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Simulations of Carbon Dioxide Injection, Seismic Monitoring, and Well Logging for Enhanced Characterization of Faults in Geothermal Systems

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ABSTRACT

Fault and fracture networks with permeability are essential in any geothermal field to provide surfaces for heat transfer and sufficient fluid production rates. Yet characterization of the geometry and hydrogeologic properties of natural faults, fractures, and stimulated fracture networks remains an outstanding problem. We propose to inject and produce supercritical CO_2 ($scCO_2$) in and out of faults and fracture networks, using push-pull well experiments coupled with active-source geophysical monitoring and well logging to characterize the fault and fracture characteristics relevant to Enhanced Geothermal Systems (EGS). Replacing formation brine with $scCO_2$ effectively increases the contrast in geophysical properties between fault/fractures and matrix. We present modeling results that explore the technical feasibility of the approach. Using TOUGH2-ECO2N, we simulate the injection and production of CO_2 into a normal fault based on faults at the Brady's geothermal field and model pressure and saturation conditions in the fault zone. Because of the combination of a dipping fault and $scCO_2$ buoyancy, the injected CO_2 plume grows upward in the fault gouge against the hanging wall. It does not enter the damage zone because of the non-wetting characteristics of $scCO_2$ relative to the liquid phase, which keeps the gas in the gouge excluding it from the damage zone and matrix. The simulated CO_2 injection results are used in the project to model seismic and well-logging approaches to fault characterization. Separate pressure-transient and coupled well-fault injection simulations are also being carried out. We model the response of the system to active seismic monitoring in time-lapse mode using anisotropic finite difference codes from SPICE with modifications for fracture compliance. Results to date show that even narrow fault and fracture zones filled with CO_2 can be detected using Vertical Seismic Profiling (VSP). The active seismic simulations are complemented by modeling of well logging, with neutron capture and induction tools showing the most promise for high-temperature systems, especially if saline water pre-flushes are carried out.

1. INTRODUCTION

Connected fractures and/or faults and associated permeability are essential in any geothermal field to provide surfaces for adequate heat transfer and sufficient fluid production rates. In many fields, fluid production is sustained by a small number of more prominent fractures and faults. Faults are obviously the best candidate for enhanced fluid production because they tend to have greater extent and permeability. At enhanced geothermal system (EGS) sites, stimulation of fractures is also done to allow hydraulic connection between the producing well and larger conductive faults (Genter et al., 2010). Therefore, strategies for reservoir development and stimulation will certainly benefit from enhanced fracture and fault network geometric and fluid-dynamic characterization.

To achieve this characterization, we propose to inject and produce supercritical CO_2 ($scCO_2$) in and out of faults, using push-pull (injection/production) well operations, and to use active-source geophysical monitoring and well logging that are sensitive to CO_2 saturation to enhance characterization of the fault zone. The key idea is to use CO_2 to effectively increase the contrast in geophysical properties between fractures or fault zone materials and the matrix rock, improving characterization of the permeable features (Borgia et al., 2015; Oldenburg et al., 2016).

The reasons that $scCO_2$ are promising as an injectate to enhance geophysical contrast of faults and fractures are:

(1) $scCO_2$ is much more compressible than water at supercritical conditions, creating variations in stiffness tensor components and resulting seismic velocity;

(2) $scCO_2$ is non-wetting and will therefore tend to stay in the fault gouge or slip plane 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 (like nitrogen or air) decreasing the buoyant rise of the CO_2 plume in vertical faults and fractures and thereby enabling better recovery during the pull phase.

In this brief paper, we present example simulations of the injection of CO_2 into a normal fault in topological conditions that are similar to those found at Rhyolite Ridge just north of the Brady's geothermal field in Nevada. The simulations produce pressure and saturation conditions in the fault gouge that can be analyzed for their active seismic monitoring and wellbore logging response. Example simulations of geophysical monitoring are presented below to demonstrate the approach.

2. CONCEPTUAL MODEL

Our "Brady's type" conceptual fault model consists of a normal fault with a 60° dip (Fig. 1). The fault has a fault gouge, with a slip-plane within it, and a damage zone on both sides of the fault gouge. Farther away is the unfractured rock matrix (Fig. 2).

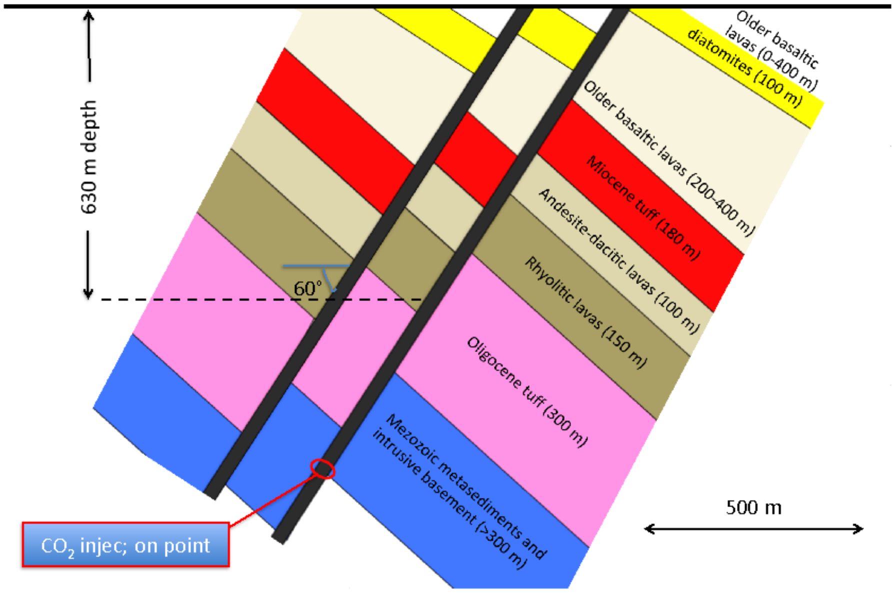


Figure 1. Schematic Geologic cross section of the Rhyolite Ridge fault system at Brady's geothermal field (modified after Faulds and Garside (2003). In our model we consider only the single fault on the right-hand side.

In the simplest configuration, we use a 2D hydrogeologic fault model in order to evaluate the $scCO_2$ injection and production processes. We model the various matrix rocks and include variations in properties of these formations depending on their locations in the damage zone or fault gouge. In the example numerical experiment shown here, we use homogeneous permeability for the cap rock and the reservoir matrix. Porosity and density are a function of rock type as shown in Table 1. Two-phase relative permeability is modeled after Corey (1954), while we use the van Genuchten (1980) model for capillary pressure (*Pc*).

3. SIMULATION OF CO_2 INJECTION IN NORMAL FAULT

We present for brevity one of the many numerical experiments that we have carried out for the Brady's model system. The example case consists of a homogeneous fault gouge with larger permeability and smaller capillary pressure than the damage zone. In the experiment, we inject $scCO_2$ at a location 2/3 of the distance from model top to bottom by fixing the pressure at 0.3 MPa above ambient hydrostatic pressure held at 100% CO_2 saturation at the local temperature over the full thickness of the fault gouge (e.g., see Fig. 3a).

Our grid is made of 10 m × 10 m elements in the across-fault (X) and down-dip (Z) directions. In the horizontal direction parallel to the fault direction (Y-direction) cells are 50 m wide. The grid has 93 grid blocks extending from -630 m below the surface to -1435.4 m below the surface including boundaries at top and bottom. The water table is assumed to be at -30 m from the ground surface. In the X-direction cell dimensions vary from 10 m in the matrix, to 5 and 1 m in the damage zone, to 1 m and then down to 1 cm in the fault gouge, and finally to 1 cm in the slip plane (Fig. 2b). The boundary conditions are open to flow at the top and bottom. For the simulations we use TOUGH2-ECO2N (Pan et al., 2015), a module that represent the CO_2 equation of state from 10 to 300 °C and up to 60 MPa.

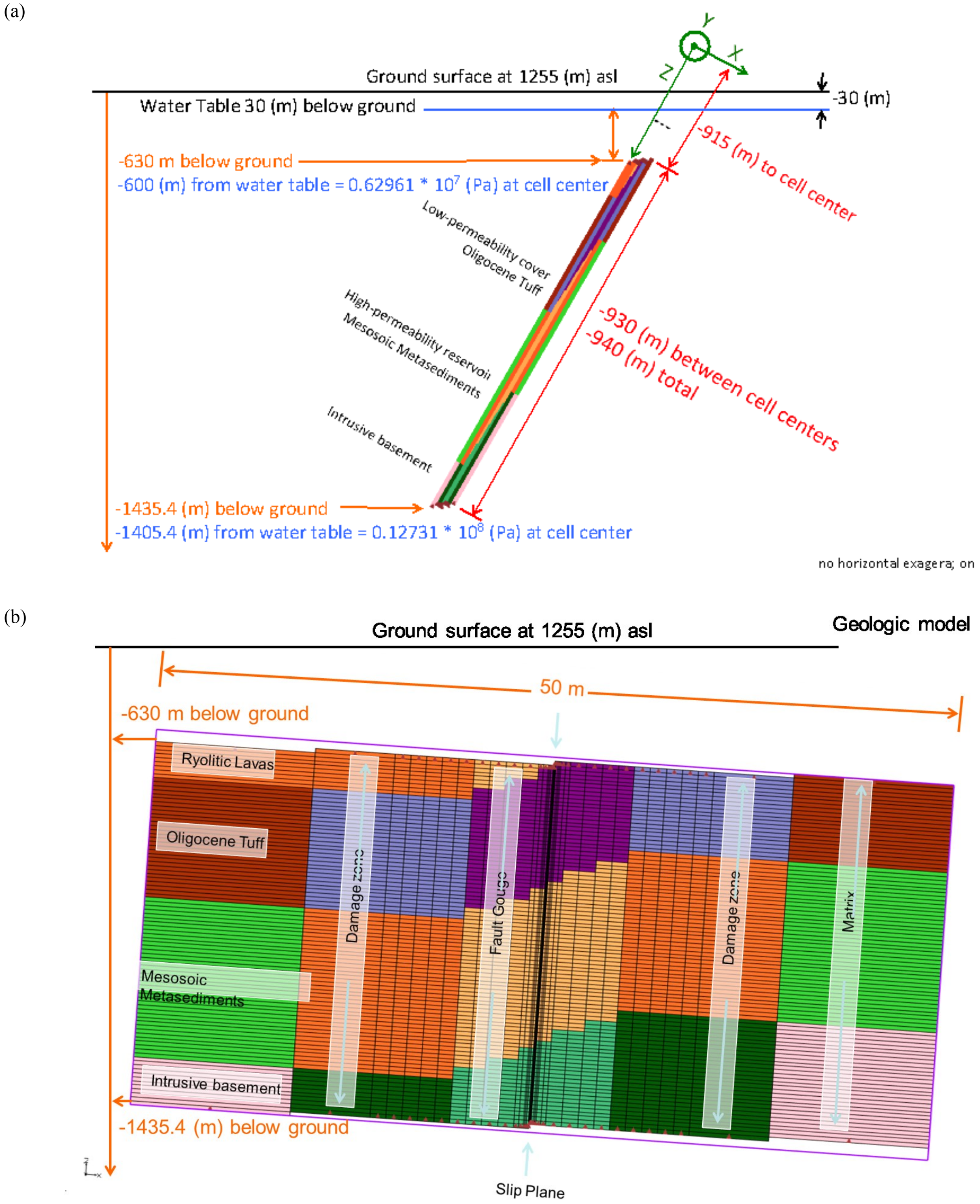


Figure 2. Conceptual model and grid for the Brady's 2D model. The 2D-fault has slip-plane (10^{-2} m in thickness), gouge (5 m on both side of slip plane), damage zone (10 m on both side of gouge) and intact matrix (10 m on both side of damage zone). The different rocks may change their hydrogeologic parameters if they are a part of the damage zone, gouge, and slip plane. Geology is after Faulds and Garside (2003). (a) no vertical or horizontal exaggeration; (b) 40 times horizontal exaggeration.

Table 1. *Properties of the Brady's system.*

Hydrogeologic property	**ρ (kg/m^3)**	**ϕ**	**$k_{x,z}$ (m^2)**	**Cp (Pa)**
High Permeability aquifer				
Matrix (Ryolitic Lavas):	2650	0.1	1.00E-16	1.00E+08
Damage zone:	2650	0.05	1.00E-15	1.00E+08
Fault gouge:	2650	0.1	1.00E-12	0
Slip plane:	2650	0.3	1.00E-12	0
Low Permeability Cover				
Matrix (Oligocente Tuff):	2450	0.1	1.00E-16	1.00E+08
Damage zone:	2550	0.05	1.00E-15	1.00E+08
Fault gouge:	2550	0.1	1.00E-12	0
Slip plane:	2550	0.3	1.00E-12	0
High Permeability Reservoir				
Matrix (Meta Sediments):	2550	0.05	1.00E-16	1.00E+08
Damage zone:	2650	0.05	1.00E-15	1.00E+08
Fault gouge:	2650	0.1	1.00E-12	0
Slip plane:	2650	0.3	1.00E-12	0
Low Permeability Basement				
Matrix (Intrusive Basement):	2750	0.01	1.00E-19	1.00E+08
Damage zone:	2750	0.05	1.00E-15	1.00E+08
Fault gouge:	2750	0.1	1.00E-12	0
Slip plane:	2750	0.3	1.00E-12	0

Although our conceptual model is simplistic, we consider it sufficient to show some of the complexities that arise during injection of CO$_2$ into a normal fault and to reveal some of the challenges for geophysical imaging. Future numerical experiments will consider 3D geometry and injection into conjugate faults such as those at Dixie Valley, Nevada.

Fig. 3 shows the results of the example case of a homogeneous fault gouge. Because of buoyancy and lower permeability in the basement rock, most of the CO$_2$ flows upward along the fault gouge against the hanging wall. The CO$_2$ does not enter the damage zone because of its lower permeability and higher capillary pressure at the brine–scCO$_2$ interface (Borgia et al., 2013). In less than 4 days the CO$_2$ has reached the top of the domain. Because of decompression, the CO$_2$ plume tends to expand in the *x*-direction at its upper extent, creating a "tooth" at 2 days. After 4 days, the fault gouge has been filled by a band of CO$_2$ about 4 m thick. Most of these details of the flow are not evident in the model results shown without horizontal exaggeration (Fig. 3e).

During the corresponding pull (production) process (not shown here for brevity) with production specified by setting pressure 4 MPa below ambient hydrostatic at the same point that CO$_2$ was injected, practically no CO$_2$ is recovered back into the well. Instead water flows back into the fault gouge largely supplied by water along the footwall side of the gouge.

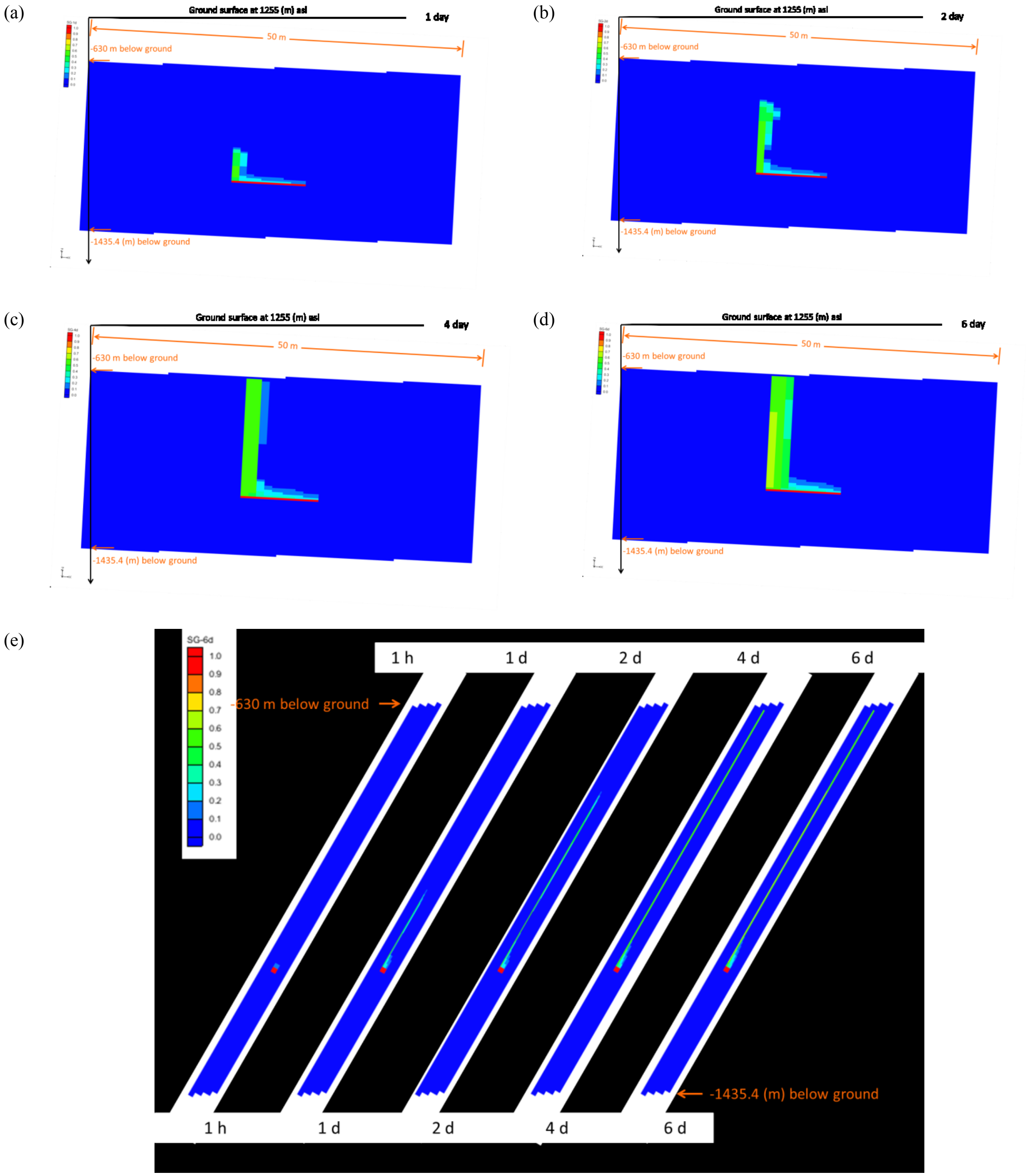


Figure 3. 2D model of CO_2 injection in a "Brady's-type" normal fault with 60° of dip. Fault gouge and slip plane are homogeneous in hydrogeologic properties. Note how the CO_2 plume develops against the hanging wall of the fault not entering the damage zone in the short time of the simulation. Note also the tooth that develops at the top of the plume. a) 1 day, b) 2 days, c) 4 days, d) 6 days, and e) the same results with no horizontal exaggeration. The inclined red line is made by the injection cells within the fault gouge.

SIMULATION OF ACTIVE SEISMIC MONITORING

The next step in the workflow to demonstrate the use of CO_2 injection for enhancing characterization of faults is to simulate the seismic response of the system. We simulate a surface seismic source located 40 m from the well in the up-dip direction with vertical seismic profiling (VSP) receivers in the well. CO_2 saturation changes the stiffness component C11 in a very narrow region (the fault zone) as shown in Fig. 4, which shows C11 change as a result of the simulated saturations shown in Fig. 3. We model seismic wave propagation using a code based on SPICE (http://www.spice-rtn.org/library/software.1.html). The differences in C11 from pre-injection (no CO_2) to post push (CO_2 injection) produce time-lapse differences on the order of 1-2% percent as shown in Fig. 5. This difference is small but potentially detectable if high-quality data are collected. We are investigating how to enhance data quality, e.g., through optimal positioning of source and receivers, or using cross-well geometry to enhance signal.

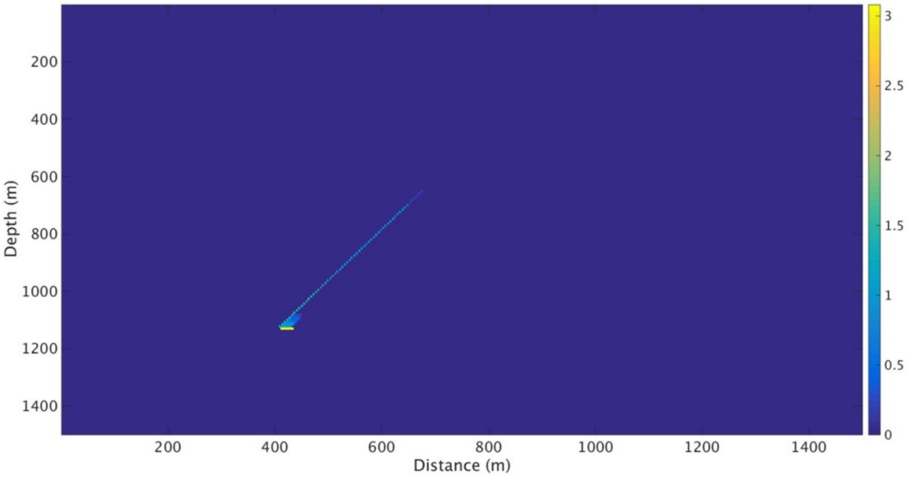


Figure 4. Changes in C11 (GPa) arising from CO_2 saturation in the fault zone as simulated in the push phase shown in Fig. 3.

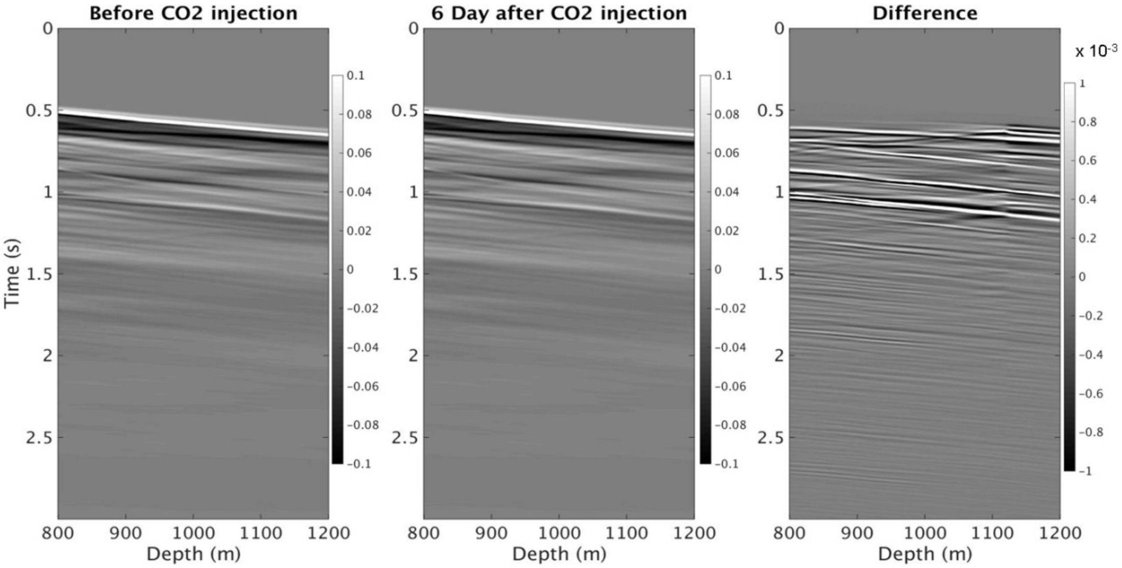
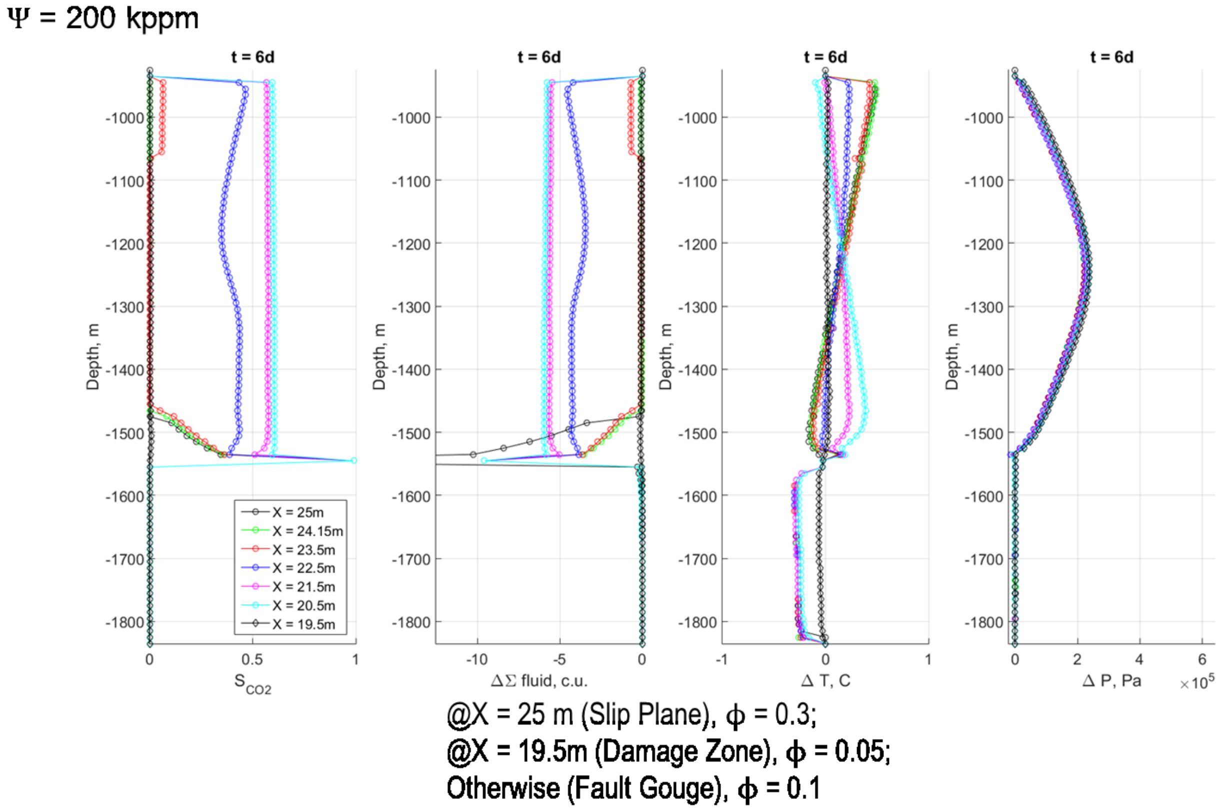


Figure 5. Pre- and post-CO_2-injection seismic modeling results along with the time-lapse difference on the order of 1-2%.

FEASIBILITY OF WELL-LOGGING METHODS

Well logging provides another method of characterizing the fault zone following injection of CO_2 into the fault. Well logging could be conducted on a similar schedule as the VSP, i.e., before, during, and after the push-pull CO_2 test. Utilization of the well for logging will require accessing the injection well. In our previous review summary Oldenburg et al. (2016), we noted that there is only a limited set of logging tools available for the EGS environment due to the high pressure, high temperature (HPHT) conditions. Sensitivity calculations suggested that induction logging (electrical conductivity) would to be the most promising measurement, although it would require either an open-hole environment or fiber-glass casing. Calculations also showed that neutron capture (HAPS) monitoring might be feasible for fault gouge (and limited for slip-plane and damage zone), provided there is enough salinity contrast, and condition that could be achieved by carrying out a pre-flush with high-salinity brine. Neutron capture is sensitive to formation properties around 5-10 inches (13-25 cm) into the formation. We present results of simulations using the Schlumberger code SNUPAR of neutron capture logging of the well at various potential locations intersecting the fault zone that is filled with CO_2.

Neutron capture cross-section (*S* [=] capture units) is sensed by gamma radiation returning to the tool. Differences in *S* greater than 1 capture unit are needed for positive detection of CO_2. The capture cross-section (*S*) has contributions from the matrix and the fluid making it a function of porosity, salinity, saturation, pressure, and temperature. These properties are simulated using TOUGH2-ECO2N as presented above, and passed to the SNUPAR code for simulating the HAPS logging tool response. Capture cross-section is sensitive to CO_2 saturation and increases approximately linearly with the water displaced. The SNUPAR simulation results are presented in Fig. 6 after six days of injection as shown in Fig. 3d. Results of HAPS response are shown along seven profile lines shown by the various colored symbols in Fig. 6 corresponding to different distances from the slip plane where X = 25 m is the slip plane. Neutron capture appears to be a very effective tool to supplement active seismic monitoring to locate CO_2 in the fault zone.



@X = 25 m (Slip Plane), ϕ = 0.3;
@X = 19.5m (Damage Zone), ϕ = 0.05;
Otherwise (Fault Gouge), ϕ = 0.1

Figure 6. Profiles of simulation results at 6 days from the SNUPAR code using the output of the TOUGH2-ECO2N runs as input. Colored symbols correspond to different sub-vertical profile lines through the system starting at the slip plane (*X* = 25 m) and moving to the left to *X* = 19.5 m. The second frame from the left-hand side shows the strong capture cross section signal that demonstrates that CO_2 can be monitoring using neutron capture.

CONCLUSIONS

We are carrying out modeling and simulation to test the technical feasibility of injecting CO_2 into fault zones to enhance geophysical contrast to improve monitoring that can be used to better characterize the fault zone. Simulations of the injection of CO_2 show that gravity effects cause the CO_2 to preferentially flow up the hanging wall in the gouge zone of a fault dipping at 60 degrees. Seismic simulation of this CO_2 shows small time-lapse changes that motivate improvements in signal-to-noise ratio for seismic detection, and/or use of cross-well configuration to enhance seismic detection of the CO_2. Neutron capture well logging appears to be very capable of detecting and characterizing the saturation distribution of CO_2 in the fault gouge. Ongoing work is focused on 3D simulations, pressure-transient analysis, and data-worth analysis to inform the question of what kinds of monitoring data should be collected and where these data can most optimally be collected.

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