PROCEEDINGS, 48th Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 6-8, 2023
SGP-TR-224

Stimulation, Tracers and Geochemistry at Utah FORGE

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Keywords: Utah FORGE, EGS, well 16A(78)-32, tracers, napthalene sulfonate, hydraulic stimulation, flowback chemistry

ABSTRACT

At Utah FORGE, a US Department of Energy sponsored EGS demonstration site, a three stage hydraulic stimulation in the toe section of highly deviated injection well 16A(78)-32 was completed in April 2022. Two types of fluids were used, slickwater and a crosslinked polymer fluid. In addition, a distinct naphthalene sulfonate compound was added to the injected fluids at each stage to act as a non-reactive tracer.

Samples of flowback waters were collected and analyzed to monitor tracer concentrations and water chemistry. Of the 10,062 bbl injected, 6,240 bbl, or 62% of the fluid was recovered.

The tracer return data are interpreted to show no cross contamination of injected fluids between stages due to either communication between stimulated volumes, or along the exterior of the casing string through the cement. These results also demonstrate the tracer's effectiveness under EGS reservoir conditions, and its utility to confirm zonal isolation in multistage hydraulic stimulations.

The chemical composition of the returned fluids shows unexpected, and drastic changes over relatively short periods of time (< 33½ hours). The dominant trend is for the concentrations of dissolved solids to increase with time. The viscous fluids appear to have limited the ability of elements to dissolve and mobilize into the aqueous phase. Changes become more pronounced the longer the fluids were in contact with the reservoir rocks. The transient chemical effects are interpreted to result from water-rock interaction in the reservoir.

1. INTRODUCTION

A method for developing an enhanced geothermal system (EGS) reservoir is to utilize hydraulic fracturing to create new, permeable fractures in low-permeability rock formations to serve as interconnected pathways between an injection-production well doublet. To be economically viable many hydraulic fracture connections between the injection and production wells are required to maximize circulated fluid volumes, surface area and heat exchange and to prevent thermal breakthrough.

At the Utah FORGE (Frontier Observatory for Research in Geothermal Energy) EGS site near Milford, Utah a three stage hydraulic fracturing stimulation was completed in the toe section of a highly deviated injection well designated as 16A(78)-32 in April 2022. The well was drilled vertically to 5,892 ft MD and then deviated at a build rate of 5°/100 ft MD until reaching an angle of 65° to the vertical at 7,262 ft MD where it was held until reaching a final depth of 10,987 ft MD (8,560 ft TVD) giving the lateral section a horizontal reach of 4,074 ft (Figure 1). A 7-inch, 38 lb/ft T95 casing string was run to 10,787 ft MD and cemented to surface leaving 200 ft of open hole below the 7-inch casing shoe.

Well 16A(78)-32 enters the EGS reservoir at temperatures greater than 175 C (347 F) near the end of the curve/start of the tangent section and reaches 220 C (428 F) at total depth. The EGS reservoir consists primarily of plutonic rock that is interfingered with mineralogically similar metamorphic rock below 8,000 ft MD (Jones et al., 2021).

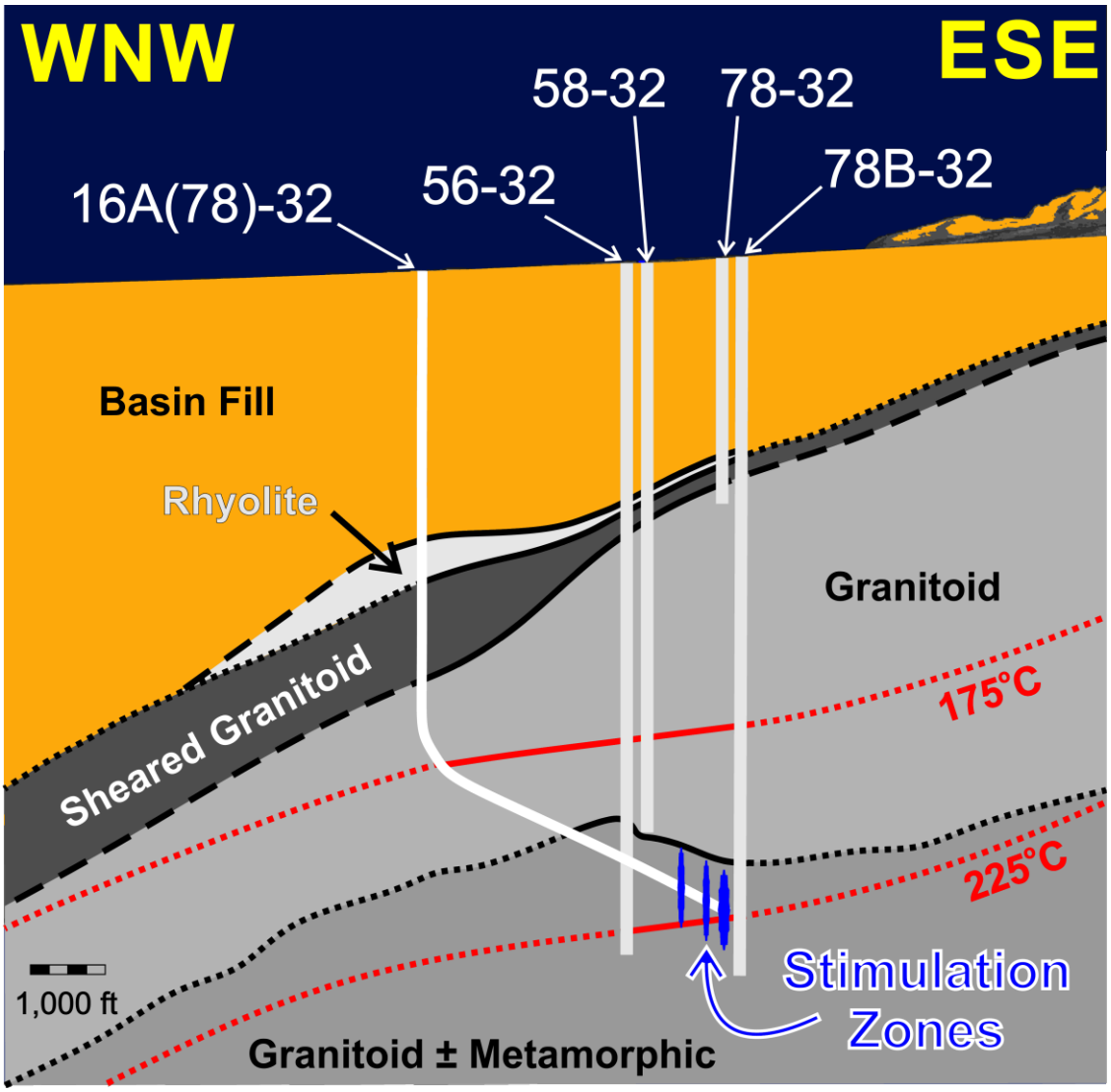

Figure 1: Cross-section of the Utah FORGE EGS site parallel to the trajectory of well 16A(78)-32 showing: deep wells (>1,000 ft) drilled at the site to date; lithologies encountered in the wellbores; inferred temperature contours in the subsurface; and the locations of the three hydraulic fracturing stages in 16A(78)-32 stimulated in April 2022.

Table 1: Summary of hydraulic fracturing and flowback stages.

Stimulation Zone	1 - Open Hole	2 - Perforations	3 - Perforations
Measured Depth, ft	10,787 - 10,987	10,560 - 10,580	10,120 - 10,140
True Vertical Depth, ft	8,490 - 8,560	8,404 - 8,412	8,221 - 8,230
Maximum Injection Rate, bpm	54.8	36.4	35.7
Formation Temperature at MD, F (C)	417(214)	427(219)	428(220)
Maximum Surface Treating Pressure, psig	6,135	7,077	7,229
Volume of Fluid Injected, bbl	4,261	2,785	3,016
Volume of Fluid Recovered Prior to the Next Stage, bbl	2,331 (55%)	1,478 (53%)	1,627 (54%)

2. HYDRAULIC STIMULATIONS

The objectives for the three hydraulic fracturing stages were to evaluate fracture geometries and fracture propagation behavior as a function of pump rate and injected fluid viscosity in stimulation operations. The overriding requirement was to develop fractures with adequate vertical extent to connect injection well 16A(78)-32 with production well 16B(78)-32 to be drilled in 2023. Well 16B(78)-32 will mirror the geometry of 16A(78)-32 with a planned offset of ~300 ft above 16A(78)-32 in the lateral section.

Stage 1 was pumped into the 200 ft open hole section of the wellbore at the end of the casing string, and stages 2 and 3 were each pumped into discrete, single cluster (six shots per foot, 60° phasing) 20 ft perforated intervals in the 7-inch casing. The three treatment stages were placed 207 to 420 ft apart to explicitly avoid interaction between stimulated volumes (Figure 1, Table 1).

The pumping schedule for each stage entailed starting at an initial rate of 5 bpm and stepping up in 5 bpm increments until reaching a maximum designed pump rate determined by considering the formation fracture gradient, the density of the fluids to be pumped, and the estimated pipe friction for the fluid being pumped. In addition, the perforation friction for stages 2 and 3 was a consideration to keep pumping pressure below the maximum allowable surface pressure of 8,000 psig.

A polyacrylamide friction reducer was added to the injected water of stages 1 and 2 to lower surface pumping pressures. Friction reducer added to water is colloquially referred to as slickwater. In stage 3 a crosslinked polymer fluid system with low concentrations of microproppant was pumped. The crosslinked polymer fluid system was chosen to evaluate the effect of increased viscosity on hydraulic fracture propagation. The polymer loading was 45 lb/1,000 gal water and the fluid system contained crosslinker, buffer, gel stabilizer, and other additives to achieve some viscosity at the elevated temperatures in the EGS reservoir. The low concentrations of microproppant were used to potentially demarcate a manufactured material when a fracture is encountered during the drilling of well 16B(78)-32.

In addition to the additives above, a distinct, thermally stable, naphthalene sulfonate tracer was added to each of the three stages at nearly constant concentration (Rose et al., 2001). These nonreactive tracers were added to test for fracture interconnectivity between the stimulated volumes of each stage and possibly as markers when drilling well 16B(78)-32.

The stage 1 slickwater treatment, tagged with tracer 1,6-naphthalene disulfonate (1,6-nds), was pumped down the 7-inch casing string into the open hole, reaching a maximum designed injection rate of ~50 bpm. After 4,261 bbl were pumped, the well was shut in for four hours to monitor pressure decline. The well was then flowed back, as described in the following section.

The stage 2 slickwater treatment, tagged with tracer 1,3,5-naphthalene trisulfonate (1,3,5-nts), was pumped through a 20 ft perforated interval in the 7-inch casing from 10,560 – 10,580 ft MD. The treatment 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 stage 3 crosslinked polymer treatment, tagged with tracer 1,3,6-naphthalene trisulfonate (1,3,6-nts), was again 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.

For a more comprehensive summary of hydraulic fracturing activities see McLennan, et al., 2023.

3. FLOWBACK

Following shut-in, fluids from each hydraulic fracturing stage were flowed back to the surface through a flow line that included throttling valves, a geothermal steam separator and a turbine meter in the liquid flow line to the sump. The flowback was planned and completed to reduce well pressure before running bridge plugs and perforating guns for the next stage without surface pressure control equipment. The primary driver was to minimize any chance of shadowing between stages. During flowback the produced fluid was sampled periodically to monitor tracer concentrations and fluid chemistry.

Flowback rate, cumulative flowback volume and temperature data (among others not discussed here) were collected at the surface with an electronic drilling recorder system during stimulation and flowback. The cumulative flowback volume was reset at the beginning of each flowback and after the bridge plugs were removed (Figures 2 and 3). In addition, inputs from the rig pumps during operations were removed to accurately track the volumes and percentage of fluid returned.

Stage 1 flowback was initiated at a controlled rate of 4 bpm at an initial wellhead pressure of 2,701 psig. The well was flowed back for 16.5 hours during which time the wellhead pressure dropped to 0 psig and the flow became intermittent at an average rate of ~0.5 bpm. A total of 2,055 bbl was recovered during the first flowback period with an additional 276 bbl returning at low rates prior to bridge plug 1 being set to isolate the open hole from stimulation zone 2. In total 2,331 bbl were recovered, or 55% of the fluid injected (Figure 2). The maximum measured wellhead temperature of the fluid during flowback 1 was 107 C (224 F) (Figure 3).

Stage 2 flowback was initiated at a controlled rate of 4 bpm and an initial wellhead pressure of 2,812 psig. The well was flowed back for 13 hours during which time the wellhead pressure dropped to 0 psig and the flow rate was intermittent at an average rate of ~0.5 bpm. A total of 1,266 bbl was recovered during the second flowback period with an additional 252 bbl returning at low rates prior to bridge plug 2 being set to isolate stimulation zone 2 from stimulation zone 3. In total 1,478 bbl were recovered, or 53% of the fluid injected (Figure 2). The maximum measured wellhead temperature of the fluid during flowback 2 was 96 C (205 F) (Figure 3).

During stage 3 flowback the control valve was initially partially opened, and a maximum rate of 3.83 bpm was achieved after the valve was fully opened. The initial wellhead pressure at the start of flowback was 2,483 psig. The well was flowed back for 15.5 hours during

which time the wellhead pressure dropped to 0 psig and the well flowed intermittently at an average rate of ~0.5 bpm. A total of 1,184 bbl was recovered during the third flowback period with an additional 443 bbl returning at low rates for a cumulative total of 1,627 bbl, or 54% returned (Figure 2). The maximum measured wellhead temperature of the fluid during flowback 3 was 94 C (202 F) (Figure 3).

After the bridge plugs were unset return rates increased to ~2 bpm (Figure 3). Cumulative flowback resets were made after the bridge plugs were retrieved to the surface (for reasons discussed below) with an additional 545 bbl and 259 bbl returned in the last two flowback intervals that consisted of injection from multiple stages (Figure 2).

Of the 10,062 bbl injected, 6,240 bbl, or 62% of the fluid was recovered. That left 3,822 bbl, or 38% in the reservoir at the end of the stimulation activities prior to well shut-in, equivalent to 21,471 ft^3 (608 m^3).

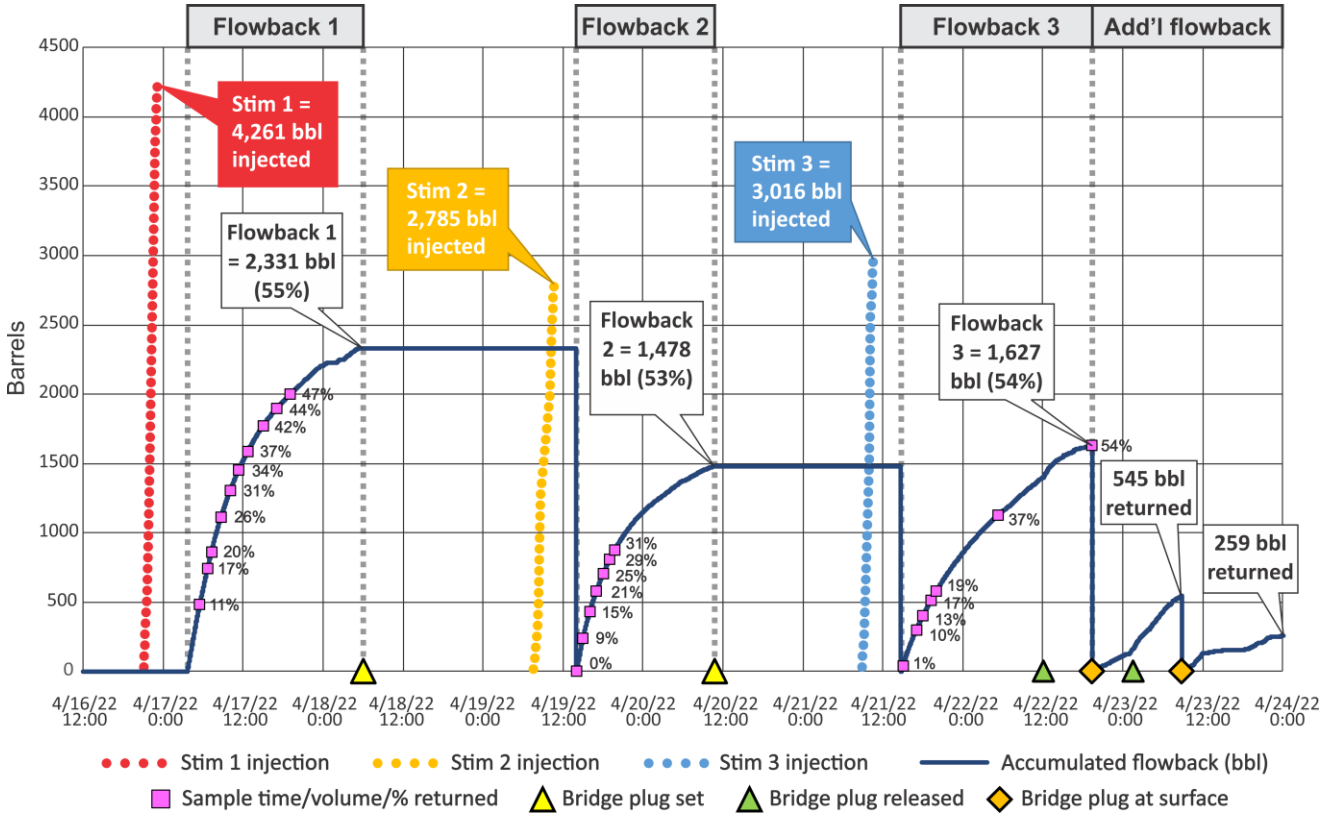

Figure 2: Summary of injection volumes, cumulative flowback volumes, flowback sample collection times at their respective cumulative flowback volumes labeled with percent of flowback, as well as indicators for the timing of the setting and unsetting of bridge plugs and when the bridge plugs were returned to the surface.

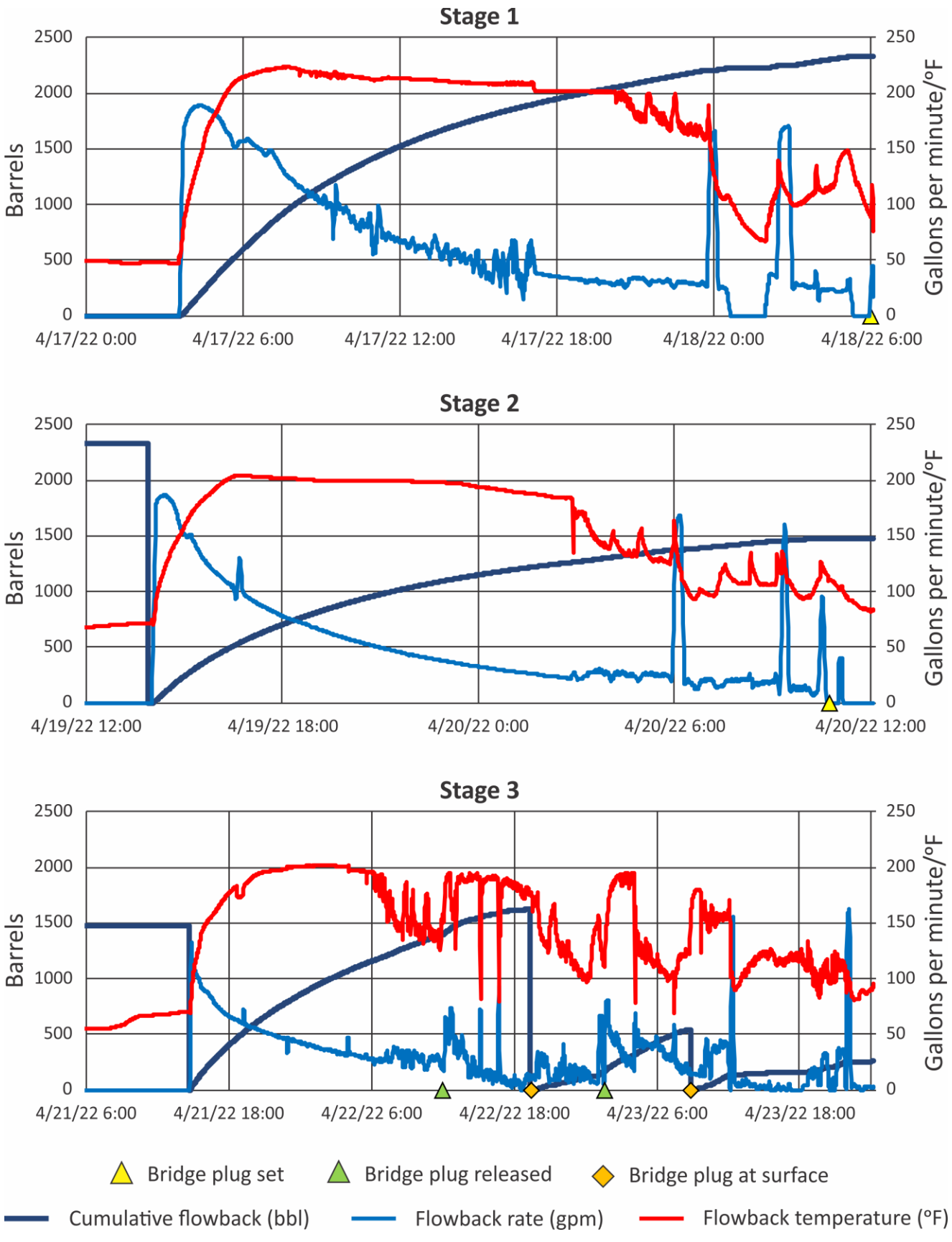

Figure 3: Summary of cumulative flowback volumes, flowback rate and flowback temperature by stage, along with indicators for the timing of the setting and unsetting of bridge plugs and when the bridge plugs were returned to the surface.

4. TRACERS IN FLOWBACK WATERS

A distinct naphthalene sulfonate compound was added to the injected fluids at each stage to act as a nonreactive tracer. These fluorescent-organic tracer compounds are thermally stable, nontoxic and highly detectable (Rose et al., 2001). The tracers added by stage are: 1) 1,6-naphthalene disulfonate (1,6-nds); 2) 1,3,5-naphthalene trisulfonate (1,3,5-nts); and 3) 1,3,6-naphthalene trisulfonate (1,3,6-nts). The tracers will be referred to by stimulation stage number below. Fluid samples were collected periodically during the three flowback periods and after the bridge plugs were removed with all three tracers analyzed for in each sample (Figure 4).

During flowback 1 concentrations of tracer 1 remained fairly constant in the samples after the ~400 bbl of untagged (i.e. no tracer added) slickwater was flushed from the casing string, with average returns of 120 parts per billion (ppb) (Figure 4).

Tracer results for flowback 2 are similar to flowback 1, with later returns having fairly constant concentrations averaging 134 ppb. Early returns that did not leave the casing string, marked by an 'X' in Figure 4, are diluted due to ~400 bbl of untagged slickwater being the final aliquot pumped in stage 2. Small concentrations of tracer 1 were observed during flowback 2 due to residual amounts of tracer 1 in the casing string at the end of flowback 1. Time and cost constraints did not allow for bottoms-up circulation of the casing string to flush tagged fluids from previous stages.

Unlike during flowback 1 and 2, the concentration of tracer 3 in fluids that entered the reservoir decline with time, from 174 to 130 ppb in flowback 3. Low concentrations of tracer 2 that remained in the system (for reasons stated above) are also measured, as are even lower residual amounts of tracer 1 (Figure 4).

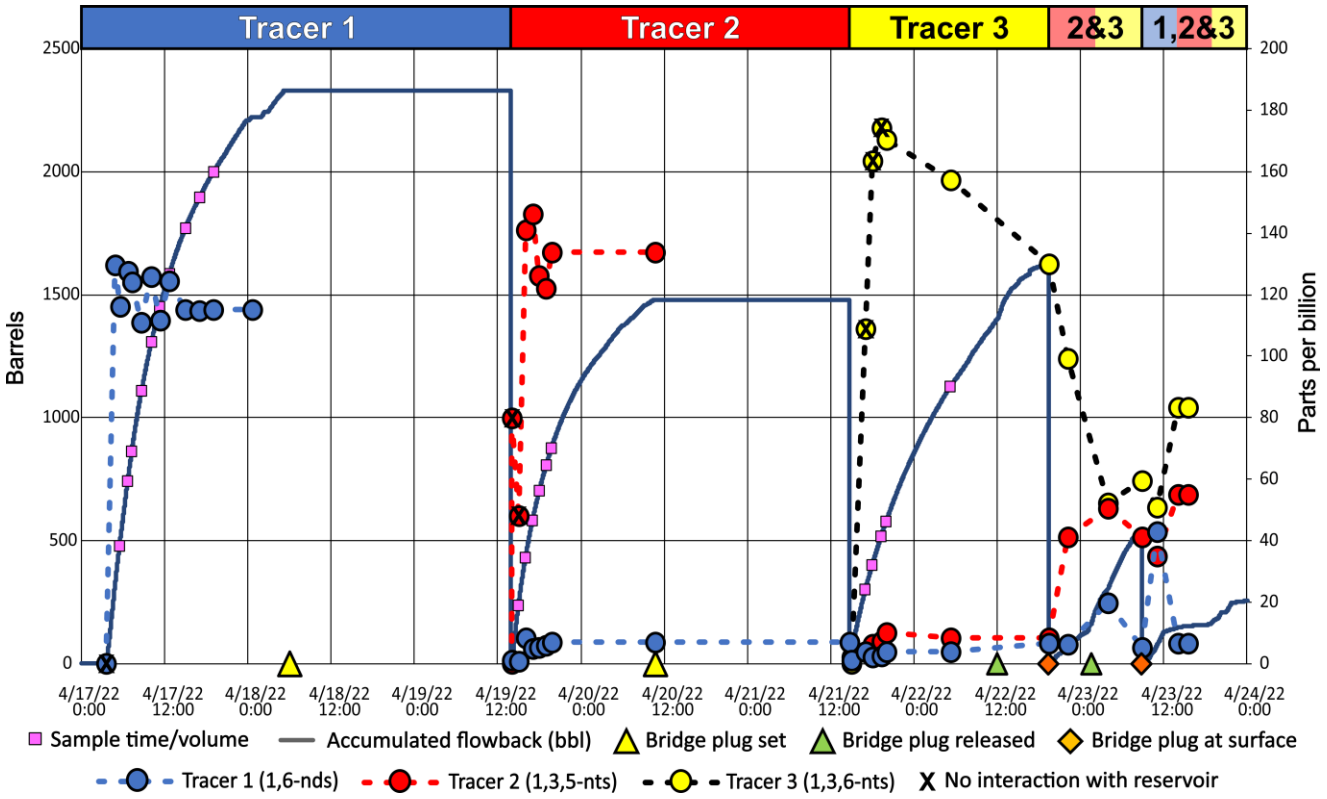

Figure 4: Summary of tracer concentrations in flowback waters vs time. Also shown are the cumulative flowback volumes with sample times plotted (also shown in Figures 1 and 2), and time indicators for setting and unsetting the bridge plugs as well as when the bridge plugs were returned to the surface. Tracer concentration values marked with an 'X' denote samples that never left the casing string and often contained water without tracer.

When setting the bridge plugs, previous feed points (open hole, perforations) and volumes of water tagged with tracers from the previous stages remain in the casing string, isolated in the lower sections of the wellbore. Although increases in flowback are observed when the bridge plugs are unset (Figure 4), the concentrations of earlier tracers do not appreciably increase until the bridge plugs reach the surface. At which point the fluids from previous stages that had been isolated in the lower reaches of the well and additional fluids squeezed out of the formation are returned. This observation suggests the bridge plugs were a barrier to flow within the casing string and hindered the earlier tracers from reaching the surface until after the bridge plug was fully removed. Once bridge plug 2 reaches the surface an increase in tracer 2 is observed, and when bridge plug 1 reaches surface the concentration of tracer 1 increases (Figure 4). These observations were used to define reset points 4 and 5 of the cumulative flowback volumes in Figures 2, 3 and 4.

The tracer returns from flowbacks 1-3 suggest that there was no cross contamination of injected fluids between stages due to either communication between stimulated volumes, or along the exterior of the casing string through the cement. These results also demonstrate the effectiveness of the tracers under EGS reservoir conditions and their utility to confirm zonal isolation in multistage hydraulic stimulations.

5. GEOCHEMISTRY OF FLOWBACK WATERS

Here we present provisional results from a full suite of analytes measured by ICP at Brigham Young University from the water samples collected in series during each flowback (Figure 1). These analyses show unexpected, and drastic changes to the composition of the water over short periods of time (< 33½ hours).

Culinary grade, low salinity water from the municipal water supply of Milford, Utah was used in the stimulations, along with the additives described above. Early sampled returns from flowback 2 and 3, marked with an 'X' in Figure 5, remained in the casing string at the end of injection and did not interact with the formation. These earliest returns are likely representative of the injected fluids. Changes in fluid chemistry are observed in water samples that have interacted with the reservoir rock. Changes become more pronounced with time, presumably due to earlier samples having had limited water-rock interaction compared with fluids sampled later that were displaced further from the wellbore and were in contact with the reservoir rocks for longer periods of time. Although concentrations increase with time for most of the elements analyzed, decreases in a few analytes are also observed.

The most pronounced increases are in the concentrations of Cl (51 to 4,643 mg/kg) and corresponding cations Na (50 to 2,319 mg/kg), K (2 to 403 mg/kg), and Ca (24 to 253 mg/kg). SiO_2 concentrations increase sharply from an initial value of ~20 mg/kg and appear to stabilize at various levels in the three flowbacks, with concentrations highest in flowback 1 and lowest in flowback 3 (Figure 5). The sharp increase in B for flowback 3 (Figure 5) is likely the result of a sodium tetraborate additive in the crosslinked polymer fluid. No contributions to the analyzed elements are expected from the slickwater additives (hydrocarbons and alcohols).

Mg shows a sharp decline with time from ~14 to ~2 mg/kg (Figure 5). Geothermal waters are generally depleted in Mg due to the precipitation of Mg-bearing minerals at elevated temperatures in geothermal reservoirs (e.g., Giggenbach, 1988). Within the Utah FORGE EGS reservoir both interlayered chlorite/smectite and ankerite are Mg-bearing phases that have been observed filling fractures. Other elements with similar trends of decreasing concentration with time are Fe and Zn.

Differences between flowback from stages 1 and 2, and stage 3 that contained additives to increase injected fluid viscosity are pronounced. The additives in the stage 3 fluids appear to have limited the ability of elements to dissolve and mobilize into the aqueous phase, with lower concentrations of most elements in the fluids recovered during flowback 3 (i.e. Cl, Na and Li in Figure 5).

To assess the degree of equilibration the fluids attained with the reservoir, multiple geothermometers (Fournier and Potter, 1982; Giggenbach, 1988; Fournier, 1979; Truesdell, 1975) were applied using the flowback analytic chemistry to see how closely they resemble measured temperatures. Formation temperatures at the depths of the stimulation zones range from 214 to 220 C (417 to 428 F) (Table 1), whereas the range of quartz-silica temperatures ranges from ~100 to 180 C (212 to 356 F) (Figure 5). For comparison, Na/K ratios correlate with geothermometer temperatures of 200 to 280 C (392 to 536 F), whereas the K/Mg ratios indicate calculated geothermometer temperatures of 130 to 210 C (266 to 410 F). At this point, fluid compositions appear to reflect only partial attainment of fluid-mineral equilibria, and this compromises the reliability of commonly used aqueous geothermometers. Nevertheless, the evidence is compelling that the transient chemical effects are related to water-rock interaction in the EGS reservoir over short time scales.

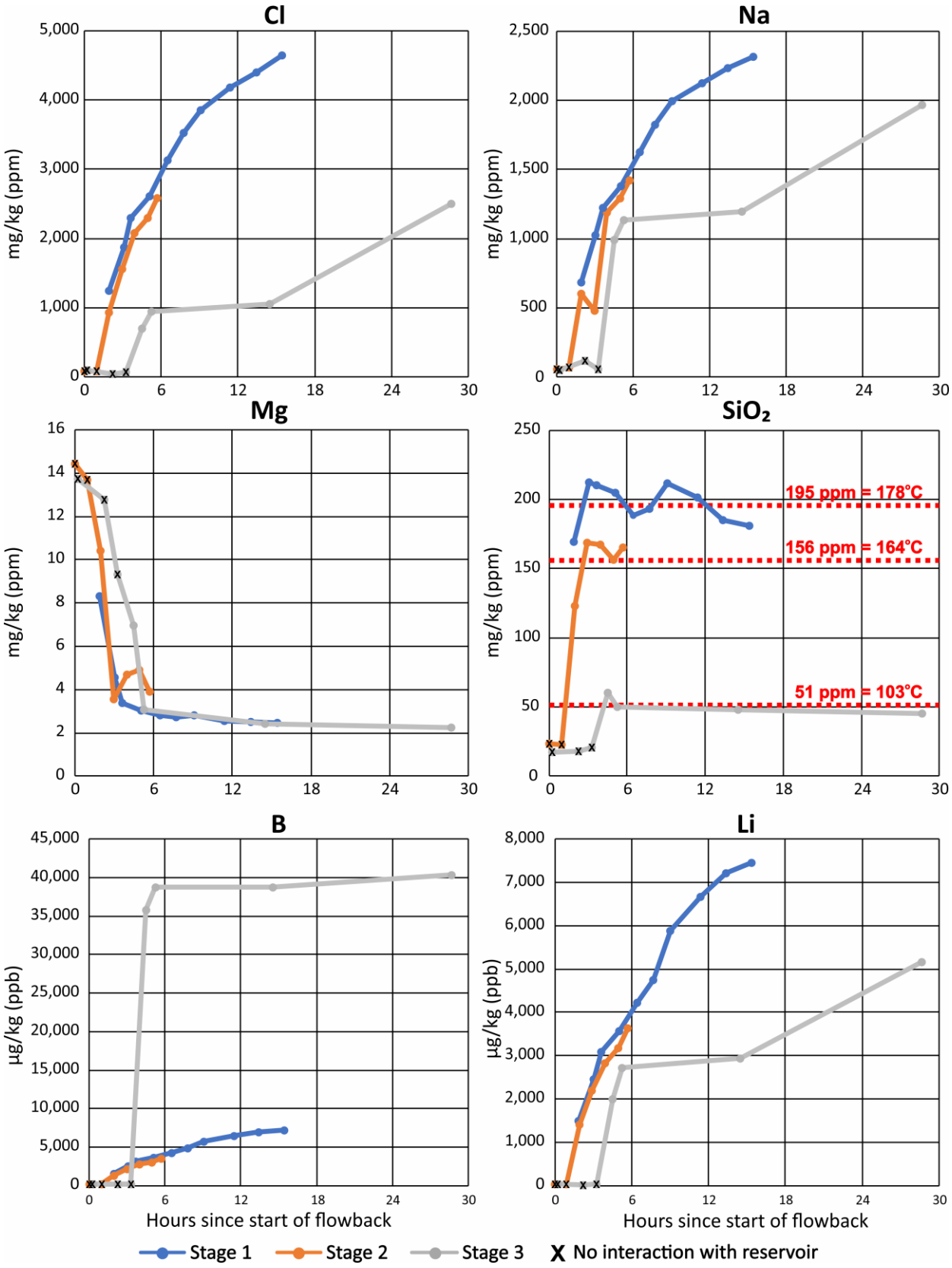

Figure 5: Select chemistry results for flowback waters plotted vs hours since start of flowback. Samples with an 'X' indicate that that aliquot of fluid did not interact with the reservoir rock (i.e. it never left the casing string). Dashed lines on the SiO_2 plot denote average concentrations for fluids that interacted with the reservoir and their corresponding values for the quartz geothermometer (Fournier and Potter, 1982). Note that the charts for B and Li are in parts per billion.

6. CONCLUSIONS

At Utah FORGE, a US Department of Energy sponsored EGS demonstration site, a three stage hydraulic stimulation in the toe section of highly deviated injection well 16A(78)-32 was completed in April 2022. The stimulation zones were in the open hole at the end of the casing string, and in two perforated intervals within the 7-inch casing, 207 to 420 ft apart. Two types of fluids were used in the stimulation stages, slickwater in stages 1 and 2 and a crosslinked polymer fluid system in stage 3. In addition, a chemically distinct naphthalene sulfonate tracer was added to the fluid in each of the three stages.

Samples were collected of the returns at the surface during flowback after each injection stage and after the removal of isolation equipment from the drill string to monitor tracer concentrations and water chemistry. Of the 10,062 bbl injected, 6,240 bbl, or 62% of the fluid was recovered. A total of 3,822 bbl, or 38%, of the injected fluid was left in the reservoir at the end of the stimulation activities prior to well shut-in, equivalent to 21,471 ft^3 (608 m^3).

The tracer return data from flowbacks 1-3 are interpreted as showing no cross-contamination of injected fluids between stages due to either communication between stimulated volumes, or along the exterior of the casing string through the cement. These results also demonstrate the tracers' effectiveness under EGS reservoir conditions and their utility in confirming zonal isolation in multistage hydraulic stimulations.

The chemical composition of the returned fluids showed unexpected, and drastic changes over relatively short periods of time (< 33½ hours). The dominant trend was for the concentrations of dissolved solids to increase with time; however, Mg declined, as is typical in geothermal reservoir fluids due to sequestration of Mg in secondary minerals within the reservoir. Differences in flowback water chemistry between slickwater and crosslinked polymer fluid systems were pronounced. The viscous fluids appear to have limited the ability of elements to dissolve and mobilize into the aqueous phase. Changes became more pronounced as flowback progressed with later returns having spent more time in contact with the reservoir rock. The observed transient chemical effects are interpreted as related to water-rock interaction over relatively short periods of time.

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