The United Nations University

GEOTHERMAL TRAINING PROGRAMME
Orkustofnun, Grensásvegur 9,
IS-108 Reykjavík, Iceland

Reports 1999
Number 6

REINJECTION AND TRACER TESTS IN THE LAUGALAND GEOTHERMAL FIELD, N-ICELAND

Liu Jiurong
Beijing Institute of Geological Engineering,
No.90, Road Beiwa, Haidian District,
100037 Beijing,
P.R. CHINA

ABSTRACT

Water injection into geothermal systems was initiated about three decades ago. In most cases the purpose is to dispose of wastewater for environmental reasons. In other cases, injection is used to counteract pressure drawdown and for extracting more of the thermal energy in place in geothermal reservoirs. Injection is one of the most complex aspects of geothermal exploitation. Therefore, careful planning and research are prerequisites for successful reinjection. One of the more serious problems which may be associated with reinjection is thermal breakthrough. Therefore, tracer tests are often carried out along with reinjection so as to detect the connections between reinjection and production wells, and to predict the subsequent cooling effect of reinjection. A production-scale reinjection experiment was started in the low-temperature geothermal field at Laugaland, N-Iceland in 1997 and will be completed by the end of 1999. Owing to insufficient recharge, the production capacity of the field is limited and the heat stored in the 90-100°C rock matrix can only by used to a limited extent. The return water from the district heating system of the town of Akureyri was used as the source for reinjection. From September 9, 1997 to June 1, 1999, a total of 749,000 m^3 of water was reinjected into the geothermal field, about 30% of the production during that time. The reinjection showed good effect on supporting the reservoir pressure and improving the heat mining. Three tracer tests were carried out in the field during reinjection. The data from the tracer tests were simulated using a multiple flow-channel model. The results show that there are direct paths between the injection and production wells, but most of the injected water diffused into the rock matrix. Tracer recovery from an adjacent geothermal field, 1800 m to the north shows a clear connection between the two geothermal fields. A future cooling effect due to reinjection in the geothermal field was predicted using the same model; results show that significant cooling is not likely to happen in the field.

1. INTRODUCTION

Since 1969, reinjection has become an ever more important measure in the management of geothermal reservoirs (Axelsson and Stefánsson, 1999). The purpose of reinjection into geothermal systems is twofold. The first is to dispose of wastewater, which may cause thermal and chemical pollution. The second is to maintain reservoir pressure so as to counteract declining production capacity, enhance the heat mining from the reservoir and reduce land subsidence due to over-extraction of geothermal fluids. Recently, increasing attention has been paid to the latter purpose because of its central importance for sustainable use of geothermal resources.

Most reinjection projects have been successful, but problems have been encountered in some cases. One of the problems, which has received the greatest attention, is premature thermal breakthrough, in which some of the colder injected water reaches the production wells before being heated up to reservoir temperature. This is especially detrimental to high-temperature wells because of the strong effect on steam production. In low-temperature geothermal fields, strong cooling should be avoided, but slight cooling is acceptable. Extensive research must be carried out before long-term reinjection is started because the economics and the benefits of such a project are strongly dependent on the behaviour of the geothermal system and wells (Axelsson and Stefánsson, 1999).

Tracer testing is one of the most important aspects of reinjection research work, which has become routine for reinjection experiments. Tracer tests can provide information about the flow paths and the flow velocity of the geothermal fluids between the injection and production wells. For fractured reservoirs, the volume of the flow channel can be deduced from the tests. This information can be used to predict cooling due to reinjection (Axelsson and Stefánsson, 1999).

The Laugaland geothermal field is a low-temperature field controlled by a fracture zone, as is typical for most of the geothermal fields in Iceland. Owing to limited recharge of water, the production capacity of the field is rather low. Because of the sparse fracture network, much of the heat stored in the 90-100°C hot rock matrix cannot be fully utilized. For a long time, reinjection has been considered a possible solution to this problem. A short-term reinjection experiment was carried out in 1991, and was followed by a production-scale experiment in 1997-1999. During the experiments, tracer tests were carried out to examine the connection between the reinjection and production wells, and to predict the cooling effect of cold water reinjection.

The reinjection experiment is to be completed by the end of 1999. In this report, data from the reinjection and tracer experiments collected before June 1, 1999 are presented and analyzed. The effect of reinjection is studied on the basis of water level monitoring data. Particular emphasis is placed on the tracer recovery profiles, which are simulated by using a multiple flow-channel model, and the thermal effect of reinjection is predicted by using a corresponding fracture model.

2. THE LAUGALAND GEOTHERMAL FIELD

The Laugaland geothermal field is located in the middle of Eyjafjordur valley, a little more than 10 km south of the town of Akureyri which is the largest town in northern Iceland (Figure 1). The field is one of five low-temperature geothermal fields supplying hot water to Akureyri.

Production at Laugaland started in late 1975. More than 10 wells have since been drilled in the field,

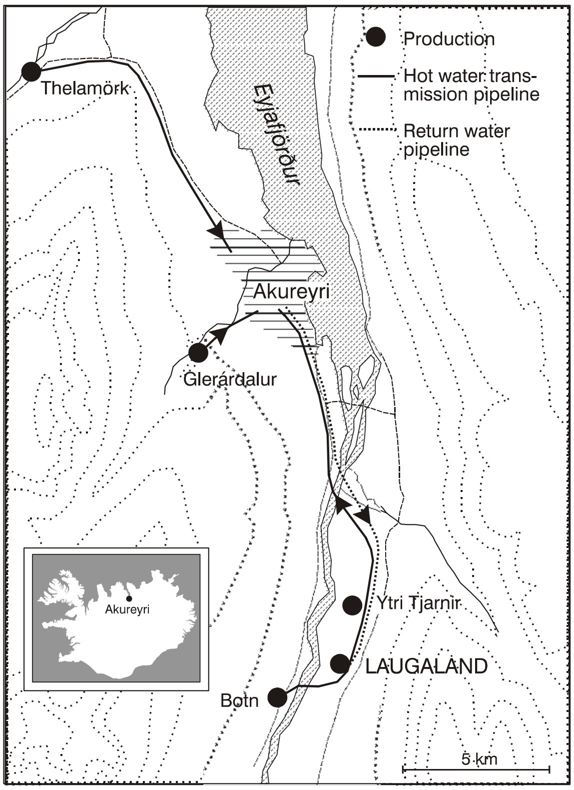

FIGURE 1: Location of the Laugaland geothermal field

three of which are productive, while three others are used as observation and reinjection wells (Figure 2). The wells in use range in depth from 1305 to 2820 m (Table 1). The production from the field has varied from 0.9 to 2.5 million tons annually since late 1977. Production was highest in 1981, but has since been cut by 50% because of the rapid decrease in productivity of the wells.

TABLE 1: Wells in use in the Laugaland geothermal field

Well	Drilled	Depth (m)	Elevation (m)	Use
LJ-05	1975	1305	34.2	Production
LJ-07	1976	1945	14.0	Production
LJ-08	1976	2820	39.4	Observation/injection
LG-09	1977	1963	46.8	Observation
LN-10	1977	1606	18.2	Observation/injection
LN-12	1978	1612	18.8	Production

The bedrock in the area is made of flood basalt as old as 6-10 million years. The lava beds dip 5-8° to the southeast in the direction of the rift zone across Iceland. The thickness of individual beds, which are usually separated by thin interbeds of sediment and scoria, varies from a few meters up to 30 m. Numerous basalt dikes, often 1-3 m thick, intersect the lava pile.

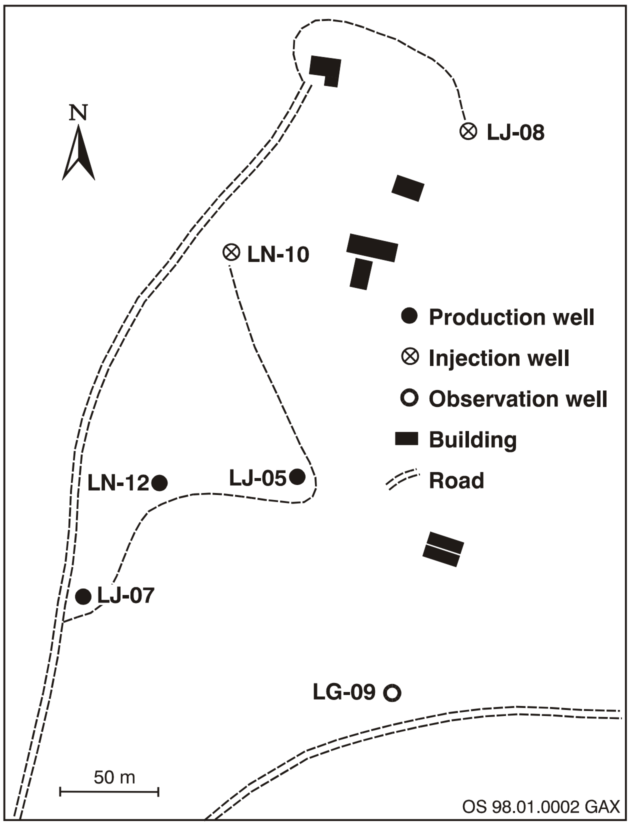

FIGURE 2: Location of the wells in the Laugaland geothermal field

The production wells at Laugaland are believed to be connected directly to each other by a near-vertical fracture zone, which stretches in a SW-NE direction. The deepest feed zones of the three production wells, which are also the most productive feed zones, are connected to the fracture. Outside the fracture zone, the bedrock is of very low permeability. A lumped parameter model shows that the average permeability of the system is on the order of a few mD and the reservoir volume is on the order of a few km^3. Therefore, only wells that intersect or are close to the fracture zone are productive (Axelsson et al., 1998).

The recharge of water to the geothermal system is believed to be mainly from infiltration of precipitation and shallow groundwater through the fracture zone as well as by some deep recharge. Lateral recharge from outside the fracture zone is believed to be very little, because of the low permeability of the lava beds. The limited recharge of the system constrains the mining of heat from the geothermal system.

The water level in the geothermal reservoir was about 200 m above sea level in its natural state. During the first few years of production it declined to more than 200 m below sea level, i.e. the drawdown of the water level reached more than 400 m (Figure 3). Because of this the production was decreased drastically and the water level has since recovered somewhat.

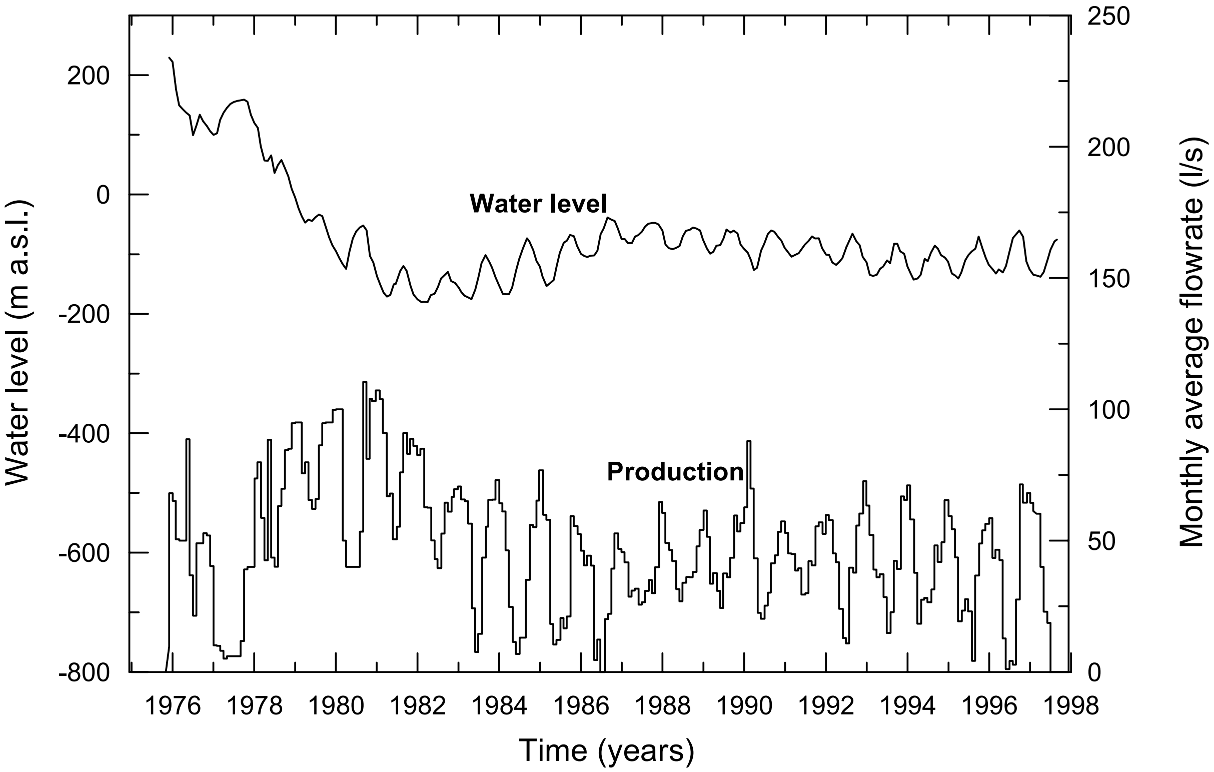

FIGURE 3: Production and water level fluctuation in the Laugaland geothermal field

3. REINJECTION EXPERIENCE

Geothermal reinjection started out as a method of disposing of wastewater from power plants in order to protect the surrounding environment. It started as early as 1969 and 1970 at The Geysers in California and Ahuachapan field in El Salvador, respectively. Today, injection is still mostly practiced to dispose of wastewater for environmental reasons, but it is also used for pressure maintenance, and for extracting more of the thermal energy in place in geothermal reservoirs. Injection is also of help in reducing land subsidence caused by large-scale geothermal production. Wastewater from geothermal power plants, return water from direct applications such as space heating, groundwater, surface water and even sewage water are all injected into geothermal reservoirs. Even though injection will cause an initial increase of operating costs, in most cases it will be an economical way of increasing energy production from a geothermal system. Injection cannot yet be considered a widespread method of reservoir management. However, its role is slowly increasing in significance, as more successful injection experiments are completed and more emphasis is put on sustainable use of energy globally (Axelsson and Stefánsson, 1999).

Presently there are 25 geothermal fields worldwide where injection is already a part of the field operation, including The Geysers field in USA, the Larderrello field in Italy, the Berlin field in El Salvador etc. And the reinjection at Laugaland, N-Iceland is a successful example of reinjection in a low-temperature geothermal field, which will be discussed below. In addition, there are at least 30 other geothermal fields where reinjection experiments have been carried out (Axelsson and Stefánsson, 1999). Some of these fields will hopefully start production-scale reinjection soon.

The possible cooling of production wells, or thermal breakthrough, has discouraged the use of injection in some geothermal operations. In some cases where the spacing between injection and production wells is too small, and direct flow-path between the two wells exist, the fear of thermal breakthrough has been justified. However, actual thermal breakthrough caused by cold water injection, has been observed in relatively few geothermal fields (Stefánsson, 1997).

The cooling effect can be minimized by proper location of injection wells, in particular by choosing injection locations at a considerable distance from the production wells. Yet, to achieve the maximum benefit from injection, i.e. thermal energy extraction and pressure recovery, injection wells should be as close to production wells as possible. For successful reinjection a proper balance between these two contradicting requirements must be selected. Therefore, careful testing and research are prerequisite for the planning of reinjection (Axelsson and Stefánsson, 1999).

Tracer tests are the most powerful tool for studying connections between injection and production wells, and hence the danger of thermal breakthrough. Numerous such tests have been carried out in geothermal fields during the past two decades (Stefánsson, 1997) and this has become a routine in most geothermal reinjection projects. In principle, the tracer breakthrough time is proportional to thermal breakthrough time. As a rule of thumb, the thermal breakthrough time is normally one or two orders of magnitude greater than tracer breakthrough time (Axelsson and Stefánsson, 1999).

Numerous models have been developed, or adopted, for interpreting tracer test data and subsequently for predicting thermal breakthrough and temperature decline during long-term reinjection (Pruess and Bodvarsson, 1984; Horne and Rodriguez, 1983; Stefánsson, 1997). Axelsson et al. (1995) described a model of solute transport in fractured media and the model has been used successfully to simulate tracer recovery profiles for a few Icelandic geothermal fields. This model is used to simulate the tracer test data at Laugaland geothermal field and will be discussed later.

Geothermal resources are also widespread in sedimentary rocks, in particular low-enthalpy geothermal energy. Geothermal energy is, at present, tapped from such rocks in China, France, Hungary, etc. Reinjection into a sandstone reservoirs has been attempted at several locations, but with limited success (Stefánsson, 1997). Reinjection into limestone aquifers has, however, been successful where attempted. During many sandstone reinjection tests, the injectivity of the injection wells decreases very rapidly, even in hours or days, rendering further reinjection difficult. The reason for this is most likely the clogging of the aquifer next to the wells. In three locations solutions to this problem have apparently been found. The first is the Tanggu geothermal area in North China, where the problem is solved by installing a down-hole pump in the reinjection well. Once the injectivity has dropped after a period of reinjection, the pump is used to redraw water from the injection well for a few hours, then the injectivity of the well will be recovered (Axelsson and Stefánsson, 1999). A similar approach is adopted in Neustadt-Glewe in Germany, apparently with success. And at Thisted in Denmark, the problem is overcome by keeping the injection water completely free of oxygen as well as passing it through very fine filters (Axelsson and Stefánsson, 1999).

4. REINJECTION AT LAUGALAND

4.1 General

Because there is not enough recharge into the Laugaland geothermal reservoir, energy production has been limited, despite the abundant heat stored in the 90-100°C rock matrix. Therefore, reinjection has long been considered a way to expand energy production in the field.

The first reinjection experiment in the Laugaland geothermal field was carried out in the spring of 1991 (Axelsson et al., 1995; Axelsson et al., 1998). During the experiment, 80°C hot water from a nearby geothermal field was injected into well LJ-08. At first, 8 l/s water were injected with only a minor well-head pressure, but later the injection rate was reduced to 4 l/s. Meanwhile, 40 l/s of 95˚C water were pumped from well LJ-05. Wells LJ-08 and LJ-05 are 2800 and 1300 m deep, respectively, and the distance between them is 250 m. Concurrently, the water level in nearby wells was monitored carefully. The duration of the experiment was 5.5 weeks. It had to be stopped because of pump failure.

The reduction of water level drawdown was observed almost instantaneously in the geothermal field as a response to injection. It was concluded that the reduced drawdown would allow for production to be increased by almost the same amount as injection (Axelsson et al., 1995).

The result of the injection experiment was very encouraging, although the duration was not long enough to enable a thorough evaluation of the response of the geothermal system to future injection. Therefore, a long-term reinjection experiment, which involved a number of tracer tests, was started on September 1997. This experiment will be completed by the end of 1999.

4.2 Water sources

There is abundant surface water and groundwater around Laugaland. At first, using local surface water or groundwater as injection water source was considered. However, the idea was rejected, since it could have caused serious problems, such as deposition of chemicals and clogging of the feed zones in the injection wells. The most likely depositions are magnesium-silicates (Bi, 1998). Such clogging would reduce the injectivity of the wells, and make further injection difficult (Axelsson et al., 1998).

Instead, it was decided that return water from the Akureyri District Heating system would be used, because the chemical composition of the return water is almost identical to that of the reservoir water (Sverrisdóttir et al., 1999), and is not likely to result in serious chemical deposition. Table 2 shows the chemical composition of return water and production water of well LN-12. Using return water is more costly, however, since it required constructing a pipeline for the return water from Akureyri to the Laugaland geothermal field (Axelsson et al., 1998).

TABLE 2: Chemical composition of return water and production water of LN-12 (mg/l)

Item	Return water			Production water	
Sampling date	Apr. 3, 1997 - A	Apr. 3, 1997 - B	Feb. 18, 1998	Sept. 8, 1997	Feb. 18, 1998
Temperat. (°C)	26.5	25	19.9	95.8	94.9
H/˚C	9.83/20.5	9.83/20.5	9.82/21.9	9.76/21.9	9.79/21.7
CO_2	21.2	22.0	19.4	18.2	19
H_2S	<0.03	<0.03	0.09	0.08	0.1
SiO_2	88.6	94.4	95.3	99.2	97.3
Na	53.0	53.1	55.3	50.8	54
K	0.96	1.00	0.99	1.11	1.16
Ca	3.15	2.82	2.96	2.91	3
Mg	<0,001	<0.001	0.002	0.004	0.001
SO_4	39.7	35.7	37.5	37.9	39.2
F	0.44	0.49	0.45	0.37	0.3
Cl	13.5	12.7	12.9	11.6	11.6
B	0.16	0.17	0.18	0.16	0.16
O_2	0	0	0.01	0	0

A 13 km long pipeline with a diameter of 150 mm, and made of high-density polyetylene plastic was constructed from Akureyri to Laugaland. To minimize the cost, it was not insulated but buried underground. Two high-pressure pumps were installed at the two proposed injection wells LJ-08 and LJ-10 (Axelsson et al., 1998).

The temperature of the return water is 6-21˚C, while the temperature drop in the 13 km return water pipeline is around 5˚C (Axelsson et al., 1998). During a short period in 1998, hot water was mixed into the return water to enable a higher injection rate. The temperature of the injecting water reached 36˚C, higher than the return water temperature (Hjartarson, 1999).

4.3 Implementation of the experiment

4.3.1 Overview

The full-scale reinjection project started at Laugaland on September 9, 1997, and will be completed by the end of 1999. In this report, only the data that had been collected by June 1, 1999 will be presented and analyzed. Before the experiment started, well LN-12 was put into production for two weeks following a summer break. The purpose was to create a relatively stable pressure condition in the reservoir before reinjection would start. The experiment can be divided into three stages based on the injection wells used (Figure 4). The total volume of injected water from September 9, 1997 to June 1, 1999 was 749,000 m^3

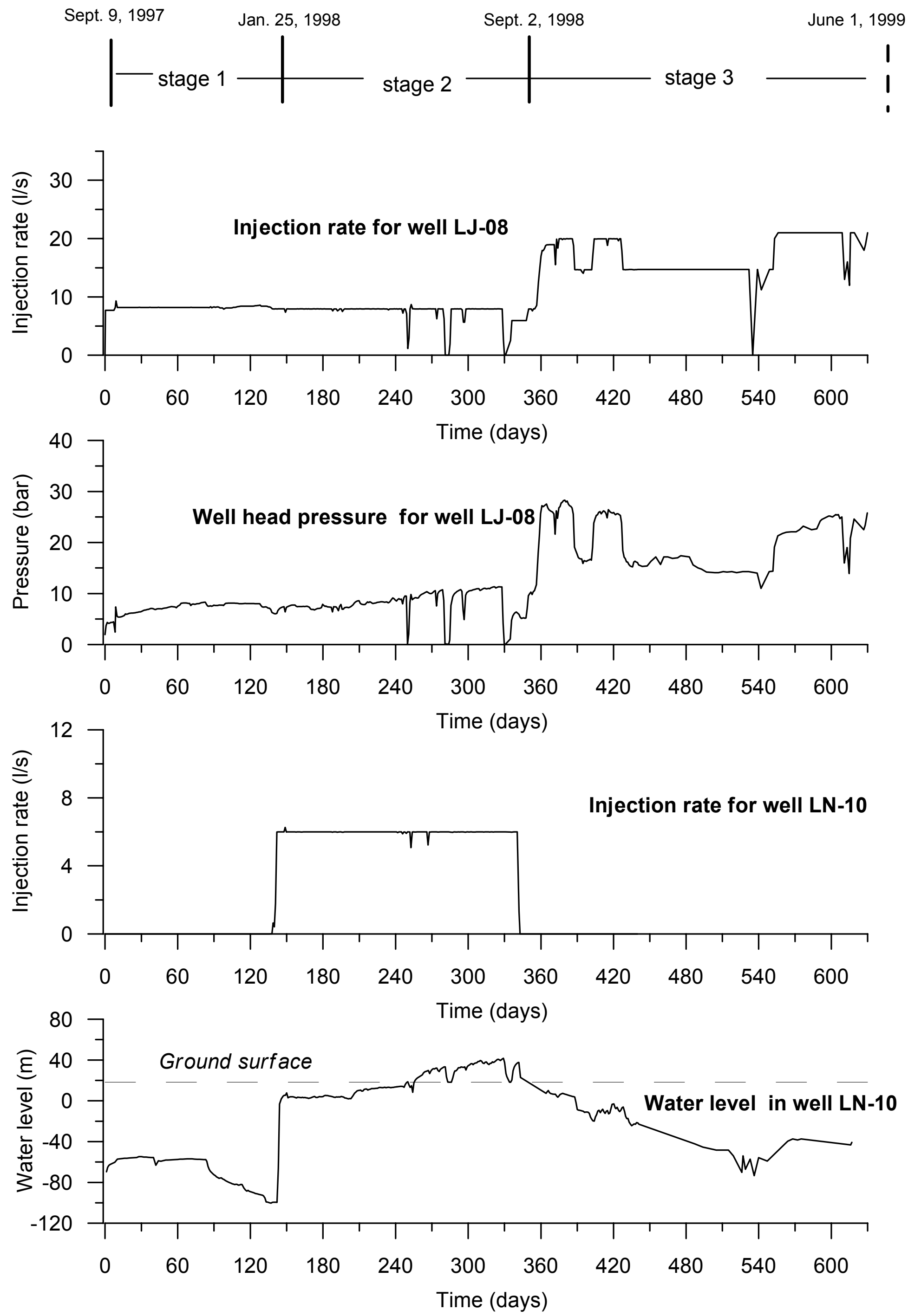

FIGURE 4: Injection flowrate and pressure/water level of injection wells

and the total volume produced was 2,602,000 m^3, i.e., injection was 28.8% of the production. Injection could reach over 30% of the production by the end of the year, because of low production in summer. Table 3 summarizes the amount of injection and production during the three stages.

TABLE 3: Summary of the reinjection and production from September 8, 1997 to June 1, 1999

Stage	Time (days)	Reinjection (m^3)			Production (m^3)			
		LJ-08	**LN-10**	**Total**	**LJ-05**	**LJ-07**	**LN-12**	**Total**
1	139	98,000	-	98,000	185,000	31,000	458,000	674,000
2	205	133,000	105,000	238,000	385,000	77,000	171,000	633,000
3	287	413,000	-	413,000	322,000	311,000	662,000	1,295,000
Total	631	644,000	105,000	749,000	892,000	419,000	1,291,771	2,602,000

Note: The third stage is not finished yet.

4.3.2 The first stage

The first stage of the injection project lasted from September 8, 1997 to January 25, 1998. During this period, only well LJ-08 was used for injection. The injection rate was about 8 l/s, and the injection wellhead pressure varied between 6 and 8 bars. Considering that the water level of the reservoir before injection was over 100 m below sea level, the injection hydraulic head was about 16-19 bars (Figure 4). At first, the only production well was LN-12, producing at a rate of about 41 l/s. From December 1, 1997 well LJ-05 was also put into production, because of the greater water demand during the winter time (Figure 5). Well LJ-07 also produced intermittently to keep two of the three production wells on line. The amount of water reinjected in this stage was 98,000 m^3, while the production was 674,000 m^3, so injection amounted to 14.5% of the production (Table 3).

4.3.3 The second stage

The second stage lasted from January 25, 1998 to September 2, 1998. Injection was carried out simultaneously into wells LJ-08 and LN-10 with injection rates of around 8 and 6 l/s, respectively. The wellhead pressure in LJ-08 was often more than 8 bars in the latter part of this period, slightly increased compared to the first stage, while the wellhead pressure of LN-10 was less than 2 bars. The production in this period was highly variable (Figure 4). To meet the large amount of hot water demand at the beginning of 1998, two of the three production wells were used alternately (Figure 5). One well was even used occasionally in the cold summer of 1998. The amount of injection and production in this period was 238,000 m^3 and 633,000 m^3, respectively. The reinjected water accounts for 37.6% of the production during this stage (Table 3).

The increase of wellhead pressure of well LN-08 was because of the elevated reservoir pressure due to injection. The wellhead pressure for well LN-10 during injection was less than 2 bar, the well was even without wellhead pressure at the beginning, although ground elevation of well LN-10 is about 20 m lower than that of well LN-12 (Table 1). This means that injectivity of well LN-10 is considerably higher than that of well LN-12.

4.3.4 The third stage

The third stage began on September 2, 1998 and will continue until the end of 1999. In this report only the data obtained by June 1, 1999 are used. The only injection well during this period was LJ-08, and the injection rate was 14-21 l/s. The injection often fluctuated from 14 to19 l/s in the period September 2, 1998 to November 10, 1998. In the following period, the injection rate was rather constant at 14.7 l/s until March 15, 1999. Later, the injection rate was increased to about 21 l/s until June 1, 1999 (Figure 4). Production from well LN-12 was rather constant in this period, 38-44 l/s, while well LJ-05 only produced intermittently (Figure 5). The amount of injection and production during this stage, prior to June 1, 1999, was 413,000 m^3 and 1,295,000 m^3, respectively, injection amounting to 31.9% of the production.

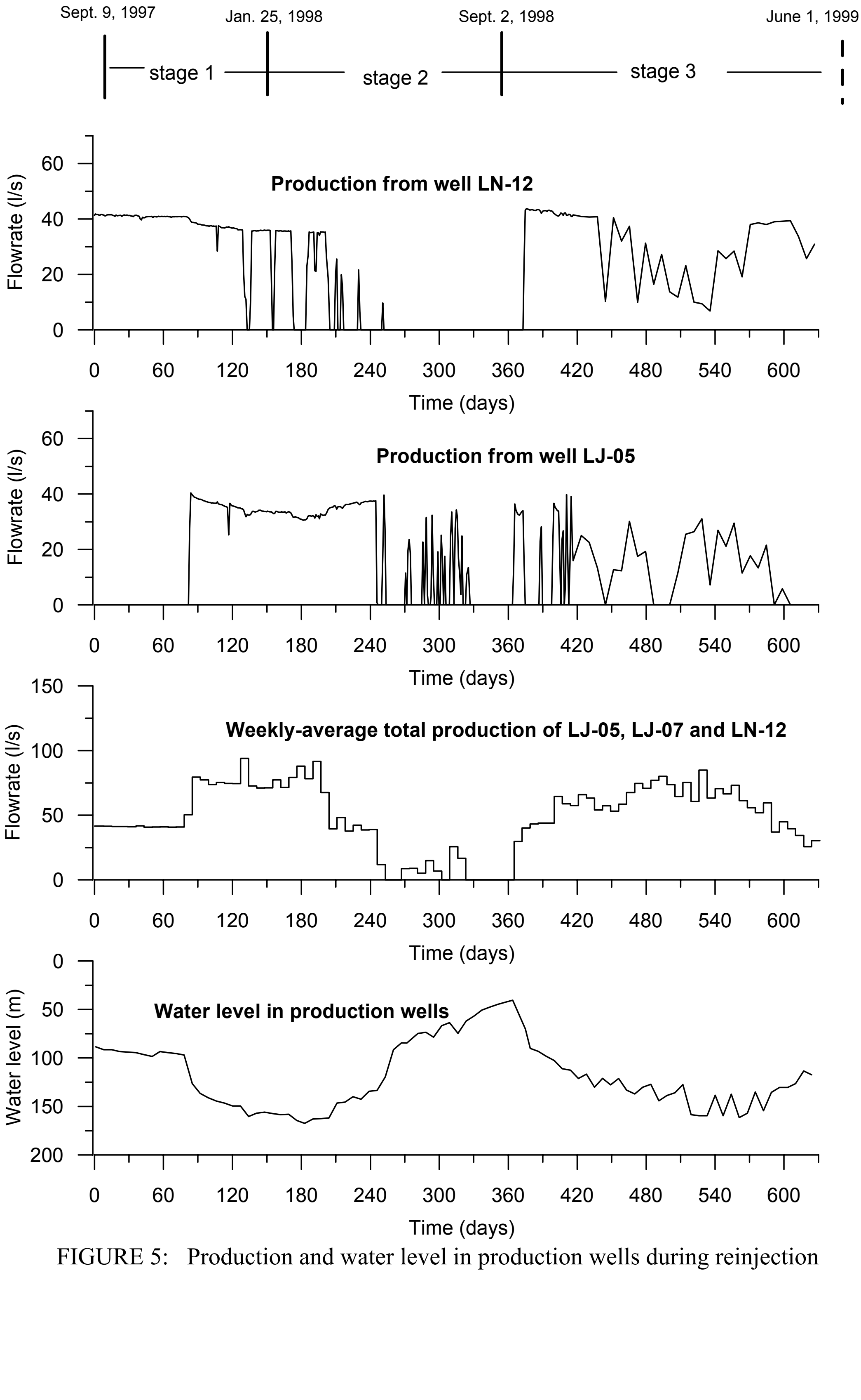

FIGURE 5: Production and water level in production wells during reinjection

4.4 Effects of reinjection

4.4.1 Changes in reservoir pressure

It is interesting to evaluate the effect of reinjection on maintaining reservoir pressure, and consequently the resulting increase of heat mining. It is not likely that all of the injected water will flow directly to the main feedzones of the production wells. A part of the injected water might flow to the northeast along the fracture zone. Some of the injected water may even flow out of the geothermal system and eventually reach the Ytri-Tjarnir geothermal field, north of Laugaland (Figure 1), as discussed later.

It is preferable to compare the water level change before and during reinjection in the same observation well so that the effect of reinjection on maintaining reservoir pressure can be clearly analyzed. Unfortunately, well LJ-08 was the observation well used at Laugaland before reinjection, while it became the main reinjection well during the experiment. Then LG-09 was adopted as a new observation well, and the water level in the well was monitored throughout the experiment. Therefore, the analysis can be based on the water level of LJ-08 before reinjection and the water level of LG-09 during reinjection. The analysis may also be partly based on water level measurements in the production wells (Figure 5). A detailed analysis, which might involve pressure response modeling, is beyond the scope of this study. Instead, a much simpler approach is adopted here.

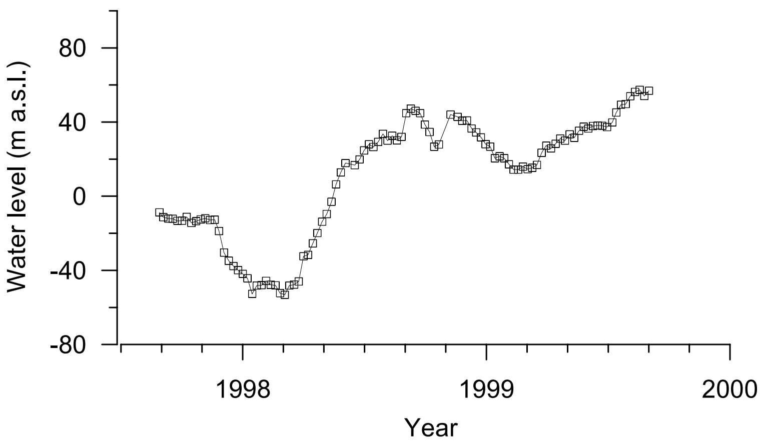

FIGURE 6: Water level fluctuation in well LG-09 during reinjection

It is clear that reinjection has a significant effect on maintaining reservoir pressure, as seen by the water level monitoring in well LG-09 (Figure 6 and Table 4). The water level rose more than 70 m in the well during the experiment from September 9, 1997 to the end of August in 1999. Water level in the production wells also rose somewhat during reinjection (Figure 5), perhaps by about 20 m.

TABLE 4: Annual production and water level fluctuation at Laugaland geothermal field

Year	Production (Mm^3)	Water level (m)		Year	Production (Mm^3)	Injection (Mm^3)	Water level in Dec. (m)	
		m a.s.l.	Yearly rise				m a.s.l.	Yearly rise
1976	-	106.0	-116.4	1988	1.434	-	-75.6	-15.2
1977	-	120.1	14.1	1989	1.381	-	-90.7	-15.1
1978	-	-5.0	-125.1	1990	1.488	-	-89.1	1.6
1979	-	-95.0	-90.0	1991	1.388	-	-100.6	-11.5
1980	-	-137.0	-42.0	1992	1.328	-	-113.6	-13
1981	2.589	-175.6	-38.6	1993	1.334	-	-120.2	-6.6
1982	2.075	-156.6	19.0	1994	1.302	-	-112.6	7.6
1983	1.589	-151.2	5.4	1995	1.205	-	-117.6	-5
1984	1.211	-120.6	30.6	1996	1.142	-	-125.4	-7.8
1985	1.252	-99.6	21.0	1997	1.255	0.079	(-39.9)	-
1986	0.974	-74.6	25.0	1998	1.366	0.439	(31.8)	-71.7
1987	1.094	-60.4	14.2	1999	0.788	0.350	-	-

NB: Water level is monitored in well LJ-08, except values inside ( ) which are measured in well LG-09; Production and reinjection values for 1999 are for the period Jan. 1 - Aug. 31.

Well LG-09 is at a distance of 425 m from LJ-08, and 304 m from LN-10 (Figure 2). It is on the opposite side of the main fracture zone from the two injection wells. Besides, none of the three wells is directly connected to the main fracture zone. The increased reservoir pressure at the injection well can only diffuse to LG-09 after passing through the fracture zone. The water level in LJ-08 was also about 100 m lower than that in well LG-09 at the end of August 1997. According to this, the water level in LG-09 would have been expected to yield a conservative estimate of water level recovery. The much smaller water level rise in the production wells contradicts this, however. This may result from the fact that reinjection has a greater, and more direct, effect on the pressure in the upper part of the Laugaland reservoir (<1000 m depth), while the production wells are mainly connected to the deeper part of the reservoir (>1000 m depth).

The average production at Laugaland in the 9 years from 1985 to 1993 was 1.30 Mm^3. The water level change history of well LJ-08 (Figure 3 and Table 4) shows that the water level was at 120.6 m below see level at the end of 1984, and at 120.2 m at the end of 1993. The difference between the water level depth at these two time points is insignificant. Therefore, the average annual production in this period can be taken as a rough estimate of the allowable exploitation of the Laugaland geothermal field. That means the water level will rise if annual production is less than 1.30 Mm^3, and the water level will drop if annual production is more than 1.30 Mm^3.

In 1998, production was 1.366 Mm^3, more than the annual allowable exploitation. Therefore, the water level in the geothermal field should have declined. In fact, the water level rose 71.7 m in well LG-09 instead of declining, because of the 0.439 Mm^3 of reinjection. Therefore, it may be concluded that injection functioned in supporting the reservoir pressure.

The reinjection in the Laugaland geothermal field is a good example of the sustainable use of geothermal resources, in particular for low-temperature fields. Due to reinjection, production from Laugaland geothermal field can be increased significantly. The amount of future production can be decided according to the annual allowable exploitation as well as the rate of reinjection.

4.4.2 Water temperature change during reinjection

A very important issue for a geothermal reinjection project is the possible cooling of the geothermal fluid produced. Therefore, the temperature of the produced water at Laugaland was observed continuously by means of an electronic sensor and a computerized data collection system. Data collected during the first two months of the experiment cannot be used, because of errors, however manual control measurements were also made intermittently by an electronic thermometer, which was recalibrated regularly, to check the computerised observation. It was found that the difference between the two kinds of measurements was on the order of 0.5˚C.

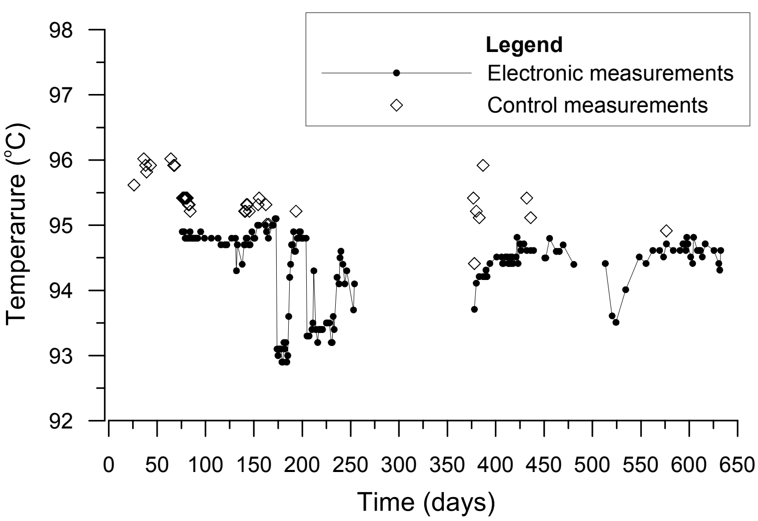

FIGURE 7: Temperature of the water produced from well LN-12 during reinjection

Figure 7 shows the temperature variation of the water produced from well LN-12 during the injection experiment. Note that there is a gap in the observations in the summer of 1998. Short-term fluctuations of the temperature are mostly due to the starting and stopping of the pump in the well. The records of lower temperature amid the records of higher temperature were observed when the pump had been restarted after being off-line for some time. Even production in the adjacent wells influenced the temperature of the produced water. Therefore, only the long-term trend of the temperature variation is useful in evaluating cooling due to reinjection.

It appears that the temperature decline due to injection has been about 0.3-0.5˚C so far. It has to be mentioned here that this estimated temperature drop is only a rough estimate because of the inaccuracy of the computerized observations and the insufficiency of the manual measurements.

4.4.3 Enhancement of heat-mining

For the Laugaland geothermal field, the base temperature used in calculating heat mining is 27˚C according to the operating conditions of the district heating system of Akureyri. And the specific heat of the production water can be taken as 4200 J/kg/˚C.

The total amount of reinjection in the 631 days from Sept. 9, 1997 to Jun. 1, 1999 was 0.749 Mm^3. If one assumes that 90% of the injected water can be re-extracted and taking into account that limited cooling has taken place, the injection will correspond to a 29.74 GWh increased heat extraction. The energy extraction from the field during the past 10 years was around 100 GWh annually. Thus, injection up to June 1, 1999 corresponds to about 30% of the annual heat-extraction.

In 1999, the injection flow rate often reached 21 l/s. If this reinjection rate will be maintained in the future, and 90% of the injected water can be re-extracted, field production can reach 1.9 Mm^3, which corresponds to a 145 GWh annual heat production capacity.

5. TRACER TESTS

5.1 General

A tracer test was carried out at Laugaland along with the short-term reinjection experiment in 1991. Two kinds of tracers were injected into injection well LJ-08 while well LJ-05 was in production. Firstly, 1 kg of sodium-fluorescein was injected instantaneously at the beginning of the experiment. Secondly, sodium-bromide was released continuously.

The return of fluorescein during the test was very slow, only 1.7 g of the injected sodium-fluorescein was recovered in 40 days. The tracer breakthrough time was about 10 days. This was believed to indicate that the injected water diffused into a very large volume and that wells LJ-05 and LJ-08 are not directly connected to each other (Axelsson et al., 1995). The tracer return data were analyzed by using a simple lumped parameter model. It was predicted that the influence on the temperature of water produced from the geothermal field would be acceptably small. In the case where 10 l/s of 15˚C water are injected into well LJ-08, and 48 l/s produced from well LJ-05, the temperature of the produced water would decline only 5˚C in 20 years (Axelsson et al., 1995).

During the 1997-1999 reinjection experiment, tracer tests were again carried out at Laugaland so as to have a sound basis for planned reinjection into the field. The data collected during the tests prior to June 1, 1999 are presented and analyzed below.

5.2 Tracer types and detection methods

Tracers should have similar flow and thermal properties as geothermal fluids but must differ in properties such as color, radioactivity or chemical concentration, to allow detection. There are three main classes of tracers: dyes, radioactive tracers and chemical tracers. The tracers used in the 1997-1999 tracer tests at Laugaland were sodium fluorescein and potassium iodide (Axelsson et al., 1998).

Fluorescent dyes have been widely used in groundwater tracing (Adams and Davis, 1991) since the late nineteenth century. They were introduced into geothermal tracing about two decades ago and have been used in most of the important geothermal countries (Adams and Davis, 1991). Fluorescein is used as a groundwater and geothermal tracer because of its low detection limits, ease of analysis, and strong color at low concentrations. These properties enable fluorescein to be readily detected during field tests. Although fluorescein is resistant to biodegradation and is unaffected by variations in water chemistry, it is subject to significant thermal degradation at elevated temperatures. Results of experiments indicate that fluorescein will decay less than 10% after transporting one month in geothermal reservoirs with temperature below 210˚C (Adams and Davis, 1991). Therefore, it is a desirable conservative tracer for low-temperature geothermal tracing.

The sampling of fluorescein is rather simple; care needs only to be taken in avoiding light-exposure since fluorescein is light sensitive. The analysis of fluorescein is by means of spectrophotometry. In this project, a PERKIN-ELMER fluorescence spectrophotometer was used for fluorescein detection. Its lower detection limit is about 0.005 ppb. Bromides and iodides are the most commonly used chemical tracers in geothermal studies, because they are very stable during transport with geothermal fluids. When using bromides and iodides as tracers, the background concentration has to be known beforehand in order to determine the amount of tracer to be injected. The background iodine content of the geothermal water at Laugaland is about 1 ppb.

A chromatographic method was used to analyze the iodide tracer in this study. The instrument used is a DX500 ion chromatography system developed by DIONEX. The lower detection limit of the instrument for iodide is about 1 ppb.

5.3 The tracer tests

5.3.1 The first test

The first tracer test started on September 25, 1997, 16 days after the injection project started. During the test, the injection well was LJ-08 and the only production well was LN-12. The injection rate was about 8 l/s, and the production rate was about 41 l/s. A quantity of 10 kg of fluorescein was injected instantaneously into well LJ-08. After about 80 days another well, LJ-05, had to be put into production to meet the increased winter demand. This made the hydraulic condition in the field complicated. After the injection of the tracer, water samples were collected and analyzed regularly, not only from well LN-12, but also from other wells within the geothermal field and wells in the neighboring geothermal fields.

The tracer breakthrough time was about 1 day. The peak concentration of fluorescein in well LN-12 was 6.05 ppm, and the peak time was around 5 days. The concentration fell to 1.5 ppm in about 25 days, then another pulse appeared, even though it was wider and lower than the first one (Figure 8). The tracer recovery by

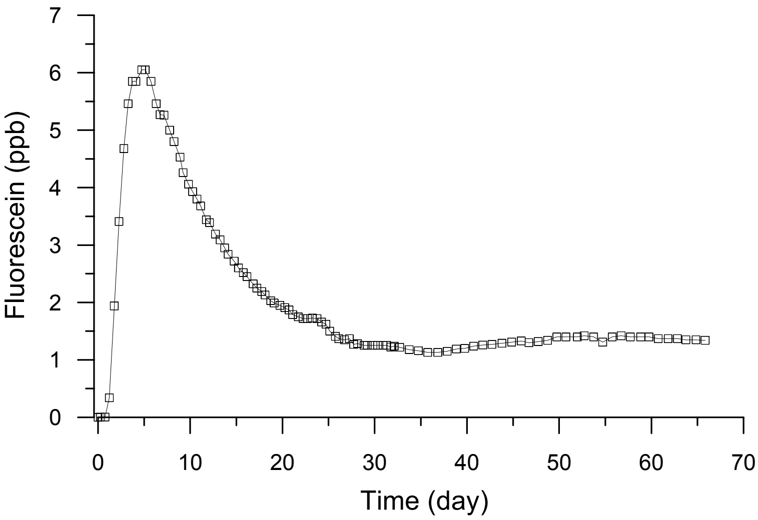

FIGURE 8: Fluorescein recovery from well LN-12 during the first tracer test

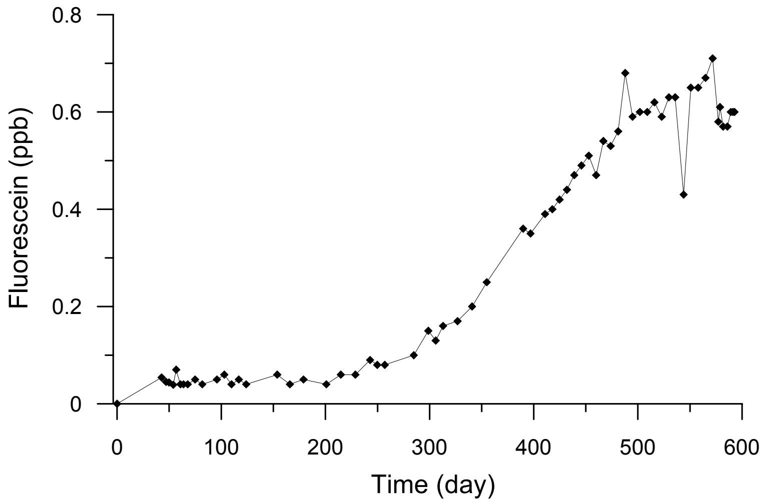

FIGURE 9: Fluorescein recovery from well TN-04 in the Ytri-Tjarnir geothermal field during reinjection at Laugaland

December 1,1997 was only 4.7% of the injected tracer mass. Recovery reached 13.7% by April 20, 1999.

When well LJ-05 started production, fluorescein was also monitored in that well. The fluorescein concentration in LJ-05 was at a constant level of about 3.3 ppm for most of the time during stage one of the project.

Fluorescein was also recovered in well TN-4 in the Ytri-Tjarnir geothermal field, about 1800 m north of well LJ-08. Figure 9 shows the fluorescein recovery in TN-4 from September 25, 1997 to May 11, 1999. The first water sample for fluorescein detection from the well was 43 days after the test started, and the concentration was about 0.05 ppb. After that the concentration was nearly constant at that level, but started to rise about 300 days after the test started.

5.3.2 The second test

The second tracer test started on February 19, 1998 when 43.5 kg of potassium iodide were injected into well LN-10 instantaneously. During the test, both LN-12 and LJ-05 were in production, LN-12 intermittently though. Figure 10 shows the tracer recovery in well LJ-05 during the following 80 days. At that time, production was stopped and monitoring was discontinued.

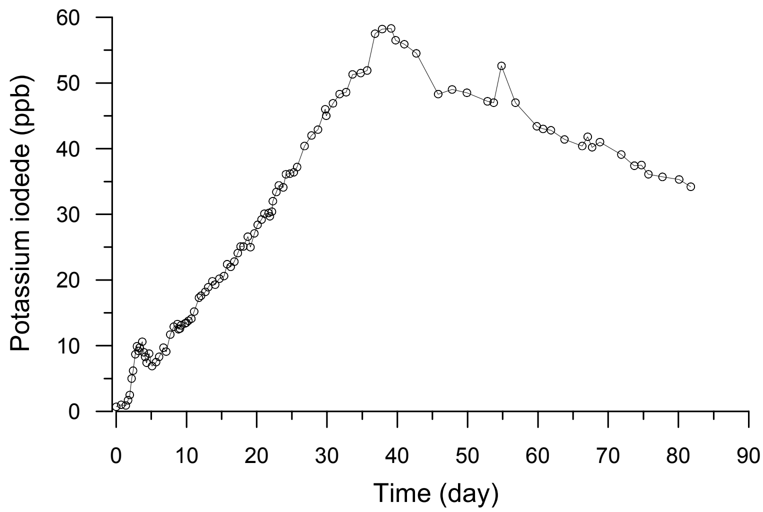

FIGURE 10: Iodide recovery from well LJ-05 during the second tracer test

The tracer breakthrough time in well LJ-05 was about 41 hours, when the iodide concentration rose to 1.7 ppb from the base concentration, which was about 1 ppb. The peak concentration was 58 ppb, about 36 days after the test started. The tracer was not recovered from wells LN-12 and LJ-07 during the 80 days of test. This may be because the concentration was too low to be detected. Another reason may be that the casings of wells LJ-05 and LN-10 are very shallow, while in wells LJ-07 and LN-12 the shallow aquifers are cased off. The injected water from well LN-10 may flow to well LJ-05 mostly through shallow aquifers. During the test, hydraulic conditions were not constant because of non-stable production, which made the tracer recovery data difficult to interpret.

5.3.3 The third test

The third tracer test at the Laugaland geothermal field began on April 23, 1999 when additional 10 kg of fluorescein were injected instantaneously into well LJ-08, while well LN-12 was in production. Tracer recovery data are available until July 22, 1999. Yet well LN-12 was only in constant production until May 11, 1999. The injection and production were rather constant, 21 and 40 l/s, respectively, until June 1, 1999.

The tracer breakthrough time in this test was as short as 10 hours, much shorter than in the first test, although the same injection and production wells were used. This is because of the increased injection rate during the third test, which increased the fluid velocity from the first test. The peak concentration of fluorescein from well LN-12 was 8.64 ppm during the third test, a little higher than the first test. And the peak time was about 2 days, which is also faster than during the first test. Figure 11 shows the tracer recovery from well LN-12 from April 23 to July 22, 1999. The mass recovery to July 22, 1999 is 7.5% of the injected fluorescein.

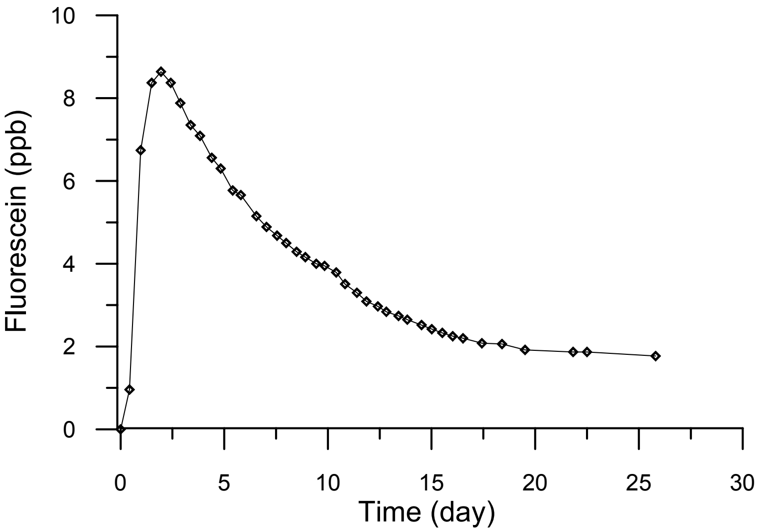

FIGURE 11: Fluorescein recovery from well LN-12 during the third tracer test

5.4 Solute transport in fractured media

Solute transport in fractured media and analysis of tracer test data has been dealt with in numerous studies (Grisak and Pickens, 1980; Jensen and Horne, 1983; Pruess and Bodvarsson, 1984; Fossum and Horne, 1982; Horne and Rodriguez, 1983). Arason and Björnsson (1994) developed a computer code, TRINV, for modeling tracer recovery profiles and has been successfully used in several different geothermal fields in Iceland (Axelsson et al., 1995). This model will be used in the simulation of the tracer recovery profile in the Laugaland geothermal field and is introduced below.

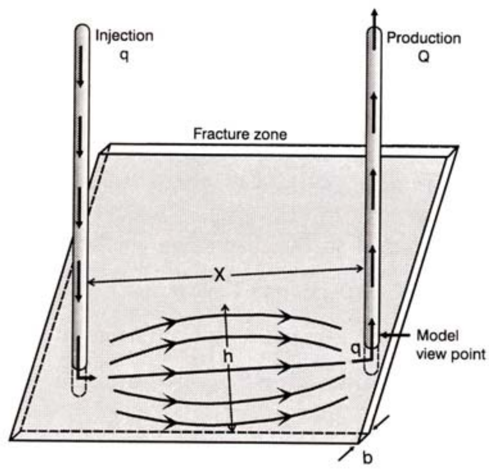

FIGURE 12: A one-dimensional flow channel model connecting injection and production wells

The one-dimensional model, which is the basis for TRINV, is shown schematically in Figure 12. A constant mass flow q_{in} is injected into a well and a constant mass flow Q is produced from an adjacent well. A basic assumption in the formulation is that the flow is along a flow-channel, which may be a part of a fracture zone. Furthermore, a near one-dimensional flow is assumed in the channel, which has a cross-sectional area A and porosity ϕ. If a fraction q of the injected water q_{in} flows through the channel and molecular diffusion is neglected, the differential equation describing solute concentration in the channel is then as follows (Axelsson et al., 1995):

$$D\frac{\partial^2 C}{\partial x^2} = u\frac{\partial C}{\partial x} + \frac{\partial C}{\partial t} \tag{1}$$

where the flow velocity u, and dispersion coefficient of the channel D, are defined as

$$u = \frac{q}{\rho A \phi} \qquad and \qquad D = \alpha_L u$$

If a certain amount of tracer M is injected instantaneously into the injection well, and a part of the tracer M_r transported along the flow channel to the production well, the solution to Equation 1 is given as

$$C(t,x) = \frac{M_r}{2\phi A\sqrt{\pi D t}} \exp\left(\frac{-(x-ut)^2}{4Dt}\right) \tag{2}$$

Considering mass conservation in the production well, with production rate Q, yields

$$C(t)q = c(t)Q \tag{3}$$

The tracer concentration of the produced fluid will then be:

$$c(t) = \frac{\rho M_r u}{2Q\sqrt{\pi D t}} \exp\left(\frac{-(x-ut)^2}{4Dt}\right) \tag{4}$$

If there are n flow channels connecting the two wells, the solute concentration in the production well will be given by

$$c(t) = \sum_{i=1}^{n} c_i(t) \tag{5}$$

where

$$c_i(t) = \frac{\rho M_i u_i}{2Q\sqrt{\pi D_i t}} \exp\left(\frac{-(x_i-u_i t)^2}{4D_i t}\right) \tag{6}$$

and

$$u_i = \frac{q_i}{\rho A_i \phi_i} \quad ; \qquad D_i = \alpha_{Li} u_i \qquad and \qquad q_i = \frac{M_i}{M} q_{in} \tag{7}$$

The computer code TRINV solves Equations 5, 6 and 7 inversely by a non-linear least squares method. Therefore, it allows the simulation of multiple flow-channels connecting the injection and production wells. Because of the inverse method, the solution is not unique for multi-flow channel solutions. Therefore, to use this code, it may be necessary to obtain a number of different solutions, and select the most suitable one. It is only possible to get a proper solution if one has a good understanding of the geothermal field. Additional information from other studies may be of help in the selection.

5.5 Simulation of tracer recovery at Laugaland

The hydraulic condition of the geothermal reservoir was rather complicated during the second tracer test, which made the tracer recovery data difficult to interpret, as mentioned before. Therefore, only the interpretation of the first and the third test is presented below.

5.5.1 Feedzones

Five feedzones in well LJ-08 accept almost all of the injected fluid, according to interpretation of temperature profiles measured during reinjection. The top feedzone at a depth of 325 m is the most important, accounting for 40-60% of the total injectivity of the well (Hjartarson, 1999). The feedzones at 600 and 1350 m depth are also rather important. There are also five feedzones in well LN-12 and the two deep ones are the major feedzones of the well. The locationof the feedzones of the two wells is listed in Table 5.

TABLE 5: Feedzones of wells LJ-08 and LN-12

Feedzone No.	Well LJ-08 (m)	Well LN-12 (m)
1	320*	310
2	600	670
3	1335	950
4	1875	1140*
5	2400	1570*

* Major feedzones

5.5.2 Flow channels

It can be seen from the shape of the first tracer recovery curve that it is composed of at least two pulses. The pulse in the tail part of the curve could be very important because it may constitute a large part of the recovered tracer. This means that there are at least two flow channels connecting well, LJ-08 and LN-12.

Considering that the purpose of a tracer test is to predict the thermal effect of reinjection, it is preferable to assume shorter flow channels so as to make pessimistic, rather than too optimistic thermal breakthrough predictions. This is because the longer the channels are, the longer time it takes the injected water to travel to the production well and more likely that the water is completely heated up before reaching the well.

The following three channels are chosen in the simulation of the tracer recovery data. The first one connects the top feedzones of wells LJ-08 and LN-12, the second connects the top feedzone of well LJ-08 and the second feedzone of well LN-12, while the third represents a connection between the top feedzone of LJ-08 and the two major feedzones of LN-12. Information on the three channels is listed in Table 6.

TABLE 6: Assumed flow channels in the simulation of tracer recovery data.

Channel No.	Feedzone depth in LJ-08 (m)	Feedzone depth in LN-12 (m)	Length (m)
1	320	310	312
2	320	670	405
3	320	1140-1570	1100

5.5.3 Interpretation results

Several different combinations of flow channels were tested in the interpretation of the first tracer test data by TRINV, including one, two and three flow channels. The fit of the models with one and two flow channel was not good enough, while the models with three flow channel yielded coefficients of determination (R^2) greater than 99%. The various tested three-channel models differ in peak

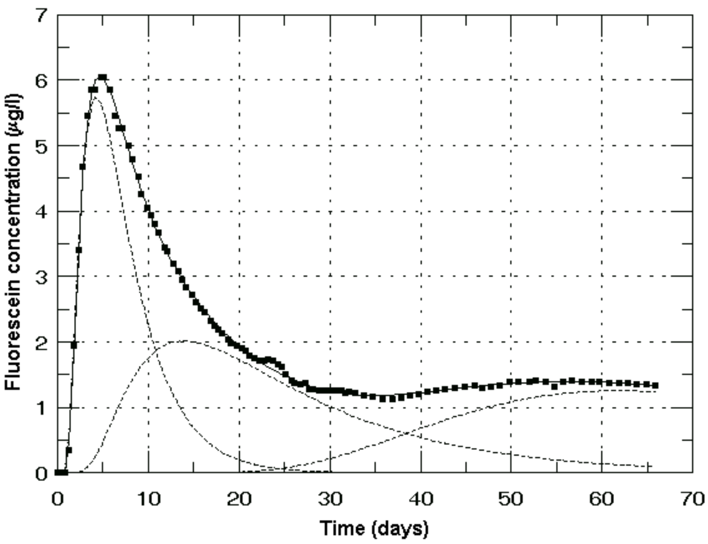

FIGURE 13: Simulation of the first tracer test

concentrations as well as dispersivity. Of the different simulation results only the one believed to be the most realistic is presented here (Figure 13). The parameters for that model are listed in Table 7. The pulses represent, with time, the first flow channel in Table 7, the second flow channel, and the third flow channel, respectively.

Based on the experiences from the first tracer test simulation, the three channels of the first test were again used in the simulation of the third test. Figure 14 shows the fit of the simulation, with the model parameters also being listed in Table 7.

TABLE 7: Parameters of the best fitting model for the tracer recovery data of the two modelled tracer tests

Channel	Parameters	Test 1	Test 3
No. 1	Flow path distance x (m)	312	312
	Mean velocity u (m/day)	60.4	162.4
	Cross-sectional area x porosity $A\phi$ (m^2)	0.186	0.102
	Longitudinal dispersivity α_L (m)	62.73	81.09
	Percentage of tracer recovery M_i/M (%)	1.591	0.896
No. 2	Flow path distance x (m)	405	405
	Mean velocity u (m/day)	23.4	48.8
	Cross sectional area x porosity $A\phi$ (m^2)	0.588	0.904
	Longitudinal dispersivity α_L (m)	89.32	131.44
	Percentage of tracer recovery M_i/M (%)	1.951	2.381
No. 3	Flow path distance x (m)	1100	1100
	Mean velocity u (m/day)	16.4	37.9
	Cross-sectional area x porosity $A\phi$ (m^2)	1.257	0.362
	Longitudinal dispersivity α_L (m)	87.49	45.97
	Percentage of tracer recovery M_i/M (%)	2.925	0.740

5.5.4 Discussion

If reservoir conditions were fully comparable, and the model entirely realistic, one would expect the parameters of the models to be the same for both tests. This is not the case, maybe because the fractures or flow-channels respond differently to different injection wellhead-pressure and reservoir-pressure conditions. Simulations of temperature profiles from well LJ-08 during reinjection support this reasoning, since the injectivity of the feedzones of the well appear to change with increasing wellhead pressure (Hjartarson, 1999).

According to the results of the simulation of tracer recovery, the volume of the fractures and flow channels connecting wells LJ-08 and LN-12 is less than 20,000 m^3, a very small fraction of the Laugaland reservoir volume.

The calculated mass recovery through the three flow channels is also very small. Only 6.5% of the injected mass will be recovered till infinite time according to the simulation of the first test, and 4.0% according to the third test. The calculated tracer recovery is lower than that observed in well LN-12. This may be because some of the injected water diffused and dispersed into the rock matrix, as well as fissures not directly connecting the injection and production wells, eventually flowing to the production wells. Therefore, a more complex model incorporating fracture flow and rock matrix diffusion should be considered for the Laugaland geothermal field, or a model with double porosity characteristics, i.e. small volume flow channels in a large volume of porous media.

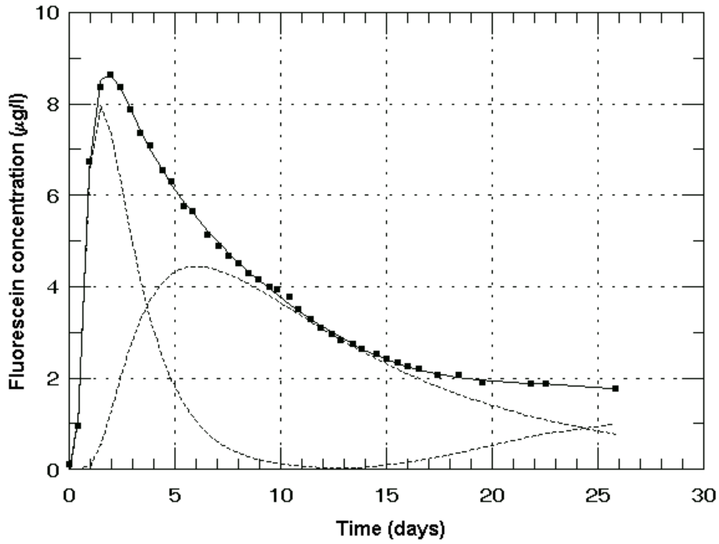

FIGURE 14: Simulation of the third tracer test

5.6 Simulation of tracer recovery in the Ytri-Tjarnir geothermal field

There has long been a dispute about the connection between the geothermal fields at Laugaland and Ytri-Tjarnir (Figure 1) and whether the production in one field influences the other field. Therefore, it is interesting to simulate the fluorescein recovery profile and see how much of the injected tracer at Laugaland flowed north to Ytri-Tjarnir.

Unfortunately, fluorescein was not sampled from well TN-04 at the beginning of the first test. The first sample was collected 43 days after the test started. It is very unlikely that this time is enough for the injected water to travel the 1800 m distance between the two fields, especially considering that the hydraulic gradient between the two wells is rather small because of the long distance. It is considered possible that the base concentration of fluorescein detected in well TN-04 was from the tracer test in 1991. Therefore, the 0.05 ppb base concentration was subtracted in the simulation of the fluorescein recovery profile.

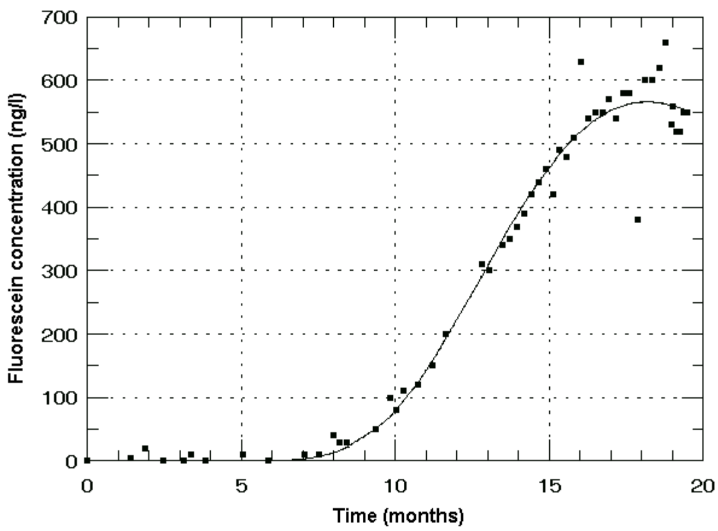

FIGURE 15: Simulated fluorescein recovery in well TN-04 at Ytri-Tjarnir

During the test, the production from well TN-04 was on the average 31 l/s and the injection into well LJ-08 10.5 l/s on the average. Figure 15 shows the simulated fluorescein recovery in well TN-04. The simulated fluid velocity between the two wells was about 3 m/day. The tracer recovery in well TN-04 will be about 7% of the amount injected into well LJ-08 till infinite time. This means that according to the model about 7% of the water injected at Laugaland will flow to Ytri-Tjarnir. Therefore, the connection between the two fields is rather good; production or reinjection at one field will influence the other field. It can be concluded that over 90% of the reinjected water recharged the geothermal reservoir at Laugaland.

5.7 Prediction of the cooling effect of reinjection

5.7.1 Model description

When colder water is reinjected into a geothermal reservoir, the reservoir rock matrix acts as a heat exchanger, which heats the water up gradually with movement in the reservoir. The heat exchange capacity depends on the surface contact area between rock and water, the rock heat capacity, fluid heat capacity, and the thermal conductivity of the rock.

The same model as used for the tracer test interpretations is used to predict the effect of cooling due to reinjection in the Laugaland geothermal field, with a fracture zone with width b, height h, length x and porosity ϕ. Colder water with temperature T_{in} is injected into the fracture at the time $t=0$, the flow rate along the fracture is q, and the initial temperature of the reservoir is T_0. The water temperature at the outlet of the fracture is denoted as T_{out}.

If only the heat conduction in the horizontal direction y is considered, then the heat conduction from the rock matrix to the fracture zone can be described by the following differential equation:

$$\frac{\partial^2 T}{\partial y^2} = \frac{1}{\alpha}\frac{\partial T}{\partial t} \tag{8}$$

where

$$\alpha = \frac{\rho_r c_r}{k_r}$$

The heat convection along the flow channel can be described by

$$\rho_w c_w b \frac{\partial T}{\partial t} + c_w \frac{q}{h}\frac{\partial T}{\partial x} = 2k_r \frac{\partial T}{\partial y}\Big|_{y=\frac{b}{2}} \tag{9}$$

When $b << h$, the initial condition and boundary conditions are

$$T(x,y)|_{t=0} = T_o \ ; \qquad T(x,y)|_{x,y=\infty} = T_o \ ; \qquad T(x,y)|_{x=0} = T_{in} \tag{10}$$

Carslaw and Jaeger (1959) gave the solution to the above problem

$$\begin{aligned} T_{out}(x,t) &= T_{in} + (T_o - T_{in})\,erf\left[\frac{x k_r h}{c_w q\sqrt{\alpha(t - x/\beta)}}\right] \qquad for \qquad t>x/\beta \\ T_{out}(x,t) &= T_{in} \qquad for \qquad t \le x/\beta \end{aligned} \tag{11}$$

where

$$\beta = \frac{q}{\beta_w h b}$$

The temperature of the produced water can be given by

$$T_Q(t) = T_o - \frac{q}{Q}(T_o - T_{out}) \tag{12}$$

Equation 12 can be used to calculate the temperature of the produced water in the case where only one fracture zone connects the injection and production wells. A computer program (TRCOOL) has been developed using this method by Axelsson et al. (1994), which has been used for several geothermal fields in Iceland.

In the case where there are i fractures connecting the two wells, the cooling would be the collective cooling of all the fractures. Considering heat conservation and assuming that the density and specific heat of the water from the different fractures or flow channels is approximately the same, then the water temperature T_p in the production well can be calculated as below:

$$T_p = T_o - \frac{q_{in}}{Q}\sum_{i=1}^{n}\left(\frac{M_i}{M}(T_o - (T_{out})_i)\right) \tag{13}$$

Here the mass recovery of tracer from fracture i, M_i and total mass injected M are used, because the percentage of mass recovery is the same as the percentage of flow in each fracture.

If the cooling caused by reinjection is not significant, or the cooling by each fracture is comparable, then the temperature of the produced water can be calculated by

$$T_Q(t) = \frac{1}{n}\sum_{i=1}^{n}\left(T_Q(t)\right)_i \tag{14}$$

Equations 13 or 14 can be used in conjunction with TRCOOL to calculate the water temperature from the production well under long-term reinjection in a fractured reservoir.

5.7.2 Prediction of production well temperature change

Simulations of tracer recovery profiles have resulted in an estimate of the product of a fracture cross-sectional area and porosity as well as the percentage of tracer recovery from each flow channel. These parameters for the first and the third tracer test (Table 7) were used to predict the long-term cooling effect of reinjection in the Laugaland geothermal field. It is assumed that well LJ-08 is the reinjection well with an injection rate of 20 l/s, and that well LN-12 is the production well with a production rate of 40 l/s. The porosity of the fracture zone is taken as 10%, the width of the fractures is assumed to be 1 m, and the height of the fracture can be determined accordingly.

Furthermore, the thermal conductivity of the reservoir is assumed to be 2 W/m/°C, the heat capacity 1000

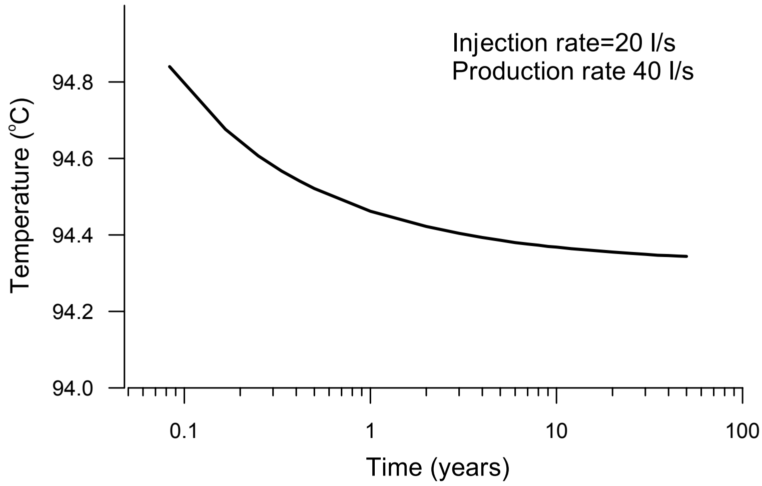

FIGURE 16: The predicted cooling due to reinjection

J/kg/°C, the density of the reservoir is taken as 2700 kg/m^3, and the heat capacity of the injected water 4200 J/kg/°C. The results show that the predicted cooling using the fracture parameters for the first tracer test is a little more pessimistic than that for the third tracer test, but the difference is not significant. The prediction result is presented in Figure 16. It shows that cooling started soon after injection started, then slowed down after injection for one year. According to these calculations, the cooling will only be 0.5°C in 13 years and about 0.6°C in 50 years. However, it has to be kept in mind that the water that diffuses into the rock matrix and disperses throughout the reservoir volume will certainly have some additional cooling effect on the geothermal field, especially as it accounts for a large part of the injected water.

6. CONCLUSIONS

During the reinjection experiment in the Laugaland geothermal field from September 9, 1997 to June 1, 1999, a total of 749,000 m^3 of return water from the Akureyri district heating system was reinjected into the reservoir, accounting for 29% of the production during that time period. Because of the reinjection, water level in observation well LG-09 rose over 70 m in about 2 years and the water level in the production wells also rose significantly. This indicates that reinjection has a significant effect in maintaining the reservoir pressure.

In 1999, the injection flow rate at Laugaland often reached 21 l/s. If this reinjection rate is continued in the future, and 90% of the injected water can be re-extracted, the production of the field can reach 1.9 Mm^3, which corresponds to 145 GWh of heat capacity. Significant cooling of the produced water was not observed during reinjection. Therefore reinjection will greatly increase productivity and improve the heat mining in the Laugaland geothermal field.

The result of the tracer tests shows that there are direct paths between reinjection well LJ-08 and production well LN-12, but most of the injected water appears to diffuse into the rock matrix and disperse throughout the reservoir volume. The fluid velocity along the flow channels ranges from 16 to 160 m/day. The volume of the flow channels between wells LJ-08 and LN-12 is less than 20,000 m^3, accounting for a tiny part of the reservoir volume.

The predicted cooling due to the direct paths is acceptable. In the case where 20 l/s of water are injected into well LJ-08 and 40 l/s of water produced from well LN-12, the cooling is estimated to reach only 0.5°C in 13 years.

The fluorescein recovery from well TN-04 in the Ytri-Tjarnir geothermal field shows that the two geothermal fields have a direct hydraulic connection. It is estimated that about 7% of the injected water at the Laugaland field will eventually flow to Ytri-Tjarnir.

The reinjection experiment at Laugaland provides a good model for other geothermal fields in the world, especially for low-temperature fields. The experience gained could be used in geothermal fields in China, such as in Beijing, Tianjin, etc., where reinjection is being considered as a future mode of reservoir management.

ACKNOWLEDGEMENTS

I would like to express my thanks to my supervisors Mr. Gudni Axelsson and Mr. Steinar Thór Gudlaugsson, for their help and direction during training, which made this report possible. Thanks are also given to the other members of the reservoir engineering group of Orkustofnun. Special thanks are addressed to Mr. Ingvar Birgir Fridleifsson, Mr. Lúdvík S. Georgsson and Mrs. Gudrún Bjarnadóttir for their sincere help, which made the training programme enjoyable.

NOMENCLATURE

C = Concentration of solute in flow channel [kg/m^3];
D = Dispersion coefficient of flow channel [m^2/s];
x = Distance from injection well [m];
t = Time [s];
u = Mean fluid velocity inside flow channel [m/s];
q = Flow rate of water through flow channel [kg/s];
ρ = Density of the fluid in flow channel [kg/m^3];
A = Cross-sectional area of flow channel [m^3];
ϕ = Porosity of flow channel;
α_L = Longitudinal dispersivity of flow channel [m];
M_r = Mass travelling through flow channel [kg];
c = Solute concentration of produced water [kg/m^3];
Q = Flow rate of production well [kg/s];
i = The number of a flow channel;
n = Total number of flow channels;
M_I = Mass travelling through flow channel [kg];
M = Mass of tracer injected [kg];
q_{in} = Reinjection flow rate [kg/s];
T = Temperature [°C];
y = Distance perpendicular to flow channel plane [m];
ρ_r = Density of rock [kg/m^3];
c_r = Specific heat of rock [J/kg°C];
k_r = Thermal conductivity of rock [J/m˚C];
ρ_w = Density of injected water [kg/m^3];
c_w = Heat capacity of injected water [J/kg˚C];
b = Width of flow channel [m];
h = Height of flow channel [m];
T_0 = Initial temperature of reservoir [˚C];
T_{in} = Temperature of injected water [˚C];
T_{out} = Water temperature at outlet of flow channel [˚C];
α = Thermal diffusivity [m^2/s];
T_Q = Temperature of production water [˚C].

REFERENCES

Adams, M.C., and Davis, J., 1991: Kinetics of fluorescein decay and its application as a geothermal tracer. *Geothermics, 20,* 53-66.

Arason, P., and Björnsson, G., 1994: *ICEBOX.* 2nd edition, Orkustofnun, Reykjavík, 38 pp.

Axelsson, G., Björnsson, G., and Arason, P., 1994: *The program TRCOOL*. Orkustofnun, Reykjavík.

Axelsson, G., and Stefánsson, V., 1999: Reinjection and geothermal reservoir management – associated benefits. *Proceedings of the Workshop on Direct Use of Geothermal Energy, Ljubljana, Slovenia*, *Nov. 1999,* 21 pp.

Axelsson, G., Sverrisdóttir, G., Flóvenz, Ó.G., Árnason, F., Árnason, Á., and Bödvarsson, R., 1998: Thermal energy extraction, by reinjection, from a low-temperature geothermal system in N-Iceland. *Draft proceedings of 4th International HDR Forum, Strasbourg*, 5 pp.

Axelsson, G., Björnsson, G., Flóvenz, Ó.G., Kristmannsdóttir, H., and Sverrisdóttir, G. 1995: Injection experiments in low-temperature geothermal areas in Iceland. *Proceedings of the World Geothermal Congress 1995, Florence, Italy, 3,* 1991-1996.

Bi Erping, 1997: Chemical aspects of fluid injection into the geothermal fields in Eyjafjördur, N-Iceland. Report 4 in: *Geothermal Training in Iceland 1997.* UNU G.T.P., Iceland, 81-112.

Carslaw, H.W., and Jaeger, J.C., 1959: *Conduction of heat in solids.* 2nd edition, Claredon Press, Oxford, 510 pp.

Fossum, M.P., and Horne, R.N., 1982: Interpretation of tracer return profiles at Wairakei geothermal field using fracture analysis. *Geoth. Resour. Counc., Transactions, 6,* 261-264.

Grisak, G.E., and Pickens, J.F., 1980: Solute transport through fractured media 1. The effect of matrix diffusion. *Water Resour. Res., 16,* 719-730.

Hjartarson, A., 1999: *Analysis of reservoir data collected during reinjection into the Laugaland geothermal system in Eyjafjördur, N-Iceland*. MSc. thesis, University of Iceland and Orkustofnun, Reykjavík, 107 pp.

Horne, R.N. and Rodriguez, F., 1983: Dispersion in tracer flow in fractured geothermal systems. *Geophy. Res. Lett., 10,* 289-292.

Jensen, C.L., and Horne, R.N., 1983: Matrix diffusion and its effect on the modelling of tracer returns from the fractured geothermal reservoir at Wairakei, New Zealand. *Proceedings of the 9th Workshop on Geothermal Reservoir Engineering. Stanford Univ. Press., Stanford, CA,* 323-329.

Pruess, K., and Bödvarsson, G.S., 1984: Thermal effect of reinjection in geothermal reservoir with major vertical fractures. *J. Pet. Technol., 36,* 1567-1578.

Stefánsson, V., 1997: Geothermal reinjection experience. *Geothermics, 26*, 99-139.

Sverrisdóttir, G., Hauksdóttir, S., Axelsson, G., and Árnason, Á., 1999: Chemical monitoring during reinjection in the Laugaland geothermal system, N-Iceland. *Proceedings of the 5th International Symposium on Geochemistry of the Earth's Surface, Iceland*, 547-550.