A Summary of Tracer and Thermal Tests Conducted at the Altona Field Laboratory

Adam Hawkins¹, Matthew Becker², Jefferson Tester³

¹TomKat Center for Sustainable Energy / Energy Resources Engineering, Stanford University
²Geology Department, California State University, Long Beach
³Robert Fredrick Smith School of Chemical and Biomolecular Engineering, Cornell University

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ABSTRACT

Meso-scale field tests at the Altona field site in Altona, NY served as a low-temperature geothermal analog for heat exchange experiments and inert/reactive tracer tests. For six days, heated water circulated through a cold, sub-horizontal bedding plane fracture 7.6 m below ground surface between two wells separated by 14 m. A network of thermal sensors monitored reservoir heat up at 13 monitoring locations throughout the 10 x 10 m well field. Reactive tracers included cesium (an adsorbing tracer) and phenyl acetate (a thermally degrading tracer). The adsorbing tracer test estimated effective heat transfer surface area and the thermally degrading tracer monitored reservoir heat up by estimating the effective reservoir temperature every other day for 5 days. An inert carbon-cored nanoparticle (C-Dots) and iodide estimated the Residence Time Distribution (RTD). Ground Penetrating Radar (GPR) measured the spatial distribution of a saline tracer circulated between the injector/producer well pair. Laboratory experiments included measurement of the adsorption reaction partition coefficient and rate constant and the temperature-dependent kinetics of phenyl acetate experiencing increased reaction rates in the presence of crushed sandstone. Modeling efforts focused on predicting production well temperatures based on tracer-calibrated reservoir geometries. Results of the field tests, laboratory measurements, and computational models suggest that rapid thermal breakthrough occurred as a result of extreme flow channeling through a narrow (roughly 1 to 4 m wide) channel that directly connected the two wells. Overly simplified reservoir geometries calibrated with inert tracer test data result in a predicted production well temperature rise of 1 °C in roughly 37 d. Measured
production well temperature, however, rose 1 in just 0.1 days. The combined use of an adsorbing and an inert tracer result in improved predictions, where predicted production well temperature rises 1 in 0.3 days. Four thermally degrading tracer tests conducted at ambient reservoir temperature and after 1, 3, and 5 heating days resulted in estimated effective reservoir temperatures of 12, 24, 27, and 30, respectively. These estimates are in good agreement with measured temperatures, which were 13, 23, 26, and 30, respectively.

1. Introduction

The following article summarizes the results, to-date, of modeling, laboratory experiments, and field tests conducted at the Altona Field Laboratory (AFL), which is a meso-scale test site ideal for investigating heat and mass transport in fracture-dominated rock. This study’s main objective is to evaluate the ability of inert and reactive tracers as predictive tools for anticipating premature thermal breakthrough in geothermal production wells. Predictions from these tracer-calibrated models were subsequently evaluated against measured reservoir temperature changes. Several publications have documented these experiments in detail (Hawkins, 2017; Hawkins et al., 2017a, 2017b, 2018). Here, each experiment is summarized and the key findings are highlighted.

Commercial geothermal reservoirs require sufficiently high enthalpy and mass flow rates from production wells to be sustained over the entire lifetime of a plant (typically 20-30 years). Continuous reinjection of thermally wasted geothermal fluids helps mitigate the negative effects of low or declining mass flow rates (in addition to several other advantages) (Horne, 1985). However, thermal interference at production wells can result if the cold front initiated at reinjection wells migrates to production wells too quickly. Premature thermal breakthrough occurs when production well fluids decline below temperatures specified by the operating/design conditions of the geothermal plant and can be a serious threat to the commercial success of a geothermal reservoir.

In fracture-dominated reservoirs, the most critical reservoir characteristic governing thermal breakthrough is the contact area between fluids flowing through rock fractures and the bulk rock matrix (i.e., effective inter-well heat transfer area) (Hawkins et al., 2017a, 2017b, 2018). Other reservoir parameters are either insignificant direct influences on heat transport (e.g., inter-well fluid volume) or have minor variations between different reservoirs (e.g., rock density, heat capacity, thermal diffusivity, etc.). Unfortunately, the heat transfer area cannot be reliably estimated by conventional reservoir characterization method, such as through the use of an inert tracer test (Hawkins et al., 2017a, 2017b, 2018).

If accurate estimates of effective heat transfer area are available, however, thermal breakthrough can be predicted. Such predictions would promote better reservoir management, plant design optimization, and improve the commercial potential of low-grade resources, such as Engineered Geothermal Systems (EGS) or Hot Dry Rock (HDR). An adsorbing tracer has long been proposed as a reservoir characterization tool for estimating effective heat transfer area (e.g., Vetter and Crichlow, 1979). Application of the method to the Altona field site provides the first field validation that the method leads to accurate predictions of thermal breakthrough.
In addition to predicting thermal breakthrough, there exists a need for actively monitoring the progression of a cold front as it migrates from injectors to producers. Such temperature measurements can be used to calibrate thermal-hydraulic models and are therefore useful in geothermal plant design/optimization and in projecting geothermal reservoir thermal performance. Unfortunately, directly monitoring the spatial distribution of thermal drawdown in a geothermal reservoir is typically cost-prohibitive due to the number of monitoring wells required to adequately capture the extent of the propagating cold front. In lieu of an adequate monitoring well network, thermally degrading tracers have long been proposed as an effective monitoring technique (Robinson et al., 1988). A lack of field tests validating the use of thermally degrading tracers has, unfortunately, prevented the commercial adoption of thermally degrading tracers as a means of monitoring reservoir thermal drawdown.

Highly constrained field tests at the 10 x 10 m Altona Field Laboratory provide a means to test these unproven tracer testing methods, including adsorbing tracers for estimating heat transfer area and thermally degrading tracers for monitoring geothermal reservoir cooling. The performance of these tracer testing methods are evaluated based on their ability to predict the onset (i.e., thermal breakthrough) and rate of temperature change at the production well. Additional characterization of the spatial distribution of fluid flow paths in the target fracture are provided by: (1) an extensive fiber-optic network for monitoring the spatial distribution of fracture/matrix heat exchange via Fiber-Optic Distributed Temperature Sensing (FO-DTS); and by (2) Ground Penetrating Radar (GPR) imaging of a saline tracer migrating between the injector and producer.

2. Methods

The field tests and modeling approaches described in this study have been discussed in detail in several other publications. Each experiment is described briefly in the following subsections and a reference to the appropriate article is provided for additional details. The most relevant publications include Hawkins et al. (2017a, 2017b, 2017c, 2018) and Hawkins (2017).

2.1 Field Site

The Altona field site is an ideal meso-scale field site, because heat and tracer tests can be performed under highly constrained conditions in a reservoir consisting of a single planar fracture that is known to exhibit channeled-flow behavior (e.g., Talley et al., 2005; Guiltinan and Becker, 2015; Hawkins, 2013; Hawkins and Becker, 2012; Tsoflias et al., 2015; etc.). The 10 x 10 m well field is located in the Altona Flat Rocks region of northern New York State, roughly 25 km northwest of Plattsburgh, NY (Figure 1). Throughout the Altona Flat Rocks, the Cambrian-aged Potsdam Sandstone is exposed at (or near) ground surface. The convenient ease of access from ground surface to this very well cemented formation (~1% matrix porosity) is ideal for these experiments, because the combination of low matrix porosity and highly permeable fractures is a good analog for conditions expected in fracture-dominated geothermal reservoirs, particularly EGS. The target fracture in this study is a sub-horizontal bedding plane fracture located roughly 7.6 m below ground surface. Since the target fracture was originally identified via reconnaissance Ground Penetrating Radar (GPR) imaging initiated by Matthew Becker in 2004, it has been the subject of numerous studies investigating fluid flow in highly-
2.2 Thermal Test

In the fall of 2015, the Altona field site served as an analog meso-scale geothermal reservoir. For 6 days, heated injectate (74 °C) circulated through the initially cold (~12) reservoir. A Grundfos submersible pump installed in a shroud assembly maintained a continuous fluid flow rate of 5.7 L/min out of production well 304. All fluids produced from well 304 were immediately piped through a propane-fired tankless water heater (AO Smith, Model #: T-H3-OS) and into injection well 204, which is located 14.1 m to the west of production well 304. The design and results of the thermal test are described in detail in Hawkins et al. (2017a, 2018) and in Hawkins (2017).

During reservoir heating, a Fiber-Optic Distributed Temperature Sensor (FO-DTS) (Sensornet Ltd, Model #: Oryx) measured the spatial distribution of fracture/matrix heat exchange in ten monitoring boreholes located throughout the 10 x 10 m well field. The FO-DTS measured temperature along a 1400 m cable wrapped around ten externally threaded schedule-80 Polyvinyl Chloride (PVC) pipes. A modified lathe and spool field wrapped a specially designed fiber-optic cable around the threaded pipe to improve the measurement spacing interval from 1 m to 2.1 cm. This improvement resulted in roughly 70 to 140 temperature measurements along the 1.5 to 3 m long pipes. The specially designed fiber optic cable (AFL, Model #: DNS-2528) compensated for the heightened attenuation of light that results from bending the cable around the radius of the pipe. As a result, temperature measurement accuracy and precision is improved, particularly at measurement positions furthest from the FO-DTS instrument where attenuation is greatest. FO-DTS temperature measurements were recorded in the dry, bulk rock matrix above the target fracture with roughly 0.5 m of undisturbed rock remaining between the deepest FO-DTS measurement and the target fracture. Fracture fluid temperature is then determined based on an
error function extrapolation of the measured temperature data to the depth of the target fracture (Hawkins et al., 2017a).

In addition to the FO-DTS temperature measurements, temperature sensors measured fluid temperature in three monitoring wells (Solinst Leveloggers®, Model #: 3001) and in the production well (RBR, Model #: Solo T). In the three monitoring wells, a pneumatic straddle packer assembly hydraulically isolated the target fracture from the uncased formation above and below the straddled interval of 25 cm, resulting in an isolated volume of 4.4 L in the straddled interval. An additional straddle packer assembly installed in injection well 204 hydraulically isolated the target fracture and constrained fluids in the straddled interval to a volume of roughly 8 L. At the production well, a single pneumatic packer inflated roughly 6 cm below the target fracture provided hydraulic isolation in the wellbore from below.

2.3 Tracer Tests

Evaluated tracers included an adsorbing cation (cesium), an inert anion (iodine), an inert nanoparticle (C-Dots), and a thermally degrading organic compound (phenyl acetate). Tracer tests were conducted over two separate field efforts; the first in the fall of 2015 and the second in the summer of 2016. In the 2015 field test, four experiments using phenyl acetate and C-Dots were tested during 6 days of continuous hot water injection (see subsection 2.2). The relative recovery of the thermally degrading tracer and the inert tracer provided estimation of changes in the effective reservoir temperature after 1, 3, and 5 days. The hydraulic conditions of these tracer tests (e.g., flow rate, straddle packer assemblies, injection/production wells) were identical to the conditions of the thermal test described in subsection 2.2. A detailed description of these experiments is provided in Hawkins et al. (2017a) and in Hawkins (2017).

In summer 2016, cesium-iodide salt and the C-Dot nanoparticle tracer were injected into the formation under nearly identical conditions as the 2015 tests. Cesium was used as an adsorbing tracer to estimate the effective heat transfer area while iodide and C-Dots were used as inert (or conservative) reference tracers. Moderate differences between the two tests included: (1) the volumetric flow rate was slightly larger in the 2016 field test (5.82 vs. 5.70 L/min) and (2) the fluid volume in the straddled interval of the pneumatic packer assembly was lower in the 2016 field test (5 vs. 8 L).

Thermally Degrading Tracers

Thermally degrading tracers can be interpreted using several different approaches (e.g., Maier et al., 2015a, 2015b; Robinson et al., 1988; etc.). In the approach described here, they are interpreted based on the assumption that an “effective” reservoir temperature can adequately describe the extent of cooling (or heating, as in the Altona experiments). This approach assumes that differences in the RTD of an inert and thermally degrading tracer result only from thermal degradation and that the extent of degradation can be related to an “effective” reservoir temperature.

In reality, a geothermal reservoir undergoing active cold water reinjection produces a heterogeneous temperature distribution in the subsurface. For a reactive tracer experiencing temperature-dependent kinetics following the Arrhenius Equation, its reaction rate will vary along a single fluid flow streamline between an injector and producer. Nevertheless, this
approach provides an informative first-order approach to quantify the extent of cooling in a reservoir and can be used to calibrate thermal-hydraulic forward-models for predicting thermal performance.

An effective reaction rate, $k_{\text{eff}}$, can be determined from the relative mass recoveries of the reacting and inert tracers such that

$$k_{\text{eff}}(\tau) = -\ln\left[\frac{M(\tau)}{M_0(\tau)}\right]^\frac{1}{\tau},$$  

(1)

where $M$ and $M_0$ are the tracer masses recovered at the production well for the thermally degrading tracer reactant and the inert reference tracer, respectively, and $\tau$ is the fluid residence time in the reservoir. If the tracer masses injected differ, then the masses must be normalized by dividing measured mass recovered by tracer mass injected. After rearranging the Arrhenius Equation (Hawkins et al., 2017a), an effective reservoir temperature, $T_{\text{eff}}$, is defined as

$$T_{\text{eff}}(\tau) = -\frac{E_a}{R} \ln\left[\frac{k_{\text{eff}}(\tau)}{A}\right]^{-1},$$  

(2)

where $E_a$ is the activation energy, $R$ is the ideal gas constant, and $A$ is the pre-exponential factor to the Arrhenius equation.

**Adsorbing Tracers**

A one-dimensional analytical model provided the computational framework for interpreting the results of the combined inert/adsorbing tracer test. The objective of the inert/adsorbing tracer test was to estimate the effective heat transfer area and subsequently use this estimate in a heat transport model to predict production well temperature rise at the Altona site. This model is described in detail in Hawkins et al. (2018) and briefly summarized here.

Solute transport modeling included the combined effects of advection, dispersion, and rate-limited adsorption. The model is derived for a one-dimensional system in which a uniform velocity field exists throughout a flow “channel” of finite volume and area.

Tracer concentration, $c$, of an adsorbing tracer is modeled in Laplace space as

$$\tilde{c}(s) = \exp\left[\frac{Pe}{2} \left(1 - \sqrt{1 + \frac{4 \kappa A f + V}{s Pe}}\right)\right].$$  

(3)

where $q$ is the volumetric flow rate through an individual flow channel, $s$ is the Laplace transform variable, $A_f$ is the flow channel area, including both the upper and lower surfaces, $V$ is the inter-well fluid volume, and $Pe$ is

$$Pe = \frac{\nu}{D_f},$$  

(4)

where $\nu$ is the fluid velocity, $x$ is distance transported, and $D_f$ is the hydrodynamic dispersion coefficient. The parameter grouping, $\kappa$, describes adsorption on the fracture surface and is defined as

$$\kappa = \frac{s P k_{\text{ads}}}{k_{\text{ads}} + s}.$$  

(5)
where $P$ is the partition coefficient on the fracture surface and $k_{ads}$ is the first-order adsorption rate constant. For an inert tracer, adsorption is negligible and $\kappa$ in Equation 3 is zero. As a result, inert tracer breakthrough is only influenced by the Peclet number, volumetric flow rate, and inter-well fluid volume. In Hawkins et al. (2018), this analytical model also includes the effect of matrix diffusion for circumstances where tracer diffusion from the fracture into the fluid-filled porosity of the bulk rock matrix is significant. Low matrix porosity at the Altona site (~1-3%) justifies neglecting matrix diffusion in this study. Values for each known parameter used in this study are listed in Table 1. The adsorption rate constant and partition coefficient of cesium onto the Potsdam Sandstone were both measured in laboratory batch experiments (Hawkins et al., 2018).

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$E_a$</td>
<td>activation energy</td>
<td>36.57</td>
<td>kJ/mol</td>
</tr>
<tr>
<td>$A$</td>
<td>pre-exponential factor</td>
<td>1002.9</td>
<td>s$^{-1}$</td>
</tr>
<tr>
<td>$q$</td>
<td>volumetric flow rate</td>
<td>5.70 or 5.82</td>
<td>L/min</td>
</tr>
<tr>
<td>$P$</td>
<td>adsorption partition coefficient</td>
<td>12.2</td>
<td>cm</td>
</tr>
<tr>
<td>$k_{ads}$</td>
<td>adsorption rate constant</td>
<td>0.865</td>
<td>d$^{-1}$</td>
</tr>
<tr>
<td>$T_r$</td>
<td>ambient rock temperature</td>
<td>11.7</td>
<td>°C</td>
</tr>
<tr>
<td>$T_w$</td>
<td>injected water temperature</td>
<td>74.0</td>
<td>°C</td>
</tr>
<tr>
<td>$C_{p,w}$</td>
<td>specific heat of water</td>
<td>4200</td>
<td>J/kg-K</td>
</tr>
<tr>
<td>$C_{p,r}$</td>
<td>specific heat of rock</td>
<td>1000</td>
<td>J/kg-K</td>
</tr>
<tr>
<td>$\mu_w$</td>
<td>viscosity of water</td>
<td>1e-3</td>
<td>Pa·s</td>
</tr>
<tr>
<td>$K_r$</td>
<td>thermal conductivity of rock</td>
<td>7.6</td>
<td>W/m·K</td>
</tr>
</tbody>
</table>

Two fluid flow channels were used in the Altona field tests to simulate tracer transport. A transfer function approach captured the combined influence of tracer transport through these two flow channels (Hawkins et al., 2018). In addition, the transfer function approach also captured the effect of an apparent background groundwater flow transporting fluids from a nearby dammed reservoir eastward to a groundwater seep roughly 50 m from the well field. A MATLAB® script provided in Hollenbeck (1998) numerically inverted Equation 3 from Laplace space to solve for concentration as a function of time.

### 2.5 Ground Penetrating Radar (GPR)

Ground Penetrating Radar (GPR) imaged saline tracer flow paths in the fracture plane as high salinity fluids were continuously circulated between injection well 304 and production well 204 (Hawkins et al., 2017a, 2017b; Tsoflias et al., 2015). GPR salt tracer imaging revealed a strong, direct flow path directly between the injection and production well over a distance of 14.1 m (Figure 1). The spatial distribution and concentration of saline tracer is represented by the strength of the amplitude difference between the amplitude measured prior to and during tracer circulation. Therefore, red regions of the map shown in Figure 2 represent areas of greatest tracer concentration. The width of the traced flow channel directly connecting the two wells is roughly
1 to 2 m in width. This result is roughly consistent with the heat exchange experiment shown in Figure 3, which constrains the flow channel width to less than 4 m.

![Figure 2: Map of radar wave reflection amplitudes at 7.6 m depth during the saline tracer GPR survey after subtracting the background amplitude signal. Note that circulating fluids were injected into well 304 and pumped from well 204 whereas in the heat exchange and other tracer experiments well 204 served as the injection well and fluids were pumped from well 304. Figure originally published in Hawkins et al. (2017a).](image)

3. Results

3.1 Thermal Test

After 6 days of continuously circulating heated fluids (74) through the target fracture, production well fluid temperature rose from 11.7 to 29.1. Production well fluid temperature began to rise after roughly 1 hour of hot water injection (Figure ). The Fiber-Optic Distributed Temperature Sensor (FO-DTS) network recorded the greatest temperature rise in the direct path between the injector and producer. An error function fit to measured temperature resulted in a fracture fluid temperature increase estimated within the 10 x 10 m well field ranging between 0.9 and 31.1 °C.
Figure 3: Map view representation of the spatial distribution of temperature rise recorded via FO-DTS after 144 hours of hot water injection into well 204. An error function fit to FO-DTS data estimated fracture fluid temperature (shown in parentheses) (Hawkins et al., 2017a, 2018). The grey arrows represent the general direction of fluid transport in the fracture from the injection well to the production well. Figure originally published in Hawkins et al. (2017a).
Figure 4: Measured temperatures compared to predicted/estimated temperatures over the 144 hour heat exchange experiment. Measured production well temperatures are shown as white circles. Measured effective reservoir temperatures (white squares) are averages based on temperature measured in wells 104, 204, 304, 404, and 504 as well as the FO-DTS temperature measurements shown in Figure 3. Predicted production well temperatures based solely on model calibration by the inert tracer test are shown as a blue curve (see Section 3.3.1). Predicted production well temperatures based on analysis of both the inert and adsorbing tracer are shown as a red curve (see Section 3.3.2). Estimated effective reservoir temperatures based on the thermally degrading tracer tests are shown as orange squares (see Section 3.3.3).

3.3 Predicted Thermal Breakthrough

3.3.1 Analysis 1: Inert Tracer Test

This first approach to predicting thermal breakthrough assumed heat and tracer circulate through a 2-D discrete fracture of uniform (i.e., homogeneous) aperture. The inert C-Dot tracer return curve collected at the Altona site in the Fall of 2015 was used to calibrate a forward-model of heat transport (Hawkins et al., 2017a). This calibrated model was subsequently used to predict production well temperature rise.

This approach is intended to demonstrate the limitations of inert tracers in calibrating thermal-hydraulic models if the reservoir geometry is over-simplified. A good fit to measured inert tracer data was found by solving an inverse problem for hydrodynamic dispersivity and fracture aperture (Figure 4). The resulting values are 0.14 m and 0.53 mm for dispersivity and aperture, respectively. See Hawkins et al. (2017a) for details.
Figure 4: Measured C-Dot tracer return curves (dots) from the 2015 test compared to the model-fit (solid line) resulting from solving the inverse problem for hydrodynamic dispersivity and fracture aperture in 2-D. Concentration is normalized by dividing measured tracer concentration by tracer mass injected. Data originally published in Hawkins et al. (2017a).

The tracer-calibrated fracture subsequently served to forecast thermal performance (see Fox et al., 2015 for a description of the thermal-hydraulic model). As discussed in Hawkins et al. (2017a, 2018), the model predicts no temperature rise at the production well over the 6 day experiment and a 1 °C temperature rise in roughly 37 days. In contrast, measured production well temperature rises 1 °C in just 0.1 days.

3.3.2 Analysis 2: Adsorbing Tracer Test

In the adsorbing tracer approach, a one-dimensional analytical model for advection-dispersion-adsorption (Equation 3) enabled estimation of the effective heat transfer area. As previously discussed in Section 1, heat transfer area is the most critical unknown reservoir property in forecasting thermal breakthrough using the analytical model from Hawkins et al. (2018). Using the iodide and cesium tracer return curves collected in 2016, a two flow channel scenario was able to capture the behavior of both the inert and adsorbing tracer (Figure 5). Estimated heat transfer area for the two flow channels is 28.3 and 80.1 m² (Hawkins et al., 2018). Estimated inter-well fluid volume for the two channels is 82.4 and 198.6 L and the Peclet number is 35.3 and 6.6 (Table 2)
Table 2: Reservoir properties identified using the results of the combined inert and adsorbing tracer test method.

<table>
<thead>
<tr>
<th>Flow channel #</th>
<th>1</th>
<th>2</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean residence time</td>
<td>20.0</td>
<td>45.1</td>
<td>min</td>
</tr>
<tr>
<td>Fluid volume</td>
<td>82.4</td>
<td>198.6</td>
<td>L</td>
</tr>
<tr>
<td>Surface area</td>
<td>28.3</td>
<td>80.1</td>
<td>m²</td>
</tr>
<tr>
<td>Peclet number</td>
<td>4.13</td>
<td>6.6</td>
<td>(-)</td>
</tr>
</tbody>
</table>

Figure 5: Measured inert (iodide) and adsorbing (cesium) tracer return curves from the 2016 field tests compared to a model-fit simulation (solid lines) using Equation 3. Estimated transport properties resulting from solving the inverse problem were subsequently used to forecast the thermal breakthrough shown in Figure . Concentration is normalized by dividing measured tracer concentration by tracer mass injected. Data were originally published in Hawkins et al. (2018).

The effective heat transfer area and inter-well fluid volume estimated by Equation 3 were subsequently used to predict thermal breakthrough (Hawkins et al., 2018). In contrast to the approach described in the previous subsection, this prediction is based on an analytical heat transport model from Hawkins et al. (2018) rather than the 2D thermal-hydraulic model described in Fox et al. (2015). The thermal-hydraulic model calibrated by the combined
adsorbing/inert tracer approach predicts a 1 temperature rise at the production well in roughly 0.3 days compared to a measured equivalent increase in 0.1 days (Figure ). After 6 days, predicted and measured production well temperatures are 32.2 and 29.3, respectively.

3.3.3 Analysis 3: Thermally Degrading Tracer Test

The thermally degrading tracer tests performed during the reservoir heat exchange experiment in 2015 were used to estimate the initial reservoir temperature and the effective reservoir temperature after 1, 3, and 5 days of continuous reservoir heat up. The product of phenyl acetate hydrolysis, phenol, was measured during the tracer tests and shows increasing peak tracer concentrations as the reservoir was progressively heated over 6 days (Figure 6). Recent laboratory measurements of the reaction rates of phenyl acetate hydrolysis by Gu (2018) provided the Arrhenius parameters necessary in estimating effective reservoir temperature by Equation 2. The pre-exponential factor and activation energy are 1002.9 s\(^{-1}\) and 36.57 kJ/mol, respectively. Laboratory experiments investigating phenyl acetate hydrolysis under both homogeneous and heterogeneous reaction conditions are ongoing, however. Therefore, the estimated effective reservoir temperatures shown here should be considered preliminary.

![Figure 6: Measured phenol (reaction product) tracer return curves collected during varying stages of progressive reservoir heating at the Altona site in 2015. Note that phenol is the reaction product (not the reactant) of phenyl acetate hydrolysis. Increasing phenol recovery between the initial curve (blue circles) and subsequent curves indicates the effective reservoir temperature is increasing. The C-Dot tracer return curve (black crosses) provides an inert tracer reference RTD. Data were originally published in Hawkins et al. (2017a). See original publication for further description of how tracer concentration is normalized.](image)

Following the approach described in Hawkins et al. (2017a), the relative mass recovery of C-Dots and phenol provided the unknown values required to estimate effective reservoir
temperature via Equation 2. Relative recovery is defined as the ratio of the mass percent recovered of phenyl acetate (reactant) over mass percent recovered of the inert C-Dot tracer ($M/M_0$ in Equation 1). These relative mass recoveries at ambient reservoir temperatures and after 1, 3, and 5 days of heating are 0.60, 0.37, 0.31, and 0.26, respectively (Hawkins et al., 2017a). These mass recoveries are measured after tracer circulation lasted 44 min. These data show progressive declines, indicating that as the reservoir is heated the tracer reactant (phenyl acetate) experiences reduced mass recoveries while the product (phenol) experiences increasing mass recoveries.

Estimated effective reservoir temperature at ambient conditions and after 1, 3, and 5 days of heating are 11.5, 23.9, 27.3, and 30.4 °C, respectively (Figure and Table 3). These estimates are compared to fracture fluid temperatures averaged across all ten FO-DTS monitoring locations shown in Figure 3 in addition to the production well temperatures (Figure ) and injection well temperature (74 °C). At ambient conditions and after 1, 3, and 5 days of heating, measured reservoir temperatures are 12.5, 22.8, 25.8, and 29.8, respectively.

Table 3: Measured and estimated effective reservoir temperature at ambient reservoir temperature and after varying days of reservoir heat up. These estimates are based on the analysis of the thermally degrading tracer data shown in Figure 6 and on preliminary measurements of the Arrhenius parameters from Gu (2018).

<table>
<thead>
<tr>
<th></th>
<th>Ambient Conditions</th>
<th>1 Day</th>
<th>3 Days</th>
<th>5 Days</th>
</tr>
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<tbody>
<tr>
<td>Estimated</td>
<td>11.5</td>
<td>23.9</td>
<td>27.3</td>
<td>30.4</td>
</tr>
<tr>
<td>Measured</td>
<td>12.5</td>
<td>22.8</td>
<td>25.8</td>
<td>29.8</td>
</tr>
</tbody>
</table>

In Hawkins et al. (2017a), the data shown in Figure 6 were used to estimate the effective reservoir temperatures shown in Figure . Unfortunately, the Arrhenius parameters for phenyl acetate hydrolysis provided in Nottebohm et al. (2012) over-estimated effective reservoir temperatures. Preliminary measurements of the reaction rates of phenyl acetate hydrolysis were measured by Gu (2018) under conditions more appropriate for the Altona site and the resulting Arrhenius parameters provide improved estimates of effective reservoir temperature (Figure and Table 3).

Laboratory measurements are ongoing and will be presented in forthcoming publications, including evidence for accelerated reaction rates of phenyl acetate hydrolysis when in contact with silica minerals. Effective reservoir temperatures will be recalculated once laboratory experiments are complete.
4. Discussion and Conclusions

This article summarizes the results of thermal and tracer transport studies conducted since 2015 at a low-temperature, meso-scale field site referred to as the Altona field laboratory. The objective of these tests was to evaluate the ability of various tracer testing methods to monitor and predict heat transport in geothermal reservoirs. Tested tracers included an inert anion (iodide), an inert nanoparticle (C-Dots), an adsorbing cation (cesium) and a thermally degrading organic compound (phenyl acetate).

The use of an inert tracer to estimate reservoir geometry resulted in inaccurate predictions of thermal breakthrough at the Altona site (see Hawkins et al. (2017a) for details). As discussed in Section 3.3.1, a 2-D discrete fracture with a uniform aperture of 0.53 mm and dispersivity of 0.14 m resulted in very good agreement between simulated and measured C-Dot concentration (Figure 4). Unfortunately, the same reservoir geometry did not result in accurate predictions of thermal breakthrough (Figure ). Predicted production well temperature after 6 days was 11.7 (i.e., no temperature rise predicted) whereas measured temperature was 29.3 in the same time span. In fact, the predicted production well temperature does not reach a 1 temperature rise until roughly 37 days whereas measured temperature rises 1 in just 0.1 days (Hawkins et al., 2018).

The combined use of an inert and an adsorbing tracer to estimate reservoir geometry resulted in relatively accurate predictions of thermal breakthrough (see Hawkins et al. (2018) for details). As discussed in Section 3.3.2, a 1-D analytical model for advection, dispersion, and rate-limited adsorption resulted in good agreement between simulated and measured iodide and cesium concentrations (Figure 5). The effective heat transfer area estimated from the solution to the inverse problem was subsequently used to predict production well temperature rise using the thermal-hydraulic model found in Hawkins et al. (2018). The model predicts a production well temperature of 32.2 after 6 days whereas measured temperature at this time was 29.3 (Figure ). Measured and predicted production well temperature rises 1 in 0.1 and 0.3 days, respectively. The partition coefficient and rate constant necessary for simulating the adsorbing tracer RTD were measured in laboratory batch experiments and demonstrated that the adsorption reaction was rate-limited at the time-scale of the field tests at the Altona site (Hawkins et al., 2018).

The combined use of an inert and a thermally degrading tracer resulted in accurate estimates of effective reservoir temperature as hot injection fluids heated up the reservoir (see Hawkins et al. (2017a) for details). Measured and estimated reservoir temperatures at ambient conditions were 12.5 and 11.5 °C, respectively. Measured effective reservoir temperatures after 1, 3, and 5 days were 22.8, 25.8, and 29.8 °C, respectively and estimated temperatures were 23.9, 27.3, and 30.4 °C, respectively. These estimates were made using Arrhenius parameters from Gu (2018). These are preliminary parameter estimates, however, which will be discussed further in a forthcoming article after completion of additional laboratory experiments. As discussed in Gu (2018), the interpretation of the thermally degrading tracer tests may be complicated by an apparent acceleration of the hydrolysis reaction when the solution is in contact with crushed rock samples collected from the Altona site.

Channeled-flow conditions appear to be responsible for the rapid temperature rise recorded at the production well. During 6 days of continuous hot water injection, the FO-DTS network identified rapid heat transport through a narrow (< 4 m wide) path directly between the injector and producer (see Hawkins et al. (2017a) for details). The spatial extent of this narrow path can
be defined by the fracture fluid temperature distribution shown in Figure 3. Compare, for instance, temperature rise at monitoring locations b4, b5, and b9. Location b5 is furthest from the injection well (~ 11.5 m), yet experienced greater temperature rise (20.0 °C) relative to b4 (4.5 °C) and b9 (10.1 °C), which both lie half-way between the injector/producer well pair, but are ~ 2 m off of the direct path.

This narrow flow channel is also evident in the GPR tracer imaging study. GPR imaged the spatial distribution of a saline tracer continuously circulated between the same well pair (see Hawkins et al. (2017a) for details). As shown in Figure 2, the GPR imaging reveals a narrow (roughly 1-2 m) wide flow channel directly connecting the injector and producer. The narrow flow channel identified by FO-DTS and GPR suggests that the temperature rise measured in the production well was relatively rapid and that the effective heat transfer area between the two wells is low.

In summary, this study provides a comprehensive and quantitative field validation of reservoir characterization methods utilizing inert, thermally degrading, and adsorbing tracers. Despite initial work on adsorbing and thermally degrading tracers beginning several decades ago (e.g., Robinson et al., 1984, 1988; Tester et al., 1986; Vetter and Crichlow, 1979), inadequate field validation appears to have prevented the adoption of these tools in commercial geothermal reservoirs (Hawkins, 2017). The results of this study suggest that the combined use of inert, thermally degrading, and adsorbing tracers should provide far better predictions of thermal breakthrough than the use of an inert tracer alone.

These methods were proven at the meso-scale Altona site, however, where tracer and heat transport is constrained to a single, shallow fracture with short well separations. In commercial geothermal reservoirs at the scale of kilometers, these methods will require extensive knowledge of fluid and rock conditions in much more complicated reservoir geometries. Future work should investigate the sensitivity of these methods to uncertain or heterogeneous reservoir conditions. While the phenyl acetate and cesium tracers used in this study were appropriate for the conditions at the Altona field site, they are likely inadequate in commercial geothermal reservoirs. Future work should investigate numerous candidate tracers that would be appropriate in a commercial setting.

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All data supporting analysis and conclusions are publically available through the U.S. Department of Energy’s Geothermal Data Repository at https://gdr.openei.org.

REFERENCES


