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INJECTION AND TRACER TESTING IN SVARTSENGI FIELD, ICELAND

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ABSTRACT

A current injection-tracer test in the Svartsengi Ueld in Iceland is described. and some of the initial results presented. *An* earlier injection test is also summarized. The problems of silica deposition and corrosion in the spent brine from the Svartsengi power plant, and the effects of injection on reservoir draw-down and tracer breakthrough, are at the center of the study. Rapid tracer breakthrough has been observed in one of the *six* production wells, as a result of sustained injection into one well. Iodide seems to be an ideal chemical tracer for high-temperature geothermal systems. Rhodamine WT appears *to* have less merit, except for qualitative testing.

INTRODUCTION

An injection-tracer test is now under way in the Svartsengi geothermal field in Iceland. This test was started in July 1984, and is expected to last €or six to twelve months. The main reason for wanting to inject spent Uuids in Svartsengi is the rapid draw-down experienced in the fleld. The injection-tracer test follows an earlier test in 1982. when cold water was injected for 24 days. In the current test, two tracers were added to the brine-condensate mixture injected. The purpose of this paper is to describe the current injection-tracer test and to report some of the initial results. The test concerns the pumping and injection of silica laden brine and the movement of injected fluids in the reservoir.

The Svartsengi field is produced by the Sudurnes Regional Heating Company. The company operates a power plant in the Svartsengi field that provides district heating water to the several communities on the Reykjanes Peninsula; also called Sudurnes Region. The capacity of the power plant is 125 MW_t For house heating and 8 MW_e of electric power; Technical details about the power plant are given by Thorhallsson (1979) and Matthiasson (1981).

Production operations in Svartsengi were initiated in 1976. From the start of production, all spent fluids have been disposed of at the surface. Field developments in Svartsengi are discussed by Gudmundsson (1983a) and Palmason et al. (1983).

SVARTSENGI FIELD

The Svartsengi high-temperature, liquid-dominated geothermal fleld is on the Reykjanes Peninsula in southwest Iceland. The reservoir temperature is in the range 235-240°C, and the fluids produced are about two-thirds seawater and one-third rainwater in composition. Reservoir engineering studies in Svartsengi are discussed by Kjaran et al. (1979). Ceorgsson (1981) considered the geophysics of the area and Franzson (1983) presented a geologic cross-section of the Svartsengi field and reported on hydrothermal mineral alteration studies. The wellfleld in Svartsengi is shown in Figure 1. The reservoir is highly permeable and the wells are prolific producers. Flowrates as high as 190 kg/s have been measured (Palmason et al., 1983).

Eleven geothermal wells have been drilled in Svartsengi. The wells are of three basic designs: (a) wells 2, 3 and 10 are shallow; 239 m, 402 m and 424 m deep and closely spaced; 35-105 m (b) wells 4, 5 and 6 are deep; 1713 m, 1579 m and 1734 m with 9-5/8" casing and (c) wells 7, 8, 9, 11 and 12 are deep; 1438 m, 1603 m, 994 m, 1141 m and 1488 m with 13-3/8" casing. Wells 2 and 3 have 8-5/8" casing while well 10 has 13-3/8" casing. All the wells in Svartsengi have slotted liners except wells 7 and 12 which are barefoot. Wells 5-12 are spaced 200-250 m apart. The nominal output of wells having 9-5/8" production casing is about 60 kg/s (steam-brine mixture) but the 13-3/8" wells have a nominal output of about 120 kg/s. Well 4 was measured to produce 60-80 kg/s at 10-15 bar absolute wellhead pressure, while wells 8 and 11 measured 120-180 kg/s. Well 10 is capable of almost the same production as the other large diameter wells. Output measurements at Svartsengi show clearly that the flowrates are controlled by the wellbore diameter.

Fluid production and reservoir draw-down have been measured and recorded for the Svartsengi deld since 1976. At the end of 1980, the field had produced about 10 million tonnes of fluid with a 50 m draw-down. The long-term production data can be smoothed to give a straight line on a log-log plot. The draw-down at the end of each year is shown in Figure 2. The line through the data points is given by the empirical expression: $Ah = 1.5\ 10^{-6} w^{3/4}$, where Δh (m) is the drawdown and w *(kg)* the total Uuid production.

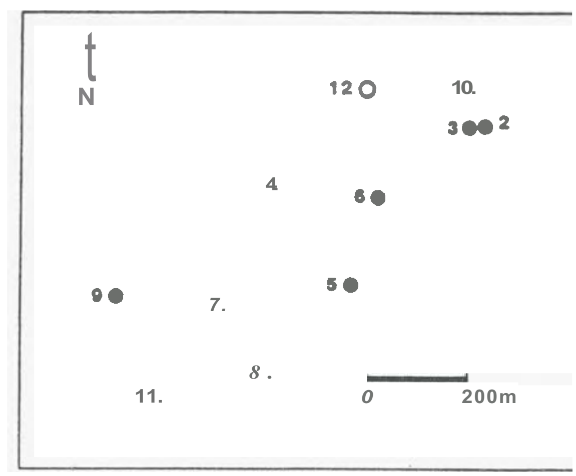

Figure 1. The wellfleld in Svartsengi.

INJECTION 1982

An injection test was carried out in Svartsengi in 1982. The results of this test have been reported by Gudmundsson (1983b). Well 12 was drilled in March 1982 as an injector. It is located on the north side of the wellfield and is 1488 m deep. The well is cased 13-3/8" to 607 m and barefoot 12-1/4" to well bottom. The reservoir temperature below the casing is 220-235°C, which is similar to other wells in the field. The well location and design were based on two main criteria: It should be within the known reservoir, and it should be a useful producer if the injection testing proved negative.

A geothermal tracer test had not been carried out in a high-temperature fleld in Iceland in 1982. It was suspected that the results from such a test would be unpredictable. as indicated by experience in other countries (Horne, 1982) *This* called for a simple first test, that could then

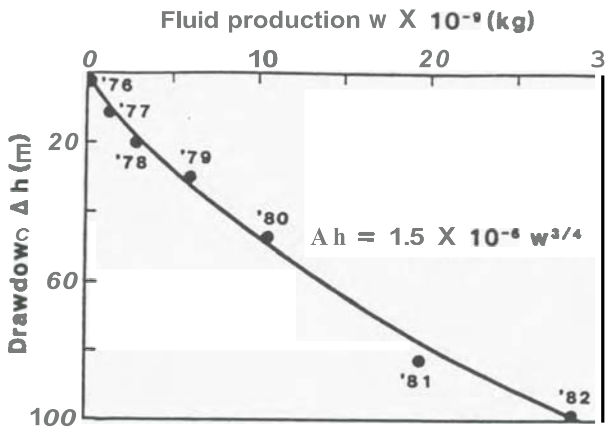

Figure 2. Fluid production and pressure draw-down in Svartsengi field.

be improved upon in a later test. The testing procedure adopted was the following:

(1) Cold fresh water (63-65 kg/s) was injected into well 12 for 24 days.

(2) Brine samples were collected from the steam-brine separators of wells 6-11 for 70 days.

(3) The sodium content of the brine was measured - using atomic absorption spectrophotometer - to monitor salinity.

(4) Steam samples were collected from the production wells alter the first 20 days of testing.

The main results of the 1982 injection test will now be summarized. Wells 2 and 3 were shut-in during the test. Well 10 produces from a two-phase zone that has developed due to draw-down. Wells 4 and 5 were shut-in during the injection test. Well 4 was used as an observation well. It has a water level recorder to monitor draw-down with time. A pressure increase was measured almost immediately when injection into well 12 was started. The sodium concentration in wells 6, 9 and 10 is shown in Figure 3. The figure shows the average daily value for the first ten days, then one sample analyzed each day. The sodium concentration in well 10 decreased suddenly within an hour after injection started. The concentration decreased from 7500 mg/kg to 4500 mg/kg for about 3-1/2 hours. The following day the concentration decreased again for about ten hours.

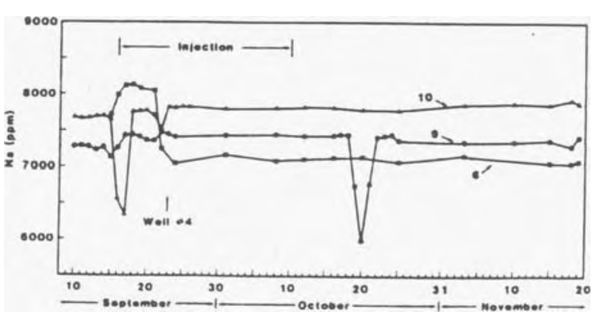

Figure 3. Sodium concentration in wells 6, 9 and 10. during 1982 injection test.

The separators for wells 8 and 10 were operated at about 5 bar-g pressure and the separators for wells 7, 8, 9 and 11 at 4 bar-g. These pressures remained constant during the test except that well 6 was not connected to the power plant until about a week into the test.

The behavior of well 9 during the first week was rather inconclusive. After 34 days, however, the sodium concentration suddenly dropped from 7400 mg/kg to 6000 mg/kg for about three days. Well 6 demonstrated an increase in sodium concentration during the first few days of production. It had been shut-in prior to the start of the injection test. The first week the well discharged through an open silencer before being connected to the power plant.

Significant changes in sodium concentration in wells 7, 8 and 11 were not observed. However, these wells showed a slight decrease in sodium at about the same time as well 9 responded. All of these wells are located on the southwest side of the wellfield. A slight increase in sodium was noticed about 24 days later. Measurements of nitrogen in the steam of wells 7, 8, 9 and 11, show an increase tbat coincides with the sodium depression.

Although well 4 was shut-in during the testing period, it was nevertheless greatly affected by the injection. After seven days of injection of cold water into well 12, the water level recorder went off scale and had to be removed because of steam and gas escaping up the wellbore. It appears, that the inert gases dissolved in the cold injection water, made their way into well 4 and increased the water level by gas-lift action.

It was concluded, that all the production wells had shown breakthrough in one form or another. Breakthrough was observed in well 10 in about one hour from the start of injection, well 4 in about one week and well 9 in less than five weeks. The breakthrough was observed to occur in pulses of both short duration, and long term dilution and gas enrichment.

TEST DESCRIPTION

The 1984 injection-tracer test in Svartsengi was initiated for the following main reasons: (1) to test the feasibility of long-term pumping and injection of spent fluids, with respect to deposition and corrosion, (2) to test fluid connectivity between injection and production wells, by conducting a tracer survey, (3) to monitor the effect of injection on reservoir draw-down with time, and (4) to monitor the output of production wells

The question of whether to inject in the Svartsengi field has been under discussion from the start of production. Work has been carried out in two technical areas to resolve the question. The first deals with fluid chemistry, the second reservoir engineering. The early chemical work has been summarized by Gudmundsson (1983c). The geothermal brine is dashed down to about 75°C in the power plant. This makes the brine highly supersaturated in silica, which deposits rapidly. It was recognized early, that the brine had to be treated in some way to allow injection. A practical solution to the silica deposition problem in Svartsengi may be to lower the pH of the discharge brine. This can be achieved by combining the brine with the steam condensate. The pH of the reservoir fluid is much lower than that of the flashed brine. The mixing of the brine and condensate, in a sense, returns the fluid to its natural state. Some acid may also have to be added to the mixture to reach a sufficiently low pH value. Such a mixture may not be as corrosive as expected in low pH waters. Silica is known to protect mild steel from corrosion. Also, oxygen should not be present in the brine-condensate mixture.

The flow diagram for the 1984 injection-tracer test in Svartsengi is shown in Figure 4. The geothermal steam-brine mixture from wells 7,8,9 and 11 flows to individual separators that operate at 5.5 bar-g pressure. The high-pressure steam is used in the power plant, and the separated brine flows to a low pressure separator, that operates at vacuum conditions through a barometric system. The brine dashes down to about 75°C. This brine has been allowed to flow into the lava field by the power plant. A disposal pond called the "Blue Lagoon" has formed due to the presence of colloidal silica. The silica seals the bottom and gives rise to the blue color also. The interest is to inject this brine back into the reservoir. The steam that enters the power plant from the high-pressure separators. passes through turbines - to generate electricity - and then condenses in plate heat exchangers - to heat water for district heating. The steam condensate has also been allowed to flow into the lava field by the power plant. The condensate comes from the power plant in two streams. In the injection-tracer test, these streams are joined together before being mixed with the flashed brine.

Early chemical experiments indicated, that the pH of the brine-condensate mixture needed to be lowered to about 5.5 to prevent significant silica deposition occurring Before the injection-tracer test was started, the system was tested at several mixing ratios of brine to condensate This was done by flowing all the available condensate, and

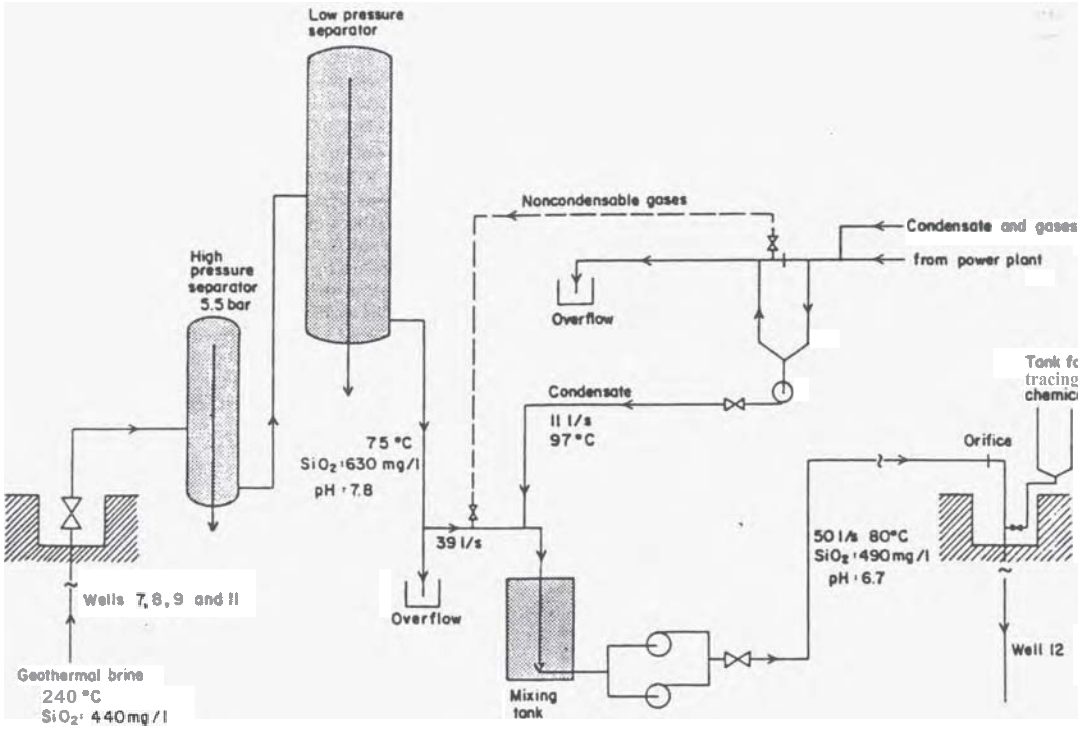

Figure 4. Flow diagram of the injection-tracer test in Svartsengi

then gradually increasing the brine dowrate. The system was operated with the flow into the disposal pond. Deposition and corrosion coupons were installed in the flowline. The system was operated at each setting for about one day. The coupons were inspected for deposition and corrosion. The purpose of this test was to determine what brine-condensate mixture could safely be injected for several months.

Figure 4 shows the flowrates of the brine and condensate in the flow scheme selected for the injection-tracer test. The figure also shown the concentration of silica in the brine from the wellhead, the low-pressure separator, and the mixture injected into well 12. A flowline is shown for noncondensable gases. mainly CO_2. These are the gases present in the steam condensate. They are very effective in lowering the mixture pH. Problems were experienced in gettii the gases to flow with the condensate and mix with the brine. Therefore, a special line had to be installed for this purpose. It was not entirely successful, so most of the gases escaped with an overflow that could not be closed due to the system configuration. When the tracer part of the test is over, further studies will be done on the mixture chemistry, including the effect of adding acid.

The polymerization of silica in the mixture selected for the test is shown in Figure 5. The figure shows the concentration of monomeric silica with time for the flashed brine, and the brine-condensate mixture. *Also* shown is the solubility of silica - in the form of opal - in water at *80* °C. With time, the silica concentration in the flashed brine and brine-condensate mixture approaches the solubility Limit. Note the effect of dilution. The flashed brine contains about 630 mg/kg of silica; the mixture contains about 490 mg/kg. From the point of view of injection, the behavior of silica in the brine-condensate mixture with time is important. Figure *5* shows that the silica concentration remains constant for about one hour. This means that the silica dissolved in the mixture is unlikely to deposit during this time. For the pipeline and well diameters and lengths involved. it takes less than one hour for the mixture to reach the reservoir.

In the injection-tracer test, 50 kg/s of a brine-condensate mixture is being injected. The mixture is 80% Bashed brine and 20%steam condensate. The mixture pH is 6.7 arid the temperature about *80* °C. The flowrate is measured in an ultrasonic flowmeter. The pumping of silica laden mixtures is not easy. The centrifugal pumps used are fitted with water lubricated bearings. using hot district heating water. This method has proved successful in other applications in Svartsengi.

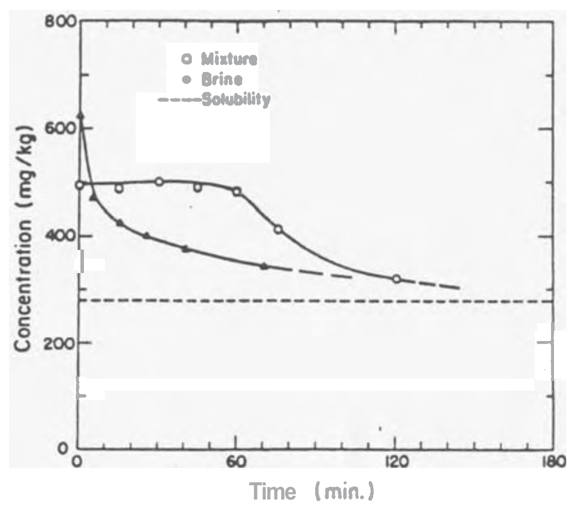

Figure *5.* Silica concentration with time at *80* °C.

Well 12 is used as the injection well. Before the injection-tracer test was commenced, the well had been left standing for about 21 months; since the and of the 1982 injection test. It was considered important to measure the downhole pressure in well 12 during the injection test. It was also considered important to monitor the deposition and corrosion behavior of the wellbore during the test. A 9-5/8" pipe (liner) was run to 300 m depth in the well. This was so that a capillary tube could be placed in the annulus between the 13-3/8" casing and 9-5/8" liner. Also, the 9-5/8" Liner could then be removed from the well after the test and examined for deposition and corrosion. However, the capillary tube was not installed when the 9-5/8" liner was lowered into the well. Later, it was not possible to place it in the annulus. The capillary tube had to be run inside the 9-5/8" liner.

The first try at injecting the brine-condensate mixture was on July 19, 1984. After the first hour it discovered that the capillary tube was leaking. The injection was stopped and the tube removed, It was repaired and installed the following day. The second try at injecting was on July 20, 1984, at 11:20 am. It soon became clear, that the capillary tube was again leaking. The injection was continued while a better solution to the capillary tube problem was sought. Five days later, on July 25, 1984, the injection into well 12 was stopped for two hours while a new capillary tube was installed. These operations meant that it was not possible to obtain meaningful measurements of the downhole pressure during the first few hours and days at the start of injection. The long term downhole pressure is being monitored.

The first tracer was injected into well 12 on July 28, 1984. at 1400 pm. At that time, the brine-condensate mixture injection had been in operation for about six days (144 hours 40 minutes). The tracer injected was 37 liters of rhodamine WT fluorescent dye solution. The dye was dissolved in a tank with a few hundred liters of the injection mixture. It was injected by opening a valve into the injection line at the wellhead. Vacuum conditions exist at the wellhead. The dye emptied from the tank in less than one-half of a minute. Rhodamine WT has been used with success in a geothermal tracer test in Klamath Falls, Oregon. (Cudmundsson et al. 1983). The dye is inexpensive and easy to measure. Fluorescent dyes are believed to chemically break down when heated to geothermal temperatures. However, no data have been found to demonstrate this. It was decided to try to use rhodamine WT in the Svartsengi injection-tracer test. If it gave similar results to the much more expensive potassium iodide, it would open the way for inexpensive tracer tests in geothermal fields under production. Fluorescein dye has been used with success in tracer tests in the Hatchobaru deld in Japan (Home, 1982). There, it was determined that fluorescein could easily provide data on first arrival times in geothermal tracer tests. Downs et al. (1982) mention that fluorescein and rhodamine B were used in tracer test in Raft River, Idaho. However, they offer no comment on the result.

The second tracer was injected on July 27, 1984 at 11:10 am. The tracer used was 350 kg of potassium iodide. It was dissolved in a few hundred liters of the brine-condensate mixture as had the rhodamine WT dye. Again. it took less than one-half minute to inject the tracer into the well. Potassium iodide has been used with success in several geothermal tracer tests (Home, 1982; Gudmundsson et al. 1983).

Well 6 was put on full discharge on July 16, 1984. Until then, it had been on a 2" by-pass line for months. Several output measurements were taken during the first ten days of fill discharge. The deliverability curve of well 6 is shown in Figure 8. The well was discharged through a flow nozzle and weir. This enabled the enthalpy to be measured in addition to flowrate and wellhead pressure. The average dowrate at 13 bar-g wellhead pressure is about 45 kg/s. The average enthalpy is 1016 kJ/kg, which represents liquid water at about 236°C.

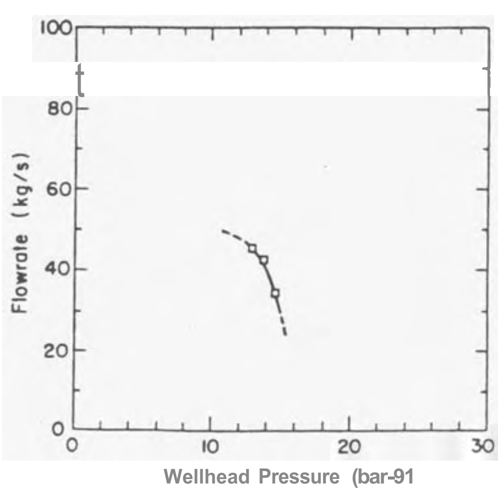

Figure 6. Well 6 deliverability curve.

Wells 7-9 were on full production when the injection-tracer test was initiated. They produce to individual steam-water separator3 that operate at about 5.5 bar-g. Well 11 was not on full production when the test started It was operated on a 2" by-pass line to a stem-water separator, but not used in the power plant. The flowrate of wells 7-9 is about 60 kg/s under normal operating conditions. The flowrate of well 11, when on by-pass, is much less. All of these wells are typical liquid-dominated wells with flashing in the wellbore.

Well 10 was put on discharge on July 13. 1984. Until then, it had been closed for months. The first few days the well was discharged through a 2" by-pass line. On July 16, 1984, the well was put on full discharge. Well 10 is very different from other wells in the Svartsengi deld. Instead of producing a two-phase mixture from a liquid-dominated feed. the well produces steam only. Well 10 is 424 m deep and draws fluid from a two-phase steam cap that has developed in the reservoir. Each year it has produced less and less liquid. During the first weeks of discharge, there was some geothermal brine "carry over" in the steam. It was not possible to collect liquid samples from well 10 to analyze for tracers.

TRACER ANALYSIS

A tracer breakthrough curve is a kind of travel log that shows the concentration of a tracer with time. It provides a record of what happens underground when a duid flows between two or more wells. Tracer analysis provides four main pieces of information (Home, 1084). The first is the arrival of the peak concentration. This indicates the speed of movement of the water through the system. The first tracer to arrive has probably dispersed ahead of the main tracer slug, whereas the concentration peak moves with the mean speed of the flow. However, in many cases the first detection and peak concentration occur within a very short t i e . Such a condition may be an indicator of subsequent difficulties with thermal breakthrough. Rapid tracer movement implies a high degree of fracturing or high permeability in the reservoir, and may suggest that the swept volume of reservoir rock will be small.

A second parameter of interest in the tracer-return information is the total tracer recovery. A production well that receives more of the injected water than others is more likely to suffer temperature decline as a result. Quantifying total recovery can be difficult because the tracer may be lost within the reservoir by chemical reaction or adsorption. Nevertheless. the relative recoveries in several production wells can be useful for comparison between wells.

A third use for the tracer-return history is the analysis of long-term equilibrium tracer concentration. In cases where the produced water is continuously injected, the tracer is again and again produced and injected. Provided the tracer is not retained or destroyed to a large extent within the reservoir, concentrations in the produced fluid will gradually reach an equilibrium value higher than the original background concentration. At this stage it is possible to estimate the volume of reservoir fluid throughout which the tracer has been dissolved.

A fourth use of the tracer-return data is to analyze the shape of the concentration/time profile (breakthrough curve). This procedure is still under development, but shows possibilities for the estimation of fracture characteristics. An estimate of fracture aperture may be useful for calculating the rate of local thermal depletion along the flow path.

BREAKTHROUGH CURVES

Geothermal tracer studies typically involve a massive sampling effort. Five of the six flowing wells in Svartsengi are being sampled in the current injection-tracer test. Initially. samples were collected every hour from the five wells. After the first few days, samples were collected every two hours. Later on the sampling frequency was decreased. The philosophy adopted was to collect many samples, but to analyze much fewer samples.

The concentration of iodide in the geothermal brine was measured using an ion chromatograph. The technology to measure iodide in brines in tens of ppb ($\mu g/kg$), has recently become available. It means that the amount of potassium iodide tracer now required in tests is kept to a minimum. Using the special chromatographic column developed for iodide analysis. has made it possible to carry out the current injection-tracer test at a reasonable cost. The details of the ion chromatographic method will not be discussed in this paper. An ion specific electrode cannot be used to measure iodide in the Svartsengi brine because of chloride and bromide interference.

The concentration of fluorescent dyes in water is easily measured using a fluorometer. Concentrations less than ppb ($\mu g/kg$) can be measured. The details of this technique will not be discussed here. It was discovered, however, that the method - as used in Svartsengi - is sensitive to some time dependent factor. The method is based on an optical technique, so the behavior of silica with time is likely to affect the dye concentration measured. The silica polymerizes with time and forms colloidal particles that are ideal adsorption sites. Some sort of a brine treatment method to overcome this problem seems to be called for.

The iodide breakthrough curve for well 6 is shown in Figure 7. It is the only well to show tracer breakthrough so far. The figure shows the iodide concentration measured in the brine that was collected at 100°C. That is, the two-phase mixture from well 8 was discharged through a critical pressure nozzle and flow metering V-notch weir. Many samples were collected before the tracer was injected to determine the background concentration of iodide. The background was found to be 90 ppb in the dashed brine. Taking the mixture enthalpy as 1016 kJ/kg, as measured during the output testing, means that 26% of the massflow dashes into steam. The background concentration of iodide in the brine feeding well 6, therefore, is about 66 ppb. As evident from *Figure 7.* the ion chromatographic method gives excellent results. Most of the samples were analyzed the day following collection.

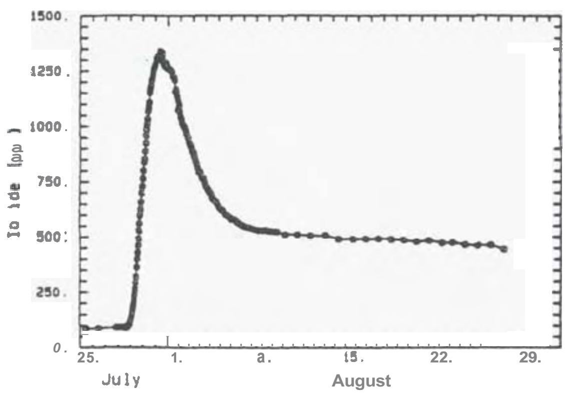

Figure 7. Iodide concentration with time in flashed brine of well 6.

Iodide breakthrough was detected in well 8 about 40 hours after the tracer was injected into well 12. Maximum iodide concentration occurred about 100 hours after injection; this time should be taken as the average fluid velocity in the reservoir. The travel time down well 12 and up well 8 is about one hour in total. The average tracer velocity, therefore, measures about 2 m/h. The first tracer breakthrough is believed to represent the effect of dispersion. Using the 40 hour breakthrough time, gives the maximum tracer velocity as 5 m/h. The distance between the wells is about 200 m.

The recovery of iodide in well 6 with time is shown in Figure 8. This figure was constructed by subtracting the iodide background from all the values shown in Figure 7, integrating the area under the resulting tracer curve with time, and then calculating the percent iodide recovered. The total flowrate of well 6 was measured as 45 kg/s. The effect of flashing on the mass balance was included in the calculation. About 2% of the iodide injected had been recovered when the maximum Concentration was reached in 100 hours. More than 15% had been recovered in *700* hours.

For the time being, the flowrates of wells 7-11 have to be assumed to determine the total fluid production during the first month of the injection-tracer test. Taking the flowrate of well 10 the same as that of well 6, the flowrate of wells 7-9 as 60 kg/s each. and that of well 11 about 5 kg/s, the total field production becomes 275 kg/s. Well 6, therefore, produces about 16% of the total. It is of interest to note that this percentage is similar to the amount of tracer recovered in well 6 for which measurements are shown in Figure 8.

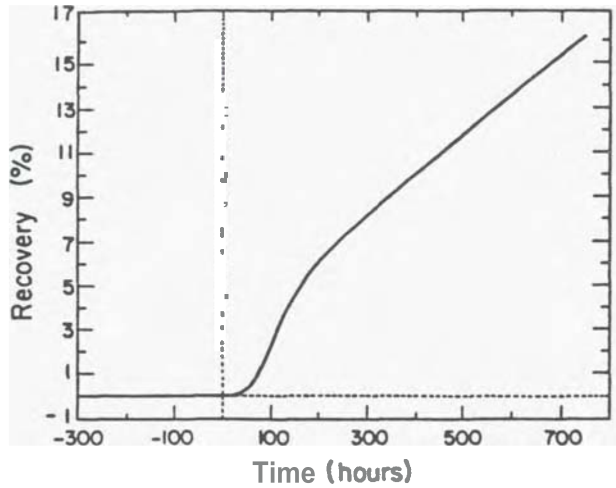

Figure 8. Iodide recovery with time in well 6.

The rhodamine WT tracer breakthrough curve is shown in Figure 9. This curve and the iodide curve give the same breakthrough time and maximum concentration. After that. however, the two curves are different. The rhodamine WT curve is not as smooth because of the effect of silica on the fluorometer readings. Note that the rhodamine WT concentrations are less than 13 ppb while the iodide values are less than 1300 ppb. An important difference between the two tracer curves is the long tail shown by the iodide. This may result from the breakdown or adsorption of rhodamine WT in the reservoir. To illustrate this difference better, the relative concentrations with time are shown in figure 10. The percent recovery of rhodamine WT has yet to be determined.

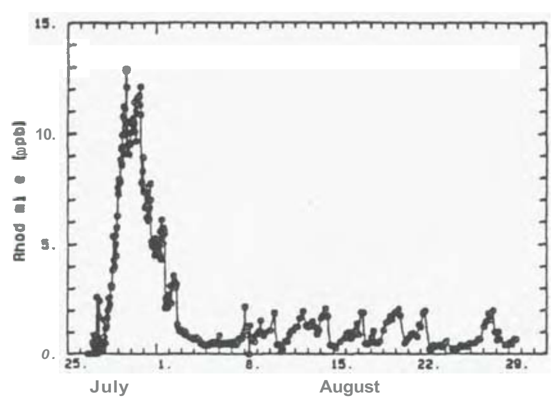

Figure 9. Rhodamine WT concentration with time in flashed brine of well 6.

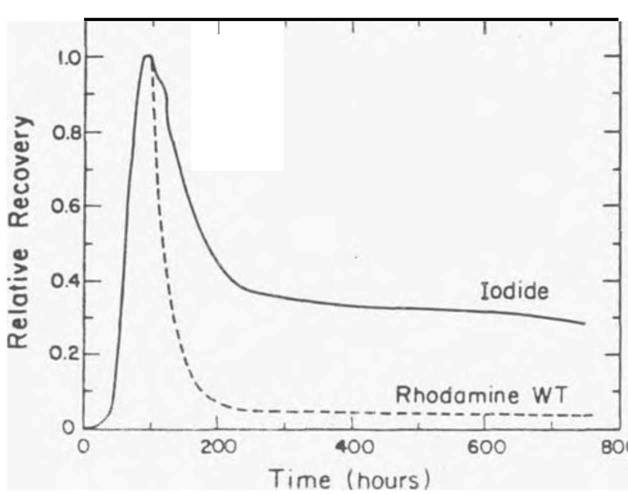

Figure 10 Relative recovery of iodide and rhodamine with time in well 6

Profile analysis concerns the shape of tracer curves with time. The shape of the iodide curve. suggests that the tracer may have flowed between wells 12 and 6 along at least two paths. These paths could be two fractures, or perhaps one major fracture and a less permeable matrix. A plausible reservoir model would be a double porosity system. The iodide tracer behavior of well 8 has yet to be matched to some of the flow models developed for geothermal reservoirs (Fossum and Horne. 1982; Jensen and Home, 1983).

CONCLUDING REMARKS

The injection-tracer test reported in this paper is still in progress. The tracer part of the test will continue for a few more months, but the deposition and draw-down aspects will receive attention for about one year. This means that most of the data analyses remain to be done. Nevertheless, several important observations have already been made.

The first observation is that there is rapid Uuid communication between wells 6 and 12 This indicates some fault or fracture that connects the two wellbores. This structure may affect *the* long-term injection behavior of the field. It appears that well 12 is not in as good a communication with wells 7-11. It remains to be seen whether iodide breaks through in other wells than 6.

The output of well 6 was monitored for about two months - after the injection started - before it had to be connected to the power plant. The dowrate. wellhead pressure, and mixture enthalpy were measure daily. No changes in output were observed. This observation has a bearing on the relationship between tracer and thermal pulses during injection. It appears that the thermal pulse moves orders of magnitude slower than the tracer pulse. It may *also* be that the thermal effects were too small to be detected.

Iodide in the form of potassium iodide appears to be a good chemical tracer for high-temperature geothermal fields. The use of iodide in the Svartsengi deld is made possible by the use of new ion chromatographic technology. It has opened up new and important possibilities in geothermal tracer testing.

Rhodamine WT dye may suffer from thermal breakdown or adsorption on reservoir rock under high-temperature geothermal conditions. It has, however, been used with success in low-temperature reservoirs. Although rhodamine WT may not be able to give quantitative information. it does give the breakthrough time and average Uuid velocity in the reservoir in some situations. These are very important parameters in tracer analysis,

In *the* Svartsengi situation. the mixing of steam condensate with the spent brine appears to solve the problem of silica deposition. What remains to be done, is to investigate further the effect of adding acid to the mixture to allow for injection of all the brine.

ACKNOWLEDGMENTS

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