Proceedings World Geothermal Congress 2015
Melbourne, Australia, 19-25 April 2015

Interpretation of the Injection and Heat Up tests at Sabalan geothermal field, Iran

Soheil Porkhial, Farhad Abdollahzadeh bina, Behnam Radmehr, Parnaz Johari Sefid

SUNA – Renewable Energy Organization of Iran, Poonake Bakhtari Ave., Shahrake Ghods P.O.Box 14155-6398, Tehran IRAN

Abdollahzadeh_bina@yahoo.com

Keywords: well testing, heat up, injection, geothermal, Sabalan, logging

ABSTRACT

The purpose of the well test analysis is to identify the type of reservoir involved and to determine the parameters of the reservoir quantitatively. The assessment of the properties and capacity of geothermal resources involves various kinds of logging tests, data interpretation, monitoring and modeling. This ranges from the analysis of data collected during the heat-up and testing of single wells to the simulation of the response of the geothermal reservoir to utilization over years or even decades. This paper presents a comprehensive review of the theoretical background and methodology used in analyzing injection-falloff test, temperature and pressure logging data from the Sabalan geothermal wells as well as a review of the methods generally used for geothermal reservoir pressure response modeling and analysis.

Data from three Sabalan wells was analyzed using the computer software Well Tester developed by ÍSOR – Iceland GeoSurvey. The results of welltest analysis for well NWS-5 are presented in this paper.

1. INTRODUCTION

North West Sabalan (NWS) geothermal field is located in the Sabalan high mountain and the north-west of Iran in Ardabil Province, its distance from Tehran is 859 km, and the distance to Tabriz (one of the large industry cities) is 160 km. The Renewable Energy Organization of Iran has identified a potentially viable geothermal resource at Mt Sabalan.

2. TEMPERATURE AND PRESSURE CONDITIONS IN SABALAN GEOTHERMAL FIELD

2.1 General information in wells

The drilling and testing program for the exploration phase in Sabalan field was carried out between November 2002 and December 2004. The drilling and testing program for the delineation phase was carried out between May 2008 and December 2012. The location of the faults and drilled wells is given in Figure 1.

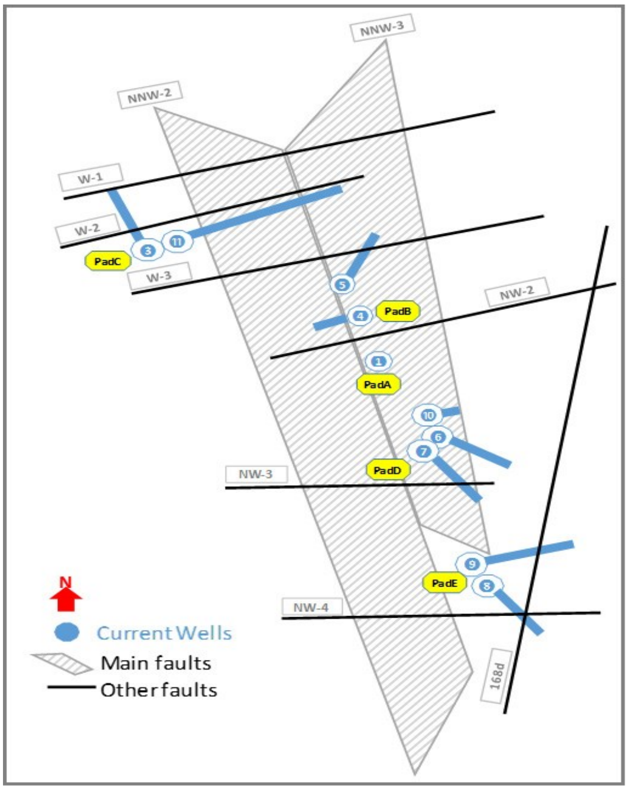

Figure 1: Faults and Wells locations of the NW Sabalan Geothermal Project (Magma and IPE 2014)

The eleven deep exploration and delineation wells that have been drilled are NWS-1 (drilled from pad A), NWS-3, NWS-11RD (drilled from pad C), NWS-4, NWS-5D (drilled from pad B), NWS-6D, NWS-7D and NWS-10D (drilled from pad D) and NWS-8D and NWS-9D (drilled from pad E). The wells vary in depth from 1901 m to 3197 m Measured Depth (MD). Well NWS-1 was drilled vertically while NWS-3, NWS-4, NWS-5D, NWS-6D , NWS-7D, NWS-8D, NWS-9D, NWS-10D and NWS-11RD are deviated wells. Additionally, one shallow injection well, NWS-2, has been drilled to 600m depth, located on pad A alongside well NWS-1. The basic well completion data are summarized in Table 1.

Table 1: Basic completion information for Sabalan wells.

Well	Completion Date	T.D.	Production	Casing	Production	Liner
		mMD	Size (in)	Depth (mMD)	Size (in)	Depth (mMD)
NWS-1	01-Jun-03	3197	9-5/8	1586	7	3197
NWS-2	25-Jun-03	638	13-3/8	360	9-5/8	638
NWS-3	27-Nov-03	3166	13-3/8	1589	9-5/8	3160
NWS-4	27-Mar-04	2265.5	9-5/8”	1166	7	2255
NWS-5D	31-Aug-08	1901	9-5/8”	750	7	1901
NWS-6D	28-Feb-09	2377	9-5/8”	1250	7	2377
NWS-7D	11-Aug-09	2705	9-5/8”	1313	7	2705
NWS-8D	17-Jan-10	2413.5	9-5/8”	1438	7	2413.5
NWS-9D	07- Dec- 10	2703	9-5/8”	1101	7	2700
NWS-10D	08- Sep-10	2300	9-5/8”	977	7	2300
NWS-11RD	22-Apr-2011	2813	9-5/8”	1286	7	2813
The Total Drilled: Km						26.5

2.2. Interpretation of temperature logs

Determining the temperature distribution within a geothermal system is a fundamental requirement of any resource assessment study. The temperature distribution is probably the most useful information that can be obtained as it indicates both the quality of the resource and the fluid flow paths within the reservoir. To determine the sub-surface temperature distribution, it is first necessary to interpret the measured temperature surveys in the wells to establish the ‘stable’ reservoir conditions as a function of depth for each well i.e. finding the rock temperature and the initial pressure in the reservoir. The stable temperature profiles for Sabalan wells have been determined based on the interpretation of the survey data and the resultant profiles are shown in Figure 2. A representative ‘Boiling-Point-for-Depth’ (BPD) curve is also shown, based on a measured water level of 2400 m above sea level (a.s.l) in well NWS-9D. By plotting the well temperature profiles together in Figure 2, it is possible to make a number of observations regarding the nature of the geothermal resource based on changes in temperature with depth:

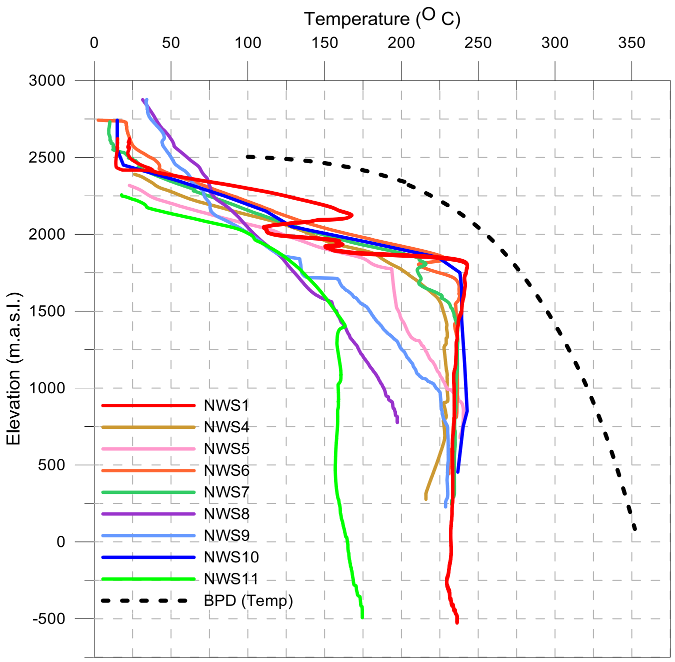

Figure 2: Stable well temperatures for Sabalan wells.

- The temperatures are all below the BPD curve, indicating that the reservoir in this area of the field does not contain a two-phase mixture of steam and water. Temperatures behind the casing of NWS-1 at an elevation of about 1900 m a.s.l are close to BPD conditions, indicating possible proximity to two-phase fluid.
- Temperatures below the elevation of +1500 m a.s.l for NWS-5D, NWS-6D , NWS-7D and NWS-10D is convectional zone.
- From +1500 m a.s.l to between +600 – 200 m a.s.l a slight temperature inversion is evident.
- Below -200 m a.s.l in NWS-1 and +600 m a.s.l in NWS-11 temperatures increase with depth.
- The hottest temperature has been estimated in NWS-1 and NWS-5D, is around 240 - 242 ^{o}C.

2.3. Subsurface Pressure Distribution

Interpretation of sub-surface pressures is generally more difficult than sub-surface temperatures because the pressure profile within the wellbore does not generally reflect the pressure profile with depth in the surrounding formation. The wellbore pressure is often in equilibrium with the formation pressure only at the major permeable feed. If there are two or more significant permeable zones then the depth of the equilibrium will lie between these zones. As the wellbore fluid heats up after drilling, the hydrostatic gradient in the wellbore will change and the pressure profile measured in the well will pivot about the 'pressure control point' (PCP). The estimated pressure data have been used to construct pressure cross-section map where data was available from the six deep wells. A cross-section (Figure 3) generated by Surfer software is shown for comparison. Blue arrows shows fluid motion based on the pressure difference

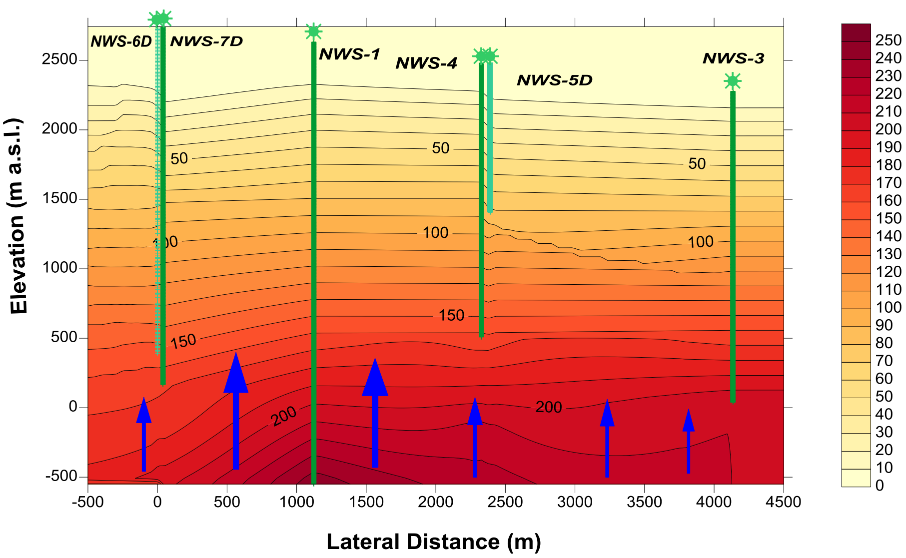

Figure 3: Sabalan geothermal field pressure cross section

3. THEORETICAL BACKGROUND ON WELL TESTING

3.1. Well and reservoir assessment procedures

In a hydrological well test, such as for a geothermal well, the pressure response of a given well and reservoir, due to production or injection, is monitored. Well testing is conducted in order to evaluate the conditions of a well, its flow capacity and the reservoir properties. The most important properties are the transmissivity or the permeability-thickness and formation storage coefficient of the reservoir. These are not evaluated directly from the data. The data has to be interpreted on the basis of the most appropriate model, resulting in average values. In addition the properties are model dependent. After a successful drilling programme, typical high-enthalpy well assessment in Iran is undertaken through multi-step injection-falloff tests, in order to estimate the main physical properties of the reservoir around the well like the transmissivity and storativity. This is done by assuming some values for the porosity and compressibility of the basalt rock and fluid. Also well parameters such as injectivity index, wellbore storage factor and skin factor are determined in the step injection test. In this study a well test simulator program Well Tester was used to simulate data from such tests and compare with the results from 'traditional methods' like semi log, log-log and type curve methods. After this, the well is closed in order to allow it to warm-up and reach the steady state formation temperature (often 3-4 months). During and after the well testing, the temperature and pressure profiles of the well are logged and from that information the phase conditions of the fluid, the real formation temperature, the flow paths and the main feed zones can be obtained. However, caution must be taken when interpreting logs as measurements are not made directly in the reservoir but in the well where internal flows and boiling can cause disturbances and give misleading results, even though the well is shut-in. When a well is not flowing, the aquifers (feed zones) usually warm up more slowly after drilling, than impermeable rock, making it easier to determine the feed zones. (Stefansson and Steingrimsson, 1990).

3.1.1. The pressure diffusion equation

The basic equation of well testing theory is the pressure diffusion equation. It is used to calculate the pressure (*P*) in the reservoir at a certain distance (*r*) from a production well producing at a given rate (*q*) as a function of time (*t*). The most commonly used solution of the pressure diffusion equation is the so-called Theis solution or the line source solution (Earlougher, 1977; Horne, 2006). The three governing laws that are used in deriving the pressure diffusion equation are the following (Earlougher, 1977; Horne, 2006):

Conservation of mass inside a given control volume:

Mass flow in - Mass flow out = Rate of change of mass within the control volume

Conservation of momentum, expressed by Darcy's law:

$$q = 2\pi rh \frac{k}{\mu}\frac{\partial P}{\partial r} \tag{1}$$

where q = volumetric flow rate (m^3/s), h = reservoir thickness (m), k = formation permeability (m^2), P = reservoir pressure (Pa), r = radial distance (m), μ = dynamic viscosity of the fluid (Pa.s)

Equation of state of the fluid:

$$\rho = \rho(P,T) \tag{2}$$

Compressibility of the fluid:

$$c_f = \frac{1}{\rho}\left(\frac{\partial \rho}{\partial P}\right)_T \tag{3}$$

where c_f = compressibility of the fluid (Pa-1), ρ = density of the fluid (kg/m3), T = temperature (°C), P = pressure (Pa)

By combining the three equations above and using the above assumptions, the pressure diffusion equation is given by:

$$\frac{1}{r}\frac{\partial}{\partial r}\left(\frac{r\partial P(r,t)}{\partial r}\right) = \frac{\mu c_t}{k}\frac{\partial P(r,t)}{\partial t} = \frac{S}{T}\frac{\partial P(r,t)}{\partial t} \tag{4}$$

where $c_t = \varphi c_f + (1-\varphi)\, c_r$ = total compressibility of rock and water (Pa^{-1}), φ = porosity, $c_r = \frac{1}{1-\varphi}\frac{\partial \varphi}{\partial P}$, is the compressibility of the porous rock., $S = c_t h$, is the storability, $T = \frac{kh}{\mu}$, is the transmisivity.

The solution to the radial diffusion equation with these boundary and initial conditions is given by:

$$P(r,t) = P_i + \frac{q\mu}{4\pi kh} Ei\left(\frac{-\mu c_t r^2}{4kt}\right) \tag{5}$$

where $Ei(-x) = -\int_x^\infty \frac{e^{-u}}{u} du$ is the exponential integral function. If $t > 100\frac{\mu c_t r^2}{4k}$ the exponential integral function can be expanded by a convergent series and thus, the Theis solution, for a pumping well with skin gives the total pressure change as:

$$\Delta P_t = P_i - P(r,t) = -\frac{2.303q\mu}{4\pi hk}\left[log\left(\frac{\mu c_t r^2}{4kt}\right) + \frac{0.5772 - 2s}{2.303}\right] \quad (6)$$

where s = skin factor. Skin is an additional pressure change to the normal pressure change in the near vicinity of the well due to the drilling of the well. A negative skin factor indicates that the well is in good communication with the reservoir.

3.1.2. Injection tests

Injection testing is in principle a simple variant of discharge flow testing, with the flow reversed. Water is injected into a well and the flow rate recorded along with the changes in the down-hole pressure or the depth to the water level. A quasi-stable flow versus pressure curve can be obtained, and transient behavior measured at changes in flow rate. Injection is a simple inverse of production if the fluid injected is of the same enthalpy (quality or temperature) as that produced. Generally, the fluid injected is water that is cooler than the reservoir temperature and thus has different viscosity and compressibility than the reservoir fluid (Grant et al., 1982). The non-isothermal injectivity index obtained from these tests depends on the mobility ratio of the cold region to the hot reservoir and the extent of the cold spot. (Sigurdsson et al., 1983) propose a method for estimating the apparent viscosity, which accounts for these effects and relates the non-isothermal injectivity index to the isothermal injectivity index. The injectivity index (*II*) obtained from injection tests, is often used as a rough estimate of the connectivity of the well to the surrounding reservoir. Here it is given in the units [(L/s)/bar] and it is defined as the change in the injection flow rate divided by the change in the stabilized reservoir pressure.

$$II = \left|\frac{\Delta Q}{\Delta P}\right| \quad (7)$$

Where $\Delta Q = Q_{end\ of\ step} - Q_{beginning\ of\ step}$ and $\Delta P = P_{end\ of\ step} - P_{beginning\ of\ step}$.

In Well Tester, the pressure values used to calculate II are taken from the modeled response (not the actual data collected).

4. INJECTION TEST DATA AND INTERPRETATION

Most of the text in this section is generated from the Well Tester report generator (Júlíusson et al., 2007).

A four-rate step injection test was conducted on 20 September 2010 lasting about 12 hours on production well NWS-5D. The pressure gauge used to monitor the pressure changes in the well was installed at around 1350 m depth. The four step injection rates were 8, 16, 26 and 4 L/s, respectively.

4.1. Initial Parameters

The estimated reservoir pressure (P_{est}) and estimated reservoir temperature (T_{est}) are average estimates for the part of the reservoir that is being investigated in the well test. These values are used to calculate approximate values of the dynamic viscosity of reservoir fluid and total compressibility. Wellbore radius (r_w) is the average radius of the well at the reservoir depth, given in meters. Dynamic viscosity of reservoir fluid (μ) is the estimated average viscosity of the fluid at reservoir conditions. In cases where the fluid is in two phases, the average viscosity can be taken as the weighted harmonic average of the two phases. If x-curve relative permeability is assumed, the weighting can depend on the mass fraction of each phase (Horne, 2006). Total compressibility (c_t) describes the ability of the fluid and reservoir rock to compress or expand as a function of pressure. Formulations for computing compressibility will be slightly different, depending on the physics of fluid and the reservoir, but a further discussion on that can be found in Grant et.al. (1982). Porosity (φ) is the volume fraction of the rock which is porous.

Table 2: Summary of initial parameters

Parameter Name	Parameter Value	Parameter Unit
Estimated reservoir temperature (T_{est})	240.00	[°C]
Estimated reservoir pressure (P_{est})	120.48	[bar]
Wellbore radius (r_w)	0.16	[m]
Dynamic viscosity of reservoir fluid (μ)	1.13×10^{-4}	[Pa·s]
Total compressibility (c_t)	5.68×10^{-10}	[1/Pa]
Porosity (φ)	0.10	[-]

4.2. Selected models for simulator

Table 3: Summary of model selected

Well Testing Model	
Reservoir	Dual Porosity
Boundary	Constant Pressure
Well	Constant Skin
Wellbore	Wellbore Storage

Figures 4, 5, 6 and 7 show the plots of the data on a log-log scale. The plots show the derivative of the pressure response, multiplied with the time passed since the beginning of the step. This trend is commonly used to determine which type of model is most appropriate for the observed data. Using this model, nonlinear regression analysis was used to find the parameters that best fit the observed data. The resulting fit is shown graphically in Figure 8. Moreover, the regression analysis gives information on the quality of the parameter estimate, represented here by the upper and lower limits of a 95% confidence interval and by the coefficient of variation C_v, given as a percentage in Table 4.

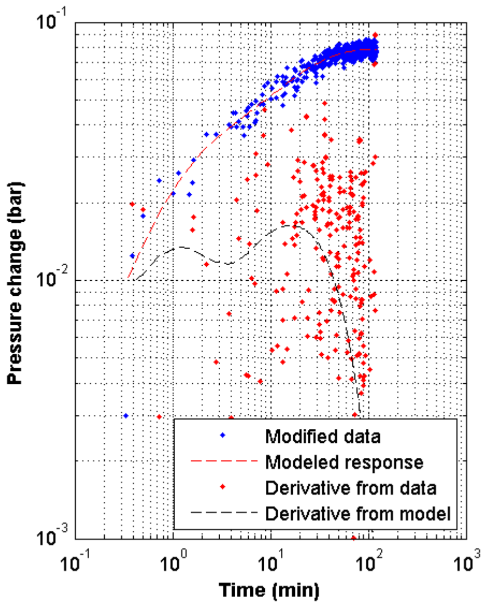

Figure 4: Log-log scale for step 1

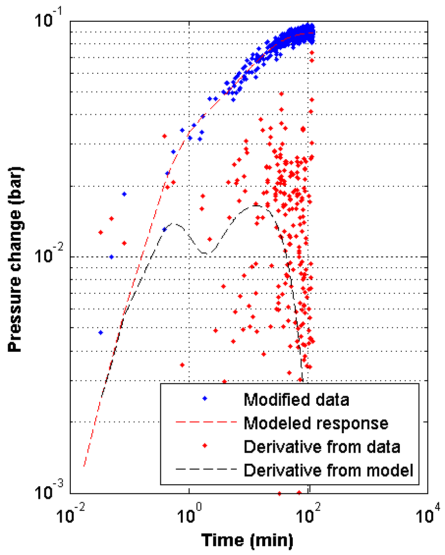

Figure 5: Log-log scale for step 2

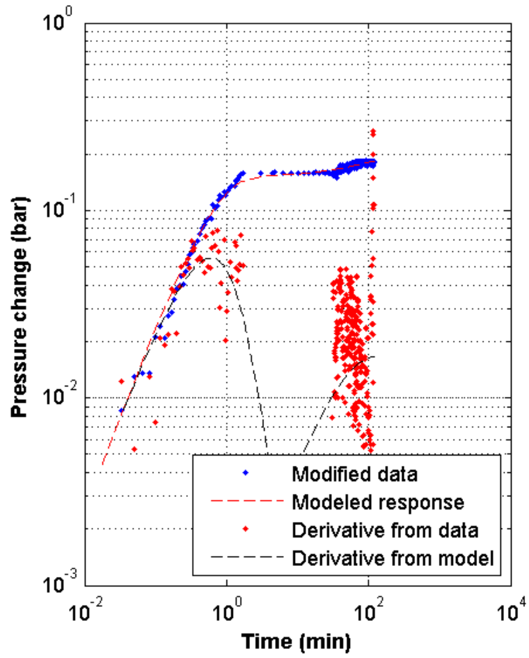

Figure 6: Log-log scale for step 3

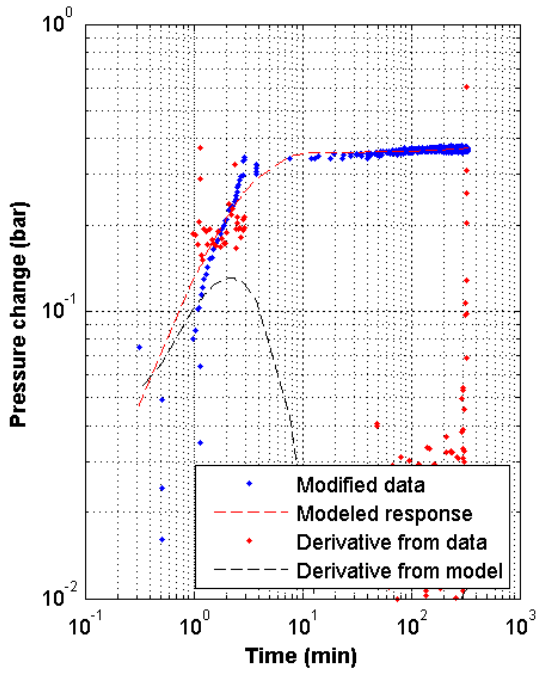

Figure 7: Log-log scale for step 4

The values obtained for transmissivity and storativity can be used in conjunction with the given initial parameters to deduce an estimate on the reservoir thickness and effective permeability. The estimated reservoir thickness is 2.04 km and the effective permeability is ≈ 52.37 mD. Note that these estimates rely on parameters that are generally quite poorly known and should therefore be viewed more as a qualitative order-of-magnitude check on the results of the well test.

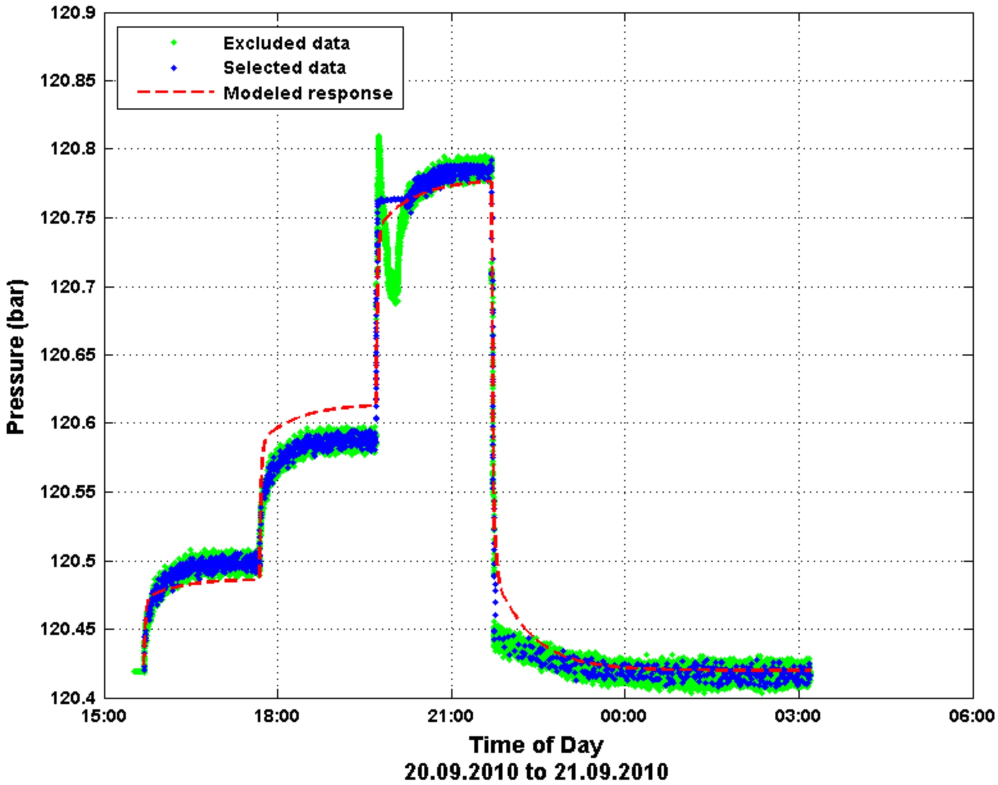

Figure 8: Fit between model and collected data.

Table 4: Summary of results from nonlinear regression parameter

Parameter Name	Parameter Value	Lower bound 95 % C.I.	Upper bound 95 % C.I.	CV [%]	Parameter Unit
Transmissivity (T)	$4.83 \cdot 10^{-7}$	$4.14 \cdot 10^{-7}$	$5.52 \cdot 10^{-7}$	7.1	$m^3/(Pa \cdot s)$
Storativity (S)	$5.92 \cdot 10^{-8}$	$4.96 \cdot 10^{-8}$	$6.88 \cdot 10^{-8}$	8.1	$m^3/(Pa \cdot m^2)$
Transmissivity Ratio (λ)	$2.02 \cdot 10^{-6}$	$1.39 \cdot 10^{-6}$	$2.65 \cdot 10^{-6}$	15.6	-
Storativity Ratio (ω)	$1.85 \cdot 10^{-3}$	$1.54 \cdot 10^{-3}$	$2.17 \cdot 10^{-3}$	8.5	-
Radius of Investigation (r_e)	195.98	169.73	222.23	6.7	m
Skin Factor Step # 1	-5.48	-5.79	-5.17		
Skin Factor Step # 2	-5.66	-5.95	-5.38		
Skin Factor Step # 3	-2.42	-2.67	-2.17		
Skin Factor Step # 4	-6.09	-6.37	-5.81		
Skin Factor for model (s)	-5.27	-5.47	-5.07		-
Wellbore Storage (C)	$1.85 \cdot 10^{-4}$	$1.72 \cdot 10^{-4}$	$1.97 \cdot 10^{-4}$	3.3	m^3/Pa
Injectivity Index (II)	32.4				(L/s)/bar

CONCLUSION

The Sabalan reservoir is a found to be a high-temperature and low pressure system. The temperature of Sabalan reservoir is below boiling point that suggests Sabalan is a liquid-dominated reservoir. The main flow to the system is coming from the south and beneath the drilled area to the system.

Northwest Sabalan geothermal system has at least around 2 km thick convective zone below approximately 1500 m a.s.l and around 700 m thick cap rock with conductive heat flow.

The estimated permeability for well NWS-5D from well test analysis is about 52 mD with a skin factor of s=-5 and an injectivity index II of about 32 (l/s)/bar. The main feed zone of well NWS-5D is at around 1100-1400 meters depth.

REFERENCES

Earlougher, R.C., Jr. 1977: *Advances in well test analysis*. SPE, New York, Dallas.

Grant, M.A., Donaldson, I.G., and Bixley, P.F., 1982: *Geothermal reservoir engineering*. Academic Press Ltd., New York, 369 pp.

Horne, Roland N. 2006 PE-269 Geothermal Reservoir Engineering. Lecture Notes Department of Petroleum Engineering, Stanford CA.

Júlíusson,E., Grétarsson, G., Jónsson, P., (2007): Well Tester 1.0 b. User guide. Íslenskar orkurannsóknir, ÍSOR-2008/063, 26 pp

Sigurdsson, O., Bodvarsson, G.S., and Stefansson, V., 1983: Nonisothermal injectivity index can infer well productivity and reservoir transmissivity. *Proceedings 9th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford,* SGP-TR-74.

Stefansson, V., and Steingrimsson, B.S., 1990: Geothermal logging I, an introduction to techniques and interpretation (3rd edition). Orkustofnun, Reykjavík, report OS-80017/JHD-09, 117 pp.