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ASSESSMENT OF THE KALDÁRHOLT GEOTHERMAL SYSTEM AND ASSOCIATED REINJECTION INTO THE NEARBY LAUGALAND SYSTEM, S-ICELAND

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ABSTRACT

The Laugaland and Kaldárholt low-temperature geothermal fields in S-Iceland have been utilized for heating the nearby towns of Hella and Hvolsvöllur since 1982 and 2000, respectively. A conceptual model for the Kaldárholt geothermal system, based on analysis of temperature conditions and geological data includes that an up-flow of 67˚C water flows from depth along a NW-SE direction. The results of well tests and interference data analyses indicate that the Kaldárholt reservoir is quite permeable. Calibrated lumped parameter models were used to predict the water level changes for different production scenarios. Based on the predictions, the production potential of the Kaldárholt system is estimated to be about 55 l/s or 95 l/s, for the next 10 years, assuming maximum allowable pressure drawdown of 100 or 240 m, respectively. Water from Kaldárholt has been reinjected at Laugaland at 3-4 l/s since January 2000. According to the cooling predictions based on a tracer test conducted at Laugaland in 1992, the reinjection induced temperature decline of well LWN-4 should be 2-5˚C. This is greater than the actual cooling observed, which is less than 1˚C at the end of 2002. The discrepancy is mainly attributed to a drastic change in flow conditions because of reduced production since 2000. Major earthquakes in June 2000 may also have influenced the reservoir flow-pattern at Laugaland.

1. INTRODUCTION

The Laugaland and Kaldárholt low-temperature geothermal fields are located in central S-Iceland. The Laugaland geothermal field has been utilized for space heating in the towns of Hella and Hvolsvöllur by Hitaveita Rangaeinga, a regional district space heating company, since 1982. Due to the low permeability of the reservoir, the water level drawdown has been great and increasing. Based on the first 10-15 years of its production history, it was estimated that the reservoir cannot sustain long-term production greater than about 17 l/s (Dong, 1993; Kristmannsdóttir et al., 2002). In order to meet the hot water demand for space heating, a new geothermal field, Kaldárholt, was brought on line in January 2000. Since then, the hot water from this second geothermal field was not only used for space heating in the above mentioned two towns, but about 3-4 l/s of the hot water was also reinjected into the Laugaland geothermal field. The

purpose of the reinjection is to counteract the water level drawdown in order to enable sustainable use of the geothermal resources at Laugaland.

Geothermal resource assessment and management plays a key role in sustainable and efficient use of geothermal resources. Successful management of geothermal resources, however, relies on properly understanding the properties and nature of the reservoirs involved, which in turn relies on adequate information on the system being available (Axelsson, 2003b). This paper mainly focuses on assessment of the Kaldárholt geothermal system, and evaluation of the associated reinjection in the Laugaland geothermal field.

Reservoir temperature is one of the most important parameters in quantifying the geothermal resources involved. In this study, temperature logs from 35 wells in the Kaldárholt geothermal field were interpreted in order to analyse the temperature conditions, such as reservoir temperature and the main hot water flow direction. Based on available geological information and this analysis of the reservoir temperature distribution, a conceptual model was constructed. By analysing well test and interference data from the Kaldárholt field, the reservoir parameters, such as permeability and storage coefficient, were estimated. Furthermore, a lumped parameter simulator was used to simulate the pressure response of the Kaldárholt reservoir to production based on nearly 3.5 years of monitoring data. More complex modelling is not justified considering the limited data available. Two models, which give equally good matches between the observed and calculated data, were used to predict the future water level changes under different production scenarios. The production potential of Kaldárholt based on given maximum allowable water level drawdown restrictions was also estimated for the next 10 years.

For sustainable and efficient use of the geothermal resources, cold or hot water injection is increasingly becoming, or is foreseen to become, an essential ingredient for successful management of geothermal resources worldwide. One of the main negative effects associated with injection is cooling, or thermal breakthrough, of the production wells. A tracer test was conducted in the Laugaland field in 1992, and the tracer recovery data was used to assess the hydraulic connections between the production and injection wells. Based on simulation of the tracer recovery data and by adding needed assumptions, the possible temperature decline in the main production well was predicted for different production-injection scenarios. A discrepancy between predicted and actual cooling has been observed. The possible reasons for this difference are discussed in this report. Chemical monitoring data, in particular concentration changes during reinjection, were also analyzed in this study.

2. BACKGROUND AND GENERAL INFORMATION

The Laugaland low-temperature geothermal field has been exploited by Hitaveita Rangaeinga since 1982. Between 1983 and 1988, the average production ranged from 18.5 to 21.8 l/s. From 1989 to 1999, the average production was stable at about 17 l/s. The mean wellhead temperature has been above 98˚C during the past two decades of production (Figure 1). In spite of the nearly constant production, the water level decreased more rapidly than had been expected. This was believed to be because of the low permeability and limited recharge of the reservoir. This problem had been of great concern to the heating company for a long time; and to be able to supply sufficient hot water for space heating, some urgent countermeasures had to be found. Different possible solutions to the energy shortage were brought forward and discussed (Kristmannsdóttir et al., 2002). Eventually, the search for a new geothermal target was chosen as the most economical solution. It started in the neighborhood to the south and east of the Laugaland area. After exploration drilling at different locations and further comparison, the exploration work focused on Kaldárholt and the surrounding area. In the year 2000, this new make-up geothermal field was put on line and has been under exploitation ever since. At present, about 56% of the energy need is met by Kaldárholt (Axelsson and Hardardóttir, 2003).

The Kaldárholt low-temperature geothermal field is located about 8.5 km to the north-northwest of the Laugaland field (Figure 2). The first 10 shallow exploration wells were drilled there before 1991. The temperature gradient in most of these older wells is about 80˚C/km, with one well having a higher temperature gradient of 96˚C/km. Chemical analyses of water samples from hot springs in the area and silica geothermometer calculations indicated that the deep reservoir temperature was about 70˚C. These are the main reasons why priority was given to Kaldárholt as a target area for further exploration drilling work. The search for potential well sites with both high permeability and relatively high temperature for production wells then became the main task for the next drilling investigations, which started in 1998. For this purpose, a total of 26 relatively shallow wells were drilled in the field (Appendix I). During the drilling period, it was found that some of the wells were artesian with initial wellhead pressures of about 0.5 bar. The final well in the area, well KH-36, was drilled as a production well. It has yielded more than 30 l/s of 67˚C hot water during the space heating period peaks. About 3-4 l/s of hot water from well KH-36 has been used for reinjection in the nearby Laugaland geothermal field since 2000, as has been mentioned. Due to good permeability at Kaldárholt, the water level drawdown in the production well is less than 30 m for production of up to 33 l/s. Preliminary estimates based on well test analyses indicate that the geothermal field can supply at least 30 l/s of hot water in the long-term with an acceptable pressure drawdown.

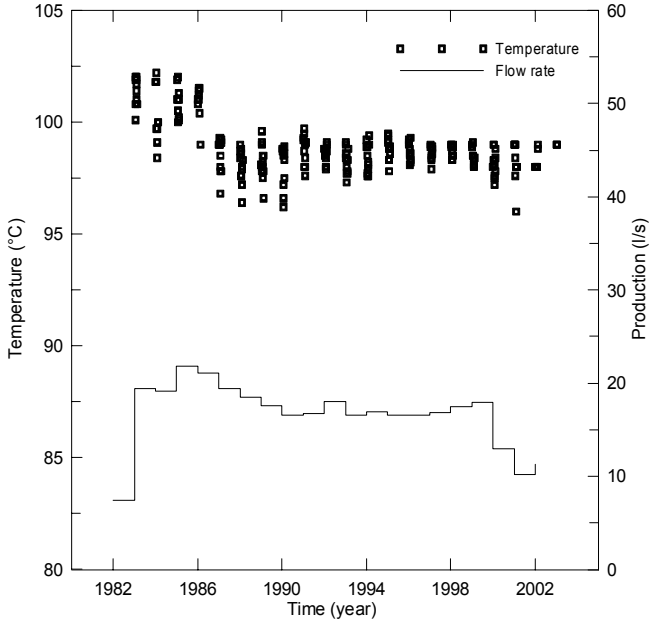

FIGURE 1: Plot of water temperature and production history of the Laugaland geothermal field

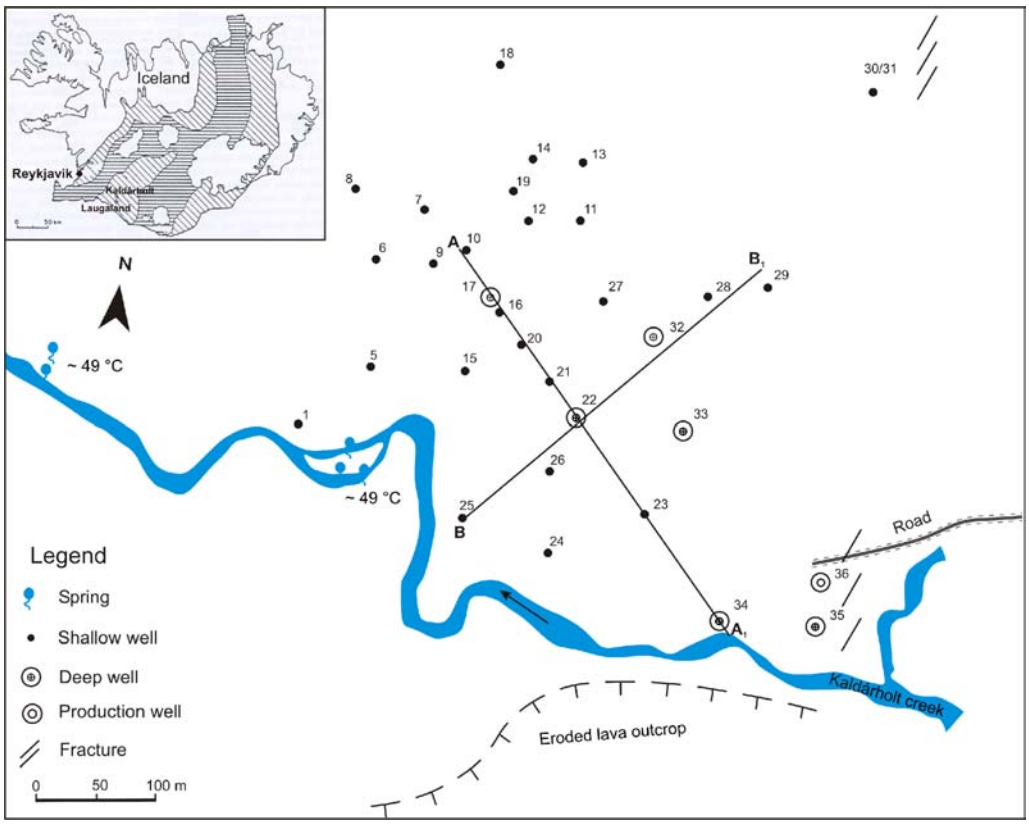

FIGURE 2: Map of the Kaldárholt geothermal area

3. ANALYSIS OF RESERVOIR TEMPERATURE CONDITIONS

Reservoir temperature, or formation temperature, which is the equilibrium temperature of the geothermal water-rock system, is one of the most important parameters in quantitative assessment of geothermal reservoirs (Björnsson, 2003). In most cases, the temperature information is obtained by lowering a temperature gauge into a well and measuring the temperature at specified depths, namely temperature logging (Steingrímsson, 2003). Because of the drilling operation, the original thermodynamic conditions around a well are usually disturbed (Bödvarssson and Witherspoon, 1989). This will result in the measured temperature at a certain depth in a well not necessarily being equal to the reservoir temperature. Therefore, this parameter can't always be obtained directly based on downhole temperature logging. It can, however, be estimated from careful interpretation of logging data collected during drilling and heating periods. Commonly, there exist two major influences that complicate the interpretation of temperature logs (Stefánsson and Steingrímsson, 1990). One is internal flow within the well being drilled. Cooling due to drilling-fluid circulation is another main influence that should be taken into consideration during the temperature log interpretation. Therefore, information on the drilling operation and the conditions of the well before temperature logging should be considered when these temperature logs are interpreted. As a rule of thumb, the bottom temperature measured during drilling is usually the most reliable reference for formation temperature, because of it being least influenced by drilling circulation. In addition, the regional mean annual temperature is also important information.

The formation temperature not only gives valuable information on aspects such as thermal gradient, actual reservoir temperature and location of feedzones, but also information on the state of the temperature distribution in the reservoir when several formation temperature profiles are available (Steingrímsson, 2003; Björnsson, 2003). Based on such information and additional geological data, a conceptual model of the reservoir can usually be constructed. As mentioned above, individual temperature logs don't necessarily give the actual formation temperature in the reservoir. Therefore, the fundamental work involves deducing the formation temperature from the temperature logs measured in each well.

A total of 145 temperature logs were measured in 35 wells at Kaldárholt (no log from well KH-30), with a combined length of 25.5 km. Based on the above rules, all the temperature logs have been interpreted and the formation temperature for each well obtained. By comparing the temperature profiles between different wells, it was found that some profiles have similar characteristics. Generally, the temperature profiles can be divided into three distinctive types, according to their observed characteristics. In this report, only three representative temperature profiles are presented (Figures 3, 4 and 5). It is also interesting to note that the corresponding wells are distributed along a SSE-NNW direction (cross-section A-A_1 in Figure 1).

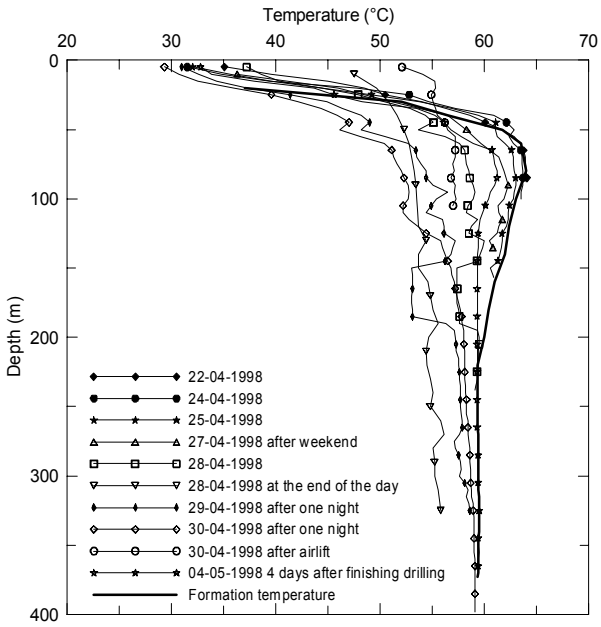

FIGURE 3: Temperature profiles for well KH-17 along with the estimated formation temperature profile

From the temperature profiles (Figures 3 and 4), it can be seen that heat conduction dominates in the upper part of the formation, and convection in the deeper part. A sharp temperature increase is seen at shallow depth in most of the wells (Figure 3). This is believed to be because the shallow parts of the system have been heated by hot upflow from depth. It should be mentioned here that well KH-34 (Figure 5) began to self-flow when a certain depth was reached. This is the reason why some of the profiles are nearly

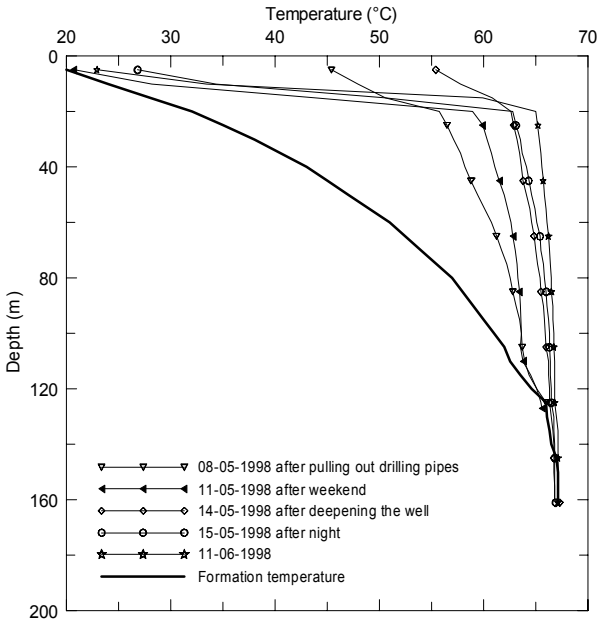

FIGURE 4: Temperature profiles for well KH-22 along with the estimated formation temperature

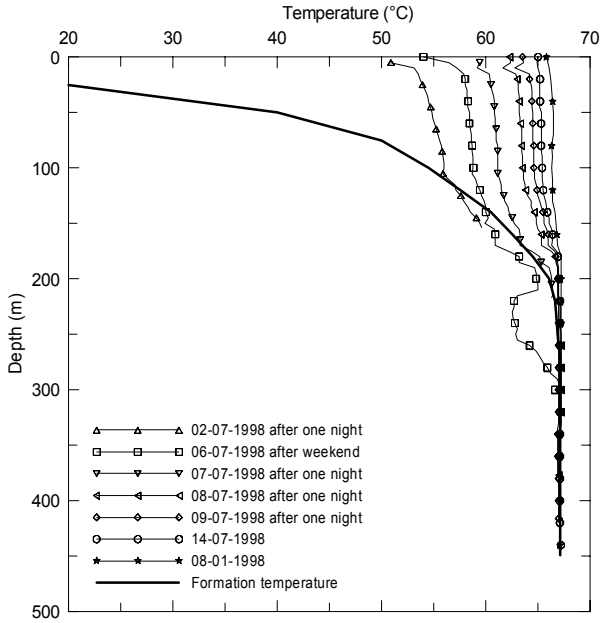

FIGURE 5: Temperature profiles for well KH-34 along with the estimated formation temperature

vertical in the upper part of the well. An obvious temperature inversion, which indicates lateral or tilted flow, is seen in temperature profiles from well 17 (Figure 3). In order to delineate hot water flow paths in the reservoir, two perpendicular temperature cross-sections were generated by using the estimated formation temperature profiles from the wells along each cross-section (Figures 6 and 7). Two temperature contour maps at 100 and 400 m depth were also generated for this purpose (Figures 8 and 9). Both the temperature cross-sections and temperature contour maps indicate an upflow directed towards north-northwest, sloping about 45˚. The upflow appears to originate at depth in the southeast part of the field and reaches the shallower formations near well KH-22. The upflow temperature is about 67˚C at 150 m depth.

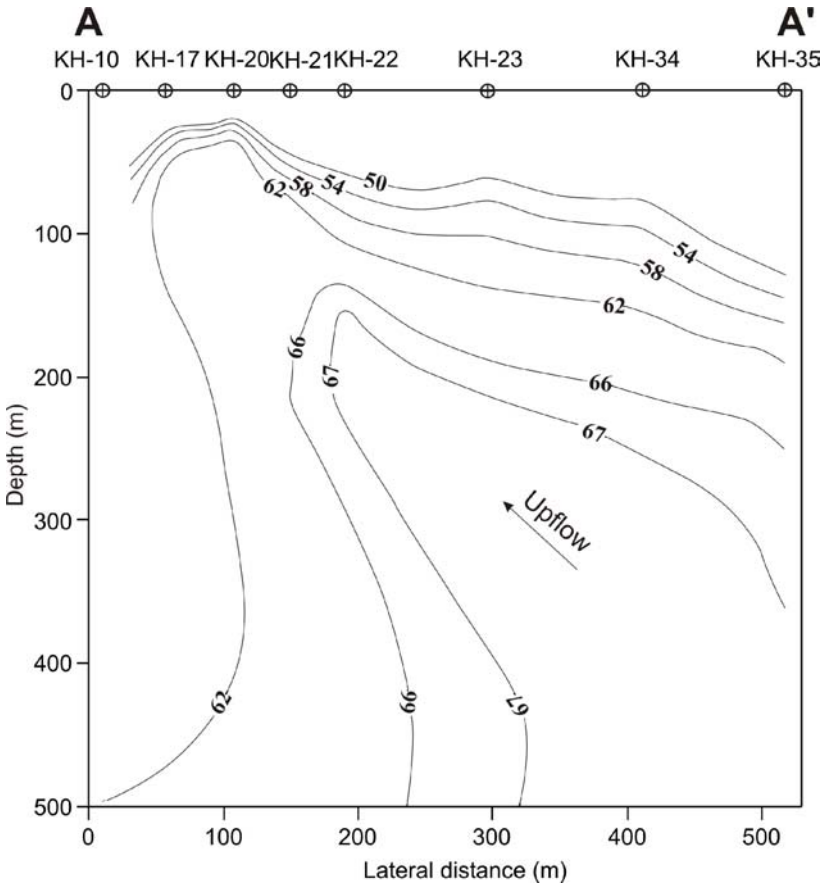

FIGURE 6: Temperature cross-section A-A_1 directed SE-NW (for location see Figure 2)

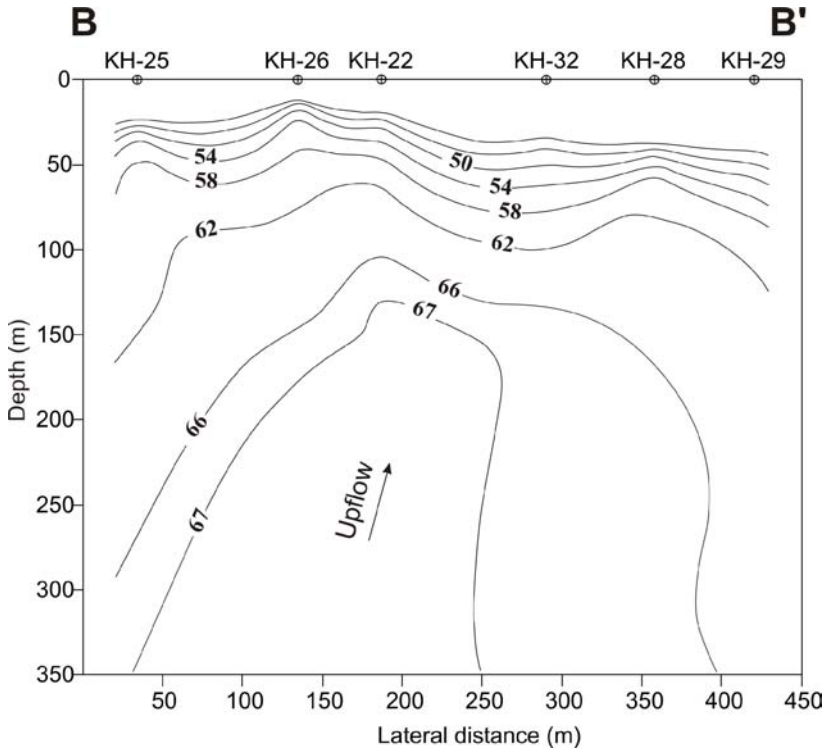

FIGURE 7: Temperature cross-section B-B_1 directed SW-NE (for location see Figure 2)

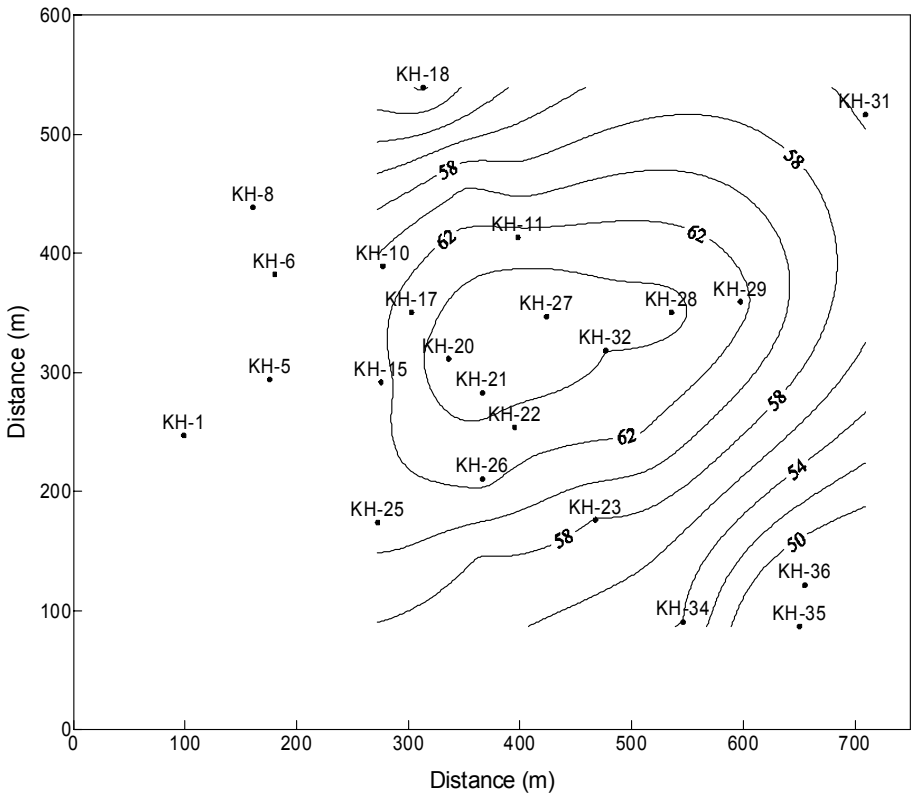

FIGURE 8: Temperature contours at 100 m depth at Kaldárholt

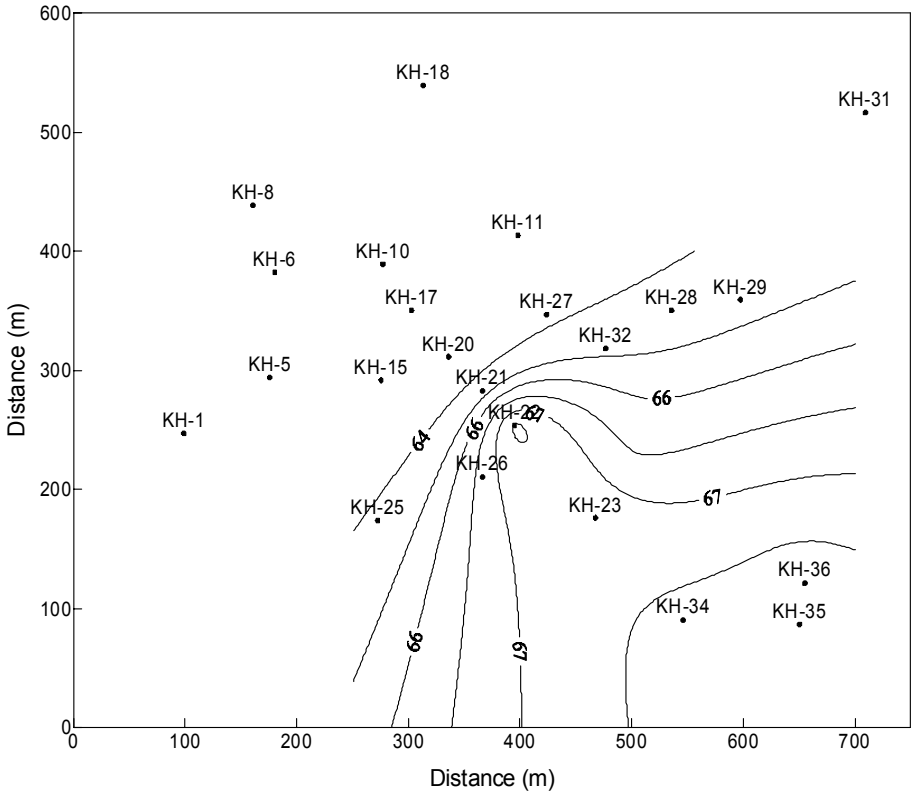

FIGURE 9: Temperature contours at 400 m depth at Kaldárholt

4. CONCEPTUAL MODEL

A good conceptual model is the basis for reservoir modelling of any geothermal system (Grant et al., 1982). According to the interpretation of temperature conditions presented in the previous chapter, along with the geological information available, a conceptual model for fluid flow in the Kaldárholt geothermal system can be briefly described as follows: Hot water flows in a sloping manner from the deeper part of the reservoir to the shallow part, along a northwesterly direction. The upflow reaches the shallow formations near well KH-22, where the intersection between two faults, fractures, or dikes is believed to occur. The temperature of the main upflow is about 67˚C. Due to the relatively high pressure of the upflow, hot water flows out from the faults or fractures into the shallow formation and to the surface, where it creates hot springs along the Kaldárholt Creek. Because of cooling during the upflow and mixing with cold groundwater, the temperature of these hot springs is about 49˚C.

5. ANALYSIS OF WELL TEST AND INTERFERENCE DATA

A well test is usually the most important tool available for estimating hydrological parameters in geothermal and other hydrological systems. According to reservoir conditions and the purpose of a study, different well test methods are selected and used. Pressure transient methods have been used extensively as one of the well test methods, to evaluate the parameters of geothermal reservoirs. In most cases, the main parameters obtained from such well tests are the formation permeability (or transmissivity) and the storage coefficient. Sometimes, the characteristics of a well, such as wellbore storage, skin factor and turbulence factor, can also be estimated by analyzing well test data.

Some pressure transient, and well test data, is available from the Kaldárholt field. These include transient well test data for well KH-34, associated interference data from wells KH-22 and 33, and step-rate data from well KH-36. These data are analyzed in the following.

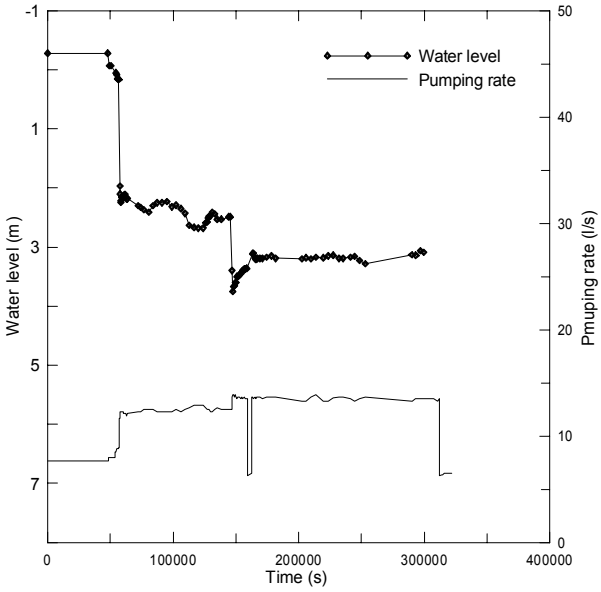

FIGURE 10: Water level versus pumping rate during well test in well KH-34

One multiple-rate interference well test was carried out in well KH-34 on August 24-27, 1998, with a total duration of about 89 hours. Water level was measured in the well (Figure 10) as well as in two observation wells (wells KH-22 and KH-33). It should be mentioned that the water level measured in production wells not only reflects the reservoir drawdown due to production, but also the water level changes caused by pressure losses inside and near the wellbore. A part of these additional pressure losses are referred to as turbulent losses. Water level changes in observation wells are seldom influenced by these additional losses. The water level data from active pumping wells, therefore, needs to be corrected before conventional analysis and estimation of reservoir parameters. In order to estimate the influence of turbulent flow, a multiple-step (at least 3 steps) well test is usually required. By plotting water level versus flowrate, and using a polynomial regression equation (Sigurdsson, 1999), the pressure loss caused by turbulent flow can be estimated:

$$H = H_0 + BQ + CQ^2 \tag{1}$$

where Q = Flowrate [l/s];
H_0 = Water level in the production well at zero flow [m];
BQ = Linear drawdown in the reservoir, caused by Darcy (laminar) flow [m];
CQ^2 = Pressure loss caused by turbulent flow at the location of inflow into the well and inside the well [m];

Figures 11 and 12 show the relationship between water level and flowrate in well KH-34 and KH-36. The results show that the pressure losses caused by turbulent flow in well KH-36 are more than 3 times greater than these losses in well KH-34. This difference may have two explanations: One is that the casing of well KH-36 (253 m) is deeper than that of well KH-34 (21 m) (Appendix I). The two wells are of similar depth, but well KH-36 (depth 445 m) has a relatively shorter permeable section than well KH-34 (depth 456 m). Therefore, the velocity of water flowing into well KH-36 may be higher than into well KH-34 for the same pumping rate. The higher velocity will consequently cause greater turbulence pressure losses. Another possible reason is that the feedzones intersected by well KH-34 may be slightly wider than in well KH-36, causing greater turbulence losses in the latter. This will also result in the permeability surrounding well KH-34 being higher than surrounding well KH-36, as is indicated by the linear drawdown factor *BQ* for the wells (Figures 11 and 12). Therefore, the greater turbulence factor of well KH-36 as compared to well KH-34 is mainly attributed to generally faster flow towards the well.

The so-called Theis model, which assumes that the reservoir is homogeneous, isothermal, isotropic, horizontal, of uniform thickness and infinite in radial extent, and that the fluid flow follows Darcy's law, is the model most commonly used to analyze pressure transient well test data (Horne, 1995). This model is also used here. The KH-34 well test was a multiple-rate well test, as mentioned previously. Therefore, a general multiple-rate analysis method was used for analyzing the data, after correcting for the influence of turbulent flow.

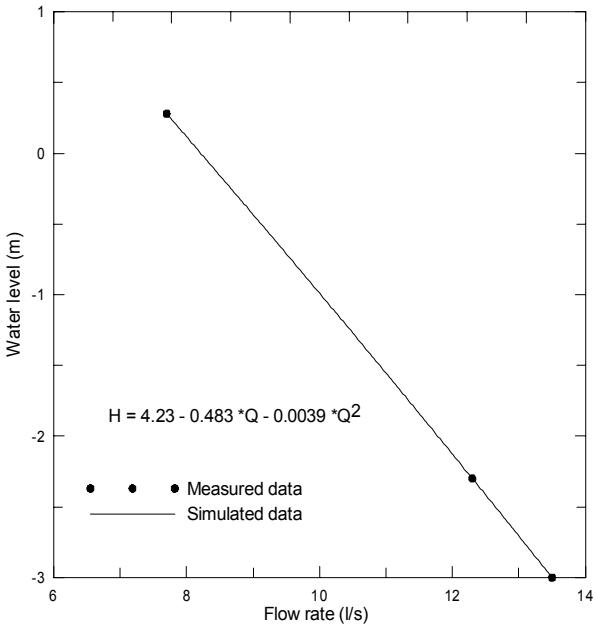

FIGURE 11: Step-rate plot of water level versus flowrate for well KH-34

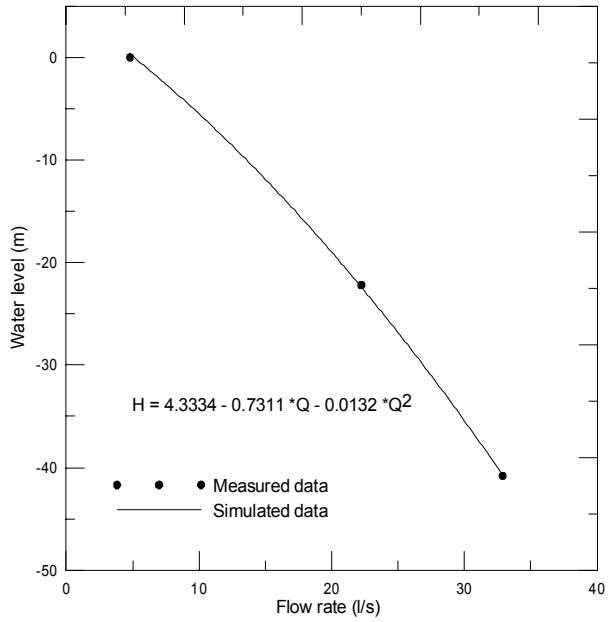

FIGURE 12: Step-rate plot of water level versus flowrate for well KH-36

By plotting $\frac{\Delta P}{q_n}$ versus $\sum_{j=1}^{n}\left[\frac{(q_j - q_{j-1})}{q_n}\log(t - t_{i-1})\right]$ where q_n refers to the last flowrate which can affect that pressure, and using a linear regression, a slope can be obtained (Figure 13) (Earlougher, 1977). Consequently, the permeability thickness can be estimated by using the following equation:

$$kh = \frac{2.303\mu}{4\pi\, m} \tag{2}$$

where k = Permeability [m^2];
h = Thickness of the aquifer [m];
m = Slope of the straight line [kg/m^{4}s];
μ = Dynamic viscosity [kg/ms];

The semi-log method was used to analyze the interference data from the two observation wells, namely wells KH-22 and KH-33, with corresponding permeability thickness and storage coefficient estimated. The results are presented in Table 1. It should be mentioned here that only the first short section of the data-set was used from each of the two wells when using the semi-log method (Figures 14 and 15). Table 1 indicates that the average storage coefficient is about 2×10^{-8} m/Pa. If the porosities are assumed to be 10% and 5%, the corresponding compressibility storage of the reservoir is about 4.4×10^{-11} Pa^{-1} and 7×10^{-11} Pa^{-1}, respectively. Thus, the thickness of the reservoir is about 300-450 m. If the thickness of the reservoir is assumed to be about 500 m, in agreement with drilling data, the permeability is about $0.3\text{-}1.3\times10^{-13}$ m^2, or 30-130 mD. This indicates that the reservoir permeability is rather

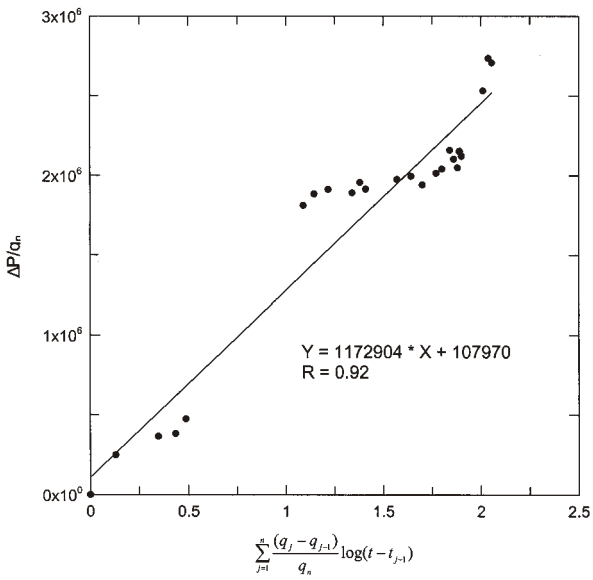

FIGURE 13: A multiple-rate plot for the well test data from well KH-34

good. The estimated parameters for the three wells are slightly variable, but of the same order of magnitude. The difference between the estimates may reflect the heterogeneous and anisotropic properties of the reservoir; or the fact that the nature of the reservoir differs from the characteristics of the model; or it results from uncertainties in the data.

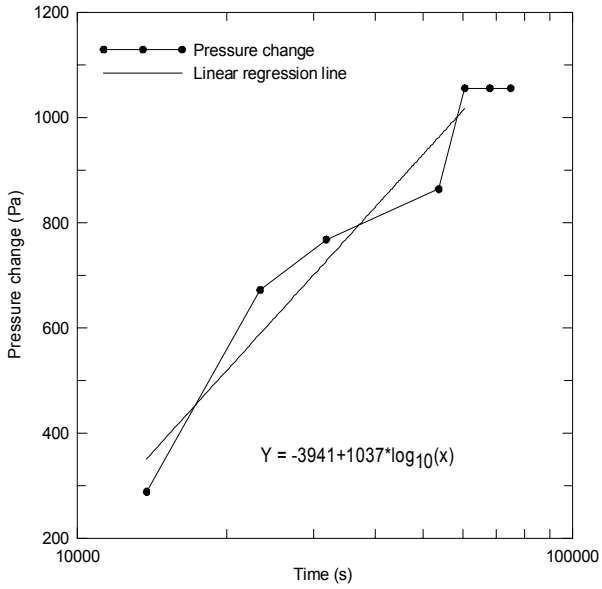

FIGURE 14: Plot of pressure interference vs. logarithmic time in well KH-22 during testing of well KH-34

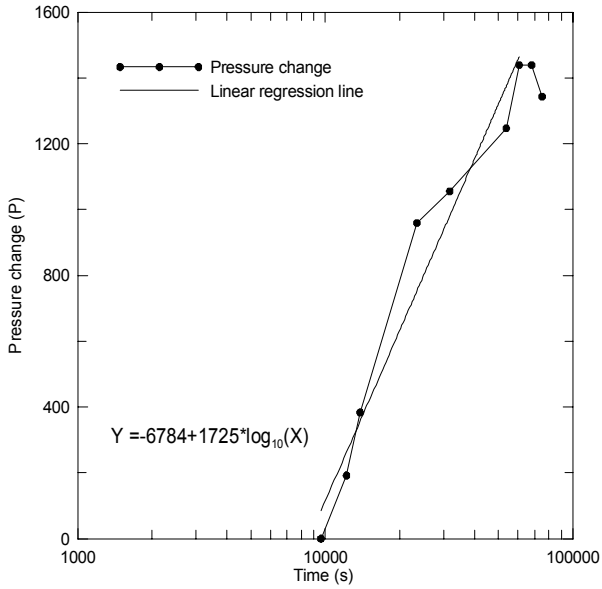

FIGURE 15: Plot of pressure interference vs. logarithmic time in well KH-33, during testing of well KH-34

Different permeability next to a well, compared to the average reservoir permeability, causes the so- called skin effect, which only affects the water level changes in production wells. For the case of KH-34 multiple-rate well test (Figure 11), the skin factor can be estimated by Equation 3 (Earlougher, 1977; Sigurdsson, 1999):

$$s = 1.1513\left[\frac{b}{m} - \log\left(\frac{kh}{\phi \mu c_t h r_w^2}\right) + 0.351\right] \tag{3}$$

where s = Skin factor;
b = Intercept of the straight line with y axis;
ϕ = Porosity;
$c_t h$ = Storage coefficient [m/Pa];
r_w = Radius of the well.

The estimated result for well KH-34 is presented in Table 1. The negative skin factor obtained indicates that there exists a 'stimulated' zone around the well with higher permeability (Hjartarson, 1999). Therefore, it is considered likely that well KH-34 may intersect highly permeable features, such as fractures or faults. This is in good agreement with the actual geological conditions encountered during drilling (Kristmannsdóttir et al., 2002).

TABLE 1: Parameters obtained through analyzing pressure transient data from different wells during testing of well KH-34

Well no	Well 34	Well 22	Well 33
Permeability thickness (m^3)	6.5×10^{-11}	2.2×10^{-11}	1.3×10^{-11}
Storage coefficient (m/Pa)	-	1.5×10^{-8}	2.5×10^{-8}
Skin factor	-3.8	-	-

6. LUMPED PARAMETER MODELLING OF KALDÁRHOLT GEOTHERMAL SYSTEM

For the purpose of efficient and sustainable use, increased emphasis is placed on geothermal resource management. Successful management of geothermal resources is, however, always based on proper understanding of the properties, conditions and dynamics of the reservoir in question (Axelsson, 2003a). Mathematical (reservoir) modelling is a powerful tool for geothermal system assessment and can play an important role in geothermal resource management. Many different modelling methods have been successfully used in different geothermal fields for the above purposes during the past decades. There are, basically, two kinds of mathematical models widely used, namely lumped parameter models and distributed parameter models. A distributed parameter model is a very general mathematical model, usually based on finite element or finite difference methods, that allows one to simulate a geothermal reservoir in as much detail as is desired (Bödvarsson et al., 1986, Axelsson and Gunnlaugsson, 2000). If extensive, high quality data is available, a distributed parameter model is, without question, the most powerful tool for detailed simulation studies of a reservoir and for complex predictions for different production scenarios. However, the development of a detailed distributed parameter model is both time and money consuming work in most cases. But scarcity of detailed data is usually the main factor deciding that detailed distributed parameter models should not be developed for a given geothermal field. Compared with distributed parameter models, lumped parameter models don't need as much data. Furthermore, the time and money that goes into developing a lumped parameter model is considerably less than for the distributed parameter models. Lumped parameter modelling is in such cases a viable alternative (Axelsson, 1989).

Lumped parameter model simulators have been developed and successfully used for geothermal resource assessment and management worldwide. LUMPFIT, a lumped model simulator included in the ICEBOX software package (Arason et al., 2003), has been extensively used for low- to medium temperature geothermal resource assessment and management in Iceland, China, Turkey, central America and other countries (Axelsson and Gunnlaugsson, 2000). It has been proven that LUMPFIT can be conveniently and reliably used to simulate reservoir pressure, or water level response to production. By using an inverse method of calculation, a good agreement between calculated and measured data can be obtained, within a very short time, if high quality data is available. The theoretical basis of lumped parameter modelling, and the details about the LUMPFIT simulator, are presented by Axelsson (1989 and 2003b). Considering the limited production response data available for Kaldárholt, i.e. water level changes during the first 3.5 years of production, only the lumped parameter models were developed for Kaldárholt using the simulator LUMPFIT.

6.1 Water level history simulated by LUMPFIT

Different lumped parameter models were used to simulate the water level response data for Kaldárholt from January 2000 to March 2003. Both a two-tank closed model and a two-tank open model yield similarly good fits. The comparison between observed and simulated water level data is shown in Figures 16 and 17. It should be mentioned here that two large earthquakes occurred in June 2000, which caused a temporary rise of the water level in well KH-36, which had faded out in late 2000. Taking this influence into account, the simulated water levels match the observed data very well.

The average reservoir properties can be estimated by simple calculations using the parameters of lumped models obtained by LUMPFIT (Axelsson 1989; 2003b). The results are presented in Table 2. It can be seen from the table that the first tank, which simulates the central (production) part of the reservoir, has a relatively small volume and surface area. Both the open and closed models, however, give an unacceptably large volume for the second tank, which represents the outer and deeper parts of the reservoir. It should be noted that these results are based on the assumption that both the central and outer parts are confined, i.e. their storativity is controlled by liquid/rock compressibility. However, if the storativity of the outer/deeper part of the reservoir is controlled by a free water surface, the volumes will only be several km^3. The results corresponding to the free water surface case are presented in parentheses in Table 2. Therefore, it is quite possible that the outer/deeper parts of the real reservoir are connected

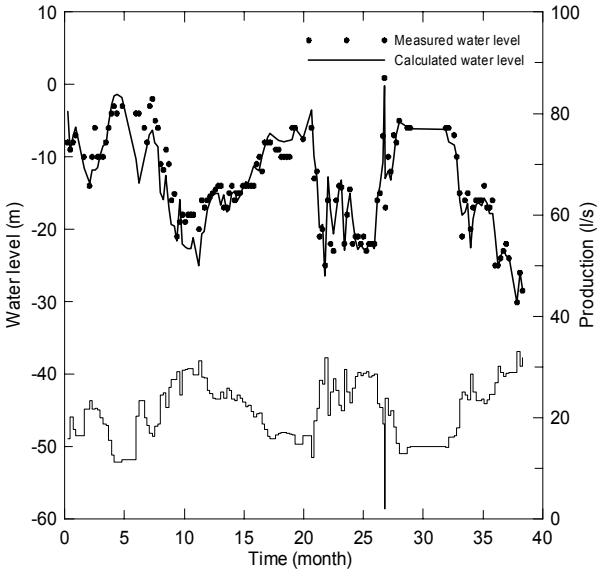

FIGURE 16: Water level changes in well KH-36 simulated by LUMPFIT with a two-tank closed model

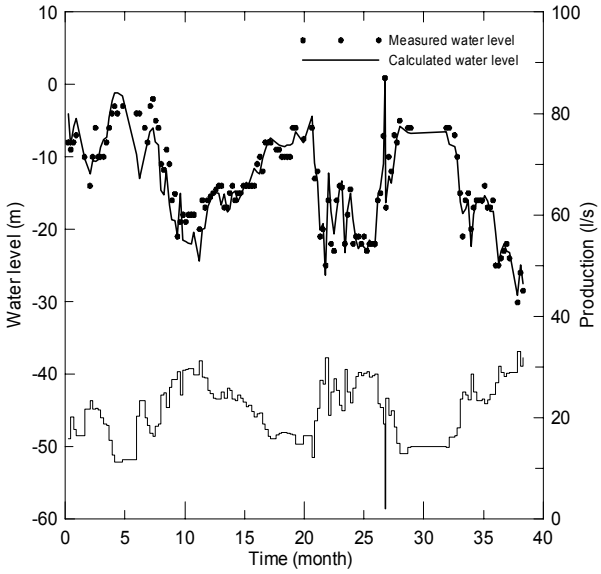

FIGURE 17: Water level changes in well KH-36 simulated by LUMPFIT with a two-tank open model

to a free water surface. It can also be seen that the permeability estimated from the lumped models conforms very well with the well test results (Table 1), if the thickness of the aquifer is assumed to be 500 m. Compared with the surface area for the first tank estimated by the two models (4.0 and 0.7 km^2), the present exploration surface area, which is about 0.3 km^2, is considerably smaller. This may indicate that the current production area only takes up a part of the whole Kaldárholt geothermal system. In conclusion, it may be stated that the successful simulation, and the realistic model properties, indicate that the lumped parameter models developed here for Kaldárholt may be considered reliable.

TABLE 2: Estimated reservoir properties according to lumped parameter models, based on compressibility controlled storativity except numbers in parentheses which are based on free-surface storativity *

Model	Parameter	First tank	Second tank
Two-tank closed model	Volume (km^3)	2.0	1606.4 (6.8)
	Surface area (km^2)	4.0	3212.8 (13.6)
	Permeability (m^2)	1.1×10^{-13} (3.0×10^{-14})	
Two-tank open model	Volume (km^3)	0.4	446.6 (1.89)
	Surface area (km^2)	0.7	893.2 (3.17)
	Permeability (m^2)	1.4×10^{-13} (2.3×10^{-14})	2.1×10^{-13} (1.5×10^{-14})

*Based on the assumption that the reservoir thickness is 500 m and the porosity of the rock is 5%.

6.2 Predicted water level changes

One of the main purposes of modelling is to use calibrated models for prediction. By calculating predictions based on a reliable model, the responses of a reservoir to production loads, both favourable and unfavourable, can be forecasted. This will, in turn, help the investors to better manage the geothermal resources and avoid/or reduce the financial risks. That is also the main reason why modelling plays an important role in successful management of geothermal resources.

As mentioned previously, both of the lumped parameter models can simulate the water level monitoring data equally well. Hence, the two models are both used to predict the water level changes under different production scenarios for the next 10 years (April, 2003 - April, 2013). Taking into account that more geothermal water may be produced from this field in the future, the assumed future production is increased from the present production according to the following scenarios:

Scenario *I*: Production of 20 l/s from April to September, 30 l/s from October to March.

Scenario *II*: Production of 30 l/s from April to September, 45 l/s from October to March.

Scenario *III*: Production of 20 l/s from April to September and 30 l/s from October to March, for the first year. Consequently, the production is assumed to increase by 5% yearly, from the second year on.

The predicted water level drawdown for each of the scenarios is shown in Figures 18-20, as well as in Table 3. The figures show that the predicted water levels, according to the two different models, are quite different for the same scenario. This difference between predictions is about 5-6 m for the three scenarios at the end of 5 years (Figures 18-20) and reaches 11-15 m at the end of 10 years (Table 3). The longer the time is, the greater the difference is. This is because equilibrium between production and recharge is eventually reached in the open model during long-term production, causing the water level drawdown to stabilize (Axelsson and Gunnlaugsson, 2000). However, because of absence of equilibrium, the water level will decrease continuously during long-term constant production in a closed model (Figures 18 and 19). As can be seen from Figures 18 and 19, the open model predicts a nearly stable water level if the production is constant. By comparing the predictions for scenarios I and II, it can also be seen that a greater production rate will cause a greater difference between the predictions by the two models. The difference between predictions by the open and closed models may be looked upon as a measure of the uncertainty in the predictions.

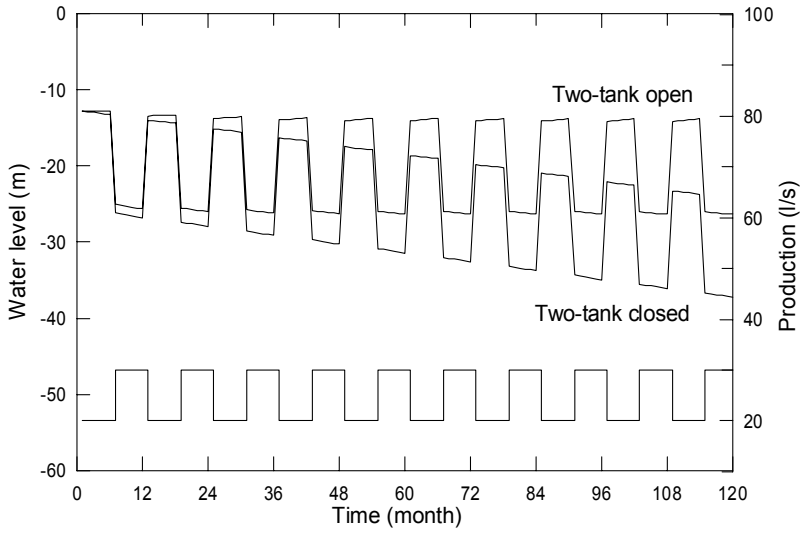

FIGURE 18: Predicted water level changes in well KH-36 for the next 10 years, according to Scenario I, based on the closed and open lumped models

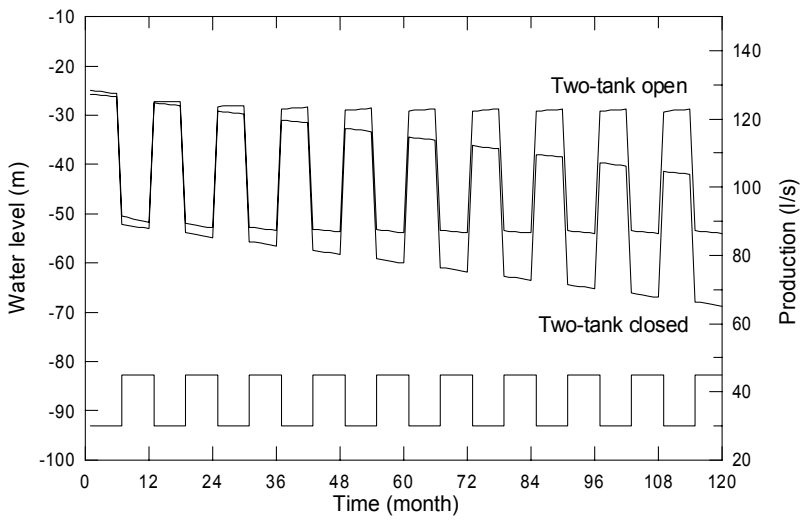

FIGURE 19: Predicted water level changes in well KH-36 for the next 10 years, according to Scenario II, based on the closed and open lumped models

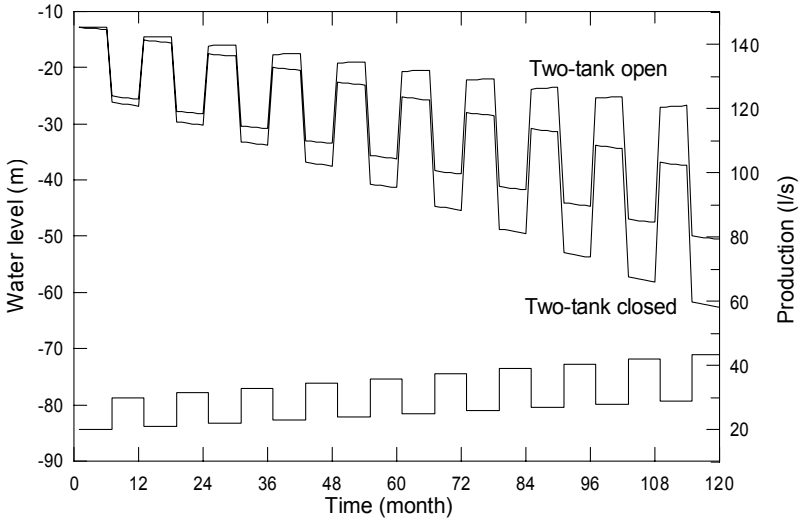

FIGURE 20: Predicted water level changes in well KH-36 for the next 10 years, according to Scenario III, based on the closed and open lumped models

It should be pointed out that the predictions are based on the above simulation models, and a relatively short (about 3.5 years) monitoring data-set is used for calibrating the models. In general, different combinations of boundary conditions and reservoir properties can give very similar mathematical solutions during modelling and sometimes it is very difficult to discern which combination reflects the nature of the reservoir in question. However, this inherent uncertainty will disappear eventually, or be discerned by the modeler, when longer monitoring data-series become available. It should also be mentioned here that the closed model always gives conservative predictions. On the contrary, the open model gives optimistic predictions (Axelsson, 2003b). The actual response should fall in-between the optimistic and pessimistic predictions. Although there may exist an inherent uncertainty in the predictions above, both the optimistic and pessimistic predictions should be treated as valuable references. More attention should especially be paid to the conservative predictions in order to avoid/minimize financial risks in managing the Kaldárholt system, by taking countermeasures timely or in advance.

TABLE 3: The lowest water level for the next 10 years predicted by the two lumped parameter models

Model	Scenario I	Scenario II	Scenario III
Open model (water level m)	-26	-54	-51
Closed model (water level m)	-37	-69	-63

6.3 Production potential assessment for Kaldárholt

Assessing the production potential of geothermal reservoirs is one of the main objectives of modelling (Axelsson, 1989). The production potential is usually based on a quantitative evaluation of the maximum yield from a geothermal reservoir, during a given exploitation period, within a certain allowable pressure decline. Giving different limits of water level drawdown will consequently yield different production potential value. By varying the production, and predicting the water level change with the lumped models in each case, the maximum production at Kaldárholt can be estimated to be about 55 l/s assuming maximum allowable water level drawdown of 100 m at the end of the next 10 year period. Similarly, when the maximum allowable water level drawdown is assumed to be 240 m, which is the maximum depth for the most commonly used downhole pumps used in Iceland, the corresponding maximum production is around 95 l/s. It should be mentioned here that only the closed model is used for the production potential assessment, and that the production rates quoted are yearly averages. If the open model is used, the maximum allowable production will be several litres higher. In reality, this potential should be in the range between the pessimistic and optimistic results from the two corresponding models.

7. REINJECTION OF KALDÁRHOLT WATER AT LAUGALAND

Geothermal water reinjection originated purely as a countermeasure against environmental pollution in the areas surrounding geothermal operations (Stefánsson, 1997). As reinjection of wastewater from geothermal power plants became part of the operation of more and more geothermal fields, it was also found that reinjection supported reservoir pressure and that more thermal energy could be extracted from the reservoir in question. In most geothermal fields, increasing pressure drawdown may happen sooner or later, because of limited recharge and long-term or large scale production. This consequently resulted in reinjection being considered as an essential measure for increasing the longevity of geothermal resources. Reinjection has not been a key part in the utilization of low-temperature resources in Iceland, but it is anticipated that injection will soon become an integral part of their management (Axelsson et al., 1995). The trend is that geothermal injection is increasingly becoming an important part of geothermal resource management worldwide.

As injection is one of the most complex aspects of geothermal exploitation, careful planning, testing, and research are prerequisites for a successful injection operation (Axelsson and Gunnlaugsson, 2000). The economics and the benefits of such a project are strongly dependent on the behaviour of the geothermal system and the wells (Axelsson and Stefánsson, 1999). As one of the potential side effects, cooling of production wells induced by long-term injection should be carefully considered and studied. This will help estimate whether injection can be conducted in the recommended injection wells and how much water can be injected into specific wells without causing cooling problems. It can never be stressed too much that extensive research should be carried out before long-term reinjection is started, although unacceptable cooling of production wells is not necessarily expected.

Reinjection in the Laugaland geothermal field, using Kaldárholt water, started in January 2000. The average reinjection rate has been about 3-4 l/s and the average production rate about 11.5 l/s during 2000-2002. The temperature of the reinjection water is stable at about 65˚C, and the observed temperature decline in production well LWN-4 is less than 1˚C during the three year period. The reinjection is conducted through the backup well GN-1, which is about 110 m from the production well LWN-4.

7.1 Tracer test

As injection is becoming an integral part of geothermal resource management worldwide, tracer tests have been extensively carried out in different geothermal fields. The main purpose of conducting tracer tests is to study the hydraulic connections between injection and production wells, which will in turn help predict cooling of the production wells associated with the injection (Axelsson, 2003c).

A tracer test was conducted in the Laugaland geothermal field in 1992, starting on August 20. One kg of sodium-fluorescein was used as a tracer and injected into the backup well GN-1. During the tracer test, the production rate was relatively stable at about 16 l/s. It should be noted that actual injection did not take place during the tracer test. According to temperature logging data from well GN-1, an obvious downflow is ongoing in the well. It has been estimated that the downflow is about 2 l/s (Björnsson et al., 1993). Therefore, this constant downflow was employed as a natural injection during the tracer test.

According to calculations using the programme TRMASS in the ICEBOX-package (Arason et al., 2003), the total mass of tracer recovered in production well LWN-4 during the test had reached about 0.915 kg by the time the last water sample was collected after 101 days (Figure 21). The tracer breakthrough-time, which reflects the maximum fluid velocity, is only about 0.4 days. It took about 18.5 days for the tracer recovery to reach maximum concentration, which indicates an average fluid velocity of 5.9 m/day. The above information indicates that the connection between the injection well GN-1 and production well LWN-4 is considerably direct. This direct connection is possibly associated with the fracture system which is believed to control the geothermal activity in the area. The rapid tracer breakthrough is also caused by the short distance between the two wells (110 m).

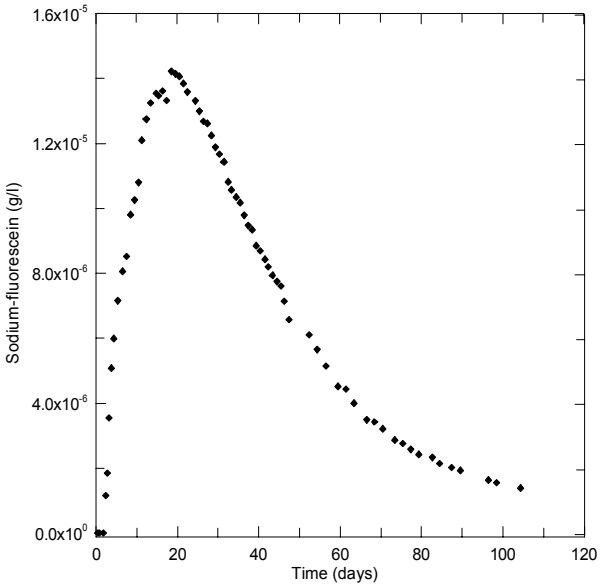

FIGURE 21: Observed sodium-fluorescein recovery in well LWN-4 at Laugaland during a tracer test starting August 20, 1992

7.2 Tracer recovery data analysis

It is widely recognized that the characteristics of the flow-channels between injection and production wells are the main factors controlling the magnitude of injection induced cooling. To quantitatively estimate the volume of these flow-channels between well GN-1 and well LWN-4, which will in turn help predict the possible temperature decline in well LWN-4, a one-dimension flow-channel model based on simulator TRINV was used to simulate the tracer recovery data-set (Axelsson et al., 1995; Axelsson et al., 2001). It should be mentioned that this model is based on the assumption that the tracer return is controlled by the distance between injection and production zones in the corresponding wells, the flow channel volumes, and dispersion.

According to drilling information and temperature logging data, there are four main feedzones in well LWN-4 and two main feedzones in well GN-1 (Björnsson et al., 1993). The two feedzones in well GN-1 are located at 450 and 900 m depths (Figure 22); and the four feedzones in well LWN-4 are located at 340, 590, 750 and 830 m depths (Figure 23). As already mentioned, downflow has been detected in well GN-1 during temperature logging, entering through the shallow feedzone (450 m) and flowing into the deep one (900 m). Therefore, it can be assumed that the deep feedzone in well GN-1 connects with each of the feedzones in well LWN-4 and that the reinjected water can flow from the injection well to the production well through four corresponding flow-channels. It should be noted that during simulation of the tracer recovery data, the two flow-channel model already fits the data-set very well. This may indicate that some of the flow-channels are interconnected and act as one or that some are relatively inactive. To simplify the simulation, only a two

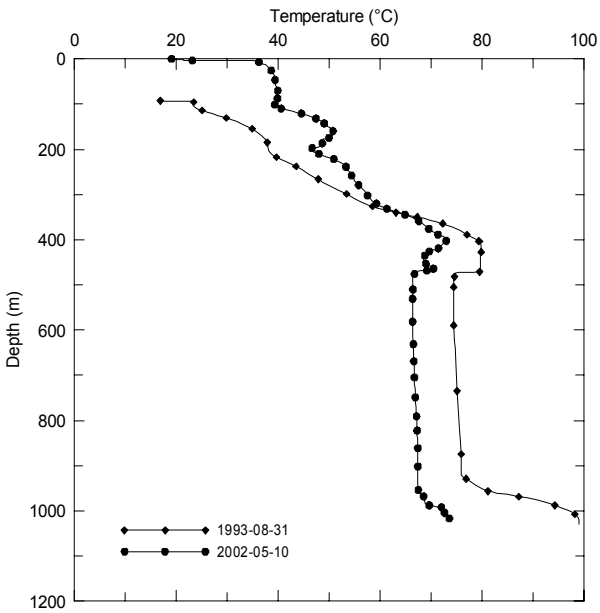

FIGURE 22: Temperature profiles in well GN-1 before and during a break in reinjection

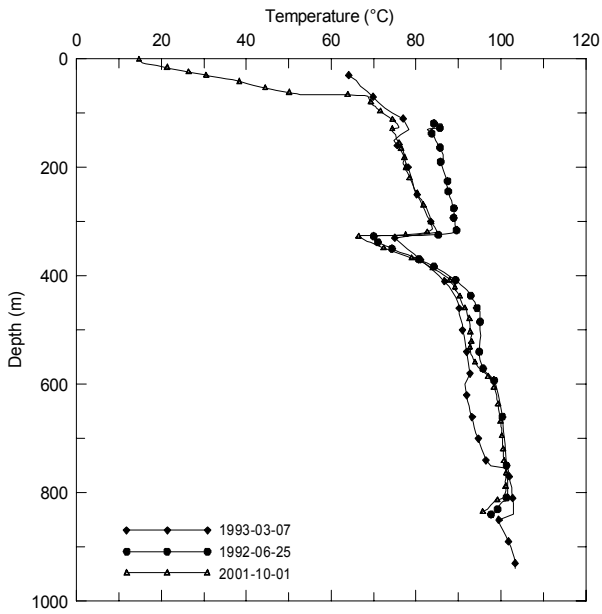

FIGURE 23: Temperature profiles in well LWN-4 before and during reinjection

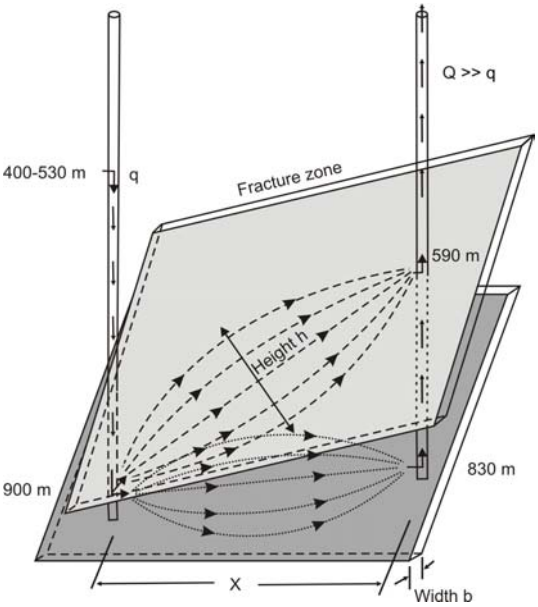

FIGURE 24: A schematic drawing of the two channel model used here for tracer test analysis (adapted from Björnsson et al., 1993)

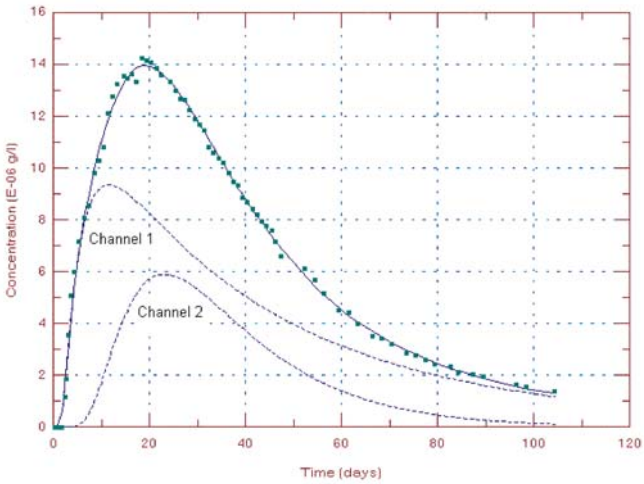

FIGURE 25: Simulation of the sodium-fluorescein recovery in well LWN-4 during the tracer test at Laugaland

flow-channel case was considered here. This model is presented in Figure 24 and the simulation results are illustrated in Figure 25. The possible influence of the above simplification, and other approximations inherent in the model, on the cooling predictions will be discussed in a later section. The properties of the flow-channels are presented in Table 4. From Table 4, it can be seen that almost 100% of the tracer injected will be recovered from well LWN-4, according to the model. This information, along with the volumes of the flow-channels, confirms that the connection between the well pair is fairly direct.

TABLE 4: Model parameters used to simulate the tracer recovery for the well pair GN-1/LWN-4 in the Laugaland geothermal field, during the 1992 tracer test

Channel length (m)	u (m/s)	$A\phi$ (m^2)	α_L (m)	M_i/M (%)
130	6.95×10^{-4}	20.9	88.0	69.3
329	1.40×10^{-4}	4.6	53.7	30.6
Total				99.9

u = Mean flow velocity
A = Cross-sectional area
ϕ = Porosity
α_L = Longitudinal dispersivity of the flow-channel
M_i = Calculated mass recovery of tracer through corresponding channel until infinite time
M = Total mass of the tracer injected

7.3 Temperature decline predictions

As already mentioned, the possible temperature decline in production wells is one of the main potential problems associated with long-term reinjection. To foresee the possible cooling in advance can provide very helpful information for the design and management of actual injection operations. By assuming the geometrical characteristics of the flow-channels, the temperature decline in well LWN-4 can be predicted under different reinjection and production scenarios. The programme TRCOOL (Arason et al., 2003), which is a one-dimensional flow-channel model, was used for the cooling predictions. It should be pointed out that the geometry of the flow-channels involved is one of the important factors determining

the magnitude of cooling in production wells. For a flow-channel with a given volume, the geometry with a larger surface area will yield less cooling of the production wells; but the detailed information required such as porosity and geometry of the fractures, is sometimes not available. To study the inherent uncertainty and estimate their influence on the predictions, different geometry and porosity parameters of the flow-channels were assumed for the cooling predictions (Table 5). The predicted temperature decline for each scenario is shown, as well as for different reinjection/production cases, in Figures 26-29. It should be noted that Figure 26 shows the prediction results for the present production and reinjection situation. In addition to four scenarios, a special case, in which the reinjection water was assumed to disperse throughout a much larger part of the reservoir instead of flowing through several relatively large flow-channels to the production well, was also included in the present injection and production study (Figure 30). This scenario, in which the porosity of the reservoir is assumed to be 1%, can be considered as an extremely optimistic one.

TABLE 5: Model parameters assumed for the cooling prediction scenarios

Case	Porosity %	Channel 1		Channel 2	
		Width b_1 (m)	Height H_1 (m)	Width b_2 (m)	Height H_2 (m)
A	8	4.0	65.28	3.0	19.13
B	8	3.0	87.04	2.0	28.69
C	8	2.0	130.56	1.0	57.38
D	10	4.0	52.23	3.0	15.30
E	10	3.0	69.63	2.0	22.95
F	10	2.0	104.45	1.0	45.90

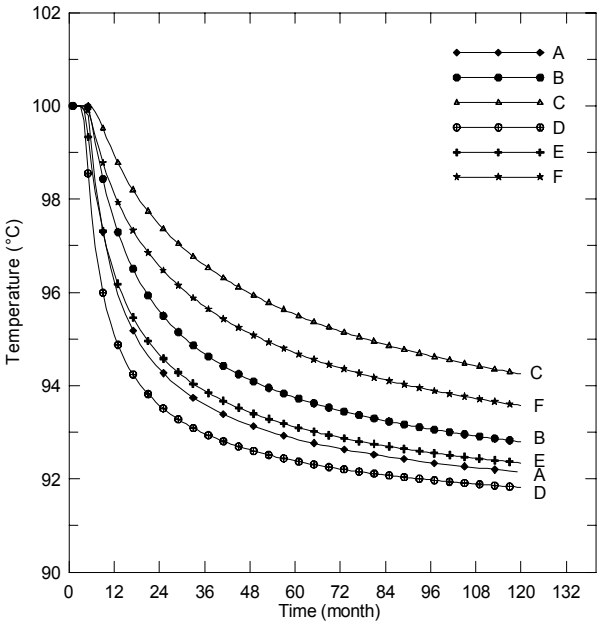

FIGURE 26: Predicted temperature decline for well LWN-4 at Laugaland during reinjection into well GN-1 for 11 l/s production and 3 l/s reinjection

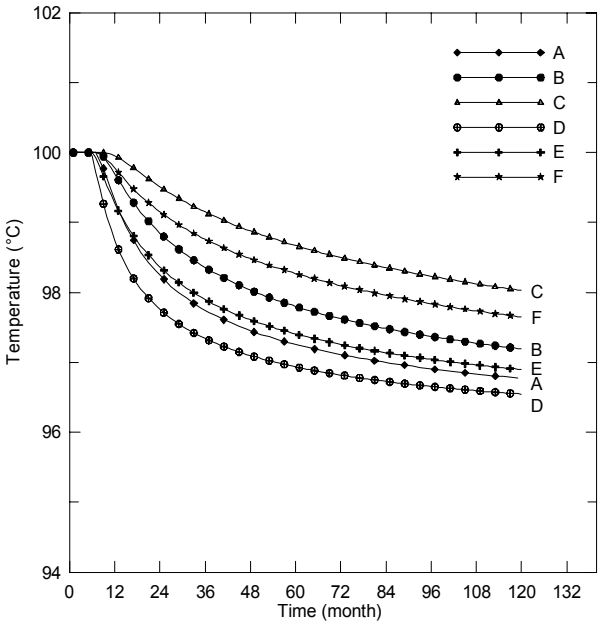

FIGURE 27: Predicted temperature decline for well LWN-4 at Laugaland during reinjection into well GN-1 for 16 l/s production and 2 l/s reinjection

From these cooling predictions, it can be seen that a low porosity and large surface area flow-channel, such as a thin fracture-zone, will lead to slow cooling and vice versa. According to Figures 26-30, it is also clear that the thermal breakthrough time for each case is different. A larger injection rate will, of course, bring about more rapid cooling of the production well. By carefully comparing the temperature decline results for different scenarios, it can also be seen that the cooling is not simply linearly related to

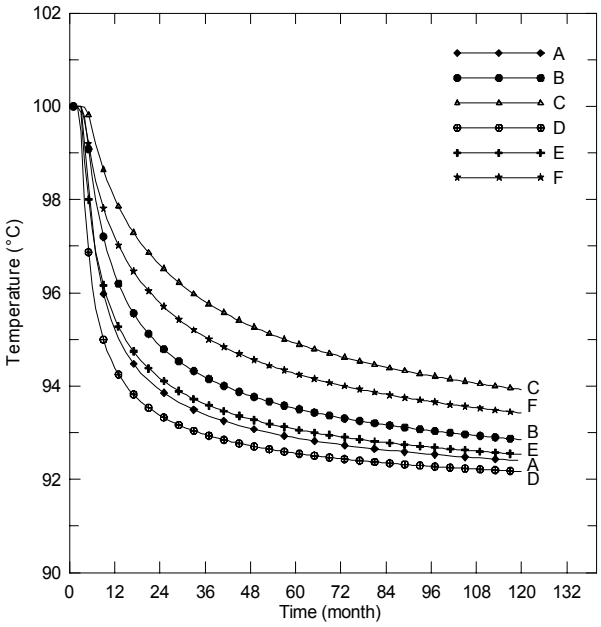

FIGURE 28: Predicted temperature decline for well LWN-4 at Laugaland during reinjection into well GN-1 for 16 l/s production and 4 l/s reinjection

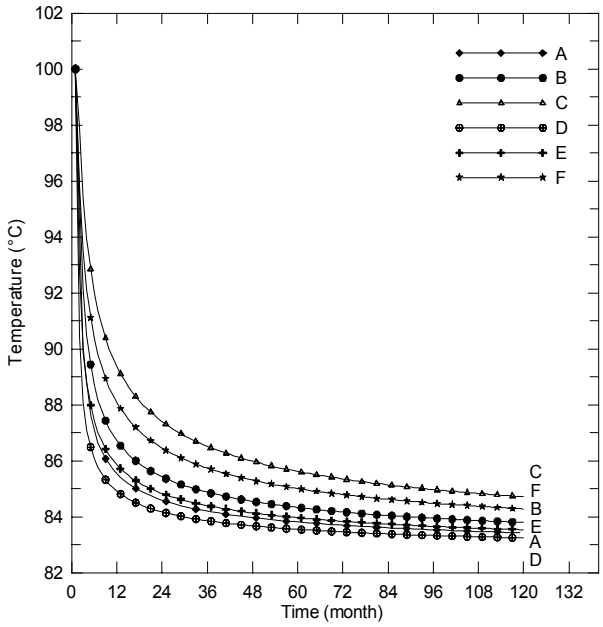

FIGURE 29: Predicted temperature decline for well LWN-4 at Laugaland during reinjection into well GN-1 for 20 l/s production and 10 l/s reinjection

reinjection rate. For example, if the reinjection rate is increased from 2 l/s to 4 l/s, the cooling would increase from 3.5 to 8˚C at the end of 10 years, which is more than double cooling (Figures 27 and 28 considering the most pessimistic case). This is because a larger injection rate will increase the flow velocities in the flow-channels and consequently cause faster cooling. From Figure 30, it can be seen that the thermal breakthrough time estimated for the most optimistic scenario is about 42 months, and it will takes about 66 months to cool the production well down by 1˚C.

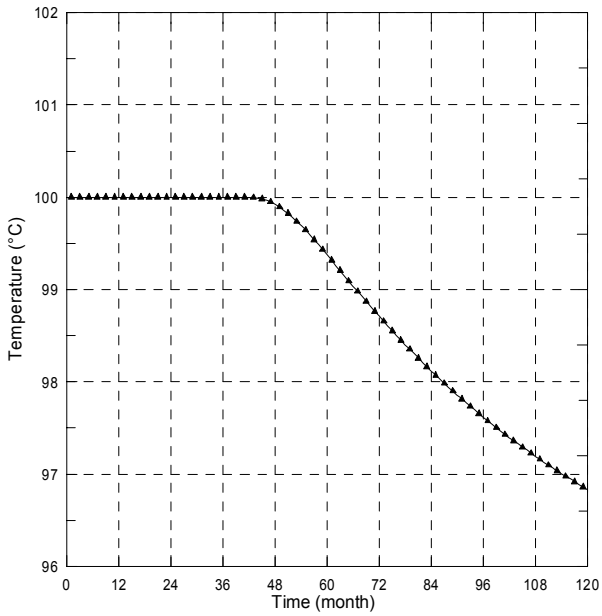

FIGURE 30: 30:Predicted temperature decline for well LWN-4 at Laugaland during reinjection in well GN-1 for 11 l/s production and 3 l/s reinjection (small flow-channels)

7.4 Analysis of chemical monitoring data

Chemical monitoring, which is an important ingredient in successful geothermal resource management, can give valuable information about the changes occurring in geothermal reservoirs. Injection, in general, acts as an artificial mixing process. If the injected water has a chemical concentration different from that of the water in the reservoir, the injection will cause concentration changes for some chemical components. In this way, chemical monitoring data can be used to obtain important information, which may be used to analyze the effect of injection on the reservoir involved.

At Laugaland, the concentration of several chemical components has been carefully monitored for a long time, before and during the reinjection operation. From the plots of the monitoring data (Figures 31-35),

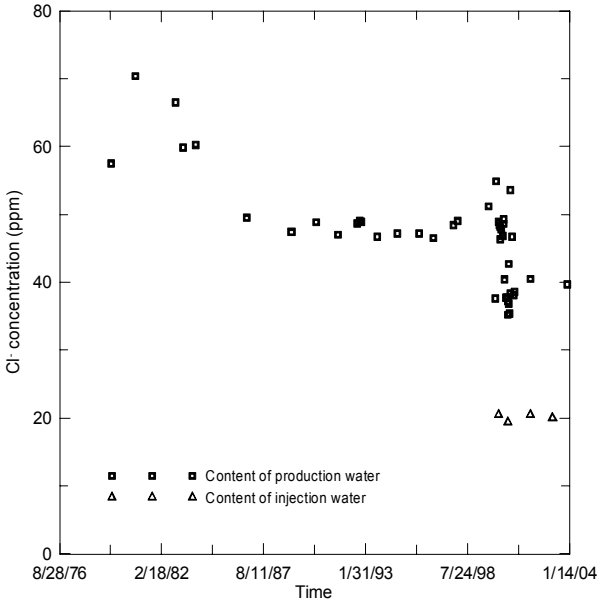

FIGURE 31: Changes in Cl^- concentration in well LWN-4 before and during reinjection

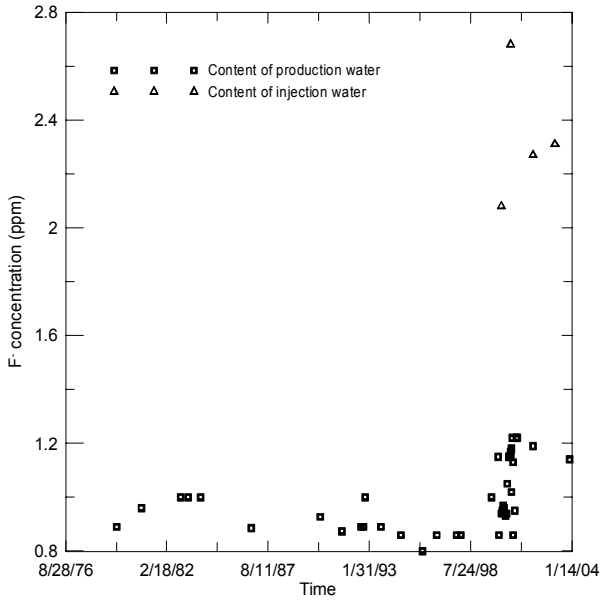

FIGURE 32: Changes in F^- concentration in well LWN-4 before and during reinjection

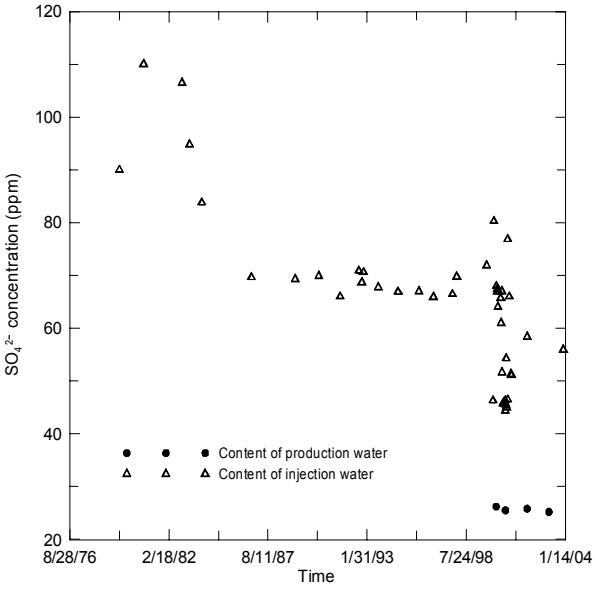

FIGURE 33: Changes in SO_4^{2-} concentration in well LWN-4 before and during reinjection

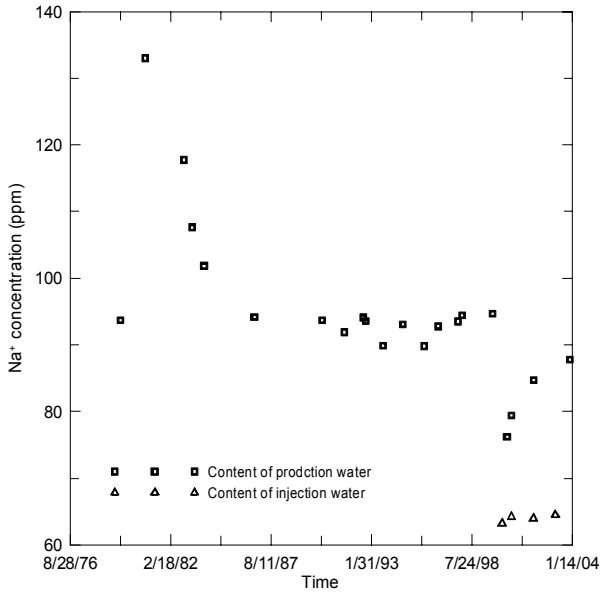

FIGURE 34: Changes in Na^+ concentration in well LWN-4 before and during reinjection

it can be easily seen that the concentration of chemical components changed clearly after the reinjection started. The tendency of the concentration changes indicates a process of mixing of two different sources, except in the case of SiO_2. The concentration of SiO_2 increased unexpectedly after the reinjection started, as can be seen from Figure 35. The main reason for this anomalous change is believed to be the major earthquakes, which occurred in the area in June 2000. On the assumption that only the mixing of the two sources is causing the concentration changes, the mass flowrate of reinjected water entering the production well LWN-4 was estimated (Table 6). Possible chemical reactions, precipitation, etc. are neglected. It should be noted that SiO_2 was not used for the estimation because of the anomalous behaviour. According to the calculation results, the concentration changes of $SO4^{2-}$ and F^- indicate that about 2.6 l/s of reinjected water flowed into the production well LWN-4, while Na^+ gives 3.0 l/s and Cl^- gives 3.5 l/s, which is greater than the average injection rate (3.0 l/s). If the result for Cl^- is excluded, the other three chemical

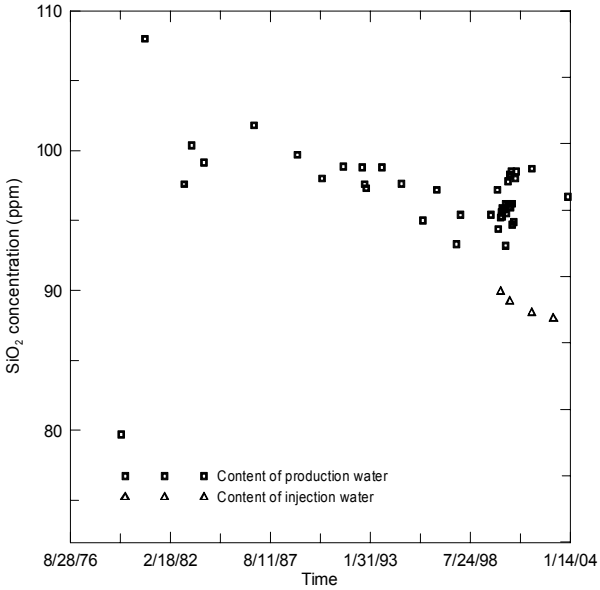

FIGURE 35: Changes in SiO_2 concentration in well LWN-4 before and during reinjection

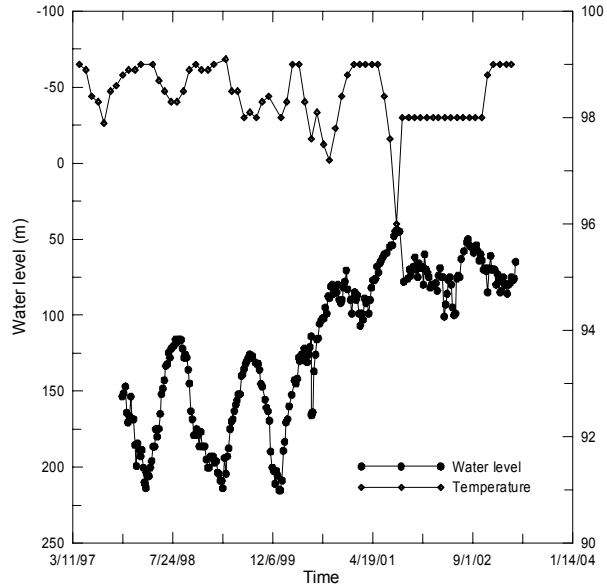

FIGURE 36: Temperature and water level history at Laugaland since 1997; reinjection started in January 2000

components give an average mass flow rate of about 2.8 l/s, which is about 93% of the average injection rate. Generally speaking, the above estimation appears reasonable, but it is more indicative than accurate. Considerable uncertainty in the calculation results may be attributed to the following reasons:

- The major earthquakes, which occurred in June 2000, may have caused some changes in the concentration of chemical components. This influence can be demonstrated by the anomalous changes in SiO_2 concentration.
- The above calculations are based on the assumption that the process of re-equilibrium between the water-rock system after mixing is very slow, or can be neglected, compared with the time it takes the injected water to flow from the injection well to the production well. This assumption may not be absolutely correct.
- The previously mentioned downflow in injection well GN-1 may cause additional changes in the concentration of the chemical components.
- Some uncertainty may also be attributed to variations and uncertainties in the chemical analyses.

TABLE 6: Estimated injection water inflow into well LWN-4 based on changes in chemical composition

Chemical composition	Na^+	Cl^-	SO_4^{2-}	F^-
Average content before reinjection (mg/l)	94.55	48.0	67.31	0.86
Average content after reinjection (mg/l)	86.25	40.1	57.15	1.2
Average content of injected water (mg/l)	63.98	20.1	25.68	2.29
Estimated injection water inflow (l/s)	3.0	3.5	2.7	2.6

7.5 Discussion

By comparing the predicted temperature decline based on the tracer test analysis with observed temperature data for well LWN-4 since reinjection started, it can be seen that the predicted cooling is greater than the monitoring results for all flow-channel scenarios except the most optimistic one (Figure 30). The observed temperature data shows that during 3 years of average production at 11 l/s, and

reinjection at 3 l/s, the total wellhead temperature decline has been less than 1˚C up to the end of 2002 (Figures 1 and 35). According to the model calculation for the same case, the temperature decline should reach 2-5˚C during the same period (Figure 26). Yet, for the most optimistic scenario, cooling of the production well should occur in the next several months and cooling of 1˚C takes 66 months. It should be mentioned that the calculated results are model dependent. The difference, however, doesn't indicate that the cooling prediction model is unreliable, but it reflects the inherent uncertainty in the assumptions made and other uncertainties, such as the earthquakes.

Generally, the difference between the calculated and observed results may be due to the following reasons:

- The flow conditions that prevailed during the tracer test in 1992, and through 1999, have changed drastically since 2000. During 2000-2002, the average yearly production was reduced from about 17 l/s to 11.5 l/s and reinjection was also carried out at the same time. This resulted in a drastic decrease in water level drawdown from more than 200 m in January 2000 to about 50 m in 2002, as can be seen from the water level history data (Figure 36). According to Darcy's Law, the corresponding decrease in pressure gradient between the two wells will reduce the fluid velocity and in turn cause less cooling of the production well than predicted because of relatively longer time being available for heat conduction from the rock matrix. In the cooling calculations, it was assumed that the recovery rate of the injected water was equal to the reinjection rate (3 l/s). Yet the mass flow estimation based on the chemical monitoring data has indicated that not all of the injected water had reached the production well. Therefore, it is quite possible that a part of the injected water has dispersed throughout the reservoir, especially taking into consideration the drastic change of flow conditions and the possible effect of the earthquakes.
- In the tracer test data analysis, only two flow-channels were used to simulate the tracer recovery data. But the temperature logging data shows that there may exist at least four flow-channels between the two wells. This simplification will, in turn, result in reducing the estimated flow-channel volume, and consequently cause relatively greater predicted cooling for the production well.
- The major earthquakes, which occurred in 2000, may also have changed the flow-pattern of the reinjection water flowing from the reinjection well to the production well. During the earthquakes, some new fractures and/or fissures may have been created or opened and some fractures and/or fissures may also have been closed.

8. SUMMERY AND CONCLUSIONS

The Laugaland and Kaldárholt low-temperature geothermal fields have been exploited for heating the towns of Hella and Hvolsvöllur in central S-Iceland since 1982 and 2000, respectively. In addition, about 3-4 l/s of 65˚C hot water from Kaldárholt has been reinjected at Laugaland since January 2000, to counteract the great water level drawdown that had developed at Laugaland.

The purpose of the study described here was to revise the conceptual model of the Kaldárholt system, estimate the production potential, and analyze the danger of cooling of the main production well at Laugaland due to reinjection of the Kaldárholt water there.

Through the interpretation of temperature logging data, the temperature conditions in the Kaldárholt field were analyzed. An upflow of 67˚C water, flowing from southeast to northwest and sloping about 45˚, has been identified.

By analyzing well test and interference data, the permeability and formation storativity of the Kaldárholt reservoir was estimated as well as the turbulence coefficients of production wells. The results show that the reservoir permeability is quite good.

Two lumped parameter models, which simulate the production response history of the Kaldárholt field very well, were used to predict water level changes for the next 10 years for different production scenarios. The production potential of the Kaldárholt system for the next decade is estimated to be about 55 or 95 l/s, depending on whether maximum allowable drawdown is assumed to be 100 or 240 m, respectively.

Based on the analysis of tracer test data from the Laugaland field in 1992, information on the connections between the injection well and production well was obtained. Based on this information and some further assumptions, temperature decline in production well LWN-4 was predicted for different production and reinjection scenarios. These cooling predictions indicate that the cooling should have been 2-5˚C during the period since January 2000, while the monitoring data shows that the actual cooling of well LWN-4 is less than 1˚C at the end of 2002. The discrepancy is mainly attributed to the drastic change in flow conditions since 2000. Yet chemical monitoring data indicates that most of the reinjected water is recovered through the production well. Major earthquakes in June 2000 may also have influenced the flow-pattern from the reinjection well to the production well. Simplification inherent in the tracer simulation model may also add uncertainty to the predicted cooling.

In the brief study presented here, it has been determined that the production potential of the Kaldárholt geothermal field is quite large and that the field can easily sustain long-term production at the current production rate (at least for 20 years). It should be stressed that this conclusion was drawn from prediction of the current lumped parameter model, which was based on 3.5 years of monitoring data. It is recommended that these models should be revised or a distributed parameter model be developed when a long-term data-set is available. The current reinjection at Laugaland is quite successful. Yet, according to the cooling predictions based on the tracer test in 1992, the most optimistic scenario shows that cooling of the production well will occur in the future. It is recommended that careful monitoring is continued and some countermeasures should be considered. If a new reinjection scheme is to be set up in this field, a new production scale tracer test should be conducted before the actual reinjection operation is started. It is also a general conclusion that exploration work should accompany any practical work and utilization in all geothermal fields.

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APPENDIX I: Information on the wells at Kaldárholt

Well no.	Completion date	X Coordinate	Y Coordinate	Depth (m)	Casing (“/m)
KH-01	14.03.1968	619901	389747	96.0	5⅝ / 9.6
KH-02	22.11.1974	619824	389794	37.5	
KH-03	19.12.1989	619820	389882	77.1	
KH-04	20.12.1989	619768	389923	45.0	
KH-05	30.12.1989	619839	389938	71.2	5⅝ /12
KH-06	04.01.1990	619756	389879	122.0	5⅝ /13.5
KH-07	18.01.1990	619723	389889	128.0	5⅝ / 12
KH-08	30.01.1990	619602	389913	130.0	5⅝ / 13
KH-09	11.02.1990	619657	389912	116.0	5⅝ / 15
KH-10	22.02.1990	619599	389960	117.0	5⅝ / 13
KH-11	07.04.1998	619650	389964	75.0	3 / 21
KH-12	08.04.1998	619724	389792	90.0	3 / 21
KH-13	14.04.1998	619687	389839	105.0	3 / 18
KH-14	15.04.1998	619697	389850	120.0	3 / 18
KH-15	16.04.1998	619687	390039	111.0	3 / 15
KH-16	17.04.1998	619673	389937	114.0	3 / 8
KH-17	17.04.1998	619664	389811	405.0	5⅝ / 63
KH-18	04.05.1998	619634	389783	120.0	3 / 15
KH-19	05.05.1998	619605	389754	120.0	3 / 15
KH-20	05.05.1998	619533	389676	120.0	3 / 15
KH-21	07.05.1998	619635	389643	85.0	3 / 15
KH-22	08.05.1998	619727	389674	161.0	3 / 15
KH-23	11.05.1998	619634	389710	121.0	3 / 15
KH-24	12.05.1998	619576	389847	121.0	3 / 15
KH-25	13.05.1998	619464	389850	120.0	3 / 12
KH-26	15.05.1998	619402	389859	120.0	3 / 15
KH-27	16.05.1998	619291	390016	139.0	3 / 15
KH-28	17.05.1998	619524	389818	90.0	3 / 15
KH-29	19.05.1998	619493	389741	126.0	5⅝ / 15
KH-30	22.05.1998	619454	389590	21.0	3 / 15
KH-31	22.05.1998	619350	389587	120.0	3 / 51
KH-32	27.05.1998	619345	389621	315.0	5⅝ / 60
KH-33	30.06.1998	619901	389747	354.0	5⅝ / 55.4
KH-34	09.07.1998	619824	389794	456.0	5⅝ / 21
KH-35	08.01.1999	619820	389882	540.0	5⅝ / 27
KH-36	03.05.1999	619768	389923	445.0	8⅝ / 253