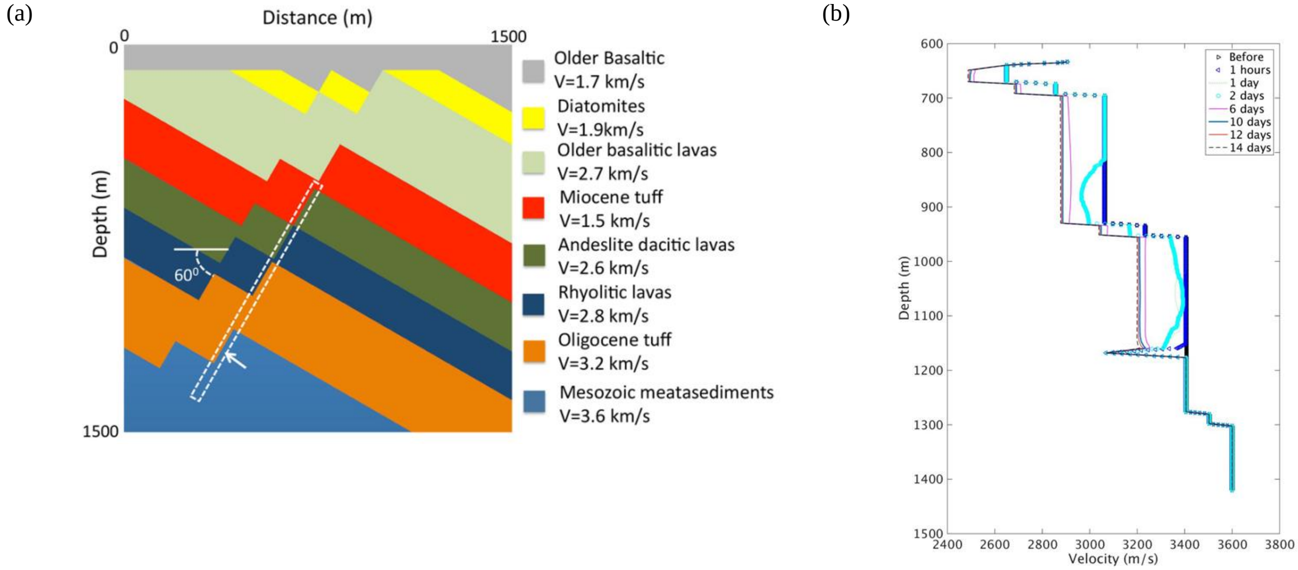

Figure 3. Conceptual model for active seismic modeling, (a) 2D model cross-section of Desert Peak (Rhyolite Ridge fault zone) after Faulds et al. (2010) showing background P-wave velocity model and (b) 1D velocity model showing effects of CO_2 saturation in the gouge. The white dashed line in (a) outlines the domain of the CO_2 injection simulations.

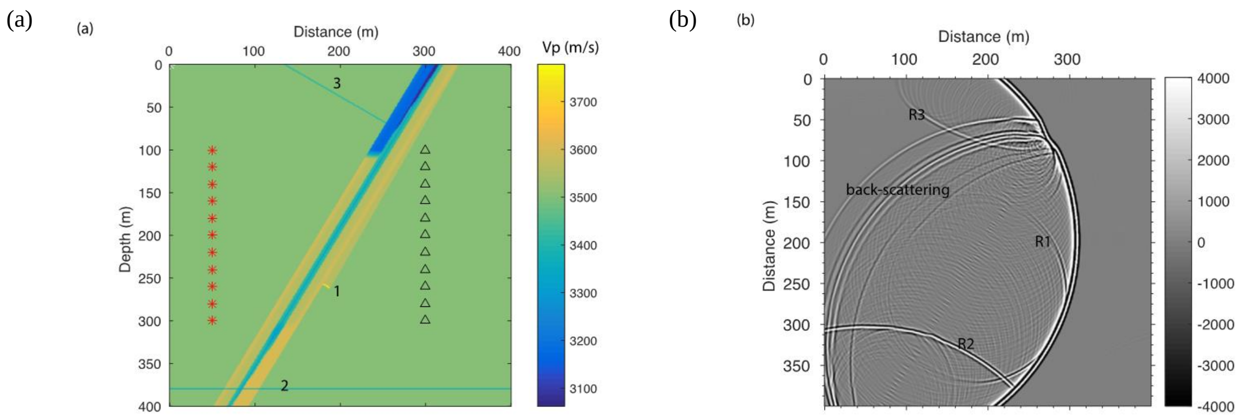

Figure 4. (a) Crosswell survey geometry with the P-wave velocity model with CO_2 in the gouge of the fault zone; (b) Modeled wavefield seismogram from one source-receiver at one time (a wavefield snapshot) with labeled reflection events.

5. PRESSURE TRANSIENT AND SENSITIVITY FOR SINGLE FAULT

We evaluated the feasibility of using pressure transient monitoring during CO_2 push-pull tests to complement active seismic and well logging for EGS characterization. For this purpose, we used the same 2D prototypical geothermal site (Desert Peak, NV) with a single fault with a larger domain appropriate for focus on pressure response. Through numerical simulation using iTOUGH2, we found that the pressure transient at the monitoring wells in the fault gouge shows unique traits due to the multiphase flow conditions developed by CO_2 injection, and varies sensitively on the arrival of the CO_2 plume and the degree of CO_2 saturation. A sensitivity analysis shows the pressure transient is most sensitive to the fault gouge permeability, but also depends on multiphase flow parameters and the boundary conditions of the fault. Some highlights of the study are summarized in this section, with details available in the full manuscript that is currently in review (Jung et al., 2018).

We used TOUGH2/ECO2N V2.0 (Pruess et al., 2012; Pan et al., 2014) to develop a model and simulate the two-phase flow of CO_2 and water during CO_2 push-pull injection-production. This code is able to simulate two-phase flow in the *P* and *T* range up to 600 bars and 300 °C, respectively, and is therefore appropriate for EGS applications. Here, consistent with the terminology in TOUGH2/ECO2N, a CO_2 -rich non-wetting phase is referred to as a gas phase. iTOUGH2-PEST (Finsterle, 1993; Finsterle, 2004; Finsterle et al., 2016; Finsterle and Zhang, 2011) was used for sensitivity and inverse analysis.

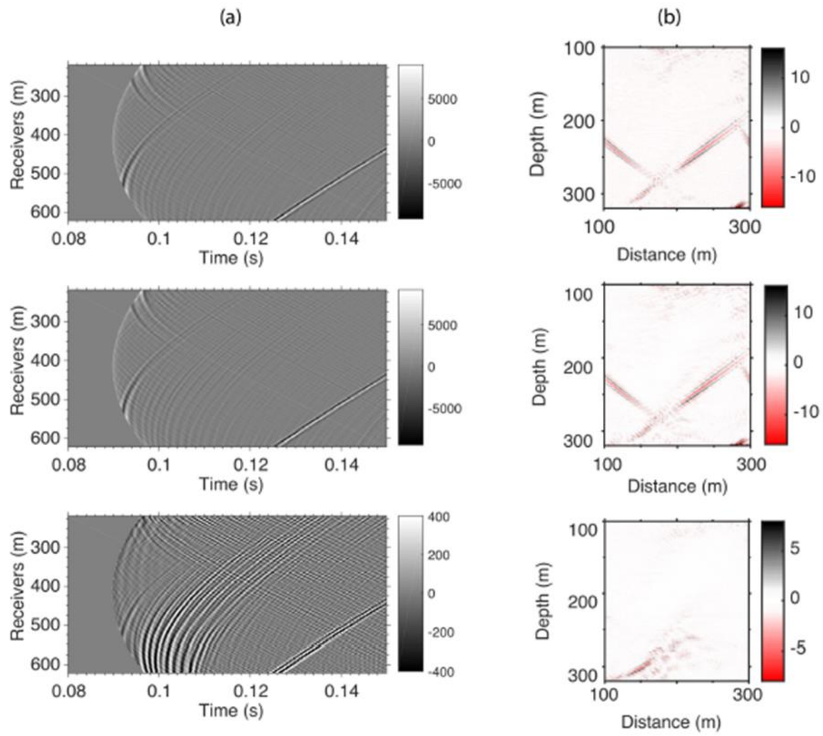

Figure 5. (a) Seismograms of pre- (top) and post- (middle) CO_2 injection after two days and the difference (bottom). (b) Results of reverse-time migration of pre- and post-CO_2 injection seismograms and their difference (bottom).

We adapted and expanded the 2D model domain originally developed by Borgia et al. (2017a; b) representing features of the Desert Peak geothermal field to explore the technical feasibility of CO_2 push-pull testing for EGS fault/fracture characterization for pressure transient analysis. The fault gouge, damage zone, and country rock matrix have distinct fluid-flow properties (i.e., permeability and porosity) along with typical multiphase flow properties (see Jung et al. (2018) for details). The injection/production well was assumed to be open only in the fault gouge and slip plane, and a constant pressure of 0.3 MPa above and below the ambient hydrostatic pressure (ΔP_{inj} = 0.3 MPa and ΔP_{prod} = -0.3 MPa) was applied for injection and production of CO_2, respectively. CO_2 was injected for 4 days, then fluid comprising a mixture of CO_2 and brine is produced for 4 days from the same well. We assumed that additional observation wells were available for pressure monitoring and frequent well logging for the purpose of fault characterization, and several potential monitoring locations along the fault gouge were considered. We assumed that CO_2 saturation data were available as the result of neutron capture well logging analysis.

Figure 6 shows the temporal variation of pressure transient and gas saturation at the selected monitoring wells. The pressure transients at the monitoring wells MW50m, MW100m, and MW200m in general show a similar pattern during the push period. As the CO_2 injection starts, the pressure propagates from the injection well and a gradual pressure increase is observed. The pressure increases rather steeply when CO_2 reaches the monitoring location. Due to the distance from the injection well, the pressure transient increases in consecutive order from MW50m to MW200m. In addition, the injected CO_2 decompresses as it rises upward through the hydrostatic pressure of the resident water.

During the pull period, the pressure transients at MW50m, MW100m, and MW200m decrease after a lag time, which proportionally increases with the distance between the production well and the monitoring well. The lag time is associated with pressure diffusion. CO_2 will keep flowing upward until the underpressure imposed at the production well propagates to the monitoring location. For the CO_2 push-pull, the lag time is additionally affected by the strong buoyant rise of CO_2. The gas saturation at the monitoring locations decreases because CO_2 keeps flowing upward and exits the fault zone, not because it is recovered at the production well. Note that Figure 6 includes as a comparison the pressure transient at MW200m when water is used as an agent for the push-pull test (ΔPw at MW200m).

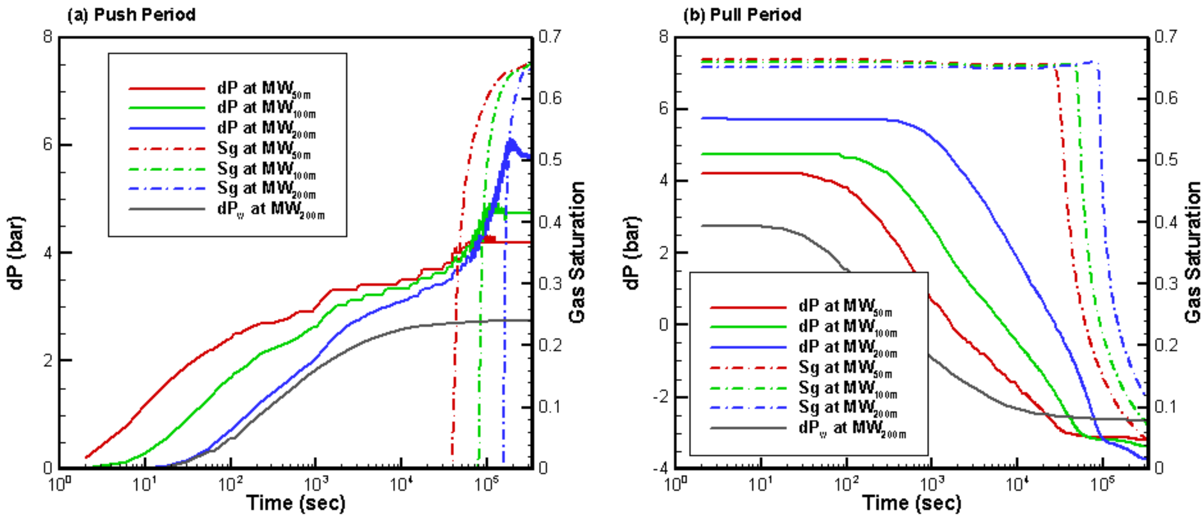

Figure 6. Pressure transient (solid) and gas saturation (dash-dot) at MW50m, MW100m, and MW200m during the push and pull periods. As a reference case, a pressure transient with water as an agent for the push-pull test (ΔPw at MW200m) is also shown.

We assessed the sensitivity of pressure-transient and gas-saturation data to various model parameters and conditions using scaled sensitivity coefficients shown in Figure 7, which normalize sensitive coefficients by the a priori standard deviation of observation and the expected parameter variation. For both the push and pull periods, the pressure transient and gas saturation are most sensitive to the fault gouge permeability. The influence of the damage zone and matrix permeability on the pressure transient is minor, and on the gas saturation is even smaller because CO_2 mainly flows through the fault gouge. Among different monitoring locations, the sensitivity is the strongest at MW200m.

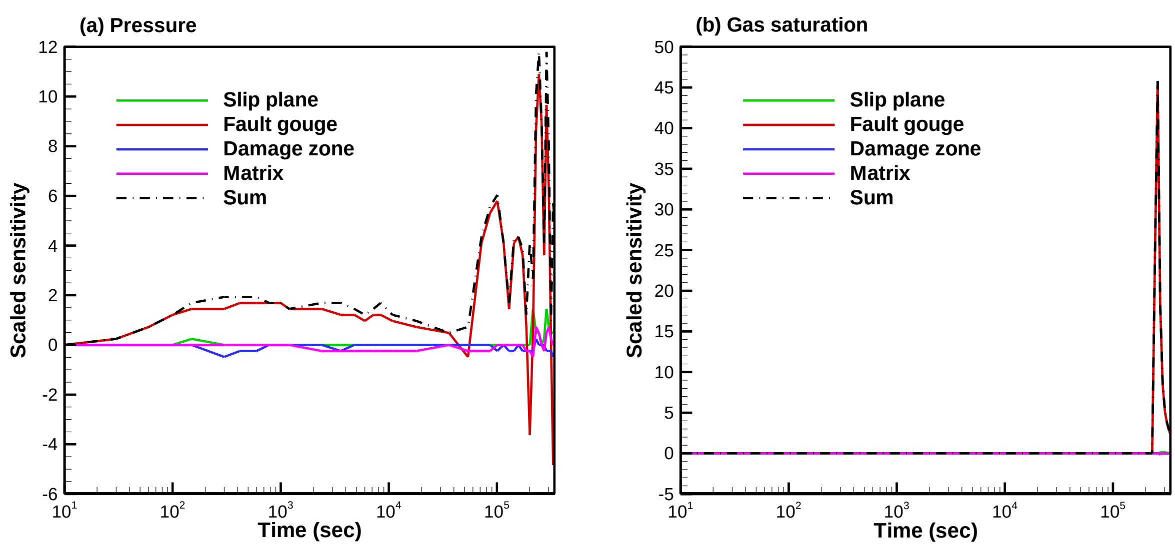

Figure 7. Temporal variation of the scaled sensitivity to material permeabilities: (a) pressure transient and (b) gas saturation.

To summarize our results, we observed that the modeled CO_2 mostly flows upward through the fault gouge and therefore the pressure transient mainly reflects the gouge properties such as gouge permeability. Consequently, the fault gouge permeability is most accurately estimated using the pressure transient data for inverse modeling. We also found that the local change in pressure at monitoring locations far above the injection point can be larger than the injection-induced pressure change at the injection well. This phenomenon occurs because of the gas column formed by the CO_2 and its lower density relative to brine. In short, the top of the gas column exerts its pressure on the water column in the fault zone above, and the associated overpressure exerted can be much larger than the injection overpressure itself.

6. HYDRAULIC DATA-WORTH ANALYSIS FOR A DUAL (CONJUGATE) FAULT SYSTEM

In the final part of this project, we developed a conceptual and numerical reservoir model of two intersecting faults based on the Dixie Valley geothermal system (DVGS) in Nevada. The 2D conceptual model consists of a system with a main fault and an intersecting conjugate fault. The corresponding numerical model is discretized using irregular grid blocks with fine discretization around the slip plane, gouge, and damage zones. We performed forward modeling along with sensitivity and data-worth analyses of scCO_2 push-pull to investigate the CO_2 distribution in the fault gouge during 30 days of push (injection) and 30 days of pull (production). Formal sensitivity analysis was conducted to determine the most controlling unknown parameters in the fault zones. Using the selected set of unknown parameters and output responses, we performed data-worth analysis to reveal the most valuable output response to be measured for the best prediction of CO_2 distribution in the fault zones and its uncertainty. From the results of data-worth analysis, we determined the optimal properties to target in monitoring, their locations, and the minimum observation time. Our results provide information on the optimal design of scCO_2 push-pull testing in a conjugate fault system modeled after Dixie Valley that can be used to enhance monitoring by active seismic and well-logging methods to better characterize the transmissive fault(s). Details of this study are presented in Lee et al. (submitted).

The conjugate fault system of the geothermal resource at Dixie Valley in central Nevada is estimated to approach a 260 °C at a depth of 3 km (Blackwell et al., 2007; Iovenitti et al., 2016). In the forward modeling of scCO_2 push-pull in this study, we simulated the injection and production of scCO_2 into the junction of two conjugate faults. We also conducted a sensitivity analysis to evaluate the factors affecting CO_2 inflow into the faults and outflow from the faults, and a data-worth analysis to predict the uncertainty of CO_2 distribution after the push and pull phases by measuring the system responses. Here, we briefly summarize the data-worth analysis.

A conceptual cross section of the DVGS (Figure 8a) shows hot brine rising along the main faults giving rise to the isotherms (Smith et al., 2011). This conceptual model is captured in our model domain as shown in Figure 8b. Although the conceptual model is very simplified, it includes the essential components that affect flow of injected CO_2 and therefore retains the fundamental fault-flow-related aspects of the system. The corresponding numerical model is discretized using irregular grid blocks with fine discretization around the slip plane, gouge, and damage zones as shown in Figure 9.

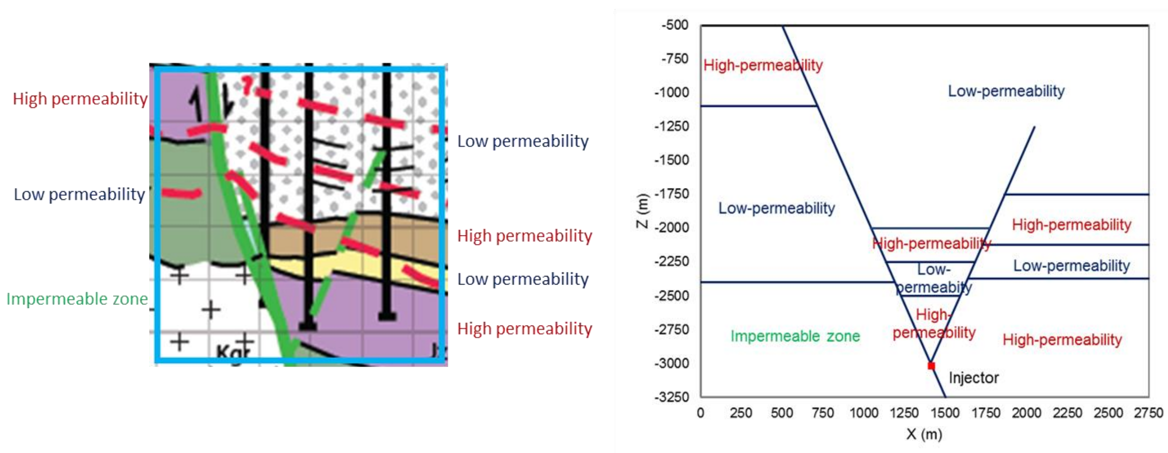

Figure 8. (a) Conceptual model of the 2D DVGS system. (b) Simplified model for simulating CO_2 push pull in a dual-fault system.

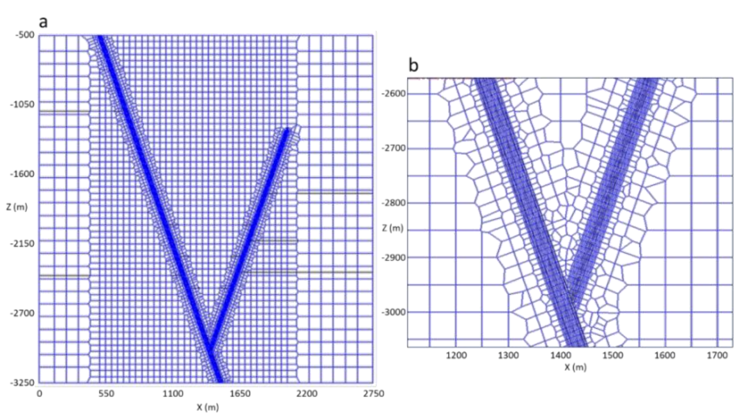

Figure 9. Grid geometry of the 2D conceptual model domain: (a) entire view, (b) expanded veiw at the junction of the two faults. Note that the horizontal black lines in (a) indicate the boundaries of different lithologic zones shown in Figure 8b.

Results of the injection simulation for pressure, temperature, and CO_2 saturation are shown in Figure 10. As shown, the CO_2 rises farther up the right-hand conjugate fault even though this fault terminates in the domain rather than at the top of the domain. The reason for this result is that this fault is surrounded by proportionally more high-permeability matrix where displaced water can flow relative to the longer limb of the conjugate fault system (see Figure 8b).

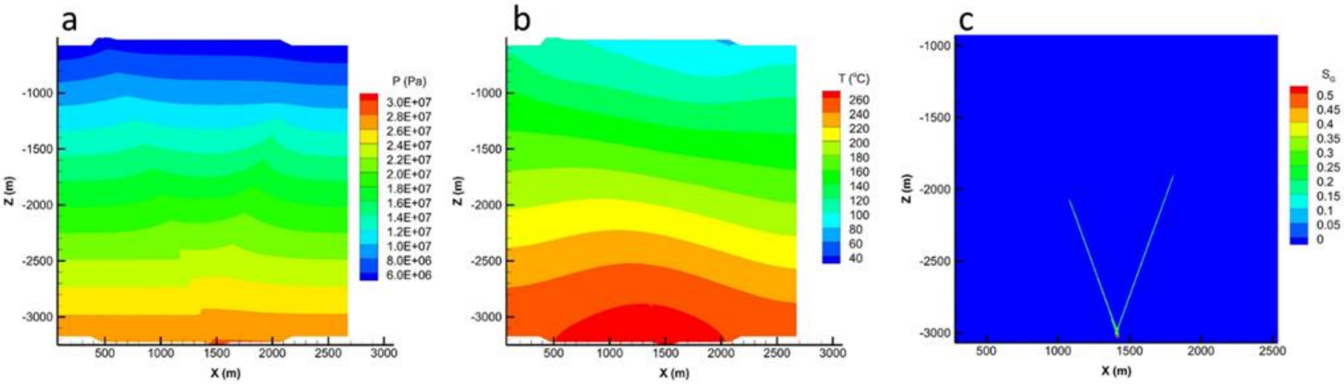

Figure 10. Reservoir simulation results after 30 days of push: (a) pressure distribution, (b) temperature distribution, (c) gas saturation distribution.

We carried out a data worth analysis to guide potential monitoring that would be done in a field deployment of CO_2 push-pull. The approach was to perturb the five most-controlling unknown parameters in each of push pull phases

- Push: slip plane (S_{gr}), fault gouge (λ, $1/P_0$, S_{lr}, S_{gr})
- Pull: slip plane (S_{gr}), fault gouge ($1/P_0$, S_{gr}), damage zone (k, S_{gr})

for 30 days of CO_2 injection, followed by observation for 20 days of the 12 measurable responses

- Pressure (main & conjugate fault @ 2925, 2520, 2100 m)
- Temperature (main & conjugate fault @ 2925, 2520, 2100 m)

Then we predict the CO_2 distributions in the fault zones after 30 days of pull

- SG at main & conjugate fault @ 2925, 2520, 2100 m)

Results of the sensitivity analysis are shown in Figure 11. In the push phase, PM_2520 m showed the highest data worth for reducing prediction uncertainty, followed by PC_2520 m, PC_2100 m, and PM_2100 m. By summing up the data-worth values, we found that the measurement of these four observation data reduced the prediction uncertainly by 86.45%. In addition to these four observations, measurement of PM_2925 m reduced the prediction uncertainty even more. The measurement of temperature was not necessarily recommended for the reduction of prediction uncertainty, owing to their low data-worth values. The reason for this result is the much higher sensitivity coefficients of pressure than temperature, which arise because of the faster and more active response of pressure relative to temperature during the push process. These results can be used to guide field monitoring efforts to measure CO_2 saturation in order to calibrate and constrain active seismic monitoring used to characterize the extent and properties of fault zones relevant to EGS objectives.

CONCLUSIONS

We have carried out a modeling and simulation study to investigate the utility of injecting CO_2 into fault zones at EGS sites to enhance geophysical contrast to aid characterization of faults by well logging and active seismic monitoring. The CO_2 injection and withdrawal process can also be used for pressure-transient analysis that can provide complementary data for characterizing the fault zone. Simulations of the injection of CO_2 show that gravity causes the CO_2 to preferentially flow up the hanging wall in the gouge zone of a dipping fault. Simulation of active seismic monitoring of the CO_2 injection in a crosswell configuration shows time-lapse changes may be large enough to be useful for characterizing the fault, e.g., by RTM approaches. High-quality seismic data will be needed, motivating improvements in signal-to-noise ratio for seismic monitoring. Neutron capture well logging appears to be capable of detecting and characterizing the saturation distribution of CO_2 in the fault gouge particularly if a saline fluid pre-flush is carried out. Complementing the geophysical methods are pressure-transient and data-worth analyses which show that pressure monitoring at specific locations provides optimal data for characterizing fault gouge permeability. Additional details, limitations, notes on future work, and a preliminary field demonstration test plan are provided in Oldenburg et al. (2018).

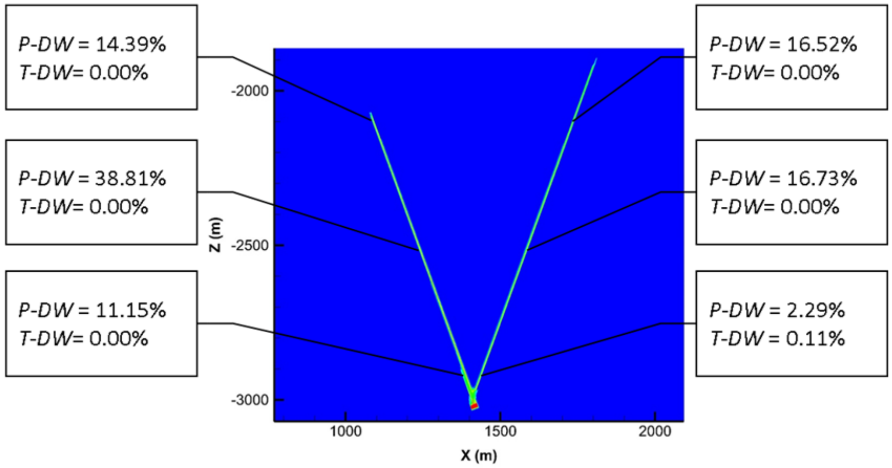

Figure 11. Data worth values at each observation point in push phase. The gas saturation shown is from immediately after the push period.

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