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Assessment of the Hofsstadir Geothermal Field, W-Iceland, by Lumped Parameter Modelling, Monte Carlo Simulation and Tracer Test Analysis

Guo Gaoxuan, Gudni Axelsson*, Ye Chao and Xin Baodong

Hydrogeology and Engineering Geology Team of Beijing, P.R. China

No.123, Xi Si Huan Bei Road, Haidian District, 100195, Beijing, P.R. China

* Iceland Geosurvey, Orkugardi,Grensasvegi 9,108, Reykjavik, Iceland

Email: g_g_x@yahoo.cn, gax@isor.is, yechao103@yahoo.com.cn, xinbd545@sohu.com,

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ABSTRACT

The Hofsstadir geothermal system is a typical liquid-dominated convection low temperature system, in West Iceland. The entire monitoring data, including 5 months initial well testing, collected in the single production well HO-01 during the past nearly 11 years, were simulated both by an open and closed version of lumped-parameter modeling. Reinjection started in early 2007 by injecting the return water from the heating system into injection well HO-02. Through simulating various scenarios of production schemes using the best fitting parameter model, the connections between the two wells were studied. The future water-level changes in the production well were predicted based on the assumption that a given percentage of the reinjected water can be re-extracted through the production well eventually. The calculated results indicate that this system will be able to sustain a stable 20 l/s production through 2032 without reinjection. The data of a tracer test were interpreted using a multiple flow-channel model. The results show that there are direct paths between the feed-zones of well HO-02 and that of well HO-01. A future cooling effect due to long term injection within this field was predicted using the same model. The Monte Carlo simulation results predicted with 90% probability that at least 25 MW can be produced for a period of 30 years, at least 12 MW for 60 years and at least 7 MW for 100 years. Finally, the energy increase due to the injected water was calculated for the future 30 years, using different assumption for flow channel modes. 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.

1. INTRODUCTION

Over the last 60 years, there has been considerable development in the use of geothermal energy for space heating in Iceland. Most towns and communities in Iceland use geothermal water directly for space heating. At present, geothermal provides more than half of the energy consumed by 300,000 inhabitants, or about 10500 GWh/y (Orkustofnun, 2008). The Hofsstadir geothermal field is one of the numerous low-temperature geothermal areas which have been identified in Iceland. In 1996, a production well, HO-01, was drilled to a depth of 855 m in the center of the main anomaly. The well was cased to a depth of 156 m and intersected two main aquifers with water at a temperature between 86 and 88°C. Utilization of well HO-01 started during middle to late 1999. The hot water from Hofsstadir geothermal field is mainly used for the Stykkisholmur district heating system. The average yearly production of the single production well since that time has been of the order of 19 l/s. A tracer test was carried out in this field in late 2007. The reinjection was started at the end of Apr. 2007. All the data, including the flow-rate, the pressure, the temperature, the chemical changes in both the production well and the reinjection well had been monitored carefully. The shape of the field and the location of the production well, injection well, monitoring well and the temperature anomaly areas are shown in Figure 1.

2. AVAILABLE INFORMATION AND DATA

2.1 Formation Lithology

The bedrock in the Hofsstadir area is mainly composed of Miocene basalts. The reservoir rock of this field consists primarily of coarse-grained basaltic units with thin layers of sediments, two of which could be acidic, and a number of mostly basaltic intrusions. From 780 to 855 m depth, i.e. to the bottom of the well, 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 (Björnsson and Fridleifsson, 1996). At depths below 150 m, the high-temperature alteration minerals chlorite and epidote are found. The reservoir rock is altered to a high degree with epidote below 150 m depth, indicating an alteration temperature of approximately 250°C. Below 300m, the rock is altered with amphibole, which suggests an alteration temperature of ~300°C (Figure 2).

2.2 Main Structures and Reservoir Features

The dominant structural grain of the area is NE-SW as defined by basaltic dykes, faults and the strike of the basalts. Narrow inlets from the sea cut into it from NE and SW. The geothermal field involves two sub-parallel fissures spaced 1200 m apart trending SSE to NNW. The two fissures are only locally recognizable by surface criteria but they show up clearly in the thermal gradient of some 30 shallow (most in 50 m depth) boreholes (Björnsson et al., 1997). A more recent tectonic pattern of east-west faults and rare NW-SE dykes is less conspicuous. Due to secondary mineralization, the Miocene basalts and dykes within this peninsula have low permeability. Permeability anomalies are fissure controlled, the feature near Stykkisholmur being the largest traced so far in the surroundings. These provide the necessary pathways for sufficiently deep circulation of ground water down to at least 2000 m to sustain a geothermal system. According to the results deriving from cuttings analysis, well logs which includes resistivity well logs, television logs and pumping tests, there are two main production aquifers in this field, one is located at depths of 819 m (90% of the flow-rate), the other is about 4 m in thickness located from 171 to 175 m (7% of the flow-rate) (as shown in Figure 2). The temperature logs show a reservoir temperature of about 86.4°C.

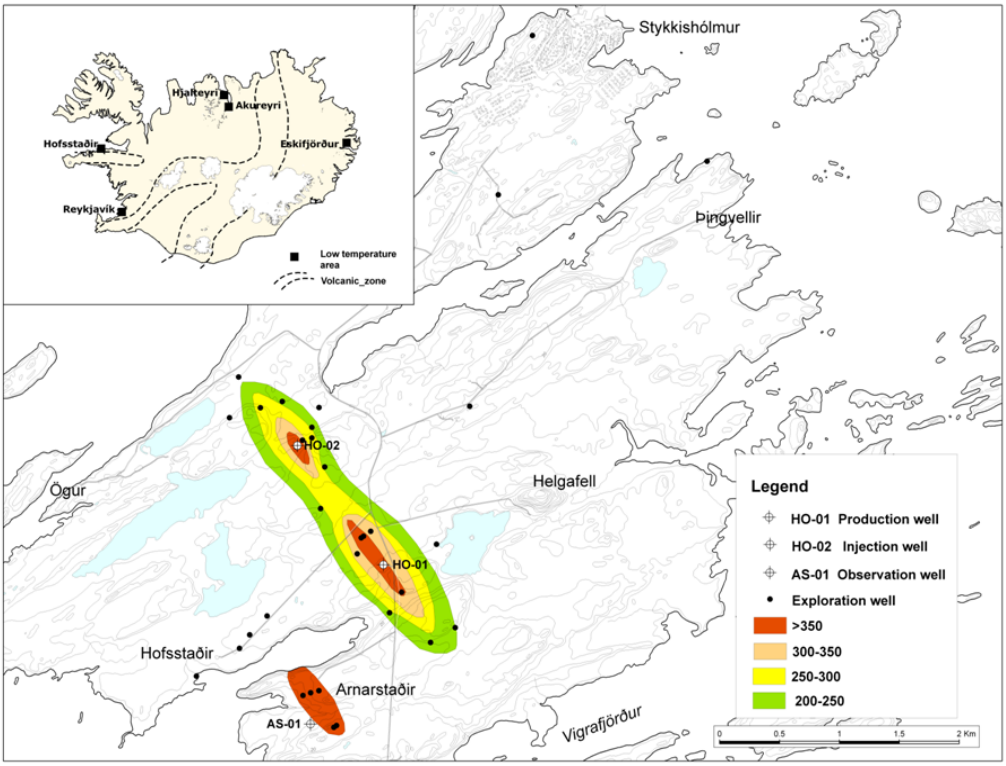

Figure 1: Location of Stykkisholmur town and Hofsstadir geothermal field in W-Iceland.

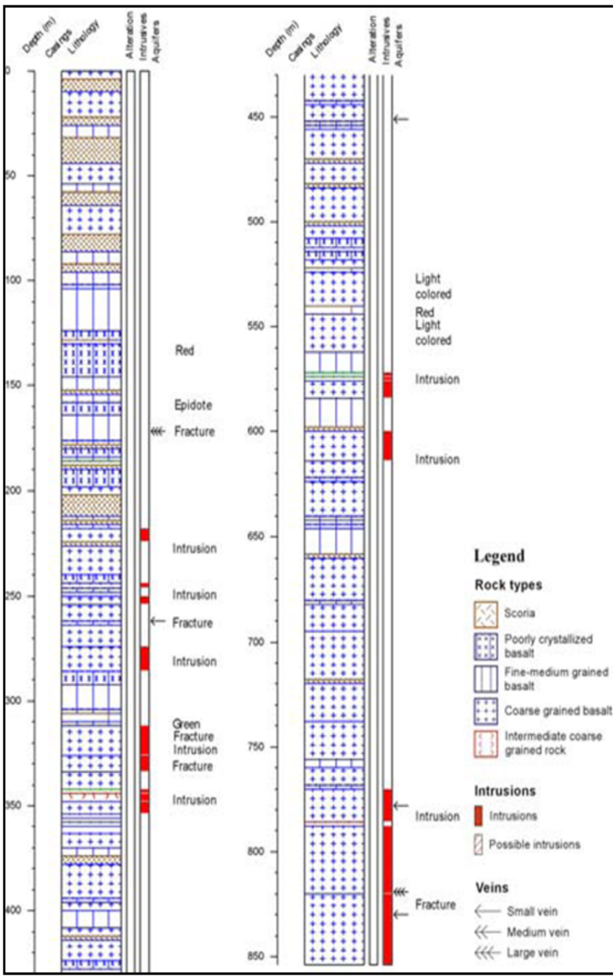

Figure 2 : Lithological profile of well HO-01

2.3 Chemical Characteristics of Hot Water and Conceptual Model and Heat Source

The water from well HO-01 is classified as calcium-sodium chloride water apparently in near chemical equilibrium with reservoir rocks. Mineral equilibrium study indicates that the temperature is near reservoir temperature. The concentration of chloride is 2.900 mg/l which is equivalent to a calculate salinity of 5.4 ‰ or 15 % of the salinity of seawater. The stable isotopic ratios δD and $\delta^{18}O$ (Figure 3) show the water to be significantly lighter than present day precipitation in the mountains in the southern part of the Snæfellsnes peninsula. Its origin probably dates back to an age prior to the latest glaciation period some ten thousand years ago (Kristmannsdóttir, 2005).

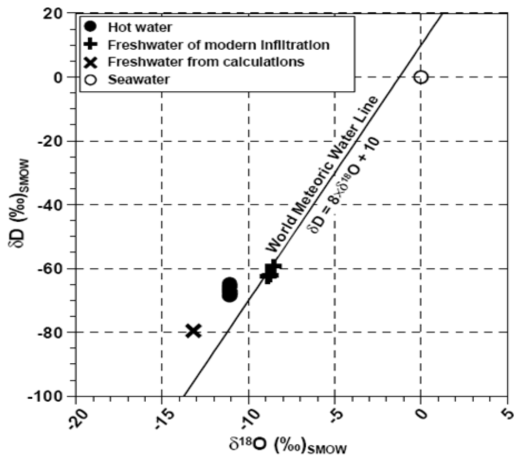

Figure 3: The relationship between $\delta^{18}O$ and δD values in the hot and cold water samples from the study area and in a freshwater from calculation.

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 4), 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.

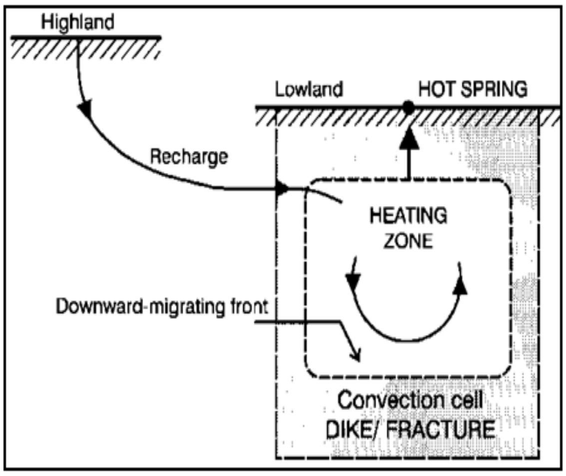

Figure 4: Conceptual model of the heat-uptake mechanism of a low-temperature system in Iceland, Bodvarsson (1982, 1983).

2.4 Monitoring Data of the Field

Since pumping hot water from the production well HO-01 started, the production rate, the water-level changes and the temperature variety (including the data of well test) were monitored carefully. The monitoring data available for this work were the following (see Figure 5):

1) Production history of well HO-01, from 19-03-1997 to 12- 08-2008;
2) Observed water-level history of well HO-01, from 19-03-1997 to 12- 08-2008;
3) Observed water-level history of well AS-01, from 23-02-2002 to 12- 08-2008;
4) Temperature history of well HO-01, from 2000-02-08 to 12- 08-2008;
5) Reinjection started in 22-04-2007, injection flowrate is monitored since 29-08-2007;
6) Tracer test data, from 29-08-2007 to 14-07-2008, carried out between injection well HO-02 and production well HO-01 still ongoing.

3. LUMPED PARAMETER MODELLING

3.1 General

Modeling plays an essential role in geothermal resource development and management. Quite a few modelling approaches are currently in use by geothermal reservoir specialists. Because of its many benefits, including time and money-saving, high precision, and 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. of China, Central America, Eastern Europe, Philippines, Turkey and many other countries during the past few decades. Lumped parameter models can simulate such data very accurately, if the data-quality is sufficient (Axelsson, 2005). In this work, the lumped parameter models were also used. For the detail of this method, 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).

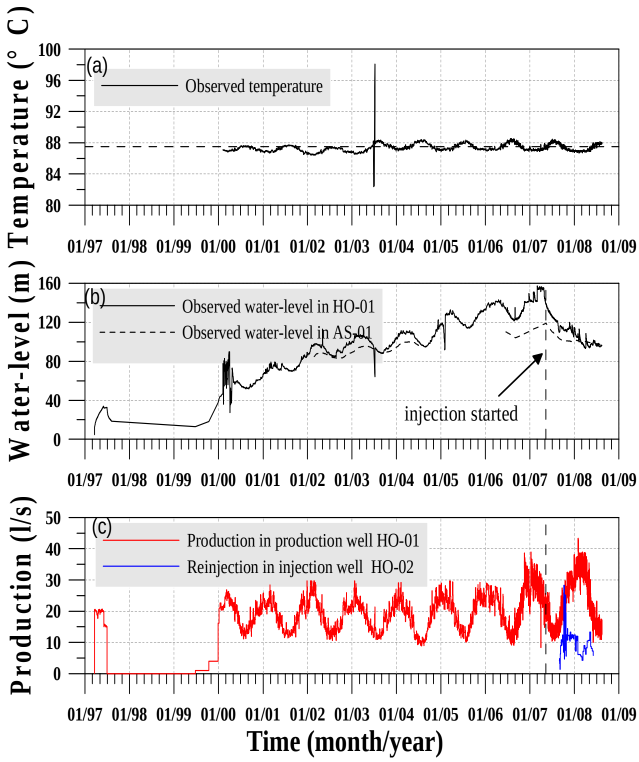

Figure 5: Production, water level and temperature in production well HO-01 and rejection flow-rate in injection well HO-02. The observed water level in well AS-01 is also presented.

3.1 Lumpfit Modelling of The Hofsstadir Geothermal System

In order to evaluate the potential of the Hofsstadir geothermal field, first new data were rearranged, which includes removing the 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. Consequently, we simulated the data step by step, starting from the most simple 1-tank model. There probably exists a shift problem in the observed water-level data since 22-04-2007 because of equipment replacement. The shift problem was solved by subtracting 10 m from the monitoring data (after that date) basing on the experiences of the worker in this station. After that, the corrected data were used as input and simulated again. The simulation results were enhanced greatly, in contrast with the results using the data without correction. The modelling results of different models are shown in Figure 6. After finding the best fitting models, then optimistic predictions of water-level changes are represented by an open version of the model as well as pessimistic predictions by a closed version model for various future production schemes (see later).

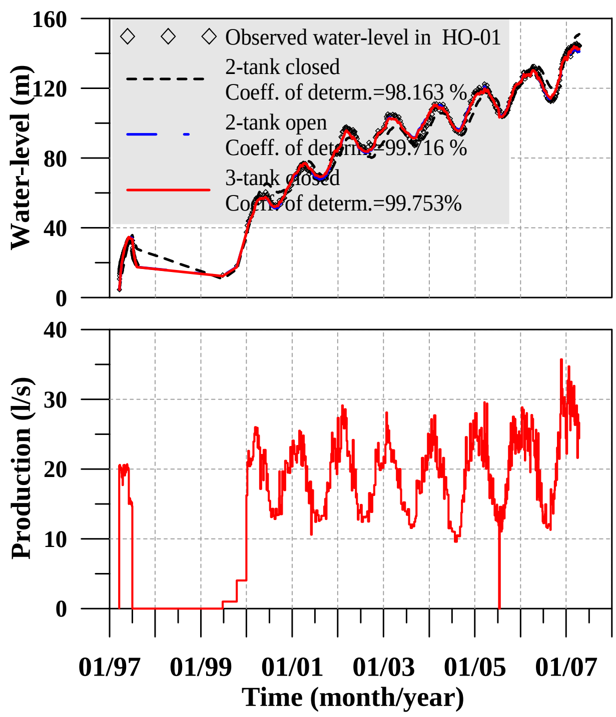

Figure 6: Simulation results of different models based on the data sets without reinjection.

By using the parameters, the main reservoir properties of the Hofsstadir geothermal system can be estimated. The water compressibility β_w is estimated to be 4.4×10^{-10} (Pa^{-1}) at reservoir condition (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. In the other case, the reservoir is confined and the storage of reservoir may be controlled both by liquid and formation compressibility. The storativity of the Hofsstadir reservoir is estimated respectively. Then the value of storativity can be used to estimate reservoir volume and area by assuming two-dimensional flow. The value $\phi = 0.1$ is 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 is 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, can be deduced based on the two dimensional flow model (Table 1).

3.2 Discussion of Simulation Results

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

If one assumes the entire reservoir in Hofsstadir field is unconfined, then the production part will correspond to a volume of 0.01km^3 for both models, based on the constant thickness of 1000m. This result may be too small comparing with 800 km^2, which is the whole area of this region. Actually, based on the geological and geophysical survey results, the Hofsstadir field is most likely a confined reservoir rather than a case with a free surface. In case of a confined reservoir, the calculated areas of the innermost part of the reservoir are very similar, 2.5 km^{2}and 2.3 km^2 for open and closed models respectively, which are little larger than the area of the thermal gradient anomaly shown in Figure 1.

Table 1: Reservoir properties of 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}		

The properties of the flow conductors can be used to estimate the reservoir permeability by assuming a given reservoir geometry. By assuming radial flow in a conventional Theis reservoir model with thickness 1000 m, the permeability-thickness between the first and second tank is 5 D-m and 0.4~2.15 D-m between the second tank and the recharge part. But according to the earlier test results (Bjornsson *et al.*, 1997), well HO-01 should most likely be able to sustain an average production of 15-20 l/s and was a quite productive well, while Figure 7 shows that 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 almost closed, which explains the continuously increasing drawdown.

Also, if discussing about the total area for both versions of the model, then the calculated results for the 2-tank open and 3-tank closed model will be 32 km^2 and 26 km^2 respectively. According to the results of thermal gradient survey, the bigger anomaly area, of which 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 range from 1.5 km^2 to 5 km^2.

4. REINJECTION STUDY AND PREDICTIONS

At Hofsstadir, a continuous draw-down trend has been observed, even when the production rate is maintained at relatively steady level. In early 2006, a reinjection well HO-02, with depth of 413.2 m, was drilled 1200 m northwest of production well HO-01. Only one main aquifer with relative good permeability was found at 319 m depth in this well. At the end of April 2007, the reinjection experiment was started. Unfortunately, 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 draw-down in production well HO-01 decreased drastically since the reinjection started, as shown in Figure 5(c).

Whether an injection project can be carried out within a given geothermal field successfully depends on two factors: first there must be flow paths between the injection well and the production well; secondly, the flow channel should have proper characteristics, which are profitable for the reinjection project. The most interesting question arising from this study issue may be how much of the injected water in well HO-02 will return to production well HO-01 and can eventually be re-extracted without causing additional pressure decline. If we take no account of the temperature and just consider this problem from the point of view of hydrodynamics, then the hydraulic relationship between the reinjection well and production well can be estimated by using the data of injection flowrate, the production flowrate and the water-level changes in production well.

4.1 First Studying Phase

For studying purpose, we assume two cases for the reinjection flowrate for the time period without data:

(I) The injection rate is constant;

(II) The injection rate is proportional to production flowrate;

In the second step, we rearrange the production data by subtracting a given percentage of injection flowrate, which is assumed to enable an equivalent production increase without further pressure decline, from the production flowrate. Then, we use the best fitting parameter model, here we select a 3-tank closed model for this purpose, to simulate the various inputs. Next, we judge the simulation results by simply comparing the coefficient of determination for various scenarios. Finally, we adjusted the assumed percentage and simulated the water-level repeatedly until the best match result was figured out.

The simulation results for the different cases are presented in Figure 7 and Figure 8. It is clear that the simulation results did not match the observed water level well. The biggest difference between them still reached an order of 10m. At this stage, one could have suggested that there may be some mistakes in the collection of the water-level data in production well HO-01. However, observed water level from another observation well AS-01 which is located 800 m southeast of the well HO-01, shows a very similar increasing trend of water table as in well HO-01. Therefore, the problem must lie in the injection flow-rate monitoring data.

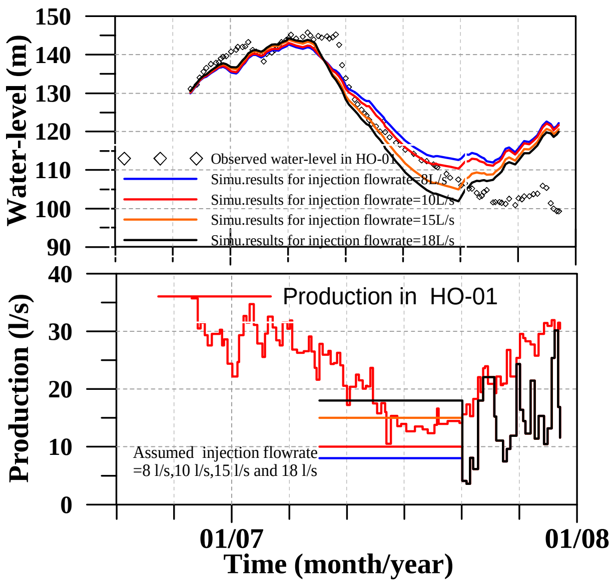

Figure 7: Simulation results based on the assumption that the reinjection flowrate is constant.

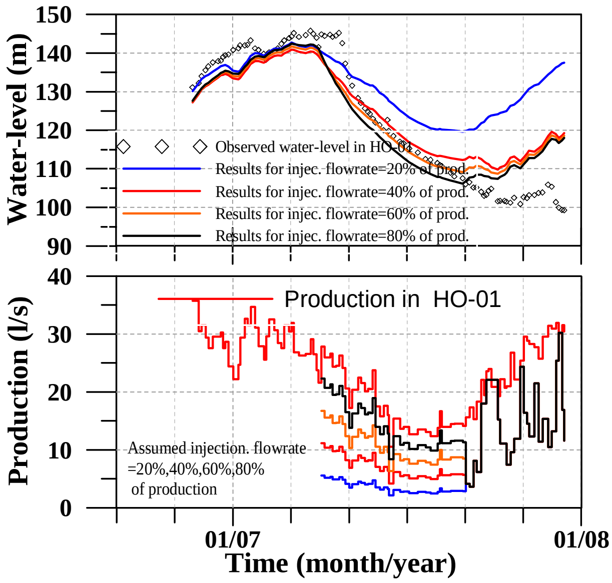

Figure 8: Simulation results based on the assumption that reinjection flowrate is a fixed ratio of the production flowrate during the period without data.

4.1 Second Studying Phase

In the second phase, the actual injection flowrate data were abandoned completely, since these did not seem to be correct. Two cases for the injection flowrate were assumed:

(III) The reinjection flowrate is a fixed ratio of the production flow-rate for the whole reinjection period;

(IV) The reinjection flowrate is one fixed ratio of the production flow-rate in summer and another in winter, which is probably more like the actual situation.

The results are presented in Figure 9 and Figure 10. 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).

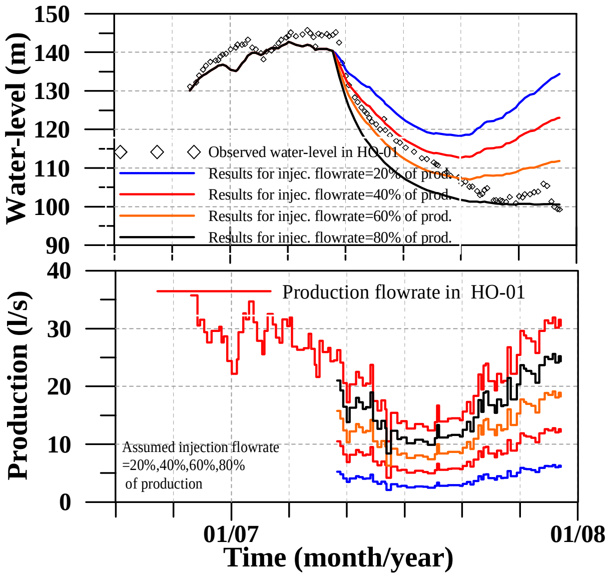

Figure 9: Simulation results based on the assumption that the reinjection flow-rate is a fixed ratio of the production flow-rate for the whole reinjection period.

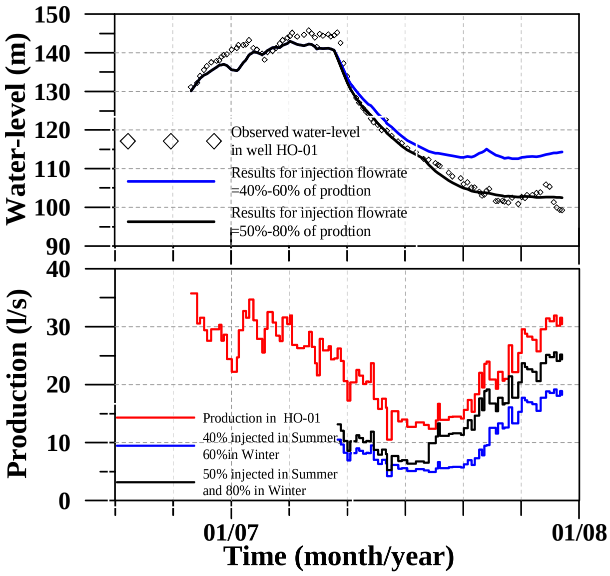

Figure 10: Simulation results based on the assumption reinjection flowrate is one fixed ratio of the production flow-rate in summer (x_1%) and another (x_2%) in winter.

So the average fraction for a whole year can be estimated by the formula as below:

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

The calculation results indicate that about 60% of the production water from well HO-01can be re-extracted through reinjection in the well HO-02 in the Hofsstadir geothermal field. On the average the reinjection must, therefore, be greater than 60%.

The contribution of reinjection to counteracting 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 repeating the simulation, a new method, which can be used to estimate the connection between the production well and injection well, was developed. So this may be a new application for the program LUMPFIT.

4.3 Water-level Change Predictions

In order to reassess the production potential of the Hofsstadir geothermal field, the lumped parameter models were used to predict the future water-level changes due to long-term production. The response of water-level in production well HO-01 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 illustrated in Figure 11.

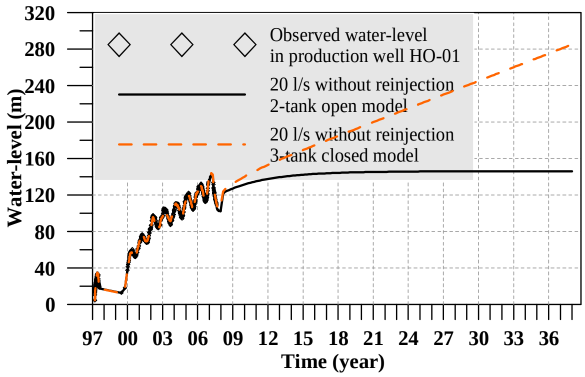

Figure 11: Predicted water-level changes in well HO-01, until 2038 for a production scenario assuming the production is maintained at 20 l/s without reinjection, calculated by a 2-tank open and 3-tank closed model.

The closed and open model results are two extreme conditions of the lumped parameter modelling. It is assumed that the real behaviour of the reservoir will be somewhere between these two simulated responses. The difference between the predictions of the open and closed models is noteworthy; it probably reflects the closed nature of the Hofsstadir reservoir.

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 reinjection study, in which about 60% the production can be injected into well HO-02 and re-extracted totally through the production well HO-01, the case of production increase to 30 l/s was calculated. Figure 12 show the results based on this assumption for both the open and closed version model. As seen on the figure, the open model gives more optimistic forecasts than the closed model. The maximum drawdown in well HO-01 will reach to the order of 270 m after 30 years production, for the cases of a closed model without injection. As seen earlier in Figure 11, this field is capable of sustaining 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, then the drawdown will be less than 200 m, which is still below the limit set by the down-hole pump presently installed.

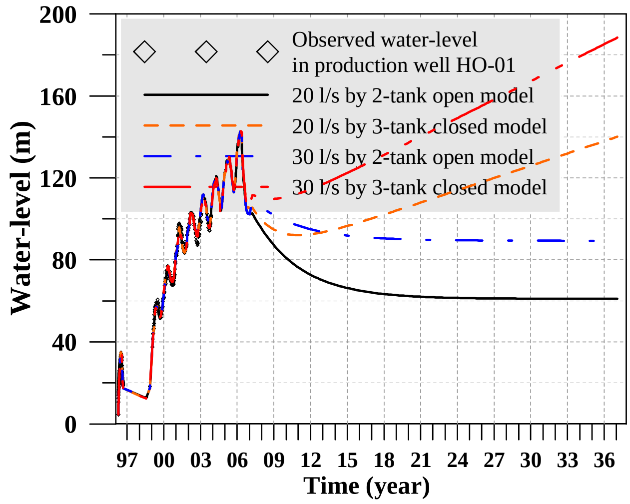

Figure 12: Predicted water-level changes in well HO-01,until 2038 due to constant 20 and 30 l/s production with 60% reinjection, calculated by a 2-tank open and 3-tank closed model.

5. MONTE-CARLO RESOURCES ASSESSMENT

In the traditional volumetric method, the entire reservoir is normally subdivided into a number of subsections, a constant parameter value is assigned for each subsection in the calculation. These parameters include the area extent of the field, the thickness, the temperature and pressure distribution, the porosity, density and heat capacity of the fluid and rock matrix. By 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 determined. 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. However, the quantification of the uncertainties of the probability distributions of the parameters can be handled quite well by using the Monte Carlo simulation method.

To build confidence in the simulation results of Hofsstadir system , a sample population of 4×10^4 random numbers was used for each parameter value. Because the hot water from this field is mainly used for space heating, the conversion efficiency was set as 100%. As mentioned before, based both on the results of the geological survey and the estimated results from the lumped parameter modeling, we adopt 3 km^2 as the best guess value, i.e. the area mostly ranges from 2.5 to 5 km^2. The detailed parameters used in this simulation are listed in Table 2.

Table 2. Values and distributions of Monte-Carlo simulation for Hofsstadir reservoir estimation

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

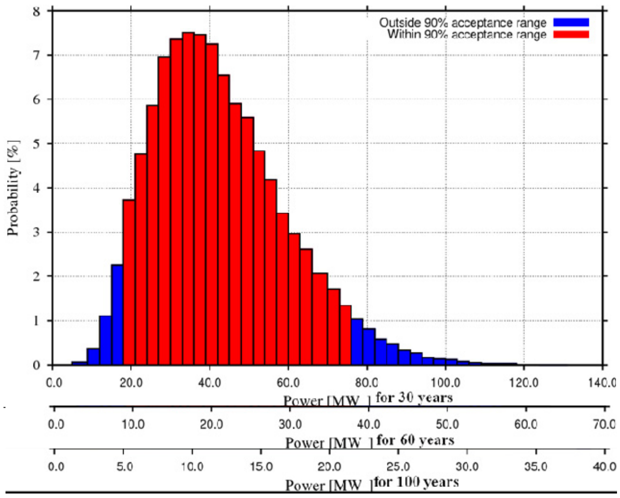

Figure 13: Probability distribution for energy production in the Hofsstadir geothermal field. Each pillar is about 3.5 MW wide for 30 years, about 2 MW for 60 years and about 1 MW for 100 years.

The results are presented as a discrete probability distribution, seen in Figure 13, and as a discrete cumulative probability distribution, seen in Figure 14. These include the likeliest outcome, 90% confidence interval, mean and median of the outcomes, standard deviation and where the 90% limit for the cumulative probability lies. These statistics are presented in Table 3 for each of the three production periods. From the statistics of the cumulative probability in Figure 14 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 of 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.

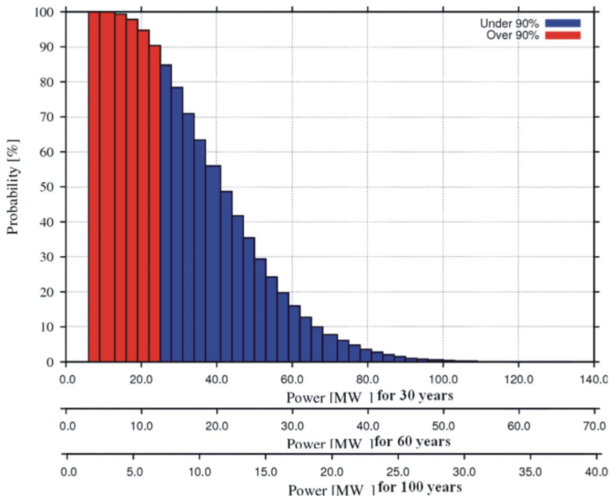

Figure 14: Cumulative probability distribution for energy production in the Hofsstadir geothermal field. The height of each pillar represents the probability that the result is in or below the interval of that pillar.

Table 3: Statistical parameters for the probability distribution for energy production for the Hofsstadir field estimated by the Monte Carlo simulation

Statistical sizes	**Values [MW] (for 30 years)**	**Values [MW] (for 60 years)**	**Values [MW] (for 100 years)**
with 7.5% probability	33.3-36.5	16.0-18.0	10.0-11.0
90% confidence 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
Corresponding production rate (l/s)	100	46	29

6. TRACER TEST

A total of 101 hot water samples were collected from the tracer test, which was carried out in the Hofsstadir geothermal field in late 2007. The Na-Florescein started to show up 2 months later. The data was simulated by the computer code TRINV and TRMAS, included in the *ICEBOX* software package (Arason and Björnsson, 1994). As shown in Figure 15, the tracer recovery in this field is very slow and in fact only about 10% had been recovered during the first 4 months. According to the results simulated by program TRINV, only 44.4% had been recovered during 320 days. It can be seen from the shape of the tracer recovery curve that it is composed of at least two pulses.

The first peak 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 well, HO-01 and HO-02. The parameters of the modelling results are listed in Table 4

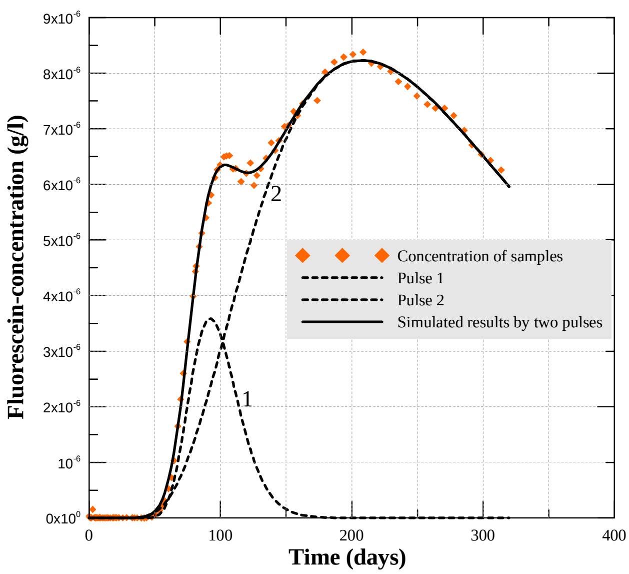

Figure 15: Simulation results of the tracer test data in the Hofsstadir geothermal field

Table 4. Model parameters used in cooling predictions for production wells HO-01 and reinjection well HO-02

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

Comparing the calculated mass recovery until infinite time, there is a quite big difference between the two channels. Only 4% of the injected solute is recovered through the first channel while 67% from the second channel. This is accordance with the results of volume calculated. The results of the analysis yield a mean flow velocity of u = 1.5 × 10^{-4} m/s and 7.7× 10^{-5} m/s for the two channels respectively, which is equal about 390 m/month and 200 m/month. According to the results of the simulation of tracer recovery, the volume of the fractures and the flow channels connecting wells HO-01 and HO-02 is about 1.3× 10^6 m^3 (assuming the porosity $\phi = 0.1$), which a very small fraction of the Hofsstadir reservoir volume.

7. COOLING PREDICTIONS

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 3). These parameters were used to predict the long-term cooling effect of reinjection in the Hofsstadir geothermal field. There are several models that can be used to calculate the cooling danger. They are: (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 (Axelsson, 2005c). For simulation, 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 the height h and the width b of the fracture zone, 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 program TRCOOL (included in *ICEBOX)* is used in calculating the temperature predictions (Axelsson et al., 1994). 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 3, are listed in Table 4. The porosity of the fracture zone within the Hofsstadir is taken as 10%. In order to predict the temperature decline of the production wells due to long-term reinjection into well HO-02, the cooling predictions in the production well HO-01 in the future 30 years were calculated for a few different reinjection scenarios. The calculation results for different production and injection rate using the different models are presented in Figure 16.

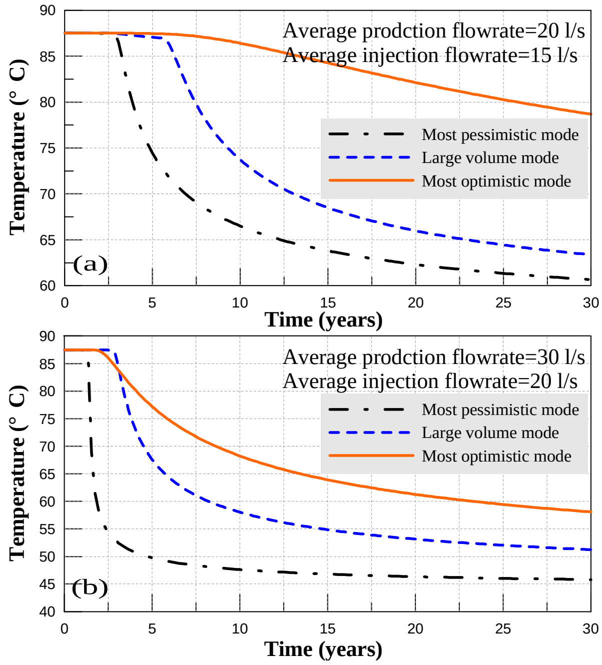

Figure 16: Cooling predictions calculated for wells HO-01 in Hofsstadir, during reinjection into well HO-02, for different flow channel modes and for different production and injection flow rate.

The total production of hot water from this field was about 7 Mm^3 during the past 11 years, the annual energy extraction from the field was around 45 GWh. The total amount of reinjection during the 14 months from April 2007 to June 2008 was estimated to be of the order of 0.3 Mm^3. Adopting the value 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 in the well HO-02 will correspond to a 24 GWh increased heat extraction.

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 will be maintained in future, the production of Hofsstadir field probably can be maintained at 30 l/s, which corresponds total production of 1 Mm^3 per year. Assuming that the temperature of the produced water in well HO-01 will not decline, then the total production of every year corresponds to a 67 GWh annual heat production capacity, which is a nearly 50% increase in comparison with that without reinjection.

8. CONCLUDING REMARKS AND RECOMMENDATIONS

Some of the major conclusions of this work are as follows:

- The Hofsstadir geothermal system belongs to the typical liquid-dominated convection low temperature systems. The geothermal reservoir is markedly small compared with numerous others. The isotopic composition indicates that the water from Hofsstadir cannot strictly be a mixture of present-day freshwater and seawater. Chemistry studies indicate the hot water at Hofsstadir is very old.

- An optimistic open two-tank model and a pessimistic closed three-tank model simulated the data equally well. The model mass storage coefficients indicate a reservoir area of 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, or behaves as almost closed, which explains the continuously increasing draw-down.

- The potential assessment indicates that the field should be able to sustain a stable 20-25 l/s production in future without reinjection. From the beginning of reinjection until 2008, at least 0.34 Mm^3 of return water has been injected into the well HO-02. If reinjection continues long term in this field successfully, then the production capacity can increase to about 30 l/s, with a maximum drawdown less than 250 m through the year 2038, assuming the system has a completely closed boundary.

- The results of the reinjection study indicate that the injected water in well HO-02 has a significant effect in rebuilding pressure in production well HO-01. Based on 11 months of reinjection, it is estimated that the effect of reinjection is comparable to about 60% reduction in production. Monitoring of the reinjection rate appears to have been lacking, but on the average the injection must have been equal to, or greater than, 60% of the production. The results of the study illustrate that two wells have a direct hydraulic connection.

- The Monte Carlo assessment for this field predicted 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.

- From the beginning of the tracer test to July 2008, about 44% of injected solute had been recovered through the production well. The simulation results of tracer recovery indicate that there are at least two flow channels between HO-01 and HO-02. 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 that estimated before. The results is that while there are direct paths between reinjection well HO-02 and production well HO-01, 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-01 supports this conclusion, i.e. that there are direct paths between these two wells.

- It is considered likely that an average long-term reinjection rate of about 15 l/s can be maintained at Hofsstadir, based on the results obtained above. 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.

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