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# Tracer Testing in Well 16B-32 at the Utah FORGE EGS Project

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## ABSTRACT

An injection/production well doublet was recently drilled at the Utah FORGE site in order to test emerging EGS concepts. During the hydrofracture of the injection well (16A-32), a distinctive tracer was dosed into each of three fracture stages near the toe of the well. While drilling an offset production well (16B-32) the following winter, drill mud was sampled and analyzed for the three tracers injected during the previous year's hydrofracturing process. All three tracers were subsequently measured in the mud samples, suggesting that well 16B-32 had intersected the fractures created during the hydrofracturing of the first well. Samples of core that were retrieved during the drilling of 16B-32 were also analyzed for the presence of tracer. These samples were obtained by rinsing core-fracture surfaces with deionized water. Laboratory analyses of the rinsate from those cores showed that tracer from the 2022 injection had absorbed onto some of the open fractures, further substantiating the notion that the 16B-32 trajectory had successfully intersected the fractures extending from well 16A-32.

Whereas these initial studies at the Utah FORGE site were focused on the use of conservative (i.e., nonreactive) tracers, future investigations will focus on field-wide, interwell flow using combinations of conservative tracers in combination with reactive (e.g., reversibly adsorbing) tracers. In a 10-well hydrofracture experiment in a hot, shale-gas reservoir at Dilly Creek, British Columbia, various combinations of conservative and reactive tracers were continuously dosed into wells during the hydrofracturing process. Measured tracer concentrations in the flowback fluids revealed a correlation between fracture surface area and subsequent gas production rate. In a future research project at Utah FORGE, the approach used to characterize fracture surface area in shale-gas reservoirs will be extended to characterize heat-exchange area in an EGS reservoir.

The tracers that we used in both of the above studies were the well-characterized naphthalene sulfonates, which had been developed for use in geothermal reservoirs under mandate from DOE/EERE at EGI two decades previously and which have subsequently been used in a variety of settings including petroleum reservoirs and groundwater aquifers. In this paper, we show how these tracers can be used to characterize reservoir fluid volume, fracture surface area, inter-well flow patterns, and flow through discrete fractures.

## 1. INTRODUCTION

A fundamental concept in the design of Engineered Geothermal Systems (EGS) is that wells drilled into the hot, deep, granitic basement can be hydrofractured in order to create a heat exchanger at depth between wells. That network of fractures can be mapped in three dimensions by measuring the location of induced microseisms—the seismic cloud—as obtained during the hydrofracturing process. If thermally stable, nonreactive tracers are dosed into a fluid stream during the initial hydrofracturing of a well, those tracers would be advected throughout the newly formed fracture network where they would remain in solution in the fractures indefinitely. If the trajectory of a second well were to successfully intersect the seismic cloud, tracers in the hydrofractures would diffuse into the drill mud of that second well and be recirculated to the surface with the mud. Thus, the presence of tracers in the returned mud would serve to indicate that the second well intersected the induced fractures created during the hydrofracturing of the first well. Our expectation of finding tracers in the drill mud was based on hydrofracturing experiments conducted 25 years ago at the Soultz-sous-Forets EGS project in Eastern France. Tracers injected into well GPK-3 during its hydrofracture were discovered in the drill mud in adjacent well GPK-4 when it was drilled one year later (Andre Gerard, personal communication). Our objective at the FORGE site was to determine if, like at Soultz, we could observe tracers from the 16A-32 hydrofracturing experiment in the 16B-32 drill mud.

Whereas the naphthalene sulfonates can be used in the above manner to characterize discrete fractures in EGS reservoirs, they can also be used to estimate the surface area of a hydrofractured reservoir and, by extension, the success of the EGS hydrofracturing process. In carefully controlled laboratory experiments using flow reactors, the measured tracer response from a flow experiment is used to quantitate a reversibly adsorbing tracer's response relative to that of a conservative tracer. This response is the relative retardation, which is related to the adsorption equilibrium constant $K_d$ by equation 1:

$$K_d = (RF - 1) * \frac{N_e}{P_b} \qquad (1)$$

where RF is the retardation factor, $N_e$ is the effective porosity of the medium (pore volume divided by total column volume) and $P_b$ is the bulk density of the porous medium (mass of shale cuttings in column divided by total column volume). Through inversion of numerical models of field tracer studies, the tracer-contacted fracture surface area can then be calculated (Rose et al., 2022).

## 2. APPROACH—TRACER INJECTION AND ANALYSIS

### 2.1 Tracer injection

A distinct, thermally stable, naphthalene sulfonate tracer was added to each of three stages during the hydrofracturing of FORGE well 16A-32 in April 2022. These tracers were developed at EGI two decades ago under mandate of EERE/DOE and have been shown to be extremely thermally stable, very detectable, nontoxic and environmentally benign (Rose et al., 2001). Each tracer solution was dosed into a blender tank that fed into the low-pressure intake of high-pressure hydrofracture pumps using and Eldex laboratory pump. We adjusted the flow rate of a tracer stream from the lab pump proportionally to the flow from the high-pressure stimulation pumps such that the tracer concentration entering the wellhead was constant at 150 parts per billion (ppb). By dosing each tracer in this fashion, we could be confident that the concentration of each tracer entering the formation would initially be 150 ppb.

The first stage of the hydrofracture of 16A-32 was tagged with the tracer 1,6-naphthalene disulfonate (1,6-nds) and pumped down the 7-inch casing string into the open hole section at the bottom of the well, reaching a maximum injection rate of ~50 bpm. After 4,260 bbl were pumped, the well was shut in for four hours to monitor pressure decline and subsequently flowed back. The second hydrofractured stage was tagged with the tracer 1,3,5-naphthalene trisulfonate (1,3,5-nts) and pumped through a 20-ft perforated interval in the 7-inch casing from 10,560 – 10,580 ft MD. The flow reached the maximum designed injection rate of ~35 bpm. A total of 2,777 bbl was pumped after which the well was shut in for four hours to monitor the pressure decline, followed by flowback. The third hydrofracture stage used a crosslinked polymer treatment; it was tagged with the tracer 1,3,6-naphthalene trisulfonate (1,3,6-nts) and pumped through a 20-ft perforated interval in the 7-inch casing from 10,120 – 10,140 ft MD, reaching a maximum designed injection rate of ~35 bpm. A total of 3,016 bbl was pumped after which the well was shut in for five hours to monitor the pressure decline, followed by flowback. Details of the hydrofracturing procedure are described elsewhere (Jones et al., 2023).

### 2.2 Tracer sampling and analysis

As summarized in the previous section, a distinct tracer was dosed into each of three intervals during the hydrofracture of adjacent well 16A-32 in April, 2022. As part of the drilling of the 16B-32 well, we searched for those same tracers in samples of drill mud as it was pumped back to the surface. We thought that if tracers were found in the mud, we could infer that the only way that they could have arrived was through the fractures created during the previous year's tracer-tagged, hydrofracture experiment. Samples of 16B-32 mud were taken every 10 ft as the drill bit reached the targeted hydrofractured zones. The samples were labeled according to the location of the bit in the wellbore, as determined from mud return times. The interval that was sampled and reported here was between 9700 ft and 10,500 ft (measured depth).

Cores were taken along the 16B-32 wellbore over three intervals suspected of including fractures that were formed during the hydrofracture of well 16A-32, as inferred from relative relocations of induced seismic events. The first (shallowest) core was retrieved at 9808-9850 ft, that of the next-deeper interval was 10,260-10,300 ft, while the deepest interval was 10,432-10,484 ft. We logged the cores and observed fracturing in each interval.

The surface area of a perpendicular fracture on a 16B-32, 3-in core is approximately 12-in$^2$, so it seemed highly improbable that tracers injected during the hydrofracture of 16A-32 during the previous year could have been advected through the reservoir and adsorbed in sufficient quantity as to be retained and detected on 12-in$^2$ fracture surfaces, when those cores were retrieved one year later. Nevertheless, we conducted the search. Fracture surfaces from the 16B-32 core were carefully rinsed in order to dissolve any adsorbed solute. Both sides of a core fracture were rinsed aggressively with deionized water from a squeeze bottle over a funnel to remove caked-on material until 50 ml of rinsate was collected in each sample. Water was also rinsed over the exterior surface of the core and collected for analysis—this in order to determine if there was a difference between the amount of tracer adsorbed on the surface of an interior fracture vs. the exterior surface of the core.

We analyzed the tracer samples using Ultra Performance Liquid Chromatography (UPLC) after using Solid Phase Extraction (weak-anion exchange) to remove interfering salts and oils dissolved in the aqueous matrix. We used paired-ion chromatography in order to take advantage of the high resolution of C18 X-Bridge (Waters) columns. The excitation and emission wavelengths of our fluorescence detector were set to 224 nm and 340 nm, respectively. Other details of the analysis are described in Rose et al (2001).

Shown in Figure 1 are plots of tracer concentration vs. depth as measured in drill mud sampled during the drilling of well 16B-32. The analyses of mud samples show significant concentrations of 1,3,6-nts (purple), and lower concentrations of 1,6-nds (red), and 1,3,5-nts (green). All three tracers were dosed into the hydrofracture fluids at 150 ppb; however, much more fluid—and therefore more tracer—was injected during the hydrofracture of the third (1,3,6-nts) stage than during the hydrofractures of stages one (1,6-nts) and two (1,3,5-nts). A higher concentration of 1,3,6-nts in the 16B-32 drill mud is consistent with the greater amount of 1,3,6-nts injected into the formation.

Shown in Figure 2 are plots of the concentrations of tracers measured in the fracture rinsates, as described above. These points are clustered at depths of about 9,825, 10,280, and 10,450 ft, respectively. The rinsate concentrations show similar trends to those in the drill mud with 1,3,6-nts (purple) in higher concentrations that the other two tracers. The concentration of 1,3,6-nts rinsed from the fracture at about 10,450 ft—with a value of almost 18 ppb—is significantly higher than any other measured value.

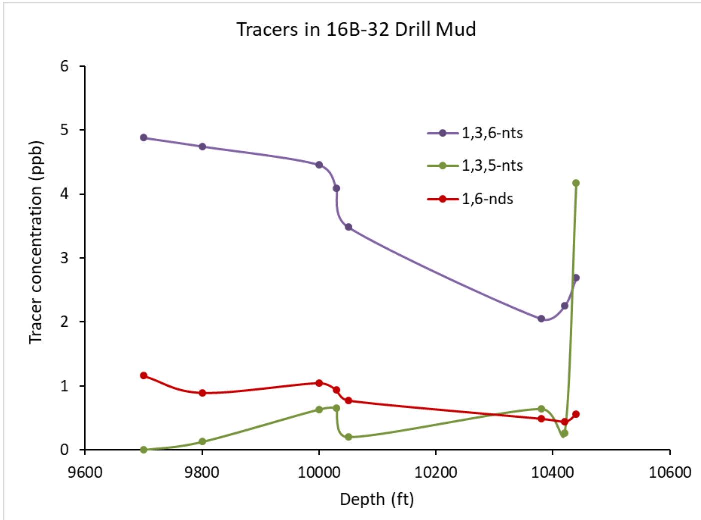


**Figure 1: Tracer concentrations in 16B-32 drill mud vs. depth for each of the three tracers used to tag the three stages during the hydrofracturing of 16A-32.**

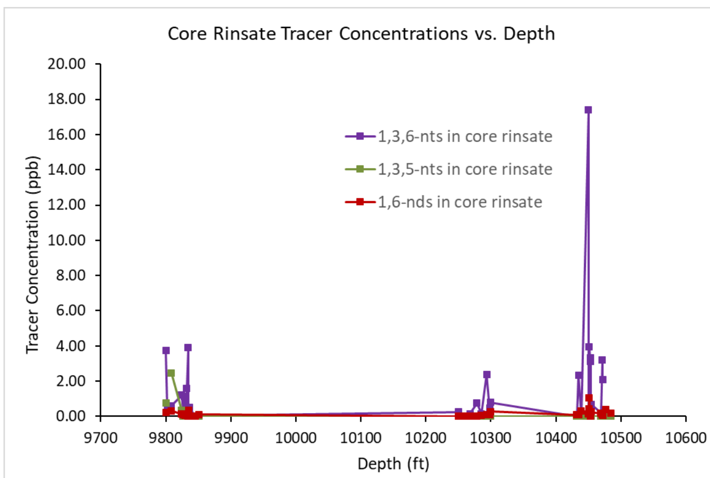


**Figure 2: Tracer concentrations in core rinsates vs. depth for each of the three tracers used to tag the three stages during the hydrofracturing of 16A-32.**

Shown in Figure 3 is a magnified view of the tracer-rinsate plots shown in Figure 2. This figure also repeats plots of the tracer concentrations measured in drill mud, as plotted in Figure 1.

The values for 1,3,6-nts and 1,6-nts in Figure 3, as measured at 9700 ft, are about 5 ppb and 1 ppb, respectively. These are background concentrations of tracers that have already entered the mud at some higher point, since they were present at a depth that is shallower than the shallowest known hydrofractures and above the point where the drill bit reached the known hydrofractures. 1,3,6-nts and 1,6-nts might have entered the drill mud as the bit intersected shallower but unknown fractures. Since no samples of mud were taken above 9700 ft, we cannot know if the tracers entered the wellbore from the formation somewhere above 9700 ft (via some unknown fractures), or if they entered the drill mud as it was prepared at the surface. It was noted anecdotally by the mud engineer that some mud was prepared using water from the sump into which water produced from 16A-32 had flowed the previous year. Since the naphthalene sulfonates are extremely persistent in both solution and in soil, it is possible that the sump contained measurable concentrations of the 16A-32 stimulation tracers.

Figure 3 also shows that the tracer 1,3,5-nts, which was injected into the 16A-32 stimulation fluids during the hydrofracturing of the middle set of fractures, had an initial concentration of 0 at 9700 ft (i.e. no background) and that it gradually grew in concentration over the hydrofractured section until spiking to above 4 ppb at about 10,450 ft. In contrast to the indeterminate origins of the tracers 1,3,6-nts and 1,6-nts, it appears that 1,3,5-nts must have entered the drill mud from the fractures that the mud intersected within the hydrofractured section and below 9700' measured depth.

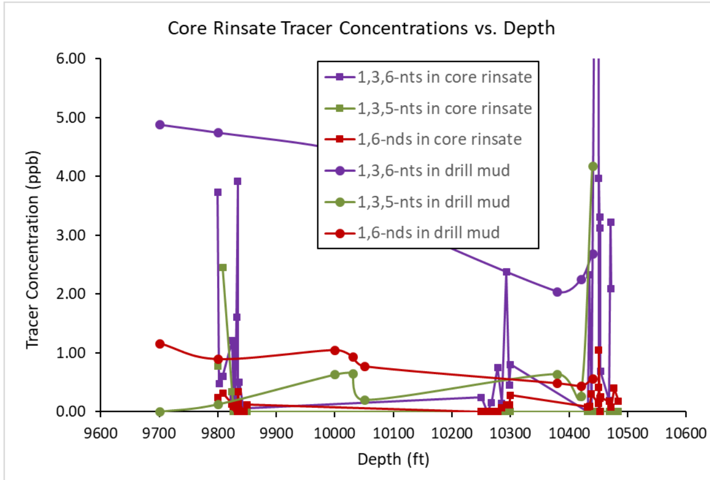


**Figure 3: Tracer concentrations in core rinsates and drill mud vs. depth for each of the three tracers used to tag the three stages during the hydrofracturing of 16A-32. Note that for each tracer, the color is the same whether it was measured in a fracture rinsate or in the drill mud, but the shape of the marker changes depending on whether the tracer is from the rinsate (square) or the mud (circle).**

## 3. AN APPROACH TO FRACTURE SURFACE AREA CHARACTERIZATION USING REACTIVE TRACERS

The section above shows how the naphthalene sulfonates can be used to identify individual fractures that connect wellbores. Tracers can also be used to characterize the reservoir's fracture surface area. Tracers that react with the reservoir rock or the reservoir fluid through either reversible adsorption or thermal decay are termed reactive tracers. With reversible adsorption, a tracer's advection through the reservoir is slightly retarded relative to that of a conservative tracer due to weakly-attractive, electrostatic forces between the tracer and the rock surface. Therefore, if a reactive tracer is co-injected and then co-produced with a conservative tracer, a measurement of the retardation of the reversibly adsorbing tracer relative to that of the conservative tracer provides an independent variable that can serve to constrain the tracer-contacted fracture surface area (Pruess et al., 2005; Fayer et al., 2009; Reimus et al., 2012; Rose et al., 2012; Cao et al., 2020; Wu et al., 2022). Fracture surface area is important because it is directly proportional to the surface area for heat transfer in geothermal reservoirs and to the surface area for gas or oil production in petroleum reservoirs. We used a reversibly adsorbing tracer in combination with a non-adsorbing tracer to investigate the tracer-swept pathway between an injection well and a production pathway at the Soda Lake Geothermal field (Rose et al., 2010; Rose et al., 2022). This tracer-contacted surface area was then used to approximate the surface area for heat exchange.

### 3.1 Reactive-tracer testing at a Dilly Creek/Horn River (Canada) shale gas reservoir

Ten long-reach horizontal wells were drilled into three, vertically stacked shale formations at a Dilly Creek/Horn River shale-gas reservoir (Figure 4).

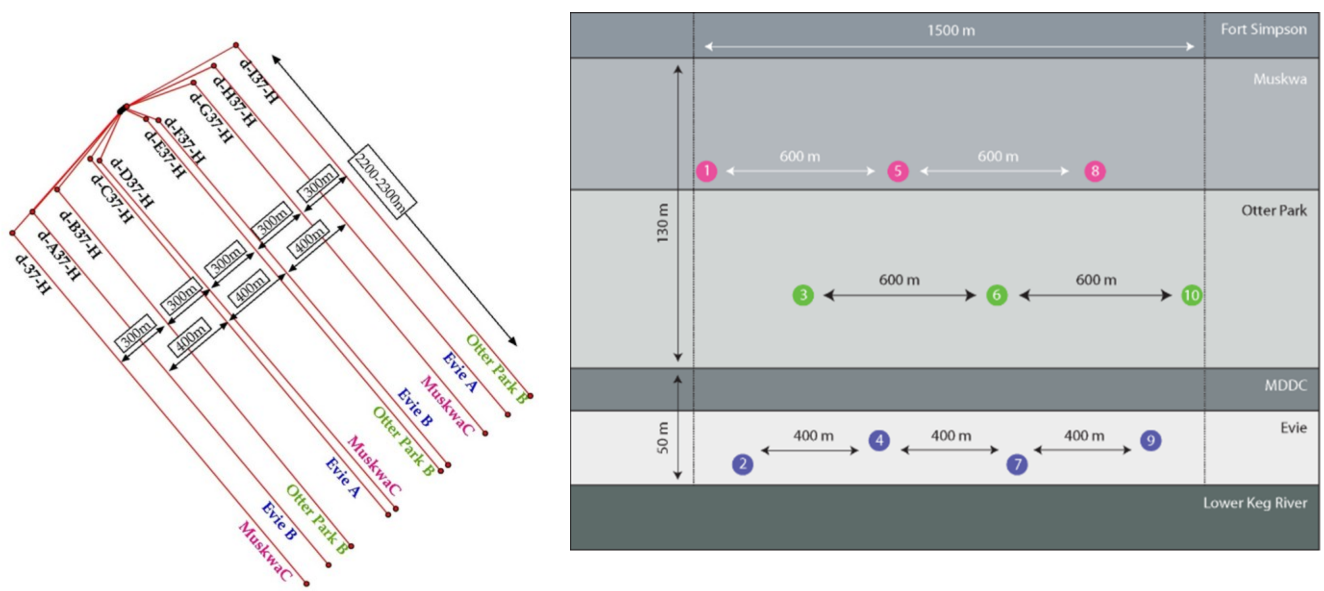


**Figure 4. Plan and cross-section views of the Dilly Creek, British Columbia shale gas reservoir.**

The measured reservoir temperature was approximately 140°C, which is near the lower limit of exploitable geothermal conditions. The wells were each subsequently hydrofractured in 25 individual stages and a unique non-reactive, naphthalene sulfonate tracer was co-injected with a common, reversibly-adsorbing tracer during the hydrofracture of each well.

Upon flow-back, the produced-water samples were analyzed for both the non-reactive (conservative) tracers and the reversibly adsorbing tracer. Figure 5 shows a correlation between short-term gas production rate and tracer adsorption for most of the wells. Where the correlation was poor was for wells 1 and 2. Field operators observed that this could be explained by the fact that there was communication between natural and hydraulically-induced fractures. Upon backflow, water that had been injected into one well found a pathway through the reservoir to an adjacent well, presumably through a large natural fracture—at least for these first two wells.

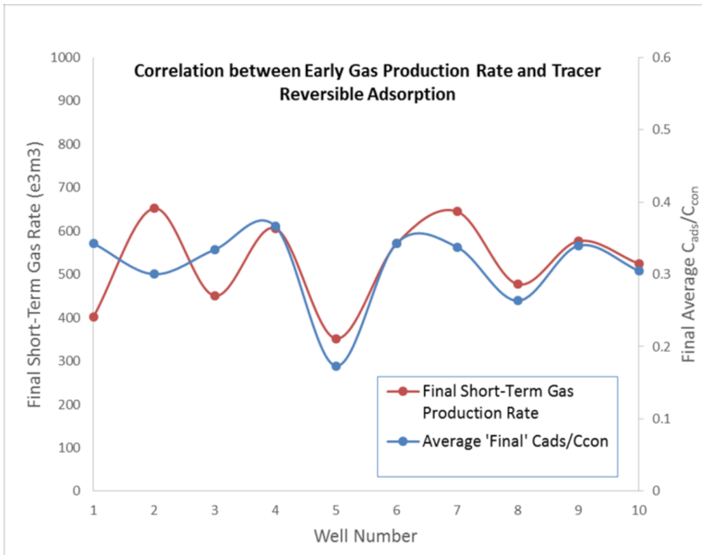


**Figure 5. Tracer adsorption correlates with short-term gas production rate for most of the Dilly Creek wells.**

We observed that the correlation between tracer adsorption and gas production rate also generally held when the data were plotted according to the formations in which the wells were completed. Figure 6 shows that there was a correlation for wells in the Evie and Otter Park formations, but not for the shallowest Muskwa formation—possibly due to the crossover in flowback for the first two wells, as explained above. The laboratory flow-reactor experiments that accompanied the 10-well Horn River, shale-gas field study are described elsewhere (Rose et al, 2022).

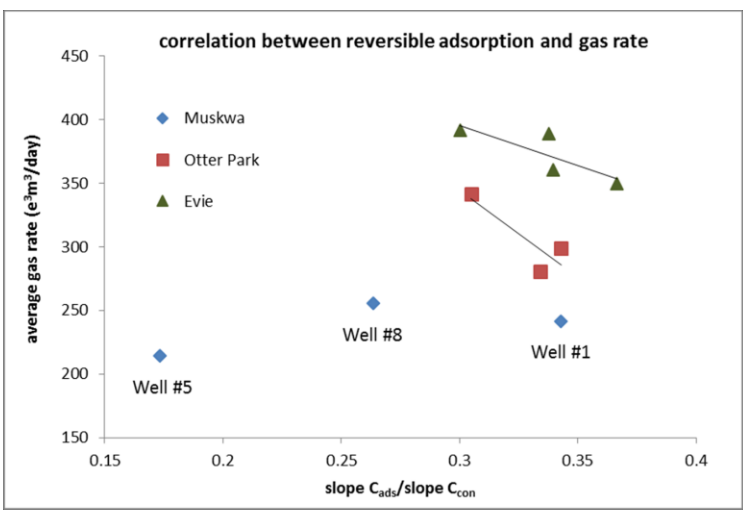


**Figure 6. Tracer adsorption correlates with average gas production rate for two of three formations at the Dilly Creek shale-gas reservoir.**

## 4. CONCLUSIONS

The naphthalene sulfonate tracers can serve to identify individual fractures intersecting a wellbore; these same tracers can likewise be used in combination with reversibly adsorbing tracers to determine reservoir-wide properties such as interwell flow patterns, reservoir pore volume, and the tracer-contacted fracture surface area.

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