Proceedings World Geothermal Congress 2020+1
Reykjavik, Iceland, April - October 2021

The Eskifjordur Low-Temperature Geothermal System in E-Iceland, Pressure Response Modelling and Tracer Test Analysis

Gunnar Thorgilsson[1], Gudni Axelsson[1], Saeunn Halldorsdottir[1,2], Vigdis Hardardottir[1,3], Bjarni Gautason[1] and Finnbogi Oskarsson[1]

[1]Iceland GeoSurvey (ÍSOR), Grensásvegur 9, 108 Reykjavík, Iceland

[2]Department of Mathematics, University of Bergen, Allégaten 41, 5007 Bergen, Norway

[3]United Nations University (UNU-GTP), Grensásvegur 9, 108 Reykjavík, Iceland

gunnar.thorgilsson@isor.is

Keywords: Eskifjordur, geothermal field, low temperature, district heating, lumped parameter modeling, pressure response, reinjection, production predictions, cooling predictions, tracer test

ABSTRACT

The geothermal system in Eskifjordur has been utilized since 2005, mainly for space-heating. There are two production wells in the geothermal field, ES-1 and ES-2A, currently producing around 77 °C hot water. In addition to these production wells there are three relatively shallow reinjection wells, FB-32, FB-35 and FB-37, of which well FB-37 has been most actively used.

This paper is based on a compilation of production, reinjection, and water table data from wells ES-1, ES-2A, and FB-37 that span the period from 2013 to 2017. The data is used to calibrate a lumped parameter pressure response model to predict the water table in well ES-2A as a function of time and net production from the geothermal system. With this model we make forward predictions for four different scenarios: current production, with and without reinjection, and fifty percent increase in production, with and without reinjection. According to the predictions the geothermal system in Eskifjordur should be able to sustain current production and a fifty percent increased production, at least until 2040, assuming that reinjection is continuously maintained.

Moreover, we present the results of a tracer test carried out in the area. Temperature of the production fluid in wells ES-1 and ES-2A has been steadily declining since reinjection started in 2009; going from 82°C down below 78°C in 2017. To estimate future drop in production fluid temperature a tracer test was performed in March 2017. Three different tracer chemicals (2-naphthalene sulfonate, 2,6-naphthalene disulfonate, and 2,7-naphthalene disulfonate) were injected into wells FB-32, FB-35, and FB-37. The concentration of the tracers was then measured in samples collected regularly from production wells ES-1 and ES-2A. Based on the result of the tracer test a 1D analytical flow model was calibrated. Along with the data from the tracer test, temperature data from the period of reinjection was also used in the calibration via a temperature model based on the flow model. The temperature model was used to make future predictions of water temperature in wells ES-1 and ES-2A for different scenarios of reinjection into wells FB-32, FB-35, and FB-37. We find that with the current reinjection scheme the water temperature will have dropped to 74°C in well ES-1 and 73°C in well ES-2A by 2040. But the temperature model predicts that this temperature drop can be mitigated by distributing the reinjection between wells FB-35 and well FB-37, with a 30/70 combination giving the best results.

1. INTRODUCTION

Production started from the geothermal system in Eskifjordur following geothermal exploration mainly based on temperature gradient drilling. Utilization commenced in 2005 and reached its current rate in 2008. There are two production wells: ES-2A, which is the main production well and ES-1, which is a backup production well. Well ES-1 is located south of Eskifjordur river between Eskifjardarsel and Byggholt, see Figure 1. Well ES-2A is located north of Eskifjordur river.

Well ES-1 was drilled in September 2002. It is 1327 m deep and cased down to depth of 430 m. The well cuts through a feed zone with 80 °C hot water at a depth of 930 m. Well ES-2 was drilled in December 2003 and January 2004 down to a depth of 1306 m. The well was cased with a 10¾" casing to depth of 467 m. In February 2004 it was decided to drill out of the well at 530 m ("kick-off point") as the temperature was not sufficiently high for utilization. The direction of the side-track well was in a south-easterly direction towards the center of the geothermal system and the well was drilled down to a measured depth of 1004 m. The side-track cut through a useful feed zone at about 850 m depth, Gautason and Egilson (2009). After the drill-out well ES-2 is identified as ES-2A.

Production and pressure response history of the system, along with an overview of previous geothermal exploration in Eskifjordur can be found in a report by Halldórsdóttir and Gautason (2013) and in an article by Axelsson et al. (2005c). Further information on monitoring of chemistry and production in the geothermal field can be found in a report by Harðardóttir and Gautason (2017). The lumped modeling work presented in the current study is based on Þorgilsson and Axelsson (2018).

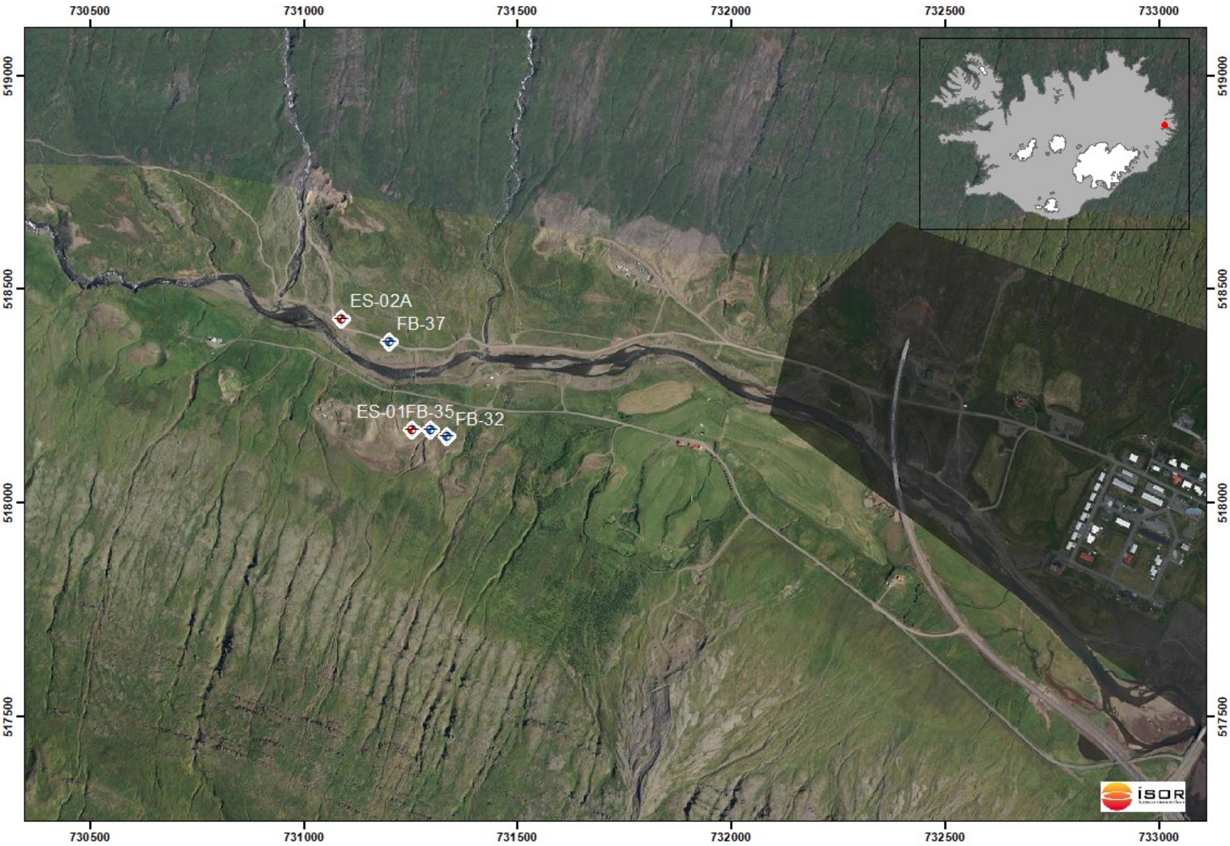

Figure 1. Map of the geothermal system in Eskifjordur. Production wells ES-1 and ES-2A (red hole symbols) and injection wells FB-32, FB-35, and FB-37 (blue hole symbols) are shown in the figure.

Reinjecting return-water from the district heating system into the geothermal system began in the fall of 2008 and reached its current rate at the beginning of the year 2009. The reinjected return-water goes into three wells: FB-32, FB-35 and FB-37. The greatest reinjection is into well FB-37. The location of the injection wells can be seen in Figure 1.

Section 2 of this paper provides an updated review of the production history for the district heating system in Eskifjordur, from the beginning of 2003 to the end of 2017. In Section 3 the production history along with water-level data is used to update an older reservoir model by Halldórsdóttir and Gautason (2013). We use the updated reservoir model to make future prediction for the water-level of the geothermal system until the end of 2040, these predictions are presented in Section 4. In 2017 a tracer test was carried out for the geothermal system. The analysis of tracer test presented in the current study is based on Þorgilsson et al. (2017). The results from this tracer test were used to calibrate a 1D flow model based on Axelsson et al. (2005b) in Section 5. Using the results from the flow model, Section 6 presents a model for temperature changes of the production fluid in response to reinjection rates. Temperature data is used to further calibrate the temperature model. The temperature model is used to predict the possible cooling of the production wells for different reinjection scenarios. These predictions are presented in Section 7. Finally, we finish with conclusions in Section 8.

2. PRODUCTION HISTORY

Two production wells have been drilled in Eskifjordur, well ES-1 and well ES-2A, and they are used to provide the Eskifjordur municipality with district heating. Usages began on the 1st of September 2005. Initially, there were few users, but at the beginning of the year 2006 users were around 60–70. Directly measured production data is missing from 2005 to 2009. Production for this period is estimated from weather data, see Halldórsdóttir and Gautason (2013). The production increased in 2006 and 2007, and by 2008 full production was reached.

Reinjection began in the fall of 2008 and was in its current state at the beginning of the year 2009. There is a lack of data on the amount of reinjection into wells FB-32 and FB-35 before 2016. Therefore, production and reinjection data over the years 2016 and 2017 are used to evaluate, via linear regression, the total reinjection in the years from 2009 until 2016.

With the reinjection history established, we can estimate the net production from the geothermal system. In an earlier model by Halldórsdóttir and Gautason (2013) the best correspondence between the model and measured water level data was achieved when half of the estimated reinjection was subtracted from the production. This is not unreasonable because it is unlikely that all the reinjected fluid finds its way to the production field. Therefore, for this work the net production was estimated in the same way. That is net production is production minus half the reinjection. Figure 2 shows the whole production history. This includes production during injection testing, estimated production from weather data (measured temperature and wind from the Icelandic Meteorological Office), measured production and net production.

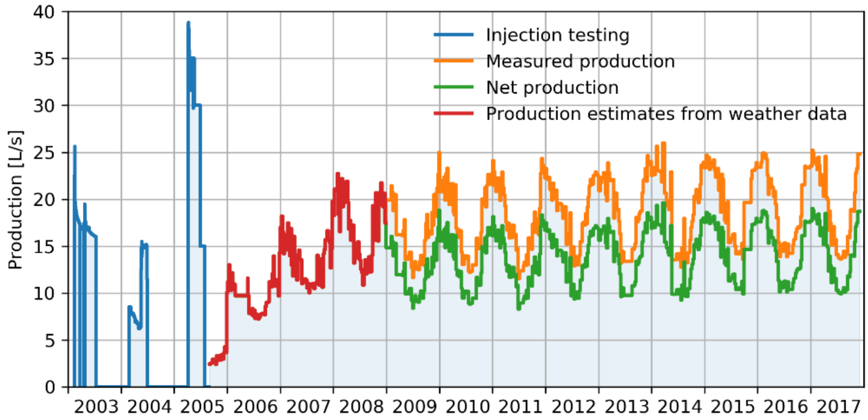

Figure 2. Production from the two Eskifjordur production wells. Net production is obtained by subtracting half the estimated reinjection from measured production (Halldórsdóttir and Gautason, 2013 and Axelsson et al. 2005b).

3. CALIBRATION OF A LUMPED PRESSURE RESPONSE MODEL

Various types of models are used to simulate the nature of geothermal systems and their water level or pressure response to production. If the simulation is successful, the model can be used to predict the system's response to production several years into the future. One type of a simple but robust model is the so called lumped model. In lumped models the geothermal system is represented by one or more connected tanks. This system of tanks can be open or closed to an infinite reservoir. Also, the tanks can be chosen to be unconfined or confined from surface pressure. A schematic of an open three tank model can be seen in Figure 3. In the figure the tanks are labeled with their effective storage coefficients (capacitance): κ_1, κ_2, and κ_3. The connection between the tanks and to the infinite reservoir are labeled by the mass conductance of the connections: σ_1, σ_2, and σ_3. Tank κ_1 represents the small inner part of the system closest to the production site. The net production Q(t) is from tank κ_1. Tanks κ_2 and κ_3 represent parts of the system that get progressively larger and further away from the production site. If the model is open, then tank κ_3 is connected to an infinite reservoir with constant pressure P_0. For closed model the mass conductance σ_3 is zero.

Lumped models have been used to simulate pressure or water level changes for many geothermal systems in Iceland and abroad and have shown to give good results, see Axelsson et al. (2005a). Note also that the predictions will be more reliable as the production and water level records are more accurately recorded and for longer periods.

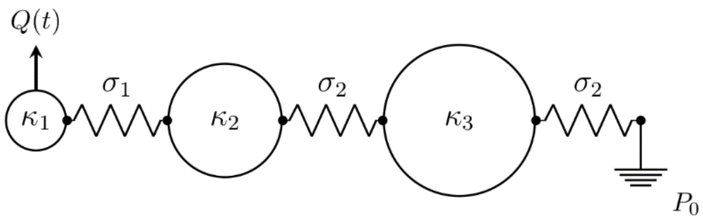

Figure 3. Schematic figure of an open three tank lumped model.

With production and water level data from the period from 2003 to 2017 we calibrate both a closed and an open three tank model. We assume that the models are confined, i.e. not connected to the surface and therefore the storativity of the tanks is only controlled by compressability of the water and rock in the reservoir. Also, we assume that the reservoir temperature is 79 °C, the reservoir thickness is 500 m, and that the reservoir has 10% porosity. Figure 4 shows a comparison of calculated water level values from (a) the closed model and (b) the open model calculated from the net production data to measured water level in well ES-2. The fit is good for both systems, but the open model has a lower root mean square error (RMS) of 9.7 m, compared to 11.1 m RMS for the closed system. The permeability thickness calculated from the calibrated parameters ranges from 3.9 Darcy meters to 4.4 Darcy meters according to the closed model and from 2.3 Darcy meters to 4.0 Darcy meters for the open one. These values are below average compared to other low temperature geothermal reservoir systems in Iceland, see Halldórsdóttir and Gautason (2013). Numerical values for the calibrated parameters for both models can be found in Table 1.

Table 1. Numerical values of the calibrated parameters of the closed and open models for the Eskifjordur system.

Parameters	Closed three tank model	Open three tank model
κ_1 [kg/Pa]:	10.2	10.1
σ_1 [kg/s/Pa]:	4.37×10^{-5}	4.41×10^{-5}
κ_2 [kg/Pa]:	126	124
σ_2 [kg/s/Pa]:	2.65×10^{-5}	2.67×10^{-5}
κ_3 [kg/Pa]:	56900	45700
σ_3 [kg/s/Pa]:	-	3.87×10^{-5}

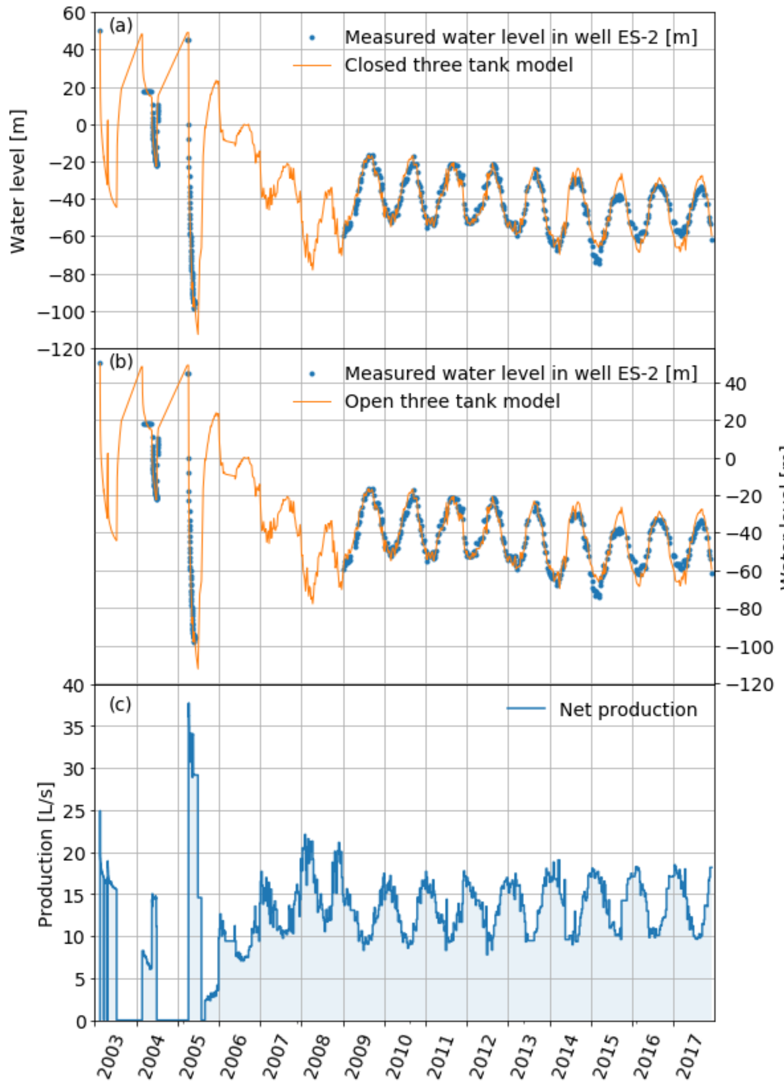

Figure 4. (a) A comparison of measured water level data from well ES-2 to that calculated by the closed three tank model. (b) A comparison of measured water level data from well ES-2 to that calculated by the open three tank model. (c) The net production from the geothermal system.

4. PREDICTIONS OF WATER LEVEL IN WELL ES-2 DUE TO ESTIMATED FUTURE PRODUCTION

Predictions were made for the evolution of the water level from the beginning of 2018 to the end of 2040. These predictions use the calibrated models for a closed and open three tank system described earlier. The following four prediction scenarios were considered:

1. Production and reinjection remains unchanged from what it was in 2014 to 2017, or about 19.4 L/s and 9.9 L/s on average. It is assumed that half of the reinjection fluid returns to the geothermal system, which gives an average net production of 14.5 L/s.
2. Reinjection stops in 2018 and onward, but the production remains unchanged. The average net production from the system is then the same as the average production, or 19.4 L/s.
3. The average production is increased from 19.4 L/s to 29.1 L/s and average reinjection increased from 9.9 L/s to 14.1 L/s. Half of the injection is assumed to return to the geothermal system. Net production is therefore 22 L/s on average for this scenario.
4. Average production as of 2018 has increased by half, from 19.3 L/s to 29.1 L/s, but reinjection is stopped. The average net production is then 29.1 L/s.

In all the estimates of future production the annual fluctuation is based on the net production during the years from 2014 to 2017. The results of these forecast cases can be seen in Figure 5 to Figure 8. In the upper part of the figures, the water level calculated by the open model and the closed model are plotted. The net production (both measured and estimated) used for each scenario can be seen in the lower part of the figures. Generally, the open model and the closed model can be thought of as representing an optimistic and pessimistic prediction, respectively. For all four scenarios the difference between the predictions made by the open model and the closed model can hardly be distinguished until the end of the forecast period. Predicted lowest water level at five years intervals between 2020 and 2040 for the four scenarios are presented in Table 2.

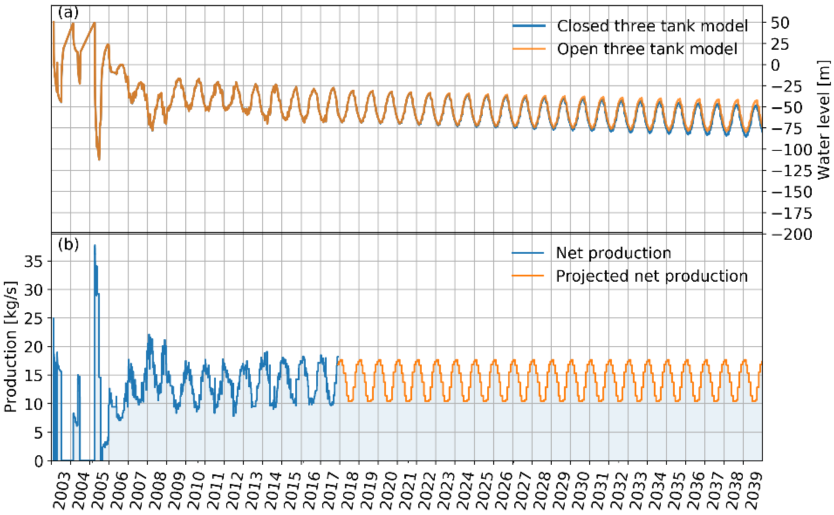

Figure 5. Results for the first scenario. (a) Prediction of the evolution of the water level in well ES-2 according to that calculated by the closed three tank model (blue line) and to that calculated by the open three tank model (orange line). (b) Production used in the predictions: measured net production (blue line) and projected net production (orange line). Here, the average projected production is 19.4 L/s and the average projected injection 9.9 L/s. Net projected production is then on average 14.5 L/s (equivalent to 14.1 kg/s of 79 °C hot water).

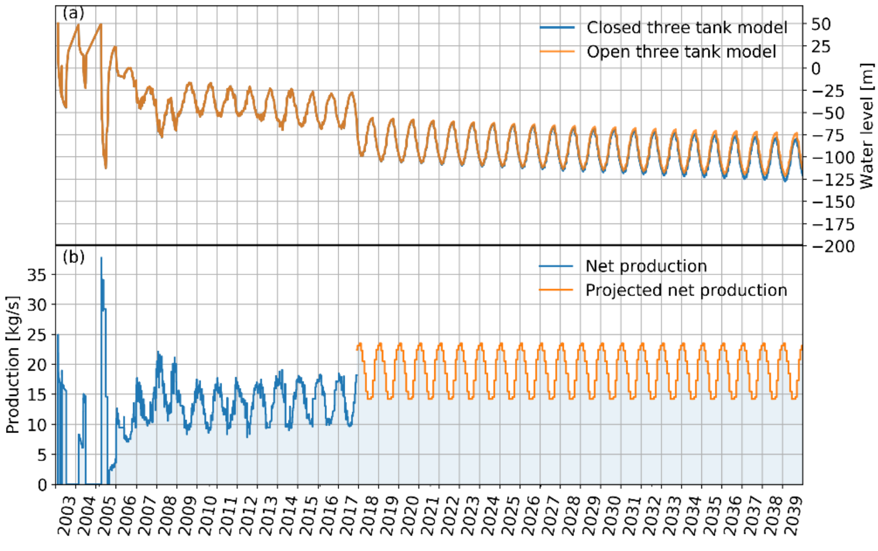

Figure 6. Results for the second scenario. (a) Prediction of the evolution of the water level in well ES-2 according to that calculated by the closed three tank model (blue line) and to that calculated by the open three tank model (orange line). (b) Production used in the predictions: measured net production (blue line) and projected net production (orange line). Here, the average projected production is 19.4 L/s but no reinjection is implemented. Net projected production is then equal to the projected production, or 19.4 L/s on average (equivalent to 18.9 kg/s of 79 °C hot water).

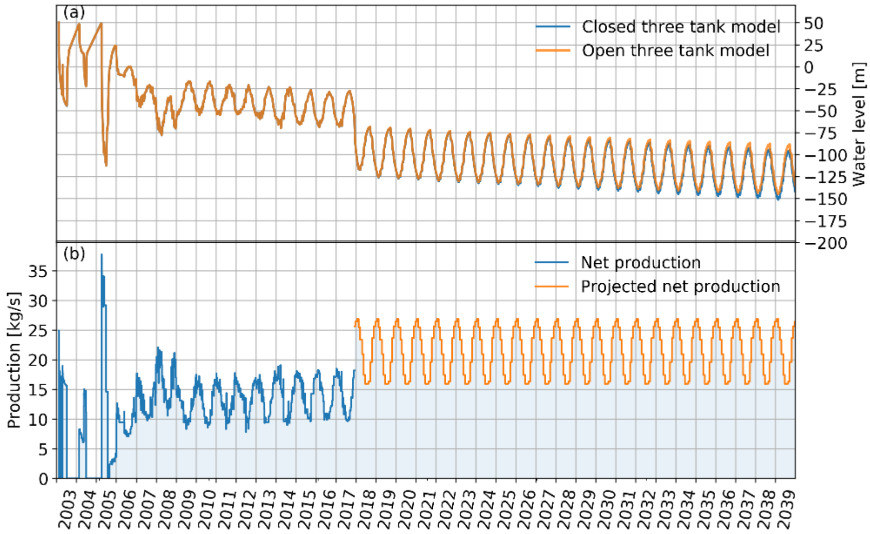

Figure 7. Results for the third scenario. (a) Prediction of the evolution of the water level in well ES-2 according to that calculated by the closed three tank model (blue line) and to that calculated by the open three tank model (orange line). (b) Production used in the predictions: measured net production (blue line) and projected net production (orange line). Here, the average projected production is 29.1 L/s and the average projected injection 14.1 L/s. Net projected production is then on average 22 L/s (equivalent to 21.4 kg/s of 79 °C hot water).

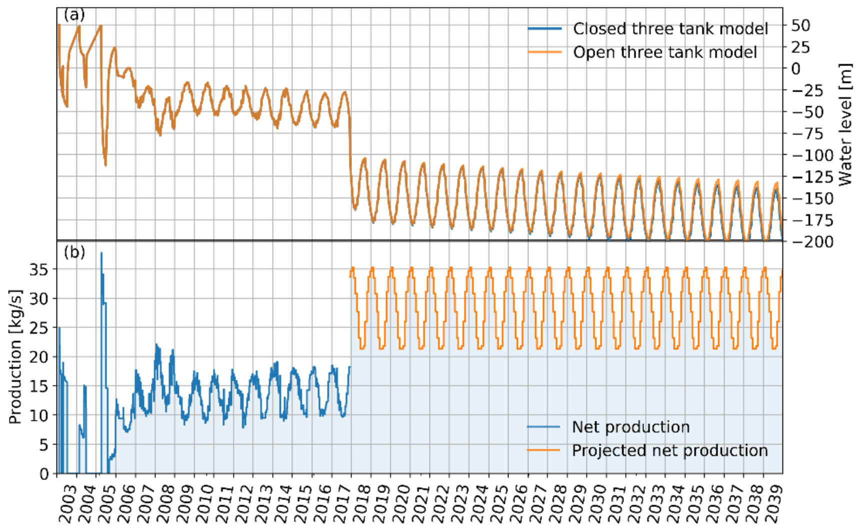

Figure 8. Results for the fourth scenario. (a) Prediction of the evolution of the water level in well ES-2 according to that calculated by the closed three tank model (blue line) and to that calculated by the open three tank model (orange line). (b) Production used in the predictions: measured net production (blue line) and projected net production (orange line). Here, the average projected production is 29.1 L/s but no reinjection is implemented. Net projected production is then equal to the projected production, or 29.1 L/s on average (equivalent to 28.3 kg/s of 79 °C hot water).

Table 2. Predicted lowest water level in well ES-2 according to that calculated by the closed three tank model and to that calculated by the open three tank model. Four scenarios of production are presented: 19.4 L/s average production with and without reinjection, corresponding to the current production, and 29.1 L/s average production with and without re-injection, which corresponds to 50% increase in current production.

Year	19.4 L/s average production				29.1 L/s average production			
	With reinjection		Without reinjection		With reinjection		Without reinjection	
	Closed model	Open model	Closed model	Open model	Closed model	Open model	Closed model	Open model
2020	-70 m	-69 m	-106 m	-106 m	-127 m	-127 m	-180 m	-180 m
2025	-74 m	-72 m	-112 m	-111 m	-133 m	-132 m	-189 m	-187 m
2030	-78 m	-75 m	-117 m	-115 m	-140 m	-137 m	-197 m	-194 m
2035	-82 m	-78 m	-123 m	-119 m	-146 m	-142 m	-205 m	-201 m
2040	-86 m	-80 m	-128 m	-122 m	-152 m	-146 m	-213 m	-206 m

5. CALIBRATION OF A FLOW MODEL BY TRACER TEST DATA

The tracer test in Eskifjordur began on the 2nd of March 2017. At the beginning of the test, 10 kg of 2,6-naphthalene disulphonate (2,6-NDS) and 10 kg of 2,7-naphthalene disulphonate (2,7-NDS) were injected into wells FB-32 and FB-35, respectively, and 20 kg of 2-naphthalene sulfonate (2-NS) was injected into well FB-37. Each tracer was dissolved in 1000 L of hot water from the production wells and injected as a slug. The next half a year the concentration of these three tracers was measured in wells ES-1 and ES-2A. The samples were collected to 100 mL HDPE bottles, without filtering or any other treatment. The tracers were analysed at the ÍSOR laboratory using HPLC with a fluorescence detector, employing a method modified from Rose et al. (2001). The quantification limit of the method is 0.1 µg/L. The results of the analyses can be seen in Figure 9.

Considerable difference is in the measured concentration of the three tracers. The highest measured concentration is for the 2-NS tracer injected into well FB-37. More than magnitude lower was measured concentration of the 2,7-NDS tracer injected into well FB-35 and the smallest measured concentration, more than two orders of magnitude lower than for 2-NS, was for the 2,6-NDS tracer injected into the well FB-32. Some of this contrasting concentration values can be explained by the difference in the volume of water injected into wells FB-32, FB-35 and FB-37; or q= 0.16 kg/s, q=1.06 kg/s, and q=8.26 kg/s, respectively.

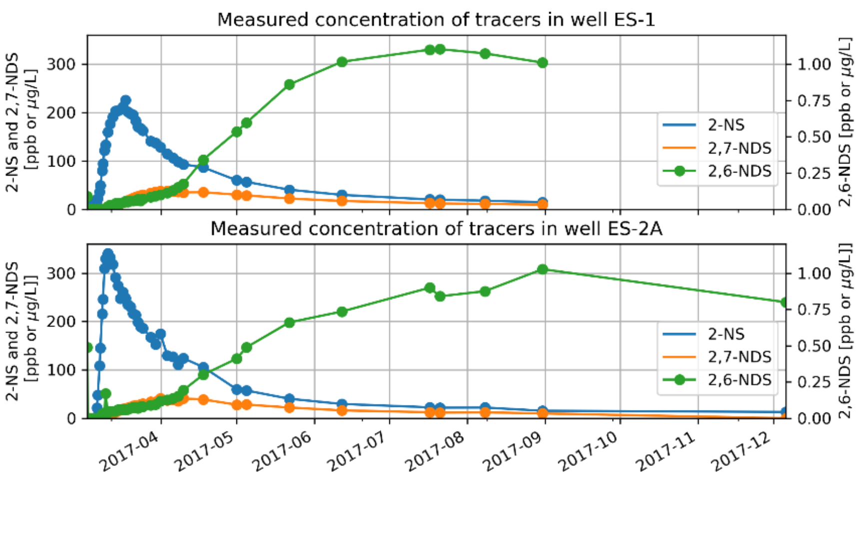

Figure 9. Measured tracer concentration in well ES-1 and well ES-2A from early March 2017 to end of August 2017. Note that the concentration of the tracer 2,6-NDS is shown on a different scale (right side) than concentration of the tracers 2-NS and 2,7-NDS (left side).

The flow of the tracers from the injection wells to the production wells is modeled with a 1D convection-dispersion equation. The parameters of the equation are calibrated so that modeled concentrations at the production well fits the measured tracer recovery data, Axelsson et al (2005b). With a successful fit we can obtain an estimation of the characteristic cross-sectional area of the flow channel. We will use this area for the temperature model described in Section 6. The 1D convection-dispersion equation is

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

Here C (kg/m^3) is the concentration of the tracer in the flow channel, x (m) the length along the channel, t (s) time, u (m/s) the average flow velocity through the channel and D the dispersion coefficient. The average flow velocity through the channel can be written as

$$u = \frac{q}{\rho A \phi} \tag{2}$$

where ρ (kg/m^3) is the density of the fluid in the channel, A (m^2) the cross-section of the channel, ϕ the porosity, and q (kg/s) is the flow rate in the channel. Note that only a portion of the reinjection fluid finds its way to each of the flow channels. The rest is assumed to flow to other parts of the geothermal system, or even out of the system. We assume that molecular diffusion is negligible, and the dispersion coefficient can therefore be written as $\mathrm{D} = \alpha_{\mathrm{L}}\mathrm{u}$, where α_L (m) is the diffusivity.

The tracer concentration is, as mention before, measured at the production wells. That is at the end of the flow channels. We are therefore interested in the solution of Equation (1) at x = L, where L is the length of the channel. To simplify, we assume that the tracers are not lost or destroyed within the flow channels. This is equivalent to $cQ = Cq$, where Q (kg/s) flow rate from the production well and c (kg/m^3) is the measured concentration of the tracers at the production wells. The average production rates for wells ES-1 and ES-2A are Q = 7.91 kg/s and Q = 11.73 kg/s, respectively. We also assume that the tracer mass m (kg) enters immediately into the flow channel at time t = 0 s. Note that m is always less than M, the total mass of the tracer material injected into the reinjection well. This corresponds to a Dirac-delta initial condition at x=0 for which Equation (1) has the following solution

$$c(t) = \frac{um\rho}{Q}\frac{1}{2\sqrt{\pi D t}}e^{-\frac{(L-ut)^2}{4Dt}}. \tag{3}$$

There may be more than one channel between a reinjection well and a production well, but we assume that the length L of those channels is the same. The length of the channels between the feed zones of the injection wells and the production wells can be found in Table 3. The density of the water is dependent on the temperature of the geothermal system, which we assume is T = 78 ° C. The density of the water is then ρ = 973 kg/m^3.

Table 3. Length of channels between reinjection wells FB-32, FB-35, and FB-37 to the production wells ES-1 and ES-2A.

	FB-32	FB-35	FB-37
ES-1	841 m	601 m	820 m
ES-2A	749 m	594 m	720 m

Before we start fitting equation (3) to measured concentration of the tracers we must make the following correction to the data. The reinjected water usually comes from production wells. This complicates the tracer analysis because tracers in the production fluid are reinjected. This over time creates a circulation of the tracers in the system. We attempt to correct for this circulation by the following transformation for each set of measured tracers

$$c_w^0(t_i) = c_w(t_i) - \sum_k \frac{\tilde{q}_k}{M\rho}\int_0^t c_k(t_i - \tau)c_w^0(\tau)d\tau. \tag{4}$$

Here, $c_w^0(t_i)$ is the corrected tracer concentration in production well w at time t_i, $c_w(t_i)$ and $c_k(t_i - \tau)$ are the measured tracer concentrations in production well w and reinjection well k at times t_i and $t_i - \tau$, $\tilde{q}_k = q_k(Q_w/\sum Q_w)$ is the rate of reinjection into well k from production well w, M is the total mass of the tracer and ρ the density of water flowing within the channel. Equation (4) can be cast into the matrix form

$$\underline{A}c^0 = c \tag{5}$$

by discretizing the integral in Equation (4), where

$$(\underline{A})_{ij} = \delta_{ij} + \sum_k \frac{q_k}{M\rho}c_k(t_i - t_j)\Delta\tau_j. \tag{6}$$

Note that $\Delta\tau_j$ is the length between discretized time points in the integral and that the values for $c_k(t_i - t_j)$ are obtained by interpolation. Solving Equation (5) gives the corrected tracer concentration.

The coefficients D, u, m are estimated by a nonlinear regression analysis from the corrected tracer concentration values at the production wells. For this we used the TR program that is found in the inhouse software package ICEBOX at ISOR. These coefficients are then used to calculate α_L, and $A\phi = hb\phi$, where h and b are the height and width of the channels. The fit of the flow models that result from the nonlinear regression analysis to the data is shown in Figure 10 to Figure 12. The 2,6-NDS tracer that was injected into well FB-32 had very low recovery rate according to the model, or just under 7%. This indicates that well FB-32 has little connection to well ES-1 and well ES-2A. It should be noted, however, that the injection rate into well FB-32 was very small and that could partly explain this low recovery of the 2,6-NDS tracer. Also, the measured recovery of the 2-NS tracer in well ES-2 is greater than predicted by the model. This can be seen in Figure 12 were the model underestimates the concentration of the corrected measured values over the period after 90 days. This is an indication that the correction process for circular flow was not able to fully remove circulation of tracers in this channel.

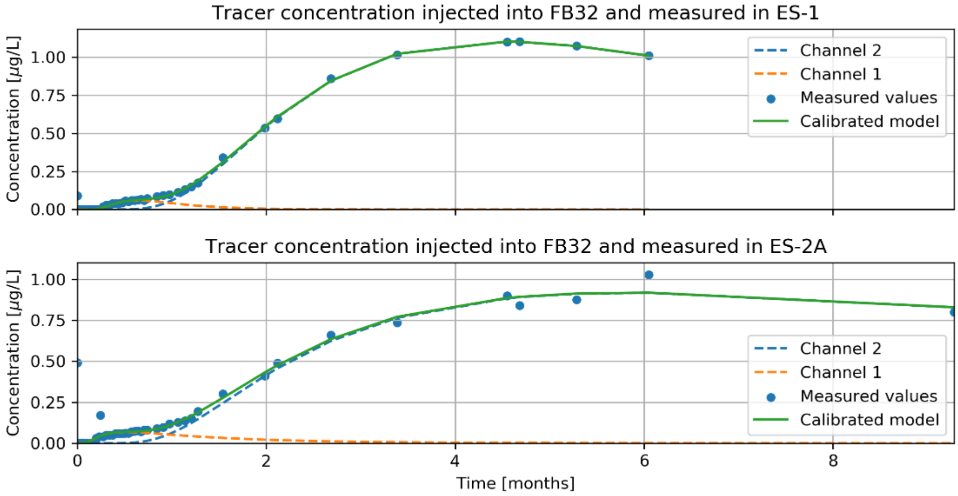

Figure 10. Measured concentration of the 2,6-NDS tracer together with calculated concentrations according to a calibrated two channel flow model. Notice that the recovery was so slow that measurements showing the tracer concentration diminishing are lacking.

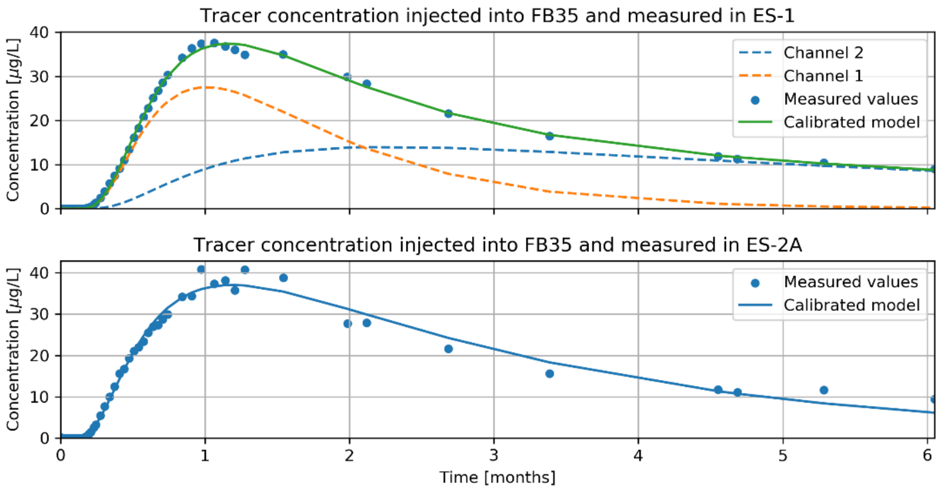

Figure 11. Corrected concentration values for the 2,7-NDS tracer together with the concentration according to calibrated two channel flow model for ES-1 and calibrated one-channel model in well ES-2A.

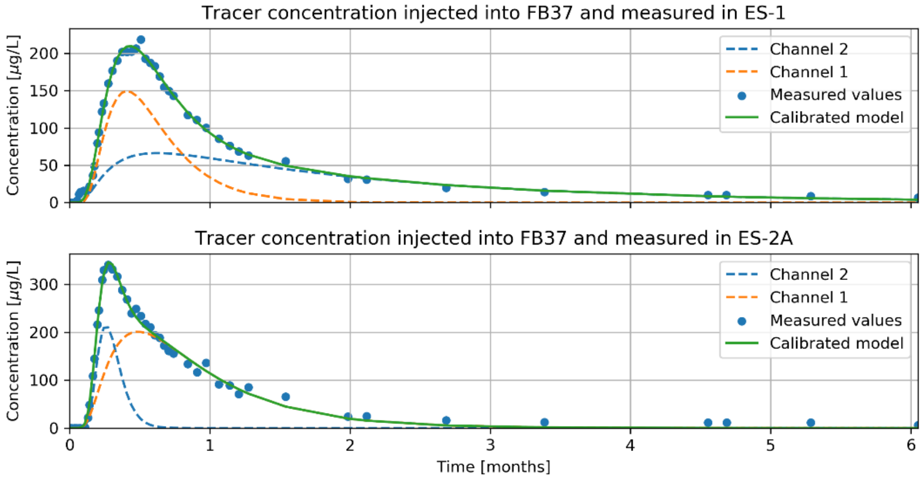

Figure 12. Corrected concentration values for the 2-NS tracer together with the concentration according to calibrated two channel flow model.

6. CALIBRATION OF THE TEMPERATURE MODEL

The results from the calibrated flow models can be used to predict possible long-term cooling of water from the production wells, see Axelsson et al. (2005b). Water flowing from the injection wells to the production wells heats up due to thermal conduction from the geothermal reservoir rock. Here we assume a fixed cross section in the flow channels. If T_0 is the initial temperature of the water from the production wells before reinjection started and T_i is the temperature of the reinjected water into the geothermal system, it can be shown that the temperature of the water from the production well evolves as follows

$$T(t) = T_0 - \sum_j \frac{q_j}{Q}(T_0 - T_i)\left[1 - \mathrm{erf}\left(\frac{kL_jh_j}{c_w q_j\sqrt{\kappa\left(t - \frac{L_j}{\beta}\right)}}\right)\right], \tag{7}$$

if reinjection rates and production rates are constant. Here the sum is over all channels connecting the reinjection wells to the production well, $q_j = q \cdot m_j/M$, $\beta = qc_w/\langle\rho c\rangle_f$ where $\langle\rho c\rangle_f = \rho_w c_w \phi + \rho_r c_r(1-\phi)$. Also, c_w = 4200 J/(kg°C), c_r=1000 J/(kg°C), ρ_w = 973 kg/m^3 and ρ_r=2700 kg/m^3 are the heat capacity and density of water and the reservoir rock, k=2 W/($m°C$) is the thermal conductivity of the reservoir rock, and $\kappa = k/(c_r\rho_r)$ is the thermal diffusivity of the reservoir rock.

Here it is worth noting, that although the flow model assumes that the tracer is conserved in the channels, it is only part of the total reinjection into the well that takes part in the flow for each channel. The fraction of the total reinjection that takes part in the flow through the channel is calculated from the recovered mass of the tracer for each channel: m_j/M where m_j (kg) is the mass of the tracer in channel j and M (kg) is the total mass of the tracer that is injected into the reinjection well.

Although we can obtain the values of most of the variables we need in Equation (7) from the nonlinear regression analysis in Section 5, the height or width for each channel, h_k or b_k, and the porosity of the rock ϕ are undefined. What we get from the regression analysis is the value of the multiplication Aϕ=$hb\phi$. If we choose a porosity of ϕ = 10%, which is reasonable for rocks in the eastern part of Iceland, the only significant uncertainty is the ratio between h_k and b_k.

Usually, uncertainty in the ratio of height and width of channel k is addressed by calculating an optimistic prediction where $h_k \gg b_k$ gives a high thermal absorption and a pessimistic prediction where $h_k \approx b_k$ gives low thermal absorption. In the case of the geothermal field in Eskifjordur, water temperature measurements for the production wells ES-1 and ES-2A are available after reinjection started in the area. We can use these measurements to calibrate the ratio between h_k and b_k, i.e. select a ratio so that the temperature model fits best with temperature measurements. The variables h_k and b_k can then be calculated from the optimized ratio. Based on the current reinjection scheme the temperature models indicate that the reinjection into well FB-32 and well FB-35 have had a negligible effect on temperature in wells ES-1 and ES-2A. This is probably due to the small amount of water injected into wells FB-32 and FB-35 compared to FB-37. We can therefore assume that the reinjection in the FB-37 well has so far been completely responsible for the temperature change in the production wells.

Figure 13 shows the weekly averaged temperature data for well ES-1 and well ES-2A compared with a calibrated temperature model. The model shown in Figure 13 has a b_k/h_k ratio of 0.014 for channels going from well FB-37 to well ES-1 and a ratio of 0.009 for channels going from well FB-37 to well ES-2A. In the models, we have assumed that the initial temperature in well ES-1 was 79 °C and 80 °C in well ES-2A. For the temperature models discussed in section 7, we will assume that the channels from well FB-32 and well FB-35 to well ES-1 and well ES-2A will have the same b_k/h_k ratio as the channels from FB-37 to well ES-1 and well ES-2A.

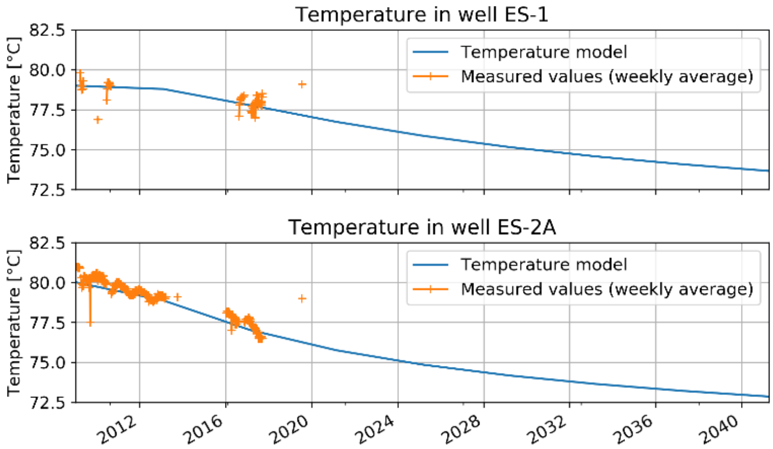

Figure 13. Calculated water temperature changes for well ES-1 and well ES-2A for the ratio of height and width of the flow channels that best matches the measured values.

7. PREDICTION OF COOLING IN PRODUCTION WELLS DUE TO REINJECTION

As previously mentioned, the current scheme of reinjection in FB-32 and FB-35 seems to have negligible effect on the temperature in the two production wells. We can therefore take the temperature models shown in Figure 13 as the prediction for the temperature in wells ES-1 and ES-2A, based on the current reinjection scheme. According to the model, the temperature in well ES-1 and well ES-2A will be almost 74 °C and 73 °C respectively by 2040. This corresponds to over 5 °C cooling in well ES-1 and over 7 °C cooling in well ES-2A.

In addition to the predicted cooling in the production wells for the current reinjection scheme, it is interesting to look at the different distributions of reinjections into the wells FB-32, FB-35, and FB-37; especially with a view to minimizing the cooling of the wells in the future. It is worth noting that the temperature model in Equation (7) is derived assuming a fixed reinjection. Therefore, it is difficult to predict with complete certainty what will happen if there is a great deal of change in the reinjection, for example if reinjection into well FB-37 were to abruptly stop and all the reinjection were directed into well FB-35. One might correctly note that some of the older injection into well FB-37 would still continue to affect the geothermal system after the reinjection has stopped.

However, it is possible to compare predictions for different reinjection schemes if we make the assumption that the system is initially undisturbed. The results of such a comparison are shown in Figure 14. There the current combined mean reinjection, totaling 9.48 kg/s, is distributed into wells FB-32, FB-35 and FB-37 in four different ways: mixed reinjection into wells FB-35 and FB-37, all reinjection into well FB-32, all reinjection into well FB-35 and all reinjection into FB-37. Based on the results in Figure 14, much more cooling would have resulted if well FB-35 had been used as the primary reinjection well instead of well FB-37. Also, if it is assumed that the channels originating from FB-35 and well FB-37 will respectively go through different parts of the geothermal system, Figure 14 shows that better utilization of the reinjection can be obtained if both wells are used for reinjection. According to the temperature model, the lowest cooling in the production wells will be obtained by reinjecting about 30% of the full reinjection into the FB-35 well and 70% into the FB-37.

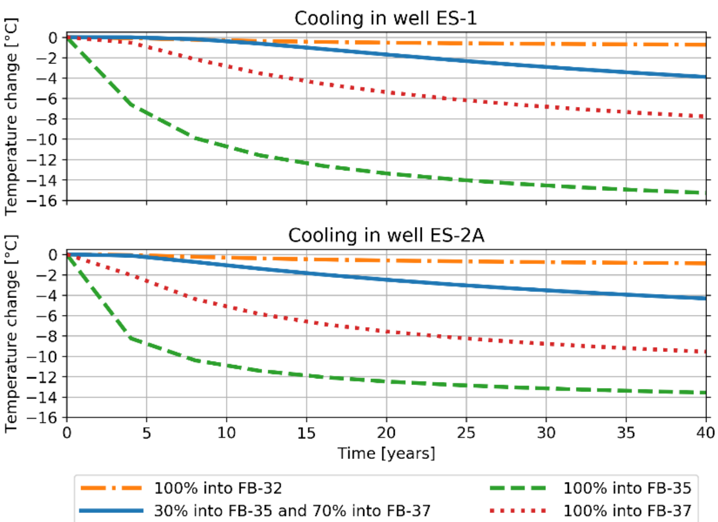

Figure 14. Comparison of the effects of full injection, q = 9.48 kg / s, distributed in four different ways into wells FB-32, FB-35 and FB-37.

8. CONCLUSIONS

Production data, reinjection data, and water level data for the Eskifjordur geothermal system was compiled from the beginning of 2003 to the end of 2017. The data was used to calibrate two lumped pressure response models with the ÍSOR Lumpfit computer software, a closed three tank model and an open three tank model. The calibrated models simulate well the measured water-level data.

The models were used to make predictions over a 20 years period based on four different production and reinjection scenarios: Current average production with and without reinjection and a 50% increase in average production with and without reinjection. For the current production scheme, the deepest water level at the end of the prediction period is in the range of 80 m depth according to the open model with reinjection and down to 128 m according to the closed model without reinjection. If production is increased by half, the deepest water level at the end of the prediction period ranges from a depth of 146 m according to the open model with reinjection and down to 213 m depth according to closed model without reinjection. If it is assumed that the maximum possible depth for a pump in the production wells is between 200 and 250 m, the geothermal system can sustain the current production scheme as well as up to a half increase in production, provided reinjection is continued.

On the 2nd of March 2017, three different tracers were injected into the reinjection wells FB-32, FB-35 and FB-37. The next half year, the concentration of these tracers was measured in the two production wells, ES-1 and ES-2A. The measured concentration of the tracers was corrected for circulating flow between the production wells and the reinjection wells and used to calibrate 1D flow models between the reinjection wells and the production wells.

Results from the calibration of the flow models served as an input into models of temperature changes in the production wells due to reinjection. The temperature models indicate that reinjection into well FB-37 has been the major contributor to temperature changes that has occurred since the onset of reinjection. With temperature measurements after the start of reinjection, it was possible to constrain calibration of the temperature model for the production wells due to reinjection into well FB-37. According to the temperature model, with the current reinjection scheme, water temperature in well ES-1 will be just below 75 °C in 2030 and 74 °C in 2040, and the temperature of the ES-2A just below 74 °C in 2030 and 73 °C in the year 2040.

Finally, the temperature changes in wells ES-1 and ES-2A were modeled for different reinjection schemes. This comparison revealed that FB-37 is more suitable as a reinjection well than FB-35. Comparison of the mixed reinjection schemes revealed that approximately 30% of full reinjection into FB-35 and approximately 70% of full reinjection into FB-37 resulted in less cooling in the production wells than with the current reinjection scheme. Because of how little was reinjected into well FB-32 during the tracer test and how poorly it seems to be connected to the production wells, it was not included in the mixed injection scheme predictions.

ACKNOWLEDGEMENTS

Fjardarbyggð Utilities, which utilize the Eskifjordur geothermal system, are acknowledged for allowing publication of data presented in this paper.

REFERENCES

Axelsson, G., Björnsson, G., Quijano, J.E.: Reliability of Lumped Parameter Modeling of Pressure Changes in Geothermal Reservoirs., *Proceedings*, World Geothermal Congress 2005. Antalya, Turkey (2005a).

Axelsson, G., Björnsson, G., Montalvo, F.: Quantitative Interpretation of Tracer Test Data., *Proceedings*, World Geothermal Congress 2005. Antalya, Turkey (2005b).

Axelsson, G., Björnsson, G., Egilson, Þ., Flóvenz, Ó. G., Gautason, B., Hauksdóttir, S., Ólafsson, M., Smárason, Ó. B., and Sæmundsson, K.: Nature and properties of recently discovered hidden low-temperature geothermal systems in Iceland. *Proceedings*, World Geothermal Congress 2005. Antalya, Turkey (2005c).

Halldórsdóttir, S. and Gautason, B.: Eskifjörður: Yfirlit um jarðhitakerfið og vinnslusögu frá 2005-2012 ásamt framtíðarspám (Eskifjordur: Overview of the geothermal system and production history from 2005-2012 with future predictions), *Report,* Iceland GeoSurvey, ÍSOR-2013/023, (2013).

Harðardóttir, V., and Gautason, B., Hitaveita Eskifjarðar: Eftirlit með vinnslu 2015 og 2016 (Eskifjordur district heating: Production monitoring 2015 and 2016), *Report,* Iceland GeoSurvey, ÍSOR-2017/013, (2017).

Gautason, B., and Egilson, Þ.: Mælingar í holu ES-02 í kjölfar dæluupptektar í mars 2009 (Measurements in well ES-02 following removal of pump in March 2009), *Report*, Iceland GeoSurvey, ÍSOR-08081, (2009).

Rose, P.E., Benoit, W. R. and Kilbourn, P.M.: The application of the poly-aromatic sulphonates as tracers in geothermal reservoirs. *Geothermics,* **30,** (2001), 617–640.

Þorgilsson, G., Axelsson, G., and Harðardóttir., V.: Ferilpróf á jarðhitasvæðinu í Eskifirði (Tracer test in the geothermal field in Eskifjordur), *Report*, Iceland GeoSurvey, ÍSOR-2017/085, (2017).

Þorgilsson, G., and Axelsson, G.: Jarðhitakerfið í Eskifirði: Endurmat á afkastagetu og mat á áhrifum borunar Norðfjarðargangna (The geothermal system in Eskifjordur: Reassessment of production capability and an assessment of effects of drilling of the Nordfjördur tunnel), *Report*, Iceland GeoSurvey, ÍSOR-2018/044, (2018).