UNITED NATIONS UNIVERSITY
GEOTHERMAL TRAINING PROGRAMME
Orkustofnun, Grensasvegur 9,
IS-108 Reykjavik, Iceland

Reports 2013
Number 31

INJECTION AND PRODUCTION WELL TESTING IN THE GEOTHERMAL FIELDS OF SOUTHERN HENGILL AND REYKJANES, SW-ICELAND AND THEISTAREYKIR, N-ICELAND

Wondwossen Redie Kewiy
Geological Survey of Ethiopia
Geothermal Energy Department
P.O. Box 2302
Addis Ababa
ETHIOPIA
rediewondwossen@yahoo.com

ABSTRACT

In this paper, different approaches and methods are used for analysing well test data. Well testing is performed in order to monitor the pressure response in a reservoir when it is subjected to injection or production. The main purpose is to evaluate the properties that govern the nature of the reservoir, flow characteristics and deliverability of the well. The project emphasis is on well completion and flow test data from Hellisheidi, Reykjanes and Theistareykir geothermal areas. An analysis of data from step-rate injection tests, temperature and pressure profiles was conducted in Hellisheidi, Reykjanes and Theistareykir geothermal areas as well as a discharge test in Reykjanes. Four wells were selected: Wells HE-04, HE-09, RN-28 and ThG-09. Well Tester software was used for the step rate injection test analysis. Temperature and pressure profiles were analysed to estimate the formation temperature and the initial reservoir pressure. The ICEBOX software was applied to get the Horner plot of rock temperature at selected depths in HE-04 and ThG-09 well, using a program called BERGHITI, and the BOILCURVE program was used to acquire the boiling curve. During the production test, measurements were made from which the fluid flow and its energy content were deduced and chemical characteristics were measured. The Russel James method can be used to determine the flow characteristics with a simple weir-box being used to measure the liquid flow.

1. INTRODUCTION

The aim of this project is to study examples of injection and production well testing at southern Hengill, Reykjanes and Theistareykir high temperature geothermal fields in Iceland. Before describing the well testing activities, the geological structure of Iceland will be reviewed in general.

The country is located in the active mid-oceanic ridge system. It is one of a few areas in the world where the mid-oceanic ridge rises above sea level. Central volcanoes and fissure swarms characterize the volcanic zones. A tectonic and active volcanic zone crosses the country from southwest to northeast (Figure 1). The high-temperature areas are narrowed to the active zones of volcanism. The Mid-Atlantic Ridge is a divergent plate boundary along which the North American plate and the European plate are drifting away from each other in the northern part of the Atlantic Ocean. The Reykjanes Ridge, southwest of Iceland, and the Kolbeinsey Ridge, to the north, are segments of the Mid-Atlantic Ridge. The spreading rate is around 2 cm/year. Iceland is formed as a result of widespread volcanism along this ridge.

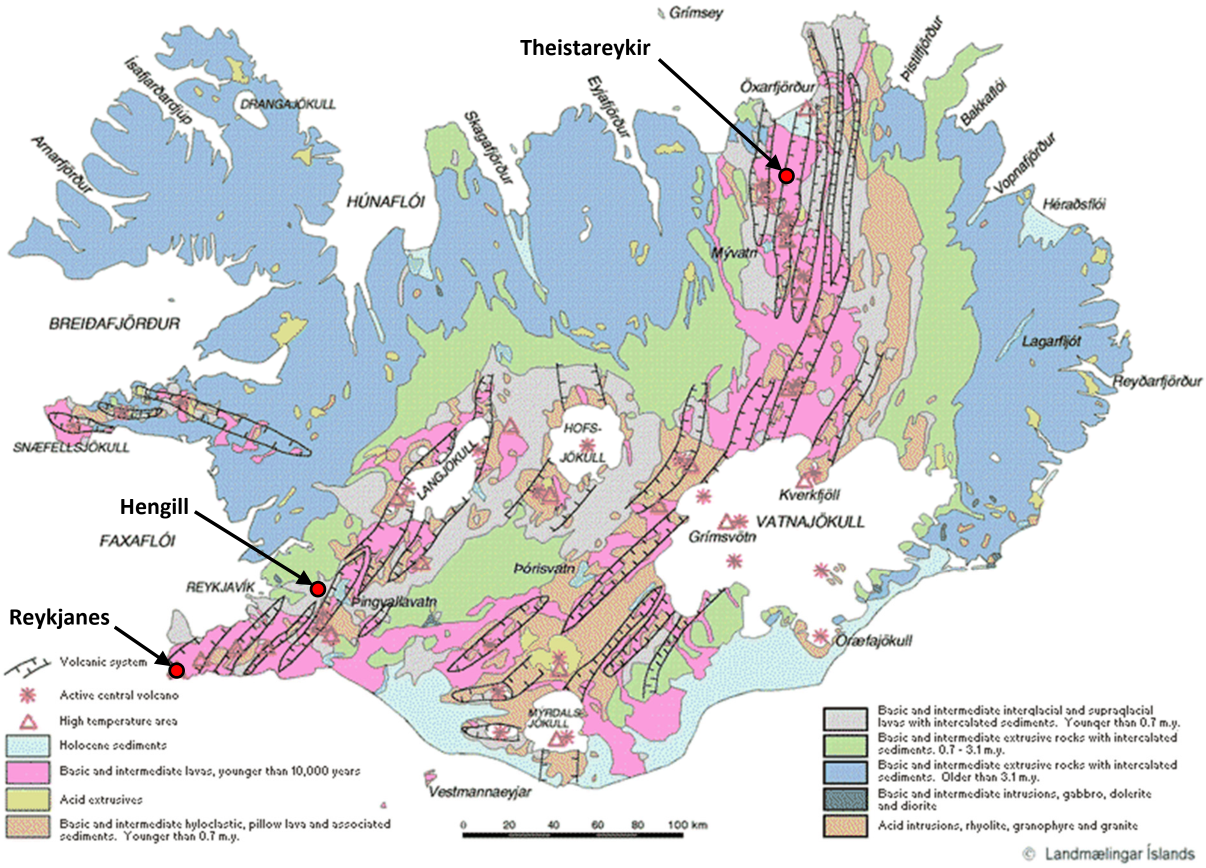


FIGURE 1: Geological map of Iceland showing the oldest Tertiary rocks, older Plio-Pleistocene eruptives, Holocene rocks and other young formations; volcanic systems follow the oceanic ridge (adopted from Jóhannesson and Saemundsson, 1999)

2. GEOLOGY OF ICELAND

Iceland is located on the Mid-Atlantic Ridge, the boundary between the North American and the Eurasian plate. Iceland is the product of an interaction between a spreading plate boundary and a hot mantle plume, the source of additional volcanism under the country; the country is moving slowly northwest across the hot spot (Vink, 1984). The spreading is approximately 8-20 mm/year or 2 cm/year according to Árnadóttir (2008). The creation of Iceland in its current form is thought to have begun some 24 million years ago (Saemundsson, 1979). The oldest rocks are 16-14 million years old and are exposed in the extreme northwest and east, while the youngest rocks are located within the volcanic rift zone (Jóhannesson and Saemundsson, 1999).

The geological formations of Iceland can be divided into the following four major groups: Tertiary (16 to 3.3 Ma - Miocene-Pliocene); Plio-Pleistocene (3.3 to 0.8 Ma); Upper Pleistocene (0.8 to 0.011 Ma); and Postglacial (11,000 to present). Iceland is mainly composed of basalts (80-85%) and intermediate to acidic rocks (10%) while sedimentary rocks of volcanic origin represent only 5-10%. The Pleistocene rocks are confined mainly to a broad SW-NE trending zone between the Tertiary plateau basalt areas, and are also exposed within the Tjörnes, Snaefellsnes and Skagi peninsulas.

3. GEOTHERMAL ENERGY

Geothermal energy is the natural heat contained within the earth that can be recovered and exploited. Heat flows from the interior of the earth to the surface, either by convection through hot water mass transfer or by heat conduction. The most obvious appearances of the earth´s thermal energy are in areas of recent volcanism and tectonic activity. The temperature increases with depth and the volcanoes, geysers, hot springs, etc. are, in a sense, the visible or tangible expression of the heat which originates in the interior of the Earth.

According to Muffler and Cataldi (1978), a geothermal resource is what should more specifically be called the accessible resource base, that is, all of the thermal energy stored between the Earth´s surface and a specified depth in the crust, beneath a specified area and estimated with respect to the local mean annual temperature.

A geothermal reservoir is usually defined as the section of an area of geothermal activity that is hot and permeable so that it can be exploited economically for the production of fluid and heat (Grant and Bixley, 2011).

Low-temperature and high-temperature reservoirs: Low-temperature geothermal systems have a reservoir temperature below 150°C, and high-temperature systems have reservoir temperatures above 200°C at 1000 m depth. The intermediate system between these two systems has a temperature between 150 and 200°C.

Liquid-dominated, vapour-dominated and two phase geothermal reservoirs: Geothermal reservoirs are conveniently categorized as either liquid-dominated or vapour-dominated. In each case, the name refers to the phase which controls the pressure in the reservoir in its undisturbed state. When one phase is dominant, the other phase may also be present and partially mobile. A reservoir where steam and water co-exist is called a two-phase geothermal reservoir. In high-temperature reservoirs, a decline in pressure caused by exploitation may initiate boiling in parts of the reservoir making a liquid-dominated reservoir become a vapour reservoir.

4. THE THEISTAREYKIR, S-HENGILL AND REYKJANES GEOTHERMAL AREAS

4.1 Theistareykir

The Theistareykir high-temperature geothermal area lies in the Theistareykir fissure swarm in NE-Iceland (Figures 1 and 2). The geothermal activity covers a 10.5 km^2 area (Sæmundsson, 2007) and the most intense activity is on the northwest and northern slopes of Mt. Baejarfjall and in the pastures extending northwards to the western part of Mt. Ketilfjall. If the old alteration in the western part of the swarm is considered to be a part of the thermal area, its coverage is nearly 20 km^2.

The bedrocks in the area are divided into breccias (hyaloclastites) from sub-glacial eruptions during the Ice Age, interglacial lava flows, and recent lava flows (younger than 10,000 years), all of which are basaltic rock. Acid rocks are only found on the western side of the fissure swarm, from a sub-glacial eruption during the last glaciation. Rifting is still active in the fissure swarm, its faults and fractures active in recent times (Ármannsson et al., 1986).

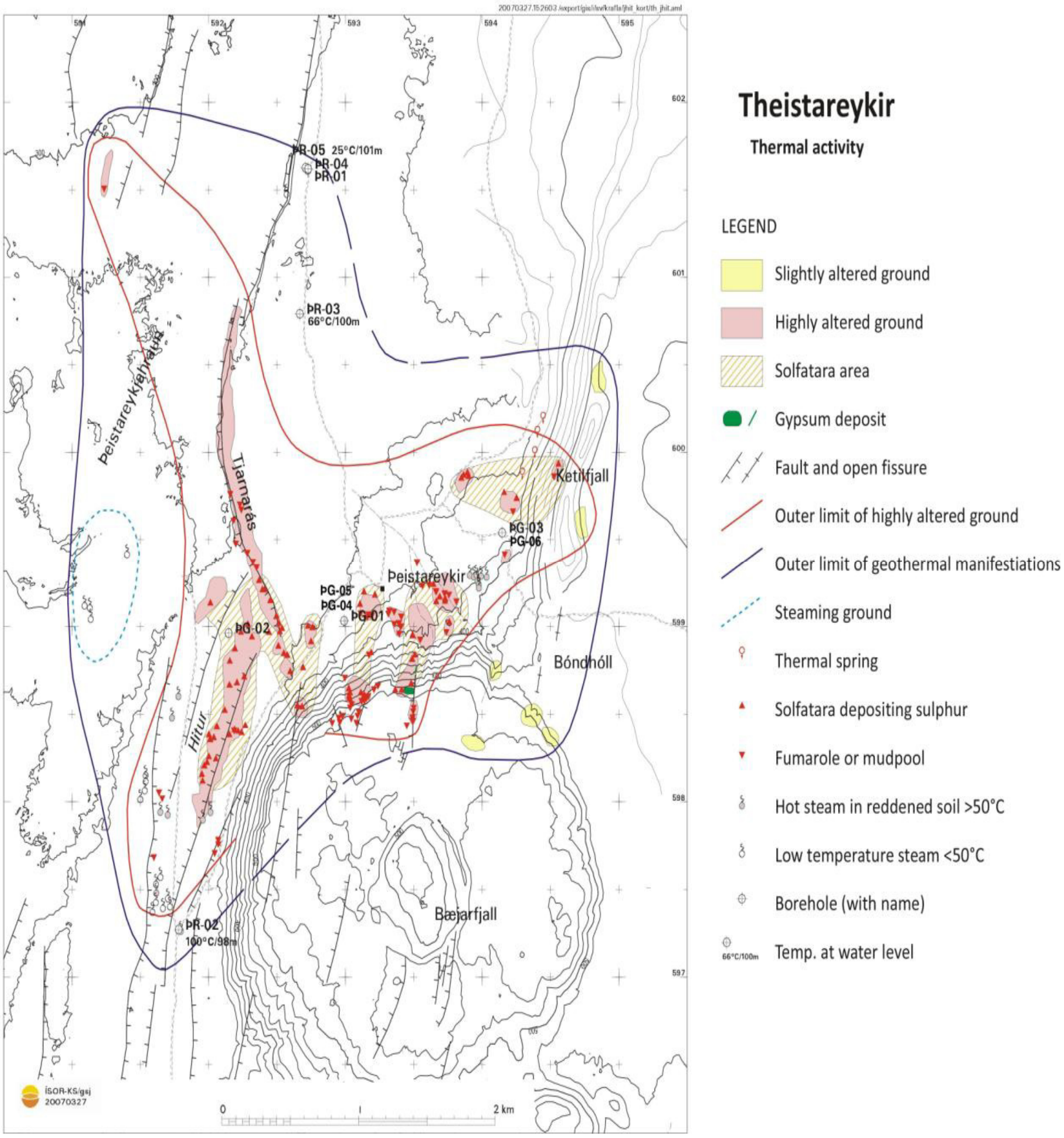


FIGURE 2: Thermal activity at Theistareykir (Ármannsson, 2008)

4.2 S-Hengill

The Hengill geothermal system lies in the middle of the western volcanic zone in Iceland, on the plate boundary between N-America and the European crustal plates. It is one of the largest high-temperature geothermal areas in the country. The geothermal activity of this area is connected to three volcanic systems. The geothermal area in Reykjadalur, Hveragerdi, belongs to the oldest system, called the Grensdalur system. North of this is a volcanic system named after Mt. Hrómundartindur, which last erupted about 10,000 years ago.

The geothermal area in Ölkelduháls is connected to this volcanic system. West of this volcanic system lies the Hengill volcanic system, with intense tectonic and volcanic NE-SW fractures and faults extending from Lake Thingvallavatn to Nesjavellir and further to the southwest through Innstidalur, Kolvidarhóll, Hveradalir (hot spring valley) and Hellisheidi (Figure 3). The bedrock in the Hengill area consists mostly of palagonite formed by volcanic eruptions below glaciers during the last ice ages. For this project, wells HE-04 and HE-09 were selected to study temperature and pressure profiles and well tests.

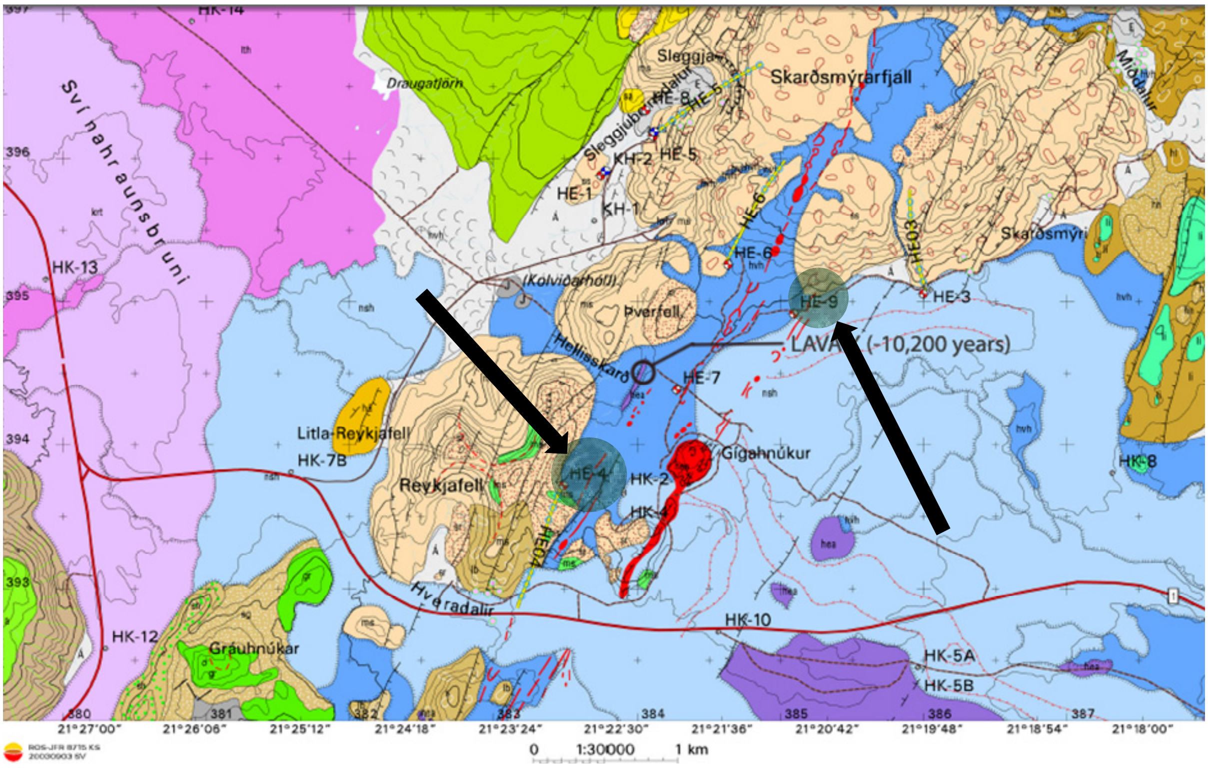


FIGURE 3: Geological map of S-Hengill showing the locations of wells HE-04 and HE-09 (Saemundsson, 1995)

4.3 Reykjanes

The Reykjanes geothermal system is located on the Reykjanes Peninsula, SW-Iceland. It is constructed of young, highly permeable basaltic formations, transected by an intense NE-SW trending fault zone, and is tectonically active. The volcanic activity on the peninsula is concentrated along fissure swarms. High-temperature geothermal systems occur in all of the Reykjanes Peninsula fissure swarms (Figure 4).

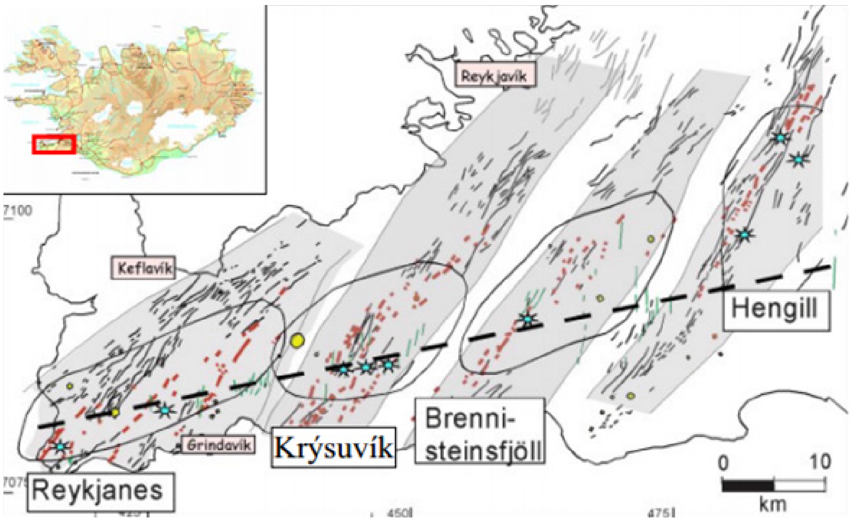


FIGURE 4: Tectonic map of Reykjanes peninsula showing fissure swarms, eruptive fissures, geothermal centres and approximate location of the plate boundary (dashed line) (modified from Clifton, 2007)

The Reykjanes geothermal area is located at the centre of active fault swarms that facilitate hydrologic convection. High-level magma chambers have apparently not formed in the Reykjanes volcanic systems and sheeted dike complexes are likely to serve as the magmatic heat source for geothermal activity. Surface geothermal manifestations occur over an area of 1 km^2, but observations from more than 30 drill holes and several activity surveys indicate that the subsurface area of the active system is at least 2 km^2.

5. THEORY OF WELL TESTING

The first step for a reservoir engineer is to estimate the relevant reservoir and wellbore parameters by a transient pressure test. This information is needed to confirm whether a well is satisfactorily drilled and to decide how to exploit the reservoir. The important reservoir and wellbore parameters are the permeability, the storativity, and the skin factor. The type of reservoir (porous and fractured) and the type and location of the reservoir boundaries are also important.

In practice, well testing (pressure transient tests) consists essentially of changing the well´s flow rate by injection into the well and measuring the well´s response as a function of time. A model is used to simulate the data and the reservoir and well parameters are deduced from the model (Figure 5).

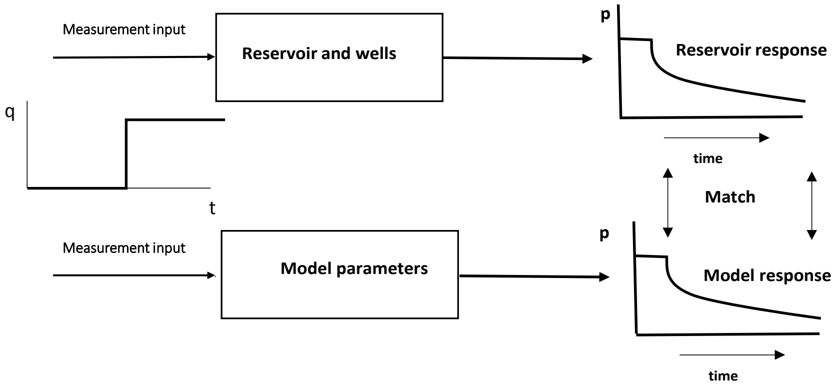


FIGURE 5: Well testing procedure (Horne, 1995)

Types of well tests

Examples of the possible types of tests are shown in Figure 6. Note that q is positive for production and negative for injection.

During well tests, fluid is extracted to the surface or injected into the well at controlled rates. A program of flow and shut-in periods is used to establish deliverability and completion efficiency of the well. Tests can involve a single well or many wells. Depending on test objectives and operational considerations, a range of well tests can be carried out.

Build-up test: This test is conducted in a well that has been producing for some time at a constant rate and is then shut-in. The build-up down hole pressure is then recorded for a given time.

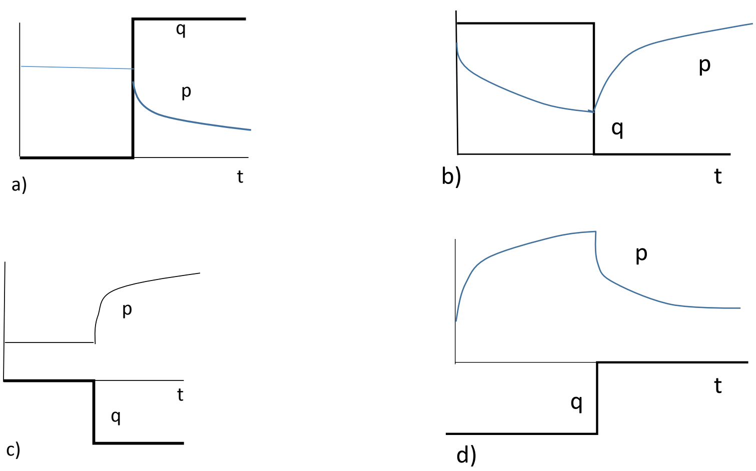


FIGURE 6: Types of well tests: a) Drawdown test; b) Build-up test; c) Injection test; and d) Falloff test (Horne, 1995)

Drawdown test: This test is conducted when a well has flowed at a constant rate. The down hole pressure and the production rate are measured as functions of time and analysed to estimate the reservoir properties. The major difficulty of the drawdown is the inability to maintain a constant flow rate.

Injection test: This test is identical to a drawdown test, except that the flow is into the well rather than out of it. Fluid is injected into the well at a constant rate, and the injection rate and the down hole pressure are measured as functions of time.

Falloff test: This test is analogous to a build-up test and it measures the pressure decline as a function of time subsequent to shut-in or the reduction of an injection.

5.1 Injection test

The injection well test is a field test method where fresh water is injected into the well to raise the water level until a steady height is attained, and the pressure or water level change in the well is recorded. The hydrogeological parameters (such as permeability) of the test layer can be determined by analysing the injection well test data. Its theoretical basis is that the water flow from the well to the stratum shall conform to the laws of seepage flow in a porous medium.

5.1.1 Theoretical background of injection well testing

When a well is subjected to injection in order to monitor the pressure response in a reservoir, it is used to evaluate the properties that govern flow characteristics and the well. The parameters that are deduced by modelling are permeability, storativity, transmissivity, wellbore skin, well bore storage, initial pressure and reservoir boundaries. To estimate all these parameters, mathematical models are used to simulate the reservoir response.

The pressure diffusion equation is used to calculate the pressure in the reservoir after a given time and at a certain distance from an injection or production well receiving or producing fluid at a specific rate. The following assumptions are made to simplify the derivation of the equation (Horne, 1995):

- Horizontal radial flow;
- Darcy´s Law;
- Homogeneous and isotopic reservoir and isothermal conditions;
- Single phase flow and small pressure gradient;
- Uniform thickness of the reservoir;
- Constant permeability (k), porosity (φ), fluid viscosity (μ) and small and constant total compressibility (c_t); and
- Gravity and thermal effects are negligible.

The pressure diffusion equation is derived by combining the equations from the three laws that govern it:

a) Law of conservation of mass (mass in - mass out = mass rate of change):

$$\left(\rho Q + \frac{\partial(\rho Q)}{\partial r}\,dr\right) - \rho Q = 2\pi r dr\,\frac{\partial(\rho\varphi h)}{\partial t} \tag{1}$$

b) Darcy´s law (conservation of momentum):

$$Q = \frac{2\pi rhk}{\mu}\frac{\partial p}{\partial r} \tag{2}$$

c) Fluid compressibility (equation relates the pressure to density at a constant temperature):

$$c_t = \varphi c_w + (1-\varphi)c_r \ where\ c_r = \frac{1}{1-\varphi}\frac{\partial\varphi}{\partial p}\ and\ c_w = \frac{1}{\rho}\frac{\partial\rho}{\partial p} \tag{3}$$

This is reduced to:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial \rho}\right) = \frac{\mu c_t}{k}\frac{\partial p}{\partial t} = \frac{S}{T}\frac{\partial p}{\partial t}\ or\ \frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{\mu c_t}{k}\frac{\partial p}{\partial t} = \frac{S}{T}\frac{\partial p}{\partial t} \tag{4}$$

$$S = c_t h\ \ and\ \ T = \frac{kh}{\mu} \tag{5}$$

where ρ = Density (kg/m^3);
Q = Volumetric flow rate (m^3/s);
φ = Porosity (-);

c_t = Total compressibility (Pa^{-1});
c_r = Rock compressibility (Pa^{-1});
c_w = Water compressibility (Pa^{-1});
T = Transmissivity (m^3/ (Pa s));
S = Storativity (m/Pa) = (m^3/ (m^2Pa));
μ = Dynamic viscosity (Pa s);
k = Permeability (m^2); and
h = Reservoir thickness (m).

5.1.2 Initial parameters

The deduced parameters found by the simulation of a well test (Júlíusson et al., 2007) are explained in the report as given by the software, and follow below almost word for word.

The *storativity* has great impact on how fast the pressure movement can travel within the reservoir. Also, the storativity varies significantly between reservoir types: liquid-dominated, two-phase or dry steam. The variation is because of its dependence on fluid compressibility. The storativity common values for liquid-dominated geothermal reservoirs are around 10^{-8} m^3/ (Pa·m^2) while for two-phase reservoirs it might have values on the order of 10^{-5} m^3/ (Pa·m^2).

The *transmissivity d*escribes the ability of the reservoir to transmit fluid, hence mainly affecting the pressure gradient between the well and the reservoir. The transmissivity can vary by a few orders of magnitude but common values from injection testing in Icelandic geothermal reservoirs are on the order of 10^{-8} m^3 / (Pa·s).

During an injection test, the *injectivity index* (*II*) is often used as a rough estimate of the connectivity of the well to the surrounding reservoir. Here it is given in units of (L/s)/bar and is defined as the change in the injection flow rate divided by the change in the stabilized reservoir pressure:

$$II = \frac{\Delta Q}{\Delta P} \tag{6}$$

Where II = Injectivity ((l/s)/bar);
ΔQ = Change of flow rate (l/s); and
ΔP = Change in pressure (bar).

By using the injection well test, the main characteristics of the reservoir and the well which can be determined are:

1) The permeability;
2) The transmissivity;
3) The storativity;
4) The boundary properties; and
5) The skin.

The skin is a variable used to quantify the permeability of the volume immediately surrounding the well (Figure 7). This volume is often affected by drilling operations, being either damaged (because of drill cuttings blocking the fractures) or stimulated (due to extensive fracturing around the well). For damaged wells, the *skin factor* is positive, and for

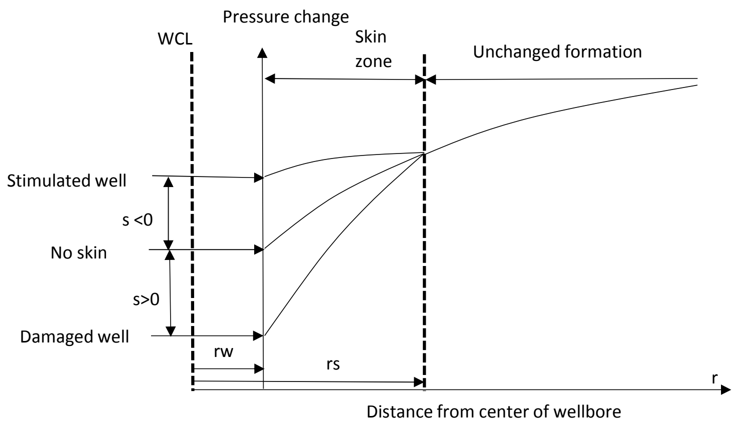


FIGURE 7: Pressure changes in the vicinity of a well due to a skin effect (*WCL* = well centre line; r_w = well radius; r_s = radius of skin) (Hjartarson, 1999)

stimulated wells it is negative. The skin factor (s) in Icelandic geothermal reservoirs is commonly around -1, though values may range from about -5 to 20. When $s < 0$, the well reacts as a wider well would (stimulated); if $s > 0$, the well seems narrower (damaged).

Different types of boundaries are shown in Figure 8.

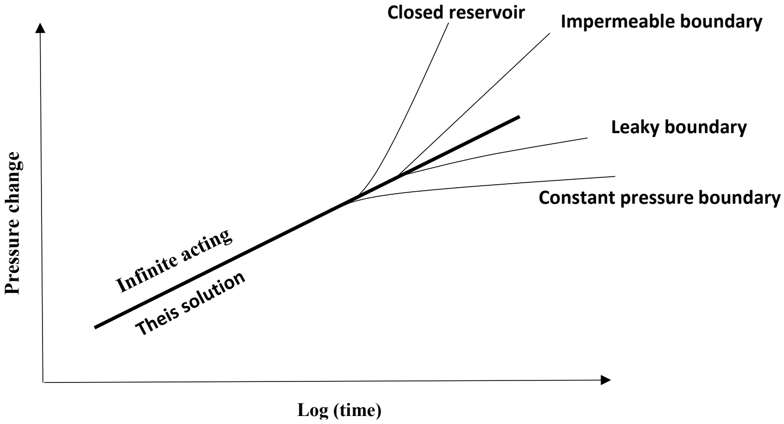


FIGURE 8: Typical pressure responses for different reservoir models (Bödvarsson and Witherspoon, 1989)

5.2 Production well testing

5.2.1 Theoretical background

Production well tests in high-temperature geothermal wells are conducted to determine the production capacity and to analyse the flow characteristics of a well. The tests are done after a geothermal well has been drilled and allowed to warm up for some time or stopped after producing for a while. Then a discharge test is conducted by starting the well´s flow, followed by measurements to calculate the fluid flow at different wellhead pressures. The well is discharged into a silencer which is designed to reduce the noise level resulting from the discharge. In addition, the silencer acts as a water-steam separator at atmospheric pressure. Figure 9 shows the setup for production well testing and the example and formulas here are adjusted to Reykjanes, where the separator and equipment were moved to the well to be monitored. The lip pressure is measured at the end of the discharge pipeline as it enters the silencer, and measurement of water separated from the silencer is done in a V-notch weir while the steam is allowed to escape into the atmosphere.

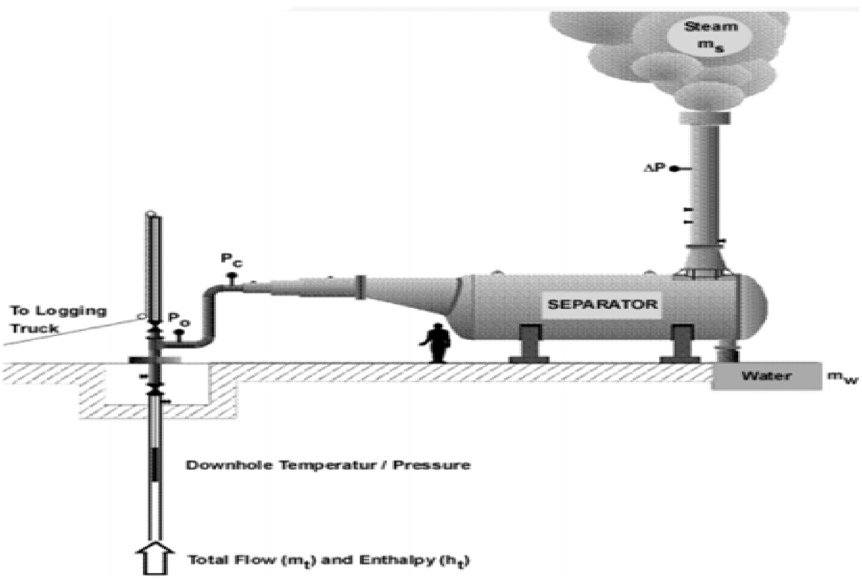


FIGURE 9: Flow and enthalpy separator measurements (Haraldsdóttir, 2013)

Russell James´s formula is an empirical formula developed in 1960 which relates mass flow, enthalpy, discharge pipe area and lip pressure as follows:

$$Q_t = KA\frac{P_c^{0.96}}{H^{1.102}} \tag{7}$$

where Q_t = Mass flow (kg/s);
K = 184 for A in cm^2;
H = Total enthalpy (kJ/kg);

A = Cross section area of the pipe (cm^2); and
P_c = Lip pressure (bar-a).

The mass ratio of steam to the the total flow and the total enthalpy as a function of the enthalpy of steam and enthalpy of water can be written as:

$$X = \frac{Q_s}{Q_t} \quad and \quad H = XH_s + (1-X)H_w \tag{8}$$

where X = The steam mass fraction;
Q_s = Mass flow of steam (kg/s);
H_s = Enthalpy of steam (kJ/kg); and
H_w = Enthalpy of water (kJ/kg).

The separated water flow Q_w is the water separated at atmospheric pressure from the total well flow with enthalpy H. Therefore,

$$Q_t = Q_w \frac{H_s - H_w}{H_s - H} \tag{9}$$

where Q_w = Mass flow of water (kg/s);

Combining Equations 7 and 9 gives:

$$\frac{Q_w}{AP_c^{0.96}} = \frac{184}{H_t^{1.102}} \frac{H_s - H}{H_s - H_w} \tag{10}$$

The enthalpies H_s and H_w can be found in a steam-table for corresponding pressure or temperature and the only unknown is H_t from which the electric power can be calculated.

6. INJECTION WELL TESTS FROM FOUR HIGH-TEMPERATURE WELLS IN ICELAND

An injection test is mostly performed in high-temperature wells at the end of drilling. Injection tests for four wells are studied in this project. When water is injected into the well, the pressure response can be monitored. The injection rate is changed in steps during the test, increasing or decreasing the rate in order to observe the different pressure responses in the well. It is possible to estimate different parameters of the well and the surrounding reservoir by simulating the pressure response to the injection, such as the injectivity index, storativity, transmissivity and skin effect, from the information gathered. The processing of the data and the Well Tester simulations are described for each of the three steps in Well HE-04, but only the results are shown for the other wells.

6.1 Well HE-04

Well HE-04 is a vertical well which was drilled in 2001 to a measured depth of 2008 m. The injection test in Well HE-04 was performed after completion of drilling on 12 Oct. 2001. All three steps in the injection test were performed the same day. The injection rates changed from 40 to 20.5 l/s; 20.5 to 30.8 l/s; and 30.8 to 45 l/s (Figure 10). The injection test was done in 7 hours and 18 minutes.

The pressure gauge was located at 1600 m which was believed to be close to the main feed zones in the well. Before the injection test started on 12 Oct. 2001, injection was constant at 40 l/s of water, to wash the formation from offensives of filtrate and cuttings formed during drilling, to improve the skin effect and achieve a stabilized flow rate before the injection test. At 02:15, injection was decreased to 20.5 l/s, and at 04:06 the injection was increased to 30.8 l/s.

From Figure 10, it can be seen that in step 1 the pressure drops after it seems to be stabilizing; this is probably due to instable injection or problems with the measuring device, but could indicate a small opening in the reservoir. But steps 2 and 3 show an increase in pressure. In step 3, the end of the injection test, the injectivity index is increased to 14.2 (l/s)/bar.

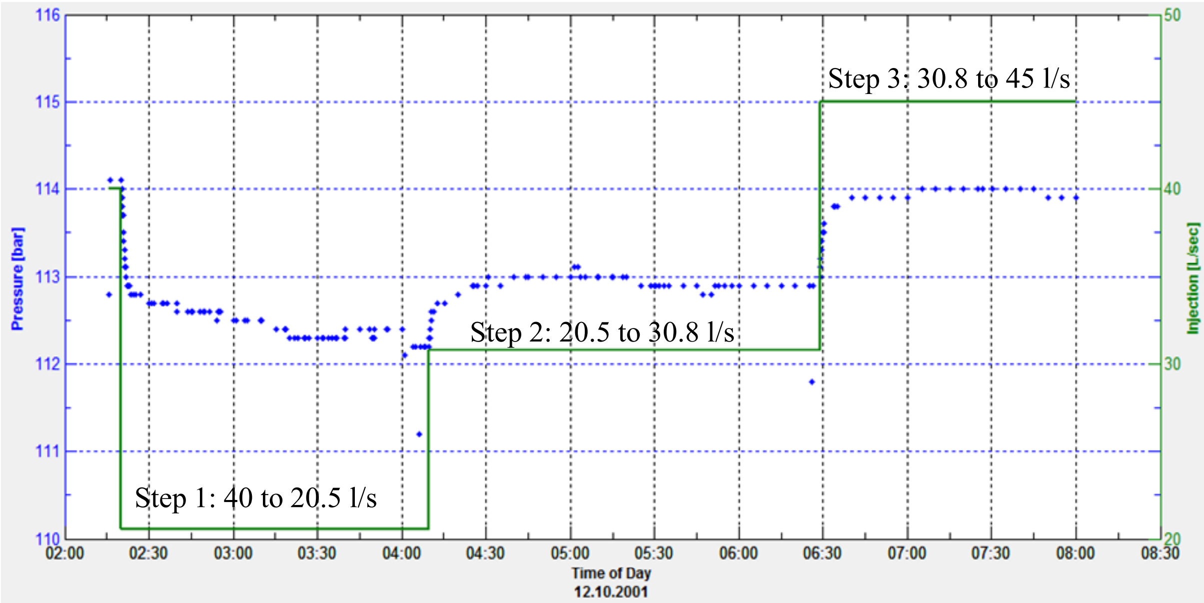


FIGURE 10: Pressure and injection as a function of time at 1600 m depth in Well HE-04 during an injection well test

To model the data (pressure vs. time) during the injection test, a software called Well Tester was used. Well Tester was developed at ISOR (Iceland GeoSurvey). The well test model selected for Well HE-04 assumed a homogenous reservoir, constant pressure boundary (Figure 8), constant skin and well bore storage for all of the steps.

The reservoir temperature was inserted into Well Tester as well as the wellbore radius r_w, the dynamic viscosity of the reservoir fluid μ, the total compressibility c_t, and the porosity φ, partly by choosing the default values in Well Tester. All parameter values are shown in Table 1, as well as the initial pressure which Well Tester deduced from the data file with time and pressure.

TABLE 1: Summary of the initial parameters given in Well Tester for Well HE-04

Parameter name	Parameter value	Parameter unit
Estimated reservoir temperature	230	°C
Estimated reservoir pressure	113	bar
Wellbore radius (r_w)	0.11	m
Dynamic viscosity of reservoir fluid (μ)	1.18×10^{-4}	Pa·s
Total compressibility	1.3×10^{-10}	1/Pa
Porosity (φ)	0.10	-

The dynamic viscosity was updated by Well Tester for the selected temperature.

The Well Tester software was used to simulate each step separately, and the parameters were calculated for each step. The results from Well Tester are shown in Table 2 and explanations of the data processing and modelling with Well Tester follow for Well HE-04.

TABLE 2: Summary of the results from the non-linear regression parameter estimate using injection test data from Well HE-04

	Storativity *S* ($m^3/(Pa \cdot m^2)$)	**Transmissivity *T* ($m^3/(Pa \cdot s)$)**	**Skin factor *s***	**Wellbore storage *C* (m^3/Pa)**	**Permeability thickness *kh* (Dm)**	**Injectivity Index *II* ((l/s)/bar)**
Step 1	1.5×10^{-10}	6.4×10^{-8}	-3.4	1.4×10^{-5}	7.5	11.4
Step 2	4.4×10^{-8}	5.7×10^{-8}	-3.5	3.0×10^{-5}	6.7	11.3
Step 3	1.9×10^{-8}	1.5×10^{-7}	-0.7	1.0×10^{-5}	17.9	14.2

Modelling step 1:
Using the Theis model, non-linear regression analysis was performed to find the parameters that best fit the selected data. The results are shown graphically for step 1 in Figure 11. Here the decrease in injection caused the pressure to decrease from 114.1 to 112.4 bar, which is a change of 1.7 bar. The total time was 1 hour and 15 minutes. Figure 12a shows additional plots of the same data on a log-linear scale and (b) a log-log scale. Figure 12b also shows the derivative of the pressure response, multiplied with the time passed since the beginning of the step. This is used to determine which type of model is most applicable for the observed data.

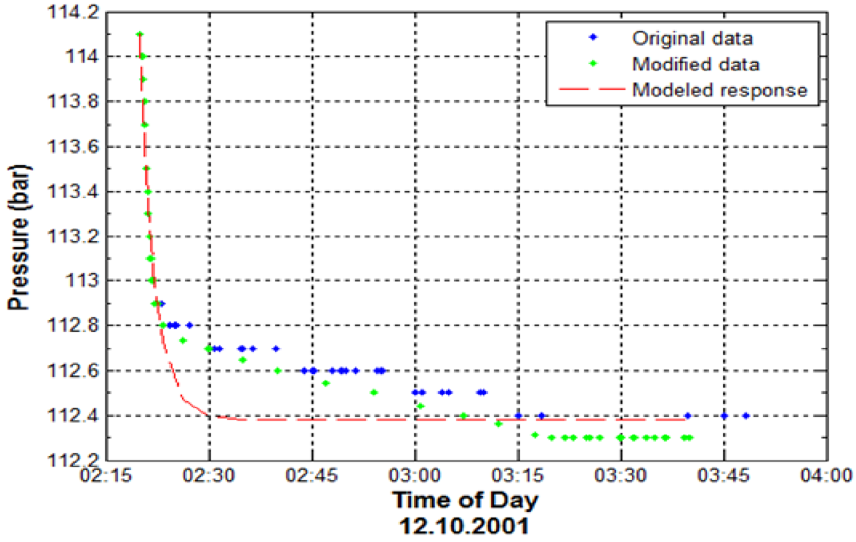


FIGURE 11: The model results and the selected data for step 1 in Well HE-04

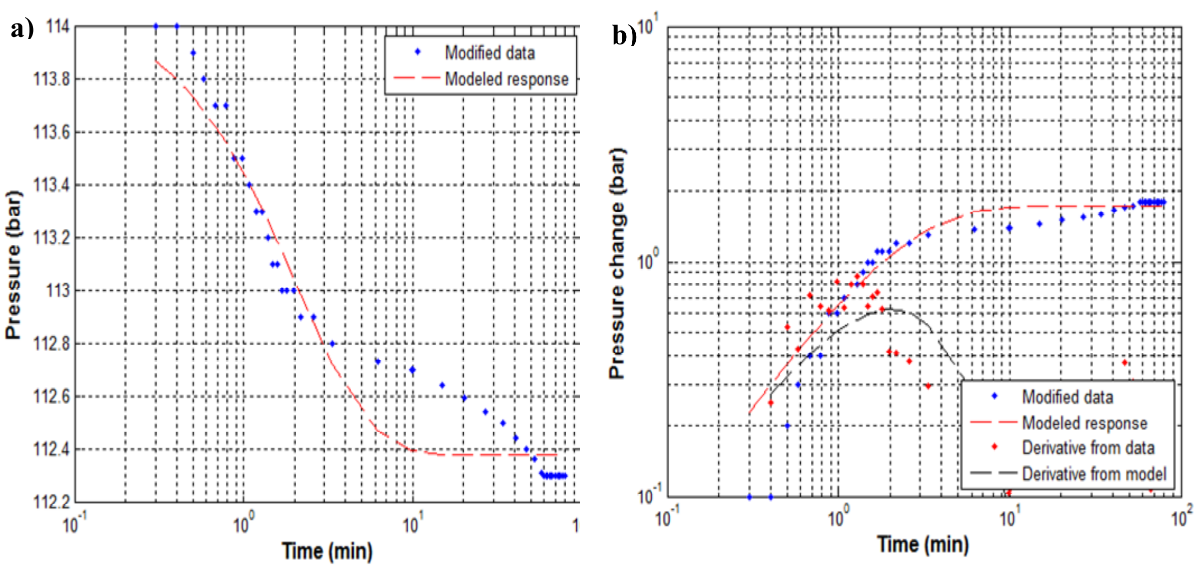


FIGURE 12: The model results and the selected data for step 1 in HE-04 on; a) a log-linear scale, and b) a log-log scale; the derivatives in (b) are commonly used to determine the most appropriate type of model

Modelling step 2:
The regression analysis results are shown graphically for step 2 in Figure 13. The modelled response and the modified data show a good fit. The pressure increases by 0.9 bar during 2 hours and 15 minutes. Figure 14 shows an additional plot of the same data on a) a log-linear scale and b) a log-log scale. In the log-linear scale, the modelled response fits quite well with the modified data.

In the log-log scale model, the derivatives from the data are scattered on Figure 14 (b).

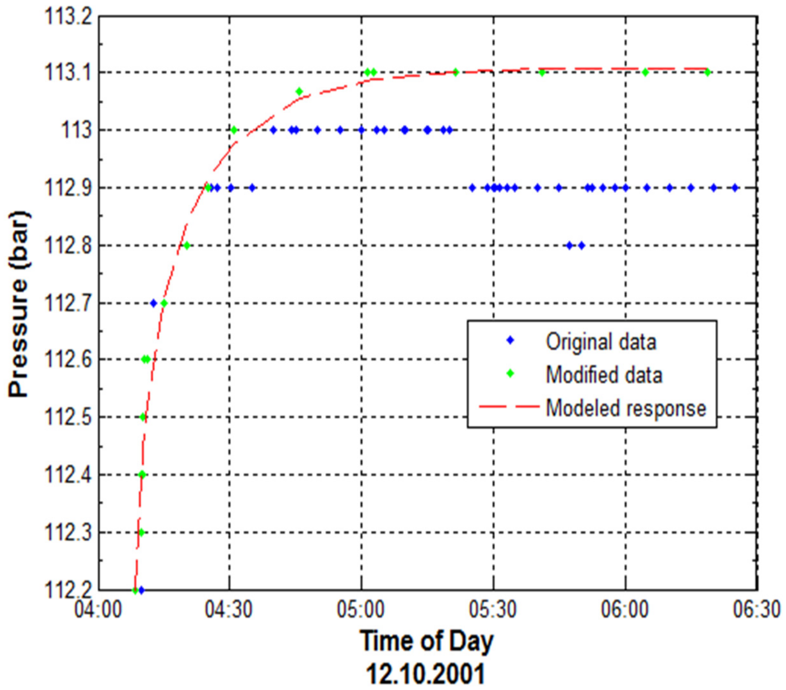
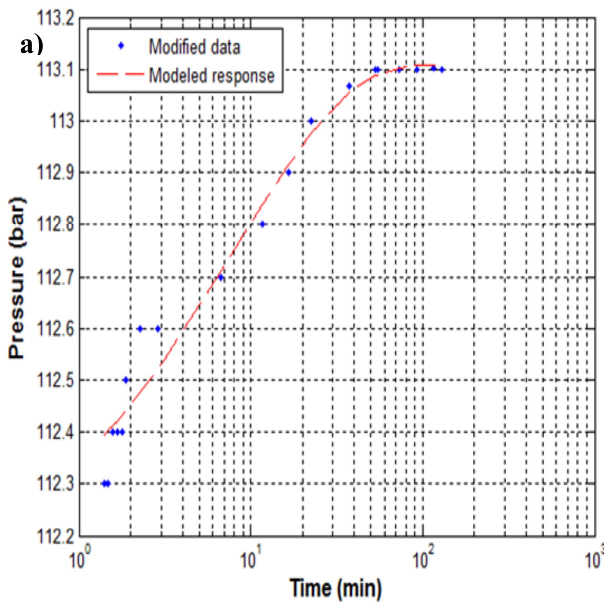


FIGURE 13: The model results and selected data for step 2 in Well HE-04



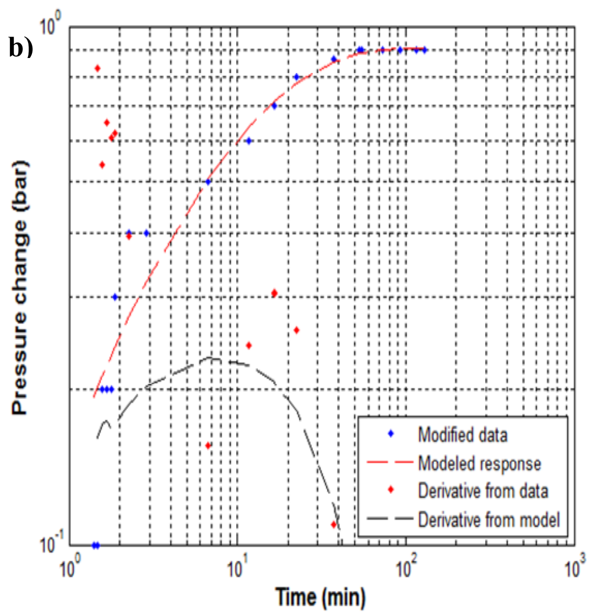


FIGURE 14: The model results and selected data for step 2 inWell HE-04 on: a) a log-linear scale, and b) a log-log scale, where the derivative plot is also shown

Modelling step 3:
The results from the regression analysis are shown graphically for step 3 in Figure 15. The modelled response and the modified data show a good fit. The injection well test showed a pressure increment from 113.0 to 114.0 bar, which is a change in 1.0 bar for a total time of 1 hour and 10 minutes. In Figure 16 (a), the graph shows a fitted modelled response and modified data for log-linear scale, and in (b) the log-log plot shows a good fit of model and data; the derivative plot from the model follows well the derivative points of the selected data.

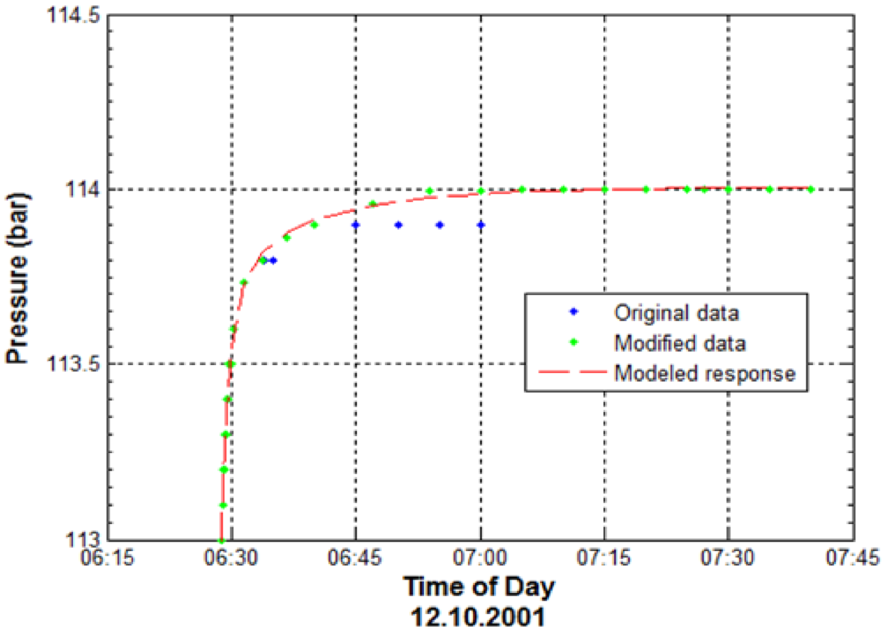


FIGURE 15: The model results and selected data for step 3 in Well HE-04

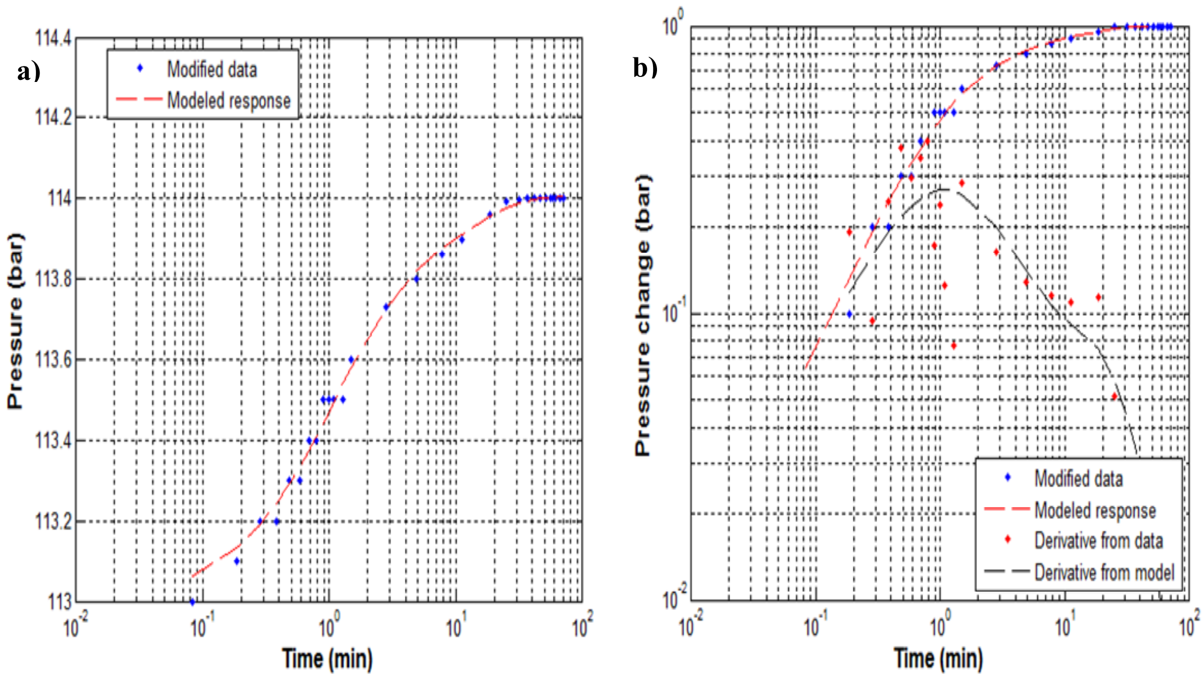


FIGURE 16: The model results and the selected data for step 3 in Well HE-04 on:
a) a log-linear, and b)a log-log scale

6.2 Well HE-09

Well HE-09 is a vertical well, drilled in 2003 to a measured depth of 1604 m. The injection test in Well HE-09 was performed after completion of drilling on 22 June 2003. During the three steps, the injection rates were changed from 25.2 to 35.4 l/s; 36.3 to 55.4 l/s; and 55.9 to 25.3 l/s, respectively (Figure 17).

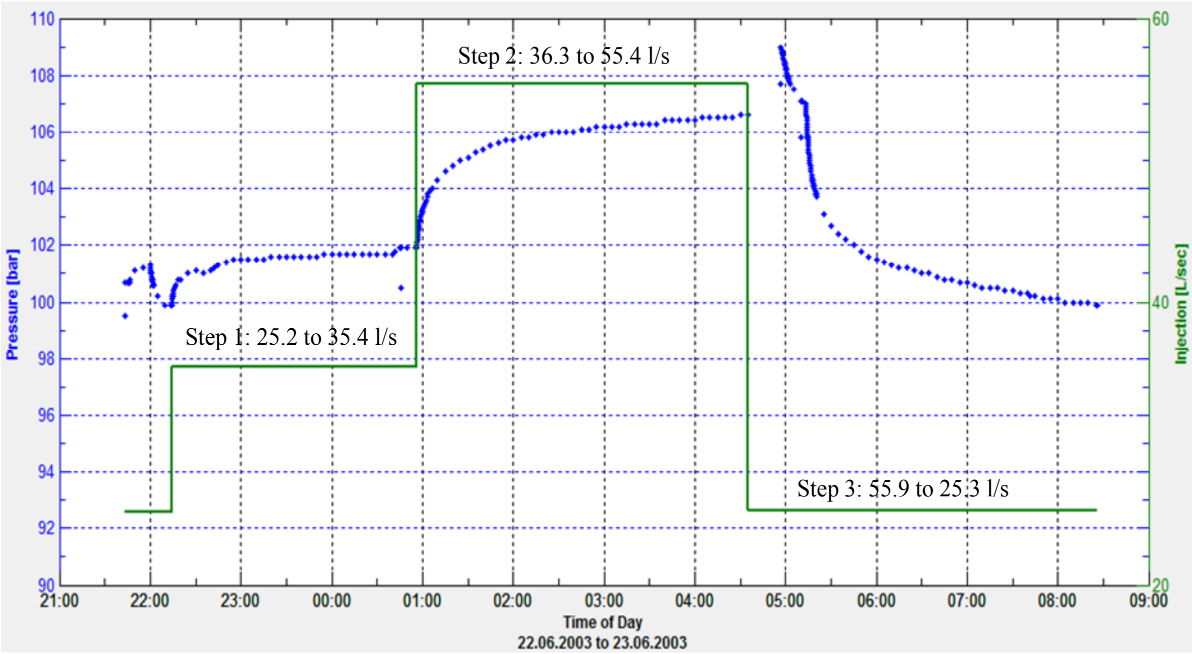


FIGURE 17: Pressure and injection as a function of time in Well HE-09 during an injection well test

The total injection test was done in 10 hours and 8 minutes with a pressure gauge being lowered to a depth of 1200 m. The results for Well HE-09 from the non-linear regression in Well Tester are listed in Table 3.

TABLE 3: Summary of the initial parameters given in Well Tester for Well HE-09

Parameter name	Parameter value	Parameter unit
Estimated reservoir temperature	295	°C
Estimated reservoir pressure wellbore	103	bar
Radius (r_w)	0.16	m
Dynamic viscosity of reservoir fluid (μ)	8.86×10^{-5}	Pa·s
Total compressibility	2.93×10^{-10}	1/Pa
Porosity (φ)	0.10	-

The initial parameters for Well HE-09 are listed in Table 3. At a temperature of 295°C, the dynamic viscosity was 8.86×10^{-5} Pa·s; the reservoir pressure deduced by Well Tester from the pressure data was 103 bar. It was assumed that the reservoir is homogenous, the boundary has constant pressure, and the well has a constant skin and well bore storage. The results from Well Tester are shown in Table 4.

TABLE 4: Summary of the results from the non-linear regression parameter estimate using injection test data from Well HE-09

	Storativity *S* ($m^3/(Pa\cdot m^2)$)	Transmissivity *T* ($m^3/(Pa\cdot s)$)	Skin factor *s*	Wellbore Storage *C* (m^3/Pa)	Permeability thickness *kh* (Dm)	Injectivity Index *II* ((l/s)/bar)
Step 1	5.4×10^{-10}	2.3×10^{-8}	-3.6	6.8×10^{-6}	2.00	5.3
Step 2	7.9×10^{-8}	1.6×10^{-10}	-3.7	7.6×10^{-6}	0.014	4.3
Step 3	7.2×10^{-10}	2.3×10^{-8}	-2.9	1.1×10^{-5}	2.05	4.3

6.3 Well ThG-09

Well ThG-09 is a vertical well, drilled in 2012 to a measured depth of 2194 m. The injection test in Well ThG-09 was performed after completion of drilling on 14 December 2012. During the three steps the injection rates were changed from 20 to 30 l/s; 30 to 40 l/s; and 40 to 25 l/s, respectively (Figure 18). The total injection test was done in 10 hours and 15 minutes with a pressure gauge being lowered to a depth of 1760 m. The initial parameters in Well Tester are shown in Table 5 and the results for Well ThG-09 from the non-linear regression parameters are listed in Table 6.

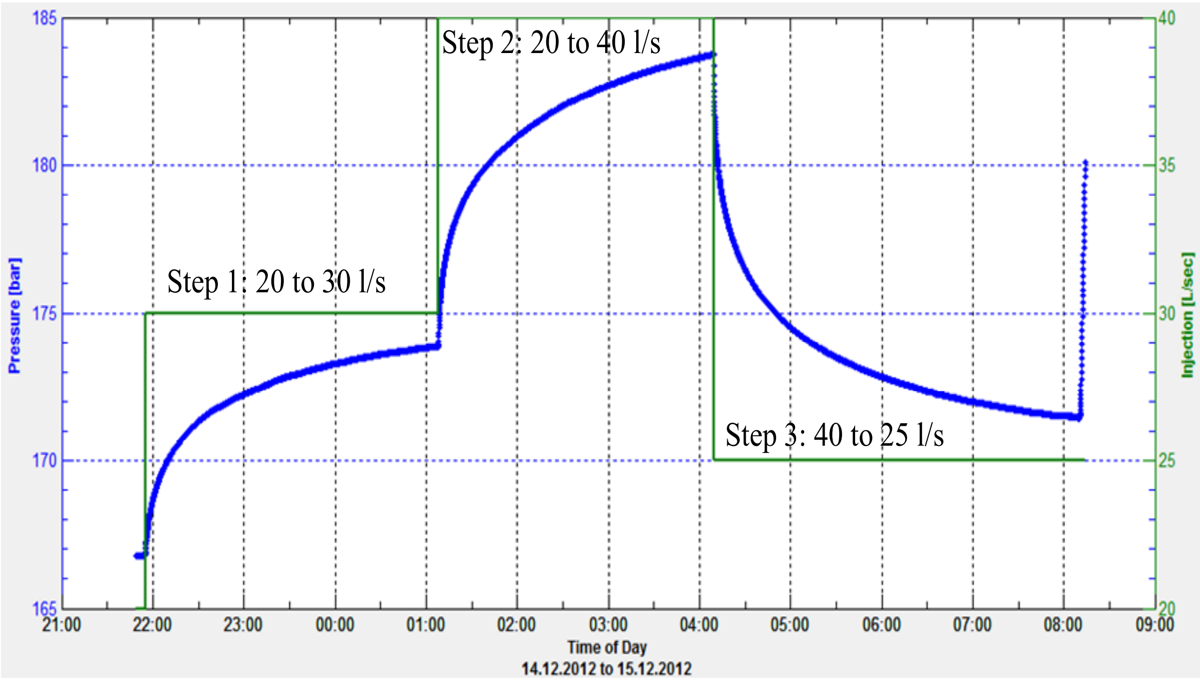


FIGURE 18: Pressure and injection as a function of time in Well ThG-09 during an injection test at 1760 m depth

TABLE 5: Summary of the initial parameters given in Well Tester for Well ThG-09

Parameter name	Parameter value	Parameter unit
Estimated reservoir temperature	280	°C
Estimated reservoir pressure	173	bar
Wellbore radius (r_w)	0.16	m
Dynamic viscosity of reservoir fluid (μ)	9.69×10^{-5}	Pa·s
Total compressibility	2.03×10^{-10}	1/Pa
Porosity (φ)	0.10	-

TABLE 6: Summary of the results from the non-linear regression parameter estimate using injection test data from Well ThG-09

	Storativity S ($m^3/(Pa\cdot m^2)$)	Transmissivity T ($m^3/(Pa\cdot s)$)	Skin factor s	Wellbore storage C (m^3/Pa)	Permeability thickness kh (Dm)	Injectivity index II ((l/s)/bar)
Step 1	5.0×10^{-8}	5.2×10^{-9}	-3.5	5.9×10^{-6}	0.50	1.4
Step 2	8.2×10^{-8}	3.1×10^{-9}	-3.4	9.7×10^{-7}	0.30	1.0
Step 3	8.4×10^{-8}	5.0×10^{-9}	-3.0	6.0×10^{-7}	0.49	1.2

The initial parameters for Well ThG-09 are listed in Table 5. At a temperature of 280°C, the estimated reservoir pressure was 173 bar at a depth of 1760 m. For all steps, it was assumed that the reservoir is homogenous, the boundary is constant pressure, and the well has a constant skin and well storage.

6.4 Well RN-28

The injection well test data for Well RN-28 could not be analysed by the Well Tester software. The reason is that, as seen from Figure 19, for each step as the injection rate increased, the pressure decreased. It was supposed to increase if the right data were used. Additionally, in step 3 as the injection flow rate decreased from 50 l/s to 10 l/s, the pressure increased as shown in Figure 19. So the behaviour of this well was different from the usual case and could not be explained with the injection changes. Notice that the pressure changes were very small.

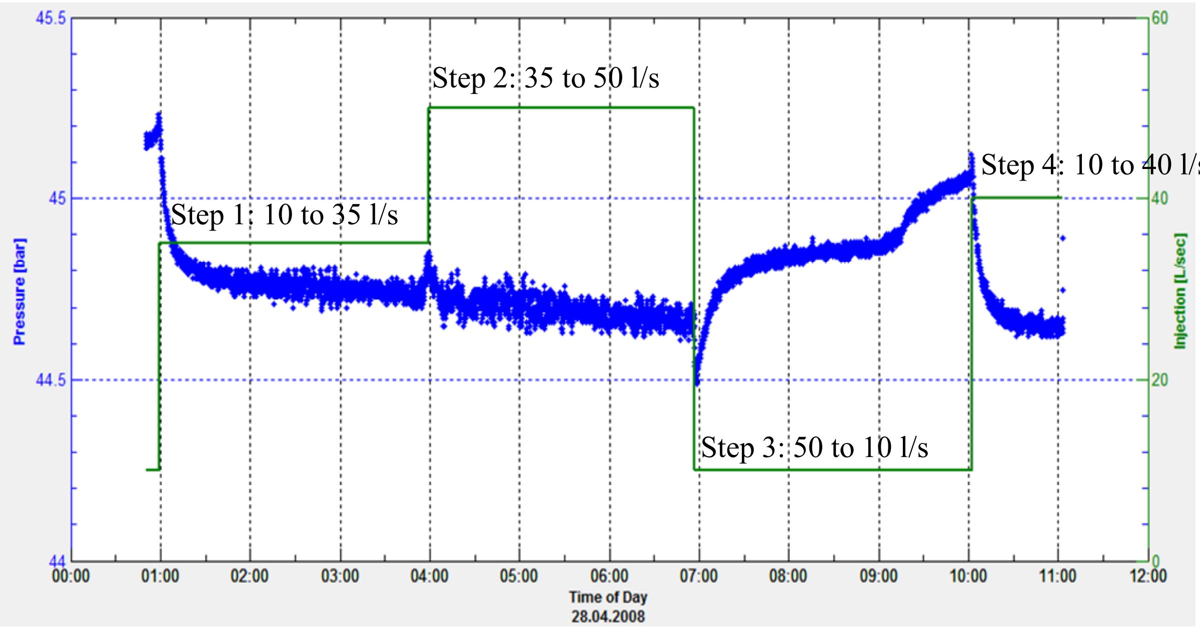


FIGURE 19: Pressure as a function of time in Well RN-28 during an injection test with 4 steps

7. PRODUCTION WELL TEST FROM THE HIGH TEMPERATURE GEOTHERMAL FIELD AT REYKJANES

7.1 Well RN-28 production test

The production test analysis is presented in Table 7. For the production testing of Well RN-28, five steps were taken with lip pipe diameter 16 cm. The water height in the V-notch weir box for step 1 is 1.2 cm and for step 2 it is 1.45 cm, while for the rest of the steps it is 0 which means the water is on the bottom of the V-noch weir box.

To obtain the flow rate and enthalpy from the measurements of the steam and water flow values for the Reykjanes separator, the Russel-James formula (Equation 7) was used.

The water flow can be found by:

$$Q_w = 0.0146 * W^{2.47} \tag{11}$$

TABLE 7: Measurements of pressure, lip diameter and water height for Well RN-28

Step	Water height W (cm)	Well head pressure P_o (bar-g)	Critical pressure P_c (bar-g)	Change in pressure ΔP (mbar)	Bottom pressure P_b (bar-g)	Well head temperature T_o (°C)
1	1.2	46.2	0.8	22.4	50.3	261
2	1.45	46.0	3.0	77.4	50.0	260
3	0	45.5	3.8	93.3	49.8	259
4	0	44.0	4.9	143.3	49.6	257
5	0	46.2	1.9	35.8	49.9	261

where Q_w = Water flow (kg/s); and
W = Water height in V-noch or weirbox (cm).

And the steam flow for the Reykjanes separator is:

$$Q_s = 2.733\sqrt{\Delta P} \tag{12}$$

where Q_s = Steam flow (kg/s); and
ΔP = Change in pressure (mbar), over an orifice in the outlet pipe for the steam.

Using the LIP program and manual calculations, the values of Q_s (the steam flow) and Q_w (the water flow) were found. The total flow rate is the sum of Q_s and Q_w. The ratio of the steam flow rate and the total flow rate is represented by X as a percentage rate:

$$X = \frac{Q_s}{Q_t} \tag{13}$$

Additionally, for finding the energy value from the power plant, the constant total flow rate of Reykjanes was taken as 1.68 kg/s for the production of 1 MWe. The results for the flow rate and enthalpy for RN-28 are stated in Table 8. For a well head pressure of 44 bar-g, the flow rate is 32 kg/s and the power is 19 MWe.

TABLE 8: Results of flow rate and enthalpy for Well RN-28

Step	Q_w (kg/s)		Q_s (kg/s)		Q_t (kg/s)		X (%)	Enthalpy H (kJ/kg)	Power (MWe)
	Lip	Manual	Lip	Manual	Lip	Manual			
1	0.03	0.02	10.9	13.38	10.9	13.4	99.8	2670	8
2	0.04	0.04	23.5	23.48	23.5	23.52	99.8	2672	14
3	0	0	28.3	26.88	28.3	26.88	100	2676	16
4	0	0	34.1	31.92	34.1	31.92	100	2676	19
5	0	0	17.3	16.8	17.3	16.8	100	2676	10

8. FORMATION TEMPERATURE AND INITIAL PRESSURE IN A WELL

Formation temperature serves as the basis for conceptual models and is important in decision making on well completion. For this reason, the formation temperature of Wells HE-04 and ThG-09 were evaluated from the warm up temperature logs by considering the condition of the well during measurements and then extrapolating the data at each depth. The ICEBOX program (Arason et al., 2004) Berghiti was used to estimate the formation temperature and compare it to the warm-up temperature values at different depths. The Horner plot was used to estimate the formation temperature using this program.

8.1 The boreholes drilled at Hellisheidi and Theistareykir

Information obtained from pressure and temperature logs are used to determine thermal gradients and heat flow, location of aquifers, reservoir temperature, the physical state of a reservoir, flow patterns, in blow out risk evaluation, and management of geothermal fields. The rate of change during circulation gives some idea about the flow rate and the time for warm up. The main problem with down hole measurements during disturbed conditions is that temperature and pressure in the wellbore do not match those in the reservoir.

An analysis of temperature and pressure profiles that were measured in two boreholes, Wells HE-04 at Hellisheidi and ThG-09 at Theistareykir is presented in this section. The locations of these wells and their casing depths are presented in Table 9.

TABLE 9: Overview of parameters for the two wells

Borehole no.	Drilled depth (m)	Casing depth (m)
HE-04	2008	779
ThG-09	2194	825

8.2 Formation temperature and pressure in Well HE-04

The warm-up temperature data for Well HE-04 were analysed using the Horner plot method to determine the formation temperature. The evaluations of the formation temperature and the initial pressure for Well HE-04 were based on pressure and temperature logs, measured after injection testing after completion of the well and the consequent warm-up period as shown in Figure 20. The warm-up temperature profiles got closer and closer as the warm-up period increased, implying that the well was approaching thermal equilibrium after a short time, which was also reflected in the formation temperature evaluated using the Horner method. The dynamic temperature profile reflected the formation temperature at the bottom of the hole. There is no down flow of fluid in the well during dynamic conditions (Björnsson, 2004).

The warm-up profiles show the location of several feed points. After a rapid warming-up for 13 days, the temperature increased more slowly and became more stable, even after 26 and 62 days, at a measuring depth between 680 m and 760 m, as seen in Figure 20. In the measuring depth range of 760

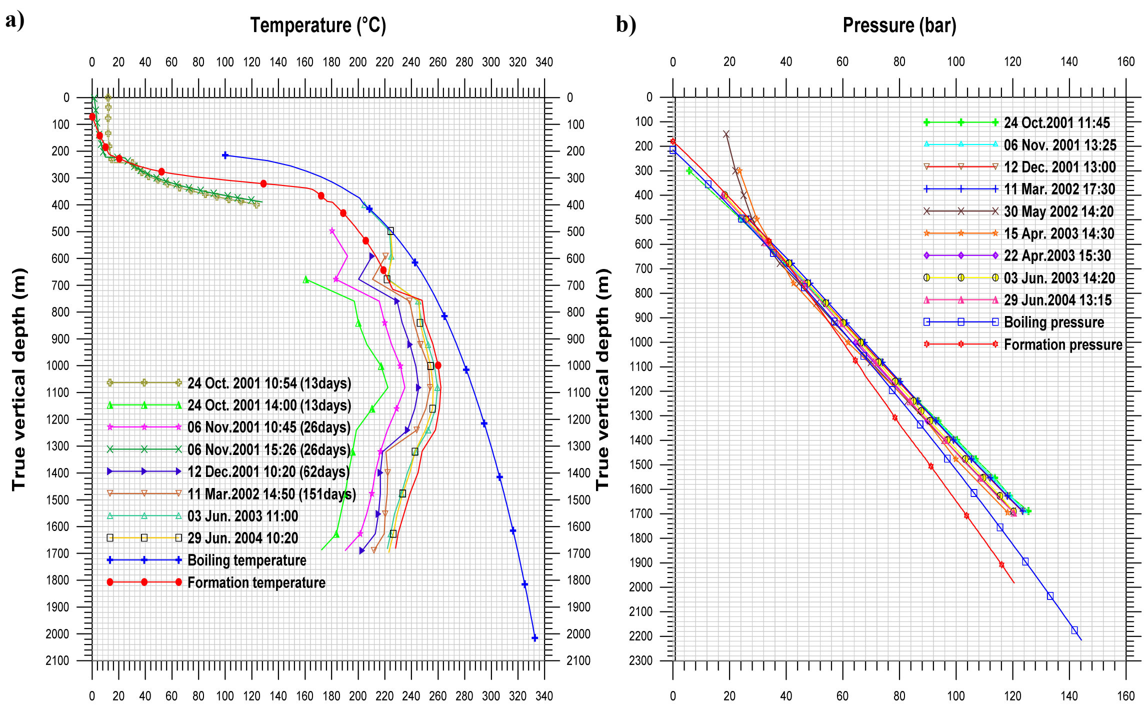


FIGURE 20: Well HE-04: a) Formation temperature; b) Formation pressure

m to 1080 m after 151 days warming up, the formation temperature curve converged and the temperature value decreased slightly. The maximum temperature measured in Well HE-04 was 262°C at a depth of 1080 m. The formation temperature never reached the boiling curve, therefore, the well is liquid dominated.

From the plots of pressure profiles during the warm-up period, the pivot point in Well HE-04 was determined to be at 765 m depth. This indicates that the controlling feed zone of the well is located at about this depth. As the well warms up, the pressure gradient decreases. Pressure profiles revolve around a pivot point that can indicate the location of either a single feed point or the main feed point of a well. Above the pivot point, the formation pressure is greater than the boiling pressure, but below the pivot point it is the reverse.

8.3 Formation temperature and pressure in Well ThG-09

The assessment of formation temperature and initial pressure for Well ThG-09 was based on pressure and temperature logs measured during the warm-up period, shown in Figure 21. The warm-up profiles show the location of several feed points. All temperature profiles in the upper part of the well up to 350 m drilled depth (vertical depth) follow the boiling curve. The most recent profile follows the boiling point curve (Figure 21).

As the well warms up, the pressure gradient increases. Pressure profiles revolve around a pivot point which can indicate the location of either a single feed point or the main feed point of a well. For Well ThG-09, the pivot point is located around 1148 m (92 bar) drilled depth. The initial pressure is almost the same as the boiling pressure throughout the well.

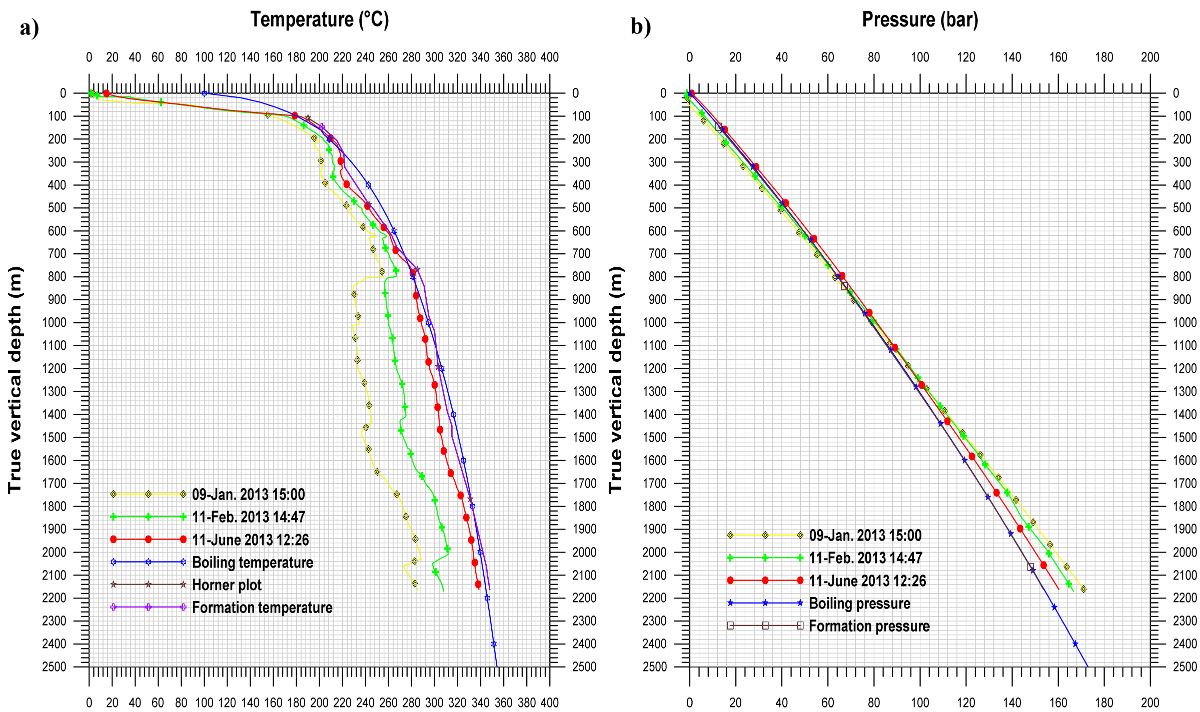


FIGURE 21: Well ThG-09: a) Formation temperature graph; b) Formation pressure graph

9. CONCLUSIONS AND RECOMMENDATIONS

The main goal of this project was to analyse the temperature and pressure characteristics of four wells in Hellisheidi, Reykjanes and Theistareykir geothermal fields. Analysis of temperature and pressure profiles as well as injection and production well tests were the main methodologies applied in characterising the various aspects of the geothermal systems. The following conclusions can be made from the combined observations of the aforementioned analysis.

During temperature and pressure log analysis for Well HE-04, two main feed zones were recognized at depths of 765 and 1400 m; smaller feed zones were identified as well. The highest rock temperature of 262°C was obtained at a depth of 1080 m. The formation temperature is far from the boiling curve which indicates that the reservoir is liquid dominated. The pivot point of this well was 45.7 bar at 765 m.

For borehole Well ThG-09, the analysis led to the conclusion that the number of feedzones was greater than in Well HE-04. These were at a depth of 797-845, 1408-1478 and 2005-2064 m, with additional smaller feedzones. The highest temperature of Well ThG-09 was recorded at a depth of 2064 m with a value of 345°C. The formation temperature follows the boiling curve. The pivot point is located at 1148 m (91.9 bar).

Injection well test conclusions for Wells HE-04, HE-09 and ThG-09, respectively, are:

1. The transmissivity calculated values are 7.8×10^{-8}, 2.8×10^{-8} and 1.0×10^{-8} $m^3/(Pa\cdot s)$, respectively. According to this the ability of a reservoir to transmit fluid for Well HE-04 was greater than for Wells HE-09 and ThG-09.
2. The storativity values can be compared as 1.6×10^{-8}, 0.1×10^{-8} and 6.3×10^{-8} $m^3/(Pa\cdot m^2)$, respectively, highest in Well ThG-09.
3. The connectivity of the well with the surroundings or the injectivity index (II) was great for Well HE-04 at 13.2 (l/s)/bar; second was Well HE-09 at 4.6 (l/s)/bar. Well ThG-09 was third with a value of 1.2 (l/s)/bar.
4. The permeability thickness of the above three wells is 10.7, 1.4 and 0.43 Dm, respectively.

Well RN-28's production well test gave a range of values for the electrical production capacity of the well, from the steps examined. This well could produce up to 19 MWe for 19 bar separator pressure.

ACKNOWLEDGEMENTS

I would like to express my sincere gratitude to my supervisors Dr. Svanbjörg H. Haraldsdóttir and Ms. Saeunn Halldórsdóttir for introducing me to injection and production well tests; for teaching me software like Well Tester, ICEBOX (PREDYP, Boiling Curve, BERGHITI, LIP); for teaching me in detail about geothermal reservoir engineering; for their patient supervision and valuable discussions during my work to complete my report successfully.

Special thanks to Orkuveita Reykjavíkur, Landsvirkjun, HS Orka and ÍSOR companies for the data from Wells HE-04, He-09, RN-28 and ThG-09, the basement and backbone of my project.

My sincere and profound thanks go to all the administrative staff members who created a comfortable and adequate work environment during my six months stay in Iceland and to all lecturers involved in transferring their precious knowledge. Finally, I would like to express my appreciation to all my UNU-GTP 2013 colleagues for our wonderful friendship.

REFERENCES

Afeworki O.M., 2010: Analysis of temperature and pressure characteristics of the Hverahlíd geothermal field in the Hengill geothermal system, SW-Iceland. Report 6 in: *Geothermal training in Iceland 2010,* UNU-GTP, Iceland, 1-28.

Arason, Th., Björnsson, G., Axelsson, G., Bjarnason, J.Ö., and Helgason, P., 2004: *ICEBOX – geothermal reservoir engineering software for Windows. A user's manual.* ISOR, Reykjavík, report 2004/014, 80 pp.

Ármannsson, H., 2008: The Theistareykir geothermal system, North east Iceland. *Paper presented at „Short Course IV on Exploration for Geothermal Resources", organized by UNU-GTP, KenGen and GDC at Lake Naivasha, Kenya*, 11 pp

Ármannsson, H., Gíslason, G., and Torfason, H., 1986: Surface exploration of the Theistareykir high-temperature geothermal area, with special reference to the application of geochemical methods. *Applied Geochemistry, 1,* 47-64.

Árnadóttir, Th., Geirsson, H., Jiang, W., 2008: Crustal deformation in Iceland: Plate spreading and earthquake deformation. *Jökull, 58*, 59-74.

Björnsson, G., 2004: *Using temperature and pressure logs to determine reservoir condition and well status.* UNU-GTP, Iceland, unpublished lecture notes.

Bödvarsson, G.S., and Witherspoon, P.A., 1989: Geothermal reservoir engineering, part 1. *Geotherm. Scie & Tech, 2-1,* 1-68.

Grant, M.A., and Bixley, P.F., 2011: *Geothermal reservoir engineering, 2nd edition*. Academic Press, New York, 359 pp.

Haraldsdóttir, S.H., and Jónsson, P., 2013: *Production well testing.* UNU-GTP, Iceland, unpublished lecture notes.

Horne, R.N., 1995: *Modern well test analysis, a computer aided approach* (2nd ed.). Petroway Inc., United States, 257 pp.

Jóhannesson H., and Saemundsson, K., 1999: *Geological map 1:1.000.000*. Icelandic Institute of Natural History.

Júlíusson, E., Grétarsson, G., Jónsson, P., 2007: *Well Tester 1.0b, User´s guide*. ÍSOR – Iceland GeoSurvey, report ÍSOR-2008/063, 26 pp.

Muffler, P., and Cataldi, R., 1978: Methods for regional assessment of geothermal resources. *Geothermics, 7*, 53-89.

Saemundsson, K., 1979: Outline of the geology of Iceland. *Jökull 29,* 7-28.

Saemundsson, K., 1995: *Geological map of the Hengill area 1:50,000*. Orkustofnun, Reykjavík.

Vink, G.E., 1984: A hotspot model for Iceland and the Voring Plateau. *J. Geophys. Res., B 89,* 9949.