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Collab Fracture Characterization: Preliminary Results from the Modeling and Flow Testing of Experiment 1

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Keywords

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ABSTRACT

The EGS Collab project is developing ~10-20 m-scale field sites where fracture stimulation and flow models can be validated against controlled, small-scale, in-situ experiments. At the first experimental site, a hydraulic fracture will be created in metamorphic rock at the 4850 level in the former Homestake Mine. The experimental concept is for fracturing to be initiated at an injection well and continue until it intersects a production well approximately 10 meters away. Initial step-pressure flow testing of the fracture are to be performed to describe pressure-aperture-flow relationships. The flow field between the injector and producer boreholes will be characterized using a series of forced gradient dipole tracer tests. A number of fracture characterization models have been used to assist in the design of the tracer tests. The tracer test program will use conservative, sorbing, and particulate tracers, as well as sampling for radon gas to describe the fracture surface area (i.e., potential heat transfer area), flow pathway distribution, and volume. Tracer concentration at the production well (i.e. break through curves) will be measured using a series of inline sensors, liquid sampling devices, filtering of the effluent, and the measuring of gas concentrations in the effluent. Tracer monitoring data will be compared against results from a collection of numerical simulators developed at U.S. national laboratories

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and universities for the purpose of validating these flow and transport models. Ultimately these same models will be used to predict the heat transfer characteristics of the fracture and will be compared to a thermal characterization field test where cold water will be injected at the injection well and the temperature will be measured at the production well. This paper discusses the early tracer transport model predictions and parameters sensitivity that affect the tracer breakthrough curves at the production well.

1.0 Introduction

Enhanced or engineered geothermal systems (EGS) offer tremendous potential as an indigenous renewable energy resource supporting the energy security of the United States. The EGS Collab project was initiated by the DOE Geothermal Technologies Office (GTO) to facilitate the success of FORGE (https://www.energy.gov/eere/forge/forge-home). This project will utilize readily accessible underground facilities to refine our understanding of rock mass response to stimulation at the intermediate scale (on the order of 10 m) for the validation of thermal-hydrological-mechanical-chemical (THMC) modeling approaches as well as novel monitoring tools. This project will focus on understanding and predicting permeability enhancement and evolution in crystalline rocks including how to create sustained and distributed permeability for heat extraction from the reservoir by generating new fractures that complement existing fractures. The project is a collaborative multi-lab and university research endeavor bringing together a team of skilled and experienced researchers and engineers in the areas of subsurface process modeling, monitoring, and experimentation to focus on intermediate-scale EGS reservoir creation processes and related model validation at crystalline rock sites (*Kneafsey et al.*, 2018a).

The Sanford Underground Research Facility (SURF) in Lead, South Dakota as the EGS Collab project experimental site is located in the former Homestake gold mine and is operated by the South Dakota Science and Technology Authority. The SURF facility offered the EGS Collab project unique opportunities with respect to the accessibility of rock under relatively high in-situ stress conditions with supporting infrastructure, such as electrical power, water, working conditions, and internet. The first experimental testbed was located near the kISMET site on the 4850 level, providing the project with immediately available data on geomechanical stress conditions and thermal profiles around the drift. Moreover this location in the West Access drift provided sufficient width and height in the drift for rotary drilling at all orientations. Observations from these kISMET sub-vertical boreholes including extracted core led us to think the rock in this area is relatively unfractured, or with healed fractures (Oldenburg et.al. 2017). Stress conditions at the Experiment 1 field site indicate that the minimum and maximum stress conditions are calculated to be about 21.7 MPa (3146 psi) and ~42-44 MPa (6090-6380 psi). These stress conditions would suggest a preference for the creation of a sub-vertical fracture. Therefore, two sub-horizontal boreholes were drilled in the direction of the minimum principal stress orientation to be used as an injection and extraction wells 10 meters apart. A notching technique was used in the injection well in an attempt to stimulate the fracture such that it would initiate and continue to propagate perpendicular to the injection well and eventually intersect the production well. The experiment designed called for a double packer to isolate the fracture intersection at both the injection and the production well. It was anticipated that a continuous flow loop could be established through the hydraulically stimulated fracture between the injection and the production wells and that the fracture could be characterized using chemical tracers at a variety of flow rates and back pressure conditions.

This paper examines tracer numerical modeling simulations used as prediction tools on the potential behavior of tracer transport between the injection and production wells through the hydraulically stimulated fracture. The goal of these numerical predictions was to evaluate potential variables that could affect the production well tracer breakthrough concentrations as a function of time as well as to design appropriate field test to distinguish between competing conceptual models of the fracture flow characterization properties.

2.0 Tracer Analysis Modeling and Results

Using the information described in the Introduction, several EGS Collab modelers built conceptual models of the expected hydraulic fracture size, shape, aperture, and roughness that was generated from the injection well. They used their conceptual model to build a numerical model domain to simulate a tracer behavior. Results were plotted as production well tracer concentration as a function of time. Besides the basic parameters described above, additional fracture variables/processes were also accounted for to examine the effects of that variable/process on the tracer breakthrough curves.

2.1 Effect of Fracture Roughness

Most EGS Collab modelers assumed a uniform fracture aperture throughout the fracture domain as a base case. Hawkins (2018) modeled the tracer breakthrough of a 2D fracture using a finite element method (FEM) solver to solve for fluid velocity and the tracer transport within the fracture. The fracture was modeled as a 15 m radius penny shaped fracture with an injection well in the middle and a production well located 10 m to the left (Figure 1a). Leakoff from the fracture to the rock matrix was not included in this set of simulations.

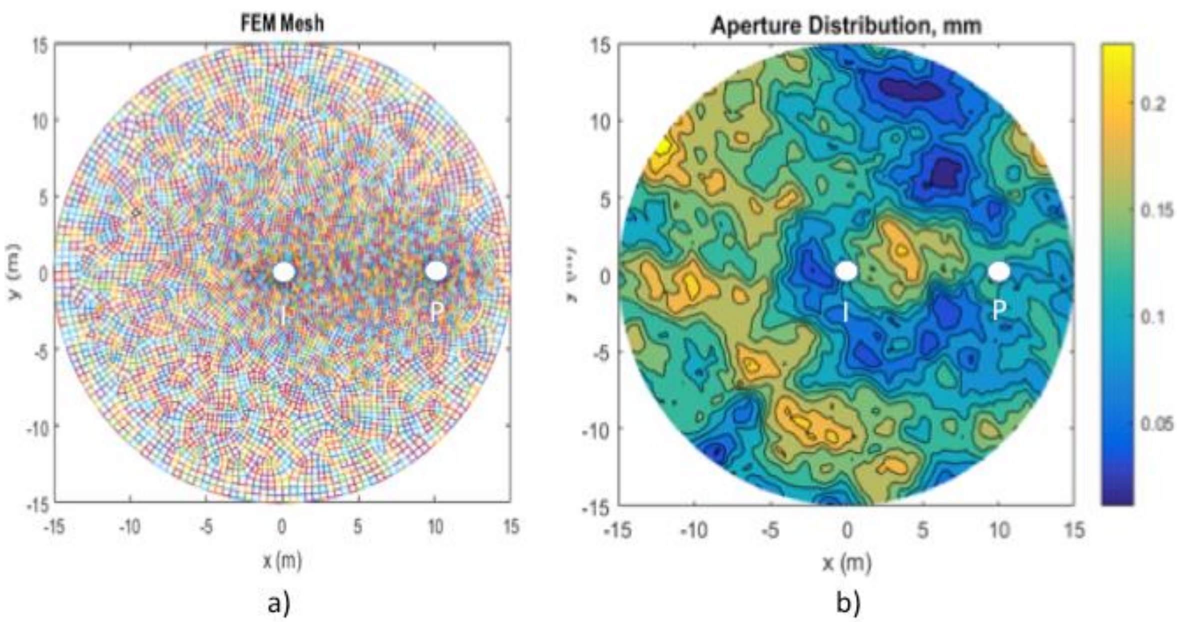

Figure 1; Illustrates of; a) the finite element mesh of a 15 m radius penny shape fracture with an injection well in the middle of the fracture and the production well located 10 m to the left of the injection well and b) an example of a fracture distribution used in a simulation (scale is in mm), (modified from Hawkins, 2018).

Rather than a uniform aperture (0.1 mm), the aperture was spatially varied using the Hurst roughness coefficient to create 500 unique fracture aperture distributions (see Figure 1b for an example fracture aperture distribution). The mean aperture ranged from 0.08 to 0.17 mm whereas the minimum and maximum aperture for all iterations is 0.01 to 0.25 mm.

The tracer breakthrough for the uniform fracture aperture distribution (Figure 2a) illustrates a concentration profile fairly similar to a typical di-pole injection/production well set up for a uniform aperture of 100 microns. In this case, initial tracer breakthrough was approximately 60 minutes with a peak concentration of 0.7 ppm. Due to the uniform aperture, there is a significant amount of tailing due to the longer flow pathways throughout the fracture.

Figure 2b illustrates the tracer breakthrough profile of the same penny shaped fracture but with a variable aperture. Due to the different aperture distributions, the shape of the tracer breakthrough illustrate a variety of tracer initial arrival times, peak concentrations and amount of dispersion. Tracer initial arrival can vary from approximately 40 minutes to over 150 minutes. Peak concentrations vary by a factor of 7 from 0.2 to 1.4 ppm. In general, the spreading of the tracer seems to be mostly correlated with the arrival time.

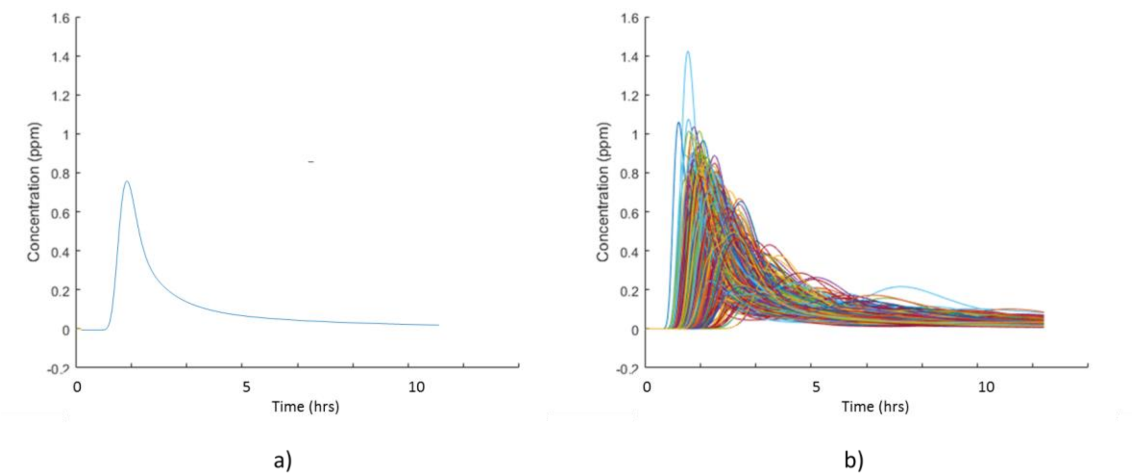

Figure 2. Tracer breakthrough for; a) an uniform aperture distribution of 100 um for the penny shaped fracture, and b) the 500 simulations of varying aperture distributions for the penny shaped fracture (modified from Hawkins, 2018)

2.2 Effect of Fracture Shape

The NREL/CSM team used commercial code (CMG STARS) and academic code (TOUGH2-CSM) to model conservative and adsorbing tracers (Johnston and Winterfeld, 2018). They examined 3 potential fracture areas (Figure 3):

a) 17 m^2 rectangle with dimensions of 11.5 m x 1.5 m,
b) 121 m^2 square with dimensions of 11 m x 11 m, and
c) 328 m^2 circle with a radius slightly greater than 10 m.

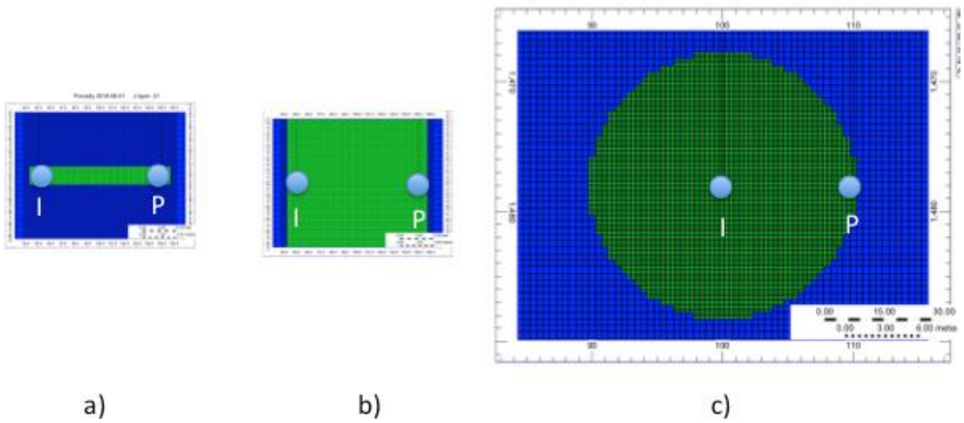

Figure 3. Cross-sections of fracture domains used for this study; a) a rectangle, b) a square, and c) a circle. Blue represents the rock matrix, green is the fracture and the injection and production wells are represented by the white circles.

The injection and production wells were placed 10 m apart. Fracture aperture was uniform in all 3 cases (50 microns). The model included tracer diffusion and fluid leakoff through the rock matrix adjacent to the fracture. Initial and boundary conditions were set at 14 MPa pressure. The matrix permeability was 2E-19 m^2 and the production well backpressure was 20 MPa. The injection well was set to a constant injection rate of 100 ml/min. Injected concentration was constant in each case (3750 mg/Liter). Tracer slug injection volume was 20% of fracture volume, which resulted in a wide range of injection durations (Table 1).

Table 1. Slug injection durations.

Fracture area and shape	Fracture volume (Liters)	Slug injection duration (min)
17 m2 rectangle	0.9	1.7
121 m2 square	6.1	12.1
328 m2 circle	16.4	32.8

Results for the tracer breakthrough curves for the three fracture shapes are shown in Figure 4, where relative concentration is equal to produced concentration / injected concentration.

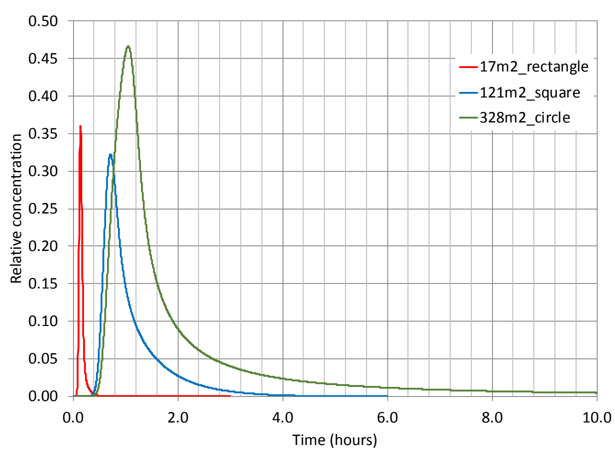

Figure 4. Relative tracer breakthrough concentrations for the three fracture domains represented in Figure 3.

As expected, the time to initial tracer detection increases as the fracture flow area increases. Due to the restrictive flow area of the small, 17 m^2, rectangular fracture (Figure 3a), peak tracer response occurs and ends quickly, with cumulative mass of tracer produced approaching 100% of the cumulative mass of tracer injected.

The two larger fracture areas have longer flow paths, slower breakthrough times and longer tails. The medium, 121 m^2, square fracture (Figure 3b) produces close to 100% of the mass of tracer injected; whereas the large, 328 m^2, circular fracture (Figure 3c) produces 93% of the mass of tracer injected within 10 hours.

2.3 Analytical solution

Zhang et al. (2018) used a streamtube model to represent the flow pathways in a penny fracture. To implement such a model, required independent determination of geometry and fluid velocity of flow tubes under steady state pressure gradient conditions. The method simplifies the tracer test into a number of streamtubes, each is characterized by the fracture aperture and length. Tracer breakthrough curve is then obtained using multiple streamlines.

The advantage of this model is that it is simple to implement and provides an idea of the aperture and length of potential flow pathways that could be responsible for rapid thermal breakthrough without actually describing the fracture.

The tracer breakthrough results (Figure 5) does not represent the typical smooth tracer breakthrough curve as seen in the previous EGS modeling scenarios. In this case the tracer breakthrough curve is much more jagged and begins to suggest the influence of individual streamtubes. The initial arrival is approximately 20 minutes whereas the peak arrival does not occur until about 1 hour after injection

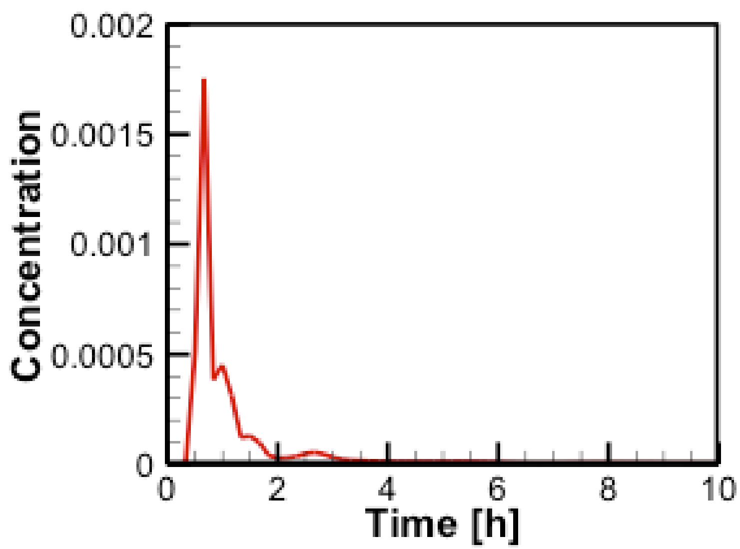

Figure 5. Illustration of the tracer concentration as a function of time recovered at the production well using the streamtube model

2.4 Injection Rate

Zhou and Oldenburg (2018) investigated the effects of lowering the injection rate to examine fracture and matrix parameters sensitivity on the production well breakthrough curves. They used the largest penny shaped model domain examined in this paper with a radius of 20 meter, with the injection well in the middle and the production well 10 meters away. They also reduced the flow rate to 10 ml/min rather than the more commonly used 100 ml/min to allow the tracer more time to interact with the matrix. The tracer pulse injection was 5 hours.

The results suggest that the fracture permeability may not have a big effect on the tracer breakthrough curve until the fracture permeability is low enough (relative to the matrix permeability) such that the net fracture pressure rises to a point that leakoff becomes significant and retards the tracer breakthrough to the production well (Figure 6). The detection of tracer first arrival is seen at about 5 hours with the peak concentration arriving at approximately 15 hours (note that the injection rate is 1/10th of the rate the others used). Similar to the previous results, the tracer breakthrough curve exhibits significant tailing. The effect of decreasing the fracture conductivity by 100x (kf reduced from 830 to 8.3 darcies in Figure 6) results in a retardation of the first and peak concentration arrival times as well as a decrease in the peak concentration.

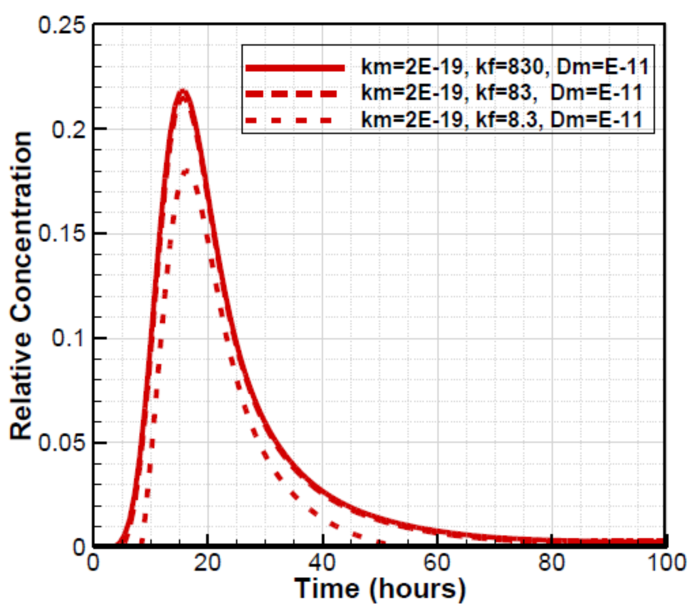

Figure 6. Example of the effect of a lower fracture permeability on the production well breakthrough curve.

Matrix diffusion is also important of the shape of the tracer breakthrough curves when the matrix permeability is low, the fracture permeability is high and the injection rate is low (Figure 7). The base case Dm (~1E-11 m^2/s) was estimated by the free water diffusivity (3E-09 m^2/s) and assuming a matrix porosity of 0.003. As the matrix diffusion is increase by 10x (i.e. Dm reduced from E-11 to E-10 m^2/s) the initial tracer or the peak concentration arrival does not change but the magnitude of the peak concentration is reduced and the tailing is greatly increased. Matrix diffusion values greater than these values are such that almost all of the tracer is lost to the matrix by diffusion (e.g. the magenta tracer breakthrough curve in Figure 7).

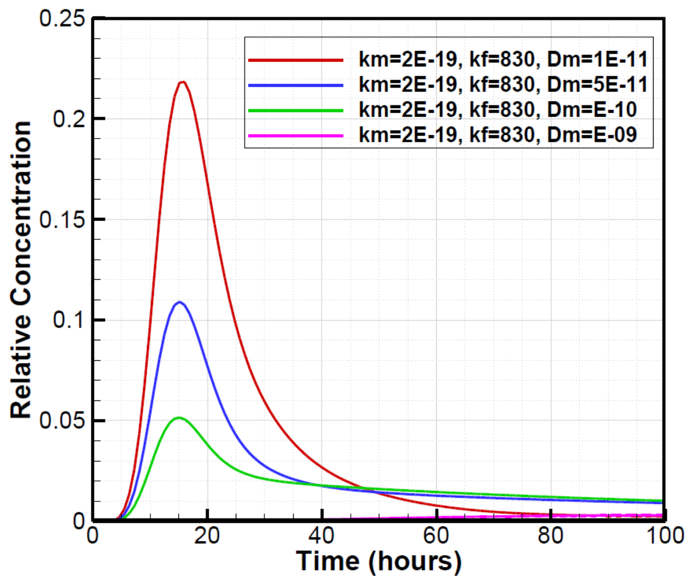

Figure 7. Example of the effect of increasing matrix diffusion on the production well breakthrough curve.

3.0 Discussion/Conclusion

This paper summarized four modeling studies used to predict the production well tracer breakthrough concentration as a function of time at the EGS Collab Experiment 1 field site. These numerical predictions were based off of limited site characterization data and prior to the Experiment 1 fracture stimulation and fracture flow testing field data. As a result, each of the tracer transport models made different assumptions as to the fracture shape, injection period, injection rate and tracer transport parameters. Tracer breakthrough-curve shapes were shown to vary by fracture roughness, fracture shape, rate of injection, and modelling approach used to investigate the tracer transport.

All models were fairly consistent in predicting the first arrival of the tracer at the production well when using similar assumptions. This is likely due to the fact that each modeler used 10 meters as the spacing between the injection and production wells, and generally the same fracture permeability and injection rate. However, Hawkins (Figure 2) illustrated that the distribution of fracture permeability and Johnston and Winterfeld (Figure 4) illustrated that the fracture shape could greatly affect this arrival time.

As the fracture surface area increases, the flow patterns begin to behave more similar to that of a dipole array in an infinite domain. For example, the smallest of the domains has a rectangular surface area of 17 m^2 (Figure 3a), which has a 1.5 m pathway resulting in a fairly sharp tracer breakthrough curve as compared to the large 20 m radius penny shaped fracture used by Zhou and Oldenburg (1018).

Significant tailing of the tracer breakthrough curve could be expected under conditions of the distribution of the fracture permeability (Figure 2b), increasing the fracture surface area (Figure 4), high fracture dispersion, and high matrix diffusion.

At this time, we've initiated fracture stimulation activities, conducted a number of flow tests at the Collab Experiment 1 field site, but have not conducted a tracer test to compare to the model predictions. Kneafsey and others (2018b) discuss "*Unexpected Conditions*" that have been identified during these subsequent tests that have not been explicitly included in the tracer prediction models. Interpretation of the fracture stimulations and the degree of heterogeneity of the rock using geophysics is ongoing. Incorporating these data into the tracer transport models should help limit the variability of the shape of the fracture and the magnitude of the leakoff to the surrounding rock matrix or natural fractures. Using the existing modeling results, the tracer characterization team is planning to conduct a series of tracer experiments in the field using a variety of conservative and sorbing tracers under different injection rates to better characterize the fracture flow properties for comparison to the modeling results.

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