R-13 TRACING OF INJECTION IN THE GEYSERS

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ABSTRACT

R-13 has been used successfully in several tracer tests at The Geysers. Rapid recovery of 74% of the injected tracer mass has been achieved in a region of The Geysers where the reservoir is characterized by low pressures and low liquid saturation. In contrast, a test conducted in a region where reservoir pressures and liquid saturation are high resulted in a low recovery percentage and a significant time delay in the appearance of the tracer peak. We interpret these differences in tracer behavior to indicate the R-13 stays in solution in the injectate until boiling occurs. Thus, the concentrations versus time curves of R-13 provide information on the residence time of the injected liquid, while contour maps indicate the flow paths of the injection derived steam (IDS). High R-13 concentrations in steam identified wells with potential to produce a large component of IDS from the traced injection source.

INTRODUCTION

Four tracer tests utilizing halogenated alkanes ("freon" compounds) as tracers have been conducted in the southeast Geysers. In all the tests, tracing the movement of injection derived steam (IDS) was a major objective. In the first test, which began in February 1990, determining whether such compounds were stable under reservoir conditions was also a major goal. In that test both R-12 (CCl_2F_2) and R-13 ($CClF_3$) were injected into a southeast Geysers well which had recently been converted from production to injection (NCPA well C-11). The new injection well was chosen based on its presumed potential to support the productivity of surrounding production wells. The success of this effort to bolster steam production by the strategic use of injection (Enedy et al., 1991) fostered an increased emphasis on the ability to trace IDS.

Natural tracers, such as oxygen-18 and deuterium (Nuti et al., 1981) and more recently, ammonia (Beall, 1993) have been well documented as effective means of determining which wells produce condensate generated IDS and in what quantities. There remains, however, the dilemma of identifying the origin of the IDS flowing from production wells when more than one potential injection source is possible. Moreover, because of various uncertainties in using natural tracers, a 5 to 10 percent IDS component in steam is required before an unequivocal injection component can be identified.

R-13 is relatively stable under Geysers reservoir conditions whereas R-12 apparently is not (Adams et al., 1991). R-13 is also detectable in concentrations as low as 0.1 to 0.5 ppb_w in steam containing low noncondensible gas (i.e. less than about 1500 ppm_w total NCG). These properties make R-13 highly useful in establishing communication and flow paths between injection and production wells. Moreover, the same reservoir characteristics which promote efficient boiling of injectate appear to result in rapid and efficient recovery of R-13 tracer. These characteristics are: a "dried out" reservoir, as indicated by low liquid saturation, low reservoir pressure and high enthalpy (i.e. conditions indicative of a "dried out reservoir").

PRACTICAL ASPECTS OF R-13 TRACER INJECTION

In all of the Geysers freon tracer tests the freon was injected as a gas into water flowing into an injection well. As is typical of Geysers injection wells, in all cases the injection wells accepted water under partial vacuum at the wellhead. The liquified freon is injected from a pressurized gas cylinder through a steam heat exchanger to vaporize the freon as it enters the wellhead. This technique prevents ice clotting at the end of the probe used to inject the gas. The freon is metered into the well by utilizing a needle valve to control flow and an electronic balance interfaced with a computer to monitor and record the mass injection rate.

The freon compounds are, in general, highly volatile. The vapor pressure of R-13, for example, is 475 psia at 21°C. As noted by Adams et al. (1991), much of the freon injected during the C-11 test is believed to have been lost. Evidently a gas phase (i.e., a large "bubble") formed in the injection well bore. It entered the reservoir at a very shallow depth and was "burped" from a nearby production well immediately upon completion of tracer injection. Consequently, subsequent R-13 tracer tests have utilized a lower injection concentration of tracer by injecting smaller amounts of freon over longer periods of time in order to prevent early gas breakout. Table 1 lists the pertinent facts with respect to the tracer injection for the two tests described below as well as the aforementioned C-11 test. At injection concentrations of 100 to 130 ppm_w, early tracer gas separation from the injected water does not appear to be a problem.

SMUD R-13 TRACER TEST

In late August 1991, well 62-6 was converted from production to injection in order to eliminate a cold water breakthrough problem with the previous injection well. Well 62-6 is located in the area of federal leases held by Calpine Corporation for the production of steam to the SMUDGEO-1 power plant (owned and operated by the Sacramento Municipal Utilities District).

Table 1

TRACER TEST LOCATION/ DATE	TOTAL LBS FREON INJECTED	AVG. WATER INJECTION RATE	AVG. FREON INJECTION RATE	FREON INJECTION TIME	AVG. PPM FREON INJECTED
SMUD 12/3/91	232*	4260 LBS/MIN	0.56 LBS/MIN	6.9 HRS	129*
BEAR CANYON 4/21/93	160*	2900 LBS/MIN	0.30 LBS/MIN	9.0 HRS	103*
NCPA C-11 2/15/90	932.4**	6047 LBS/MIN	3.50 LBS/MIN	4.5 HRS	579**

* R-13 Only
** R-12 and R-13

An R-13 tracer test was conducted to determine where IDS would be produced as a consequence of the new injection well location. Unocal Geothermal participated in the tracer test by monitoring several of their wells for R-13. The irregular shape of the SMUD leases (Figures 1 and 2) results in Unocal production wells being located near the 62-6 injection well both to the northwest and south.

As shown in Table 1, 232 lbs of R-13 were injected into 62-6 at an average concentration of 129 ppm. Figures 1 and 2 show the contoured distribution of R-13 concentrations in produced steam on days 1 and 8 (tracer injection on day zero). Tracer was recovered as much as 3000 feet from the injection well on day 1. A similar rate of movement was documented by Adams et al. (1991) for the C-11 tracer test. Figure 3 shows concentration versus time curves for four of the wells which produced high R-13 steam. All but two wells peaked in R-13 concentration by day 8. Wells which experienced concentrations above 0.5 ppm_w all peaked by day 6. The peak concentrations of the four wells span a range of two orders of magnitude (0.1 to 10 ppm). The curves, however, are very similar in shape, which is typical of nearly all wells, regardless of peak concentration.

Based on plots of R-13 steam concentration versus time and the well flow rates, the total daily recovery of R-13 was estimated. Figure 4 shows the cumulative R-13 recovered versus time. 172 lbs of the total 232 lbs injected (74%) was recovered by day 60. 158 lbs (68%) was recovered in the first 14 days.

The molar ratio of ammonia to noncondensible gas has been shown to be useful in quantifying the injected condensate fraction in steam (Beall, 1993). An increase in this ratio (mNH_3/m NCG) indicates an increase in the fraction of boiled condensate in steam flow. Figure 5 shows this ratio plotted against time for the three wells which experienced the highest steam R-13 concentrations (62-13, 62-18 and 62-19; Figure 3). For those three wells, mNH_3/mNCG increased by factors of 2.3, 7.1 and 8, respectively, in the months following the initiation of injection at 62-6. In every case, a high rate of tracer recovery in the early days of the R-13 test presaged a high IDS component in that wells steam flow in the months to come.

Bear Canyon R-13 Tracer Test

The Bear Canyon area, located at the extreme southeast edge of the Geysers field, produces steam to a power plant owned and operated by Calpine Corporation. The injection well at Bear Canyon, D-4, was originally, based on natural tracers, in poor communication with the Bear Canyon production wells. The well was plugged back and redrilled toward the west (closer to the production wells) in an effort to increase IDS recovery, thereby enhancing both production and reserves. Figure 6 shows the distribution of Bear Canyon wells. The dots represent the steam-production weighted midpoints for single bore production wells. The traces of multi-leg wells (D-9 and DS-4) are also shown, along with their steam entry locations plotted as tick marks along the well course.

The presence of multi-leg wells hinders contouring of tracer concentrations of steam, as was done for the SMUD tracer test. Nevertheless, tracer was recovered only from the four wells with bores passing closest to the injection wellbore. Figure 7 shows the R-13 concentration versus time for those wells. The lower limit of detection in R-13 analyses is raised in steam having high concentrations of noncondensible gas. At Bear Canyon there is a large range of noncondensible gas concentrations in produced steam. One Bear Canyon well, D-8, produces steam with eight to ten times the noncondensible gas (NCG) concentration of "typical" Calpine wells. For that reason, no points were obtained on the ascending portion of the concentration versus time curve for D-8 (Figure 6).

COMPARISON OF SMUD AND BEAR CANYON TRACER RECOVERY

Several significant differences are apparent in comparing the R-13 concentration versus time graphs for the SMUD and Bear Canyon tracer tests (Figures 3 and 7, respectively).

1. The maximum recorded concentrations are over three orders of magnitude lower than those seen at SMUD.

2. Tracer movement in the Bear Canyon reservoir was very slow relative to tracer velocities at SMUD. No tracer was detected in any Bear Canyon well until day 15.

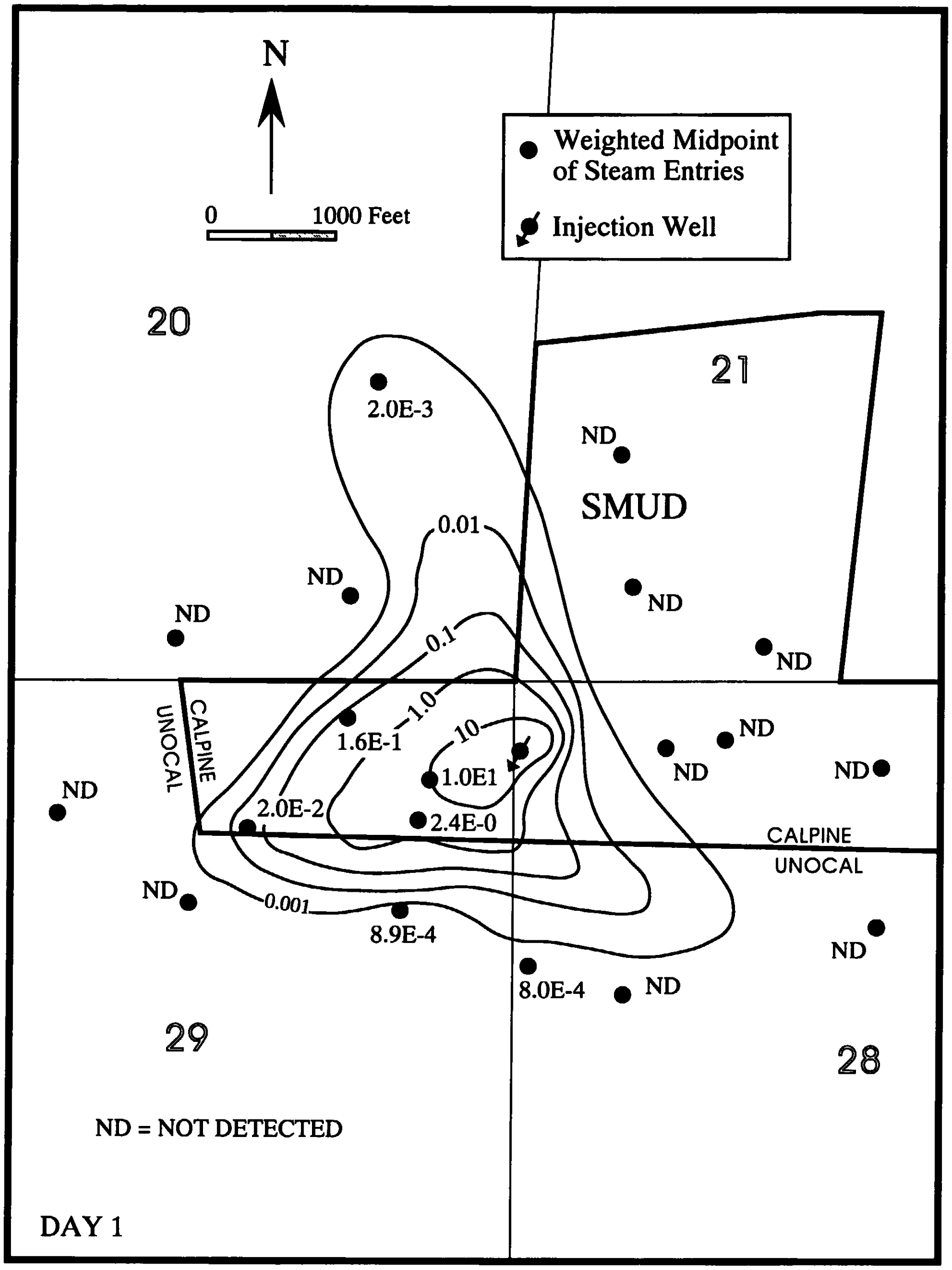

Figure 1. Contoured R-13 concentrations (ppm) in produced steam on the day following injection of R-13 tracer at SMUD.

3. The concentration peaks for Bear Canyon wells are very broad compared with those for SMUD. Near-maximum concentrations at Bear Canyon tend to be sustained for periods of 30 to 60 days. At SMUD, near-maximum concentrations lasted only a few days.

Because of the very low R-13 concentrations measured in Bear Canyon steam samples, only a fraction of one percent of the injected R-13 was recovered during the 110 days of this test. This contrasts very sharply with the 74% recovered during the 60 days of the SMUD test.

EFFECT OF LIQUID SATURATION ON THE RATE OF R-13 RECOVERY

The contrasting results described above for the SMUD and Bear Canyon R-13 tracer tests are best understood in light of the reservoir conditions which exist in each area. At SMUD a high level of reservoir depletion results in low reservoir pressure (less than 200 psia) and low liquid saturation. Under these conditions, injectate boils very rapidly on entry into the reservoir. R-13 tracer injected into these conditions migrates rapidly in the steam phase to production wells and is recovered at relatively high concentrations in the IDS (Figures 3 and 8).

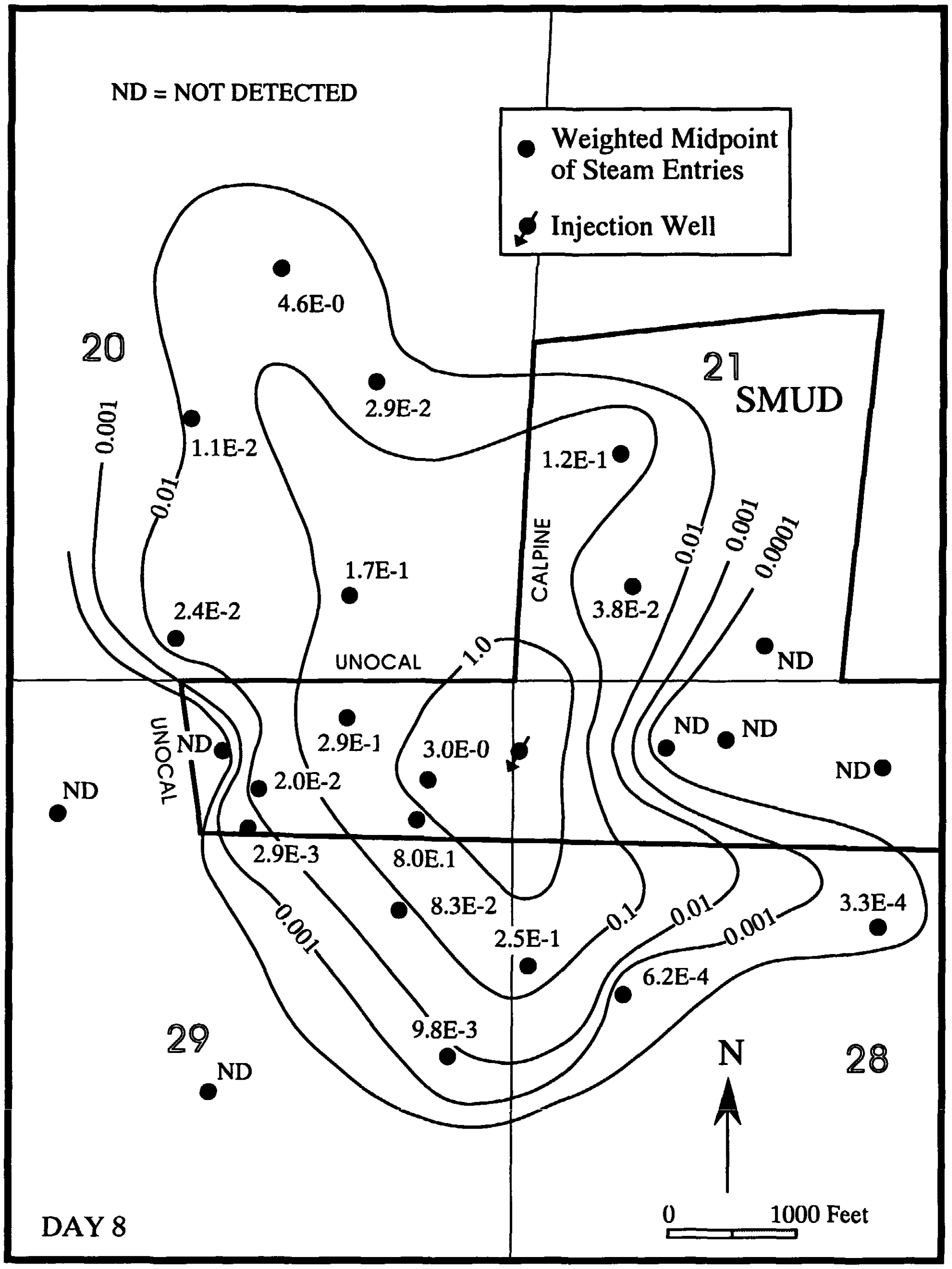

Figure 2. Contoured R-13 concentrations (ppm) in produced steam eight days after injection of R-13 tracer at SMUD.

At Bear Canyon, the reservoir is significantly less depleted, with higher reservoir pressure (over 300 psia) and higher liquid saturation. Under these conditions boiling occurs at higher temperatures resulting in a lower rate of heat transfer from rock to water. Consequently, boiling is inhibited relative to lower pressure reservoir conditions (such as at SMUD). This allows a zone of liquid filled fractures adjacent to the injection well bore. This zone has important implications with respect to tracer behavior. Compared with the SMUD tracer test, the Bear Canyon test demonstrates a much longer residence time of injectate prior to boiling (Figures 7 and 8). The long period (15 days) between R-13 injection and its first detection in produced steam, and the low R-13 concentrations observed are typical of flow through a liquid reservoir, as documented in numerous tracer tests in liquid dominated systems (e.g. Adams et al., 1989). This implies that R-13 tracer tests in The Geysers provide information on the liquid saturation near the injection wellbore and the residence time of the injected liquid.

Although R-13 partitions strongly into the steam phase upon boiling, at low concentrations typical reservoir pressures (i.e., 200 to 400 psia) are sufficient to keep it in solution prior to boiling. For example, as shown in Figure 9, water containing 100 ppm R-13 injected into a reservoir with a pressure of

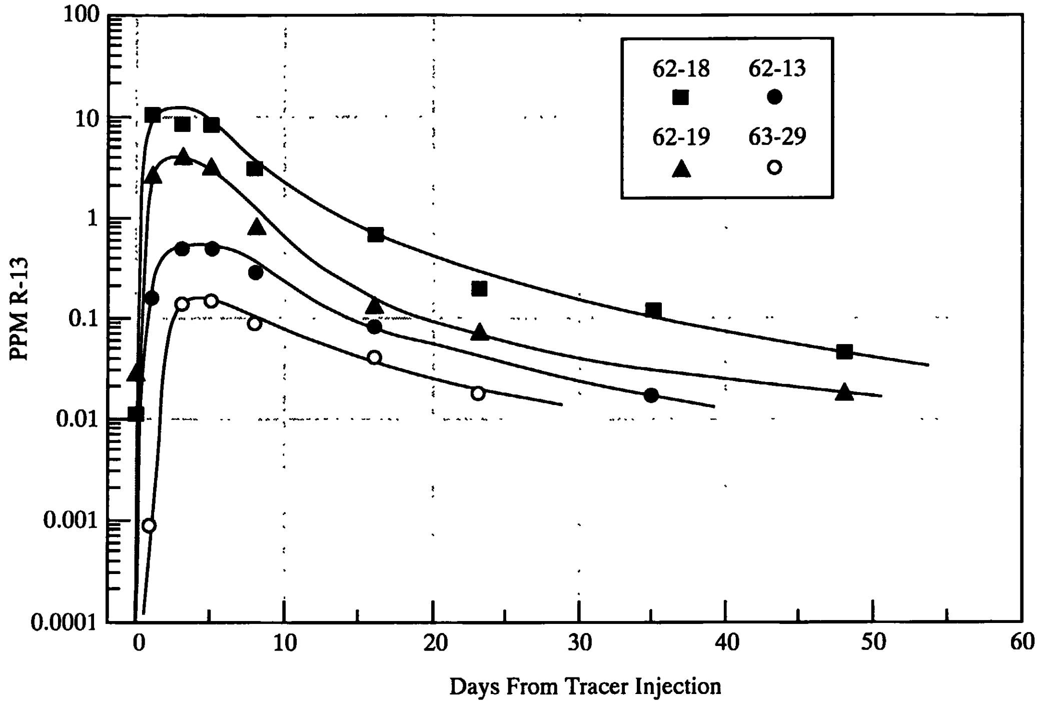

Figure 3. R-13 concentration in produced steam from SMUD and Unit 20 wells versus time elapsed since tracer injection.

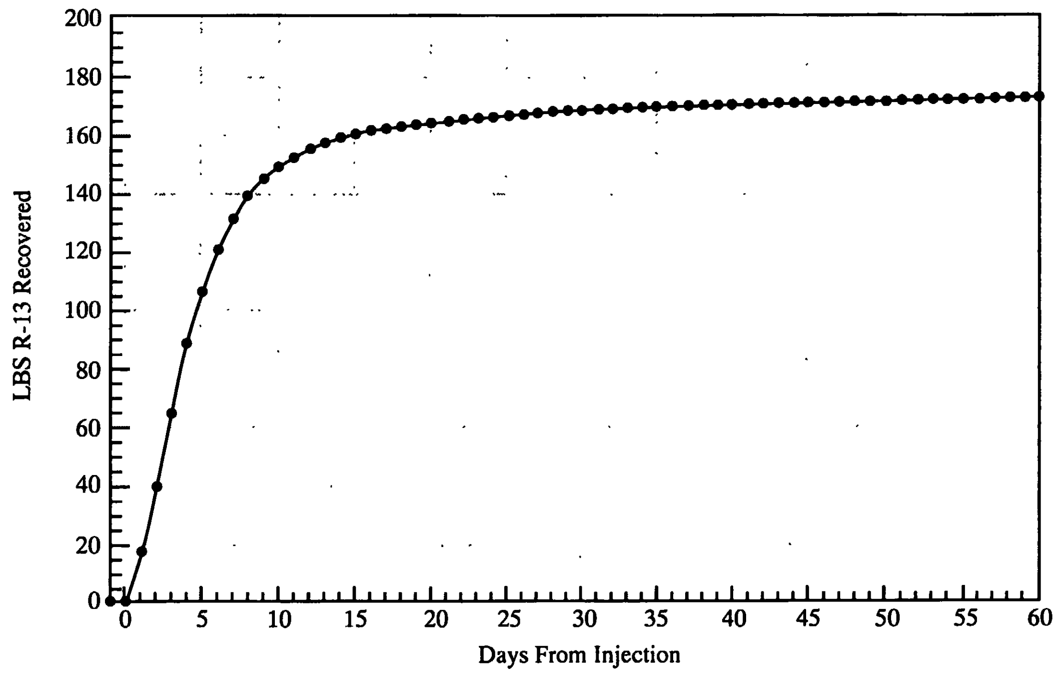

Figure 4. Cumulative pounds of R-13 tracer recovered during the SMUD test.

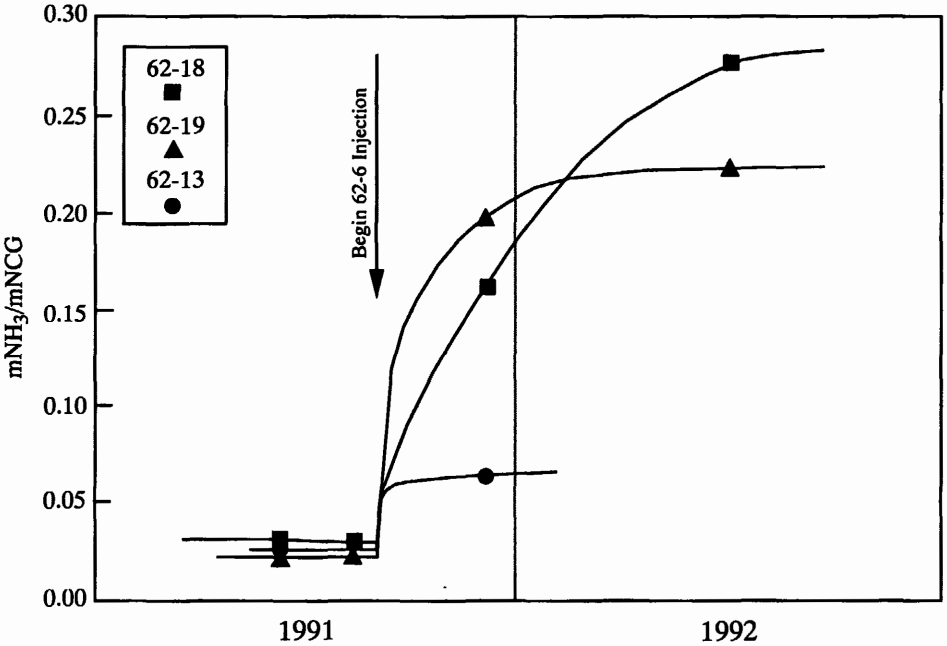

Figure 5. Molar ammonia to noncondensible gas ratio versus time for SMUD wells with high R-13 concentrations in steam.

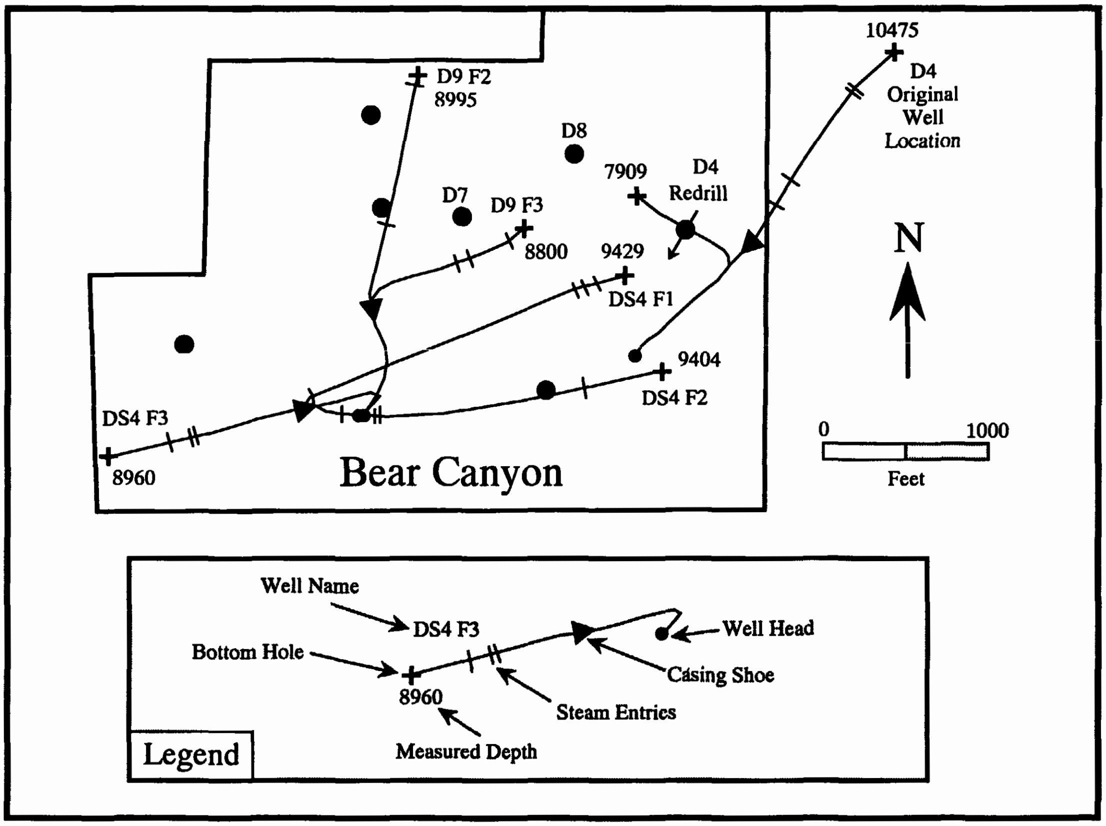

Figure 6. Bear Canyon area wells. Dots represent production-weighted midpoints of steam for single well bore completions. For multi-leg completions well courses are shown with tick marks indicating the locations of steam entries. For D-4 injection well both original well course (now plugged) and current well course are shown. The dot with the arrow marks the primary injection zone.

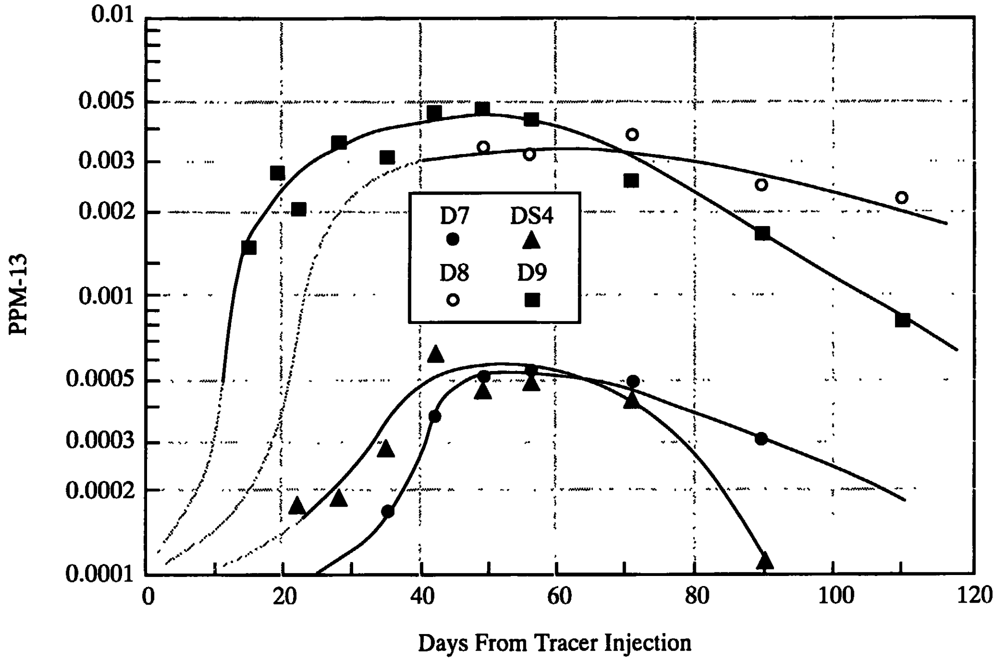

Figure 7. R-13 concentration in produced steam from Bear Canyon wells versus time elapsed since tracer injection.

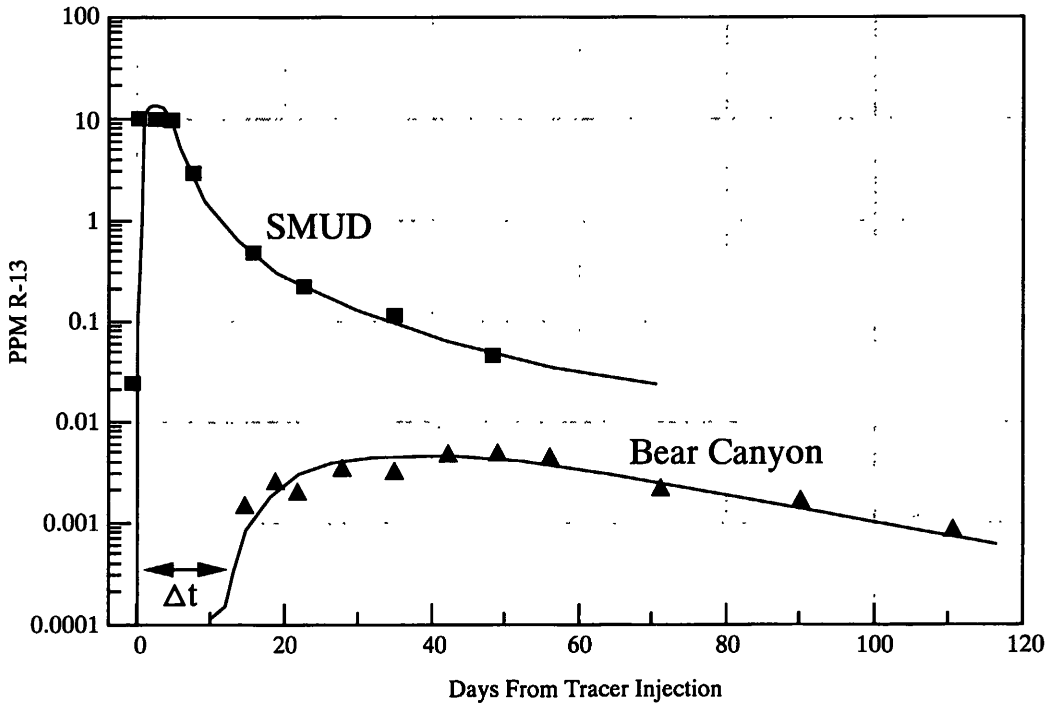

Figure 8. Maximum R-13 tracer concentrations versus time for SMUD and Bear Canyon. Δt represents R-13 residence time in water phase.

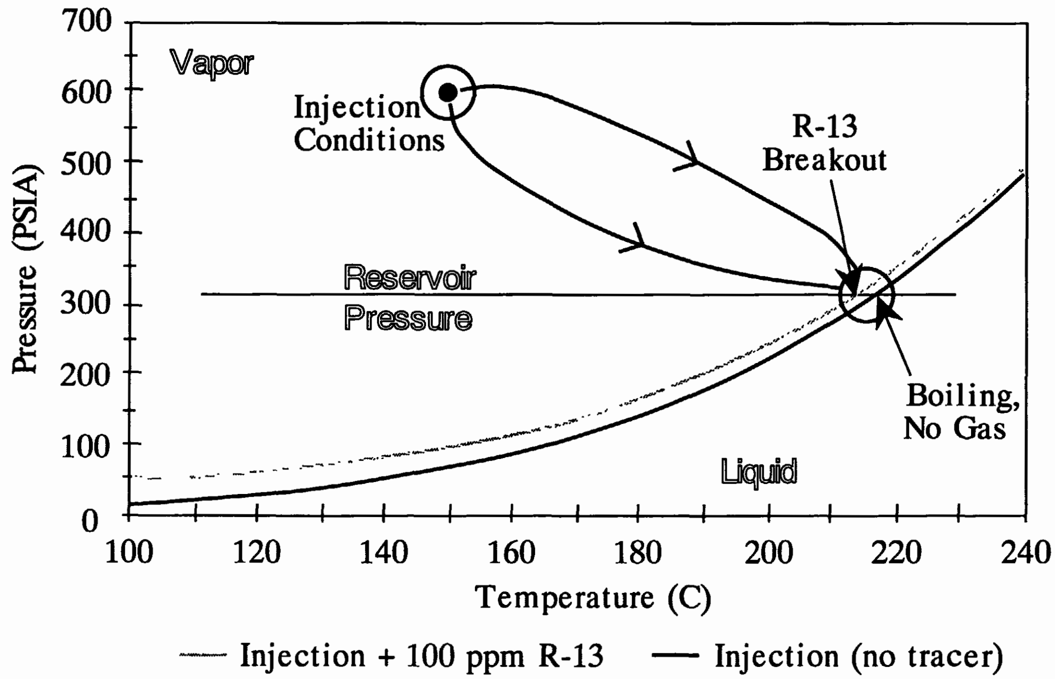

Figure 9. Liquid-vapor phase boundaries for water and water plus 100 ppm R-13. Bear Canyon pressure-temperature conditions at the injection point in the wellbore and for injectate boiling in the reservoir are also shown. The vapor pressure of R-13 was extrapolated from the data of Wilhelm et al.(1977). The extrapolation method is detailed in Adams et al. (1991).

300 psia will experience gas breakout (i.e., separation of a vapor phase containing nearly all the R-13) at a temperature only a few degrees before the boiling point of pure water. Consequently, the effect of 100 ppm R-13 is to lower the boiling point of the injectate by a few degrees. Due to the large difference in specific volume between steam and liquid water (80:1 at 300 psia) vapor phase transport of tracer will be much faster than liquid phase transport at a given injection rate. A long hiatus between R-13 injection and detection in produced steam (Δt, Figure 8) therefore implies complete water saturation adjacent to the injection wellbore.

Pressure and temperature logging of the Bear Canyon injection well indicates P-T conditions at the injection zone of approximately 600 psia and 150°C. P-T conditions in non-injection affected reservoir fractures are approximately 320 psia and 220°C. Consequently, any likely P-T path from wellbore to injectate boiling is likely to retain the R-13 within the liquid phase until a temperature very close to the boiling point of water is reached (Figure 9).

COMPLETE VERSUS PROGRESSIVE BOILING

One question which is not readily answered by R-13 tracer testing alone is whether boiling is complete at a distinct "front" or whether boiling begins at some point after the water leaves the wellbore and continues as the remaining water migrates outward into the formation. In the latter case, only the early boiling fraction will contain significant concentrations of R-13, while residual water will produce almost tracer-free steam. Under low pressure, dried out (SMUD type) reservoir conditions all indications are that injected water has a very low residence time. Under higher pressure reservoir conditions (e.g., Bear Canyon) the question of complete boiling at a front versus continuous boiling along a flow path becomes more relevant.

CONCLUSIONS

Compared with SMUD, the Bear Canyon R 13 tracer results show low R-13 concentrations, low reservoir velocity, broad concentration peaks and low total tracer recovery. These contrasts very likely reflect a low rate of IDS recovery at Bear Canyon even though communication between the Bear Canyon injection and production wells has been verified. The conditions which promote efficient boiling of water in the reservoir are high permeability, high enthalpy, low liquid saturation and low pressure (Enedy et al., 1991; Beall, 1993). Bear Canyon, because it has been in production only since 1988, has relatively high average reservoir pressure (over 300 psia) and high pore liquid saturation. By comparison, the SMUD area has been in production since 1983 and the average reservoir pressure is less than 200 psia, indicating a more "dried out" reservoir with less pressure support from original reservoir liquid. It is quite likely that production will ultimately lower liquid saturation and reservoir pressure at Bear Canyon so that higher recovery rates of steam from injectate boiling will occur.

The results of R-13 tracer testing in the Geysers suggest that, at least qualitatively, results can be used to estimate the efficiency of injectate boiling and IDS recovery. Delays of more than a few days between tracer injection and first detection of R-13 in produced steam indicates liquid saturated reservoir adjacent to the injection wellbore. At an early stage in an injection well's history, R-13 tracing allows a prediction of which production wells will produce high IDS components in total steam flow.

In April of 1994, a multiple tracer test is planned by Unocal for a recently converted southeast Geysers injection well. In this test R-13 as well as SF_6 will be injected along with tritium. A comparison of tritium and R-13 concentrations should allow a quantitative analysis of the extent to which R-13 partitions into an early formed vapor phase. If boiling is essentially complete at a liquid/vapor interface (a boiling "front"), then partitioning effects should be minimal. If, however, water migrates outward from an injection plume, boiling continuously as it moves, then early separating steam fractions should contain highly enriched R-13 concentrations relative to steam separating from a residual water.

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