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ASSESSMENT OF THE HOFSSTADIR GEOTHERMAL FIELD, W-ICELAND, BY LUMPED PARAMETER MODELLING, MONTE CARLO SIMULATION AND TRACER TEST ANALYSIS

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ABSTRACT

The Hofsstadir geothermal system, which was discovered during an extensive regional reconnaissance survey in W-Iceland in 1995, is a typical liquid-dominated convective low-temperature system. The entire monitoring data available for the only production well, HO-1, were simulated by lumped parameter modelling. Due to insufficient recharge, a continuous water-level decline -1has been observed. Reinjection started in early 2007 by injecting the return water from the heating system into injection well HO-2. Through simulating various production scenarios, using the best fitting model based on data collected without reinjection, the connection between the two wells was studied. The future water-level changes in the production well were predicted, based on the assumption that a given percentage of the reinjected water could eventually be re-extracted through the production well, without causing additional pressure drop. The calculated results indicate that this system will be able to sustain a 20 l/s average production through 2032, without reinjection. This will require that the down-hole pump in HO-1 be lowered. If reinjection is applied in the long term, then the production capacity of the field can reach up to 30 l/s with minor cooling of the production well. Monte Carlo volumetric assessment was applied to the Hofstadir field. The results predict with 90% probability that at least 25 MWth can be produced for a production period of 30 years, at least 12 MWth for 60 years and at least 7 MWth for 100 years, based on the area estimate from the lumped parameter model. During the tracer test, which was started on 29-8-2007, a total of 101 hot water samples were collected and analyzed. The data were interpreted using a multiple flow-channel model. The simulations of transport pulses show that there are direct paths between the feed-zones of well HO-2 and those of well HO-1. A future cooling effect due to long term injection within this field was predicated using the same model. Finally, the energy increase, due to the injected water being heated up and re-extracted through the production well, was calculated for the next 30 years, using different assumptions for flow channel models. The results show that large-scale cooling is not likely to happen in this field. The injection conditions within this field are optimal and the contribution of reinjection to maintaining the reservoir pressure is quite significant. Through reinjection, the annual energy production of the Hofsstadir geothermal system can be enhanced by approximately 50%.

1. INTRODUCTION

1.1 General

Use of geothermal resources, as a clean and renewable form of energy, has developed rapidly and great achievements have been obtained in the past decades, not least after the oil crises in the 1970s and 1980s. In recent years, geothermal energy has played a more and more important role in supplying green energy for economic development in many parts of the world. Another aspect of geothermal energy is its contribution in reducing greenhouse gas emissions and counteracting global climate change. It is precisely because of this, that geothermal energy is attracting more and more attention, becoming a hot issue and getting a lot of economical and political support from governments all over the world. Of course, Iceland, as a country rich with potential for geothermal energy, is one of the largest beneficiaries of this development. Over the last 60 years, there has been big development in the use of energy for space heating in Iceland. Most towns and communities in Iceland now use geothermal water directly for space heating. At present, geothermal energy provides more than half of the energy consumed by the 300,000 inhabitants, or about 10,500 GWh/y, including space heating, electricity generation, aquaculture, balneology, and agriculture, etc. As Figure 1 reveals, the largest share, 50% of the use of geothermal energy goes to space heating of 90% of all Iceland‘s households, followed by electricity production accounting for 34% (Orkustofnun, 2008).

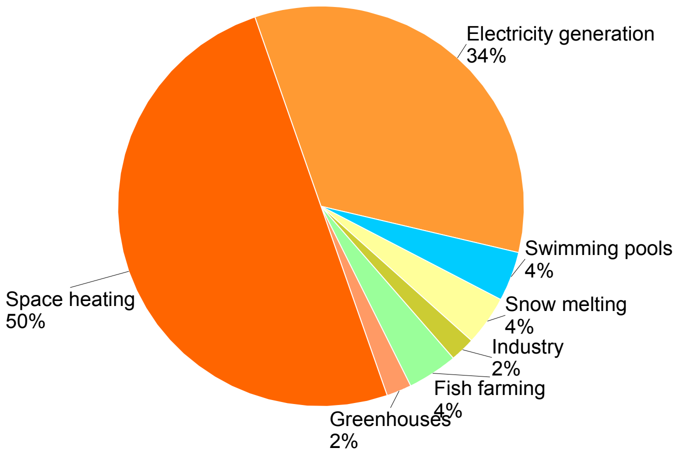

FIGURE 1: Utilization of geothermal energy in Iceland in 2007

1.2 Hofsstadir geothermal field

The Hofsstadir geothermal field is one of the numerous low-temperature geothermal areas in Iceland. It is located in W-Iceland, about 10 km south of the town of Stykkishólmur which has a population of 1500 inhabitants (see Figure 2). The hot water from Hofsstadir geothermal field is mainly used for the Stykkishólmur district heating system.

The geothermal system was discovered during an extensive regional reconnaissance survey on the northern part of the Snaefellsnes peninsula in W-Iceland. During the survey a temperature gradient anomaly with a NW-SE direction was discovered at Hofsstadir. It was followed up by more localized geological-, magnetic- and temperature gradient surveys, which confirmed a pronounced temperature gradient anomaly of up to 400°C/km (Figure 2). The thermal gradient observed within the anomaly was well above the gradient values (on the order of 70°C/km) predominant in the region. In order to get a comprehensive understanding of the region, more than 120 exploration wells, mostly 50-100 m in depth, have been drilled in this field since 1995.

During the autumn of 1996, production well HO-1 was drilled to a depth of 855 m in the centre of the main anomaly. The well was cased to a depth of 156 m and intersected two main aquifers with water at a temperature of 86-88°C. Air-lift testing at the end of drilling indicated that the well was quite productive (~40 l/s) (Björnsson et al., 1997). In order to evaluate the feasibility of constructing a heating system, including a main hot-water pipeline from Hofsstadir to Stykkishólmur, the necessary heat exchangers, and the distribution system within the town, a well test of well HO-1 was carried out in late 1997. It lasted 5 months, and the pumping flowrate was about 15-20 l/s.

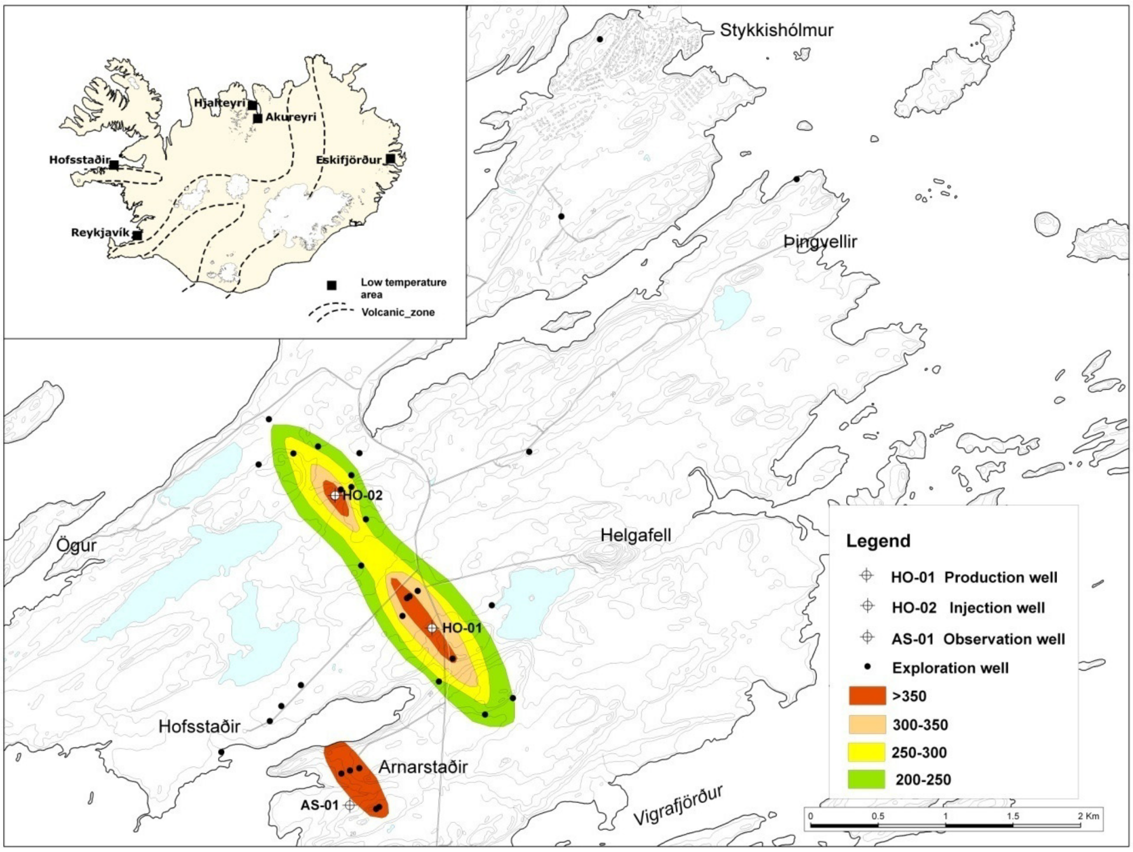

FIGURE 2: The Hofsstadir geothermal field and Stykkishólmur town;
the map shows also the gradient anomalies (°C/km) and the location of wells

Utilization of well HO-1 started during middle to late 1999. The average yearly production through this single production well since that time has been on the order of 19 l/s. The hot water production, as well as the response of the well and geothermal reservoir, including the pressure and the temperature, has been monitored carefully with a computerized monitoring system (Kristmannsdóttir et al., 2002).

In order to provide better understanding of the reservoir characteristics of the Hofsstadir geothermal system, it was decided to carry out a tracer test in late 2007. The tracer pulse was captured very well and will be discussed in detail in a later section.

1.3 Previous studies in Hofsstadir geothermal field

Because Hofsstadir geothermal field is devoid of surface manifestations, the question has arisen as to whether their nature and/or properties are in some ways different from the nature and properties of other low-temperature systems in Iceland. Another question is whether this system can be utilized in a sustainable manner, on the time order of 100-300 years. Since exploitation started, several studies involving reservoir engineering modelling, chemical characteristics of the hot water and a lithological analysis based on cuttings from the well, have been carried out as soon as the data became available.

Björnsson and Fridleifsson (1996) submitted a report which described the drilling history and well logs as well as other information on well HO-1. Björnsson et al. (1997) stated in a report that well HO-1 was productive and that it could sustain a 30 l/s flow-rate. This was based on a simple lumped parameter model that was developed on the basis of data from a 5-month production test conducted in 1997. According to chemical analysis results (Kania and Ólafsson, 2005), the geothermal water is brackish, calcium is the dominant cation, and the water is of a Cl-Ca-Na type. The isotopic composition of the thermal water indicates that it is not strictly a mixture of seawater and present-day freshwater. The results from geothermometry equations indicate that chalcedony controls the silica concentration in the reservoir. The isotopic ratios for δD and $\delta^{18}O$ demonstrate that the hot water of Hofsstadir field is significantly lighter than present day precipitation in the mountains of the Snaefellsnes peninsula. Its origin probably dates back to an age well into the latest glaciation period some ten thousand years ago. Also, the high mineral content of the water, which may result from a long time to equilibrate with rock matrix, seems to indicate that this system has closed boundaries.

Kristmannsdóttir et al. (2005) and Axelsson et al. (2005a) updated the lumped parameter model of the geothermal field and simulated the system with a closed and an open model version, respectively. The modelling results indicate that the reservoir appears to have very low external permeability, and behaves as if almost closed, which explains the continuously increasing draw-down. Also in 2005, the Hofsstadir geothermal field was used as an example to discuss the reliability of lumped parameter modelling. The observed water-level changes lie between the results of an open and closed version of the model. This effectively demonstrates the reliability of lumped models in simulation of low-temperature geothermal fields (Axelsson et al., 2005b). In 2008, lumped parameter modelling was applied to predict behaviour for the next 20 years of production; and currently available tracer test data were also interpreted by simple modelling (Rezvani Khalilabad and Axelsson, 2008).

1.4 This work

The production of geothermal fluid/heat will, in most cases, inevitably create a hydraulic/heat sink in the reservoir, especially for systems with little or no recharge. This leads to pressure and temperature gradients which, in turn, – after termination of production – generate fluid/heat inflow to re-establish the pre-production state. The energy production potential of geothermal systems is highly variable, and the production capacity of geothermal systems is not, as most people imagine, unlimited. The regeneration of geothermal resources is a process which occurs over various time scales, depending on the type and size of the production system, the rate of extraction, and on the attributes of the resource.

Geothermal exploitation and production are quite different from that of groundwater flow and petroleum reservoirs, even though geothermal science draws heavily from the theory of these two fields. The biggest difference is that geothermal production focuses not only on the mass of water or steam, but also on temperature and enthalpy, that is on "energy mining." There is a common agreement across the world that geothermal energy is classified as a "renewable" resource and that geothermal resources can be used in a "sustainable" manner, which means that the production system applied is able to sustain the production level over long periods of time.

Unfortunately, the terms "renewable" and "sustainable" are often confused. The former concerns the nature of a resource; the word "renewable" describes a characteristic of the resource: the energy removed from the resource is continuously replaced by more energy on time scales similar to those required for energy removal. The latter term applies to how a resource is utilized. Axelsson et al. (2001) proposed the following definition for the phrase "sustainable production of geothermal energy from an individual geothermal system":

> *"For each geothermal system, and for each mode of production, there exists a certain level of maximum energy production, $\boldsymbol{E_0}$, below which it will be possible to maintain constant energy production from the system for a very long time (100-300 years). If the production rate is greater than $\boldsymbol{E_0}$ it cannot be maintained for this length of time. Geothermal energy production below, or equal to $\boldsymbol{E_0}$, is termed **sustainable production** while production greater than $\boldsymbol{E_0}$ is termed **excessive production.**"*

Anyway, the longevity of production for a given system can be secured and sustainable production can be achieved by using moderate production rates, which take into account the local resource characteristics (field size, natural recharge rate, etc.). As mentioned above, the value of E_0 for an individual system is not known a priori, but it may be estimated by many assessing methods, such as the volumetric method, simple analytical modelling, lumped parameter modelling and detailed numeric modelling, all of which are based on exploration and production monitoring data as they become available. Using these methods, a level of sustainable utilization can be found and many unfavourable outcomes can be avoided.

The main objective of reservoir engineering is to assess the production potential of a geothermal reservoir and predict its response to future utilization. Similarly, for the case of the Hofsstadir geothermal field, the study target in this paper is modelling and simulation of reinjection studies and the interpretation of tracer tests were carried out to seek the best exploitation strategy. The main purpose of this report can be summarized by the following:

1) Build a more reliable conceptual model of the system based on geological, geophysical and well log data;
2) Revise the current relatively simple lumped parameter model. A much longer set of monitored data, from 19-03-1997 to 14-12-2007, was used for simulation than before and for the estimation of the reservoir properties, such as the area and the rock permeability of different parts of the reservoir;
3) Conduct a reinjection study including to what extent reinjection affects the water-level in the production well using the best-fitting parameter model developed, based on data collected when there was no reinjection, and estimate the properties of the flow channels between the injection well and the production well;
4) Optimize the injection program based on the best-fitting model parameters and predict the future water-level changes for various production scenarios;
5) Assess the production capacity of the Hofsstadir geothermal field by using the Monte Carlo volumetric assessment method, in which some parameters are adopted from results of lumped parameter modelling;
6) Interpret data from the tracer test, which started on 29-08-2007 and is currently ongoing, using a multiple flow-channel model. The contribution of reinjection in counteracting drawdown in the production well was also analyzed;
7) Calculate the total energy increase based on the most pessimistic, medium and the optimistic modes, respectively, for the next 30 years;
8) Finally, several modelling results and suggestions, which are important for the development of this field, are presented at the end of this study.

2. AVAILABLE INFORMATION AND DATA

2.1 Formation lithology

The bedrock in the Hofsstadir area is mainly composed of Miocene basalts from which about 1000 m have been eroded. The reservoir rock of this field consists primarily of coarse-grained basaltic units with thin layers of sediments, two of which may be acidic, and a number of mostly basaltic intrusions. From 780 to 855 m depth, i.e. to the bottom of well HO-1, the rock consists of a gabbroic intrusion. Pyrite, mixed layer clays of smectite and chlorite, with chalcedony, quartz, and calcite are found from the surface to 150 m depth. At depths below 150 m, the high-temperature alteration minerals chlorite and epidote are found (see Figure 3).

The reservoir rock is altered to a high degree with epidote below 150 m depth, indicating an alteration temperature of approximately 250°C. Below 300 m, the rock is altered with amphibole, which suggests an alteration temperature of ~300°C. The high temperature alteration and intrusions indicate

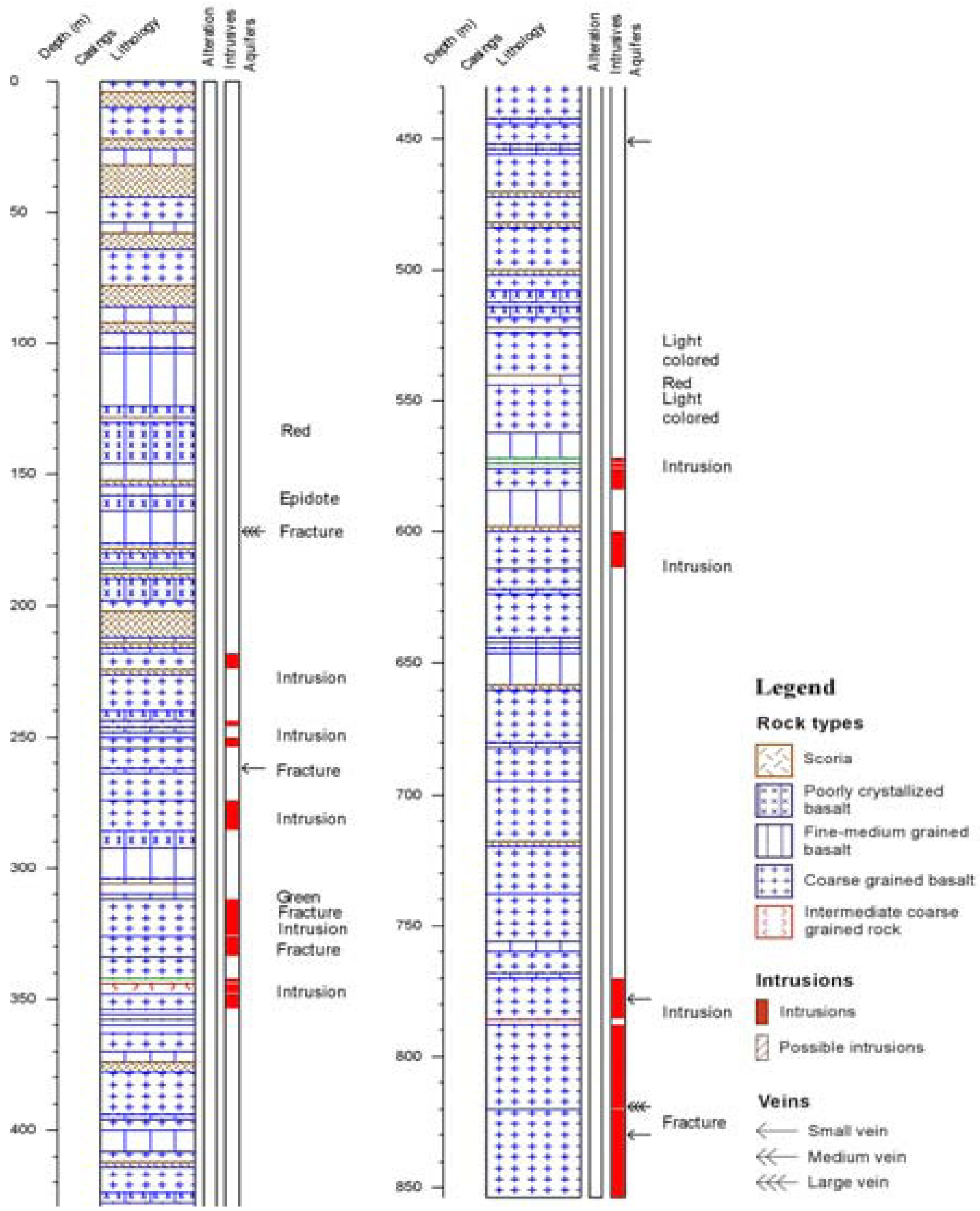

FIGURE 3: Lithological profile of well HO-1
(Björnsson and Fridleifsson, 1996)

that the well is situated within an extinct central volcano (from Miocene time, >5 MY). The high degree of alteration of the reservoir rocks indicates much higher temperatures than are presently observed. The aquifers in well HO-1 are all associated with fractures, and the last mineral to precipitate in all cases is stilbite.

2.2 Main structures

The peninsula were the Hofstadir field is located is rather barren with low rocky hills and boggy depressions. The dominant structural trend of the area is NE-SW as defined by basaltic dykes and faults, and the strike of the basalts. Narrow inlets from the sea cut into it from northeast and southwest. The geothermal field involves two sub-parallel fissures spaced 1200 m apart, trending SSE-NNW. The eastern fissure closely approaches the sea shore at its north-northwest end, and one of the inlets crosses the western one. The two fissures are only locally recognizable by surface criteria but they show up clearly in the thermal gradient of some 30 shallow (mostly ~50 m deep) boreholes

(Björnsson et al., 1997). A more recent tectonic pattern of east-west faults and rare NW-SE trending dykes is less conspicuous. This is interpreted as a conjugate set in response to the maximum WNW-ESE horizontal compression. The geothermal system at Hofsstadir is related to dykes trending NW-SE. Although of Miocene age, they form a plane of weakness which breaks up under the present stress field.

Due to secondary mineralization, the Miocene basalts and dykes within this peninsula have low permeability. Permeability anomalies are fissure controlled, the feature near Stykkishólmur being the largest traced so far in the surroundings. These provide the necessary pathways for sufficiently deep circulation of groundwater down to at least 2000 m to sustain a geothermal system.

2.3 Reservoir features

According to the results deriving from cuttings analysis, well logs which include resistivity well logs, televiewer logs and pumping tests, there are two main production aquifers in this field (i.e. well HO-1), one located at a depth of 819 m (90% of the flowrate), and the other about 4 m in thickness located at 171-175 m depth (7% of the flowrate). Besides these two main feed-zones, several minor aquifers were also found at depths of 262, 451, 778, 785, and 830 m. The aquifer at 171-175 m is a fracture within a basaltic layer, whereas the main aquifer is related to a fracture in a gabbroic intrusion (as shown in Figure 3). Since the completion of drilling, a total of 15 temperature logs have been conducted in production well HO-1; the first was carried out at the end of drilling, while the last was measured in April 2000 (Figure 4). The temperature logs show a reservoir temperature of about 86-87°C.

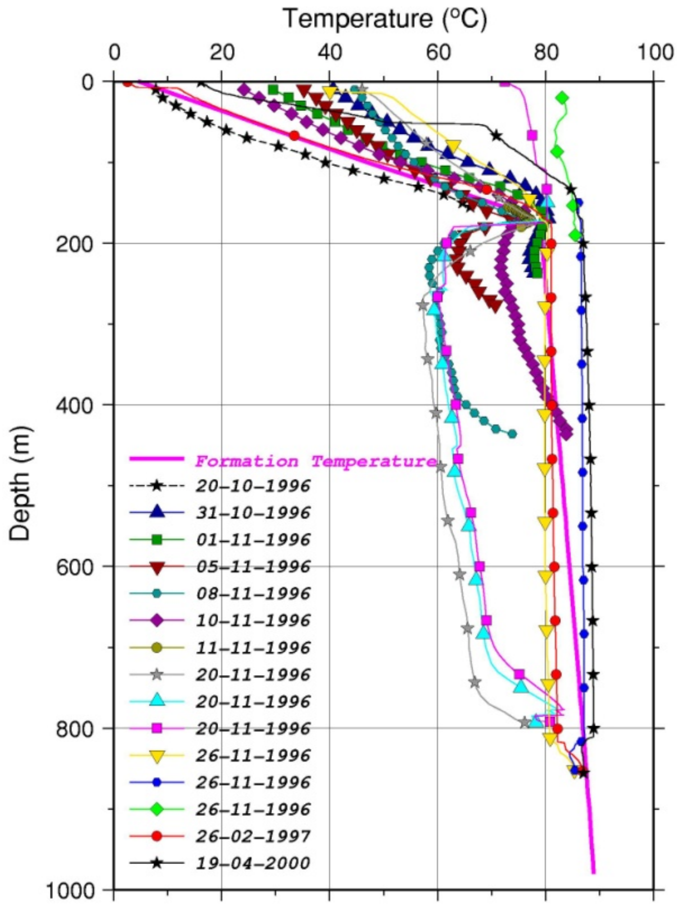

FIGURE 4: Temperature logs from production well HO-1

2.4 Conceptual model and heat source

In Iceland, the low-temperature areas, which have a reservoir temperature less than 150°C, are all located outside the volcanic zone passing through the island. The largest low-temperature areas are located in SW-Iceland on the flanks of the volcanic zone, but smaller areas are found throughout the country. The heat source for the low-temperature systems is believed to be the abnormally hot crust in Iceland. Bodvarsson (1982, 1983) proposed a model for the heat source mechanism, which appears to be consistent with the data now available. According to this model (see Figure 5), the *recharge* to a low-temperature system is shallow ground water flow from the highlands to the lowlands. Inside a geothermal area, the water sinks through an open fracture, or along a dyke, to a depth of a few km where it takes up heat from the hot adjacent rock and ascends subsequently because of reduced density. This *convection* transfers heat from the deeper parts of the system to the shallow parts. The fracture is closed at depth, but according to Bodvarsson's model, the fracture opens up and continuously migrates downward during the heat mining process by cooling and contraction of the adjacent rock. Thus, the low-temperature activity is a transient process. Recent studies on low-temperature resources in Iceland indicate that dykes may not be the primary fluid conductors, but rather younger fractures or faults. For the given abnormal thermal condition in Iceland's crust, it appears that the regional tectonics and the resulting local stress field control the low-temperature activities (Axelsson, 1991).

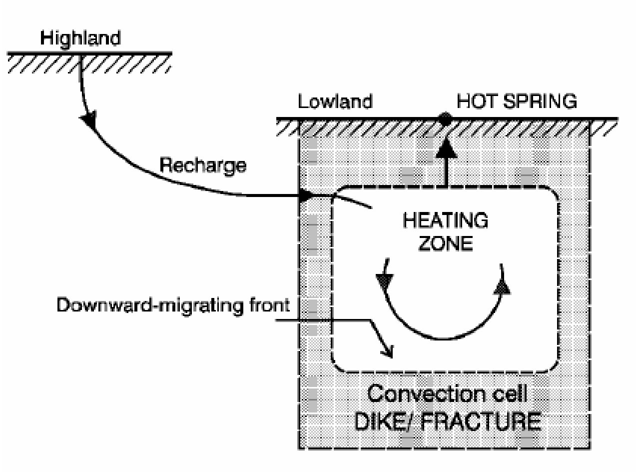

FIGURE 5: Conceptual model of the heat uptake mechanism for a typical low-temperature system in Iceland (Bodvarsson, 1983)

The Hofsstadir geothermal field discussed in this paper is one of numerous low-temperature geothermal fields existing throughout Iceland. The characteristics of this system, like for many other low-temperature fields found in Iceland, are those of a typical liquid-dominated convection low-temperature system and are controlled by regional tectonic activity, including the size of the field, the recharge, the field boundary, etc.

3. ANALYSIS AND MODELLING OF LONG TERM MONITORING DATA

3.1 Available data of the Hofsstadir geothermal field

Since pumping hot water from production well HO-1 started, the production rate and water-level changes (including the well test data) have been monitored carefully. On 08-02-2000, a computerized monitoring system was installed in production well HO-1. Since then, all the parameters including the wellhead pressure and temperature data have been carefully collected. It is these good quality data that constitute the basis of this study. Most of the data available for this study are presented in Figure 6, these are:

1) Production history of well HO-1, from 19-03-1997 to 12-08-2008;
2) Observed water-level history of well HO-1, from 19-03-1997 to 12-08-2008;
3) Observed water-level history of well AS-1, from 23-02-2002 to 12-08-2008;
4) Temperature history of well HO-1, from 08-02-2008 to 12-08-2008;

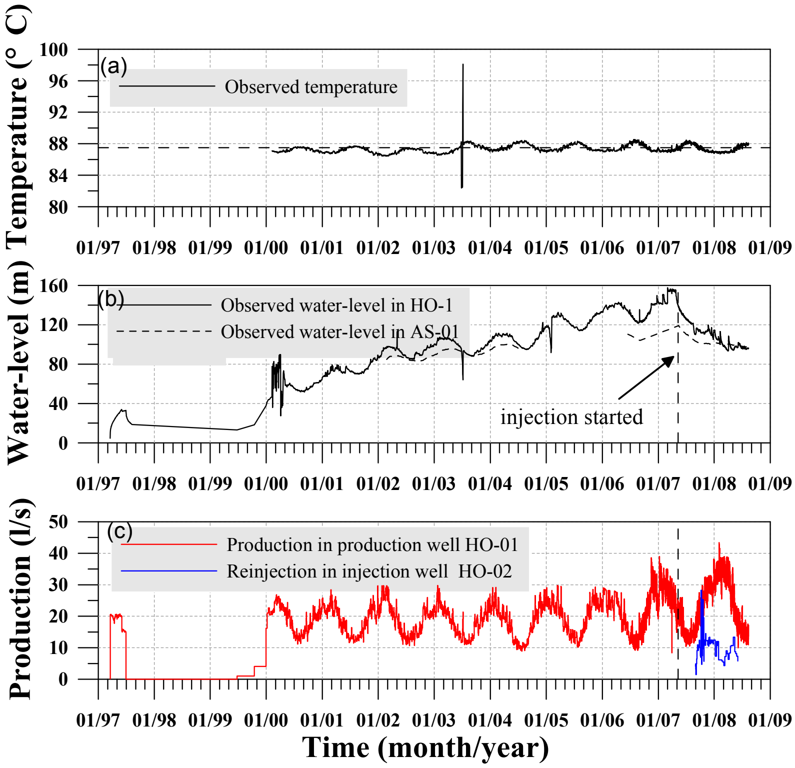

FIGURE 6: Production, water level and temperature in production well HO-1 and re-injection flowrate in injection well HO-2, with the observed water level in observation well AS-1

5) Reinjection started on 22-04-2007, injection flowrate have been monitored since 29-08-2007;
6) Tracer test data, from 29-08-2007 to 14-07-2008, carried out between the injection well HO-2 and production well HO-1, which is still ongoing.

During the past decade, the average production of Hofsstadir geothermal field was maintained at about 20 l/s with the actual flowrate fluctuating from 11 to 29 l/s. As shown in Figure 6, the water lever has decreased continuously since production started and the maximum drawdown of 155 m was reached in production well HO-1 in Apr 2007. Also, a continuous drawdown trend has been observed in observation well AS-1, which is located 800 m southeast of well HO-1 (as shown in Figure 2). The temperature of the hot water produced from production well HO-1 is rather constant at 87.5°C. After reinjection, which was started on 22-04-2007, the water-level recovered considerably in production well HO-1 and a clear water-level recovery was also observed in observation well AS-1, even though the annual changes were not obvious due to poor data collecting. Unfortunately, the injection flowrate was not monitored simul-taneously. However, about two months later manual recording of the injection flowrate was started at a fixed frequency.

3.2 Lumped parameter modelling for the Hofsstadir geothermal field

3.2.1 General

Mass and heat transfer are the two predominant processes during the undisturbed natural state of a geothermal system. During production, the mass and heat transport forced upon the system causes spatial as well as transient changes in the pressure state of a reservoir. The production potential of a geothermal system is predominantly determined by a pressure decline due to production. If the energy supply is sufficient, then the drawdown or pressure decline becomes the unique parameter influencing the production capacity of a geothermal system.

Various methods have been used over the last several decades to assess geothermal resources during both exploration and exploitation phases of development. Modelling plays an essential role in geothermal resource development and management. The two most important purposes of geothermal modelling are to obtain information on the conditions in a geothermal system as well as on the nature and properties of the system. Quite a few modelling approaches are currently in use by geothermal reservoir specialists. In a few words, modelling involves a mathematical model being developed that simulates some, or most, of the data available on the geothermal system involved. This ranges from basic volumetric resource assessment and simple analytical modelling of the results of a short well test to detailed numerical modelling of a complex geothermal system, simulating an intricate pattern of changes resulting from long-term production. These can be (a) simple analytical models, (b) lumped parameter models or (c) detailed numerical models. Numerous examples are available on the successful role of modelling in geothermal resource management (Axelsson and Gunnlaugsson, 2000; O'Sullivan et al., 2001). Also, through modelling, one can predict the response of the reservoir to future production and estimate the production potential of the system as well as estimate the outcome of different management actions (Axelsson, 2008a).

3.2.2 Method description

Because of its many benefits, including time and cost effectiveness, high precision, and their basis being easily grasped, lumped parameter models have been used extensively to simulate data on pressure (water-level) changes in geothermal systems in Iceland as well as in the P.R. China, Central America, Eastern Europe, The Philippines, Turkey and many other countries during the past few decades. They can simulate such data very accurately, if the data quality is sufficient (Axelsson et al., 2005a). The principal purpose of this method is, of course, as mentioned above, to estimate the production potential of geothermal systems through pressure response predictions and to estimate the effects of various production scenarios.

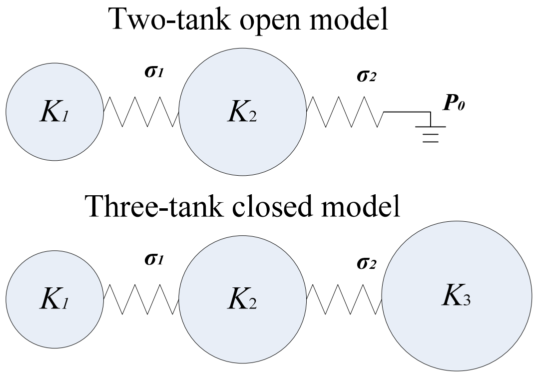

FIGURE 7: General lumped parameter models used to simulate water level or pressure changes in a geothermal system (Axelsson, 1989)

Figure 7 shows a sketch map of a lumped parameter model used to simulate the observed water-level changes resulting from long-term production history of wells. For details, the reader is referred to (Axelsson, 1989) and (Axelsson and Arason, 1992). The program LUMPFIT (included in the *ICEBOX* package) tackles the simulation problem as an inverse problem and will automatically fit the analytical response functions of lumped models to the observed data by using a nonlinear iterative least-squares technique for estimating the model parameters (Axelsson, 1989). The innermost tank in both models, which has a mass storage coefficient κ_1, simulates the volume of the production part in the geothermal system. This tank is connected by a conductor σ_1 to a second tank κ_2, which simulates the outer and the deeper parts of the reservoir. The conductor simulates the rock conductivity (permeability) between those two parts. In the open model, the second tank is connected to a constant pressure recharge source (represents the boundary conditions). In the closed model the second tank is connected to a third tank which probably simulates both the deeper parts of the reservoir and the overlying groundwater system.

The procedure for finding the best fitting parameters for a specific model, which could best fit the observed data, is as follows: First, begin with a one-tank closed model, then turn to a one-tank open model. After that, a two-tank closed model and a two-tank open model follows. Each previous model will give suggestions on the initial guesses of the model coefficients for the next more complex model. In this way, it should be continued step by step until it is expanded to a three tank open model, which is the most complicated model allowed by the program and often is sufficient for most systems. The pressure response (ΔpP) of a general open lumped model with *N* tanks, to a constant production (Q), since time t = 0, is given by the equation:

$$\Delta p(t) = -\sum_{i=1}^{N} Q\frac{A_i}{L_i}\left[1 - e^{it}\right] \tag{1}$$

The pressure response of an equivalent *N*-tank closed model is given by the equation:

$$\Delta p(t) = -\sum_{i=1}^{N-1} Q\frac{A_i}{L_i}\left[1 - e^{-L_i t}\right] - QBt \tag{2}$$

The coefficients A_i, L_i and B are functions of the storage coefficients of the tanks (κ_i) and the conductance coefficients of resistors (σ_i) of the model.

3.2.3 Lumpfit modelling of the Hofsstadir geothermal system

In order to evaluate the potential of the Hofsstadir geothermal field, a more reliable lumped parameter model, in which a longer data sets are used, was developed. Firstly, new data were rearranged, which included removing bad data-sets, combining the data in accordance with the standard format of program LUMPFIT as a new input file, which has a continuous series of 10 years production and water-level history. Then, the data was simulated from the simplest 1-tank model and on, step by step. There probably exists a shift problem in the observed water-level data since 22-04-2007, because of equipment replacement. Based on the experiences of the engineer working at the pumping station of well HO-1, the shift should most likely be about 10 m. So the shift problem was corrected by subtracting 10 m from the monitoring data (after that date).

After that, the corrected data was used as an input file and simulated again, the simulation results were greatly enhanced, in contrast with the results of the data without correction. The modelling results of different models are shown in Figure 8. The parameters for variable sized models are listed in Table 1. After finding the best fitting models, optimistic predictions of water-level changes were represented by an open version of the model as well as pessimistic predictions by a closed version model for various future production schemes (this will be discussed later in the section on reinjection).

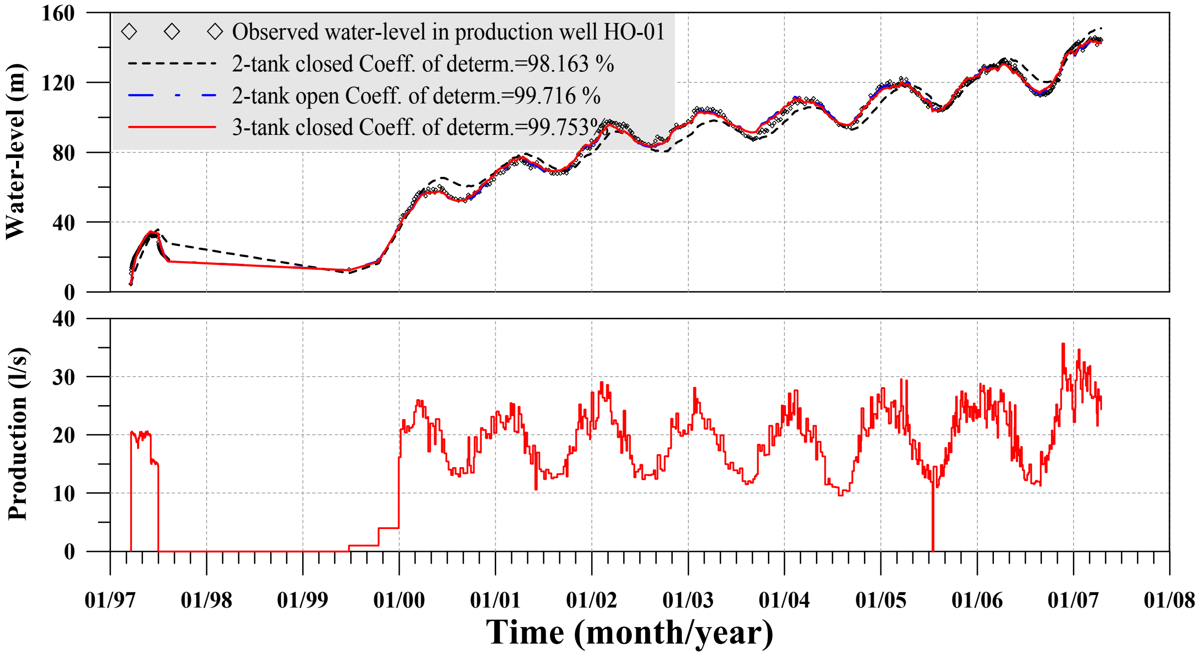

FIGURE 8: Simulation results of different models based on the data set up to the reinjection period

TABLE 1: Parameters of lumped models for the production well HO-1 based on all monitoring data before reinjection started (from 19-03-1997 – 21-08-2007)

Model number	3	4	5
Number of tanks	2	2	3
Number of parameters	3	4	5
Model type	closed	open	closed
A_1	2.66×10^{-7}	5.52×10^{-7}	5.76×10^{-7}
L_1	9.91×10^{-8}	4.17×10^{-7}	4.77×10^{-7}
A_2		4.84×10^{-8}	5.07×10^{-8}
L_2		8.35×10^{-9}	1.55×10^{-8}
B	1.62×10^{-8}	0	8.24×10^{-9}
$\kappa_1(ms^2)$	361.810	170.02	160.70
$\kappa_2(ms^2)$	5933.37	202.49	167.28
$\kappa_3(ms^2)$			10551.80
$\sigma_1(10^{-5}ms)$	3.38×10^{-3}	6.52×10^{-4}	6.97×10^{-4}
$\sigma_2(10^{-5}ms)$		1.84×10^{-4}	2.43×10^{-4}
Root mean square misfit	5.33	2.09	1.96
Estimate of standard deviation	5.34	2.10	1.96
Coefficient of determination	98.16%	99.72%	99.75%

By using the parameters, the main reservoir properties of the Hofsstadir geothermal system could be estimated. Water compressibility β_w was estimated to be 4.4×10^{-10} (Pa^{-1}) at reservoir conditions (87°C). The compressibility of the rock matrix β_r, composed of basalt, is approximately 3×10^{-11} Pa^{-1}. Storage, in a liquid-dominated geothermal system, can be the result of two types of storage mechanisms. One case is the mobility of a free surface of the reservoir, (see Equation 3); in the other case, the reservoir is confined and the storage of the reservoir may be controlled both by liquid and formation compressibility (see Equation 4). The storativity of the Hofsstadir reservoir was estimated using Equations 3 and 4, respectively.

$$s = \phi/gh \tag{3}$$

$$s = \frac{\Delta m}{\Delta pV} = \rho_w[\phi\beta_w + (1 - \phi)\beta_r] \tag{4}$$

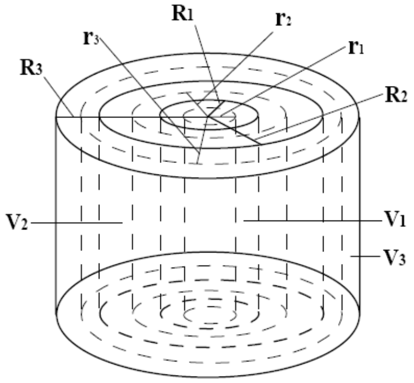

FIGURE 9: Three-tank model with two-dimensional flow

Then the value of storativity can be used to estimate reservoir volume and area by assuming two dimensional flow. The value $\phi = 0.1$ was used for the porosity of the reservoir rock which is not fresh basalt. This value is commonly used in Iceland. Based on geophysical surveys in Hofsstadir field, a 1000 m reservoir thickness was assumed, and considered for calculations. Using the following series of equations, the principal properties and characteristics of the reservoir, such as the volumes of different parts, their areas and permeability, could be deduced based on the two-dimensional flow model (see Figure 9 and Table 2):

$$\kappa_1 = V_1 s;\ \kappa_2 = V_2 s;\ \kappa_3 = V_3 s \tag{5}$$

$$R_1 = \sqrt{\frac{V_1}{\pi H}};\ R_2 = \sqrt{\frac{V_1+V_2}{\pi H}};\ R_3 = \sqrt{\frac{V_1+V_2+V_3}{\pi H}} \tag{6}$$

$$r_1 = R_1/2\ ; r_2 = R_1 + (R_2 - R_1)/2\ ; r_3 = R_2 + (R_3 - R_2)/2 \tag{7}$$

$$k = \sigma_j \frac{\ln\left({}^{r_{j+1}}/_{r_j}\right)\nu}{2\pi H} \tag{8}$$

TABLE 2: Reservoir properties of the Hofsstadir system according to lumped parameter models

Model	Properties		First tank	Second tank	Third tank	Total
2-tank closed	Reservoir volume (m^3)	Confined	5.20×10^{9}	8.53×10^{10}		9.05×10^{10}
		Free surface	3.55×10^{7}	5.81×10^{8}		6.17×10^{8}
	Area (m^2)	Confined	5.20×10^{6}	8.53×10^{7}		9.05×10^{7}
		Free surface	3.55×10^{4}	5.81×10^{5}		6.17×10^{5}
	Permeability k (m^2)	Confined	2.98×10^{-14}			
2-tank open	Reservoir volume (m^3)	Confined	2.45×10^{9}	2.91×10^{10}		3.16×10^{10}
		Free surface	1.67×10^{7}	1.98×10^{8}		2.14×10^{8}
	Area (m^2)	Confined	2.45×10^{6}	2.91×10^{7}		3.16×10^{7}
		Free surface	1.67×10^{4}	1.98×10^{5}		2.14×10^{5}
	Permeability k (m^2)	Free surface	5.34×10^{-15}	4.00×10^{-16}		
3-tank closed	Reservoir volume (m^3)	Confined	2.31×10^{9}	2.41×10^{10}	1.52×10^{11}	1.78×10^{11}
		Free surface	1.57×10^{7}	1.64×10^{8}	1.03×10^{9}	1.21×10^{9}
	Area (m^2)	Confined	2.31×10^{6}	2.41×10^{7}		2.64×10^{7}
		Free surface	1.57×10^{4}	1.64×10^{5}		1.8×10^{5}
	Permeability k (m^2)	Confined	5.52×10^{-15}	2.15×10^{-15}		

3.2.3 Discussion of simulation results

From an overall perspective, the three models simulate the data quite well, while if only comparing the coefficients of determination of the three models above, the best model was the 2-tank open model with a coefficient of 99.716% and the 3-tank closed model with a coefficient of 99.753%; so both simulated the observed water-level very well.

If one assumes the entire reservoir in Hofsstadir field is unconfined, the production part will correspond to a volume of 0.01 km^3 for both models, based on the constant thickness of 1000 m. This result may be too small compared to 800 km^2, the entire area of this region. Actually, based on the geological and geophysical survey results, the Hofsstadir field is most likely a confined reservoir rather than the case with a free surface. In the case of a confined reservoir, the calculated areas of the innermost part of the reservoir were very similar, 2.5 and 2.3 km^2 for open and closed models, respectively, little larger than the area of the thermal gradient anomaly shown in Figure 1. The second tank in both models (κ_2) which simulated the overall reservoir, corresponded to a volume of around 29 and 24 km^3 by using the same porosity for the confined assumption.

The properties of flow conductors can be used to estimate reservoir permeability by assuming a given reservoir geometry. By assuming radial flow in a conventional Theis reservoir with thickness 1000 m, the permeability-thickness between the first and second tank is estimated as 5 Dm and 0.4~2.15 Dm between the second tank and the recharge part. But according to the earlier test results (Björnsson et al., 1997), well HO-1 should most likely be able to sustain an average production of 15-20 l/s and is a quite productive well. Figure 6 shows that the water-level has, in fact, declined rapidly. The Hofsstadir reservoir appears to have fairly good internal permeability; this explains the well's high short term productivity. In contrast, the reservoir appears to have very low external permeability, or behaves as if almost closed, which explains the continuously increasing draw-down.

And also, if discussing the total area for both models, then the calculated results for 2-tank open and 3-tank closed models are 32 and 26 km^2, respectively. According to the results of the thermal gradient survey, the larger anomaly, i.e. where the gradient is higher than 250°C/km (as shown in Figure 1), is around 1.5 km^2. Therefore, the total estimated area of the reservoir must be at least around 2 km^2 with a range from 1.5 to 5 km^2.

4. REINJECTION STUDY AND PREDICTIONS

4.1 Reinjection experience

Geothermal reinjection started in Ahuachapan, El Salvador, in 1969, in the Geysers, California, in 1970 and in Larderello, Italy, in 1974. At the beginning, it started out as a method for waste-water disposal for environmental reasons. Now, it is also being used to counteract pressure draw-down (water-level decline) due to long term production, i.e. as artificial water recharge, to extract more of the thermal energy stored in the reservoir system and to reduce land subsidence caused by over-extraction of geothermal fluids. The increasing role of reinjection during the last decade or so is reflected in the number of geothermal fields where reinjection is an integral part of the field operation, as reported by different authors. Stefánsson (1997) reported 20 fields in 8 countries, Axelsson and Gunnlaugsson (2000) 29 fields in 15 countries, and Axelsson (2003) at least 50 fields in 20 countries. However, some of this apparent increase may be the result of better information. A recent, reliable number has not been compiled, but the number of fields is likely to be more than 60 today (Axelsson, 2008c).

Without reinjection the mass extraction and, hence, production capacity, would only be a part of what it now is in many of these fields. Reinjection is also a key part of all EGS (enhanced, or engineered, geothermal system) operations (Axelsson et al., 2005c). Clearly, it provides supplemental recharge and theoretical studies, as well as operational experience, have shown that injection may be used as an efficient tool to counteract pressure draw-down due to production, i.e. for pressure support. This applies, in particular, to systems with closed, or semi-closed, boundary conditions and thus limited recharge. Therefore, reinjection is fast becoming an integral part of all modern, sustainable and environmentally friendly geothermal utilization projects.

Geothermal reinjection is essential for sustainable utilization of geothermal systems which are virtually closed and have limited recharge. It is either applied inside a production reservoir, on the periphery of the reservoir, above or below the main reservoir or outside the main production field. Reinjection will, therefore, in most cases increase the production capacity of geothermal reservoirs, while counteracting the inevitable increase in investment and operation costs associated with reinjection. It is likely to be an economical way of increasing the energy production potential of geothermal systems in most cases (Axelsson, 2008c).

Some operational dangers and problems are associated with reinjection. These include the possible cooling of production wells, often because of short-circuiting or cold-front breakthrough, and scaling in surface equipment and injection wells because of the precipitation of chemicals in the water. Injection into sandstone reservoirs has, furthermore, turned out to be problematic. Because of this, extensive testing and research are prerequisites to successful reinjection operations. This includes tracer testing, which is the most powerful tool available to study the connections between reinjection wells and production wells (Axelsson, 2008b).

Because of different characteristics of the field, the most important task for the reinjection project is to seek the best injection strategy, which involves selecting the best location for the reinjection well, determining the depth of the well and estimating the maximum reinjection flowrate for a given system (Mannington et al., 2004). For hot-water systems, the danger of cooling due to reinjection can be minimised by locating injection wells far enough away from production wells, while the main benefit from reinjection (pressure support) is maximised by locating injection wells close enough to production wells. A proper balance between these two contradicting requirements must be found. The design of such a system depends on details of the structure of the field and the practicalities of well location. Therefore, careful testing and research are essential when planning injection. Tracer testing is probably the most important tool for this purpose, and will be discussed in detail in a separate section (Axelsson et al., 2005c).

4.2 Reinjection in the Hofsstadir geothermal field

At Hofsstadir, a continuous drawdown trend was observed, even when the production rate was maintained at a relatively steady level. Considering the increasing need for hot water in the future, which may be caused by population increase and production expanding in some other aspects, or the desire to seek a sustainable utilization manner, injection has to be applied in this field. Therefore, it was decided to carry out reinjection within the Hofsstadir geothermal system. In early 2006, reinjection well HO-2, with a depth of 413.2 m, was drilled 1200 m northwest of production well HO-1. Only one main aquifer with relatively good permeability was found at 319 m depth in this well. Since completion of this well, three temperature logs have been conducted (see Figure 10). At the end of Apr. 2007, the reinjection experiment was started. As mentioned before, the injection flowrate was not monitored during the first two months. While this did not tamper with the reinjection study, it is clear that the drawdown in production well HO-1 decreased drastically once reinjection started, as shown in Figure 6b. The temperature of the produced water during reinjection was rather constant. There was no evidence of cooling in the production well. The injection in Hofsstadir geothermal field was therefore quite successful.

4.3 Reinjection studies

4.3.1 First study phase

Whether an injection project can be carried out successfully within a given geothermal field depends on two factors: first there must be flow paths between an injection well and a production well; secondly, the flow channel should have proper characteristics profitable for the reinjection project. The most interesting question arising from this study might be: How much of the injected water in well HO-2 will return to production well HO-1 and can eventually be re-extracted without causing additional pressure decline? If no account is taken of the temperature and just this problem considered from the point of view of hydrodynamics, then the hydraulic relationship between the reinjection well and the production well can be estimated by using the injection and production flowrate data, and the water-level changes in the production well.

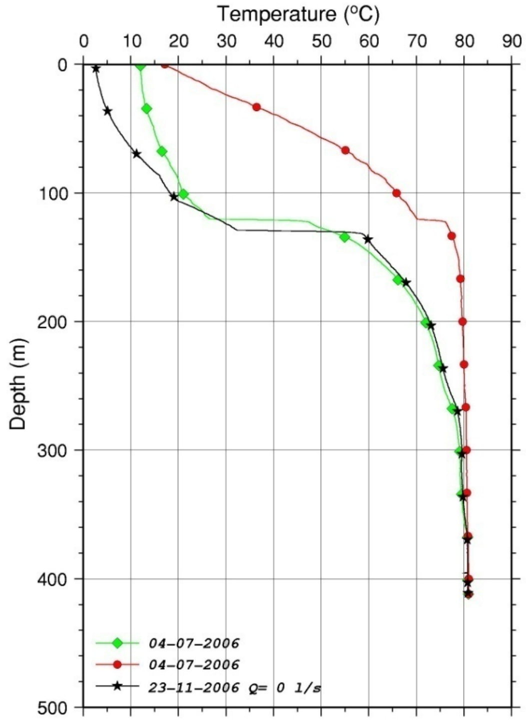

FIGURE 10: Temperature logs in injection well HO-2

The study process can be described as follows: First, select the best fitting parameter model, which is proper and can best represent the actual situation of the reservoir in question – here a 3-tank closed model was used for this purpose. In the second step, the production data were re-arranged by subtracting a given percentage of the injection flowrate, which is assumed to enable an equivalent production increase without further pressure decline, from the production flowrate. Consequently, use the best fitting parameter model to simulate the water level for the injection period. And then, judge the simulation results by simply comparing the coefficient of determination for various scenarios. Finally, adjust the assumed percentage and simulate the water-level repeatedly until the best match result is figured out.

As mentioned before, unfortunately the reinjection flowrate was not monitored synchronously with the reinjection work. So, for study purposes, we therefore assume two cases for the reinjection flowrate for the time period lacking data:

I. The injection rate is constant;
II. The injection rate is proportional to the production flowrate.

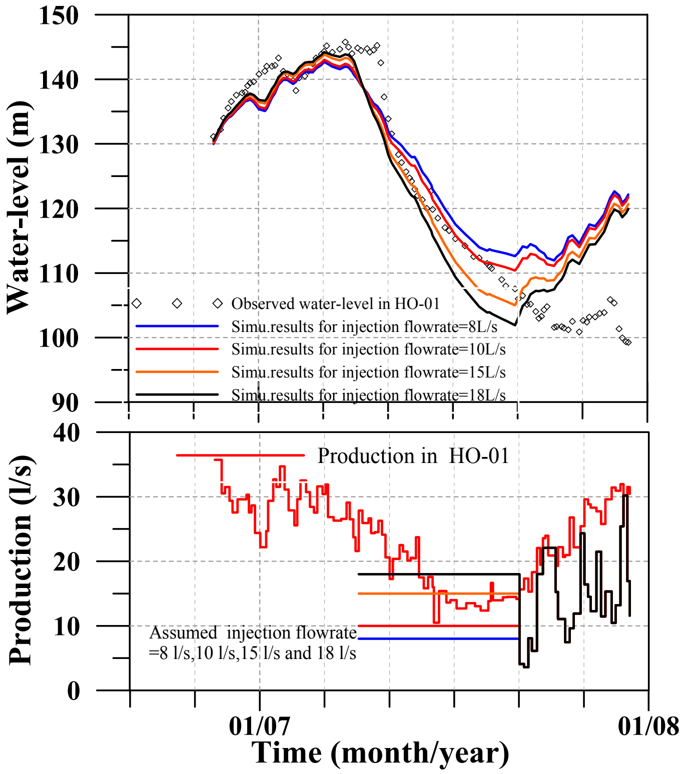

FIGURE 11: Simulation results based on the assumption that the reinjection flowrate is constant during the period lacking injection-data

For the two cases, various scenarios were tried. The simulation results for the different cases are presented in Figures 11 and 12. It is clear that the simulation results do not match the observed water level very well. The biggest difference between them is of the order of 10 m. At this stage, one could suggest that there may have been some mistakes in the collection of the water-level data in production well HO-1. However, observed water level in observation well AS-1, located 800 m southeast of the well HO-1, showed a very similar increasing trend of the water table as in well HO-1. Therefore, the problem must be in the injection flowrate monitoring data.

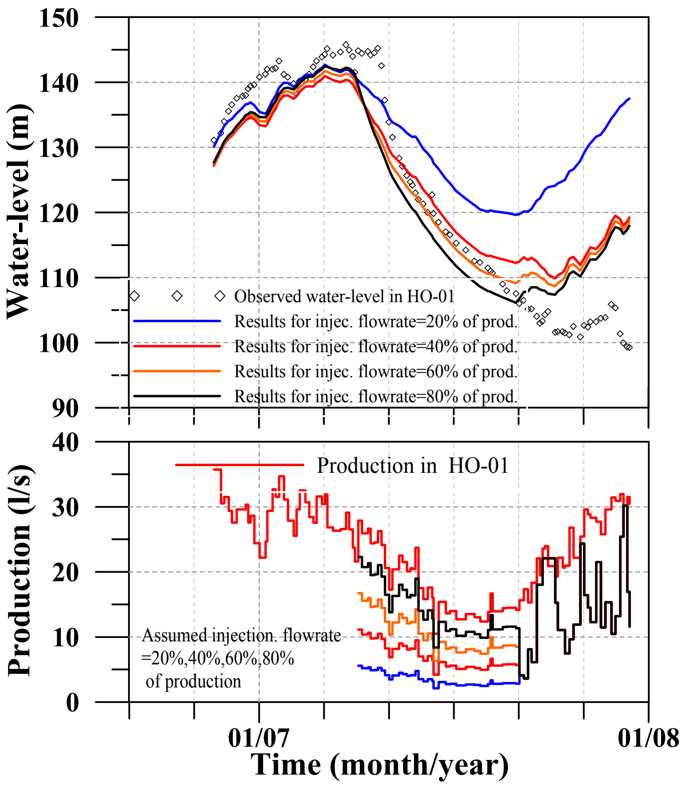

FIGURE 12: Simulation results based on the assumption that the reinjection flowrate is a fixed ratio of the production flowrate during the period lacking injection-data

4.3.2 Second study phase

In the second phase, the actual injection flowrate data were abandoned completely. Two cases for the injection flowrate were assumed:

I. The reinjection flowrate is a fixed ratio of the production flowrate for the whole reinjection period;
II. The reinjection flowrate is one fixed ratio of the production flowrate in summer and another in winter, which is probably more like the actual situation.

The results are presented in Figures 13 and 14. After only a few cases had been tried, the best simulation result was obtained. The calculated results of the water-level fitted the observed value quite well, by setting the value like this: x_1=50% (from 22-4-2007 to 22-07-2007) and x_2=80% (from 23-7-2007 to 14-12-2007, end of the data series). So the average fraction for a whole year could be estimated by the formula below:

$$x\% = \frac{x_1\%\times T_{summer}\times q_{in\ in\ summer} + x_2\%\times T_{winter}\times q_{in\ in\ winter}}{total\ injection\ in\ whole\ year} \tag{9}$$

The calculated results indicate that about 60% of the production water from well HO-1can be re-extracted through reinjection in well HO-2 in the Hofsstadir geothermal field. On average, the reinjection must, therefore, be greater than 60%.

4.3.3 Discussion

The results above indicate that the effects of reinjection into well HO-2 were equivalent to about 60% of the produced water being recovered from well HO-1 without additional pressure decline. The contribution of reinjection to counteract the draw-down was, therefore, highly significant. Like the process described above, through adjusting the fraction of injection, which was assumed to flow back into the production well entirely, and by repeating the simulation, a new method, which can be used to estimate the connection between the production well and injection well, was developed. This may be a new application for the program LUMPFIT.

4.4 Water-level change predictions for different cases

In order to reassess the production potential of the Hofsstadir field, lumped parameter models were used to predict future water-level changes due to long-term production. A future production period of 30 years was appended to the input file. At present, Stykkishólmur is expected to require an average annual hot water flowrate between 14 and 20 l/s. Consequently, the response of the water-level in production well HO-1 was predicted for constant production cases of 20 l/s using an open 2-tank model and a closed 3-tank model, respectively. The simulated results are shown in Figure 15.

The closed and open model results were two extreme conditions of the lumped parameter modelling. It was assumed that the real behaviour of the reservoir would be somewhere between these two simulated responses. The difference between the predictions of the open and closed models is noteworthy and probably reflects the closed nature of the Hofsstadir reservoir. As seen in the figure, the open model gave more optimistic forecasts than the closed model. The maximum drawdown in well HO-1 will reach ~ 270 m after 30 years production, for the case of a closed model without injection.

With the local economic development, more and more hot water will be needed to supply the increasing requirements of the Stykkishólmur community. Adopting the results of the reinjection study above, about 60% of the production can be injected into well HO-2 and re-extracted totally through production well HO-1. The case of production increased to 30 l/s was calculated. Figure 16 shows the results based on this assumption for both the open and closed models. As seen in the figure, this field is capable of sustaining a constant 20 l/s production of 87.5°C water fully through the year 2038. For the case of 30 l/s in the future, the drawdown will be less than 200 m, which is still below the limit set by the down-hole pump presently installed.

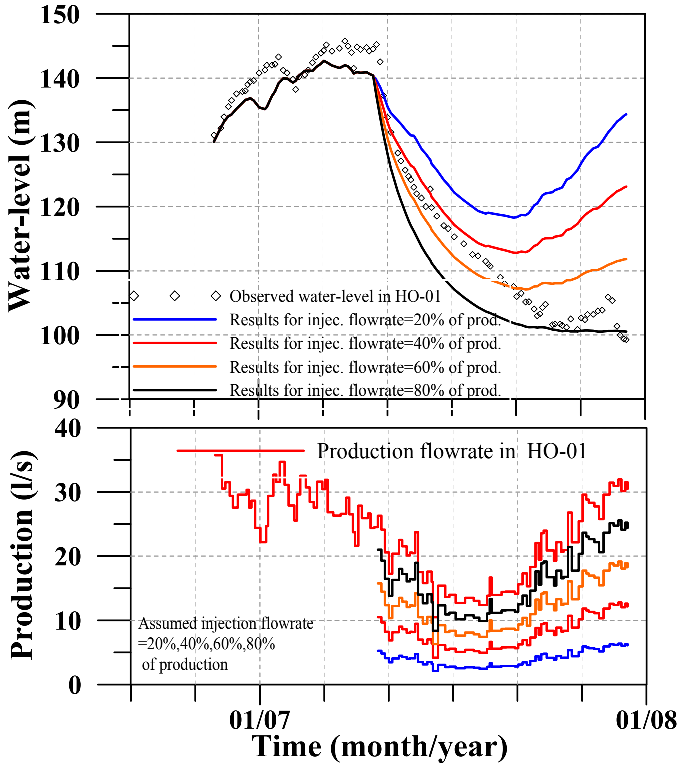

FIGURE 13: Simulation results based on the assumption that the reinjection flowrate is a fixed ratio of the production flowrate for the whole reinjection period

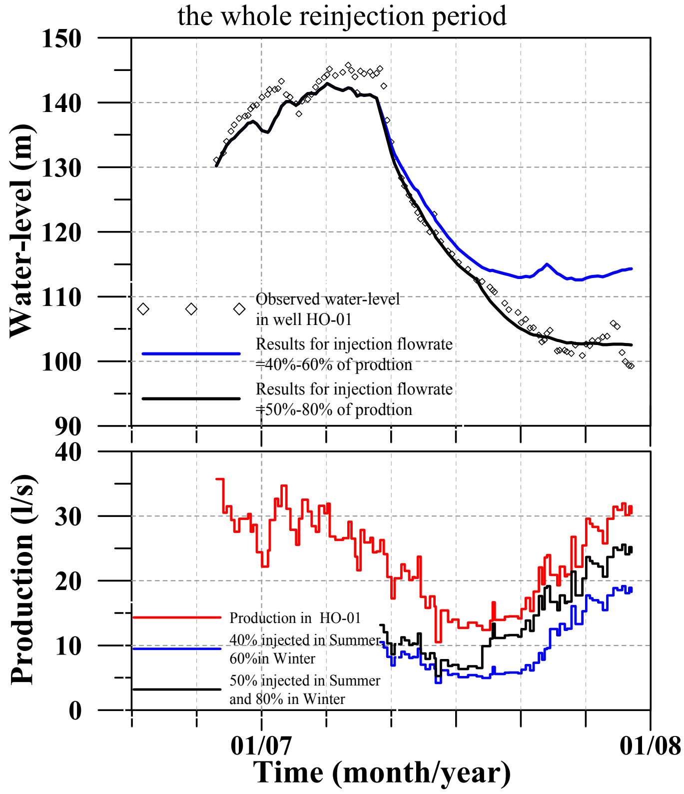

FIGURE 14: Simulation results based on the assumption that the reinjection flowrate is one fixed ratio of the production flowrate in the summer (x_1%) and another (x_2%) in winter

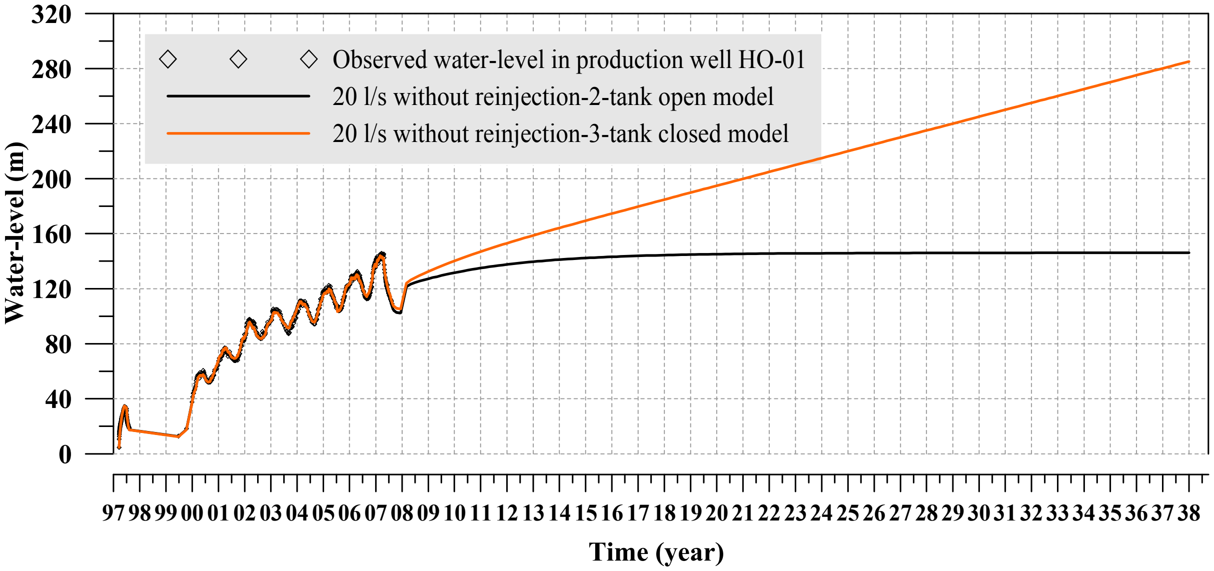

FIGURE 15: Predicted water level changes in well HO-1 until 2038 for a production scenario assuming the production is maintained at 20 l/s without reinjection, calculated by 2-tank open and 3-tank closed models

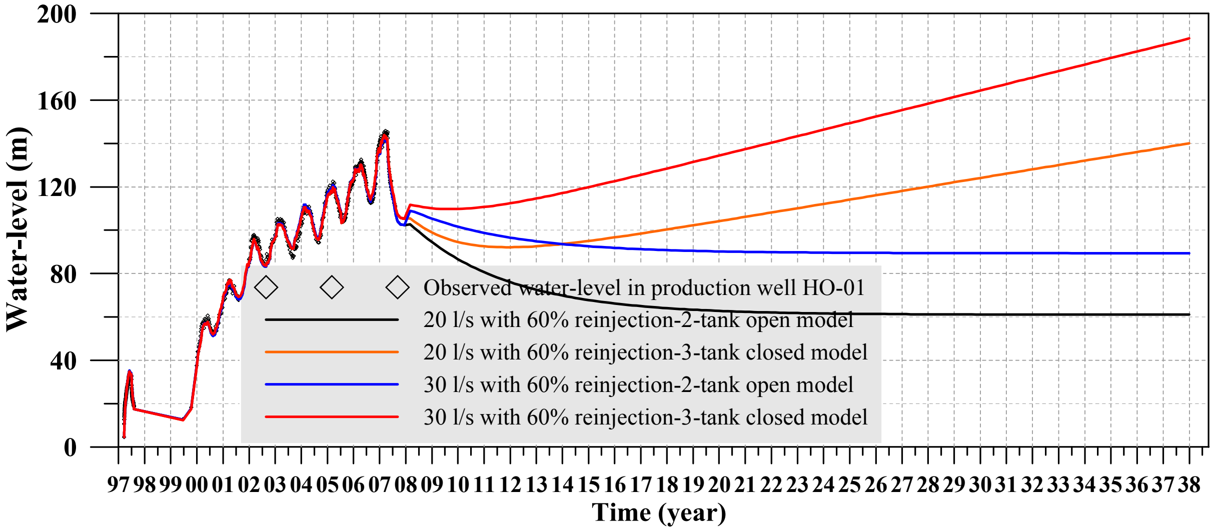

FIGURE 16: Predicted water level changes in well HO-1 until 2038 for a scenario assuming constant 20 and 30 l/s production with 60% reinjection, calculated by 2-tank open and 3-tank closed models

5. MONTE-CARLO RESOURCES ASSESSMENT

The traditional volumetric method involves calculating the thermal energy contained in the system in question and then estimating how much of this energy might be recoverable. The total thermal energy stored in the subsurface can be calculated as follows:

$$E = E_r + E_f = Vc_r\rho_r(1-\emptyset)(T-T_r) + Vc_w\rho_w\emptyset(T-T_r) \tag{10}$$

where E_r and E_f present the energy stored in the rock and water, respectively.

Then the reservoir potential is estimated by:

$$Reserve(MW) = \frac{total\ energy \times recovery\ factor \times conversion\ efficiency}{serve\ time} \quad (11)$$

In the traditional volumetric method, the entire reservoir is normally subdivided into a number of subsections, and then a constant value corresponding to the parameters is assigned for each subsection, respectively, in the calculation. These parameters include the areal extent of the field, the thickness, the temperature and pressure distribution, the porosity, and the density and heat capacity of the fluid and rock matrix. Through calculating the energy stored within each subsection and summing up the results of every subsection, the total potential of the reservoir in question can be figured out. However, due to the limited number of blocks or subsections allowed to divide the whole reservoir, and the use of a constant value in each subsection in the calculation, the final results of the traditional volumetric method are often questionable in practice. The quantification of the uncertainties of probable distributions in the parameters can be dealt with quite well by using the Monte Carlo simulation method.

This method was applied for the Hofsstadir reservoir. The randomness of the uncertain values was defined either by square or triangular probability distribution. To build confidence in the results of the simulation, a sample population of 4×10^4 random numbers was used for each parameter. Here the serve time means the production time of the geothermal system in seconds. For Hofsstadir, the hot water is mainly used for space heating, so the conversion efficiency is set as 100%. Table 3 shows the best guess value and the probability distribution used in the calculation. Triangular probability distributions were assigned to the upper and lower depths of the reservoir. The total thickness is most likely 1000 m as shown in Table 3. For the area, as mentioned before, based both on the results of the geological survey and the estimated results from the lumped parameter modelling, 3 km^2 were adopted as the best guess value, i.e. the area mostly ranges from 2.5 to 5 km^2. According to the well log in HO-1, below 180 m, the temperature of the formation is around 86°C versus depth (see Figure 4). The densities, porosity, and specific heat of the rock within this system were assumed to follow triangular distribution. This means that the possibility of using either the minimum or the maximum value is negligible, whereas the most probable value has the highest probability.

TABLE 3: Values and distributions of Monte-Carlo simulation for Hofsstadir reservoir estimation

Description	Distribution	Minimum	Most probable	Maximum
Surface area (km^2)	Triangular	1.5	3	5
Upper depth (m)	Triangular	100	150	200
Lower depth (m)	Triangular	1000	1500	2000
Temperature at upper depth (°C)	Fixed value	N/A	86	N/A
Cut-off temperature (°C)	Fixed value	N/A	25	N/A
Porosity (%)	Squared	8	10	12
Specific heat of rock (J/kg°C)	Triangular	900	950	980
Density of rock (kg/m^3)	Triangular	2680	2700	2720
Specific heat of water (J/kg°C)	Triangular	4150	4200	4250
Density of water (kg/m^3)	Triangular	950	967	980
Linear water heat gradient (°C/km)	Triangular	1.1	1.2	1.3
Recovery factor (%)	Triangular	2	6	10
Conversion coefficient (%)	Fixed value	N/A	100	N/A
Accessibility (%)	Fixed value	N/A	100	N/A
Production time (years)	Fixed value	N/A	30/50/100	N/A

The results are presented as a discreet probability distribution, seen in Figure 17, and as a discreet cumulative probability distribution, seen in Figure 18. These include the likeliest outcome, 90% confidence interval, mean and median of the outcomes, standard deviation and where the 90% limit

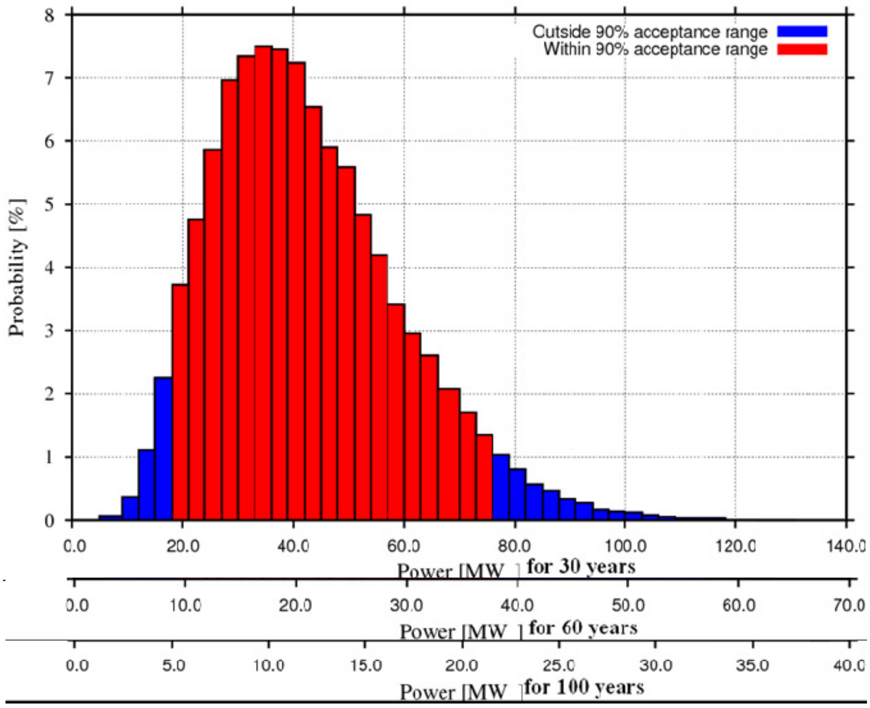

FIGURE 17: Probability distribution for energy production in the Hofsstadir geothermal field; each pillar is about 3.5 MWwide for 30 years, about 2 MW for 60 years and about 1 MW for 100 years

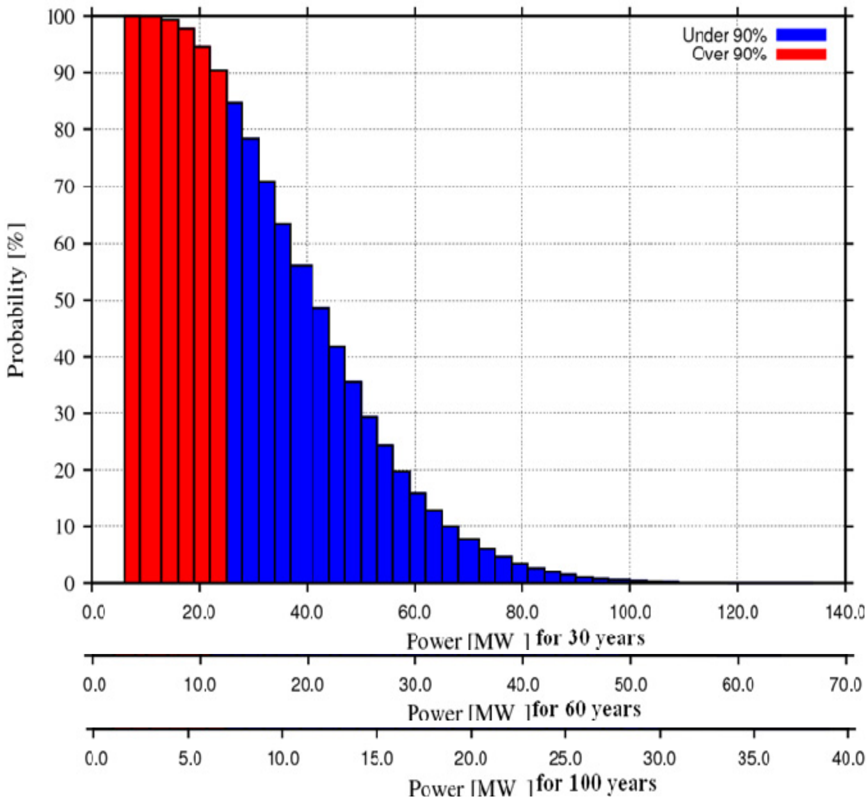

FIGURE 18: Cumulative probability distribution for energy production in the Hofsstadir geothermal field; the height of each pillar represents the probability that the result is in or below the interval of that pillar

for the cumulative probability lies. These statistics are presented in Table 4 for each of the three production periods. From the statistics of the cumulative probability in Figure 18, it can be seen that the volumetric model predicts with 90% probability that at least 25 MW can be produced for a production period of 30 years, at least 12 MW for 60 years and at least 7 MW for 100 years.

It should be emphasized that the great range in values resulting from the Monte Carlo calculations simply reflects the uncertainty in results obtained by the volumetric assessment method. It is primarily caused by uncertainty in the size, temperature and recovery factor for the Hofsstadir resource. For instance, we used the area of the innermost part of the reservoir, i.e. the calculated results of the first tanks in Chapter 3, as the whole area for calculation; this may be a relatively conservative value. Also, the recovery factor and the accessibility, as the two most sensitive parameters involved in the calculation, have a linear relationship with the final calculated results. So the results here are not in conflict with that of the lumped parameter modelling.

TABLE 4: Statistical parameters for the probability distribution for energy production for the Hofsstadir field estimated by the Monte Carlo simulation

Statistical sizes	**Values for 30 years (MW)**	**Values for 60 years (MW)**	**Values for 100 years (MW)**
With 7.5% probability	33.3-36.5	16.0-18.0	10.0-11.0
90% confide. interval	19.1-77.0	9.16-38.4	5.6-22.9
Mean	42.7	21.4	12.8
Median	40.4	20.0	12.1
Standard deviation	17.1	8.4	5.1
90% limit	25.5	11.8	7.3
Corresp. prod. rate (l/s)	100	46	29

6. INTERPRETATION OF TRACER TEST DATA

6.1 Tracer tests in Hofsstadir geothermal field

A tracer test was carried out in the Hofsstadir geothermal field in late 2007. The test had two main purposes: one was to provide a better understanding of the reservoir characteristics of this field; the other was to get comprehensive information in order to prevent cooling of the production well. Tracers should have similar flow and thermal properties as geothermal fluids but must differ in properties such as colour, radioactivity or chemical concentration, to allow detection. Na-Fluorescein, which has been successfully used in many other low-temperature fields in Iceland, was used in this test (Hauksdóttir et al., 2000).

On 29-08-2007, 10 kg of Na-Florescein were fully diluted on the surface and injected instantaneously into the ongoing injection of the geothermal field. During the test, the average production rate was about 20 l/s and the estimated injection rate was about 13 l/s. The distance between production well HO-1 and injection well HO-2 is about 1200 m. The tracer started to show up 2 months later. Samples are still being taken at an efficient frequency. From the beginning of the tracer test to this day, a total of 101 samples have been collected and analysed according to the experiment plan which was specially designed for this field. As shown in Figure 19, the sampling frequency was reduced gradually; the recovery figure of the tracer test, however, indicated the sampling frequency was adequate and the transporting plumes have been captured very well.

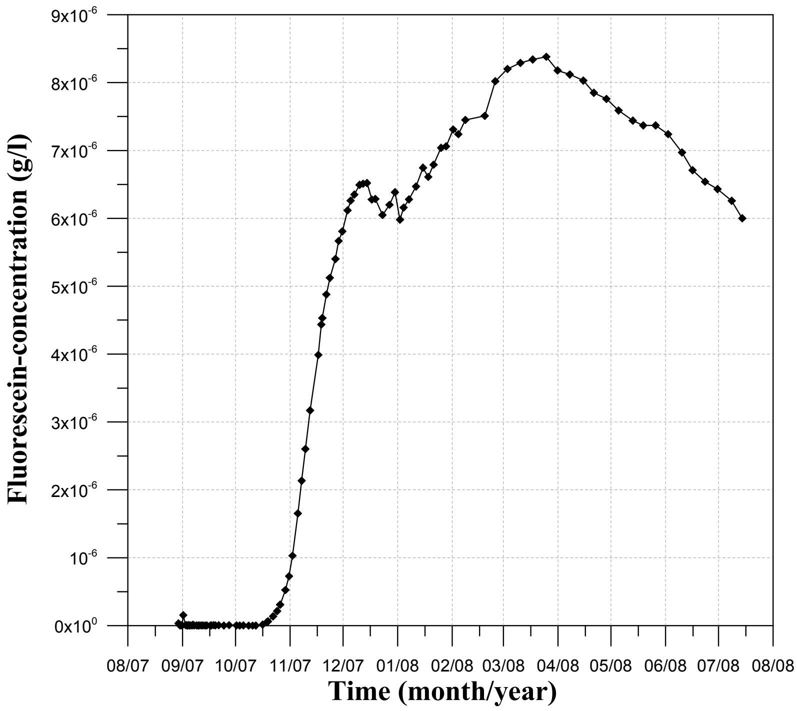

FIGURE 19: Observed Na-Fluorescein recovery in well HO-1 at Hofsstadir

6.2 Basic theory of solute transport

The theory of solute transport in porous and fractured hydrological underground systems is discussed in various publications (Bear et al., 1993; Javandel et al., 1984). In past decades, quite a few papers involving tracer test interpretation within geothermal fields have been published (Grisak and Pickens, 1980; Pruess and Bodvarsson, 1984; Horne and Rodriguez, 1983; Pruess, 2002).

A simple one-dimensional flow-channel tracer transport model has turned out to be quite powerful in simulating return data from tracer tests in geothermal systems. It assumes the flow between injection and production wells may be approximated by one-dimensional flow in flow-channels, as shown in Figure 20. It simulates a flow path along a fracture-zone, an interbed or permeable layer. In the model, *b* indicates either the width of the fracture-zone or the thickness of the interbed or layer, whereas *h* indicates the height of the flow-path inside the fracture-zone or its width along the interbed or layer.

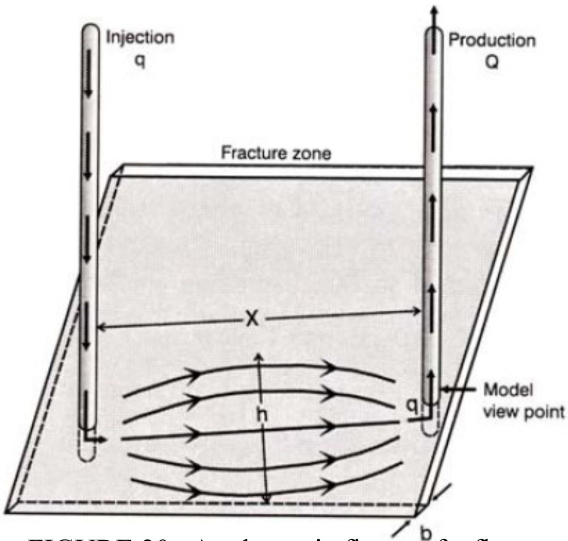

FIGURE 20: A schematic figure of a flow-channel with one-dimensional flow connecting an injection well and a production well

A computer code, TRINV, for modelling tracer recovery profiles. has been successfully used in several different geothermal fields in Iceland (Axelsson et al., 1995; Arason and Björnsson, 1994). This model was used in the simulation of the tracer recovery profile in the Hofsstadir geothermal field and is introduced below.

The general differential equation for solute transport in a saturated medium is:

$$\frac{\partial}{\partial x}\left[D_x\frac{\partial C}{\partial x}\right]+\frac{\partial}{\partial y}\left[D_y\frac{\partial C}{\partial y}\right]+\frac{\partial}{\partial z}\left[D_z\frac{\partial C}{\partial z}\right]-\frac{\partial}{\partial x}[u_xC]-\frac{\partial}{\partial y}[u_yC]-\frac{\partial}{\partial z}[u_zC]=\frac{\partial C}{\partial t} \tag{12}$$

In the case of one-dimensional flow in a homogeneous medium, Equation 12 simplifies to:

$$D\frac{\partial^2 C}{\partial x^2}=u\frac{\partial C}{\partial x}+\frac{\partial C}{\partial t} \tag{13}$$

If molecular diffusion is neglected and assuming instantaneous injection of a mass *M* (kg) of tracer at time $t = 0$ and a part of the tracer M_r transported along the flow channel to the production well, the solution to Equation 13 is given as (Axelsson et al., 1995):

$$C(t,x)=\frac{M_r}{2A\emptyset\sqrt{\pi Dt}}exp\left(\frac{-(x-ut)^2}{4Dt}\right) \tag{14}$$

where C is the tracer concentration in the flow-channel;
D is the dispersion coefficient, defined as: $\boldsymbol{D}=\boldsymbol{\alpha_L u}$;
u is the average fluid velocity in the channel (m/s) given by: $\boldsymbol{u}=q/\rho A\Phi$,
with q the flow channel flow rate $\boldsymbol{q}=q_{in}M_r/M$, q_{in} the injection rate, M_r the tracer mass recovered through the channel and ρ the water density,
A *is* the average cross-sectional area of the flow-channel; and
$\emptyset$ is the flow-channel porosity.

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

$$C(t)q = c(t)Q.$$

If there are *n* flow channels connecting the two wells, the tracer concentration in the production well will be given by (subscript j refers to flow channel j):

$$c(t) = \sum_{j=1}^{n} \frac{\rho M_j u_j}{2Q\sqrt{\pi D_j t}} exp\left(\frac{-(x_j - u_j t)^2}{4D_j t}\right) \tag{15}$$

The tracer interpretation computer code TRINV, included in the *ICEBOX* software package, solves Equations 15 inversely by a non-linear least-squares method. Through simulation, one can obtain the main properties for every flow channel, i.e. the flow channel volumes ($Ax\emptyset$) and dispersivities (α_L). 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.

6.3 Interpretation results

The first step in analyzing tracer test data involves estimating the mass (activity) of tracer recovered throughout a test. This is done on the basis of the following equation:

$$m_j = \int_0^t C_j(s)\, Q_j(s)\, ds \tag{16}$$

The program TRMASS in the *ICEBOX* package can be used for this purpose. If the analysis results of hot water samples are combined into one file, then the program will calculate the cumulative tracer recovery from the beginning of the tests to the end of the data, based on the model described above. In the calculation, the variability of the production flowrate and injection flowrate are both neglected. Methods of analyzing and interpreting tracer test data include (I) the tracer breakthrough-time, which depends on the maximum fluid velocity, (II) the time of maximum concentration, which reflects the average fluid velocity, (III) the width of the tracer pulse, which reflects the flow-path dispersion, and (IV) the tracer recovery (mass or percentage) as a function of time (Axelsson et al., 2005c).

As the drilling results revealed, there is only one feed-zone at 319 m depth in reinjection well HO-2. Tracer recovery in this field is very slow and in fact only about 10% was recovered during the first 4 months. According to the results simulated by program TRINV, only 44.4% has been recovered over the past 320 days. It can be seen from the shape of the tracer recovery curve that it is composed of at least two pulses (Figure 21). The first peak

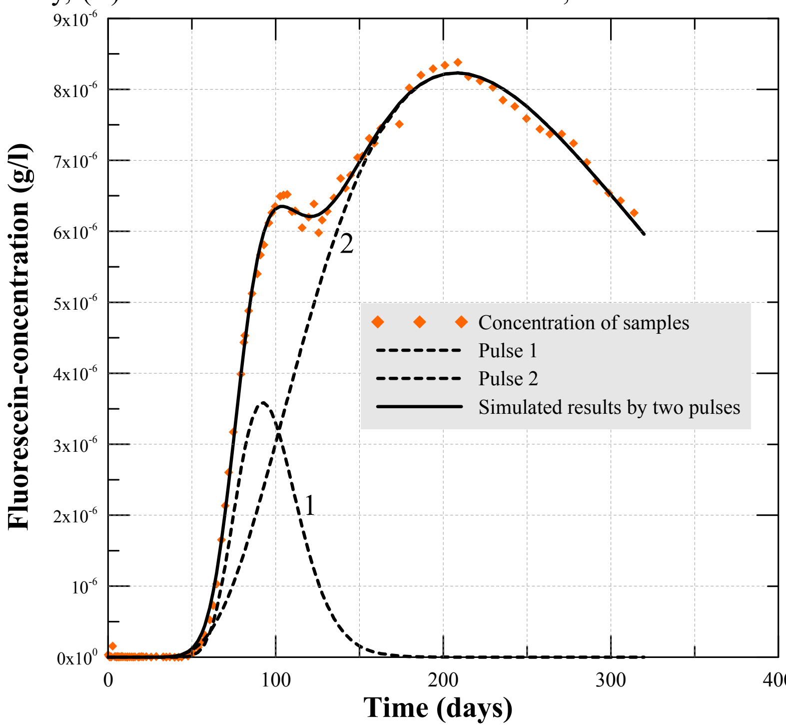

FIGURE 21: Simulation results of the tracer test data in the Hofsstadir geothermal field

concentration appeared after 100 days, while the other appeared at about 200 days after the test started. This means that there are at least two flow channels connecting wells HO-1 and HO-2. The parameters of the modelling results are listed in Table 5.

TABLE 5: Parameters of the best fitting model for the tracer recovery data

	Channel 1	**Channel 2**
Flow path distance x (m)	1200	1600
Mean velocity u(m/s)	1.48×10^{-4}	7.72×10^{-5}
Dispersion coefficients(m^2/s)	3.39×10^{-2}	1.79×10^{-2}
Cross-sectional area×porosity (m^2)	2.71	80.84
Estimated volume of channel (m^3)	3.25×10^{4}	1.29×10^{6}
Longitudinal dispersivity (m)	23.00	232.46
Tracer recovery Mi/M (%)	4.32	67.41

Comparing the calculated mass recovery to infinite time, there is quite a big difference between the two channels. Only 4% of the injected solute travels through the first channel while 67% travels through the second channel. This is in accordance with the results of the calculated volume. The results of the analysis yield a mean flow velocity of $u = 1.5\times10^{-4}$ m/s and 7.7×10^{-5} m/s for the two channels, respectively, which is equal to about 390 m/month and 200 m/month. According to the results of the simulation of tracer recovery, the volume of the fractures and flow channels connecting wells HO-1 and HO-2 is about 1.3×10^{6} m^3 (assuming $\phi = 0.1$), a very small fraction of the Hofsstadir reservoir volume.

6.4 Discussion

The tracer recovery results are quite interesting. Firstly, they confirm a direct connection between the two wells. Secondly, they provide some quantitative information on this connection. Furthermore, this quantitative information, to some extent, is consistent with the lithological analysis, i.e. there are two main feed-zones located at 171 m and 819 m in production well HO-1, and one main aquifer at a depth of 360 m in injection well HO-2. For the first channel, if one assumes the flow-channel to be along an interbed or a fracture-zone a few metres thick, then its average width, or height, is less than 10 m. If, on the other hand, the flow-channel is more like a pipe, then its diameter would only be around 5 m. The connection appears to be direct because of relatively low dispersivity and a large average flow velocity (compared to the 1200 m distance) and small flow-channel volume. However, conditions are considerably different for the second channel. Here, the height and diameter are estimated to be about 100 m and 16 m for rectangular and pipe mode, respectively. Furthermore, the higher dispersivity of the second channel is about 232 m, which is about ten times larger than that of the first and propitious for reducing the cooling risk in the production well.

Despite the fact that the test is still ongoing and the recovery curve is not completed yet, a conclusion can be drawn just from the point of view of hydrodynamics, that the prospect of reinjection in this field is quite good.

6.5 Cooling predictions

6.5.1 Model description

When colder water is injected into a geothermal reservoir, the reservoir rock matrix acts like a heat exchanger, heating the water up gradually through movement in the reservoir. The heat exchange capacity depends on quite a few parameters such as the surface contact area between rock and water, the rock heat capacity, fluid heat capacity, and the thermal conductivity of the rock.

In this project, the same model as was used for the tracer test interpretations was used to predict the effects of cooling in a fracture zone with width *b*, height *h*, length *x* and porosity ϕ. Assuming colder water with temperature T_{in} is injected into the fracture at time *t*=0, the flowrate 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}. Here only the heat conduction in the horizontal direction *y*, i.e. perpendicular to the flow, is considered; then the heat conduction from the rock matrix to the fracture zone can be described by the following differential equation:

$$\frac{\partial^2 T}{\partial y^2} = \frac{1}{\alpha}\frac{\partial T}{\partial t} \tag{17}$$

where α is defined as: $\alpha = \rho_r c_r / k_r$,

The heat convection along the flow channel can be described by:

$$\rho_w c_w b \frac{\partial T}{\partial t} + c_w \frac{q}{h}\frac{\partial T}{\partial x} = 2k_r \frac{\partial T}{\partial y}\bigg|_{y=\frac{b}{2}} \tag{18}$$

When $b << h$, the initial condition and boundary conditions are: $T(x,y)|_{t=0} = T_o$, $T(x,y)|_{x,y=\infty} = T_o$, $T(x,y)|_{x=0} = T_{in}$. Carslaw and Jaeger (1959) gave the solution to the above problem:

$$T_{out}(x,t) = T_{in} + (T_0 - T_{in}) erf\left[\frac{x k_r h}{c_w q \sqrt{\alpha(t - x/\gamma)}}\right] \text{ for } t > x/\gamma \tag{19}$$

$$T_{out}(x,t) = T_{in} \text{ for } t \le x/\gamma \tag{20}$$

where $\gamma = q/\langle \rho c \rangle_f hb$; and
$\langle \rho c \rangle_f = \rho_w c_w \phi + \rho_r c_r (1-\phi)$ is the volumetric heat capacity of material in the flow channel, and ρ and c are density and heat capacity, respectively.

Then the temperature of the produced water is given by:

$$T_Q(t) = T_0 - \frac{q}{Q}(T_0 - T_{out}) \tag{21}$$

In a case where there are *n* 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, the water temperature T_p in the production well can be calculated as below (Liu, 1999):

$$T_p = T_0 - \frac{q_{in}}{Q}\sum_{j=1}^{n}\left[\frac{M_j}{M}(T_0 - (T_{out})_i)\right] \tag{22}$$

Here the mass recovery of tracer from fracture *j*, M_j and total mass injected *M* are used, because the percentage of mass recovery is assumed to be the same as the percentage of flow in each fracture. A computer program TRCOOL (included in *ICEBOX*) was developed using this method by Axelsson et al. (1994), and has been used for several geothermal fields in Iceland.

6.5.2 Predictions of temperature change in the production well

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 (as listed in Table 5). These parameters were used to predict the long-term cooling effects of reinjection in the Hofsstadir geothermal field. There are several modes that can be used to calculate the cooling danger, such as (Axelsson, 2005c):

a) A high porosity, small surface area, pipe-like flow channel. This can be looked upon as the most pessimistic case, resulting in rapid cooling predictions.
b) A low porosity, large volume flow channel. It simulates dispersion throughout a large volume or fracture network.
c) A high porosity, large surface area flow channel, such as a thin fracture-zone or thin horizontal layer. This is the most optimistic case, resulting in slow cooling predictions.

In practical terms, one may, however, prefer a conservative channel mode, which is expected to pose a high risk of premature thermal breakthrough in order to ensure the security of the hot water supply.

It is important to keep in mind that while tracer tests provide information on the volume of flow paths between injection and production wells, thermal breakthrough and decline are determined by the surface area involved in heat transfer from reservoir rock to the flow paths. Some assumptions must, therefore, be made on the flow channel geometry, i.e. the average flow path porosity, which is often approximately known, and the ratio between *h* and *b* which, in contrast, is normally poorly known. In most cases, such as the cases studied here, more than one channel may be assumed to connect an injection and a production well, for example connecting different feed-zones in the wells involved.
The porosity of the fracture zone within the Hofsstadir is taken as 10%. For calculation, the assumptions on the width and the height of the fractures, which are based on the same flow-channel model as the tracer test analysis and the results in Table 5, are listed in Table 6. The program TRCOOL was used in calculating the predictions. In order to predict the temperature decline of the production well due to long-term reinjection into well HO-2, cooling predictions in production well HO-1, the next 30 years, were calculated for a few different reinjection scenarios. Here we assume two possible future cases in this field. One case is an average injection flowrate in well HO-2 of 15 l/s, and a production rate from well HO-1 maintained at 20 l/s; the other case is an injection flowrate of 20 l/s, and production reaching 30 l/s. Some short-term variations in the injection rate are, of course, expected, but were discounted in the calculations. The calculation results for different production and injection rates using different models are presented in Figure 22.

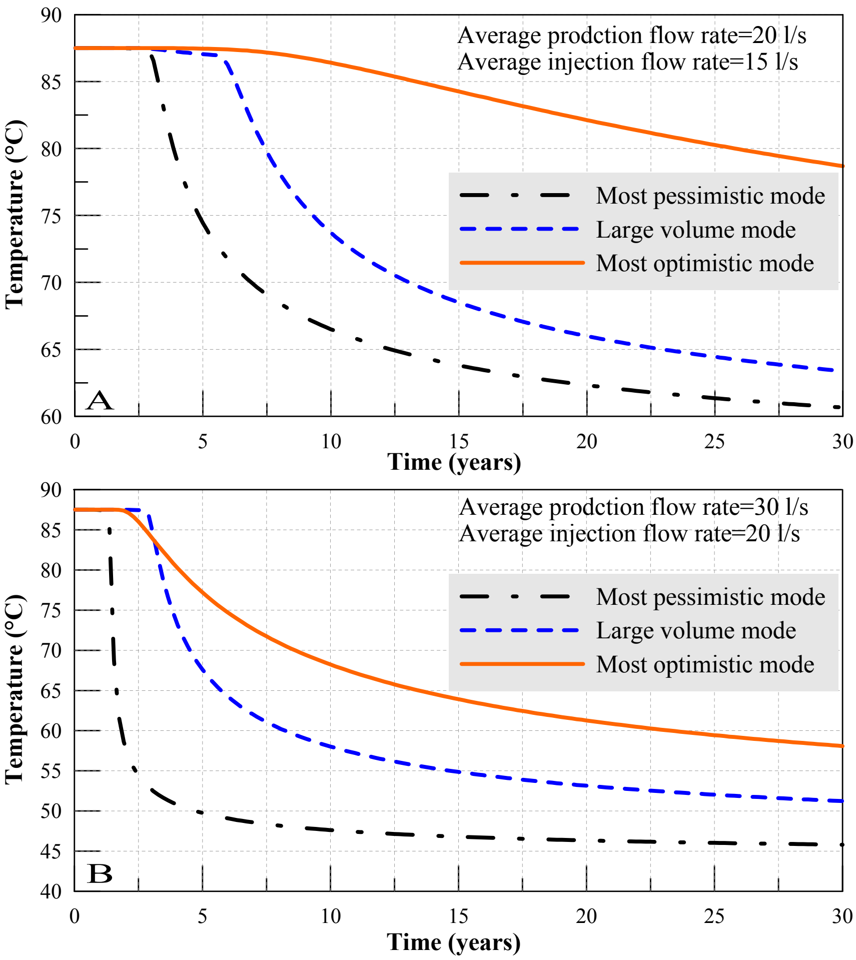

FIGURE 22: Cooling predictions calculated for well HO-1 in Hofsstadir during reinjection into well HO-2, for different flow channel modes and different production and injection flowrates

TABLE 6: Model parameters used in cooling predictions for production well HO-1 and reinjection well HO-2

Case	Channel	X (m)	b (m)	h (m)	φ (%)
Most pessimistic	1	1200	2.61	10.4	10
	2	1600	14.22	56.86	10
Large volume	1	1200	6.78	8	5
	2	1600	20	80.84	5
Most optimistic	1	1200	1.5	18.06	10
	2	1600	3	269.5	10

The purpose of the tracer tests at Hofsstadir was to try to quantify the danger of premature thermal breakthrough and rapid cooling of production wells during reinjection. Therefore, one should preferably 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 the more likely the water is to be completely heated up before reaching the well.

6.6 Heat mining enhancement

In order to estimate the increase in energy production enabled through long-term reinjection into well HO-2, the possible increase in mass extraction was estimated and the predicted temperature changes were simply combined. According to the operating conditions of the district heating system in Stykkishólmur, the base temperature used in calculating heat mining was approximately 25°C for the Hofsstadir geothermal field and the specific heat of the production water was taken as 4200 J/kg/°C. Here we use temperature changes in the case of a larger volume mode (Figure 22a) as reference values. The final results, using different modes, are presented in Figure 23, which shows the estimated cumulative additional energy production for well HO-1 during the whole 30-year period under consideration.

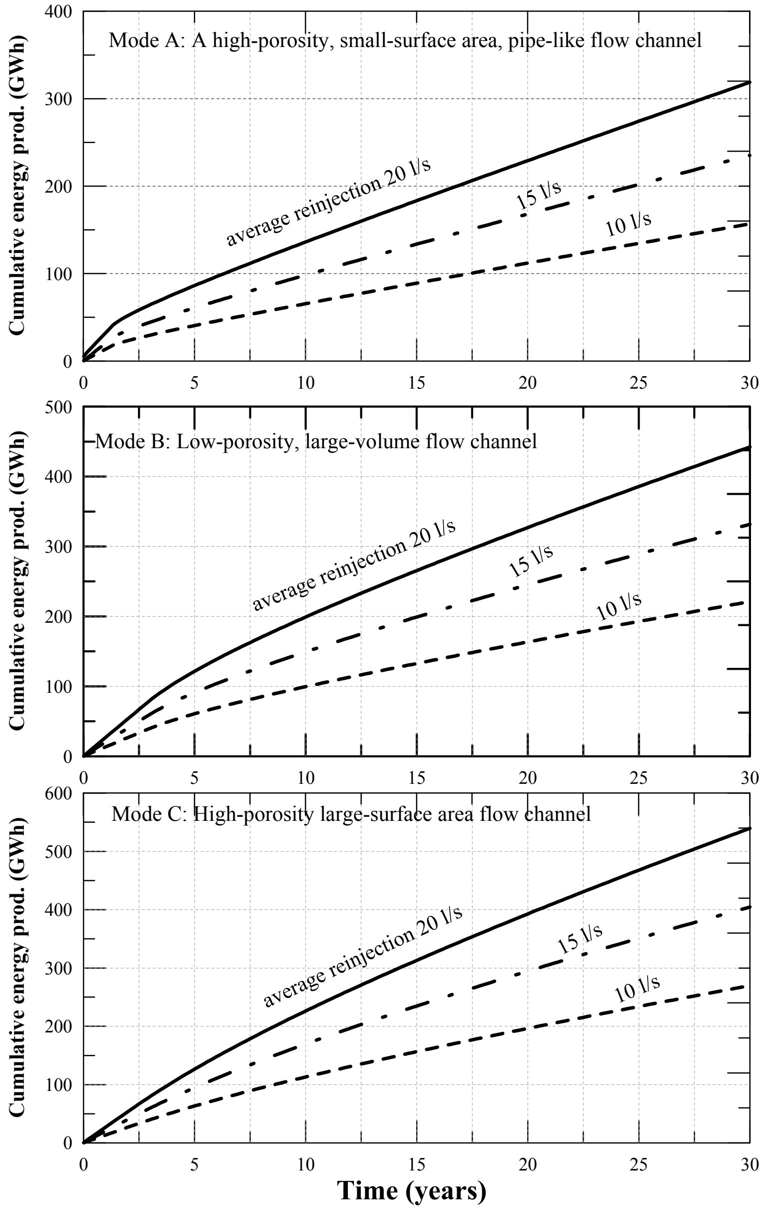

FIGURE 23: Estimated cumulative increase in energy production for 30 years of reinjection into well HO-2; calculated for three cases of average injection using different flow channel modes and assuming production from well HO-1

The total production of hot water

from this field was about 7 Mm^3 during the past 11 years time, the annual energy extraction from the field was around 45 GWh. The total amount of reinjection during the past 14 months, from Apr. 2007 to Jun. 2008, was estimated to be on the order of 0.3 Mm^3. Adopting the value of 60% for the reinjection, which was obtained in the previous section, for the injected water that can be re-extracted eventually and taking into account that limited cooling will take place, the total reinjection into well HO-2 will correspond to a 24 GWh increased heat extraction per year.

It is considered likely that an average long-term reinjection rate of about 15 l/s can be maintained at Hofsstadir. The maximum rate will be about 20 l/s during the winter-time, when the return water supply is sufficient. During the summertime, the reinjection rate may, however, decrease down to about 10 l/s. In 2008, the injection flowrate often reached 19 l/s. If this reinjection rate is maintained in the future, the production of Hofsstadir field probably could be maintained at 30 l/s, which corresponds to a total production of 1 Mm^3 per year. Assuming that the temperature of the produced water in well HO-1 will not decline, and the total production of every year corresponds to a 67 GWh annual heat production capacity, that means a near 50% increase in comparison to that without reinjection.

7. CONCLUDING REMARKS AND RECOMMENDATIONS

This report is based on a systematic collection of information and data on the Hofsstadir geothermal field, W-Iceland. More than 11 years worth of monitoring data, from 19-03-1997 to 12-08-2008, was simulated by a 2-tank open model as well as a 3-tank closed lumped parameter model. Because of injection that started on 22-04-2007, the water-level in production well HO-1 rose over 40 m in about 1 year and the water-level in observation well AS-1 also rose significantly.

By using the best-fitting 3 tank closed model to simulate the water-level in production well HO-1 during the injection period, the fraction of the production to be injected back into the production well and later re-extracted without additional pressure decline, was estimated. Consequently, the response of the water-level in well HO-1 was predicted for different production schemes by using both an open and closed model. Then the Monte Carlo method was applied to assess the production capacity of the Hofsstadir field. Finally, based on the results of a tracer test in the Hofsstadir field, which was interpreted by a simple model, the temperature decline of the produced water was predicted and the cumulative energy increase calculated for the next 30 years. The main conclusions of these calculations can be summarized as follows:

1) The Hofsstadir geothermal system belongs to the typical liquid-dominated convection low-temperature systems. The geothermal reservoir is markedly small compared with numerous others which have been studied across Iceland. The chemical content and isotopic composition of the hot water in the system suggests mixing of seawater with geothermal water of meteoric origin, but not a mixture of present-day freshwater and seawater, however. The hot water at Hofsstadir, therefore, appears to be very old. The high mineral content of the water also seems to indicate that the system has almost closed boundaries.

2) The monitoring data of production and water-level collected during the past 11 years were simulated with two lumped reservoir models. An optimistic open two-tank model and a pessimistic closed three-tank model simulated the data equally well. The models' mass storage coefficients indicate a reservoir area on the order of 3 km^2. The fluid flow coefficients of the models reflect an overall average permeability of about 5 mD. The Hofsstadir reservoir appears to have fairly good internal permeability. In contrast, the reservoir appears to have low external permeability, and behaves as if almost closed, which explains the continuously increasing draw-down.

3) The potential assessment indicates that the field should be able to sustain a stable 20-25 l/s production in the future without reinjection. From the start of reinjection to the present, at least 0.34 Mm^3 of return water has been injected into well HO-2. If reinjection runs successfully long term in this field, then the production capacity can be increased to about 30 l/s, with a maximum drawdown of less than 250 m through the year 2038, assuming the system has a completely closed boundary.

4) The result of the reinjection study indicates that the injected water in well HO-2 has a significant effect in re-building pressure in production well HO-1. Based on 11 months of reinjection, it is estimated that the effect of reinjection is comparable to about a 60% reduction in production. Monitoring of the reinjection rate appears to have been defective but, on average, the injection must therefore have been equal to, or greater than 60% of the production. The results of the study illustrate that the two wells have a direct hydraulic connection.

5) The Monte Carlo volumetric assessment for the field predicts with 90% probability that at least 25 MW can be produced for a production period of 30 years, at least 12 MW for 60 years and at least 7 MW for 100 years.

6) From the beginning of the tracer test, 14-07-2008, nearly 44% of the injected solute has been recovered through the production well. The simulation results of tracer recovery indicate that there are at least two flow channels between HO-1 and HO-2. The high average flow velocity, ranging from 201 to 390 m/month, of the two channels indicates that the connection between the two wells is not as pessimistic as estimated before. The results indicate that there are direct paths between reinjection well HO-2 and production well HO-1; but about 40% of the injected water appears to diffuse into the rock matrix and disperse throughout the reservoir volume. Also, the considerable contribution of injection in counteracting the drawdown in well HO-1 supports this conclusion, i.e. that there are direct paths between these two wells.

7) Using the simulation results of the tracer test, the temperature decline in well HO-2 is predicted for 30 years, based on three geometric modes. The temperature of the water produced at Hofsstadir is predicted to decline by 20-30°C in 30 years, assuming 15-20 l/s average future reinjection into well HO-2 and a conservative flow channel geometry.

8) It is considered likely that an average long-term reinjection rate of about 15 l/s can be maintained at Hofsstadir, as the results obtained above indicate. It is furthermore estimated that future reinjection at the above rate will enable an increase in energy production amounting to about 12 GWh_{th}/year, which is roughly 30% over the average yearly energy production at Hofsstadir during the last decade. It is obvious that the outcome of the reinjection project is highly positive, since it appears that energy production from the field may be increased significantly, and economically, through reinjection. Therefore, reinjection will greatly increase productivity and improve the heat mining in the Hofsstadir geothermal field.

Based on the results of this study some recommendations are put forward:

1) In order to ensure the security of the hot water supply and for further detailed research, more observation wells should be drilled to enhance the quality of the observed data. Besides this, an EIA (Environment Impact Assessment) project should be conducted for this field if possible.

2) Reinjection is a very effective countermeasure for declining water-levels in the Hofsstadir field and should be considered to have a future basic role in the management of this reservoir. Therefore, the monitoring of the injection flowrate should be improved.

3) Although the reinjection project in Hofsstadir has been successfully performed, some related work is expected to continue. Tracer recovery, for example, will be monitored for a few more years. The results of the present analysis should not be considered a unique solution, so the tracer test data collected within the Hofsstadir field should be subjected to further analysis and interpretation.

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NOMENCLATURE

A = Cross-sectional area of flow channel [m^3];
A_i = Coefficients of the tanks;
B = Coefficients of the tanks;
b = Width of flow channel [m];
C = Tracer concentration in flow channel [kg/m^3];
c = Tracer concentration of the produced fluid [kg/m^3];
c_w = Heat capacity of water [J/kg°C];
c_r = Specific heat of rock [J/kg°C];
D = Dispersion coefficient of flow channel [m^2/s];
E = Total thermal energy in the rock and the water [kJ];
H = Thickness of reservoir [m];
h = Height of flow channel [m];
i = Number of tank in lumped parameter models;
j = The number of a flow channel;
k_r = Thermal conductivity of rock [J/m°C];
L = Longitudinal dispersivity of flow channel [m];
L_i = Coefficients of the tanks;
M = Mass of tracer injected [kg];
M_I = Mass travelling through flow channel [kg];
M_i = Cumulative mass recovered in production well number [kg];
M_r = Mass travelling through flow channel [kg];
Δm = Mass changes in reservoir [kg];
n = Total number of flow channels;
ΔP = pressure changes in reservoir [Pa];
Q = Flowrate of production well [kg/s];
q = Flowrate of water through flow channel [kg/s];
q_{in} = Reinjection flowrate [kg/s];
R_1, R_2, R_3 = Radii of the different tanks [m];
r_1, r_2, r_3 = Radii of corresponding cylindrical shells [m];
s = Storativity of reservoir [kg/m^3Pa];
t = Time [s];
T = Temperature [°C];
T_0 = Initial temperature of reservoir [°C];

T_{in} = Temperature of injected water [°C];
T_{out} = Water temperature at outlet of flow channel [°C];
T_Q = Temperature of production water [°C].
T_r = Cut-off temperature in Monte Carlo simulation [°C];
u = Mean fluid velocity inside flow channel [m/s];
V = Volume of reservoir [m^3];
x = Distance from injection well [m];
y = Distance perpendicular to flow channel plane [m].

α = Thermal diffusivity [m^2/s];
β_r = Rock compressibility [Pa^{-1}];
β_w = Fluid compressibility [Pa^{-1}];
φ = Porosity of reservoir and flow channel [dimensionless];
κ_1 ,κ_2 , κ_3 = Capacitance of a tank [kg/Pa];
ρ_r = Density of rock [kg/m^3];
ρ_w = Water / fluid density [kg/m^3];
σ = Conductance of a tank [kg/Pa]
v = Kinematic viscosity of water [m^2/s].

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