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Early time flowback tracer test for stimulated crystalline-georeservoir of multiple parallel fracture characterization

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ABSTRACT

Stimulated georeservoir needs to deal with the fracture properties of which, most of them are estimated from geological inherent knowledge, hydraulic test and geophysical methods except transport effective parameters such as fracture aperture and effective porosity. Single-well tracer injection-flowback based 'early time' tracer signal provides a relatively small duration and efficient test method to estimate those transport effective parameters, that is relevant not only for EGS of sedimentary formation but also other stimulated geo-reservoirs (e.g. HDR or oil/gas reservoirs). The application that described in early-time flowback tracer test study article has not exhaustively demonstrated its complete range of uses for stimulated georeservoir. Sorptive tracer either on proppant or on a matrix that used for stimulated fracture characterization has raised the question about the range of sorptive tracer to produce for an effective tracer test that is very important to know beforehand conducting such a field experiment. This study accounts the full array of sorptive tracers for different candidate georeservoir and at the same time, a guideline for candidate tracer in relation to georeservoir properties proposed. For the purposes of the present study, a lower sorptive tracer than its minimum necessary was suggested, assuming a sensitivity improvement factor (ratio between sorptive tracer signal changes to conservative tracer signals changes, s/c) approximately equal to $\sqrt{(1 + 0.7\times \text{ sorption coefficient}, \kappa)}$. One needs to note that the higher the tracer's retardation, the lower is its fracture invasion, and consequently a poorer capability for characterizing the fracture as a whole. In principle, this could be compensated by increasing the chaser volume (i.e., by injecting sorptive tracers earlier than conservative tracers).

1. INTRODUCTION

Over the years, different definitions of EGS (Schulte et al. 2010, Breede 2013, Ghergut et al 2016 and others) have been proposed, covering a broad variety of formation, depth, temperature, reservoir permeability and porosity and type of stimulation technique involved, etc. Therefore, typical geological settings for EGS includes a range of formation covering igneous (e.g. Iceland), metamorphic (e.g. Lardarello, Italy), magmatic (e.g. Soultz, France) and sedimentary (e.g. Groß-Schönebeck and Horstberg, Germany) formations. Among different EGS, the hot dry rock (HDR) type geothermal energy is important one because it composed more than 90 % of the total accessible geothermal energy (Jiang et al. 2014). The HDR system recovers the earth's heat via closed-looped circulation of fluid from the surface through a manufactured confined reservoir, which is several kilometers deep. The technology bears little similarity to that of the hydrothermal industry and carries a worldwide applicability hence it claims as ubiquitous (Breede 2013). Jung (2013) has reconstructed the background to 'contemporary EGS', from the original HDR concept based on multi-zone hydraulic fracturing in crystalline formations to a multiple wing crack model in naturally fractured crystalline formations.

Early-time tracer injection flowback test that relies on the tracer signal during very early phase of flowback and sampling even for less than a day after injection can determine fracture porosity and fracture thickness/aperture in the realm of stimulated fracture georeservoir (Karmakar et al. 2015a, 2015b). In these two studies, they have discussed proppant and matrix sorptive tracers that can be used to characterize fracture aperture, fracture porosity and dispersivity in stimulated fracture of enhanced geothermal system (EGS) both in sedimentary formation and crystalline. However, the sensitivity regime of single-well tracer test as described in Schroth et al. 2001, Ghergut et al., 2013 have included fracture aperture and dispersion in the sensitivity parameter structure as both of this parameter affect flowback tracer signal in a similar manner (cf. Karmakar et al. 2015b). Fracture length as an unknown parameter in multiple parallel fracture model as proposed and discussed in many studies (Jung 2013, Zau et al. 2015 and others), the early-time tracer flowback signal would be embroidered with the extend fracture surface area. This article highlights the use of early-time tracer flowback signal for fracture length characterization in hot, dry rock (HDR) system EGS where single fracture represents a limited number of parallel fracture stimulated on the same plane. In addition, for our simulation study, we refer the 'HDR type EGS' as the multiple parallel fractures in tight rock formation stimulated hydraulically with a minuscule aperture having a specific fracture spacing.

2. MODEL CONCEPT AND PARAMETER SELECTION

A conceptual model for stimulated fracture parameter estimation using single-well tracer method founded on the lesson learned from several tracer study in Northern and Southeast German sedimentary basin. Ghergut et al (2013) have demarcated main ten parameters in the transport equation 1-7 initial-boundary value problems (IBVP) for single-well tracer test. It includes two fracture geometrical parameters (fracture aperture ‘b’ and fracture spacing ‘a’ in parallel fracture system), five hydrogeological properties (matrix porosity, matrix diffusion coefficients, longitudinal dispersivity within fracture, “aquifer” thickness, hydraulic diffusivity), and three SWPP test design variables, pull phase duration, injection and extraction rates or volumes.

$$\frac{\partial c}{\partial t} + \frac{Q}{2\pi B_{eff}} \frac{\partial c}{r\partial r} - \frac{\alpha|Q|}{2\pi B_{eff}} \frac{\partial^2 c}{r\partial r^2} - \frac{\varphi_m D_m}{b} \frac{\partial c}{r\partial y}\bigg|^{y=a} = 0 \quad (1)$$

$$\frac{\partial c_m}{\partial t} - D_m \frac{\delta^2 c_m}{\delta y^2} - D_m \frac{\delta^2 c_m}{\delta r^2} = 0 \quad (2)$$

$$Initial\ conditions: C(t=0,r) = 0, C_m(t=0,r,y) = 0 \quad (3)$$

$$Boundary\ conditions:\ vC - D_{hyd} \cdot \nabla C|_{r=0} = Tracer\ flux\ (t) \quad (4)$$

$$v_m C_m - D_{hyd} \cdot \nabla C_m|_{r=0} \approx 0 \quad (5)$$

$$C(t, r \rightarrow \propto, y) \rightarrow 0)\ C_m(t=0, r \rightarrow \propto, y) \rightarrow 0) \quad (6)$$

$$C_m(t,r,y=b) = C(t,r),\ \frac{\partial C_m(t,r,y)}{\partial y}\bigg|^{y=a} = 0 \quad (7)$$

Here D_{hyd} [LT^{-2}] - Hydrodynamic dispersivity in fracture or in matrix, B_{eff} or b [L] is the total fracture thickness for gel-proppant fracture or fracture aperture for water-fracture (Tang et al 1992), density of fluid, ρ_0 [ML^{-3}], source or sink of fluid or solute Q [L^3T^{-1}], C_m [ML^{-3}]- concentration of solute in matrix, v_m[LT^{-1}] -Darcy velocity in matrix

One-eighth of fracture-matrix volume found suffice to model while assuming a symmetry of fracture axis perpendicular to the injection well with a planar fracture (Ghergut et al., 2013b for parallel-fracture systems). The partial differential equation of linear flow and transport equation are solved the IBVPs numerically by using a commercial finite element software, FEFLOW analyzing the output (i.e., the simulated tracer signals) regarding sensitivity to target parameters and of parameter interplay, as applicable). However, all hydrogeological parameters are of distributed (local) type, and their values may change with time by virtue of coupled THMC processes (as induced by SWPP-forced hydraulic and thermal gradients). This implies that a virtually infinite number of degrees of freedom. One global value for each parameter is assumed during the simulation study, i.e. a spatially homogeneous system whose properties do not change with time (A brief discussion on it is written by Ghergut et al. 2006, 2011, 2013).

2.1 Fracture model for injection-flowback test

To understand parameter estimation of the early-time SWIF method in HDR type EGS, it is necessary to re-define the ratio of fracture volume vs. injection volume because injected tracer (while it is very low sorptive) will flow out the fracture while the ratio is <1. A vertical cluster of fractures, here six fracture with equal spacing between 40m to160m in a granite formation is considered (Fig. 1). However, symmetry along the horizontal injection well and remoteness between two adjacent parallel fracture-matrix have assumed for solute tracer transport. Hence, we have considered one-eighth of a single fracture for the simulation with an assumption of zero gravitation effect valid for the model (Fig 1). The half of fracture (b) is implemented using ‘discrete feature element’ of Feflow 5.4 (Diersch 2009) by choosing ‘*Hagen-Poiseuille’s* (‘*cubic law’*) flow assuming a linear flow. The transport equation (PDEs) contains an oblique boundary condition for the IBVP. Injection borehole expected to be placed in the middle of the fracture. This alignment will facilitate maximum circulation of fluid as well as energy output. The distance between injection and production well assumed as 300-500m following common HDR type EGS of the world. For our study, we took a standardized case as a set of effective fracture aperture, matrix porosity and permeability combination for volcanic formation. We considered different fracture spacing and fracture length in multiple oblique 2D fractures on a 3D matrix domain that discretized into eight-nodded quadrilateral prism elements. To be noted here, all three mechanisms relate to one major process is *matrix sorption* on the fracture surface and inside the matrix; no further process (like matrix diffusion, dispersion, reactions, etc.) has considered in this study. However, for the high sorptive tracer, exchange at the fracture boundary can be ignored as tracer will be sorbed at the fracture surface at the immediate vicinity of the well or need very long tracer injection duration as assumed in Schroth et al. (2001), Ghergut et al. (2013a) and Karmakar et al (2015a,b) after studying retardation tracer. Therefore, early time tracer signals sensitivity was investigated over four injection volume regime (1/3, ½, ¾ and 1½ of fracture volume) using same injection rate while varying the injection duration only. The matrix parameter set consist with a conductivity ranges from 3.2×10^{-10} m/s to 1×10^{-13} m/s, and with a porosity ranges from 0.03- 0.005.

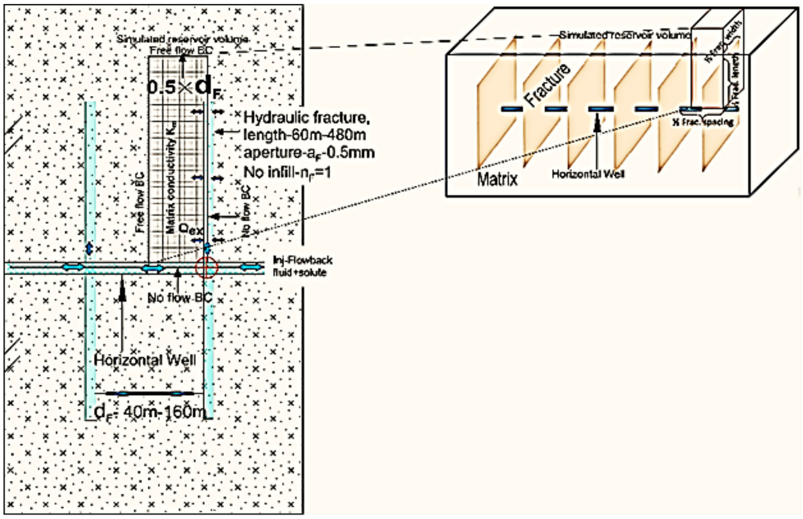

Figure 1: Conceptual model of HDR type EGS formation and injection- flowback well. The box indicates fracture and matrix domain for simulation that pertaining one-eighth of a fracture volume from equally spaced fractures.

3. RESULTS

A range of matrix sorptive tracers (MSTs) flowback signal is simulated using different tracer injection duration as well as injection volume in HDR type parallel fracture stimulated geo-reservoirs. Conservative tracer, as well as sorptive tracer flowback signals for various fracture length in fracture aperture of 2mm and 1mm geo-reservoirs, is considered for the simulation. Two classes of MSTs (Karmakar et al. 2015a and 2015b) is sorted viz. weak MSTs and strong MSTs based on relative strength of sorption coefficient on fracture wall (matrix sorption). Fracture length 60m, 120m, 180m, 210, 240m 420m and 480m are considered for weak matrix sorptive tracer (k-0.01,0.1, 1, 2) and strongly matrix sorption tracer (5, 10, 30, 50, 100) with a matrix porosity of 1% and 0.5%. The early flowback tracer signal is sensitive to a certain fracture length range (Fig 2). Low/weak sorptive tracer is relatively more sensitive to the fracture length (Fig 3). It must me noted that, while very low fracture length is assumed from a stimulated fracture in HDR formation, using a very low sorptive tracer for a specific chaser volume, it would act as a conservative tracer and reveal the whole fracture length and flow into the matrix. In that instance, it may reveal a cyclic form of tracer curve from different fracture length, which means additional ambiguity with the tracer signal and the clear-cut relationship with fracture length and tracer flowback signal will be broken. It follows the monotonic trend of lower breakthrough concentration with lower fracture length.

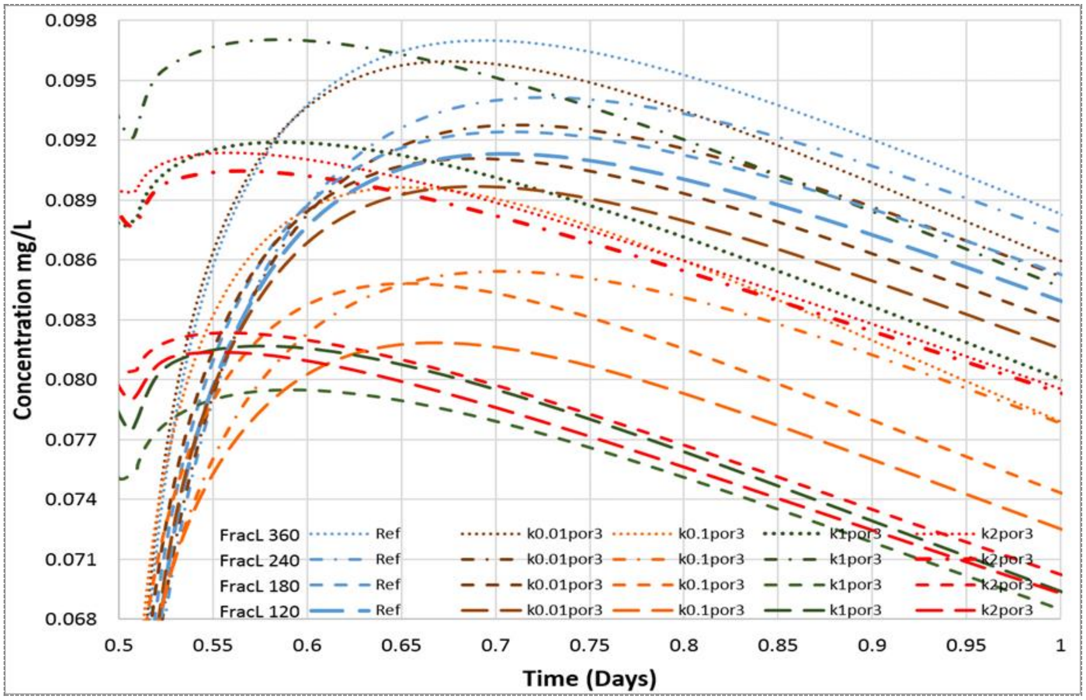

Figure 2: Weak matrix sorption tracer (MSTs) sensitivity in different fracture length for hydraulically stimulated fracture in HDR type EGS. It shows that very weak sorptive or conservative tracer R=1-1.5, matrix porosity 3%, k=0-0.01 is sensitive to the fracture length while a big aperture (1mm-2mm) is created.

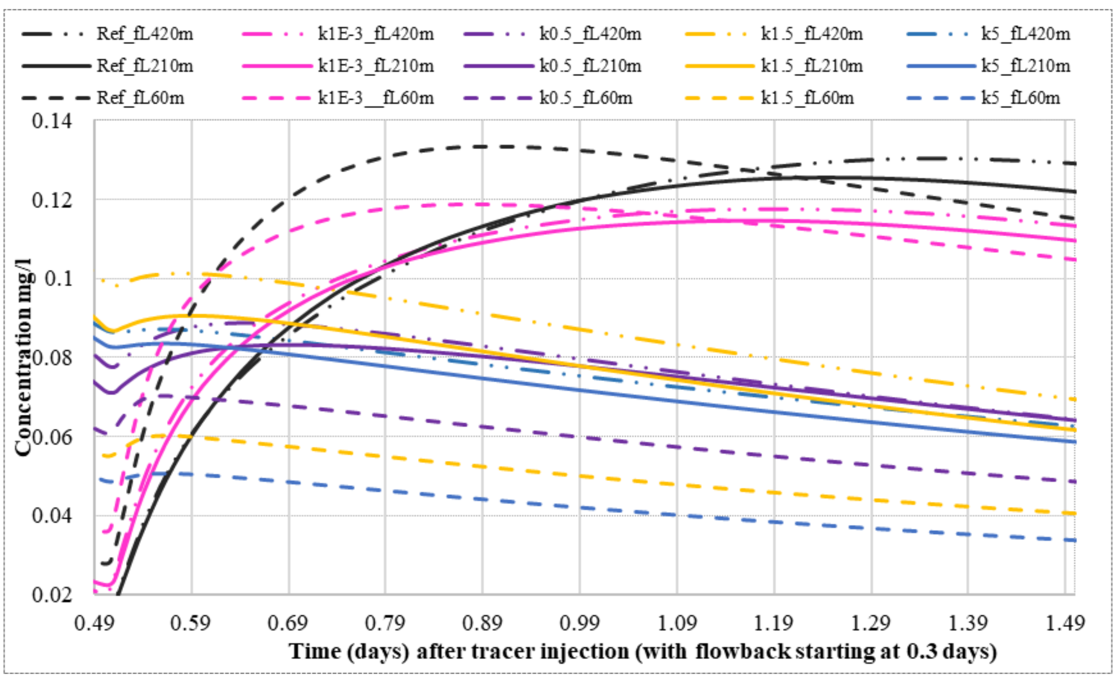

Figure 3: Strong MST (matrix sorption tracer) sensitivity in different fracture length for hydraulically stimulated fracture in HDR type EGS, matrix porosity 1% for a fracture aperture 2mm. Sensitive sorptive tracer range is k-0.5-1.5.

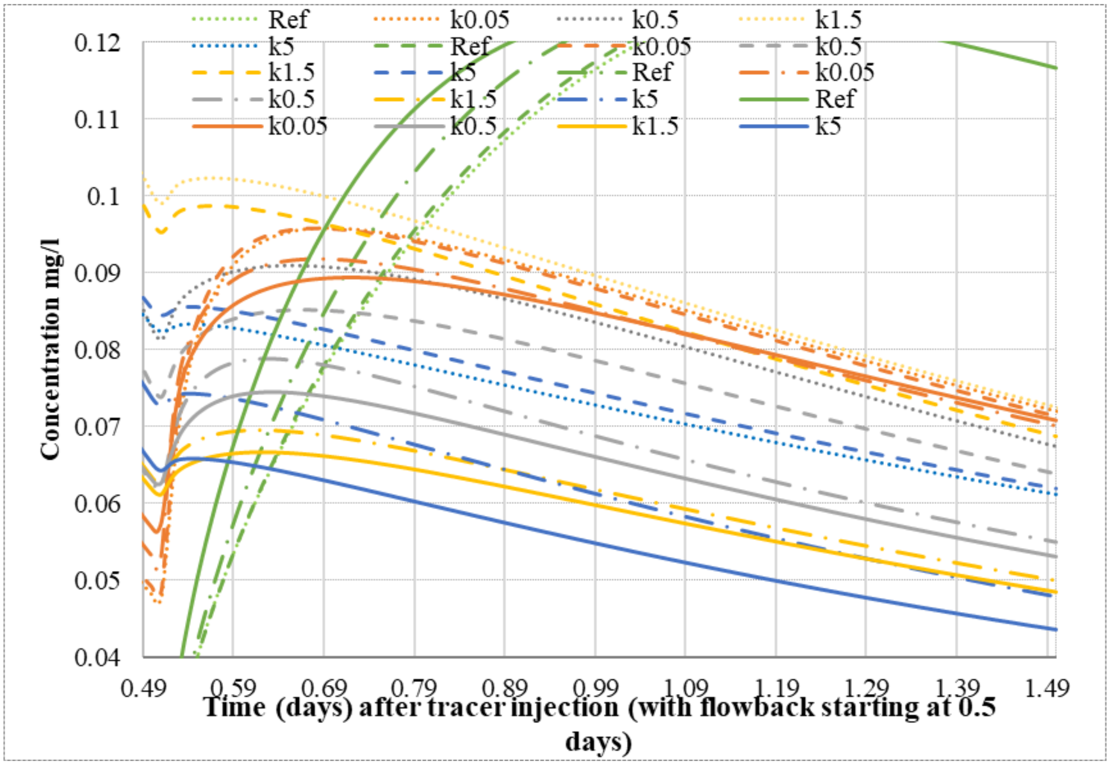

Figure 4: Medium range MSTs sensitivity in different fracture length for hydraulically stimulated fracture in HDR type EGS, matrix porosity 1% for a fracture aperture 1mm. Sensitive sorptive tracer range is k-0.5-1.5.

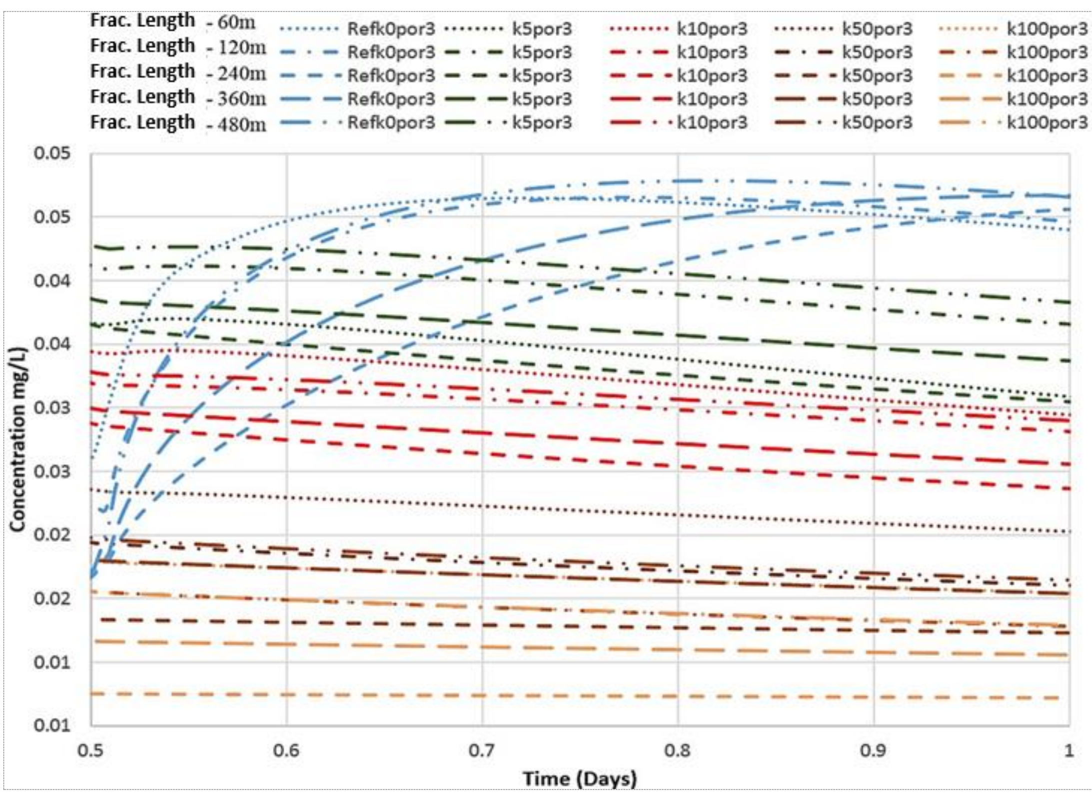

Figure 5: Effect of higher injection rate/volume, that exceed the fracture volume, for the high MST (k 5-100, matrix porosity-3%). It reveal that strong MSTs exhibit no clear trend with the fracture length.

Figures 3 and 4 shows that strong sorptive tracer (here k=1.5 to 5), is sensitive to the fracture length up to 210 m. It reveal a very narrow range of sorptive tracer for lower fracture length. In addition, a low sorptive or conservative tracer signal is independent to the fracture length. However, with highly sorptive tracer, tracer signal sensitivity is not clearly understood due very low penetration length and less number of mesh element to interpolate or calculate tracer concentration near to the test well. We observed solute tracers pull signals were independent or very low sensitive to matrix porosity (Fig. 2) as well as matrix permeability due to very high contrast in flow regime between fracture and matrix. A medium sorptive tracer range is found sensitive for a broad range of fracture length 120m to 480m in the case of fracture aperture 1mm-2mm. Hence, using a particular range of matrix sorptive tracer will be effective to estimate fracture length (Figs. 3 and 4).

From the tracer breakthrough, it revealed that fracture length influence tracer breakthrough for the higher matrix sorptive tracer. To have a consistent tracer signal one should choose very high sorption tracer or very lower sorption tracer while fracture length is the parameter in question. However, it is important to note that fracture aperture must know before estimating the extent of fracture length from this kind of test. The monotonicity of the tracer signal 'cyclically reversed' while injection volume is higher than fracture volume (Fig. 5). Hence, during parameter inversion, it needs to be cautious and necessary to consider the injection volume design to avoid ambiguous fracture length estimation.

4. SORPTION TRACER SELECTION AND SENSITIVITY

Sorptive tracer is particularly useful to determine fracture size in stimulated reservoir both in sedimentary and crystalline formations that are of particular interest in method development process that described in Karmakar 2016. However, it is important to make available a range of sorption properties tracer for this kind of test. In that instance, it observes a decreased sensitivity for fracture thickness with an increase of sorption properties in case of proppant sorptive tracer that described in Karmakar et al (2015a and 2015b). From above sorptive tracer implementation case in HDR type EGS, it also perceives not a universal range of sorptive tracer would be effective nor all range sensitive for different stimulated georeservoir formation. In that instance, a medium to higher range sorptive tracer would be particular importance for HDR application for fracture length, as it would not be affected by lower fracture volume. However, for fracture length estimation should follow a preliminary evaluation, which would determine the appropriate range of sorption tracer to be used.

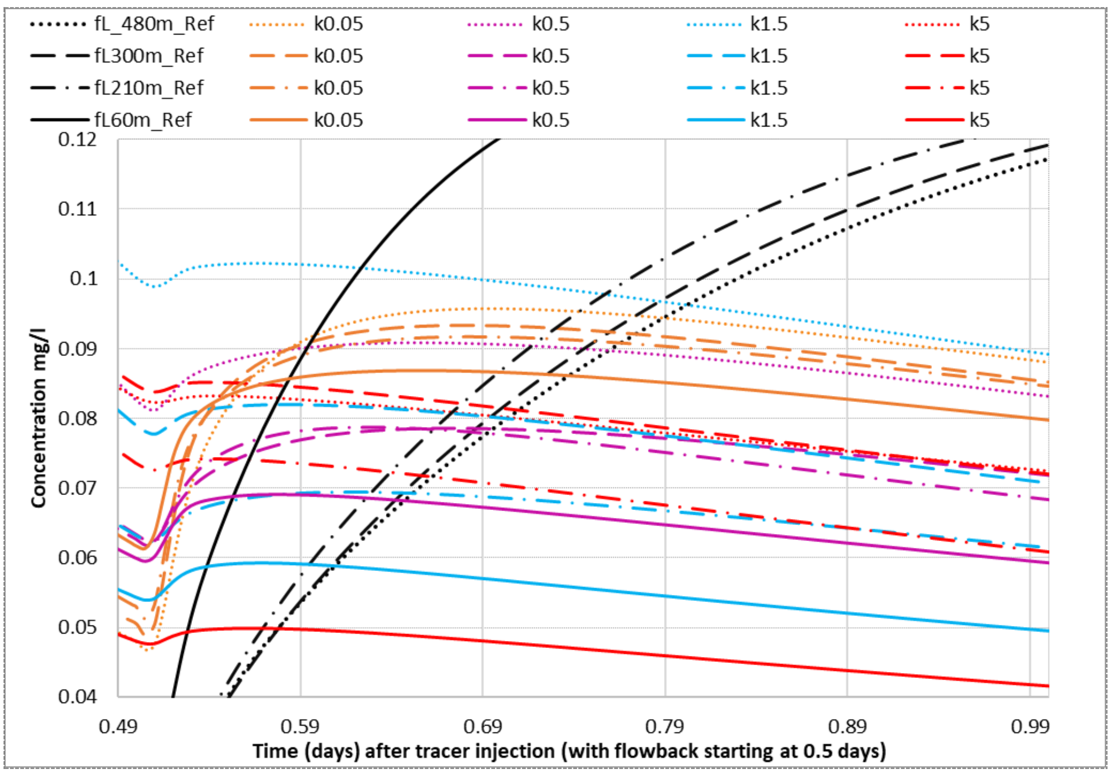

Figure 2: The injection volume is in a same size or higher fracture volume for two lower fracture length, which break the monotonicity of tracer breakthrough. Tracer signal grows rather reversibly.

The minimum sorptivity (minimum κ value) that required to induce sufficient contrast between measurable tracer signals for different values of target parameters has discussed in Karmakar et al 2015a. The scheme is: a *p* % change in a target parameter value produces *c*% change in the signal of a conservative tracer, and a *s*% change in the signal of a sorptive tracer, *s* being a function of κ. For fracture infill sorptive tracer (PSTs) and MSTs based single well injection flowback (SWIF) test study, a lower sorptive tracer than its minimum necessary is suggested, assuming an increase sensitivity factor (ratio between sorptive tracer signal changes to conservative tracer signals changes, s/c) approximately equal to √ (1 + 0.7× sorption coefficient, κ). This empirical relationship delimits that too much investment on highly sorptive tracer will not affect tracer parameter sensitivity at same magnitude (Fig. 4 and 5). One needs to note that the higher the tracer's retardation, the lower is its fracture invasion, and consequently a poorer capability for characterizing the fracture as a whole. In principle, this could be compensated by an increase of the chaser volume (i.e., by injecting sorptive tracers earlier than conservative tracers) or longer injection duration rather applying higher the injection rate. Hence, for early-time tracer injection-flowback test, it is advisable to apply a medium ranged MSTs (0.7<k<2.5, matrix porosity 3%) and PSTs (25<k<80), to avoid ambiguity due to the error in detection.

Table 1: Solute tracer uses and sensitivity with different EGS georeservoirs

Stimulation techniques	Gel proppant fracture (GPF)	Water fracture (WF)	
EGS type	Sedimentary formation	Single fracture	Parallel fracture in HDR type
Sensitive parameters	Fracture thickness and fracture porosity	Longitudinal dispersivity, Fracture aperture	Fracture length
Tracer types	PSTs and MSTs	Conservative tracers	MSTs
Tracer ranges, R	MSTs-k=0.7-2.5, Matrix porosity φ_m=3%, PSTs-25<k<80	Effective with Fracture aperture-1.08 mm-0.18 mm	MSTs, k=0.5-1.5, φ_m=1%, Fracture aperture 0.5 mm-2mm
Injection Volume/Tpush	monotonic	monotonic	Affect sensitivity, Variable injection volume would be effective

Figures 2 and 6 suggest that for the fracture length estimation from matrix sorptive tracer, it is essential to evaluate the tracer signal at very early stage. The ‘early-middle’ or ‘early-late time’ tracer signals would be insensitive to the fracture length for low sorptive tracer (k-0.7 φ_m=1%) as well as high sorption tracer (k-1.5 φ_m=1%) as it observed that the stronger the sorption related retardation, the earlier the ‘late time regime’ (Ghergut et al., 2013b). This is because the stronger the retardation, the shorter the pervasion distance into the fracture and thus the corresponding ‘back travel’ time. Moreover, in all the cases of fracture length, tracer comprehends a tiny part of the matrix and has little penetration too due to very short tracer injection duration and small injection volume too.

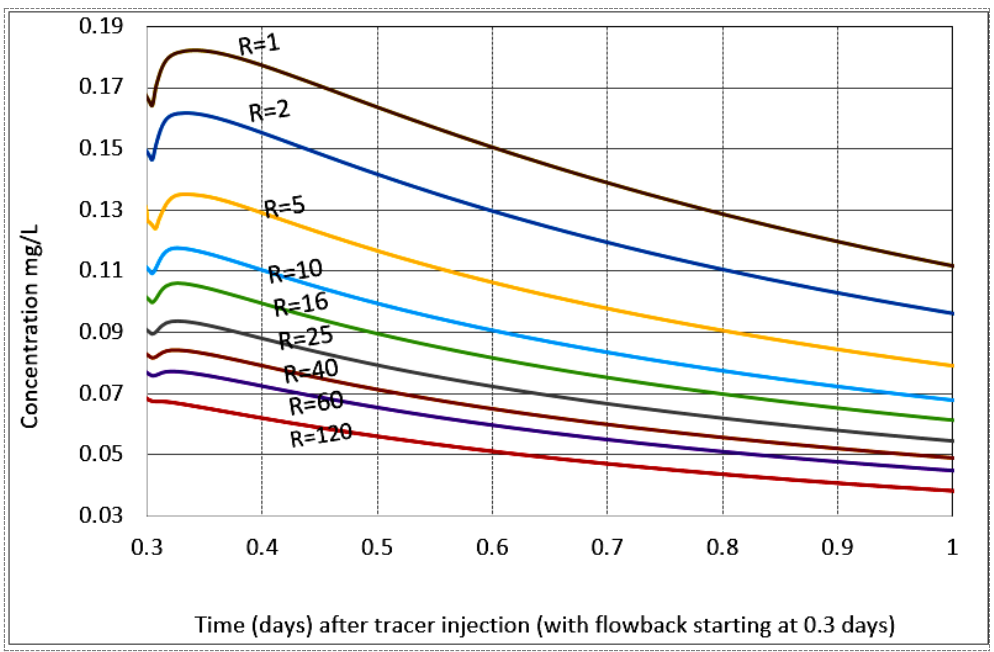

Figure 5: Simulated signals of multiple PST and MST (characterized by different Kd values) during GPF flowback, at a fixed value of GPF thickness (12mm) and proppant-packing porosity (30%).

From the simulation results, in HDR type EGS geo-reservoir, tracer application scheme is recommended to evaluate fracture length as follows- a) Weak matrix sorptive tracers for relatively longer fracture length/higher fracture volume. The matrix sorption coefficient, κ value, should be a range of 0.1 to 1 for a matrix porosity 0.5% - 3%. b) Strong matrix sorptive tracer would be recommended for all cases however specifically useful while stimulated fracture length expected to be relatively small (<200 m). c) Early-time tracer signal from conservative solute can determine the aperture of fractures created by a WF treatment. However, the effectiveness needs to be verified for very thin fractures (<0.2 mm) as suggested in (Karmakar et al., 2015a and 2015b).

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