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TRACER PROPERTIES, AND TRACER TEST RESULTS (FROM GEOTHERMAL RESERVOIR TESTING): PART 2

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ABSTRACT

Two situations are described in which heat transport prediction in geothermal reservoirs can get misled by tracer-based estimations of transport parameters. In situation A, fracture densities derived from single-well or inter-well tracer tests lead to an underestimation of reservoir lifetime. In situation B, fluid residence times derived from inter-well tracer tests lead to an overestimation of thermal breakthrough time. There are, on the other hand, (C) important aspects of reservoir behavior rendering tracer tests indispensable for its characterization. Issues A or B may occur simultaneously with C but do not necessarily impede upon its outcome.

INTRODUCTION

For any liquid-based geothermal reservoir (operated by circulating liquid between two ore more wells), one can expect its (*a*) heat recovery performance at a given time to result from (*a1*) flow rates, i. e., permeabilities, (*a2*) temperature fields, (*a3*) heat exchange areas; its (*b*)sustainability to be determined by the rate at which temperatures and permeabilities decrease as a consequence of operation-induced, and coupled THMC processes; its (*c*) operation costs to be controlled by the frequency and extent of 'extraordinary' hydraulic and/or chemical treatments required to maintain (*a1*) without exceeding certain pressure gradients.

To quantify *a1*, *a2*, *b* and *c*, hydro-geophysical and hydraulic testing is required. To quantify *a3*, *b* and *c*, tracer tests are indispensable.

Regardless of coupled THMC effects of reservoir operation, and regardless of reservoir geometry details, fluid temperature evolution at the production well (and, in particular, thermal 'breakthrough') is roughly determined by 2 parameters: fluid residence times, and the heat exchange area (density) encountered along the flow path between injection and production wells. Kocabas and Horne (1987, 1990), Pruess and Bodvarsson (1984), Shook (1999) derived various forms of such a two-parameter formula (*F2*) for thermal breakthrough prediction.

Since 2003, tracer tests are being conducted in Germany with the aim of deep-geothermal reservoir characterization, basing on the conception that

(*i*) flow-path spikings under the relevant hydraulic regimes allow to determine fluid residence times – the first parameter needed for predicting production temperature evolution (and for applying *F2*); they further allow to characterize 'reservoir geometry' according to Shook (2003, 2005); underlying test principles, and typical sensitivities are summarized in fig. 1 (upper half, marked in gray);

(*ii*) either from single-well push-pull (Sauter and Herfort, 2004), or from flow-path spikings, characteristic features of tracer signals (retardation, peak damping, tailing, etc.) of several selected solutes allow (by comparison among each other, or with those of one 'reference' signal) to determine heat exchange areas – the second parameter needed for predicting the evolution of production temperatures (and for applying *F2*); underlying test principles, and typical sensitivities are summarized in fig. 1 (lower half, marked in yellow);

(*iii*) physico-chemical properties of the tracers used are known in advance, and under geothermal reservoir conditions they always influence tracer signals in a predictable way.

Situations A, B, and C discussed in the sequel reveal some limitations confronting the application of principles *i* and *ii*; questions and doubts concerning *iii* remain unaddressed here. For the time being, we feel that these limitations do not impede upon the main results (fig. 2) derived, so far, from deep-geothermal reservoir testing in Germany, but they will need to be paid increased attention in the future.

For the sake of simplicity, illustrative calculations are restricted to minimalistic reservoir geometries, and to the dispersion-free approximation of transport (determined only by advection and matrix diffusion). Tracer signals are all simulated for a solute that is hydrodynamically indiscernible from the fluid (this is an essential assumption, defining the very notion of a fluid flow *tracer*), and which is also physico-chemically stable (this assumption is not essential to the conclusions drawn below, which equally apply to a reactive tracer).

SITUATION A: TRACER-BASED UNDER-ESTIMATION OF RESERVOIR LIFETIME

Let the reservoir consist of one or more parallel 'permeable features' (fissure, fracture or fault zones) with a minimum spacing of ~50 m between the 'large-scale' features (fig. 3). Assume a geothermal well doublet (injection – production) intersecting one or more of these features. Assume a steady dipole flow field. Some solute tracer is added at the injection well; at the production well, tracer breakthrough can, sooner or later, be measured. Figure 4 (upper part) shows calculated tracer breakthrough curves (BTCs) that would be measured at the production well, for various values of the fluid-rock interface density (to which the dimensionless parameter shown on the plot relates like a logarithm). Tracer BTCs allow for non-ambiguous inversion w. r. to this parameter. Inserting its value into some version of (*F2*), one would get the temperature evolutions shown in fig. 4 (lower part). Obviously, this thermal prediction is absurd; thermal breakthrough results to be much too fast. The reason for this can be understood from fig 3: fluid-rock interface densities, or fracture spacings y[solute] resulting from solute tracer tests are not encountered at reservoir scale. Solute diffusivities being at least 3 magnitude orders lower than thermal diffusivities, tracer BTCs will 'feel' fluid-rock interface densities that do not exist at reservoir scale, whereas heat transport will be controlled by the larger spacing y[thermal] while being insensitive w. r. to y[solute]. In turn, the influence of y[thermal] upon solute tracer BTCs will be overwhelmed by that of y[solute], such that y[thermal] will be difficult to determine from solute tracer tests. This must also be a reason why Kocabas and Horne (1987, 1990) recommend to use solute tracers only for determining inter-well residence times, and to use only heat as a tracer for determining heat exchange areas (which, however, remains restricted to single-well testing scales).

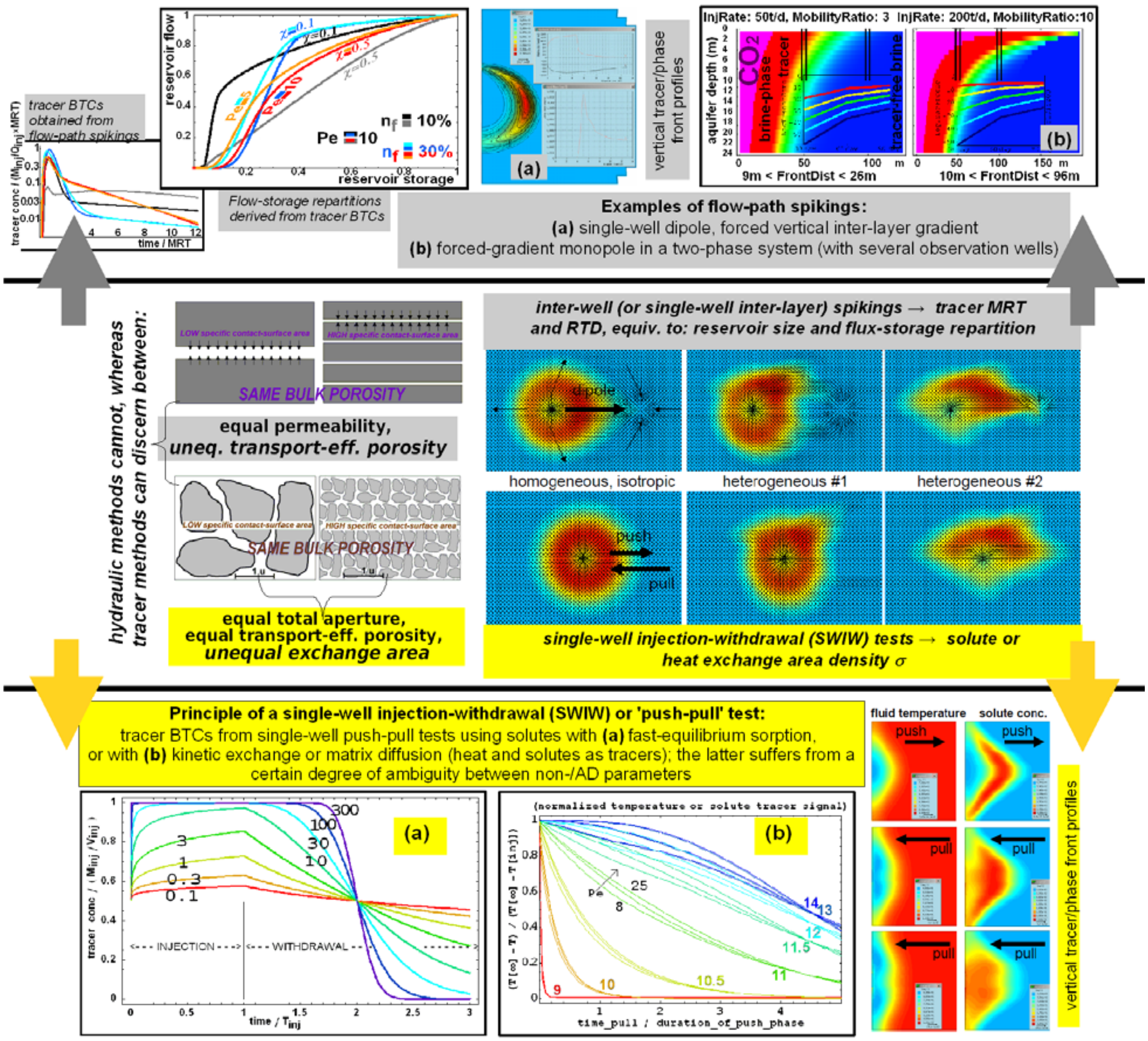
Probably, y[thermal] and y[solute] are not completely uncorrelated (as they always have something in common: a given geological setting), but a general correlation formula making y[thermal] predictable from y[solute] is unlikely to exist (cf. also Table 1).

SITUATION B: TRACER-BASED OVER-ESTIMATION OF RESERVOIR LIFETIME

Let the reservoir consist of two large planar 'permeable features' (fracture or fault zones), of thickness $h1$, $h2$, transport-effective apertures $w1$, $w2$, intersected by the injection and production well of a geothermal well doublet, with a distance y between their screens and a fluid flow rate Q. The planar permeable features intersect each other, sharing a thickness h, at distance $r1$, $r2$ from the respective well screens. At scales much larger than their effective apertures, the permeable features are treated like homogeneous continua.

The fluid turnover time can be approximated as $(w1\ r1 + w2\ r2)\ h/Q$, or, if dipole focusing is negligible, by $Pi\ (w1\ r1^2 + w2\ r2^2) / Q$. On the other hand, thermal breakthrough time will be in the range of y^2 / D (cf., for instance, Carrera et al. 1998), with D denoting thermal diffusivity. If fluid turnover volume is very large, and/or well spacing y is not large enough, thermal breakthrough will occur before one fluid turnover cycle. This will be the case when, approximately, $(y/r) < \mathrm{Sqrt}\ (2\ Pi\ D\ w / Q)$, as represented in fig. 5. In this case, thermal breakthrough can no longer be predicted from tracer test results, since it would already be 'too late' for the latter to become available. And in fact, for this special case, there is no correlation at all between thermal breakthrough and fluid residence times.

Of course, such a situation is not typical of normal practice, since the location of fault zones etc. is known with some certainty beforehand (one would not drill and operate a geothermal well doublet without first exploring the geometry of target fault or fracture zones), and drilled well paths can be controlled up to few meters spread. Yet, there are situations in which the existence and actual location of the target 'permeable features' (supporting the fluid flow for reservoir operation) remains largely unknown even after reservoir operation has begun. In the 'Horstberg problem' (innovative, single-well 'doublet' configuration described by Jung et al. 2005), questions regarding the very existence(!), geo-mechanical type, aperture, area and time-dependent characteristics of (presumed) hydraulically induced faults or fractures, and especially of their effective spacing (playing the role of 'y' above) are still open, despite extensive hydraulic testing (cf. Tischner et al. 2004; Sulzbacher 2008). This must not mean that thermal breakthrough in this single-well configuration will necessarily occur too early, but it may well happen that thermal breakthrough is uncorrelated with fluid residence times (thus rendering solute tracer tests irrelevant for thermal predictions).


tracer BTCs obtained from flow-path spikings

Flow-storage repartitions derived from tracer BTCs

Examples of flow-path spikings:
(a) single-well dipole, forced vertical inter-layer gradient
(b) forced-gradient monopole in a two-phase system (with several observation wells)

hydraulic methods cannot, whereas tracer methods can discern between:

equal permeability, *uneq. transport-eff. porosity*

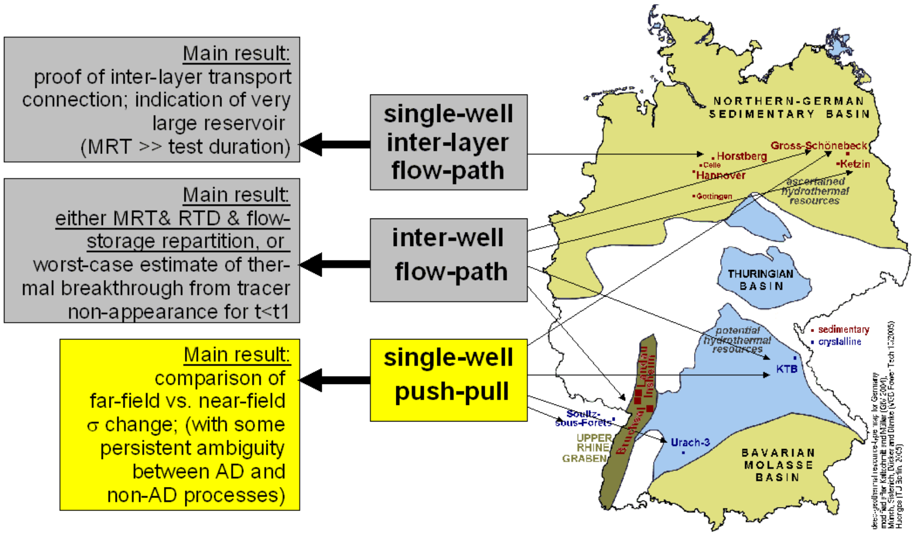
equal total aperture, equal transport-eff. porosity, *unequal exchange area*

inter-well (or single-well inter-layer) spikings → tracer MRT and RTD, equiv. to: reservoir size and flux-storage repartition

single-well injection-withdrawal (SWIW) tests → solute or heat exchange area density σ

Principle of a single-well injection-withdrawal (SWIW) or 'push-pull' test:
tracer BTCs from single-well push-pull tests using solutes with **(a)** fast-equilibrium sorption, or with **(b)** kinetic exchange or matrix diffusion (heat and solutes as tracers); the latter suffers from a certain degree of ambiguity between non-/AD parameters

Figure 1: Tracer test principles for determining fluid residence times [gray] and heat exchange areas [yellow].


Main result: proof of inter-layer transport connection; indication of very large reservoir (MRT >> test duration)

Main result: either MRT& RTD & flow-storage repartition, or worst-case estimate of thermal breakthrough from tracer non-appearance for t<t1

Main result: comparison of far-field vs. near-field σ change; (with some persistent ambiguity between AD and non-AD processes)

Figure 2: Main results from tracer tests at deep-geothermal reservoirs in Germany, to date.

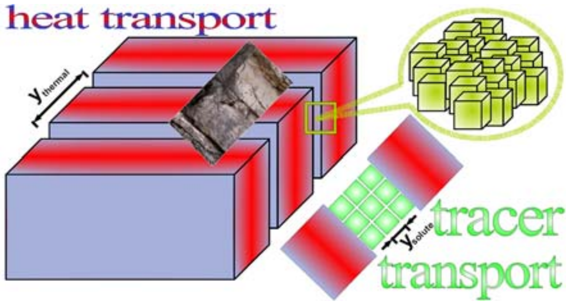


Figure 3: Fluid-rock interface densities, from hydrodynamic to crack and reservoir scale (simplified representation).

Table 1: Suggested field methods to determine heat and solute transport - effective crack, fracture or fault-zone spacings.

Parameter	heat ...	solute ...
	transport-effective fracture spacing	
	y[thermal]	*y*[solute]
is essential for predicting:	thermal lifetime of reservoir	hydro-geochemical processes, and thereby induced porosity / permeability changes
determinable from ….		
– geophysical exploration?	not really	no
– borehole geophysics?	no	not really
– hydraulic testing?	no	no
– tracer tests?	yes (using heat as a tracer); restricted to single-well testing scale	yes (using soluble tracers); restricted by ambiguity of effects from non-/ advective-dispersive processes
– micro-seismic experiments?	maybe	no

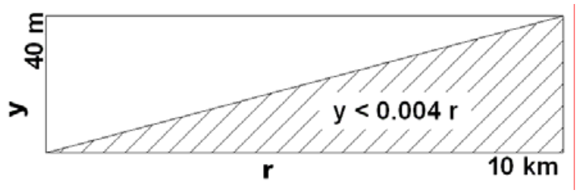


Figure 5b: Minimum fault- or fracture-zone spacing required to avoid thermal short-cut. Below this limit, solute tracer signals (and fluid RTDs themselves) become irrelevant to thermal prediction.

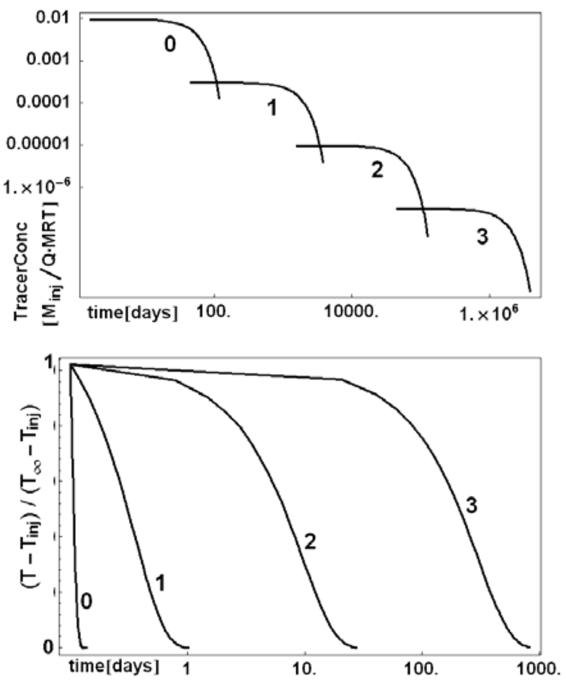


Figure 4: Tracer signals for situation A (in the dispersion-free approximation), and production temperature evolutions (mis-)predicted from them.

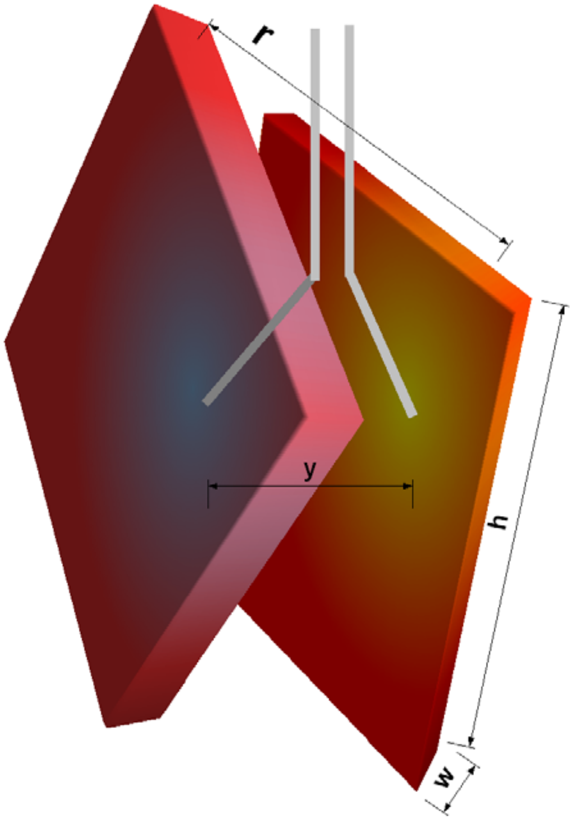


Figure 5a: Fault or fracture zone geometry for situation B.

SITUATION C: TRACER INSENSITIVITY W. R. TO FAULT PARAMETERS (THE 'HORSTBERG PROBLEM', REVISITED)

The 'Horstberg problem' provides yet one more example of how tracer test results can become confusing.

At the Horstberg site in the Northern-German sedimentary basin, innovative single-well heat extraction procedures proposed by the Federal Institute for Geoscience and Natural Resources and the Leibniz Institute for Applied Geosciences, Hannover (Tischner et al. 2004, Jung et al. 2005) are being tested since 2003. Work details were already described elsewhere (Jung et al. 2005, Tischner et al. 2004, Behrens et al. 2006, Ghergut et al. 2009). One of the procedures tested consisted in establishing a vertical (more or less focused) dipole flow between two wellscreens located in two different sandstone layers, separated by a ~120 m thick claystone layer.

In order to analyze tracer test results, we assume the system to consist of five alternating clay- and sandstone layers with prescribed thickness and permeability values (fig. 6a,b). Massive fluid injection into the 'Detfurth' horizon produces a large-area vertical fault (propagating through the claystone layer upwards until reaching the 'Solling' horizon, and possibly reaching down into 'Volpriehausen' horizons). Moderate fluid injection into 'Solling' horizon induces a small-area vertical fracture that remains confined to this sandstone layer. The drill hole being inclined, 'Detfurth' fault and 'Solling' fracture will lie in different vertical planes.

Following fault creation, tracers are injected at the 'Detfurth' wellscreen (fig. 6c). Tracer BTCs measured at the 'Solling' wellscreen (fig. 6d) are supposed to provide information about hydraulic and transport parameters of the induced fault and fracture.

From preliminary numerical simulations, however, assuming a steady flow field (fig. 6b), it turns out that fluid residence times in the system are controlled by merely two parameters: the effective distance between 'Solling' fracture and 'Detfurth' fault; and the area of the 'Solling' fracture.

Tracer BTCs turn out to be relatively insensitive w. r. to the apertures of the induced fault/fracture, as well as w. r. to transport parameters of 'Detfurth' sandstone and overlaying claystone horizons (once a major fault in these horizons was assumed). To be noted, steady flow is not achieved in reality; errors induced by the steady-flow assumption will need to be evaluated, they are not expected to be negligible; but the same BTC controlling parameters are seen in preliminary unsteady-flow simulations, as well.

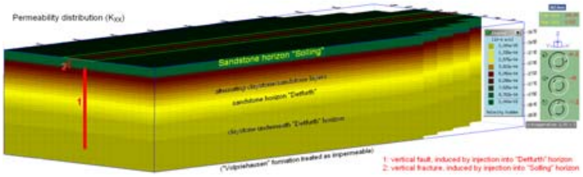


Figure 6a: Conceptual model for the 'Horstberg problem'.

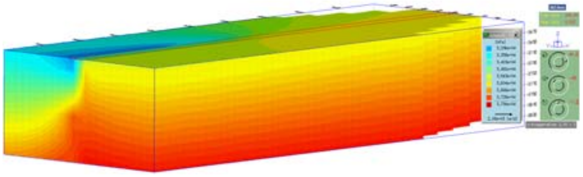


Figure 6b: Pressure distribution corresponding to steady flow in the two-fault system.

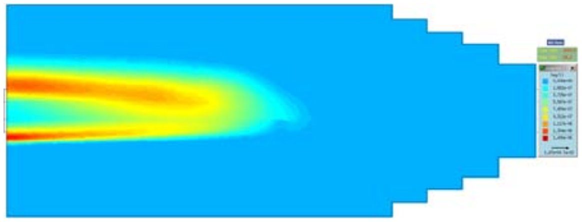


Figure 6c: Simulated tracer concentration in the horizontal plane containing lower wellscreen (injection screen, in 'Detfurth' layer), 100 days after tracer injection.

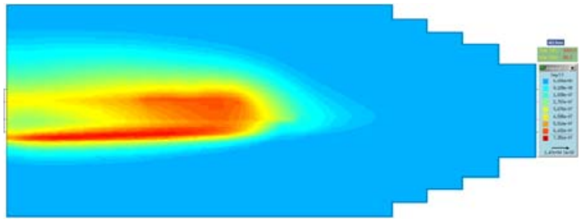


Figure 6d: Simulated tracer concentration in the horizontal plane containing upper wellscreen (production screen, in 'Solling' layer), 100 days after tracer injection.

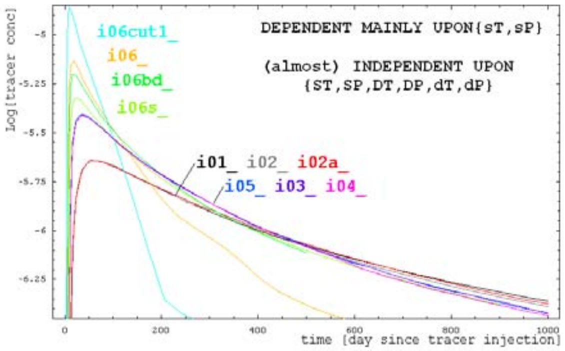


Figure 7: Simulated tracer BTCs for the 'Horstberg problem', assuming various combinations of fault, fracture and matrix parameters.

Figure 8a: Simulated tracer concentration 100 days after tracer injection (envelope view, left side showing the vertical plane defined by injection and production wellscreens).

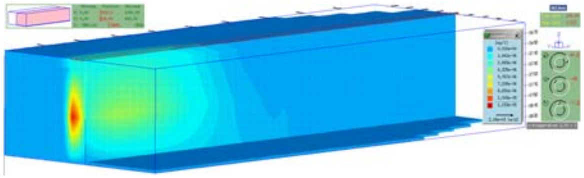


Figure 8b: Simulated tracer concentration in the 'Detfurth' fault plane, 100 days after tracer injection.

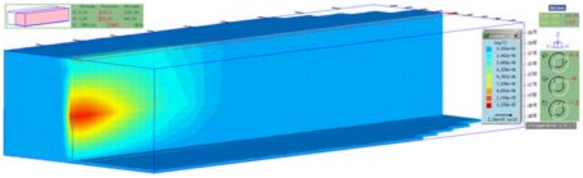


Figure 8c: Simulated tracer concentration in the 'Solling' fracture plane, 100 days after tracer injection.

DISCUSSION

In case A, it is the physics itself that uncouples solute diffusion from heat diffusion, rendering hydrodynamic-scale, and small fissure/crack-scale interface densities (as determinable from solute tracer tests) irrelevant for thermal lifetime prediction.

In case B, it is the chosen geometry and dimensioning of a heat extraction dipole, that uncouples the onset of thermal breakthrough from fluid residence times in the reservoir (as determinable from flow-path spikings).

Case C combines features from both issues (A and B), in that the strong retardation of tracers (due to a matrix-dominated *flow and* transport regime at the upper layer, with extremely high fluid-rock interface density) additionally reinforces a (possibly false) expectation of very long reservoir lifetime.

There is hope of partly alleviating these issues by using reactive (thermo-sensitive, etc.) tracers – as proposed, for instance, by Nottebohm et al. (2010). This could indeed eliminate the need to deal with problem A, but for situations like B or C it is unlikely that any solute-based approach can help.

SUMMARIZING...

Geo-reservoirs are heterogeneous. They contain fault and fracture zones that are relevant to heat transport, and, within those zones, additional crack-fissure patterns that are relevant (primarily, or only) to solute transport; in many cases, solute tracer signals will be affected by the latter much stronger than by the former structures. The reservoir-scale fracture spacing (*y*[thermal] on fig. 3) is essential to the prediction of thermal lifetime; the hydrodynamic and micro-crack scale fluid-rock interface density (*y* < = *y*[solute] on fig. 3) is essential to the understanding and prediction of hydro-geochemical processes associated with reservoir operation, which may strongly effect upon porosity and permeability (and thus, in turn, on thermal lifetime). Generally, the size of *y*[thermal] and of *y*[solute] correlate with each other very poorly, if at all; they need to be determined independently of each other. Whereas *y*[solute] influences tracer BTCs in a variety of ways, on short-, mid- and long-time scales, rendering it almost impossible to specify unambiguously, *y*[thermal] can theoretically be determined unambiguously from heat transport tests (Kocabas and Horne, 1987; 1990), with the sole limitation that the necessary test duration (depending on the degree of reservoir heterogeneity) may become comparable to reservoir lifetime itself. It is yet unclear how well *y*[thermal] correlates with “enhanced permeability feature” spacings derivable from micro-seismic observations. Secondly, a lateral thermal 'shortcut' between injection and production zones, especially as it may occur in single-well heat extraction procedures (Tischner et al., 2004; Jung et al., 2005), does not correlate with fluid residence times, and thus can remain undetected in solute tracer tests; this is not the tracers' fault – the *fluid* RTDs themselves are not the whole truth. Thirdly, matrix diffusion has a number of effects upon RTDs of solute tracers that may become confusing when inferring from tracer test results to reservoir temperature evolutions.

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