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CHARACTERIZATION OF INJECTION WELLS IN A FRACTURED RESERVOIR USING PTS LOGS, STEAMBOAT HILLS GEOTHERMAL FIELD, NEVADA, USA

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ABSTRACT

The Steamboat Hills Geothermal Field in northwestern Nevada, about 15 km south of Reno, is a shallow (150m to 825m) moderate temperature (155°C to 168°C) liquid-dominated geothermal reservoir situated in highly-fractured granodiorite. Three injection wells were drilled and completed in granodiorite to dispose of spent geothermal fluids from the Steamboat II and III power plants (a 30 MW air-cooled binary-type facility). Injection wells were targeted to depths below 300m to inject spent fluids below producing fractures. First, quasi-static downhole pressure-temperature-spinner (PTS) logs were obtained. Then, the three wells were injection-tested using fluids between 80°C and 106°C at rates from 70 kg/s to 200 kg/s. PTS logs were run both up and down the wells during these injection tests. These PTS surveys have delineated the subsurface fracture zones which will accept fluid. The relative injectivity of the wells was also established. Shut-in interzonal flow within the wells was identified and characterized.

INTRODUCTION

The Steamboat Hills Geothermal System is part of the Steamboat Springs Geothermal Area which was classified as a Known Geothermal Resource Area ("KGRA") by the United States Geological Survey. The KGRA is located on the eastern flank of the Sierra Nevada Mountains about 15 km south of Reno, Nevada along Highway 395 (see Figure 1). The Steamboat Hills geothermal reservoir is a fracture-controlled geothermal resource hosted in granitic rocks. The first geothermal well was drilled in 1920, located at a site about one mile south of the Far West Capital, Inc. ("FWC") geothermal electric power development area. A chronological account of the commercial development of geothermal power plant facilities at the Steamboat Hills Geothermal Area was presented by Combs and Goranson (1994) based primarily on earlier work by Goranson and coworkers (1990, 1991).

Injection is the necessary and acceptable disposal method for handling spent geothermal fluids. Thus, the effects of injection must be understood, with respect to the geothermal and surrounding hydrologic system. The geothermal and surrounding hydrologic system are monitored at Steamboat Hills to ascertain effects of geothermal power plant operations. Specifically, the geothermal/hydrologic system is monitored to determine any thermal, hydrologic or geochemical changes. Of direct concern, with respect to sustainable reservoir management, is thermal breakthrough of cooled injected fluids to production wells. Therefore, injection of spent geothermal fluids must be matched to reservoir geology, subsurface fracture zones and reservoir fluid circulation patterns.

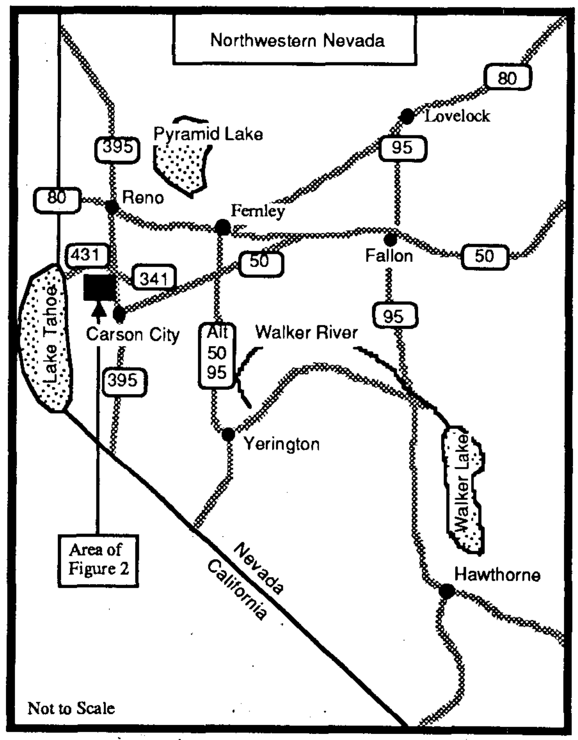

Figure 1. Regional location map of the Steamboat Hills Geothermal System.

Three injection wells; IW-1, IW-4, and IW-5, were drilled and completed in granodiorite to dispose of spent geothermal fluids from FWC Steamboat II and III (SB II&III) power plants; a 30 MW air-cooled binary-type facility (see Figure 2).

During October, 1992, with financial support from the U.S. Department of Energy through Sandia National Laboratories, injection tests were conducted on the three injection wells IW-1, IW-4 and IW-5. The injection well testing program was designed (i) to identify subsurface fracture zones accepting fluids using PTS logs, (ii) to examine the relative injectivity of the wells, and (iii) to document whether there was interzonal flow within the injection wells.

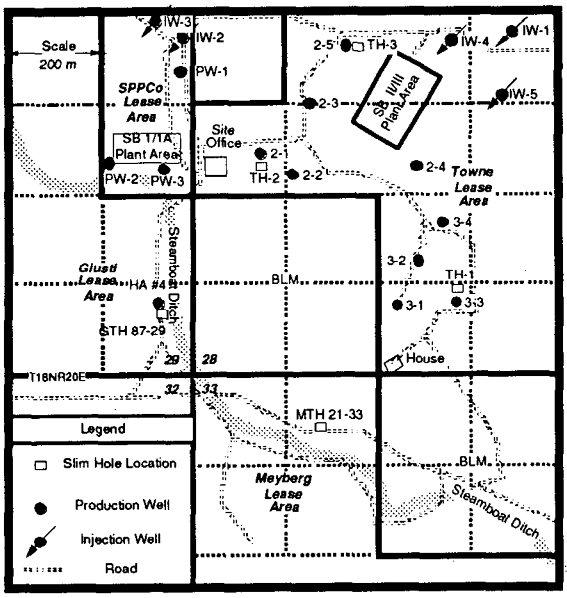

Figure 2. Location map of FWC Steamboat Hills power plants, production and injection wells.

GEOLOGICAL AND STRUCTURAL SETTING

A detailed description of the geology, hydrology, and hydrothermal alteration is beyond the scope of this paper, but a general description of the geology and structure of the Steamboat Hills Geothermal Area is provided based on the work of van de Kamp (1991). The geology of the Steamboat Springs area was initially mapped in detail by Thompson and White (1964) and White, et al. (1964). These two publications formed the basis for the geological evaluation of the geothermal system beneath the FWC leases. The moderate-temperature geothermal system covers about 6.5 km^2, including hot springs and numerous fumaroles associated with siliceous sinter surface deposits. The geothermal fluid in the reservoir has a chlorinity and temperature of approximately 800 ppm and 165°C, respectively. The fluid is produced from fractured granodiorite at a depth of approximately 300m. All of the produced fluid is injected back into the geothermal reservoir.

The oldest rock unit present in the northeast Steamboat Hills, and the geothermal reservoir host, is granodiorite of Mesozoic age (estimated as 150 to 80 mya, Silberman, et al., 1979). Younger Tertiary sediments, volcanic rocks and alluvial deposits overlie the granodiorite. In outcrops, it is apparent that there has been fracturing and faulting in the granodiorite. A fine- to medium-grained granodiorite is the major portion of the rocks penetrated by the injection wells. Additionally, the granodiorite has no intrinsic permeability, nor is there any appreciable rock matrix porosity. Therefore, the granodiorite has essentially no fluid storage capacity and all fluid flow within the granodiorite is confined to fractures. The rock is generally hard and only slightly altered to chlorite and clay minerals with abundant minute pyrite crystals located within fracture zones. Apparently, there was an early stage of chloritic alteration and fracturing in the granodiorite, followed much later by fracturing related to geothermal processes. In the later stage of fracturing, there was also chloritic alteration and filling of fractures with calcite, chlorite, silica, and minor amounts of heavy-metal mineralization.

The structural setting of the northeastern Steamboat Hills, which is part of the larger Steamboat Hills structural block, has been described in detail by van de Kamp (1991). The Steamboat Hills were uplifted relative to areas to the east, north, and west in late Tertiary and Recent times. The uplift is bounded by steep dipping north-northeast and east-northeast trending normal faults with displacement of tens to hundreds of meters or more. Fault and fracture strikes range from northeast to northwest, with measured dips ranging from 45° to 90°. Cenozoic warping and block faulting are responsible for the present mountainous topography in the Steamboat Hills area.

Three systems of faulting have been recognized in the Steamboat Hills (van de Kamp, 1991). One set strikes northeast, parallel to the axis of the Steamboat Hills. A second set, essentially at right angles to the first, strikes northwest. The third set of faults strike north-northeast and are prominent on the sinter terrace associated with dormant hot springs. In the distant past, this fault zone issued geothermal fluids to the surface, where active hot springs and associated siliceous sinter precipitation occurred, similar to the modern situation at the Steamboat Hot Springs located east of the FWC leases. Additionally, based on the results of a tracer test (Adams, et al., 1993), there is clear evidence of anisotropy within the reservoir. The primary faults controlling fluid circulation in the geothermal reservoir appear to be the northeast trending series of steep normal faults. The abundance of fractures appears to increase with depth. Near-vertical, open fractures in the granodiorite control movement of geothermal fluids.

DRILLING AND COMPLETION DATA

Three injection wells, IW-1, IW-4 and IW-5, are located on the northeast side of the Steamboat Hills SB II&III well field (see Figure 2). The injection wells were drilled and completed deeper than producing wells. The injection well locations and design were based on three main criteria: (i) injection wells should be situated on a set of surface lineaments that strike northeast, parallel to the axis of the Steamboat Hills, within the known reservoir to provide pressure support; (ii) the injectors should be completed at depths greater than production wells to avoid thermal breakthrough, which could decrease the temperature of produced geothermal fluids (however, the possibility of lower permeability at greater depths was also of concern); and (iii) since injection wells

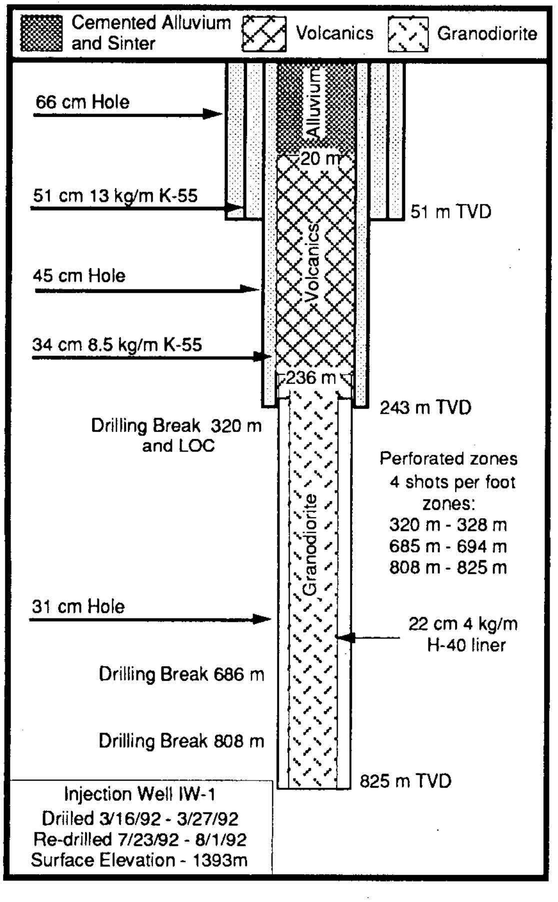

Figure 3. Geology and well completion schematic of injection well IW-1.

were located at the outer margin of the geothermal field, it was thought that they could possibly be deepened later to reach hotter fluids and converted into production wells.

All nine of the SB II&III production wells were completed into the granodiorite formation. Production well depths vary between 180m and 670m, with the majority completed to less than 300m. Injection wells were also completed into the granodiorite formation. In order to inject the spent fluids at depths below the producing fractures, and due to down dropping of the granodiorite reservoir formation with distance from Steamboat Hills, (as was expected prior to drilling), the depths and completion programs for the injection wells were designed to encounter fracture sets at subsurface depths greater than 300m.

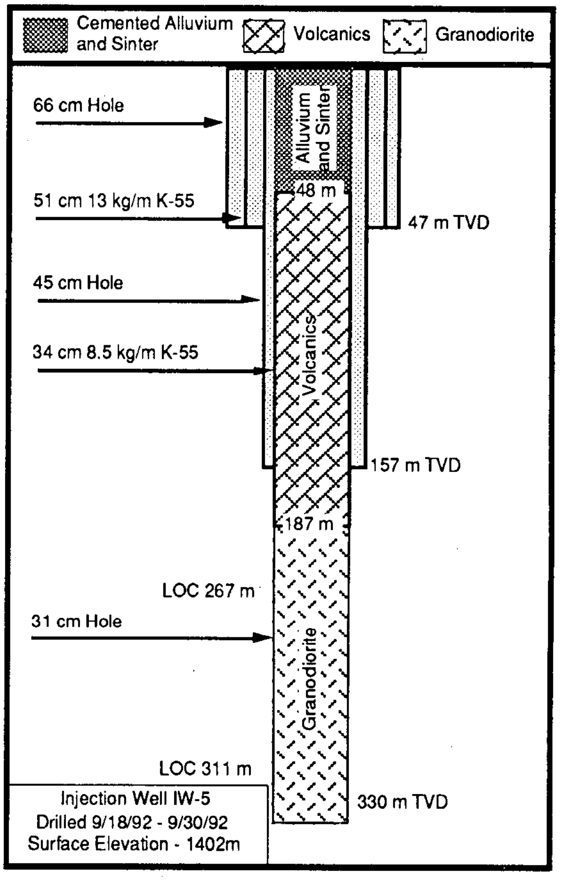

Figure 4. Geology and well completion schematic of injection well IW-5.

Injection wells, IW-1, IW-4 and IW-5, were cased to 243m, 238m, and 157m, respectively, in order to eliminate interzonal flow from the fractures above these depths. Total depths of the injectors are 825m, 550m and 330m with bottom-hole diameters of 31-cm. Each of the injection wells was drilled through a sequence of alluvium and sinter, volcaniclastic materials, and granodiorite (see Figure 3 and Figure 4). Injection well completions consisted of a surface casing of 51-cm diameter, an intermediate casing of 34-cm diameter and a 31-cm open-hole section to total depth. Injection well IW-1, to reduce sloughing problems encountered at the contact between the volcanics and granodiorite formations, was completed with a 22-cm liner perforated over three depth intervals, corresponding to drilling breaks (see Figure 3). IW-4 and IW-5 were completed open-hole to total depth, similar to SB II&III production well completions. No circulation-loss zones were encountered above the granodiorite formation in these wells. Within the granodiorite formation circulation losses occurred; these, together with drilling breaks (with drilling rates increasing from 1.5 m/hr to >15 m/hr) serve to identify permeable subsurface fracture zones.

INJECTION AND DISCHARGE TESTING

Initial injection well testing consisted of discharging the well to an atmospheric flash tank attached to a weir box (water flow measurement device) while measuring downhole pressures with the drilling rig still in place. Well discharge was initiated by injecting air through open-ended drill pipe. Drill pipe was, typically, set at 180 m during discharge test operations.

The total discharge rate was estimated based on (1) the measured water rate through the weir box and (2) a steam flow rate, estimated based on the known reservoir temperature, one-atmosphere enthalpies of saturated water and steam and an assumption of isenthalpic flow up the well. Downhole pressures were measured with a gauge attached to the drill pipe. Based on the results of downhole pressure versus discharge rate behavior of production wells, it was determined that sufficient well injectivity existed when downhole pressure changes between static (maximum pressure measured during air injection and before initiation of discharge) and flowing downhole pressure (drill pipe pressure measured without air injection) were less than 7 kPa at a total discharge rate of 65 kg/s.

During October 1992, injection tests were conducted on the three injection wells in the Steamboat Hills reservoir associated with the SB II&III power plants. The purpose of the present injection testing program was (i) to determine the location of subsurface fracture zones accepting fluids using PTS logs, (ii) to examine the relative injectivity of the wells, and (iii) to document whether interzonal flow existed within the individual injection wells. The injection tests were carried out during the 30-day power plant acceptance test, which somewhat inhibited test operations. PTS logs were conducted under quasi-static conditions, during injection and following shut-in (fall-off). In addition, downhole pressure, temperature and spinner behavior during injection was also obtained at particular depths. From injectivity tests, spinner data and PTS log evaluation, an understanding of subsurface injection characteristics of the wells was obtained.

RESULTS AND DISCUSSION

Pressure, temperature and spinner survey data obtained during the injection test of well IW-1 are shown in Figure 5 (well completion shown in Figure 3). Fluid was injected at a rate of 75 kg/s. Initial injection fluid temperature was 83°C. Injection fluid temperature increased during the test, due to power plant operations, to a maximum of 106°C. The data shown in Figure 5 indicate that several reservoir zones are accepting the injected fluid. These zones correspond with drilling breaks encountered during drilling. The granodiorite formation has a high compressive strength, and, within the granodiorite, drilling breaks are assumed to occur only in fractured/altered sections.

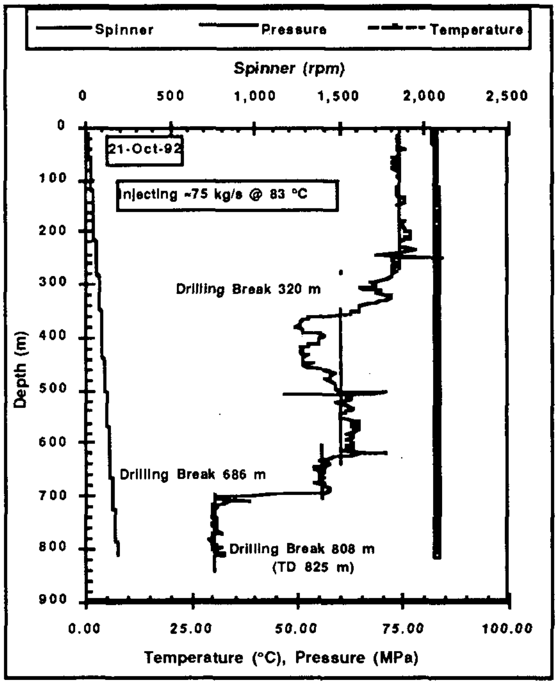

Figure 5. PTS survey plot for IW-1 during injection of 75 kg/s of 83°C water.

Pressure fall-off data were also obtained for IW-1. The data are plotted in Figure 6 and Figure 7. The spinner data shown in Figure 6 indicate that it took approximately 10 minutes to shut-in the well. This is due partly to the power plant operations, which limit abrupt line pressure changes, and the fact that 41-cm valves are used on the injection lines. These valves require ≈220 turns for full valve closure. Also noted in Figure 6 is that the spinner tool did not return to a zero read-out after injection shut-in, indicating that flow was still occurring within the well; whereas, visual inspection and the surface pipeline flow meter indicated zero injection rate. The downhole PTS tool

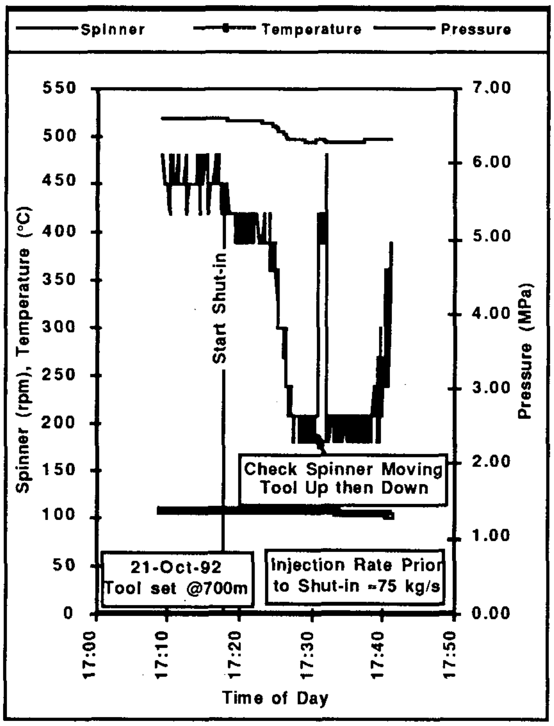

Figure 6. PTS plot for IW-1 during fall-off with tool set at 700m.

was moved to ensure proper operation. The tool was moved upwards and downward to the original position (700m). These data indicate that interzonal flow was downwards (note that movement of the tool in an upwards direction caused an increase in spinner output). In addition to the interzonal flow within the wellbore, the data shown in Figure 7 indicate a pressure fall-off of ≈0.3 MPa and a temperature decrease of ≈3°C.

It should be noted that permeability of a particular fracture zone depends on the square of fracture aperture. The amount of fluid accepted by a particular fracture zone is proportional to transmissivity, (permeability-thickness product), and therefore, approximately depends on the cube of the fracture aperture. However, The number of the fractures within a particular zone, and their individual apertures, control the Reynolds number. The Reynolds number, in turn, controls the measured downhole pressure drop incurred from injection (or production) of fluids in fractured reservoirs. In other words, the larger the fracture aperture, the larger the Reynolds number, the greater the chance that turbulent flow will occur.

Since interzonal flow within the wellbore existed, and the fact that wellbore pressure drop may be proportional to flow rate squared during turbulent flow conditions, rather than being directly proportional to flow rate under Darcy conditions, detailed pressure transient analyses were not carried out on the data. Nevertheless, simple analyses of the data suggests that the Steamboat geothermal reservoir has a relatively high permeability (i.e., 25 kg/s per MPa, or 10 gpm per psi).

Downhole PTS survey data and fall-off data were obtained for injection well IW-5 (well completion shown in Figure 4). The injection rate was 70 kg/s at 80°C. A quasi-static PTS survey was run prior to injection. PTS survey data during injection are shown in Figure 8. The spinner data indicate that a large portion of the injected fluid is exiting directly below the cased portion of the hole. In addition, the spinner and temperature data indicate that fluid is exiting the

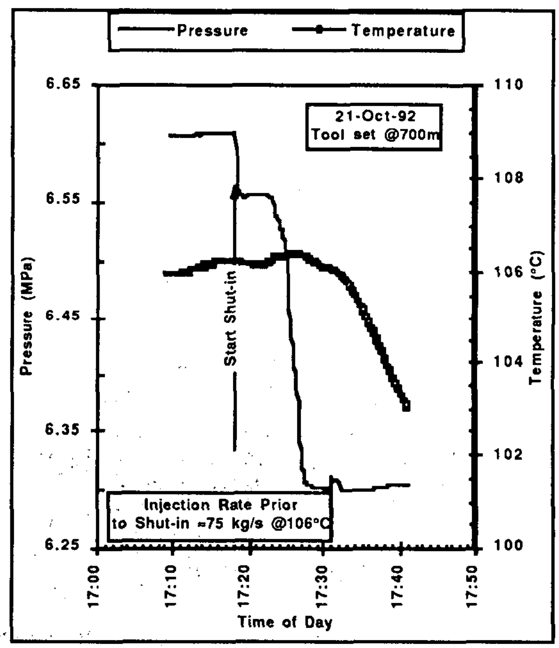

Figure 7. Pressure and temperature data for well IW-1 during fall-off with tool set at 700m.

lowest portion of the wellbore. Compare Figure 8 with Figure 9 and note the difference in spinner output and temperature versus depth during the injection period and during static conditions directly after injection.

A static PTS survey was run after fall-off data were obtained (≈20 minutes after injection). These data are shown in Figure 9. A temperature spike is noted between 215m and 240m. This corresponds to an area of zero spinner output measured during the injection PTS survey (see Figure 8). The static survey data after injection suggests that fluid is flowing through the reservoir and past the wellbore at this depth.

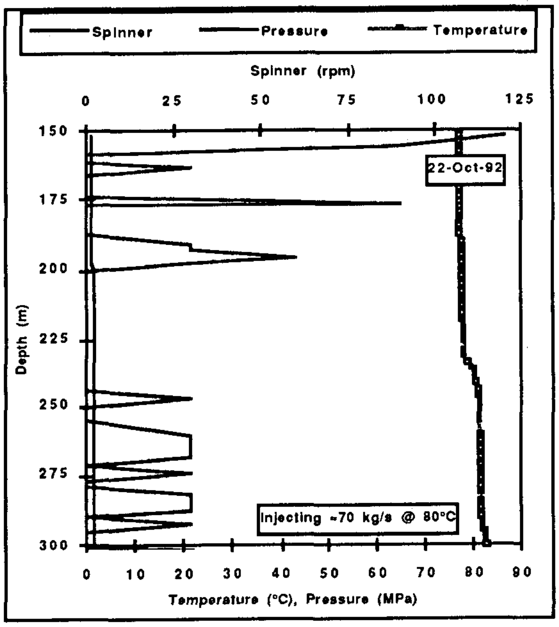

Figure 8. PTS survey plot for IW-5 during injection of 70 kg/s of 80°C water.

Pressure transient test analyses were not carried out on the IW-5 injection data. Maximum pressure change was ≈0.07 kPa during fall-off. There was no distinct pressure trend versus time. The reason for the erratic behavior of the spinner tool (±25 rpm) is unknown, but was noted during both injection and static surveys.

INJECTION TRACER TESTING

In order to gain additional experience and information about reservoir flow paths and possible injection fluid breakthrough to the production wells during long-term injection, a tracer test was conducted in the Steamboat Hills Geothermal Field. Rhodamine WT was used in conjunction with Fluorescein (Adams, et al., 1993). The two fluorescent dyes were injected simultaneously in injection well IW-4 (see Figure 2.) at a weight ratio of 1:2 (Rhodamine WT:Fluorescein). Fluid was simultaneously injected into IW-1 and IW-5. Injection rates were approximately equal for all of the three wells. Tracers analyses indicated recovery of dyes from the nine production wells (see Figure 2) over a period of approximately 330 days. The tracer peaks were detected in one production well (2-4) at 15 days, two wells (2-2 and 2-4) at 50 days, three wells (2-5, 3-3, and 3-4) at 77 days, and four wells (2-1, 2-3, 3-1, and 3-2) at 92 days. During the sampling period, ≈109%

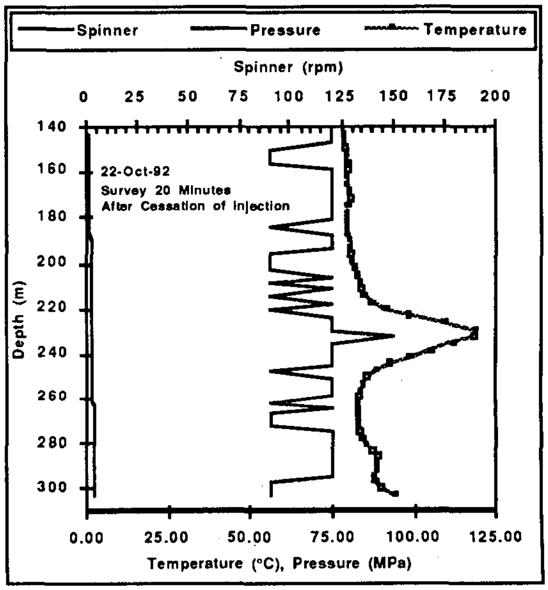

Figure 9. PTS survey plot in well IW-5 about 20 minutes after cessation of injection .

of the Fluorescein and 65% of the injected Rhodamine WT were recovered within 200 days, suggesting that 35% of the Rhodamine WT was adsorbed, absorbed, transformed or un-accounted for during the tracer test.

Using the decay kinetics obtained from buffer-solution laboratory testing, and, the reported well temperatures, Rose and Adams (1994) predicted the ratio of Rhodamine WT to Fluorescein for the nine production wells. The predicted (laboratory) ratios correlated with the measured ratios for all nine wells. In turn, the measured data documented that injected fluids are returned through the fractured geothermal reservoir from IW-4 to all of the production wells. Additionally, the tracer test results suggest permeability anisotropy within the geothermal system.

CONCLUSIONS

Data from injection testing of these wells support the premise that it is possible to obtain definitive reservoir parameters, define subsurface injection zones and provide a cost effective initial geothermal reservoir assessment using injection wells. In addition, PTS logging and analyses during static conditions and while injecting fluids can document interzonal flow between subsurface fractures.

Test data from injection wells can be used to predict the discharge performance of geothermal production wells. The injection pressure data versus time obtained for these wells suggest, essentially, infinite reservoir permeability. It should be noted that injection wells IW-4 and IW-5 can each, individually, accept 100% of the power plant injected fluid (1050 kg/s), which is equivalent to the output of nine pumped production wells.

Finally, the results of the tracer test suggest permeability anisotropy within the reservoir. Furthermore, the variation of tracer peak arrival times seems to reflect the importance of northeasterly trending fractures.

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